

**CARBONSAFE ROCKY MOUNTAIN PHASE I: ENSURING SAFE SUBSURFACE
STORAGE OF CARBON DIOXIDE IN THE INTERMOUNTAIN WEST**

Final Report

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EXECUTIVE SUMMARY

An integrated CCS pre-feasibility study, CarbonSAFE Rocky Mountain Phase I, was conducted by the University of Utah and its partners as part of the US Department of Energy's Carbon Storage Assurance and Facility Enterprise (CarbonSAFE) program. The assembled project team consisted of academic, industry and governmental agencies covering the technical and non-technical challenges of a commercial-scale CO₂ storage facility capable of storing 50 million tonnes of anthropogenically-sourced CO₂.

The Rocky Mountain CarbonSAFE team identified the Hunter Power Plant in central Utah as the primary source of CO₂ on which this study would be focused. The nearby Huntington power plant, also operated by Rocky Mountain Power, was evaluated as a secondary source of CO₂. The Hunter plant was chosen because of an interest in CO₂ capture technology by the plant operator, Rocky Mountain Power, and also because it is a representative example of a typical coal-fired generating station in the Rocky Mountain west. Amine-based and cryogenic-based capture assessments were performed for approximately 2.75 million tonnes per year for one of the boiler units at the Hunter plant, yielding cost of capture estimates of \$45.50/tonne and \$37.75/tonne. Transportation and intermediate compression would increase the per tonne costs, but will be highly dependent on specific injection locations and available rights-of-way.

A high-level technical sub-basinal evaluation was performed on the area surrounding the Hunter and Huntington power plants to verify CO₂ storage capacity and integrity. Initial geologic characterization efforts focused on sites immediately adjacent to the Hunter plant, including the deep eolian Permian White Rim Sandstone, which in outcrop and core from other locations indicates high permeability and high porosity. However, petrophysical logs from wells near Hunter indicate porosity of only 2-4%. As a result, potential injection sites were moved structurally down-dip (to the west), into the high permeability (~200 mD) and high porosity (20%) Navajo sandstone. A comprehensive analysis of the reservoir and seals was conducted, providing data to the model, simulation and risk assessment groups on the project. CO₂ capacity estimates for the Navajo Sandstone approximately 18 kilometers from the Hunter plant are well in excess of the 50 million tonnes goal of the project. Area of Review Delineation and Risk Assessment on the Navajo, associated seals and shallow groundwater aquifers identified the most significant risks and mitigation options.

A non-technical assessment to a commercial-scale CO₂ storage facility in central Utah was conducted. EPA Underground Injection Control Class VI and National Environmental Policy Act permitting present particularly challenging issues related to the development of any saline aquifer for CO₂ storage, including the area around the Hunter plant. While surface and subsurface ownership and rights are not straightforward, especially on any private land, many of the stakeholders in central Utah are accustomed and open to oil/gas/mineral-related activities similar to what would be required for CO₂ storage sites.

Acronyms

ADM	Archer Daniels Midland
AoR	Area of Review
AQCS	Air Quality Control Systems
BLM	Bureau of Land Management
CCS	Carbon Capture and Sequestration
CE	Categorical Exclusion
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
CFR.	Code of Federal Regulations
CO2	Carbon Dioxide
DEIS	Draft Environmental Impact Statement
DOE	United States Department of Energy
EA	Environmental Assessment
EIS	Environmental Impact Statement
EOR	Enhanced Oil Recovery
EPA	United States Environmental Protection Agency
ESA	Endangered Species Act
FEIS	Final Environmental Impact Statement
FLPMA	Federal Land Policy and Management Act
FWS	United States Fish and Wildlife Service
GCS	Geologic Carbon Sequestration
GS	Geologic Sequestration
IP/LP	Intermediate Pressure/Low Pressure
MEA	Monoethanolamine
NEPA	National Environmental Policy Act
NCA	National Conservation Area
NHPA	National Historic Preservation Act
NOI	Notice of Intent to Prepare an Environmental Impact Statement
PHMSA	Pipeline and Hazardous Materials Safety Administration
PSD	Prevention of Significant Deterioration
RCRA	Resource Conservation and Recovery Act
RMP	Resource Management Plan
ROD	Record of Decision
ROW	Right of Way
SDWA	Safe Drinking Water Act
SITLA	[Utah] School and Institutional Trust Lands Administration
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water
USFS	United States Forest Service
VOC	Volatile Organic Compound
WFGD	Wet Flue Gas Desulphurization

1.0 INTRODUCTION

The Rocky Mountains of the western United States contain and produce over 50% of the coal in the country (U.S. Energy Information Administration, 2017). Because of this ready availability of coal in the region, coal-fired power plants continue to dominate electricity production. Despite recent uncertainty in federal regulations advocating “clean coal” and a boom in natural gas production, coal will likely continue to be the least expensive option for the near future due to existing plants and coal transport systems.

In order to address the CO₂ emissions from legacy coal-fired power plants, the U.S. Department of Energy solicited investigations of the long-term feasibility of an integrated CCS storage complex, with considerations toward commercial-scale CO₂ storage and/or utilization. The Rocky Mountain CarbonSAFE Phase I project was formed to address the conditions and attributes that would facilitate feasible and practical commercial-scale CCS. A site was chosen in central Utah that represents a typical scenario for the Rocky Mountain States, including a commercial CO₂ source in the form of a coal-fired power plant emitting approximately 9 MMT of CO₂ per year, and a commercial-scale CO₂ storage sink in the form of a 7,000 ft deep brine-bearing sedimentary rock formation that can accommodate over 50 MMT. The analyses contained within this document not only provides an evaluation of the feasibility of a CCS complex for Utah, but it also serves as the blueprint for additional CCS complexes elsewhere in the region, where coal power generating facilities and geology are similar.

1.1 OUTCOMES AND OBJECTIVES

The primary outcome of the Rocky Mountain CarbonSAFE Phase I project is a template protocol for existing and future coal-fired as well as natural-gas-fired plants in the Rocky Mountain states, with PacifiCorp’s Hunter Plant in central Utah as the representative example of a typical generating station in the Rocky Mountain west. The template will benefit future CCS projects that utilize the vast, stacked deep-saline aquifers systems within the Rocky Mountain west that are capable of storing *billions* of metric tons of CO₂. The protocols developed by this project have addressed the technical and non-technical challenges specific to the Hunter power plant and the Buzzard Bench CO₂ storage complex near Castle Dale, Utah (Figure 1).

1.2 ROCKY MOUNTAIN CARBONSAFE TEAM

The Rocky Mountain CarbonSAFE Phase I formed a coordination team with extensive experience in the regulatory, legislative, geotechnical, stakeholder, commercial and financial challenges specific to CCS deployment. The team consisted of the geologists, geophysicists, engineers and law experts from the University of Utah, Utah Geological Survey, New Mexico Tech, Los Alamos National Laboratory and Sandia National Laboratory. The State of Utah Department of Environmental Quality took a lead role in interfacing with the U.S. EPA on their Class VI rules, as well as evaluating those rules as they apply to the project site. Schlumberger provided model development expertise. The Rocky Mountain CarbonSAFE Phase I industry partner was Rocky Mountain Power (an operational division of PacifiCorp, a Berkshire Hathaway Energy company), which operates several power plants in the region. The Hunter

power plant, in central Utah, was proposed by Rocky Mountain Power as a test facility for CO₂ capture (part of a different U.S. Dept of Energy project) and the Primary Site option for this

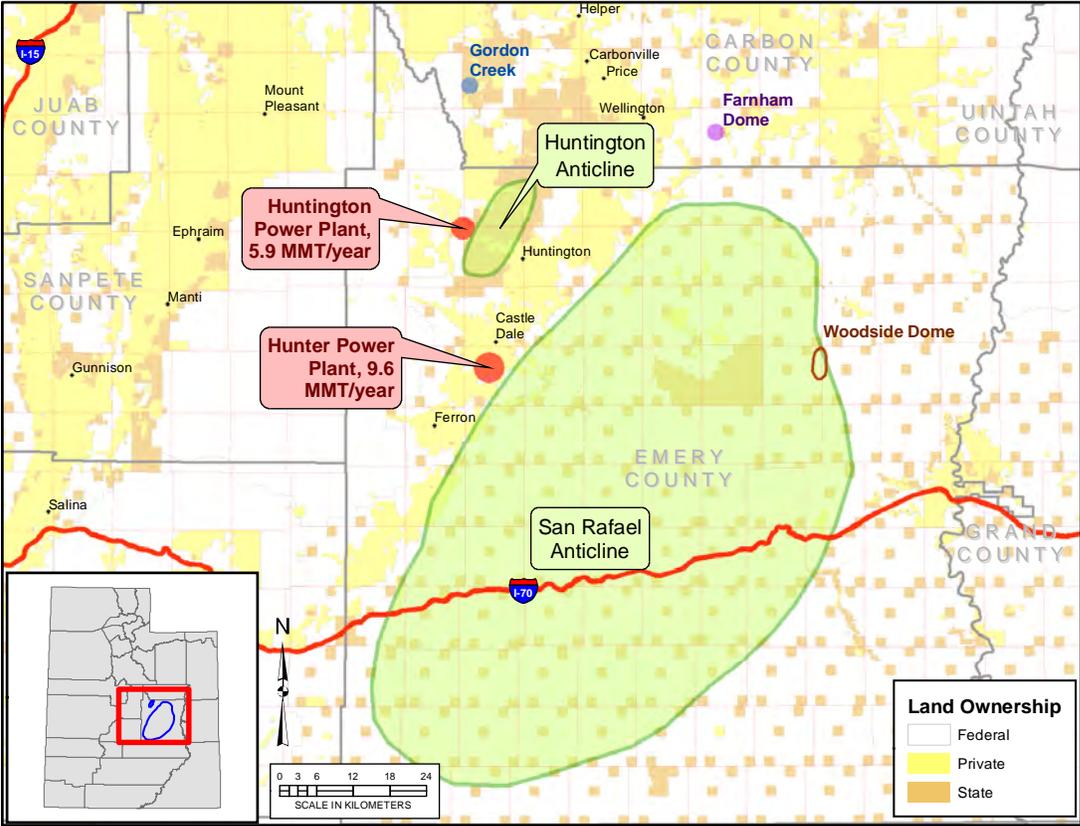


Figure 1. Map detailing locations of the primary and secondary CO₂ sources and the assessed CO₂ storage complex comprised of the San Rafael Anticline and the adjacent Huntington Anticline.

proposal.

2.0 CO₂ Management

2.1 CO₂ SOURCE ASSESSMENT

2.1.1 Post Combustion CO₂

CO₂ in flue gas from a coal-fired power plant is targeted for capture in this study. The data from the Hunter power plant operated by Rocky Mountain Power is presented. Hourly flue gas rate, the compositions and net power generation are obtained from the data.

CO₂ in flue gas

The flue gas rate and compositions are varied hourly depending on the power requirement from the power plant. The mean CO₂ concentration (volume fraction) and mean flue gas rate are around 10.5% and 60 mmscf/hr respectively as shown in Figure 2 (a) and (b).

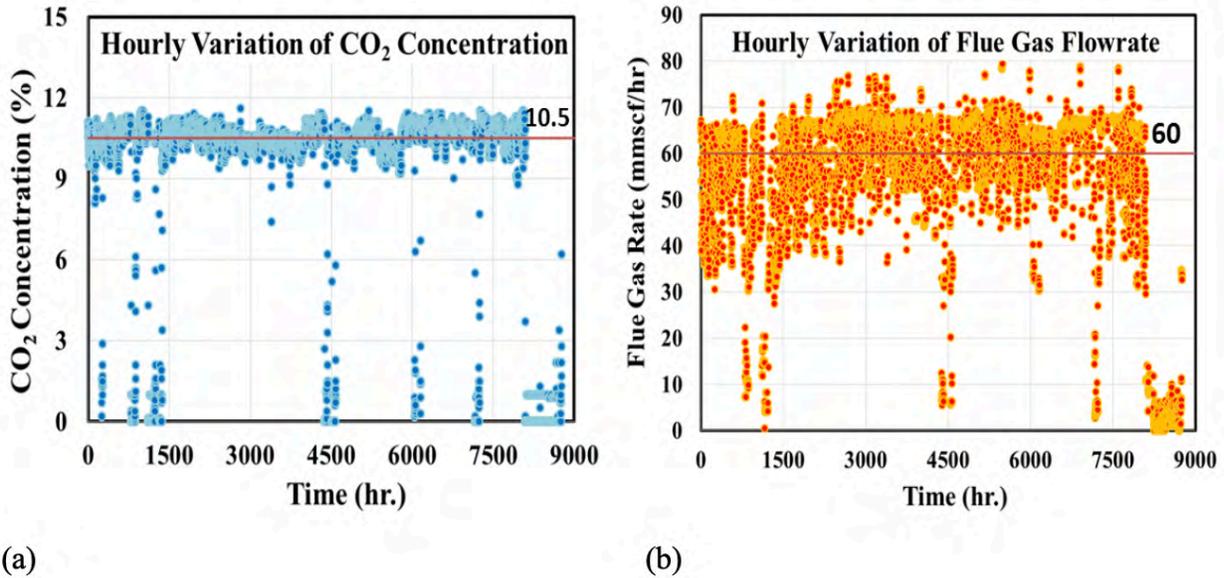


Figure 2. (a) Variation of CO₂ concentration in flue gas (b) Variation of flue gas rate.

Emission Factor

The way to measure the environmental impact of power plant due to the emission of CO₂ with the flue gas is the determination of emission factor. This factor is defined as the amount of CO₂ (short ton) emitted to generate 1 MWhr of net power, as shown in Equation 1.

Equation 1.

$$\text{Emission factor} = \frac{\text{CO}_2 \text{ emission (short ton)}}{\text{Net Power Generated (MWhr)}}$$

The emission factors calculated from the available data are plotted in Figure 3.

An approximate average 1.1 short ton of CO₂ is produced to generate 1 MW-hr power in coal fired power plant. Hunter power plant has a capacity of 1320 MW, thus providing a possible source of over 34,000 tons of CO₂ per day, and over 12 million tons per year. It is shown later that Hunter Unit 3 at various levels of capture is capable of providing 50 million tons of CO₂ over 30 years of operation.

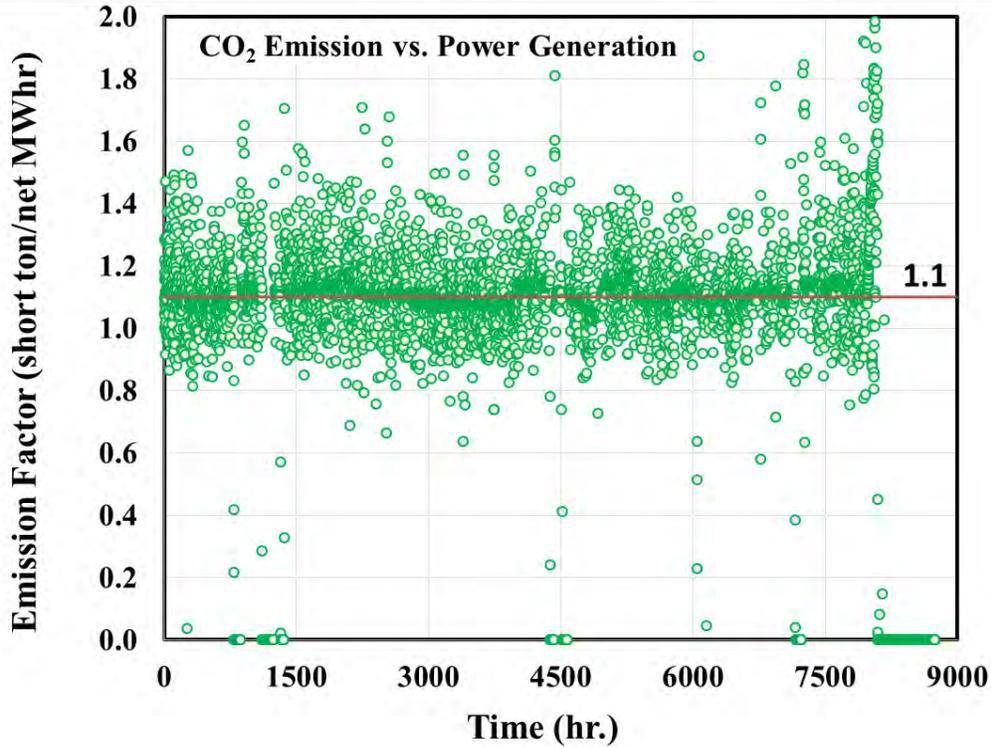


Figure 3. Emission factor for a unit of Pacific Corporation.

The Huntington power plant, as a secondary source has very similar emission characteristics, and with 895 MW capacity, provides well over 8 million tons of CO₂ per year as a source.

Monoethanolamine (MEA), a primary amine, is widely used as solvent for absorbing CO₂ in the method. Two main processing units namely absorber and regenerator are associated in the method. A typical process diagram for CO₂ capture and amine regeneration is shown in Figure 4.

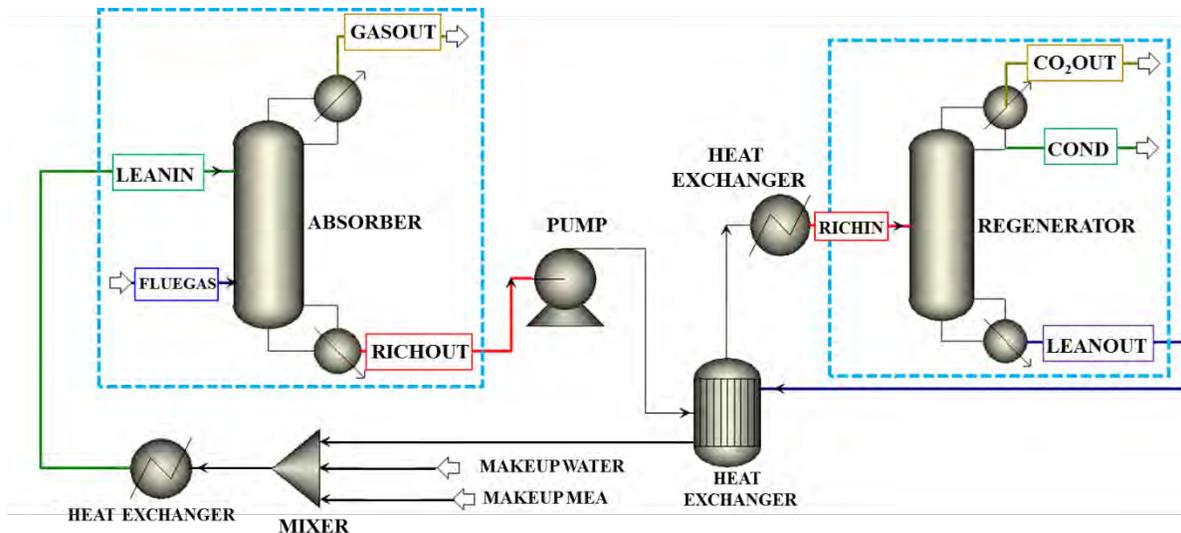


Figure 4. Integrated flow sheet of entire MEA process in ASPEN plus.

Absorber is used to capture CO₂ from flue gas and regenerator is used to separate the absorbed CO₂ from solvent i.e., to regenerate the MEA solvent. Lean aqueous MEA stream is recycled to absorber with fresh makeup MEA. As the part of the process plant, pumps, compressors, mixer, heat exchanger etc. are also connected. Simulations are run to evaluate the performance of the plant in removing CO₂ in flue gas from power plant.

CO₂ loading in lean MEA stream (α_L) is defined as shown in Equation 2.

Equation 2.

$$\text{CO}_2 \text{ loading in lean MEA stream, } \alpha_L = \frac{\text{mole of CO}_2 \text{ in Lean MEA}}{\text{mole of MEA in lean MEA}} = \frac{L x_{CO_2}^L}{L x_{MEA}^L} = \frac{x_{CO_2}^L}{x_{MEA}^L}$$

Where, L is the molar flowrate of lean MEA stream.

The cost of solvent for continuous makeup in the absorber is one of the major operating costs. Use of minimum flowrate of lean MEA stream to capture specified amount of CO₂ can reduce the operating cost. Using minimum lean MEA flow rate, more than 80% CO₂ is captured using absorber heights of 25 to 40 meters and CO₂ loading in lean MEA of 0.2 and less. Insignificant amounts of MEA (less than 0.2%) are lost for the entire range of absorber height (7m to 40 m) and CO₂ loading in lean MEA stream (0.1 to 0.35) according to results from this study. Operating cost due to handling MEA stream (pumping, cooling etc.) and make up MEA and water can be significantly reduced using minimum lean MEA flowrate with an optimized absorber height.

2.2 CO₂ CAPTURE ASSESSMENT FOR A COMMERCIAL CAPTURE PLANT

2.2.1 CO₂ Capture Assessment Using Established Technology

The University of Utah engaged Sargent & Lundy LLC (S&L) to evaluate the feasibility and overall cost of retrofitting Hunter Unit 3 with a state-of-the-art carbon capture system (see Appendix A for the full S&L report). Unit 3 was selected based on the amount of CO₂ in the flue gas, which was most practical for the goals of this project. This study effort included evaluation of multiple capture levels using a commercially available amine-based system as the basis for the capture technology. Three different levels of CO₂ capture possibilities on Hunter 3 were evaluated. The design basis was at least 50 million tons of CO₂ available over 30 years of project life for sequestration.

1. 65% capture, targeting no less than 1.84 million tons per year;
2. 90% capture, treating 100% of flue gas; and
3. Equivalent capture required (~48%) to achieve CO₂ emissions rate consistent with New Source Performance Standards (NSPS) for greenhouse gases for a natural gas-fired combined cycle plant (i.e. 1,000 lbs/MWh, gross)

This study effort includes evaluation of a commercially available amine-based system as the basis for the capture technology. S&L considered commercially available processes to be those that have

been demonstrated during slipstream tests or have been implemented on permanent installations treating a quantity of flue gas that is at least equivalent to 5 MWe. Amine solvent-based technology has recently established itself as a viable technology for CO₂ capture. The commercial technology that was evaluated was Mitsubishi Heavy Industries (MHI) KM-CR Process® with KS-1™ solvent. As part of the techno-economic evaluation, the major balance of plant (BOP) impacts were identified and quantified, including loss of power generation due to both the auxiliary power load and the required process steam to be supplied from the base unit. Other BOP impacts are identified, including cooling and process water consumption, waste water generation rates, and solid waste generation rates. S&L also developed material balances and general arrangement drawings that reflect the integration of the CO₂ capture system with the base facility.

A full-scale capture system (Case 2: 90% capture) served as the basis for development of heat balances, mass balances, process flow diagrams, general arrangements, equipment sizing, and capital costs. The full-scale system inputs were adjusted for the two other capture facility design sizes: Case 1: 65% and Case 3: 1,000 lb CO₂/MWhg.

Overall, the project is technically feasible for the PacifiCorp’s Hunter Unit 3. Process steam will be provided by the base unit and extracted at the Intermediate Pressure (IP)/ Low Pressure (LP) crossover without disrupting the performance of the LP turbine; however, this will cause a unit derate by limiting the total amount of megawatts the turbines can produce. Other utilities provided by the base plant include process water makeup from the existing demineralized water system, cooling tower makeup water from the on-site storage basin and auxiliary power from the on-site storage basin, and auxiliary power from the existing auxiliary power transformer. Flue gas will be routed to the CO₂ capture island downstream of the Wet Flue Gas Desulfurization (WFGD) system, which reduces the amount of acid gas polishing that is required in the pre-scrubber. The CO₂ process is expected to generate pipeline quality liquid CO₂ for transportation to a storage field.

The costs of the projects for the three cases identified are summarized in Table 1.

Table 1. Cost of CO₂ Capture for the Hunter Power Plant Unit 3, using a commercially-available amine-based process.

Cost	Case 1 (65% Capture)	Case 2 (90% Capture)	Case 3 (1000 lb/MWh)
Total Cost, Millions of Dollars	518.14	666.22	421.94
Annualized Cost Millions of Dollars	64.4	82.11	52.45
Operation and Maintenance – Annual Cost in Millions of Dollars	66.27	85.84	52.7
Annual CO ₂ Captured in millions of tons	2.16	2.99	1.6
Cost of Capture per ton (\$/ton)	61	50	74

2.2.2 Evaluation of Emerging Technology

This study included evaluation of feasibility and economics of an emerging CO₂ capture technology that is being developed by Sustainable Energy Solutions (SES). The SES Cryogenic Carbon Capture™ (CCC) system was identified by the University of Utah for evaluation in this study. The proposed technology differs from typical commercially available emerging CO₂ capture technologies inasmuch as it is not an amine-solvent-based process. Rather than circulating a solvent to absorb CO₂ from flue gas, the SES process uses a proprietary cryogenic process to chill flue gas and desublimates CO₂. S&L relied on SES to provide the process and cost information for the CO₂ island. S&L did not validate or verify the information provided. Based on the scope of supply from SES, S&L developed the balance of plant (BOP) design and overall costs for the project.

As part of the conceptual design, the major BOP impacts associated with the SES-specific CO₂ capture facility were identified and quantified by S&L. Other BOP impacts are identified, including cooling and process water consumption, waste water generation rates, and solid waste generation rates. S&L also developed material balances and general arrangement drawings that reflect the integration of the SES CO₂ capture system with the base facility. SES has yet to scale up their process to a commercial scale (> 5 MWe). Furthermore, prior to scaling up to the size of 100% treatment on Hunter Unit 3 would require additional intermediate stages for SES. Based on the limited details provided by SES and the infancy of the technology at this time, the project is not recommended for full scale CO₂ capture on PacifiCorp's Hunter Unit 3. However, a slipstream size island may be technically feasible with more process scale up from SES. At this time, there is not expected to be a fatal flaw based on the process design.

While no fatal flaw in the process design was identified, there may be some limiting factors due to permitting considerations. The factors that have the highest probability of becoming limiting factors moving forward are (1) the ability to dispose of hazardous pollutants in large quantity, (2) the ability to store hydrocarbons onsite, and (3) the potential for Prevention of Significant Deterioration (PSD) permitting to be triggered, based on criteria pollutant emissions increases. Volatile organic carbon (VOC) emissions are expected to increase after project execution, due to the hydrocarbon liquid coming in contact with the flue gas.

The total capital cost is based on the conceptual design of the CO₂ capture system defined in this study. SES provided capital cost information for the CO₂ capture process equipment for the Hunter application. S&L supplemented the CO₂ process equipment cost with a study-level BOP cost estimate based on S&L's experience within the utility industry, particularly experience on other CO₂ capture projects, projects at Hunter, and general Air Quality Control System (AQCS) projects.

Similarly, an estimate of the annual operation and maintenance (O&M) cost was developed based on the conceptual design defined in this study, using operating cost estimates from SES, supplemented by S&L's BOP O&M costs.

The results of this evaluation including the total capital cost, annual O&M cost, and cost of electricity (COE) are included in Table 2.

Table 2. Summary of cost of CO₂ Capture using an emerging technology.

Cost	SES 95% Capture
Total Capital Cost in Millions of Dollars	507.22
Annualized Capital Cost in Millions of Dollars	63.05
Annual Operating Cost in Millions of Dollars	67.91
CO ₂ Captured in Millions of tons (Annual)	3.156
Cost of Capture (\$/ton)	41.50

2.3 CO₂ TRANSPORT ASSESSMENT

Two CO₂ pipeline to transport the captured CO₂ to potential injection sites were designed. The pipeline routing is shown in Figure 5

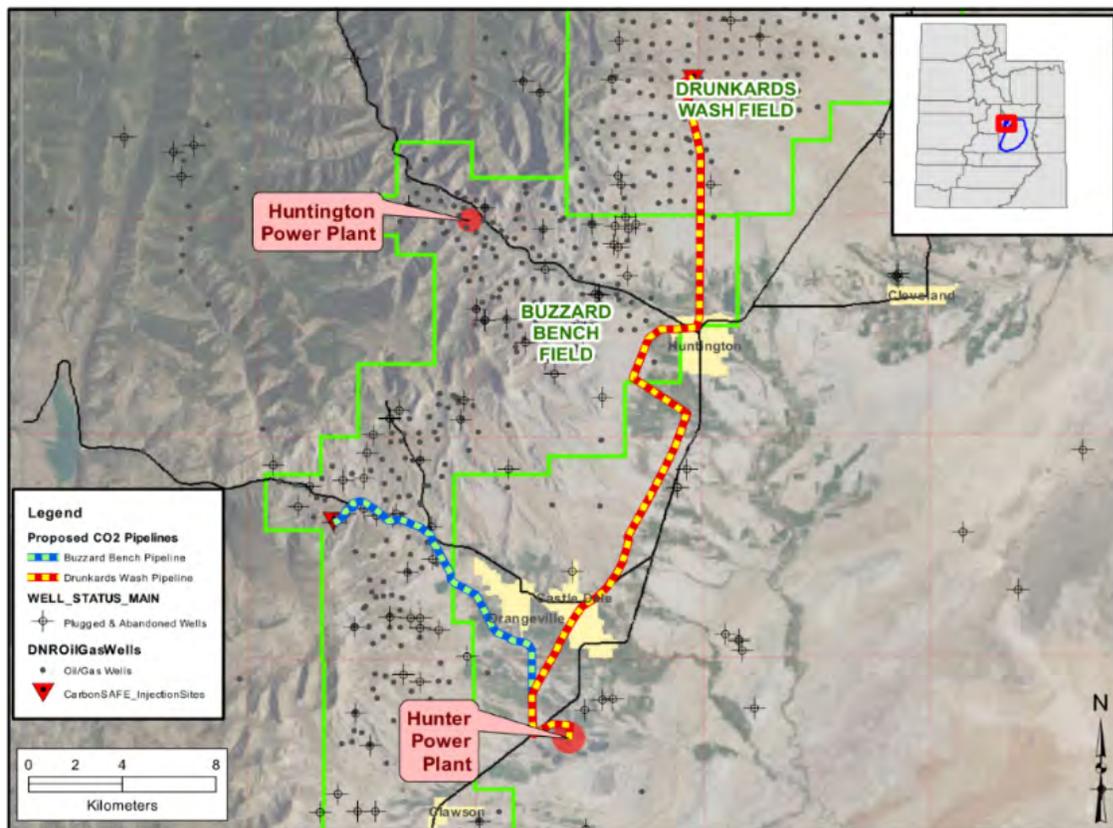


Figure 5. Aerial view of proposed injection sites and pipelines from Hunter power plant.

Detailed pressure drop calculations for the two pipelines were performed. Results are shown in Table 3.

Table 3. Results Summary for two proposed pipeline with 500 to 1500 psi pressure drop.

Parameters	Buzzards Bench	Drunkards Wash
Mass flow rate (ton/day)	5000	5000
Pipeline length (m)	18158	36593
Elevation gain (m)	218	293
Minimum p_1-p_2 (psi)	372	276
Mean velocity (m/s)	1.07-2.47	1.74-3.33
Pipeline diameter (inch)	7.2-10.9	6.2-8.6

2.4 INTERMEDIATE COMPRESSION

Intermediate compression or wellhead compression may be required depending on the elevation and length of pipeline. To determine the location of compression station, a pressure profile along the pipe line is calculated by the Equation 3.

Equation 3.

$$p = p_1 - \frac{8 f Q_m^2 x}{D^5 \rho \pi^2} + \rho g (Z_1 - z)$$

To illustrate the pressure profile along the pipelines, mass flow rate (Q_m) of 5000 ton/day and pressure drop (p_1-p_2) of 1000 psi are selected. Using calculated diameter ($D=8.1$ and 6.9 inches for Drunkards Wash and Buzzard Bench respectively) for the specified parameters, the pressure profiles of pipelines from Hunter power plant to Drunkards Wash and to Buzzard Bench are shown in Figure 6.

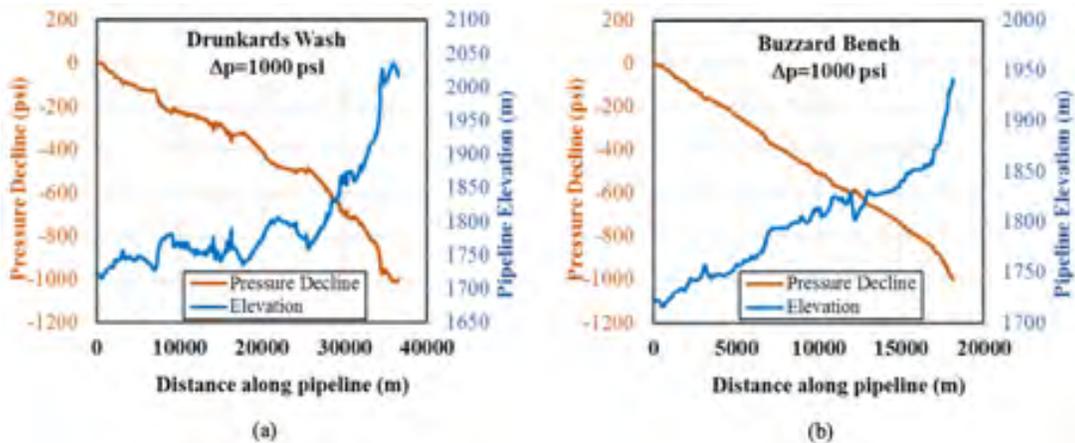


Figure 6. Pressure decline along the pipelines (a) Drunkard Wash Field and (b) Buzzard Bench Field.

3.0 Site Pre-Feasibility Plan

3.1 SITE CHARACTERIZATION

3.1.1 Overview of the San Rafael Swell

This project evaluated the potential for carbon capture and storage (CCS) of carbon dioxide (CO₂) from the Hunter and possibly Huntington coal-fired power plants in Castle Valley along the west flank of the San Rafael Swell in Emery County, Utah (Figure 7 and Figure 8). The San Rafael Swell is a broad, asymmetric, north-south- to southwest-northeast-trending anticlinal structure (Figure 8 and Figure 9), about 75 miles long and 35 miles wide in the Colorado Plateau physiographic province. The structure formed in response to compressional forces of the Laramide orogeny between late-Cretaceous time (about 70 million years ago [Ma]) and the Eocene (about 40 Ma) (Hintze and Kowallis, 2009).

The rocks in the San Rafael Swell have been folded, faulted, jointed, fractured, and uplifted. The major uplift and deformation of the San Rafael Swell was likely controlled by a large, blind, basement-involved reverse fault (up on the west side) bounding the east flank of the structure (Figure 9). Small to large subsidiary anticlines (e.g., Farnham Dome on the north-plunging nose) and synclines occur north to south along the uplift. Three sets of high-angle normal faults are mapped on the surface: (1) northwest-southeast striking, (2) east-west striking, and (3) north-south to northeast-southwest striking (Chidsey, 2013). Two styles of reverse faulting are identified in the San Rafael Swell: (1) west-directed, blind reverse faults on the east flank, and (2) east-directed, ramp-style thrusting. Sandstone beds are quartz rich and brittle, and when folded or bent produce prominent joints and fractures.

The subsurface sedimentary section consists of Cambrian, Devonian, Mississippian, and Pennsylvanian strata overlying Precambrian crystalline basement rocks consisting of schist and granite dated at 1800 Ma (Hintze and Kowallis, 2009). The surface sedimentary section consists of Permian through Cretaceous strata (Figure 10) (note: a small location in Eardley Canyon exposes Mississippian Redwall Limestone). These rocks were deposited in a wide range of environments including eolian, floodplain, fluvial, braided stream, deltaic, paludal, tidal flat, and shallow and restricted marine. Several major unconformities represent significant periods of erosion or non-deposition.

Gray marine shale beds of the Upper Cretaceous Mancos Shale form the strike valleys that surround the San Rafael Swell and upon which most highways and towns are located, as well as the Hunter Power Plant (Figure 7 and Figure 9). The deltaic sandstone and coal beds of the Upper Cretaceous Mesaverde Group make up the Book Cliffs to the north and east, and Wasatch Plateau to the west of the San Rafael Swell where the Huntington Power Plant is located (Figure 7).

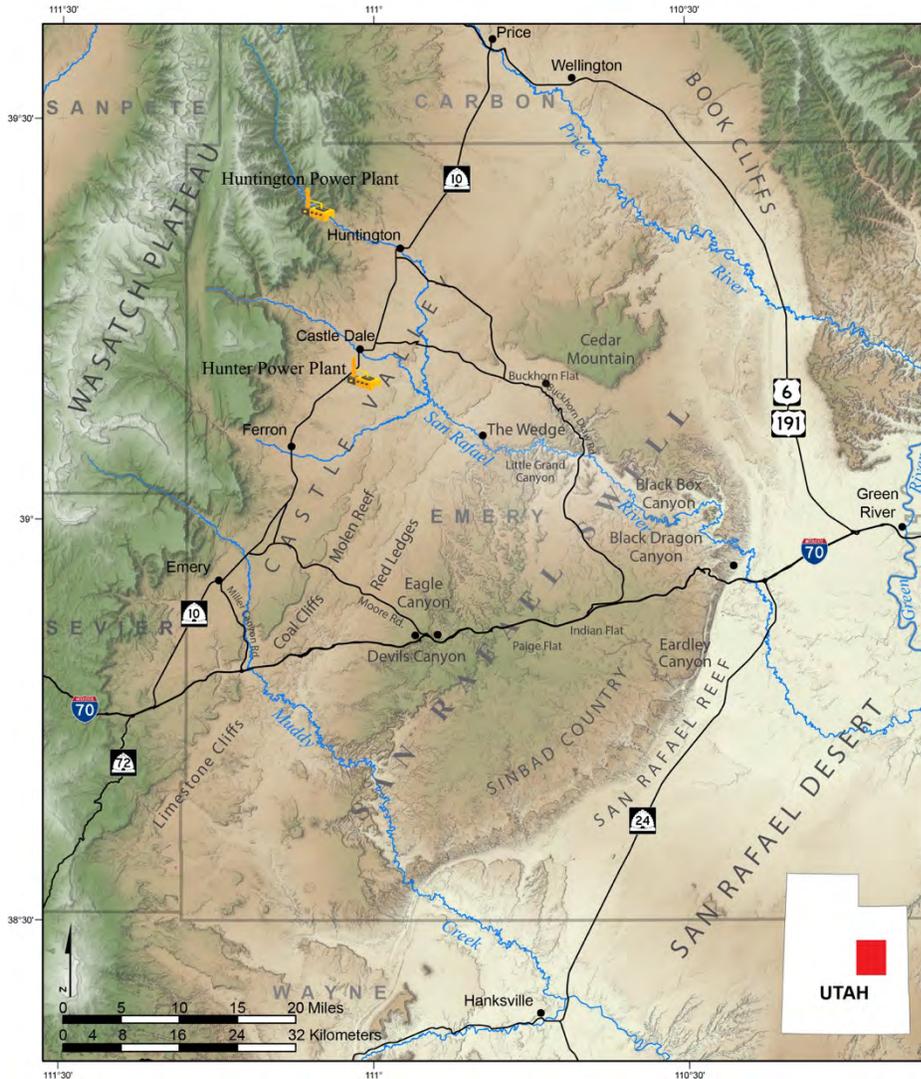


Figure 7. Physiographic map of the San Rafael Swell, east-central Utah, showing the location of major physiographic features, surrounding towns, highways, and the Hunter and Huntington power plants.

Site Characterization Subtasks

Ideally, reservoir and seal characterization should offer insight into both large-scale stratigraphic trends via outcrop-study, as well as petrophysical and geochemical characterization of the subsurface via core descriptions and/or well analysis, where data are available. The goal of subtask 3.1, Site Characterization, was to provide the geologic, geophysical, and hydrologic properties of reservoir formations (Permian White Rim and Jurassic Navajo Sandstones as primary targets; Mississippian Redwall Limestone as a secondary target) and all overlying seal formations (Permian Kaibab, Triassic Moenkopi, and Jurassic Carmel Formations) for both Primary (Hunter) and Secondary (Drunkards Wash) sites (Figure 8 and Figure 10). This work included (1) mapping and determining the extent and integrity of storage and sealing formations, (2) mapping and describing known faults and fractures, (3) evaluating both outcrops and available cores (porosity, permeability, and petrography), (4) analyzing the water chemistry from area wells, (5) determining the hydrological properties of the reservoirs, and (6) describing the

potential for seismic activity. This site characterization provided the geologic model for the development of a reservoir simulation model that was utilized to assess the storage potential and behavior. A geologic model of the site options was the outcome of this subtask.

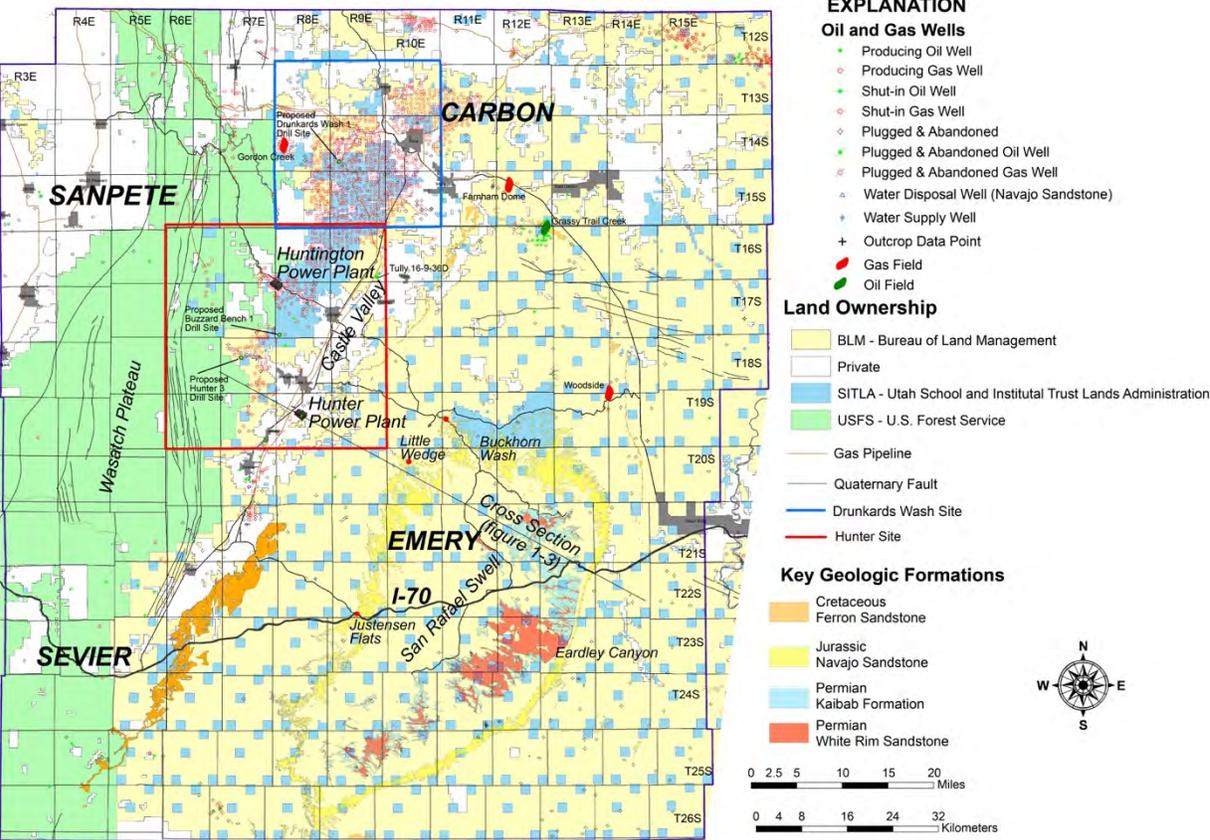


Figure 8. Regional index map of the study area, Carbon, Emery, and parts of Sanpete and Sevier Counties, Utah. Hunter site (red outline) and Drunkards Wash site (blue outline). The proposed Buzzard Bench No. 1 in the Hunter site is the primary injection location and the proposed Drunkards Wash No. 1 (DW1) location is the secondary. Cross section shown on Figure 9.

Discussion: Selection of the Reservoir for Carbon Dioxide Storage

Permian White Rim Sandstone

Originally, the eolian Permian White Rim Sandstone (Figure 10) was considered a likely potential storage reservoir for the project. The CO₂ storage potential of the White Rim Sandstone was investigated by Harston and others (2013) where it is exposed on the east flank of the San Rafael Swell and in the subsurface at Woodside field on a subsidiary anticline along the east flank of the Swell. Porosity measurements from outcrop samples have a range of 7.6% to 24.1% and permeability up to 2.1 millidarcies (mD). The eolian facies has the best reservoir quality and is volumetrically the most significant in comparison to the marine part of the White Rim (Harston and others, 2013). However, storage capacity at Woodside field is limited by the structural closure and was calculated at 2.2, 8.8, and 23.7 million metric tonnes for P10, P50, and P90, respectively (Harston and others, 2013).

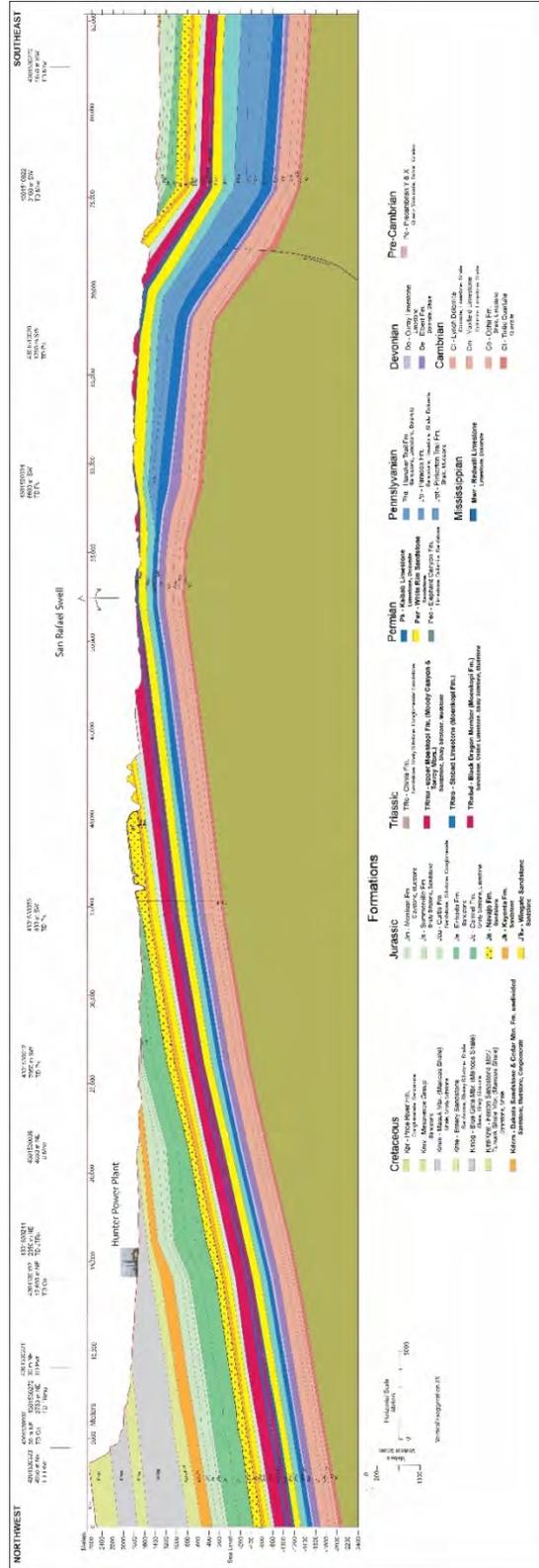


Figure 9. Northwest to southeast geologic cross section of the San Rafael Swell through the Hunter Power Plant location. Navajo Sandstone, targeted for CO₂ injection, shown with dotted pattern. See Figure 8 for location of cross section.

High flow rates of CO₂ were tested from the White Rim Sandstone at Gordon Creek field in the Wasatch Plateau within the Drunkards Wash area southwest of Price (Figure 8). A drill-stem test of the White Rim in the Gordon Creek No. 1 well (SENE section 24, T. 14 S., R. 7 E., Salt Lake Base Line & Meridian (SLBL&M), Carbon County) gauged a flow of 8.8 million cubic feet of gas per day (MMCFGPD). The well was completed as a CO₂ well but never produced. Three other wells drilled and tested CO₂ at Gordon Creek, confirming a large resource. Geophysical well logs show porosity of 2% to 4% suggesting fractures play a significant role in the White Rim reservoir at Gordon Creek (Morgan and others, 2013). The White Rim was also going to be a source for CO₂ in the Gordon Creek saline aquifer demonstration which was canceled when the Environmental Protection Agency (EPA) made the Class VI requirement for the demonstration wells (Morgan and others, 2013).

Finally, Whiting Petroleum Company cored most of the Triassic Moenkopi Formation, all of the Permian Kaibab Formation, and the upper White Rim Sandstone (50 feet) in the Tully No. 16-9-36D (NWNW section 36, T. 16 S., R. 9 E., SLBL&M, Emery County). The White Rim reservoir quality in the core, particularly permeability, was poor. The core also had very low porosity (mostly 1% to 2%) which matches density-neutron-log porosity values throughout the entire White Rim when correlated to porosity logs from other wells in the area. The White Rim is deeper in Castle Valley than Woodside Dome, and at that greater depth, the diageneses of the sandstone that created porosity at Woodside has not occurred at Castle Valley.

These factors led to the conclusion that the White Rim Sandstone most likely does not have the reservoir quality necessary to be considered for CO₂ injection and storage in Castle Valley. As a result, a second potential target was identified and studied.

Jurassic Navajo Sandstone

Our attention shifted to the eolian Lower Jurassic Navajo Sandstone as a top candidate for CO₂ injection. The Navajo Sandstone is relatively undeformed, widespread, and thick. It has excellent reservoir and aquifer properties producing oil in the central Utah thrust belt, CO₂ in the San Rafael Swell, and serves as a water disposal unit. The Navajo reservoir is sealed by overlying marine units of the Middle Jurassic Carmel Formation.

Farnham Dome field, located on the north-plunging nose of the San Rafael Swell (Figure 8), produces naturally occurring CO₂ from the Navajo Sandstone. The trap for the field is a broad, elongate, south-north- to southwest-northeast-trending anticline defined by surface mapping, drilling, and seismic data (Morgan, 2007). The CO₂ was likely generated from the thermal decomposition of Paleozoic carbonates deep in the Uinta Basin to the north and migrated up the stratigraphic section to Farnham Dome (Morgan, 2007). The net Navajo reservoir thickness is 40 feet over a 6200-acre area; the gas column is about 400 feet (Morgan, 2007). Despite the massive nature of the Navajo Sandstone, interdune deposits and other factors contribute to reservoir heterogeneity. Porosity ranges from 18% to 20%; permeability is poorly-constrained. Cumulative production as of May 1, 2018, is estimated at 6.4 BCFG and no water (Utah Division of Oil, Gas and Mining, production records). Total gas-in-place reserves are estimated at 430 BCFG at Farnham Dome (Morgan, 2007).

The Navajo Sandstone has also been used for disposal of produced water from the many coalbed methane wells in the area producing from the Cretaceous Ferron Sandstone (Figure 10),

demonstrating the formation’s high-injectivity potential and effective overlying seal. There are no cores of the Navajo in Castle Valley and therefore permeability is based on outcrop studies (Dalrymple and Morris, 2007) and porosity and permeability from core taken in the Covenant field about 65 miles southwest of Hunter (Chidsey and others, 2007). Porosity is better in the Castle Valley area, as such the permeability in Castle Valley is likely better than the Covenant field as well.

The Farnham Dome field has served as a model for geologic carbon capture, utilization, and storage of flue gases from coal-fired power plants on the Colorado Plateau (Allis and others, 2001). Findings from this study and our initial well log correlations,

subsurface mapping, and characterization studies of the Navajo Sandstone reservoir and the Carmel Formation seal concluded that the Navajo was the best reservoir in the region for CO₂ storage. Note: a major concern with the Navajo is the close proximity of the outcrop to the Hunter Power Plant (Figure 8). As a result, an injection location west and down dip from the plant was selected—the proposed Buzzard Bench No. 1 well (NENE section 31, T. 17 S., R. 8 E., SLBL&M) within the Hunter study site (figure 1-2). A secondary injection location within the Hunter study site is the Hunter No. 3 well (NWNW section 16, T. 17 S., R 7 E., SLBL&M). Finally, the proposed injection location for the Drunkards Wash study site is the Drunkard Wash No. 1 well (SESE section 30, T. 14 S., R 9 E., SLBL&M) (Figure 8).

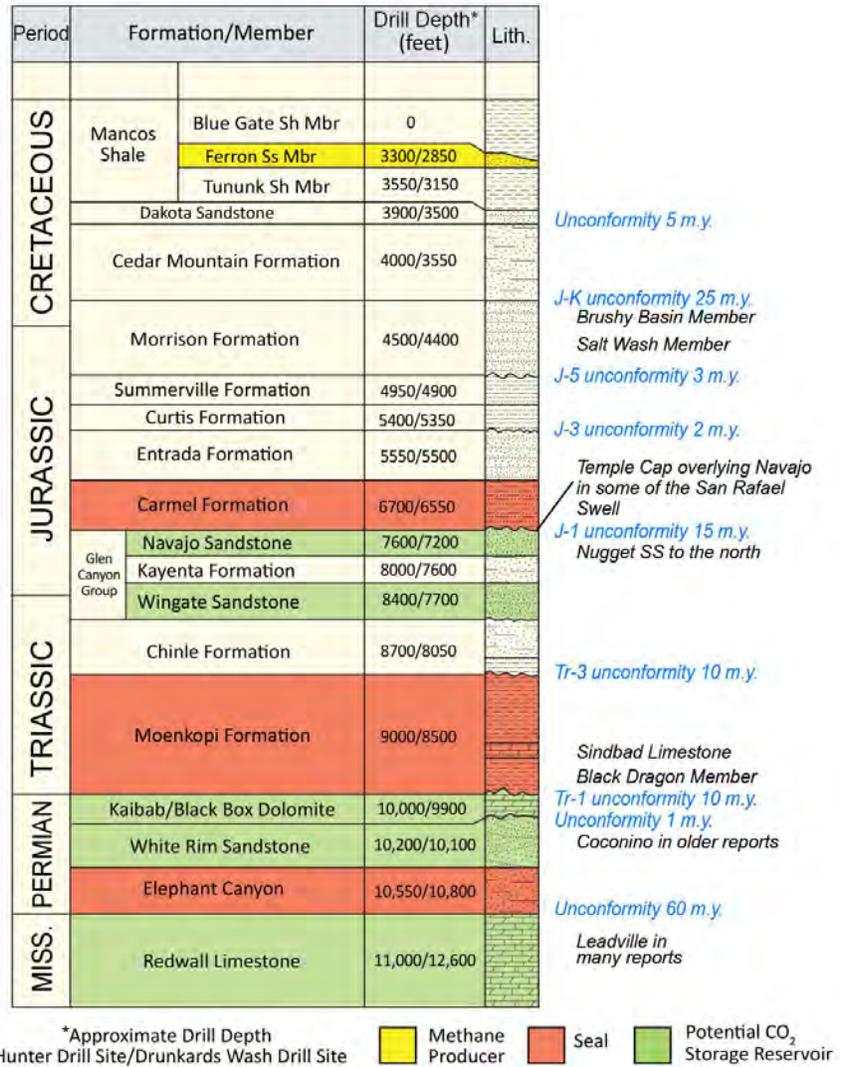


Figure 10. Stratigraphic column for the Castle Valley area, Emery County, Utah. Drill depths are for the proposed drill sites Hunter No. 3 (NWNW section 16, T. 18 S., R. 7 E., Salt Lake Base Line & Meridian [SLBL&M]) and Drunkards Wash No. 1 (SESE section 30, T. 14 S., R. 9 E., SLBL&M). Modified from Hintze and Kowallis, 2009.

3.2 MODEL DESIGN AND SIMULATION

During this project, we built three different simulation models to address different aspects of the storage site pre-feasibility study. An initial 2D scoping model was developed to determine if CO₂ storage at this site was possible due to the ‘unconfined’ nature of the potential reservoir. A second model was then developed to address the storage of 50 million tons of CO₂ at a primary storage site, Buzzards Bench, and a secondary storage site, Drunkards Wash. And finally, we developed a third model that encompassed both the Buzzards Bench and Drunkards Wash storage sites into one domain. The primary goal of the simulation part of the study was to determine if the permanent storage of 50 million tons of CO₂ is feasible in this area of central Utah. A second goal was to explore the total possible capacity in the area if it was used as a regional geologic carbon storage site. A detailed discussion of these three models is described below.

3.2.1 2D Vertical Scoping Model

A 2D vertical reservoir model was created as an initial scoping tool to determine the magnitude of plume movement up-dip from two possible injection sites, one directly under the Hunter Power Plant and one about 6 miles west of the power plant. The model is from the Colorado Plateau on the west to the crest of the San Rafael Swell to the east, A to A’ in Figure 11. The San Rafael Swell is an anticline, with the formations dipping to the west at about 3.5% (Figure 12).

Only the major formations of interest were model while the overlying and underlying formations were combined to reduce computational overhead and unnecessary complexity. Two injection zones were initially evaluated, the Glen Canyon Formation, consisting of the Navajo Sandstone, the Kayenta Formation, and the Wingate Sandstone, and the White Rim Sandstone. The sealing formation for the Glen Canyon Formation is the Carmel, which is a laterally continuous formation overlying the Navajo Sandstone in this area. The Moenkopi Formation and Black Box Dolomite are sealing units overlying the White Rim Sandstone. The Carmel and Glen Canyon Formation all outcrop about 11 miles (18 km) east of the Hunter Power Plant site, while the White Rim Sandstone only outcrops in a few isolated areas of the Swell even further east.

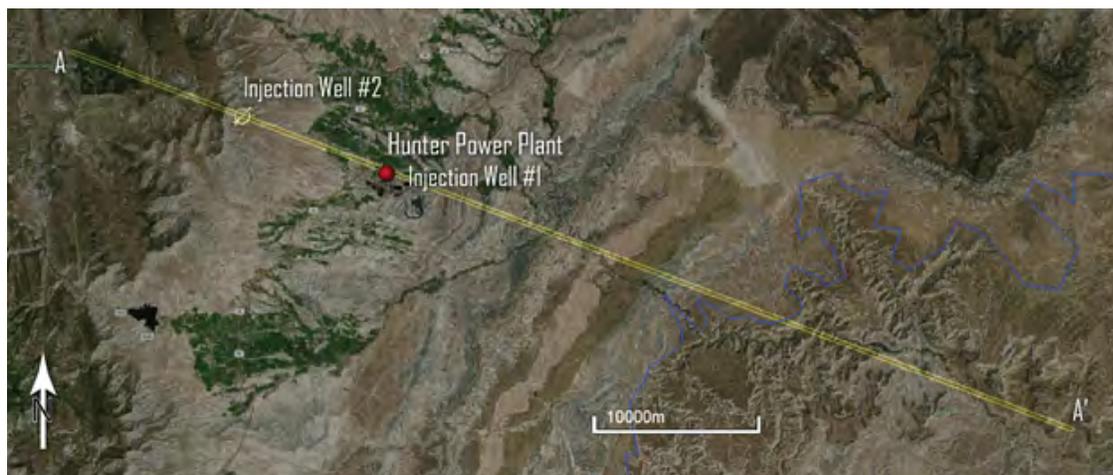


Figure 11. Overview of the area that encompasses the 2D vertical model. The model domain follows the slice from A to A'. The purple line represents where the Navajo Sandstone outcrops in the area.

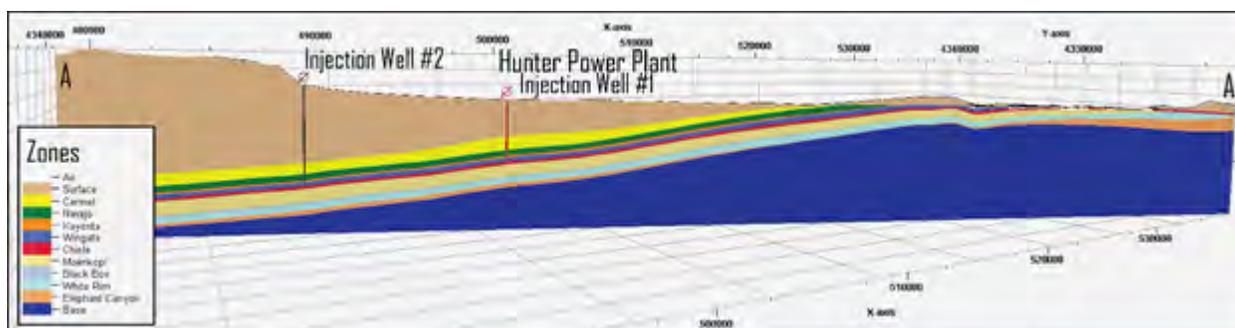


Figure 12. A plot of the model domain showing the relevant stratigraphy under Hunter Power plant. There is a 5x vertical exaggeration in the plot.

CO₂ Injection – Potential Location

Two potential CO₂ injection well locations were specified and analyzed, one directly under the Hunter Power plant (Injection Well #1) and a second injection well 5.8 miles (9.3 km) northwest or down-dip from the power plant site (Injection Well #2). The injection well #1 is the ideal location for the injection well, directly under the power plant. But, this well, at 4215 feet (1285 m) deep, may be too shallow and too close to the outcrops to effectively contain the CO₂ plume in the Glen Canyon Formation over the long term. The White Rim Sandstone is much deeper under the power plant, 6587 feet (2008 m), making it a better storage target than the shallower Glen Canyon Formation. The second injection well, Injection Well #2, was located further east, down-dip, of the power plant. Here the top of the Glen Canyon Formation is at a much greater depth, 7103 feet (2165 m). The White Rim Sandstone is 10,040 feet (3060 m) deep at this injection site.

Carbon dioxide is injected for 30 years with a bottom hole pressure limit of 5800 psi (400 bar). The injection wells are set for bottom hole pressure control so they will inject CO₂ at the maximum rate the reservoir will allow while keeping the bottom-hole pressure below 5800 psi. The simulation was run for a total of 500 years, from 2017 to 2517.

Reservoir Properties

Very little was known about the fluid and rock properties of this potential storage site. For this model, some assumptions and simplification were used in lieu of formation and site-specific data. Those will be discussed in detail below.

Permeability and Porosity

When this model was constructed there was very little petrophysical data in the study area for the formations of interest. The majority of petrophysical data is for the much shallower, natural gas producing Ferron Sandstone. Due to this, permeability and porosity values were estimated from very generic data presented by Hood and Patterson (1984) and assigned homogeneously across the reservoir domain. Table 4 has the permeability and porosity values used in this model.

Table 4. Permeability and porosity values assigned homogeneously across each formation.

Formation	Porosity	Permeability (mD)
Overburden	10%	0.1
Carmel	2%	0.1
Navajo	20%	200
Kayenta	20%	100
Wingate	20%	200
Chinle	2%	0.1
Moenkopi	2%	0.1
Black Box	10%	0.1
White Rim	7%	1
Elephant Canyon	2%	0.1
Basement Granite	2%	0.1

Relative Permeability and Capillary Pressure

Characterization of fluid/rock interaction for the formations of interest, such as relative permeability and capillary pressure, was also lacking. Three different relative permeability relationships were specified that covered the possible parameter space. We chose the default relative permeability relationship for ‘sandstone’ in Petrel©, the van Genuchten formula, and the Corey’s Curve formula (Pruess et al., 1999). Figure 14 shows the three curves with the default as the solid lines, the van Genuchten curve as the dashed lines, and the Corey’s Curve as the dotted lines.

The capillary pressure was ignored in the default case. The capillary pressure was calculated using Leverett’s formula for the other two cases (Pruess et al., 1999).

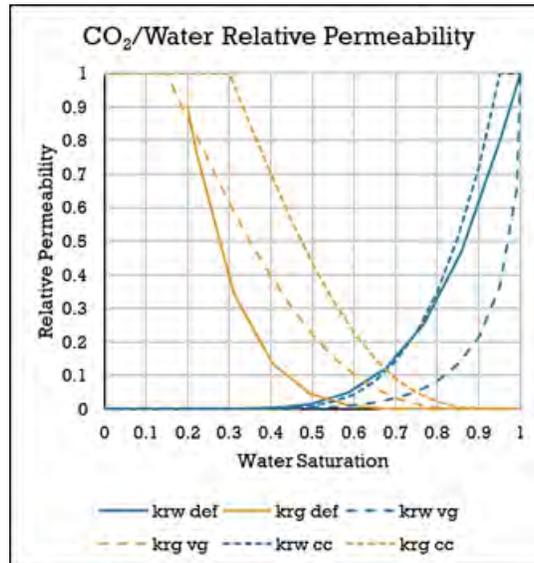


Figure 13. Three relative permeability curves used in the scoping model. ‘ k_{rw} ’ is the relative permeability to water and ‘ k_{rg} ’ is the relative permeability to gas. The solid lines represent the default relative permeability curve in Petrel, the dashed line is the relative permeability calculated with the van Genuchten formula, and the dotted curve is the relative permeability calculated with the Corey’s Curve formula.

Fluid Model & Boundary Conditions

The two-phase CO₂ and water system was modeled by using the CO2STORE keyword in the Eclipse© simulator. This keyword models CO₂/Brine interactions more accurately than the default three-phase equation of state. Initially, there is only brine present in the reservoir with a temperature of 131 °F (55 °C). The pressure is hydrostatic and initialized through equilibrations with a datum depth of mean sea level and a reservoir pressure at the datum depth of 2755 psi (190 bar). Dirichlet boundary condition was specified for the surface layer and set to 14.7 psi (1 atm) and assigned a ‘large volume’ (10⁷ m³). The lateral and bottom boundaries were set to no flow. The lateral boundaries are far enough away from both injection wells such that injection pressures are not influenced by the boundary conditions.

Results

As was initially suspected, CO₂ injected directly under the Hunter Power Plant (Injection Well #1) into the Glen Canyon Formation migrated up-dip until it reached a depth of about 800 meters where the CO₂ changed phase from supercritical CO₂ to gaseous CO₂. This phase change happened at about 135 years into the simulation and indicated a loss of CO₂ containment.

The White Rim Sandstone proved to be a poor candidate for CO₂ storage as it is hampered by poor injectivity resulting from low permeability. Further simulations were not carried out using the White Rim Sandstone as a reservoir.

Table 5. Total gas (CO₂) in each model permutations at the end of injection, the end of the monitoring period: (Post-Injection Site Care; PISC), and the end of the simulation. Units are in short tons.

Model	Total CO ₂ In Place (tons)		
	End of Injection		
	Free Gas	Trapped Gas	Dissolved Gas
Default RP	5,606,750	677,131	607,784
Corey's Curve RP	6,391,868	536,575	439,170
van Genucten RP	5,788,011	1,076,159	417,360
	End of PISC		
	Free Gas	Trapped Gas	Dissolved Gas
Default RP	5,250,764	796,976	843,917
Corey's Curve RP	6,352,068	533,600	481,958
van Genucten RP	5,754,908	1,069,190	457,427
	End of Simulation		
	Free Gas	Trapped Gas	Dissolved Gas
Default RP	5,606,750	1,106,769	1,664,986
Corey's Curve RP	6,391,868	539,067	505,188
van Genucten RP	5,788,536	1,079,243	475,107

Moving CO₂ injection to Injection Well #2, located about 6 miles to the west of Hunter, showed mixed results. Achieving containment at this injection site depends on the specified relative permeability and capillary pressure relationship. Using the default relative permeability relationship without capillary pressure, injected CO₂ migrates about 16km (~10 miles) up-dip by the end of the simulation. A distance far past the Hunter site and close to where the reservoir outcrops, indicating a loss of containment (Figure 14a). Changing the relative permeability

relationship and adding capillary pressure slows the plume movement and keeps it more localized, moving between 4 and 6 miles over 500 years (Figure 14b and Figure 14c). Results show that ignoring the capillary pressure has a significant impact on the distance the CO₂ plume can migrate. One consideration for this site is ignoring capillary pressure may be unrealistic as CO₂ and brine are not miscible at the conditions found under the Colorado Plateau. At the pressure and temperature regime at the site, there will be a distinct capillary pressure relationship.

The maximum amount of CO₂ that can be injected is affected by the relative permeability and capillary pressure relationship specified. Table 5 shows that changing the relative permeability curves imparted about a 6% variation in total CO₂ injected into the model.

Overall this scoping model has indicated that this area of the Colorado Plateau and nearby San Rafael Swell is a possible candidate for long-term storage of anthropogenic CO₂. These results warrant further investigation and construction of a more detailed geologic model.

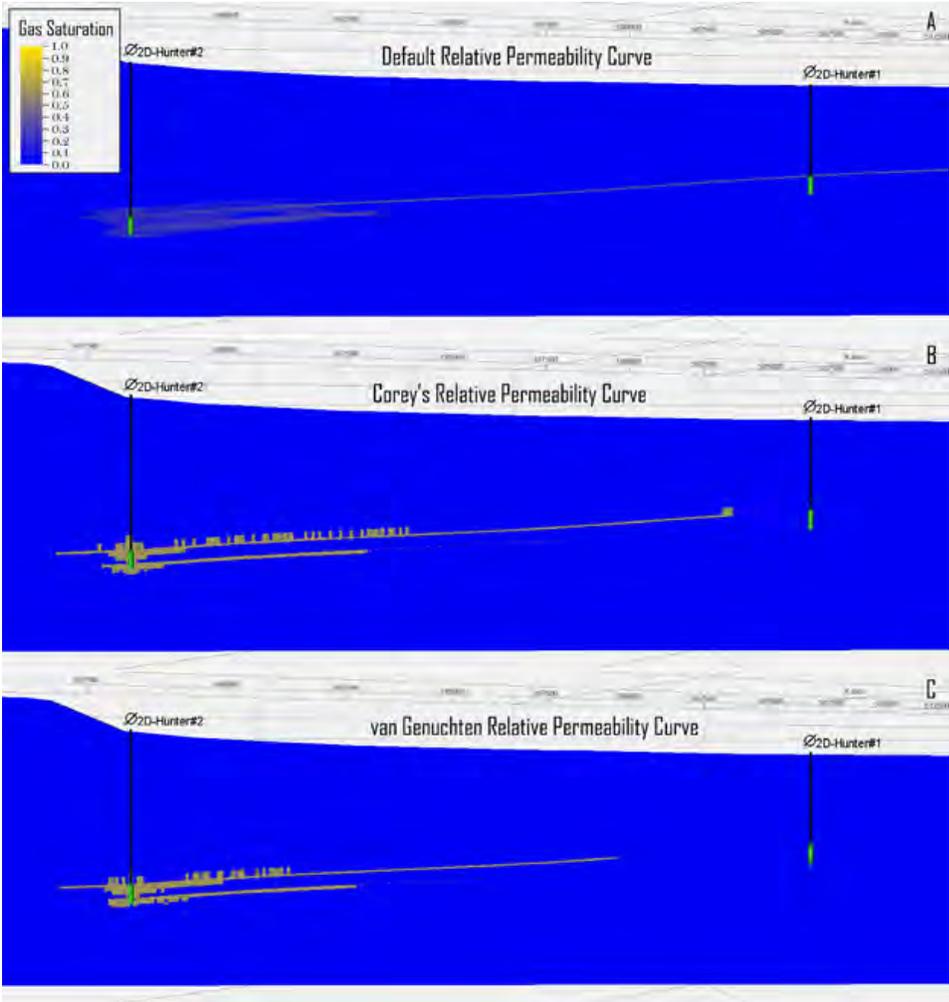


Figure 14. Predicted CO₂ saturation at the end of the simulation (500 years) using the Petrel default curve for sandstone (a), Corey's curve (b) and the van Genuchten curve (c).

3.2.2 NRAP Well-Bore Leakage Models

The EPA class VI guidance documents specify that if a reservoir is in a hydrostatic to overpressurized state than the Area of Review (AOR) assessment need to be delineated using numerical modeling. We determined that the Navajo Sandstone in our study area is likely at hydrostatic to slightly over pressurized state. To address this requirement a geologic model was constructed, and two model domains were delineated by the Schlumberger team (Si-Yong Lee). One model domain encompassed our primary injection site about 8.5 miles northwest of the Hunter Power Plant in an area called Buzzards Bench. The second model domain encompasses our secondary injection that is 28 miles north of Hunter in an area of called Drunkards Wash. Figure 15 shows these two domains in relation to Price and Castle Dale, Utah.

Simulation Domains and Initial Model Conditions

The model encompassing our primary injection site is referred to as the Buzzards Bench model and the model encompassing our secondary injection site as the Drunkards Wash model. Figure 16 shows an overview of the study area with a yellow square for the Buzzards Bench model domain and a red square for the Drunkards Wash model domain along with the location of each of the two proposed injection wells.

The Buzzards Bench model domain is discretized into 200,000 cells, 100(x) by 100(y) by 20(z). The Drunkards Wash model domain is discretized into 273,798 cells, 123(x) by 106(y) by 21(z). The simulation domain models only the Carmel Formation that forms the sealing unit overlying our principal reservoir, the Glen Canyon Formation (Navajo, Kayenta, Wingate formations) and the underlying sealing unit of the Chinle Formation. The overlying layers were omitted to reduce model complexity and computation overhead. The thickness and low permeability of the Carmel Formation should not allow any vertical fluid migration. The lateral boundaries were set to a large volume to maintain a constant pressure, and the top and bottom boundaries were set to no flow. The initial pressure distribution was set to hydrostatic conditions, consistent with the available data (Hood and Patterson, 1984).

The porosity and permeability were derived from initial characterization data take in the field and from well logs and well reports. To keep the simulation design simple, it is assumed that the porosity and permeability are correlated and have a homogeneous distribution. We believe that the homogeneous distribution is adequate for our purpose because the cell size (200 x 200 meters) is much larger than the correlation length seen in the field, on the order of only tens of meters.



Figure 15. Regional overview of the two simulation domains. Buzzards Bench domain is outlined in yellow and the Drunkards Wash domain in red.

Model Permutations

The project team has identified ranges of permeability and porosity for proposed storage formations based on literature (see Table 6).

Table 6. Variation range of permeability and porosity for Navajo, Kayenta, and Wingate formations.

	Permeability (mD)	Porosity (-)
Navajo	50 ~ 300	7 % ~ 20 %
Kayenta	10 ~ 150	7 % ~ 25 %
Wingate	50 ~ 200	7 % ~ 20 %

Based on preliminary simulation results, the project team refined the sources of uncertainty in estimating CO₂ storage at the proposed storage complex. Three factors were identified, including porosity of Navajo formation, anisotropy ratio (k_z/k_x) of Navajo formation, and CO₂ injection rate. Specific reasons for selecting these factors are listed below.

- (1) Only the Navajo formation was considered as a source of uncertainty, while the underlying Kayenta and Wingate formations were not treated as primary sources of uncertainty at this stage. Because injection occurred at the Navajo formation and most of CO₂ stayed in this formation, only a small amount of CO₂ migrated to deeper formations (i.e., Kayenta and Wingate).

(2) Considering the correlation between porosity and permeability, only porosity was considered as an independent source of uncertainty, while permeability was derived from porosity using empirical relationship.

(3) Three different injection rates were used to achieve the goal of 50 million tons of CO₂ storage.

With Box-Behnken Design (BBD), a total of 13 realizations were designed to cover the uncertainty space based on three uncertainty factors (shown in Figure 16). Details of the realizations are listed in Table 7, where -1,0, and 1 represent three equally spaced values. Table 8 presents the values for uncertainty factors and associated dependent model settings (permeability and injection duration) for the 13 realizations. These values were populated to both storage sites, the Buzzard Bench site and the Drunkards Wash site. A total of 26 realizations was simulated with the Eclipse E300 module.

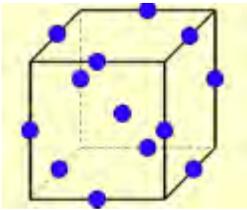


Figure 16. Diagram showing Box-Behnken-Design with three uncertainty factors.

Table 7. A list of 13 realizations formulated by BBD with three uncertainty factors.

Sim#	X1 (Porosity)	X2 (kz/kx)	X3 (Inj. Rate)
1	-1	-1	0
2	1	-1	0
3	-1	1	0
4	1	1	0
5	-1	0	-1
6	1	0	-1
7	-1	0	1
8	1	0	1
9	0	-1	-1
10	0	1	-1
11	0	-1	1
12	0	1	1
13	0	0	0

Table 8. Values of uncertainty factors and associated model settings for the 13 realizations.

Sim#	X1 (vol/vol)	X2 (mD/mD)	X3 (million tonnes per year)	Permeability (mD)	injection duration (year)
1	12%	0.05	2.5	17.16	20
2	20%	0.05	2.5	636.01	20
3	12%	0.5	2.5	17.16	20
4	20%	0.5	2.5	636.01	20
5	12%	0.275	1.67	17.16	30
6	20%	0.275	1.67	636.01	30
7	12%	0.275	5	17.16	10
8	20%	0.275	5	636.01	10
9	16%	0.05	1.67	131.24	30
10	16%	0.5	1.67	131.24	30
11	16%	0.05	5	131.24	10
12	16%	0.5	5	131.24	10
13	16%	0.275	2.5	131.24	20

Injection Well Locations & CO₂ Injection

Initially, three different CO₂ injection well locations were explored, directly under the power plant, the Buzzards Bench site west of the power plant, and the Drunkards Wash site north of the power plant. The well at the power plant was located on Hunter property while the rest of the well locations evaluated are sited on State of Utah School and Institutional Trust Lands Administration (SITLA) land (Figure 17 and Figure 18). Initial results showed that CO₂ injected under the Hunter Power Plant property migrated close enough to the Navajo Sandstone outcrops to exclude it from further consideration. Due to this, the two additional well location was the focus of the rest of this study.

The Buzzards Bench #1 well is about 9 miles northwest of the power plant. It is perforated at the Navajo Sandstone interval, from 7471 feet to 7616 feet. This site is about 22 miles from where the Navajo Sandstone outcrops and we believe this will provide sufficient to contain the CO₂ plume.



Figure 17. The proposed location for the Buzzards Bench CO₂ injection well. The well is located just over 8.5 miles (14 km) northwest from the Hunter Power Plant on SITLA land (highlighted with orange).

The Drunkards Wash #1 well is located 28 miles north of the Hunter Power Plant on SITLA land (Figure 18). The well is perforated in the Navajo Sandstone at an interval of 7202 feet to 7519 feet. This well location has an advantage over the Buzzards Bench site in that the reservoir and caprock do not outcrop in the vicinity, reducing the risk of loss of CO₂ containment.

Carbon dioxide injection occurred at three different rates, a low rate of 1.67 million tons per year for 30 years, a medium rate of 2.5 million tons per year for 20 years and a maximum rate of 5 million tons per year for ten years. This injection scheme is designed to ensure that 50 million tons of CO₂ are injected into the reservoir during the simulation. Table 8 shows the injection rate and duration for each of the 13 simulations.



Figure 18. The proposed location for the Drunkards Wash CO₂ injection well. This well is located 28 miles (45 km) north of the Hunter Power Plant in the Drunkards Wash gas fields on SITLA land (highlighted with orange).

Results

Results show that regardless of the model permutation, the reservoir can accommodate just under 50 million tons. Figure 19 and Figure 20 indicates that the limiting factor for CO₂ injection in these models is the injection rate and duration. At both sites, the reservoir properties do not limit the injection rate under any of the model permutations. Under all scenarios, the injected CO₂ is contained within the target formation, and there is no significant migration towards the outcrops.

At the Buzzards Bench site, CO₂ migrates slowly towards Castle Dale and the Navajo outcrop 13 miles to the east. Over the 100 years simulated the plume only moves a couple of kilometers towards the outcrop (Figure 21). At that rate, it could take more than 1300 years for the plume to reach the outcrop. More than likely the CO₂ will have all dissolved into the formation brine and become immobilized before then. This slow plume movement indicates that this is a suitable storage site for CO₂.

At the Drunkards Wash site, the CO₂ migrate to the southwest, away from any potential outcrops to the southeast (Figure 22). From this standpoint, this site is a better storage candidate than the Buzzards Bench site. It has the storage capacity for at least 50 million tons of CO₂ and has better containment potential than Buzzards Bench. The downside is that it is much further away from the Hunter Power Plant, increasing transportation-related costs.

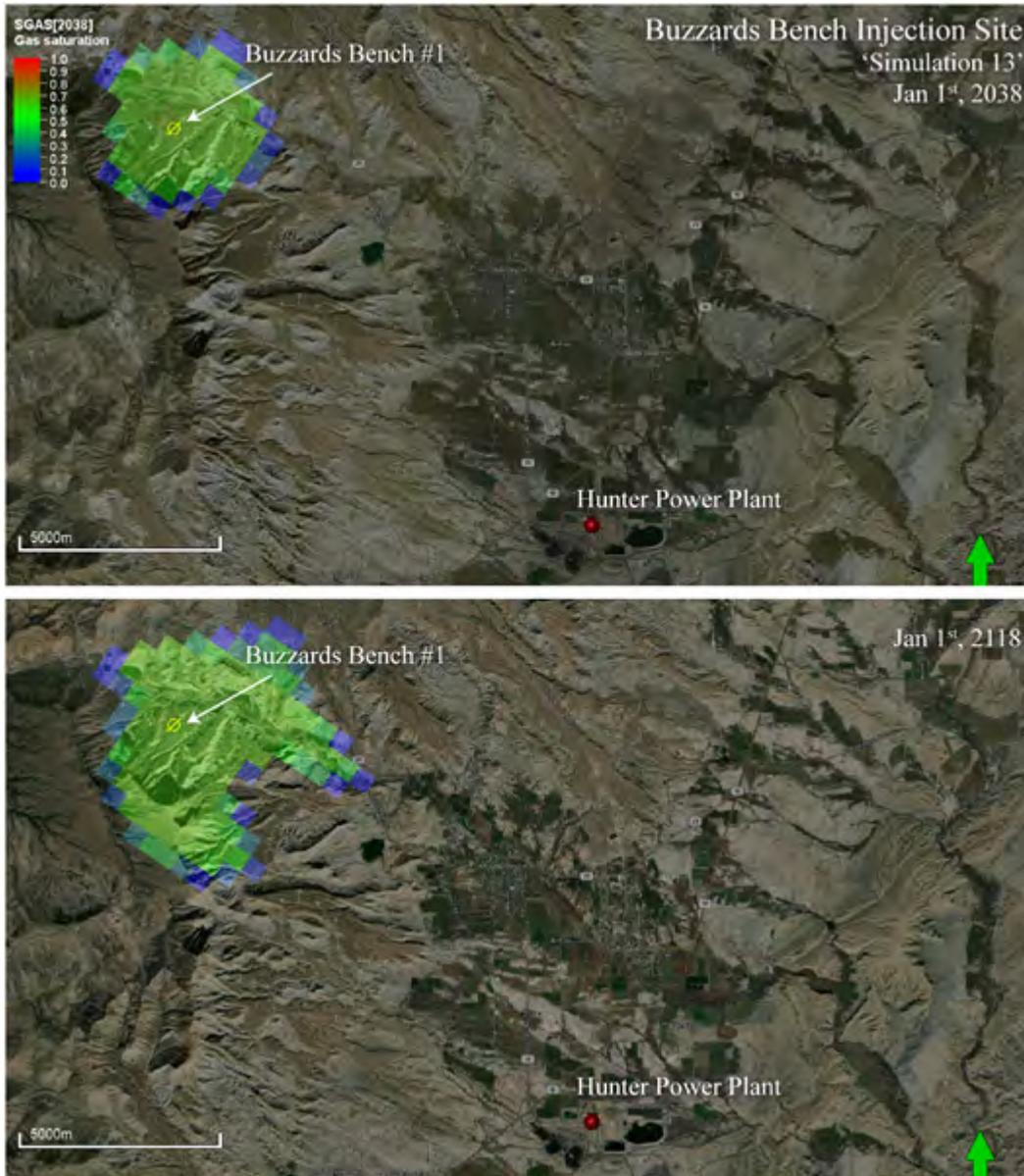


Figure 21. This plot shows the gas saturation results for the Buzzards Bench domain at the end of injection (2038) and the end of the simulation (2118) for simulation permutation #13. This simulation permutation represents the medium injection time along with the medium porosity/permeability and anisotropy. See Table 8 for simulation parameters.

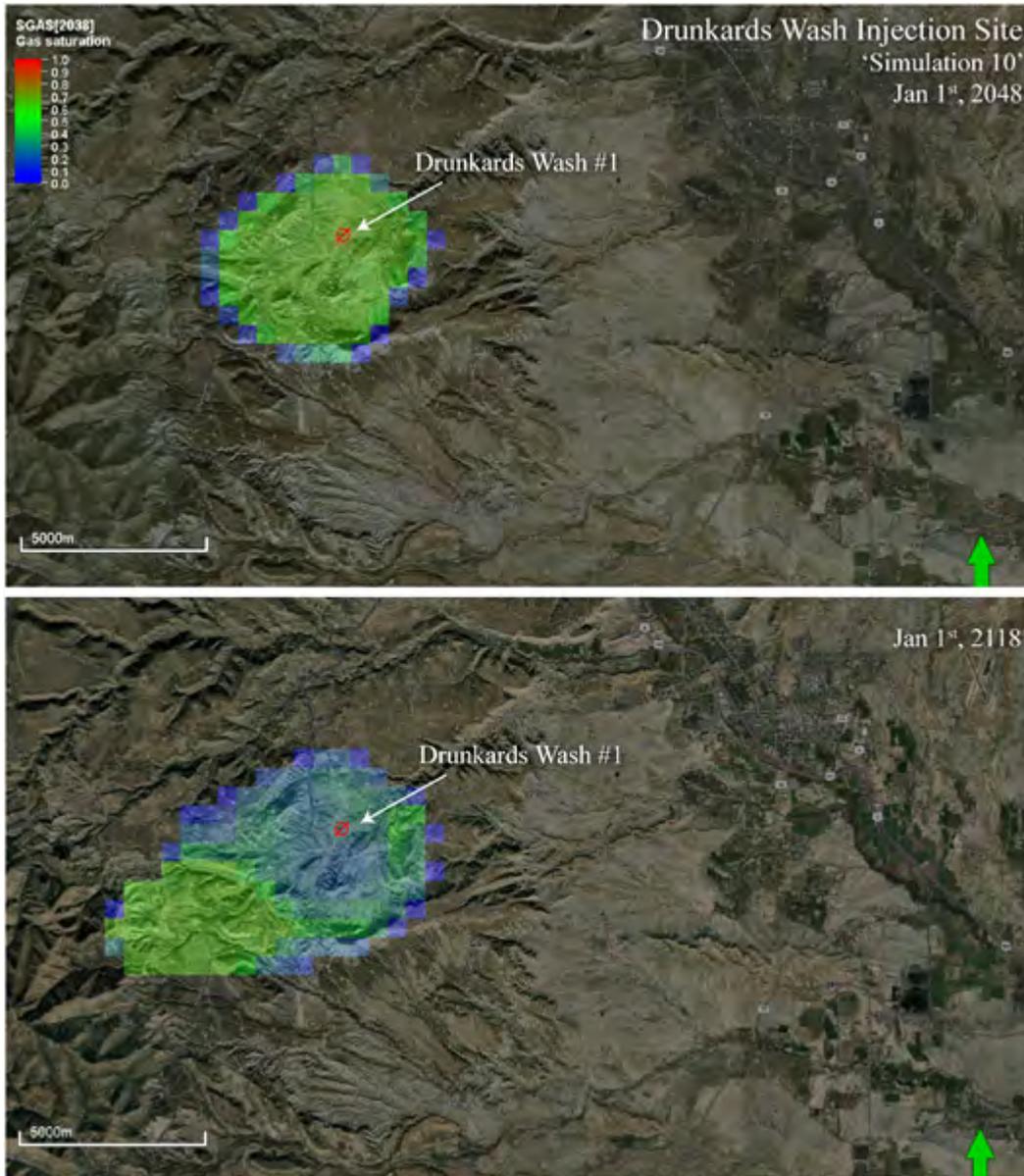


Figure 22. This plot shows the gas saturation results for the Drunkards Wash domain at the end of injection (2038) and the end of the simulation (2118) for simulation permutation #13. This simulation permutation represents the medium injection time along with the medium porosity/permeability and anisotropy. See Table 8 for simulation parameters.

Simulation results from the 26 permutations were further analyzed in Section 3.3.1 and Section 3.4.2.

3.2.3 Regional Geologic Carbon Storage Model

The third major simulation model permutation developed during this study was a regional capacity model. The model encompassed both of our possible injection sites, Buzzards Bench and Drunkards Wash, into a single model domain (Figure 23). This was done for a couple of reasons. Foremost was that the results from the NRAP simulations indicated that the very edge of the pressure plume was reaching the boundaries of the model. We did not believe this was

having enough of an impact to warrant re-running all of the NRAP simulations. Another reason for this larger model was to explore the overall capacity of this area beyond just the 50 million tons mandated by this project. We wanted to begin to address the question “*Can this area be used as a regional geologic carbon storage site for all of the point source CO₂ emissions in Utah?*”

Large Domain Model Development

Analysis of the NRAP wellbore leakage modeling indicated that the Buzzards Bench and Drunkards Wash model domains were too small for effective analysis. Specifically, the pressure plume consistently reached the model boundaries, and thus the boundary conditions were compromising the model results. A larger dynamic model domain was delineated that encompassed both the Buzzards Bench and Drunkards Wash injection sites to resolve this issue (Figure 23, section outlined in blue). This domain measures 44 miles by 62 miles and includes the Carmel formation (overlying seal unit), the Navajo Sandstone (primary reservoir), the Kayenta Formation (secondary reservoir), the Wingate Sandstone (tertiary reservoir), and the Chinle Formation (underlying sealing unit). The model is discretized into 1,053,864 active cells.

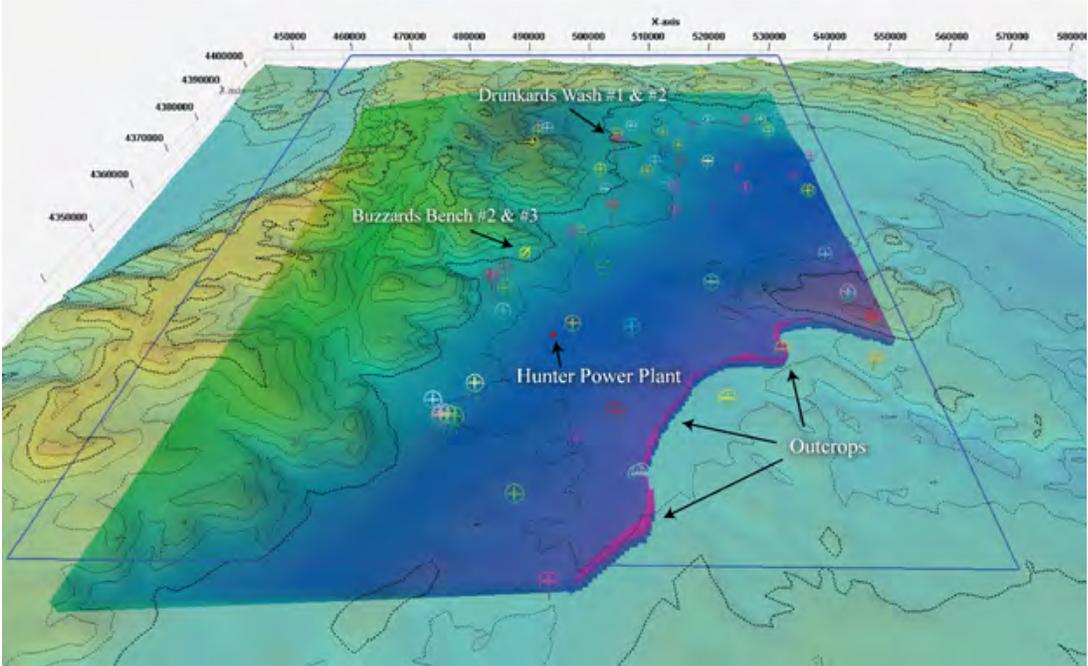


Figure 23. This figure shows the surface topography overlain on the simulation model domain. The wells used to delineate the stratigraphic horizons are shown as circles with pluses in them, and the project wells are indicated with a circle with an arrow through it.

A total of 77 wells have well top data that extends below the Navajo Sandstone and are thus critical for accurately modeling the stratigraphic interval of interest. During the model building process, we identified issues with formation top picks in some of these wells. These were not an issue for the previous modeling work as they were all outside the model domains. This new model domain encompasses a much larger area and a few wells with incorrect formation top picks were adversely affecting model creation. All 77 wells had to each be checked to ensure that the formation top picks were in the proper stratigraphic order and if well logs were available, the

formation top picks were matched to these well logs to fix any obvious errors. Figure 23 shows the model domain with the surface topography and the 77 wells used to create the horizons. The southeast portion of the model was truncated along an area where the Carmel and Navajo Sandstone outcrop. The area where the formations outcrop is indicated along with the location of the Buzzards Bench and Drunkards Wash wells.

Permeability and Porosity Data

Petrophysical properties and outcrop analysis done by the characterization group indicates that the Navajo Sandstone consists of three major horizons. Figure 24 shows a select group of well logs for SWD #1 (salt water disposal well) alongside the zone delineation being modeled for the Navajo. Three major horizons can be seen from these logs and were also observed in the outcrop study. The dynamic model has three zones delineated so that representative petrophysical properties can be assigned to each.

Table 9. Porosity and permeability assigned to each of the formation being modeled.

	Carmel	Navajo	Kayenta	Wingate	Chinle
Porosity	2.0%	12.3%	8.0%	10.0%	2.0%
Permeability (mD)	0.02	38.9	10.0	60.0	0.02

Porosity and permeability data collected as part of the characterization effort was incorporated into the dynamic model. Legacy data from two wells about 45 miles southwest of Hunter, Wolverine Federal No. 17-2 and No. 17-3, and one of the salt water disposal wells, SWD #1, provided porosity and permeability measurements with depth. Porosity and permeability were also measured from outcrop samples taken from Buckhorn Wash in the San Rafael Swell area. This data was then used to create a homogeneous porosity and permeability model. Each of the three zones in the Navajo was assigned the same homogeneous porosity and permeability distribution. Table 9 shows the values assigned to each of the five formations being modeled; the Carmel, the Navajo, the Kayenta, the Wingate, and the Chinle. Data for the formation other than the Navajo was from the literature as there was not any petrophysical analysis done by the characterization group or provided in the well logs that could provide meaningful values. These values are consistent across all model cases.

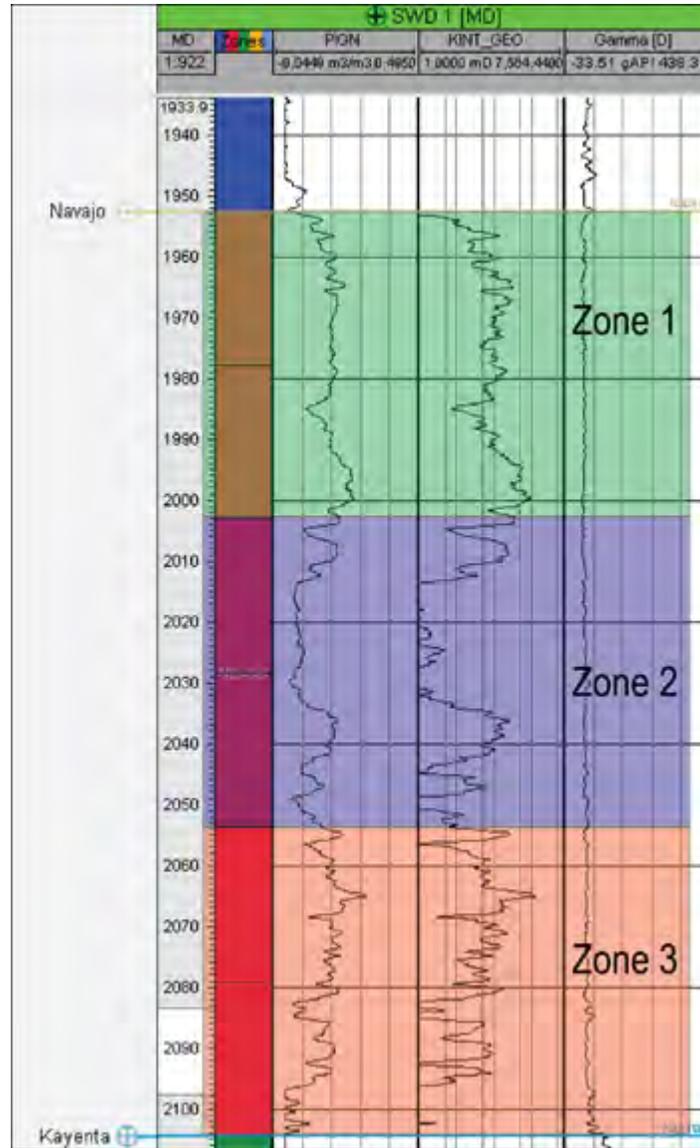


Figure 24. Navajo Sandstone interval from the well logs for SWD#1. This highlights the three major horizons showing a clear difference between the bottom, middle and top of the Navajo Sandstone.

Relative Permeability and Capillary pressure

Relative permeability and capillary pressure measured on Navajo Sandstone core by the characterization group was incorporated into the dynamic model. Three relationships were measured, one for each of the three zones identified in core and outcrop samples from the Navajo Sandstone. These three relative permeability and capillary pressure relationships were then incorporated into the dynamic simulation model for each of the three zones. Due to a lack of data in the literature, the Wingate Sandstone and the Kayenta Formation were assigned a 'default' curve for sandstone from Petrel©, and the capillary pressure was estimated using van Genuchten's formula (Pruess et al., 1999). The seal layers, Carmel and Chinle, were assigned shale relationships derived from the literature (Bennion and Bachu, 2007). Figure 25, Figure 26, and Figure 27 show the relative permeability and capillary pressure relationship assigned to the three zones within the Navajo Sandstone.

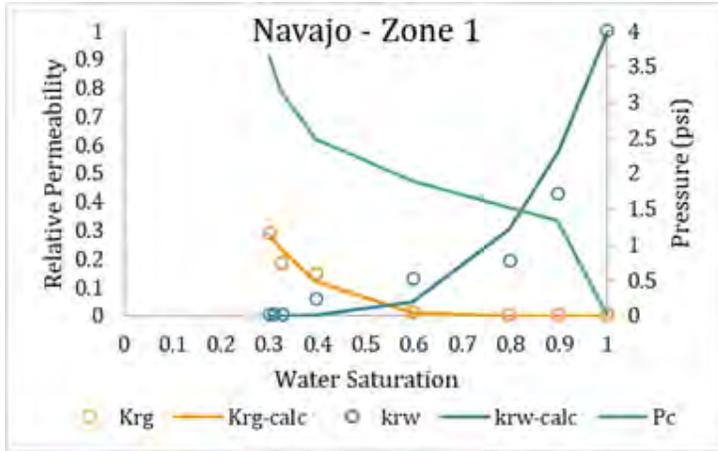


Figure 25. Relative permeability and capillary pressure relationship assigned to zone 1 (upper) of the Navajo Sandstone formation.

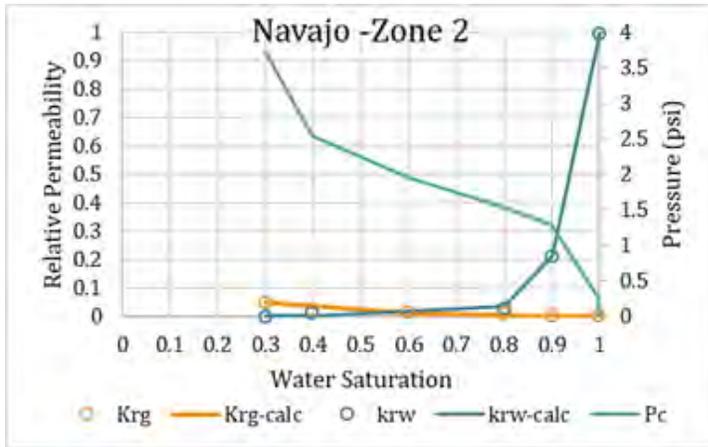


Figure 26. Relative permeability and capillary pressure relationship assigned to zone 2 (middle) of the Navajo Sandstone formation.

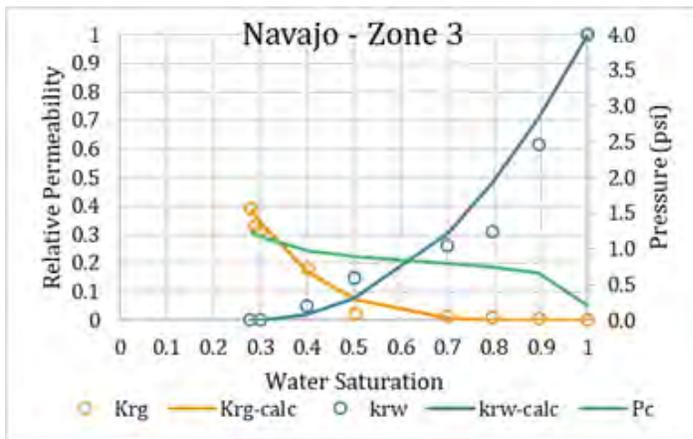


Figure 27. Relative permeability and capillary pressure relationship assigned to zone 3 (lower) of the Navajo Sandstone formation.

Boundary and Initial Conditions

The Glen Canyon Formation, which the Navajo Sandstone is part of, as well as the Carmel Formation, are regionally continuous formations across our study area and beyond. The boundary conditions for the large domain model needed to mimic this extensive lateral extent. The four lateral boundaries are set to infinite volume cells so that a constant head is maintained. The top and bottom boundaries are set to no flow as we did not observe any indications of vertical fluid migration from the Navajo through the Carmel. The outcrop area is modeled as an aquifer recharge zone for the Navajo Sandstone with a constant flux of $2.7e^{-5}$ m³/day of fresh water. That recharge rate equates to roughly 3000 acre-ft/year over the whole San Rafael Swell, about 93,000 acres (Hood and Patterson, 1984).

The initial pressure distribution was set to hydrostatic conditions. The model was then simulated for 1000 years with only the aquifer recharge zone active to create the pre-exploration initial conditions. This pressure distribution was then applied to a second model case that simulates the historic saltwater injection occurring in Buzzards Bench area from January 1996 to January 2018. The results of this simulation set up the initial pressure and water saturation distribution that was used as the initial conditions for all subsequent model cases. Figure 28 shows this ‘initial conditions’ pressure distribution.

Model Permutations

We created five simulation cases using this large domain model. The first case (Buzzards Bench 50MT) injected CO₂ at the Buzzards Bench site at a rate of 2,347,358 m³/day for 30 years, and then the plume movement was monitored for an additional 70 years. The goal of this case was to explore the feasibility of storing 50 million tons of CO₂ within the vicinity of the Hunter Power Plant. The second case (Drunkards Wash 50MT) injected CO₂ at the Drunkards Wash site at the same rate and duration as the Buzzards Bench case. The goal of this case was similar to the first case but with the idea of leveraging surface infrastructure, pipeline rights of way and well pads, that are in the Drunkards Wash area. The third case (Buzzards Bench Capacity) injected CO₂ at the Buzzards Bench site at the maximum rate the formation will allow with a bottom-hole pressure limit of 4780 psi for 30 years. This case explores the total amount of CO₂ that can be injected at the Buzzards Bench site if the injection rate is determined by the injectivity of the formation. The fourth case (Buzzards Bench & Drunkards Wash Capacity) injected CO₂ using the same bottom hole pressure limiting injection scheme as the third case but at both injection sites. The fifth case (Regional Capacity) injected CO₂ into 21 wells spread across the model with the goal of injecting all of the anthropogenic CO₂ that Utah produces from point-source emitters. This case explores the question ‘*Is there capacity to store all of the CO₂ that Utah emits from point sources like power plants and other heavy industry?*’ Table 10 lists the point-source CO₂ emitters in Utah, what industry they are a part of, and their annual CO₂ emission in millions of tons per year. This data was used to create the injection schedules for this model case.

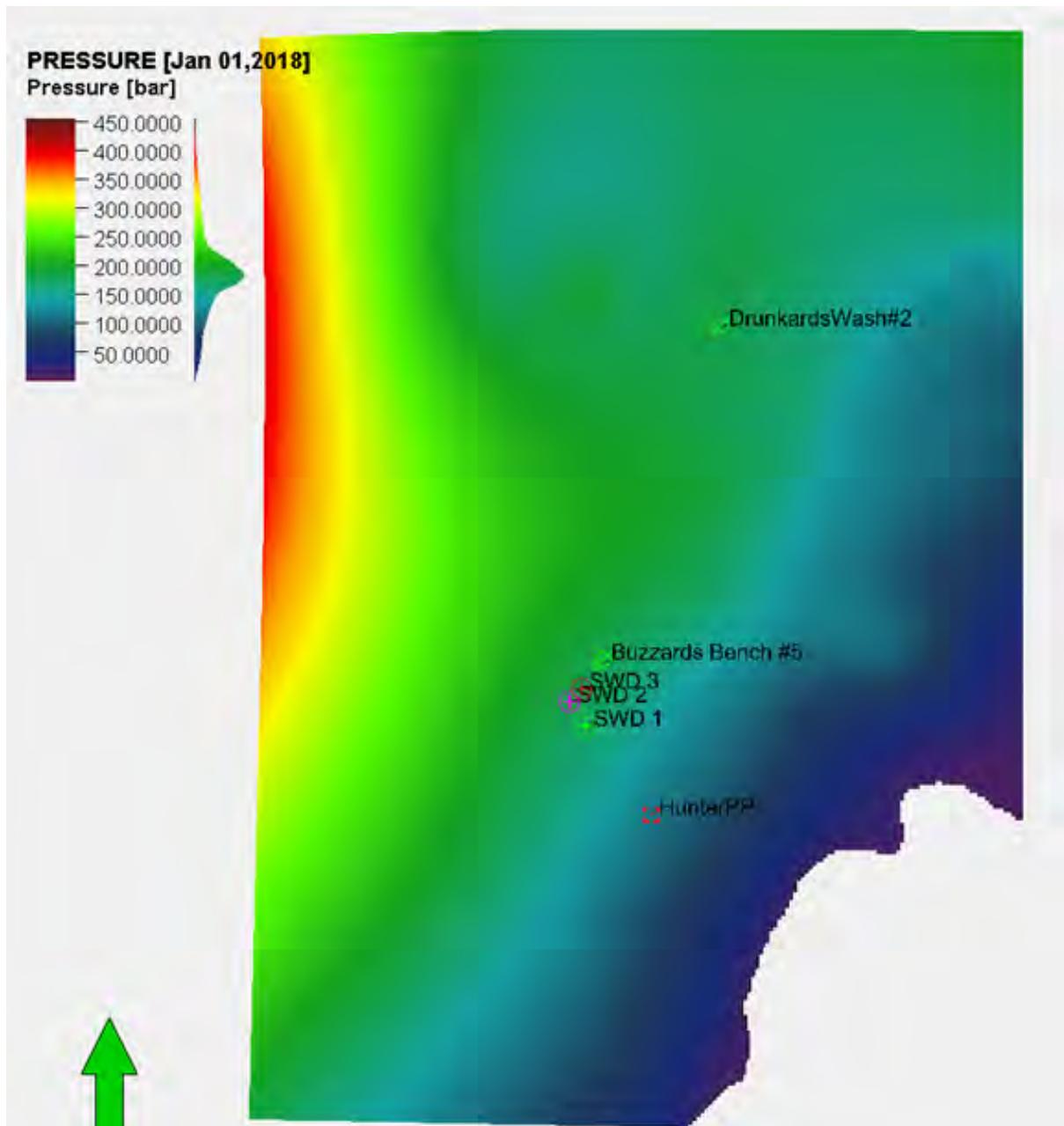


Figure 28. The pressure distribution used as initial conditions for all subsequent models.

Table 10. CO₂ sources used to build the injection schedule for the 'Regional CCS' simulations.

CO ₂ Emissions from Point Sources in Utah		Emissions (MtCO ₂ /y)
Source Name	Source Type	
Deseret Power	Fossil Fuel Electric Power Generation	3
Carbon Power Plant	Fossil Fuel Electric Power Generation	1.2
Currant Creek Power Plant	Fossil Fuel Electric Power Generation	0.8
Hunter Power Plant	Fossil Fuel Electric Power Generation	8.8
Huntington Power Plant	Fossil Fuel Electric Power Generation	6.2
Intermountain Power Project	Fossil Fuel Electric Power Generation	8.8
Lake Side Power Plant	Fossil Fuel Electric Power Generation	1.2
Sunnyside Cogen Associates	Fossil Fuel Electric Power Generation	0.5
Total Power Generation		30.5
Linde Gas North America LLC	Industrial Gas Manufacturing	0.1
Nucor Steel	Iron and Steel Mills and Ferroalloy Manufacturing	0.1
Big West Oil LLC	Petroleum Refineries	0.3
Chevron Products Co.	Petroleum Refineries	0.5
Holly Refining & Marketing Co.	Petroleum Refineries	0.3
Tesoro Refining and Marketing Co.	Petroleum Refineries	0.5
Ash Grove Cement Co.	Cement Manufacturing	0.4
Lafarge Holcim Devif's Slide	Cement Manufacturing	0.6
Total non-Power Generation		2.8
Total Emissions		33.3

Injection Well Location and Schedule

When we were exploring injection well locations, there were a number of things to consider, distance from the Hunter Power Plant, depth to the injection zone, distance to any known outcrops, and surface land ownership. The ideal location for the CO₂ injection wells would be at the Hunter Power Plant site. Unfortunately, this location is too close to where the Navajo and Carmel outcrop for long-term CO₂ storage. Simulations showed that under certain reservoir conditions CO₂ will flow towards the outcrop 13 miles away and would eventually be released to the atmosphere. This injection site was deemed not suitable for long-term CO₂ storage, and alternative sites had to be considered.

For the 'Buzzards Bench 50MT' and 'Drunkards Wash 50MT' simulation cases two wells per injection location were deemed necessary. Engineers on the project indicated that an injection well has a physical rate limit of 1 million tons of CO₂ per year. This limit requires two wells per site to handle the injection rate of 2,347,358 m³/day (1.87 MT/yr) needed to store 50 million tons in 30 years. The injection wells at each site are perforated across the entire Navajo Sandstone interval and modeled as deviated wells, sharing the same well pad but becoming 1 km apart at the injection interval. The injection wells at both project location were relocated to sites of abandoned wells within SITLA property boundaries. Moving sites was done to leverage existing surface infrastructure and ensure that wells are located in areas that can be accessed by drilling rigs. Figures 25 and 26 in Appendix I show the locations of each of these injection wells.

The ‘Buzzards Bench Capacity’ and the ‘Buzzards Bench & Drunkards Wash Capacity’ cases use the same well locations as the ‘Buzzards Bench 50MT’ and ‘Drunkards Wash 50MT’ cases. Unlike the previous cases, these two cases specify a bottom hole pressure limit and let the wells flow at the maximum rate that the formation will accept. These cases do not consider the engineering limit of 1 million tons per year for each well, allowing the wells to inject at a much higher injection rate. Figure 29 shows the injection rates for these four cases.

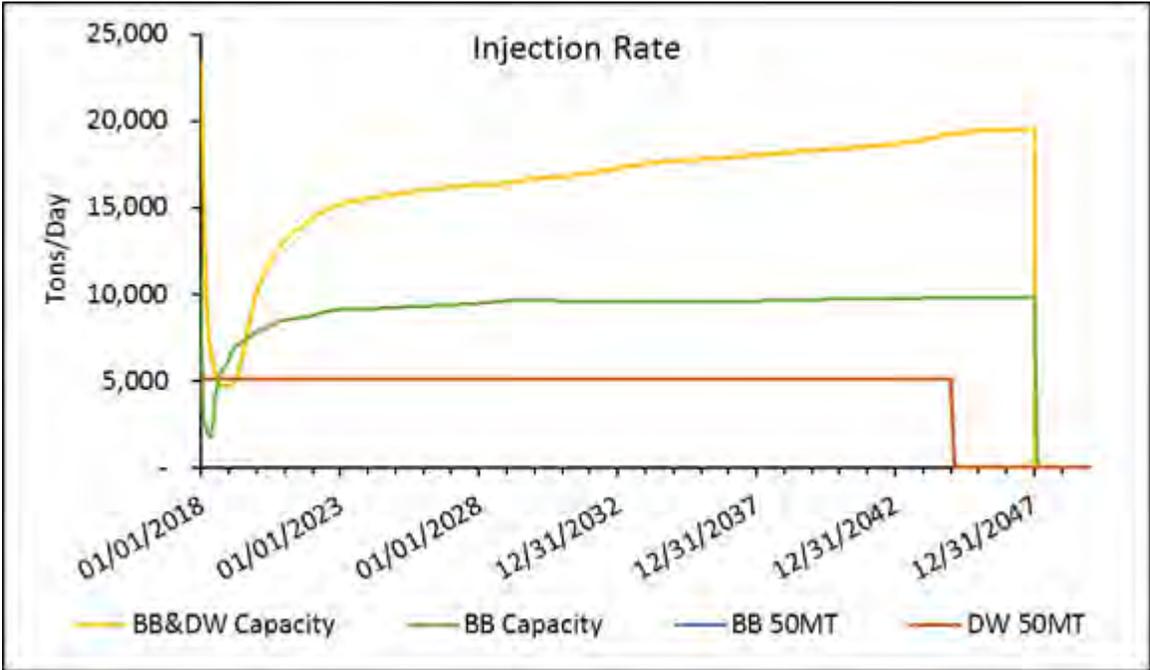


Figure 29. Injection rates for the Buzzards Bench 50MT case (BB 50MT), the Drunkards Wash 50MT case (DW 50MT), the Buzzards Bench Capacity case (BB Capacity) and the Buzzards Bench & Drunkards Wash case (BB&DW Capacity).

In addition to the CO₂ injection wells, there are two saltwater disposal wells near the Buzzards Bench injection site that inject waste water from the overlying Ferron Sandstone gas deposits. These wells show current, as of February 2018, wastewater injection, so they are modeled with continuing injection of wastewater for an additional 20 years.

The fifth case models the area as a regional geologic carbon storage site. The emission data from Table 10 was used as the injection targets for this case. A total of 33.3 million tons of CO₂ needs to be injected annually. With a maximum injection rate of 1 million tons per year per well we needed 21 wells to accommodate that mass of CO₂. In addition to the four project wells, 17 other well locations were identified along the corridor from the Hunter Power Plant to the Drunkards Wash injection site (Figure 30). These are the sites of current plugged and abandoned wells. The injection schedule has stepped down injection targets through time. We attempted to model a gradual phase-out of fossil fuel power generation through the first 50 years of the simulation. For the next 50 years, there is just injection of emissions from heavy industry. By 2118 all CO₂ injection stops with the idea that we have figured out how to run heavy industry without fossil fuels. Table 11 shows the injection rate, the number of wells needed to inject that rate, and the data that injection rate stops. Figure 31 graphically shows the injection wells and their duration of CO₂ injection. Comparing the wells shut-off dates in Figure 31 to the map of the well locations in Figure 30 shows that the wells in the southern portion of the field, around the

Buzzards Bench area and south, are shut off first with the wells in the Drunkards Wash area shut off last. This was done because the reservoir does not outcrop in the Drunkards Wash area and thus the risk of CO₂ leakage to the surface is less. In the southern portion of the field, there is a greater potential for CO₂ to reach the outcrops and escape to the atmosphere.

Table 11. Injection rate targets through time for the 'Regional Capacity' case.

Injeciton Rate		Number of Wells	Durration (yrs)	Injection Stops
(MT/yr)	(m ³ /day)			
33.55	42,114,372	21	30	2048
18.50	23,222,530	21	40	2058
9.70	12,176,137	10	45	2063
6.70	8,410,322	7	50	2068
2.80	3,514,761	3	100	2118



Figure 30. Proposed well locations for the CarbonSAFE Rocky Mountain CCS project, Buzzards Bench #2 & #3 and Drunkards Wash #2 & #3 along with 17 other plugged and abandoned wells that could be used for a regional CCS site. The blue rectangle is the model boundary. The CO₂ injection wells are indicated with white labels.

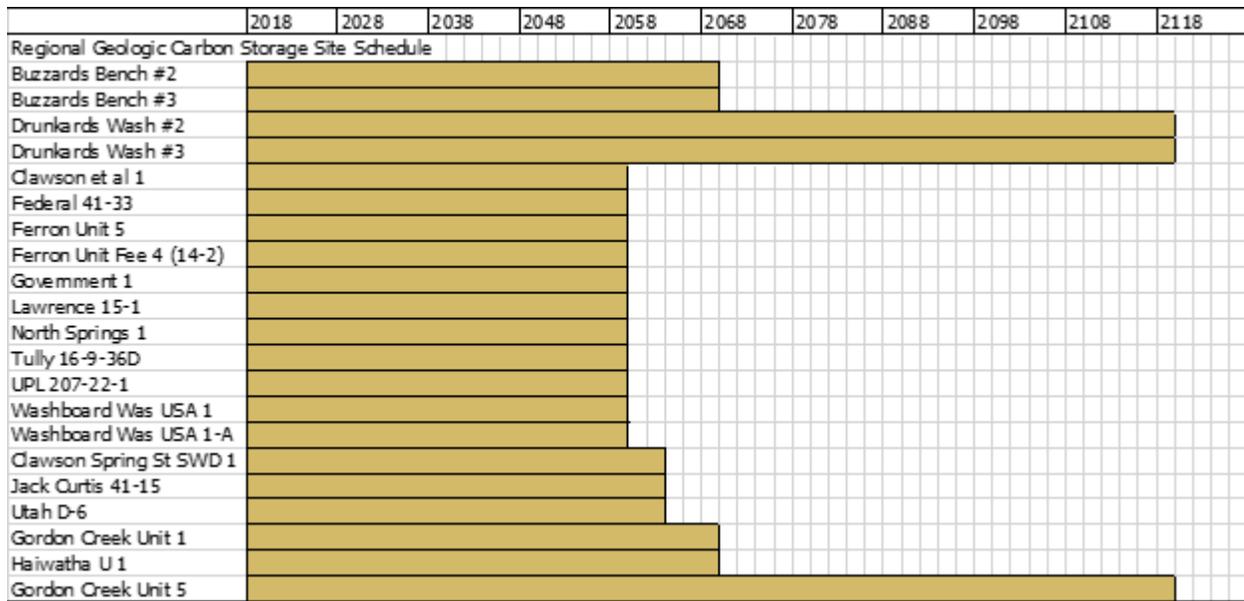


Figure 31. Injection schedule for the Regional Geologic Carbon Storage simulation.

Results

Results of this study show that it is feasible to store far more than the 50 million tons of anthropogenic CO₂ in the Buzzards Bench or Drunkards Wash area of Emery County, Utah. More than 1.4 billion tons of CO₂ were injected in the ‘Regional Capacity’ case, with no loss of containment over 1000 years, indicating that this area would make an ideal regional geologic carbon storage site.

Both of the ‘50MT’ cases successfully inject slightly more than the required capture mass of 50 million tons of CO₂ (Table 12). Results of the ‘Buzzards Bench 50MT’ case show that 6.1 MT or about 12% of the CO₂ dissolved into the formation brine by the end of the simulation (Table 13). The ‘Drunkards Wash 50MT’ case showed 4% more, or about 8.2 MT CO₂ dissolving into the formation brine over 100 years (Table 13). Greater plume movement over the same period at the Drunkards Wash site is likely causing this observed difference in CO₂ dissolution. As the plume moves, the supercritical CO₂ comes into contact with unsaturated brine, resulting in higher CO₂ dissolution than at the Buzzards Bench site. The mass of supercritical CO₂ is there for higher at the Buzzards Bench site (43.1 MT) than the Drunkards Wash site (41.6 MT) (Table 14). The amount of CO₂ that is at or below residual saturation and is effectively trapped is consistent across all cases at 6%. Both injection sites will make suitable areas to store the emissions from the Hunter Power Plant.

Results of the ‘Capacity’ cases indicate that almost double the CO₂ can be stored in the same area. Removing injection limitation greatly increases the mass of CO₂ that can be injected (Table 12). The ‘Buzzards Bench Capacity’ case injected double the mass of CO₂ (101 MT) that the rate limited case did (50.5 MT). The ‘Drunkards Wash & Buzzards Bench Capacity’ case injected not quite double what is injected at Buzzards Bench site (Table 12). It is likely that there is less injectivity at the Drunkards Wash site because it is at a slightly shallower depth and the bottom hole pressure reaches the limit quicker. As seen in the previous cases, there is more CO₂ dissolution and at the Drunkards Wash site than at the Buzzards Bench site (Table 13).

The simulation results showed there is the capacity to store all of the anthropogenic CO₂ emission from point-sources for all of Utah. The ‘Regional Capacity’ case indicates that a very significant amount of CO₂ can be stored in the Castle Dale/Price area, 1.4 billion tons (Table 12). Unlike the previous cases, this case shows that 25% of the CO₂ is going to dissolve into the formation brine, leaving only 80% in the mobile phase after a thousand years. The longer simulation time, 1000 years, versus 100 years for the previous four cases, give more time for the CO₂ plume to move and contact unsaturated brine, increasing CO₂ dissolution.

Table 12. The total mass of CO₂ in tons injected into the model domain.

Total Mass CO ₂ Injected [tons]	
Regional Capacity	1,412,952,644
Buzzards Bench & Drunkards Wash Capacity	180,478,080
Buzzards Bench Capacity	101,269,252
Buzzards Bench 50MT	50,525,976
Drunkards Wash 50MT	50,527,098

Table 13. The total mass of CO₂ dissolved in brine.

Total Mass Dissolved CO ₂ [tons]		
Regional Capacity	357,107,434	25.3%
Buzzards Bench & Drunkards Wash Capacity	25,306,228	14.0%
Buzzards Bench Capacity	10,033,749	9.9%
Buzzards Bench 50MT	6,143,243	12.2%
Drunkards Wash 50MT	8,151,902	16.1%

Table 14. The total mass of mobile supercritical CO₂.

Total Mass Mobile Spercritical CO ₂ [tons]		
Regional Capacity	1,141,116,004	80.8%
Buzzards Bench & Drunkards Wash Capacity	150,117,470	83.2%
Buzzards Bench Capacity	87,576,484	86.5%
Buzzards Bench P50	43,161,731	85.4%
Drunkards Wash P50	41,678,529	82.5%

Analysis of the CO₂ saturation distribution gave us even greater confidence in this area as an effective storage site. All simulation cases indicated that CO₂ would be effectively trapped for the foreseeable future. Analysis of the ‘Buzzards Bench 50MT’ case showed a plume size at the end of the simulation of about 4 km by 2 km (Figure 32). The plume doesn’t migrate towards the outcrop as was expected. There are two reasons that in combination create an effective pressure barrier to up-dip migration of the CO₂ plume, the salt water disposal injection and aquifer recharge from the outcrop area. This, in turn, keeps the CO₂ plume from moving and account for the lower mass of dissolved CO₂ seen in Table 13. The CO₂ plume is fairly evenly distributed vertically across the Navajo interval (Figure 32).

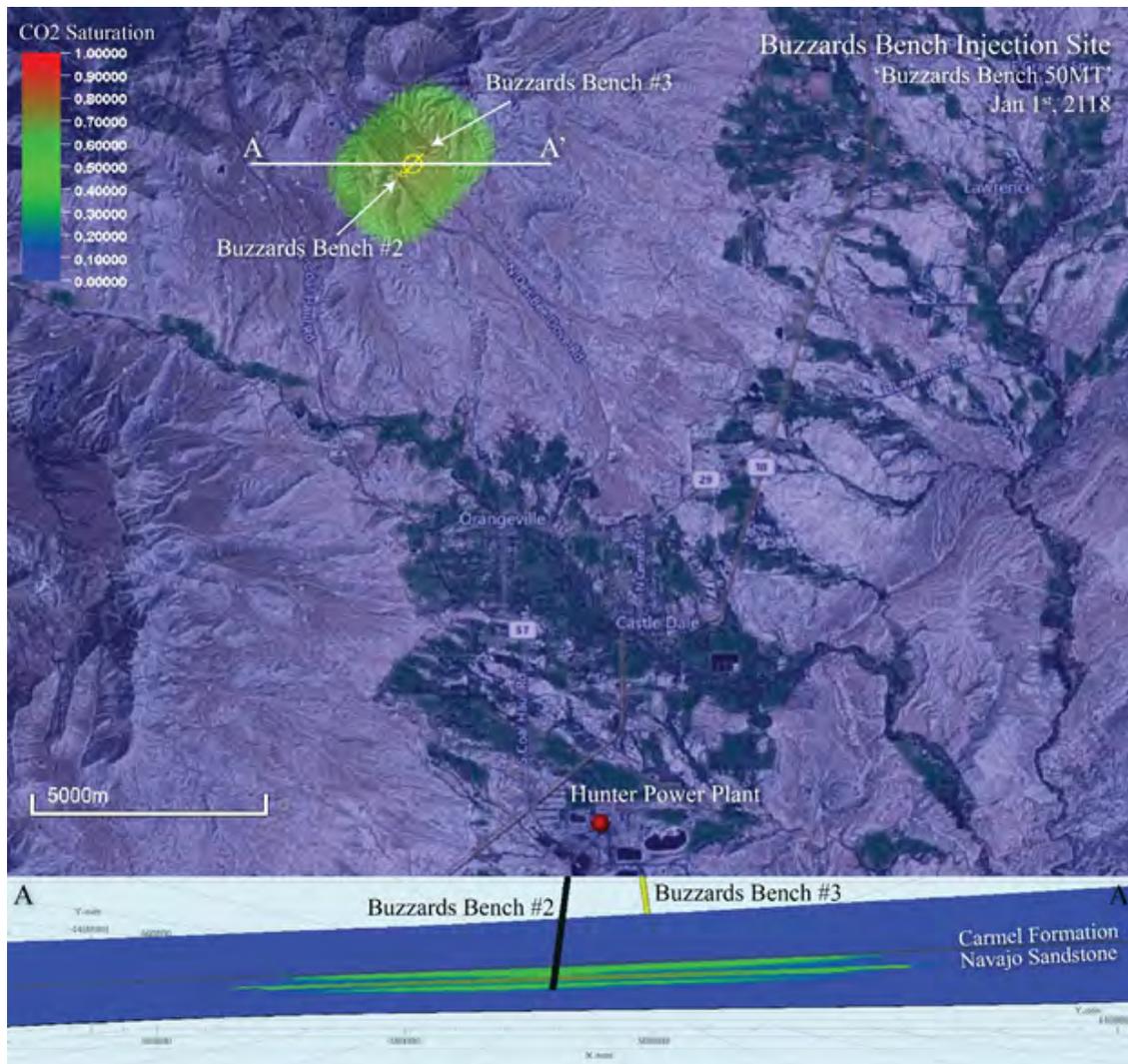


Figure 32. Results for buzzards bench at 50 MT total injection at the end of the simulation, 2118.

Results from the ‘Drunkards Wash 50MT’ case show a plume size of about 4 km by 2.5 km, similar in extent to what is seen in the ‘Buzzards Bench 50MT’ case. The main difference is that the plume has migrated about 0.5 km to the southwest, away from any potential outcrops (Figure 33). The plume movement is the reason that there is a higher fraction of dissolved CO₂ when compared to the ‘Buzzards Bench 50MT’ case. As with ‘Buzzards Bench 50MT’ case the CO₂ is evenly distributed across the Navajo interval, with the least amount of CO₂ in the middle zone and a small CO₂ in the Kayenta Formation.

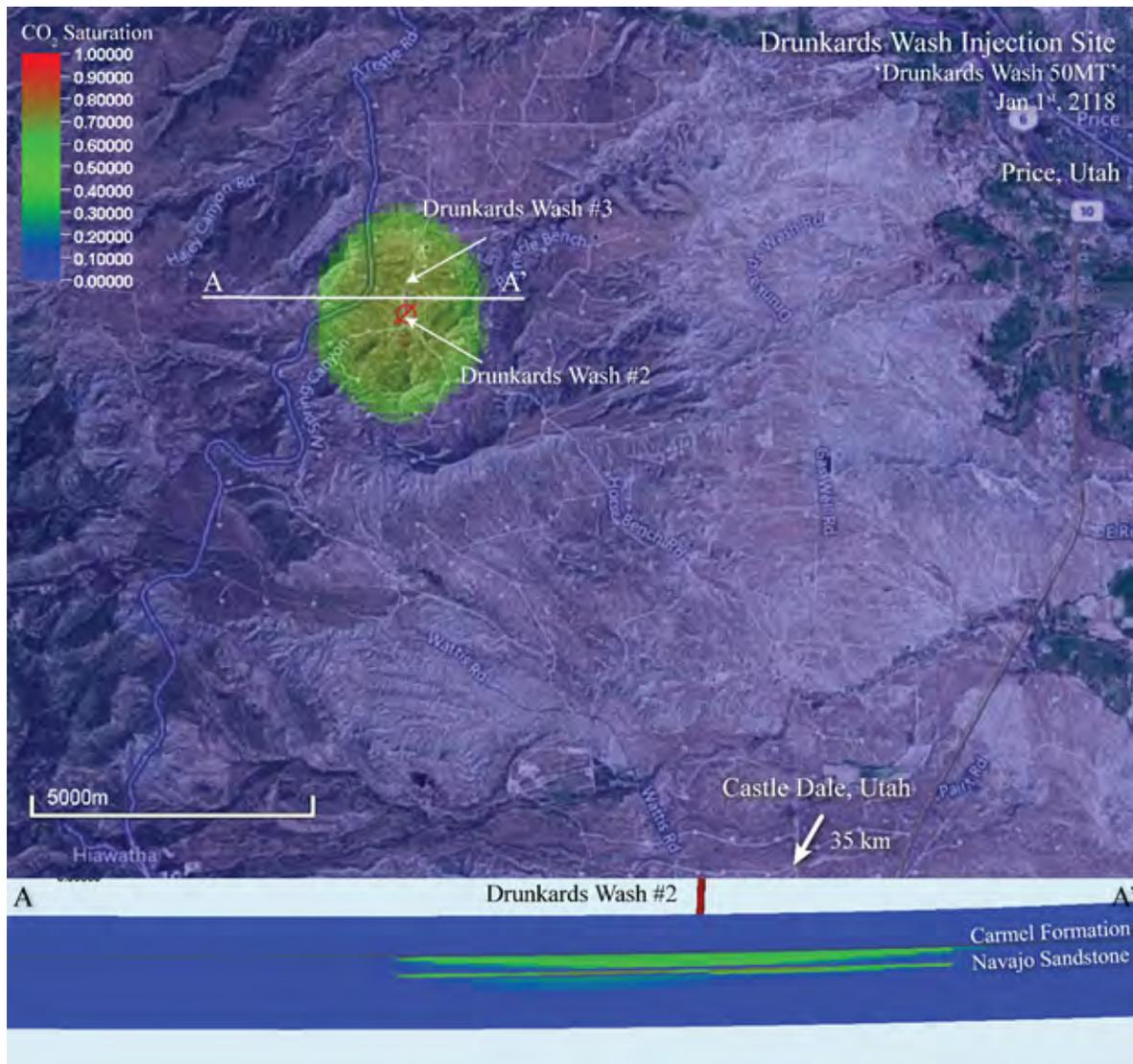


Figure 33. Results for drunkards wash at 50 MT total injection at the end of the simulation, 2118.

The saturation distributions for the ‘Buzzards Bench Capacity’ and the ‘Buzzards Bench & Drunkards Wash Capacity’ are very similar to what is seen in the previous cases. The plume sizes have increased in size a little, 4.3km x 3km at Buzzards Bench and 4.5km x 3.5km at Drunkards Wash, while the plume movement and distribution is very similar.

Analysis of the ‘Regional Capacity’ case shows very similar plume movement and shape as seen in all the previous cases. None of the CO₂ from any of the wells reaches the outcrops and is contained for the entire 1000-year simulation. At the end of the injection period (2118), there is very little plume movement away from the injection wells. Similar to what is seen in all previous cases (Figure 34). By the end of the simulation (3118), the CO₂ plumes have spread out laterally due to the buoyancy of CO₂ (Figure 35). There is very little lateral migration of the plumes beyond what is caused by the upward mobility of the CO₂. The plumes in the Buzzards Bench area don’t move laterally more than a kilometer. The plumes generated by the three wells at the very south of the model, Ferron Unit 5, Ferron Unit Fee 4(14-2), and UPL 207-22-1, have moved a couple of kilometers to the east towards the outcrop area of the San Rafael Swell. The plume

movement in the Drunkards Wash area is much larger than the rest of the model. This is likely due to the longer injection time, and consequently greater volume of CO₂ injected. There are not any outcrops in the area for the CO₂ to escape from, making this larger plume movement less of a concern.

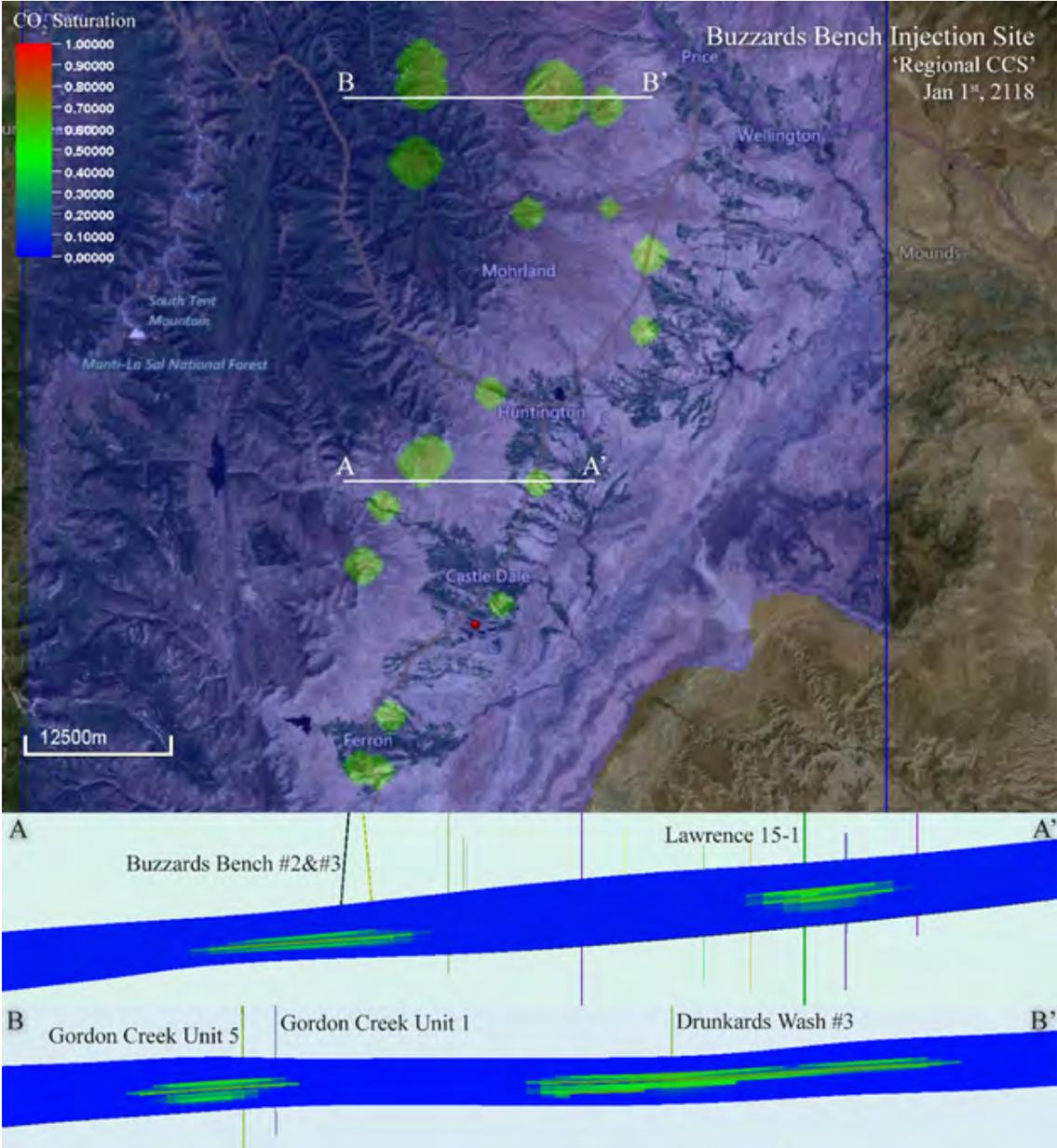


Figure 34. Results from the 'Regional Capacity' case showing the CO₂ saturation at the top of the Navajo at the end of CO₂ injection (top). Cross-sections A-A' shows the vertical CO₂ saturation profile in the Buzzards Bench area and cross-section B-B' shows the vertical CO₂ saturation distribution in the Drunkards Wash area (bottom).

A benefit of having two formations underlying the Navajo that are of reservoir quality is that they can accommodate additional CO₂. The injection pressure forced some of the CO₂ into the lower formations of the Kayenta and a little into the Wingate providing additional capacity. By the end of the simulation CO₂ has migrated vertically out of these reservoirs, but there is still

residual CO₂ trapped in these lower formations. This all makes this area of the Colorado Plateau an ideal location for continuous CO₂ injection for regional storage over a long-time period.

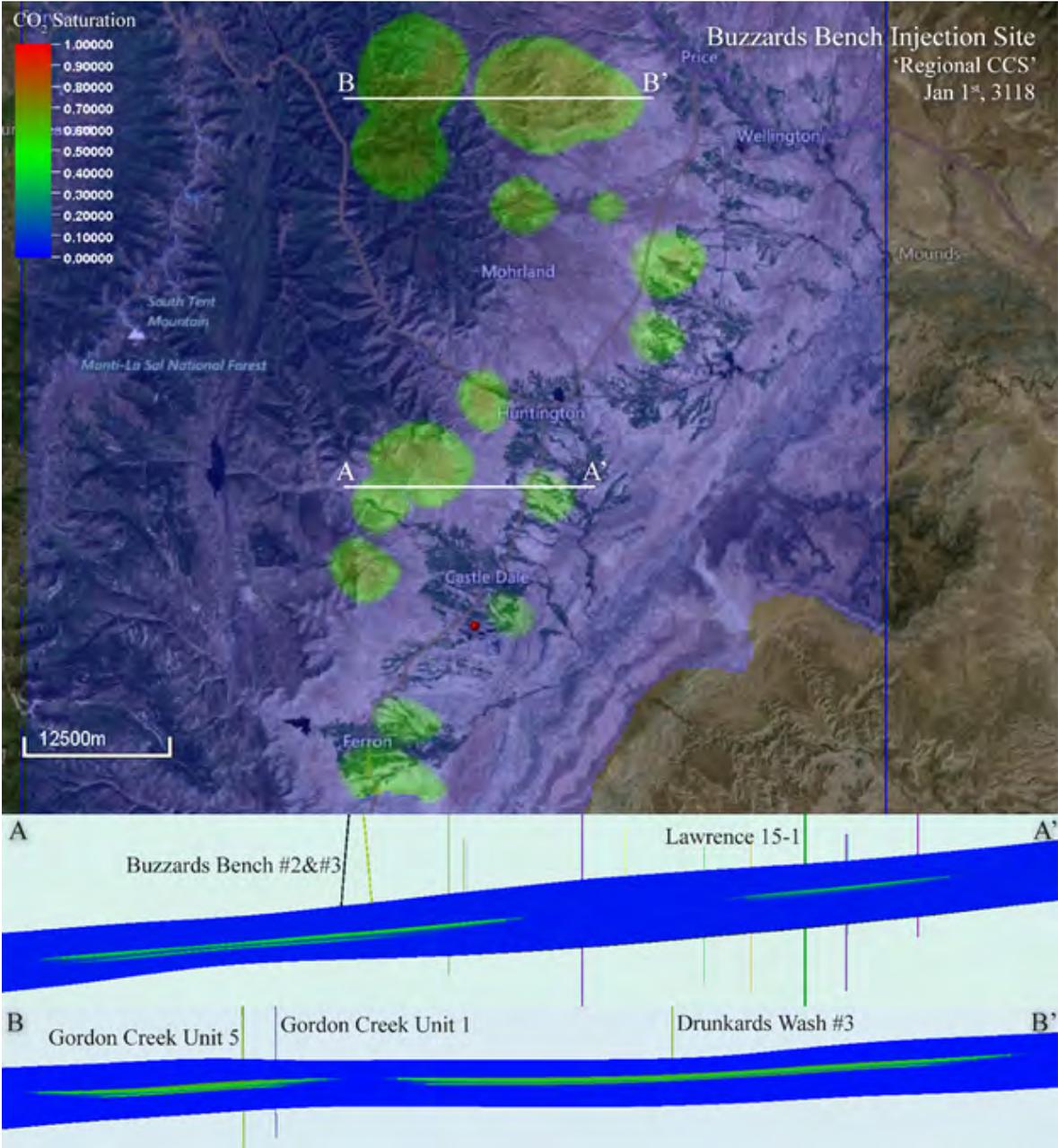


Figure 35. Results from the ‘Regional Capacity’ case showing the CO₂ saturation at the top of the Navajo at the end of the simulation (top). Cross-sections A-A’ shows the vertical CO₂ saturation profile in the Buzzards Bench area and cross-section B-B’ shows the vertical CO₂ saturation distribution in the Drunkards Wash area (bottom).

Conclusion and Discussion

The main conclusions of this study are as follows:

- 1) Both sites can effectively store the project’s target amount of CO₂, 50 million tons, effectively permanently. For the Buzzards Bench area the surface water recharge and distance to the

outcrops prevents the CO₂ from escaping to the atmosphere. In the Drunkards Wash area there is no outcrop for the CO₂ to escape from and is effectively and permanently stored.

2) This area has the capacity to be a regional geologic carbon storage site. Simulations showed that this area can accommodate all the point-source anthropogenic CO₂ emission from Utah for the foreseeable future, next 100 years. The area has a total estimated capacity of over 1.4 billion tons. The injected CO₂ doesn't migrate more than a couple of kilometers and is trapped for the full 1000-year simulation.

At first glance the area to the west of the San Rafael Swell encompassing the town of Castle Dale, Utah and the Buzzards Bench and Drunkards Wash gas fields does not look like a good candidate for CO₂ sequestration. The San Rafael Swell is an anticline with the target reservoir, the Navajo Sandstone, and seal, the Carmel Formation, outcropping along its spine. It would be assumed that any CO₂ injected in the vicinity would migrate to this area and escape to the atmosphere. But after a detailed simulation study using the best characterization data we could obtain, we determined that this area would make an ideal candidate for a regional geologic carbon storage site.

3.3 AREA OF REVIEW ASSESSMENT

EPA class VI guidance documents require that an Area of Review (AOR) be designated around the potential injection well. The AOR defined as the maximum allowable pressure differential between the target reservoir and the lowest overlying USDW that will cause reservoir fluid to migrate into the overlying USDW. It assumes that there is an open well that connects the target reservoir (Navajo Sandstone) with the lowermost USDW (Ferron Sandstone) and calculates the pressure differential allowed before fluid from the target reservoir flows up the well and into the USDW. The maximum areal extent of this pressure delta and CO₂ plume extent (whichever is larger) is then mapped out to give an area that must be examined for potential well leakage.

3.3.1 Area of Review Delineation by Analytical Methods

A formula (Equation 4) and guidance on defining and calculating the area of influence from a CO₂ injection well are specified in these guidance documents. Table 15 has the pressure, elevation, and fluid density information used in Equation 4.

Equation 4.

$$\Delta P_{if} = P_u + \rho_i g * (z_u - z_i) - P_i$$

Table 15. Parameters used to calculate the pressure differential for AOR delineation.

Formula Parameter			
Buzzards Bench	Drunkards Wash		
12,575,444	10,621,088	P_u	USDW Pressure
22,364,000	21,801,300	P_l	Reservoir Pressure
1020	1020	ρ_{o_i}	Reservoir Fluid Density
711	881	z_u	Elevation of USDW
-326	-232	z_l	Elevation of Reservoir

When Equation 4 is solved for our storage site, it shows that we have a near hydrostatic condition at Buzzards Bench and a slightly over pressurized condition at Drunkards Wash (Table 15). The guidance documents stipulate that if Equation 4 indicates a hydrostatic condition, then numerical simulation must be used to determine the AOR. A suite of simulations was then designed and executed to address the AOR requirement. See sections 3.2.2 and 3.3.2 for details on model design and results.

Table 16. Pressure delta results using the EPA formula.

DeltaP Buzzards Bench
583,671 Pa
5.84 bar
Drunkards Wash
-46,713 Pa
-0.47 bar

3.3.2 Area of Review Delineation and Risk Assessment with NRAP Tools

U.S. Environmental Protection Agency’s (EPA’s) Class VI regulations require owners or operators of carbon storage projects to determine an Area of Review (AoR) representative of project risk to underground sources of drinking water (USDWs). The AoR is an estimate of the region potentially impacted by the CO₂ injection and is used to develop monitoring plans to ensure protection of USDWs.

For this study, the approach is to use the National Risk Assessment Partnership (NRAP) tools developed by the U.S. Department of Energy (DOE) for quantitative risk assessment of geologic sequestration of carbon dioxide (CO₂) (Dilmore et al., 2016; Pawar et al., 2016) to perform the risk-based AoR assessment for Buzzards Bench and Drunkards Wash two sites.

Among the NRAP toolset used for this study, the Integrated Assessment Model for Carbon Storage (NRAP-IAM-CS) adopts a stochastic approach in which predictions address uncertainties in storage reservoirs, leakage scenarios, and shallow groundwater impacts. It is derived from detailed physics and chemistry simulation results that are used to train more computationally efficient models, referred to here as reduced-order models (ROMs), for each component of the system. The Reservoir Reduced-Order Model Generator (RRROM-Gen) (King,

2016) is a utility program for creating reservoir ROM lookup tables to be fed into the NRAP-IAM-CS model. These tools can be used to help regulators and operators define the AoR and better understand the expected spatiotemporal changes of changes in water quality caused by CO₂ and brine leakage from a storage reservoir into drinking water aquifers.

Approach

The risk-based AoR calculated using the NRAP-IAM-CS model is the area where CO₂ or brine leakage from a hypothetical open (i.e., uncemented) well connecting the storage reservoir to the shallow drinking water aquifer would cause drinking water quality to change outside no-impact thresholds. For both Buzzards Bench and Drunkards Wash sites, the no-impact thresholds are pH = 6.6 and total dissolved solids (TDS) = 420 ppm (i.e., pH not less than 6.6 and TDS not greater than 420 ppm). The boundaries of the AoR were determined by calculating pH and TDS in the shallow drinking water aquifer at hypothetical open wells located at increasing distances from the injection wells until no impact to the aquifer was observed. CO₂ or brine leakage at a location beyond the AoR boundary is possible, but the leaked mass is too small to cause pH or TDS to change outside their threshold values.

The Reservoir Reduced-Order Model – Generator (RROM-Gen) was used to create NRAP-IAM-CS model reservoir ROM look-up tables from the 3D reservoir simulations performed with the ECLIPS code (Exploration Consultants Limited (ECL) Implicit Program for Simulation Engineering in a native format).

Reservoir pressures and CO₂ saturations were calculated for the top of Navajo formation at different simulation times including beginning of injection, during injection, at the end of injection, post injection period and at the end of simulation at 100 years for both sites. For each site, thirteen reservoir scenarios were simulated with different permeability, porosity, and anisotropy of formation sampled; and also with varied CO₂ injection rate and duration. The total amount of CO₂ injected are 50 MT for each scenario.

NRAP-IAM-CS (Pawar et al., 2017) utilizes results of reservoir simulations through lookup tables for reservoir pressures and CO₂ saturations to compute CO₂ and brine leak rates through wellbore. Potential leakage wells inside AoR were used in the risk assessment CO₂ and brine leakage calculations.

Reservoir Pressure and CO₂ Saturation

Following figures show reservoir pressure and CO₂ saturation processed by RROM-Gen for one of the reservoir scenarios at Buzzards Bench and Drunkards Wash, respectively. In this scenario (1), reservoir has CO₂ injection rate of 2.5Mt/yr, injection duration 20 years, reservoir permeability 17.16 mD, reservoir porosity 12%, and reservoir anisotropy (kz/kx) 0.05 mD/mD.

Figure 36 and Figure 37 show the spatial distribution of scenario 1 reservoir pressures and CO₂ saturations at three different times for Buzzards Bench. These times reflect initial conditions (0 years), after 20 years of injection (20 years), and after an additional 80 years of post-injection monitoring (100 years). The pressure values from these modeling results were used as inputs into the NRAP-IAM-CS to determine the AoR and potential leakage from a hypothetical open wellbore.

NRAP-IAM-CS Model Setup

Buzzards Bench:

- Reservoir top elevation -331 m (top of the Navajo)
- Hypothetical well Open well
- USDW Generic carbonate aquifer geochemistry
- USDW Impact criterion No impact
- Reservoir Brine Molality 1.9 mole/kg
- USDW hydrologic parameters:
 - Thickness 262 m
 - Top elevation 968 m
 - Pressure 11.03 MPa
 - Temperature 24.6 °C
 - Permeability 1.15e-12 m²
 - Porosity 0.2

Drunkards Wash:

- Reservoir top elevation -240 m (top of the Navajo)
- Hypothetical well Open well
- USDW Generic carbonate aquifer geochemistry
- USDW Impact criterion No impact
- Reservoir Brine Molality 1.9 mole/kg
- USDW hydrologic parameters:
 - Thickness 209 m
 - Top elevation 1091 m
 - Pressure 9.6 MPa
 - Temperature 20.6 °C
 - Permeability 1.15e-12 m²
 - Porosity 0.2

Reservoir Pressure – 0 Yrs

Reservoir Pressure – 20 Yrs

Reservoir Pressure – 100 Yrs

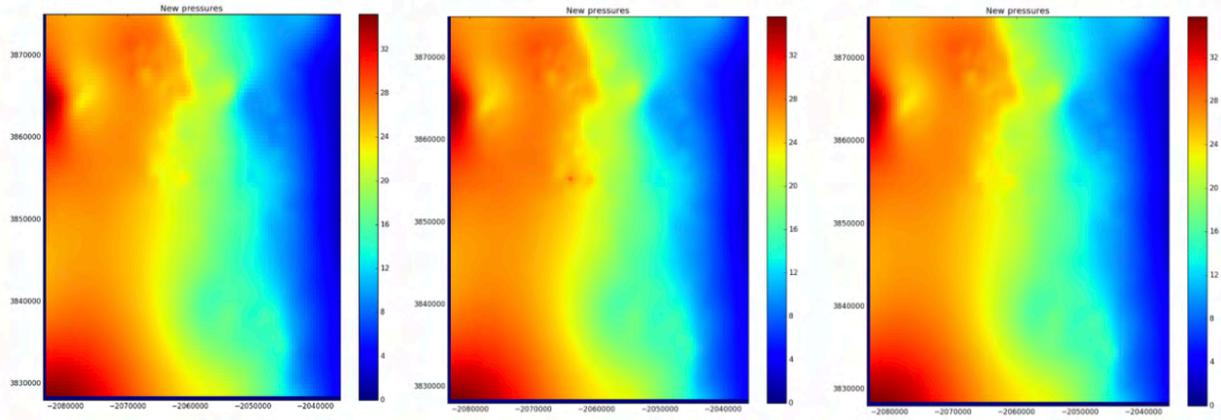


Figure 36. Plots showing predicted pressures in the storage reservoir due to CO₂ injection.

CO₂ Saturation – 0 Yrs

CO₂ Saturation – 20 Yrs

CO₂ Saturation – 100 Yrs

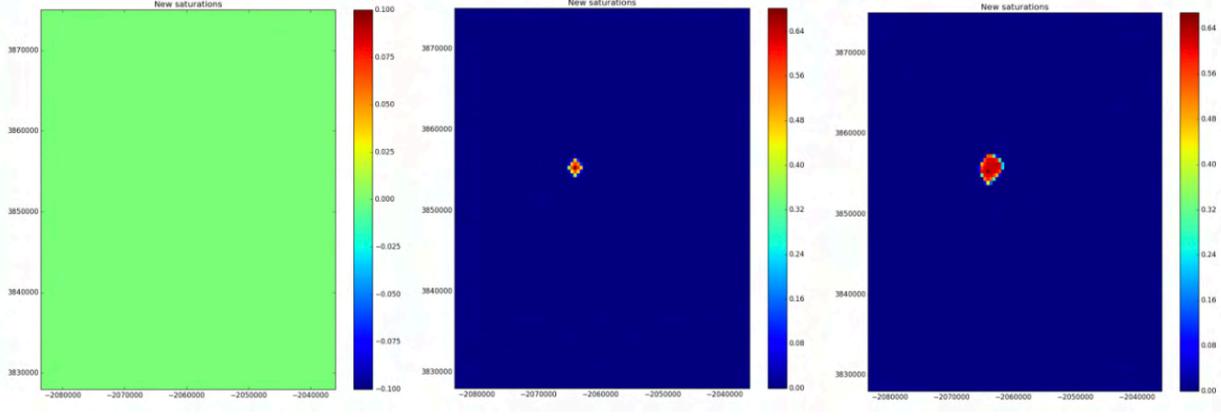


Figure 37. Plots showing predicted CO₂ saturations in the storage reservoir due to CO₂ injection.

Figure 38 and Figure 39 show the spatial distribution of scenario 1 reservoir pressures and CO₂ saturations at three different times for Drunkards Wash.

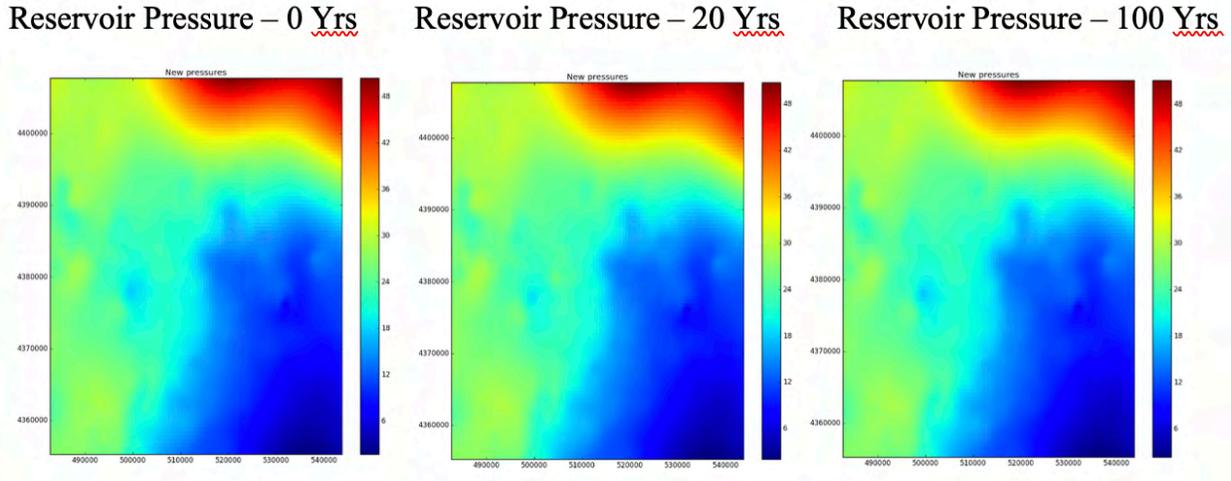


Figure 38. Plots showing predicted pressures in the storage reservoir due to CO₂ injection.

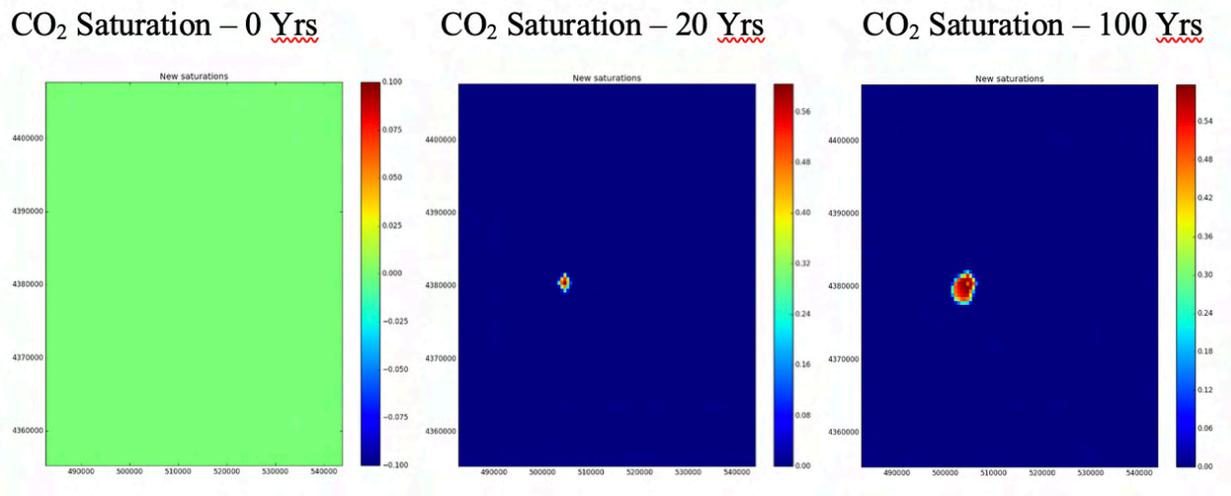


Figure 39. Plots showing predicted CO₂ saturations in the storage reservoir due to CO₂ injection

Risk based Area of Review Delineation Process

Risk-based AoR is determined by the impact to USDW due to wellbore leakage. AoR is defined as an area outside of which there is no impact to USDW due to leakage through a hypothetical open well (i.e. zero plume volumes of TDS > 420 ppm and pH < 6.6).

For risk-based AoR delineation, a hypothetical open well is placed at various locations around the injection well. Multiple different cases were simulated, each representing a distinct spatial location of the hypothetical well. Note that each IAM simulation had only one open well. For both sites, the simulation duration are set to be 100 years.

IAM model sampled over all 13 reservoir scenarios for both sites. Figure 40, Figure 41 and Figure 42 show example of AoR delineation process model results for hypothetical open wells located at a distance of 1, 2 and 3 km from the North of injection well at Drunkards Wash for one of the 30 year injection duration reservoir scenarios.

Figure 40 and Figure 41 demonstrate:

- No CO₂ and brine leakage was found in hypothetical open wellbores located beyond 3 km from the injection well.
- CO₂ and Brine leakage gradually decreases for hypothetical open wellbore located farther away from the injection well.

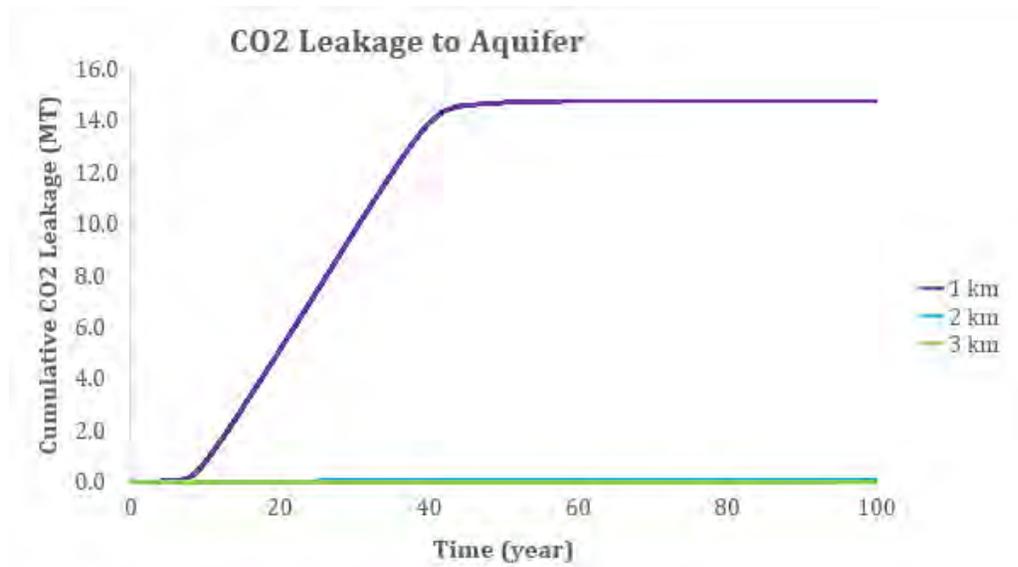


Figure 40. Cumulative CO₂ leakage to groundwater aquifer from wells located at different locations from the injection well.



Figure 41. Cumulative brine leakage to groundwater aquifer from wells located at different locations from the injection well.

Figure 42 and Figure 43 show:

- The reservoir pressure at hypothetical open wellbores located at 1km, 2km and 3km away from the injection well. For this 30 year injection and 70 year of post-injection monitoring scenario, pressure builds over first 30 years and drops off to a common level after about an additional 10 years.
- The CO₂ saturation plume extends 3 km from the injection well.

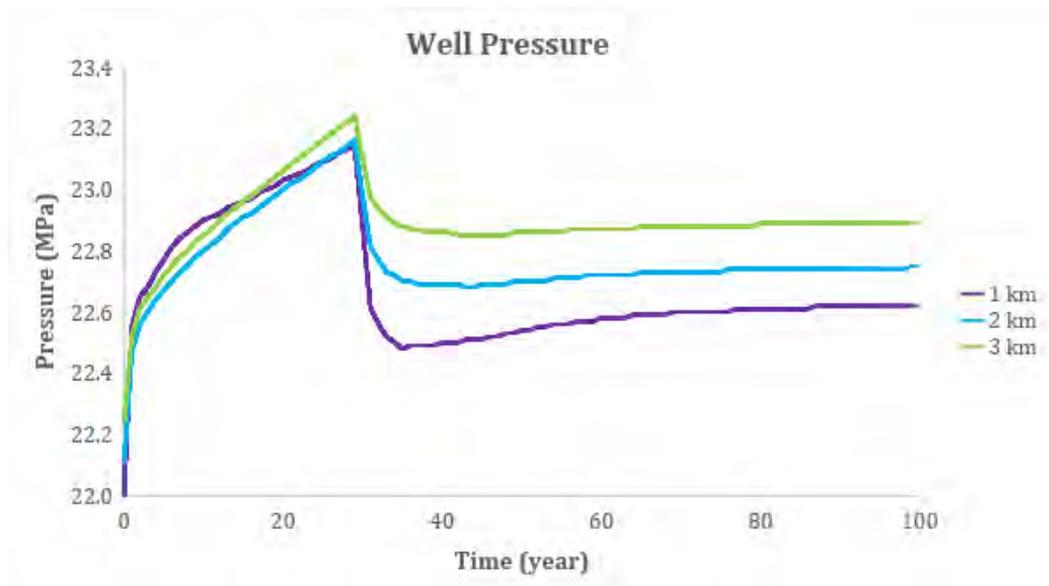


Figure 42. Time-dependent reservoir pressure plots at different well-placement locations.

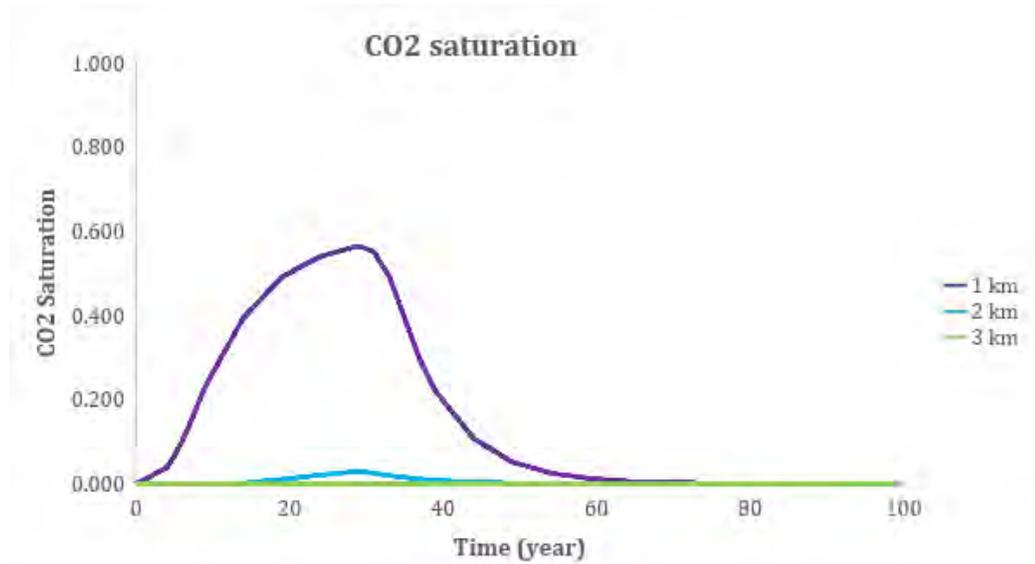


Figure 43. Time-dependent CO₂ saturation plots at different well-placement locations.

Figure 44 and Figure 45 demonstrate that:

- There is no pH and TDS impact due to leakage from hypothetical open wellbores located beyond 3 km from the injection well.
- The time at which the pH and TDS impact starts increases with the distance of hypothetical open wellbore from the injection well.

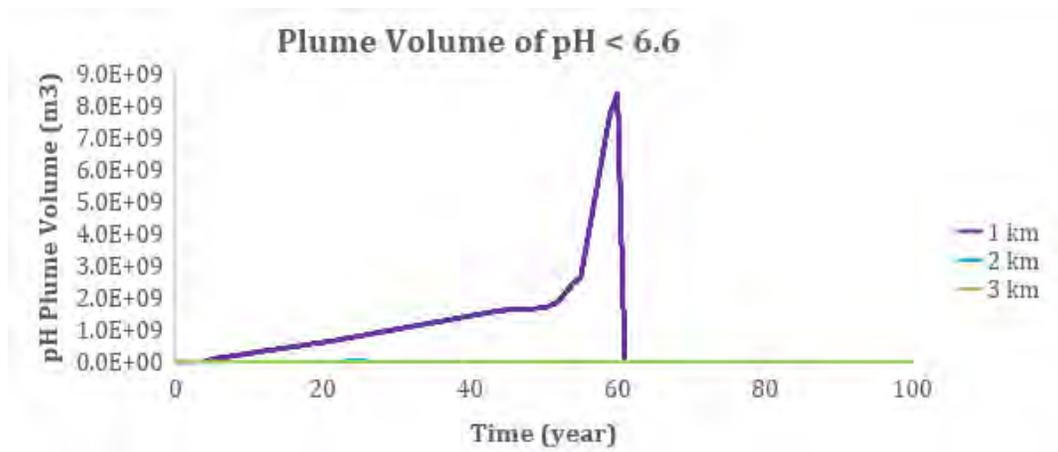


Figure 44. Time-dependent volume of pH < 6.6 plume due to leakage from wells placed at different locations.

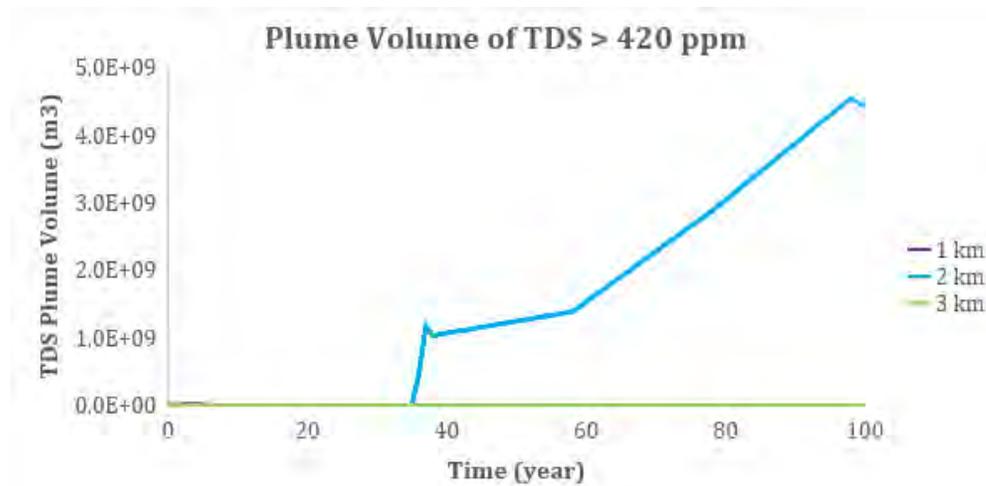


Figure 45. Time-dependent of volume of TDS > 420 ppm plume due to leakage from wells placed at different locations.

Results

Risk-based analysis employing hypothetical wells placed at different locations around the injection well led to delineation of AoR for Buzzards Bench and Drunkards Wash as follows:

The AoR are irregular shaped area surrounding the injection well for both sites. Note that the AoR delineation processed in this study is a conservative estimate, because the criteria used for delineation AoR is that it is an area outside of which there is no impact to USDW due to leakage through a hypothetical open well (i.e. zero plume volumes of TDS > 420 ppm and pH < 6.6) for ANY of the 13 reservoir scenarios. As IAM only identifies models with x- and y- axes that are horizontal and vertical, the Buzzards Bench model had to be rotated by 55.4445 degrees clockwise, during which process the x- and y- coordinates were rotated. Once IAM analysis was completed, the rotated coordinates were back-transformed to the original coordinate system (as shown in Table 17).

Figure 46 and Figure 47 show the AoR shape for Buzzards Bench and Drunkards Wash, respectively. Note that Buzzards Bench site coordinates may need to be rotated as the coordinates for reservoir results were rotated.

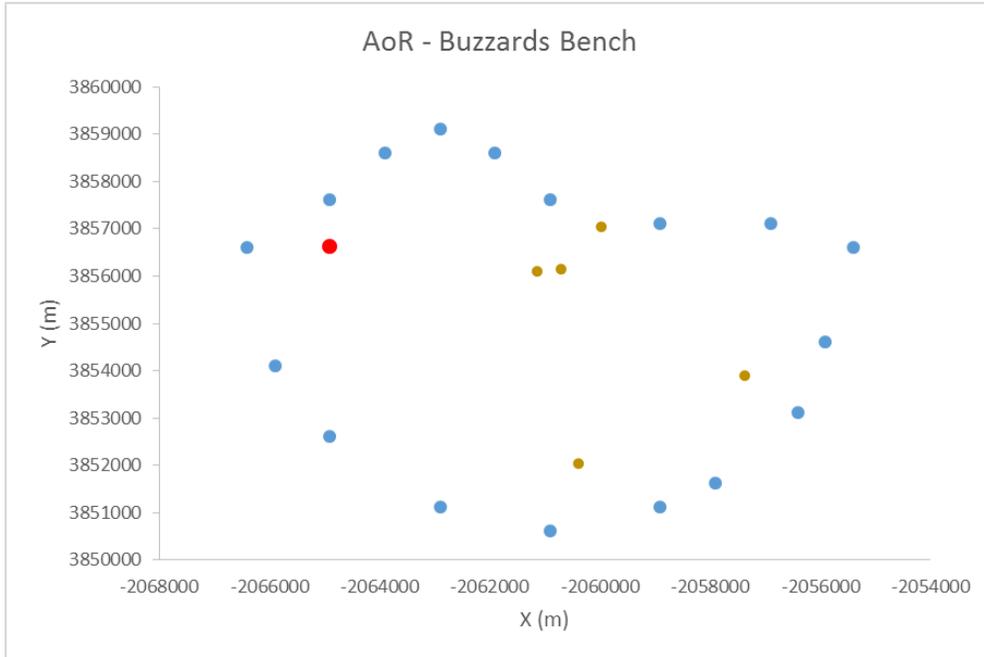


Figure 46. Buzzards Bench site risk-based AoR range shown in blue dots. The Red dot is the injection well location, and the brown dots are the potential leakage wells located inside the AoR.

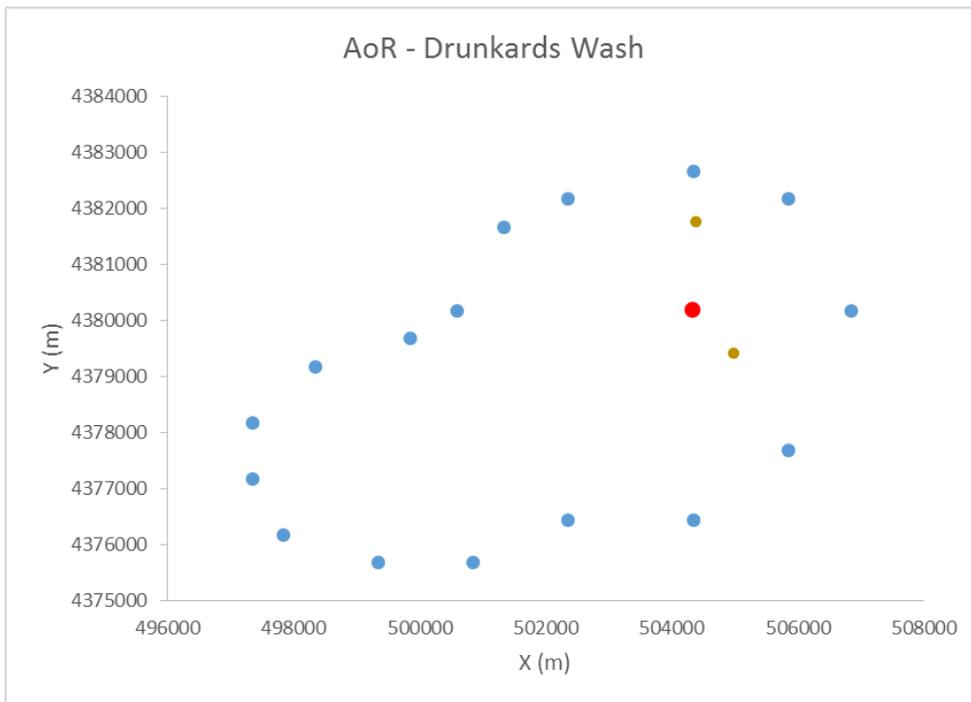


Figure 47. Drunkards Wash site risk-based AoR range shown in blue dots. The Red dot is the injection well location, and the brown dots are the potential leakage wells located inside the AoR.

Table 17 and Table 18 show the AoR boundary points coordinates for the two sites, respectively. Injection well location and inside AoR potential leakage well locations are also included in the tables.

Table 17. Coordinates of injection well, AoR boundary points and potential leakage wells inside AoR for Buzzards Bench.

Well Locations	X-rotated (m)	Y-rotated(m)	X-original (m)	Y-original (m)
Injection Well 1 (IW)	- 2064908	3856616	486878	4347445
AoR boundary point Location 1	- 2066408	3856616	485643	4348296
AoR boundary point Location 2	- 2055408	3856616	494702	4342057
AoR boundary point Location 3	- 2064908	3857616	487445	4348269
AoR boundary point Location 4	- 2064908	3852616	484609	4344151
AoR boundary point Location 5	- 2056408	3853116	491893	4339742
AoR boundary point Location 6	- 2060908	3850616	486769	4340235
AoR boundary point Location 7	- 2060908	3857616	490740	4346000
AoR boundary point Location 8	- 2058908	3857116	492103	4344454
AoR boundary point Location 9	- 2058908	3851116	488700	4339513
AoR boundary point Location 10	- 2062908	3851116	485406	4341781
AoR boundary point Location 11	- 2062908	3859116	489943	4348370
AoR boundary point Location 12	2056908	3857116	493750	4343320
AoR boundary point Location 13	- 2057908	3851616	489807	4339357
AoR boundary point Location 14	- 2065908	3854116	484636	4345954
AoR boundary point Location 15	- 2055908	3854616	493156	4340693
AoR boundary point Location 16	- 2063908	3858616	488836	4348525
AoR boundary point Location 17	- 2061908	3858616	490483	4347391
Inside AoR potential leakage well location 1	- 2060374	3852025	488008	4341093
Inside AoR potential leakage well location 2	- 2061131	3856092	489691	4344872
Inside AoR potential leakage well location 3	- 2057356	3853877	491544	4340906
Inside AoR potential leakage well location 4	- 2060697	3856134	490073	4344660
Inside AoR potential leakage well location 5	- 2059968	3857032	491182	4344986

Table 18. Coordinates of injection well, AoR boundary points and potential leakage wells inside AoR for Drunkards Wash.

Well Locations	X (m)	Y(m)
Injection Well 1 (IW)	504347	4380173
AoR boundary point Location 1	504347	4382673
AoR boundary point Location 2	504347	4376423
AoR boundary point Location 3	506847	4380173
AoR boundary point Location 4	500597	4380173
AoR boundary point Location 5	502347	4376423
AoR boundary point Location 6	502347	4382173
AoR boundary point Location 7	505847	4382137
AoR boundary point Location 8	505847	4377673
AoR boundary point Location 9	500847	4375673
AoR boundary point Location 10	499347	4375673
AoR boundary point Location 11	497347	4378173
AoR boundary point Location 12	498347	4379173
AoR boundary point Location 13	497847	4376173
AoR boundary point Location 14	497347	4377173
AoR boundary point Location 15	501347	4381673
AoR boundary point Location 16	499847	4379673
Inside AoR potential leakage well location 1	504401	4381752
Inside AoR potential leakage well location 2	504984	4379410

Figure 48, Figure 49, Figure 50 and Figure 51 show the CO₂ and brine leakages from the potential leakage wells inside the AoR for all 13 reservoir scenarios for Buzzards Bench and Drunkards Wash, respectively. The leakage calculations are carried out assuming all these wells with cement permeability of $5 \times 10^{-11} \text{ m}^2$

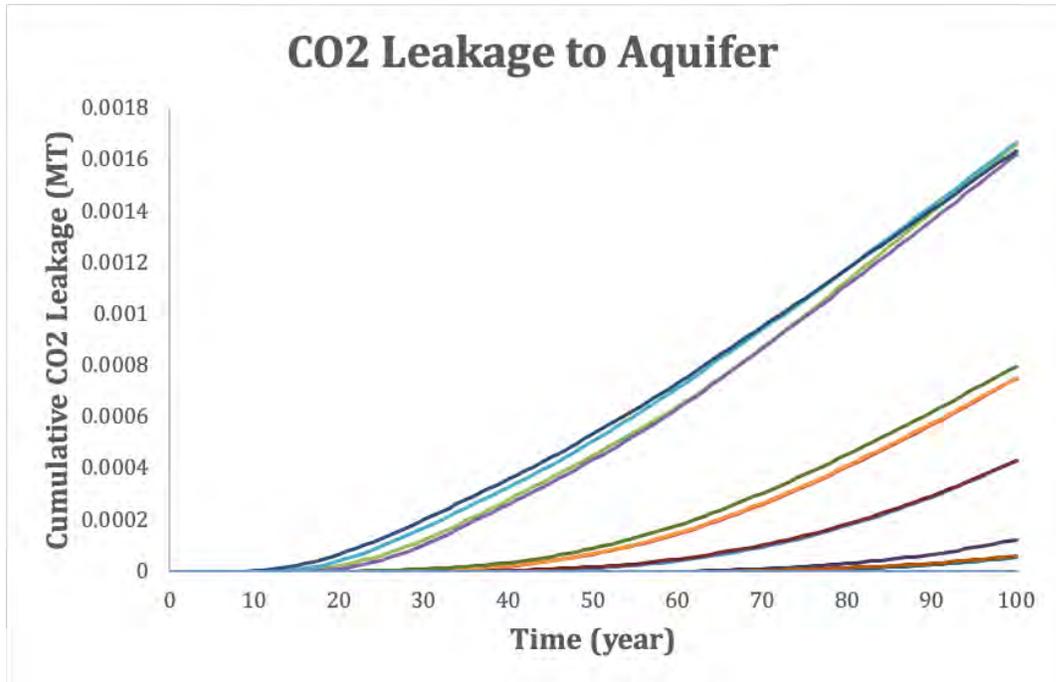


Figure 48. Cumulative CO₂ leakage to groundwater aquifer from potential leakage wells inside AoR for Buzzards Bench.

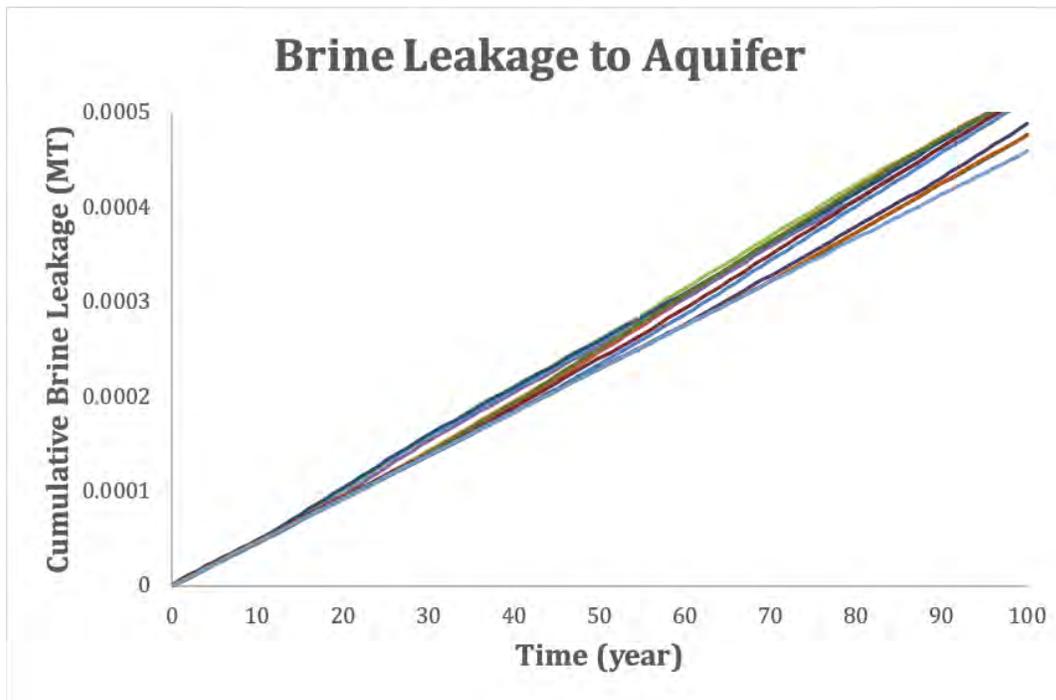


Figure 49. Cumulative brine leakage to groundwater aquifer from potential leakage wells inside AoR for Buzzards Bench.

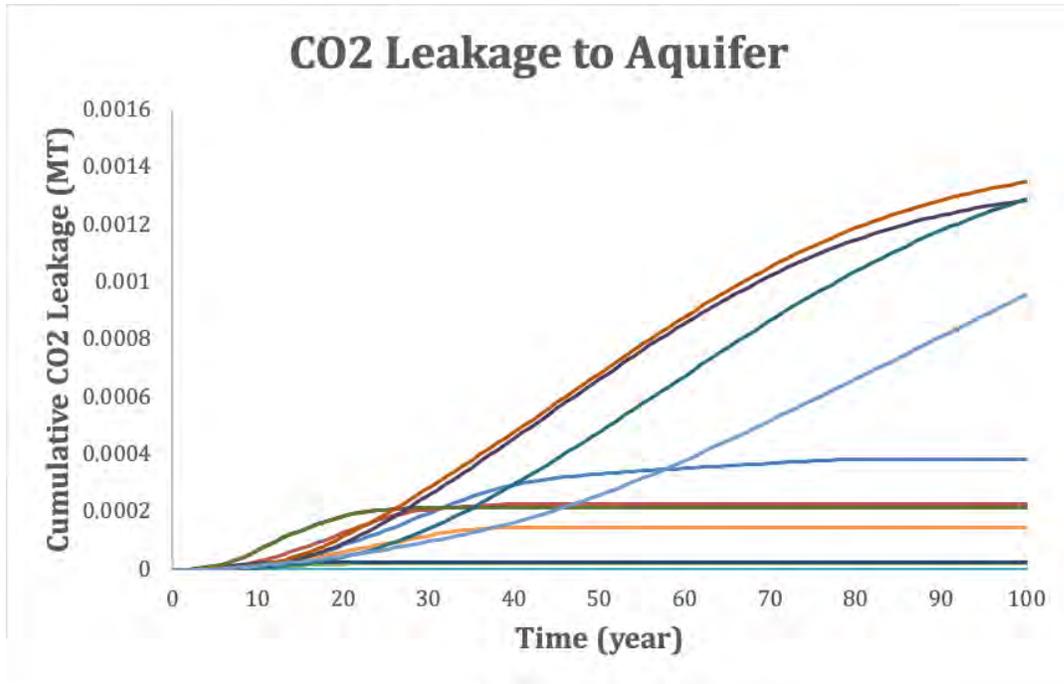


Figure 50. Cumulative CO₂ leakage to groundwater aquifer from potential leakage wells inside AoR for Drunkards Wash.

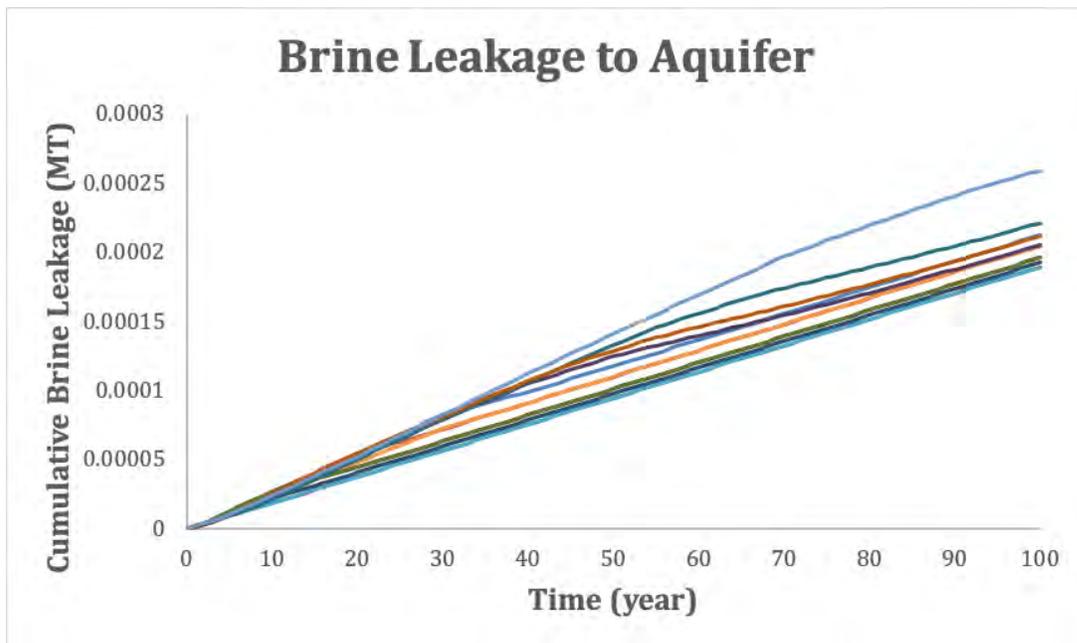


Figure 51. Cumulative brine leakage to groundwater aquifer from potential leakage wells inside AoR for Drunkards Wash.

3.4 RISK ASSESSMENT AND MITIGATION

3.4.1 Qualitative Risk Assessment

Catalog of Project Challenges

At an early stage of the project (Q2 2017), the project team has identified Catalog of Project Challenges for this Risk Assessment and Mitigation subtask:

- (1). Scarcity of data. Similar to other saline storage projects, the project suffers from lack of data in the target saline formation due to the lack of interest in the past. This might cause significant uncertainty in the feasibility study. Assessment of storage capacity, injectivity, and containment should account for this uncertainty.
- (2). Geologic feature (target formation cropping out). Due to the regional geologic structure, proposed target formations are cropping out around San Rafael Swell. If the CO₂ continuously migrates through up-dip direction due to the buoyant force, it would undergo phase change and reach the surface. This should be well understood during the feasibility study and be considered for MVA plan.

Risk Registry

The project team has worked on conducting a Failure Mode and Effects Analysis (FMEA) with information gathered under other subtasks. A type of FMEA has been used for analysis of specific operational (programmatic) risk. This is a procedure in development and operations management for analysis of potential failure modes within a system for classification by the severity and likelihood of the failures. A successful FMEA activity helps a team to identify potential failure modes based on past experience with similar products or processes, enabling the team to design minimal effect of those failures out of the system with the minimum effort and resource expenditure is widely used in industries in various phases of the life cycle of a process. Failure modes are any errors or defects in a process, design, or item. Effects analysis refers to studying the consequences of those failures.

FMEA can provide an analytical approach, when dealing with potential failure modes and their associated causes. When considering possible failures – like safety, cost, performance, scheduling, reliability, and personnel changes – a manager can get a lot of information about how to alter the process, in order to avoid or minimize the adverse effects of these events. FMEA provides a tool to determine which risk has the greatest concern, and therefore an action is needed to prevent, minimize, or provide alternate options for a problem before it arises. The development of these specifications will increase probability of a successful project. The risk priority number, which is the product of occurrence, severity, and detection, will provide a gauge of relative importance.

The project team assembled a risk registry for the Primary (Buzzards Bench) and Secondary (Drunkards Wash) Site options, which summarize potential risks for all major activities of a commercial-scale CCS project.

A total number of 404 risk features/events/processes (FEPs) are listed in the risk registry. It includes 23 main aspects of risk categories, including programmatic/operational risks as well as sequestration/technical risks. We continuously updated the risk registry, including relative ranking of project risks; risk categorization by cause and potential impacts; identify risks that require near-term vs. long-term responses, and identify risks that require more investigation.

The FEPs were evaluated based on site-specific information via Failure Modes and Effects Analysis (FMEA). In particular, potential failure mode, cause of failure, potential failure effect, method of detecting failure early, and risk prevention steps/risk mitigation steps are defined for each FEP. The project team assessed failure probability (P), failure severity (S), and difficulty of failure detection (D) on a scale of 1~5, with lower values suggesting lower failure probability, lower failure severity, and easier failure detection. As this project is focused on pre-feasibility study, many FEPs are not applicable (e.g., site construction and operation); therefore, zero values were assigned to those FEPs. Risk priority number was calculated as the product of the P, S, and D. All FEPs were sorted by risk priority numbers. Due to the cost of CO₂ capture facilities, FEPs associated with CO₂ sources exhibit high risk priority numbers.

Please refer to the Appendix J for the full Risk Registry.

3.4.2 Quantitative Risk Assessment

Uncertainty analysis of AoR

For each proposed storage site, a set of 13 Eclipse simulations were used to develop reduced order models (ROMs) for calculating area that has overpressure greater than 5 bar and 10 bar, respectively. The same set of simulation results were also used by NRAP-IAM-CS tool to generate risk-based AoR. Accuracy of ROMs are measured by R2 between results from ROMs and overpressure area based on Eclipse simulation results, as shown in Table 19. During injection period (up to 30 years to 2048), predictions from ROMs are very close to Eclipse simulation results with most of R2 values greater than 0.95. During monitoring period, most ROMs hold acceptable accuracy with a few exceptions where there were no ROMs developed as not enough training data were provided.

Table 19. R2 between results from ROMs and Eclipse simulations (N/A indicates not enough data to generate ROMs, therefore R2 values are missing).

Case/Year	2023	2028	2038	2048	2068	2098	2118
5 bar @ Buzzards Bench	0.996	0.989	0.786	0.991	0.974	0.955	0.961
5 bar @ Drunkards Wash	0.985	0.983	0.959	0.903	N/A	0.704	0.697
10 bar @ Buzzards Bench	0.964	0.987	0.875	0.957	0.849	N/A	N/A
10 bar @ Drunkards Wash	0.956	0.942	0.969	0.779	0.917	0.848	0.866

The validated ROMs were employed to predict overpressure areas at both proposed sites with 500 realizations, parameters of which were randomly generated from the uncertainty range

shown in **Error! Reference source not found.** Figure 52 and Figure 53 show area with 5 bar overpressure at Buzzards Bench and Drunkards Wash sites, respectively. The risk-based AoR predicted by NRAP-IAM-CS tool is presented in black lines for both sites (63.44 km² for Buzzards Bench and 44.45 km² for Drunkards Wash). It is shown that uncertain range of 5-bar overpressure area increases with time at both sites. The 5-bar overpressure area at year 2023 (i.e., 5 years of injection) has the least deviation from the risk-based AoR prediction by NRAP-IAM-CS (black vertical lines). The 10-bar overpressure areas at two sites are shown in Figure 54 and Figure 55. The risk-based AoR predictions fall in the uncertain range of 10-bar overpressure areas forecasted by ROMs. The comparison between overpressure area and risk-based AoR implies that NRAP-IAM-CS tool was able to predict a reasonable AoR with limited data (i.e., 13 simulation results versus 500 realizations in this case).

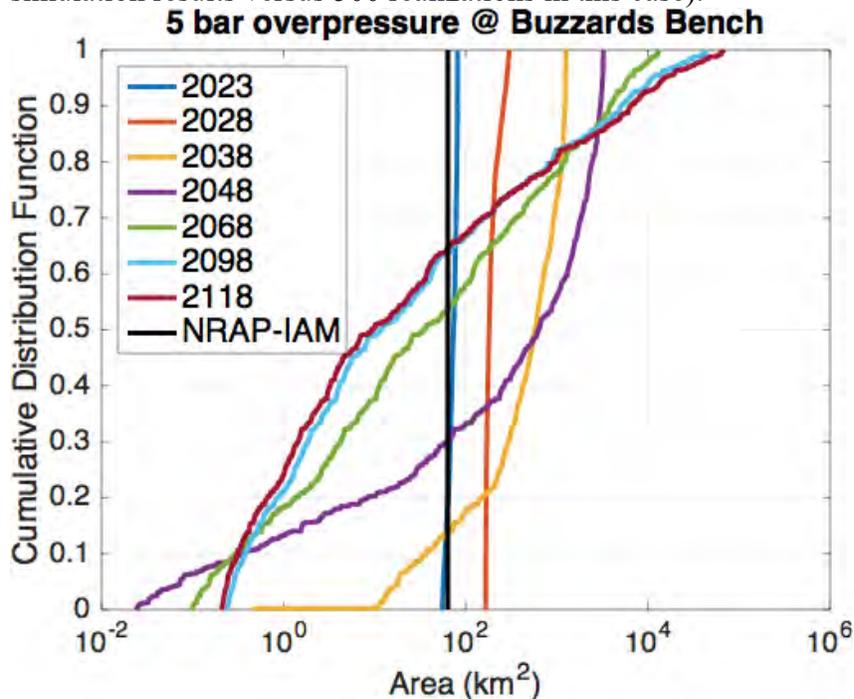


Figure 52. Cumulative distribution function of 5-bar overpressure area at Buzzards Bench.

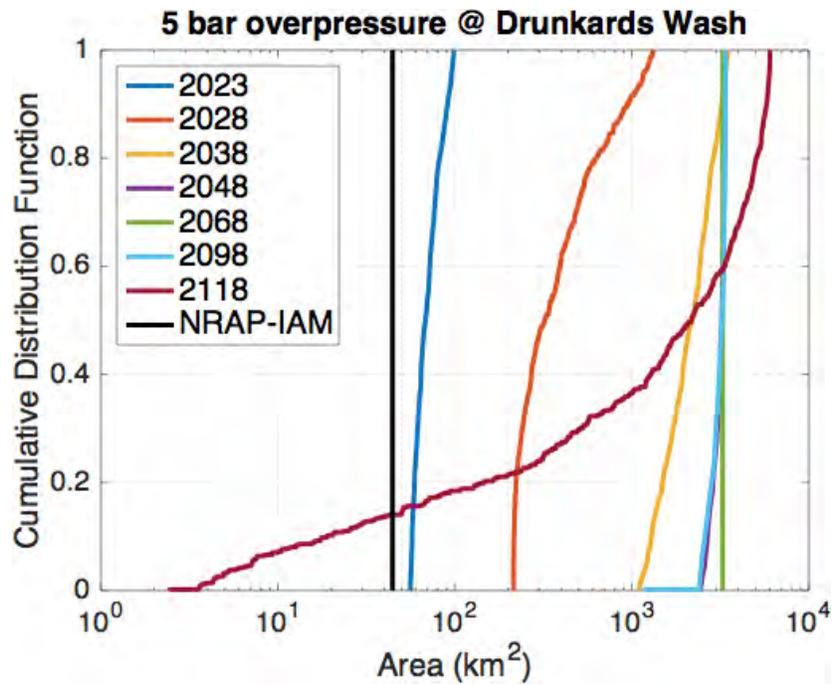


Figure 53. Cumulative distribution function of 5-bar overpressure area at Drunkards Wash (ROMs at 2068 are missing, an average of Eclipse simulation results was used to calculate the area, green line).

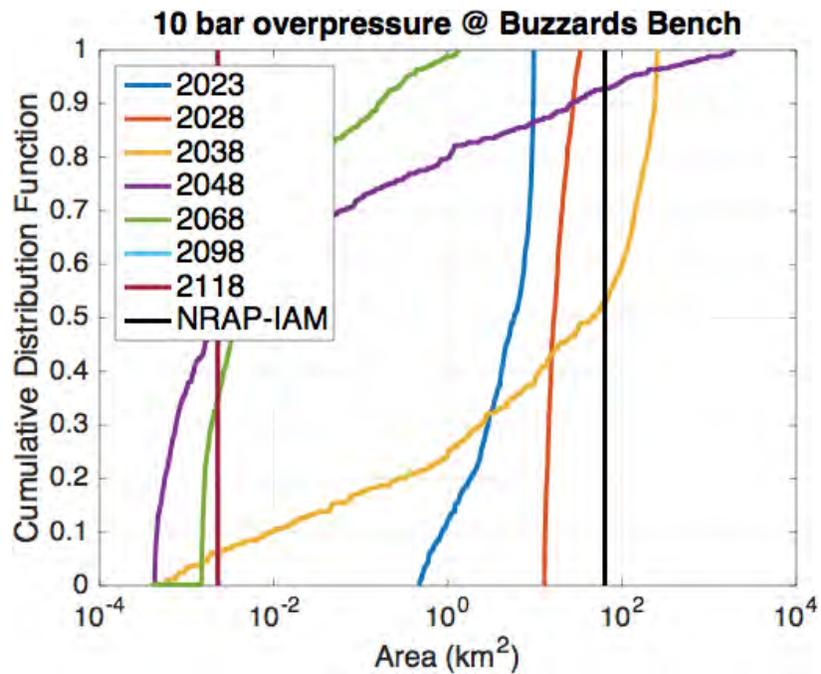


Figure 54. Cumulative distribution function of 10-bar overpressure area at Buzzards Bench (ROMs at 2098 and 2118 are missing, average of Eclipse simulation results were used to calculate the area, light blue and dark red lines).

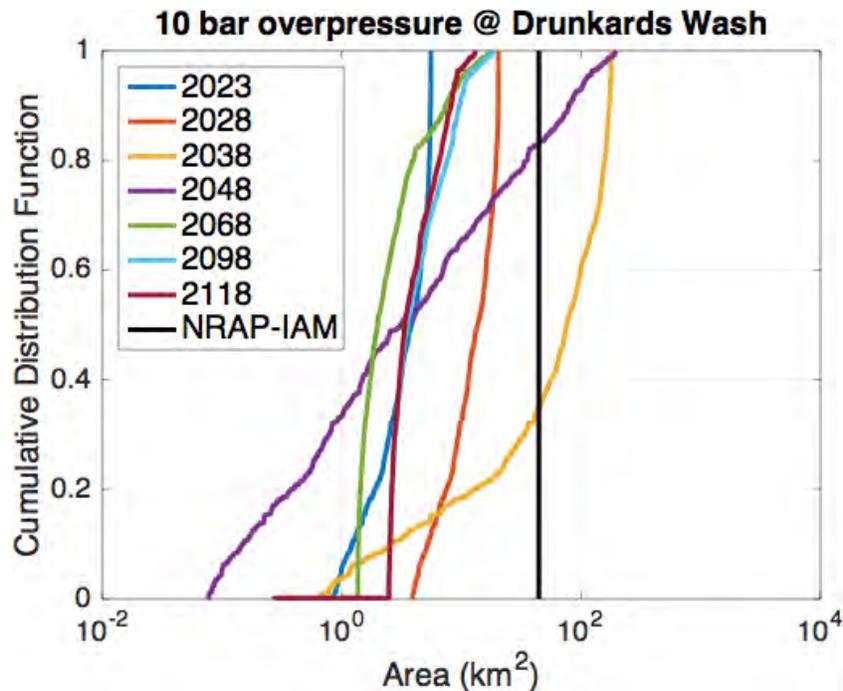


Figure 55. Cumulative distribution function of 10-bar overpressure area at Drunkards Wash.

CO₂ Storage Capacity Analysis

Successful implementation of geological carbon dioxide (CO₂ sequestration (GCS) projects requires long-term storage capacity and security (Celia et al., 2015; IPCC, 2005). Quantitative assessment of CO₂-water-rock interactions and potential changes to geological properties that might affect storage capacity and seal reliability are required by the United States Environmental Protection Agency (U.S. EPA) prior to a CO₂ storage permit being granted (EPA, 2013).

To date, forecasting long-term CO₂ migration and evaluation of storage capacity and security in deep saline reservoirs largely relies on modeling and numerical simulations with site-specific geological data (Jiang, 2011). However, quantitative analyses of trapping mechanisms and/or storage efficiency over time with special impacts, especially for commercial-scale (> 50 MT) storage, are limited in number. Therefore, a primary goal of this task was to quantify potential temporal and spatial impacts on CO₂ migration, CO₂-water-rock interactions, potential changes of storage capacity due to mineral alteration, and leakage risks of the Navajo Sandstone in the potential storage site at Buzzard’s Bench with reactive transport simulations. To overcome an obstacle of limited data prior to a detail site characterization, different scenarios with different ranges of parameters were conducted. Specific objectives of this study include: (1) to evaluate long-term (1,000 years) storage capacity and security of the Navajo Sandstone; (2) to quantify trapping mechanisms and storage efficiency through time and space; (3) to quantify the potential changes of storage capacity due to mineral alteration and porosity changes; and (4) to evaluate CO₂ migration and sealing reliability of the overlying caprock.

Results suggest that the Navajo formation may be a reliable CO₂ sequestration reservoir, capable of trapping commercial volumes. The Jurassic Kayenta and Wingate formations may also store some injected CO₂, with these and other clastic formations forming a “stacked storage” system.

Storage efficiency decreases with distance away from an injection well, and the estimated storage efficiency for the case study simulations (Navajo storage only) are $2.3 \pm 1\%$ within the area of review (AoR) calculated by National Risk Assessment Partnership (NRAP) toolset. After 1000 years, about half of the injected CO₂ may be sequestered in safe phases including residually-trapped CO₂ via surface tension, aqueous and mineral phases. A small amount of total injected CO₂ (~3%) tends to migrate into the caprock, but is mostly stored in the sandstone reservoir. Simulated porosity enhancement caused by mineral alteration is negligible within 1000 years of the start of injection, with only ~0.6% added to the total pore volume by the end of simulations. Future studies of detailed reservoir and caprock characteristics with in-situ samples may be helpful for further determining reservoir sequestration capacity and reliability.

Additional information on the CO₂ storage capacity of the Buzzard's Bench site can be found in (Xiao et al., 2019).

3.4.3 NRAP Screening and Application

The project team has identified two NRAP tools that may be applicable to this project. These tools are the NRAP-IAM-CS (Integrated Assessment Model for Carbon Storage) tool, and the RROM-GEN (Reservoir Reduced Order Model Generator) tool.

Particularly, the WLAT and AIM tool are integrated in the NRAP-IAM-CS tool. The project team has downloaded the installer and installed the tool on the main workstation. However, while running sample problems, unexpected errors occurred and terminated the simulation. The project team scheduled multiple WebEx meetings with developers of this tool, who are also collaborators of the project. The diagnosis process is still ongoing.

The project team was able to successfully run the NRAP-IAM-CS tool on a different personal computer. In April of 2018, an outreach of NRAP tools was conducted at the University of Utah, with participants from the College of Engineering at the University of Utah and from the China University of Petroleum (Beijing). A comprehensive introduction about NRAP and its current toolset were presented, followed by a workshop of installation and using the NRAP-IAM-CS tool. Simple scenarios of CO₂ storage were designed to help participants understand how injection volume and model properties (e.g., porosity and permeability) affect potential CO₂ leakage rates. Impacts of numbers and locations of legacy wells were also assessed.

The other evaluated NRAP tool was the RROM-GEN tool. The project team initially planned to use RROM-GEN to generate ROMs based on numerical simulation results for predicting CO₂ plume migration and quantifying associated uncertainty. The project team had an in-depth discussion with the developer of RROM-GEN regarding to theory and algorithms used in this tool. However, it was found that such feature is not included in the current version of RROM-GEN. Therefore, the initial working plan may have to be revised.

The project team has identified two applicable NRAP tools to this project, the NRAP-IAM-CS (Integrated Assessment Model for Carbon Storage) tool, and the RROM-GEN (Reservoir Reduced Order Model Generator). Team members at the University of Utah (UU) and LANL have discussed the approach to use these tools via email communication, teleconference, and in-person meetings. Particularly, UU will conduct reservoir simulations with reservoir simulation package, and apply the RROM-GEN tool to generate look-up tables; these results will be

transferred to LANL for following analysis with the NRAP-IAM-CS tool. In addition, LANL will also need information on the top of storage formation, (depth, top, thickness) of regional aquifer, and information on wells (location, depth, vintage, status and other information that can be used to determine the potential integrity) that will be present in the area around the injection wells.

In order to conduct the NRAP-IAM-CS analysis, the project team have assembled information of storage complex (formation tops and thickness) and existing wells (location, depth, and perforation).

The project team also processed the Eclipse simulation results of the 26 realizations. A special version of the RROM-GEN (Reservoir Reduced Order Model Generator) was received from the developer at NETL to analyze the simulation results and create input files for NRAP-IAM-CS tool. Pressure and CO₂ saturation at the top of the storage formation (Navajo) were analyzed at 31 selected time steps, including the initial time step, every year for the first 10 years of injection period, every 5 years for the rest of the injection period, every other year for the first 10 years of post-injection period, and every 5 years for the rest of the 100-year simulation period.

Figure 56 to Figure 59 present selected pressure and CO₂ saturation distribution in the top of the Navajo formation at the end of simulation for both injection sites. Results for all realizations and 31 time steps were evaluated.

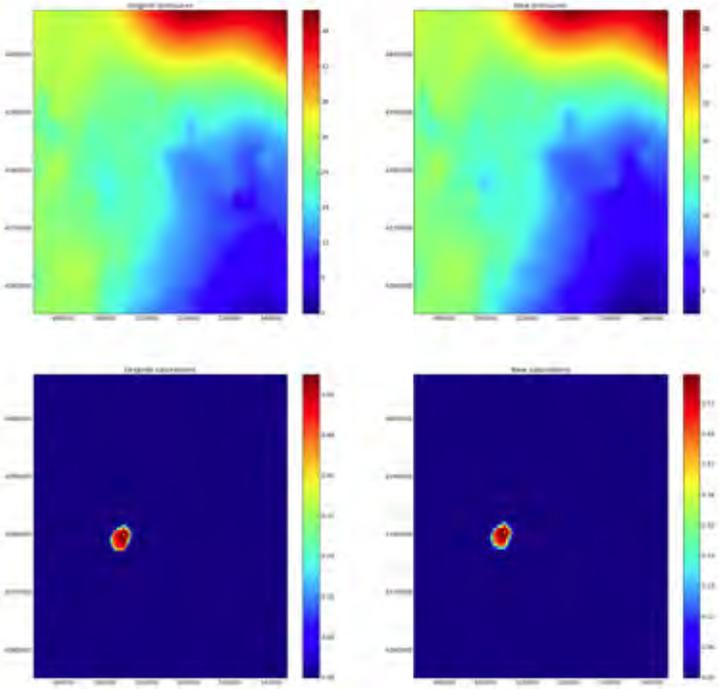


Figure 56. Pressure and CO₂ saturation distribution in the top of Navajo at the end of 100-year simulation of Realization #1 at the Drunkards Wash injection site

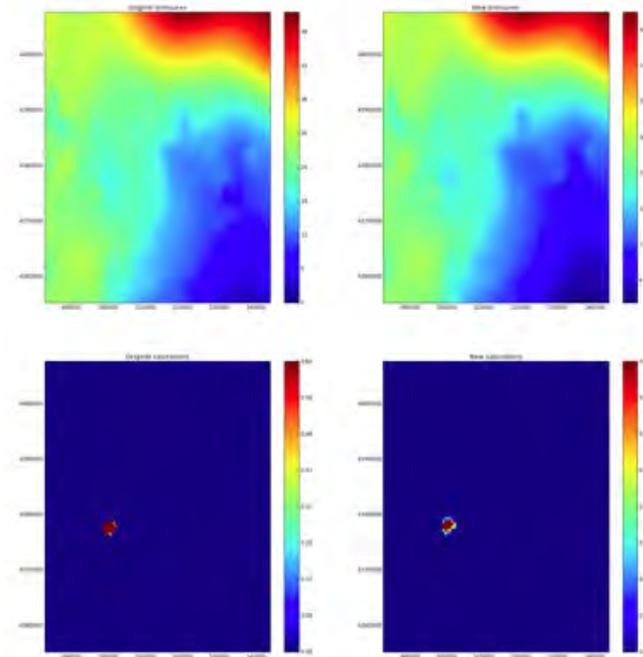


Figure 57. Pressure and CO2 saturation distribution in the top of Navajo at the end of 100-year simulation of Realization #13 at the Drunkards Wash injection site.

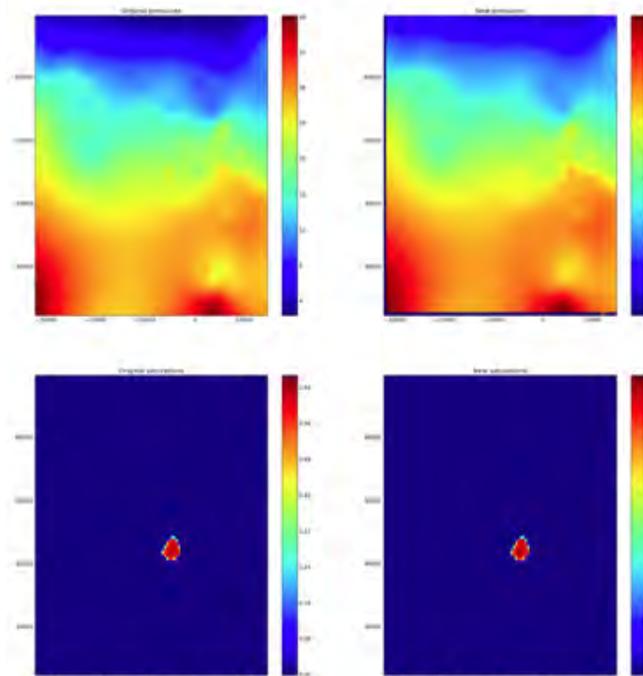


Figure 58. Pressure and CO2 saturation distribution in the top of Navajo at the end of 100-year simulation of Realization #1 at the Buzzard Bench injection site.

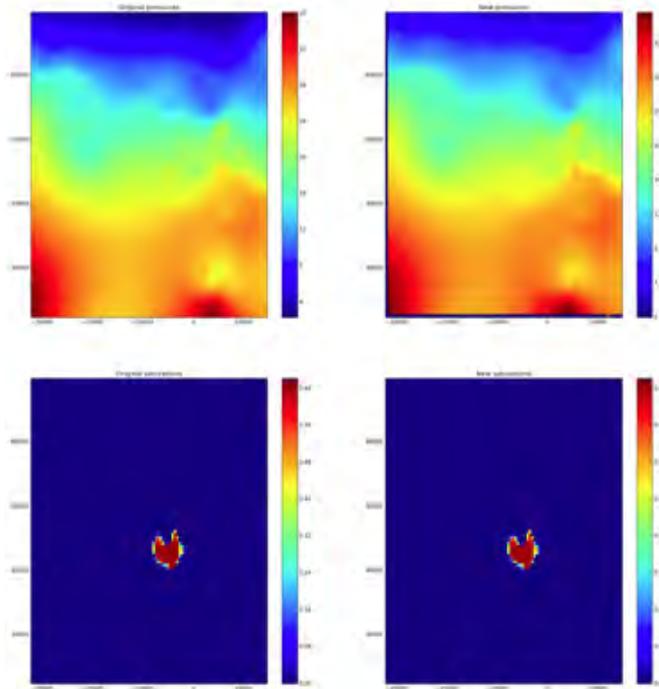


Figure 59. Pressure and CO₂ saturation distribution in the top of Navajo at the end of 100-year simulation of Realization #31 at the Buzzard Bench injection site.

3.4.4 Comments and Feedback on Using NRAP Tools

The NRAP tools used for this project were able to deliver expected outcomes in general. For example, results from the NRAP-IAM-CS tool provide a risk-based Area of Review for the two potential storage sites. The tools were easy to learn. The overall process of using the tools was relatively easy, because of the availability of many built-in options and the simplification of the NRAP tools made to the original physics-based models. However, the project team hope the tools could be even more helpful by enhancing capability and flexibility:

- (1) Format compatibility. The project team identified that RROM-GEN has restricted capability of reading simulation results. In particular, the grid has to have the same number of cells in each column (or each row). Otherwise, the grid is not compatible with the current version of RROM-GEN. This is usually not an issue for simplified models; however, models representing complex geological settings will cause errors using RROM-GEN. We hope this could be improved in the next version of RROM-GEN.
- (2) Plotting styles. Both RROM-GEN and NRAP-IAM-CS provide visualization outputs, including line graphs and 2-D slices. While these plots are helpful for quick understanding simulation data, the plotting quality could be substantially improved. We hope the tools would allow users to customize the plotting styles, including font style and size, line color and width, axis title and labels, and legends.
- (3) Reduced Order Model and Export options. The NRAP-IAM-CS tool uses output from RROM-GEN as look-up tables for uncertainty analysis. It would be more helpful if the RROM-GEN tool could provide more types of reduced order models other than the look-up table, such as linear or polynomial regression models. In addition, we would also like

to have an export option in these NRAP tools to export the reduced order model they use for leakage risk analysis. The exported files could be coupled with external software packages for either comparison study or further analysis.

4.0 Non-Technical Challenges

Prior analyses have identified a wide variety of legal, regulatory, and other hurdles that Carbon Capture and Sequestration (CCS) projects may face. Many of these studies suggest that what limits CCS deployment is not always legal or regulatory in nature. Several early studies, for instance, suggested that the lack of commercial-scale CCS demonstration projects act as a key constraint on societal appetite for CCS generators.¹ However, subsequent research revealed that technology demonstration tends not to be the key impediment to commercial-scale CCS development. Rather, a 2013 survey of more than 200 experts² in the United States revealed that there are four key barriers to CCS commercialization:

- (1) cost and cost recovery;
- (2) the lack of price signal or financial incentive for using CCS;
- (3) liability risks; and
- (4) an overall lack of comprehensive CCS regulation.³

The 2013 study provided important context to the legal, regulatory, and social barriers that, at a broad scale, CCS projects face. Specifically, it showed that, above all else, the cost of CCS—including the energy penalty that CCS imposes on electricity generation as well as public resistance to higher energy prices—is the greatest impediment facing commercial-scale CCS deployment. Following cost, the experts surveyed in the 2013 study suggested that the lack of any clear price signal or other financial incentive for CCS use, such as a carbon tax or greenhouse gas cap-and-trade system, is the second most significant barrier to CCS commercialization. Following cost and the lack of a price signal, those respondents found the

¹ See generally, e.g., CARNEGIE-MELLON UNIV., DEPARTMENT OF ENGINEERING AND PUBLIC POLICY, CARBON CAPTURE AND SEQUESTRATION: FRAMING THE ISSUES FOR REGULATION, AN INTERIM REPORT FROM THE CCSREG PROJECT (2009); PETER FOLGER, CONG. RESEARCH SERV., CARBON CAPTURE AND SEQUESTRATION (CCS) (2009); GOV'T ACCOUNTABILITY OFFICE, REPORT TO THE CHAIRMAN OF THE SELECT COMMITTEE ON ENERGY INDEPENDENCE AND GLOBAL WARMING, HOUSE OF REPRESENTATIVES: FEDERAL ACTIONS WILL GREATLY AFFECT THE VIABILITY OF CARBON CAPTURE AND STORAGE AS A KEY MITIGATION OPTION (2008); INT'L ENERGY AGENCY, CARBON CAPTURE AND STORAGE: PROGRESS AND NEXT STEPS (2010); LARRY PARKER ET AL., CONG. RESEARCH SERV. CAPTURING CO₂ FROM COAL-FIRED POWER PLANTS: CHALLENGES FOR A COMPREHENSIVE STRATEGY (2009); WORLD RESOURCES INST., OPPORTUNITIES AND CHALLENGES FOR CCS (2007).

² These experts consisted of with experience as CO₂ emitters, CCS operators, consultants, regulators, researchers, and nonprofit organizations relevant to CCS.

³ Lincoln L. Davies et al., *Understanding Barriers to Commercial-Scale Carbon Capture and Sequestration in the United States: An Empirical Assessment*, 59 ENERGY POL'Y 745, 749 (2013).

most significant barrier to CCS to be liability risks associated with CO₂ storage, followed by the lack of an overall CCS regulatory framework.⁴

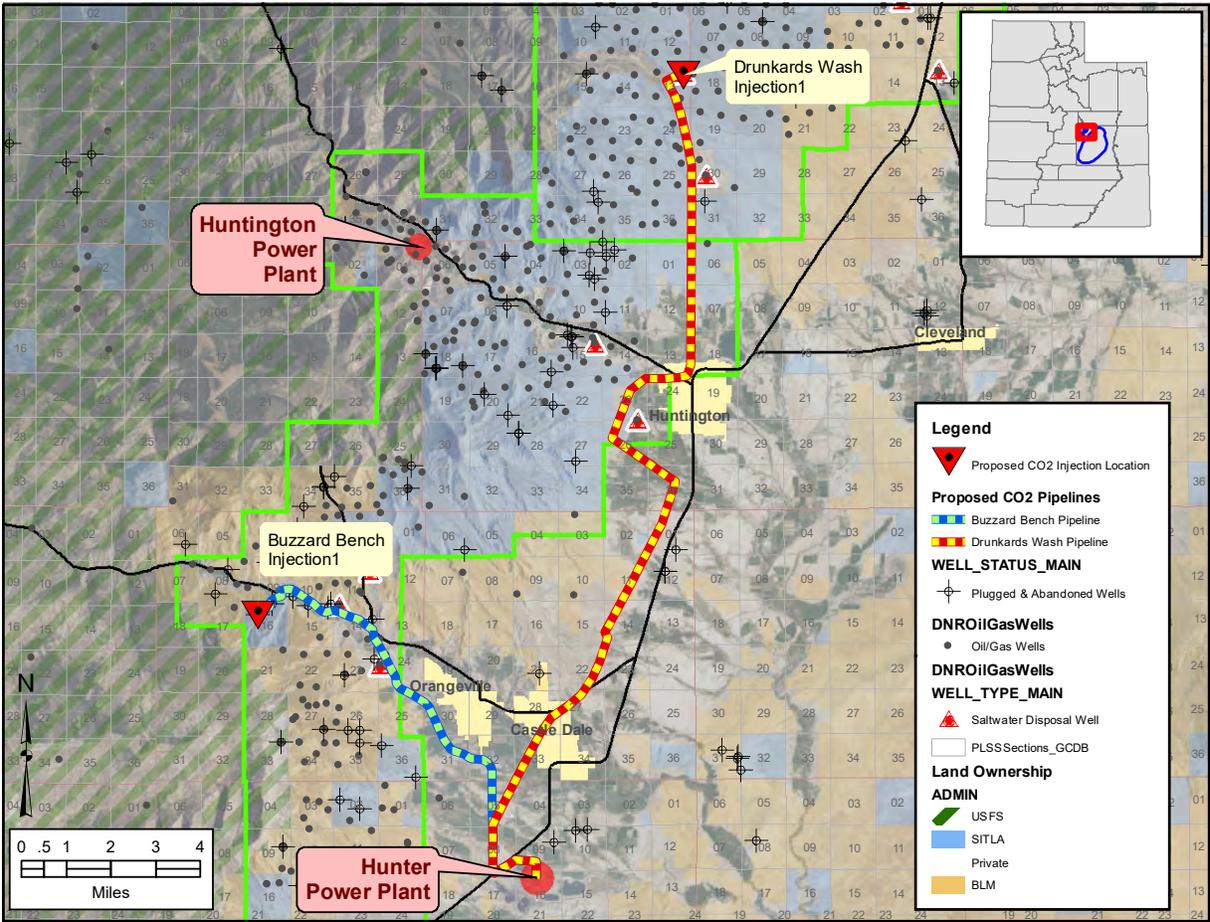


Figure 60. CarbonSAFE Rocky Mountain Location Map.

This project and report seek to identify the legal and regulatory structure that will govern development of any commercial-scale CCS project, including potential gaps in the legal and regulatory scheme. It does so in the context of the potential CarbonSAFE Rocky Mountain project, which would capture CO₂ from Rocky Mountain Power’s Hunter or Huntington power plants and geologically store the CO₂ in the geographically proximate Navajo sandstone saline formation. A rough schematic of the proposed project, as it is currently envisioned and on which this analysis is based, is shown below as Figure 60. The analysis conducted by the project team and described in more detail in Appendix C is by necessity conceptual. It identifies and details

⁴ Subsequent research has broadly confirmed the 2013 study’s results. In a 2017 study, researchers evaluated expert views of CCS risk perception in three European countries. Perceived barriers across countries and experts included the high cost of implementing technologies, the slow development of policy and regulation, the absence of storage sites, and general liability. See generally Farid Karimi & Nadejda Komendantova, *Understanding Experts’ Views and Risk Perceptions on Carbon Capture and Storage in Three European Countries*, 82 GEOJOURNAL 185 (2017).

overarching categories of applicable law and regulation, because more concrete application of that law to the proposed project cannot be achieved until the specific contours and location of the project are delineated following more in-depth geologic analysis, at a later date.

CCS occurs in three industrial segments: first, *CO₂ capture*; second, *CO₂ transport*; and, finally, *CO₂ storage*. Consistent with the scope of this Phase I study, this portion of the report addresses legal, liability, and regulatory barriers for transport and storage.

This section of the report is organized as follows. It first addresses use of the land necessary for both CO₂ transport and storage, including surface land use, subsurface use, and Bureau of Land Management (BLM) regulation.⁵ It then discusses potential liability associated with geologic storage of CO₂ as part of CCS technology, including permitting under the Safe Drinking Water Act (SDWA). Because the proposed CarbonSAFE Rocky Mountain project is proximate to federal land and will likely require federal permits, we then discuss application of the National Environmental Policy Act (NEPA). Finally, other generally applicable legal and regulatory requirements are discussed, along with key lessons learned from parallel CCS projects.

4.1 LAND USE

Both surface and sub-surface access for CCS potentially implicate three general categories of land ownership near the CarbonSAFE Rocky Mountain project: privately owned lands, state owned lands, and federally owned lands. Surface uses include pipeline access connecting the CO₂ source to the injection site, as well as the injection site itself and associated infrastructure. Sub-surface use includes permanent geologic CO₂ sequestration within the receiving geologic formation, which is defined spatially by the extent of the CO₂ plume. We address surface and sub-surface rights in turn, for each type of ownership category, followed by general discussions of pore space ownership for the CarbonSAFE Rocky Mountain project as well as how to acquire access to such rights, including by negotiation (leasing, easement, or purchase) or exercise of governmental authority (eminent domain).

4.1.1 Surface Land Use

As noted, three different types of landowners possess surface property rights near the proposed CarbonSAFE Rocky Mountain project: private, state, and federal. Acquiring rights to use the surface of land owned or managed by these entities will necessarily involve different processes.

Private Ownership

Private landowners are generally free to alienate all or some subset of the rights that they hold. In the law, property often is referred to as a “bundle of sticks.” This means that a landowner may sell, lease, or otherwise grant rights to the use of the surface estate while still retaining overall ownership of the property. With respect to the CarbonSAFE Rocky Mountain project, then, if access is needed to privately owned surface lands, negotiated transactions would likely need to be used, particularly since eminent domain authority has not been developed fully in the CCS

⁵ CarbonSAFE Rocky Mountain is not anticipating use of the surface of National Forest System land.

context, and the cost of such proceedings would likely be prohibitive both financially and in terms of potential project delays.

State Ownership

The Utah School and Institutional Trust Lands Administration (SITLA) manages most, if not all, of Utah’s surface and sub-surface estate within the vicinity of the proposed CarbonSAFE Rocky Mountain project area. State law provides mechanisms for the sale of state lands, but obtaining a lease or easement would likely be a more efficient solution. With respect to pipelines transmitting CO₂ from the power plant to the injection site, rights-of-way may already be in place, depending on what transport path is selected. An existing easement could presumably be amended to accommodate additional pipeline infrastructure. Alternatively, a new easement could also be acquired.

Federal Ownership

The process for acquisition of rights to utilize federally managed surface resources is relatively well-defined. Indeed, over the last several decades, the Department of the Interior promulgated an extensive series of regulations that makes securing a surface lease or utility right-of-way on the type of federal lands proximate to the proposed CarbonSAFE Rocky Mountain project comparatively routine.

All federal lands (both surface and sub-surface) within the project area are believed to be under BLM administration. The Federal Land Policy and Management Act⁶ (FLPMA) requires the BLM to “prepare and maintain on a continuing basis an inventory of all public lands and their resource[s].”⁷ Based on this inventory, the BLM must “develop, maintain, and, when appropriate, revise land use plans which provide by tracts . . . for the use of the public lands.”⁸ These plans, commonly referred to as Resource Management Plans (RMPs), establish the management direction for a defined region of public land, although in practice such regions can be quite large, covering millions of acres. Critical RMP decisions include, among other things, which lands will be available for mineral development, which lands will be managed to emphasize resource protection, and what management stipulations are required to balance BLM’s multiple use and sustained yield mandates across the federal landscape.⁹

The Price RMP applies to the CarbonSAFE Rocky Mountain project area and was most recently revised in 2008. It contains management stipulations applicable to lands proximate to both the primary and secondary injection sites of the CarbonSAFE Rocky Mountain project, likely pipeline corridors and the injection site(s). The Price RMP contains mapped management stipulations for approximately eighty different resources. As RMP consistency is a central focus

⁶ 43 U.S.C. §§ 1701–1787 (2012).

⁷ *Id.* § 1711(a).

⁸ *Id.* § 1712(a).

⁹ *Id.* § 1701(a)(7).

of any BLM lease or right-of-way approval, we reviewed¹⁰ the requirements contained in the Price RMP applicable to both the primary and secondary project sites.¹¹

Hunter Power Plant (Primary CO₂ Source)

The Hunter Power Plant is located on privately owned lands south of the town of Castle Dale. CO₂ injection and geologic sequestration would likely occur west of Castle Dale, at the Buzzards Bench site. Injection is likely to occur on state trust lands that are surrounded by BLM-managed public lands. CO₂ would be transported via pipeline as shown in **Figure 69**. Further investigation will be needed to confirm that this right-of-way could serve the project. Alternatively, CO₂ could be piped to the Drunkards Wash oil field approximately eighteen miles to the north, also as shown in **Figure 69**. Lands proximate to the Drunkards Wash injection site are largely managed by SITLA, with a parcel of BLM-managed lands existing immediately east of the injection site. The Drunkards Wash site is discussed in more detail below, in conjunction with the Huntington Power Plant.

The RMP includes oil and gas surface use stipulations that are uniquely important to the project, as these stipulations apply much more broadly than their name might suggest. The RMP explains:

The Approved RMP specifies restrictions for permitted activities to resolve concerns regarding the impacts of these uses. These conditions apply not only to oil and gas leasing, but also apply, where appropriate, to all other surface disturbing activities associated with land-use authorizations, permits, and leases, including other mineral resources.¹²

BLM-managed lands in the Buzzards Bench area are generally open to mineral development under “standard lease terms and conditions” or under “minor constraints.”¹³ Standard lease terms and conditions are the least restrictive category of stipulations and allow the BLM to require the

¹⁰ To conduct the review, we mapped the approximate location of the Hunter and Huntington power plants, the primary and secondary injection sites, and the approximate route for a pipeline connecting the power plants with the associated injection site. We then compared those maps with resource maps contained in the Price RMP and identified the resources most likely to constrain project development. Only those resource that were identified as likely to impact project development are addressed here.

¹¹ As noted, our analysis is by necessity conceptual in nature, which is particularly pertinent with respect to BLM permitting. As the location and contours of the CarbonSAFE Rocky Mountain project are more clearly defined via further geologic study, evaluation of the applicable RMP will need to be updated based on that more detailed information, once that information becomes available and is needed for use, such as in a Phase II study of the proposal. CCS operators should also bear in mind that not all management constraints can be mapped at the scale or resolution considered in an RMP. Project proponents should meet with BLM officials to identify any additional constraints that may exist prior to project implementation and development.

¹² BUREAU OF LAND MGMT., DEP'T OF THE INTERIOR, PRICE FIELD OFFICE RECORD OF DECISION AND APPROVED RESOURCE MANAGEMENT PLAN 40 (2008) (hereinafter the Price RMP).

¹³ *Id.* at Maps R-24 and R-26.

operator to move proposed facilities by up to 200 meters and prohibit new surface disturbing operations for up to sixty days per year.¹⁴ “Minor constraints” may include timing limitations, controlled surface use stipulations, or lease notices that could result in a cumulative timing limitation of three to six months.¹⁵

The BLM applies a Visual Resource Management classification system to describe limits on visual impacts allowed across the landscape. Lands near Buzzards Bench are subject to Class 3 and Class 4 stipulations, which are generally facilitative of more intensive forms of development. Class 4 areas are managed to “provide for management activities which require major modification of the existing character of the landscape. The level of change to the characteristic landscape can be high.”¹⁶ The BLM manages Class 3 areas to “partially retain the existing character of the landscape. The level of change to the characteristic landscape should be moderate.”¹⁷

With respect to ecological considerations, few riparian areas are identified in the RMP as proximate to the injection site, with the exception of two riparian areas north of Orangeville and one riparian area west of Castle Dale. Impacts to riparian areas, wetlands, and waters of the United States are regulated under the Clean Water Act and may require additional permitting. Care should be taken to identify all wetland areas, surface waters, and intermittent drainages; to avoid such areas whenever possible; and to obtain appropriate permits for unavoidable impacts. Given the resolution of mapping contained in the RMP, CCS operators should not assume that RMP mapping of aquatic resources is complete or accurate.

Lands west of the Buzzards Bench injection site are characterized by a mix of sagebrush and Pinyon-Juniper cover. These lands provide mule deer habitat that is mapped as part of the Big Game Crucial Habitats layer contained in the Price RMP.¹⁸ The Price RMP does not identify either winter habitat or crucial value nesting or brood rearing habitat for the greater sage grouse in the general area.¹⁹ No crucial year-long white-tailed prairie dog habitat has been identified in the area.²⁰ Similarly, the Price RMP does not identify any designated critical habitat for threatened or endangered species, or state wildlife management areas in the immediate vicinity of Castle Dale.²¹ Areas of Critical Environmental Concern, Wilderness Study Areas, and Non-WSA Lands with Wilderness Characteristics have not been identified in the Orangeville area.²²

Huntington Power Plant (Secondary CO₂ Source)

The Huntington Power Plant, considered the secondary source for this proposed project, is located north of the Hunter Power Plant and northwest of the town of Huntington. The

¹⁴ 43 C.F.R. § 3101.1-2 (2017).

¹⁵ Price RMP, *supra* note, at Map R-26.

¹⁶ *Id.* at Tbl. 3-12.

¹⁷ *Id.* at Map R-5.

¹⁸ *Id.* at Map R-8.

¹⁹ *Id.* at Map R-6.

²⁰ *Id.* at Map R-9.

²¹ *Id.* at Map R-7.

²² *Id.* at Maps R-11, R-28, and R-29.

Huntington Power Plant is located on private land and ringed by private and SITLA-managed lands. The approximate CO₂ injection site is roughly thirteen miles northeast of the power plant, in the Drunkards Wash oil field. Lands proximate to the injection site are largely managed by SITLA, with a BLM-managed lands existing largely to the east of the injection site.

The Price RMP identifies a utility corridor extending to the southeast from the approximate location of the Huntington Power Plant, to points south and southwest of the town of Huntington. From there, rights-of-way extend to the northeast along Utah State Highway 10, and due north.²³ Either route could provide access to the Drunkards Wash Field, though transport distances would increase significantly over those associated with the Hunter Power Plant.

There is generally less BLM-managed land proximate to the Huntington Power Plant compared to the Hunter Power Plant. What BLM-managed lands do exist near the Drunkards Wash injection site are generally managed under “minor” surface constraints that could limit surface-disturbing activities for three to six months of the year.²⁴ Visual Resource Management stipulations for BLM-managed lands due east of the likely injection site are unlikely to pose a constraint, as they are managed to “provide for management activities which require major modification of the existing character of the landscape. The level of change to the characteristic landscape can be high.”²⁵ The Price RMP identifies riparian habitat near the likely injection site and, as with the Hunter Power Plant site, care should be taken to identify and avoid wetlands, surface waters, and intermittent drainages. Where these features cannot be avoided, additional permitting will be required.

4.1.2 Subsurface Land Use

In addition to use of surface land for CO₂ transport and injection, CCS projects also implicate use of the subsurface. These issues are somewhat more complicated than the surface land issues. Typically, the question boils down to ownership of the subsurface lands. However, this ownership question can be complicated for a variety of reasons. First, a situation may arise where there is a different owner of the surface land than the subsurface land—a situation known as the “split estate” question. Second, the subsurface estate itself may be subdivided further into component estates based on the existence of specific minerals or other geological characteristics. Third, the subsurface owner may have leased some or all of the subsurface estate, potentially creating overlapping mineral interests. Ownership of the subsurface estate often is referred to as ownership of the “pore space”: the “spaces within a rock body that are unoccupied by solid material.”²⁶ This is the portion of the subsurface that geologically stored CO₂ will occupy.

²³ *Id.* at Map R-21.

²⁴ *Id.* at Maps R-25 and R-26.

²⁵ *Id.* at Map R-5.

²⁶ *Definition: Pore Space*, www.idahogeology.org/services/hydrogeology/portneufgroundwaterguardian/my_aquifer/vocab/vocab_text/pore_space.html (last visited Jul 29, 2017).

Historically, property rights have been referred to as “sticks” in a “bundle” of various rights.²⁷ Different rights can be separated from each other in a legal sense; each such right is referred to as a “stick” in the overall “bundle” of property rights, and it is appropriate to look at pore space ownership as its own “stick” in the property bundle.²⁸

Generally, the owner of a fee simple estate (*i.e.*, full ownership of the surface and sub-surface land) will own the pore space beneath their land.²⁹ This is an application of the *ad coelum* doctrine, which historically stood for the proposition that an owner of a surface estate owns from the depths of the earth to the extent of the universe. As society has evolved, courts have recognized limits on the *ad coelum* doctrine. For instance, courts typically now place a ceiling on the ownership of a surface owner’s airspace. However, judicial decisions have not attempted to place a floor on the ownership of the subsurface estate underlying a fee-simple property owner’s land. Therefore, generally, the owner of a fee-simple estate will own the pore space that lies underneath a given tract of land.

This quickly becomes murkier in split estate or competing use issues, situations very familiar to the oil and gas arena. Split estates are created “when the surface estate and all or part of the mineral estate in a particular parcel are not owned by the same party.”³⁰ Internationally, the majority of countries reserve ownership of the mineral and other subsurface estates to the sovereign government. In the United States, however, there is widespread private ownership of subsurface estates.³¹ The rise in usage of pore space outside of the context of CCS necessitated resolution first in the courts and later, in a minority of states, by legislation. Typically, two distinct rules guide the analysis for resolving split estate questions: the American Rule and the English Rule. Understanding these rules is important because ownership of pore space is not a settled issue, particularly with respect to ownership of pore space for CCS.³²

²⁷ See M. GRANGER MORGAN & SEAN T. MCCOY, CARBON CAPTURE AND SEQUESTRATION 95 (2012).

²⁸ See Trae Gray, *A 2015 Analysis and Update on U.S. Pore Space Law—The Necessity of Proceeding Cautiously With Respect to the “Stick” Known as Pore Space*, 1 OIL & GAS, NAT. RESOURCES & ENERGY J. 277, 279 (2015).

²⁹ See MORGAN & MCCOY, *supra* note 33, at 95

³⁰ Kendor P. Jones et al., *Split Estates and Surface Access Issues*, in LANDMAN’S LEGAL HANDBOOK, ch. 9 (Rocky Mt. Min. L. Fdn., 5th ed. (2013)).

³¹ *Id.*

³² This report draws heavily from MORGAN & MCCOY, *supra* note 27; Alexandra B. Klass & Elizabeth J. Wilson, *Climate Change, Carbon Sequestration, and Property Rights*, 2010 U. ILL. L. REV. 363, 381 (2010); STEFANIE L. BURT, WHO OWNS THE RIGHT TO STORE GAS: A SURVEY OF PORE SPACE OWNERSHIP IN U.S. JURISDICTIONS (2012); and Gray, *supra* note 34.

The American Rule

The American Rule cleaves the mineral estate from the pore space,³³ regardless of whether they are physically bound together, and vests ownership of the pore space with the surface estate owner.³⁴ This rule developed through applying common maxims used to determine the ownership of the subsurface generally.³⁵ These maxims include the *ad coelum* doctrine, the narrow drafting of conveyances and narrow interpretation of those conveyances by courts,³⁶ and a presumption of a reservation of rights by surface holders when they are not expressly conveyed or necessary to reduce and capture a given mineral resource.³⁷

Because no court has dealt with the issue of pore space solely in the CCS context, application of the American Rule to CCS must be guided by other subsurface storage uses, such as natural gas storage. The case of *Ellis v. Arkansas Louisiana Gas Co.* provides an example³⁸ There, the court was asked to determine from whom a natural gas storage injector needed to obtain permission to store its natural gas, where a split estate existed. Plaintiffs owned seventy-eight acres of a surface estate in Oklahoma.³⁹ The mineral estate had been severed through a series of deeds. The gas reservoir had been depleted, so the mineral estate holder had been using the reservoir to store gas. The court held that the surface estate owned the subsurface pore space created by the depleted gas reservoir. This was because the legal instruments that severed the mineral estate conveyed the right to explore and develop the minerals in the estate but said nothing about who owned the depleted reservoir.⁴⁰ As a result, under the American rule, ownership of that space remained with the surface estate owner—and that was from whom the gas storage operation needed to acquire storage rights.

³³ *Ellis v. Arkansas Louisiana Gas Co.*, 450 F. Supp. 412, 421 (1978), *aff'd*, 609 F.2d 436 (10th Cir. 1979).

³⁴ This principle is likened to excavating a basement. If party A contracts with party B to remove the dirt underneath a tract of land owned by party A, party B does not obtain title to the newly created space. Accordingly, the owner of a mineral estate cannot lay claim to the pore space they create after extraction of gas or other mineral deposits, or even when the space is naturally occurring rather than created through extraction. *See, e.g., Burlington Res. Oil & Gas Co., LP v. Lang & Sons Inc.*, 259 P.3d 766, 771 (Mont. 2011).

³⁵ *See* Owen L. Anderson, *Geologic CO₂ Sequestration: Who Owns the Pore Space?*, 9 WYO. L. REV. 97 at 99–100 (2009); *see also* MORGAN & MCCOY, *supra* note 33, at 95–96.

³⁶ *See Ellis*, 450 F. Supp. at 420.

³⁷ *See* MORGAN & MCCOY, *supra* note 33, at 95–96; *see also Ellis*, 450 F. Supp. at 421.

³⁸ *Ellis*, 450 F. Supp. 412 at 414.

³⁹ *See Ellis*, 609 F.2d at 439.

⁴⁰ *Ellis*, 450 F. Supp. at 421.

4.1.3 Pore Space Ownership for a Utah CCS Project

A majority of oil-producing states follow the American rule.⁴¹ This is often via development of the common law. Many jurisdictions have yet to codify this principle, instead resolving pore space issues in court. A small number of states have enacted legislation that places pore space ownership in the surface estate. Utah, however, has not adopted legislation defining pore space ownership, and no case law from Utah directly addresses ownership in the CCS context.

While Utah law is not entirely clear which entity owns the pore space into which CO₂ would be injected, the surface estate owner or the mineral estate holder, the Utah Legislature has enacted legislation regarding natural gas storage which implies that pore space should be considered part of the surface estate. The Utah Legislature has directed the state Department of Natural Resources, to create pore space ownership and other rules for CCS.⁴² Utah began to undertake an effort to adopt such rules in 2009 and 2010. However, after the EPA announced its final rule for Class VI Underground Injection Control wells under the Safe Drinking Water Act, Utah put its plans to adopt CCS rules on indefinite hold. Notwithstanding that hold, recommendations from the state's CCS Rules Working Group⁴³ suggest that Utah likely would have adopted the American rule with respect to CCS pore space ownership.⁴⁴

Further, Utah Code § 78B-6-501(6)(d) grants the mineral estate owner the right to condemn “any subsurface stratum or formation” for natural gas storage. By granting the mineral estate owner the power of condemnation for pore space to store natural gas, the legislature necessarily concluded that the mineral estate owner did not already own the pore space—if they did, there would be no need for the power of condemnation. Since the strong implication from § 78B-6-501(6)(d) is that pore space does not belong to the mineral estate owner, it logically follows that, in accord with the American rule, pore space is owned by the surface estate owner in Utah.

In Utah, an argument could also be made that, as applied to state lands, conveyance of pore rights must be express—a position again consistent with the American rule. Under SITLA's mineral reservation statutes, pore space must be reserved to the state when SITLA sells lands to private parties. Utah Code § 53C-1-102 imposes several “fiduciary duties” on SITLA, including a duty to “manage the lands . . . in the most prudent and profitable manner possible[.]”⁴⁵ Further,

⁴¹ See generally BURT, *supra* note 38; see also Gray, *supra* note 34.

⁴² See UTAH CODE § 54-17-701.

⁴³ See UTAH CODE § 54-17-701 (creating this CCS Rules Working Group); see also Utah Dep't of Env'tl. Quality, Utah Dep't of Natural Resources, Recommended Rules for Carbon Capture and Geologic Sequestration (Nov. 15, 2010), <https://psdocs.utah.gov/misc/miscindx/documents/RecommendedRulesforCarbonCaptureandGeologicSequestration11-15-2010.pdf> (hereinafter Utah Rec. Rules).

⁴⁴ See Utah Rec. Rules, *supra* note 61. It appears that no further action is being taken regarding adoption of the rules.

⁴⁵ UTAH CODE § 53C-1-102.

sales of state lands “[must] contain . . . a [coal and mineral] reservation.”⁴⁶ Excepted from that reservation are “common varieties of sand, gravel, and cinders”—but not exempted are “deposits which are valuable because the[y] contain[] characteristics which give it distinct and special value.”⁴⁷ Therefore, if pore space is of distinct and special value, it may be statutorily reserved to SITLA. While this provision applies only to land sales, SITLA may apply the same principle when issuing mineral leases.

As part of Phase II, the CarbonSAFE Rocky Mountain Team should review all existing mineral leases proximate to the injection site, whether those leases were issued by the BLM, SITLA, or a private entity, and determine whether any of these leases address pore space use. If leases fail to indicate pore space ownership, the weight of authority implies that the surface owner also owns the pore space, and that ownership must be addressed in turn as part of legal approval for CCS operations.

4.1.4 Obtaining Land Use Rights

Because accessing private, state, and federal lands—both at the surface and subsurface—may be necessary to execute the proposed CarbonSAFE Rocky Mountain project, it is necessary to understand the process for obtaining such rights. This subsection describes available processes. At the outset, however, it is worth noting that particularly with respect to subsurface property rights, obtaining pore space remains a rather novel legal question. The state of Utah and the BLM have never granted an interest in pore space solely for the purpose of injecting CO₂ for permanent geologic sequestration. Therefore, each of the avenues presented below should be considered as options only, and not necessarily the only way to obtain an interest in pore space, while also recognizing that the processes could be altered when relevant decisional bodies are faced with the new situation of CO₂ injection and storage.

Acquiring Private Land Use Rights

Generally, fee-simple landowners are free to alienate or dispose of their property, including a subset of their rights. There are several ways to go about this, but they break down into two broad categories: agreement via negotiation and acquisition via governmental authority (*i.e.*, eminent domain).

Agreement

Three primary mechanisms tend to be used to acquire property rights from a fee simple landowner: leases, easements, and outright conveyances. Each of these could be used for both surface and subsurface rights acquisition.

Leases have been used in the mineral context for some time and are particularly common in the oil and gas context. Adapting this established framework could facilitate a CCS project. A lease for surface access would allow for ingress and egress, and use of the land to, for instance, transport CO₂ or inject it. For subsurface rights, obtaining a right to occupy the pore space would

⁴⁶ *Id.* § 53C-2-401.

⁴⁷ *Id.*

require the drafting and execution of a pore space lease. When using a lease, the operator should be mindful of the permanence of the sequestered CO₂ and the potential for interference with other uses. Presumably, oil and gas leases could serve as a starting point for tailoring a CO₂ storage lease.

An easement may provide a more permanent and elegant solution than a lease. Easements are particularly common in the energy and utility infrastructure context, where they are typically referred to as rights-of-way (ROW). Easements are “created by express words of either a formal grant or of a reservation or exception in a conveyance of land.”⁴⁸ Like a lease, an easement does not create an ownership interest in the subject property, but rather, only the mere right to use the property in a given manner. The advantage of an easement is that it could exist in perpetuity until abandoned. This could be beneficial at the surface and subsurface level, and for pore space rights, may help navigate around the issue of permanence.

Lastly, a CCS operator could obtain the right to use land from an outright conveyance through a deed or other similar instrument. Use of such a mechanism is rather uncommon in the surface land context where the land is of significant value, and particularly where the property in question is large or the acquisition of the property will split the larger tract. In the subsurface context, however, the advantage of this route would be that ownership of the pore space will remain with the CCS operator in perpetuity. Still, this could be a costlier approach than the lease or easement options.

Eminent Domain

Eminent domain allows the taking of private property for public use by the state, municipalities, private individuals, or corporations that are authorized to exercise functions of a public character. Eminent domain can be utilized to obtain surface rights, subsurface rights, or both. Eminent domain authority is not available against the federal government unless expressly authorized by an act of Congress.⁴⁹

Utah’s eminent domain statute does not expressly grant a CCS operator authority to condemn certain real property.⁵⁰ The touchstone of eminent domain authority is a taking for a public use. Utah’s eminent domain statute lists several statutory public uses, including “any subsurface stratum or formation in any land for the underground storage of natural gas.”⁵¹ Uses identified in

⁴⁸ UTAH REAL PROPERTY LAW § 12.02 (Lexis).

⁴⁹ *Utah Power & Light Co.*, 243 U.S. 389, 405 (1914). While the Utah Legislature has enacted legislation authorizing the use of eminent domain against the federal government, *see* UTAH CODE § 78B-6-503.5, this statute is almost certainly unconstitutional. As the Utah Office of Legislative Research and General Counsel warned the Legislature before enactment, “[T]he state has no standing as sovereign to exercise eminent domain or assert any other state law that is contrary to federal law on land or property that the federal government holds under the Property Clause.” H.R. 143, 2012 Gen. Sess. (Utah 2012) (fiscal note appended to the introduced version of the bill).

⁵⁰ *See generally* UTAH CODE §§ 78B-6-501 *et seq.* (2017)

⁵¹ *Id.* § 78B-6-501(6)(d).

the statute are “not exclusive . . . and merely establish a general starting point.”⁵² Therefore, if a CCS operation could demonstrate that geologic sequestration is a public use, the operator could conceivably claim authority to condemn property.⁵³ It is also noteworthy that the CCS Rules Working Group recognized the lack of express eminent domain authority for CCS operators, and recommended expansion of several areas of the eminent domain statute.⁵⁴

Second, Utah law also provides that “the right of eminent domain may be exercised on behalf of . . . any occupancy in common by the owners or possessors of different mines, quarries, coal mines, mineral deposits, mills, smelters, or other places for the reduction of ores, or *any place for the flow, deposit or conduct of tailings or refuse matter*”⁵⁵. While tenuous, a CCS operator—or coal mine operator—could argue that CO₂ should be classified as refuse matter to coal production. The argument would be that what is being sought is a place to dispose a product that, for commercial purposes, has little value. Thus, by analogy, CO₂ arguably could be considered akin to waste or, in statutory terms, “refuse matter.” In response, an owner of condemned property would argue that such a reading of the statute is not in character with its intended meaning and, further, that CO₂ storage is not in the public use.

Given the untested nature of these arguments, the much safer route for a CCS operator seeking to use eminent domain authority would be to obtain a legislative amendment of the existing law, in accord with the CCS Rules Working Group’s recommendation.⁵⁶ That is, an attempt to exercise eminent domain authority without such a legislative enactment would carry a high risk of litigation.

Another downside of using eminent domain bears mention. Eminent domain proceedings tend to provoke litigation and delay. Further, even if successful, they require payment for the resources seized, and valuation can invite further litigation. Negotiated transactions therefore appear highly preferable for CCS purposes.

Acquiring State Land Use Rights

A portion of the land granted to Utah at statehood is held by the state in trust for the benefit of the public schools and institutions.⁵⁷ These lands are now managed under the authority of the State of Utah School and Institutional Trust Lands Administration (SITLA).⁵⁸ SITLA lands are ubiquitous in and around the location of the proposed CarbonSAFE Rocky Mountain project.

⁵² *Utah Dep’t of Transp. v. Carlson*, 2014 UT 24, ¶ 20, 332 P.3d 900, 904; *Salt Lake City Corp. v. Evans Dev. Grp., LLC*, 2016 UT 15, ¶ 11, 369 P.3d 1263, 1266.

⁵³ *See, e.g., Watkins v. Somonds*, 354 P.2d 852 (Utah 1960); *Jacobsen v. Memmott*, 354 P.2d 569 (Utah 1960).

⁵⁴ *See Utah Rec. Rules, supra* note 61, at att. 2.

⁵⁵ UTAH CODE § 78B-6-501(6)(f).

⁵⁶ *See Utah Rec. Rules, supra* note 61, at Att. 2.

⁵⁷ *See* UTAH CODE § 53C-1-102.

⁵⁸ *See id.* §§ 53C-1-101 *et seq.*

There are several ways in which a private entity could obtain ownership or an interest in SITLA-managed lands. These fall into three broad categories that track the negotiation-based options for obtaining access to private lands: easements, leases, and land sales.

Notably, of these three avenues, private parties typically obtain an interest in SITLA lands through a variety of leases, including agricultural, grazing, and mineral leases. Commercial and renewable energy leases are also common. Obtaining the right to pore space under current SITLA regulations, however, would be a matter of first impression and would necessarily involve conferring and negotiating directly with SITLA.

Easement

To obtain an easement, a CCS operator would need to apply to SITLA under the procedures delineated in Utah Admin. Code R850-40 *et. seq.* Much of the language in these provisions suggests that these easements are not permanent, but it appears that SITLA may extend the life of an easement into perpetuity.⁵⁹ The minimum cost to the CCS operator would be the cost of administering the easement. If a CCS operator obtains an easement, the operator can assign the easement, but only with approval from SITLA.⁶⁰ Easements are managed by the Surface Group at SITLA and are commonly used for electrical lines, pipelines, and roads.

While technically allowable under SITLA's authority, easements are not commonly used when developing a resource. Instead, an entity typically requests a lease or a permit. A CCS operator is arguably developing the pore space estate, not merely using it passively, as is done for utility lines or roads. After the CO₂ is injected, no one could further use the pore space, meaning that it is depleted, whereas after a pipeline is no longer needed, the land it has been occupying can be used for other purposes since the pipeline can be removed. Therefore, a lease would be a more logical—and perhaps more likely—way to develop a CCS project on SITLA lands, particularly with respect to subsurface rights as opposed to CO₂ transport.

Lease

Utah Admin. Code R850-30-100 *et seq.* defines SITLA's authority to issue special use leases. Special use leases may be required for pipelines or other infrastructure needed for CCS operations. Industrial special use leases are issued for periods of up to fifty-one years,⁶¹ but in extraordinary circumstances, the lease term can be extended to ninety-nine years.⁶² A lease for CCS use of pore space would most likely be classified as a special use lease because it is not within the standard definition of a mineral lease.⁶³ To obtain a special use lease, the applicant must follow procedures listed in Utah Admin. Code R850-30-500. The applicant may be required to submit a bond for reclamation as well as lease payments.⁶⁴ The lease rate will be based on market value and income-producing capability.⁶⁵

⁵⁹ UTAH ADMIN. CODE R850-40-800 (2016).

⁶⁰ *Id.* R850-40-1600.

⁶¹ *Id.* R850-80-200(3)(e); R850-80-200(2).

⁶² *Id.* R850-80-200(2).

⁶³ *Id.* R850-80-100.

⁶⁴ *Id.* R850-80-800.

⁶⁵ *Id.* R850-80-400(1).

Land Sale

State law vests SITLA with authority to sell trust lands under its management. There are two avenues by which SITLA may sell trust lands: a public sale or a negotiated sale.⁶⁶ SITLA commonly reserves the mineral estate during land sales, and most sales involve developable lands rather than linear features. Whether SITLA would entertain a proposal to sell lands for either CCS or for a pipeline is unclear, but it appears less likely than a lease. This is because a land sale permanently divests the property from SITLA, whereas a lease extracts income from the property while preserving the corpus of the land for future income-generating activity. As a trustee for the state's lands, SITLA has a fiduciary obligation to maximize benefit to the state from the trust lands. This likely explains why SITLA tends to reserve mineral rights when it engages in land sales.

Acquiring Federal Land Use Rights

Several different entities manage federally owned lands within the United States. In Utah, most federally owned land is managed by the Bureau of Land Management (BLM) and the U.S. Forest Service, and the BLM is responsible for the management of the federal subsurface mineral estates.

Both the BLM and the Forest Service manage lands under the broad and flexible principles of multiple use. That is, the statutes governing these agencies require them to seek to accommodate a balance of uses on federal lands, with the general idea in mind that the lands will produce a “sustained yield.”⁶⁷

Two primary authorities govern which lands the BLM can dispose of or grant usage rights to: The Federal Land Planning and Management Act (FLPMA)⁶⁸ and the Mineral Leasing Act (MLA).⁶⁹ FLPMA would govern rights-of-way needed for the transport phase of a CCS operation on federal lands managed by the BLM. Likewise, a CCS operator that is not pursuing an enhanced oil recovery project would obtain the right to use pore space under FLPMA. If the project also involves oil and gas development, the rights would be obtained under the MLA. The National Forest Management Act governs surface uses of lands managed by the Forest Service while the BLM manages minerals beneath Forest Service managed land surface pursuant to the MLA.

As in the state context, acquisition of rights of way for pipeline or other utility or transport uses is quite common on federal lands. However, use of federal lands for CO₂ storage would be a rather novel proposition. To our knowledge, no entity operates a CCS project on BLM land for

⁶⁶ *See id.* R850-80-610–615.

⁶⁷ 43 U.S.C. §§ 1701(a)(7), 1712(c)(1); 16 U.S.C. § 529.

⁶⁸ 43 U.S.C. §§ 1701 *et seq.*

⁶⁹ 30 U.S.C. §§ 181 *et seq.*

the sole purpose of CO₂ sequestration.⁷⁰ The lack of clear precedent for the CarbonSAFE Rocky Mountain project could complicate permitting efforts.

A CCS operator could obtain a right-of-way to transport or store CO₂ under FLPMA, which gives the BLM broad authority to issue rights-of-way. FLPMA states:

The Secretary . . . [is] authorized to grant, issue, or renew rights-of-way over, upon, under, or through such lands for . . . such other necessary transportation or other systems or facilities which are in the public interest and which require rights-of-way over, upon, under, or through such lands.⁷¹

To obtain a right of way from the BLM, a CCS operator would need to meet with the local BLM office, conduct a pre-planning meeting, complete a Standard Form 299 (SF299),⁷² and pay a processing fee.⁷³ If the application is approved, the BLM may require a bond, and the CCS operator would need to pay monitoring fees during development, plus annual rent for the life of the project.

According to employees at the BLM's Utah office, FLPMA could be a means of obtaining a right not only to transport CO₂ across BLM lands but also potentially to use BLM pore space for CO₂ storage (so long as the project is outside of an oil and gas context, such as enhanced oil recovery). Although BLM officials have preliminarily indicated that the FLPMA right-of-way process could possibly be used for CO₂ storage, to date the BLM has not issued any ROW for a project of this nature. Such a first-of-kind ROW grant could be seen by the BLM as having a potential precedent-setting effect, and thus, would likely require input from high-ranking BLM or Department of the Interior officials. This could delay ROW issuance.

4.2 LIABILITY RISK

Any activity involves an element of risk. For the proposed CarbonSAFE Rocky Mountain project, these risks exist for both the transport and storage phases of CCS. With respect to transport, the primary risk is that there will be some kind of accident as CO₂ is being moved. Such an accident could, for instance, harm employees or contractors involved in achieving transport, or the general public or surrounding lands, if a leak occurred. Transport of CO₂ is governed by safety regulations implemented by the Pipeline and Hazardous Materials Safety Administration (PHMSA). This section of the report focuses on that regulation, recognizing that

⁷⁰ Our analysis assumes that the sole purpose of the proposed CarbonSAFE Rocky Mountain CCS operator is to sequester CO₂ rather than to engage in further mineral development, such as through enhanced oil recovery.

⁷¹ 43 U.S.C. § 1761(a)(7).

⁷² See GSA Forms Library, Form: SF299, www.gsa.gov/portal/forms/download/117318 (last visited Aug 14, 2017).

⁷³ See Bureau of Land Mgmt., Division of Lands and Realty, *Obtaining a Right-of-Way on Public Lands* (Mar. 10, 2009), www.blm.gov/sites/blm.gov/files/ObtainingaROWPamphlet.pdf.

other legal frameworks for liability might apply, particularly under tort law and property law. With respect to geologic storage of CO₂, a host of issues could impact long-term liability exposure. The three main issues are ownership of injected CO₂, permitting requirements for underground injection control under the Safe Drinking Water Act, and long-term liability exposure under other environmental laws. This section addresses each in turn.⁷⁴

4.2.1 Transport Regulation

The Pipeline and Hazardous Materials Safety Administration (PHMSA) within the Department of Transportation regulates the movement of a large array of materials via pipeline. This includes CO₂, which PHMSA regulations define as “a fluid consisting of more than 90 percent carbon dioxide molecules compressed to a supercritical state.”⁷⁵ PHMSA regulation of CO₂ transport is extensive and focused on ensuring safety and the lack of accidents.⁷⁶ Here, we review six key aspects of these regulations.

Minimum Design Requirements

The PHMSA imposes minimum design requirements for new, relocated, replaced, or modified CO₂ pipeline systems. The pipeline must be “made of steel of the carbon, low alloy-high strength, or alloy type that is able to withstand the internal pressures and external loads and pressures anticipated for the pipeline system.”⁷⁷ If there are segments of the system that operate under different pressure levels, the system must be designed so that components operating at lower pressures will not be overstressed.⁷⁸ The system must also account for possible external pressures, such as earthquakes, vibration, and thermal expansion and contraction.⁷⁹ All materials in the system also must be chemically compatible with CO₂ and selected for the temperature environment in which the system will operate, maintaining structural integrity.⁸⁰ The pipeline also must be designed and constructed to accommodate internal inspection devices.⁸¹

Construction, Inspection, and Testing

Each phase of pipeline construction and repair must be inspected by a person trained and qualified in the specific aspect of construction.⁸² Beginning with initial construction, the operator

⁷⁴ Other sources of liability exist, including but not limited to liability for an inadvertent CO₂ release from compression, transport, or injection infrastructure or from the reservoir itself. These issues are treated as the kind of generalized liability that is associated with more routine energy industry development and therefore beyond the scope of this analysis.

⁷⁵ 49 C.F.R. § 195.2.

⁷⁶ For an overview of regulatory issues of CO₂ transport for CCS, see Jennifer Skougard Horne, *Getting from Here to There: Devising an Optimal Regulatory Model for CO₂ Transport in a New Carbon Capture and Sequestration Industry*, 30 J. LAND RESOURCES & ENVTL. L. 357 (2010).

⁷⁷ 49 C.F.R. § 195.112(a).

⁷⁸ *Id.* § 195.104.

⁷⁹ *Id.* §§ 195.108, 195.112.

⁸⁰ *Id.* § 195.102.

⁸¹ *Id.* § 195.120.

⁸² *Id.* § 195.204.

is responsible for maintaining a complete inspection record for the life of the system.⁸³ Pipeline location, materials, components, welds, valves, and pumping equipment must all be inspected at the time of installation or construction of each segment. Likewise, breakout tanks must be inspected for adequate emergency venting or pressure relief.⁸⁴ Further, no owner may operate a pipeline or return to service any segment unless it has been pressure tested without leakage.⁸⁵ The test pressure must be maintained for at least four continuous hours at a pressure equal to 125 percent or more of the maximum operating pressure.⁸⁶ The operator must keep records of every pressure test and retain the records as long as the pipeline facility is in use.⁸⁷

Operation and Maintenance

Each operator is responsible for the maintenance and safe operation of its pipeline system. If the operator discovers an adverse condition within the system, it must correct the condition within a reasonable time. If the condition presents an immediate hazard, the operator must cease use of the affected part of the pipeline system until it corrects the condition.⁸⁸

The operator must maintain a manual with written procedures for conducting normal operations and maintenance, as well as protocols for abnormal operations and emergencies. The manual must be reviewed and updated annually and kept in locations where operations and maintenance activities are conducted.⁸⁹

Each operator also must keep adequate firefighting equipment at each pump station and breakout tank area, prohibit smoking and open flames, develop and implement a written continuing public education program, establish and conduct a training program for emergency personnel, maintain current maps and records of its pipeline systems, maintain a system of communication for the transmission of information regarding the safe operation of the pipeline system, and place and maintain line markers over each buried pipeline.⁹⁰ Signs visible to the public must be maintained around each pumping station and each breakout tank area.⁹¹

At least 26 times per year, at intervals of no more than 3 weeks, the operator must inspect the surface conditions on or adjacent to each pipeline right-of-way.⁹² Operators must also inspect all overpressure safety devices and overfill protection systems at intervals not to exceed 7.5 months, at least twice a year, to ensure that all pressure control equipment is properly functioning, remains in good mechanical condition, and is adequate for capacity and reliability.⁹³ Repairs must be made in a safe manner so as to prevent damage to persons or property.⁹⁴ Each operator

⁸³ *Id.* § 195.266.

⁸⁴ *Id.* § 195.264.

⁸⁵ *Id.* § 195.302.

⁸⁶ *Id.* § 195.304.

⁸⁷ *Id.* § 195.310.

⁸⁸ *Id.* § 195.401.

⁸⁹ *Id.* § 195.402.

⁹⁰ *Id.* §§ 195.403-.404.

⁹¹ *Id.* § 195.434.

⁹² *Id.* § 195.412(a).

⁹³ *Id.* § 195.428.

⁹⁴ *Id.* § 195.422.

must also carry out a written program to prevent damage to pipeline from excavation activities, including blasting, boring, tunneling, backfilling, removal of aboveground structures, and other earth moving operations.⁹⁵

Corrosion Control

CO₂ pipeline operators also must comply with PHMSA regulations ensuring against corrosion. Each buried or submerged pipeline must have an external coating for external corrosion control.⁹⁶ The coating material must be designed to mitigate corrosion, have sufficient adhesion, be sufficiently ductile, resist damage due to handling and soil stress, and support any supplemental cathodic protection.⁹⁷ Each buried pipeline must have cathodic protection in operation no later than one year after the pipeline is constructed as well as electrical test leads for external corrosion control.⁹⁸

Corrosion control must be conducted regularly, with tests for external corrosion at least once every 15 months.⁹⁹ Whenever any portion of a buried pipeline is exposed, the operator must examine the exposed portion.¹⁰⁰ Likewise, pipeline interior must be investigated at least every 7.5 months. If corrosion reduces sufficient wall thickness, the pipe must be replaced.¹⁰¹ When corrosion requiring corrective action is found, the operator must investigate circumferentially and longitudinally beyond the removed pipe to determine that further corrosion does not exist.¹⁰²

Unless electrically interconnected and cathodically protected, all buried pipeline must be electrically isolated from other metallic structures. One or more insulating devices must be installed wherever electrical isolation of a portion of pipeline is necessary to facilitate corrosion control. Each electrical isolation must be inspected and electronically tested to assure the isolation is adequate. If an insulating device is installed in an area where a combustible atmosphere is reasonably foreseeable, precautions must be taken to prevent arcing.¹⁰³ Operators must have a program to identify, test for, and minimize damage to pipelines exposed to stray currents.¹⁰⁴

Records of corrosion control must be maintained. An operator must keep current maps or records showing the location of cathodically protected pipelines, cathodic protection facilities, and neighboring structures bonded to cathodic protection systems. Records of each analysis, check, demonstration, examination, inspection, investigation, review, survey, and test must be kept with sufficient detail to demonstrate the adequacy of corrosion control measures for at least 5 years.¹⁰⁵

⁹⁵ *Id.* § 195.442.

⁹⁶ *Id.* § 195.557.

⁹⁷ *Id.* § 195.559(a)-(e).

⁹⁸ *Id.* §§ 195.563(a), 195.567.

⁹⁹ *Id.* § 195.573(a)(1).

¹⁰⁰ *Id.* § 195.569.

¹⁰¹ *Id.* § 195.585(a).

¹⁰² *Id.* § 195.579(c).

¹⁰³ *Id.* § 195.575(a)-(e).

¹⁰⁴ *Id.* § 195.577(a).

¹⁰⁵ *Id.* § 195.589.

Annual, Accident, and Safety-Related Reporting

PHMSA regulations require pipeline operators to submit a variety of regular and incident-specific reports. Annual safety reports are due no later than June 15 for each previous year.¹⁰⁶ Written accident reports, along with updates on the status of an accident, must be submitted within 30 days of the occurrence. Separate reports must be submitted for each failure that results in any (1) unintentional explosion or fire, (2) release of 5 gallons or more of CO₂, (3) death of any person, (4) injury to any person that requires hospitalization, (5) damages estimated to exceed \$50,000.¹⁰⁷ In addition to the written report, operators must provide telephonic notice of qualifying accidents as soon as reasonably possible following the discovery of the accident. Accidents that result in the pollution of any stream, river, lake, reservoir, or other similar body of water also requires immediate telephonic notice.¹⁰⁸ If an accident is investigated by PHMSA or other government regulator, the operator has a duty to provide all records, information, and assistance reasonably available or necessary.¹⁰⁹

Qualifications of Pipeline Personnel

Each operator must have and follow a written personnel qualification program that will, among other things, identify covered tasks, evaluate the qualifications of individuals assigned to covered tasks, provide training, allow individuals who are not yet qualified to perform a covered task under supervision of a qualified individual, and communicate changes that affect covered tasks to the individuals responsible for performing those covered tasks.¹¹⁰ Additionally, each operator must maintain records that contain (1) the identification of qualified individuals, (2) the identification of the covered tasks each individual is qualified to perform, (3) the dates of the individual's current qualification, and (4) the methods of training the individual received. Records of prior/expired qualifications and of individuals no longer performing covered tasks must be retained for 5 years.¹¹¹

4.2.2 Storage Liability

Three key issues outline the likely scope of liability for permanently sequestered CO₂. These relate to who owns the CO₂, permitting under the Safe Drinking Water Act, and potential long-term liability under both environmental and other statutory and common law.

CO₂ Ownership

A threshold question for possible liability from the storage phase of CCS is who owns the geologically deposited CO₂. That is, once the CO₂ is injected into the ground, does the injector maintain ownership of it and thus risk liability from any harm that may arise from the injected CO₂?

¹⁰⁶ *Id.* § 195.49.

¹⁰⁷ *Id.* § 195.50.

¹⁰⁸ *Id.* § 195.52.

¹⁰⁹ *Id.* § 195.60.

¹¹⁰ *Id.* § 196.505(a)-(e).

¹¹¹ *Id.* § 195.507.

The law is not clear on this question, although analogous reasoning from other areas suggests that an injector of CO₂ is likely to retain title to the gas. Indeed, ownership of injected CO₂ is not a settled issue. It has not been addressed in a published court opinion, and Utah statutory law does not address the question. However, applying property law doctrines from the natural gas context may help delineate ownership of sequestered CO₂.

Two theories have been suggested to address ownership of injected natural gas: the so-called “non-ownership” and “ownership” theories. Under the non-ownership theory, it can be reasoned that once natural gas is injected into the ground, the injector loses ownership of the resource because it is available for anyone to take. This reasoning derives from the longstanding “rule of capture,” which serves as the foundation of oil and gas law. The rule of capture holds that, because oil and gas are fugitive minerals and can transverse subterranean property boundaries, 112[~~112~~] Building on this idea, which has long been invoked in oil and gas law in part to encourage exploration and extraction, the theory of non-ownership would hold that once the resource— here, CO₂^{113, 114}.

In place of the non-ownership theory, states instead have adopted the ownership theory. Under this theory, “title to natural gas once having been reduced to possession is not lost by the injection of such gas into a natural underground reservoir for storage purposes.”¹¹⁵ The rationale for this theory should be plain. It would be incongruous to promote natural gas extraction under the rule of capture, only to turn around and limit the producing party’s incentive to extract by restricting its ability to feasibly store the extracted resource. To reach such holdings, courts have thus distinguished the geological context of injected gas from naturally occurring gas. Whereas the latter can be pulled across property boundaries through extraction techniques, the former is unlike releasing an animal into the wild because there is a “well[-]defined storage field . . . subject to the control of the storage companies[.]”¹¹⁶ Accordingly, in cases where a gas has previously been reduced to possession but is later injected into a well-defined underground space capable of being maintained with integrity, title to the gas remains with the original owner.

While sequestered CO₂ is distinguishable from natural gas in that the former is part of the waste stream while the latter is an economically valuable commodity, a formidable argument can be made that the ownership theory should also apply to geologically stored CO₂. Because CO₂ is sequestered in a similar manner as natural gas is stored, application of the ownership theory would appear appropriate. Indeed, the mirror image of the policy incentives created by applying

¹¹² *Westmoreland & Cambria Nat. Gas Co. v. De Witt*, 130 Pa. 235, 249 (1889).

¹¹³ *Hammonds v. Cent. Kentucky Nat. Gas Co.*, 75 S.W.2d 204, 206 (1934), *overruled by* *Texas Am. Energy Corp. v. Citizens Fid. Bank & Trust Co.*, 736 S.W.2d 25 (Ky. 1987)

¹¹⁴ Mark deFigueiredo, *The Liability of Carbon Dioxide Storage* 304 (Feb. 2007) (unpublished Ph.D. dissertation, Massachusetts Institute of Technology), http://sequestration.mit.edu/pdf/Mark_de_Figueiredo_PhD_Dissertation.pdf.

¹¹⁵ *White v. N.Y. State Nat. Gas Corp.*, 190 F. Supp. 342, 349 (W.D. Pa. 1960).

¹¹⁶ *Id.* at 348.

the ownership theory to natural gas exist for stored CO₂ as well. For natural gas, the ownership theory preserves the incentive to extract the resource in the first instance. That is, the theory avoids the inequity of a gas producer incurring the cost of extraction but allowing another party to profit from that by taking the gas once it is stored. Similar reasoning could apply in the stored CO₂ context. It would seem incongruous to require the CO₂ owner to incur liability while the CO₂ is above ground but remove the potential of such obligations simply because the CO₂ is moved underground.

Nonetheless, a possible limit on the application of the ownership theory to stored CO₂ might derive from a factual difference between it and natural gas. Injected CO₂ could mineralize within as little as two years, depending upon the medium into which it is injected.¹¹⁷ This could have significant implications for legal liability, because once the CO₂ turns into a solid, an argument could be made that any possibility of liability should be curtailed since solid rock will not leak or spread.

Safe Drinking Water Act Permitting

The Safe Drinking Water Act (SDWA) requires operators to obtain permits before conducting underground injection of certain materials. The Act relies on a cooperative federalism model whereby the EPA sets minimum standards and states develop programs to attain those objectives in light of local conditions. One such program under the Act is the Underground Injection Control (UIC) program. The UIC program aims to “protect public health and prevent contamination of underground sources of drinking water (USDWs).”¹¹⁸ The program specifies six classes of well permits that may be granted to inject underground materials subject to the Act. Class VI permits are the relevant permit for CCS operations.

In Utah, the Utah Department of Environmental Quality and the Department of Natural Resources issue Class I-V UIC permits.¹¹⁹ That is, these state-level agencies have received primacy from the EPA to administer permits for wells within classes I-V. Utah has not petitioned for authorization to administer Class VI UIC permits. That authority rests solely with the EPA. A

¹¹⁷ J.M. Matter et al., *Rapid Carbon Mineralization for Permanent Disposal of Anthropogenic Carbon Dioxide Emissions*, 352 *SCIENCE* 1312 (2016).

¹¹⁸ Underground sources of drinking water are defined as “an aquifer or its portion: (a)(1) Which supplies any public water system; or (2) Which contains a sufficient quantity of ground water to supply a public water system; and (i) Currently supplies drinking water for human consumption; or (ii) Contains fewer than 10,000 mg/l total dissolved solids; and (b) Which is not an exempted aquifer.” 40 C.F.R. § 144.3 (2017).

¹¹⁹ Each class of UIC permits covers a different use. Class I deals with industrial and municipal waste. Class II covers enhanced oil recovery, salt water disposal, and storage of hydrocarbons that are liquid at standard temperature and pressure. Class III covers solution mining. Class IV covers hazardous wastes. And Class V covers injection of fluids not covered in other well classes.

CCS operator must therefore obtain a Class VI UIC permit from the EPA prior to injecting CO₂.¹²⁰

Class VI Well Requirements Under the SDWA

Class VI wells are used exclusively for the injection of CO₂ into the subsurface in aid to a geologic sequestration (GS) or CCS projects. The EPA's main health and environmental concerns regarding CCS are the "[l]arge CO₂ injection volumes associated with GS, the buoyant and mobile nature of the [CO₂ stream], the potential presence of impurities in the CO₂ stream, and its corrosivity in the presence of water."¹²¹ In addition, EPA has expressed concern about the "pressures induced by injection" from CCS, as those pressures "may force naturally occurring salty water (brine) into USDWs, causing degradation of water quality and affecting drinking water treatment processes."¹²²

Class VI permits address a wide range of issues: site characterization, computational modeling of the Area of Review (AoR), periodic reevaluation of the AoR, well construction, project monitoring, comprehensive post-injection monitoring and site care, and financial responsibility requirements.¹²³

Obtaining and complying with a Class VI permit under the SDWA provides important liability protection for CCS project operators. This liability protection, however, is far from universal and addresses only SDWA liability. EPA regulations make clear that "compliance with a permit during its term constitutes compliance, *for purposes of enforcement*, with Part C of the SDWA."¹²⁴ This rule, commonly referred to as a "permit shield" provision, is echoed in EPA's site closure¹²⁵ guidance documents:

[O]nce an owner or operator has met all regulatory requirements under the UIC program for Class VI wells [at 40 C.F.R. § 146] and the UIC Program Director has approved site closure pursuant to requirements at 40 C.F.R. § 146.93, the owner or operator will generally no longer be subject to enforcement for regulatory noncompliance. However, following site closure, the owner or operator

¹²⁰ 40 C.F.R. § 144.18.

¹²¹ See U.S. EPA, *Class VI - Wells Used for Geologic Sequestration of CO₂*, www.epa.gov/uic/class-vi-wells-used-geologic-sequestration-co2#well_def (last visited Sept. 15, 2017).

¹²² *Id.* at II(A)(3).

¹²³ *Id.*

¹²⁴ 40 C.F.R. § 144.35 (emphasis added).

¹²⁵ See U.S. EPA, *Geologic Sequestration of Carbon Dioxide Underground Injection Control (UIC) Program Class VI Well Plugging, Post Injection Site Care, and Site Closure Guidance* (Dec. 2016), www.epa.gov/sites/production/files/2016-12/documents/uic_program_class_vi_well_plugging_post-injection_site_care_and_site_closure_guidance.pdf.

is financially responsible for any remedial action deemed necessary for USDW endangerment caused by the injection operation.¹²⁶

In short, the EPA will not bring enforcement actions under Part C of the SDWA, which addresses protection of USDWs, once a CCS site has undergone official site closure. However, as discussed in more detail below, the rule does not shield enforcement of Part D of the SDWA, which addresses the EPA Administrator’s emergency powers to address imminent and substantial endangerment to health. Nor does compliance with Part C preclude other enforcement mechanisms or different kinds of liability. As the above guidance document makes clear, CCS owners/operators remain “financially responsible for any remedial action” that becomes necessary even after site closure.¹²⁷ Another portion of EPA’s SDWA guidance further reinforces this point:

[S]ite closure does not eliminate any potential responsibility or liability of the owner or operator under other provisions of law[, or § 1431 of the SDWA¹²⁸]. . . . Furthermore, after site closure, an owner or operator may remain liable under tort and other remedies, or under other federal statutes including, but not limited to, the Clean Air Act (CAA); the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA); and the Resource Conservation and Recovery Act (RCRA).¹²⁹

Stiff penalties may be imposed for violating the SDWA’s USDW protections. Violators are subject to civil penalties of up to \$25,000 for each day of violation. If the violation was “willful,” the violator may also be subject to criminal prosecution and imprisonment of not more than three years.¹³⁰

Lessons Learned from SDWA Permitting for CCS Facilities

We reviewed permitting documents for three other CCS facilities in order to identify lessons learned from those experiences. While the CarbonSAFE Rocky Mountain project will be subject to the same procedural requirements, factual differences between the project at hand and prior CCS facilities need to be acknowledged when considering the experience at other CCS facilities.

¹²⁶ *Id.* § 4.4.

¹²⁷ *Id.*

¹²⁸ *See id.* Under Section 1431 of SDWA, the Administrator may require an owner or operator to take necessary response measures if he or she receives information that a contaminant is present or is likely to enter a public water system or USDW and may present an imminent and substantial endangerment to the health of persons, and the appropriate state and local authorities have not acted to protect the health of such persons. The action may include issuing administrative orders or commencing a civil action for appropriate relief against the owner or operator of a Class VI well. If the owner or operator fails to comply with the order, he or she may be subject to a civil penalty for each day in which such violation occurs or failure to comply continues.

¹²⁹ *Id.* (internal citations omitted).

¹³⁰ 42 U.S.C. § 300h-2(b).

FutureGen

FutureGen involved CO₂ capture from Unit 4 of Ameren's Meredosia Energy Center, approximately 20 miles west of Jacksonville, Illinois, and was intended to be the world's first full-scale oxy-combustion clean coal repowering of an existing power plant fully integrated with CO₂ transport and permanent geologic storage. CO₂ would have been transported approximately thirty miles from the plant site to the storage location, where approximately one million metric tons per year of compressed and purified CO₂ would have been injected into the Mt. Simon saline formation for a projected twenty-year period.

FutureGen was the first full-scale CCS project in the United States to undergo SDWA Class VI permitting, and twenty-nine parties submitted comments on the draft permit to EPA. After responding to the comments, the EPA issued FutureGen a Class VI permit on March 31, 2014. As the first of such permits issued by the EPA, the agency stated throughout the permit file that particular care was taken to ensure protection of underground sources of drinking water. In addition, the EPA stated that modifications to the permit may be required as the project developed and therefore more data was acquired, despite all of requirements prior to issuing the permit. However, FutureGen 2.0 was discontinued due to funding limitations resulting from the expiration of American Recovery and Reinvestment Act funds on September 30, 2015. Despite the project's failure, the comments received may provide some indication of the kinds of issues that are likely to arise for the CarbonSAFE project.

Notably, the EPA took an exceedingly narrow view of the issues that it needed to consider during the FutureGen 2.0 UIC permitting process, focusing exclusively on protection of USDW. Whether plume migration had ceased prior to closure was oddly considered outside the scope of the permit analysis. Similarly, the EPA took the approach that Class VI rules were not concerned with pore space rights, just safety and project operation. The EPA therefore did not address pore space ownership, concluding that the permit does not prevent private rights from being asserted.

Also, of note, by statute and as acknowledged in the permit, Illinois would have taken ownership of the site ten years after the site closure. Therefore, any long-term liability associated with the project would rest with Illinois. Utah does not have such a statute and it appears that ownership of the site would remain with the operator until it disposes of the site in some way upon site closure. EPA appeared to acknowledge this in issuing the FutureGen 2.0 permit. It stated that "any remediation costs incurred in the very long term (i.e., after the non-endangerment determination and the release from post-injection site care responsibilities) is beyond the scope of the Class VI financial responsibility requirements and the UIC permitting process."

ADM

The Archer Daniels Midland Company (ADM) Illinois ICCS project involves sequestration of CO₂ generated as a byproduct of processing corn into ethanol at ADM's biofuels plant adjacent to the storage site in Decatur, Illinois. The CO₂ is collected at atmospheric pressure, compressed, and dehydrated to deliver supercritical CO₂ to the injection wellhead for storage. Injection occurs on a 200-acre site adjacent to the ethanol plant, which is also owned by ADM. While not addressed in detail in permitting documents, it appears that ADM owns the pore space into which the CO₂ would be injected. The project is designed to sequester 2.5 million tons of CO₂ over a 2.5-year period.

On May 3, 2011, the Department of Energy concluded its NEPA analysis¹⁵¹ for the ADM project and issued a Finding of No Significant Impact.¹⁵² The ADM project received the U.S. EPA's UIC Class VI injection well permit effective March 6, 2017 and started commercial operations accordingly. ADM characterized the CO₂ streams generated by this project as liquids, supercritical fluids, or gas. It will be injected into the Mount Simon at depths between 5,553 feet and 7,043 feet.

Class VI injection well permitting appeared to generate very little controversy, with only one member of the public submitting comments on the draft permit. Most relevant to the CarbonSAFE project, the commenter asserted that pore space rights must be taken into account when issuing the permit. The EPA, however, responded that under Class VI rules, it need not consider pore space rights, and the permit does not grant any real property rights. As noted above, CarbonSAFE Rocky Mountain would be wise to anticipate a higher level of scrutiny and that other federal approvals will need to address pore space ownership, even if the EPA does not address the issue directly.

4.2.3 Managing Financial Risk and Long-Term Liability

Risk exposure is a function of the likelihood of harmful event combined with the consequences of such an event, both of which are influenced by numerous site-specific factors. In this section, we treat financial risk as the economic cost of mitigating the injuries caused by a harmful event as well as compensation for unmitigable injuries associated with any such event. For purposes of risk assessment, CCS operations can be broken into four discrete phases: (1) capture, (2) transport, (3) injection and CO₂ plume stabilization, and (4) post-closure stabilization and monitoring. This analysis focuses on the transport, injection and CO₂ plume stabilization, and post-closure stabilization and monitoring phases.

Events giving rise to financial liability could take many forms, the most likely of which involve damage caused by: (1) the puncture of a CO₂ pipeline or failure of other pipeline infrastructure, (2) seismicity induced by CO₂ injection, (3) ground surface damage or surface heaving caused by injected CO₂, (4) interference with a surface owner's rights to occupy or use the ground surface (trespass), (5) interference with a sub-surface owner's rights to occupy or use the sub-surface, or infringement with development of their mineral rights (trespass on minerals), (6) contamination of an underground source of drinking water or other water source, and (7) an atmospheric release of CO₂. Loss of CO₂ containment and failure to maintain permanent sequestration, as required by regulation or contract, could also require the operator to refund payments received for sequestration. Damage to property, damage to natural resources or livestock, and injury to humans also involve potential economic costs to an operator.

The risk profile for each stage of operation underpins the range of costs and loss values associated with potential mitigation, remediation, and, as necessary, compensation for damages. The risk profile is a function of numerous phase-specific considerations. With respect to CO₂

¹⁵¹ U.S. Dep't of Energy, Final Environmental Assessment of Industrial Carbon Capture and Sequestration (ICCS) Area 1 Project, "CO₂ Capture from Biofuels Production and Sequestration into the Mt. Simon Sandstone," Archer Daniels Midland Company Decatur, Illinois (2011).

¹⁵² U.S. Dep't of Energy, Finding of No Significant Impact for Archer Daniels Midland Company's "CO₂ Capture from Biofuels Production and Sequestration into the Mt. Simon Sandstone," Decatur, Illinois (2011).

transport, pipeline length, period of pipeline operation, CO₂ pressure, CO₂ purity, and proximate land use activities are examples of factors that could contribute to the risk associated with an unintended release. The location of an unintended release of CO₂ could also directly impact the consequences of such a release. A CO₂ release would be more likely to cause injury or property damage if it occurred in a populated area, for example.

During the injection and plume stabilization phase, the volume of CO₂ injected, the injection pressure, the length of the injection period, the geology of the receiving formation, the number and integrity of other wells penetrating the receiving formation, and the existence of underground sources of drinking water or valuable minerals all contribute to the risk profile. As with the risk profile associated with CO₂ transportation, the proximity to populated areas is also a critical factor in assessing risk. This necessarily requires consideration of current population as well as anticipated population growth.

Many of the same factors that shape injection and plume stabilization period risks impact the risk profile during the post-closure and post-CO₂-plume-stabilization period. However, in contrast to the risk profile during the injection and stabilization phase, which increases with injection volume and pressure until stabilization occurs, the post-stabilization and closure risk profile is likely to decline¹³³ as reservoir pressures stabilize, plume migration slows or stops, and as CO₂ reacts with brine and minerals in the rock to form bicarbonate that permanently traps that portion of the injected CO₂, as shown in Figure 61.¹³⁴

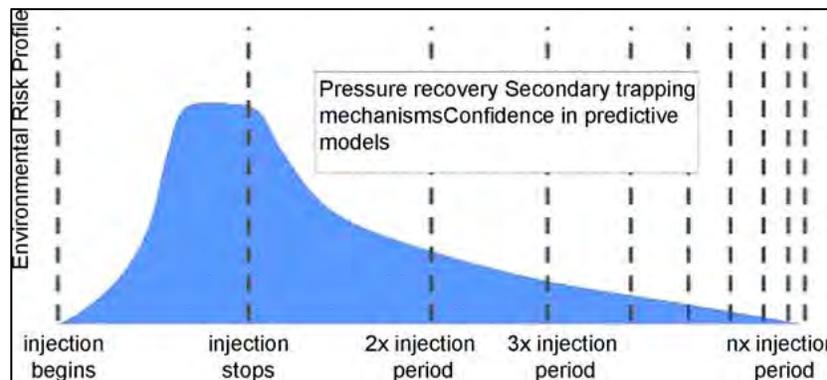


Figure 61. Life-Cycle Risk Profile for Geologic CO₂ Storage¹³⁵

Other factors further underscore how quantifying CCS financial risks necessarily requires site-specific risk assessments. Reservoir size and permeability, injection volume and pressure, CO₂ stream purity, structural geology, faulting and reservoir perforations (including existing and abandoned wells), proximity to groundwater, proximity to valuable mineral resources, proximity

¹³³ See, e.g., James J. Dooley et al., *Design Considerations for Financing a National Trust to Advance the Deployment of Geologic CO₂ Storage and Motivate Best Practices*, 4 INT'L J. GREENHOUSE GAS CONTROL 381, 382 (2010).

¹³⁴ For a summary of CO₂-trapping mechanisms, see National Energy Technology Lab, U.S. Dept. of Energy, *How Is CO₂ Trapped in the Subsurface?*, <https://www.netl.doe.gov/research/coal/carbon-storage/carbon-storage-faqs/how-is-co2-trapped-in-the-subsurface> (last visited Apr. 25, 2018).

¹³⁵ Figure 2 is from S.M. Benson, *Multi-Phase Flow and Trapping of CO₂ in Saline Aquifers* (Paper No. OTC 19244) in PROCEEDINGS OF 2008 OFFSHORE TECHNOLOGY CONFERENCE (2008).

to populated areas, proximity to sensitive surface resources, and pipeline length are all examples of the kinds of factors that must be considered on a case-by-case basis. Should the CarbonSAFE Rocky Mountain project proceed past Phase I, then, a quantitative risk assessment specific to the project, taking into account this site-specific information, would be necessary.

While a precise quantification of financial risk for the CarbonSAFE Rocky Mountain project is not currently possible, a review of other CCS projects may provide a rough indication of the scale of financial risk at hand. A 2011 study in ENERGY PROCEDIA provides preliminary estimates of potential public health damages during the operational phases at three proposed FutureGen sites: Tuscola, Illinois; Jewett, Texas; and Odessa, Texas.¹³⁶ As the authors explain:

[A]ll three sites are in highly rural areas and have favorable geologic and geographic characteristics that result in relatively low damages relative to the expected cost of these facilities. Notably, the Odessa damages estimate is particularly low, reflecting the near absence of human receptors near the plant site, CO₂ pipeline, and sequestration site.¹³⁷

Specifically, damage estimates ranged from \$50,000 to \$7,400,000. These estimates equate to less than \$0.20 per ton of CO₂, assuming a 50-year injection period and 50 million metric tons of CO₂ stored per site. Critically, however, these valuation estimates are limited to valuation of events arising during the operational period through a defined post-injection period for each site. It is also important to note that these estimates relate only to damages associated with injuries involving public health and do not contemplate damages associated with environmental resources, such as groundwater or atmospheric releases of CO₂.

A 2014 study involving two of the same authors and also published in ENERGY PROCEDIA used a risk-based probabilistic model to estimate several categories of potential financial damages on a site-specific basis.¹³⁸ This model estimated the financial consequences arising from potential human health, safety, environmental, and business interruption events associated with CCS, in light of their anticipated site-specific likelihood and magnitude.

The authors utilized this model to quantify financial risk at the Alabama Gulf Coast-Plant Barry pilot project in Mobile, Alabama based on forty-eight potential site-specific CCS-related events at the site. The authors contemplated two scenarios: an “experimental injection well” that operated for nine years and a theoretical commercial injection well that operate for 103 years (including ten years of post-injection monitoring). Damages under the experimental injection well scenario were estimated to range up to \$27 million, with a median damage estimate of \$3.3 million.¹³⁹ The five events contributing the highest potential damage for the experimental scenario were:

- Failure to maintain sustained operation of capture unit, pipeline, and injection to enable storage of sufficient volumes of CO₂ (100-300 kt) to meet project goals;

¹³⁶ Michael Donlan & Chiara Trabucchi, *Valuation of Consequences Arising from CO₂ Migration at Candidate CCS Sites in the U.S.*, 4 ENERGY PROCEDIA 2222 (2011).

¹³⁷ *Id.* at 2228.

¹³⁸ Chiara Trabucchi et. al, *Application of a Risk-Based Probabilistic Model (CCSvt Model) to Value Potential Risks Arising from Carbon Capture and Storage*, 63 ENERGY PROCEDIA 7608 (2014).

¹³⁹ *Id.* at 7612.

- Unexpected transport requirements;
- Monitoring program unable to meet monitoring intents due to movement of CO₂ and demonstration of containment;
- Decreased performance of capture unit based on fuel switch; and
- Injection pump failure or downtime.

Together, these five categories of events represented 66.5 percent of total costs across all model runs.

Modeling for the commercial scenario produced damage estimates of up to \$131 million, with a median damage estimate of \$6 million. The five events contributing to the highest potential damage estimated under the commercial scenario were:

- Monitoring program unable to meet monitoring intents due to movement of CO₂ and demonstration of containment;
- Unexpected transport requirements;
- Unexpected size of plume expansion (larger than anticipated) triggering permit review, expanded monitoring activities, and implementation of preventive measures on wells;
- Loss of containment due to migration along transmissive faults; and
- Return of low quality condensate that could impact water chemistry and cause problems at the plant.

Together, these five categories of events represented 83.7 percent of the total costs across all model runs. The authors also compared the cost per ton of sequestered CO₂ to those projected for the non-selected FutureGen site in Jewett, Texas, as shown in Table 20.

Table 20. Cost Per Ton Summary Model Outputs for Commercial Well Scenario and Non-Selected FutureGen Site in Jewett, TX¹⁴⁰

Category	Commercial Well Scenario - Plant Barry				Non-Selected FutureGen Site Jewett, TX
	30-Year Post-Injection Monitoring		10-Year Post-Injection Monitoring		
	All Events	Business Risks Excluded	All Events	Business Risks Excluded	
Minimum \$/ton cost	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
50th percentile \$/ton cost	\$0.17	\$0.12	\$0.12	\$0.07	\$0.17
95th percentile \$/ton cost	\$1.05	\$1.01	\$0.92	\$0.88	\$0.37
99th percentile \$/ton cost	\$1.54	\$1.49	\$1.36	\$1.32	\$0.48
Maximum \$/ton cost	\$2.67	\$2.85*	\$2.63	\$2.56	\$0.74

* All Monte Carlo simulations across scenarios were conducted independently. In this case, the highest-cost trial for the "business risks excluded" scenario exceeded the costs of the highest-cost trial for the scenario where no events were excluded. This outcome has a very low probability of occurrence. \$/ton assume 50MM tons CO₂ injected.

While the costs and risks associated with the CarbonSAFE Rocky Mountain project will undoubtedly differ from those associated with either the Plant Barry or Jewett, Texas facilities, it seems reasonable at this preliminary phase to plan for financial risks in the range of \$1.00 to \$1.50 per ton of CO₂ injected. This represents approximately the ninety-fifth to ninety-ninth percentile for the Plant Barry Facility and is more than the estimate for the Jewett, Texas site.

¹⁴⁰ Figure 3 is from Trabucchi et al., *supra* note 185.

Insurance for CCS operations needs to consider all of the risks associated with more traditional industrial operations as well as the risks associated with long-term sequestration. Insurance markets for post sequestration and stabilization liability remain undeveloped. The possibility of open-ended liability—including the potential for a large payout—has discouraged investment in this area, as has the slow development of commercial scale CCS facilities. There may also be a mismatch between the real and perceived risk profile for long-term CCS, as reservoir pressures are anticipated to decrease over time, especially given that CO₂ is likely to react with brine and minerals in the rock to form bicarbonate and permanently trap a significant portion of the injected CO₂. This may, in turn, result in reliance on less accurate analogues for insurance model development.

Legislation at either the state or federal level that assumes long-term responsibility once injection has ceased and the CO₂ plume has stabilized may help in addressing these issues. This is what Congress has done for other industries, including, for example, for the nuclear power industry through the Price-Anderson Act. Otherwise, operators may need to explore more creative ways of developing insurance options.

4.3 FEDERAL ENVIRONMENTAL IMPACT REVIEW

The National Environmental Policy Act (NEPA)¹⁴¹ has been described as the Magna Carta of environmental laws.¹⁴² Notably, however, the law does not require the federal government to do anything substantive with respect to the environment. Rather, the statute requires the government to consider what impact different actions that it takes will have on the environment before taking those actions. The idea is that NEPA facilitates federal agencies making informed decisions because they consider the consequences of various alternative courses of action before proceeding. Indeed, NEPA does not require selection of the least damaging alternative, only that agencies take a hard look at tradeoffs before moving forward. Where an action involves approvals from multiple agencies, those agencies can combine their NEPA analyses. While several states have adopted state environmental policy acts that involve procedural mandates similar to NEPA, Utah is not one of those states.

4.3.1 The NEPA Process

NEPA requires that, prior to authorizing or undertaking any “major Federal action significantly affecting the quality of the human environment,” the lead federal agency must analyze the likely impacts of that action on the environment. This often results in a detailed statement discussing the purpose and need for the proposed action, alternative means of satisfying the purpose and need, and the environmental impacts that are anticipated to result from each considered alternative, including an alternative of “no action.”¹⁴³ Under NEPA, the “human environment” is defined broadly to include “the natural and physical environment and the relationship of people

¹⁴¹ 42 U.S.C. §§ 4321–4370(h).

¹⁴² DANIEL R. MANDELKER, *NEPA LAW AND LITIGATION* § 1:1 (2d ed. 2014).

¹⁴³ 42 U.S.C. § 4332(2)(C).

with that environment.”¹⁴⁴ Major federal actions typically include the issuance of project permits, such as mineral leases on federal lands.

Not all federal actions have a “significant” impact, and the scope and intensity of impacts associated with the proposed action determine the level of analysis required. Where impacts are “significant” in both their context and intensity, an Environmental Impact Statement (EIS) is required. “Context” varies by project and is evaluated at multiple scales.¹⁴⁵ “Intensity” may reflect a wide array of factors, including but not limited to controversy surrounding the nature of the effects¹⁴⁶ and the degree to which the action may establish a precedent for future actions with significant effects.¹⁴⁷

Where the significance of impact is uncertain, the lead federal agency may elect to prepare either an EIS or a less onerous Environmental Assessment (EA).¹⁴⁸ If the agency chooses the latter path and the EA shows that the impacts are significant, then the agency must prepare a full-fledged EIS. If, however, the EA shows that the impacts are not significant, the agency may issue a finding of no significant impact (FONSI) and a record of decision (ROD) on that determination.

Agencies are also authorized to promulgate regulations identifying categories of action that “do not individually or cumulatively have a significant effect on the human environment.”¹⁴⁹ Agencies can then categorically exclude these actions from further NEPA review. However, even if a categorical exclusion (CE) has been established by rule, the existence of “extraordinary circumstances” may prevent its application.¹⁵⁰ Under Department of Energy regulations, certain small-scale CO₂ injection wells are categorically exempt from NEPA analysis.¹⁵¹ CarbonSAFE, however, is likely to inject more than the 500,000-ton limit allowed under these regulations.

EISs are part of an iterative analytical decision making process that begins with publication of a Notice of Intent (NOI) to prepare an EIS.¹⁵² The NOI kicks off a public scoping period in which the public is invited to submit comments about the proposal, the environmental issues the proposal raises, and potential alternative means of achieving the purpose of the proposed action.¹⁵³ Those comments help the lead federal agency identify issues, formulate alternatives, and collect or conduct necessary research. The reasonably foreseeable direct, indirect, and cumulative impacts anticipated to result from implementation of each alternative (including a “no action alternative”) are then analyzed and disclosed in a Draft EIS (DEIS).¹⁵⁴ The DEIS is made available for public review and comment.¹⁵⁵ After considering public input, the lead federal agency releases a Final EIS (FEIS) that reflects public input on the agency’s methods and

¹⁴⁴ 40 C.F.R. § 1508.14.

¹⁴⁵ *Id.* § 1508.27(a).

¹⁴⁶ *Id.* § 1508.27(b)(4).

¹⁴⁷ *Id.* § 1508(b)(6).

¹⁴⁸ *Id.* § 1508.9.

¹⁴⁹ *Id.* § 1508.4.

¹⁵⁰ *Id.* § 1508.4; *see e.g.*, 43 C.F.R. § 46.215 (2017) (listing extraordinary circumstances for BLM NEPA).

¹⁵¹ 10 C.F.R. § Pt. 1021. Subpt. D App. B § B5.13 (2017).

¹⁵² 40 C.F.R. § 1501.7.

¹⁵³ *Id.* § 1501.7(a).

¹⁵⁴ *Id.* §§ 1502.9(b), 1508.8.

¹⁵⁵ *Id.* § 1503.1(a)(4).

analysis.¹⁵⁶ Following a period in which the governor of the state within which the project occurs can comment on consistency with state requirements, the lead federal agency then issues a ROD stating the agency's decision and initiating a protest or appeals period.¹⁵⁷ Figure 62 details this process.

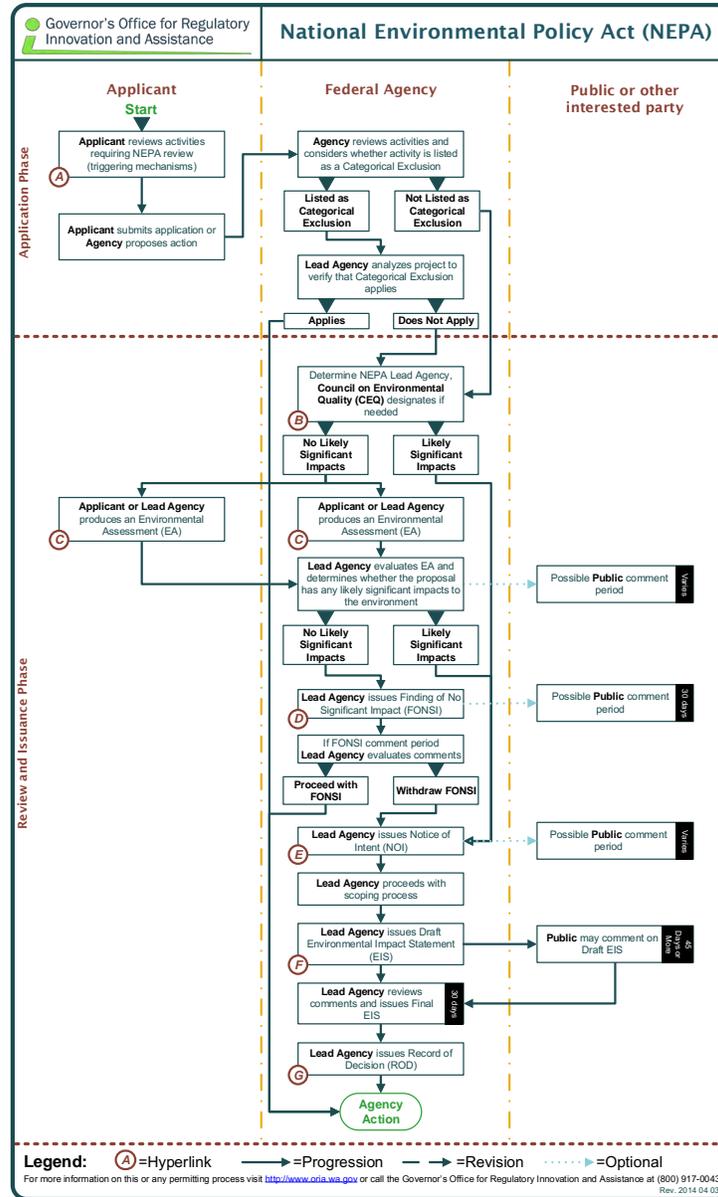


Figure 62. The NEPA Process¹⁵⁸

¹⁵⁶ *Id.* § 1502.9(b).

¹⁵⁷ *Id.* § 1505.2.

¹⁵⁸ Schematic from Washington State, Governor's Office of Regulatory Innovation and Assistance https://www.oria.wa.gov/Portals/_oria/VersionedDocuments/Schematics_N-Z/National-Environmental-Policy-Act-Schematics.pdf.

Agencies are directed not to speculate when conducting their NEPA analysis, and therefore frequently choose to undertake a phased approach to NEPA implementation. The BLM, for example, may undertake a NEPA analysis as part of a planning-level decision to determine which lands are available for oil and gas development and which surface use stipulations will apply to those broad areas. Not all lands that are available for leasing will be of interest to industry, and the BLM may therefore need to review or update NEPA determinations in response to an expression of interest prior to leasing an individual parcel, if project-scale information was not considered at the multi-million-acre planning scale. The BLM may also need to conduct NEPA reviews on, for instance, the actual development of the well or well field if the viability of the field, the number of wells, likely field and pipeline layouts, or other associated impacts that were not discernable at the time of leasing. The federal agency, however, cannot segment one project into its component parts in order to reduce the level of analysis required under NEPA.¹⁵⁹

4.3.2 NEPA Considerations for the CarbonSAFE Rocky Mountain Project

Multiple federal actions associated with the CarbonSAFE Project are likely to trigger NEPA review. If the CO₂ plume is anticipated to migrate into pore space that is under federal ownership or control, issuance of a federal lease to utilize the pore space will likely require NEPA analysis by the Bureau of Land Management. If the injection well compressors, pipelines, or other infrastructure are located on federal lands, obtaining rights to use these lands (leases or rights-of-way) will also require NEPA review. Issuance of federal permits that may be required by other laws may also require analysis under NEPA, including, potentially, for a CCS pipeline.¹⁶⁰ Finally, future funding of project implementation by the Department of Energy would also likely require NEPA analysis.¹⁶¹

Notably, Class VI injection well permitting, which is conducted by the EPA and occurs pursuant to the Safe Drinking Water Act, is likely exempt from NEPA review. Safe Drinking Water Act permitting is exempt from NEPA because the SDWA's requirements to consider the environment are "functional equivalents" of the impact statement process.¹⁶²

With respect to the level of review that agencies are likely to employ, we believe that federal agencies are likely to conclude that an EIS is required for any possible CCS project like CarbonSAFE in light of the context and intensity of potential impacts. If a less rigorous level of analysis is available, permitting could move forward more expeditiously. A less rigorous approval process, however, may be more difficult to defend in the face of potential legal challenges. This is because, when challenging an EA, a party must show that impacts were either

¹⁵⁹ *Coalition on Sensible Transportation v. Dole*, 826 F.2d 60, 68 (D.C. Cir. 1987) ("Agencies may not evade their responsibilities under NEPA by artificially dividing a major federal action into smaller components, each without 'significant' impact.").

¹⁶⁰ Most Clean Water Act permitting is exempt from NEPA, *see* 33 U.S.C. § 1371(c), as are most Clean Air Act permits, *see* 15 U.S.C. § 793(c)(1).

¹⁶¹ Under DOE regulations, certain small-scale CO₂ injection wells are categorically exempt from NEPA analysis. 10 C.F.R. § Pt. 1021. Subpt. D App. B § B5.13.

¹⁶² *Western Nebraska Resource Council v. EPA*, 943 F.2d 867, 871 (8th Cir. 1992).

inadequately considered or that impacts exceed the “significance” threshold. By contrast, in legal challenges to EISs, significance of impact is not an issue. Instead, the litigant must demonstrate that the agency failed to take the requisite “hard look” at potential impacts.¹⁶³ Proceeding as if an EIS is required therefore represents a conservative assumption for a project such as CarbonSAFE.

To expedite the NEPA process and reduce paperwork, federal agencies may integrate the NEPA review with other environmental reviews and consultation processes,¹⁶⁴ incorporate other NEPA documents by reference,¹⁶⁵ or “tiering from statements of broader scope to those of narrower scope, to eliminate repetitive discussions of the same issues.”¹⁶⁶ Accordingly, CarbonSafe may be able to utilize the information contained in the Class VI injection well permit application to satisfy much of their NEPA obligation.

A recent review of EISs prepared for large oil and natural gas field development projects in the Intermountain West found that it takes an average of 4.4 years to complete an oil and gas field EIS, as measured from the NOI to ROD (the range was 1,057 to 2,556 days).¹⁶⁷ This represents a rough estimate of the time likely involved in obtaining NEPA approval for the CarbonSAFE Project, as the smaller geographic scope of the CarbonSAFE Project is likely to minimize the level of analysis required. However, as a first-of-kind project associated with a highly scrutinized industry and located proximate to areas that are of great interest to the environmental community, intense public scrutiny should be anticipated.

Notably, on September 1, 2017, the Secretary of the Interior issued an order to all agencies within the Department, including the Bureau of Land Management, directing them to complete their NEPA analyses within a one-year limit. The order also directs agencies to limit their EISs to 150 pages normally, or 300 pages for unusually complicated projects.¹⁶⁸

Operators should not assume that the Department of the Interior will adhere to either time limits or page restrictions. Accelerating the NEPA process may impact the quality of the analysis and invite litigation. Rushing may, in short, prove to be counterproductive. We anticipate that the BLM will work hard to comply with the Secretarial Order without compromising document defensibility. The best way to do this is to frontload the NEPA analysis by completing requisite studies before publishing a NOI. This will result in delayed initiation of the formal NEPA process.

More importantly, when a federal agency is sued for failing to comply with NEPA’s procedural requirements, the reviewing court will still ask whether the agency took the requisite “hard look” at the environmental consequences of the project and a reasonable range of alternatives.¹⁶⁹ This standard of review has not changed. The BLM has a strong incentive to ensure that EISs are defensible in court and is therefore likely to move text from the EIS into an appendix. This

¹⁶³ *Citizens to Preserve Overton Park, Inc. v. Volpe*, 401 U.S. 402 (1971).

¹⁶⁴ 40 C.F.R. § 1500.4(k) (2017).

¹⁶⁵ *Id.* § 1500.4(j).

¹⁶⁶ *Id.* § 1500.4(i).

¹⁶⁷ John Ruple & Mark Capone, *NEPA—Substantive Effectiveness Under a Procedural Mandate: Assessment of Oil and Gas EISs in the Mountain West*, 7 G. WASH. J. ENERGY & ENVTL. L. 39, 43 (2016).

¹⁶⁸ U.S. Dep’t of the Interior Secretarial Order 3355 (Sept. 1, 2017).

¹⁶⁹ *Citizens to Preserve Overton Park, Inc. v. Volpe*, 401 U.S. 402 (1971).

practice will change the formatting of NEPA documents but not reduce the overall analysis. The BLM likewise has a similar incentive to delay document completion in order to increase defensibility.

A final consideration involves the potential scope of review that would be required if the CCS operator intends to use only state or private pore space, but where that operator needs to acquire limited surface use rights for pipelines, monitoring wells, or other infrastructure. If such a question arises, the issue becomes the scope of the analysis required pursuant to NEPA. NEPA requires analysis of the direct, indirect, and cumulative effects of the various alternatives regardless of whether those impacts occur on federal land. “Direct” environmental effects are those “which are caused by the action and occur at the same time and place.”¹⁷⁰ Indirect effects are those “which are caused by the action and are later in time or farther removed in distance, but are still reasonably foreseeable.”¹⁷¹ A cumulative impact is “the impact on the environment which results from the incremental impact of the action when added to other past, present, and reasonably foreseeable future actions. . . . Cumulative impacts can result from individually minor but collectively significant actions taking place over a period of time.”¹⁷² Connected actions cannot be divided into their component parts in order to narrow or expedite the analysis.¹⁷³

While NEPA compliance can be costly and time-consuming, it will likely be a necessary component of CarbonSAFE Rocky Mountain implementation. Possibly the best advice that we can provide regarding NEPA compliance is to coordinate closely with the BLM, be patient, and avoid the temptation to cut corners. A rushed NEPA analysis is more likely to contain errors or omissions that would cause a reviewing court to require a supplemental analysis. Any time saved by streamlining analysis on the front end will likely be more than consumed by litigation and revisions on the back end.¹⁷⁴

4.3.3 The National Historic Preservation Act

Enacted in 1966, the National Historic Preservation Act¹⁷⁵ (NHPA) was intended, in part, to preserve historical and archaeological sites. Section 106 of the NHPA requires that federal agencies complete a review process for all federally funded and permitted projects that will impact sites listed on, or that are eligible for listing on, the National Register of Historic Places.¹⁷⁶ Under section 106, federal agencies must “take into account” the effect a project may have on historic properties. Section 106 allows interested parties an opportunity to comment on the potential impact that projects may have on significant archaeological or historic sites. Like NEPA, the NHPA is a procedural statute that does not require substantive protections. Rather, both statutes require federal agencies to “look before they leap.”

¹⁷⁰ 40 C.F.R. § 1508.8(a).

¹⁷¹ *Id.* § 1508.8(b).

¹⁷² *Id.* § 1508.7.

¹⁷³ *Id.* § 1508.25(a)(1).

¹⁷⁴ See John Ruple & Mark Capone, *NEPA, FLPMA, and Impact Reduction: An Empirical Assessment of BLM Resource Management Planning and NEPA in the Mountain West*, 46 ENVTL. L. 952 (2017).

¹⁷⁵ 16 U.S.C. §§ 470 *et seq.*

¹⁷⁶ *Id.* § 470f.

Any federal agency whose project, funding, or permit may affect a historic property that is either listed or eligible for inclusion in the National Register of Historic Places must consider project effects and seek to avoid, minimize, or mitigate any adverse effects on historic properties. NHPA compliance will require early consultation with BLM archaeologists and the State Historic Preservation Officer. These individuals will be able to search agency records and identify known cultural and historic sites. Surveys and tribal consultation may be required to determine whether additional cultural or historic sites are found within the project area and, if so, whether these sites are potentially eligible for inclusion on the National Register of Historic Places.

Of note for the CarbonSAFE Rocky Mountain project, oil and natural gas lease sales in the region have been challenged and sometimes deferred because of possible impacts to petroglyphs and pictographs that are known to exist near the San Rafael Swell. These sites, which are almost certainly eligible for inclusion on the National Register of Historic Places, have not been the subject of comprehensive surveys and are therefore not well documented. While the project at hand has a limited geographic footprint and is therefore less likely to impact sites across a broad area, the project team should still consult with the BLM and Utah State Historic Preservation Officer to identify archaeological sites, historic mining properties, homesteads, or other sites that may warrant special attention.

4.3.4 Lessons Learned from Permitting Other CCS Facilities

We reviewed permitting documents for other CCS facilities in order to identify lessons that could be learned from those experiences, as detailed above. While the CarbonSAFE Rocky Mountain project will be subject to many of the same procedural requirements, factual differences between the project at hand and prior CCS facilities need to be acknowledged when considering the experience at other CCS facilities. Nonetheless, the experience of the other projects is useful when appraising the path forward for a potential CarbonSAFE Rocky Mountain project.

NRG Energy (W.A. Parish Post Combustion Project)

NRG Energy's proposed W.A. Parish PCCS Project involved construction of a CO₂ capture facility at NRG's 4,880-acre W.A. Parish Plant in rural Fort Bend County, Texas (sometimes also referred to as the Petra Nova Project). The capture facility would use an amine-based absorption technology to capture at least 90% of the CO₂ from a 250-megawatt equivalent portion of the flue gas exhaust from Unit 8 at the plant. The project would be designed to capture approximately 1.6 million tons of CO₂ per year, and the captured CO₂ would be compressed and transported via a new, 81-mile-long, 12-inch-diameter underground pipeline to the existing West Ranch oil field in Jackson County, Texas. There, the CO₂ would be used for enhanced oil recovery and ultimately sequestered in geologic formations approximately 5,000 to 6,300 feet below the ground surface.

The DOE completed an EIS for the W.A. Parish Project, addressing the following issues: air quality and climate, greenhouse gas emissions, geology, physiography and soils, surface waters, ground water, floodplains, wetlands, biological resources, cultural resources, land use, aesthetics, traffic, transportation, noise, materials and waste management, human health and safety, utilities, community services, socioeconomics, and environmental justice. For purposes of the EIS, the DOE assumed that the project would continue for twenty years. The DOE was required to conduct a NEPA analysis because the project involved DOE funding.

The W.A. Parish Project did not generate significant controversy; there were just four comments on the Draft EIS. Of the four comments received, three came from government agencies, and one was from a member of the general public. Comments from the public focused on air quality impacts associated with the continued combustion of coal and how conversion to a natural gas-fired facility would help reduce both VOC and NO_x emissions. The EPA was concerned about damage to navigable waters and jurisdictional wetlands. The DOE asserted that all navigable water would be identified and that any wetland permanently impacted would be mitigated. The FWS was concerned with impacts to listed species under the ESA. The DOE amended the EIS to ensure that more migrating birds would not be impacted during pipeline construction. The Texas Parks and Wildlife Department echoed the FWS and the DOE ensured their concerns were addressed. Pore space ownership was not an issue, as CO₂ was injected into an existing field for EOR.

ADM

The ADM project was considered a “federal action” and therefore subject to NEPA because of DOE funding. The NEPA analysis considered only two alternatives, the proposed action and a no action alternative under which the DOE would not contribute any funds. EPA permitting documents do not mention public comments received in response to the ADM proposal. The narrow range of alternatives and absence of a discussion of public comments likely indicate that the project received little public scrutiny. While the reasons for limited public interest are difficult to identify, the setting and short duration of the project were likely contributing factors. Notably, ADM appears to own the pore space into which the CO₂ is injected, thus limiting potential impacts to public lands and removing a major concern that is likely to face the CarbonSAFE project.

As noted in the earlier discussion of SDWA permitting for the ADM project, the EPA did not address pore space ownership as part of its analysis. It also appears that no claim of federal pore space ownership was implicated by the ADM project. CarbonSAFE Rocky Mountain is therefore distinguishable from the ADM permit because the BLM will need to complete a NEPA review before granting rights to utilize the federal surface or sub-surface, and this analysis will necessarily consider pore space ownership. This NEPA analysis will be independent of the EPA’s NEPA analysis for the Class VI injection permit. Proximity to the San Rafael Swell is also likely to attract a level of public attention that was absent from the ADM project.

With respect to the ADM project, the EPA also disclaimed any need to consult with the Fish and Wildlife Service regarding impacts to species protected pursuant to the Endangered Species Act. The EPA stated that they found there was no jeopardy to listed species or critical habitat, thus ending the inquiry. Further, EPA disclaimed any need for NEPA review because the action was “administrative in nature.” Again, CarbonSAFE should not assume such expedient treatment of its project. While the EPA may consider impacts to wildlife to be beyond the scope of their permitting analysis, the likely use of federal surface or sub-surface for either infrastructure or sequestration will necessitate BLM involvement, and as issuance of a right-of-way or permit to utilize federal lands could represent an irretrievable commitment of resources, the BLM will almost certainly need to consider wildlife impacts before rendering a decision.

4.4 ADDITIONAL LEGAL AND REGULATORY CONSIDERATIONS

The above analysis highlights the key legal issues that tend to be focused on with respect to CCS projects. However, there are several other issues that may arise, and that would need to be addressed depending on the particular facts of the project. Those facts should come into clearer focus should the CarbonSAFE Rocky Mountain project proceed beyond Phase I.

4.4.1 Public Utility Regulation

One key regulatory approval that the CarbonSAFE Rocky Mountain project would have to obtain is a determination that the cost imposed by the project on electricity customers is not too great. This involves six determinations, not one. Rocky Mountain Power is a subsidiary of PacifiCorp. In turn, PacifiCorp allocates portions of its broad generation portfolio among its various utility subsidiaries serving customers in six states: California, Idaho, Oregon, Utah, Washington, and Wyoming. Unless PacifiCorp chose to alter this allocation, conceivably the public service commission in each of those states would need to pass on the cost impacts of the CarbonSAFE project at some point.

At one level, this form of regulation would not appear to pose too high of a burden for the CarbonSAFE project. Although regulatory approval eventually would be needed, utility law generally does not require electricity providers to file a new rate case every time they incur some new cost. Rather, they must only do so when they seek a general rate increase or change.¹⁷⁷ So, the CarbonSAFE project theoretically could be operational before such a rate approval were sought.

However, two caveats limit how much leeway the proponents of the CarbonSAFE project might actually enjoy. First, public utility commissions typically can start their own investigations of a utility, if they see fit. Thus, if the CarbonSAFE project raised concerns for any of these states' public service commissions, regulatory oversight could arrive more quickly than planned. Second, when a rate case is brought, even by the utility itself, the utility must justify the cost as both "just and reasonable"—that is, not too expensive—as well as "prudent"—that is, an economically efficient investment that a reasonable or prudent manager of the company would make.¹⁷⁸

Under this substantive standard, the two biggest hurdles to the CarbonSAFE project likely would be economic and policy-based. The economic obstacle is obvious and relates back to the cost barrier to commercial-scale deployment that CCS technology faces. Since the objective of utility regulation is to ensure that companies only incur necessary (and economically efficient) costs in providing service, there is a risk that parties would argue the comparatively high cost of CCS is neither. Of course, were some kind of greenhouse gas emission limit placed on PacifiCorp or Rocky Mountain Power, this might be easier to show, but the receding nature of federal regulation in that context and the absence of it in many state contexts renders that argument more difficult to make. Moreover, even with climate regulation of the electricity sector in place, proponents of the CarbonSAFE project arguably would need to either show that CCS technology

¹⁷⁷ See, e.g., UTAH CODE § 54-7-12.

¹⁷⁸ See, e.g., UTAH CODE § 54-3-1.

is as cost-effective as other ways of mitigating climate emissions (such as solar or wind) or point to a CCS-specific mandate of some kind. This may be difficult.

From a policy-based perspective, the CarbonSAFE project also could face challenges. Many of the states from which PacifiCorp would need regulatory approvals have renewable energy requirements for the electricity sector in place.¹⁷⁹ This could raise questions about why the CarbonSAFE project is appropriate in light of those statutory mandates. Further, two of the states—California and Washington—have climate regulations in place that affect the electricity sector,¹⁸⁰ and one of the states—Oregon—has an outright ban on coal generation beginning in 2030.¹⁸¹ Again, PacifiCorp potentially could eliminate these concerns by reallocating how it operates its generation fleet, but in the absence of that step, this state-level regulation would appear to create challenges for the CarbonSAFE project, if the electricity generation associated with it is allocated to any of these states. These are concerns for which the project team would want to have a plan before proceeding to implementation of the CarbonSAFE Rocky Mountain project.

4.4.2 Brine Disposal

The Navajo sandstone into which the CarbonSAFE Rocky Mountain would inject CO₂ contains saline brine. CO₂ will react with brine to form carbonate, but some brine may be displaced by injected CO₂. The extent to which brine would be displaced was uncertain at the time this report was written. Displacement of brine must be considered as noted in SDWA permitting and tort liability discussions, above. If brine must be extracted to increase storage capacity, extracted brine will need to be dealt with, possibly by using brine for EOR. Use of brine for EOR would trigger the SDWA's UIC class II permitting requirements.

If brine cannot be utilized for EOR, it will need to be disposed of in accordance with applicable environmental laws and regulations. In that case, permits would need to be obtained in accordance with the Clean Water Act and other applicable requirements before brine could be discharged into a receiving water or via land application. Any water treatment that results in sludge or contaminated filter materials could trigger hazardous waste disposal permitting requirements.

Alternatively, brine could be disposed of in evaporative ponds, though this could pose additional regulatory challenges, and highly concentrated minerals would require additional processing and disposal. Portions of Eastern Utah suffer from elevated ozone levels, which have been attributed, in part, to oil and gas development activities. Evaporation of oil and gas product water has been identified as a contributor to elevated ozone levels because product water often contains volatile organic compounds (VOCs). VOCs evaporate readily and are subject to atmospheric photochemical reactions that produce ground-level ozone. Any brine that is removed from the storage reservoir may therefore need to be treated to remove VOCs, if VOCs are present in the

¹⁷⁹ See CAL. PUB. UTIL. CODE § 399.11; OR. REV. STAT. § 469A.052; UTAH CODE § 10-19-201; WASH. REV. CODE § 19.285.040.

¹⁸⁰ See, e.g., CAL. HEALTH & SAFETY § 38566; Code CAL. PUB. UTIL. § 8341; WASH. REV. CODE § 80.80.040.

¹⁸¹ See OR. REV. STAT. § 757.518.

brine, before evaporation could proceed. Similar concerns could arise if the brine contains trace quantities of radionuclides, or hazardous chemical elements such as arsenic.

Surface disposal could also raise environmental concerns if brine is stored in evaporation ponds that attract wildlife. Hydrocarbons in the brine could coat the wings of migratory birds that are attracted to the water surface. Similarly, salts or other minerals that are toxic to migratory birds can cause avian mortality. Mortality that is attributable to surface disposal operations could trigger liability under the Migratory Bird Treaty Act, the Bald and Gold Eagle Protection Act, the Endangered Species Act, or other state and federal statutes.

4.5 PUBLIC OUTREACH & STAKEHOLDER ASSESSMENT

The Rocky Mountain CarbonSAFE team identified stakeholders with potential interests to a potential CO₂ capture/storage complex project or area, identified potential benefits and concerns for these stakeholders, and began to develop strategies to maximize benefits, mitigate identified concerns, and facilitate stakeholder acceptance. The team identified 48 principal stakeholders (see Appendix M), including government officials and agencies, environmental health directors from local health departments, regulators, business interests, local interested citizens, local and regional environmental groups, national environmental groups, and educators.

The team developed and distributed an outreach flyer designed to provide basic information about the project; developed an informative public website (www.carbonsafe.rocks); and published a non-technical article in the September 2017 issue of the Utah Geological Survey's Survey Notes, detailing the project and how it benefits Utah (<https://geology.utah.gov/map-pub/survey-notes/energy-news/carbonsafe/>).

On October 10th, 2017 the team held a public town hall discussion to answer stakeholder questions and address concerns. The team emailed all identified stakeholders an invitation which included the project's informational flyer and webpage link.

The team consulted with Phase 2 Productions, a local studio with experience filming and producing energy sector videos. Phase 2 Productions provided general ideas on how short videos can be used to promote the project and provided a specific proposal to produce a series of short, three- to four-minute videos highlighting the project and its potential benefits.

5.0 Scenario Development of Commercial-scale CCS Complex

5.1 SCENARIO DEVELOPMENT & DATA

Scenarios of interest span from small-scale scenarios of single sources and single reservoirs, to larger-scale scenarios integrating EOR with consideration given to the long-term performance of a proposed CCS complex in a carbon-constrained world. The scenarios developed for the Rocky Mountain CarbonSAFE project fall into three categories:

1. Core Scenarios: Scenarios consisting of single sources and single reservoirs covering the Hunter and Huntington power plants and Buzzard’s Bench and Drunkard’s Wash saline aquifers.
2. EOR Scenarios: Scenarios consisting of capturing from multiple sources (primarily the Hunter and Huntington power plants) and injecting into the Uintah Basin oil fields.
3. Cortez Pipeline Scenarios: Scenarios consisting of capturing from multiple sources (primarily the Hunter and Huntington power plants) and transporting to the Cortez pipeline terminus at McElmo Dome in southwestern Colorado.

Costs and capacities associated with the different reservoir types are detailed in Table 21 and for the different source types in Table 22. Capture costs for the different source types were taken from current literature (Bains et al., 2017; Rubin et al., 2015).

Table 21. Storage costs associated with the different reservoir types.

Reservoir Type	Capacity (MtCO ₂)	Opening Cost (\$M)	Well Cost (\$M)	Injection Cost (\$/tCO ₂)
Saline	581	7.31	3.85	-
*Buzzards	*201			*3.15
**Drunkards	**380			**3.18
EOR	1023	0	0	-30
Cortez	24	0	0	-30

Table 22. Capture costs associated with the different source types.

Source Type	Capacity (MtCO ₂ /yr)	Capture Cost (\$/tCO ₂)
Electricity (Coal)	28.7	46
*Hunter	*8.8	
**Huntington	**6.2	
Electricity (Gas)	2	74
Petroleum	1.6	67.5
Cement	1	34
Iron/Steel	0.1	33
Chemical	0.1	14

5.1.1 Core Scenarios

The core scenarios developed center on capturing partial emissions from either the Hunter or Huntington power plants and injecting into saline aquifers below Buzzard’s Bench or Drunkard’s Wash. Primary and auxiliary capture/storage configurations for the core scenarios were determined by the project team and are detailed in Table 23.

Table 23. Ranking of capture/storage scenarios from most desirable (#1) to least (#4).

Column1	Buzzard’s Bench	Drunkard’s Wash
Hunter	#1	#2
Huntington	#4	#3

Injection well locations in Buzzard’s Bench and Drunkard’s Wash were determined by the project team after surveying the existing well pads in the region. The storage capacity of the saline aquifers at Buzzard’s Bench and Drunkard’s Wash were estimated by the project team to be 201 MtCO₂ (Buzzard’s Bench) and 380 MtCO₂ (Drunkard’s Wash). The target capture amount considered for these core scenarios is the minimum DOE requirement of 50 MtCO₂ over a 30-year project timeline.

5.1.2 EOR Scenarios

EOR scenarios involve capturing CO₂ from sources and injecting it into the Uintah Basin oil fields in the most cost-effective manner. For each scenario, the Hunter and Huntington power plants emissions are all captured before other sources are utilized to better support the core aim of the Rocky Mountain CarbonSAFE project. EOR reservoir locations were taken to be the centroids of the individual Uintah oil fields from NatCarb (www.natcarb.netl.doe.gov). The target capture amounts considered for these scenarios are:

1. Minimum DOE requirement of 1.7 MtCO₂/yr captured.
2. Full Hunter and Huntington plant emissions of 15 MtCO₂/yr captured.
3. All available source emissions of 33.5 MtCO₂/yr captured.
4. Intermediate capture values of 20 MtCO₂/yr, 25 MtCO₂/yr, and 30 MtCO₂/yr.

5.1.3 Cortez Pipeline Scenarios

To explore the possibility of offsetting CO₂ mined from McElmo Dome with anthropogenic CO₂, scenarios were constructed that transport captured CO₂ to the Cortez pipeline terminus in south western Colorado. The scenarios involved capturing from just the Hunter and Huntington power plants and from all available sources. Costs associated with transferring (not including to cost to transport CO₂) CO₂ to the Cortez pipeline are detailed in Table 22. The target capture amounts considered for these scenarios are:

1. Minimum DOE requirement of 1.7 MtCO₂/yr captured from Hunter or Huntington.
2. Full Hunter and Huntington plant emissions of 15 MtCO₂/yr captured.
3. Full capacity of Cortez pipeline (24 MtCO₂/yr) captured.

5.2 SCENARIO ANALYSIS TOOL

SimCCS is an optimization model for integrated CCS system design, originally introduced in 2009, and recently modernized in a complete, ground-up redesign that allows collaboration on the design of CCS infrastructure networks across CCS research, industrial, policy, and public communities (Middleton and Bielicki, 2009; Yaw et al., 2018). *SimCCS* utilizes user-provided data for the CO₂ sources (capture capacities and costs), sinks (geologic parameters), and CO₂ transportation information (weighted-cost surface of the deployment region). *SimCCS* creates candidate transportation routes using novel network generation algorithms and formalizes an optimization problem that determines the most cost-effective CCS system design. This optimization problem is then solved either locally through user-provided third-party software on their local machine or through a high-performance computing (HPC) platform hosted by Indiana University. Integration with HPC resources allows for solutions to problems of unprecedented size (e.g., national-scale domains the size of the United States or China) and complexity (e.g., massive ensembles incorporating uncertainty within the integrated CCS system). Finally, *SimCCS* employs an open-access GIS framework to enable analysis and visualization capabilities.

The Rocky Mountain CarbonSAFE project used *SimCCS* to characterize the CCS infrastructure designs for the various scenarios and quantify their costs. *SimCCS* was parameterized with relevant regional source and sink data, as well as a weighted-cost surface of the greater Utah region to accurately reflect pipeline routes and their associated costs. For each scenario considered, a set of possible pipeline routes, called the *candidate pipeline network*, was constructed to feed the optimization model. Final pipeline routes for a given scenario are generated using a four-step process: First, the geographic area is rasterized into a weighted-cost surface that multiplies the base cost of building a CO₂ pipeline across a uniform surface to match the corresponding geography of the real world. This base cost is established from published values for natural gas pipelines. Second, a set of potential origin-destination paths between all source/sink location pairs is calculated using a modified Dijkstra shortest-path algorithm on the weighted-cost surface. Third, a subset of these paths is selected as a candidate network by selecting edges that connect node pairs; these pairs are defined by a Delaunay triangulation of all source/sink locations. And fourth, final routes are selected by a Mixed Integer Linear Program (MILP) that aims to minimize cost while connecting source/sink locations in a way to ensure a target CO₂ capture amount is met. In the last step, final pipeline routes are selected from the candidate network. This is done in conjunction with selecting which sources and sinks to open and how much to capture and inject into each location. An MILP is formulated that minimizes capture, transport, and storage costs while ensuring that enough CO₂ is captured and injected so as to meet project targets. From this optimization problem, a completed CCS infrastructure design is produced, that includes the necessary pipelines (of the appropriate size) to transport CO₂ from its capture location to its storage location.

5.3 SCENARIO ECONOMIC ANALYSIS

For each scenario illustrated in the previous section, candidate pipeline networks were built with *SimCCS* using the greater Utah weighted-cost surface. Optimization models were constructed with project lengths of 30 years and target capture amounts specific to the scenario. The models were solved using IBM’s CPLEX software package. The costs associated with each scenario are summarized in Table 24. Scenario-specific pipeline routes produced by the optimization model are available to the project team. The infrastructure designs produced by *SimCCS* for all the scenarios are presented in Figure 63 for the core scenarios, Figure 64 for the EOR scenarios, and Figure 65 for the Cortez pipeline scenarios.

Table 24. Scenario cost comparisons.

Scenario	Capture Target (MtCO ₂)	Cost (\$M/yr)	Capture Cost (\$M/yr)	Transport Cost (\$M/yr)	Storage Cost (\$M/yr)	Unit Cost (\$/tCO ₂)
Hunter-Buzzard’s	51	85.68	78.2	0.84	6.64	1.68
Hunter-Drunkard’s	51	87.33	78.2	2.44	6.69	1.71
Huntington-Buzzard’s	51	86.14	78.2	1.3	6.64	1.69
Huntington-Drunkard’s	51	86.66	78.2	1.76	6.69	1.7
EOR-1.7/yr	51	28.68	78.2	1.48	-51	0.56
EOR-15/yr	450	261.93	690	21.93	-450	0.58
EOR-20/yr	600	361.58	920	41.58	-600	0.6
EOR-25/yr	750	445.31	1150	45.31	-750	0.59
EOR-30/yr	900	540.16	1374.45	65.71	-900	0.6
EOR-33.5/yr	1005	904.02	1814.9	94.12	-1005	0.9
Cortez-1.7/yr	51	41.77	78.2	14.57	-51	0.82
Cortez-15/yr	453	276.17	694.6	34.57	-453	0.61
Cortez-24/yr	720	437.56	1088.8	68.76	-720	0.61

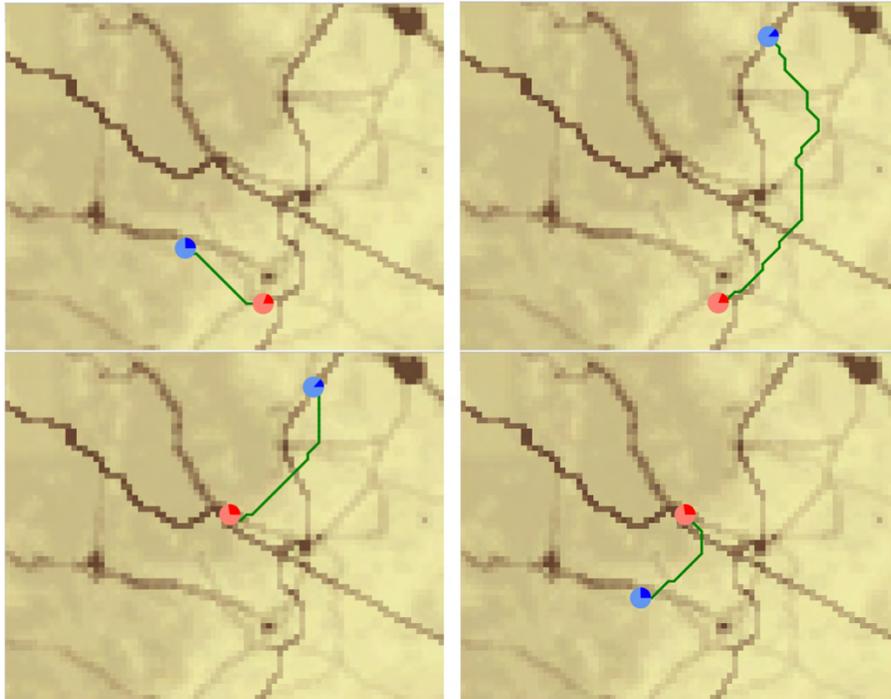
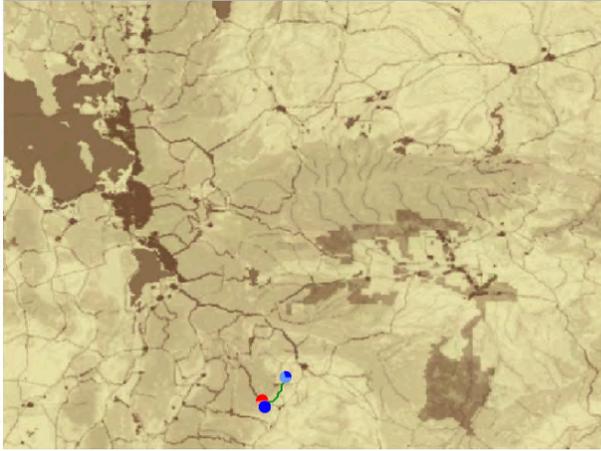
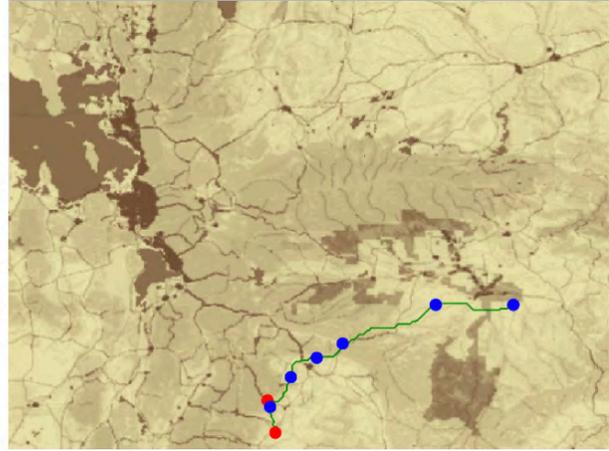


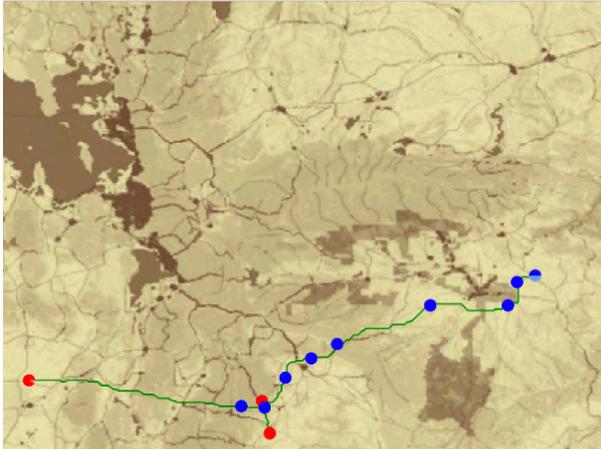
Figure 63. Infrastructure designs for the core scenarios: Hunter and Buzzard's Bench (top left), Hunter and Drunkard's (top right), Huntington and Drunkard's (bottom left), and Huntington and Buzzard's (bottom right).



(a) 1.7 MtCO₂/yr



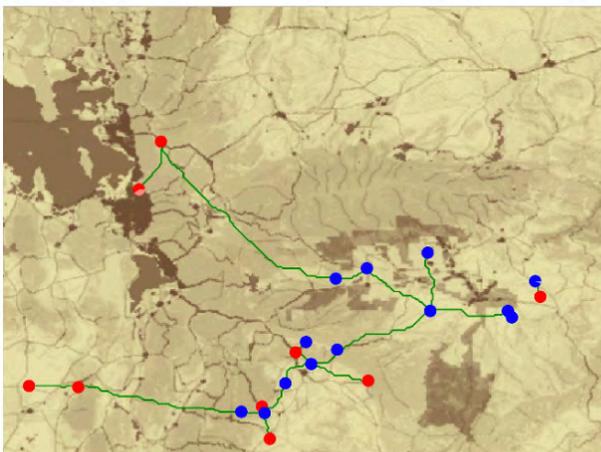
(b) 15 MtCO₂/yr



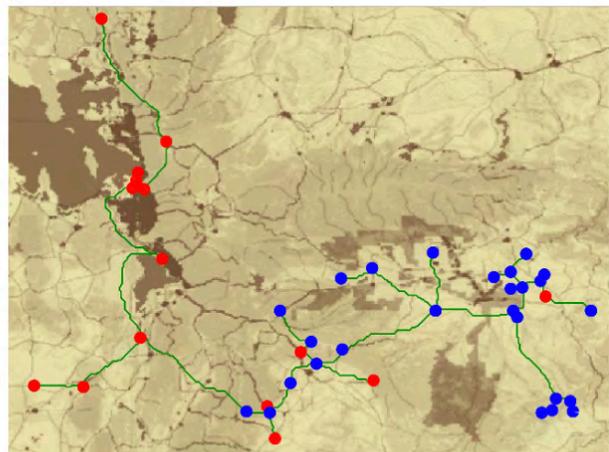
(c) 20 MtCO₂/yr



(d) 25 MtCO₂/yr



(e) 30 MtCO₂/yr



(f) 33.5 MtCO₂/yr

Figure 64. Infrastructure designs for the EOR scenarios with varying target capture amounts from 1.7 MtCO₂/yr (DOE minimum) to 33.5 MtCO₂/yr (capturing maximum amounts from all available sources).

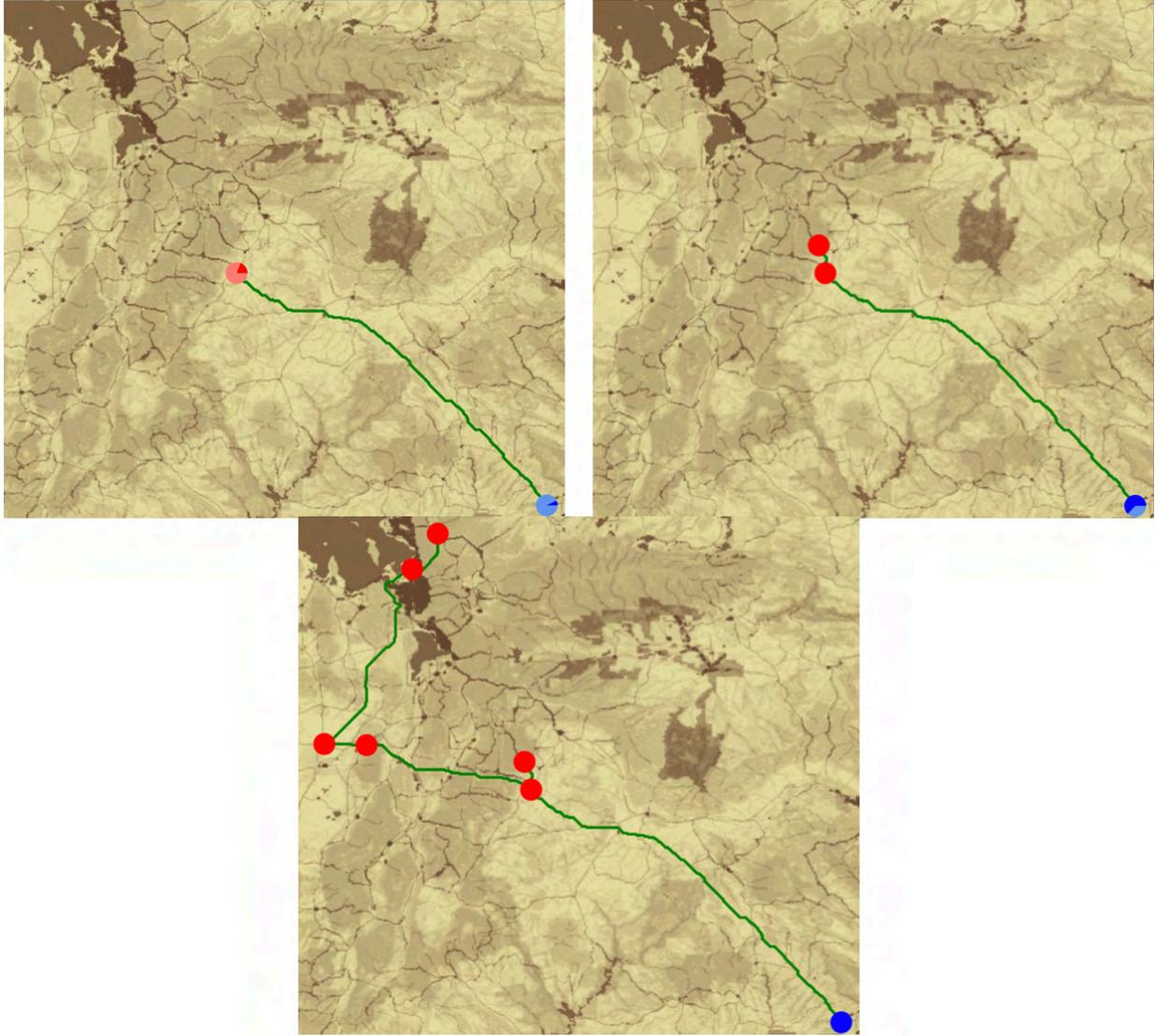


Figure 65. Infrastructure designs for the Cortez pipeline scenarios: 1.7 MtCO₂/yr captured from Hunter (top left), 15 MtCO₂/yr captured from Hunter and Huntington (top right), and 24 MtCO₂/yr (Cortez pipeline capacity) captured from the most cost-effective sources (bottom).

5.4 CONCLUSION

This report documents the motivation, development, and analysis of a wide range of scenarios for a commercial-scale CCS complex in the Rocky Mountains. Cost analysis supports the primary core scenario developed by the Rocky Mountain CarbonSAFE of capturing CO₂ from the Hunter power plant and transporting and injecting it into saline aquifers below Buzzard's Bench. However, larger-scale infrastructure deployments that include economic offsets may result in lower unit cost per ton of CO₂ stored. Selling CO₂ to oil fields in the Uintah Basin for EOR applications could result in a cost savings of up for 67% per ton of CO₂. Offsetting CO₂ mined from McElmo Dome also provides an enticing economic opportunity with near the cost savings as Uintah EOR. CO₂ from all sources considered accounted for 98% of the EOR capacity, so none of the scenarios benefitted from utilizing available EOR before spilling excess

captured CO₂ to the saline aquifers. However, recent 45Q tax incentives could change the economic tradeoff between shipping CO₂ to a remote oil field versus injecting into nearby saline storage. Finally, the EOR and Cortez pipeline scenarios all show a clear network of trunk pipelines being constructed in the smaller-capture scenarios that increase in utilization for the larger-capture scenarios. This suggests that this region would be a strong candidate for staged deployments, where the pipeline infrastructure is initially overbuilt in anticipation of future capture sites coming online at a later date which has been shown to add resiliency to a project (Middleton and Yaw, 2018).

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8.0 APPENDICES

- A. CO₂ Capture Assessment: Sargent & Lundy - CO₂ Capture Techno Economic Assessment
- B. Site Characterization: Subsurface Mapping
- C. Site Characterization: Extensional Faulting in the Jurassic Navajo Sandstone at Little Wedge on the Western Flank of the San Rafael Swell and its Potential Impact on Carbon Dioxide Storage Reservoirs, Emery and Carbon Counties, Utah
- D. Site Characterization: Sedimentology, Diagenesis, and Reservoir Characterization of the Permian White Rim Sandstone – Prospective Storage Efficacy for Carbon Capture and Sequestration
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- F. Site Characterization: Reservoir Seals Based on Outcrops of the Middle Jurassic Carmel and Temple Cap Formations, Northern San Rafael Swell
- G. Site Characterization: Compiled Fluid Geochemistry for Potential Carbon Sequestration Reservoirs in Castle Valley
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- K. Legal, Regulatory, and Liability Assessment CarbonSAFE Rocky Mountain Phase I
- L. CarbonSAFE Class VI Requirement Matrix
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- N. Site Characterization Guidance
- O. Stakeholders



Rocky Mountain CarbonSAFE Phase I

Appendix A

CO₂ CAPTURE TECHNO ECONOMIC ASSESSMENT



**University of Utah
PacifiCorp's Hunter Station Unit 3**

CO₂ CAPTURE TECHNO ECONOMIC ASSESSMENT

FINAL Revision 0

December 15, 2017
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Prepared by



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APPENDICES:

A – HEAT BALANCE (90% CAPTURE – CASE 2)

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D – GENERAL ARRANGEMENT AND PLANT LAYOUT (90% CAPTURE – CASE 2)

Executive Summary

The University of Utah is evaluating the technical and commercial feasibility of carbon dioxide (CO₂) capture with sequestration (CCS) in a geologic formation adjacent to PacifiCorp's Hunter Plant. This is being conducted as part of the University's participation in a USDOE funded Phase 1 CO₂ Capture and Sequestration study (USDOE FOA DE-FE0029280). As part of this overall effort, the University engaged Sargent & Lundy LLC (S&L) to evaluate the feasibility and overall cost of retrofitting Hunter Unit 3 with a CCS system.

This study effort includes evaluation of multiple capture levels using a commercially available amine-based system as the basis for the capture technology. As part of the project, S&L evaluated three different levels of CO₂ capture on Hunter 3:

1. 65% capture, targeting no less than 1.84 million tons per year;
2. 90% capture, treating 100% of flue gas; and
3. Equivalent capture required (~48%) to achieve CO₂ emissions rate consistent with New Source Performance Standards (NSPS) for greenhouse gases for a natural gas-fired combined cycle plant (i.e. 1,000 lbs/MWh, gross)

This study effort includes evaluation of a commercially available amine-based system as the basis for the capture technology. S&L considers commercially available processes to be those that have been demonstrated during slipstream tests or have been implemented on permanent installations treating a quantity of flue gas that is at least equivalent to 5 MWe. Amine solvent-based technology has recently established itself as a viable technology for CO₂ capture. The commercial technology that was evaluated was MHI's KM-CR Process® with KS-1™ solvent.

As part of the TEA, the major balance of plant (BOP) impacts have been identified and quantified, including loss of power generation due to both the auxiliary power load and the required process steam to be supplied from the base unit. Other BOP impacts are identified, including cooling and process water consumption, waste water generation rates, and solid waste generation rates. S&L also developed material balances and general arrangement drawings that reflect the integration of the CO₂ capture system with the base facility.

A full scale capture system (Case 2: 90% capture) served as the basis for development of heat balances, mass balances, process flow diagrams, general arrangements, equipment sizing, and capital costs. The full scale system inputs were adjusted for the two other capture facility design sizes: Case 1: 65% and Case 3: 1,000 lb CO₂/MWh_g.

Overall, the project is technically feasible PacifiCorp's Hunter Unit 3. Process steam will be provided by the base unit and extracted at the IP/LP crossover without disrupting the performance of the LP turbine; however, this will cause a unit derate by limiting the total amount of megawatts the turbines can produce. Other utilities provided by the base plant include process water makeup from the existing demineralized water system, cooling tower makeup water from the on-site storage basin, and auxiliary power from the

existing auxiliary power transformer. Flue gas will be routed to the CO₂ capture island downstream of the WFGD system, which reduces the amount of acid gas polishing that is required in the pre-scrubber. The CO₂ process is expected to generate pipeline quality liquid CO₂ for transportation to a storage field or an EOR facility.

The total capital cost is based on the conceptual design of the CO₂ capture system defined in this study. S&L scaled and adapted cost information for the MHI technology to develop the cost for the CO₂ capture process equipment for the Hunter application. S&L supplemented the CO₂ process equipment cost with a study-level BOP cost estimate based on S&L’s experience within the utility industry, particularly experience on other CO₂ capture projects, projects at Hunter, and general AQCS projects.

Similarly, an estimate of the annual O&M cost was developed based on the conceptual design defined in this study, using cost information for the MHI technology and other industry experience.

The results of this evaluation including the total overnight capital cost, annual O&M cost, and cost of electricity (COE) are included in Table ES-1. Due to economies of scale, the overall cost of capture (\$/ton of CO₂ removed) is less at larger capture rates. Depending on the project size selected, the estimated cost of capture at Hunter 3 ranges from \$50-74/ton CO₂ removed.

Table ES-1: Evaluated Cost of CO₂ Capture Systems

Description	Units	Case 1 (65% Capture)	Case 2 (90% Capture)	Case 3 (1,000 lb/MWh_g)
Total Capital Cost	\$	518,136,300	666,222,700	421,935,100
CCF		0.1243	0.1243	0.1243
Annualized Capital Cost	\$/yr	64,404,400	82,811,500	52,446,600
Annual O&M Cost	\$/yr	66,268,000	85,840,000	52,697,000
Total Annual Cost	\$/yr	130,672,400	149,079,500	118,714,600
Annual CO ₂ Captured	tons	2,158,460	2,991,500	1,595,240
Cost of Capture w/ TS&M	\$/ton	61	50	74

1 Introduction

The University of Utah is evaluating the technical and commercial feasibility of carbon dioxide (CO₂) capture with sequestration (CCS) in a geologic formation adjacent to PacifiCorp's Hunter Plant. This is being conducted as part of the University's participation in a USDOE funded Phase 1 CO₂ Capture and Sequestration study (USDOE FOA DE-FE0029280). As part of this overall effort, the University engaged Sargent & Lundy LLC (S&L) to evaluate the feasibility and overall cost of retrofitting an existing power plant with a CCS system.

The evaluation includes development of expected performance, environmental impacts and capital and operating costs associated with implementing CCS on Unit 3 at the Hunter Plant.

Hunter Station is located in Castle Dale, Utah. Unit 3 is a 511 MWg boiler that burns low-sulfur, subbituminous coal. Unit 3 is equipped with low-NO_x burner technology and over fire air for NO_x mitigation, a baghouse for particulate matter removal, and wet flue gas desulfurization (WFGD) for SO₂ control.

This study effort includes evaluation of multiple capture levels using a commercially available amine-based system as the basis for the capture technology. Amine solvent-based technology has recently established itself as a viable technology for CO₂ capture. This technology is applicable to the fossil power industry, especially for high CO₂ producing coal-fired plants. However, there have been very few full scale CO₂ capture projects which have been implemented in the industry. Commercial scale CO₂ capture is still a relatively new technology and, therefore, still has some obstacles associated with minimal experience designing, building, and operating these facilities in full scale.

1.1 Key Project Goals

The University of Utah requested that S&L perform a Techno-Economic Assessment (TEA) of the commercially available amine-based CO₂ capture technologies. The TEA is intended to determine the technical feasibility and economic impacts of implementing CO₂ capture on Unit 3 at Hunter Station (Hunter 3). As part of the project, S&L will evaluate three different levels of CO₂ capture on Hunter 3:

1. 65% capture, targeting no less than 1.84 million tons per year;
2. 90% capture, treating 100% of flue gas; and
3. Equivalent capture required (~48%) to achieve CO₂ emissions rate consistent with New Source Performance Standards (NSPS) for greenhouse gases for a natural gas-fired combined cycle plant (i.e. 1,000 lbs/MWh, gross)

As part of the TEA, the major balance of plant (BOP) impacts have been identified and quantified, including loss of power generation due to both the auxiliary power load and the required process steam to be supplied from the base unit. Other BOP impacts are identified, including cooling and process water consumption, waste water generation rates, and solid waste generation rates.

1.2 Scope and Approach

The first step of the techno-economic assessment (TEA) was to establish the design criteria to be used as the basis for the CO₂ capture facility. Site-specific design criteria and conditions for Hunter 3 were developed using process information from the station. Process assumptions were based on previous S&L projects for the Hunter Station.

The commercial technology that was evaluated was MHI's KM-CR Process® with KS-1™ solvent. S&L considers commercially available processes to be those that have been demonstrated during slipstream tests or have been implemented on permanent installations treating a quantity of flue gas that is at least equivalent to 5 MWe. The MHI technology is a leader in CO₂ capture, with the largest installation on a coal-fired power plant in the world.

The design of the CO₂ capture system for this TEA reflects the MHI-specific process, to the greatest degree possible. As input to the TEA, S&L used a composite of budgetary pricing and process information for the MHI system supplemented with S&L's industry experience.

A conceptual design of the CO₂ capture system was developed using site-specific design criteria for Hunter Unit 3, supplemental information derived from the MHI technology and S&L's experience. As part of the conceptual design, S&L identified the major BOP impacts associated with the slipstream CO₂ capture facility, based on the utility requirements of the process. S&L also developed material balances and general arrangement drawings that reflect the integration of the CO₂ capture system with the base facility. The mass balances and process flow diagrams are included in Attachment A.

The total capital cost is based on the conceptual design of the CO₂ capture system defined in this study. S&L scaled and adapted cost information for the MHI technology to develop the cost for the CO₂ capture process equipment for the Hunter application. S&L supplemented the CO₂ process equipment cost with a study-level BOP cost estimate based on S&L's experience within the utility industry, particularly experience on other CO₂ capture projects, projects at Hunter, and general AQCS projects.

Similarly, an estimate of the annual O&M cost was developed based on the conceptual design defined in this study, using cost information for the MHI technology and other industry experience.

2 CO₂ Capture Technology

2.1 Process Description

A typical amine-based CO₂ capture system consists of a quencher, an absorber column, and a stripping column; in addition, the flue gas will require a booster induced draft (ID) fan to overcome the pressure loss through the CO₂ capture system. A compressor train is also included after the stripper column. A high-level block diagram of the system is shown in

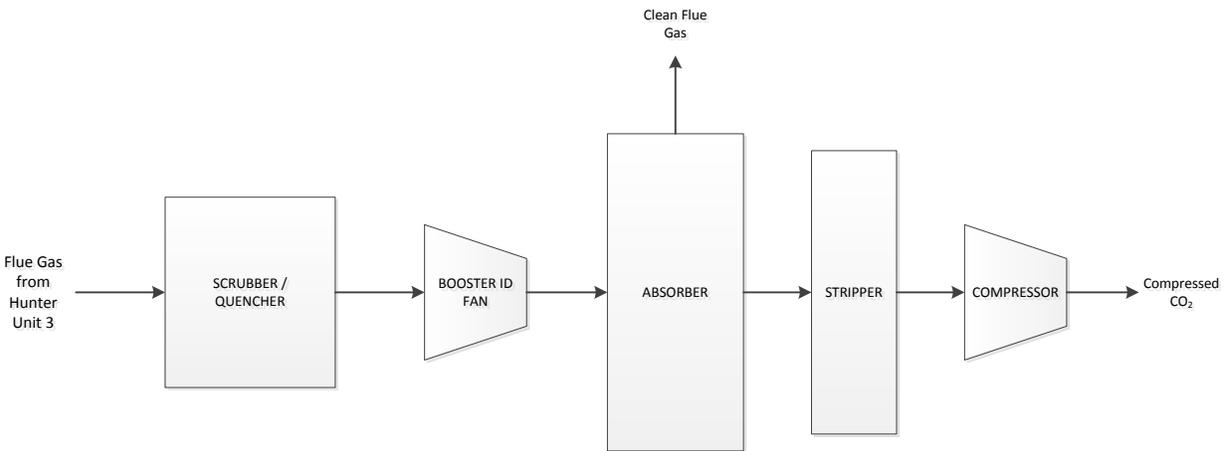


Figure 2-1: CO₂ Capture Block Diagram

Amine solvents are sensitive to impurities and will react with SO₂ and SO₃ molecules present in the flue gas. These reactions contaminate the solvent by forming intermediate salts, which in turn leads to higher solvent regeneration requirements and increased operational costs. While Hunter 3 is equipped with a lime-based WFGD system, it does not currently provide adequate SO₂ and SO₃ removal efficiency required for an amine-based system.

Additional SO₂ and SO₃ removal is required for more efficient operation of the CO₂ capture system and is completed by passing the flue gas through a caustic scrubber. The caustic scrubber uses a 10% (by weight) solution of caustic soda (NaOH) to remove residual acid gases. In the scrubber, the flue gas passes through a counter-current packed tower, where caustic solution is recirculated to scrub the flue gas to approximately 1 ppmv SO₂. Residual particulates, water, sulfates, and other soluble components will build-up in the caustic solution as it is recycled; therefore, a blowdown stream is required to reduce the concentration of contaminants and overall liquid volume. The blowdown stream is sent to a new wastewater treatment system.

In addition to removal of residual acid gases, flue gas needs to be cooled prior to being introduced to the solvent. This is due to the improved absorption efficiency of the solvent at lower temperatures. To provide this cooling, the polishing scrubber also functions as a quencher. The flue gas leaving the scrubber/quencher is cooled to approximately 100°F. The contact cooling water is cooled with a heat

exchanger and returned to the quencher. The cooling process results in additional condensed water; therefore, a blowdown stream is required to reduce the volume of recirculating water. The blowdown stream is sent to the cooling tower as makeup.

The cool flue gas then passes through a counter-current packed absorber column, where the amine-solvent absorbs CO₂ present in the flue gas. Several levels of packing, spray zones, and trays facilitate the appropriate liquid-to-gas contact to ensure a high level of CO₂ absorption by the solvent ($\geq 90\%$). The temperature of the absorber is controlled using an intercooler or heat exchanger which cools the semi-rich solvent and returns it to the absorber. A water wash is located at the top of the absorber to remove any entrained solvent in the flue gas. The clean gas exits the absorber and is exhausted through a new stack located on top of the absorber.

The CO₂-rich solvent from the absorber enters the top of a counter-current packed stripper column, where CO₂ is desorbed from the amine-solvent through the addition of heat energy to break the weak intermediate bond between the amine-solvent and the dissolved CO₂. The reboiler at the base of the stripper utilizes low quality steam as the source of energy to vaporize water in the dilute solvent. This water vapor rises through the stripper providing energy to facilitate in stripping the CO₂ and regenerating the amine-solvent.

The hot-lean (or regenerated) solvent which is free of CO₂ is returned to the absorber. The hot-lean solvent is directed to the lean/rich exchanger to recover sensible heat and preheat the cool/rich solvent from the absorber. This preheating helps to recover some of the energy used for regeneration, reducing the overall energy requirements of the process, especially in the regeneration stage.

A mixture of CO₂ and steam exits the top of the stripper and is sent to the compressor system, which both dehydrates and compresses the CO₂ stream. The compressor is designed to pressurize the CO₂ product stream to pipeline quality. This system involves eight stages of compression including an intercooler after each stage. As part of this process, additional moisture is removed to provide a CO₂ stream with $\geq 99\%$ purity at 2,215 psia. Moisture removed from the dehydration system and during the compression process is collected and sent back to the stripper.

Figure 2-2 shows the process flow diagram (PFD) of the CO₂ capture system for Hunter 3. It is expected that the CO₂ capture system would consist of 1x100% train, regardless of if the system is treating 100% of the flue gas (Case 2) or less than 50% (Case 3).

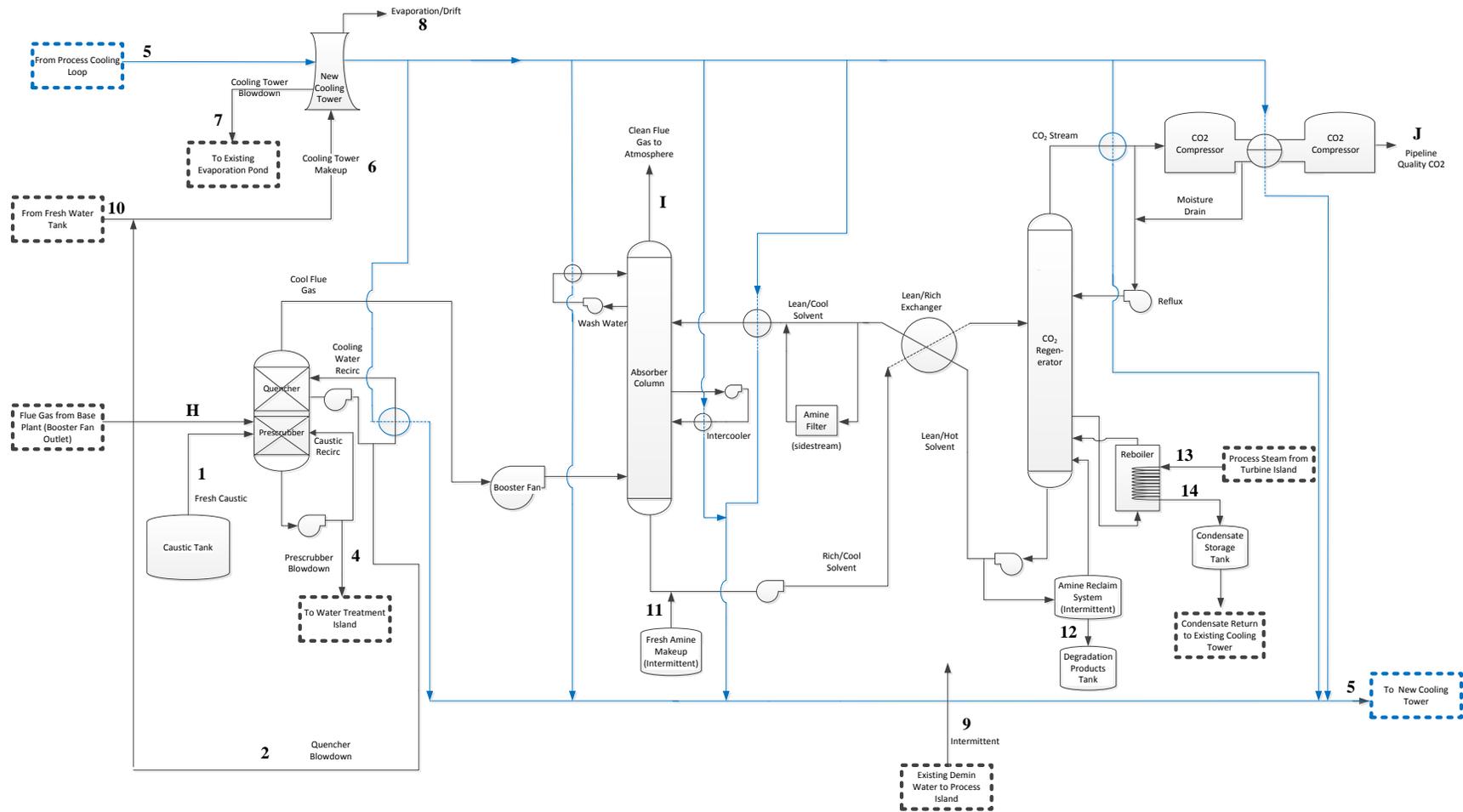


Figure 2-2: MHI CO₂ Capture Slipstream Process Flow Diagram

2.2 Integration with Hunter Unit 3

The major process equipment and BOP systems needed for a complete CO₂ capture system require a very large footprint. The Hunter property includes a relatively large open area directly adjacent to Unit 3, which was originally allocated to build Unit 4. This area is sufficiently sized to accommodate the CO₂ capture facility and to be close-coupled to the Unit. The close proximity of the CO₂ capture equipment reduces the costs of some BOP items by reducing the pipe and ductwork runs from the existing Unit to the new facility. A PFD of the base unit was developed (see Appendix B), highlighting the tie-in locations.

The ductwork to the Hunter 3 CO₂ capture system will be tied-in downstream of the existing WFGD system, prior to the stack breaching. A booster ID fan will be located in the CO₂ capture facility to pull the slipstream flue gas through the ductwork to the CO₂ capture facility. MHI's design includes locating the booster fan between the quencher and the absorber, where the gas is fully scrubbed and cooled.

The scrubbed flue gas will exit the absorber vessel through a new stack. This generates a secondary emission point that will have to be incorporated into the existing Hunter air permit. While the overall emissions are expected to be reduced based on the polishing scrubber and CO₂ capture system, there is the potential for an increase in VOC or aerosol emissions. In order to minimize the release of these emissions a second water wash is typically included in the absorber design.

The regeneration energy for the stripper comes from low quality steam, which can be provided by the unit's existing steam cycle or by a new steam generation unit. For the purposes of this study, steam will be extracted from the existing steam turbine. Low quality steam will be extracted from the crossover between the IP and LP sections of the turbine. The steam quality at the tie-in location is at a higher temperature and pressure than required by the reboiler. Some pressure will be lost through the piping from the boiler island to the CO₂ capture island, but pressure reduction and attemperation will be required once the steam reaches the CO₂ island. The associated condensate from the reboiler will be pumped back to the base plant's condensate system at the feedwater heaters.

Based on the size of the CO₂ capture facility, it is expected to be designed with 50% turndown capability. This is especially necessary for the 90% capture case, where the system is designed to treat 100% of flue gas at full load. When the base unit is dispatched at a lower load, the CO₂ capture equipment will need to be turned down to account for the smaller flue gas flow.

As part of the study, S&L reviewed the Hunter 3 steam turbine heat balances to understand approximately how much the unit will be derated due to process steam extraction. In addition, the heat balances were reviewed to ensure that the extraction rates for the maximum steam consumption case (Case 2) will not detrimentally impact the steam turbine.

The addition of a new cooling tower is included to provide cooling to the integrated heat exchangers in the CO₂ capture facility. The CO₂ capture system consists of a large quantity of heat exchangers used for process cooling as well as intercoolers to maintain temperature within the various process vessels. Process

water will also be required for operation of the CO₂ island equipment for pump seals and intermittently for solvent regeneration or filtering purposes. Based on the station water balances, there is sufficient margin on the demineralizer system that can be supplied for consumption at the maximum treatment design capacity. The cooling tower consumes a large quantity of water; however, the quality of this fresh makeup water can be standard lake or well water. Information provided by the station suggests there is sufficient margin in the makeup water capacity of the reservoir on site. To minimize the amount of makeup water required for the cooling tower, water is reused from the process to the maximum extent possible. Blowdown from the new cooling towers will be reused at Hunter station, by means of the bottom ash system, where the existing cooling tower blowdown water is sent.

The CO₂ capture and BOP systems include a significant quantity of pumps, compressors, fans, and other components which will result in significant auxiliary power consumption. The primary power consumer is the compressor, which pressurizes the CO₂ stream to the required pipeline pressure. The auxiliary power can either be provided by the existing unit or a new power generation unit. For the purposes of this study, it is assumed that power will be supplied by the existing Unit, which will lower the net unit capacity. Based on the expected unit capacity factor over the next decade, it is expected that the unit will be dispatched at full load less consistently which may accommodate the loads associated with the CO₂ capture system without negatively impacting the plant.

There is additional integration with the facility based on disposal or treatment of solid and liquid wastes. Waste water generated from the caustic scrubber will be treated by a new physical/chemical wastewater treatment system; the product stream will be used for makeup water to the new cooling towers, while the sludge will be disposed of in a landfill. Blowdown from the new cooling towers will be reused by the existing facility or routed to the facility's evaporation ponds. Other potential waste streams include the degradation products of the amine-based solvent. As part of MHI's and other commercial solvent-based systems, the degraded solvent will be filtered out occasionally and disposed of separately as hazardous waste.

Makeup water, cooling tower blowdown water, demineralized water, steam supply, and condensate return piping will be routed together from the boiler building to minimize the overall plant impact, and for ease of construction.

A visual representation of the proposed plant layout can be found in Appendix D.

3 Project Design Basis

3.1 Inputs and Assumptions

Table 3-1 summarizes the major inputs and assumptions used as the basis for the design of the Hunter 3 CO₂ capture system. These inputs were based on information provided by Hunter Station, from work S&L previously completed for Hunter Station or assumptions based on those included in the US Department of Energy (DOE) and the National Energy Technology Laboratory (NETL) Report for BBS Case 12. Assumptions based on typical industry standards and engineering judgment were also used, where appropriate.

Table 3-1: Summary of Design Inputs and Assumptions

Variable	Units	Hunter Unit 3
Fuel	% composition by mass	Carbon – 65.8 Hydrogen – 4.60 Nitrogen – 1.40 Sulfur – 1.25 Chlorine – 0.02 Oxygen – 8.03 Moisture – 7.00 Ash – 11.90
Boiler Sizing	MW _{gross}	Full - 511 Low - 170
Auxiliary Power Consumption	%	Full – 5.9 Low – 12.8
Heat Input	MMBtu/hr	Full – 4,806 Low – 1,880
Unit Capacity Factor*	%	77

*Note: Future expected capacity factor information was provided by station personnel; 77% represents the expected average over the next decade of operation.

Table 3-2 summarizes the current properties of the Hunter 3 flue gas downstream of the WFGD system. This information is based on flue gas data provided by station personnel and recent stack test results, where available.

Table 3-2: Current Flue Gas Properties based on S&L Mass Balance

Variable	Unit	Hunter Unit 3
Flue Gas Concentration	vol %	N ₂ – 70.32
		O ₂ – 4.17
		H ₂ O – 13.22
		CO ₂ – 12.29
	lb/TBtu	Hg – 0.09
	lb/MMBtu	NO _x – 0.31
		SO ₂ – 0.14
HCl – 0.002		
PM – 0.004		
ppm	SO ₂ – 56	
	SO ₃ – 3.5	
Total Volumetric Flow	acfm	1,574,000
Total Flue Gas Mass Flow	lb/hr	5,248,000
Temperature	°F	123
Pressure	psia / in.wc.	12.063 / +1

Flue gas properties were gathered from previous reports, testing results, and other projects that S&L has completed for PacifiCorp’s Hunter station. SO₂ flue gas data was provided by the station, and the highest average stack SO₂ content was selected as the basis to be conservative. Associated utility consumption rates were calculated based on these facility parameters and CO₂ quality requirements.

As part of this evaluation, three different CO₂ capture rates were explored. The largest design was based on achieving 90% removal of the CO₂ from the base facility, which sizes the capture system based on 100% of the Hunter 3 full load flue gas rate. The second largest design assumed 65% capture from the base facility, which sizes the capture system based on approximately 72% of the Hunter 3 full load flue gas rate. The smallest design uses an equivalent capture rate to an emission rate of 1,000 lbs CO₂/MWh-gross as the basis. Based on the Hunter 3 unit size and CO₂ concentration, this results in a capture system sized for approximately 48% of the Hunter 3 full load flue gas rate.

Table 3-3 summarizes the expected Hunter 3 CO₂ capture facility requirements and estimated utility consumption for each of the three capture ranges. This information is based on S&L’s understanding of the MHI process, outputs from the mass balance, and pipeline standards for CO₂ delivery.

Table 3-3: CO₂ Capture Facility Requirements and CO₂ Quality

Variable	Unit	Case 1 (65% Capture)	Case 2 (90% Capture)	Case 3 (1,000 lbs/MWh _g)
CO ₂ Capture	--	65%	90%	48% Capture
CO ₂ Stream Purity	%	≥ 95	≥ 95	≥ 95
CO ₂ Product Temperature	°F	95	95	95
CO ₂ Product Stream Pressure	psia	2,215	2,215	2,215
CO ₂ Production	lb/hr	640,000	887,000	473,000
	ton/yr	2,159,700	2,991,500	1,595,200
Capture Island Size	MWe	370	511	273
	lb/hr	3,790,000	5,248,000	2,799,000
	acfm	1,137,000	1,574,000	840,000
	CO ₂ lb/hr	712,000	985,000	526,000
CO ₂ Emissions	lb/MWh	675	193	1,002
Aux Power*	MW	Compressor – 18 Process – 33	Compressor – 25 Process – 46	Compressor – 13 Process – 25
Steam	lb/hr	788,000	1,000,000	617,000
Raw Make Up Water	gpm	2,600	3,600	1,900
Demin Make Up Water	gpm	20	28	15

*Note: Aux power requirement listed is in addition to the existing plant aux power requirements.

Material balance calculations were developed for the CO₂ capture systems based on this design basis and are provided in Appendix C.

3.2 System Redundancy

The CO₂ capture facility at Hunter will consist of one (1) x 100% train for any of the three capture facility sizes. Multiple trains are not typically necessary and would require additional capital cost. In addition, as operation of this unit is not critical to the operation of Hunter 3, complete train redundancy is not required. Redundancy on large complex pieces of equipment, such as the vessels and ID fans, is not necessary as this equipment is typically very reliable based on industry experience. In addition, heat exchangers, compressors, and other large components are expected to have very high availability, with regular inspections and maintenance of these pieces of equipment during scheduled outages.

4 Project Execution

4.1 Regulatory Considerations

Integration of a CO₂ capture facility at the existing Hunter station would consist of routing flue gas from the WFGD system outlet of Unit 3 to a CO₂ capture facility located on PacifiCorp property. Based on the ability to extract steam from the existing turbine and the ability to tie into the existing auxiliary power transformer, a new combustion or power source is not required. However, the CO₂ capture system may require environmental permits or approvals for air emissions, water use, wastewater discharges, and solid waste management and disposal. Specific limitations and permitting requirements depend upon the type, size, and location of the facility being permitted. Based on the preliminary design of the CO₂ capture facility, there are expected to be no fatal flaws that would prohibit the construction or operation of the new CO₂ capture facility at this time. The following permits are identified by S&L to potentially require modifications for a project of this scope:

- Application for a revised Title V permit from the WDEQ;
- Determination of composition and treatment requirements for the process wastewaters or if they can be treated using the existing resources onsite;
- Application for a revised NPDES permit, if necessary;
- Determination of whether a new solid waste stream from wastewater sludge dewatering could be disposed at another landfill that accepts industrial solid wastes; and
- Determination of whether a new hazardous waste stream of the amine degradation products could be disposed of off-site at a facility that accepts industrial or hazardous wastes.

While it is not expected that the project has any fatal flaws at this time, there may be some limitation to the facility size and, subsequently, the compressed CO₂ production rate, based on some permitting requirements. The factors that have the highest probability of becoming limiting factors moving forward are (1) the ability to permit a new point source as part of the station's Title V permit and (2) the potential for PSD permitting to be triggered, based on criteria pollutant emissions increases. VOC emissions would have the highest likelihood of increasing after project execution.

Based on the flue gas treatment equipment that is integrated with the CO₂ capture facility, the base unit air emissions are expected to change, resulting in decreased CO₂, SO₂, SO₃, and PM emissions. Mercury and NO_x rates are also likely to decrease, though this has not been well documented at this time. VOC emissions or aerosols have the biggest potential to increase with amine-based technology CO₂ capture projects due to amine carryover. As discussed previously, a second water wash section in the top of the absorber column will help reduce the potential for an increase in emissions. At this time, it is unknown what changes to VOC or aerosol emissions might occur, if any.

Table 4-1: Estimated Emission Changes

Variable	Unit	Baseline Emissions	Case 1 (65% Capture)	Case 2 (90% Capture)	Case 3 (1,000 lb/MWh_g)
CO ₂	lb/hr	984,920	344,722	98,492	512,158
SO ₂	lb/hr	654	191	13	312
SO ₃	lb/hr	51	41	38	44
HCl	lb/hr	8	3	1	4
NO _x	lb/hr	1,490	1,490	1,490	1,490
Hg	lb/hr	0.00043	0.00043	0.00043	0.00043
VOC	lb/hr	unknown	unknown	unknown	unknown
PM	lb/hr	20	17	15	18

In addition to air, water, and waste permits, there is the need for construction permits for the construction of the CO₂ capture facility and a new pipeline. Permits and approvals will be required at the federal and state level to construct and operate these.

4.2 Overall Net Output Impact

As discussed previously, there are two parameters that will derate the base facility: steam extraction and auxiliary power usage. The steam extraction from the IP/LP cross-over reduces the overall gross capacity of the turbine by removing the steam prior to passing through the LP turbine. Based on review of the Hunter 3 heat balance, it is estimated that the gross output is derated by approximately 63 MW for the 90% capture case. The overall derate for the 90% capture case can be seen in Appendix A. At the lower capture rates, the derate will be less, but is not expected to scale linearly. The CO₂ capture facility also utilizes a significant amount of auxiliary power to operate the mechanical equipment. This also reduces the net power that can be provided to the grid and is provided by the station’s existing auxiliary power transformers and metered within the fence-line. Based on the sizes of the facility, the total net output of the unit for each case is provided below.

Table 4-2: Plant Net Output with CO₂ Capture

	Case 1 (65% Capture)	Case 2 (90% Capture)	Case 3 (1,000 lb/MWh_g)
Gross Boiler Size/Steam Generation	511	511	511
Process Steam Equivalent Power Derate	54	63	47
Steam Turbine Gross Output	457	448	464
Base Plant Aux Power	30	30	30
CO ₂ Island Process Aux Power	33	46	25
CO ₂ Compressor Aux Power	18	25	13
CO ₂ Island BOP	3	4	2
Net Power Output	373	343	394

When the CO₂ capture facility is not in operation, the station regains full gross capacity of 511 MWg.

4.3 Project Schedule

As with any large retrofit project, a new CO₂ capture facility requires a schedule of significant duration, regardless of size. Due to the infancy of the technology being developed on a commercial scale size, there is an extended preliminary development period required prior to beginning detailed engineering. A project of this size would likely include a Front End Engineering and Design (FEED) study prior to award, which would consist of developing technical requirements and more detailed costs. After the FEED study, the project would be competitively bid to qualified vendors and an award would start the engineering process. BOP engineering and CCS engineering would be completed concurrently. Depending on the overall project scope, construction can start about six months after award and will continue for around two years. After all tie-ins are complete and all equipment is installed onsite, commissioning and performance testing will take place, ensuring all equipment is working as intended individually and as a system. This is expected to require approximately eight months after construction. A high level example schedule is provided in Figure 4-1.

Figure 4-1: Milestone Project Schedule

ID	Task Name	Start	Finish	Duration	2018				2019				2020				2021			
					Q1	Q2	Q3	Q4												
1	Conduct FEED Study	1/1/2018	6/29/2018	26w	█															
2	Award Contracts	7/2/2018	7/2/2018	1d																
3	Engineering	7/3/2018	3/2/2020	87w					█											
4	Construction	1/1/2019	1/4/2021	105w					█											
5	Unit Tie-In	2/3/2020	3/13/2020	6w									█							
6	Commissioning	1/5/2021	5/3/2021	17w													█			
7	Final Acceptance Testing	5/4/2021	8/30/2021	17w													█			

5 Economic Evaluation

5.1 Capital Costs

CO₂ capture island equipment costs were estimated based on S&L proprietary costs, budgetary pricing and allowances. All costs are provided in 2017 dollars. Installation costs were estimated by S&L based on similar work. Labor costs were estimated for each individual subcontracted process or component rather than a blanket percentage over the whole project, and include the associated labor indirect costs which apply to this type of work such as overtime, per diem, contractor's G&A and profit.

Project contingency was added, due to the risk of a relatively new technology application. A contingency factor of 20% was added to the BOP project scope only, since the CO₂ capture system risk is accounted for in the EPC fee. Indirect project costs, such as engineering, construction management, startup and commissioning support, construction materials and initial fills for testing were also included in the estimate to provide a total capital investment. Owner's costs were not included.

The overall cost for the commercially available amine-based CO₂ capture system is provided for each of the three facility sizes. Table 5-1 provides a breakdown of the capital cost.

Table 5-1: Capital Cost Summary of CO₂ Capture Slipstream Systems

Description	Case 1 (65% Capture)	Case 2 (90% Capture)	Case 3 (1,000 lb/MWh_g)
BOP Scope			
Civil, Site Prep, and Structural	6,168,200	7,125,500	5,434,200
Architectural	4,812,000	5,850,000	4,016,100
Mechanical	15,945,200	18,867,300	13,704,900
Electrical and I&C	2,342,900	2,342,900	2,342,900
CO ₂ Capture System (EPC)	470,000,000	610,000,000	380,000,000
Total Direct Capital Cost	499,268,300	644,185,700	405,498,100
Other Direct and Construction Indirect Costs (Excludes EPC)	6,221,000	7,266,000	5,420,000
Engineering (Excludes EPC)	3,549,000	4,145,000	3,092,000
Construction Management (Excludes EPC)	710,000	829,000	618,000
Startup/Commissioning (Excludes EPC)	366,000	427,000	318,000
Contingency (Excludes	8,022,000	9,370,000	6,989,000

Description	Case 1 (65% Capture)	Case 2 (90% Capture)	Case 3 (1,000 lb/MWh _e)
EPC)			
Total Capital Investment	518,136,300	666,222,700	421,935,100

5.2 Operating Costs

Operating costs were estimated based on a capacity factor of 77% and are provided in 2017 dollars. Unit costs for consumables were estimated by S&L, except as noted. Fixed O&M costs for operators, maintenance material and labor, and administrative labor costs were also included based on typical assumptions.

The overall O&M cost for the commercially available amine-based CO₂ capture system is provided for each of the three facility sizes. Table 5-2 provides a breakdown of the annual O&M cost.

Table 5-2: O&M Cost Summary of CO₂ Capture Slipstream Systems

Description	Case 1 (65% Capture)	Case 2 (90% Capture)	Case 3 (1,000 lb/MWh _e)
Total Fixed Operating Cost	7,195,000	7,195,000	7,195,000
Annual Operating Labor ¹	3,295,000	3,295,000	3,295,000
Maintenance Material & Labor	3,900,000	3,900,000	3,900,000
Total Variable Operating Cost	39,492,000	51,507,000	31,030,000
Makeup Water	1,052,000	1,465,000	769,000
Demin Makeup Water	41,000	57,000	30,000
Water Treatment ²	356,000	454,000	235,000
Pre-scrubber Caustic Solution	809,000	1,079,000	540,000
Lost Generation/Auxiliary Power	14,570,000	20,236,000	10,793,000
Lost Generation/Process Steam	14,570,000	16,998,000	12,681,000
CO ₂ Capture Solvent ³	8,094,000	11,218,000	5,982,000
CO₂ Transportation, Storage and Monitoring⁴	19,581,000	27,138,000	14,472,000
Total Annual O&M Cost	66,268,000	85,840,000	52,697,000

Notes:

1. Operating labor is based on the addition of 24 operators for the CO₂ capture system.
2. Water treatment costs include chemical and solids disposal costs.
3. Solvent costs include the cost for new makeup solvent and disposal of the degradation products.
4. TS&M is based on the DOE suggested rate of \$10/tonne of CO₂ captured.

5.3 Cost of Capture

To calculate the total cost per mass of CO₂ captured, all costs must be evaluated on an annual basis. In previous U.S. Department of Energy (DOE) case studies, a capital annualization factor of 0.1243 was used to evaluate costs on a constant dollar basis. This methodology was used to calculate the total cost of capture for this TEA. Table 5-3 provides an estimate of the total quantity of CO₂ captured in a year as well as the evaluated cost for the CO₂ capture system.

Table 5-3: Evaluated Cost of CO₂ Capture Systems

Description	Units	Case 1 (65% Capture)	Case 2 (90% Capture)	Case 3 (1,000 lb/MWh_e)
Total Capital Cost	\$	518,136,300	666,222,700	421,935,100
CCF		0.1243	0.1243	0.1243
Annualized Capital Cost	\$/yr	64,404,400	82,811,500	52,446,600
Annual O&M Cost	\$/yr	66,268,000	85,840,000	52,697,000
Total Annual Cost	\$/yr	130,672,400	149,079,500	118,714,600
Annual CO ₂ Captured	tons	2,158,460	2,991,500	1,595,240
Cost of Capture	\$/ton	61	50	74

6 Summary and Conclusions

The purpose of this TEA was to determine the technical and economic feasibility of installing a CO₂ capture facility at Hunter Station, utilizing a commercially available technology at three different capture scales. A full scale capture system (Case 2: 90% capture) served as the basis for development of heat balances, mass balances, process flow diagrams, general arrangements, equipment sizing, and capital costs. Case 2 represents the worst case scenario with respect to impacts on the base unit and, therefore, the other levels of capture will be feasible if this level of capture is deemed feasible. The full scale system inputs were adjusted for the two other capture facility design sizes: Case 1: 65% and Case 3: 1,000 lb CO₂/MWh_g.

Overall, the project is technically feasible for implementation on PacifiCorp's Hunter Unit 3. Process steam will be provided by the base unit and extracted at the IP/LP crossover without disrupting the performance of the LP turbine; however, this will cause a unit derate by limiting the total amount of megawatts the turbines can produce. Other utilities that the base plant will provide include process water makeup from the existing demineralized water system, cooling tower makeup water from the on-site storage basin, and auxiliary power from the existing auxiliary power transformer. Flue gas will be routed to the CO₂ capture island after the majority of SO₂ has been removed from the WFGD system, which reduces the amount of acid gas polishing that is required in the pre-scrubber. The CO₂ process is expected to generate pipeline quality liquid CO₂ for transportation to a storage field or an EOR facility.

As part of this evaluation, S&L developed capital costs, O&M costs, and cost of capture for each of the three cases. Using previous information gathered from MHI and S&L's engineering judgement, the system design and costs were developed based on the MHI KM-CR Process® with KS-1™ solvent. Due to economies of scale, the overall cost of capture (\$/ton of CO₂ removed) is less at larger capture rates. Depending on the project size selected, the cost of capture ranges from \$50-74/ton CO₂ removed.

APPENDIX A: HEAT BALANCE (90% CAPTURE – CASE 2)

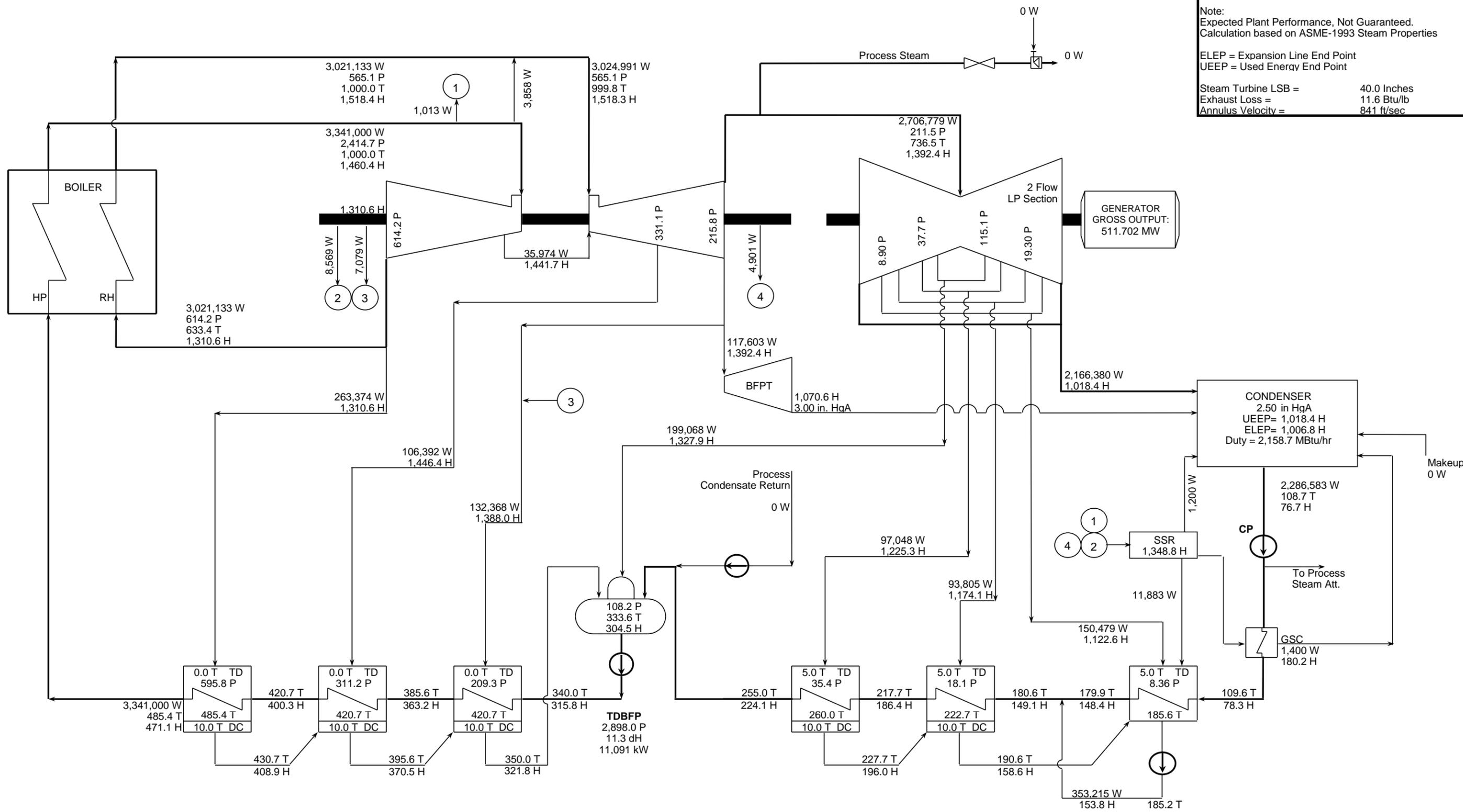
Notes and Assumptions:

1. Steam Turbine (ST) design is based on Hitachi, Ltd heat balance diagram 310SC74-636 Rev. 0, dated Dec. 11, 2008.
Steam turbine is a TC2F machine with a 40.0" last stage blade length, operating at 3600 RPM (60 Hz).
A typical exhaust loss curve for this last stage blade length was used to approximate the exhaust loss.
ST generator efficiency is based on Hitachi, Ltd heat balance diagram 310SC74-636 Rev. 0, dated Dec. 11, 2008.
2. Boiler feed pump turbine drive efficiency is per reference heat balance and is assumed constant for all cases.
3. Feedwater heater operating conditions are based on Hitachi, Ltd heat balance diagram 310SC74-636 Rev. 0, dated Dec. 11, 2008.
It is assumed that constant terminal temperature differences and drain cooler approach temperatures are maintained for all cases.
4. Condenser design operating pressure = 2.5 inHgA based on the reference heat balance.
5. Match case uses no deaerator venting flow rate per Hitachi, Ltd heat balance diagram 310SC74-636 Rev. 0, dated Dec. 11, 2008.
All other cases assume deaerator venting of 0.25% of the incoming feedwater flow rate.
6. Carbon capture process Steam is supplied by extracting steam from the IP crossover and attemperating to the required process conditions.
Clean condensate is returned from the carbon capture process and re-enters the cycle at the deaerator.
A 99% condensate return rate is assumed.
A pressure loss of 20% is assumed from the process steam exit to the process condensate return.
Process condensate is assumed to return with 5°F of subcooling.
It is assumed that condensate polishing of the returning condensate is not required.
7. Process Steam conditions are as follows:
Pressure: 85.7 psia (71 psig)
Temperature: 320°F (3°F of superheat)
8. Piping, reheater, and extraction losses are based on Hitachi, Ltd heat balance diagram 310SC74-636 Rev. 0, dated Dec. 11, 2008.
9. Heat balance results determined using GateCycle Program, Version 6.1.2
Steam Property Method: ASME 1993 steam properties are used to match Hitachi heat balance.
All other cases use the IAPWS-IF97 (ASME 1999) steam properties.

Note:
 Expected Plant Performance, Not Guaranteed.
 Calculation based on ASME-1993 Steam Properties

ELEP = Expansion Line End Point
 UEEP = Used Energy End Point

Steam Turbine LSB = 40.0 Inches
 Exhaust Loss = 11.6 Btu/lb
 Annulus Velocity = 841 ft/sec



Net Turbine Heat Rate = Heat Input / Generator Output = 7,686 Btu/kWh

PRELIMINARY

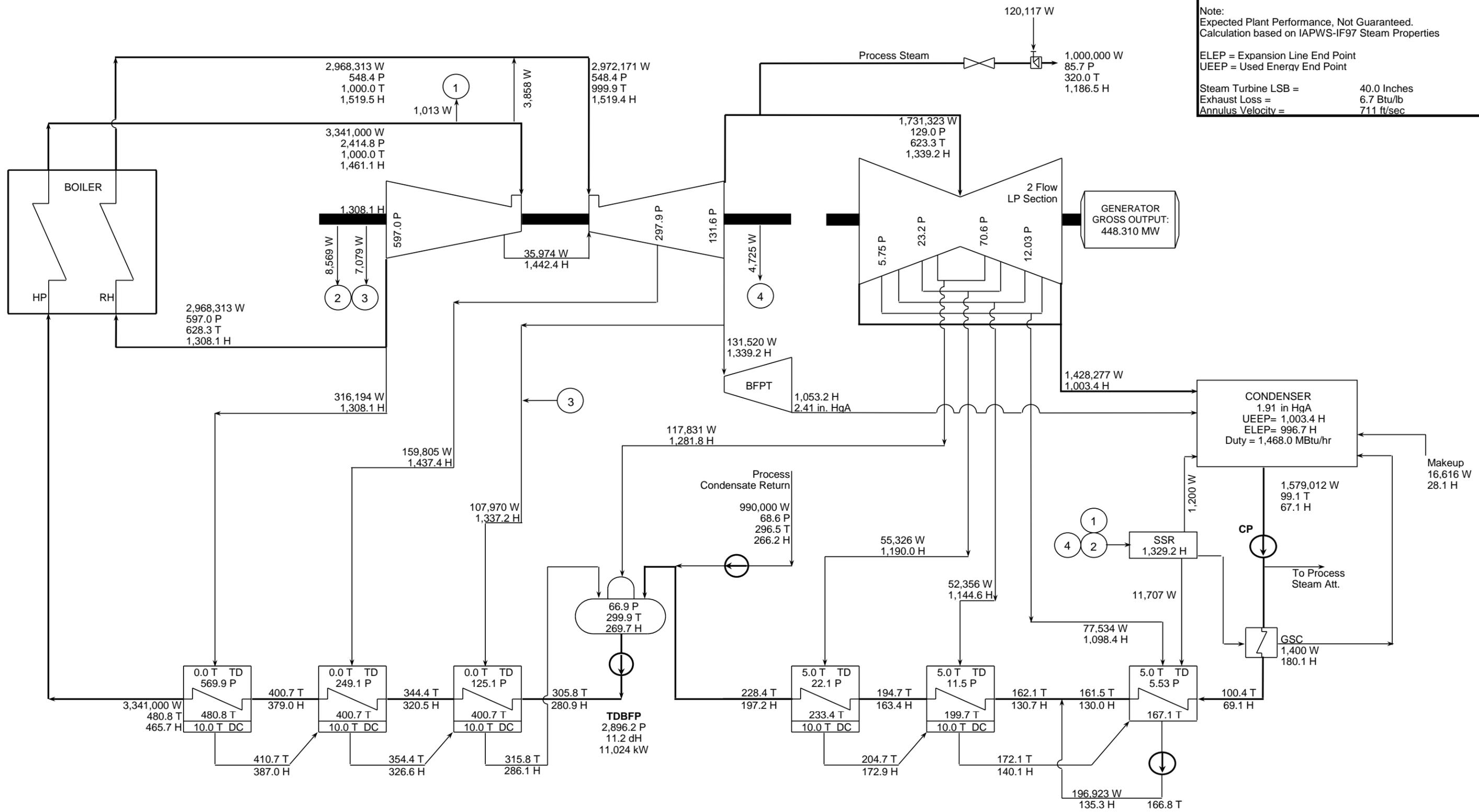
Legend:		
W=	Flow	lb/h
P=	Pressure	psia
T=	Temp.	°F
H=	Enthalpy	Btu/Lb

Drawing Release Record					
Rev.	Date	Prepared	Reviewed	Approved	Purpose
0	31-Oct-2017	D Jarard	J Cobb		Original Issue

Project No.:	
13644-001	
GateCycle v6.1.2	
Model	Case
HU3	HU3

University of Utah
 Hunter Unit 3 Carbon Capture Study
 Expected Performance Summary
 Match Case: No Process Steam Extraction





Note:
 Expected Plant Performance, Not Guaranteed.
 Calculation based on IAPWS-IF97 Steam Properties

ELEP = Expansion Line End Point
 UEEP = Used Energy End Point

Steam Turbine LSB = 40.0 Inches
 Exhaust Loss = 6.7 Btu/lb
 Annulus Velocity = 711 ft/sec

Net Turbine Heat Rate = Heat Input / Generator Output = 8,818 Btu/kWh

PRELIMINARY

Legend:		
W=	Flow	lb/h
P=	Pressure	psia
T=	Temp.	°F
H=	Enthalpy	Btu/Lb

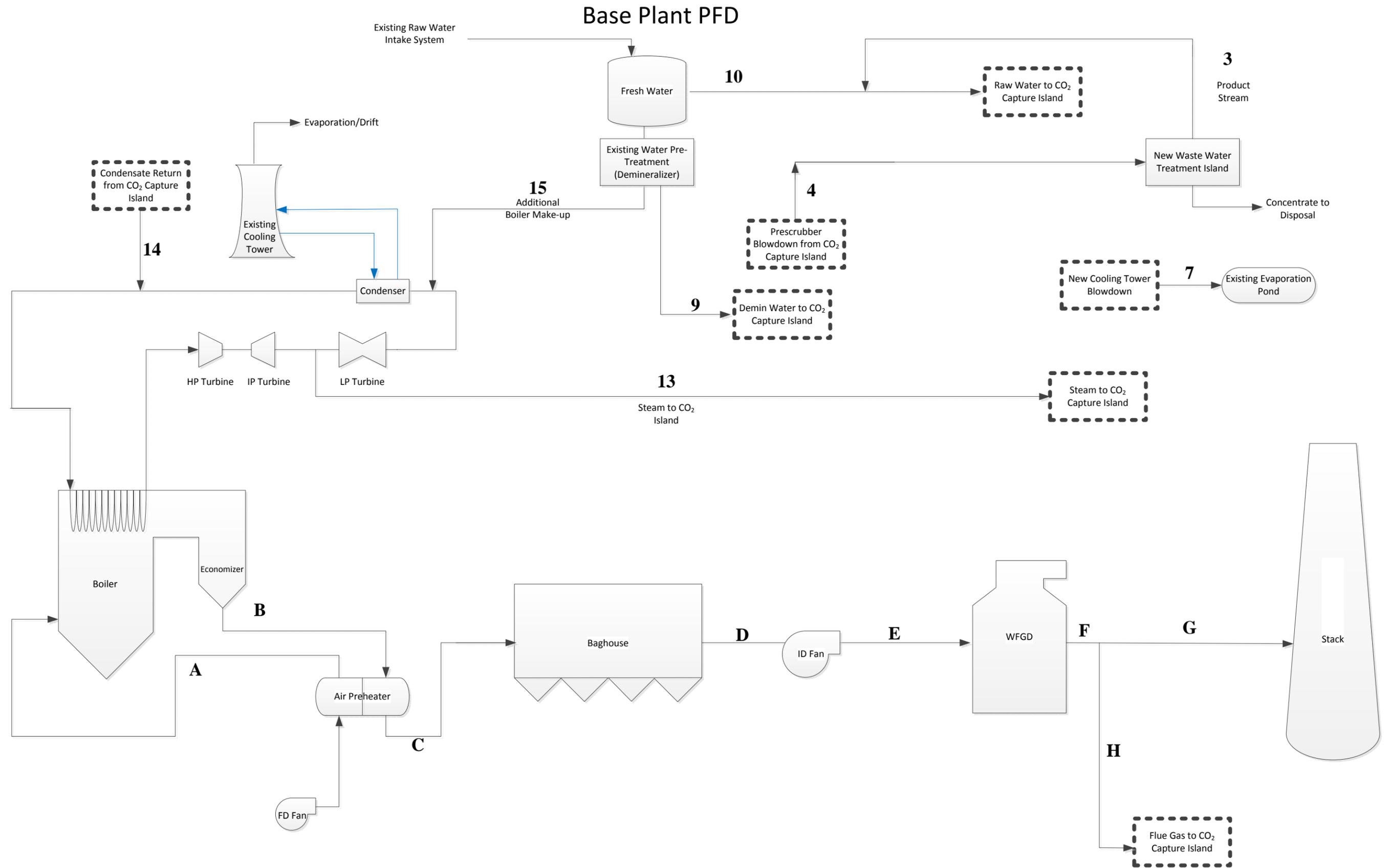
Rev.	Date	Prepared	Reviewed	Approved	Purpose
0	31-Oct-2017	D Jarard	J Cobb		Original Issue

Project No.:	
13644-001	
GateCycle v6.1.2	
Model	Case
HU3	Case1

University of Utah
 Hunter Unit 3 Carbon Capture Study
 Expected Performance Summary
 Case 1: 1,000,000 lb/hr Process Steam

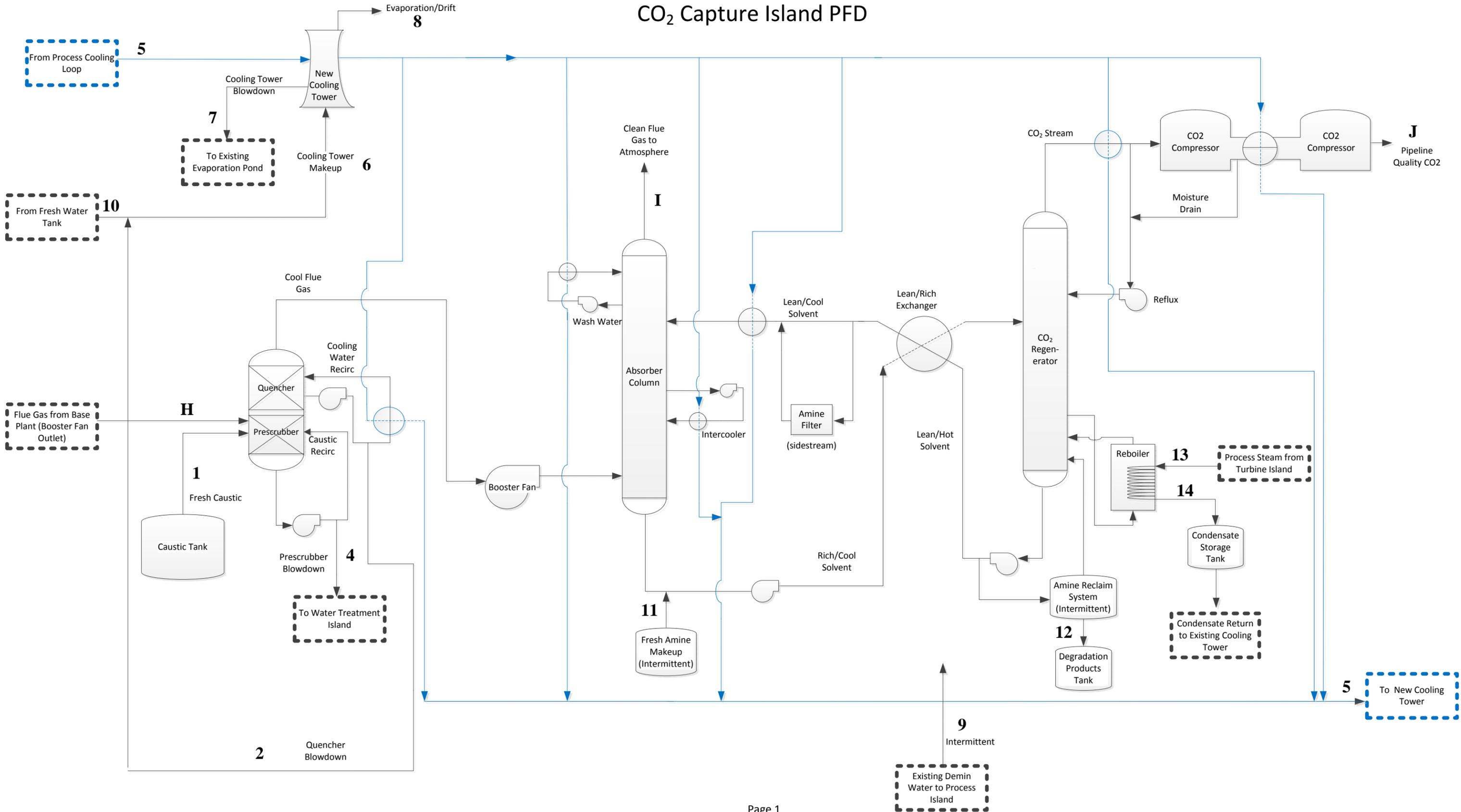


APPENDIX B: BASE PLANT PROCESS FLOW DIAGRAM



APPENDIX C: CO₂ ISLAND PROCESS FLOW DIAGRAM AND MATERIAL BALANCES

CO₂ Capture Island PFD





Case 1: Material Balance - 65% CO₂ Capture

Flue Gas Stream Characteristics		Combustion Air		Economizer Outlet		Air Heater Outlet		Baghouse Outlet		ID Fan Outlet		Wet FGD Outlet		To Existing Stack		To CO ₂ Capture Island		Clean Flue Gas to New Stack		Pipeline Quality CO ₂	
		A		B		C		D		E		F		G		H		I		J	
Temperature	°F	103		750		300		300		316		123		123		123		Proprietary		112	
Pressure	psia	12.027		11.775		11.558		11.270		12.387		12.063		12.063		12.063		12.045		2215	
N ₂	lb/hr-vo1%	3,237,000	76.09	3,242,000	72.66	3,563,000	72.95	3,563,000	72.95	3,563,000	72.95	3,586,000	70.32	996,000	19.53	2,590,000	70.32	2,590,000	85.52	0	0.00
O ₂	lb/hr-vo1%	975,000	20.06	142,000	2.78	238,000	4.27	238,000	4.27	238,000	4.27	243,000	4.17	67,000	1.16	175,000	4.17	175,000	5.07	0	0.00
H ₂ O	lb/hr-vo1%	105,000	3.85	302,000	10.51	312,000	9.94	312,000	9.94	312,000	9.94	433,000	13.22	120,000	3.67	313,000	13.22	154,000	7.91	157	0.06
CO ₂	lb/hr-vo1%	0	0.00	978,000	13.95	978,000	12.75	978,000	12.75	978,000	12.75	985,000	12.29	274,000	3.41	712,000	12.29	72,000	1.49	640,000	99.94
SO ₂	lb/hr-ppmv	0	0	10,000	986	10,000	901	10,000	901	10,000	901	700	56	180	56	500	56	9	1	0	0
SO ₃	lb/hr-ppmv	0	0	100	8	71	5	67	5	67	5	51	3	14	3	37	3	27	3	0	0
HCl	lb/hr-ppmv	0	0	83	14	83	13	83	13	83	13	8	1	2	1	6	1	1	0	0	0
HF	lb/hr-ppmv	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NO _x	lb/mmbtu	0		0.31		0.31		0.31		0.31		0.31		0.31		0.31		0.31		0	
Hg	lb/tbtu	0		10		0.09		0.09		0.09		0.09		0.09		0.09		0.09		0	
Total Flow	lb/hr-acfm	4,317,000	1,271,000	4,674,000	2,928,000	5,101,000	2,050,000	5,101,000	2,103,000	5,101,000	1,952,000	5,248,000	1,574,000	1,458,000	437,000	3,790,000	1,137,000	2,991,000	910,000	640,000	700
Moist.	lb/lb	0.025		0.069		0.065		0.065		0.065		0.090		0.090		0.090		0.054		0.000	
MW	lb/lbmol	28.42		29.33		29.25		29.25		29.25		28.81		28.81		28.81		27.65		43.98	
Ash	lb/hr	0		38,606		38,606		27		27		20		6		15		11		0	
Process Stream Characteristics		Fresh Caustic	Quencher Blowdown	WWT Recovery	Prescrubber Blowdown	CO ₂ Cooling Loop	Cooling Tower Water Makeup	Cooling Tower Water Blowdown	Cooling Tower Water Evaporation	Process Water Makeup	Fresh Water to CT	Amine Make Up	Degradation Products	Steam to CO ₂ Island	Condensate Return	Additional Boiler Makeup					
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15					
Solids	lb/hr	300	0	0	300	0	0	0	0	0	288	0	0	288	0	0					
Water	lb/hr	3,000	124,700	22,700	31,600	67,728,000	1,444,200	360,500	1,083,600	Intermittent	1,296,700	0	0	788,000	779,300	8,700					
Total Flow	lb/hr	3,300	124,700	22,700	31,900	67,728,000	1,444,200	360,500	1,083,600	Intermittent	1,297,000	Intermittent	Intermittent	788,000	779,300	8,700					
Total Flow	gpm	5	300	50	100	136,000	2,900	700	2,200	Intermittent	2,600	Intermittent	Intermittent	--	--	--					
Solids	wt%	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0					



Case 2: Material Balance - 90% CO₂ Capture

Flue Gas Stream Characteristics		Combustion Air		Economizer Outlet		Air Heater Outlet		Baghouse Outlet		ID Fan Outlet		Wet FGD Outlet		To Existing Stack		To CO ₂ Capture Island		Clean Flue Gas to New Stack		Pipeline Quality CO ₂	
		A		B		C		D		E		F		G		H		I		J	
Temperature	°F	103		750		300		300		316		123		123		123		Proprietary		112	
Pressure	psia	12.027		11.775		11.558		11.270		12.387		12.063		12.063		12.063		12.045		2215	
N ₂	lb/hr-vol%	3,237,000	76.09	3,242,000	72.66	3,563,000	72.95	3,563,000	72.95	3,563,000	72.95	3,586,000	70.32	0	0.00	3,586,000	70.32	3,586,000	85.52	0	0.00
O ₂	lb/hr-vol%	975,000	20.06	142,000	2.78	238,000	4.27	238,000	4.27	238,000	4.27	243,000	4.17	0	0.00	243,000	4.17	243,000	5.07	0	0.00
H ₂ O	lb/hr-vol%	105,000	3.85	302,000	10.51	312,000	9.94	312,000	9.94	312,000	9.94	433,000	13.22	0	0.00	433,000	13.22	213,000	7.91	218	0.06
CO ₂	lb/hr-vol%	0	0.00	978,000	13.95	978,000	12.75	978,000	12.75	978,000	12.75	985,000	12.29	0	0.00	985,000	12.29	99,000	1.49	886,000	99.94
SO ₂	lb/hr-ppmv	0	0	10,000	986	10,000	901	10,000	901	10,000	901	700	56	0	0	700	56	13	1	0	0
SO ₃	lb/hr-ppmv	0	0	100	8	71	5	67	5	67	5	51	3	0	0	51	3	38	3	0	0
HCl	lb/hr-ppmv	0	0	83	14	83	13	83	13	83	13	8	1	0	0	8	1	1	0	0	0
HF	lb/hr-ppmv	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NO _x	lb/mmbtu	0		0.31		0.31		0.31		0.31		0.31		0.00		0.31		0.31		0	
Hg	lb/tbtu	0		10		0.09		0.09		0.09		0.09		0.00		0.09		0.09		0	
Total Flow	lb/hr-acfm	4,317,000	1,271,000	4,674,000	2,928,000	5,101,000	2,050,000	5,101,000	2,103,000	5,101,000	1,952,000	5,248,000	1,574,000	0	0	5,248,000	1,574,000	4,141,000	1,260,000	887,000	900
Moist.	lb/lb	0.025		0.069		0.065		0.065		0.065		0.090		0.000		0.090		0.054		0.000	
MW	lb/lbmol	28.42		29.33		29.25		29.25		29.25		28.81		0.00		28.81		27.65		43.98	
Ash	lb/hr	0		38,606		38,606		27		27		20		0		20		15		0	
Process Stream Characteristics		Fresh Caustic	Quencher Blowdown	WWT Recovery	Prescrubber Blowdown	CO ₂ Cooling Loop	Cooling Tower Water Makeup	Cooling Tower Water Blowdown	Cooling Tower Water Evaporation	Process Water Makeup	Fresh Water to CT	Amine Make Up	Degradation Products	Steam to CO ₂ Island	Condensate Return	Additional Boiler Makeup					
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15					
Solids	lb/hr	400	0	0	400	0	0	0	0	0	399	0	0	399	0	0					
Water	lb/hr	4,100	172,700	31,500	43,700	94,122,000	2,007,000	501,000	1,506,000	Intermittent	1,802,800	0	0	1,000,000	990,000	10,000					
Total Flow	lb/hr	4,500	172,700	31,500	44,100	94,122,000	2,007,000	501,000	1,506,000	Intermittent	1,803,200	Intermittent	Intermittent	1,000,000	990,000	10,000					
Total Flow	gpm	10	350	60	90	189,000	4,030	1,010	3,020	Intermittent	3,620	Intermittent	Intermittent	--	--	--					
Solids	wt%	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0					



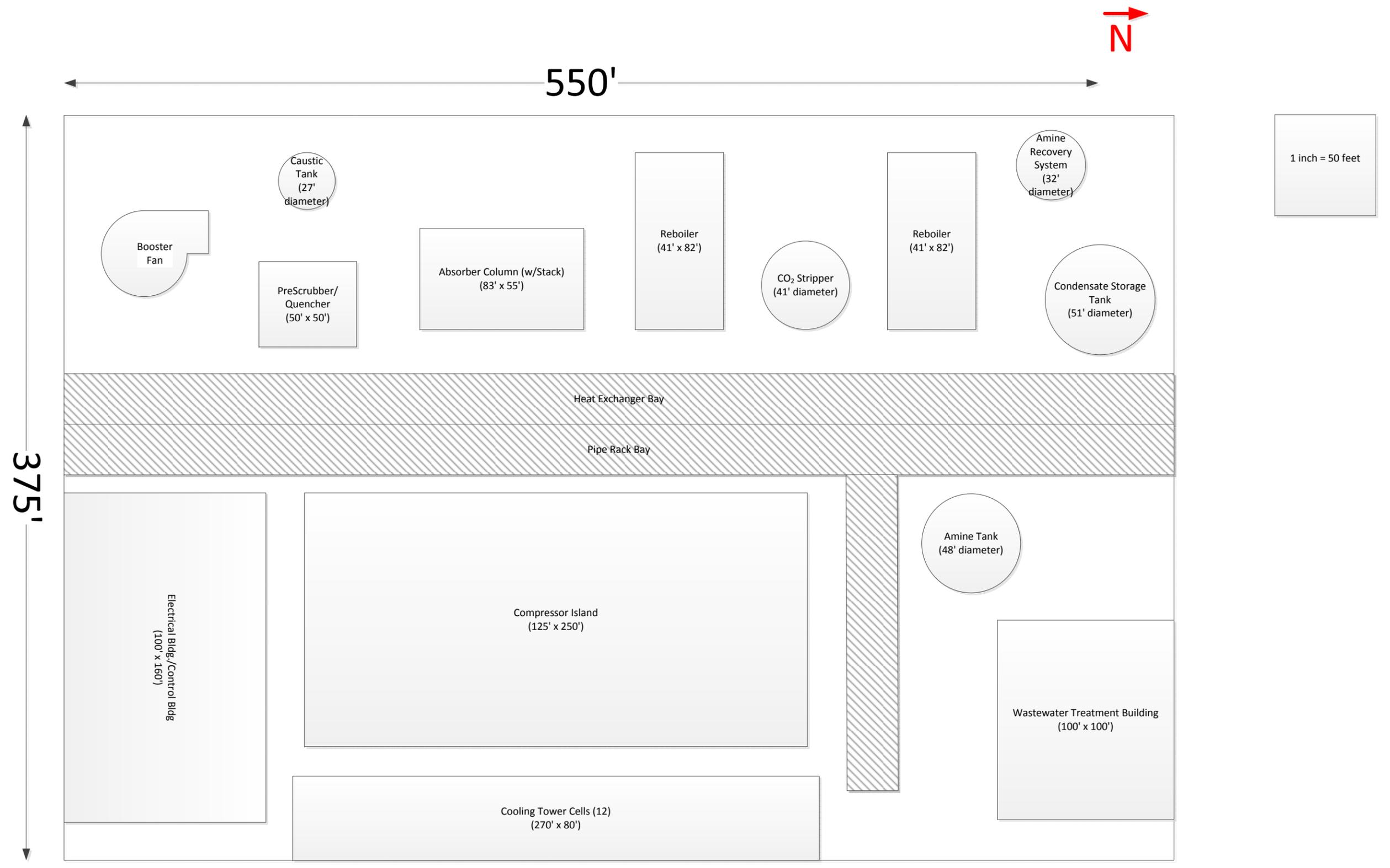
Case 3: Material Balance – 1,000 lb/MWhg

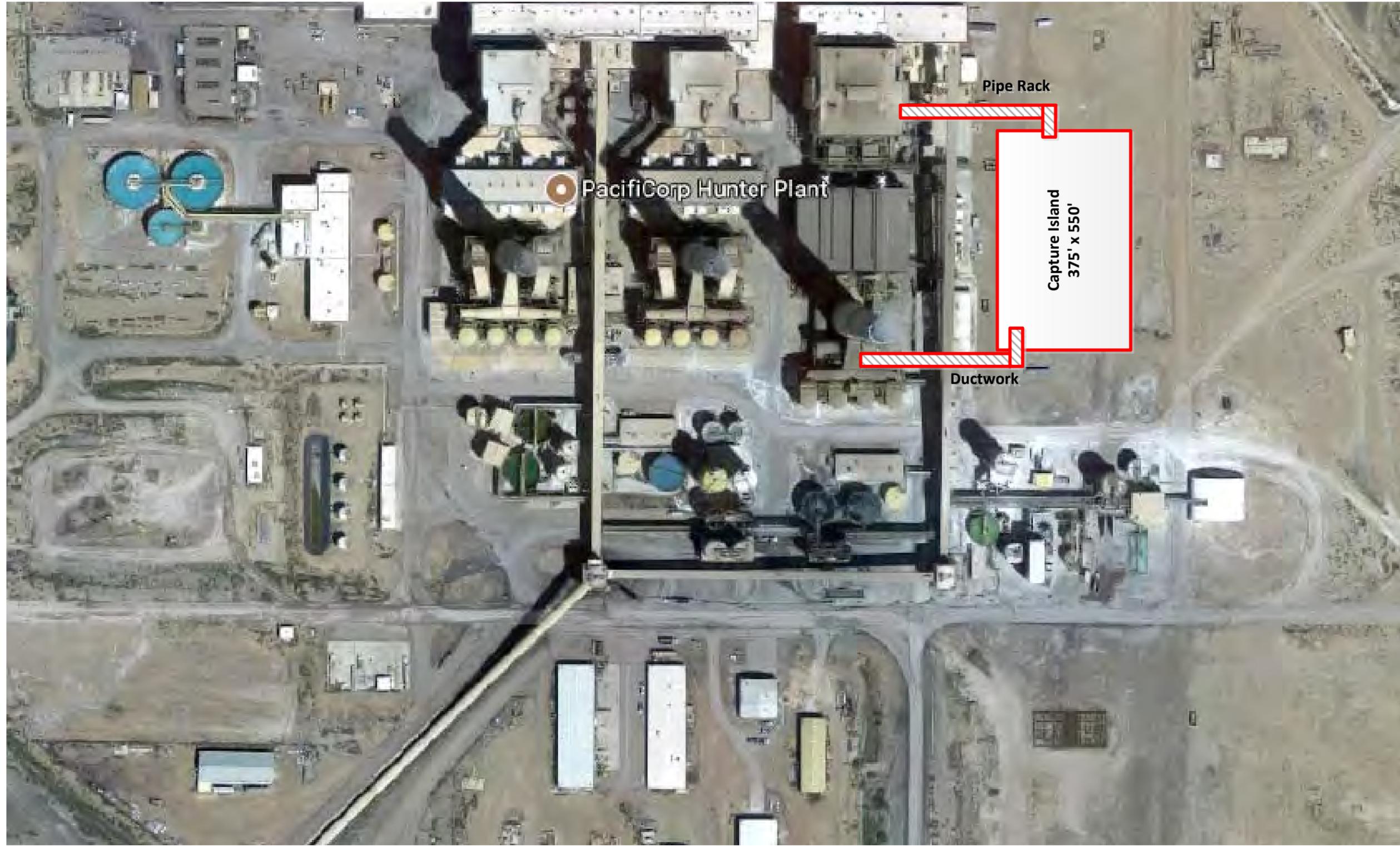
Flue Gas Stream Characteristics		Combustion Air		Economizer Outlet		Air Heater Outlet		Baghouse Outlet		ID Fan Outlet		Wet FGD Outlet		To Existing Stack		To CO ₂ Capture Island		Clean Flue Gas to New Stack		Pipeline Quality CO ₂	
		A		B		C		D		E		F		G		H		I		J	
Temperature	°F	103		750		300		300		316		123		123		123		Proprietary		112	
Pressure	psia	12.027		11.775		11.558		11.270		12.387		12.063		12.063		12.063		12.045		2215	
N ₂	lb/hr-vol%	3,237,000	76.09	3,242,000	72.66	3,563,000	72.95	3,563,000	72.95	3,563,000	72.95	3,586,000	70.32	1,674,000	64.13	1,913,000	70.32	1,913,000	85.52	0	0.00
O ₂	lb/hr-vol%	975,000	20.06	142,000	2.78	238,000	4.27	238,000	4.27	238,000	4.27	243,000	4.17	113,000	3.80	130,000	4.17	130,000	5.07	0	0.00
H ₂ O	lb/hr-vol%	105,000	3.85	302,000	10.51	312,000	9.94	312,000	9.94	312,000	9.94	433,000	13.22	202,000	12.05	231,000	13.22	114,000	7.91	116	0.06
CO ₂	lb/hr-vol%	0	0.00	978,000	13.95	978,000	12.75	978,000	12.75	978,000	12.75	985,000	12.29	460,000	11.21	526,000	12.29	53,000	1.49	473,000	99.94
SO ₂	lb/hr-ppmv	0	0	10,000	986	10,000	901	10,000	901	10,000	901	700	56	310	56	300	56	7	1	0	0
SO ₃	lb/hr-ppmv	0	0	100	8	71	5	67	5	67	5	51	3	24	4	27	3	20	3	0	0
HCl	lb/hr-ppmv	0	0	83	14	83	13	83	13	83	13	8	1	4	1	4	1	0	0	0	0
HF	lb/hr-ppmv	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
NO _x	lb/mmbtu	0		0.31		0.31		0.31		0.31		0.31		0.31		0.31		0.31		0	
Hg	lb/tbtu	0		10		0.09		0.09		0.09		0.09		0.09		0.09		0.09		0	
Total Flow	lb/hr-acfm	4,317,000	1,271,000	4,674,000	2,928,000	5,101,000	2,050,000	5,101,000	2,103,000	5,101,000	1,952,000	5,248,000	1,574,000	2,449,000	734,000	2,799,000	840,000	2,208,000	672,000	473,000	500
Moist.	lb/lb	0.025		0.069		0.065		0.065		0.065		0.090		0.090		0.090		0.054		0.000	
MW	lb/lbmol	28.42		29.33		29.25		29.25		29.25		28.81		28.81		28.81		27.65		43.98	
Ash	lb/hr	0		38,606		38,606		27		27		20		9		11		8		0	
Process Stream Characteristics		Fresh Caustic	Quencher Blowdown	WWT Recovery	Prescrubber Blowdown	CO ₂ Cooling Loop	Cooling Tower Water Makeup	Cooling Tower Water Blowdown	Cooling Tower Water Evaporation	Process Water Makeup	Fresh Water to CT	Amine Make Up	Degradation Products	Steam to CO ₂ Island	Condensate Return	Additional Boiler Makeup					
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15					
Solids	lb/hr	200	0	0	200	0	0	0	0	0	213	0	0	213	0	0					
Water	lb/hr	2,200	92,100	16,800	23,300	50,298,000	1,072,500	267,800	804,800	Intermittent	963,600	0	0	617,000	610,220	6,790					
Total Flow	lb/hr	2,400	92,100	16,800	23,500	50,298,000	1,072,500	267,800	804,800	Intermittent	963,800	Intermittent	Intermittent	617,000	610,220	6,790					
Total Flow	gpm	5	200	30	50	101,000	2,200	500	1,600	Intermittent	1,900	Intermittent	Intermittent	--	--	--					
Solids	wt%	9	0	0	0	0	0	0	0	0	0	0	0	0	0	0					

APPENDIX D: GENERAL ARRANGEMENT AND PLANT
LAYOUT (90% CAPTURE – CASE 2)



CO₂ Capture Island Layout







Rocky Mountain CarbonSAFE Phase I

Appendix B

SUBSURFACE MAPPING

SUBSURFACE MAPPING

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INTRODUCTION

Depth, structure, and thickness maps of key reservoir and seal formations were prepared for the CarbonSafe study area. Geophysical logs from oil and gas wells were correlated within the Castle Valley and San Rafael Swell area to develop a database for the region; geophysical logs of significant wells were digitized. The oil and gas well tops are from the Utah Geological Survey (UGS) state-wide databases. The UGS downloaded basic well information from the Utah Division of Oil, Gas and Mining (DOG M) files and added formation top information from numerous sources such as DOGM, published papers, and tops picked by the UGS geologists. The spatial analyst interpolation tool and the natural neighbor algorithm in ARCGIS software were used to create maps from data in the well database. Both regional and site-specific areas were mapped (figure 1-2).

Key reservoirs in the study area are the Mississippian Redwall Limestone, Permian White Rim Sandstone, and Jurassic Navajo Sandstone (figure 1-4). Key seals are the Permian Kaibab Formation, Triassic Moenkpoi Formation, and Jurassic Carmel Formation (figure 1-4). The Cretaceous Ferron Sandstone Member of the Mancos Shale is an important coal-bed methane producer.

Castle Valley lies on the west flank of the San Rafael Swell with formations dipping to the west-northwest (figures 1-1 and 1-3). There are no major structural closers at depth near the Hunter Power Plant so injection must be sufficiently downdip from the outcrop to avoid the CO₂ migrating to a depth where the phase change from high-density CO₂ to CO₂ gas takes place, approximately 2500 to 3000 feet.

KEY RESERVOIRS

Mississippian Redwall Limestone

The Mississippian Redwall Limestone (also known as the Leadville Limestone) (figure 1-4) is an important oil and gas reservoir in the Paradox Basin of southeast Utah and southwest Colorado. Hydrocarbons have been produced from Lisbon, Salt Wash, Big Flat, and Cleft oil fields and Big Indian, Lightning Draw Southeast, and Little Valley gas fields in Grand and San Juan Counties, Utah (Chidsey and Eby, 2016). The Redwall has been an exploration target in Carbon and Emery Counties but there is no production from the Mississippian reservoir.

The Redwall Limestone in Utah's Colorado Plateau is a shallow-marine shelf carbonate platform deposit with the deep basin to the west, spanning the middle Kinderhookian through the middle Meramecian (Rose, 1976; Hintze and Kowallis, 2009). During Late Mississippian time the carbonate platform in Utah was subaerially exposed resulting in carbonate dissolution, solution breccias, and karstified surfaces (Fouret, 1996; Chidsey and Eby, 2016). In the northern San Rafael Swell, the Redwall is overlain by the Mississippian Humbug and Doughnut

Formations (Morgan and Wanders, 2013). In most of the San Rafael Swell and in Castle Valley near the Hunter Power Plant, the Redwall is overlain by the Pennsylvanian Elephant Canyon Formation and the two are separated by an unconformity representing up to 60 million years (Hintze and Kowallis, 2009). Some paleohighs formed before deposition of the Elephant Canyon resulting in significant erosion of the Redwall. Two areas of thinning are along the east flank of the San Rafael Swell reflecting the Emery shelf and in Castle Valley near the Hunter plant (figure 2-1).

The Redwall is exposed in Eardley Canyon where it has been eroded as part of the Emery shelf and highly dolomitized eliminating nearly all porosity. Doelling and others (2015) described an incomplete section (105 feet) of Redwall Limestone in Eardley Canyon as light-gray to pink limestone, dolomite, and chert; locally brecciated into large angular fragments. The nearest well is the T P Utah No. 27-1 well (SENE section 7, T. 23 S., R. 13 E., SLBL&M) which encountered less than 700 feet of Redwall (Morgan and Waanders, 2013). Few wells have been drilled to the Redwall between Castle Valley and Eardley Canyon, and as a result, we cannot determine if the thinning in Castle Valley represents a separate paleohigh on the Emery shelf or if the Redwall continuously thins from Eardly Canyon to Castle Valley.

Drill depths to the Redwall Limestone in the study areas range from more than 16,000 feet (figure 2-2) to exposure at the surface in Eardley Canyon (Doelling and others, 2015). The top of the Redwall is modeled to be less than 7500 feet deep at the Hunter Power Plant, about 11,000 feet deep at proposed Hunter No. 3 location, and about 12,600 feet at the proposed Drunkards Wash No. 1 location. The Redwall is about 400 feet thick at the Hunter Power Plant and 500 feet thick at Hunter No. 3 well (figure 2-1). There is not sufficient well control to accurately predict the thickness of the Redwall at Drunkards Wash No. 1 location.

The Redwall Limestone has good reservoir quality in local areas, such as Lisbon oil field in the Paradox Basin to the southeast, but regionally it is often low in porosity and permeability. Based on available well logs, the Redwall in Castle Valley is thin, lacks porosity, and is not a potential CO₂ storage reservoir. The overlying seal is the Permian Elephant Canyon Formation consisting of dolomite, dolomitic sandstone, red fine-grained sandstone, conglomerate, and limestone (Doelling and others, 2015). Thus, the Permian Elephant Canyon is a poor-quality seal.

Permian White Rim Sandstone

The Permian White Rim Sandstone crops out in small washes and major canyons along the axis of the San Rafael Swell and near the steep east flank (figures 1-2 and 1-3). It is mapped as the Coconino or Cedar Mesa Sandstone in some older publications. In major exposures, the White Rim is 500 to 950 feet thick and consists entirely of sandstone. The sandstone is composed of fine- to coarse-grained, lightly frosted, moderately to well-sorted, subangular to rounded quartz sand cemented with calcite and/or silica (Witkind, 1988; Doelling, 2002; Doelling and Kuehne, 2008). The White Rim is friable to well cemented, and contains intergranular porosity locally filled with dead oil in some units (Doelling and Kuehne, 2008; Harston and others, 2013). In outcrop it forms thick to massive beds containing well-displayed high-angle cross-stratification and some planar bedding. Locally, limonitic or hematitic zones are present as well as irregular red and brown stained patches within sections bleached by possible hydrocarbon migration.

The White Rim Sandstone was deposited mainly in an eolian shoreline environment

during Early Permian (Leonardian). The top of the formation is marine (Huntoon and Chan, 1987; Stanesco and others, 2000; Blakey and Ranney, 2008). The White Rim consists of a lower sand-sheet deposit overlain by a thick interval of eolian dune deposits. Sea level rise resulted in the upper part of the White Rim being eroded and reworked. However, some researchers interpreted all or major portions of the White Rim to be marine (Baars and Seager, 1970; Orgill, 1971; Baars, 2010).

Drill depths to the top of the White Rim Sandstone are 10,200 feet at Hunter No. 3 location and 10,100 at Drunkards Wash No. 1 location. A well drilled at the Hunter Power Plant, as originally hoped, would encounter the White Rim at 6700 feet (figure 2-3). The White Rim is projected to be 350 feet thick at Hunter No. 3 location, 500 feet thick at the Hunter Power Plant, and up to 700 feet thick at Drunkards Wash No. 1 location (figure 2-4). Note that figure 2-4 shows what the thickness of the White Rim was across the San Rafael Swell where it has since been removed by uplift and erosion.

Lower Jurassic Navajo Sandstone

The Lower Jurassic Navajo Sandstone and equivalent formations were deposited throughout most of Utah and neighboring states of Wyoming, Colorado, New Mexico, Arizona and Nevada. The Navajo with its spectacular cross-stratification is perhaps the most well-known formation in Utah, where it forms the magnificent cliffs and canyons in Zion and other parks in the southern part of the state. Navajo outcrops in the San Rafael Swell are just as outstanding, where they are displayed as rounded cliffs, alcoves, domes, and knobs exposed along the flanks of the San Rafael Swell and often used to define the geographic boundary of the Swell (figure 1-2). The Navajo also serves as an excellent outcrop analog for hydrocarbon reservoirs and has been used in past CO₂ sequestration models (Allis and others, 2002, 2003; White and others, 2001, 2003).

The Navajo Sandstone ranges in thickness from 400 to 1000 feet in outcrops in the San Rafael Swell. To the east of the San Rafael Swell, the Navajo Sandstone pinches out at the erg margin (Blakey, 1994; Parrish and Falcon-Lang, 2007). To the west near Zion National Park, the Navajo erg thickens where there was the greatest accommodation during deposition into a foreland-arc basin (Gregory, 1950; Peterson and Pippingos, 1979; Blakey, 2008). The Navajo near Zion consists of sandstone that has likely been bleached by iron-reducing hydrocarbons, weak acids, or hydrogen sulfide (Witkind, 1988; Chan and others, 2000; Chan and Parry, 2002; Doelling, 2002); it also contains subordinate carbonates. The sandstone beds are friable and composed of clean, fine- to medium-grained, frosted, subrounded to subangular, moderately to well-sorted quartz sand with minor amounts of feldspar and scattered heavy mineral grains. Cementation is calcareous or siliceous with minor iron oxides. Sedimentary structures include sets of large, high-angle trough cross-stratification as well as planar or wedge-planar cross-stratification; bedding is thick to massive. Contorted bedding and soft-sediment deformation, wind ripples, and small-scale trough cross-stratification are additionally abundant. Dune facies from the crest (brink point) to the toe of the dune slipface consist of (1) thin, graded, tabular grainfall laminae (rarely preserved), (2) thick, subgraded avalanche laminae, and (3) thin, tightly packed, reworked ripple strata at the dune toe. Massive, homogenous beds having no distinct sedimentary structures or laminations are also recognized in the Navajo and were probably formed by water-saturated sand. Laminated, thin-bedded carbonate units consist of sandy microbial (algal) boundstone and wackestone composed of limestone or dolomitic limestone.

In Early Jurassic time, Utah had an arid climate and lay 15° north of the equator (Hintze and Kowallis, 2009). The Navajo Sandstone and age-equivalent rocks were deposited in an extensive erg, which extended from present-day Wyoming to Arizona, and was comparable to the Sahara in North Africa or the Alashan area of the Gobi Desert in northern China. The eolian deposits included dunes, interdunes, and sand sheets. Paleowind direction was dominantly from the north and northwest (Peterson, 1988). In addition, the Navajo erg system included interdune playas and oases.

Dune facies are laterally and vertically extensive in the Colorado Plateau and San Rafael Swell region and have excellent reservoir properties. The Navajo Sandstone outcrop can be divided into informal upper and lower members, which are dominantly highly porous dune facies with few interdunal deposits, and a middle member which is dominantly lower porosity interdunal facies with interbedded dune facies. This division was carried into the subsurface using gamma-ray and porosity logs to define the members, porosity intervals, and lateral distribution as displayed well-log cross section through the study sites (figure 2-5). Evaluation of the Navajo Sandstone with the Carmel Formation as an overlying seal determined that the Navajo was a high-quality potential storage reservoir. Navajo properties were mapped regionally and then more detailed reservoir mapping was conducted in the two areas of interest: primary Hunter site and secondary Drunkards Wash site (figure 1-2). A major concern with the Navajo was the close proximity of the outcrop to the Hunter plant. As a result, an injection location west and down dip from the Hunter plant was selected.

Drill depths to the Navajo Sandstone in the study areas range from 1500 to 13,000 feet within the Hunter site and 3500 to 10,000 feet within the Drunkards Wash site, deepening to the northwest and west, respectively, and shallowing rapidly to southeast towards the surface exposure (figure 2-6). Drill depths to the top of the Navajo are projected to be 7600 feet at Hunter 3 and 7200 feet at Drunkards Wash No. 1. Regional subsurface structural mapping of the Navajo, based on limited well control, shows relatively gentle dip in a northwest direction (figure 2-7). No faults are indicated in either the Hunter or Drunkards Wash project CO₂ injection sites (figure 2-7); there are some Quaternary normal faults in the westernmost part of the Hunter site but they may not be present at depth in the Navajo. Note that figure 2-7 shows what the structural elevation would be of the Navajo across the San Rafael Swell where it has been removed by uplift and erosion.

Well-log correlations show the Navajo Sandstone is thick and highly porous throughout the Castle Valley area (figure 2-5). Regionally, the gross thickness Navajo Sandstone thins from southwest to northeast through the Castle Valley area and is about 400 to 450 feet thick at Hunter No. 3 and 300 feet thick at Drunkards Wash No. 1 locations (figure 2-8). As a result, net reservoir thickness thins from the Hunter No. 3 location to the Drunkards Wash No. 1 location. Some thickening of the net reservoir is mapped from west-northwest to east-southeast (updip direction) showing some diagenetic effect related to the shallowing depths. Note that figure 2-8 shows what the thickness of the Navajo was across the San Rafael Swell where it has since been removed by uplift and erosion.

The UGS has only one well core of the Navajo Sandstone in central Utah: the Wolverine Gas & Oil Corp. Federal No. 17-3 well (sec. 17, T. 23 S., R. 1 W., SLBL&M, Sevier County) from Covenant oil field about 45 miles southwest of the Hunter site. Based on porosity and permeability data from the 17-3 core, we are confident that 12% or more porosity will have sufficient permeability to be a quality reservoir. Good quality reservoir may exist at 10% or even as low as 8% porosity, but the core does not have sufficient data at lower porosities to make a

reliable determination. Therefore, 12% or more porosity was used as the lower limit to be a good quality reservoir.

Density porosity from upper, middle, and lower members of the Navajo Sandstone was sorted and feet of porosity were tabulated. We assumed that the higher porosity beds are dunes and the lower porosity beds are interdune. The feet of porosity data were mapped at 12% or more porosity, 16% or more porosity and 20% or more porosity for the gross Navajo Sandstone and for each of the three members in the Navajo, to show the distribution of net reservoir in the two sites. The Hunter 3 location has 300 to 400 feet net reservoir at 12% or more porosity whereas the Drunkards Wash site has 150 to 200 feet of net reservoir (figure 2-9A). The Hunter site has 200 to 300 feet of reservoir with 16% or more porosity; the Drunkards Wash site has 80 to 120 feet (figure 2-9B). At 20% or more porosity the Hunter site has 100 to 150 feet and the Drunkards Wash site has 20 to 50 feet (figure 2-9C). Feet of porosity at 12% or more, 16% or more, and 20% or more for each of the three members (upper, middle, and lower) has the same distribution pattern as the net reservoir for the total Navajo (figures 2-10 through 2-12). The upper Navajo is better developed at the Hunter site than the Drunkards Wash site whereas the lower Navajo is about equally developed at both locations. The middle member is defined by low porosity and therefore is mostly a poor reservoir at both locations.

Upper Cretaceous Ferron Sandstone, Mancos Shale

The Upper Cretaceous (Turonian to Coniacian) Ferron Sandstone Member of the Mancos Shale was deposited in a wave-influenced, fluvial-deltaic environment. It reflects a balance between changing sediment supply from the advancing Sevier orogenic belt in western Utah and changes in accommodation space resulting from transgressions and regressions of the Cretaceous Interior Seaway in eastern Utah. The Ferron is one of the most studied units in the San Rafael Swell (described in Chidsey and others, 2004). Along the west flank of the Swell, the 80-mile-long Ferron outcrop belt of cliffs and side canyons provides a three-dimensional view of vertical and lateral changes in the Ferron's facies and sequence stratigraphy, and, as such, is an excellent analog for fluvial-deltaic oil and gas reservoirs worldwide. In addition, the Ferron produces methane gas from its coal and sandstone beds within the northern Castle Valley and Wasatch Plateau, respectively. The Ferron is exposed along the east side of Castle Valley just east of the Hunter Power Plant (figure 1-2).

The Ferron Sandstone ranges in thickness from 325 to 720 feet on the west flank, 160 feet on the north-plunging nose, and as thin as 60 feet of the east flank of the San Rafael Swell (Witkind, 1988; Weiss and others, 1990; Doelling, 2002, 2004; Hintze and Kowallis, 2009). In the west flank outcrop belt, the Ferron consists of sandstone and siltstone, sandy to black carbonaceous shale, and coal. Sandstone is very fine to medium grained, poor to moderately sorted, subrounded to angular, and cemented with calcite, dolomite, or iron oxide. Bedding in the sandstone is thin or lenticular to massive, forming vertical cliffs, whereas siltstone, shale, and coal create recesses and slopes. Sedimentary structures in sandstone that determine facies include ripples, channel scours, soft-sediment deformation, cross-stratification, and planar beds. Many beds contain rooted zones, a variety of burrows, or intense bioturbation.

Major cliff-forming sandstone units in the Ferron Sandstone are referred to as delta-front units or parasequence sets based on genetically related parasequences within each set, bounded by major flooding surfaces, and paired to coal zones. The Ferron parasequence sets create seaward-stepping, vertically stacked, and landward-stepping stacking patterns (Anderson and

Ryer, 2004). The alluvial to lower delta or coastal plain of the Ferron contained meander belts, swamps and peat bogs, distributary channels, levees, crevasse spays/overbanks, and bays. Sediment supply was high during early Ferron time resulting in fluvial-dominated conditions that created lobate deltas consisting of delta-front deposits, distributary channel, splay complexes, and interdistributary bays. Later, conditions changed to wave-dominated or wave-modified deltaic deposition forming cusped deltas that grade laterally into strandplains and barrier islands. Facies associated with wave-dominated or wave-modified deltas consist of prodelta deposits; lower, middle, and upper shoreface; foreshore; distributary channels; and distributary-mouth bars. The strandplains and barrier island facies include washover fans, lagoons, bays, and tidal inlets and associated flood-tidal deltas (Ryer and Anderson, 2004).

Drill depth to the top of the Ferron Sandstone is 300 feet at the Hunter Power Plant, 3200 feet at the Buzzard Bench No. 1 (Danish Flat) location and 3000 feet at the Drunkards Wash No. 1 location (figure 2-13). Structural mapping of the Ferron shows relatively the typical gentle dip in a northwest direction (figure 2-14). No faults are indicated in either the Hunter or Drunkards Wash project CO₂ injection sites. Note that figure 2-14 shows what the structural elevation would be of the Ferron across the San Rafael Swell where it has been removed by uplift and erosion. Total structural elevation of the Ferron is about +3500 feet at the Hunter Power Plant and +3600 feet thick at Buzzard Bench No. 1.

Total thickness of the Ferron is 350 feet at the Hunter Power Plant and 250 feet thick at Buzzard Bench No. 1 (figure 2-15). Thickness at the Drunkards Wash 1 site will be about 300 feet. Note that figure 2-15 shows what the thickness of the Ferron was across the San Rafael Swell where it has since been removed by uplift and erosion. As shown, it thins because the Ferron delta did not extend very far east into the Cretaceous Interior Seaway in central Utah.

The thickness from the top of the Ferron Sandstone to the top of the Navajo Sandstone is shown on figure 2-16. This interval is slightly less than 4000 feet at the Hunter Plant, about 4100 feet at the Buzzard Bench No. 1, and 4400 feet at the Drunkards Wash No. 1 locations (figure 2-16). Again, note that figure 2-16 shows what the thickness of this interval was across the San Rafael Swell where it has been removed by uplift and erosion.

KEY SEALS

Permian Kaibab Formation

The Permian Kaibab Formation overlies the White Rim Sandstone. The Kaibab is exposed over a fairly widespread area along the crest of the San Rafael Swell (figure 1-2) where it ranges in thickness from 0 to 85 feet. It consists of dolomite and limestone with some thin sandstone (Doelling and others, 2015). Carbonates range from thin to thick bedded forming step-like cliffs with a blocky weathering character. The Kaibab was deposited on a shallow carbonate shelf as part the great worldwide Permian epicontinental marine transgression (Blakey and Ranney, 2008; Hintze and Kowallis, 2009).

The Kaibab Formation generally has very low porosity and permeability and would be a baffle or seal for the CO₂ injected into the White Rim Sandstone. However, there are a few intervals of vugular porosity with low permeability in the carbonates and in the sandstones that could reserve/hold small amounts of CO₂. As a result, the Kaibab would be both a seal and a good monitoring bed by tracking upward movement of CO₂ into the porous intervals.

Drill depth to the top of the Kaibab Formation is 6500 feet at the Hunter Power Plant, 10,000 feet at Hunter No. 3, and 9900 at Drunkards Wash No. 1 (figure 2-17). The Kaibab reaches a thickness of as much as 260 feet in the subsurface near the west flank of the Swell (Hintze and Kowallis, 2009). Our thickness mapping shows the Kaibab to be about 140 feet thick at the Hunter No. 3 and Drunkards Wash No. 1 locations (figure 2-18), but this is questionable due to the lack of down dip control wells. Again, note that figure 2-18 shows what the thickness of Kaibab was across a relatively small part of the San Rafael Swell where it has since been removed by uplift and erosion. Subtracting the mapped top of the White Rim Sandstone from the top of the Kaibab Formation results in an interval thickness of 200 feet at both locations.

Triassic Moenkopi Formation

The Triassic Moenkopi Formation overlies the Kaibab Formation and provides an additional seal to the White Rim Sandstone. The Moenkopi is widely exposed along the flanks of the San Rafael Swell structure and is divided into four members, which in ascending order are: Black Dragon, Sinbad Limestone, Torrey, and Moody Canyon. Whereas the classic outcrops of the Moenkopi in southern Utah and northern Arizona are chocolate brown, those in the Swell have been bleached to various shades of yellow, possibly by migrating hydrocarbons and iron-reducing groundwater. The Moenkopi Formation contains numerous tar-sand deposits in the channel sandstones. In general, the Moenkopi consists of interbedded sandstone, siltstone, and shale in the upper and lower members and a carbonate in the middle Sinbad Limestone Member. The Sinbad represents a mixed carbonate-siliciclastic cyclic sequence consisting of limestone, dolomitic limestone, and calcareous sandstone with a few shaly siltstone beds.

The Moenkopi Formation was deposited in various shallow-marine and tidal-flat environments. The Sinbad Limestone was deposited in a marine environment, the farthest extent east of a shallow sea that transgressed from the northwest (Blakey and Ranney, 2008; Doelling and others, 2010). Facies include peritidal, offshore, foreshore/shoal, restricted lagoon/backshoal, and tidal channel (Goodspeed and Lucas, 2007).

The Sinbad Limestone has porosity and yielded high flow rates of CO₂ during testing in many of the wells throughout the study area. It represents a good potential monitoring bed, if upward migration of injected CO₂ occurs. The gas saturation within the Sinbad should be easily detected. However, the Sinbad would need to become fully gas charged before significant vertical migration would continue.

Drill depth to the Moenkopi Formation is about 9000 feet at Hunter No. 3 and 8500 feet at Drunkards Wash No. 1 locations (figure 2-19). The formation thins from west to east and is about 1000 feet thick at Hunter No. 3 and 1400 feet thick at Drunkards Wash No. 1 locations (figure 2-20). The Sinbad Limestone Member ranges in thickness from 0 to 150 feet, thickening north, and represents a mixed carbonate-siliciclastic cyclic sequence. The Sinbad is about 150 feet thick at the Hunter No. 3 and Drunkards Wash No. 1 locations (figure 2-21). Again, note that figures 2-20 and 2-21 show what the thicknesses of Moenkopi and Sinbad, respectively, were across a relatively small part of the San Rafael Swell where they have since been removed by uplift and erosion.

Middle Jurassic Carmel Formation

The Middle Jurassic (Bajocian through Callovian in age) Carmel Formation overlies the Navajo Sandstone in most areas of the San Rafael Swell. The Carmel is divided into four members (described in Chapter 4), which in ascending order are the: Co-op Creek Limestone (or equivalent Judd Hollow), Crystal Creek, Paria River, and Winsor. The Carmel ranges from 280 to as much as 1100 feet thick in the San Rafael Swell (Witkind, 1988; Doelling, 2002, 2004; Doelling and Kuehne, 2008). In general, the Carmel consists of interbedded limestone, sandstone, siltstone, mudstone, and most important in terms of its sealing quality—thick beds of gypsum. Sedimentary structures include ripples, low-angle cross-bedding, bioturbation, and mudcracks. The Carmel ranges from thin to thick to massive bedded forming steep slopes and blocky ledges. The various facies of the Carmel depict a range of depositional environments: nearshore intertidal marine, oolitic shoal, restricted shallow marine, tidal flat, and sabkha.

The Carmel Formation serves as the seal for the naturally occurring CO₂ deposit in the Navajo reservoir at Farnham Dome on a subsidiary structure on the north-plunging nose of the Swell (Morgan, 2007). Based on subsurface mapping, the Carmel should provide an excellent seal in the Hunter and Drunkard Wash sites as well.

Drill depth to the Carmel Formation is about 6500 feet at both Hunter No. 3 and Drunkards Wash No. 1 (figure 2-22). The Carmel Formation thickens west towards the Wasatch Plateau forming 1000-foot-thick pods in the Hunter Power Plant and Buzzards Bench No. 1 areas (figure 2-23). Some local thickening is caused by duplex faulting associated with the basal detachment in the region. The Carmel is projected to be 900 feet thick at Hunter No. 3 and 600 feet at Drunkards Wash No. 1 (figure 2-23). As with the other isochore maps, figure 2-23 shows what the thicknesses of Carmel was across the San Rafael Swell where it has been removed by uplift and erosion. The primary seal in the Carmel are the numerous anhydrite beds (figure 2-24). More than 80 feet of total anhydrite has been mapped in the Hunter area (figure 2-25).

CHAPTER 2 FIGURE CAPTIONS

Figure 2-1. Isochore map of the Redwall Limestone. Contour interval 50 feet.

Figure 2-2. Drill-depth map to the top of the Redwall Limestone. Contour interval 500 feet.

Figure 2-3. Drill-depth map to the top of the White Rim Sandstone. Contour interval 500 feet.

Figure 2-4. Isochore map of the White Rim Sandstone. Contour interval 50 feet. Note: the map shows what the thickness would be of the White Rim across the San Rafael Swell where it has been removed by uplift and erosion.

Figure 2-5. South to north gamma-ray and density-porosity log cross section through the Hunter and Drunkards Wash sites showing the upper, middle, and lower Navajo Sandstone.

Figure 2-6. Drill-depth map to the top of the Navajo Sandstone. Contour interval 500 feet.

Figure 2-7. Top of the Navajo Sandstone structure map. Contour interval 500 feet. Note: the map shows what the structural elevation would be of the Navajo across the San Rafael Swell where it has been removed by uplift and erosion.

Figure 2-8. Isochore map of the Navajo Sandstone. Contour interval 100 feet. Note: the map shows what the thickness of the Navajo was across the San Rafael Swell where it has been removed by uplift and erosion.

Figure 2-9. Feet of Navajo Sandstone with (A) 12% or more, (B) 16% or more, and (C) 20% or more density porosity; contour interval 50 feet.

Figure 2-10. Feet of upper Navajo Sandstone with (A) 12% or more, (B) 16% or more, and (C) 20% or more density porosity; contour interval 20 feet.

Figure 2-11. Feet of middle Navajo Sandstone with (A) 12% or more, (B) 16% or more, and (C) 20% or more density porosity; contour interval 20 feet.

Figure 2-12. Feet of lower Navajo Sandstone with (A) 12% or more, (B) 16% or more, and (C) 20% or more density porosity; contour interval 20 feet.

Figure 2-13. Drill-depth map to the top of the Ferron Sandstone. Contour interval 500 feet.

Figure 2-14. Top of the Ferron Sandstone structure map. Contour interval 500 feet. Note: the map shows what the structural elevation would be of the Ferron across the San Rafael Swell where it has been removed by uplift and erosion.

Figure 2-15. Isochore map of the Ferron Sandstone. Contour interval 50 feet. Note: the map shows what the thickness of the Ferron was across the San Rafael Swell where it has been removed by uplift and erosion.

Figure 2-16. Isochore map of the interval thickness between the base of the Ferron Sandstone to the top of the Navajo Sandstone. Contour interval 500 feet. Note: the map shows what the thickness of this interval was across the San Rafael Swell where it has been removed by uplift and erosion.

Figure 2-17. Drill-depth map to the top of the Kaibab Formation. Contour interval 500 feet.

Figure 2-18. Isochore map of the Kaibab Formation. Contour interval 20 feet. Note: the map shows what the thickness would be of the Kaibab across the San Rafael Swell where it has been removed by uplift and erosion.

Figure 2-19. Drill-depth map to the top of the Moenkopi Formation. Contour interval 1000 feet.

Figure 2-20. Isochore map of the Moenkopi Formation. Contour interval 100 feet. Note: the map shows what the thickness would be of the Moenkopi across the San Rafael Swell where it has been removed by uplift and erosion.

Figure 2-21. Isochore map of the Sinbad Limestone Member of the Moenkopi Formation. Contour interval 20 feet. Note: the map shows what the thickness would be of the Sinbad across the San Rafael Swell where it has been removed by uplift and erosion.

Figure 2-22. Drill-depth map to the top of the Carmel Formation. Contour interval 500 feet.

Figure 2-23. Isochore map of the Carmel Formation. Contour interval 100 feet. Note: the map shows what the thickness would be of the Carmel across the San Rafael Swell where it has been removed by uplift and erosion.

Figure 2-24. Gamma-ray and density-porosity log cross section of the Carmel Formation at the Hunter site. The Carmel has numerous anhydrite beds (shown in red) that are laterally extensive. Anhydrite 3 (informal operator designation) is the thickest anhydrite bed.

Figure 2-25. Isochore map of the anhydrite in the Carmel Formation. Contour interval 20 feet. Note: the map shows what the thickness would be of the anhydrite across the San Rafael Swell where it has been removed by uplift and erosion.



Rocky Mountain CarbonSAFE Phase I

Appendix C

Extensional Faulting in the Jurassic Navajo Sandstone at Little Wedge on the Western Flank of the San Rafael Swell and its Potential Impact on CARBON DIOXIDE Storage Reservoirs, Emery and Carbon Counties, Utah

EXTENSIONAL FAULTING IN THE JURASSIC NAVAJO SANDSTONE AT LITTLE WEDGE ON THE WESTERN FLANK OF THE SAN RAFAEL SWELL AND ITS POTENTIAL IMPACT ON CARBON DIOXIDE STORAGE RESERVOIRS, EMERY AND CARBON COUNTIES, UTAH

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Utah Geological Survey*

INTRODUCTION

The Navajo Sandstone outcrop in the Little Wedge area, which is updip and nearest the Hunter Power Plant, has a system of normal faults and thus was the focus of this part of the project (figure 3-1). The Little Wedge study area is about 12 miles southeast of the Hunter Power Plant in sections 5, 8, and 17, T. 20 S., R. 10 E., SLBL&M, Emery County, Utah (figure 1-2). The San Rafael River cuts through the Navajo Sandstone at Little Wedge, exposing the sandstone east and west of the river (figure 3-1).

The Normal faults at Little Wedge trend about north-south with displacements of a few feet to tens of feet in the Navajo Sandstone. Displacement is generally down to the west; slickensides indicate near vertical movement. Fault planes are polished and crushed sandstone grains with associated deformation bands. Solum and others (2010) describe deformation bands as a zone of localized grain rearrangement (packing geometry, rotation, and sliding) and cataclasis (breaking, spalling, and crushing). Minor amounts of azurite and malachite are present along the faults. There is no evidence of springs associated with the fault system.

The fault plane and associated zones of deformation bands would most likely impede but not fully stop the migration of injected CO₂ in the Navajo Sandstone reservoir. Due to the limited length of individual faults and the fault system, some migration could occur around and in between individual faults with the majority of the CO₂ migrating around the fault system.

FAULTING IN THE SAN RAFAEL SWELL

Our efforts in the Little Wedge area focused on identifying faults, measuring strike and dip with a Brunton compass, and walking along a fault trace whenever possible. Faults were plotted on the U.S. Geological Survey Sids Mountain, Utah, 7.5-minute topographic map and on a Google™ map image and were later plotted in ArcMap. We noted direction of fault movement based on slickensides and mineralization at a few locations. Total stratigraphic displacement was estimated for most of the faults.

Surface faulting in the San Rafael Swell has been mapped by Kent (1956), Witkind (1988), Weiss and others (1990), and Doelling (2002, 2004) (figure 1-2). Three sets of normal faults are mapped: (1) northwest-southeast Paradox Basin and Uncompahgre uplift trend, (2)

east-west trend generally parallel to the doubly plunging San Rafael Swell axis, and (3) north-south Basin and Range extensional trend. Faulting at Big Hole was studied by Shipton and others (2002). Iron Wash fault was studied by Richey and Evans (2013). North-south-trending faults at Little Wedge, southeast of the Hunter Power Plant, are the focus of this study.

The northwest-southeast striking faults are found mostly on the east flank of the San Rafael Swell and reflect the structural trend of the Paradox Basin and Uncompahgre uplift. The Iron Wash fault zone is one of the longest northwest-southeast fault zones in the area and is described in detail by Richey and Evans (2013). The east-west striking faults are generally along the north- and south-plunging axis of the San Rafael Swell. The Big Hole fault zone is an example of east-west striking faults and is described in detail by Shipton and others (2002). The north-south striking faults are the most common type along the west flank of the San Rafael Swell and the most likely to be encountered in the subsurface in the Castle Valley area. These faults represent Miocene Basin and Range extension.

FAULTING AT LITTLE WEDGE

The series of north-south normal faults at Little Wedge were mapped by Kent (1956) and later by Witkind (1988). The faults at Little Wedge trend north-south with strikes measured from N. 12° W. to N. 15° E. They dip west from 60° to near vertical; most of the dips measured are in the 75° to 80° range. Slickensides are near vertical with no indication of lateral shear motion. Fault planes consist of polished crushed grains with associated deformation bands.

Typically, a high density of deformation bands occurs near the fault and rapidly decreases in density away from the fault (figures 3-2 and 3-3). Most of the deformation bands are on the upthrown (footwall) side of the fault. The fault system consists of a series of faults with displacement translated from one fault to the next (figure 3-1). Some minor antithetic faults are present (figures 3-4 and 3-5). Displacement ranges from a few feet to an estimated 30 feet (figure 3-6). At Big Hole the deformation bands are limited to the damage zone—the narrow area parallel to the fault and formed under significantly less mean effective stress than in a compressional case (Solum and others, 2010).

Evidence of past or present fluid flow along the faults is rare. Past fluid flow is indicated by iron concretions in a few locations (figure 3-3) and rare deposits of copper minerals. The Sorrel Mule mine (figure 3-7) along the west side of the San Rafael River was discovered by Jack Montis (McClenahan, 1986; referenced in Lipton, 1989). The mine is a single adit 1060 feet in length in the Navajo Sandstone along a fault (Lipton, 1989). Lipton (1989) reports the fault strikes N. 60° E. with vertical to 70° northwest dip but we mapped it as a prominent lineament, not a fault, having no displacement. However, we did find a north-south striking fault associated with the mine (figure 3-1). Lipton (1989) observed iron- and manganese-oxide staining but did not find any copper mineralization. The mine is accessible by canoe or raft along a popular stretch of the San Rafael River and may have been picked clean of any mineral samples. We did not visit the mine but found a vertical shaft, about 6 feet deep, along the same fault but near the top of the Navajo about 200 feet above the river (figure 3-8). We collected small samples containing malachite and azurite from the shaft (figure 3-9). There are no mining adits or shafts along the faults on the east side of the river at Little Wedge, but one sample containing traces of malachite and azurite was collected along one fault.

No evidence of springs were found associated with the faults the Little Wedge area, although we did not visit the fault locations along the river. No springs issue from the Navajo Sandstone at Little Wedge, based on the work by Hood and Patterson (1984) and Doelling (2002), and the Sids Mountain 7.5-minute topographic map. The lack of springs associated with the faults in the Little Wedge area indicates no upward movement of water along the fault system.

Using a tiny permeameter, team members from the University of Utah measured the relative permeability of the fault and the host rock. Hand samples of the fault and the host rock collected from the Little Wedge area were brought back to the Utah Core Research Center (figure 3-10). The samples analyzed indicated a one order of magnitude reduction in permeability between the fault plane and host rock, but these measurements may underestimate the reduction in permeability. The analysis was conducted on a small hand sample and the host rock may have been sufficiently altered, reducing its permeability. Antonellini and Aydin (1994) found that host rock near deformation bands may have greater cementation due to precipitation resulting from the interaction between fluids contained in the host rock and those contained in the band(s). Shipton (1999) and Shipton and others (2002) studied faulting in the Navajo Sandstone in the Big Hole area near the axis of the San Rafael Swell east of the Little Wedge (figure 1-2). Shipton and others (2002) studied numerous cores drilled through the Big Hole fault that strikes N. 70° E. and dips 64° north and contains numerous associated deformation bands. A probe permeameter showed permeability declining from >2000 to < 0.1 millidarcies (mD); whole core analysis showed >1 mD. Solum and others (2010) reported shear bands in the Big Hole area with a permeability reduction of three to five times that of the underformed Navajo host rock. Zuluaga and others (2016) reported a permeability reduction of two to three orders of magnitude in deformation bands compared to Navajo host rock in the San Rafael Swell. Pitman (1981) and Antonellini and Aydin (1994), working near Moab, Utah, reported that deformation bands reduce the permeability of host rock by about three orders of magnitude on average. However, the slip plane can have more than seven orders of magnitude reduction in permeability compared to unaltered host rock (Antonellini and Aydin, 1994). Flow simulations by Zuluaga and others (2016) show the fault zone does not completely block the flow. Deformation bands with permeability one to two orders of magnitude lower than the host rock had negligible effect on simulated fluid flow (Zuluaga and others, 2016). Assuming a host rock permeability of 100 mD, a three orders of magnitude reduction would result in a fault and associated deformation bands having 0.1 mD. This would greatly impede but not completely stop the migration of CO₂. A CO₂ plume encountering a fault system in the Navajo would be mostly diverted around the fault zone, with some CO₂ migrating around individual faults, and a very small amount would migrate through the fault (figure 3-11).

The Carmel Formation typically forms an eroded dip slope on the Navajo Sandstone in the San Rafael Swell. As a result, outcrops with faults in the Navajo have only a thin veneer of overlying Carmel. We were unable to determine from outcrop if the faults in the Navajo penetrate the entire Carmel or if they die out within the formation. The Carmel in Castle Valley has salt, anhydrite, and numerous shale and siltstone beds, all of which have the potential for plastic deformation instead of brittle fault displacement. Shallow faults above the Carmel may become listric within the Carmel resulting in a deep and shallow set of extensional faults that are not connected (figure 3-12). This plastic deformation would provide an excellent seal preventing upward movement of CO₂ along a fault plane. If the fault continues through the Carmel, the

numerous salt and anhydrite beds should still provide an adequate seal preventing upward migration of CO₂.

SUMMARY

The most likely type of faults that will be encountered in Castle Valley near the Hunter and Huntington Power Plants are Basin and Range extensional, normal faults having down-to-the-west displacement. Displacement on most of the faults will likely be on the order of feet to tens of feet. The Little Wedge area is the nearest Navajo Sandstone outcrop updip from the Hunter plant and has several extensional faults that are good analogs to the faulting expected in Castle Valley. The fault system at Little Wedge is a series of north-south faults that translate displacement from one fault to the next. The fault system is less than 2 miles in length and is composed of much shorter individual faults. The fault planes are polished, crushed sandstone grains with a zone of near-parallel deformation bands. The fault planes and damage zones typically have a permeability reduction compared to undamaged host rock of three to four orders of magnitude. As a result, migration of CO₂ up the fault plane is not expected. The faults should impede, but not be a complete barrier to, up-dip migration of CO₂ in the Navajo reservoir. Some CO₂ is expected to migrate around and through the individual faults while the majority of the CO₂ will probably migrate around the fault system.

CHAPTER 3 FIGURE CAPTIONS

Figure 3-1. Faulting at Little Wedge in the Navajo Sandstone and Carmel Formation. The Navajo Sandstone is cut by the San Rafael River at this location. Carmel/Navajo contact drawn using ESRI World Imagery (satellite imagery compiled from numerous sources). Fault displacements are a few feet to a few tens of feet.

Figure 3-2. Examples of fault planes in the Navajo Sandstone at Little Wedge. Fault planes consist of polished crushed grains. Slickensides indicate near-vertical movement.

Figure 3-3. Deformation bands and iron-sandstone concretions associated with faults in the Little Wedge area. The density of the deformation bands and concretions decreases with distance from the fault. Deformation bands are associated with all the faults, but concretions were found at only a few locations.

Figure 3-4. A series of faults in the Navajo Sandstone and overlying Carmel Formation at Little Wedge. (A) Northernmost exposure of faulting in the Navajo, view north. (B) Westernmost fault (left) has reverse motion and is interpreted to be antithetic to the eastern main fault (right). View is to the north; all three faults join up to become a single fault to the south (figure 3-1). U = upthrown and D = downthrown side of the faults.

Figure 3-5. View of the side of a small canyon (looking northwest) showing minor reverse fault with a few feet of displacement in the Navajo Sandstone and overlying Carmel Formation. Fault may be antithetic to the larger normal fault to the east (right) not shown.

Figure 3-6. View east across the fault on the west side of the San Rafael River, same location as the mine shaft (figures 3-1 and 3-8). Displacement at this location is about 30 feet down to the west.

Figure 3-7. View south from the east side of the San Rafael River looking at the Sorrel Mule mine. The abandoned mine is a 1060-foot adit reported to have found minor amounts of copper. A 6-foot-deep shaft on top of the Navajo Sandstone along the same fault shows some minor copper mineralization. The fault on the east side of the river (foreground) does not appear to be directly connected to the faults on the west side of the river. U = upthrown and D = downthrown side of the faults.

Figure 3-8. View to the north on the west side of the San Rafael River. The shaft is dug along the fault contact between the Navajo Sandstone and Carmel Formation. This is the same fault that is in the Sorrel Mule mine along the San Rafael River (see figures 3-1 and 3-7).

Figure 3-9. Samples of malachite and azurite collected from the shaft along the fault on the west side of the San Rafael River (see figure 3-8).

Figure 3-10. Sample collected from the fault at Little Wedge on the east side of the San Rafael River. Sample contains slickensides and deformation bands in the Navajo Sandstone. The deformation bands and host rock are from the footwall of the fault.

Figure 3-11. A conceptual model showing the up-dip migration of CO₂ around and through faults that might be encountered in the Navajo Sandstone in Castle Valley. Fault pattern based on faults mapped at Little Wedge. Arrow thickness represents an estimated percent of the total CO₂. Most of the CO₂ will migrate around the fault system which typically has a limited length, some CO₂ will migrate around the individual faults, and a very small amount will migrate through the faults.

Figure 3-12. Examples of possible extensional (normal) faulting in the Castle Valley area. (A) Normal fault probably originating in the basement, with displacement in the Navajo Sandstone extending upward through shallow formations. (B) Normal fault in Navajo and deeper formations dies out upward and transitions to ductile folding within the evaporite facies of the Carmel Formation. Shallow extension dies out downward in the evaporite facies. The shallow and deep faults are related but not directly connected. (C) Similar to B but extension in the shallow formations is accommodated by a normal fault unrelated to the deeper normal fault. Also shown is duplex faulting of the basal detachment within the Carmel (not discussed in this report) resulting in shallow structures such as the Huntington anticline. These shallow structures are not associated with faulting in the Navajo.

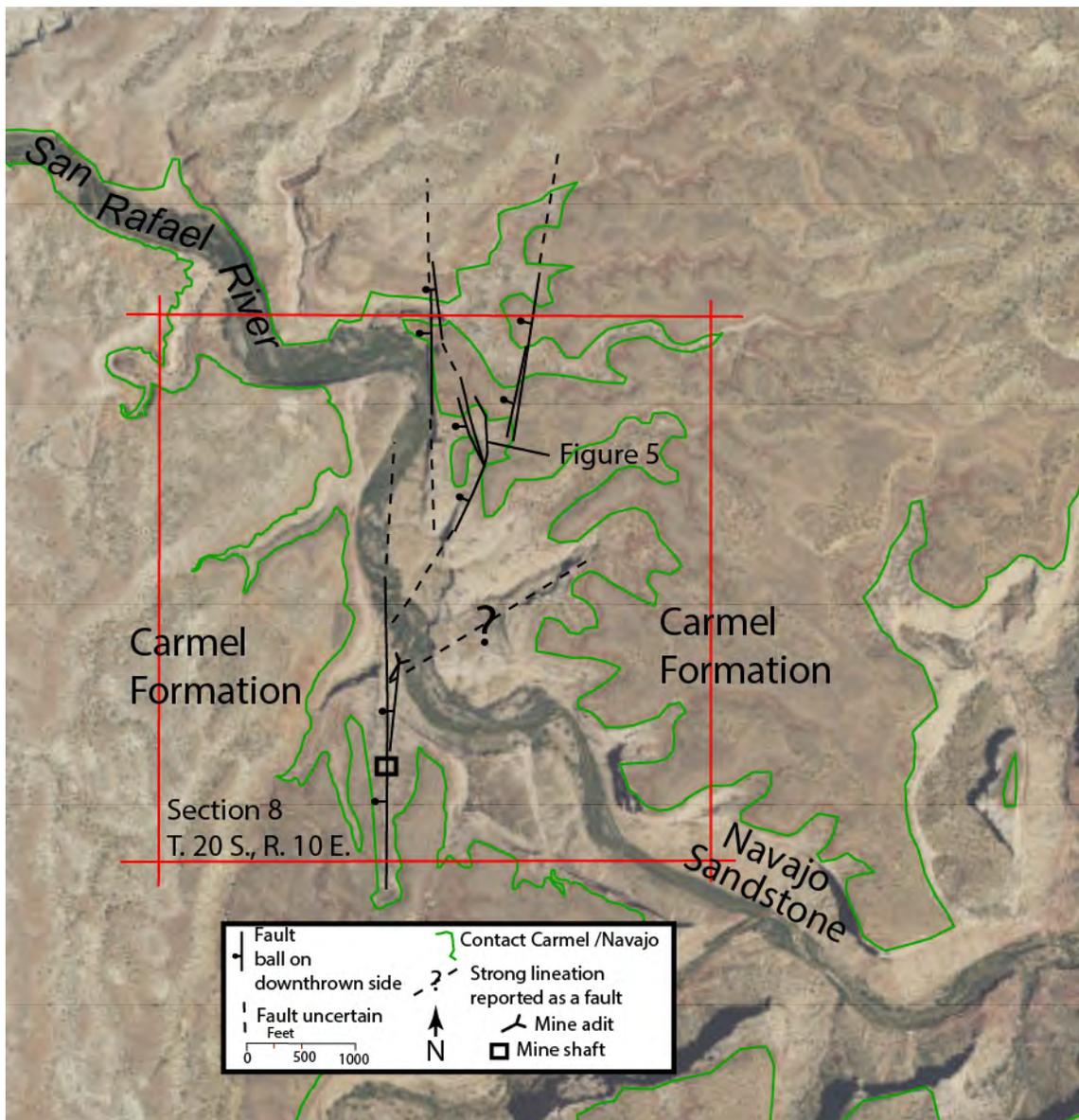


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(A)



(B)

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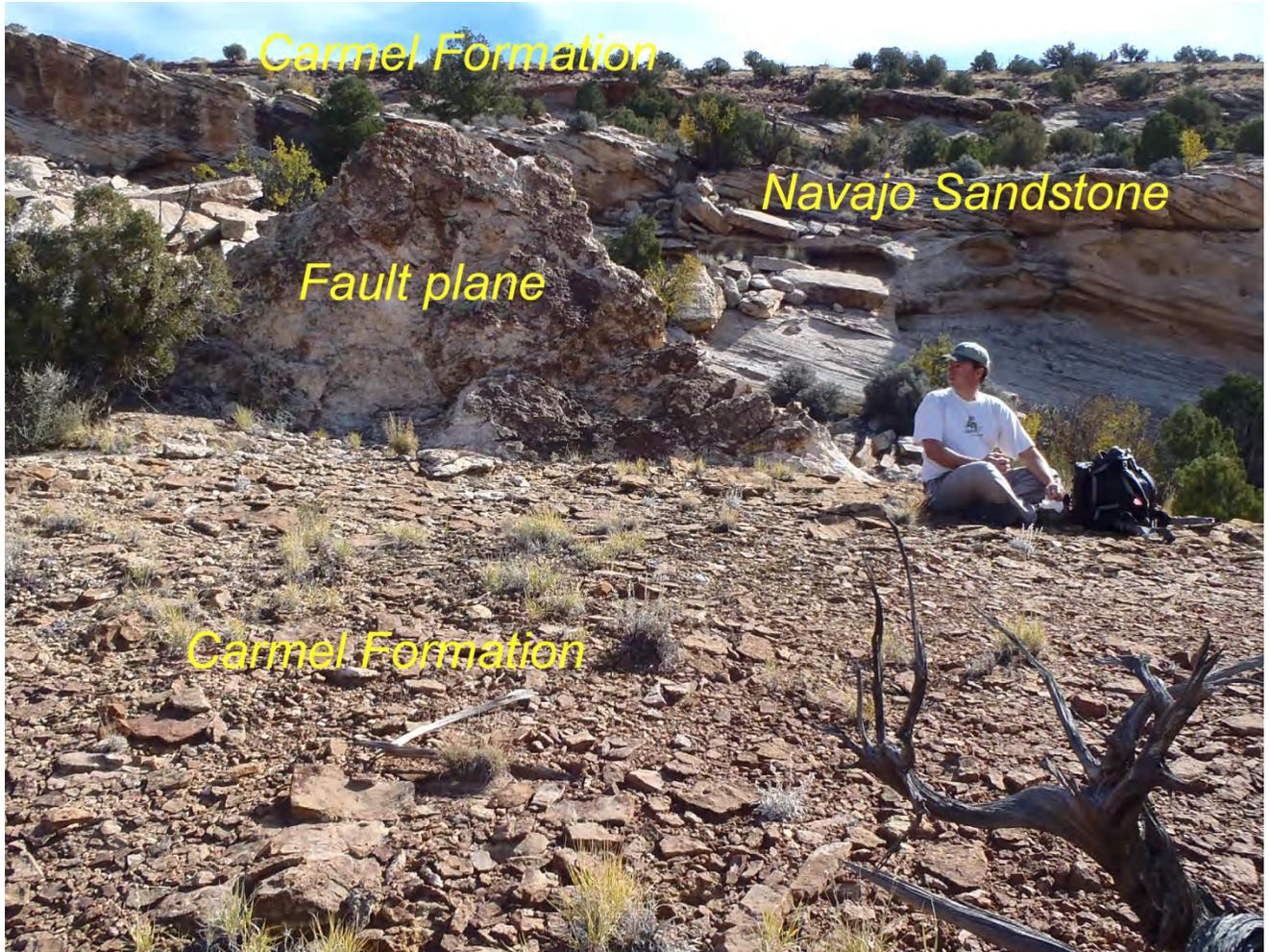


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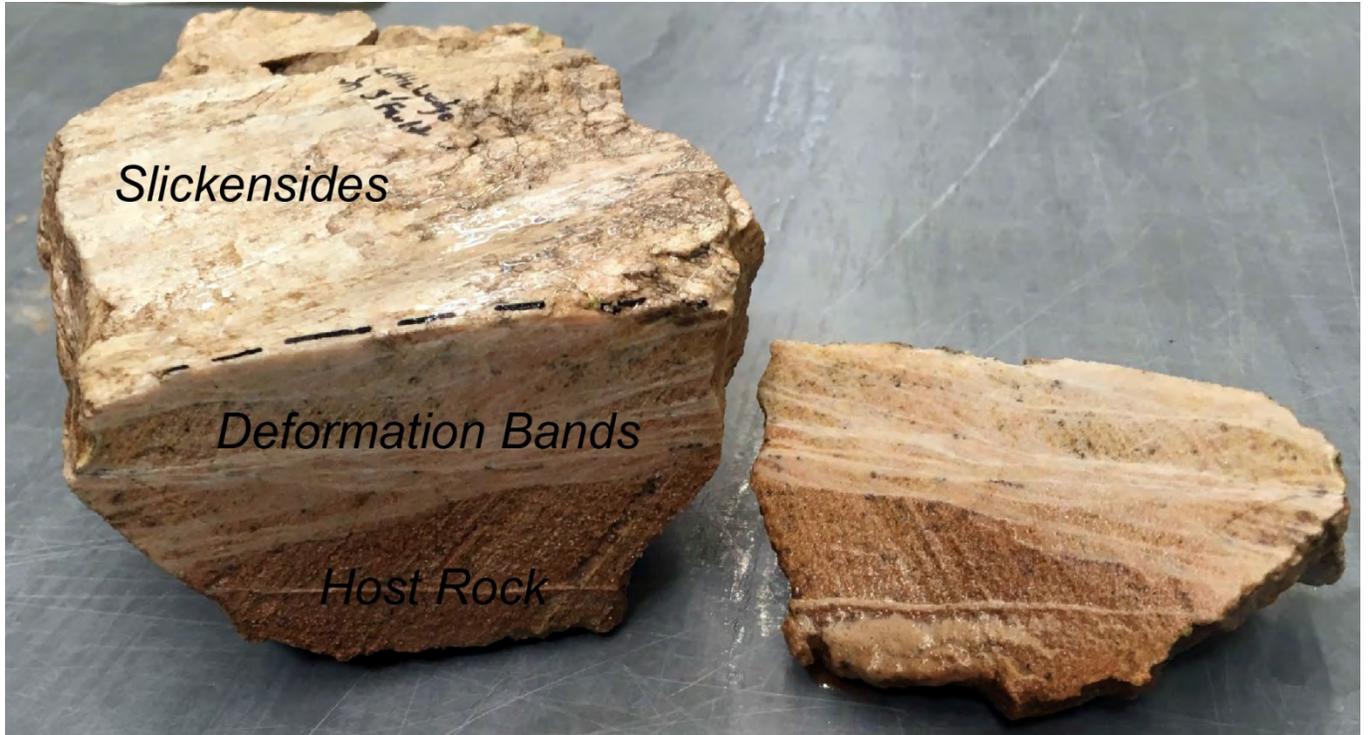


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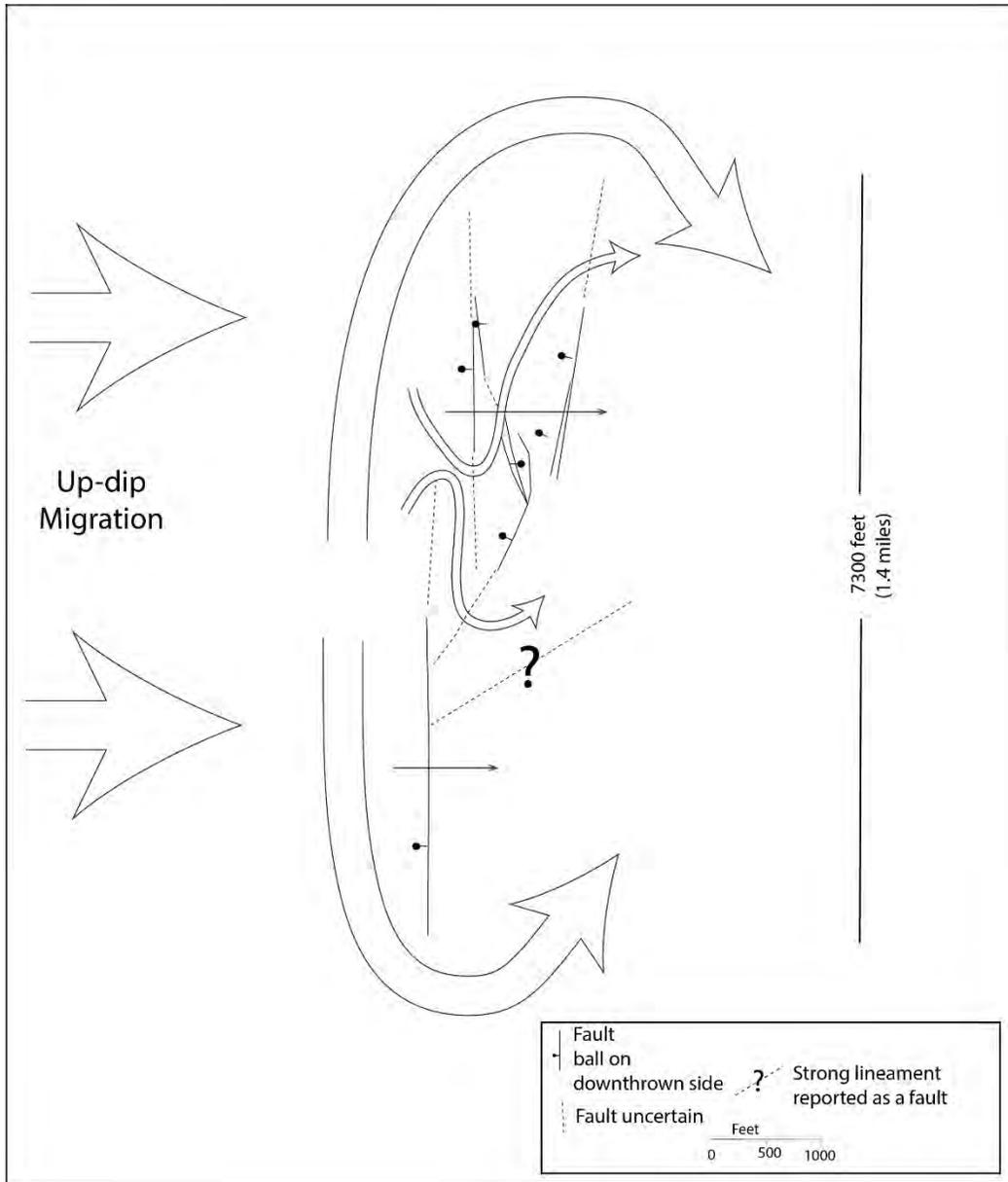


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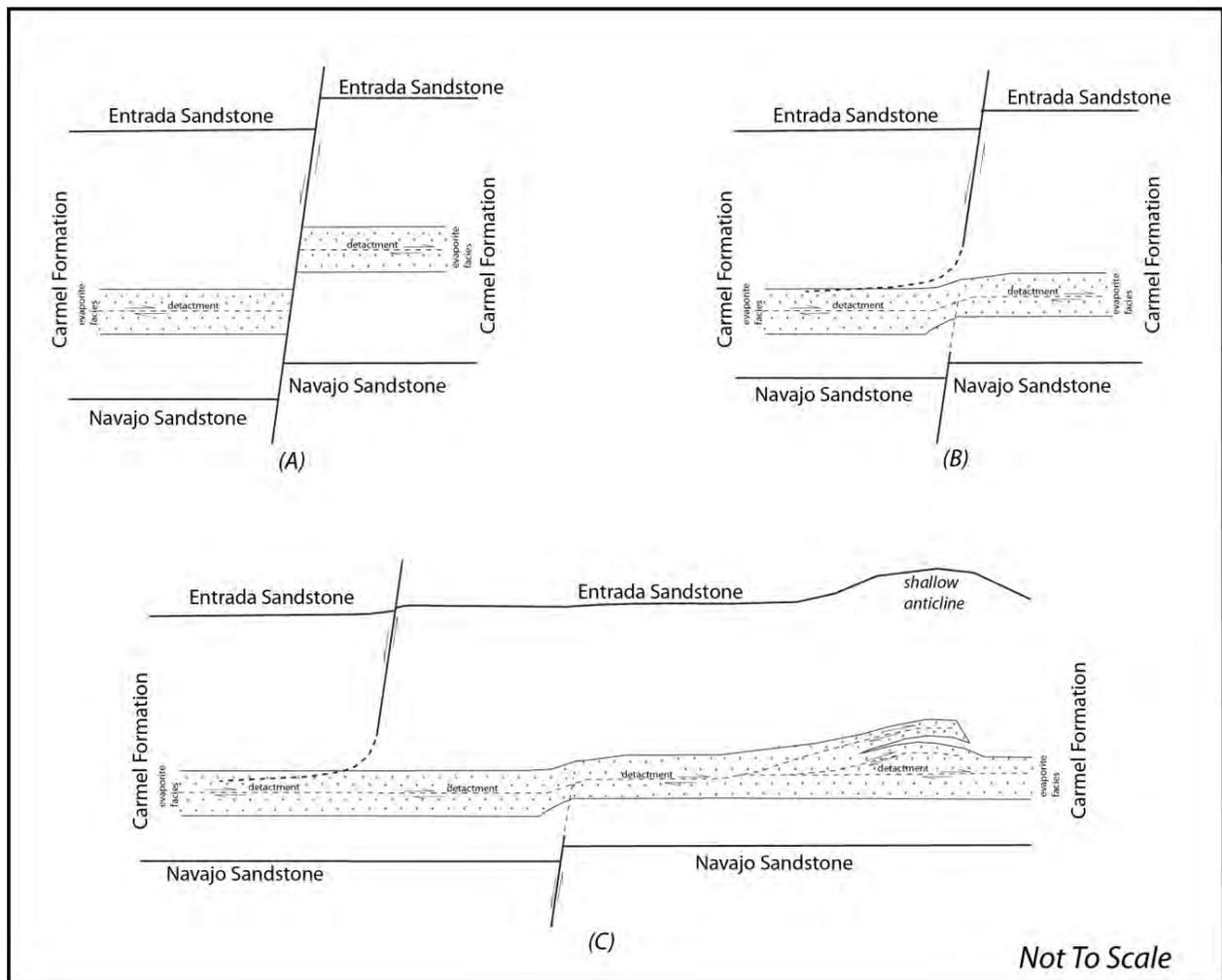


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Rocky Mountain CarbonSAFE Phase I

Appendix D

**SEDIMENTOLOGY, DIAGENESIS, AND RESERVOIR
CHARACTERIZATION OF THE
PERMIAN WHITE RIM SANDSTONE—
PROSPECTIVE STORAGE EFFICACY FOR CARBON
CAPTURE AND SEQUESTRATION**

SEDIMENTOLOGY, DIAGENESIS, AND RESERVOIR CHARACTERIZATION OF THE PERMIAN WHITE RIM SANDSTONE— PROSPECTIVE STORAGE EFFICACY FOR CARBON CAPTURE AND SEQUESTRATION

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INTRODUCTION

Geologic reservoir characterization studies commonly focus on the reservoir size, structural geometry, rock properties (e.g., porosity and permeability), fluid flow paths, and reservoir heterogeneities, as well as describing the overlying sealing units (White and others, 2005; Boot-Handford and others, 2014; Niu and others, 2014). The Permian White Rim Sandstone is a CO₂-bearing reservoir that is 450 m thick and overlain by the Permian Kaibab Limestone and Triassic Moenkopi Formation that could serve as reasonable seals. This chapter has two major research goals: (1) characterize the Permian White Rim Sandstone reservoir (e.g., stratigraphic architecture, facies, and diagenesis), and (2) provide input parameters for modeling work (e.g., rock properties). These goals lead to a set of driving research questions. (1) How do stratigraphic architecture and sedimentary textures/structures affect fluid flow through the reservoir sandstones? (2) How has diagenesis affected reservoir properties (porosity/permeability), and are there any stratigraphic or spatial distributions to these effects? Collectively, these questions aim to assess the reservoir quality and preferential flow pathways of the White Rim, with applications to stratigraphically equivalent subsurface reservoir units via a potential injection well west of the San Rafael Swell near the Hunter and Huntington Power Plants.

PERMIAN WHITE RIM SANDSTONE

Past petroleum- and diagenetic-focused studies have observed multiple fluid-flow episodes through the eolian Permian White Rim Sandstone in the Canyonlands National Park region to the southeast. Although the exact timing and sources for each episode differ slightly between studies (Schenk, 1989; Hansley, 1995; Gorenc and Chan, 2015), most report several episodes of fluid flow with iron oxide, pyrite, and hydrocarbon diagenetic phases. Paleoenvironmental-focused studies record two major stratigraphic intervals in the White Rim: (1) a lower eolian unit characterized by wind ripple and grainflow laminae and large-scale, cross-stratified sandstones, and (2) an upper reworked unit characterized by oscillation (wave) ripples, soft-sediment deformation and massive beds, and marine trace fossils (Huntoon and Chan, 1987; Steele, 1987; Huntoon and Kamola, 1988; Kamola and Huntoon, 1994). Our study presents both

the diagenetic and sedimentological history of the White Rim Sandstone in the relatively understudied San Rafael Swell outside of the Canyonlands region.

Study Area

The main study areas for this project occur on the more gently dipping western and northwestern flank of the San Rafael Swell at Sids Draw (field site A), Sids Reservoir (field site B), and Black Box trailhead (field site C) (figure 4-1). We chose several representative sites that adequately demonstrate the variability within the Upper Permian to Lower Triassic section. These sites are located to the west of the study done by Harston and others (2013) in the eastern portion of the San Rafael Swell. Because the core of the anticline is eroded, injection into the White Rim would rely on solubility/residual trapping (i.e., the CO₂ dissolves into the formation water as the plume spreads out over a large geographic area) or mineralization instead of structural trapping (White and others, 2005). The outcrop locations were compared to the Hamon USA No. 8-1 (SENW section 8, T. 19 S., R. 9 E., SLBL&M, Emery County) and Tully No. 16-9-36D White Rim Sandstone cores ~33 km and ~50 km northwest of the study sites, respectively. These cores provide examples of the potential reservoir quality of the White Rim Sandstone in the general area of a prospective injection well and at the prospective injection depths. The White Rim core interval in the Hamon USA No. 8-1 well is 1561–1577 m and in the Tully No. 16-9-36D well is 2230–2243 m.

Depositional Features

The White Rim Sandstone has seven individual lithofacies in the study interval (figure 4-2, table 4-1), based on mineralogy, grain-size and texture, sedimentary structures, and ichnology: (1) grain flow facies, (2) wind ripple facies, (3) ripple laminated facies, (4) soft-sediment deformation (SSD) facies, (5) symmetrically ripped facies, (6) bioturbated facies, and (7) massive facies. These lithofacies are grouped into facies associations (A–B), which correspond to distinct stratigraphic changes in facies (table 4-1).

The White Rim Sandstone has two major units each defined by a separate facies association (figure 4-3). The lower eolian unit, which comprises the majority of the White Rim, is characterized by facies association A with nested sets of bounding surfaces. The upper reworked unit (4–10 m thick), characterized by facies association B, exhibits a distinct, repeated sequence of facies at all three field sites (figure 4-3). The lower White Rim unit (facies association A) is characterized by cross-bedded dm- to m-scale trough cross-bedded sandstone with internal grain flow and wind ripple laminae. The internal grain flow facies (also called avalanche tongues) has thick, cm-scale, wedge shaped, internally massive, fine- to lower medium-grained beds. The wind ripple facies has thin, mm-scale, parallel, “pin stripe” inversely graded, translant laminae. These laminae are more common towards the base of the dune sets. The ripple laminated facies is relatively thin (<10 cm), fine-grained, and ripple laminated. The ripple laminated facies has mm-scale, sinusoidal laminae with each lamination eroding portions of the previous one (i.e., “traditional” ripple laminations).

The cross-bedded internal grain flow and wind ripple facies are separated by three nested orders of bounding surfaces that repeat throughout the section (figure 4-4). The most laterally extensive and “highest order” surfaces are the deflation surfaces, also termed interdune migration surfaces (Kocurek, 1988), and are equivalent to the 1st order bounding surfaces described by

Brookfield (1977). The deflation surfaces are relatively flat (after removal of structural dip), laterally extensive (100s of meters), truncate cross-bed sets and internal bounding surfaces, and have a vertical spacing of meters to 10s of meters. The rippled laminated facies commonly occurs at deflation bounding surfaces. Cross-bed set surfaces, equivalent to 2nd order bounding surfaces described by Brookfield (1977) occur between cross-bed sets (i.e., dune set boundaries), and typically extend for meters to 10s of meters with vertical spacings of 10s of centimeters to meters. Internal laminae surfaces, the “lowest” (nested) order bounding surfaces, occur between individual wind ripple and grainflow laminae and/or beds.

The upper unit (~4- to 10-m thick) of the White Rim Sandstone (facies association B) exhibits a different set of facies and ichnology compared to the lower unit. All three study sites show a similar stratigraphic progression of facies. In ascending order they are: (1) soft-sediment deformation (SSD) facies, (2) symmetrically rippled facies, (3) bioturbated facies (dominantly horizontal burrows), and (4) bioturbated facies (dominantly vertical burrows). Although the expression and thicknesses of each facies changes slightly between locations, the same general progression exists at all sites. The SSD facies encompasses several expressions of soft-sediment deformation including deformed/crinkled bedding and clastic pipes, which are a cylindrical type of injectite. At field site B (Sids Reservoir) the transition between the upper and lower unit is marked by clastic pipe eruption structures (i.e., the eruption horizon coincides with the transition) (figure 4-5). Within the bioturbation facies, the bioturbation index increases upward in the section and includes beds with bioturbation indices of 1–6 (i.e., slightly or sparsely bioturbated to completely bioturbated or homogenization of the sediment) (Taylor and Goldring, 1993). The lower beds have mostly horizontal traces such as *Thalassinoides* and *Planolites*. The overlying beds are dominated by vertically oriented *Ophiomorpha* trace fossils followed by beds containing other vertical traces such as *Skolithos*. The final beds have a mix of horizontal and vertical traces along with ripple laminated beds.

Diagenesis

Petrography

White Rim Sandstone lithofacies in outcrop are compositionally and textural mature, well-rounded, well- to very well-sorted, fine-grained quartz arenites. Grain size varies from very fine to lower medium-grained sand. Very fine grained sand is concentrated in the wind ripple laminae, with lower medium-grained sand concentrated in the grain flow laminae or beds. Thin sections from outcrop samples show multiple diagenetic stages and phases including: (1) initial quartz overgrowth cements, (2) subsequent carbonate cementation, (3) iron oxide precipitation, and, in some cases, (4) oil staining. All outcrop samples regardless of facies or stratigraphic position experienced initial quartz overgrowth cementation. Very fine grained carbonate cements commonly form a coating on the quartz grains and previous quartz cements (figure 4-6A through 4-6D). In some cases, the very fine grained calcite cements are intermixed with iron oxide cements. The cross-cutting relationships between these two phases are typically unclear, but in places where the cross-cutting relationships are distinct, the iron oxide precipitation occurred after the carbonate cementation. Examination of outcrop samples does not indicate that there were previously precipitated carbonate cements that might have subsequently dissolved. Oil staining is rare in the White Rim Sandstone at these San Rafael Swell the field sites (restricted to a <1-m-thick interval).

White Rim Sandstone core samples are texturally and compositionally similar to all of the outcrop samples. However, the core samples have a distinctly different set of diagenetic characteristics. Core samples show stages of (1) initial quartz overgrowth cements, and (2) subsequent carbonate cementation (figure 4-6E through 4-6H). The core samples have undergone significantly more compaction (shown by more long and concavo-convex grain contacts) which greatly reduced the primary porosity in the sandstones shown on the photomicrographs. The porosity was further destroyed by quartz overgrowth cements and a later stage of patchy, large, pore-filling calcite cement that nearly eliminated any remaining primary porosity (figure 4-6E through 4-6H).

Visible and Near Infrared Spectroscopy

Visible and near infrared spectroscopy (VNIR) of both outcrop and core samples aided the assessment of diagenesis on reservoir properties. VNIR is an ideal tool to determine composition of diagenetic minerals in sandstones because many of the dominant grain mineralogies such as quartz and feldspar do not have major absorption peaks within the target wavelengths (300–2800 nanometers [nm]). In contrast, common diagenetic minerals such as iron oxides, carbonates, sulfates, and clay minerals all have major absorption peaks within this range. Therefore, absorption peaks between 300–2800 nm commonly represent different diagenetic phases in quartz arenites like the White Rim Sandstone.

Spectrographic information confirms the diagenetic phases observed in petrography, and further indicates additional clay mineralogies, although it could not be determined if the clays are diagenetic pore filling cements or a result of the degradation of feldspars. VNIR data from 58 White Rim Sandstone outcrop samples show a single carbonate phase, multiple iron oxides phases, and at least one clay mineral phase (figure 4-7). Consistent absorption peaks across samples at ~2340 nm indicate the presence of calcite (no dolomite peaks were observed). The White Rim contains only a small percentage of patchy iron oxide cements as indicated by field and petrographic observations. However, multiple samples contain two iron oxide phases: (1) hematite and (2) goethite. Samples have absorption peaks at ~383, ~477, ~508, ~683, and ~897 nm indicating hematite and goethite iron oxide phases. In addition to carbonate and iron oxide phases there is at least one clay mineral phase with a major absorption peak at ~2201 nm. Core samples (n = 76) have absorption peaks for calcite and a clay mineral but lack absorption peaks for any iron oxide phases.

Reservoir Properties

The White Rim Sandstone has permeability values that range from 10s to 100s of mD, but not exceeding 500 mD. Although all facies described in the White Rim are compositionally and texturally similar there are significant permeability differences related to each facies (figure 4-8). Grainflow laminae and/or beds have the highest median and average permeability of all facies (177 mD and 190 mD, respectively). In contrast, wind ripple laminae have the lowest median and average permeability of all facies (49 mD and 60 mD, respectively). Between these two end members lies the bioturbated facies (median permeability of 131 mD), the ripple laminated facies (median permeability of 93 mD), the SSD (e.g., deformed cross-beds) facies (median permeability of 87 mD), and the massive facies (median permeability of 64 mD). The rippled laminated facies, the SSD facies, and the massive facies have few discrete beds

throughout the section and are under sampled relative to the grain flow, wind ripple, and bioturbated facies. Therefore, the ripple laminated, SSD, and massive facies permeability values should be taken as rough approximates instead of statistically significant assemblages. Even with differentiation between facies, all recorded outcrop measurements, with the exception of three data points, have reservoir grade permeabilities (defined by this study as >25 mD). However, these outcrop measurements differ significantly from those taken from the White Rim core. Core measurements of permeability are <0.01 mD (the detection limit for the instrument) across all facies.

Most outcrop samples have porosity values between 10% and 20% with several outliers that fall into the 5%-25% range (data from Harston and others, 2013, petrographic and porosity/permeability plug analysis). Internally, there is no significant difference in values between Harston and others' (2013) eolian dune and interdune facies (equivalent to facies association A) and the reworked facies (equivalent to facies association B). In contrast, thin sections from the Hamon No. 8-1 core show no discernable porosity across all samples. Primary porosity was nearly completely destroyed via compaction, quartz overgrowth cements, and subsequent calcite cementation.

Interpretations

Depositional Environments

The grain flow, wind ripple, and ripple laminated facies (facies association A) indicate an eolian environment for the lower unit and the majority of the White Rim section. The dm- to m-scale trough cross beds likely represent small barchanoid dunes in a coastal dune field (dominant paleocurrent direction to the southwest). The ripple laminated facies is the result of interdunes that coincided with the laterally extensive deflation surfaces (i.e., 1st order bounding surfaces). Other studies interpret a variety of interdune facies that occur almost exclusively at deflation surfaces (Kocurek, 1988, 1991; Parrish and others, 2017). The transition to the upper unit (facies association B) with subaqueously deposited symmetrical ripples, SSD, and burrows indicates a marine transgression. The SSD and injectite eruptions were most likely triggered by (1) the rapid increase in pore pressure, (2) destabilization of the newly saturated, high-porosity sands by strong ground motion (i.e., earthquakes), or (3) both in combination. The presence of wave ripples further confirms the marine interpretation for the upper unit and indicates a period of stabilization after the SSD and prior to the establishment of biological communities. The overlying highly bioturbated beds follow a classic shoreface sequence beginning with dominantly horizontal burrows such as *Thalassinoides* and *Planolites* in the lower shoreface and progressing to dominantly vertical burrows such as *Ophiomorpha* and *Skolithos* in the upper shoreface. Finally, the eolian system was fully transgressed resulting in the deposition of marine carbonates in the Permian Kaibab sea.

Diagenetic History

The White Rim Sandstone outcrop and core samples likely experienced distinctly different burial and fluid-flow histories. All outcrop facies show initial quartz overgrowth cements with some samples showing subsequent carbonate and iron oxide precipitation. A small interval of the White Rim (<1 m) and beds stratigraphically above the White Rim exhibit oil

staining. Although the relative timing of the outcrop diagenetic phases is established by petrographic relationships, their absolute timing proves more difficult in the absence of any definitive makers (e.g., specific temperatures or pressures).

The White Rim Sandstone cores near the prospective injection site exhibit a different degree of diagenesis. Increased compaction and extensive initial quartz overgrowth cements across all core samples removed nearly all of the primary porosity. Any remaining porosity was filled with subsequent calcite cementation. The large, pore-filling cements from the core contrast with the “fine-grained” rim-forming calcite of the outcrop samples. Additionally, there is no evidence of secondary dissolution of previously precipitated calcite and the creation of secondary porosity at the outcrop surface. The different styles of carbonate cementation, different degree of compaction, and absence of iron oxide and hydrocarbon diagenetic phases in the core indicate that the outcrop and core samples likely experienced different burial and fluid flow histories. This differing diagenetic history results in high quality reservoir properties in outcrop and poor reservoir properties in the core, if these results are representative of the majority of the subsurface White Rim. With the current data, the prospective injection site near the power plants appears as though it would likely have poor reservoir quality and be an inadequate storage reservoir.

Discussion and Reservoir Characterization

The White Rim Sandstone has nested levels of heterogeneities related to nested scales of bounding surfaces. The permeability differences in facies correspond largely to the number and relative spacing of horizontally or obliquely oriented, internal laminae or bounding surfaces, which baffle fluid flow. Consequently, eolian units have a greater degree of horizontal permeability (K_h) relative to their vertical permeability (K_v) (Goggin and others, 1988). Although facies and bounding surfaces are the primary control on porosity and permeability, all facies in outcrop have reservoir quality permeability and porosity values. Therefore, modeling and reservoir characterization of the White Rim does not rely on reservoir and non-reservoir distinctions and architecture, and instead necessitates the appropriate distribution of reservoir properties and incorporation of bounding surfaces into the modeling workflow.

Grainflow deposits, which are internally massive and have fewer internal heterogeneities compared to wind ripple laminae, have the highest permeability of all facies. Depositional processes that destroy original bedding such as bioturbation or SSD create relatively high permeability pathways. Facies with closely spaced mm-scale bedding such as ripple laminated or wind ripple laminae on average had the lowest permeabilities.

Bounding surfaces in the White Rim Sandstone and other eolian units occur at a variety of scales from the mm to 10s of m scale (vertical scale) (figures 4-2A and 4-9). The deflation surfaces (i.e., 1st order bounding surfaces) can be incorporated as stratigraphic breaks or potential baffles in the model and can aid in determining the vertical cell size. The deflation surfaces act as flow barriers which can be incorporated as low vertical cell transmissibility if these surfaces are used to determine cell height. Internally, cross-bed set and internal laminae surfaces (2nd and 3rd order surfaces, respectively) create vertical anisotropy ($K_h > K_v$). This can be incorporated into the models via cell anisotropy. These findings are applicable to other eolian modeling projects or reservoirs (e.g., Navajo Sandstone); however, the White Rim Sandstone in the subsurface region of the prospective injection site has non-reservoir porosity and permeability due to calcite cementation, which makes the entire interval an unsuitable injection site.

These findings have broader implications for eolian reservoir modeling and petrophysics. The appropriate partitioning of eolian reservoirs into flow units for modeling purposes poses a challenge. Texturally, eolian dune lithofacies have similar grain sizes and composition. Furthermore, eolian dune facies commonly do not have statistically different porosity populations that can be resolved on log data. However, minute changes in the ordering of the individual grains (e.g., mm-scale inversely graded beds in wind ripple laminae versus “disordered” packing in massive beds) can result in vastly different permeability values. Therefore, traditional porosity logs may not be adequate to appropriately characterize flow units within an eolian reservoir because higher permeability and lower permeability eolian lithofacies do not have resolvable porosity differences.

In contrast, the vertical spacing of bounding surfaces and other sedimentary structures (or lack thereof) can be used to more accurately populate permeability values in reservoir models. State-of-the-art borehole imaging techniques could prove useful in determining facies and the presence of bounding surfaces through the reservoir and lead to a more accurate reservoir model. Additionally, grainflow and wind ripple facies, which are commonly lumped as “dune facies,” should be broken out into their individual components or at least their relative proportions (e.g., wind ripple facies are more common at dune toes). Although these two facies represent the same environment, eolian dunes, they have vastly different rock properties and need to be modeled separately.

SUMMARY

The White Rim Sandstone in the San Rafael Swell has two main stratigraphic reservoir units characterized by different sedimentary textures and structures: (1) the lower dm- to m-scale, cross-bedded eolian dune sets (i.e., alternating sets of grain flow and wind ripple laminae), and (2) the upper 4 to 10 m of the formation that represents a marine transgression and reworking of the sediment. The transgression that reworked and deposited the upper unit resulted in a distinct change in facies and the presence of abundant marine trace fossils. For outcrop samples, lithologic facies is the dominant control on permeability. Facies that had either minimal original bedding or disturbed original bedding such as grain flow, SSD, and bioturbation facies had higher permeability values (typically 100s of mD) than the finer-grained, thinly bedded wind ripple and ripple laminated facies (typically 10s of mD).

Outcrop samples of White Rim Sandstone show initial quartz cementation (i.e., quartz overgrowth cements) followed by rim forming calcite and iron oxide cementation. These samples have porosities of 10% to 20% and permeabilities of 10s to 100s of mD. Core samples had a different diagenetic history with increased compaction, initial quartz cementation, and subsequent patchy, pore-filling calcite cementation that destroyed much of the primary porosity and reduced the permeability by three to four orders of magnitude from 10s to 100s of mD to <0.1 mD.

Overall, given the poor reservoir quality of the core samples directly below the prospective injection site, the White Rim Sandstone likely would not make a good CCS reservoir target despite initial promising outcrop results.

CHAPTER 4 FIGURE AND TABLE CAPTIONS

Figure 4-1. Digital elevation model of the San Rafael Swell and regional stratigraphic section. The field sites for this study (A – Sids Draw, B – Sids Reservoir, C – Black Box trailhead) are marked in blue, the study sites from the Harston and others (2013) study are marked in purple, the Hamon USA No. 8-1 core location is denoted by the green circle, and the Hunter Power Plant is denoted by the white circle. The Huntington Power Plant is an ~58 km to the north-northwest of the study sites and the Tully No. 16-9-36D core is ~50 km to the north-northwest of the study sites. Insert: stratigraphic column for the field sites; star indicates the Permian White Rim Sandstone targeted for CO₂ injection.

Figure 4-2. Eolian dune facies consist of tens of cm to m-scale cross-bedded grain flow and wind ripple laminae that intertongue with subaqueous ripple laminated interdune deposits (A) (blue dotted lines indicate cross-bed set bounding surfaces). These facies are capped by 4 to 10 m of marine reworked sandstone with soft-sediment deformation (deformed bedding and injectites) (B), symmetric ripples (E and H), and extensive bioturbation (C, D, F, and G). The trace fossil assemblage, including *Ophiomorpha* (D and F) and *Thalassinoides* (G), indicates a marine shoreface environment.

Figure 4-3. Measured sections at all three field sites indicate a marine transgression of the Permian Kaibab sea and sediment reworking on top of a series of eolian facies.

Figure 4-4. Bounding surfaces typically occur at three nested scales. Deflation surfaces are relatively flat, laterally extensive horizons that commonly occur tens of m apart stratigraphically. Bedset surfaces denote individual cross-bed sets and can occur at tens of cm to m intervals. Internal bed/laminae surfaces separate individual grain flows or wind ripple laminae. These surfaces can occur at the mm to cm scale.

Figure 4-5. A and B – Clastic pipe eruption horizons are marked by outward flaring surfaces (blue solid and dashed lines) (Wheatley and Chan, 2016). C and D – Pipe eruption horizons occur at the transition between the lower and upper units at field site B and are likely related to the marine transgression of the Permian Kaibab sea.

Figure 4-6. Outcrop examples (A–D) indicate high quality reservoir potential sandstones; blue areas represent porosity. Petrographic studies show quartz overgrowth cements and, in some samples, minor carbonate and iron oxide cements. However, subsurface core examples (E–H) of the same formation ~34 to 48 km to the west indicate sandstones with very limited to no reservoir potential. Compaction and carbonate cementation have destroyed nearly all of the primary porosity. Images in E and G have been stained with alizarin red to identify calcite cement. A, B = wind ripple; C, D = eolian dune (undifferentiated) (D is a crossed nicols image of C); E, F = Hamon USA No. 8-1 core (F is a crossed nicols image of E), depth 1568.5 m; G, H = Hamon USA No. 8-1 core, depth 1569.1 m.

Figure 4-7. VNIR indicates that outcrop samples (n = 58) have multiple diagenetic phases including: (1) calcite, (2) hematite, (3) goethite, and (4) a clay mineral. In contrast, core samples (n = 76) do not have any iron oxide phases and only have absorption peaks for (1) calcite, and (2) a clay mineral.

Figure 4-8. Depositional textural and the presence and spacing of bounding surfaces plays a key role in determining permeability. Facies with fewer internal laminae or bounding surfaces tend to have higher permeability values than facies with preserved mm-scale bedding. Destruction of primary bedding through soft-sediment deformation or bioturbation can increase permeability by creating preferential flow pathways.

Figure 4-9. Although dune facies (i.e., cross-bedded grain flow and wind ripple facies) are compositionally and texturally similar, internal laminae bounding surfaces greatly affect the comparative permeability between each facies. The wind ripple facies has mm-scale, inversely graded laminae, which creates minor flow baffles compared to the internally massive grainflow facies, which results in lower permeability values. Yellow triangles indicate grading.

Table 4-1. White Rim Sandstone facies and facies associations.



Rocky Mountain CarbonSAFE Phase I

Appendix E

**SEDIMENTOLOGY, STRATIGRAPHIC ARCHITECTURE, AND
RESERVOIR CHARACTERIZATION OF THE LOWER
JURASSIC NAVAJO SANDSTONE—PROSPECTIVE STORAGE
EFFICACY FOR CARBON CAPTURE AND SEQUESTRATION**

**SEDIMENTOLOGY, STRATIGRAPHIC
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CHARACTERIZATION OF THE LOWER JURASSIC
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INTRODUCTION

The goal of this study is to describe the Lower Jurassic Navajo Sandstone in terms of its potential as a lithological reservoir for storage of supercritical carbon via subsurface injection. The Navajo Sandstone was selected as the reservoir target for injection and storage sites of the Hunter and Huntington Power Plants. Outcrop exposures were chosen based on accessibility, proximity to the proposed injection locations, completeness of section, and relative distribution across the San Rafael Swell. Navajo cores were examined from Covenant oil field in the central Utah thrust belt about 55 miles to the west of the San Rafael Swell as a producing reservoir analog to the outcrops and the study sites. Porosity and permeability are among the two most important lithologic properties of a potential storage reservoir (Olierook and others, 2014). Multiphase flow measurements were conducted on core from Covenant oil field as well as outcrop samples. These properties are key in describing: (1) the volume of carbon that could potentially be stored, (2) limits on injection rate, and (3) probable fluid pathways. Therefore, the distribution of stratigraphic, lithologic, and diagenetic features, and their effect on porosity and permeability both spatially and stratigraphically, is key in understanding the utility of the Navajo Sandstone as a potential reservoir.

JURASSIC NAVAJO SANDSTONE: OUTCROP ANALYSIS

Past studies of the Navajo Sandstone in the San Rafael Swell have focused on it as a classic example of eolian facies (Sanderson, 1974) and as an excellent outcrop analog for hydrocarbon reservoirs and CCS models (Dalrymple and Morris, 2007; Hansen, 2007; Allen and others, 2013). Our study aimed to examine both outcrop and core scales of investigation with a focus on the stratigraphic evolution of the Navajo in order to understand large-scale regional trends which would affect both the storage and migration of carbon-fluids in a subsurface injection scenario.

Study Area

Observations focused on outcrops along Buckhorn Draw Road, which is the study site nearest to the Hunter Power Plant. In order to interpret regional-scale stratigraphic trends, this study identified two additional study sites: Justensen Flats, which is located on the western flank of the San Rafael Swell and is south of Buckhorn Draw Road, and Temple Mountain Campground, which is located along the southeastern flank of the San Rafael Swell north of Goblin Valley State Park.

Buckhorn Wash

The Buckhorn Wash region is located along the northwestern flank of the San Rafael Swell south of Price, Utah, and east of the Hunter Power Plant along Buckhorn Draw Road. Buckhorn Wash follows an incised valley through the majority of Jurassic, Triassic, and some Permian age units, which comprise much of the San Rafael Swell (figure 5-2).

Justensen Flats

Justensen Flats is located south of Interstate 70 (figure 5-2) and represents the westernmost outcrop location studied. Justensen Flats is interpreted as the top of an interval of interdune deposits, which forms an erosionally resistant bench relative to the cross-bedded sandstones above and below. The bench sits stratigraphically in the middle of the formation. This unique location allows for easy examination of Navajo section via a dirt road that gently traverses from the upper contact with the Middle Jurassic Carmel Formation, down to the lower contact with the Lower Jurassic Kayenta Formation.

Temple Mountain Campground

The Temple Mountain Campground site is the easternmost study location (figure 5-2) and the Navajo section was measured in most cases directly adjacent to, or very near the camp road which cuts directly down-section. Given the roughly north-south strike and eastern dip of units in this part of the San Rafael Swell, walking east along this road enables the observer to traverse upwards stratigraphically. A petroglyph view area north of the camp road roughly defines the contact between the Jurassic Kayenta Formation and the Navajo Sandstone, and farther east a rocky wash to the south of this road exposes the upper contact with the Jurassic Carmel Formation.

Lithofacies Categories

Together, the four complete measured sections recorded in this study describe the three locations. These sections show that across tens of kilometers, distinct stratigraphic intervals are persistent. Deposition appears relatively uniform across this region (figures 5-3 and 5-4). All study sites expressed 14 distinct lithofacies (table 5-1). These lithofacies were classified based on grain-size, texture, primary sedimentary structures, thickness, lateral extent, and bed contact relationships.

Three lithofacies contain undeformed, high-angle ($<35^\circ$) cross-bed sets of varying geometries. These three quartz-arenite lithofacies are classified as planar cross-bedded sandstone (Pxb), large trough cross-bedded sandstone (Tx1), and small trough cross-bedded sandstone (Tx2). The Pxb beds are generally ~1 to 5 m thick, with flat erosional tops and flat erosional bases, and thin laterally over 10 to 100 m. The Tx1 beds are ~5 to 30 m thick, with erosional tops and gentle concave-up or sinusoidal basal contacts extending for 10 to 100 m. The Tx2 beds are 0.1 to 1 m thick over lateral distances of 1 to 10 m, and have erosional concave-up top and basal contacts.

Four non-cross-bedded lithofacies are characterized by some or all of five diagnostic features: (1) thinly bedded, (2) lenticular beds, (3) distinct horizontal sedimentary structures or completely structureless (massive), (4) high concentration of carbonate-cement relative to other facies, and (5) laterally extensive, ~10 to 100 m. Sheet plane-bedded quartz arenite sandstone (Spb) facies remain thin (<0.1 m) over 10 to 100 m, have flat erosional top contacts, and flat bottom contacts that are either conformable or erosional. Ripple laminated sandstone (Rip) facies are composed of hematite and carbonate-cemented quartz arenite. This Rip facies is 0.1 to 0.5 m thick over lateral distances of 10 to 100 m, with flat erosional top contacts, concave-up

conformable basal contacts, and internal mm-cm asymmetric or symmetric ripple laminae. Undulose laminated sandstone (Unl) facies remain thin (<0.1 m) over 10 to 50 m, have flat erosional top contacts, and concave-up conformable basal contacts. The Unl facies exhibit undulose/crinkly lamina composed of carbonate cement-rich quartz arenite. Massive sandstone (Mss) facies have a lack of sedimentary structures, thick 1 to 5 m over 10 to 100 m, have flat, conformable top and basal contacts, and commonly underlie either Rip or Unl beds. The Rip and Unl facies both have high concentrations of carbonate cement, whereas both the Mss and Spb facies lack carbonate cement. The Spb facies can resemble the toe of a dune but are easily distinguished where a three-dimensional (3-D) outcrop exposes a laterally extensive, very thin sandstone bed.

Two lithofacies are classified by the presence of either brittle or ductile deformation. Soft-sediment deformed sandstone (Ssd) facies are 1 to 10 m thick over 10 to 100 m. The Ssd facies contain plastically folded, contorted, and overturned cross-bedding, of which strata are laterally conformable and connected to undeformed cross-bedding. Brittily deformed sandstone (Bss) facies are 1 to 7 m thick over 10 to 100 m, and contain brittle, or non-plastic, stratal deformation of other semi-lithified cross-bedded strata such as Pxb, Txs, and Txl facies.

Four lithofacies are classified based on the geometries of their deposition and close stratigraphic relationships to one another. Interbedded sheet sandstone and conglomerate (Isc) facies contain alternating strata of sandstone and matrix-supported pebble conglomerates. The Isc strata are 0.5 to 5 m thick, extending 100 m, and are conformable with overlying high-angle cross-beds. Intraformational conglomerate (Itc) facies are matrix-supported conglomerates with green pebble-sized clasts suspended in carbonate-rich mud/sand matrix. The Itc strata remain thin (0.1 to 1 m) extending 100 m, and appear conformable along basal and top contacts. Sheet mudstone (Smd) facies are thin (0.1 to 1 m) green mudstones extending 10 to 100 m. The Smd strata have sharp erosional bases and are conformable with overlying beds. Internally, Smd clasts appear in Isc conglomerate horizons as apparent rip-up clasts. Cross-bedded to cross-laminated sandstone (Xxs) facies are 1 to 5 m thick over 10 to 100 m, with very deep erosional bases that incise cross-bedded strata. The Xxs facies have very small, mm-cm thick low-angle cross-beds and/or cross-laminations that occur in erosional contact with larger, higher-angle cross-bed sets. These Xxs strata appear below or very near to Smd, Itc, and Isc facies.

Pseudo-bedded sandstone (Psb) lithofacies are characterized by noticeably white, bleached beds that are mostly structureless, but contain some primary bedding. These intervals are very thick 3 to 30 m, extending >500 m.

Lithofacies Associations

Five lithofacies associations group and link related facies from table 5-1 and the lithofacies descriptions above. Here they are classified into lithofacies associations based on the major depositional environment interpreted for each group of lithofacies.

The Pxb, Txl and Txs facies express high angle, tabular, regular cross-bedding, and thus they were grouped together into an eolian dune lithofacies association (figure 5-5).

The Spb, Rip, Unl, and Mss facies are grouped based the common lack of cross-bedding, consistent stratigraphic successions in which they are observed to occur together, and presence of carbonate cement in the case of Rip and Unl. These four interpreted non-dune lithofacies are correspond to sedimentary features associated with interdune deposition (ID; figure 5-6).

The Mss and Bss facies are grouped into a deformed association because they represent intervals of rock which have primary structures preserved, but have been apparently deformed since original deposition (figure 5-7). The deformed facies association contains both syndepositional soft-sediment (plastic) deformation (Ssd) facies and brittle (non-plastic) deformation (Bss) facies (figure 5-8), the latter of which may preserve either syndepositional deformation and/or post-lithification structural deformation. Post-lithification structural deformation is distinguished from syndepositional deformation by the observation of characteristics and features including but not limited to large fault surfaces extending >100 m, deformation bands, and slickensides. In many cases Ssd and Bss strata occur either adjacent to one another or within the same interval, in which case there is likely a genetic syndepositional cause.

A mixed eolian-fluvial association is applied to the Isc, Itc, Smd, and Xxs lithofacies due to their common occurrence together, the genetic relationship between Smd strata and Isc clasts, and the energy regime required to deposit pebble-sized clasts in the Isc and Itc facies (figure 5-7). The Psb facies is classified as a distinct association which is consistent with a post-lithification fluid-alteration process that preserves a form of pseudo-bedding association (figure 5-9). The Psb facies either lack primary bedding structures entirely or have very faint cross-bedding visible. The Psb beds are very white, appearing bleached, which may be due the migration of a reducing-chemistry fluid that passed through the rock. A reducing fluid may dissolve iron from the host rock into solution and transport it. This lithofacies is interpreted as a pseudo bedded association without implying a genetic cause for these features. The Psb lithofacies warrant additional study.

Reservoir-Pertinent Depositional Fabrics

Although there are a number of distinct lithofacies (table 5-1) present throughout Navajo section, a smaller set of three reservoir-pertinent depositional fabrics are likely the most important factors to affect fluid flow and compose ~95% of vertical section. The two reservoir-supporting fabrics are: internal cross-bedded intervals of wind ripples (WR) and grainflow (GF) tongues (figure 5-10A through 5-10E), and both fabrics are present in the Pxb, Txs, and Txl lithofacies. A third important reservoir-baffle/barrier fabric is interdune deposition (ID) (figure 5-10E and 5-10F), and comprised of the Spb, Rip, Unl, and Mss lithofacies. The Rip and Unl lithofacies comprise ~80% of all the ID fabrics.

Reservoir-Support Fabrics: Wind Ripple and Grainflow Cross-Bedding

The WR fabrics are thin (mm) translent laminae that record the migration of a rippled dune-slope and occur because of the preferential sorting of eolian grains along either a ripple trough or crest. The WR cross-beds preserve inverse grading and show typical pin-stripe lamination within cross-beds (Hunter, 1977). The GF fabrics are tongues that occur at various scales, usually proportional to their cross-bed foreset thickness. A single GF tongue records a sand avalanche along a dune slope and is internally structureless. A GF tongue is thickest at the top of its bed with high-angle bounding surfaces, and thins at the base of its bed becoming nearly tangential with the lower bounding surface of the foreset (Hunter, 1977). Together, WR and GF reservoir-pertinent fabrics comprise all interpreted dune-associated lithofacies in varying ratios and 85% to 90% of Navajo Sandstone vertical section. Additionally, the WR cross-beds tend to

have lower porosity (~7%) and the GF cross-beds tend to have higher porosity (~22%), which was confirmed via petrographic thin section (figures 5-11 through 5-13).

Reservoir-Baffle/Barrier Fabric: Interdune Lenses

The ID baffle/barrier fabrics are defined as all interdune-associated lithofacies (the Spb, Rip, Unl, and Mss lithofacies). The Rip and Unl lithofacies comprise ~80% of all ID fabrics. Although the ID fabrics represent 5% to 10% of Navajo Sandstone vertical section they are crucial to reservoir characterization because they generally represent baffles and/or barriers to flow. The ID lenses are finer grained and have lower porosity and lower permeability than the WR or GF fabrics. All laboratory analyses focused on these three fabrics to make interpretations about reservoir quality.

Utility of Reservoir-Pertinent Fabrics

The Navajo Sandstone can be understood more efficiently by examining the stratigraphic occurrence and relationships of the WR, GF, and ID fabrics. Given that the WR, GF, and ID intervals have very different porosity (~7%, ~22%, and ~3%, respectively) and permeability (figures 5-12 and 5-13), and represent 95% of vertical section, they are the most useful fabrics for analysis to effectively characterize the Navajo Sandstone as a reservoir.

Porosity and Permeability

Porosity

Hand samples of the Navajo Sandstone were collected at Buckhorn Wash, Little Wedge, and Justensen Flats areas. For the three major reservoir-pertinent fabrics, porosities were measured via thin section pore-space estimates and analyzed with respect to reservoir fabric type and stratigraphic height above the base of the Navajo Sandstone (figure 5-12). Sampling for porosity was concentrated in the lower stratigraphic zone because this stratigraphic interval has the greatest lithologic variation within the unit and has not been previously characterized by other studies. Photomosaics of 19 thin sections at 25-50x power were used to estimate porosity by isolating the area of blue epoxy in the Image J™ software package using a color threshold tool. Porosity estimates are based on cross-sectional (2-D) data and may be limited by the single orientation from which they were derived (figure 5-11). The WR cross-beds have average porosity of ~7% whereas the GF cross-beds have average porosity of ~22%. Most notably, there appears to be a positive correlation between the cross-bedded reservoir fabrics (WR and GF) and stratigraphic height. The ID samples have much lower average porosity (~3%) than the WR and GF fabrics (7% and 22%).

Navajo samples, including the avalanche, wind ripple, and interdune facies were also sent to Schlumberger Laboratories and analyzed for porosity (and permeability) (table 5-2). All samples were analyzed at ambient pressure and several were also tested at 2700 psi and then 3500 psi to simulate the change with burial. Porosity in dune facies ranges from 15.6% to 21.1%, with GF (avalanche) averaging 14.5% and WR at a surprising 18.1%. Grain density averages 2.65 cm³. The interdune samples averaged 8% porosity.

Permeability

Permeability has a similar distribution as porosity among reservoir-pertinent fabrics (figure 5-13). Reservoir-supporting cross-bedding fabrics (GF and WR) have outcrop permeabilities range from ~100 to 9000 mD. These values were acquired using a TinyPerm II permeameter which is extremely susceptible to changes in temperature (pressure), poor instrument-target seals, and high measurement variability, as observed during data collection in this study. Measurements were typically repeated four to six times and averaged out, however, values are likely unrealistically high. Thus, we recommended that these permeabilities should not be used for subsurface modelling because they reflect a low precision. Permeability measurements are based on outcrop, and though fresh surfaces were used to estimate permeability, values from fresh surfaces did not differ from weathered surfaces. The maximum values obtained for permeability sometimes exceeded 20,000 mD, suggesting a poor seal or overly weathered media for accurate measurement. Additionally, subaerial exposure and periodic precipitation may have enhanced or impeded pore fluid pathways, and are not representative of subsurface rock.

The lowest permeabilities measured correspond to the ID fabrics at 5 to 590 mD (figure 5-13) whereas higher average permeabilities were measured in both types of reservoir-supporting fabrics (~100 to 3000 mD). The ID fabrics regardless of stratigraphic range, have lower porosity and permeability than any cross-bedding fabric.

Laboratories analysis of hand samples from the dune facies show nitrogen permeabilities ranging just 2.96 to 2416 mD%, with GF (avalanche) averaging 268 mD and WR at a 1278 mD (table 5-2). The interdune samples had a maximum permeability of 18.5 mD.

Architectural Observations

The lithofacies present within the Navajo Sandstone are stratigraphically controlled by original depositional textures. The consistent stratigraphic division of the formation is evident in each section measured from the eastern flank of the San Rafael Swell across to the northwest. Some lithofacies are limited to either the upper or lower stratigraphic zones, but others span both. The lower Navajo stratigraphic zone defined by Marzolf (1983) is the stratigraphic interval from Navajo base up to the youngest observed occurrence of an ID bed (Spb, Rip, Unl, or Mss lithofacies). Therefore, the upper stratigraphic zone is defined as the interval from the top of the youngest ID bed to the Navajo top contact. The boundary between the lower and upper stratigraphic zones is not exact and it is possible that this study did not identify the absolute youngest ID beds present in measured sections given the limited lateral continuity of ID lenses.

Lower Navajo Sandstone Stratigraphic Zone

In the lower stratigraphic zone of the Navajo Sandstone (60 to 80 m thick), the most prominent architectural features are flat lying, conformably deposited lenses of carbonate-cemented sandstone; Rip and Unl lithofacies; ID baffle/barrier fabrics. The lenses are lenticular with erosionally truncated tops, marking major bounding surfaces. They are thin (0.1 to 5 m) and their lateral extent is proportional to their thickness at a ratio of ~1:200 (e.g., a 1 m-thick bed typically extends ~200 m across). These lenses are thickest towards the center and taper to the

sides where they pinch out. The ID beds are not always symmetrical in thickness. The thickest ID fabric observed was ~5 m whereas the thinnest was ~5 cm. The greatest ID fabric lateral extent directly observed was ~500 m whereas the thinnest was ~10 m.

Cross-bedding in the lower stratigraphic zone of the Navajo Sandstone is limited to thin (< 5 m) foresets of the Pxb and Txs facies, and major erosional bounding surface spacing is ~5 to 10 m. These beds lack thick GF intervals and are dominated by WR cross-beds and thin (<20 cm) GF cross-beds. The maximum cross-bed foreset thickness observed is ~10 m.

Interpreted Ssd facies occur in some isolated beds in the lower stratigraphic zone. Small <1 m Ssd facies below or adjacent to eolian-fluvial and interdune associated lithofacies are common.

Upper Navajo Sandstone Stratigraphic Zone

The upper zone of the Navajo Sandstone (60 to 80 m thick) is notable for its lack of ID fabrics, its thick cross-bed foresets (5 to 20 m), and the presence of both thick Ssd and Bss lithofacies. The Txl cross-beds are the dominant lithofacies present. The Txl foreset thickness increases dramatically from the lower stratigraphic zone and reaches a maximum of 20 m. Individual GF tongues increase in size (up to 1 m) and increase in concentration relative to WR fabrics (up to 100%) within cross-bed foresets. The WR cross-beds are also present in the upper stratigraphic zone; however, GF fabrics are distinctly thicker and comprise a greater concentration of cross-bed foresets than in the lower stratigraphic zone.

The deformed Bss and Ssd facies are most prominently expressed in the upper zone, commonly in adjacent beds. The Bss facies are only observed in the upper zone, whereas the Ssd facies are observed in both zones. From Bss beds, structureless sandstone matrix commonly extends into Ssd beds. Transmissivity seems to occur between adjacent Bss and Ssd intervals. The thickness and the degree of Ssd deformation is much greater in the upper stratigraphic zone than in the lower. The Ssd facies have a locus of contortion that decreases laterally in outcrop where strata become conformable with adjacent undeformed cross-bedding structures. In the upper stratigraphic zone, the most prominent Ssd fabric is >10 m in thickness with large isoclinal folds. This deformation spans two cross-bed foresets and is erosionally truncated (figure 5-8A). Deformed intervals are commonly truncated by major erosional bounding surfaces and both the Bss and Ssd lithofacies are often bleached and/or stained.

Architectural Interpretation

The disparate occurrence of lithofacies across lower and upper stratigraphic zones likely reflects a long-term evolution of the erg (figure 5-14). The environmental conditions and internal organization of the sand-sea present in the early history of the Navajo Sandstone were likely wetter than those during the latter part of deposition. The deposition of the ID deposits in the lower stratigraphic zone only occurs in a wet-eolian framework in which the water table is sufficiently shallow and the ground has enough moisture to hold sediments in place. As interdune areas stabilize from sufficient subsurface moisture and/or vegetation, windblown sediments derived from dunes continue to be transported. This transport occurs at the volumetric cost of dunes which are the source of these sediments, and results in decreased dune heights (Kocurek and Havholm, 1993). Thus, smaller dune foresets are typically associated with wet eolian environments. The zone in which dunes can potentially accumulate is proportional to the

height of dunes crests and also relies on sediments being dry so that winds are able to entrain sediment. Vegetation and surface moisture in an erg act as a baffle and/or barrier to eolian transport (Kocurek and Havholm, 1993). As sediment erodes from dunes, transport-inhibiting interdune areas continue to grow the cost of dunes. The continuous entrainment of sediment, and thus the construction of taller dunes, is not possible when moist surface conditions and/or vegetation are present. Large dune forms are associated with drier conditions and smaller dune forms are associated with wetter conditions (Kocurek and Havholm, 1993).

The absence of all interdune-associated lithofacies in the upper stratigraphic zone and presence of large Ssd and Bss intervals may reflect the presence of a deeper groundwater table, and larger dunes in the latter history of the Navajo Sandstone. This hypothesis is also supported by the presence of thicker Tx1 lithofacies in only the upper stratigraphic zone. The larger thickness of the Tx1 cross-beds relative to the Pxb and Txs cross-beds of the lower stratigraphic zone physically require either a larger original dune form or less post-depositional erosion in order to be preserved. Given the consistent occurrence of thick Tx1 beds across all study locations, it likely reflects a larger original dune form, and thus an evolution in the Navajo paleoenvironment and/or sediment-supply.

Diagenesis

Observations

Limited mineralogical diagenetic interpretations were made from both thin section data of reservoir-pertinent fabrics and outcrop observations of lithofacies. Three main diagenetic cements found in the 34 thin section samples analyzed include quartz overgrowths, iron-oxide coatings, and pore-filling carbonate cements.

Carbonate cements are only observed in the ID fabrics as pore-filling cements. No other cements are observed in ID fabrics. All other reservoir-pertinent fabrics and lithofacies contained some amount of quartz overgrowths, which are most common in “bleached” and white rocks, and iron-oxide coatings, which are common in yellow, orange, red, and dark brown rocks.

Interpretations

The development of specific minerals, mineral fabrics, and filling of pore-space between framework grains are divided into three stages of diagenesis. These three stages describe the relative depth of the rocks during each stage and the specific mineralogical and textural changes that occur during each stage (Walker and others, 1978; Burley and others, 1985).

Eogenesis is the earliest stage of diagenesis and occurs during shallow burial. The Ssd facies and adjacent intervals of syndepositional Bss facies were likely formed during this stage when sediments were not yet totally lithified. This is also most likely the stage in which carbonate minerals developed as cements in the pore space of the ID fabrics and caused a large decrease in any original porosity in these beds. Many of the iron-oxide coatings around grain boundaries were also likely formed during this stage. Iron oxide-rich strata within the Ssd fabrics are deformed, suggesting that deformation occurred post iron oxide development. It is unlikely that there was preferential development of iron oxide coatings in isolated segments of strata in the Ssd intervals post deformation. Compaction, decreased pore-space volume, and development of some accessory clay minerals likely occurred during this stage as well.

Mesogenesis is the middle stage of diagenesis associated with deep burial of rock. This stage is likely reflected in quartz overgrowths, more grain point contacts with compaction, and an overall decrease in porosity and permeability.

Telogenesis is the final stage of diagenesis during which rock is exhumed after deep burial. Structural deformations, associated with Laramide orogenesis, including faulting, development of joints, and deformation bands likely occurred during telogenesis. This stage may include the presence of migrating fluids, which caused the preferential bleaching and/or precipitation of iron minerals. The geomorphic patterns of bleaching and iron precipitation appear to be controlled by primary sedimentary features, most notably erosional bounding surfaces, the ID lenses, the WR and GF cross-beds, as well as many of the structural deformations such as fault surfaces.

Previous studies suggested that various buoyant fluids migrated in the Navajo reservoir (Potter-Mcintyre and others, 2013), which would behave similarly to a super-critical carbon fluid. In this previous study, large intervals of sandstone are bleached and lack iron-oxide cements, whereas other intervals appear to preserve oxidizing fronts where iron-bearing minerals occur along various boundaries. Faults, erosional bounding surfaces, and syndepositional deformation intervals commonly show iron cements. This suggests that these surfaces and intervals interacted with migrating fluids for sufficiently long periods of time to precipitate iron minerals, and perhaps acted as stratigraphic baffles and/or barriers which impeded flow. The movement of these fluids is complex and warrants additional investigation to better understand the past history of fluid alteration within the Navajo Sandstone.

Structural Deformation

Structural deformation, or brittle displacement of original rock by mechanical failure due to stress after lithification, exists in a spectrum ranging from major displacement along normal faults (10 to 20 m) to cm-scale en-echelon microfaults (figure 5-8C). The majority of faults observed within the Navajo Sandstone are contained within the upper zone, perhaps due to the lack of ID lenses and/or higher porosity. Some of the larger displacement (20 m normal offset) faults likely penetrate the lower stratigraphic zone, but smaller faults and microfaulting associated with main fault strands seem to be limited to the upper stratigraphic zone. Slickensides, or fabrics of extremely fine-grained material produced from the cataclasis of larger, pre-existing grains during faulting, are present along many fault surfaces and weather in positive relief. Slickenside thicknesses ranged from 1 to 4 mm and were composed of both quartz and/or iron oxides. There was no significant difference in permeability between beds that contained faults and beds that did not in the same stratigraphic zone. However, several measurements of permeability normal to fault slickensides (on the fault surface) yielded results between ~1 to 500 mD.

In the upper stratigraphic zone of the Navajo Sandstone there are many examples of deformation bands, which are linear (sometimes conjugate) or sinusoidal fabrics of fine grained or recrystallized material formed from the brittle cataclasis of preexisting grains resulting in reduced porosity and permeability (Fossen and Hesthammer, 1997; Davis, 1999; Zuluaga and others, 2014). Deformation bands in the Navajo are most common in high-strain zones near fault strands, in relatively high porosity (>15%), thick cross-bedded sandstones (Fossen and Hesthammer, 1997; Zuluaga and others, 2014). Past measurement of eolian facies associated with deformation bands suggest that more porous rock (>15% porosity and >1000mD),

specifically the GF fabrics, are more likely to develop deformation bands than less porous beds, including the WR fabric-dominated beds (Fossen and Hesthammer, 1997; Schultz and others, 2010; Zuluaga and others, 2014). This study did not find a difference in the permeability between beds that contained deformation bands and beds that did not, which may be a result of Tiny Perm II precision. These features have small lengths (on average <4 m) and thin widths (<2 mm). It is unlikely these features represent a major baffle or barrier to flow. However, the exclusive occurrence of deformation bands in areas <100 m from major faults, may be useful to integrate in high-resolution modeling of fluid migration in highly faulted regions.

DISCUSSION

Depositional Environments

The lower stratigraphic zone of the Navajo Sandstone likely represents deposition in high water table conditions. Given that the fluvial Kayenta Formation commonly intertongues with the basal Navajo Sandstone, the lower stratigraphic zone represents a progressively drying environment that periodically flooded between dunes when there were sufficiently high water table conditions present. These periods may have included fluvial deposition (both channel and floodplain), lacustrine deposition, possible sabkha deposition, and uncommon drier (Spb lithofacies) interdune deposition.

The upper stratigraphic zone of the Navajo Sandstone likely represents a much drier, lower water table environment, which precluded the formation of interdune flats (Kocurek and Havholm, 1993) and was dominated by large draas and dunes. Seismic activity and dune slope-failure may have caused deeper groundwater to move to the surface causing violent deformation in the subsurface. Additionally, the Navajo did not likely have desert oases in the latter part of its depositional history. Navajo deposition likely evolved from a periodically wet eolian environment with common interdune flats to a very dry erg-dominated environment devoid of interdune flats.

Fluid Pathways

Records of past fluid migrations provide important clues as to the preferential fluid pathways that exist within eolian units. Major erosional bounding surfaces act as first-order controls on fluid movement (Potter-Mcintyre and others, 2013). Additionally, faults, joints, and other fractures likely act as diagenetic fluid conduits. A summary of potential baffles and barriers to flow as well as fluid migration in unrestricted flow environments is outlined in figure 5-15.

The Navajo Sandstone vertical section can be efficiently assessed for reservoir potential through the examination of key reservoir-pertinent fabrics that include wind ripple (WR) cross-bedding, grainflow (GF) cross-bedding, and interdune (ID) lenses. The WR cross-beds and GF cross-beds comprise 85% to 90% of Navajo section, range in porosity between ~7% to 22%, and have permeabilities between 100 to 1500 mD(?). The ID fabrics, which comprise only 5% to 10% of total vertical section but are limited to the lower stratigraphic zone, have average porosity of ~3%, and permeabilities between 5 and 590 mD.

The architectural arrangement of reservoir-pertinent fabrics is the largest-scale control on fluid flow in the Navajo Sandstone. In particular, the high concentration of the GF cross-beds

relative to WR cross-beds, and thickness of rock between major erosional bounding surfaces are perhaps the most important characteristics of reservoir-supporting rock fabrics in the Navajo. These reservoir-supporting rock fabrics are dominant in the upper stratigraphic zone. The presence of baffles and barriers to flow such as thin WR-dominant cross-beds, and the ID fabrics act to impede fluid migration and are dominant in the lower stratigraphic zone. Furthermore, the lensoidal, thin morphology of ID fabrics may act to preferentially deflect fluid laterally, and may actually slow injected fluids from migrating vertically as quickly as they would in the GF and WR fabrics.

COVENANT OIL FIELD: CORE ANALYSIS

Field Overview

The only available and relevant subsurface Navajo Sandstone core applicable to our study was from the Wolverine Gas & Oil Federal No. 17-3 well (SENW section 17, T. 23 S., R. 1 W., SLBL&M, Sevier County) in Covenant oil field in the central Utah thrust belt (figure 5-1). Covenant field was discovered in 2004 and has produced over 25 million bbls of oil from the Navajo Sandstone and Temple Cap Formation (Middle Jurassic) (Utah Division of Oil, Gas and Mining, 2018). The field trap is an elongate, symmetric, northeast-trending fault-propagation/fault-bend anticline (figure 5-16), with nearly 800 feet of structural closure and a 450-foot-thick oil column (Chidsey and others, 2007). The Navajo and Temple Cap reservoirs are effectively sealed by mudstone and evaporite in the overlying Middle Jurassic Arapien Formation.

Lithology

The productive part of the Navajo Sandstone at Covenant field is about 240 feet thick and is characterized by thick, large-scale, trough, planar, or wedge-planar cross-beds (35 to 40°) commonly recognized as classical eolian dune features (figure 5-17); contorted bedding, wind ripples, and small-scale cross-beds are also common. Massive, homogenous beds with no distinct sedimentary structures or laminations are also recognized in the Navajo cores and were probably formed by water-saturated sand.

In general, core from the Navajo Sandstone consists of very well to well-sorted, very fine to medium-grained (1/16 mm to ½ mm), subangular to subrounded, light-yellow-gray sand or silt grains cemented by carbonate cement. However, some intervals show a bimodal grain-size distribution representing silty laminae between sand beds (figure 5-18A). The typical sandstone is 97% white or clear quartz grains (usually frosted) with some quartz overgrowths, illite, and varying amounts of K-feldspar (figure 5-18B). Feldspar is more common in the Navajo Sandstone than White Throne Formation (Chidsey and others, 2007).

Reservoir Properties

The Navajo Sandstone cores from Covenant field show heterogeneous reservoir properties because of (1) various cyclic dune lithofacies with better porosity and permeability in certain dune morphologies, (2) diagenetic effects, (3) extensive fracturing. Identification and

correlation of the numerous bounding surfaces as well as recognition of fracture set orientations and types in individual Navajo reservoirs are critical to understanding their effects on production rates and fluid movement pathways. The average porosity for the Navajo Sandstone at Covenant field is 12% (Chidsey and others, 2007); the average grain density is 2.651 g/cm³ based on core-plug analysis. Permeabilities in the Navajo from the core data are upwards of 100 mD. Porosity and permeability are greatest in thickly laminated avalanche deposits and along bounding surfaces (bedding planes), with preferred directions along the dip and strike of the individual slipfaces or lee faces (cross-beds).

Fractures and Diagenesis

Fractures in the Navajo Sandstone cores consist of two types: (1) early, bitumen and gouge-filled, silica-cemented, impermeable fractures (figure 5-17), and (2) later, typically open (little gouge or cement), permeable fractures. The later fractures are related to fault-propagation folding during the Sevier orogeny after deep burial.

Diagenetic effects and fracturing both reduce and enhance the reservoir permeability of the Navajo Sandstone at Covenant field. Quartz grains have minor overgrowths and some authigenic clay mineralization has occurred in the form of grain-coating, pore-bridging, and fibrous illite. Some ferroan(?) dolomite and fractured, corroded K-feldspar are also present. Development of bitumen and gouge-filled, silica-cemented fractures locally reduce reservoir permeability. Dissolution of silicate minerals and the development of open fractures increase reservoir permeability.

MULTIPHASE FLOW PROPERTIES OF THE NAVAJO SANDSTONE

To enable estimates of storage capacity, injectivity, and sealing behavior of the confining zone, we conducted measurements of multiphase fluid properties of available samples from core and outcrops. Herein we present methods and results for the following: mercury porosimetry on Navajo Sandstone samples; absolute and relative permeability on Navajo Sandstone samples, including stress-sensitivity; and petrographic observations of Navajo Sandstone thin sections. We also provide information on pore size types and flow characteristics of the Navajo. Our goal was to document our methods and disseminate results to the CarbonSAFE modeling team.

Sample Selection

A goal of the Site Characterization group was to perform capillary pressure and relative permeability tests on Navajo Sandstone samples that are at least representative of the three major facies—the upper dune facies, the middle interdune facies, and the lower dune facies—that have been identified as relevant for the injection site. Three challenges were the following:

- (1) core from near the proposed injection site area was not readily available,

- (2) it is not clear if the outcrop samples were that are representative of the subsurface, and
- (3) our budget was limited to three relative permeability tests using the brine-CO₂ fluid pair.

We again evaluated the Navajo Sandstone core from the Federal No. 17-3 well in Covenant field, which is ~55 miles from the proposed injection targets near the Hunter Power Plant (figure 5-19). The core contains the upper dune facies, but not the middle interdune nor lower dune facies. To assess the relevancy of the core, we compared well logs from the Federal No. 17-3 well to wells near the Hunter Plant (figure 5-20). The Navajo thickens to the southwest as in seen within Castle Valley. The correlations show that the core in the Federal No. 17-3 well is entirely in the upper Navajo Sandstone. The Castle Valley area has better porosity development than in Covenant field. A question is the following: are the permeabilities from Covenant relevant to the Castle Valley area? We cannot be certain since there is no permeability data from Castle Valley area to compare. However, there was no geologic reason to suspect that there would be a significant difference in the porosity/permeability ratios between the two areas.

The concern about outcrop samples was that while they reveal trends in permeability and porosity for different facies that are similar to trends in the subsurface, the absolute values may be different. Thus, based on the above discussion, we used plugs from the Federal No 17-3 core, but also obtained plugs from outcrop to facilitate subsurface core-outcrop comparison. Table 5-3 lists the locations of six plugs from the Federal No. 17-3 core, at approximately 1.5-inch diameter, which were taken previously for permeability and porosity measurements. We sampled additional plugs at the same depths from the core, at approximately 1-inch diameter by 1-inch long for mercury porosimetry capillary pressure measurements. Relative permeability measurements were performed on three of the previously sampled plugs from table 5-3, namely at depths of 6805.2 feet, 6820.6 feet, and 6830.4 feet. The six plugs of table 5-3 are related to the core descriptions shown on figure 5-21. Two outcrops samples were taken, one from an avalanche tongue facies near the Buckhorn Wash site, and one from an interdune facies from the Little Wedge area described in Chapter 3.

Geomechanical Results

Leeb Hardness and seismic velocities were measured on core from the Federal No. 17-3 well. A Proceq Piccolo Hammer and Pundit ultrasonics system measured point load hardness and P- and S-wave velocities on samples from the Navajo Sandstone and the overlying Sinawava Member of the Middle Jurassic Temple Cap Formation at regular intervals (see Chapter 6 for description of the Temple Cap). Results are shown in figure 5-22. In general, velocities track hardness values, and both show a transition at about 6760 feet (the Temple Cap–Navajo lithological boundary as shown in figure 5-21 with Navajo lithofacies being slightly weaker than Temple Cap (Sinawava). There is also the suggestion of a slight lowering of velocities and Leeb hardness (which correlates to macroscopic geomechanical properties like unconfined compressive strength, and thus fracture gradient) of Navajo samples with depth.

Mercury Porosimetry

The mercury porosimetry measurements involve injection or intrusion of the “non-wetting” mercury into a rock sample from low to high (i.e., 60,000 psia) pressure. Extrusion was also performed, which is the release of pressure with measurement of extruded mercury volumes. Rock samples are placed under vacuum prior to the measurements. Data produced include incremental (and cumulative) volumes of mercury injected into (or extruded from) the penetrometer bulb containing the rock sample and the corresponding pressures. A total of eight sample plugs were used in the mercury porosimetry tests (table 5-4) with six from the Federal No. 17-3 core and two from outcrop samples. Poro-Technology performed the mercury porosimetry tests on a Micromeritics AutoPore IV 9500 V1.09™ instrument.

Results are summarized in figure 5-23 (capillary pressure curves for six the samples listed in table 5-3 plus the two outcrop samples) and figure 5-24 (interpreted pore size distributions). Sample 3 (5-117 in table 5-3 at the depth of 6805.2 feet; eolian dune facies) has the lowest intrusion capillary pressures, whereas sample 2 (4-96 in table 5-3 at the depth of 6784.6 feet; dune toe) has the highest intrusion pressures. As discussed below, sample 5-117 (depth of 6802.0 feet) is medium grained with larger observed pore apertures (figure 5-25) compared to the other samples investigated. Porosity and permeability derived from the mercury intrusion results are given in table 5-4, which do not correlate with values obtained from earlier analyses on these cores.

Petrography

Petrographic observation was made on previously prepared standard-size thin sections from the Federal No. 17-3 core. Thin sections closest to the sample plugs and in the same lithofacies (based on figure 5-21) were selected. Photomicrographs of selected samples used for the relative permeability results (discussed in the next section) are shown in figure 5-25.

Sample 129 (sample 5 in table 5-3) is fine sand, moderately well sorted, and shows very little cement overgrowths. It is composed mostly of quartz grains and minor heavy mineral grains. Almost all quartz grains show signs of mechanical compaction, including trans-granular fractures emanating from grain contacts. Sample 139 (sample 6 in table 5-3) is fine to very fine sand, moderate-to-poorly sorted, and contains slightly less trans-granular fractures compared to sample 129. However, a long fracture is seen to traverse the sample from upper right to lower left. Again, very little cement is observed. Sample 117 is medium grained, well sorted, and shows abundant tangential contacts. Similar to samples 129 and 139, there is very little observed cement and textures are consistent with mostly mechanical compaction with minor amounts of chemical compaction. Porosity of these samples ranges from 12% to 17%.

Absolute and Relative Permeability Measurement and Stress Sensitivity

Absolute and relative permeability measurements were performed on three core samples (129, 139, and 117; see table 5-3) to examine the range of stress sensitivity and

relative permeability within the Navajo reservoir in the Federal No. 17-3 well. Horizontal plugs were measured, weighed, and jacketed in a multi-layer configuration required for compatibility with supercritical CO₂ and acidified brines. For single phase permeability measurements, samples were flooded under vacuum with an NaCl brine made from reagent grade NaCl and milli-Q deionized water. The NaCl content matched measured values from nearby wells. Permeability measurements were made at increasing values of effective pressure (equal to confining pressure minus pore pressure) with the final effective pressure matching estimated in situ values of the core at the Federal No. 17-3 well depths. For two-phase supercritical CO₂-brine relative permeability measurements, CO₂ and brine were prepared from ultrapure CO₂ and the above brine solution and pre-equilibrated in a Hastelloy Parr reactor. Steady-state relative permeability measurements were made by simultaneously injecting CO₂ and brine at predetermined flow rates using Hastelloy ISCO high pressure syringe pumps. Relative permeability measurements were made after seven residence times (equal to pore volumes divided by volumetric flow rates). These measurements were followed by four CO₂ injection rates at increasing flow rates from ~1 mL/min to ~20 mL/min). These were used to determine capillary pressure curves for comparison to the mercury results, as well as to determine CO₂ relative permeability at irreducible water saturations. A final step used 100% brine flooding to assess relative permeability hysteresis and values of residual CO₂ saturation (extent of CO₂ trapping). These steps were carried out successfully for two of the three cores (samples 177 and 129); sample 139 failed due to a jacket leak.

Results of effective pressure-dependent brine permeability and brine-CO₂ relative permeability are shown in figure 5-26 with brine relative permeabilities shown in blue symbols and CO₂ relative permeabilities shown in orange symbols. Preliminary fits to Brooks-Corey functions are shown by the solid lines of like color. Single phase permeability for all three samples shows a similar stress dependency with monotonically decreasing permeability with effective pressure (we show curve fits for the higher effective stress values using a simple exponential function), with values for the sample 117 being slightly higher than the other two samples. This is consistent with the mercury intrusion measurements (sample 117 having slightly larger pore throats than the samples 129 and 139).

Relative permeability curves for samples 117 and 129 are very similar, with slightly lower irreducible water saturations and higher CO₂ relative permeability at irreducible water saturations for the medium grained 117 compared to the fine grained 129. Sample 117 has higher lower residual CO₂ saturations (i.e., trapped CO₂), and slightly higher brine relative permeability at residual CO₂ saturation than sample 129, again consistent with its slightly larger pore sizes and better sorting. Sample 139 has very low relative permeabilities compared to the other two samples, and this we attribute to grain flow and loss of cohesion of the sand pack observed after introduction of acidified brine. It is not known why 139 responded so differently to CO₂ exposure relative to the other samples.

SUMMARY

Measured sections and outcrop samples across the San Rafael Swell, and cores from Covenant oil field help characterize the suitability of the Navajo Sandstone as a CCS reservoir. There are 14 distinct lithofacies which are grouped into five lithofacies associations that

correspond to interpreted depositional environments. Additionally, the sedimentological differences and stratigraphic distributions of three key reservoir-pertinent fabrics have the greatest impact on reservoir quality. Dune-associated lithofacies have the highest porosity and permeability, whereas interdune-associated lithofacies have the lowest permeability and porosity. Reservoir-supporting fabrics, WR and GF cross-beds, in the lower stratigraphic zone appear to have lower porosity and permeability than those in the upper stratigraphic zone. Moreover, the ID reservoir-baffle/barrier fabrics only occur in the lower stratigraphic zone.

Excellent porosity (~7% to 25%) and permeability (on average ~1500 mD[?]) exist within the entire Navajo outcrop to support substantial subsurface injection of sequestered carbon fluids in the western portion of the San Rafael Swell. The division of the Navajo Sandstone into a lower stratigraphic “wet” zone and an upper “dry” zone is also a suitable division of the unit in terms of reservoir quality. The lower zone is more lithologically heterogeneous, with baffles, and the upper is a more homogenous, “ideal reservoir” zone. Major erosional bounding surfaces act as first order controls on fluid migration. Horizontal interdune lenses, which are exclusive to the lower zone, act as baffles or potential barriers to vertical flow, and would likely deflect migration fluids laterally. Structural deformation as well as soft-sediment deformation occur on a larger scale in the upper stratigraphic zone. The upper stratigraphic zone would likely allow a buoyant carbon fluid to migrate vertically more readily than the lower Navajo zone due to the lack of ID fabrics and higher concentration of GF fabrics. Despite the differences in hydraulic conductivity between the upper and lower stratigraphic zones, both would comprise a reasonable storage reservoir for CCS.

Cores from the Navajo Sandstone in Covenant field display a variety of eolian desert lithofacies (dune and interdune), fracturing, and minor faults which, in combination, create reservoir heterogeneity. They also provide the subsurface petrological and petrophysical analog data critical modeling the Navajo reservoir in the study sites.

We provide measurements on geomechanical properties, mercury intrusion capillary pressure, and single and relative permeabilities of selected samples of the Navajo Formation from the Federal No. 17-3 well west of the San Rafael Swell. In general, the different lithofacies of the Navajo Sandstone are expected to behave similarly geomechanically and hydrologically to CO₂ injection, with small variations attributable to observed heterogeneities in grain and pore size. One possible item of concern is the apparent sensitivity of one sample with exposure to acidified brine, which exhibited a marked loss of cohesion. It is not known why this sample (139) responded in this fashion but should be investigated further in subsequent studies.

CHAPTER 5 FIGURE AND TABLE CAPTIONS

Figure 5-1. Location of Covenant field, Navajo Sandstone outcrops, uplifts, and selected thrust systems in the central Utah thrust belt, often referred to as the “Hingeline.” Numbers and sawteeth are on the hanging wall of the corresponding thrust system. Colored (yellow) area shows present and potential extent of the Jurassic Navajo Sandstone/Temple Cap Formation play area. Modified from Hintze, 1980; Sprinkel and Chidsey, 1993; and Peterson, 2001.

Figure 5-2. Locations of measured stratigraphic sections and geologic units with major unconformities labeled (modified from Doelling and others, 2017). The Hunter Power Plant,

which is one of two prospective carbon-capture sites, is located less than 40 km away from the Buckhorn Wash (BW) study site.

Figure 5-3. View to the northeast from a cliff overlooking Buckhorn Wash.

Figure 5-4. Navajo Sandstone measured sections displayed as interpreted lithostratigraphic facies; color denotes facies association.

Figure 5-5. Cross-bedded dune-associations (table 5-1) include the Pxb, Txs, and Txl lithofacies. A – Planar cross-bedded sandstone (Pxb) facies contain grainflow (GF) fabrics outlined by blue dashed lines, and are bounded by erosional bounding surfaces outlined in red. A thin lens of sheet plane-bedded sandstone (Spb) facies sits above the Pxb bed and is bounded by erosional surfaces. The picture is from the lower stratigraphic zone. B – Small trough cross-bedded sandstone (Txs) facies are dashed in red, are observed in erosional contact with underlying strata, and are erosionally truncated as indicated by the green dashed line in the lower stratigraphic zone. C – Large trough cross-bedded sandstone (Txl) beds are in erosional contact with one another along red dashed surfaces and truncated by a major erosional bounding surface (green dashed line), whereas individual dune migration slope surfaces are outlined in blue dashed lines. This picture represents the upper stratigraphic zone.

Figure 5-6. Interdune associations include the Spb (figure 5-5) Rip, Unl, and Mss facies. A – Ripple-laminated sandstone (Rip) facies display asymmetric ripples indicating apparent paleoflow trajectory to the left. B – Undulose laminated sandstone (Unl) facies display irregular, mm-thick laminae. C – Massive sandstone (Mss) facies lack internal structure and only occur beneath the Rip and/or Unl facies.

Figure 5-7. Fluvial associations. A – Interbedded sheet sandstone and conglomerate (Isc) facies, which are partly comprised of sheet mudstone (Smd) clasts. B – Cross-bedded to cross-laminated sandstone (Xxs) facies are present. C – Isc facies overlie both an Mss interval and an intraformational conglomerate (Itc) interval which appears to be plastically deformed by Mss and Isc beds, which thicken to the right. D – Sheet mudstone (Smd) facies composed of green siltstone and gypsum are present.

Figure 5-8. Deformed associations include the Ssd and Bss lithofacies. A – Soft-sediment deformed (Ssd) facies exhibit plastically deformed strata which are laterally conformable with undeformed Txl strata below and erosionally truncated by Txl strata above. B – This example of Bss facies contains a structureless sandstone matrix with horizons of non-plastically deformed strata. C – The Bss facies also include faulting, such as en-echelon faulting shown in this photo.

Figure 5-9. Psuedo-bedded sandstone (Psb) facies resemble massive sandstone (Mss) facies due to diagenetic bleaching, but unlike the Mss facies, are not completely structureless.

Figure 5-10. A – Wind ripples (WR) fabrics in outcrop. B – This example of WR cross-bedding in thin section displays characteristic inverse grading. C – Grainflow (GF) tongues are pinching out at a dune toe. D – This example of GF cross-bedding in thin section exhibits a typical massive texture. E – This carbonate-cemented sandstone is interpreted as an interdune deposit

(ID) fabric. F – This example of an ID fabric in thin section exhibits carbonate-rich matrix and pore-filling carbonate which has reduced porosity.

Figure 5-11. Thin sections prepared perpendicular to bedding were mounted in blue epoxy to estimate porosity. A – Wind ripple (WR) cross-bedding has low porosity values and B grainflow (GF) cross-bedding has generally higher porosity values.

Figure 5-12. Porosities plotted as a function of stratigraphic height above base of Navajo Sandstone by key reservoir-pertinent fabrics. Note greater porosity values in the GF and WR fabrics. The ID sample porosities appear limited to ~12% porosity across stratigraphic intervals.

Figure 5-13. A – Rock porosities and B – permeabilities are plotted as a function of key reservoir-pertinent fabrics.

Figure 5-14. Overall stratigraphic trends as a function of height above the base of the Navajo Sandstone. A – Syndepositional deformation in the Navajo includes both non-plastic and plastic deformation and is analyzed separately from structural deformation. B – Interpreted interdune deposits are absent from the upper stratigraphic zone of the Navajo. C – The relative dominance of internal cross-bedded fabrics changes from wind ripple (WR) dominated-fabrics in the lower zone to grainflow (GF) dominated-fabrics in the upper zone.

Figure 5-15. Idealized fluid pathways based on facies elements with highly unrestricted flow in green, to highly restricted flow in red. Blue arrows represent likely flow pathways around the red-dashed relative baffles and barriers to flow. Note the variation in spatial scale of fluid pathways.

Figure 5-16. Northwest-southeast structural cross section through Covenant field. Modified from Schelling and others (2007), Chidsey and others (2007).

Figure 5.17. Cross-bedding in fine-grained sandstone deposited in an eolian dune environment of the Navajo Sandstone, from the Federal No. 17-3 well (slabbed core from 6776 feet), Covenant field. Also shown are early, bitumen and gouge-filled, silica-cemented, impermeable fractures that have slight offsets.

Figure 5-18. Representative photomicrographs from the Navajo Sandstone in the Federal No. 17-3 well. A – Bimodal distribution of subangular to subrounded quartz sand and silt (plane light) deposited in a vast eolian desert dune field. Note a few fractured and corroded K-feldspar grains are present. Blue space is intergranular porosity. Porosity = 14.8%, permeability = 149 mD based on core-plug analysis, 6773 feet. Courtesy of Wolverine Gas & Oil Corporation. B – Dolomite cement around a subangular microcline (striped gray) feldspar among bimodally distributed quartz grains (crossed nicols). Federal No. 17-3 well, 6757 feet. Courtesy of David E. Eby, Eby Petrography & Consulting, Inc.

Figure 5-19. Map showing locations of the Federal No. 17-3 well and the injection targets, which are three salt water disposal wells northwest of the Hunter Power Plant (courtesy Google Earth Pro).

Figure 5-20. Well log comparison between Covenant oil field and the Hunter Power Plant area.

Figure 5-21. Federal No. 17-3 core descriptions with the six locations of mercury porosimetry samples indicated by red dots and depths in bold. Note that relative permeability samples are also from this subset of the depths: 6805.2 feet, 6820.6 feet, and 6830.4 feet.

Figure 5-22. P- and S-wave velocity and Leeb Hardness measured on core samples of the Federal No. 17-3 well.

Figure 5-23. Capillary pressure curves for six samples from the Federal No. 17-3 core (in blue; see table 5-3) and two outcrop samples (in red and dashed).

Figure 5-24. Pore aperture distributions based on capillary pressure data for six samples from the Federal No. 17-3 core (in blue; see table 5-3) and two outcrop samples (in red and dashed).

Figure 5-25. Photomicrographs (plane polarized light) of three samples representative of ones used for relative permeability tests. Sample 129 is from 6820.6 feet, eolian dune lithofacies; sample 139 is from 6830.4 feet, small dune lithofacies; and sample 117 is from 6805.2 feet, and is eolian dune lithofacies. The red scale bar in each case is 1 mm.

Figure 5-26. Single phase permeability plotted as a function of effective pressure (left hand plots) and brine-CO₂ relative permeability (right hand plots) for samples 129 (top) and 117 (bottom).

Table 5-1. Lithostratigraphic facies and facies associations described and grouped.

Table 5-2. Basic petrophysical properties of outcrop hand samples from the Navajo Sandstone, San Rafael Swell.

Table 5-3. Federal No. 17-3 core plugs selected for relative permeability measurements. The porosity and permeability measurements were performed previously at 1400 psi net confining stress. All six plugs listed are horizontal in orientation.

Table 5-4. Porosity and permeability based on mercury porosimetry for Federal No. 17-3 core and outcrop samples.



Rocky Mountain CarbonSAFE Phase I

Appendix F

**RESERVOIR SEALS BASED ON OUTCROPS OF THE MIDDLE
JURASSIC CARMEL AND TEMPLE CAP FORMATIONS,
NORTHERN SAN RAFAEL SWELL**

RESERVOIR SEALS BASED ON OUTCROPS OF THE MIDDLE JURASSIC CARMEL AND TEMPLE CAP FORMATIONS, NORTHERN SAN RAFAEL SWELL

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INTRODUCTION

The Middle Jurassic Carmel Formation is well exposed over large areas of the gently dipping west flank of the San Rafael Swell (figure 6-1). Along the east flank this section is steeply dipping to near flat lying (figure 6-2). Based on the lithologic characteristics determined from regional correlations (figure 6-3), outcrop observations, and measured sections (figure 6-4, plates 6-1 through 6-5), the Carmel should also provide an effective seal for CO₂ injected into the underlying Navajo near the Hunter and Huntington Power Plants along the northwest flank of the San Rafael Swell.

The Middle Jurassic Temple Cap Formation is present in some areas of the San Rafael Swell (plates 6-2, 6-4, and 6-5). The Temple Cap was deposited in coastal dune, sabkha, and tidal flat environments. Where present, the Sinawava Member of the Temple Cap directly overlies the Navajo Sandstone and represents an additional potential seal. There are sections where the eolian White Throne Member lies on the Navajo making it difficult to separate the Navajo from the Temple Cap.

REGIONAL CORRELATIONS

The Carmel and Equivalent Formations

The Carmel Formation is widespread regionally and thus attests to its consideration as a seal for the Navajo Sandstone reservoir. The correlation of Middle Jurassic formations and their members as well as their lithofacies is summarized on figure 6-3. The strata naturally fall into three regions based on lithology: 1 – northern Utah, 2 – central Utah, and 3 – southwestern Utah. The central region includes the Carmel Formation in the San Rafael Swell and the equivalent Arapien Formation in the central Utah thrust belt to the west. The Carmel is equivalent to Twin Creek Limestone in the northern region. The colored boxes on figure 6-5 represent the general east-west lithofacies distribution and depositional environments. Note that the Twin Creek Limestone and Arapien Formation in the northern and western central regions, respectively, generally represent open, restricted, and marginal marine environments grading eastward and southeastward in the Carmel Formation to marginal marine, fluvial, and eolian environments.

Ages

Middle Jurassic isotopic ages for the Carmel and other Middle Jurassic formations in Utah are based on samples from volcanic ash beds (Kowallis and others, 2001, 2011; Sprinkel and others, 2009). The red dots on figure 6-3 represent the approximate stratigraphic position of radiometric ages obtained from sanidine, biotite, or zircon crystals, and palynomorph assemblage distribution. The age of the underlying Gypsum Springs Formation is 185 Ma in the northern region; the preferred age range of the Temple Cap Formation is 173 to 170 Ma in the central and southern regions; Sliderock, Rich, and Co-op Creek Limestone Members is 169 to 167 Ma; Boundary Ridge-Crystal Creek and Watton Canyon-Paria River Members is 166 to 165 Ma; and Leeds Creek-Giraffe Creek-Twelvemile Canyon-Winsor Members is 164 to 162(?) Ma. The numeric ages of the time boundaries are from Cohen and others (2013).

Unconformities

The Carmel Formation overlies the Temple Cap Formation, where it is present, or the Lower Jurassic Navajo Sandstone of the Glen Canyon Group. The Middle Jurassic Carmel (or Temple Cap) is separated from the underlying Navajo by the J-1 unconformity (figure 6-3) (Pipiringos and O'Sullivan, 1978). Recent research indicates the J-1 is a major regional unconformity representing a hiatus of over 10 million years (Kowallis and others, 2001, 2011; Sprinkel and others, 2009, 2011; Dickinson and others, 2010; Phillips and Morris, 2013). At the top of the Navajo, the J-1 is indicated by angular chert fragments, desiccation cracks, brecciation zones, carbonate nodules, bioturbation, and thick bleached intervals (Pipiringos and O'Sullivan, 1978); however, the J-1 can be very subtle in some areas. In addition, the upper Navajo contact undulates up to 200 feet over long distances, creating paleohighs and providing further evidence that the J-1 is a significant regional unconformity (Sprinkel and others, 2009; Anderson and others, 2010; Phillips and Morris, 2013).

The Carmel Formation and the underlying Temple Cap Formation were thought to be separated by the J-2 unconformity of Pipiringos and O'Sullivan (1978). However, age dating and stratigraphic work show that there is little evidence for the J-2 in the central and southern regions. The J-2 is present in the northern region where the Twin Creek Limestone lies unconformably on the Gypsum Springs Formation. Based on radiometric age dating, the J-2 may represent a gap of as much as 17 million years. Many exposures show no lithologic evidence of an unconformity (Anderson and others, 2010).

The Middle Jurassic Entrada Sandstone lies conformably above the Carmel Formation in the San Rafael Swell.

CARMEL FORMATION

The four members of the Carmel Formation—the Co-op Creek Limestone (or equivalent Judd Hollow), Crystal Creek, Paria River, and Winsor (figure 6-5)—are described in detail in the following sections. They have been mapped on the surface, measured, and described by Doelling and Kuehne (2008) and Sprinkel and Doelling prior to this study. All four members are not always present within the San Rafael Swell. The formation is highly heterolithic consisting of siliciclastics, carbonates, shales, and has numerous evaporite beds, all contributing to form an

excellent seal.

The Carmel Formation is the result of deposition during the transgression of the shallow marine Sundance Sea, which extended south from Canada into a narrow embayment or arm (called the Utah-Idaho trough) through northern, central, and southwestern Utah (Blakey and Ranney, 2008; Hintze and Kowallis, 2009). Shoreline fluctuations produced variations between restricted- and more open- to marginal-marine conditions, causing significant changes in deposition. This was especially the case along the eastern margin of the marine embayment, which is now exposed within the San Rafael Swell. The Co-op Creek and Paria River Members correspond to marine transgressions and the Crystal Creek and Winsor Members represent regressions (Doelling and others, 2010a). Doelling and Kuehne (2008) suggest a possible unconformity (angular) separates the Crystal Creek and Paria River Members.

Co-op Creek Limestone/Judd Hollow Members

The basal Co-op Creek Limestone Member is exposed along the western half of the San Rafael Swell (figure 6-5) and the stratigraphically equivalent Judd Hollow Member is exposed on the east side (figure 6-6A), forming the classic dark flatirons on the lighter Temple Cap Formation and Navajo Sandstone along the steep east flank of the San Rafael Swell structure. The members are Bajocian in age and range in thickness from 33 to 80 feet. The Co-op Creek and Judd Hollow consist of interbedded sandstone, siltstone, mudstone, and limestone with subordinate amounts of dolomite, doloarenite, calcarenite, and calcisiltite. Limestone dominates the Co-op Creek whereas sandstone dominates the Judd Hollow, representing a gradational change in lithofacies from west to east across the San Rafael Swell area. Sandstone is light brown to light gray or yellow, friable, and composed of very fine to coarse-grained, generally calcareous, well-sorted, and subrounded to rounded quartz sand. Sandstone beds can be slightly planar to cross-stratified or bioturbated. Limestone is light and dark gray to yellow-gray or green gray to pink lavender, hard and densely crystalline (micritic) but can be silty or sandy. Limestone beds are often laminated and may display ripples, mudcracks, or some low-angle cross-beds. Some units are vuggy, oolitic, or bioclastic; megascopic fossils include pelecypods and a few gastropods. Siltstone is red to gray, calcareous and often nodular. Mudstone is medium to dark gray to green, slightly silty, calcareous, platy to fissile, with some fine and wavy laminations or flaser bedding. Shale is medium brown-gray or dark gray, clayey, fissile, non- to slightly calcareous. Calcite veins, nodules, as well as and blebs, chert can be present in many units. The Co-op Creek and Judd Hollow form steep slopes or blocky ledges with thin to medium bedding.

The Co-op Creek and Judd Hollow Members were deposited in moderate- to low-energy, normal-salinity, nearshore intertidal marine environments during transgression of the Sundance Sea into the Utah-Idaho trough. The Co-op Creek represents marine conditions, whereas the Judd Hollow represents marginal marine (tidal flat) settings.

Crystal Creek Member

The Crystal Creek Member (Bathonian) ranges in thickness from 0 to 36 feet. It consists of yellow, yellow-gray, or yellow-brown to light-gray sandstone and medium to dark red-brown, gray-pink siltstone (figures 6-5 and 6-6A). Sandstone is calcareous to dolomitic, very fine to medium grained, subrounded, well sorted, porous, and horizontally laminated. It is thin to medium bedded or massive, forming ledges or steep slopes that weather into pale red- or brown-

colored plates that commonly contain ripple marks. Siltstone is nodular and calcareous or non-calcareous and it forms earthy slopes with indistinct or contorted bedding. Both sandstone and siltstone beds contain crisscrossing to subhorizontal satin spar gypsum veinlets.

The Crystal Creek Member was deposited during regression of the Sundance Sea. Environments included moderate- to low-energy, normal-salinity, nearshore intertidal marine.

Paria River Member

The Paria River Member (Bathonian) ranges in thickness from 15 to 170 feet. A few reworked, light-green, air-fall ash beds are present in the Paria River and contain very fine grained sand and small biotite and zircon crystals that provide Bathonian isotopic age dates (see Sprinkel and others, 2011).

The Paria River Member consists of a wide variety of light- to medium-gray, pink-gray, green-gray, brown-gray, yellow-gray or tan-gray lithotypes: sandstone, calcarenite, calcisiltite, limestone, mudstone, siltstone, and gypsum (figures 6-5 and 6-6A). Sandstone (calcareous) and calcarenite are very fine to fine grained, and well sorted; low-angle, small-scale planar cross-stratification, ripple marks, and bioturbation may be present; some calcarenite beds contains oolites. Limestone may be laminated, micritic, or finely crystalline, with silty, argillaceous, and dolomitic or vuggy zones. Pelecypods are found in limestone near the base of the Paria River. Some units contain ooids and ripple marks. The Paria River characteristically displays pencil weathering. Mudstone and siltstone beds are friable, usually calcareous, and in places contain low-angle trough cross-stratification. These lithotypes are generally thin to medium bedded, forming ledges (weathering into slabs and plates) and slopes. Gypsum, which forms the base of the member, is white alabaster, massive, and nearly pure.

The Paria River Member was deposited during a second major transgression of the Sundance Sea (Blakey and Ranney, 2008). Shallow-marine and coastal environments included restricted inner to outer shelf, oolitic shoal, sabkha, and tidal flat.

Winsor Member

The Winsor Member (Bathonian and lower Callovian, based on palynomorphs [Anderson and Lucas, 1994; Sprinkel and others, 2011]) ranges in thickness from 190 to 380 feet. It consists of two main informal units: the lower gypsiferous and the upper banded. The gypsiferous unit consists of interbedded red, red-brown, green-gray, or light-gray sandstone, calcarenite, calcisiltite, and siltstone, and white alabaster gypsum and a few limestone beds. Sandstone is friable, fine grained, well sorted, and cemented with calcite or iron oxide. Calcarenite is very fine grained, well sorted, and laminated to thin bedded with well-developed ripple marks and some bioturbation. Calcisiltite appears shaly and weathers into small plates. Siltstone is coarse grained, gypsiferous (often with fine laminae of gypsum), and contains small lenses of calcarenite. Sandstone and siltstone beds form steep earthy slopes. Gypsum is silty and forms ledges as much as 20 feet thick. The banded unit consists of interbedded sandstone, calcarenite, siltstone, and mudstone that display colored bands of red and gray in various shades, and white gypsum. These rocks have characteristics similar to those in the underlying gypsiferous unit. Gypsum veins crisscross the clastic rocks. Gypsum beds produce frothy “popcorn-like” or sugary weathering on sparsely vegetated surfaces and drape into drainages (Rigby and others, 1974).

The Winsor Member was deposited in restricted, muddy, hypersaline marine and coastal

environments during a second major regression of the Sundance Sea (Blakey and Ranney, 2008).

TEMPLE CAP FORMATION

Outcrops of the Temple Cap Formation within the San Rafael Swell range in thickness from 0 to 60 feet, possibly due to pinchouts against paleohighs of the underlying Navajo Sandstone along the J-1 unconformity (figure 6-6) (Hintze and Kowallis, 2009; Anderson and others, 2010; Doelling and others 2013). The Temple Cap is divided into the three members: the Sinawava (basal marine), White Throne (eolian), and Esplin Point (capping marine) Members (Sprinkel and others, 2009, 2011; Biek and others, 2010). The White Throne and a few very thin beds of the Sinawava are observed in outcrop at the San Rafael Swell (figure 6-6, plates 6-2, 6-4, and 6-5); most of the Sinawava and Esplin Point are present in the subsurface in wells at Farnham Dome gas field and others in the northern part of the San Rafael Swell.

Sinawava Member

The Sinawava Member of the Temple Cap Formation is a heterogeneous, generally 0 to 50-foot-thick section; note that the Sinawava is not present in the outcrop measured sections closest to the Hunter Power Plant (figure 6-4, plates 6-3 and 6-4). This unit is characterized by low-angle to horizontal laminae (figure 6-6) or distorted bedding consisting of red-brown, very fine to fine-grained, thin, poorly sorted sandstone to mudstone, limestone, and gypsum (Sprinkel and others, 2009). Horizontal stratification often contains silty laminae between beds. These beds may also display ripples or channel characteristics (scour) suggesting tidal flow or flooding events.

The Sinawava Member represents a brief time of coastal sabkha and tidal flat environments. This interpretation is supported by the presence of glauconite in sandstone from cores at Covenant field (located about 50 miles west of the San Rafael Swell) indicating marine to marginal marine conditions.

White Throne Member

The White Throne Member of the Temple Cap Formation is homogeneous, generally 0 to 200-foot-thick section; the White Throne is not present in the outcrop measured section along the San Rafael River southeast of the Hunter Power Plant (figure 6-4, plate 6-3) but is present directly east (plate 6-4). It consists of light gray-pink, light-brown, yellow-brown, light red-brown, light-gray, gray, or white sandstone composed of fine- to coarse-grained, moderately sorted quartz sand (figure 6-6). The sandstone is friable, poorly cemented with calcite and/or iron oxides, porous, and locally saturated with dead oil. The White Throne forms cliffs and resistant benches that are medium to thick bedded and partly cross-stratified (Doelling, 2002, 2004; Doelling and Kuehne, 2008).

The White Throne Member was deposited under eolian conditions as a coastal dune field (Blakey, 1994; Peterson, 1994; Blakey and Ranney, 2008). White Throne dunes were smaller than Navajo dunes (widths up to 1650 feet) (Hartwick, 2010). Regional analyses of the mean dip of dune foreset beds from outcrop and Covenant field core indicate paleowind directions were dominantly from the northeast (Peterson, 1988; Hartwick, 2010). About half of the oil production at Covenant field is from the White Throne, the rest coming from the Navajo Sandstone. The

White Throne produces nowhere else at this time.

Esplin Point Member

The Esplin Point Member capping the Temple Cap has characteristics similar to the basal Sinawava Member. It ranges in thickness from 0 to 12 feet and consists of dark red-brown, light-gray, and green-gray siltstone and sandstone. Sandstone beds are very fine to fine grained, well sorted, and thinly laminated to irregularly bedded. Siltstone beds are thinly laminated and form slopes and recesses. The Esplin Point Member documents a rise in sea level and a return to coastal sabkha, tidal flat, and nearshore marine conditions.

DISCUSSION

Carmel Formation Seals

The Carmel Formation is a proven seal for the naturally occurring CO₂ stored in the Navajo Sandstone reservoir at Farnham Dome gas field on the north end of the San Rafael Swell. Based on outcrops throughout the northern Swell, the members of the Carmel contain various beds that would provide a seal for CO₂ injected into the Navajo near the Hunter and Huntington Power Plants.

Foremost among the sealing Carmel lithologies are the multiple, massive gypsum (CaSO₄·2H₂O) beds found in the Paria River and Winsor Members. The Carmel gypsum beds are fairly continuous (plates 6-1 through 6-5). The Paria River typically contains a basal gypsum unit that is 6 feet or greater in thickness (plates 6-1 and 6-2). However, the Winsor contains six to nine gypsum beds ranging in thickness from 1 to 20 feet; total thickness ranges from 50 to 90 feet in outcrops east and southeast of the Hunter and Huntington Power Plants (figures 6-1 and 6-4, plates 6-3 and 6-4). Gypsum is produced from one mine in the Winsor Member on the west flank of the San Rafael Swell and is used for manufacturing wallboard (sheetrock) and plaster (Gloyn and others, 2003). The Carmel contains an estimated 7.3 million tons of minable gypsum. Cumulative gypsum production from the Winsor in the San Rafael Swell since 1990 is about 1.8 million tons (verbal communication, Andrew Rupke, Utah Geological Survey, 2018).

The Judd Hollow/Co-op Creek, Crystal Creek, and Winsor Members of the Carmel Formation contain numerous beds of mudstone and shale that can also serve as a reservoir seal to the Navajo Sandstone below. Individual shale/mudstone beds range in thickness from just a few feet to 45 feet; total thickness ranges from 13 to 70 feet. However, mudstone and shale are more prevalent to the south and southeast of the power plants (plates 6-1, 6-2, and 6-5).

The members of Carmel also include many beds of low-permeability crystalline limestone, marl, and siltstone that are likely barriers to fluid and gas migration.

Core was not available for the Carmel Formation, which is preferred for assessing petrophysical and sealing properties. The Site Characterization team was limited to using outcrops samples for preliminary sealing capacity estimates based on mercury intrusion capillary pressure (MICP) measurements (following methods presented in Chapter 5 for mercury porosimetry). Sealing capacity can be expressed as the height of a non-wetting phase held by capillary forces before it penetrates a rock that is saturated with the wetting phase (Dullien, 1992). To convert mercury capillary pressure curves to sealing capacity in terms of CO₂ columns

heights, we follow methods of Dewhurst et al. (2002) to obtain breakthrough pressures, and we assume: 10° and 140°, respectively for the air-mercury-rock and water-CO₂-rock systems; 27 and 480 mN/m for the interfacial tensions of the CO₂-water and air-mercury systems; and water/brine and CO₂ densities of 1,020 and 740 kg/m³, respectively. The values of CO₂-brine and contact angles for the rock-water-CO₂ system can vary greatly as a function of pressure, temperature, and mineralogy, and thus our choices should be considered preliminary. CO₂ column heights for Carmel Formation samples range from 3 to 1151 m (Table 6-1). These samples were collected from the Buckhorn Wash and Justensen Flats study areas (see Chapter 5). The CO₂ column heights confirm that the Carmel Formation has lithologies with high capillary sealing capacity. Note that the outcrop samples may have undergone weathering, and thus subsurface samples may have different (and probably higher) sealing capacity. The Carmel Formation capillary pressure curves and pore aperture distributions are generally distinct, as expected, from the Navajo Sandstone samples (Figure 6-7).

Temple Cap Formation Seals

The Sinawava and Epslin Point Members of the Temple Cap Formation, where present, also contain lithologies similar to those in the Carmel Formation that serve as seals. These include low-permeability siltstone, mudstone, limestone, and some gypsum. Units are generally thin, 2 to 5 feet thick.

CHAPTER 6 FIGURE CAPTIONS

Figure 6-1. Generalized geologic map of the San Rafael Swell with the Carmel and Temple Cap Formations highlighted in blue. Cross section A-A' shown on figure 6-2. After Doelling and Hylland (2002).

Figure 6-2. Diagrammatic cross section across the middle of the San Rafael Swell with the Carmel and Temple Cap Formations highlighted in blue. The cross section is not drawn to scale, and the vertical dimension is exaggerated about eight times relative to the horizontal. The horizontal length of the cross section covers about 50 miles. Symbols and colors of geologic formations correspond to those shown on figure 6-1; location of cross section also shown on figure 6-1. After Doelling and Hylland (2002).

Figure 6-3. Correlation chart of Middle Jurassic formations and their members in central Utah and the Sevier thrust belt. Modified from Sprinkel and others (2011); compiled from Kowallis and others (2001), Dickinson and others (2010), Sprinkel and others (2011), Doelling and others (2013), Sprinkel, Doelling, Kowallis, Waanders, and Kuehne, 1998-2017 unpublished data, Utah Geological Survey; numeric boundary ages from Cohen and others (2013).

Figure 6-4. Map of the San Rafael Swell showing the location of measured stratigraphic sections (plates 6-1 through 6-5) of the Middle Jurassic Carmel Formation. Also shown are major physiographic features, major towns, highways, and coal-fired power plants.

Figure 6-5. Excellent exposure of Middle Jurassic Carmel Formation, San Rafael Group, west flank of the San Rafael Swell, Devils Canyon south of I-70, view to the east. The Co-op Creek, Crystal Creek, Paria River, and part of the Winsor Members are shown. The Carmel is in direct contact with the underlying Navajo Sandstone represented by the J-1 unconformity. Note: the Temple Cap Formation is not present at this locality. Photograph by Michael Chidsey, Sqwak Productions Inc.

Figure 6-6. Middle Jurassic Temple Cap and Carmel Formations, east flank of the San Rafael Swell, north side of Black Dragon Canyon north of I-70. A – Thin Sinawava and planar to cross-stratified White Throne Members of the Temple Cap Formation separated from the underlying Navajo Sandstone by the J-1 unconformity. The Temple Cap is overlain by the red Judd Hollow-Crystal Creek Members of the Carmel Formation. B – Close-up view of the J-1 unconformity, and thin planar bedding in the Sinawava and White Throne Members. Photographs by Michael Chidsey, Sqwak Productions Inc.

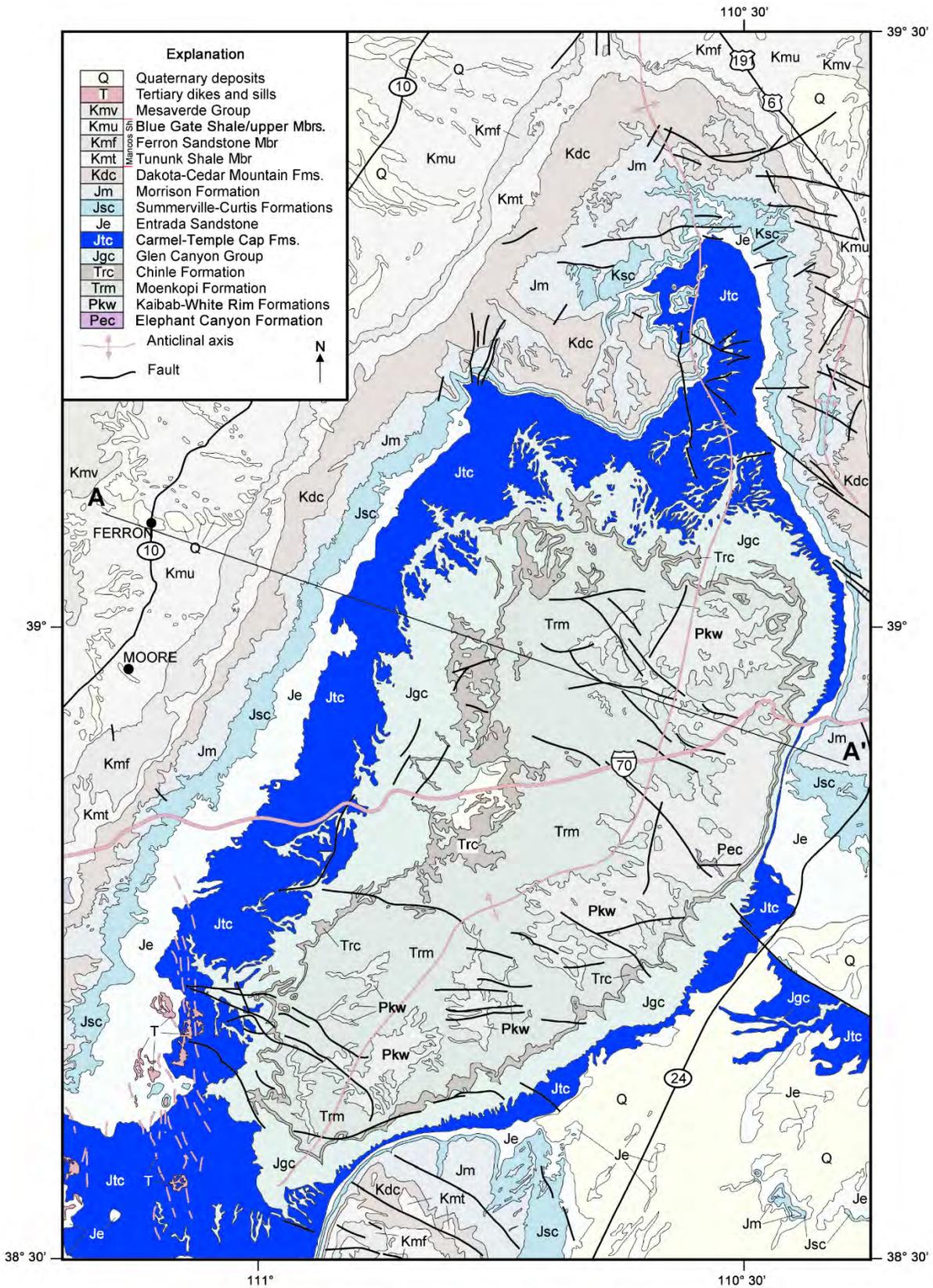


Figure 6-1. Generalized geologic map of the San Rafael Swell with the Carmel and Temple Cap Formations highlighted in blue. Cross section A-A' shown on figure 6-2. After Doelling and Hylland (2002).

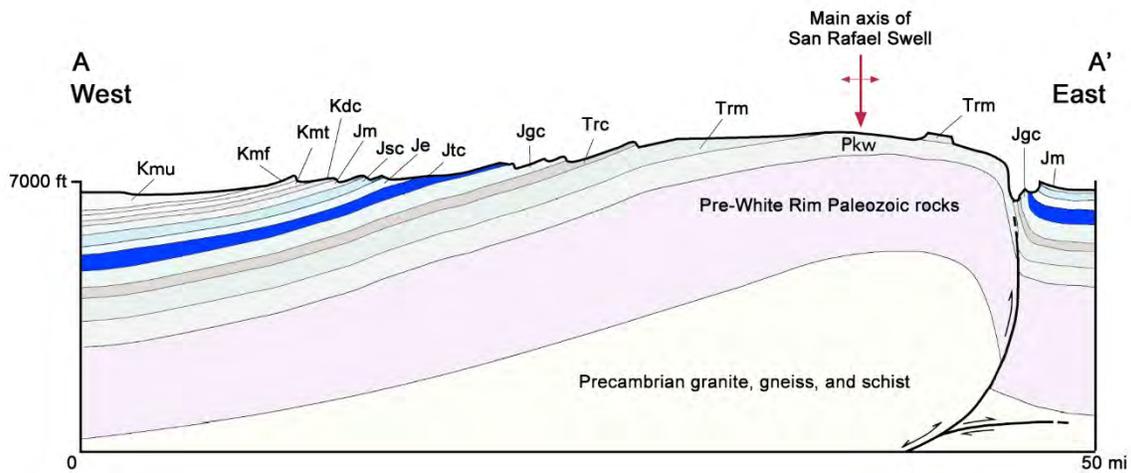
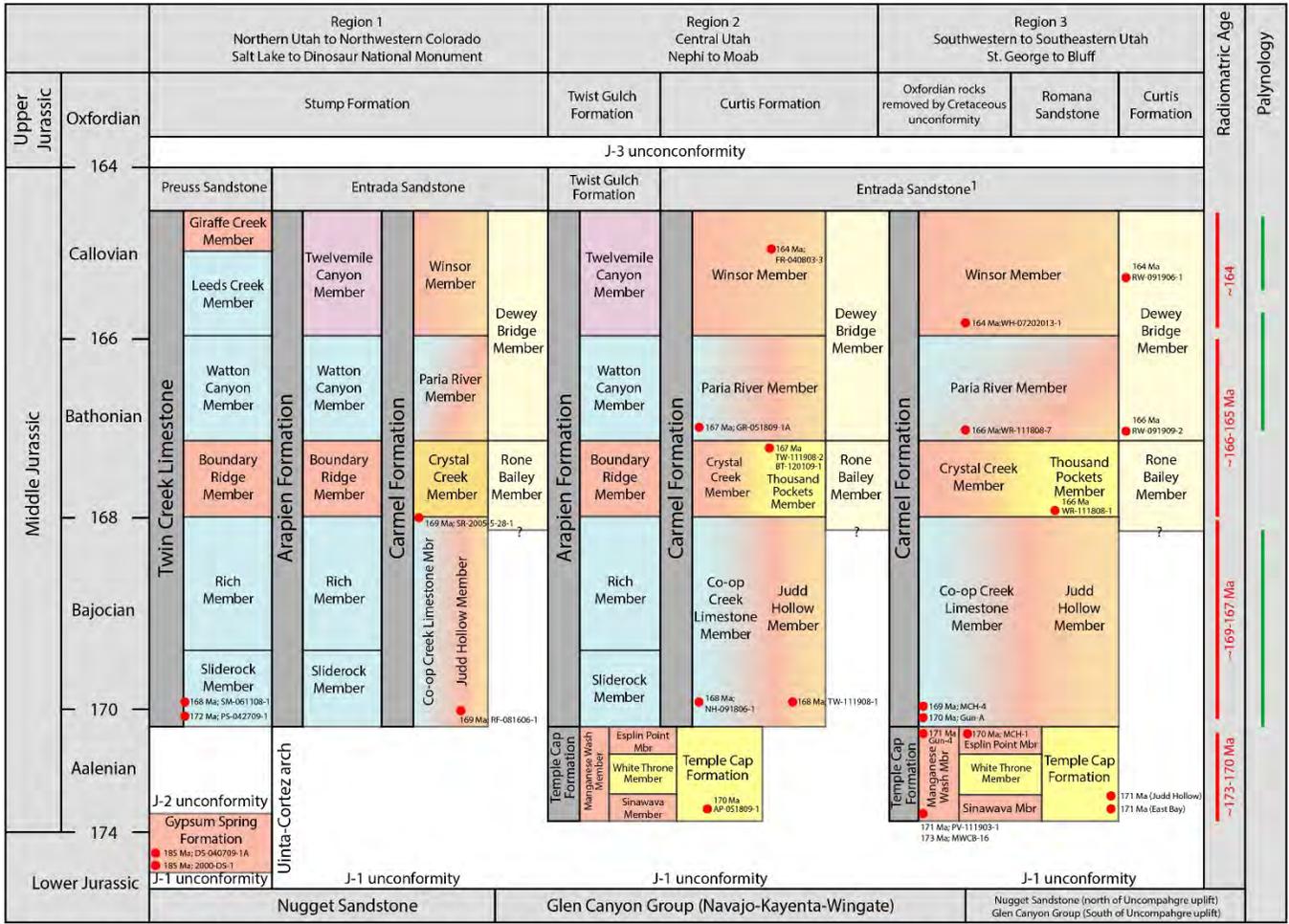


Figure 6-2. Diagrammatic cross section across the middle of the San Rafael Swell with the Carmel and Temple Cap Formations highlighted in blue. The cross section is not drawn to scale, and the vertical dimension is exaggerated about eight times relative to the horizontal. The horizontal length of the cross section covers about 50 miles. Symbols and colors of geologic formations correspond to those shown on figure 6-1; location of cross section also shown on figure 6-1. After Doelling and Hylland (2002).



¹Entrada Sandstone and upper Carmel Formation are removed in the western part of Region 3

 open marine	 marine to marginal marine	 mostly fluvial
 restricted marine	 marginal marine to fluvial	 mostly eolian
● age determined		

Figure 6-3. Correlation chart of Middle Jurassic formations and their members in central Utah and the Sevier thrust belt. Modified from Sprinkel and others (2011); compiled from Kowallis and others (2001), Dickinson and others (2010), Sprinkel and others (2011), Doelling and others (2013), Sprinkel, Doelling, Kowallis, Waanders, and Kuehne, 1998-2017 unpublished data, Utah Geological Survey; numeric boundary ages from Cohen and others (2013).

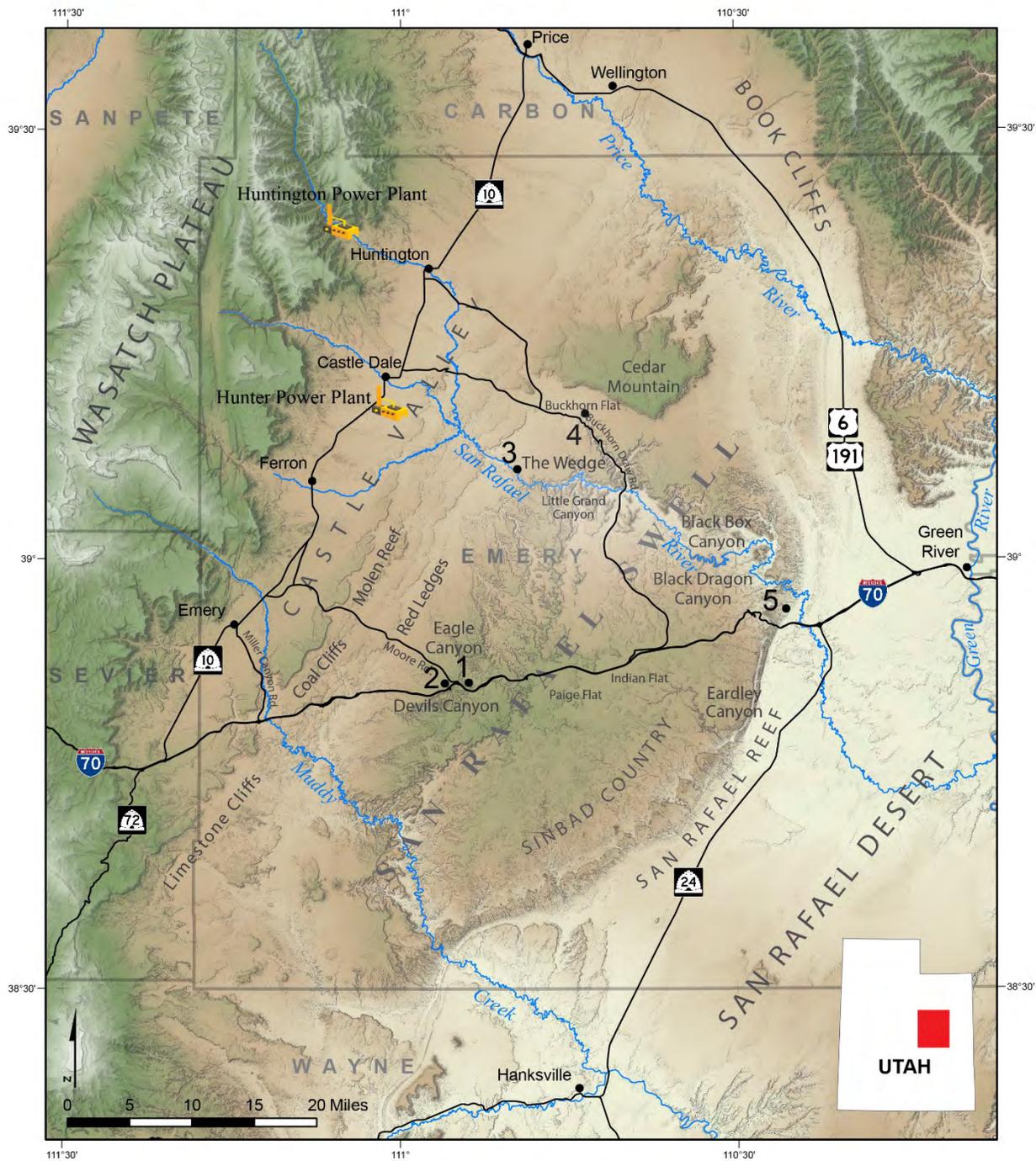


Figure 6-4. Map of the San Rafael Swell showing the location of measured stratigraphic sections (plates 6-1 through 6-5) of the Middle Jurassic Carmel Formation. Also shown are major physiographic features, surrounding towns, highways, and coal-fired power plants.

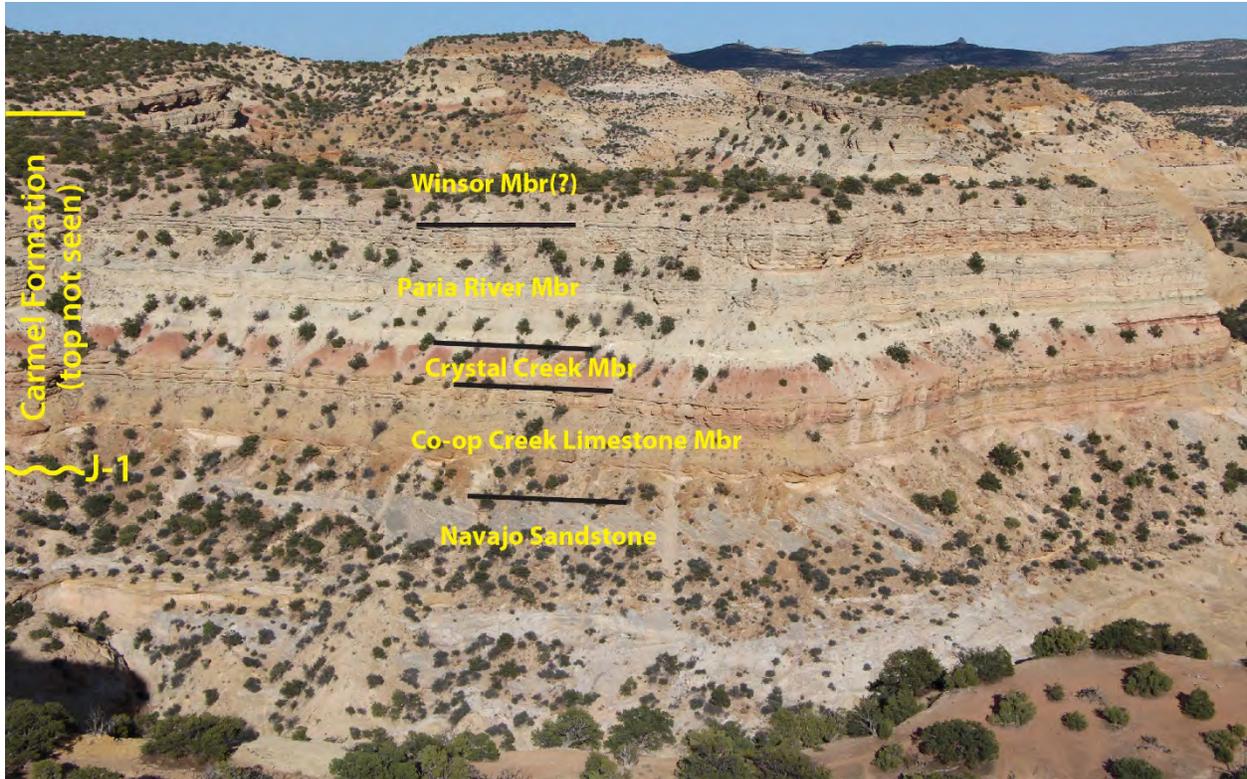


Figure 6-5. Excellent exposure of Middle Jurassic Carmel Formation, San Rafael Group, west flank of the San Rafael Swell, Devils Canyon south of I-70, view to the east. The Co-op Creek, Crystal Creek, Paria River, and part of the Winsor Members are shown. The Carmel is in direct contact with the underlying Navajo Sandstone represented by the J-1 unconformity. Note: the Temple Cap Formation is not present at this locality. Photograph by Michael Chidsey, Sqwak Productions Inc.

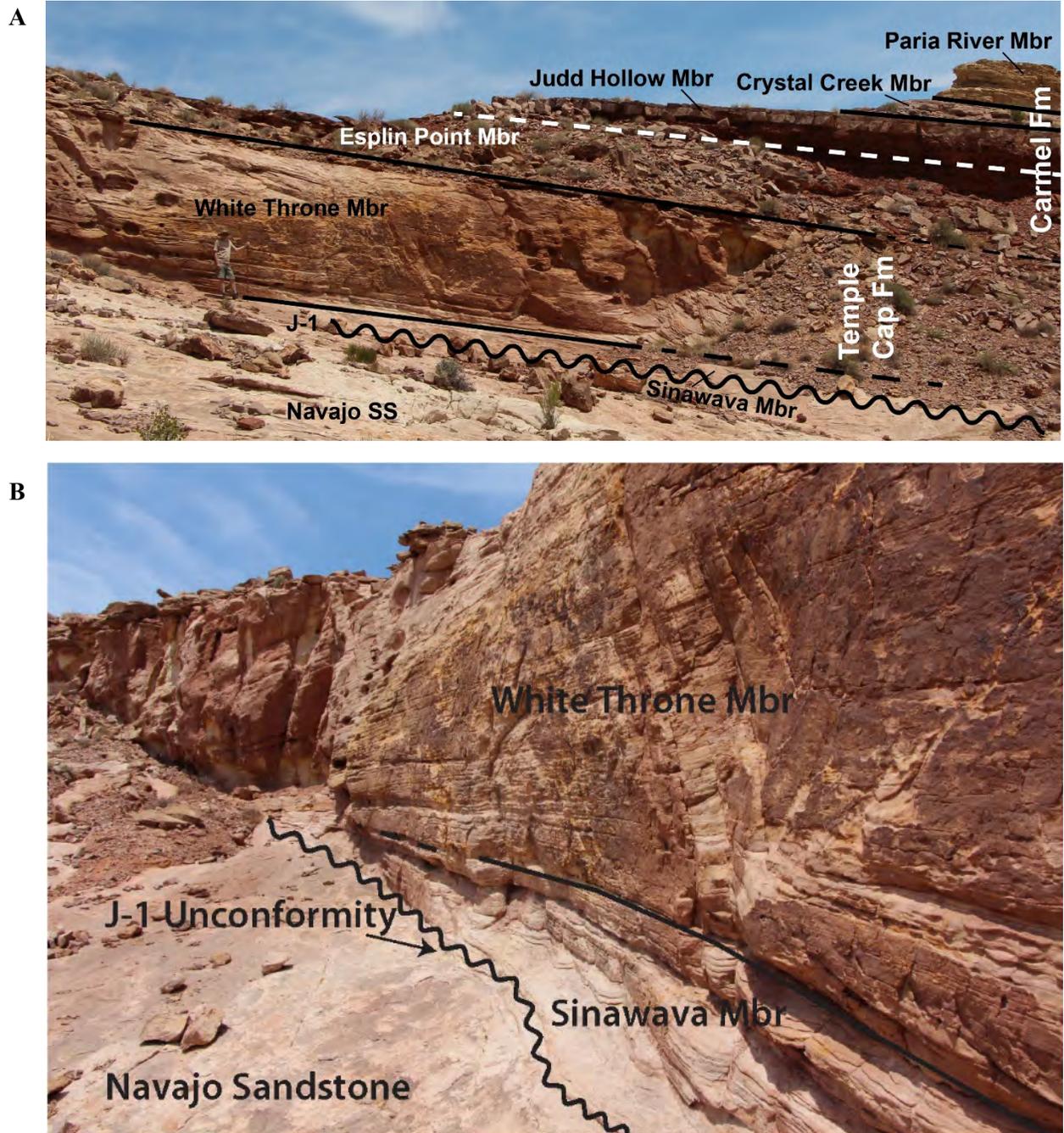


Figure 6-6. Middle Jurassic Temple Cap and Carmel Formations, east flank of the San Rafael Swell, north side of Black Dragon Canyon north of I-70. A – Thin Sinawava and planar to cross-stratified White Throne Members of the Temple Cap Formation separated from the underlying Navajo Sandstone by the J-1 unconformity. The Temple Cap is overlain by the red Judd Hollow-Crystal Creek Members of the Carmel Formation. B – Close-up view of the J-1 unconformity, and thin planar bedding in the Sinawava and White Throne Members. Photographs by Michael Chidsey, Sqwak Productions Inc.

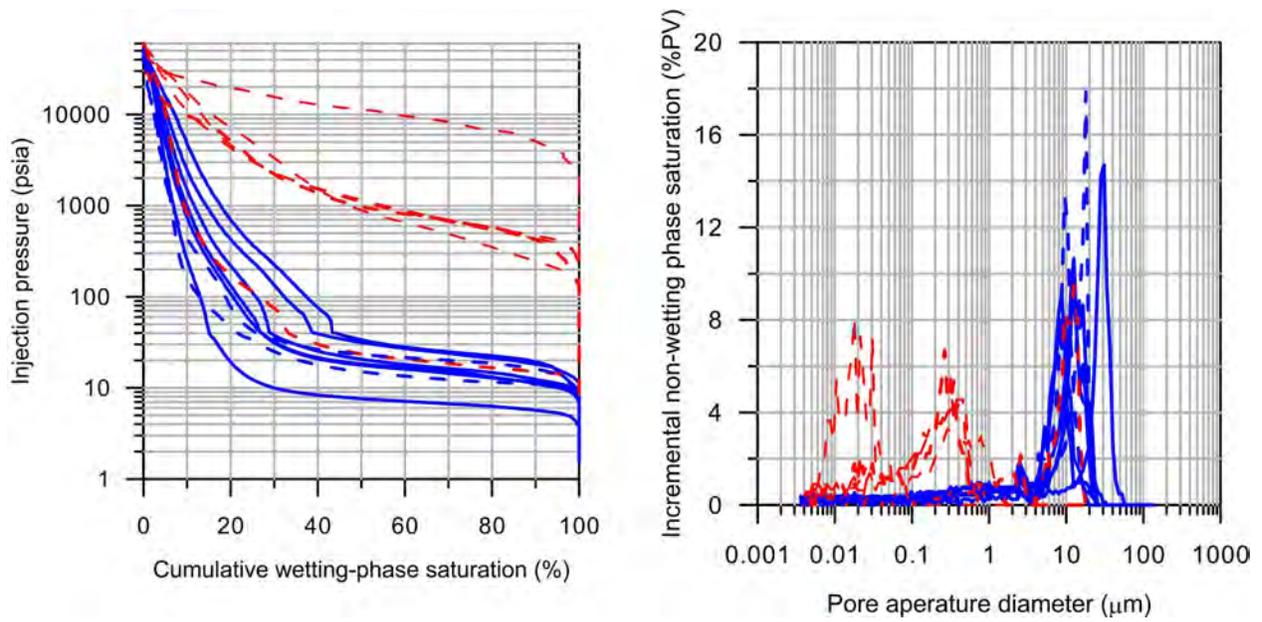


Figure 6-7. Left: Mercury intrusion capillary pressure curves (left) for Navajo Sandstone and Carmel Formation samples. Right: Pore aperture size distributions converted from the capillary pressure curves. Core samples are solid lines, and outcrops samples are dashed lines. Blue represents Navajo Sandstone samples, and red is for Carmel Formation samples. The Navajo Sandstone data from figure 5-23 is reproduced here for comparison to the Carmel Formation data. PV stands for pore volume.

Table 6-1. Samples and mercury capillary pressure results used to estimate CO₂ column heights.

Study area	Sample ID	Formation /lithology	Mercury breakthrough pressure (psia)	Breakthrough pore aperture diameter (µm)	Breakthrough pressure, water-CO ₂ (psia)	CO ₂ column height (m)
Buckhorn Wash	Sample 3 Basal Judd Hollow	Carmel, Judd Hollow member (basal above J1), fossiliferous calcarenite	15.56	13.713	1.13	2.83
Justensen Flat	Sample 15 JF2	Carmel, Judd Hollow member, probable calcarenite	614.69	0.347	44.45	111.61
Justensen Flat	Sample 19 JF1	Carmel, Judd Hollow member (basal above J1), probable dolomite	428.25	0.489	30.97	77.76
Justensen Flat	JC Red Bed	Carmel	428.29	0.489	30.97	77.77
Justensen Flat	JC First Limestone	Carmel, limestone	226.95	0.940	16.41	41.21
Justensen Flat	JC Sandstone	Carmel, sandstone	6340.59	0.034	458.51	1151.30
Study area	Sample ID	Formation / lithology	Mercury breakthrough pressure (psia)	Breakthrough pore aperture diameter (µm)	Breakthrough pressure, water-CO ₂ (psia)	CO ₂ column height (m)
Buckhorn Wash	Sample 3 Basal Judd Hollow	Carmel, Judd Hollow member (basal above J1),	15.56	13.713	1.13	2.83

		fossiliferous calcarenite				
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Rocky Mountain CarbonSAFE Phase I

Appendix G

**COMPILED FLUID GEOCHEMISTRY FOR
POTENTIAL CARBON SEQUESTRATION RESERVOIRS IN
CASTLE VALLEY**

COMPILED FLUID GEOCHEMISTRY FOR POTENTIAL CARBON SEQUESTRATION RESERVOIRS IN CASTLE VALLEY

*Stephan M. Kirby,
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INTRODUCTION

Fluid chemistry places basic constraints on development of carbon storage reservoirs. Beneath the Hunter and Drunkards Wash sites (figure 1-2), potential storage reservoirs include the Navajo Sandstone, White Rim Sandstone, Kaibab Limestone, and Redwall Limestone as described previously. This chapter presents compiled major ion chemistry for these reservoirs taken from a larger compilation of available major ion chemistry from both produced water and groundwater in the greater Uinta Basin area, which includes parts of the San Rafael Swell and the Wasatch Plateau (Chidsey, 2017).

The sample set covers an area that includes Emery County, Utah, and adjoining areas to provide representative samples near the Hunter site (figure 7-1). The data were taken from the National Water Information System (NWIS) database (U.S. Geological Survey, 2018). Each sample in the database includes data source, basic location information, and a unique identifier (Chem ID) that correlates to the geochemical database presented by Chidsey (2017). General data fields include a site name, site number, altitude, depth of sample, and date of sampling. The altitude is the land surface elevation in feet derived from the 5 meter (16.4 feet) digital elevation model for Utah for a given location. The depth of the sample is listed as a discrete value in feet below land surface. Samples are categorized into four simplified geologic units based on geologic information in the original data source. The simplified geologic units are Navajo Sandstone, White Rim Sandstone, Kaibab Limestone, and Redwall Limestone. Fields that have no data are given with the value -9999.

Sample chemistry fields in the database include temperature, pH, conductivity, total dissolved solids (TDS), and chemical concentration values. Solute concentrations for CO₂, HCO₃, Ca, Mg, Na, K, SO₄, F, and SiO₂, are in mg/L. The concentration of As is µg/L. The milliequivalent concentration of each major solute in the database was calculated using standard methods with the AquaCHEM™ software. Milliequivalent concentrations were used to calculate charge balance of the percent difference between the sum of charge equivalents for major anions and cations.

Geochemical samples were subdivided based on calculated water type or hydrochemical facies. Water type was calculated for all samples using AquaCHEM™ geochemical software based on standard methodologies by Kehew (2000). Water type is listed in both long and short forms in separate database fields. The long water type lists the two or three major anions and cations for a given sample, and the short water type provides only the single anion and cation with greatest relative concentration.

DATA SUMMARY

A total of 25 samples were chosen to represent the target reservoirs in fluid geochemistry (tables 7-1 and 7-2). These include ten samples from the Navajo Sandstone, six samples from the White Rim Sandstone, two samples from the Kaibab Limestone, and seven samples from the Redwall Limestone. Depths of the samples range from several hundred feet to greater than 8000 feet (figure 7-2). Most Navajo samples are from groundwater supply wells with depths less than 1000 feet. Samples of the Kaibab and the Redwall likely represent samples from oil/gas exploration wells. The samples from the White Rim include two shallow water wells and a single sample from a deeper oil/gas exploration well. None of these exploration wells are currently producing hydrocarbons.

TDS is a basic measure of the dissolved chemical load in a given sample. Figure 7-2 shows TDS versus depth for these samples. TDS concentration increases with depth for the Redwall Limestone. Deep samples from the Redwall have relatively high TDS values between 10,000 and 20,000 mg/L. Samples from the other geologic units do not show clear trends with depth and generally have TDS concentrations less than 10,000 mg/L.

Major ion chemistry is both a product and driver of water-rock interaction, scaling, corrosion, and ultimately the use of a fluid. Major ion chemistry ranges from CaHCO_3 for a single shallow sample from the White Rim Sandstone to CaSO_4 for most of the Navajo Sandstone samples to NaCl type typical of the deeper samples from the Kaibab and Redwall Limestones. A piper diagram of the samples (figure 7-3) shows that chemistry spans a wide range from water dominated by calcium and sulfate to water dominated by sodium and chloride. These chemical differences are most prominent between the calcium and sulfate-dominated water typical of shallow Navajo sandstone and sodium- to chloride-dominated water found in deeper samples from the limestone units (Kaibab and Redwall). Variation in chemistry in these units is controlled by sulfate, sodium, and chloride concentrations that are likely driven by water-rock interaction in the case of the shallow samples. Chemistry of the deeper samples may also be influenced by additional interaction with hydrocarbons. Ultimately in situ fluid chemistry in potential carbon storage reservoirs will control the total potential storage in a given unit due to CO_2 saturation and mineral composition of the host rocks.

CHAPTER 7 FIGURE AND TABLE CAPTIONS

Figure 7-1. Sample location map of selected fluid geochemical samples. These samples are a subset of the database found in Chidsey (2017).

Figure 7-2. Graph of sample depth versus total dissolved solids (TDS).

Figure 7-3. Piper diagram of selected samples.

Table 7-1. Location and sample parameters of selected samples.

Table 7-2. Compiled fluid chemistry of selected samples. See table 7-1 for sample locations.

Table 7-1. Location and sample parameters of selected samples.

Chem ID	Location		Formation	Depth (ft)	Temperature (C°)	Conductivity (µs/cm)	pH
	Northing	Easting					
105	4299086	509604	White Rim Sandstone	-9999	-9999	1650	7.20
232	4329146	513555	Navajo Sandstone	475	13	870	7.00
241	4271381	525799	Navajo Sandstone	400	-9999	1550	7.00
279	4269190	524911	Navajo Sandstone	802	-9999	1300	7.10
320	4270788	492558	Navajo Sandstone	767	-9999	2840	7.80
331	4258684	587367	White Rim Sandstone	500	13	2870	7.70
334	4270788	492558	Navajo Sandstone	-9999	18	3050	6.70
335	4270788	492558	Navajo Sandstone	-9999	-9999	-9999	-9999.00
338	4258684	587367	White Rim Sandstone	500	13	2830	7.60
376	4260997	484919	Navajo Sandstone	-9999	-9999	-9999	-9999.00
408	4259010	591677	White Rim Sandstone	581	20	2970	7.70
493	4259040	594270	White Rim Sandstone	-9999	20	2560	8.00
503	4293026	517211	Redwall Limestone	2197	-9999	6060	7.50
637	4295548	574661	White Rim Sandstone	2510	-9999	4230	7.10
728	4251688	526469	Navajo Sandstone	750	18	5290	7.60
833	4350371	543433	Navajo Sandstone	353	16	12800	6.10
874	4251881	548173	Redwall Limestone	6820	-9999	22700	7.40
915	4294952	562798	Redwall Limestone	7702	-9999	35500	6.90
953	4336949	551546	Kaibab Limestone	3373	-9999	55000	7.40
960	4324304	488379	Kaibab Limestone	7224	-9999	-9999	7.80
972	4374453	544374	Redwall Limestone	8080	-9999	-9999	6.20
976	4258815	481668	Navajo Sandstone	950	16	82000	7.00
986	4288639	555436	Redwall Limestone	6353	-9999	-9999	7.70
987	4299578	573828	Redwall Limestone	8715	-9999	186000	6.40
991	4295548	574661	Redwall Limestone	8440	-9999	220000	6.90



Rocky Mountain CarbonSAFE Phase I

Appendix H

Hydrodynamics

HYDRODYNAMICS

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INTRODUCTION

Two regionally extensive formations, the Upper Triassic Lower Jurassic Glen Canyon Group (particularly the Lower Jurassic Navajo Sandstone) and the Middle Jurassic Carmel Formation in outcrops in the San Rafael Swell and subsurface of Castle Valley, are considered in this chapter. The Middle Jurassic Entrada Sandstone and Cretaceous Dakota Formation are well exposed on the western side of the Swell. The Entrada and Dakota are considered locally as good quality aquifers with bracketing confining units. However, they are not considered to be good candidates for CO₂ injection because they are not deep enough, greater than 3000 ft. measure depth, to have the necessary hydrostatic pressure in the Hunter and Drunkards Wash study areas. Most hydrogeologic researchers consider the Navajo Sandstone, Kayenta Formation, and Wingate Sandstone of the Glen Canyon Group to be significant water-bearing aquifers. The Navajo is considered as the primary aquifer in the Glen Canyon Group because its porosity and permeability are considerably higher than that of the Kayenta and Wingate, which are mentioned here because several injection wells at Buzzards Bench field are perforated in the Kayenta Formation and Wingate Sandstone along with the entire thickness of the Navajo Sandstone.

PREVIOUS STUDIES

The regional hydrogeology of Castle Valley and the San Rafael Swell have been studied by several investigators. Hood and Patterson (1984) studied the bedrock aquifers, particularly the Navajo Sandstone, and provided regional aquifer parameters deduced from several wells that produced from each aquifer. Several formations were defined as regional aquitards. Freethy and Cordy (1991) reviewed the hydrogeology of the Mesozoic rocks in the upper Colorado River Basin in Utah, Colorado, and Wyoming, and confirmed the earlier aquifer properties of Hood and Patterson (1984) and added additional aquifer properties from the Glen Canyon Group (Navajo/Nugget Sandstone) and Carmel Formation. Freethy and Stolp (2009) also looked at the flow and solute transport in the Glen Canyon Group aquifers in the San Rafael Swell region. Gloyn and others (2003) summarized the groundwater conditions in the western San Rafael Swell and Wasatch Plateau. Randall (2009) investigated the suitability of the Navajo Sandstone for saline water disposal and CO₂ injection in the Drunkards Wash and Buzzard Bench areas. Montgomery Watson (2009) submitted results of injection modeling into the Navajo Sandstone via salt water disposal wells at Buzzard Bench (within the Hunter study site). A report by Stim-Lab (1997) described the pore pressure regime and fracture permeability in the Navajo Sandstone and anhydrites in the lower Carmel Formation in the Hunter study site. This chapter will be referring to all the above studies while summarizing the hydrogeologic properties of the Carmel Formation and Navajo Sandstone.

HYDROGEOLOGY OF THE NAVAJO SANDSTONE

The Navajo Sandstone is considered the primary aquifer on the western side of the San Rafael Swell and Castle Valley region, particularly in the Drunkards Wash and Hunter study areas. The sandstone is 300 to 600 ft thick below the Hunter study area and 300 to 400 feet thick below the Drunkards Wash study area (figure 2-8). The Navajo outcrops approximately 11 miles southeast of the Huntington Power Plant and has 5.5 miles of exposed surface measured along the dip (figure 1-2). This is a very large surface area for recharge into the sandstone. The sandstone is very fine to fine grained at the bottom of the formation and coarsens to medium grained at the top of the formation (for a detailed description refer to chapter 5). The eastern Navajo recharge area is topographically higher than the sandstone at the Hunter and Drunkards Wash sites. Groundwater bifurcates at a divide south of the Hunter site near the southern end of the San Rafael Swell and flows towards the Dirty Devil River drainage. The groundwater recharge, southeast of Castle Dale, flows northwest towards Huntington (figure 8-1) then north and northeast around the northern nose of the San Rafael Swell.

Porosity and Permeability

Hood and Patterson (1984) indicated that the permeability of the Navajo Sandstone in the northern San Rafael Swell area ranges from very low to moderate. Several Navajo facies were observed, and outcrop samples were collected and plugged (figure 8-2) for permeability and porosity testing. Samples were collected from each sandstone facies including avalanche, wind ripple facies, and interdune. Porosities range from 7.9% in the fine-grained interdune facies to 18.7% in the coarse-grained, well-sorted wind ripple facies (see table 5-2). These results agree very well with very low to moderate porosity reported by Hood and Patterson (1984). It is important to note that the Navajo Sandstone porosity is not much higher than the porosity measured in the Carmel Formation limestone and siltstone beds at the lower contact. The permeability measured from the Navajo outcrop plugs ranges from 17.7 mD in the interdune to 1375 mD in the wind ripple facies. The permeability is three orders of magnitude greater in the Navajo compared to the overlying Carmel.

Hydraulic Conductivity

Hydraulic conductivity (K) is a measure of the ease that a fluid transfers through a medium. K is a function of matrix intrinsic permeability, matrix fluid saturation, fluid density, and viscosity. Hydraulic conductivity is measured in the lab or determined from flow testing. Hood and Patterson (1984) reported measured K values ranging from 0.0037 to 5.1 ft/d from several short-term aquifer tests from wells in the Navajo Sandstone in the region. Transmissivities from the same aquifer tests ranged from 27 to 643 ft²/day. Specific Yield is between 5% and 10%. These aquifer parameters were not correlated to a sandstone facies identified in this study.

Fracturing

Fracturing is observed in most of the Navajo Sandstone outcrops on the west side of the San Rafael Swell. Fracturing occurred during tensional uplifting in the Navajo (see chapters 5

and 6). Many fractures are filled with calcite, gypsum, or silica cement. Cores from the Navajo at the Federal No. 17-3 well in Covenant field have both filled and open fractures. Near the recharge areas and progressing downward from the top of the Navajo, fractures are probably filled with precipitated cement. Fractures deeper in the Hunter and Drunkards Wash study sites may be open and fluid filled. The study by Stim-Lab (1997) showed a step-rate test at disposal well SWD No. 1 suggesting short-length fractures enhance permeability in the Navajo and that the aquifer is underpressured. There is probably a significant component of fracture flow in the overall permeability of the Navajo in the Hunter and Drunkards Wash study sites.

HYDROGEOLOGY OF THE CARMEL FORMATION

The Carmel Formation varies from 600 to 1000 feet thick (see figure 2-23) in the Hunter and Drunkards Wash study sites and at the recharge area. The Carmel is widely exposed 8.5 miles southeast of the Hunter Power Plant, reaches a maximum of 700 feet in thickness (Hintze and Kowallis, 2009), and has approximately 4.5 miles of exposed formation, measured along dip. As described in chapter 6, it consists of interbedded siltstone, mudstone, carbonaceous mudstone, limestone, and evaporites (gypsum and anhydrite) which are generally fluid flow and fracture barriers. Almost all recharge to the Carmel occurs at outcrops southeast of the Hunter and Drunkards Wash study sites on the western side of the San Rafael Swell and is primarily from snow melt and heavy spring rains. Annual precipitation at the recharge area is between 6 and 8 inches (Hood and Patterson, 1984). Locally, heavy thunderstorms are common in this region but contribute a very small amount of recharge to the formation as storm runoff because it either evaporates or flows to the local washes and into the San Rafael River. The formation can be a locally good, perched aquifer with several low-flow springs and shallow wells with water sourced from the carbonates and siltstones. Most recharge in the Carmel moves west to northwest saturating the aquifer and discharging as perched springs or from shallow wells.

Porosity and Permeability

Four outcrop samples were collected from the lower part of the Carmel Formation and analyzed for porosity and permeability (figure 8-2). Vertical and horizontal porosity and permeability were measured for all samples. Table 6-1 shows the analytical results of the Carmel Formation plug samples. Vertical porosity ranges from 5% to 16.1% and the highest porosity is in the limestone. The lower sandstone sample has the lowest porosity. Two horizontal samples from the limestone and Judd Hollow samples have 13.9% and 8.4% porosity, respectively. The permeability ranges from 0.02 mD in the lower sandstone (JcFirst_SS) to 0.52 mD in the lower limestone (JcFirst_LS) above their contact. The very low permeability in the lower Carmel makes it a good seal. Regardless of the low permeability in the lower Carmel Formation, there is sufficient recharge to flow down into the Navajo Sandstone. The hydraulic properties of the Carmel Formation are generally unknown or are estimated because of the lack of flow tests or tested outcrop samples.

Fracturing

Fracturing is also observed in most of the Carmel Formation outcrops on the west side of the San Rafael Swell. Many fractures are filled with calcite, gypsum, or silica cement similar to those in the Navajo Sandstone. Hood and Peterson (1984) suggest that the calcite filling the fractures in the Navajo is probably sourced from the Carmel limestone and gypsum. The majority of the water from the springs and wells in the Carmel outcrops have moderate to high TDS (see chapter 7). The Carmel Formation is likely a significant source of calcium and sodium found in fluids in the sandstone of the Carmel and other formations in the region.

WATER INJECTION WELLS

The Ferron Sandstone of the Mancos Shale produces methane gas from coal beds within the Ferron. The produced water is disposed of into numerous injection wells into the Navajo Sandstone (table 8-1). The produced water from the Ferron Sandstone is less than 10,000 TDS and therefore qualifies the Navajo Sandstone in that area as a Underground Source of Drinking Water or a USDW aquifer.

Seven produced water injections wells are currently operating at Buzzards Bench gas field. All are screened through the entire Navajo Sandstone and several are also screened in the underlying Kayenta Formation and Wingate Sandstone. Table 8-1 shows the average monthly injection rates and cumulative injection amounts (in barrels of water). Injection wells SWD No. 3 and SWD No. 1 became operational in 1996; SWD No. 2 became operational in 1998; and Clawson Spring ST SWD No. 1, SWD No. 4, PPCO D13, and SWD No. 5 became operational in 2001, 2002, 2003 and 2010, respectively. Figure 8-3 is a plot showing the average monthly injection rate for all seven injection wells along with the cumulative injected water. The average injection rate of the seven wells is 66,316 barrels per month with a high of 589,576 barrels in August 2002. Almost 94 million barrels of water have been injected into the Navajo Sandstone and secondarily into the Kayenta Formation and Wingate Sandstone.

Montgomery Watson (1997) investigated the impact of injecting large volumes of produced water into the Navajo Sandstone at wells SWD No. 1 and SWD No. 2 (table 8-1). Their study used THWELLS™ (IGWMC™) to calculate the potentiometric head during injection modeling at two different rates: 100 gallons per minute (gpm) and 500 gpm for 5-, 10-, and 30-year periods. With the projected injection rate of 100 gpm for 30 years, the maximum hydraulic head was calculated at 6360 feet with a tight mound of water 6 miles in diameter. At a higher injection rate of 500 gpm for 30 years, the hydraulic head was calculated to be 10,390 feet with a broader water cone 8 miles in diameter. The modeling shows that the Navajo can accommodate large volumes of water with very negligible impact. It has been 20 years since injection started and additional research could see if the modeling predicted the actual hydraulic head and water mounding.

SUMMARY

The regional hydrogeology of the western San Rafael Swell has been studied by several different investigators in the last 50 years. Multiple aquifers and aquitards are identified and are locally good sources of water. The Entrada Sandstone and Dakota Formation are two potential aquifers in the region near the Huntington Power Plant. However, they do not have enough

hydrostatic pressure in the Hunter and Drunkards Wash study sites to keep the CO₂ in the liquid state. The Glen Canyon Group consisting of the Wingate Sandstone, Kayenta Formation, and Navajo Sandstone has the most regionally extensive aquifer system on the western side of the San Rafael Swell. The Kayenta and Wingate have limited thickness, less than 600 feet combined, and their hydrogeologic parameters are not well known. There are several active injection wells at Buzzards Bench (see figure 8-1) that are perforated through the entire thickness of the Glen Canyon Group. The combined units were tested as one continuous unit so individual parameters are unknown. The lithology of the Kayenta and Wingate suggests that the porosity and permeability will be significantly lower than the Navajo. The Carmel Formation has great aerial outcrop exposure and has locally perched aquifers that make springs and wells. Thick gypsum and anhydrite are found in the Carmel on the western side of the San Rafael Swell which make barriers to fluid flow.

Several samples were collected from the eolian sandstone facies of the Navajo Sandstone and the base of the Carmel Formation. The Navajo porosities ranged from 7.9% in the interdune sample to 18.7% in the wind ripple sample. It should be noted that these numbers are in general agreement with those presented by Hood and Patterson (1984). Measured permeability varies widely from 17.7 mD in the interdune to 1375 mD in the wind ripple. Carmel porosity except in the gypsum and anhydrite units can be considered low to moderate with vertical porosity ranging from 5% to 16.1%; horizontal porosity ranged from 8.4% to 13.9%. Measured permeability ranged from 0.02 to 0.52 mD. Vertical fluid flow between the Carmel and Navajo is suggested by the relatively high TDS of water in the Navajo sandstone as well as by calcite fracture fill observed in outcrop and core.

Hood and Patterson (1984) presented hydraulic parameters for the Navajo Sandstone from several, short-term aquifer tests on wells completed in the sandstone. Hydraulic conductivity ranged from 0.0037 ft/d to 5.1 ft/d. Transmissivities ranged from 23 ft²/day to 643 ft²/day. Specific yield ranged between 5% and 10%. The different eolian facies and fracturing can widely impact fluid flow in the Navajo. Stim-Lab (1997) indicates the short length fracturing is part of the overall permeability and that the reservoir is likely underpressured. The hydrologic properties of the Carmel Formation have not been measured on outcrop samples or by flow testing in the study areas and must be estimated from previous regional studies.

Seven produced water injection wells are active in the Buzzards Bench gas field west of the Huntington Power Plant. Several have been in operation since 1996 with the last coming online in 2010. Average injection is 66,316 barrels of water with a high of 589,576 barrels. A total of 93,584,842 barrels have been injected into the Navajo Sandstone since the operation started in 1996. Montgomery Watson (1997) modeled the water injection into two closely spaced injection wells, the SWD No. 1 and SWD No. 2, at 100 and 500 gpm injection rates for 5, 10, and 30 years. The predicted hydraulic head for the 100 gpm and 500 gpm rates varied from 6360 feet to 10,390 feet with a tight water mound diameter of 6 to 8 miles. The modeling predicted a very small impact to the potentiometric surface in the Navajo Sandstone after 30 years of injection.

CHAPTER 8 FIGURE AND TABLE CAPTIONS

Figure 8-1. Map showing the Navajo Sandstone and Carmel Formation recharge areas surrounding the San Rafael Swell. Groundwater recharge splits south of the Hunter study site.

Groundwater in the Navajo flows northwest towards Price and then bends to the east and southeast to the lower Green River discharge area. Modified from Freethey and Stolp (2009).

Figure 8-2. Map showing the Huntington and Drunkards Wash study areas and the location of the outcrop samples collected from the Navajo Sandstone and lower Carmel Formation. Red dots indicate approximate locations of sample sites; Jn = Jurassic Navajo samples, Jc = Jurassic Carmel samples, LW = Little Wedge fault area.

Figure 8-3. Average monthly injection and cumulative injection of produced water (in barrels) amount into the seven injection wells at Buzzard Bench field and listed in table 8-1.

Table 8-1. List of injection wells and produced water injected (bbls) at Buzzards Bench field which is within the preferred Hunter study site.

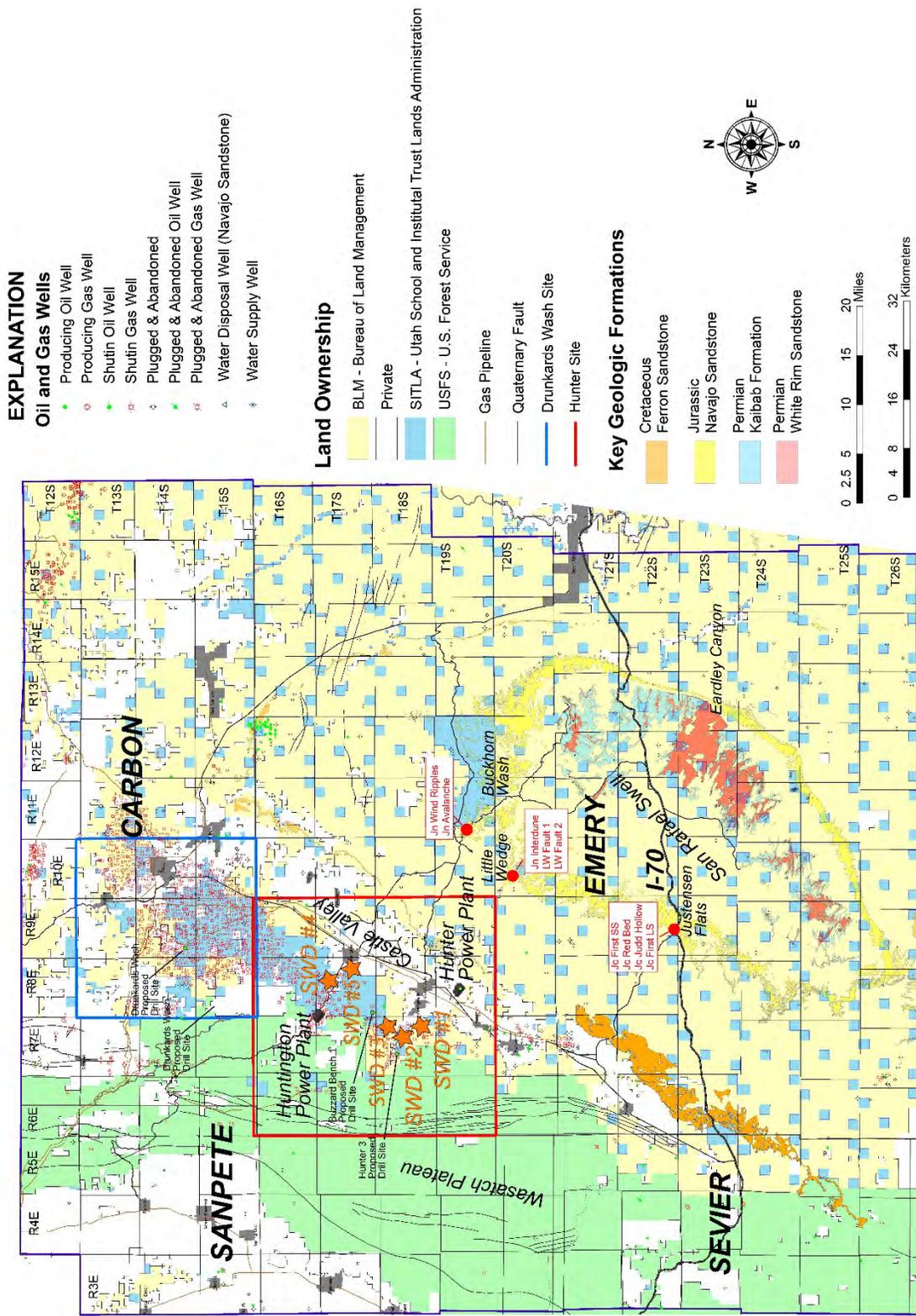


Figure 8-2. Map showing the Huntington and Drunkards Wash study areas and the location of the outcrop samples collected from the Navajo Sandstone and lower Carmel Formation. Red dots indicate approximate locations of sample sites; Jn = Jurassic Navajo samples, Jc = Jurassic Carmel samples, LW = Little Wedge fault area.

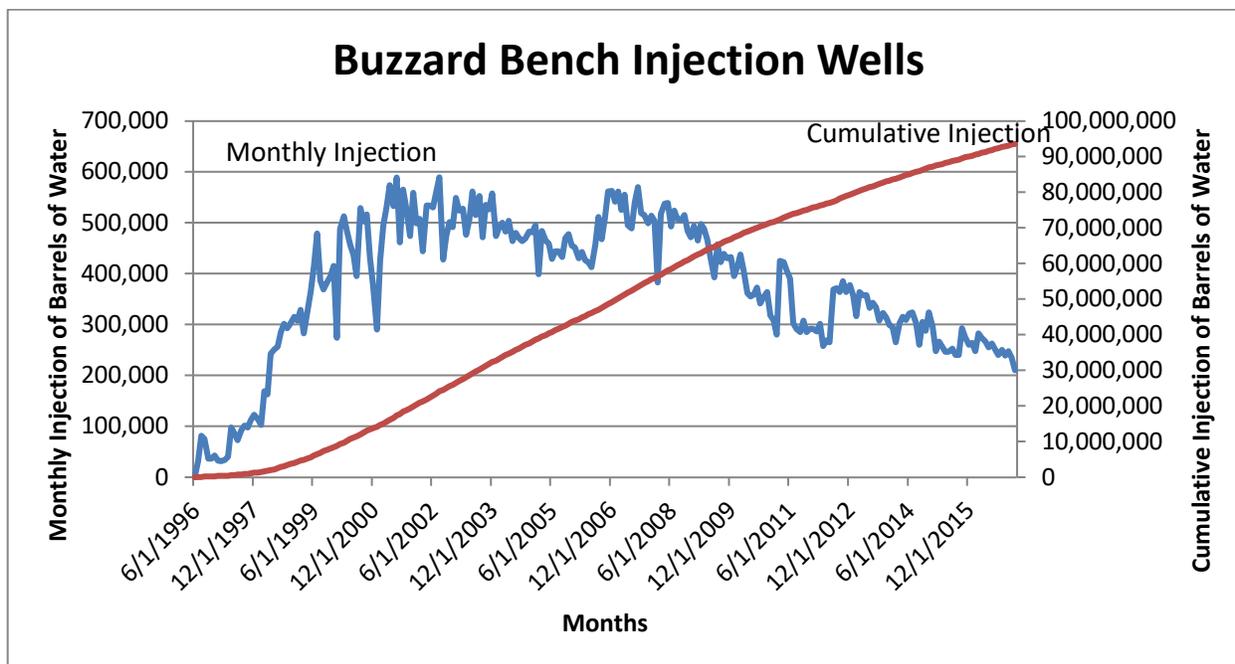


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Table 8-1. List of injection wells and produced water injected (bbls) at Buzzards Bench field which is within the preferred Hunter study site.

Injection Well	Operation Date	Operational Months	Average Injection Rate (bbls/month)	Cumulative Injection Amount (bbls)
SWD No. 1	1996	248	145,957	36,197,231
SWD No. 2	1998	227	117,172	26,598,120
SWD No. 3	1996	176	72,453	7,897,371
SWD No. 4	2002	179	62,097	11,115,390
SWD No. 5	2010	160	25,592	4,094,775
Clawson Spring St SWD 1	2001	192	32,834	6,304,091
PPCO D13	2003	170	8105	1,377,864
TOTAL			66,316	93,584,842



Rocky Mountain CarbonSAFE Phase I

Appendix I

POTENTIAL FOR SEISMIC ACTIVITY

POTENTIAL FOR SEISMIC ACTIVITY

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INTRODUCTION

The western flank of the San Rafael Swell is on the northwestern boundary of the Colorado Plateau. The western boundary of the Colorado Plateau is a region of increased seismicity called the Intermountain Seismic Belt (ISB). ISB seismicity is associated with tectonic extension in the Basin and Range physiographic province to the west. Seismicity is relatively low on the Colorado Plateau, with the exception of seismicity concentrated in a transition zone between extension of the Basin and Range province and the thick continental crust of the Colorado Plateau (figure 9-1). A few notable earthquakes could have been felt within the Hunter and Drunkards Wash study areas west-northwest of the San Rafael Swell (figure 1-2).

QUATERNARY-ACTIVE FAULTS

There are no mapped Quaternary-active faults within the San Rafael Swell or on its western axis according to the Utah Quaternary Fault and Fold Database (2018). Non-Quaternary faults in the San Rafael Swell include the northwest-southeast Paradox Basin and Uncompahgre uplift trend, an east-west trend, and north-south Basin and Range extensional trend.

The closest Quaternary-active faults to the study sites in the Castle Valley area are those in the southern extent of the Joes Valley fault zone (~30 km to the west) and the Price River area faults (~30 km to the northeast) (figure 9-2). The Joes Valley fault zone is a normal-fault-bounded graben with north-south-trending, locally overlapping fault traces, and is divided into southern and northern segments. The southern segment, which is closest to the study areas, is thought to be less active than the northern segment due to a decrease in fault throw and relatively few scarps cutting Quaternary deposits (Black and others, 2006). The Price River area faults are thought to be related to the salt-cored anticlines associated with the Paradox Basin (Hecker, 1993).

SEISMICITY

Historical Seismicity

Historical seismicity has occurred on the western flank of the San Rafael Swell, including the 1988 M_L 5.3 San Rafael Swell earthquake. At 13:03 MST on August 14, 1988, a local magnitude (M_L) 5.3 earthquake occurred that had an epicenter proximal to the study sites (Pechmann and others, 2011). The earthquake had a Modified Mercalli Intensity (MMI) magnitude of VI with a felt area of ~110,000 square kilometers over areas of Utah and Colorado. The earthquake epicenter was about 18 km northwest of Castle Dale, Utah (figure 9-2).

Hypocenters of the mainshock and aftershock sequence occurred at 11 to 18 km depth in a 5-km-long zone having a dip of $60^{\circ} \pm 5^{\circ}$ east-southeast. The depth of the earthquake sequence is deeper than typical ISB or Basin and Range earthquakes. Earthquakes associated with this sequence showed left-lateral oblique-normal faulting down to the east-southeast. The earthquake occurred outside of any known areas of historical seismicity, such as the ISB or transition zone (figure 9-1). The San Rafael earthquake has no surface fault associated with its location (Pechmann and others, 1992). The earthquake shaking triggered numerous rockfalls (figure 9-3) occurring within 40 km of the epicenter during the main shock (Case, 1988). In addition to numerous accounts of seismically triggered rockfalls, field investigation at Fuller Bottom along the San Rafael River noted cracking due to liquefaction and sand boils in saturated sediments 1.9 km from the epicenter (Case, 1988).

Induced Seismicity

North and east of the study sites is a region of induced seismicity associated with coal seam exploration and extraction in the Wasatch Plateau and Book Cliffs mining districts (figure 9-1). These earthquakes are typically small (magnitude ≤ 4.2) and result from coal mining down to ~ 0.75 km depth. The seismicity of coal mining earthquakes in Utah are characterized by the University of Utah Seismograph Stations (<http://quake.utah.edu/>) and have been studied previously in detail to conduct earthquake research and address mine safety (Arabasz and Pechmann, 2001).

SUMMARY

Seismicity is relatively low in the Colorado Plateau, with the exception of seismicity concentrated in a transition zone from the Basin and Range physiographic province west of the study sites in Castle Valley. There are no mapped Quaternary-active faults within the San Rafael Swell or in Castle Valley. A few notable earthquakes have occurred in the region. Although historical seismicity has occurred on the western flank of the San Rafael Swell, including the 1988 M_L 5.3 San Rafael Swell earthquake, we conclude that the potential for significant seismic activity in and around the study areas is low. A region of induced seismicity associated with coal mining in the Wasatch Plateau and Book Cliffs is north and east of the study sites and would not affect CCS in the study sites.

CHAPTER 9 FIGURE CAPTIONS

Figure 9-1. Historical regional earthquake epicenters in the San Rafael Swell area from 1962 – 1990, including the 1988 M 5.3 San Rafael Swell earthquake and the 1989 M 5.4 Wasatch Plateau earthquake. Earthquakes typical of the Basin and Range (BR) and Colorado Plateau (CP) have different seismicity that shifts in the transition zone (TZ). The Middle Rocky Mountains (MRM) is at the northern boundary of the CP. Yellow box indicates approximate area covered in figure 9-2. Modified from Pechmann (1988).

Figure 9-2. Regional Quaternary faults, historical earthquakes, and mining induced earthquakes in the study areas. The cluster of larger earthquakes and aftershocks near the center of the image

is the 1988 San Rafael Swell earthquake sequence. Data sources: Quaternary faults from the Utah Geological Survey; epicenters from the University of Utah seismograph stations.

Figure 9-3. Rockfall dust associated with the 1988 San Rafael Swell earthquake taken from the Bureau of Land Management (BLM) Cedar Mountain picnic area, 18 km from the epicenter. The mainshock caused numerous rockfalls that occurred within 40 km of the epicenter. Photo taken by Terry Humphrey of the BLM Price office (1988) and accessed from the Utah Geological Survey Geodata Archive System (2018).

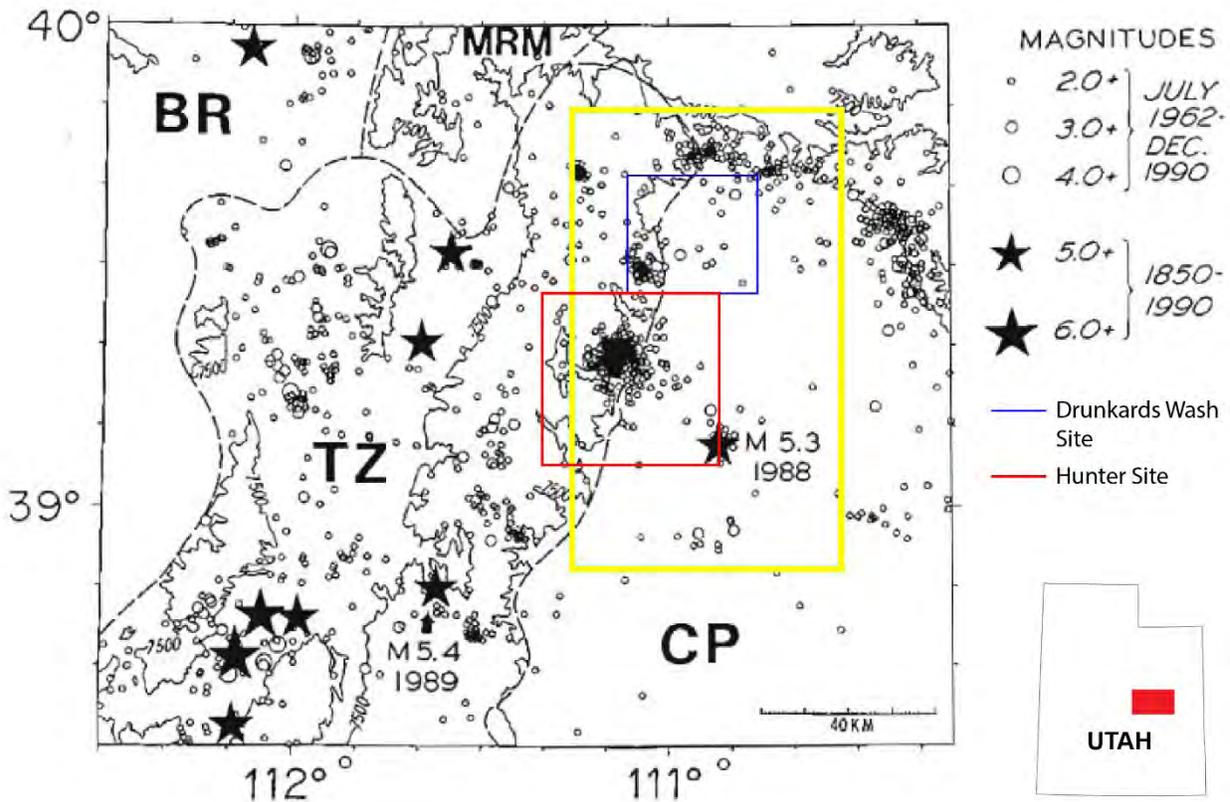


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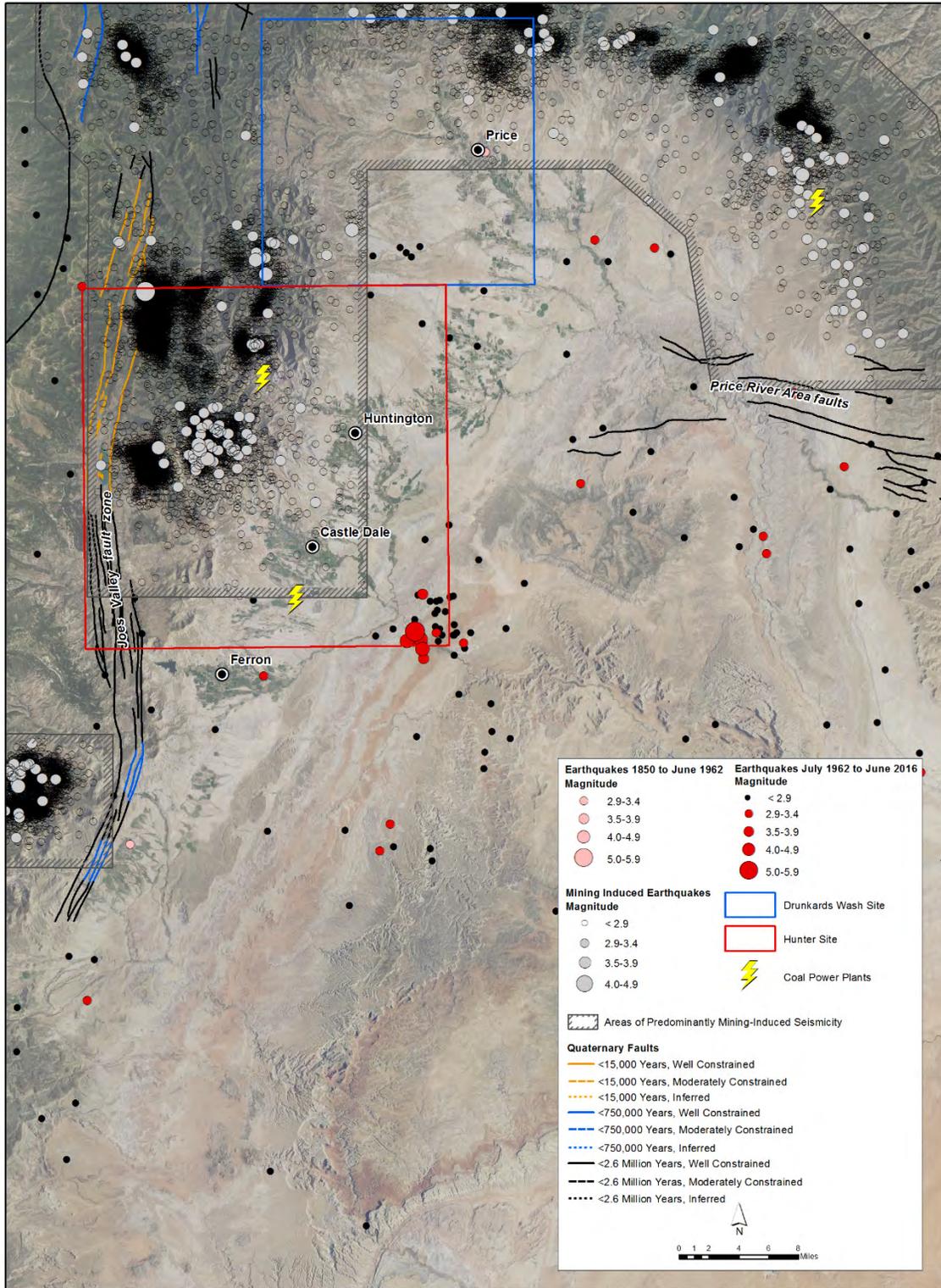


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Rocky Mountain CarbonSAFE Phase I

Appendix J

Risk Registry

QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA)				
CarbonSAFE Rocky Mountains Phase I, CO ₂ -Storage Subsurface, Surface, Technical and Programmatic Risk Areas				
Line #	Index #	Risk Area/FEP	Description	Relevance
1	00.00.00.00.	ASSESSMENT BASIS	This category of FEPs determines the boundary conditions for any assessment, specifying the spatial and temporal domain of the system. The Assessment Basis determines what is being assessed and why, so that those FEPs that need to be considered in the analysis can be defined, and those which can be screened out as being outside the scope of the assessment can be identified.	
2	00.01.00.00.	Purpose of the assessment	The purpose of the assessment of geological CO ₂ sequestration.	The general purpose of an assessment of geological CO ₂ sequestration is to determine the performance of the sequestration system. In any specific case, however, the purpose of conducting an assessment may vary from simple calculations to test initial ideas for sequestration concepts, to support for an application for regulatory approval requiring detailed, site-specific performance assessment against relevant criteria. The level of complexity and comprehensiveness will vary according to the use to which it will be put. Additionally, the assessment endpoints of interest may not only vary in type, depending on the assessment purpose, but also in the level of rigor required for compliance demonstration.
3	00.02.00.00.	Endpoints of interest	The assessment endpoints of interest.	The structure and composition of an assessment will tend to reflect the endpoints that are required to be assessed. These in turn, will reflect the criteria that are adopted to judge the overall performance of the sequestration system. Thus, for example, an assessment may be constrained to considering the degree of containment within a geological feature, alternatively, it may need to address potential near-surface impacts. Invariably, a combination of endpoints will be required.
4	00.03.00.00.	Spatial domain of interest	The spatial domain of interest in the assessment.	The spatial domain of interest will be dependent on the site context, which may vary from generic assessments to site specific assessments, the sequestration concept and the endpoints of interest. The spatial domain will contribute to determining the information requirements and modeling capabilities that may be required.
5	00.04.00.00.	Timescales of interest	Timescale of interest for the assessment.	Timescales over which the assessment will be performed will constrain processes which must be considered in the assessment. In general terms, there are three timescales of interest for geological storage of carbon dioxide. Firstly, there is the timescale during construction and operation which has a lifetime in years or decades. secondly there is a timescale over which isolation of carbon dioxide from the atmosphere is necessary to mitigate climate change. This timescale is likely to be in the order of a few hundred years at most. The third timescale of interest is potentially much longer and is that pertaining to the assessment of potential hazard to humans and the environment. This timescale could be in the order of thousands to tens of thousands of years.
6	00.05.00.00.	Sequestration assumptions	High level assumptions concerning the sequestration system(s) of relevance to the assessment. For example, the quantity and quality of CO ₂ sequestered, the method of injection and information concerning the assumed performance of the sequestration system.	Provides a background to the sequestration technique adopted. Note that more detailed consideration of the CO ₂ sequestration system is provided in subsequent FEP categories.

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7	00.06.00.00.	Future human action assumptions	The assumptions made in the assessment concerning general boundary conditions for assessing future human action and exposure.	For example, it can be expected that human technology and society will develop over the timescales of relevance for the assessment of CO ₂ sequestration systems, however, this development is unpredictable. Therefore it may be necessary to make some assumptions in order to constrain the range of future human actions that are considered, such as assuming that only present-day technologies, or technologies practiced in the past, will be considered.
8	00.07.00.00.	Legal and regulatory framework	The legal and regulatory framework within which the assessment takes place.	In undertaking an assessment it is vital to consider the appropriate regulatory framework requirements. At one extreme these may be specific, prescriptive quantitative requirements, at the other they could be non-prescriptive or may not have been fully developed. The legal and regulatory framework can shape various aspects of an assessment, such as the required assessment endpoints, timescales of interest and assumptions concerning future human actions.
9	00.08.00.00.	Model and data issues	General methodological issues affecting the assessment modeling process and use of data	Examples of general model and data issues include the treatment of uncertainty; the availability, collection and method for handling site specific data; and the reduction/simplification of models and data.
10	00.09.00.00.	Public acceptance and information	The amount and type of information needed for public acceptance and to comply with industry best management practices.	Focus on health, safety and environmental risks as well as economic and lifestyle impact on the public at large.
11	00.10.00.00	Financial viability	The minimum return on investment needed to justify the risks involved in undertaking the project.	Higher risks require higher rewards to justify undertaking a project. The risk assessment may give an indication of the minimum rate of return required to attract capital funding for the project.
12	00.11.00.00	Adequate risk characterization	The level of detail and depth of risk characterization needed.	Characterization of risks can include identifying potential modes of failure, estimating probability of failure occurring and impact severity of failure and determining potential steps to prevent or mitigate failure.
13	01.00.00.00.	EXTERNAL FACTORS	This category of FEPs describes natural or human factors that are outside the system domain. These FEPs are most important in determining scenarios for the future evolution of the system, and are often referred to as EFEPs (External FEPs). Three classes of FEPs are considered. Geological Factors and Climatic Factors are concerned with natural processes and events, whilst Future Human Actions is concerned with those human activities that can directly affect the sequestration system.	This category is divided into three classes: 1. Geological factors 2. Climate factors 3. Human action factors
14	01.01.00.00.	Geological factors	Natural geological processes and events in the environment outside the system domain that are relevant to the evolution of the sequestration system.	Changes in the geological environment outside the system domain may directly affect the transport of carbon dioxide within the system.
15	01.01.01.00.	Neotectonics	Neotectonics is the study of crustal movements that both occurred in the Earth's recent past and are continuing at the present day. These movements, which are driven directly or indirectly by global plate motions (tectonics), result in the vertical and horizontal warping, folding or faulting of the Earth's surface.	Neotectonic events have the potential to cause sudden changes in the physical properties of rocks due to stress changes and induced hydrogeological changes.
16	01.01.02.00.	Volcanic and magmatic activity	Magma is molten, mobile rock material, generated below and within the Earth's crust, which gives rise to igneous rocks when solidified. A volcano is a vent or fissure in the Earth's surface through which molten or part-molten materials (lava) may flow, and ash and hot gases be expelled.	The high temperatures associated with volcanic and magmatic activity may result in permanent changes in the surrounding rocks, either directly, or through circulating high temperature fluids. This FEP is relevant to CO ₂ disposal in areas of potential magmatic activity, e.g. Japan. Besides bedrock damage, pressure and temperature changes due to heating, stress, or displacement could affect CO ₂ density and solubility, creating the risk of uncontrolled, rapid migration and escape of stored CO ₂ . (CO ₂ STORE page 69)

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17	01.01.03.00.	Seismicity (Natural earthquakes)	<p>Events and processes related to naturally occurring seismic events and also the potential for seismic events. A seismic event is caused by rapid relative movements within the Earth's crust usually along existing faults. The accompanying release of energy may result in rock movement and/or rupture, e.g. earthquakes.</p> <p>Many people are convinced that we want to avoid seismically-active areas for CO₂ storage. In reality there are very large natural gas fields associated with some of the planet's major fault zones (Indonesia, Malaysia and California). Earthquakes in these areas have never been associated with sudden emissions of significant quantities of natural gas or oil from deep reservoirs. (CCP 2009)</p> <p>Major earthquakes (magnitude 6 and above) occur primarily in strong, brittle basement rock at depths on the order of 10 km (6 miles) or more. Very small earthquakes occur at depths as shallow as 3 km (2 miles).</p> <p>Micro-seismicity consists of very tiny seismic events often responding to subsurface fluid flow and relative pressure changes. All parts of the Earth's crust are in continuous movement and generate micro-seismic events, and the analysis of micro-seismicity offers unique insights into subsurface properties(CCP 2009).</p> <p>1. Earthquake induced fractures/faults 2. Natural micro-seismicity</p>	<p>Seismic events may result in changes in the physical properties of rocks due to stress changes and induced hydrogeological changes. Seismic events are most common in tectonically active or volcanically active regions at crustal plate margins.</p> <p>Seismic disturbances might cause caprock failure (Damen 2006). Earthquakes could disrupt drilling, well operation, and monitoring activities, and damage surface facilities including the CO₂ source. An earthquake on a fault through the CO₂ plume could create or close an open pathway. Earthquakes may cause public concern about the project even if not project related.</p> <p>Micro-seismicity may cause public concern about the project even if not project related, may add noise interfering with micro-seismic monitoring.</p> <p>Earthquake near Nakaoka, Japan CO₂ injection site caused significant public concern causing project to be moved off shore, even though earthquake was not directly caused by CO₂ injection.</p>
18	01.01.04.00.	Hydrothermal activity	<p>Processes associated with high temperature groundwaters, and hydrothermal alteration of minerals in the rocks through which the high temperature groundwater flows. Hydrothermal activity may be directly associated with volcanic and magmatic activity.</p> <p>Hot springs, geysers and submarine hydrothermal vents provide evidence of hydrothermal activity.</p>	<p>Can result in the hydrothermal alteration of rocks or minerals by the reaction of hot water (and other fluids) with pre-existing rocks.</p> <p>Springs, geysers and submarine hydrothermal vents can provide pathways for CO₂ to reach the surface.</p>
19	01.01.05.00.	Hydrological and hydrogeological response to geological changes	<p>Processes arising from large-scale geological changes and could include changes of fluid boundary conditions due to the effects of changes of fluid properties of geological units due to changes in rock stress or fault movements.</p>	<p>In and below low-permeability geological formations, hydrogeological conditions may evolve very slowly and often reflect past geological conditions, i.e. be in a state of disequilibrium</p>
20	01.01.06.00.	Large scale erosion (See 06.01.03.00)	<p>Processes related to the large scale (geological) removal of rocks and sediments, with associated changes in topography and geological/hydrogeological conditions of the system.</p>	<p>Potential to modify the geological and hydrogeological environment.</p>
21	01.01.07.00.	Bolide impact (meteorite impact)	<p>An extraterrestrial body in the 1-10 km size range, which impacts the earth at high velocity, explodes upon impact, and creates a large crater.</p>	<p>A low probability, high consequence event that has the potential to substantially disrupt the CO₂ storage system. Often screened out on the basis that the impact of the bolide will greatly exceed that of the disruption caused to the sequestration system.</p>

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22	01.02.00.00.	Climatic factors	Natural processes and events in the atmospheric environment that are relevant to the evolution of the sequestration system.	Changes in climate may directly affect the nature of any impacts that are incurred if carbon dioxide returns to the near-surface environment.
23	01.02.01.00.	Global climate change (See 01.02.02.00.)	<p>The process of global climate change due to natural and/or anthropogenic causes. The last two million years of the Quaternary have been characterized by glacial/interglacial cycling. According to the Milankovitch Theory, the Quaternary glacial/interglacial cycles are caused by long-term changes in seasonal and latitudinal distribution of incoming solar radiation which are due to the periodic variations of the Earth's orbit about the Sun (Milankovitch cycles).</p> <p>Evidence suggests that the Earth is presently in a period of global warming. The anthropogenic release of gases into the atmosphere may be increasing the rate of global warming by enhancing the natural greenhouse effect, a process by which long wave radiation emitted from the Earth is trapped in the atmosphere by greenhouse gases.</p>	<p>Changes in the global climate are likely to impact the CO₂ sequestration system in a number of ways. For example, through its affect on sea levels and the local and regional climate.</p> <p>Changes in ecology and human behavior in response to climate change will influence the relevant FEPs to be considered in the surface environment as an assessment extends into the future.</p> <p>Changes in air emission policies in response to global climate change will impact the feasibility of using CCS.</p>
24	01.02.02.00.	Regional and local climate change (extreme weather events damaging facilities)	<p>Processes related to the possible future changes, and evidence for past changes, of climate at a storage site. This is likely to occur in response to global climate change, but the changes will be specific to situation, and may include short term fluctuations.</p> <p>Climate is characterized by a range of factors including temperature, precipitation and pressure as well as other components of the climate system such as oceans, ice and snow, biota and the land surface. Climatic changes lasting only a few decades may be referred to as climatic fluctuations. These are unpredictable at the current state of knowledge although historical evidence indicates the degree of past fluctuations.</p> <ol style="list-style-type: none"> 1. Warm climate effects (01.02.06.00) 2. Cold climate effects 3. Wet climate effects 4. Dry climate effects 5. Hydrological and hydrogeological response to climate change (01.02.07.00) 	<p>Changes in the regional and local climate could affect the CO₂ sequestration system in a number of ways. For example, changes in groundwater recharge could affect regional hydrogeology and hence the transport of CO₂ dissolved in groundwater. It may also alter the near-surface environment to which some of the disposed CO₂ may migrate.</p> <p>Regions with a tropical climate may experience extreme weather patterns (monsoons, hurricanes) that could result in flooding, storm surges, high winds etc. with implications for erosion and hydrogeology. The high temperatures and humidity associated with tropical climates result in rapid biological degradation and soils are generally thin. In arid climates, total rainfall, erosion and recharge may be dominated by infrequent storm events.</p> <p>The hydrology and hydrogeology of a region is closely coupled to climate. Climate controls the amount of precipitation and evaporation, seasonal ice cover, and thus the soil water balance, extent of soil saturation, surface runoff groundwater recharge, sediment load and seasonality. Vegetation and human actions may modify these responses.</p>
25	01.02.02.01.	Extreme weather event causing human injury/death	Extreme weather events such as tornadoes or hurricanes may cause human injury/death.	Site may not provide sufficient protection for operators against extreme weather events such as tornadoes
26	01.02.03.00.	Sea level change	<p>Processes related to changes in sea level which may occur as a result of global (eustatic) change and/or regional geological change, e.g. isostatic movements.</p> <p>The component of sea-level change involving the interchange of water between land ice and the sea is referred to as eustatic change. As ice sheets melt so the ocean volume increases and sea levels rise. Sea level at a given location will also be affected by vertical movement of the land mass, e.g. depression and rebound due to glacial loading and unloading, referred to as isostatic change.</p>	Sea level change may affect the sequestration system through its impact on the near surface environment and the regional or local hydrogeological regime.

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27	01.02.04.00.	Periglacial effects	Related to the physical processes and associated landforms in cold but ice-sheet-free environments.	An important characteristic of periglacial environments is the seasonal change from winter freezing to summer thaw with large water movements and potential for erosion. Frozen sub-soils are referred to as permafrost. Melt water from seasonal thaw is unable to percolate downwards due to permafrost and saturates the surface materials. Permafrost layers may isolate the deep hydrogeological regime from surface hydrology, or flow may be focused at "taliks" (localized unfrozen zones, e.g. under lakes, large rivers or at regions of groundwater discharge).
28	01.02.05.00.	Glacial and ice sheet effects	Processes related to the effects of glaciers and ice sheets within the region of a storage site. This is distinct from the effects of large ice masses on global and regional climate. The ice sheet and the permafrost beneath the ice sheet may constitute a barrier to groundwater flow and to heat loss. If the basal transmissivity of the till and bedrock below the ice is low, water pressures may rise to levels equaling the ice pressure inducing the formation of major conduits in the subglacial material. The central parts of the ice sheet are likely to be warm-based and could permit groundwater recharge to take place. Discharge of groundwater is likely to take place close to and beyond the frontal parts of the ice sheet. Excessive recharge at the margin of the ice sheet could provide direct recharge of oxidizing water to considerable depths in conductive fracture zones. If the permeability at and beyond the rim of the ice is low, the water pressures may again build up resulting in hydrofracturing of the ice or the rock mass. As the ice sheet advances, these induced fractures may increase their aperture and depth due to freezing of subglacial melt water.	Erosional processes (abrasion, over deepening) associated with glacial action, especially advancing glaciers and ice sheets, and with glacial melt waters beneath the ice mass and at the margins, can lead to morphological changes in the environment, e.g. U-shaped valleys, hanging valleys, fjords and drumlins. Depositional features associated with glaciers and ice sheets include moraines and eskers. The pressure of the ice mass on the landscape may result in significant hydrogeological effects and even depression of the regional crustal plate.
29	01.02.06.00.	Warm climate effects (See 01.02.01.00.)		
30	01.02.07.00.	hydrological and hydrogeological response to climate changes (See 01.02.01.00.)		
31	01.02.08.00.	Responses to climate change (See 01.02.01.00.)		
32	01.03.00.00.	Future human actions	Human activities that are relevant to the evolution of the sequestration system.	Human activities may directly interfere with the sequestered fluid resulting in immediate or delayed impacts.
33	01.03.01.00.	Human influence on climate (See 01.02.01.00.)		
34	01.03.02.00.	Motivation and knowledge issues (Future interference with or intrusion into the CO ₂ reservoir by third parties)	Events and processes related to the degree of knowledge of the existence, location and/or nature of the storage site. Also, reasons for deliberate interference with, or intrusion into, a CO ₂ storage site after closure with complete or incomplete knowledge. Knowledge of the sequestration site may be regained through post-closure airborne, geophysical or other surface-based non-intrusive investigation of a sequestration site. Such investigations might occur after information of the location of the sequestration system has been lost and therefore excludes monitoring of the disposal system, but includes activities such as prospecting for geological resources. The evidence of the sequestration, such as injection boreholes, may itself prompt investigation. 1. Inadvertent interference with or intrusion into the CO ₂ reservoir. 2. Deliberate interference with or intrusion into the CO ₂ reservoir. 3. Malicious intrusion and sabotage.	Some future human actions could directly impact upon performance of the storage system. The following could be distinguished: - inadvertent actions, which are actions taken without knowledge or awareness of the storage site, and - deliberate actions, which are actions that are taken with knowledge of the storage systems existence and location, e.g. deliberate attempts to retrieve any hydrocarbons (e.g., EOR and ECBM) associated with the CO ₂ - malicious intrusion and sabotage. Intermediate cases, of intrusion with incomplete knowledge, could also occur. Terrorist activities against pipelines and facilities.

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35	01.03.03.00.	Social and institutional developments	<p>Events and processes related to changes in social patterns and degree of local government, planning and regulation.</p> <p>Potentially significant social and institutional developments include:</p> <ol style="list-style-type: none"> 1. Changes in planning controls (zoning) 2. Environmental legislation; 3. Demographic change and urban development; 4. Changes in land use; 5. Loss of archives/records, loss/degradation of societal memory. 	Social and institutional developments have the potential to affect motivation and knowledge issues, human use of the surface and sub-surface environments and the type of impacts that may be considered.
36	01.03.04.00.	Technological developments	<p>Events and processes related to future developments in human technology and changes in the capacity and motivation to implement technologies. This may include retrograde developments, e.g. loss of capacity to implement a technology.</p> <ol style="list-style-type: none"> 1. New technology replacing the need for CO₂ geologic sequestration 2. New low-cost desalination making saline aquifers more valuable 3. Lack of CO₂ capture technology improvements making it too expensive 4. Robotic underground mining making deeper resources 	Of interest are those technologies that might change the capacity of humans to intrude deliberately or otherwise into a storage site, to cause changes that would affect the movement of CO ₂ and associated contaminants, or that may otherwise affect the performance and safety of the sequestration system. Technological developments are likely but may not be predictable especially at longer times into the future.
37	01.03.05.00.	Drilling activities (third-party drilling through caprock)	<p>Events related to any type of drilling activity in the vicinity of the CO₂ sequestration system. These may be taken with or without knowledge of the disposal and may include activities such as:</p> <ol style="list-style-type: none"> 1. Exploratory and/or exploitation drilling for natural resources; 2. Attempted recovery of residual hydrocarbon resources (e.g., EOR, ECBM, shale gas); 3. Drilling for water resources; 4. Drilling for site characterization or research; 5. Drilling for liquid waste or other fluids disposal; 6. Drilling for geothermal resources. 	Has the potential to disrupt geological features that provide a barrier to CO ₂ migration and provide a relatively quick migration pathway to the near-surface.
38	01.03.06.00.	Mining and other underground activities	<p>Events related to any type of mining or excavation activity carried out in the vicinity of the storage site. These may be taken with or without knowledge of the site.</p> <p>Mining and other excavation activities include:</p> <ol style="list-style-type: none"> 1. Resource mining or quarrying; 2. Excavation for industry, storage, disposal or military purposes; 3. Scientific or archaeological investigation; 4. Shaft construction, underground construction and tunneling; 5. Underground nuclear testing; 6. Malicious intrusion, sabotage or war; 	Mining and other underground activities have the potential to disrupt the geosphere (storage reservoir, surrounding and overlying rock) and near-surface environment. They therefore have the potential to significantly affect the migration and distribution of sequestered CO ₂ .
39	01.03.07.00.	Human activities in the surface environment	<p>Events and processes related to any type of human activities that may be carried out in the surface environment that can potentially affect the performance of the storage system, or leakage pathways, excepting those FEPs related to water management which are described elsewhere.</p> <p>Examples include:</p> <ol style="list-style-type: none"> 1. Residential, industrial, and infrastructure construction; 2. Pollution of surface environment and groundwater. 3. Change in groundwater geochemistry not caused by project. 4. Human activities in the surface environment offsite (farming, harvesting, irrigation maintenance) in low areas with limited air circulation. 	Human activities in the surface environment have the potential to affect CO ₂ release processes, should leakage occur. They may also determine the types of impact to be considered or activities that would increase risk exposures.

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CarbonSAFE Rocky Mountains Phase I, CO ₂ -Storage Subsurface, Surface, Technical and Programmatic Risk Areas				
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40	01.03.08.00.	Water management	<p>Events and processes related to groundwater and surface water management including water extraction, reservoirs, dams, and river management.</p> <p>Water is a valuable resource and water extraction and management schemes provide increased control over its distribution and availability through construction of dams, barrages, canals, pumping stations and pipelines. Groundwater and surface water may be extracted for human domestic use (e.g. drinking water, washing), agricultural uses (e.g. irrigation, animal consumption) and industrial uses.</p> <ol style="list-style-type: none"> 1. Water extraction 2. Surface water reservoir construction 3. Dam construction 	Extraction and management of water may affect the movement of CO ₂ or associated contaminants to and in the surface environment.
41	01.03.09.00.	CO ₂ presence influencing future operations	The presence of injected CO ₂ may hinder future extractive operations by obscuring seismic traces or by making the drilling process more difficult. Conversely, the presence of CO ₂ locally, might allow for more economic future enhanced oil recovery operations. This FEP assumes that future technical advances might identify useable resources in the vicinity of previous CO ₂ injection.	Drilling through a formation filled with supercritical CO ₂ might cause 'blowouts' or loss of CO ₂ along the wellbore. A CO ₂ 'bubble' will change the velocity of seismic waves, distorting the 'image' of the underlying formations, and reducing confidence in the understanding of this structure.
42	01.03.10.00.	Explosions and crashes (See 16.27.00.)		
43	02.00.00.00.	CO₂ STORAGE	This category of FEPs specifies details of the sequestration concept under consideration. It is split into two classes for the pre- and post-closure periods.	This category is divided into two classes: <ol style="list-style-type: none"> 1. Pre-closure 2. Post-closure
44	02.01.00.00.	Pre-closure	Details of the sequestration concept, the fluids injected, and factors for the design, construction, operation and decommissioning phases.	The details of the sequestration concept are fundamental to determining which FEPs in other categories need to be considered in a given assessment. Some details of sequestration operations may affect the post-closure performance.
45	02.01.01.00.	Storage concept	<p>Features related to the concept of storage, such as whether a closure exists (sequestration in an abandoned oil or gas field or coal seam) or whether isolation of CO₂ is dependent upon slow diffusion rates through an extensive open structure (saline aquifer sequestration).</p> <ol style="list-style-type: none"> 1. Deep saline aquifer CO₂ storage <ul style="list-style-type: none"> - Sealed reservoir - Open reservoir 2. EOR CO₂ storage 3. ECBM CO₂ storage 4. Temporary CO₂ storage and pumping facilities <ul style="list-style-type: none"> - Above ground - Underground (see Reversibility) 	Different processes will be relevant to different storage concepts. For example, the rate of CO ₂ migration in an open aquifer will be relevant to safety assessment of saline aquifer storage, but less relevant to sequestration in a closed geological structure.

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46	02.01.02.00.	CO ₂ quantities, injection rate	Features related to the amounts of CO ₂ injected and their rate of injection into the storage aquifer/reservoir.	<p>High rates of CO₂ injection could have adverse effects, such as formation fracturing.</p> <p>For fast injection rates, displacement of oil/water will not be efficient during enhanced oil recovery; instead one will recover CO₂; premature breakthrough is undesirable from an economic perspective.</p> <p>Larger volumes of injected CO₂ are likely to result in more frequent and more intense induced seismicity unless compensated for with simultaneous production of fluids.</p>
47	02.01.03.00.	CO ₂ composition	<p>The composition and physical state (liquid, supercritical fluid etc.) of injected CO₂, with contents of impurities etc. Temperature and pressure of injected fluid are also relevant.</p> <p>During CO₂ storage operations, the principal injected gas is CO₂ captured and concentrated from human activity sources. However, the gas that is injected into a reservoir may not be 100 % CO₂, especially if there is some recycling of gas (in the case of enhanced oil recovery). Impurities can include: H₂S, CH₄, N₂, NO_x, SO₂ and mercaptans. These may be present either intentionally or because it could be particularly difficult or superfluous to separate them from CO₂.</p> <p>The CO₂ stream may contain such things as: corrosives, noncondensable gases, oxidants, toxic impurities, flammable/combustible/pyrophoric constituents, odorous constituents, organics or particulates.</p>	<p>The presence of even small amounts of other gases has a strong effect on the phase behavior of CO₂-dominated gases. High-pressure equations of state for CO₂-dominated gas mixtures are required to take into account changes in critical pressures and temperatures caused by the presence of other gases. Impurities will reduce the critical temperature which, in turn, has effects on interfacial tension.</p> <p>Impurities may affect pore water chemistry (pH and redox conditions, for example) depending on the impurities involved. Special care is needed when considering corrosive gases, such as H₂S.</p>
48	02.01.03.01.	CO ₂ containing H ₂ S	<p>High concentration of hydrogen sulfide (H₂S) in the CO₂ makes it a toxic waste which can lead to more stringent permitting and compliance requirements. It also increases the safety risks. The exposure threshold at which H₂S is immediately dangerous to life or health, according to the National Institute of Occupational Safety and Health, is 100 ppm, compared to 40,000 ppm for CO₂ (IPCC 2005)</p> <p>H₂S should be kept below maximum concentration of 10 to 200 ppm in the CO₂ for safety reasons.</p>	<p>Sufficient quantities of H₂S + H₂O in CO₂ can cause corrosion or sulfide stress cracking (CCP 2009) and increase safety risks.</p> <p>H₂S is strong smelling and requires additional sealing around the wellhead to capture fugitive emissions and minimize odors.</p> <p>On a positive side, H₂S in CO₂ can decrease minimum miscibility pressure (MMP) for enhanced oil recovery and makes small CO₂ leaks easier to detect due to the smell.</p>
49	02.01.03.02.	CO ₂ containing H ₂ O	In order to prevent corrosion in pipeline and wellhead systems, CO ₂ is normally dehydrated to less than 0.5 g/m ³ (30 lb per MMCF) or less than 20 ppm. (WRI 2008)	If the water vapor is not removed prior to compression, the CO ₂ product will be very corrosive and the pipeline well head and borehole would have to be built with much more expensive materials than carbon steel.

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50	02.01.03.03.	CO ₂ containing O ₂	<p>EOR and deep saline applications can tolerate some oxygen (air) in the CO₂, but ECBM can't. Oxygen in CO₂ will shift the boundary of the two-phase region toward higher pressures and would require a higher operating pressure to avoid two-phase flow. The preferred specification is less than 10 ppm oxygen.</p> <p>Oxygen in the 1-2% range or above could impact mineralogical reactions in the reservoir.</p>	<p>Oxygen in CO₂ can cause pipeline corrosion, oxidize oil in EOR or oxidize coal and/or methane in ECBM.</p> <p>High oxygen content (5-10%) will not liquefy or dissolve in downhole storage of CO₂, and therefore will result in undesirable back pressure and downhole gas pockets.</p> <p>Oxygen can contaminate or degrade CO₂ capture and CO₂ dehydration sorbents.</p> <p>Oxygen could cause subsurface microbial growth but is not expected to have a significant impact.</p>
51	02.01.03.04.	CO ₂ containing N ₂	<p>Nitrogen in CO₂ will shift the boundary of the two-phase region toward higher pressures and would require a higher operating pressure to avoid two-phase flow. Nitrogen is normally kept to less than 4% of volume in CO₂.</p>	<p>Nitrogen is undesirable for EOR because it raises the minimum miscibility pressure (MMP) of the fluid and makes the injection process less efficient. Nitrogen is not a problem in ECBM as a minor component of CO₂. It will lower the partial pressure of methane and allow more methane to be released and recovered.</p> <p>Minor amounts of nitrogen in CO₂ can increase compression and transmission energy consumption and can result in two phase operation.</p> <p>Nitrogen (and argon) will not liquefy or dissolve in downhole storage of CO₂, and therefore will result in undesirable back pressure and downhole gas pockets.</p>
52	02.01.03.07.	CO ₂ containing CH ₄ and other hydrocarbons	<p>Total hydrocarbons are normally kept to less than 5% of volume in CO₂.</p>	<p>Methane and other hydrocarbons can be a combustion concern in the presence of oxygen.</p> <p>Methane can impact the maximum miscibility pressure (MMP) of CO₂ and oil in EOR.</p>
53	02.01.03.08.	CO ₂ containing mercaptans	<p>Mercaptans are organic compounds containing sulfur.</p> <p>Total sulfur in CO₂ is normally kept to less than 35 mg/l.</p> <p>Methyl mercaptan is susceptible to photo oxidation in the atmosphere to hydrogen, sulfur dioxide, dimethyl disulfide and other polysulfide's. Therefore it has a relatively low half-life.</p> <p>Methyl mercaptan exhibits a toxicity similar to, but less than that of hydrogen sulfide. The OSHA permissible exposure level (PEL) is 10 mg/l.</p>	<p>Mercaptans and other malodorous sulfur compounds are strong smelling and toxic and require additional sealing around the wellhead to capture fugitive emissions and minimize odors.</p> <p>The strong odor of mercaptans suggests it is unlikely humans would willingly tolerate concentrations much above the odor threshold for any substantial period of time. However humans in occupational settings may rapidly succumb to extremely high levels of methyl mercaptan.</p>
54	02.01.03.09.	CO ₂ containing NO _x , SO _x	<p>Traces of NO_x and SO_x may occur when CO₂ is captured from a post-combustion operations.</p> <p>Although sulfur is present in most fossil fuels, the amount of SO_x in the CO₂ stream is expected to be very low because deep sulfur removal is required prior to post-combustion CO₂ capture to prevent excessive sorbent degradation/loss.</p> <p>Pre-combustion and post-combustion are likely to produce <0.01 vol % SO_x and <0.01 vol % NO_x in the CO₂ stream (IPCC 2005).</p> <p>Oxyfuel combustion may produce 0.5 vol % SO_x and 0.01 vol % NO_x in the CO₂ stream (IPCC 2005).</p>	<p>NO_x and SO_x may increase corrosion in pipeline and wellhead systems if H₂O is present.</p> <p>NO_x and SO₂ are polluting gases that are generated by the same power plants that generate massive amounts of CO₂ and attract emission taxes in certain countries (e.g. Italy). Their injection, in smaller amounts, with CO₂ could therefore help the economics of sequestration. Different sets of geochemical reactions are expected when these trace contaminants are present.</p>
55	02.01.03.10.	CO ₂ containing particulates	<p>CO₂ is normally scrubbed clean of particulates prior to input into the pipeline. Particulates could carry over due to upset conditions.</p>	<p>Particulate matter can cause valve and instrumentation plugging or erosion of piping.</p>

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56	02.01.03.11.	CO ₂ containing toxic volatile metals (mercury, lead, or cadmium)	Most CO ₂ capture systems are likely to include mercury capture either as an upstream unit or an integral part of the CO ₂ capture system. It is not expected that mercury, lead or cadmium ion complexes will follow the CO ₂ concentrate stream during regeneration, other than by physical entrainment as aerosols, which can be eliminated by an in-line mist eliminator stage.	Presence of toxic volatile metals in the CO ₂ stream could classify it as a hazardous waste.
57	02.01.03.12.	CO ₂ containing pyrophoric compounds	Pyrophoric compounds can spontaneously ignite when in contact with air. Iron sulfide is one of the most common pyrophoric compounds associated with the oil and gas industry.	Pyrophoric materials can cause fires or explosions when exposed to air.
58	02.01.03.13	CO ₂ containing organic compounds	Trace amounts of organic compounds (derivatives or fragments of amine sorbents) could be carried over into the concentrated CO ₂ stream.	Organic compounds could feed microbial growth underground which can lead to plugging of wells and/or decreased permeability.
59	02.01.03.14	CO ₂ containing CO or H ₂	Traces of CO and H ₂ may occur when CO ₂ is captured from a pre-combustion operation such as those involving gasification..	CO and H ₂ are safety risks due to their combustibility in the presence of oxygen and potential for H ₂ embrittlement of metal components. CO ₂ combined with CO is more toxic than when CO ₂ or CO are separate. (Duncan 2012).
60	02.01.04.00.	Microbiological contamination	Microbiological contamination of injected fluid. Contamination of supercritical CO ₂ is considered unlikely due to its being a very good solvent. However, other fluids (like water) may be injected into the storage site that may be contaminated with microbes. Microbes are known to populate geologic strata to at least 2750 meters below the surface.	The introduction of microbes into the sequestration system may affect both the performance of the storage system and the endpoints considered. Microbial growth can lead to well plugging and/or decreased permeability.
61	02.01.05.00.	Schedule and planning (See 11.03.00.)		
62	02.01.06.00.	Pre-closure administrative control (See 11.06.00.)		
63	02.01.07.00.	Pre-closure monitoring of storage (See 23.08.00.)		
64	02.01.08.00.	Quality control (See 11.08.00.)		
65	02.01.09.00.	Accidents and unplanned events (See 16.01.00.)		
66	02.01.10.00.	Over pressuring	The CO ₂ injection process is greatly influenced by the target reservoir formation pore pressure. The formation pressure is considered over pressured if it is above the normal hydrostatic pressure for the given depth. Over pressuring may occur at any depth, naturally or artificially. Man-made overpressure may be accidental or deliberate. An example of deliberate overpressure is injecting gaseous CO ₂ in an aquifer at a faster rate than water can drain from the reservoir zone. In such a case the overpressure is caused by the injection activity (not natural processes). The maximum tolerable overpressure is calculated as a function of the desired storage volume and of a chosen safety factor below the critical fracturing gradient of the top seal rock. Deliberate overpressure induction is a mechanism for storing energy (associated with the pressure) for later extraction. An example of accidental overpressure is the depressurization of a storage reservoir where the CO ₂ is in liquid form, below but near the critical phase change pressure. The change of phase to gas creates a gas column that could exercise an unforeseen overpressure at the top of the gas column. 1. Deliberate over pressuring 2. Accidental over pressuring 3. Regional-scale over pressuring	Deliberate or accidental over pressuring during the operational phase will affect the initial geosphere conditions for a post-closure assessment. It has the potential to cause fractures in the sealing formation and hence provide migration pathways for the sequestered CO ₂ . Induced fractures in the caprock can be created by over pressuring the reservoir. Fractures could be sealed in time by precipitation of newly formed minerals, but could also be re-opened as a consequence of new changes in stresses during storage of CO ₂ .

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67	02.02.00.00.	Post-closure	Details of post-closure activities associated with sequestration.	Human activities post-closure may affect the likelihood of specific impacts being incurred.
68	02.02.01.00.	Post-closure administrative control (See 11.07.00.)		
69	02.02.02.00.	Post-closure monitoring of storage (See 23.09.00.)		
70	02.02.03.00.	Records and markers (long-term knowledge retention) (See 11.04.00.)		
71	02.02.04.00.	Reversibility	The degree to which the sequestered CO ₂ could be deliberately removed, if required. Either as an extreme remedial action, because the CO ₂ is required as a resource, or because its presence is impeding access to other geological resources.	The degree to which reversibility is considered in the design of a sequestration system may influence its long-term performance, by leaving viable boreholes in-situ after closure, for example.
72	02.02.05.00.	Remedial actions	Events and processes related to actions that might be taken following closure of a storage site to remedy problems that, either, are associated with its not performing to the standards required, result from disruption by some natural event or process, or result from inadvertent or deliberate damage by human actions.	The aim of possible future remedial actions will be to modify the performance and safety of the CO ₂ sequestration system.
73	03.00.00.00.	CO₂ PROPERTIES, INTERACTIONS & TRANSPORTATION	This category of FEPs is concerned with those Features, Events and Processes that are relevant to the fate of the sequestered fluid. Carbon dioxides properties can vary greatly between conditions at depth and near surface, and a wide range of physical and chemical reactions can be important. The category is divided into three classes for the properties, interactions and transport of carbon dioxide.	This category is divided into three classes: 1. CO ₂ properties 2. CO ₂ interactions 3. CO ₂ transport These properties will have a significant impact on all of the risk calculations.
74	03.01.00.00.	CO ₂ properties	The fundamental physical and chemical properties of carbon dioxide, taking into account impurities. 1. CO ₂ properties changed by pressure 2. CO ₂ properties changed by temperature 3. CO ₂ properties changed by impurities 4. CO ₂ properties changed by reservoir geochemistry (i.e. CO ₂ migrating from quartz into calcite cemented sand)	Carbon dioxides properties can vary greatly with pressure, temperature and impurities, and an understanding of these properties is essential before the fate of sequestered fluid can be assessed.
75	03.01.01.00.	Physical properties of CO ₂	Physical properties of CO ₂ including density, viscosity, interfacial tension and thermal conductivity and their dependence on pressure and temperature. 1. CO ₂ density 2. CO ₂ viscosity 3. CO ₂ interfacial tension 4. CO ₂ thermal conductivity	The physical properties of CO ₂ determine the way in which it will behave in the environment once injected. Calculation of overpressure at constant rate injection and of injectivity at constant pressure injection are impacted by the choices of properties.

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76	03.01.02.00.	CO ₂ phase behavior	<p>FEPs related to the phase behavior (gas, liquid, supercritical fluid) of CO₂. The presence of contaminants in the injected CO₂ (e.g. N₂) and gas and hydrocarbons (e.g., in EOR and ECBM operations) in the reservoir will affect the phase behavior and partition of CO₂ between different physical states.</p> <p>CO₂ mixing with other fluids and gases, leads to modified flow behavior that is not fully understood (CCP 2009)</p>	CO ₂ phase behavior is a primary consideration for modeling CO ₂ migration. CO ₂ is expected to be in the supercritical state under most sequestration scenarios.
77	03.01.03.00.	CO ₂ solubility and aqueous speciation (See 03.02.13.02. and 03.02.13.06.)	<p>CO₂ solubility is the amount of CO₂ that can dissolve for given conditions in water. It can vary as a function of temperature, pressure and precise composition of the fluid (e.g. salinity, dissolved species/complexes, presence of hydrocarbons - e.g., EOR and ECBM). Changing temperature and pressure accompanying migration of CO₂ can therefore influence CO₂ solubility, potentially leading to gas exsolution.</p> <p>CO₂ is present in the aqueous phase as: aqueous CO₂; carbonic acid (H₂CO₃); bicarbonate (HCO₃⁻); and carbonate (CO₃⁻²). Note that other dissolved ions (Na⁺, Mg⁺⁺, Ca⁺⁺, etc.) are also involved and provide an array of linked, reversible reactions.</p>	<p>CO₂ solubility has an impact on the chemical composition of formation fluids, pressure distribution, 'sorption' processes, mineral-fluid reactions and the overall storage capacity of CO₂. Dissolved CO₂ may migrate in a different manner to 'free' supercritical CO₂. CO₂ solubility in water and its partition between aqueous, gaseous, and organic phases controls the efficiency of diffusive transport and successive mineral reactions.</p> <p>The aqueous speciation of dissolved CO₂ will impact upon the mobility of sequestered CO₂ and associated contaminants.</p>
78	03.02.00.00.	CO ₂ interactions	Potential interactions of carbon dioxide with solid, liquid or gaseous media.	A wide range of physical and chemical reactions can be important, and an understanding of these interactions is essential for the assessment of potential impacts.
79	03.02.01.00.	Effects of pressurization of reservoir on caprock (See 02.01.10.00.)	A storage reservoir will experience enhanced pressure due to injection of CO ₂ . This may exceed original 'natural' pressurization due to hydrocarbon emplacement (EOR or ECBM, for example), or clay mineral transformations during diagenesis.	Over pressuring of the reservoir may involve leakage of CO ₂ through the caprock due to fracturing or enhanced interactions with CO ₂ .
80	03.02.02.00.	Effects of pressurization on reservoir fluids	Increased pressurization caused by the injection of supercritical CO ₂ will affect the behavior of other fluids within the reservoir.	The potential importance of increased pressurization to enhanced oil and gas recovery indicates that it can modify the mobility of other fluids in the receiving reservoir.
81	03.02.03.00.	Interaction with hydrocarbons (See 0.3.02.03.01 through 03.02.03.15)	<p>In EOR or ECBM sites, for example, hydrocarbons could be mobilized by CO₂, by miscible displacement and transported to the near-surface. This is of particular relevance if enhanced oil recovery is an additional aim of the sequestration concept. Kolak and Burruss (2003) demonstrate that polyaromatic hydrocarbons (PAHs) can be mobilized by sequestration in deep coal beds.</p> <p>Sequestered CO₂ can also precipitate asphaltenes from crude oil under certain conditions of composition, temperature and pressure. Such precipitation in the vicinity of injection wells can lead to loss of injectivity and even plugging of the wells.</p>	<p>Mobilized hydrocarbons may migrate to the near-surface environment.</p> <p>Precipitated asphaltenes can clog pores, reducing permeability and affecting fluid flow paths.</p>

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82	03.02.03.01.	EOR attribute range	<p>Technical screening guidelines for CO₂ flooding: recommended (current projects range) Crude oil gravity, °API: >22 (27 to 44) Crude oil viscosity, cp: <10 (0.3 to 6) Crude oil composition: High percent of C₅ to C₁₂ Reservoir oil saturation: >40% (15 to 70%) Type of formation: Relatively thin sandstone or carbonate unless dipping Permeability: Not critical if sufficient rates can be applied Depth/temperature: For miscible displacement, depth must be great enough to allow injection pressures greater than the minimum miscible pressure (MMP), which increase with temperature and for heavier oils (Meyer 2007).</p> <p>Oil formation volume factor (ratio reservoir barrels/stock tank barrels): 1.2 to 1.4 Reservoir barrels at subsurface conditions (at depth) Recommended depths of CO₂ floods of typical Permian Basin oils</p>	Operating outside the EOR attribute range could lead to low oil recovery. This could impact CO ₂ sequestration economics.																
83	03.02.03.02.	EOR reservoir depth	<p>CO₂ Miscible</p> <table border="1"> <thead> <tr> <th>Gravity, °API</th> <th>Depth</th> </tr> </thead> <tbody> <tr> <td>>40</td> <td>> 762 m (2500 ft)</td> </tr> <tr> <td>32 to 39.3</td> <td>> 853 m (2800 ft)</td> </tr> <tr> <td>28 to 31.9</td> <td>> 1006 m (3300 ft)</td> </tr> <tr> <td>22 to 27.9</td> <td>> 1219 m (4000 ft)</td> </tr> <tr> <td><22</td> <td>Fails CO₂ screening</td> </tr> </tbody> </table> <p>CO₂ Immiscible</p> <table border="1"> <thead> <tr> <th>Gravity, °API</th> <th>Depth</th> </tr> </thead> <tbody> <tr> <td>13 to 21.9</td> <td>> 549 m (1800 ft)</td> </tr> </tbody> </table>	Gravity, °API	Depth	>40	> 762 m (2500 ft)	32 to 39.3	> 853 m (2800 ft)	28 to 31.9	> 1006 m (3300 ft)	22 to 27.9	> 1219 m (4000 ft)	<22	Fails CO ₂ screening	Gravity, °API	Depth	13 to 21.9	> 549 m (1800 ft)	Operating conditions outside miscible range could lead to low oil recovery. This could impact CO ₂ sequestration economics and result in more CO ₂ recycling.
Gravity, °API	Depth																			
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Gravity, °API	Depth																			
13 to 21.9	> 549 m (1800 ft)																			
84	03.02.03.03.	EOR oil recovery	<p>Typical oil recovery by recovery mechanism as a function of Original Oil in Place (OOIP) Primary: 6 to 15% OOIP Secondary: 6 to 30% OOIP Miscible CO₂ EOR: 8 to 20% OOIP Remaining: 8 to 35% OOIP (Meyer2007)</p> <p>Miscible CO₂ EOR: 7-23% OOIP Immiscible CO₂ EOR: 9 to 19% OOIP (Meyer 2007)</p>	Prior oil production and methods could impact CO ₂ EOR results and amount of CO ₂ that can be sequestered.																
85	03.02.03.04.	EOR CO ₂ utilization	For field scale miscible CO ₂ EOR floods net (purchased) amount of CO ₂ required is estimated to be between 60 to 262 m ³ CO ₂ /m ³ oil (2.5 to 11 MCF/STB) of incremental recovery with an average value of 143 to 167 m ³ /m ³ (6 to 7 MCF/STB). For immiscible floods, actual incremental oil recovery has been on the order of 119 to 286 m ³ /m ³ (5 to 12 MCF/STB) (Meyer 2007).	Increased CO ₂ demand per barrel of oil produced will impact EOR project economics. This could impact CO ₂ sequestration economics as well.																
86	03.02.03.05.	EOR viscosity relations	<p>Because the viscosity of CO₂ at reservoir conditions is much lower than that of most oils, viscous instability will limit the sweep efficiency of the displacement and, therefore, oil recovery (Meyer 2007).</p> <p>Crude oil viscosity, cP: <10 (0.3 to 6)</p>	Can lead to adverse hydrodynamic instabilities, such as fingering, which lead to vertical fluid stratification and reduced oil recovery (Meyer 2007). This could also result in more CO ₂ breakthrough and require more CO ₂ recycling.																

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87	03.02.03.06.	EOR oil reservoir heterogeneity	Oil reservoir rock is extremely heterogeneous, exhibiting zones of high permeability in close proximity to those of low permeability. These permeability differences may be innate, that is caused by differences in pore structure at the time of geological deposition, or a product of fractures, natural or man-made (Meyer 2007)	Can decrease efficiency of oil recovery and CO ₂ sequestration.
88	03.02.03.07.	EOR hydrocarbon precipitation	CO ₂ injection encourages precipitation of asphaltenes or paraffins.	Precipitation of asphaltenes can clog pores, reducing permeability and affecting fluid flow paths. It can also cause plugging of boreholes.
89	03.02.03.08.	EOR miscibility	<p>Flooding a reservoir with CO₂ can occur either miscibly or immiscibly. Miscible CO₂ displacement is only achieved under a specific combination of conditions, which are set by four variables: reservoir temperature, reservoir pressure, injected gas composition, and oil chemical composition (Meyer 2007). Miscible displacement is achieved at pressures above the minimum miscibility pressure (MMP). If the reservoir pressure is below the MMP, CO₂ can still be injected, but the efficiency of the enhanced oil recovery process is adversely impacted. Typically this does not occur since, after primary depletion, water flooding operations commence which restore reservoir pressure to values above the MMP(Meyer 2007).</p> <p>1. Miscible CO₂ flooding 2. Immiscible CO₂ flooding</p>	Operating under miscible conditions results in significantly higher oil recovery than operating under immiscible conditions. Higher oil recovery improves economics of EOR and CO ₂ sequestration.
90	03.02.03.09.	EOR early CO ₂ breakthrough	Early breakthrough of CO ₂ results in production of significant amounts of CO ₂ and water along with oil. The alternating water and CO ₂ gas (WAG) approach is typically applied in CO ₂ EOR to minimize CO ₂ use (as it is purchased) and to avoid early breakthrough of CO ₂ .	Breakthrough of CO ₂ increases operating costs due to the need to recycle the CO ₂ and can also result in lower oil recovery.
91	03.02.03.10.	EOR water alternating gas (WAG)	<p>WAG involves alternating injection of water and gas (CO₂) to optimize EOR performance.</p> <p>WAG ratios range: 1:1 to 5:1 (0.5:1 to 4:1 per NETL 2009) Slug range: 0.1% to 2% of reservoir hydrocarbon pore volume (NETL 2009) Cumulative CO₂ volume: 15 to 30% of hydrocarbon pore volume (NETL 2009)</p>	WAG ratio may have a positive or negative impact on oil recovery.

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92	03.02.03.11.	EOR injection water quality / attributes / chemistry	<p>Water quality can impact EOR performance.</p> <p>Injection of low salinity water into an EOR reservoir where the sandstone cement consists of anhydrite could cause the anhydrite to convert to gypsum and its volume would increase up to 1.5 times resulting in decreased pore space and permeability.</p> <p>Injection microbial contaminated water could result in well plugging or decreased permeability due to microbial growth.</p> <p>Injection of corrosive water could result in corrosion of equipment, piping and borehole liners.</p> <p>Injection of hard water could lead to scale buildup.</p>	Lower oil recovery. Corrosion, scale buildup or microbe growth in system equipment. Decreased permeability near injection wells.
93	03.02.03.12.	EOR injection water pressure	<p>Water is denser than CO₂. When changing from CO₂ injection to water injection, a pressure differential needs to be overcome. To do so, the water supply header operates at a pressure in excess of the CO₂ supply header pressure. This allows water to be throttled into the well, its pressure declining to the appropriate value once the CO₂ is displaced from the wellbores (Meyer 2007).</p>	System should be designed to provide the proper water injection pressure.
94	03.02.03.13.	EOR injection and production well pattern and spacing	<p>The pattern is typically a 5-spot (one injection well in center surrounded by four production wells) or inverse 5-spot (one production well in center surrounded by four injection wells), or a variety of other patterns. Typically there are 0.5 to 4.0 production wells for every injection well.</p> <p>The spacing of injection and production wells refers to the area covered by the well pattern. It may be 8, 12, 16 or more hectares (20, 30, 40 or more acres).</p>	Improper injection and production well spacing and pattern can lead to early CO ₂ breakthrough and/or low oil recovery.
95	03.02.03.14.	EOR intermittent CO ₂ supply	<p>Intermittent CO₂ supply can be caused by interruptions at the source, CO₂ capture, compression, pipeline or wellhead.</p>	Intermittent CO ₂ supply can negatively impact sweep efficiency of EOR and therefore make sequestration less attractive.
96	03.02.03.15.	EOR flood type	<p>CO₂ flooding types include gravity stable and conventional piston flooding. In gravity stable flooding, CO₂ is injected in the top of a reservoir (dome) as a supercritical fluid or dense gas and builds an oil bank by mobilizing residual oil downward as the CO₂ cap expands. It is important to maintain a relatively uniform front and avoid coning.</p> <p>In the conventional piston flooding, CO₂ is injected into an oil reservoir and builds an oil bank by mobilizing residual oil horizontally as the CO₂ plume expands.</p> <ol style="list-style-type: none"> Gravity stable CO₂ flooding Piston CO₂ flooding 	Flooding should be optimized to maintain a relatively uniform front and avoid coning or CO ₂ early breakthrough (profile control).
97	03.02.04.00.	Displacement of saline formation fluids	<p>Injection of CO₂ into a geologic formation may result in displacement of saline formation fluids into potable water supplies. Limitations on the pressure in a formation (for seal integrity) will mean that existing fluids are displaced/replaced. Displaced fluids are highly likely to be saline. Because the pressure wave created by injection travels much further than the physical CO₂ front, displacement of saline formation fluids can occur at locations outside the CO₂ storage area. Inter-connection of aquifer systems may enable saline fluids to enter potable water formations.</p> <p>For significant storage to be possible, it is necessary for a significant amount of the native pore space fluid to be displaced from the reservoir over the injection period. This may occur either by production of fluids (oil or gas), by</p>	Displaced saline formation fluids may contaminate near-surface aquifers with subsequent impacts, such as contamination of potable water supplies.

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98	03.02.05.00.	Change in mechanical processes and conditions	<p>Features and processes related to the mechanical processes and conditions resulting from the injection of CO₂ that affect the rock, boreholes and other engineered features, and the overall mechanical evolution with time. This includes the effects of hydraulic, mechanical and thermal loads imposed on the rock by the injected CO₂. Injection of CO₂ into a reservoir can cause (directly or indirectly) changes of the geomechanical properties of the reservoir rock. Direct changes can be due to change of reservoir pressure and temperature (PVT system). Indirect changes (of rock properties) might result from geochemical and mineralogical changes after storage of CO₂.</p>	<p>Mechanical changes of the reservoir resulting from CO₂ injection (such as generation of fractures, reactivation of fractures/faults, changes of bulk elastic properties and effective reservoir) could lead to subsidence/uplift (at surface), induced seismicity, changes in migration pathways, even burst/leakage of the seal. Examples of other relevant processes are: borehole lining collapse; rock volume changes, leading to cracking</p>
99	03.02.06.00.	Induced seismicity	<p>Injection of CO₂ may cause and trigger seismic events and earthquake hazards through processes such as reducing friction at existing faults. This may occur both in seismically active areas and in areas characterized by a low background seismicity (reactivation of ancient fault planes, changes in the orientation, fluid-pockets occurrence). This FEP includes micro seismicity.</p> <p>Induced macro-seismicity activity is a function of existing regional and local stresses, of porosity structure, and of imposed injection stresses. Induced macro-seismicity is less likely if the injection formation is dominated by intergranular and not fracture porosity.</p> <p>The problem of seismicity might be more serious when CO₂ is injected into a reservoir in tectonically active regions with high density of active faults (Damen 2006).</p> <ol style="list-style-type: none"> 1. Induced macro-seismicity 2. Induced micro-seismicity 3. Seismicity tied to activation of an existing structure (fault/fracture) 4. Seismicity tied to creation of a new structure (fault/fracture) 	<p>Seismicity can introduce sudden physical changes to the sequestration system and may expose any local population to earthquake hazards.</p> <p>Potential effects of reservoir-induced seismicity (RIS) are damage to the caprock and wells, which might cause CO₂ leakage, and damage to building and infrastructure (Damen 2006).</p> <p>In a reservoir that is under high tectonic stresses, any significant reduction of pressure (pressure acting between individual rock particles) may trigger faults. This may lead to uplifting or down-faulting of the surface (Damen 2006).</p>
100	03.02.07.00.	Subsidence or uplift	<p>Injecting the CO₂ may cause acidification of formation water, leading to mineral dissolution and subsidence. This is of particular relevance to shallow storage sites.</p> <p>Chemical compaction or dissolution of the reservoir rock will particularly be a matter of concern in carbonate rocks with high porosity (Damen 2006).</p> <p>Injection of large quantities of CO₂ into a confined aquifer may increase pore pressure and lift the overlying rocks upwards.</p> <p>It is not envisaged that uplift will take place in a CO₂ reservoir as long as the maximum storage pressure is kept below the geostatic pressure (Damen 2006).</p> <ol style="list-style-type: none"> 1. Subsidence 2. Uplift 	<p>Deformation may affect geological processes and may result in impacts of concern at the surface.</p> <p>Dissolution of the reservoir rock (chemical compaction) can lead to the reservoir caving in under the weight of the overburden formation (Damen 2006)</p> <p>Vertical subsidence or uplift above large reservoirs could affect lake levels and shift streams in lowland areas with low topographic relief.</p> <p>Subsidence or uplift could damage buildings or farmland.</p>

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101	03.02.08.00.	Thermal effects on the injection point	<p>Temperature of the injected fluid could result in geological modification of the region around the point of injection due to thermal gradients.</p> <ol style="list-style-type: none"> Cooling due to CO₂ changing from supercritical to gas phase. Injected CO₂ may be 25 to 50°C cooler than the in-situ temperature. 	These thermal effects could influence the mobility of the injected CO ₂ and impurities.
102	03.02.09.00.	Reservoir water chemistry	<p>Water phase geochemistry of sequestered CO₂. This includes the solubility trapping of CO₂ in water (H₂O) to form carbonic acid (H₂CO₃). Subsequent ionic trapping of carbonic acid with hydroxide ions (OH⁻) forms bicarbonate ions (HCO₃⁻), which can react in turn with further hydroxide ions to form carbonate (CO₃²⁻).</p> <ol style="list-style-type: none"> Formation of carbonic acid (H₂CO₃) Formation of bicarbonate ions (HCO₃⁻) Formation of carbonate (CO₃²⁻) 	Modification of the water phase geochemistry can disturb the equilibrium between the water and solid phase of the reservoir and result in further geochemical (for example, solid phase geochemistry) and physical changes with resulting implications for the long-term performance of the sequestration system.
103	03.02.10.00.	Interaction of CO ₂ with chemical barriers	<p>Chemical barriers (pH, Eh-pH, ion exchange) may exist in aquifers to retard the migration of CO₂ from depth. The precipitation of CO₂ bearing solids may result from such interactions.</p> <ol style="list-style-type: none"> pH barrier Eh-pH barrier Ion exchange barrier 	Such barriers will affect the rate of migration of CO ₂ from depth.
104	03.02.11.00.	Sorption and desorption of CO ₂ (CO ₂ interaction with coal seams)	<p>The sorption and desorption of CO₂ on geological materials. Sorption onto coal and the displacement of methane (CH₄) is the primary mechanism behind the enhanced coal bed methane recovery (ECBM) method for geological CO₂ sequestration.</p>	The rate of sorption and desorption of CO ₂ on geological materials affects its mobility and therefore the performance of the storage system.
105	03.02.11.01.	ECBM sorption of CO ₂ on coal and release of methane	<p>Based on the Langmuir isotherm, CO₂ has higher affinity to coal and therefore displaces CH₄ adsorbed on the coal.</p> <p>2-3 moles CO₂ adsorbed on coal for every mole of CH₄ desorbed.</p> <p>CO₂ adsorption: up to 41 Nm³/tonne coal (1400 scf/st coal)</p> <p>CH₄ release: up to 13-15 Nm³/tonne coal (450-500 scf/st coal) at 22°C 72°F) and 0-7 MPa (0-1000 psi).</p> <p>The CO₂/CH₄ sorption ratio of coal varies depending on the rank of coal.</p> <p>Typical CO₂/CH₄ sorption ratios for various coals are as follows:</p> <p>Low volatile bituminous: 1:1 Medium volatile bituminous: 1.5:1 High volatile A bituminous: 3:1 High volatile bituminous: 6:1 Sub bituminous: 10:1</p>	Adsorption of CO ₂ on coal can have a positive effect on CO ₂ sequestration.
106	03.02.11.02.	ECBM desorption of CO ₂ from coal or other solids	CO ₂ desorption can occur with decreased pressure.	Release of CO ₂ could lead to leakage.
107	03.02.11.03.	ECBM coal swelling	<p>The chemical reactions and physical processes that occur during CO₂ injection into coal seams and their impact on the integrity of the coal seams are not well understood. One of the reactions is swelling of the coal matrix when injecting CO₂. (Damen 2006)</p> <p>When CO₂ is injected into a coal seam, the coal matrix swells causing the cleat permeability to decrease.</p>	Coal seam swelling may cause a reduction in permeability and injectivity. Swelling might also induce stresses on the overlying and underlying rock strata in non ideal coal seams (thin, low permeability and highly faulted), that could cause faulting and possible migration pathways out of the coal seam (Damen 2006).
108	03.02.11.04.	ECBM release of polyaromatic hydrocarbons (PAH) from coal seams	Polyaromatic hydrocarbons are chemical compounds that consist of aromatic rings. They are found in oil, coal and tar deposits. They tend to be released as a by-product of coal fires.	Toxicity issues and operation issues with decreased permeability.

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109	03.02.11.05.	ECBM coal seam dewatering	<p>As a coal seam is dewatered, its pressure decreases. Cleat permeability increases. Coal matrix shrinks, opening up cleat fractures. Assume that the coal cleats are originally 100% saturated with water.</p> <p>Recommendation for ECBM: Coal seams with low water saturation (Bachu 2008)</p>	Coal dewatering produces large quantities of water that must be properly treated and disposed of. In some cases, this may be a limiting factor in obtaining environmental permits and take a significant toll on project economics.
110	03.02.11.06.	ECBM original gas in place	<p>Original gas (methane) in place (OGIP) depends on the rank of coal. Free gas occurs within natural fractures. Dissolved gas occurs in water within the natural fractures. Adsorbed gas occurs within the coal matrix Adsorbed gas typically represents over 95% of total. (Mansourine 2003)</p> <p>Coal bed methane may be formed by bacteria (biogenic methane) at depths less than 300 meters, or formed by heat and pressure transformation of coal organic matter (thermogenic methane) at greater depths in higher-rank coals. Thermogenic methane frequently contains trace amounts of H₂O, CO₂, N₂ and H₂S.</p> <p>Existing gas in place = original gas in place - previous gas production.</p> <p>Recommendation for ECBM: Methane-saturated seams should be preferred from a methane production perspective. From a storage perspective, under saturated coal seams can still be effective (Bachu 2008).</p>	OGIP impacts the amount of methane available for ECBM recovery.
111	03.02.11.07.	Previous working of the coal seam	<p>Primary CBM takes out 20-60% of the original gas in place (OGIP). CO₂ ECBM can recover an additional 30%. Up to 80-90% of OGIP can be recovered with primary CBM plus CO₂ ECBM.</p> <p>Production stages of a coal bed methane well</p> <ol style="list-style-type: none"> 1. Dewatering stage 2. Stable production stage 3. Decline stage (Mansourine 2003) 4. CO₂ injection stage 	Wells selected for ECBM CO ₂ injection should be near depletion to optimize CBM and ECBM performance.
112	03.02.11.08.	ECBM coal seam pressure	<p>Coal seam hydrostatic pressure increases with depth.</p> <p>CO₂, N₂ and water injection increase hydrostatic pressure.</p> <p>Dewatering and methane production decrease hydrostatic pressure.</p> <p>CO₂, CH₄, N₂ and H₂S adsorption capacity of coal increases with coal seam hydrostatic pressure.</p>	<p>Gas adsorption is pressure dependent. The pressure profile in the reservoir must be understood and the injection operation designed appropriately.</p> <p>Gas adsorption of coal increases with pressure. Gas desorption of coal increases as pressure decreases. As reservoir pressure decreases, the rate at which CH₄ desorbs increases. However, CO₂ adsorption decreases with decreased pressure.</p> <p>At supercritical pressures, CO₂ adsorption may be replaced by absorption as CO₂ diffuses in coal. CO₂ is a coal plasticizer, lowering the temperature required to cause the transition from a glassy, brittle structure to a rubbery, plastic structure. The transition temperature may drop from ~400°C at 3MPa to <30°C at 5.5 MPa. Coal plasticization, or softening, destroys any permeability that would allow CO₂ injection. (Bachu 2006).</p>
113	03.02.11.09.	ECBM coal seam temperature	<p>Coal seam temperature increases with depth.</p> <p>CO₂ adsorption is an exothermic reaction and will provide a heat source, at least during the active injection phase of the project. As temperature of the coal seam increases, the adsorption of CO₂ decreases.</p>	Impacts CO ₂ adsorption and methane release.

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114	03.02.11.10.	ECBM coal seam fluid pH	The pH of aqueous solutions affects the surface of material it is in contact with. In the case of coal, at a high pH value, the carbonaceous surface assumes a net negative charge. At a low pH, the carbonaceous surface assumes a net positive charge. Theoretically, a pH of 9 would favor and a pH of 2 would disfavor the aqueous capture of CO ₂ .	pH of water in the coal seam may impact CO ₂ adsorption.
115	03.02.11.12.	ECBM injection and production well pattern and spacing	The most common drilling pattern is a 5-spot (injection well in the center and production wells in the corners or inverse 5-spot (injection in the corners and production in the center). Drilling on 16, 65 or 233 hectare (40, 160 or 640 acre) spacing. When injecting CO ₂ , it is important to allow sufficient time for displacement of the methane (locating production wells far away enough from the injection wells).	Impacts the sweep efficiency of ECBM and the effective sorption of CO ₂ .
116	03.02.11.13.	ECBM injection strategy	Constant injection rate or variable injection rate "huff and puff"(alternating starting and stopping CO ₂ injection over time.	Impacts the sweep efficiency of ECBM and the effective sorption of CO ₂ .
117	03.02.11.14.	ECBM early CO ₂ breakthrough	Early breakthrough of CO ₂ can be caused by high permeability areas in the coal seam or improper well pattern/spacing.	Impacts the sweep efficiency of ECBM and increases costs due to the need for excess CO ₂ recycling.
118	03.02.11.15.	ECBM coal seam thickness	For ECBM at least one coal seam should be at least 0.5 m (1.5 ft) thick. However, the thicker the seam, the more likely it could be mineable. Recommended for ECBM: Concentrated coal deposits (few, thick seams) are generally favored over stratigraphical dispersed beds comprising multiple, thin seams (Bachu 2008).	Seams less than 0.5 m (1.5 ft) thick can limit injectivity.
119	03.02.11.16.	ECBM complex structural geology of coal seam	Complex structural geology can make ECBM more difficult to model, less efficient to implement and more susceptible to leakage. Recommendation for ECBM: Simple structure. The reservoir should be minimally faulted and folded. The coal seams should be laterally continuous and vertically isolated from surrounding strata to prevent migration of excess CO ₂ and CH ₄ into adjacent aquifers and possibly to the surface (Bachu 2008).	Potential for CO ₂ leakage and lower methane yields.
120	03.02.11.17.	ECBM CO ₂ injection into mineable coal seams	CO ₂ ECBM is normally applied to coal seams that are too thin or too deep to be mined.	CO ₂ ECBM in mineable coal seams will complicate the recovery of those coal reserves. However, removing methane decreases the explosion possibility for future mining.
121	03.02.11.18.	ECBM coal seam permeability	The permeability of coal varies in two basic ways: 1. Phase relative permeability effects 2. Change in the effective stress within the seams (Mansourine 2003) Cleat permeability is primarily controlled by the prevailing horizontal stresses. ECBM wells that produce little water or gas may indicate low permeability. Recommended permeability for ECBM: 1 to 5 mD (Bachu 2008). Coal permeability decreases with depth, such that injectivity	Low permeability makes CO ₂ ECBM more difficult and more expensive.

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122	03.02.11.19.	ECBM coal porosity	<p>Micro-porosity: < 2 nm pore diameter impacts sorption</p> <p>Meso-porosity: >2 nm <50 nm pore diameter impacts diffusion</p> <p>Macro-porosity (fracture porosity): > 50 nm impacts Darcy flow</p> <p>Induced fractures: pipe flow (Mansourine 2003)</p> <p>Cleat porosity represents the initial water storage volume in the coal seam.</p>	Coal bed porosity and permeability increases as reservoir pressure is lowered and gas production occurs.
123	03.02.11.20.	ECBM coal seam heterogeneity	Permeability can vary by more than an order of magnitude in coal seams.	Heterogeneity in permeability can result in CO ₂ early breakthrough, limit CO ₂ storage capacity and limit methane recovery.
124	03.02.11.21.	ECBM coal seam vertical and horizontal injectivity	Vertical and horizontal injectivity in coal seams is largely determined by the cleat size and cleat angle.	Vertical and horizontal injectivity may determine whether to use vertical or horizontal type wells for CO ₂ injection.
125	03.02.11.22.	ECBM CO ₂ storage capacity of coal	Typical sorption of coal can be up to 41 Nm ³ /tonne (1400 scf/st) at 22°C and 0- 6.9MPa (0-1000 psi).	Depending on the objective of CO ₂ ECBM, the CO ₂ storage capacity can have a positive or negative impact. If the objective is to minimize CO ₂ consumption/cost it can be a negative. If the objective is to maximize CO ₂ sequestration, it is a positive.
126	03.02.11.23.	ECBM coal bed methane composition	Coal bed methane tends to be sweet (no H ₂ S). It contains small amounts of CO ₂ and nitrogen.	Impacts gas treatment facilities on surface and value of coal bed methane.
127	03.02.11.24.	ECBM induced fracturing of coal	Coal is an extremely stress-sensitive rock	Limits CO ₂ injection pressure.
128	03.02.11.25.	ECBM nitrogen injection into coal seam	Nitrogen has a lower affinity to coal than CH ₄ . Nitrogen injection lowers the partial pressure of CH ₄ which allows CH ₄ to diffuse through the coal matrix with greater ease, improving recovery of CBM at a faster rate.	<p>Nitrogen is not a problem in ECBM as a minor component of CO₂. It will lower the partial pressure of methane and allow more methane to be released and recovered.</p> <p>Some of the nitrogen injected with CO₂ may end up in the coal bed methane, resulting in a lower value product.</p>
129	03.02.11.26	ECBM coal fines generation and transport	Induced fracturing of coal seams can lead to fines generation. These fines can be mobilized by injected gases or fluids. Some types of medium- and low-volatile bituminous coals are weaker, and have a greater tendency of generating fines, than other coals.	<p>Coal fines can:</p> <ol style="list-style-type: none"> 1. Plug and reduce coal seam permeability 2. Plug and reduce fracture conductivity 3. Plug submersible pumps 4. Erode ECBM systems 5. Accumulate in ECBM separators 6. Require disposal (Palmer 2008)

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130	03.02.11.27	ECBM coal plasticization	CO ₂ is a coal plasticizer, lowering the temperature required to cause the transition from a glassy, brittle structure to a rubbery, plastic structure. The transition temperature may drop from ~400°C at 3MPa to <30°C at 5.5 MPa. (Bachu 2006). Recommendation for ECBM: Avoid deep ECBM sites that have CO ₂ supercritical pressures and temperatures above 30°C (Bachu 2008).	Coal plasticization, or softening, destroys any permeability that would allow CO ₂ injection. (Bachu 2006).
131	03.02.12.00.	Heavy metal release	Heavy metal ions may be dissolved in formation fluids or adsorbed on rock/mineral surfaces. Complexation may occur between CO ₂ and heavy metals dissolved in formation fluids. The influence of dissolved CO ₂ on pore water chemistry can also reduce the pH and change the equilibrium between sorption/desorption of metals, thereby resulting in significant release of these metals.	This process has the potential to release heavy metals, which may then migrate to the near-surface environment with resulting impacts of interest. These heavy metals will also change pore water chemistry, which could impact on carbonate complexation.
132	03.02.13.00.	Mineral phase (See 03.02.13.01. through 03.02.13.06.)	Geochemistry of the mineral phase relevant to sequestered CO ₂ , including ion exchange and mineral dissolution.	Geochemical reactions between sequestered CO ₂ and the mineral phase of the storage system will affect the evolution of the system and the sorption (and therefore mobility) of the CO ₂ .
133	03.02.13.01.	Mineral dissolution and precipitation (See 03.02.13.02.; 03.02.13.03 and 03.02.13.06.)	The dissolution of minerals (grains or cement) due to the addition of CO ₂ (an acid gas) to the geochemistry and precipitation. For example, the dissolution of albite and precipitation of calcite modeled for the Sleipner site by Gaus et al. (2003). 1. Mineral dissolution and precipitation in the reservoir 2. Mineral dissolution and precipitation in or near the borehole 3. Mineral dissolution and precipitation in the caprock 4. Mineral dissolution and precipitation in faults and fractures	CO ₂ reaction with the host rock will modify: the porosity and permeability of the reservoir; fluid flow (direction or velocity); mechanical properties (e.g. strength); and CO ₂ storage capacity.
134	03.02.13.02.	Precipitation of carbonate minerals (scale buildup)	CO ₂ reacts with brine to form hard water which can lead to scaling in or near a production well. Calcium carbonate and magnesium carbonate can be formed when HCO ₃ ⁻ reacts with Ca ²⁺ or Mg ²⁺ .	Scale buildup can cause reduced porosity and permeability in the reservoir, especially near the borehole.
135	03.02.13.03.	Salt precipitation	Dry CO ₂ can pick up moisture from high salinity brines in the reservoir. This increases the salinity of the brines. (CCP 2009)	Increased salinity of brines can lead to precipitation of salt in pore space, which can decrease reservoir permeability and impair injection rates of CO ₂ . (CCP 2009) "Dry out" and "salt out" may cause reduced porosity and permeability in the reservoir, especially near the borehole.
136	03.02.13.04.	Ion exchange (mineral dissolution and precipitation) (See 03.02.13.02.; 03.02.13.03 and 03.02.13.06.)	The process of exchanging one ion in the liquid phase for another ion on a charged, solid substrate. Injected CO ₂ may perturb ion exchange equilibrium between relevant minerals (such as sheet silicates) and the pore fluid. Some cations may be released to the pore fluid and others fixed as a consequence.	Disturbance of the rock-pore fluid equilibrium may affect the capacity of the rock to store CO ₂ .
137	03.02.13.05.	Desiccation of clay	CO ₂ is likely to be dried to prevent corrosion during transport. Injection of dry CO ₂ will cause it to take up water from the pores of the host formation and overlying rocks. It has the potential to suck water out of an overlying clay. CO ₂ can also be adsorbed by clay.	If clay dehydrates, it will shrink and crack. This might aid CO ₂ migration upwards.

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138	03.02.13.06.	Mineral dissolution	<p>The dissolution of minerals (grains or cement) due to the addition of CO₂ (an acid gas) to the geochemistry.</p> <ol style="list-style-type: none"> 1. Mineral dissolution in the reservoir 2. Mineral dissolution in or near the borehole 3. Mineral dissolution in the caprock 4. Mineral dissolution in faults and fractures 	CO ₂ reaction with the host rock will increase: the porosity and permeability of the reservoir; increase fluid flow (direction or velocity); decrease mechanical properties (e.g. strength); and increase CO ₂ storage capacity.
139	03.02.14.00.	Gas chemistry (CO ₂ interacting with gases in the reservoir)	<p>Gases such as CO₂, methane and H₂S, will occur naturally in the geosphere, either sorbed onto minerals, dissolved in formation fluids or as a free gas phase. Gas solubility will depend upon pressure, temperature and the salinity of the formation fluid.</p> <ol style="list-style-type: none"> 1. CO₂ interacting with free gases in the reservoir 2. CO₂ interacting with gases sorbed onto minerals 3. CO₂ interacting with gases dissolved in formation fluids 4. CO₂ interacting with gaseous hydrocarbons in the reservoir 	Gases naturally present in the geosphere could affect the behavior of CO ₂ injected into a storage reservoir and could accompany CO ₂ along potential migration paths.
140	03.02.15.00.	Gas stripping in overlying formations	<p>CO₂ migration through the reservoir and into the overlying barrier sequence could result in the CO₂ stripping other gases entrained within the sediments. This could include:</p> <ol style="list-style-type: none"> 1. Radon stripping 2. Methane (CH₄) stripping, and 3. Hydrogen sulfide (H₂S) stripping. 	<p>The presence of other gases in a leaking CO₂ gas stream is important in deciding the level of CO₂ leakage that can be tolerated and may constitute an important hazard.</p> <p>H₂S acts as an odorant for early detection of CO₂ and any stripped gases.</p>
141	03.02.16.00.	Gas hydrates	<p>Gas hydrates are 'ice-like' solids that form at low temperatures and high pressures. They are formed of 'cages' of water molecules surrounding a gas molecule. CO₂ can form hydrates in the presence of water. The prevention of hydrate formation in the well during startup will need to be considered. It is likely that methanol spacers will need to be used. (CCP 2009)</p> <p>Hydrate potentially could form in the well when starting back up after a shut down. During the process of shutting down, measures should be taken to mitigate the formation of hydrates when starting back up. Often a methanol "cap" is pumped in the top of the tubulars. (CCP 2009)</p> <p>As a consequence of well control using a brine or similar fluid, there can be intermixing of the CO₂ and the well control fluid that could result in hydrate formation or hydrate blocks. Using hydrate inhibited fluids or having operational practices that minimize the amount of CO₂ inflow during workovers should be considered. (CCP 2009)</p> <p>There is a lack of experimental data and models for predicting the water solubility of CO₂ at temperatures below 10°C. Moreover, there is a need to investigate hydrate formation conditions with CO₂ near and below water saturated conditions in the presence of carbon steel surfaces. (DNV CO₂PIPETRANS Phase 2)</p> <ol style="list-style-type: none"> 1. Gas hydrates formed below deep water 2. Gas hydrates formed below permafrost 	<p>Cooling of the reservoir (e.g. by injecting cold CO₂ or through adiabatic expansion) well below normal in-situ temperatures might stabilize gas hydrates. Their growth might seal fluid flow pathways (at least temporarily).</p> <p>If CO₂ is injected below deep water or permafrost, then rising CO₂ might hit the hydrate stability zone before escaping to the ocean or air, so hydrates could act as a secondary chemical barrier. Similarly, storage could be focused on actively forming CO₂ hydrate as a stable, immobile phase to lock up the CO₂ (Koide et al., 1997).</p>

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142	03.02.17.00.	Biogeochemistry	<p>Features and processes related to the biological/biochemical processes that affect the CO₂, borehole seals and rock/pore fluid, and the overall biological/biochemical evolution with time. This includes the effects of biological/biochemical influences on the CO₂ and engineered components by the surrounding geology. Microbes exist in the subsurface and are used in hydrocarbon operations to improve hydrocarbon recovery (e.g., in EOR and ECBM operations). Microbes can also catalyze geochemical reactions, including methanogenesis, but the latter reaction is thermodynamically unfavorable and is unlikely.</p>	<p>Examples of relevant processes are: - microbial growth; - microbial/biological mediated processes; and - microbial/biological effects of evolution of redox (Eh) and acidity/alkalinity (pH) , etc.</p> <p>This FEP has probably low relevance to the safety/fate of CO₂. However, CO₂ releases may affect/impact microbe populations being used in independent hydrocarbon-recovery enhancement projects.</p>
143	03.02.18.00.	Microbial processes	<p>Microbes can metabolize CO₂, for example, methanogenic microbes use H₂ to reduce CO₂ to methane (CH₄), a process called methanogenesis. These microbes need anaerobic conditions.</p> <p>Microbes can produce SO_x, NO_x, and CO under oxic conditions and H₂S and CH₄ under anoxic conditions.</p>	Methanogenesis, if it occurs, could affect the pressure distribution of CO ₂ . The fate and impact of the CH ₄ produced may be an endpoint of interest in itself.
144	03.02.19.00.	Biomass uptake of CO ₂	If sequestered CO ₂ migrates to the biosphere, it can be taken up by microbes, plants and algae (including phytoplankton).	This mechanism may provide a sink for CO ₂ that has migrated from the sequestration system.
145	03.02.20.00.	Mobilization of particulates by CO ₂	Insoluble particulates could be mobilized by CO ₂ via chemical hydrodynamic interaction with the reservoir rock.	Particulate mobilization could increase permeability at the point of mobilization, but it could also decrease permeability in reservoir locations where particulates are deposited or trapped.
146	03.03.00.00.	CO ₂ transport	Transport processes that may affect sequestered carbon dioxide and associated impurities.	An understanding of those processes that could transport carbon dioxide, and associated impurities, within the geosphere, near-surface and surface environments is fundamental to the assessment of long-term performance and safety.
147	03.03.01.00.	Advection of free CO ₂	<p>Advection of free CO₂ occurs in response to differences in pressure. The pressure difference may be due to differences in the pressure of injected CO₂ and formation pressures.</p> <p>The rate and direction of advection is affected by the physical properties of the rock, such as porosity and permeability.</p> <p>Advection may also occur through fractures. Fracture flow will be episodic with high transport efficiencies. Resealing of fractures (for example by cementation) will reduce and ultimately block fluid flow.</p> <p>1. Advection causing change in CO₂ migration direction 2. Hydrodynamic gradients</p>	Advective flow is a key transport process for migrating CO ₂ , and associated contaminants, in the geosphere (reservoir, surrounding and overlying rock), near-surface and surface environments.

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148	03.03.01.01.	Fault valving and reactivation	<p>Fault valving is a process resulting from gradual build up of pore pressure due to fluid generation, causing the subsequent opening of a fault along with fluid escape towards surface. This mechanism has been recognized as causing earthquakes in many parts of the world, as a result of hydrocarbon generation (e.g., in EOR or ECBM operations) or infiltration of other fluids.</p> <ol style="list-style-type: none"> 1. CO₂ leakage through an existing open fault 2. CO₂ leakage through a reactivated fault 	Large releases of pore fluids may occur during fault valving episodes.
149	03.03.02.00.	Buoyancy-driven flow	<p>Different relative densities of fluids in a geological system will result in buoyancy-driven flows as less dense fluids will have a tendency to flow upwards. The density of fluids will depend on its temperature and pressure.</p> <p>If a stream of CO₂ begins to move upward, expansion of the volume and decrease in the density provides increasing energy to drive flow upward, which can result in gas lift, a strong process for moving fluid upward (NETL 2010).</p> <ol style="list-style-type: none"> 1. CO₂ exceeding reservoir spill point 2. Lateral CO₂ flow across top of reservoir 3. CO₂ buoyancy putting pressure on caprock 	Carbon dioxide can be less dense than water, which may cause injected CO ₂ to flow upwards and accumulate above the water phase below the caprock of a reservoir. Water with dissolved CO ₂ is more dense than water, which can result in stratification of water bodies into which CO ₂ may leak, if conditions are suitable.
150	03.03.03.00.	Displacement of formation fluids	<p>This depends on interfacial tension and capillary pressure.</p> <p>Capillary pressure is the pressure difference existing across the interface separating two immiscible fluids due to interfacial tension. The interfacial tension itself is caused by the imbalance in the molecular forces of attraction experienced by the molecules at the surface and is a function of temperature and pressure.</p> <p>At a given pressure, increased interfacial tension values between water and CO₂ will make larger pores accessible to CO₂ (this is only valid for water-wet systems). The change from a water-wet system to a CO₂-wet system has an effect on capillary forces (i.e. displacement of water by enhanced pressure versus CO₂ injection with less capillary pressure) and the displacement capacity (i.e. as a non-wetting fluid, CO₂ will have less displacement capacity). If the injection velocity is high, effects of capillary forces are small.</p>	Interfacial tension and capillary pressure determine the location of CO ₂ within the pore spaces of the reservoir and the displacement capacity of the reservoir.
151	03.03.04.00.	CO ₂ dissolution in formation fluids	The process of dissolution of CO ₂ in formation fluids. The rate of dissolution depends on factors such as the interfacial area between the CO ₂ and the formation fluids and temperature.	Dissolution in formation fluids can be an important positive process in decreasing the free CO ₂ remaining in the reservoir.

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152	03.03.04.01.	CO ₂ exsolution from formation fluids	<p>Long-term risks might result from the gravitational sinking of dense CO₂ saturated brines; if they come into contact with salt formations this could lead to a degassing of the formation water and the ascent of CO₂ outside of the original closed storage structure. (CO₂STORE, page 68)</p> <p>Exsolution can also occur under significant (large) changes in pressure or temperature. The risk of major changes in pressure or temperature in a deep reservoir is very low.</p>	Displaced brine containing dissolved CO ₂ flows to the surface and releases CO ₂ to the atmosphere or ocean.
153	03.03.05.00.	Water mediated transport	<p>Processes related to the transport of CO₂, and associated contaminants, in groundwater and surface water, including advection, dispersion and molecular diffusion.</p> <p>Advection is the process by which contaminants are transported by the bulk movement of the water in which they are dissolved. Advective groundwater flow can occur along connected porous regions, such as fractures and faults.</p> <p>Dispersion is the collective name for the consequences of a number of processes that cause 'spreading-out' of CO₂, and associated contaminants, dissolved in water in all directions, superimposed on the bulk movement predicted by a simple advection model. It results in a spatially distributed contaminant plume.</p> <p>Diffusion is the process whereby chemical species move under the influence of a chemical potential gradient (usually a concentration gradient).</p>	<p>The transport of CO₂, and associated contaminants, within groundwater is likely to be a key migration process and therefore an important consideration in determining performance and safety.</p> <p>CO₂ dissolves in brine at CO₂/brine interface and brine transports CO₂ out of closure.</p>
154	03.03.06.00.	CO ₂ release processes	<p>Processes by which CO₂ is lost from the sequestration system. Once in the near-surface, changes in pressure and temperature result in the potential for phase changes and degassing, with resulting changes in the transport properties of sequestered CO₂. Examples of CO₂ release processes include:</p> <ol style="list-style-type: none"> 1. Surface blowouts (rapid release of CO₂) 2. Undersea blowouts (rapid release of CO₂) 3. CO₂ geysers (such as Crystal Geyser in Utah) 4. Submarine gas release (Slow or moderate release of CO₂) 5. Diffusion through soil (slow release of CO₂) 6. CO₂ released through mud volcano or mud flow. <p>In fine-clastic unconsolidated rocks, suspensions could form and cause mud-volcanism and mud flows. (CO₂STORE p.68)</p>	<p>The potential for CO₂ to be lost from a sequestration system will determine the performance of that system.</p> <p>Rapid release of CO₂ will tend to shoot CO₂ into the atmosphere where it will quickly mix with air and diffuse.</p> <p>Slow release of CO₂ will diffuse into soil gas.</p> <p>Moderate release of CO₂ will tend to blanket the ground unless there is sufficient air circulation (wind). Thus moderate release of CO₂ can be a greater safety risk than rapid or slow release.</p>
155	03.03.06.01.	Limnic eruption	<p>The rapid turnover and degassing of CO₂ from a surface water body.</p> <p>Due to the high solubility of CO₂ in water, a lake can dissolve a volume of CO₂ that, in gaseous form, is more than five times its volume. CO₂ rich water is denser than pure water which can result in an unstable stratification. A drop in temperature will reduce the solubility of CO₂ in water. If the water reaches its solubility limit as a result, bubbles will nucleate. As the bubbles rise and grow, a chain reaction occurs where a sudden ex-solution of CO₂ can result in a rapid degassing of the water body with an eruption of rising, expanding bubbles.</p> <p>Limnic eruptions can be triggered by events such as landslides that disturb the unstable stratification.</p>	<p>Limnic eruption provides a release mechanism for CO₂, migrating from a storage system to the atmosphere.</p> <p>Natural limnic eruption events can be catastrophic. On the 29th of August 1986, a massive limnic eruption from Lake Nyos in Cameroon resulted in 1800 deaths as the CO₂ smothered local villages. The CO₂, which is volcanic in origin, seeps through the lake bed sediments and builds up in the lower strata of the water column.</p> <p>The Lake Nyos sudden release involved an estimated 240,000 tonnes of CO₂ (Damen 2006).</p>

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156	03.03.07.00.	Co-migration of other gases	Surface seepages of CO ₂ may contain significant amounts of other gases due to co-migration, such as hydrogen sulfide (H ₂ S). This is especially the case where the CO ₂ reservoir is a reducing chemical environment. H ₂ S is derived from the hydration of sulfide minerals (e.g. FeS ₂) or from the chemical reduction of aqueous sulfate species. H ₂ S is highly toxic and therefore potentially harmful to the biosphere. Even in low concentrations it is deleterious to long-term health (human/animal), in addition to being extremely unpleasant.	The co-migration of other gases to the surface environment may cause areas of leakage to become uninhabitable – at least temporarily. The detection of H ₂ S provides a quick (non-analytical/aesthetic) test for CO ₂ escape and thus can be used as a "marker" gas.
157	03.03.08.00.	Diffusion of CO ₂	Diffusion is the net movement of a constituent in response to a concentration gradient. Diffusion always results in mass transfer from the region of high concentration to regions of low concentration. Diffusion will occur in conjunction with flow, but it will also occur in the absence of flow, and it is the primary transport mechanism in the absence of flow (as through a highly impermeable rock).	Diffusion is a transport process by which CO ₂ can access portions of the reservoir that are not directly exposed to advective flow. It can also be a primary transport mechanism in highly impermeable rocks such as caprock.
158	04.00.00.00.	GEOSPHERE	This category of FEPs is concerned with the geology, hydrogeology and geochemistry of the geosphere. The category covers the reservoir, overburden and surrounding rock up to the near-surface which is considered in a separate FEP category. Taken together, the FEPs in this category describe what is known about the natural system prior to sequestration operations commencing. The category is divided into three classes: Geology, Fluids, and Geochemistry.	This category is divided into three classes: 1. Geology 2. Fluids 3. Geochemistry
159	04.01.00.00.	Geology	Geological features of the geosphere, which comprises of the reservoir, overburden and surrounding rock prior to injection of CO ₂ .	An understanding of the natural system into which the carbon dioxide is injected is essential for the assessment of long-term performance and safety.
160	04.01.01.00.	Geographical location	The geographic location of a CO ₂ storage reservoir will influence the type of impacts to consider, e.g. continental or sub-marine, in the vicinity of a volcano, or tectonic activity, etc. In addition, proximity to human populations will increase importance of any release to the surface. 1. Onshore reservoir 2. Offshore reservoir 3. Near volcanic or tectonic activity 4. In densely populated areas	Proximity to natural hazards will increase their importance in being considered in the assessment. Proximity to human populations place more emphasis on the significance of near-surface releases. The potential impact on human beings of a sudden release of CO ₂ from an onshore reservoir will be higher than from an offshore reservoir (Damen 2006) The potential impact on human beings of a sudden release of CO ₂ from an offshore reservoir will be lower than from an onshore reservoir (Damen 2006). However CO ₂ storage costs are likely to be higher for offshore reservoirs.

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161	04.01.02.00.	Natural resources	<p>Natural resources within the geosphere including: solid mineralogical resources, such as coal or minerals, fluid and gaseous resources, such as hydrocarbons (EOR and ECBM) or water, and other resources such as geothermal or microbial resources.</p> <p>Deep aquifers with high porosity suitable for CO₂ storage would also be potentially suitable for geothermal energy production. (CO₂STORE, page 70)</p> <p>Rights to pore space normally stay with the owner of the surface land. However, this may vary from state to state.</p> <p>Although saline water has few uses currently, these resources are protected by mining law in some EU states. And in some countries and states, brines legally are classified as groundwater and protected by law, (CO₂STORE page 70).</p> <p>Depths for known natural major CO₂ fields range from 200 to 5,000 m (656 to 16404 ft). (CCP 2009)</p> <ol style="list-style-type: none"> 1. Mineral resources 2. Coal seams 3. Oil resources 4. Natural gas resources 5. Underground drinking water sources 	<p>The presence of natural resources may mean that future human exploitation of the system cannot be ignored in assessing long-term performance since they may increase the possibility of future human intrusion.</p> <p>Owners of mineral rights could claim primacy over CO₂ injection.</p> <p>Unmineable coal seams could become mineable with robotic mining systems.</p> <p>There may be adjacent oil properties owned by third-parties that could be contaminated by CO₂ injection.</p> <p>Natural gas could be released when drilling and injecting CO₂. CO₂ mixed with natural gas would need to be captured and reinjected.</p> <p>Underground drinking water could be contaminated by CO₂ or displaced brine.</p> <p>CO₂ combined with water could lead to corrosion of geothermal systems.</p> <p>CO₂ from adjacent injection projects could infringe the project's pore space</p>
162	04.01.03.00.	Reservoir type	<p>The generic type of reservoir being considered for storage of CO₂.</p> <p>Brownfield developments, for example in mature oil and gas fields, will offer the benefit of beginning with a well-characterized system and a significant amount of infrastructure. However, field redevelopments for CO₂ storage will require a significant amount of work to assess the integrity and re-usability of existing well, flow lines and facilities. (CCP 2009)</p> <p>Greenfield developments, such as deep saline aquifers, require significant new infrastructure and additional initial characterization work and are associated with greater uncertainty. A steeper learning curve is to be expected and modifications to an initial development plan may occur as additional knowledge is gained during early development work. (CCP 2009)</p> <ol style="list-style-type: none"> 1. Oil reservoir - EOR (such as the Weyburn project); 2. Gas reservoir (such as the Coal-Seq project); 3. Deep saline aquifer (such as at Sleipner); and 4. Coal seams - ECBM (such as the Coal-Seq and RECO₂POL projects). 	<p>The generic reservoir type will provide a high-level indication of the geological characteristics of the storage location. It will also contribute towards the extent and type of historical exploitation of any geological resources.</p> <p>Development of brownfield sites can expect to include a significant number of well re-completions, abandonments and possibly re-abandonment of old wells, new drilling and upgrades to surface infrastructure. (CCP 2009)</p> <p>Greenfield sites require more time and money to develop sufficient site characterization data but are less likely to have leakage through existing wells due to the lack of existing wells.</p>
163	04.01.04.00.	Reservoir geometry	<p>Geometry of the CO₂ storage reservoir including the spatial distribution, depth and the topography of the top.</p>	<p>The geometry of the storage reservoir helps to determine the capacity of the geosphere.</p> <p>The geometry of the top is particularly important because supercritical CO₂ is buoyant and will therefore migrate to the top of a reservoir. Once at the top of the reservoir, it will migrate according to the precise topography of the top. Local "highs" could produce small-scale traps within the overall aquifer; bigger structures would produce bigger traps.</p> <p>Spill points are determined by the lowest point that can retain the sequestered CO₂.</p>

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164	04.01.04.01.	Reservoir depth (Reservoir hydrostatic pressure)	<p>The hydrostatic pressure varies with depth.</p> <p>It is desirable to store CO₂ at depths greater than approximately 800-1000 m where the hydrostatic pressure will maintain CO₂ in a supercritical (dense) phase. (CCP 2009).</p> <p>Excessive depth will result in excessive hydrostatic pressure, which will require higher CO₂ injection pressure.</p> <ol style="list-style-type: none"> 1. Insufficient reservoir depth 2. Insufficient hydrostatic pressure 3. Excessive reservoir depth 4. Excessive hydrostatic pressure 	<p>Insufficient reservoir depth may result in pressures that are too low for keeping CO₂ in a supercritical state.</p> <p>Excessive depth will require higher CO₂ injection pressure and increase cost of CO₂ injection..</p>
165	04.01.04.02.	Reservoir thickness	<p>Normally, a formation thickness of around 20 m (66 ft) would be considered as a minimum requirement, but this varies with injection volume requirements.</p> <ol style="list-style-type: none"> 1. Insufficient reservoir thickness 	Insufficient reservoir thickness will result in an extended CO ₂ plume and limit the storage capacity of the reservoir
166	04.01.04.03.	Reservoir lateral continuity (spatial distribution)	<p>Lateral flow barriers can include unconformities or pinch-outs that erode the porous and permeable material and provide direct contact to a low permeability seal, faults and naturally over pressured zones.</p> <ol style="list-style-type: none"> 1. Insufficient reservoir lateral continuity 	Insufficient lateral continuity (or spatial distribution) of a reservoir will limit its CO ₂ storage capacity
167	04.01.04.04.	Reservoir top topography	<p>Reservoirs with dipping top topography (monocline) are susceptible to buoyancy-driven up dip CO₂ migration. The migration up dip may enhance CO₂/brine contact and CO₂ dissolution in the brine.</p> <p>The preferred top topography is an anticline or dome structure to restrict the flow of injected CO₂ on multiple sides.</p> <p>Spill point is the lowest point that can retain sequestered CO₂.</p> <ol style="list-style-type: none"> 1. Flat 2. Monocline 3. Dome 	<p>Flat top topography of the reservoir may make it difficult to contain the CO₂ plume</p> <p>Dipping top topography of the reservoir may make it difficult to trap buoyant CO₂. Injected CO₂ migrates up dip out of closure.</p> <p>Shallow spill point in a dome structure may limit the amount of CO₂ that can be locally contained in a reservoir</p>
168	04.01.04.05.	Reservoir buffer zone for CO ₂ plume	<p>The buffer zone represents additional land owned or leased beyond the ultimate extent of the CO₂ plume.</p> <ol style="list-style-type: none"> 1. Insufficient buffer zone for CO₂ plume 	Insufficient buffer zone may result in CO ₂ plume infringing on third-party pore space.
169	04.01.04.06.	Reservoir CO ₂ storage capacity	<p>Reservoir CO₂ storage capacity is primarily determined by pore volume.</p> <ol style="list-style-type: none"> 1. Insufficient reservoir storage capacity. 	Insufficient reservoir storage capacity will require alternative storage site(s). Increased storage costs.
170	04.01.04.07.	Reservoir lateral sealing	<p>Lateral flow barriers can include unconformities or pinch-outs that erode the porous and permeable material and provide direct contact to a low permeability seal, faults and naturally over pressured zones.</p> <ol style="list-style-type: none"> 1. Open reservoir (lack of lateral sealing of reservoir) 2. Closed reservoir 3. Semi-closed reservoir 	Potential for CO ₂ plume to infringe on third-party pore space or escape if lateral seal is lacking.
171	04.01.04.08.	Reservoir and caprock structural geology complexity	<p>In tectonically complex areas, there are too many small structures to be identified, delineated and investigated individually.</p> <ol style="list-style-type: none"> 1. Reservoir and caprock structural geology too complex 	Complex structural geology may result in greater difficulty in modeling, monitoring and controlling CO ₂ storage.

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172	04.01.04.09.	Reservoir compartmentalization	A once continuous reservoir can become compartmentalized. CO ₂ migration restricted to an isolated part of the formation. Unexpected bottom hole pressure increase. Pressure transient analysis suggests hydraulically isolated wells.	Greater difficulty in modeling, monitoring and controlling CO ₂ storage.
173	04.01.04.10.	Reservoir temperature (See 04.01.13.00.)		
174	04.01.04.11	Reservoir rock thermal properties	Rock thermal properties included: 1. Thermal conductivity 2. Heat capacity 3. Thermal expansion coefficient	These properties will dictate how fast the rock will change temperature in response to injected CO ₂ that is warmer or cooler than the reservoir, and they will also dictate whether fracture or pore permeability will increase or decrease as a result of temperature changes in the rock mass.
175	04.01.05.00.	Reservoir exploitation	Degree to which geological resources (such as oil and gas) have been exploited prior to the injection of CO ₂ . 1. Existing boreholes 2. Oil previously removed 3. Gas previously removed 4. Existing mine workings (for ECBM) 5. In-situ gasification (for ECBM) 6. Natural gas storage 7. Compressed air storage 8. Radioactive waste storage 9. Hazardous waste disposal (Class 1 wells) 10. Water extracted	The extent of previous exploitation will help to determine the initial state of a storage reservoir. For example: - the existence and nature of boreholes; and - the presence of geological resources, such as oil and gas. Previous exploitation of the storage reservoir area will improve the amount of historical information available concerning the reservoir characteristics.
176	04.01.06.00.	Caprock or sealing formation	The nature of the relatively impermeable layer of rock overlying the storage reservoir that forms a barrier to the upward migration of buoyant fluids, such as sequestered CO ₂ .	The caprock or sealing formation plays a key roll in preventing the sequestered CO ₂ from migrating to the surface environment.
177	04.01.06.01.	Caprock geometry	Geometry of the caprock including the spatial distribution, depth and the topography of the bottom.	CO ₂ migration diverges from expected path. Significant CO ₂ volumes migrate off structure. Insufficient capacity for planned injection volume of CO ₂ . Unexpected pressure increase during injection.

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178	04.01.06.02.	Caprock thickness	Greater thickness improves the strength and sealing capacity of the caprock. Preferred caprock thickness:> 100m Minimum caprock thickness: >20m	Insufficient caprock thickness could lead to caprock failure and/or release of CO ₂ from the reservoir.
179	04.01.06.03.	Caprock discontinuous	Caprock discontinuities can be caused by unconformities or pinchouts.	CO ₂ escapes through gap in caprock into higher formation or aquifer
180	04.01.06.04.	Caprock geochemical properties	CO ₂ chemical reaction with caprock can weaken the physical strength of the caprock. High permeability zones might exist or be formed by reaction of CO ₂ with the caprock, causing the caprock to dissolve. CO ₂ can dehydrate clay shales in the caprock, thereby increasing its permeability. (Damen 2006)	Unintended migration of CO ₂ by chemical reaction induced breaching of the caprock.
181	04.01.06.05.	Caprock geomechanical properties	Low fracturing pressure	Could limit CO ₂ injection rate. Increased CO ₂ injection cost. In general, the mechanical behavior of shale will show more elastic change and is more resistant to elevated pressure than other brittle hard rock.
182	04.01.06.06.	Caprock permeability	The permeability of a caprock capable of retaining fluids through geologic time is approximately 0.001 to 0.00001 milli-darcies (mD). Mudstone caprock permeability is typically less than 0.001 mD.	Permeable zones in the caprock could form CO ₂ pathways of escape.
183	04.01.06.07.	Caprock capillary entry pressure	No rocks have zero porosity, but the sealing layer provides a seal because the pore throats are too small to permit CO ₂ to enter the water-filled pores. (CCP 2009)	If the CO ₂ injection pressure exceeds the capillary pressure of the caprock, CO ₂ can penetrate or pass through the caprock
184	04.01.06.08.	Caprock fracture pressure	The critical pressure to avoid exceeding is the fracture pressure of the confining interval (caprock) above the reservoir, which is normally higher than the fracture pressure in the injection interval. (CCP 2009) Maximum injection pressure is typically at least 0.34 MPa (50 psi) below fracture pressure. EPA UIC Class VI regulations limit CO ₂ injection pressure to 90 percent of fracture pressure.	If the CO ₂ injection pressure exceeds the fracture pressure of the caprock, the caprock could fracture and allow CO ₂ to pass through the caprock.
185	04.01.07.00.	Additional seals and sinks (secondary seals)	This concerns the concept of successive lithological, hydraulic and/or chemical barriers acting successively to prevent fluid escape to surface environments. From a geological point of view the permeability barrier is probably the most important, in comparison with other types of traps. However, it may be necessary to consider a sequence of traps in CO ₂ migration models in addition to the conventional low permeability barriers. For example, within the Weyburn sequestration project, the primary caprock is the Watrous formation, however, low permeability formations at higher stratigraphical layers provide potential additional seals, preventing upward migration of sequestered CO ₂ . Stacked reservoirs consist of multiple alternating seals and reservoirs above the primary reservoir. The additional reservoirs can provide a back up for CO ₂ containment if the primary seal is broken. 1. Multiple stacked seals	Without multiple stacked seals and sinks there is no fallback position if CO ₂ escapes through the primary seal.

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186	04.01.08.00.	Lithology	<p>The systematic description of rocks in terms of their mineral assemblage and texture.</p> <p>The lithology of the geosphere (including both the reservoir and the caprock) determines the reservoir physical and transport properties (including porosity and permeability). It concerns the mineralogical composition, texture (grain size, sorting) and fabric (sedimentary structures, vertical and horizontal heterogeneities). Potential reservoir lithologies include sandstones and limestones.</p> <ol style="list-style-type: none"> 1. Caprock lithology 2. Reservoir lithology 	<p>The physical and chemical and mineralogical properties of the reservoir rocks affect: the capacity to store CO₂; fluid flow and CO₂ migration; determine which water-rock reactions can take place; and influence the rock strength and elastic properties (such as compressibility, shear strength, Poisson's ratio etc).</p>
187	04.01.08.01.	Lithification / diagenesis	<p>The slow physical, chemical and/or biological processes by which unconsolidated sediments become sedimentary rock. These processes can result in changes to the original mineralogy.</p>	<p>The state of lithification/diagenesis contributes to determining the physical and chemical characteristics of sedimentary rock. For example, porosity usually decreases during diagenesis, except in rare cases such as dissolution of minerals and dolomitization.</p> <p>It is very unlikely that deep subsurface geologic formations are unconsolidated. Unconsolidated formations are young in geologic time and located at shallow depths.</p>
188	04.01.08.02.	Pore architecture (See 04.01.08.03. and 04.01.08.04.)	<p>Structure and density of discrete voids within the rock (pores).</p> <ol style="list-style-type: none"> 1. Reduced pore volume or distribution limiting CO₂ injection 	<p>The pore architecture determines the porosity and permeability of the rock, which are key features when considering the mobility of fluids and gases within the rock.</p> <p>Rate of long-term pressure build-up greater than expected. Increases CO₂ injection cost. Need for additional wells.</p> <p>In EOR, pore architecture impacts sweep efficiency and oil recovery.</p>
189	04.01.08.03.	Reservoir porosity	<p>Porosity values greater than 10% in carbonate formations or 15% in clastic formations are generally desirable. (CCP 2009).</p> <p>It is important to distinguish between total porosity and effective (flowing) porosity. Flowing porosity is what can be readily displaced by CO₂ invasion. Total porosity minus flowing porosity is pore space that will likely remain occupied by residual pore fluids after CO₂ invasion, although CO₂ can diffuse into this pore space.</p> <ol style="list-style-type: none"> 1. Total porosity 2. Effective (flowing) porosity 	<p>Low porosity makes CO₂ injection more difficult and can limit the rate of injection into a reservoir.</p> <p>In EOR, porosity impacts oil in place and oil recovery.</p>

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190	04.01.08.04.	Reservoir permeability and injectivity	<p>Permeability measures the ability of fluids to flow through a formation. High values indicate a well-connected pore space while low values indicate convoluted conduits that disconnect the pores. Porous rocks have a wide range in permeability between around 0.1 milli-Darcy (mD) for very tight rocks, to several darcies for very permeable formations. (CCP 2009)</p> <p>In general, the better the porosity, the better the permeability (and thus injectivity) - however, large variations in permeability mean the porosity and permeability variations need to be mapped in detail (CCP 2009)</p> <p>Ideally, CO2 storage requires high permeability (>100 mD) to ensure near well bore injectivities for quick access to pore space. However, this is not always possible and near wellbore permeabilities may need to be enhanced by artificially stimulating the wells to allow for improved injectivity. (CCP 2009)</p> <p>Injectivity is impacted by porosity and permeability. Low injectivity can be partially compensated for by greater injection pressure and/or more wells.</p> <p><u>Decreasing injectivity can result when initial injection rate</u></p>	<p>Low permeability makes CO2 injection more difficult and can limit the rate of injection into a reservoir.</p> <p>While high permeabilities are generally desirable, very high permeability pathways or conduits can enhance CO2 migration along concentrated pathways reducing the effective storage within the target formation. (CCP 2009)</p> <p>In moderate to low permeability, or poorly connected reservoirs, a higher well density will be needed to limit pressure evolution and allow for efficient injection. (CCP 2009)</p> <p>Uncertainty in permeability could lead to high numbers of wells needed.</p> <p>Low reservoir injectivity will limit the rate of CO2 injection and require increased bottom hole pressure and/or more injection wells.</p> <p>In EOR, permeability impacts sweep efficiency and oil recovery.</p>
191	04.01.09.00.	Unconformities	<p>Geological surfaces separating older from younger rocks and representing a gap in the geologic record. Such a surface might result from a hiatus in deposition of sediments, possibly in combination with erosion, or deformation such as faulting. An angular unconformity separates younger strata from eroded, dipping older strata. A disconformity represents a time of no deposition, possibly combined with erosion, and can be difficult to distinguish within a series of parallel strata. A nonconformity separates overlying strata from eroded, older igneous or metamorphic rocks.</p> <ol style="list-style-type: none"> 1. Unconformities 2. Disconformities 3. Nonconformities 	<p>Unconformities can act both as potential seals or lateral migration pathways for fluids. For example, the impermeable barrier resulting from the widespread development of diagenetic anhydritized carbonate associated with the unconformity between the Mississippian beds and overlying Triassic Watrous Formation in the vicinity of the Weyburn pool.</p>
192	04.01.10.00.	Heterogeneities (See 03.02.03.06.)	<p>Heterogeneities are variations in the rock properties of a geological formation.</p> <ol style="list-style-type: none"> 1. Reservoir heterogeneity 2. High permeability layers in reservoir 3. Interstitial layers of shale or baffles in reservoir 4. Caprock heterogeneity (high permeability zones) 5. Heterogeneity of overlying aquifers (more difficult to monitor for CO2) 6. Heterogeneity of porosity 7. Heterogeneity of mineralogy 8. Heterogeneity of degree of fracturing 9. Heterogeneity of geochemistry 	<p>Heterogeneities can result in directional variations in permeability, which affects the mobility of fluids and gases in the rock. For example, experience from the Saline Aquifer CO2 Storage project (SACS) has shown that both stratigraphical and structural local permeability heterogeneities have the potential to profoundly affect CO2 distribution and migration (Chadwick et al., 2003).</p> <p>The image below shows seismic sections through the Sleipner injection site from Zweigel et al. (2001). The strong amplitudes are taken to be CO2 accumulations.</p>

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193	04.01.11.00.	Fractures and faults (CO ₂ leakage through new or existing fractures or faults)	<p>Fractures are cracks or breaks in rock. Fractures along which displacement has occurred are called faults. Fractures and faults can occur over a wide range of scales.</p> <p>The presence of a fault does not imply a leakage problem. Most rocks are faulted and fractured in some way over geological time. The critical question for CO₂ storage is whether there are any faults or fractures that could provide leakage pathways under present day geological conditions. In addition to the basic geometry of connected rocks and flow paths, this involves the study of geomechanics, stress fields and fracture behavior. Simply put many "faults: do not leak at all and many huge oil and gas fields that include faults prove the point. (CCP 2009)</p>	<p>Fractures can enhance conductivity, for example, by a conductive fracture connecting permeable regions together. They can also act as seals, by bringing a relatively permeable region into contact with low conductivity rock, for example.</p> <p>Movement on a fault that transverses a wellbore could damage or sever casing or tubing.</p> <p>CO₂ might leak through open (no-sealing) faults, which extend into the caprock.</p> <p>CO₂ might leak through natural fractures in the caprock.</p>
194	04.01.12.00.	Undetected features	<p>Natural or man-made features within the geological environment that may not be detected during site investigations.</p> <p>Examples of possible undetected features are fracture/fault zones, the presence of brines or old mine workings. Some physical features of the storage environment may remain undetected during site surveys and even during preliminary borehole drilling. The nature of the geological environment will indicate the likelihood that certain types of undetected features may be present and the site investigation may be able to place bounds on the maximum size or minimum proximity to such features.</p> <ol style="list-style-type: none"> Existing fracture/fault zones Underground cavities/karsts (natural or man made) Existing boreholes Subsurface infrastructure (piping, underground utilities) Gas chimneys Shallow gas/drift gas (above bedrock) Clustered small gas-related amplitude anomalies along fault planes 	<p>Undetected features could significantly affect the performance of a sequestration system. For example, local permeability heterogeneities with the potential to profoundly affect the distribution and migration of CO₂ at Sleipner (within the Saline Aquifer CO₂ Storage project, SACS) were only discovered after effectively being illuminated by the sequestered CO₂ (Chadwick et al., 2003).</p> <p>Shallow gas (above bedrock) can cause drilling problems and impede monitoring.</p>
195	04.01.13.00.	Vertical geothermal gradient 04.01.04.10.	<p>Temperature profile in the geosphere prior to the injection of CO₂.</p> <p>Temperature generally increases with depth, but the rate of increase varies significantly depending on the geothermal gradient.</p> <p>The critical temperature for CO₂ is 31.1°C. The average geothermal gradient is approximately 25°C per km. If the surface temperature is 10°C, the critical temperature will be reached at a depth of 840 m. However, a considerable variation in geothermal gradients and sub-surface temperatures can be expected at a depth of 1000 m. For example, in Europe temperatures at 1000 m range from 20 to 75°C, with local temperatures of more than 200°C in volcanic areas.</p>	<p>Relevant to temperature dependent physical/chemical/biological/hydraulic processes, such as CO₂ phase behavior.</p> <p>Temperature, coupled with pressure, will affect the phase behavior of CO₂ as well as the solubility of many other constituents present in the reservoir (including gases, liquids and solids.)</p>

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196	04.01.14.00.	Formation pressure	<p>The pressure of fluids within the pores of a formation, normally hydrostatic pressure, or the pressure exerted by a column of water from the formations depth to the sea level prior to the injection of CO₂.</p> <p>The critical pressure of CO₂ is 7.38 MPa. The average underground hydrostatic pressure increases with depth by approximately 10.5 MPa per km for aquifers that are in open communication with surface water. Applying this average gradient, the critical pressure of CO₂ will be reached at a depth of around 690 m. However, aquifers or hydrocarbon reservoirs (e.g., EOR and ECBM) that are sealed off from the rest of the sub-surface may be under- or over pressured.</p> <ol style="list-style-type: none"> 1. Hydrostatic pressure 2. Fracture pressure 3. Lithostatic pressure 	Contributes towards determining the mobility of sequestered CO ₂ .
197	04.01.15.00.	Initial stress and mechanical properties	The stress condition and mechanical properties of the geosphere prior to injection of CO ₂ .	The initial stress state and mechanical properties are a baseline from which the potential effect of injecting supercritical CO ₂ can be assessed.
198	04.01.16.00.	Petrophysical properties (See 03.02.03.01.; 04.01.08.03. and 04.01.08.04.)	Petrophysical properties of the geosphere prior to the injection of CO ₂ . This includes features such as permeability, porosity, residual saturation, capillary pressure and wettability.	Petrophysical properties influence how injected CO ₂ will migrate in the geosphere. For example, permeability influences the direction and rate of CO ₂ movement, and porosity and residual saturation influence the dimensions of the CO ₂ plume.
199	04.02.00.00.	Fluids	Details of fluids in the geosphere, which comprises of the reservoir, overburden and surrounding rock prior to the injection of CO ₂ . Water will generally be present, but other fluids, particularly hydrocarbons (e.g., EOR and ECBM), may be important, dependent on the sequestration concept.	Water and other fluids in the sequestration system will affect the transport and interactions of injected carbon dioxide.
200	04.02.01.00.	Fluid properties (See 03.02.13.03)	<p>Properties of the geosphere fluids prior to injection of CO₂, including composition and geochemistry.</p> <p>The high salinity of deep aquifers is, generally, an indication of very low or insignificant throughput of meteoric waters.</p> <ol style="list-style-type: none"> 1. Fluid chemical composition and geochemistry 2. High salinity fluid 3. Fluid density 	<p>The fluid properties and geochemistry of the geosphere will contribute towards determining how injected CO₂ will behave in the geosphere.</p> <p>Very high salinity can lead to deposition of halite in pore spaces and cause decreased permeability and injectivity.</p>
201	04.02.02.00.	Hydrogeology	<p>Natural formation water flow pathways (directions, velocities) in the geosphere will be important in determining the long-term migration paths for CO₂. This depends on factors including: hydraulic heads, permeability and porosity distribution, the existence of fracture networks, connection between aquifers, position of the recharge and discharge areas.</p> <ol style="list-style-type: none"> 1. Natural fluid flow pathways 2. Position of aquifer recharge and discharge areas 3. Connection between deep saline aquifer and shallow drinking water aquifer 	This will affect the migration of dissolved CO ₂ in the reservoir and the geosphere (direction, timing), the position of the interface between supercritical CO ₂ and aquifer water (inclined interface). There may also be a possible effect on overlying aquifers used for drinking water.

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202	04.02.03.00.	Hydrocarbons	The presence and distribution of hydrocarbons, such as oil and/or gas (e.g., EOR and ECBM), within the storage system.	Hydrocarbons have potentially important implications for a storage system, by both influencing the likelihood of previous geological exploitation of the area, and by being an important component of the system with which sequestered CO ₂ can interact.
203	05.00.00.00.	BOREHOLES	This category of FEPs is concerned with the way that activity by humans alters the natural system. Both boreholes used in the sequestration operations and those drilled for other purposes are relevant to the long-term performance of the system. The category is divided into two classes for the drilling process, and sealing and abandonment.	This category is divided into two classes: 1. Drilling and completion 2. Sealing and abandonment
204	05.01.00.00.	Drilling and completion	FEPs relevant to the operation of boreholes drilled within the system domain.	Boreholes can potentially provide short circuits for carbon dioxide transport.
205	05.01.01.00.	Formation damage (CO ₂ leakage through damaged caprock near borehole)	Alteration of the far-field or virgin characteristics of a formation, usually by exposure to drilling fluids. Fracturing associated with formation damage can increase porosity, whereas the water or solid particles in the drilling fluids, or both, can decrease the pore volume and effective permeability of the formation in the near-wellbore region. Some boreholes in the early 20th century may have been explosive fractured with nitroglycerin. Later boreholes may have been hydrofractured. 1. Explosive fracturing 2. Hydrofracturing A number of mechanisms can result in a decrease in porosity, including: 3. Solid particles from the drilling fluid physically plug or bridge across flow paths in the porous formation 4. Water from drilling causing clay minerals in the formation to swell 5. Chemical reactions between drilling fluid and the	Formation damage has a number of potential implications for assessing CO ₂ sequestration: - it can make information from affected boreholes non-representative of the true characteristics of the damaged formations; and - damaged regions themselves may provide flow paths for CO ₂ migration, particularly if damage results in fracturing. - decrease in near borehole porosity can result in unexpected increase in bottom hole pressure
206	05.01.02.00.	Well lining and completion	At the time of drilling, boreholes are lined with a metal casing. Cement is pumped downhole inside the casing string, and it is pushed upward under and outside the casing lower end, between the casing and the rock wall. In multi-stage cement jobs, cement is squeezed between the casing and the rock wall through purpose made perforations. The cement could be pushed behind casing from the bottom hole to the surface, or to a predetermined depth. Curing of cement is the process of maintaining the proper temperature and moisture conditions to promote optimum cement hydration immediately after placement. Proper moisture conditions are critical because water is necessary for the hydration of cementitious materials. As cement hydrates, strength increases and permeability decreases. When hydration stops, strength gain ceases. Therefore, proper hydration of the cement is important in the fabrication of strong, durable concrete. Alteration of borehole linings will occur with time, depending on the natural fluid composition of the deep reservoir and the input of high concentrations of CO ₂ carrying natural H ₂ S, which may accelerate corrosion.	Borehole lining and completion will contribute to determining the performance of a borehole both during its operational and post-closure phases. This is important from the perspective of CO ₂ sequestration, since boreholes may provide preferential short circuits to the surface with potential release of CO ₂ and contamination of upper aquifers.

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207	05.01.03.00.	Workover	<p>The process of performing major maintenance or remedial treatments on a borehole often associated with the re-use of existing boreholes. Workover techniques include flushing of the formation and the removal and replacement of the borehole lining.</p> <p>Well control procedures during workovers must provide for unique phase behavior of any CO₂ being circulated out. (CCP 2009)</p> <p>EOR operations often re-complete old wells. Proper re-completion includes: Examining cement bond logs to evaluate bonding between the casing and adjoining formation. Use of squeeze cement if insufficient or inadequate bonding was detected. Wellbore drilling of plugged and abandoned wells to bottom of target formation. Run a casing mechanical integrity test. If pressure fall off was observed, the leaking section of casing should be identified and resealed by squeeze cementing or, in extreme cases, install a liner over the leaking section.</p>	Workover will result in modified borehole properties that may need consideration within an assessment.
208	05.01.04.00.	Number and location of monitoring wells	<p>Often, monitoring wells (observation wells or verification wells) are needed to monitor the physical conditions (pressure, temperature, etc.) of the storage reservoir, both inside and/or outside the area immediately affected by the storage operations, or above the storage reservoir. Monitoring wells could be "adopted", by using existing wells to host the appropriate instrumentation (piezometers, pressure gauges, thermometers, etc.), or they could be purpose drilled anew. Direct monitoring techniques usually require access from wellbores that penetrate the containment system into the storage reservoir (CCP 2009) Direct measurements can also be obtained from observation wells at shallower horizons above the expected seal. Wells of this type might provide direct and early indication of unexpected movement. (CCP 2009) General the concept is to minimize monitoring wells that penetrate the seal because they are, by default, potential leakage pathways. (CCP 2009)</p> <ol style="list-style-type: none"> 1. Lack of or insufficient number of monitoring wells 2. Too many monitoring wells 3. Improperly located monitoring wells. 	<p>Observation or monitoring wells may provide an accidental leakage route for the stored CO₂, particularly wells drilled inside the area of storage.</p> <p>There are unique tradeoffs associated with the number and location of monitoring wells.</p>
209	05.01.05.00.	Well records	<p>The drilling of boreholes for site investigation, resource exploitation and/or CO₂ injection will result in many documents being generated in paper or digital form. Typical well records include location co-ordinates, depth, electric logs, mud logs, drilling parameter logs, composite log, testing reports (if applicable), coring report (if applicable), and a final report. Physical records from cutting samples, cores and fluid samples will also be documented.</p> <p>The principal tool to gain knowledge about the sequence of drilled rock formations is Borehole Logging. Common measures include hole diameter, natural gamma ray response, spontaneous electrical potential, rock resistivity, velocity of acoustic waves through rock, neutron susceptibility, etc.</p> <p>The documents originating at the time of drilling are often the most accurate records of the succession of events associated with the drilling of the well. The curation of such unique records is an invaluable tool to pass knowledge to future generations.</p> <ol style="list-style-type: none"> 1. Lack of or incomplete records for existing wells 2. Retention/management of well records and data 	<p>Well records provide a key source of baseline information regarding the sequestration site. They provide information concerning the nature of the rocks drilled by the well and their petrophysical characteristics in terms of sealing potential and reservoir potential. Additionally, records from wells drilled over a period of time can give a picture of how the system is evolving either naturally, or as a result of the exploitation of geological resources. This baseline information is an important input both into the initial conditions relevant to the system to be assessed, as well as providing an indication of the likely importance of other FEPs.</p> <p>Incomplete well records equate to a potential gap in understanding of the storage system and may result in potentially important features being overlooked in the assessment process.</p> <p>Large amounts of data will be generated by the project. Data could be poorly communicated between groups, or be badly managed to the point that important data is lost, or used incorrectly.</p>

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210	05.02.00.00.	Borehole seals and abandonment	FEPs relevant to the closure of boreholes drilled within the system domain.	The way that boreholes are closed and sealed is directly relevant to the likelihood that they could act as short circuits for carbon dioxide transport.
211	05.02.01.00.	Closure and sealing of boreholes	<p>Features related to the cessation of CO₂ injection operations at a site and the sealing of injection and monitoring wells.</p> <p>When a borehole is drilled to the potential storage reservoir, it creates communication with possible overlying reservoirs and with the surface. Cementing and abandonment procedures are designed to permanently plug such communication channel.</p> <p>The cement plugs are commonly located across potential problem spots, to minimize leaking risks. Particular attention should be paid to the quality of the original cement job behind the casing string. If uncemented space is detected, known or suspected behind casing, depending on the lithology across such interval, it may be important to squeeze extra cement between the rock face and the casing to complement the final abandonment plugs inside the casing.</p> <p>Individual boreholes may be closed in sequence, but closure refers to final closure of the whole system, and may include removal of surface installations. The schedule and procedure for sealing and closure may need to be considered in the assessment.</p> <p>A typical well abandonment may include the following:</p> <ul style="list-style-type: none"> - Remove tubing and packer - Permanently seal the formation with a fluid that reduces permeability 	The intention of borehole sealing is to prevent human access to the sequestered CO ₂ and to prevent the borehole from providing a migration pathway for the CO ₂ . Correct cementing and abandonment operations are essential to achieve restoration of pristine sealing above the designed storage reservoir formation.
212	05.02.02.00.	Seal failure	<p>occur with time, depending on the natural fluid composition of the deep reservoir and the input of high concentrations of CO₂. Any H₂S present may accelerate corrosion of metal linings. Cement will be attacked by high partial pressures of CO₂, low pH and appreciable concentrations of sulfate, chloride, and magnesium ions in the formation fluids. Seal failure will occur once liners have degraded and corroded. Portland cement blended with 50% fly ash had a 30 year life in a field that produced 96% CO₂ with water saturation of approximately 20%. (CCP 2009). Conventional Portland cement-fly ash systems can inhibit CO₂ migration even after carbonation of the cement because permeability remains relatively low and capillary resistance is relatively high. (CCP 2009). The Basis of Design for new wells should emphasize barrier performance using fundamentals of wellbore preparation, mud removal and cement placement to provide tight interfaces that inhibit fluid migration. Material selection of cement and metallurgy are important, but should be considered secondary to the process of cement placement. (CCP 2009). The cement interfaces between the boreholes and the casing through the caprock are the key to well integrity and seal integrity. Good isolation requires tight cement interfaces with the formation and casing. (CCP 2009)</p>	<p>Seal failure may provide preferential short circuits to the surface with potential release of CO₂ and associated contaminants to the surface or near-surface environment. The failure may provide a preferential pathway either through the borehole annulus or around the outside of the casing.</p> <p>Cement interfaces, not cement matrix are the most likely path for migration. (CCP 2009).</p> <ol style="list-style-type: none"> 1. CO₂ leakage at cement-casing interface 2. CO₂ leakage through the cement matrix 3. CO₂ leakage through pathways created by chemical dissolution of cement 4. CO₂ leakage through fractures in cement 5. CO₂ leakage through an open annular region due to inadequate cement placement 6. CO₂ leakage at cement caprock interface 7. CO₂ leakage through corroded or cracked casing 8. CO₂ leakage through packer

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213	05.02.03.00.	Blowouts	<p>Uncontrolled flow (CO₂, brine, oil, gas or mixture of these) from depth leading to gas and/or fluid erupting from a well or borehole to either the terrestrial or aquatic environments.</p> <p>Blowout is an ordinary drilling hazard, well understood and controlled by current technology. Assuming that ordinary blow-out risk controls are present, particular risks might include: (1) A monitoring or verification well drilled into a porous formation that has elevated pressure due to CO₂, or (2) A drilled formation with significant unexpected H₂S (MCSG 2009).</p> <p>The greatest danger for loss of well control is during workover operations.</p> <p>Estimates based on both oil and gas wells give a frequency of 3x10⁻⁴ blowouts per well per year (IEA GHG, 2003) (Damen 2006).</p> <ol style="list-style-type: none"> 1. Blowout due to equipment failure (packer, blowout preventer, valve failure) 2. Blowout due to accident (truck backing over injection well) 3. Blowout due to human error (valve left open) 4. Blowout of CO₂ injection well 5. Blow out of production well 	<p>A surface or undersea blowout would provide a rapid pathway for CO₂ to reach the surface.</p> <p>Apart from the CO₂ release, the potential consequences are casualties among operators and economic damage caused by explosion or fire when upcoming hydrocarbons are ignited or by parts of the well, which can be launched by the pressure release. (Damen 2006)</p>
214	05.02.04.00.	Orphan wells	<p>CO₂ storage projects may be part of an Enhanced Oil Recovery (EOR) project or stand-alone deep saline aquifer projects. Either way, it is likely that the target geological structure has been the object of past exploration efforts, possibly involving drilling wells.</p> <p>The existence of old wells could be obvious if the wells are still active, but could be overlooked if the old (orphan) wells have been long cemented and abandoned. Technical details of such abandoned vintage wells may in fact not be readily available, or altogether lost. In such a case, the old cementing (sealing) job could be substandard.</p> <p>Some coal bed methane operations used open completion wells (no casing). It is possible to stabilize a hole without casing with gravel packing or sorted liners</p> <ol style="list-style-type: none"> 1. Failure to identify and locate existing wells - active wells, abandoned wells, shallow wells that don't penetrate the caprock, deep wells that penetrate the caprock 2. Failure to test wells for mechanical integrity 3. Failure to remediate old wells 4. Failure of old well due to poor cementing, sealing, closing 5. Improper workover/recompletion of old well 6. Leakage of CO₂ or brine through old well to overlying formations, underground aquifers or surface. 6. Collapse of open borehole (non-cased, open-completion holes often used in CBM) 	<p>Old substandard plugged well could provide a potential CO₂ leakage route to the surface or to possible reservoirs above the designed CO₂ storage reservoir.</p> <p>There is little chance of detecting a substandard well abandonment before the beginning of CO₂ injection to the designed reservoir, particularly if the existence of an old well has been overlooked. If old abandoned wells are known in the area of the CO₂ injection operations, the risk is minimized by carefully check any potential CO₂ leak to the surface at the old well head location.</p> <p>If old wells are unknown and not suspected, it is good practice to run a baseline soil gas survey (if applicable) and successive soil gas surveys at intervals after the beginning of CO₂ injection.</p> <p>Open completion wells are more likely to leak than other wells and subject to collapsing.</p>
215	05.02.05.00.	Soil creep around boreholes	<p>The slow downward gravitational movement of soil around boreholes.</p>	<p>This process results in changing properties of the soil around borehole casings after abandonment. It may either increase or decrease the degree of sealing and therefore the potential for the region immediately around the borehole to act as a migration pathway for CO₂ and/or associated contaminants.</p>

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216	05.02.07.00.	Borehole sand control (sand blocking)	<p>Applies to unconsolidated reservoirs. Sand control may be necessary to maintain the structure of the reservoir around the wellbore. Migration of sand and fines into the near wellbore area may severely restrict production/injection.</p> <p>Sand blocking is a problem when the reservoir is unconsolidated and the wellbore is shut in for maintenance or upsets. (CCP 2009)</p> <p>Dehydration and deposition of gravel pack contents that cannot be displaced or removed from the well (CCP 2009)</p> <ol style="list-style-type: none"> Sand blocking Dissolution of sand control resins Dehydration and deposition of gravel pack contents 	Operation delays. Maintenance costs.
217	05.02.08.00.	Wellbore fluids (causing corrosion or scale buildup)	<p>Once the well is completed, impairment implications of the fluids or non-fluids left in the wellbore during startup will need to be considered. (CCP 2009)</p> <p>It is important to consider the displacement of any fluids into the reservoir during start up and the effect of injectivity resulting from the introduction of the fluids. (CCP 2009)</p> <p>Stimulation fluids should be carefully selected in terms of compatibility with the well materials, workover materials and reservoir. (CCP 2009)</p> <ol style="list-style-type: none"> Wellbore fluids Startup fluids Stimulation fluids 	<p>Fluids left in the wellbore for extended amounts of time could potentially corrode the tubulars, drop out precipitants, or cause bacterial growth. (CCP 2009)</p> <p>Startup fluids may impact injectivity due to precipitation of solids.</p> <p>Stimulation fluids may cause corrosion or precipitation of solids.</p>
218	06.00.00.00.	NEAR-SURFACE ENVIRONMENT	This category of FEPs is concerned with factors that can be important if sequestered carbon dioxide returns to the accessible environment. The environment could be terrestrial or aquatic, and human behavior in that environment needs to be described. The category is divided into three classes: Terrestrial Environment; Aquatic Environment; and Human Behavior.	This category is divided into three classes: <ol style="list-style-type: none"> Terrestrial environment Aquatic environment Human behavior
219	06.01.00.00.	Terrestrial environment	This class of FEPs is concerned with factors that can be important if sequestered carbon dioxide returns to the accessible terrestrial environment.	The near-surface environment is where most potential impacts would be incurred. The FEPs in this class are relevant if that environment is terrestrial.
220	06.01.01.00.	Topography and morphology	<p>Features related to the relief and shape of the surface environment and its evolution.</p> <ol style="list-style-type: none"> Low surface areas (valleys, gullies, ditches) Rugged terrain Confined spaces (caves, canyons) 	<p>This FEP refers to local land form and land form changes with implications for the surface environment, e.g. plains, hills, valleys, and effects of river and glacial erosion thereon. In the long term, such changes may occur as a response to other geological changes.</p> <p>Leaked CO₂ can accumulate in low surface areas and confined spaces.</p> <p>Rugged terrain may make it difficult to access the site, difficult to lay pipeline and difficult to monitor or conduct seismic studies.</p>

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221	06.01.02.00.	Soils and sediments impact on project	<p>Features related to the physical and chemical characteristics of the soils and sediments and their evolution.</p> <p>Different soil and sediment types, e.g. characterized by mineralogy, particle-size distribution and organic content, will have different properties with respect to erosion/deposition, sorption etc.</p>	Soil and sediment characteristics will influence the type of vegetation and land use. They will also determine relevant processes to consider should CO ₂ and/or associated contaminants migrate to the terrestrial surface environment.
222	06.01.03.00.	Erosion and deposition	FEPs related to all the erosional and depositional processes that operate in the surface environment, and their evolution with time. Relevant processes may include fluvial and glacial erosion and deposition, denudation, Aeolian erosion and deposition. These processes will be controlled by factors such as the climate, vegetation, topography and geomorphology.	Erosional and depositional processes will influence the way in which the surface environment has evolved and will evolve over the time-scale of interest.
223	06.01.04.00.	Atmosphere and meteorology (See 10.01.01)	<p>FEPs related to the characteristics of the atmosphere, weather and climate, and their evolution with time. In case of CO₂ leakage to the surface, the weather is a relevant factor determining the dispersion or the displacement of the gas: currents, evolution of the concentration of the gas, gas accumulations.</p> <p>Atmospheric characteristics include physical transport of gas, aerosols and dust in the atmosphere and chemical and photochemical reactions.</p> <p>Meteorology is characterized by atmospheric precipitation, temperature, pressure, wind speed and direction. The variability in meteorology should be included so that extremes such as drought, flooding, storms and snow melt are identified.</p>	<p>This information will determine the behavior of CO₂ should it reach the atmosphere and is therefore an important factor when considering exposure of the local population and of the local environment.</p> <p>Meteorological characteristics also influence the near-surface hydrological regime with its subsequent consequences for CO₂ migration.</p>
224	06.01.05.00.	Hydrological regime and water balance	<p>Processes related to near-surface hydrology at a catchment scale and also soil water balance, and their evolution with time.</p> <p>The hydrological regime is a description of the movement of water through the surface and near-surface environment. It includes the movement of materials associated with the water such as gas or particulates and extremes such as drought, flooding, storms and snow melt.</p> <ol style="list-style-type: none"> 1. CO₂ and associated contaminants leakage affecting the hydrological regime and water balance. 2. Displaced brine affecting the hydrological regime and water balance 3. Groundwater withdrawal causing change in CO₂ or brine migration 4. FGM water extraction impacting water level in shallow aquifers 	The hydrological regime and water balance will influence the way in which CO ₂ migrates should it reach the near-surface environment.
225	06.01.06.00.	Near-surface aquifers and surface water bodies	Features related to the physical and chemical characteristics of aquifers and water-bearing features and their evolution.	<p>Shallow Aquifers</p> <p>Aquifers may yield significant amounts of water to wells or surface springs and may thus be a flow path for CO₂ to the surface environment. The presence of aquifers and other water-bearing features will be determined by the geological, hydrological and climatic factors.</p> <p>Shallow aquifers will be able to dissolve CO₂, reducing further upward migration. The amount of CO₂ that can dissolve will depend on factors such as the location of the water table, the chemical composition of pore waters, CO₂ flux rates, and hydrogeology.</p> <p>Surface Water Bodies</p> <p>Streams, rivers and lakes often act as boundaries of hydrological systems. They may also act as flow paths for CO₂ to the surface environment.</p>

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226	06.01.07.00.	Terrestrial flora and fauna	<p>Features and processes related to the characteristics of terrestrial and freshwater flora and fauna, and their evolution. Includes plants, animals, fungi, algae and microbes.</p> <p>Plants usually have a higher resistance against CO₂ than mammals, but persistent leaks could suppress respiration in the root zone. Tree kills associated with soil gas concentrations in the range of 20-30% have been observed at Mammoth Mountain, California, where volcanic out gassing of CO₂ (0.13-0.44 Mt/yr) has been occurring since at least 1990. The leakage rate (flux) varies between 25 and 7000 g CO₂/day/m². (Damen 2006).</p> <p>1. Natural flora and fauna 2. Agricultural flora and fauna</p>	Flora and fauna may be affected by concentrations of CO ₂ in the near-surface environment and may be indicators of CO ₂ leakage.
227	06.01.08.00.	Terrestrial ecological systems (See 06.01.07.00)	<p>Features and processes related to interactions between terrestrial and freshwater populations of animals, plants, algae, fungi, microbes and their evolution.</p> <p>Characteristics of the ecological system include the vegetation regime, and natural cycles such as forest fires or flash floods that influence the development of the ecology. The plant, animal, algal, fungal and microbial populations occupying the surface environment are an intrinsic component of its ecology. Their behavior and population dynamics are regulated by the wide range of processes that define the ecological system. Human activities have significantly altered the natural ecology of most environments.</p>	The ecology of the terrestrial near-surface environment determines the types of organisms present and their inter-dependencies. These can influence the types of impact of interest and can provide a mechanism for monitoring CO ₂ leakage.
228	06.02.00.00.	Aquatic environment	This class of FEPs is concerned with factors that can be important if sequestered carbon dioxide returns to the accessible aquatic environment (seas, lakes, rivers).	The near-surface environment is where most potential impacts would be incurred. The FEPs in this class are relevant if that environment is aquatic.
229	06.02.01.00.	Coastal features	Features and processes related to the characteristics of coasts and the near shore, and their evolution. Coastal features include headlands, bays, beaches, spits, cliffs and estuaries.	The processes operating on these features, e.g. active erosion, deposition, longshore transport, may affect mechanisms for the migration of CO ₂ , and associated contaminants, entering the surface environment.
230	06.02.02.00.	Local oceanography	Features and processes related to the characteristics of seas and oceans and their evolution. This includes the topography and morphology of the seabed; thermal stratification and salinity gradients; and marine currents.	The local oceanographic features and processes determine the potential for dilution or accumulation of CO ₂ , or associated contaminants in the marine environment.
231	06.02.03.00.	Aquatic sediments	Features and processes associated with sediments in the aquatic environment. This includes both the physical and chemical characteristics of the sediments, along with sedimentation and resuspension processes.	Aquatic bed sediment characteristics will influence the ecology of the aquatic environment. They will also determine relevant processes to consider should CO ₂ and/or associated contaminants migrate to the aquatic environment.
232	06.02.04.00.	Aquatic flora and fauna	Features and processes related to the characteristics of aquatic flora and fauna, and their evolution. Includes plants, animals, fungi, algae and microbes.	Flora and fauna may be affected by concentrations of CO ₂ in the aquatic environment and may be indicators of CO ₂ leakage.
233	06.02.05.00.	Aquatic ecological systems	<p>Features and processes related to interactions between populations of algae, animals, microbes and their evolution.</p> <p>Characteristics of the ecological system. The algal, animal and microbial populations occupying the aquatic environment are an intrinsic component of its ecology. Their behavior and population dynamics are regulated by the wide range of processes that define the ecological system.</p>	The ecology of the aquatic environment determines the types of organisms present and their inter-dependencies. These can influence the types of impact of interest and can provide a mechanism for monitoring CO ₂ leakage.

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234	06.03.00.00.	Human behavior	Details of the human behavior in the near-surface environment where impacts may be incurred.	Human behavior will affect the nature and magnitude of potential impacts to human beings.
235	06.03.01.00.	Human characteristics	<p>Features and processes related to characteristics, e.g. physiology, metabolism, of individual humans. This includes considerations of variability, in individual humans, of physiology and metabolism due to age and other variations.</p> <p>Physiology refers to body and organ form and function. Metabolism refers to the chemical and biochemical reactions which occur within an organism, or part of an organism, in connection with the production and use of energy.</p> <p>Children and infants, although similar to adults, often have characteristic differences, e.g. metabolism and respiratory rates, which may lead to different characteristics of exposure to CO₂ or contaminants.</p>	Human physiology and metabolism determine the effect of exposure to CO ₂ and associated contaminants.
236	06.03.02.00.	Diet and food processing	<p>Features related to intake of food and water by individual humans and the compositions and origin of intake. This includes considerations of how diets, of individual humans, may vary with age and other variations (ingestion of soil by infants, for example).</p> <p>This FEP also includes processes related to the treatment of foodstuffs and water between origin and consumption. For example, once a crop is harvested it may be subject to a variety of storage, processing and preoperational activities prior to human or livestock consumption. Water sources may be treated prior to human or livestock consumption, e.g. chemical treatment and/or filtration.</p>	<p>The human diet provides a potentially important exposure pathway to contaminants released into the food chain as a result of the CO₂ sequestration system.</p> <p>Food preparation processes may change the distribution and content of CO₂ and/or associated contaminants in the product.</p>
237	06.03.03.00.	Lifestyles	<p>Features related to non-diet related behavior of individual humans, including time spent in various environments, pursuit of activities and uses of materials. This includes consideration of variability of the habits of individuals due to age and other factors.</p> <p>The human habits refer to the time spent in different environments in pursuit of different activities and other uses of materials. The diet and habits will be influenced by agricultural practices and human factors such as culture, religion, economics and technology.</p>	Human habits will determine the exposure pathways of interest in an assessment. Camping, plowing, fishing, and swimming are examples of behavior that might give rise to extended close proximity exposure to CO ₂ and/or contaminants mobilized in an area of CO ₂ sequestration.
238	06.03.04.00.	Land and water use	<p>FEPs related to land and water use by humans in the near-surface environment and the resulting implications for CO₂ leakage and contaminant transport and exposure pathways. This includes consideration of:</p> <ul style="list-style-type: none"> - the use of natural or semi-natural tracts of land and water such as forest, brush, rivers, lakes and the sea; - rural and agricultural land and water use (including freshwater and marine fisheries); - urban and industrial land and water use related to developments, including transport, and their effects on hydrology; and - leisure and other uses of environment. 	<p>These FEPs can influence the potential transport and exposure pathways for CO₂ and its associated contaminants as well as the potential evolution of the system during the timescales of interest. Particular considerations are relevant for each type of land use addressed, for example:</p> <ul style="list-style-type: none"> - special foodstuffs and resources may be gathered from natural land and water which may lead to significant modes of exposure to CO₂ or contaminants; - an important set of processes are those related to agricultural practices, their effects on land form, hydrology and natural ecology, and also their impact in determining contaminant uptake through food chains and other exposure paths; - human populations are concentrated in urban areas in modern societies. Significant areas of land may be devoted to industrial activities. Water resources may be diverted over considerable distances to serve urban and/or industrial requirements; - significant areas of land, water, and coastal areas may be devoted to leisure activities. e.g. water bodies for recreational uses, mountains/wilderness areas for hiking and camping activities.

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239	06.03.05.00.	Community characteristics	<p>Features related to characteristics, behavior and lifestyle of groups of humans that might be considered as target groups in an assessment.</p> <p>Relevant characteristics might be the size of a group and degree of self-sufficiency in food stuffs/diet. Associated with this is a consideration of the amount of resources required to meet the needs of the community.</p>	This FEP involves a consideration of aggregated human behavior in order to consider their dependency on and interactions with their environment. It therefore provides input to a consideration of potential human interference with the CO ₂ storage system as well as input to considering potential exposure pathways.
240	06.03.06.00.	Buildings	<p>Features related to houses, or other structures or shelters, in which humans spend time.</p> <ol style="list-style-type: none"> Basements/cellars Subterranean pathways 	The structure or materials used in building construction be significant factors for determining potential exposure pathways to CO ₂ or contaminants. For example, given that CO ₂ is denser than air, it may accumulate in the basements/cellars of dwellings.
241	07.00.00.00.	IMPACTS	<p>This category of FEPs is concerned with any endpoint that could be of interest in an assessment of performance and safety. The classes of impact considered are: Impacts to Humans; Impacts to Flora and Fauna; and Impacts to the Physical Environment. Note that:</p> <ul style="list-style-type: none"> - financial impacts are assumed to be implicitly considered within each of the impact FEPs; and - unless stated, the FEPs refer to both CO₂ and mobilized contaminants (minerals, heavy metals, hydrocarbons (e.g., EOR and ECBM), gases). 	<p>This category is divided into four classes:</p> <ol style="list-style-type: none"> System performance Impacts on the physical environment Impacts on flora and fauna Impacts on humans
242	07.01.00.00.	System performance	Performance of the sequestration system from the perspective of its success at preventing sequestered CO ₂ from reaching the atmosphere.	The fate of sequestered CO ₂ is a fundamental endpoint for an assessment.
243	07.01.01.00.	Loss of containment	Loss of sequestered CO ₂ from the intended storage reservoir. Loss includes both consideration of loss to other parts of the geosphere and to the near-surface and surface environments, such as loss to marine water and surface water bodies, where CO ₂ may result in stratification or pooling.	Loss of containment may be an endpoint of interest to the assessment. For example, the assessment context may dictate that near-surface or surface processes are outside the scope of the assessment.
244	07.02.00.00.	Impacts on the physical environment	FEPs relevant to adverse impacts on the physical environment. Note that these may be endpoints of interest in themselves, but may also cause other impacts of interest.	Adverse impacts on the environment can be postulated as a result of sequestration operations, even if there are no associated impacts to humans or on flora and fauna.
245	07.02.01.00.	Contamination of groundwater (and/or surface water)	<p>The existence of water aquifers may be important if they are subject to CO₂-induced chemical changes or CO₂-induced saline intrusion. The migration of CO₂ into an aquifer will result in the acidification of the water. Depending on the mineralogical composition of the aquifer and the chemical composition of the water, chemical reactions may occur which release heavy metals from the solid phase. The mechanisms which may cause this release include dissolution of metal oxides or oxyhydroxides, the reaction/diagenesis of clay minerals, and the desorption of metals that are adsorbed on clay surfaces or organic complexes.</p> <ol style="list-style-type: none"> CO₂ contamination of underground drinking water sources CO₂ contamination of surface waters Displaced brine contamination of groundwater. EOR oil spill (see 16.22.00) 	<p>Contamination of groundwater resources may result in impacts on flora, fauna and/or humans if the water is abstracted or flows to the surface environment. These potential impacts are considered in the subsequent FEP classes, however, contamination of groundwater may be an endpoint of interest in itself.</p> <p>An increase in CO₂ concentration might cause a decrease in pH to a level of 4-5, which might cause calcium dissolution, increase in the hardness of water and alteration of minerals from minerals from rocks and soils that could release elements such as heavy metals into the water supply.</p> <p>Foundations of buildings could be damaged by seepage of groundwater containing CO₂ in shallow unconsolidated sediments and soils. This could be a problem if CO₂ were to be stored (and leak) underneath, for example, historical city centers, other heritage objects, or archeological sites (CO₂STORE)</p> <p>Surface water could be contaminated by CO₂ leakage, which could affect aquatic ecosystems by decreasing pH, especially in stagnant or stratified waters (Damen 2006)</p> <p>Displaced brine may cause undesirable effects such as a rise of the water table (which could have negative impact on land quality and use) and an increase in salinity of sweet water reservoirs used for drinking</p>

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246	07.02.02.00.	Impacts on soils and sediments	<p>Soils and sediments may have elevated concentrations of CO₂, should it leak from the storage system, and/or other contaminants, such as heavy metals, hydrocarbons (e.g., EOR and ECBM) or even increased salinity resulting from CO₂ sequestration.</p> <p>For example, natural CO₂ leaking from a trapped reservoir near Mammoth Mountain, in California, has resulted in soil gas concentrations of 20 to 90%.</p> <ol style="list-style-type: none"> 1. Contamination of soil 2. Contamination of sediments 	Increased CO ₂ concentrations and/or contamination of soils and sediments with associated substances may be sufficient to modify the ecology and/or use of the impacted area by humans.
247	07.02.03.00.	CO ₂ release to the atmosphere	Release of CO ₂ (or other contaminants, such as radon or methane, mobilized as a result of the sequestration) to the atmosphere from the storage system .	<p>Release of sequestered CO₂ or mobilized methane to the atmosphere will reduce the effectiveness of the storage system at preventing greenhouse gases from being emitted to the atmosphere.</p> <p>Atmospheric contamination could also lead to health impacts on humans and wildlife.</p> <p>Rapid release likely to effectively disperse the CO₂ higher in the atmosphere.</p> <p>Moderate release likely to concentrated CO₂ near the ground, representing the highest risk.</p> <p>Slow release likely to disperse CO₂ in the soil and atmosphere.</p>
248	07.02.04.00.	Impacts on exploitation of natural resources	<p>The impact of CO₂ sequestration on the exploitation of natural resources such as oil and gas.</p> <p>Enhanced oil recovery (EOR) and enhanced coal bed methane (ECBM) recovery projects involving the injection of CO₂ are based on improved recovery of oil and methane respectively resulting from CO₂ sequestration. However, CO₂ sequestration may result in the contamination of geological resources (such as hydrocarbons and minerals) or inhibit their recovery or future exploitation.</p> <p>Note that the potential impact on groundwater resources is considered in Impacts on groundwater.</p> <ol style="list-style-type: none"> 1. Contamination of mineral resources 2. Contamination of mineable coal seams 3. Contamination of oil resources 4. Contamination of natural gas resources 5. Contamination of geothermal resources 6. Contamination of pore space owned by others. 	Impacts on the exploitation of natural resources can be positive (such as EOR and ECBM) and/or negative (such as inhibited recovery). These may result in other (for example, financial) impacts, or may be endpoints of interest in themselves.
249	07.02.05.00.	Modified hydrology and hydrogeology	The injection of CO ₂ may result in modifications to both the deep hydrogeology and near-surface hydrology.	Changes in the deep hydrogeology or near-surface hydrology may affect aquifer abstraction or even surface hydrology for groundwater driven features. These impacts may be either positive or negative.
250	07.02.06.00.	Modified geochemistry	The injection of CO ₂ will modify the geochemistry of the sequestration system. This may be confined to the immediate vicinity of the storage location, or, through leakage from the reservoir, may affect other locations.	The extent of geochemical modifications may be an endpoint of interest, due to resulting changes to geological processes. For example, the acidification of the geochemical regime may cause minerals to be dissolved, with potential implications for the porosity and stability of the geological formations.
251	07.02.07.00. (See 03.02.06.00)	Modified seismicity	Injection of supercritical CO ₂ into a geological formation may induce seismic events and processes.	Induced seismicity may be an endpoint of interest in itself, or it can result in other impacts, such as physical disruption of the surface environment.

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252	07.02.08.00.	Modified surface topography	The gradual or sudden sinking (subsidence) or elevation (uplift) of the topography of the terrestrial surface or marine sea-bed.	Deformation of the terrestrial surface or sea-bed may be an endpoint of interest in itself, or may result in other impacts, such as damage to property.
253	07.02.08.01.	Sinkhole formation	<p>Addition of CO₂ in a limestone or carbonate-rich aquifer could result in dissolution of the rock matrix and the enlargement of voids. If this process takes place at relatively shallow depth collapse may result in subsidence at the surface and sinkhole formation.</p> <p>For example, CO₂ leakage around a borehole drilled to extract natural CO₂ from a reservoir in Florina, Greece, resulted in subsidence around the borehole that filled up with water.</p>	Large scale collapse structures may cause significant change to surface topography and possible CO ₂ migration paths. Sinkholes can provide locations where leaking CO ₂ can accumulate.
254	07.03.00.00.	Impacts on flora and fauna	<p>FEPs relevant to impacts on flora and fauna.</p> <p>1. Natural flora and fauna 2. Agricultural flora and fauna</p>	Impacts on flora and fauna can be postulated as a result of sequestration operations, even if there are no associated impacts to humans.
255	07.03.01.00.	Asphyxiation effects	<p>Asphyxiation effects of CO₂ on terrestrial and aquatic fauna. Oxygen is an essential requirement for respiration in animals and is therefore needed to sustain life. High concentrations of CO₂ in air or water will lead to suffocation of terrestrial and aquatic animals due to a lack of oxygen reaching the blood stream.</p> <p>If meteorological conditions do not disperse CO₂ released to the atmosphere, it can gather close to the surface and remain in depressions, such as natural hollows. This property allows CO₂ to reach high concentrations if released in sufficient quantities under particular atmospheric conditions.</p> <p>The 1986 Lake Nyos disaster in Cameroon provides a graphic example of the potential effects of high atmospheric concentrations of CO₂. A large limnic eruption resulted in the death of wildlife and approximately 1800 people in the surrounding area and up to 27 km away.</p> <p>In a similar way to gaseous CO₂ being denser than air, water containing high concentrations of dissolved CO₂ is denser than pure water, a factor that contributes to the limnic eruption phenomenon observed at Lake Nyos. In addition to the possibility of dissolved CO₂ causing asphyxiation in aquatic organisms, if gaseous CO₂ forms a layer at the surface of water bodies, it can prevent the oxygenation of the water and lead to a reduction of the O₂ concentration thereby contributing to asphyxiation of aquatic</p>	Levels of CO ₂ from a sequestration project sufficient to cause asphyxiation of fauna would be an endpoint of concern in assessing the geological sequestration of CO ₂ .
256	07.03.02.00.	Effects of CO ₂ on plants, algae, fungi and microorganisms	<p>Plants, algae, fungi and microorganisms (in both terrestrial and aquatic environments) use energy in sunlight to photosynthesize carbohydrates from CO₂ and water (H₂O). Increasing concentrations of CO₂ around the photosynthetic tissues, increases the rate of photosynthesis and therefore growth and productivity in terrestrial and aquatic plants and algae.</p> <p>However, the roots of most plants need oxygen to breakdown carbohydrates to provide energy for root growth and healthy metabolism, a process called aerobic respiration. High concentrations of CO₂ in the soil reduces the availability of O₂ and can cause roots and therefore plants to die.</p> <p>At Mammoth Mountain, in California, CO₂ has accounted for up to 95% of the gas concentration in soil at the edge of Horseshoe Lake due to release from natural geological CO₂ reservoirs caused by volcanic activity. These high soil concentrations have resulted in areas of forest being killed.</p>	Concentrations of CO ₂ in the soil, atmosphere and/or water sufficient to impact on the growth of plants and algae would be an endpoint of interest in assessing the geological sequestration of CO ₂ .

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257	07.03.03.00.	Ecotoxicology of contaminants	<p>Ecotoxicology deals with the toxic effects of contaminants on the biosphere.</p> <p>Contaminants other than CO₂ may be introduced to the biosphere as a result of geological CO₂ sequestration due to:</p> <ul style="list-style-type: none"> - impurities associated with the sequestration fluid, such as hydrogen sulfide (H₂S), methane (CH₄), nitrogen oxides (NO_x) and mercaptans; - the mobilization of substances in the geological environment due to the sequestration of CO₂, such as hydrocarbons (e.g., EOR and ECBM), brine, CH₄ and heavy metals. <p>These substances may have a toxic effect on organisms in the biosphere, including plants, animals, algae and fungi.</p>	<p>The potential for contaminants associated with and/or mobilized by CO₂ sequestration to have a toxic effect on organisms should they migrate to the biosphere will be of interest in an assessment of the geological sequestration of CO₂.</p> <p>Methane leakage may affect shallow water quality and pose a lethal threat when accumulating in confined spaces such as basements/cellars. The global warming potential of methane is circa 23 times that of CO₂ (Damen 2006)</p>
258	07.03.04.00.	Ecological effects	<p>Geological sequestration of CO₂ may have an impact on the biosphere at a community, population and/or ecological level, with subsequent implications for biodiversity. The potential impact of releases of CO₂ and associated or mobilized contaminants into the biosphere may disrupt biological interactions sufficiently to modify the terrestrial or aquatic ecosystems affected.</p> <p>For example, the sudden release of natural CO₂ due to the limnic eruption at Lake Nyos, Cameroon, resulted in the sudden death of wildlife, but was unlikely to affect the ecology in the longer term. However, the continued gradual release of natural CO₂ into soil near Mammoth Mountain, California, has been sufficient to kill trees and damage the local ecosystem since 1996 until the present day.</p>	<p>The degree of potential ecological disruption resulting from geological CO₂ sequestration may be an endpoint of interest, especially if the ecosystem affected is considered valuable and/or sensitive to perturbations.</p>
259	07.03.05.00.	Modification of microbiological systems	<p>Microbes will be present in the geosphere as well as in the terrestrial and/or marine environments above the CO₂ storage reservoir. CO₂ sequestration may disrupt microbial aerobic respiration but may enhance anaerobic respiration, with subsequent implications for the processes in which the microbes are involved.</p> <p>Microbes play an important roll in all terrestrial and aquatic ecosystems, including those associated with extreme environments, such as deep sea hydrothermal vents.</p>	<p>The potential impact of CO₂ sequestration on aerobic and anaerobic microbial respiration in the geosphere, terrestrial and aquatic biosphere may be an endpoint of interest.</p>
260	07.04.00.00.	Impacts on humans	FEPs relevant to adverse impacts on people.	A range of possible impacts to human beings can be postulated as a result of sequestration operations.

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261	07.04.01.00.	Health effects of CO2	<p>Elevated atmospheric concentrations of CO2 can result in both acute and chronic health effects in humans. If meteorological conditions do not disperse CO2 released to the atmosphere, it can gather close to the surface and remain in depressions, such as the basement of buildings or at the surface of lakes. This property allows CO2 to reach high concentrations if released in sufficient quantities under particular atmospheric conditions.</p> <p>The primary health effect of concern is asphyxiation. High concentrations of CO2 in air will lead to suffocation of humans due to a lack of oxygen reaching the blood stream. Asphyxiation can occur once atmospheric concentrations reach approximately 10% CO2.</p> <p>Other health effects include those directly associated with elevated concentrations of CO2 in the blood stream, such as acidosis and physiological responses to the elevated blood CO2.</p> <p>The 1986 Lake Nyos disaster in Cameroon provides a graphic example of the potential effects of high atmospheric concentrations of CO2. A large limnic eruption resulted in the death of approximately 1800 people in the surrounding area and up to 27 km away. (Note that this event resulted from natural volcanic activity rather than CO2 storage). Asphyxiation requires high CO2 concentration in occupied (usually confined) space, plus either poor ventilation or high release rate.</p>	<p>The potential for CO2 to be released to the atmosphere in sufficient quantities to cause health effects in humans will be an endpoint of interest in assessing the geological sequestration of CO2.</p> <p>CO2 combined with CO is more toxic than when CO2 or CO exist separately (Duncan 2012).</p>
262	07.04.01.01.	Elevated CO2 in air	<p>CO2 = 5000 ppm (0.5%): OSHA permissible exposure limit: Time weighted average concentration for 8-hour work day. American Conference of Governmental Industrial Hygienists (ACGIH) threshold limit value: Time weighted average concentration for normal 8-hour work day or 40-hour work week.</p> <p>CO2 = 30,000 ppm (3%): Breathing increases to twice normal rate and a person would experience impaired hearing, headache, and increased blood pressure (Shell). Occupational Safety & Health Administration (OSHA) short-term exposure level: Maximum concentration for 15-minute period (maximum of 4 periods per day with at least 60 minutes between exposure periods).</p> <p>CO2 = 40,000 ppm (4%): National Institute for Occupational Safety and Health (NIOSH) immediate danger to life and health: The maximum level to which a healthy individual can be exposed to a chemical for 30 minutes and escape without suffering irreversible health effects or impairing symptoms.</p> <p>CO2 = 50,000 ppm (5%): Breathing increases to approximately 4 times normal rate, symptoms of intoxication become evident and slight choking may be felt (Shell).</p> <p>CO2 = 75,000 ppm (7.5%): A sharp odor is noticeable. At this level a person would experience very labored breathing, headache, visual impairment, and ringing in the ears. Judgment may be impaired, followed within minutes by loss of consciousness.</p>	<p>CO2 combined with CO is more toxic than when CO2 or CO exist separately (Duncan 2012).</p>
263	07.04.02.00.	Toxicity of contaminants	<p>Contaminants other than CO2 may be introduced to the biosphere as a result of geological CO2 sequestration due to:</p> <ul style="list-style-type: none"> - impurities associated with the sequestration fluid, such as hydrogen sulfide (H2S), methane (CH4), nitrogen oxides (NOx) and mercaptans; - the mobilization of substances in the geological environment due to the sequestration of CO2, such as hydrocarbons (e.g., EOR and ECBM), CH4 and heavy metals. <p>Such contaminants may be toxic to humans and could cause harm if exposure pathways exist.</p> <p>The toxicity will depend on: the form of exposure, e.g. ingestion or inhalation, leading to internal exposure or</p>	<p>The potential for contaminants associated with an/or mobilized by CO2 sequestration to cause harm to humans is an endpoint of interest when assessing the geological sequestration of CO2.</p> <p>CO2 combined with CO is more toxic than when CO2 or CO exist separately (Duncan 2012).</p>

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264	07.04.03.00.	Impacts from physical disruption	Impacts on humans due to physical disruption of the environment caused by geological CO ₂ sequestration. For example, damage to buildings due to induced seismicity, damage to farmland due to subsidence or uplift.	Physical disruption of the environment caused by CO ₂ sequestration may have a detrimental impact on humans.
265	07.04.04.00.	Impacts from ecological modification (See 06.01.08.00)	Impacts on humans due to ecological modification. These may be negative (for example, reduced timber yields due to damage caused to trees by CO ₂ in the soil) or positive (for example, increased crop yields due to higher atmospheric CO ₂).	Ecological modification caused by CO ₂ sequestration may have a positive or negative impact on humans.
266	08.00.00	ECONOMIC RISKS		
267	08.01.00.	Cost escalation / inflation	Cost escalation/inflation may be higher than budgeted. Cost escalations are of particular concern because field-service costs (drilling, geophysics, etc.) and equipment may continue to increase as the price of oil stays high. Key cost items that may be effected by escalation/inflation include: <ol style="list-style-type: none"> 1. Steel cost 2. Other material cost 3. Equipment cost 4. Labor cost 5. Imported goods cost (due to currency exchange) 6. Financing/risk transfer costs 7. Assessment and permitting costs 8. Mitigation and closure costs 	The risk of cost escalations is significant; cost increases may force a change in scope-of-work.
268	08.02.00.	CO ₂ value/cost	Incentives for CO ₂ capture and storage are particularly important for CO ₂ sequestration in deep saline aquifers. In this case, the value or cost of CO ₂ may be determined by cap-and-trade, carbon tax or emission credits. In EOR and ECBM the value of CO ₂ may be tied to the price of oil or natural gas. However, the cost of CO ₂ capture and transport may be higher or lower than the assigned value. Value of emission credits provide incentive for CO ₂ sequestration, particularly in deep saline aquifers (DSA). CO ₂ purchase cost higher than budgeted. CO ₂ has traditionally been purchased for EOR and ECBM use. Economic arrangements among project participants could have negative project impacts under changed or unanticipated conditions. <ol style="list-style-type: none"> 1. Value of CO₂ emissions credits lower than budgeted 2. CO₂ purchase cost higher than budgeted 	A low value for emission credits may be insufficient to cover the cost of CO ₂ capture and sequestration in deep saline aquifers.

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269	08.03.00.	Price of oil (or other related commodities)	<p>The prices of related commodities can impact the value and/or availability of CO2.</p> <ol style="list-style-type: none"> 1. Oil price - impacts EOR economics 2. Natural gas price - impacts ECBM economics 3. Fertilizer price - impacts CO2 supply from fertilizer plants 4. Ethanol price - impacts CO2 supply from ethanol plants 5. Cement price - impacts CO2 supply from cement plants 	<p>Low commodity prices can impact the viability of a CO2 capture and storage project.</p> <p>An economic downturn can cause capital constrains and significant energy price volatility leading to:</p> <ol style="list-style-type: none"> 1. Business failures of vendors, suppliers or customers. 2. Failure of hedging counterparties to fulfill delivery or purchase obligations 3. Decreased consumption of commodities 4. Increased cost of capital and increased difficulty accessing capital.
270	08.04.00.	Project development costs	<p>Project development costs that could be higher than expected or budgeted include:</p> <ol style="list-style-type: none"> 1. Surface land and/or pore space access costs -purchase or lease 2. Water rights costs 3. Mineral rights costs - needed for EOR or ECBM 4. Pipeline right-of-way (ROW) costs 5. Site characterization costs 6. Permitting costs 7. Technology licensing costs 8. Engineering, procurement and construction (EPC) costs 9. Insurance costs 10. Project financing costs 11. Legal costs 12. Closure and post-closure costs 	<p>High project development costs can make the project economically infeasible.</p> <p>Project may be halted if some of the necessary requirements are unobtainable.</p>
271	08.05.00.	Project capital costs	<p>Project capital costs that could be higher than budgeted include:</p> <ol style="list-style-type: none"> 1. CO2 capture system 2. CO2 dehydration 3. CO2 compression 4. CO2 pipeline 5. Well head system 6. CO2 recycle system - for EOR 7. Oil tankage - for EOR 8. Natural gas processing system - for ECBM 9. Water tankage - for EOR or ECBM 10. Water treatment system - for EOR or ECBM 11. New well drilling and completion 12. Old well remediation/replugging 13. Old well workover 14. Site preparation 15. Access roads 16. Power supply system 17. Water supply system 18. Communications system 19. Monitoring system costs 	<p>High project capital costs can make the project economically infeasible.</p> <p>Accidental loss can result in Business Interruption / Advanced Loss of Profit type exposure, or even result in the project becoming uneconomic to continue.</p>

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272	08.06.00.	Operating and maintenance costs	<p>Project operating and maintenance costs that could be higher than budgeted include:</p> <ol style="list-style-type: none"> 1. CO₂ capture operating costs 2. CO₂ dehydration/compression operating costs 3. CO₂ pipeline operating costs 4. Injection operating costs 5. Monitoring costs 6. Simulation modeling costs 7. Maintenance costs 8. Lease operating expenses 9. Management fees 10. Working capital 11. Severance and ad valorem tax 12. Investor reporting costs 13. Power cost 14. Make-up water cost 15. Water treatment/disposal cost 16. Labor cost 17. Security costs 18. Site close costs 19. Verification costs 20. Regulatory compliance costs 21. Insurance costs 22. Cost for losses 23. Post-closure costs for DSA 	<p>High operating and maintenance costs can impair project economic viability.</p> <p>Accidental loss can result in Business Interruption / Advanced Loss of Profit type exposure, or even result in the project becoming uneconomic to continue.</p>
273	08.07.00.	Project Financing	<p>Factors which could impact project financing include:</p> <ol style="list-style-type: none"> 1. Government project funding withdrawn for technical reasons. 2. Government project funding withdrawn for political reasons 3. Change in equity project funding 4. National/global economic downturn impact on project financing 5. Lack of economic incentives for CCS impact on project financing 6. Private financing 	<p>Lack of or loss of project financing could halt the project or delay expansions.</p> <p>High level of indebtedness can lead to:</p> <ol style="list-style-type: none"> 1. Restrictions on business operation due to terms of the debt agreements 2. Use of substantial portion of cash flow to pay interest on outstanding debt 3. Competitive disadvantage compared to competitors with proportionally less debt 4. Impairment of additional financing for working capital, capital expenditures, debt servicing, restructuring, acquisitions, or general corporate purposes 5. Limited flexibility in planning for, or reacting to, changes in the business and industry 6. Vulnerability to economic downturns and adverse business developments 7. Vulnerability to interest rate increases.
274	08.08.00	Hedging or derivative positions	<p>Hedging or derivative positions may be used as a risk management tool to control the adverse impact of fluctuating commodity prices.</p>	<p>Hedging arrangements are used to reduce exposure to fluctuations in commodity prices (i.e., CO₂, oil, natural gas). Hedging can create financial risks when:</p> <ol style="list-style-type: none"> 1. Production is less than hedged amount. 2. The counterparty to the hedging contract defaults on its contract obligations 3. Change in the expected differential between the underlying price in the hedging agreement and the actual price received 4. Limitation of the benefit when commodity prices increase <p>Under certain circumstances, or if hedges are deemed ineffective, discontinued, or terminated for any reason, substantial financial losses may be incurred in closing out a company's position.</p>
275	09.00.00.	PERMITTING RISKS		

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276	09.01.00.	Permit compliance - obtain or maintain permits	<p>Permitting and NEPA compliance are lengthy processes, and are subject to even more delays because of uncertainty associated with permitting sequestration (a relatively new issue for federal, state and local regulatory agencies). The procedures for permit compliance could cause delays. Potential permits required for a CCS project include:</p> <ol style="list-style-type: none"> 1. National Environmental Policy Act (NEPA) <ul style="list-style-type: none"> - Environmental Assessment (EA) - Environmental Impact Statement (EIS) 2. Underground Injection Control (UIC) permit 3. CO₂ storage permit 4. Drilling permit 5. Water discharge/disposal permit 6. Crossing permits for wetlands, federal land, tribal land, railroads, highways, roads 7. Construction general permit 8. Storm water discharge permit 9. Air quality construction permit 10. Seismic permit 11. Storage tank permit 12. Closure financial assurance 13. Post-closure financial assurance 	Lack of permit could halt or restrict construction or operation; permit delay could have other impacts including increased costs.
277	09.02.00.	Public outreach and education	<p>Public acceptance support and trust is critical to obtaining environmental permits. Public outreach and education can be more difficult than expected.</p> <ol style="list-style-type: none"> 1. Lack of public acceptance that CO₂ emissions contribute to global warming 2. Lack of public acceptance that global warming is an eminent danger to society 3. Lack of public that carbon capture and storage (CCS) is safe 4. Poor public perception of CCS projects 5. Local community actions and reactions 6. Special interest groups or non-governmental organizations actions and reactions 7. Lack of political support for the project 8. Risk off-sets 	<p>Failure to get public acceptance for a project can lead to significant delays in, and costs for, permitting</p> <p>An unexpected situation arises that is not technically impacting but the appearance of unpreparedness spurs public concern.</p>
278	09.03.00.	Saline water extraction, treatment and disposal	<p>Large amounts of saline water are pumped out of the ground for EOR and ECBM. EOR water production increases over time. In high water cut cases, water may represent 99% of the production volume and oil only 1% of the volume.</p> <p>ECBM employs water production to lower the over pressure in the coal seam, decrease swelling and increase permeability.</p> <p>Water may be extracted in a DSA operation to make room for injected CO₂ and manage pressure. Extracted water is increasingly becoming a prominent issue, particularly deliberately extracting water to manage CO₂ plume (e.g. extracting water to encourage plume migration and reinjecting the extracted water into a different part of the reservoir so that it is not extracted again). Some researchers believe CO₂ can be injected into reservoirs without extracting water. This may be true in an open storage reservoir. But in a closed reservoir, injecting CO₂ without extracting water will build up pressure in the reservoir and severely restrict the CO₂ storage capacity.</p> <p>CO₂ changes water composition and makes water more acidic (pH 4-5). Therefore EOR and ECBM production water may require more treatment before it can be disposed of.</p>	<p>Saline water disposed could be one of the most critical issues in permitting.</p> <p>Treating the water will concentrate brine that will need to be reinjected.</p>

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279	09.04.00	Natural resources nearby	<ol style="list-style-type: none"> 1. Mineral resources 2. Mineable coal seams 3. Oil reservoirs 4. Natural gas reservoirs 5. Underground drinking water sources 6. Surface waters - lakes, rivers, streams 7. Geothermal resources 8. Pores space owned by others 9. Deep saline aquifers 10. Microbial resources 11. Soil - farmland 12. Flora and fauna - endangered species and critical habitats 	CO2 or brine fluid migration could contaminate others' natural resources and lead to permitting delays due to legal contest.
280	09.05.00.	Dense population nearby	<p>Present and future urban sprawl.</p> <ol style="list-style-type: none"> 1. Sensitive receptors (schools, hospitals, care centers, churches, prisons) in or near injection site 2. Dense population located downhill or downwind of injection site 3. Populated subsurface structures located nearby 	Additional safety precaution measures are required to protect against CO2 leakage in dense population areas..
281	09.06.00.	Conflicts with use of surface	<ol style="list-style-type: none"> 1. Agriculture 2. Fishing 3. National parks/monuments 4. Wetlands 5. Timberland 6. Recreational areas 7. Military areas 8. Heavy industry sites 9. Urban areas 10. Archeological sites 11. Tribal sacred ground 12. Endangered species critical habitats 13. Bird sanctuaries 14. Historical sites 15. Groundwater protection zones. 17. Change in land use (zoning change) 	<p>Some land uses may impact site selection and permitting. Others may require additional monitoring and modeling to provide added protection from CO2 leakage.</p> <p>Nearby heavy industry can interfere with seismic readings.</p> <p>Land use changes could restrict access to and use of land for CO2 sequestration</p>
282	09.07.00.	Conflicts with use of subsurface	<p>Conflicts with use of the subsurface may include:</p> <ol style="list-style-type: none"> 1. Natural gas storage 2. Compressed air storage 3. Geothermal plants 4. Radioactive waste disposal 5. Petroleum production 6. Coal mining 7 Health spas 	Could impact site selection and permitting.
283	09.08.00.	Permit denied or modified by government agency	<p>A permit may be modified by government agency to require increase data access and approval by NGOs and/or public</p> <ol style="list-style-type: none"> 1. Permit denied because the project is considered high risk to public 2. Permit denied because there is uncertainty over the safety of the project 3. Permit revoked due to owner failing to comply with regulations (action or inaction) 4. Permit delayed due to owner action or inaction 	Causes delays leading to price escalation. Could halt the project.

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284	09.09.00.	Pre-existing contaminated site	Site may have already been contaminated by non-CO ₂ storage related activities.	Pre-existing contamination of groundwater, surface water, and/or soil. Requires assessment to determine if proposed project would be impacted by or exacerbate existing condition. Or assume responsibility for remediation of pre-existing conditions.
285	10.00.00.	EXTERNAL RISKS		
286	10.01.00.	Natural disaster risks (01.02.02.00.)	<ol style="list-style-type: none"> 1. Fire -wildfires, industrial fires 2. Flood - flood plain, dry wash areas, flash floods, tsunami, debris flows 3. Earthquake - natural seismic activity, rock slides, mud slides 4. Winter storms - blizzards, ice storms, arctic cold 5. Hail storm 6. High winds - tornadoes, hurricanes, typhoons, cyclones 7. Heat wave 8. Drought 9. Heavy rain - monsoons, tropical storms, thunder storms 10. Lightning 11. Sand/dust storms 12. Avalanche 13. Electromagnetic disturbances - sunspots 14. Volcano 15. Corrosive atmospheres - high humidity, coastal sea breeze, industrial plant acid gas emissions 	Natural disasters can delay, impair or shutdown a project.
287	10.02.00.	Security risks	<ol style="list-style-type: none"> 1. Theft 2. Vandalism - onsite equipment or offsite monitoring equipment 3. Employee sabotage 4. Civil unrest - riots, civil war, rebellion, insurrection, military or usurped power or confiscation 5. Terrorist activities 6. War - invasion, acts of foreign enemies, hostilities 7. Nationalization 8. Government sanctions, blockade, embargo 9. Labor disputes - strike, lockout 10. Damage to surface facilities by human activity 11. Hunting season - stray bullets 	Risks to employees, public and equipment.
288	10.03.00.	Competition	<p>Other projects in the area may compete for the same CO₂, labor, infrastructure, land, pore space, funding</p> <ol style="list-style-type: none"> 1. Interaction with adjacent CO₂ sequestration sites 2. Infringement of project's pore space by third-party injection of CO₂, water or waste disposal 	<p>Could halt the project or increase costs.</p> <p>Potential decreased storage capacity.</p>

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289	10.04.00.	CO ₂ supply	Changes in the operation of the CO ₂ source plant may impact CO ₂ properties and/or flow rate. Unanticipated change in demand for injected CO ₂ (flow rate, pressure, water content, etc.) due to either uncontrollable physical changes or operating decisions, will affect operations of the CO ₂ source facility and potentially impose stresses upon surface and down hole equipment and borehole. Changes may be gradual or sudden. Also includes changes arising from characterization data, e.g., limits placed by reservoir on injectivity, capacity, etc. CO ₂ sources and sinks need to coordinate supply and demand and scheduled outages to avoid constraint startup/shutdown of compression facilities and maintain consistent pipeline pressure. This is normally done through a nomination process at least one week in advance. Operators of CO ₂ storage projects may incorporate excess injection capacity (i.e. spare wells) to permit continued injection during planned or unplanned well downtime. (CCP 2009)	<p>Interruption of CO₂ supply could result in a Business Interruption / Advanced Loss of profit type exposure, or even result in the project becoming uneconomic to continue.</p> <p>Lack of adequate CO₂ supply could halt or limit injection. Intermittent injection schedule could increase stress on surface and down hole mechanical elements, could affect EOR/ECBM sweep efficiency, and could increase concentrations of various contaminants in the injected gas.</p> <p>The timing of CO₂ availability may not match up with the time when CO₂ is needed for EOR or ECBM.</p> <ol style="list-style-type: none"> 1. CO₂ outside of design specification - flow rate, composition, pressure, temperature 2. Change in CO₂ supply conditions 3. Change in CO₂ demand conditions 4. CO₂ supply interruptions due to source plant outage/failure 5. CO₂ supply interruptions due to CO₂ capture outage/failure 6. CO₂ supply interruptions due to compressor outage/failure 7. CO₂ supply interruptions due to pipeline outage 8. Disparity in timing CO₂ supply/demand 9. CO₂ interruption due to accident at the CO₂ supplier
290	10.05.00.	Water supply	<ol style="list-style-type: none"> 1. Water supply design specifications <ul style="list-style-type: none"> - Flow rates - Composition - Pressure - Temperature 2. Water supply interruptions 	Could impact water and gas (WAG) flooding
291	10.06.00.	Power supply	<ol style="list-style-type: none"> 1. Power surges 2. Power brown outs 3. Power interruptions (black outs) 	Could shut operations down.
292	10.07.00.	Communication system	<p>Communications could be interrupted. The SCADA system may be dependent on one or more of the following communications systems:</p> <ol style="list-style-type: none"> 1. Phone line 2. Fiber optics 3. Satellite 4. Internet 	Loss of communication system could impair operations especially if the SCADA link is disconnected.
293	10.08.00.	Road access	Road to injection site could be blocked by snow, accident, washout, wildfire, flooding	Lack of road access to sites could impair operations
294	11.00.00.	PROJECT MANAGEMENT RISKS		
295	11.01.00.	Management team	<p>The project may include some unfamiliar activities and workflows, may acquire and respond to a wide range of newly acquired data, and may experience changes in objectives. Operational conflicts, anticipated or not, could impact project values.</p> <p>Inexperienced managers tend to be over optimistic in taking risks and taking short cuts. for example: failing to avoid high risk sites.</p> <ol style="list-style-type: none"> 1. Inexperienced management team 2. Inability to execute contracts among project partners in a timely manner 3. Lack of stakeholder coordination 	<p>An inexperienced management team has a higher potential for mistakes and poor judgment</p> <p>Inefficient interface management can result in delays and failure to achieve project goals.</p>
296	11.02.00.	Operator training	<ol style="list-style-type: none"> 1. Under qualified operators 2. Untrained operators 3. Operator error 	Inadequate operator training can result in low labor productivity and greater potential for human error.

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297	11.03.00.	Execution strategy	<p>Poor execution strategy can result from:</p> <ol style="list-style-type: none"> 1. Insufficient funding 2. Insufficient resources 3. Unrealistic schedule 4. Schedule and planning conflicts (02.01.05.00) 5. Poor timing 6. Lack of risk management plan <p>Scheduling and planning covers the sequence of events and activities occurring during all phases of the project.</p>	<p>Poor execution strategy can result in project delays and increased project costs.</p> <p>Project development decisions generally are based on subjective judgments and assumptions that, while they may be reasonable, are by their nature speculative. It is impossible to predict with certainty the production potential of a particular property or well. Furthermore, the successful completion of a well does not ensure a profitable return on investment.</p>
298	11.04.00.	Record keeping (See 02.02.03.00.)	<p>Large amounts of data will be generated by the project. Data could be poorly communicated between groups, or be badly managed to the point that important data is lost, or used incorrectly.</p> <p>Features related to the retention of records of the content and nature of a CO₂ storage site after closure and also the placing of permanent markers at or near the site.</p> <ol style="list-style-type: none"> 1. Poor data management 2. Loss of archives/records 3. Unable to accurately verify the amount of CO₂ retained in storage 	<p>It is expected that records will be kept to allow future generations to recall the existence and nature of the storage reservoir/aquifer following closure.</p> <p>Insufficient record keeping could lead to noncompliance with regulations and failure to achieve project goals.</p>
299	11.05.00.	Multi-party project	<p>CCS projects may involve multiple participants for CO₂ supply, CO₂ transportation, EPC (engineering, procurement and construction), CO₂ storage, computer simulation, MVA (monitoring, verification and accounting), carbon trading, and risk management. There are challenges and risks in coordinating the responsibilities and liabilities among multiple organizations involved in a project.</p> <p>In case of too deep involvement of partners in day to day operations, shareholders may assume joint and several liability for actions of the partnership.</p> <p>Disagreement among partners may lead to deadlock in unanimous decision making.</p>	<p>Lack of communication, coordination and cooperation among project participants can lead to project delays and failure to achieve project objectives.</p>
300	11.06.00	Pre-closure administrative control (02.01.06.00.)	<p>Features related to measures to control events at or around the sequestration site during the design, construction, operation and decommissioning phases. The type of administrative control may vary depending on the stage in the storage system lifetime. (02.01.06.00.)</p>	<p>The pre-closure administrative control will influence the quantity and quality of information about the sequestration project that is available post-closure, therefore helping to determine societal memory. The better the amount and quality of information available, the lower the possibility of inadvertent intrusion.</p>
301	11.07.00	Post-closure administrative control (02.02.01.00.)	<p>Administrative control of the sequestration site after closure of the project.</p> <p>The administrative control of the post-closure site may differ from that of the pre-closure site with subsequent implications for the resources available for administrative control, the degree of access and availability of information etc.</p>	<p>There may be potential for loss of information in any transfer of administrative control. A lack of awareness about the details of a CO₂ sequestration project could result in inadvertent disruption in the future.</p>

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302	11.08.00	Quality Control (See 02.01.08.00.)	<p>Features related to quality control procedures and tests during the design, and operation of the storage system.</p> <p>It could be expected that a range of quality control measures would be applied during operation of the storage system and supply of CO2 to be sequestered. There may be specific regulations governing quality control procedures, objectives and criteria.</p>	<p>The degree of quality control during the design, construction, operation and decommissioning of a sequestration system can affect the post-closure performance by influencing the integrity of the engineered parts of the system (borehole seals, for example) and by influencing the quantity, quality and accuracy of records.</p> <p>Quality of equipment could have a big impact on the project.</p>
303	11.09.00	Monitoring	<p>There are many market and business conditions that should be monitored by management in order to make informed business decisions. These may include:</p> <ol style="list-style-type: none"> 1. Environmental conditions 2. Public health 3. Public opinion 4. Legislation and regulations 5. Economic conditions 6. Operations 7. Natural resources 8. Water supply 9. Transportation logistics 10. Construction schedule 11. Climate change and weather conditions 12. Security 13. Pipeline 14. CO2/brine movement 15. Operating permit requirements. 	<p>Effective decision making requires timely knowledge and understanding of all factors that may influence or be influenced by the decision.</p>
304	12.00.00.	ENGINEERING RISKS		
305	12.01.00.	Technical design	<p>Technical design errors can be caused by:</p> <ol style="list-style-type: none"> 1. Insufficient data 2. Lack of data - typical of greenfield sites 3. Inaccurate data 4. Misinterpretation of data 5. Use of wrong standards - unit conversion 6. Specification errors 7. Undefined specifications 8. Ignoring data 9. Calculation and modeling errors 10. Failure to design for full range of operating conditions and climate conditions. 11. Failure to design for high operating availability 12. Failure to design for failsafe protection for compression 	<p>Technical design errors can lead to poor performance or failure of equipment/systems and possible CO2 release.</p>
306	12.02.00.	Modeling and simulation	<p>Use of multiple static and dynamic models that are populated and run by different people using different assumptions and methods can result in errors.</p>	<p>Modeling and simulation errors can result in uncertainties, interpretive disagreements and poor operational choices.</p>
307	12.03.00.	Baseline studies	<p>Baseline surveys are important for determining ambient or background conditions prior to CO2 injection. They include:</p> <ol style="list-style-type: none"> 1. Soil baseline 2. Water (surface and groundwater) baseline 3. Atmosphere baseline 4. Seismic baseline 5. Aquatic environment baseline 6. Fauna baseline 7. Flora baseline 8. Land use 9. Natural resources 10. Population 11. Local/regional economic baseline 12. Formation chemical baseline 13. Injection site contamination 14. Coastal features 15. Local oceanography 16. Aquatic sediments 17. Location and condition of existing wells 18. Formation geophysical baseline 	<p>Without baseline surveys the project will be unable to quantify what impact the project has had on the environment.</p>
308	13.00.00.	PROCUREMENT RISKS		

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309	13.01.00.	Procurement delays	<p>Procurement delays may threaten project goals. Infrastructure components may include power block, compressors, gas processing equipment, pumps, valving, metering and monitoring equipment.</p> <ol style="list-style-type: none"> 1. Procurement delays - equipment and infrastructure 2. Procurement delays - drilling services 3. Vendor supply chain disruptions 4. Material supply shortages 5. Changes in materials and equipment costs 	Could delay completion of construction
310	13.02.00.	Vendor errors	<ol style="list-style-type: none"> 1. Vendor engineering errors 2. Defective manufacturing 	Potential poor performance or failure of equipment/systems. Potential CO ₂ leakage.
311	13.03.00.	Contracting	<p>The ability of project partners to formulate and execute contracts with third parties (non-partners) in a timely manner (not causing delays) apart from their specific contents.</p> <ol style="list-style-type: none"> 1. EPC contract omissions 2. EPC contract insufficient detail 3. EPC contract change orders 	The principal risk is delay and its impact upon achieving goals including cost.
312	13.04.00.	Transportation logistics	<p>Project-related traffic in and out of site; its effects upon both injection well, monitoring and CO₂ supply operations.</p> <ol style="list-style-type: none"> 1. Site traffic impact on injection and monitoring 2. Limitations on size/height/weight shipments to site 	Could cause interruptions and delays.
313	14.00.00.	CONSTRUCTION RISKS		
314	14.01.00.	Cost overruns	<p>Construction cost overruns can be due to</p> <ol style="list-style-type: none"> 1. Change orders 2. Cost escalation 3. Unexpected problems 4. Rework 5. Poor management. 	Increased costs
315	14.02.00.	Schedule delays	<p>Construction schedule delays can be due to</p> <ol style="list-style-type: none"> 1. Permitting delays 2. Bad weather 3. Labor issues 4. Procurement delays 5. Accidents 6. Poor planning/management 7. Funding delays 	Startup delay and increased costs.
316	14.03.00.	Construction defects	<p>Construction defects may be identified during or after construction. They may include</p> <ol style="list-style-type: none"> 1. Improper installation 2. Wrong installation 3. Damage during installation 4. Defective welding 5. Omissions 	Increased costs, project delays due to need for rework, and potential human injury and equipment/systems damage
317	15.00.00.	COMMISSIONING AND STARTUP RISKS		
318	15.01.00.	Major rework	Major rework may be required to correct poor performance or failure of equipment/systems due to improper design, manufacturing, construction or operation.	Project delays and added costs.
319	15.02.00.	Unable to achieve design capacity	Operating capacity may be limited due to improper design, manufacturing, construction or operation.	Loss of revenues and increased costs.
320	15.03.00.	Operator error or over confidence during commissioning and startup	Incorrect operation due to lack of operator training	Potential human injury, equipment damage, project delays, added costs.
321	15.04.00.	Startup pressure	Facilities sometimes do not have sufficient pressures to re-start injection. In these cases, injection tubing should be loaded with sufficient fluids to allow for a re-start. (CCP 2009)	Insufficient startup pressure can result in operating delays.
322	16.00.00.	FIELD SAFETY RISKS		

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323	16.01.00.	Accidents and unplanned events (02.01.09.00.)	<p>Events related to accidents and unplanned events during site investigation, CO2 emplacement and closure which might have an impact on long-term performance or safety.</p> <p>Accidents are events that are outside the range of normal operations although the possibility that certain types of accident may occur should be anticipated in operational planning. Unplanned events include accidents but could also include deliberate deviations from operational plans, e.g. in response to an accident, unexpected geological events or unexpected aspects of CO2 quality and injection arising during operations.</p> <p>Project related accidents can be caused by human error or equipment/system failure/malfunction. Accidents may occur during construction, commissioning, operation, maintenance or closure.</p> <p>Non-project related accidents may include: rupture of train or truck transport vessel, train derailment, site or water supply contamination.</p> <p>1. Project related accidents 2. Non-project related accidents</p>	<p>Potential for human injury and/or equipment damage</p> <p>Accidental loss can result in Business Interruption / Advanced Loss of Profit type exposure, or even result in the project becoming uneconomic to continue.</p> <p>Accidents and unplanned events may affect the post-closure performance of the sequestration system. One example may be the incomplete sealing of an injection borehole that may subsequently provide a pathway for CO2 migration.</p>
324	16.02.00.	Moving equipment	<p>Moving equipment risks may include:</p> <p>1. Hitting other equipment 2. Hitting personnel 3. Hitting power lines</p>	Potential for human injury and/or equipment damage
325	16.03.00.	Excavation/drilling	<p>The one-call system should be used to locate underground utilities and pipelines before excavating or drilling. Excavation/drilling could hit other subsurface hazards such as gas pockets or underground storage tanks.</p>	Potential for equipment damage, release of gases or liquids, fire, explosion, and/or human injury.
326	16.04.00.	Defective equipment	<p>Equipment should be properly maintained and regularly inspected. Equipment defects may include:</p> <p>1. Exposed electric wiring 2. Leaky hoses 3. Loose connections 4. Frayed cables</p>	Higher risk for equipment failure and human injury

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327	16.05.00.	Use of power tools	Operators should be properly trained in the use of power tools.	Potential for human injury and/or equipment damage
328	16.06.00.	Contact with rotating equipment	Proper safeguards should be used to prevent contact with rotating equipment	Higher risk for being injured
329	16.07.00.	Working near pinch points	Proper safeguards should be used to prevent contact with pinch points	Higher risk for being pinched
330	16.08.00.	Working in confined areas	Working in confined areas can represent high risk especially where CO ₂ is involved.	Higher risk of asphyxiation or being crushed.
331	16.09.00.	Working in high places	Working in high places is a common industrial occurrence	Higher risk of injury due to falling
332	16.10.00.	Working in trench/ditch	Pipeline construction involves trenching which is subject to cave-ins. Sufficient shielding or cave-in protection devices should be used if people go into a trench	High risk of being crushed and/or asphyxiated

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333	16.11.00.	Working under a lifted load	Working under a lifted load should be avoided	Higher risk for being crushed
334	16.12.00.	Contact with venomous snakes or insects	Field operations and data collection can be in close proximity to venomous snakes and insects in some parts of the country.	Potential for human injury.
335	16.13.00.	Contact with poisonous plants	Field operations and data collection can be in close proximity to poisonous plants such as poison ivy or poison oak in some parts of the country.	Potential of human rash/irritation
336	16.14.00.	Contact with hot surface, or exposure to heat or flame	Overheated equipment, welding areas, heaters and open flames are present at industrial sites.	Contact with hot surface or flame can cause burn injuries. Exposure to prolonged high temperatures can cause heat exhaustion or dehydration.
337	16.15.00.	Exposure to noise	Operation of heavy equipment, pumps and compressors can generate loud noise.	Prolonged exposure to loud noise can cause hearing damage.
338	16.16.00.	Exposure to dust	Dust is generated in pipeline construction and field operations.	Prolonged exposure to dust can cause respiratory health problems.
339	16.17.00.	Exposure to hazardous materials	Fluids, fuels and chemicals used in field operations may be classified as hazardous materials.	Prolonged exposure to hazardous materials are known to cause health problems.

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340	16.18.00.	Struck by object or flying debris	Drilling can often generate flying debris	Flying debris can cause human injury and/or equipment damage.
341	16.19.00.	Release of compressed gases or liquids	Compressed CO2 pipelines, pressurized water lines, compressed air tanks are at risk for rupture.	Release of compressed gases or liquids can cause human injury and/or equipment damage.
342	16.20.00.	Ignition of flammable gases or liquids	Acetylene tanks, natural gas lines, liquid fuel lines could be ignited.	Ignition of flammable gases or liquids can cause explosions, severe injuries and property damage.
343	16.21.00.	Trips, slips and falls	Trips, slips and falls are common at industrial sites.	Potential for human injury
344	16.22.00.	Leaks and spills (related to oil spills rather than CO2, H2S and CH4)	Leaks and spills of lubricants, fuels, chemicals or hazardous materials are common at industrial sites. If they are not promptly taken care of they can lead to more serious problems.	Potential for human injury, equipment damage, fire or environmental damage.
345	16.23.00.	Head bumping	Industrial sites are prone to have low hanging or falling objects that could injure unprotected heads	Potential for human head injury
346	16.24.00.	Overexertion from manual heavy lifting, pulling, or pushing	Improper lifting of pipes, ducts, bars, boxes, bags, machine parts. Pulling/pushing wrenches, hoses, machine parts or heavy loads.	Potential for human back injury. Overexertion represented 11.3% of injuries requiring days away from work in drilling oil and gas wells in 2007. The injury rate was 2E-03 per worker per year.

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347	16.25.00.	On-road driving	Vehicle travel to and from the site is typically among the highest risks in similar projects.	Potential for human injury and/or equipment damage
348	16.26.00.	Off-road driving	Field data collection often requires off-road driving, sometimes in rocky, muddy, or steep terrain. Some personnel may lack experience with safe driving under challenging conditions.	Potential for human injury and/or equipment damage
349	16.27.00	Explosions and crashes (01.03.10.00.)	<p>Events related to deliberate or accidental explosions and crashes such as might have some impact on a closed storage site, e.g. underground nuclear testing, an aircraft crash on the site, acts of war, marine collisions or trawler damage to exposed sea-bed structures.</p> <ol style="list-style-type: none"> 1. Accidental explosions and crashes 2. Deliberate explosions and crashes 3. Project related 4. Non-project related 	<p>Explosions and crashes are likely to be low probability events that could have a significant impact on the performance of the sequestration system by disrupting the expected evolution of the system.</p> <p>Likely to have greater impact on surface facilities rather than subsurface systems.</p>
350	16.28.00	Electric shock	Contact with electric current associated with electric machines, tools, appliances, light fixtures, overhead power lines, underground cables, transformers, wiring, and lightning.	Potential for human injury
351	17.00.00.	LEGAL, LEGISLATION & REGULATION RISKS		

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352	17.01.00.	CO ₂ legislation	<p>Some outstanding CO₂ legislation issue are as follows:</p> <ol style="list-style-type: none"> 1. Cap and Trade or Carbon tax incentives for CCS 2. Certification process for tradable carbon credits 3. Pore space access and ownership 4. Certification for transfer of long-term stewardship/liability for closed CO₂ sites from operator to competent legal authority 5. Eminent domain authority 6. Forced unitization for EOR or ECBM 7. Priority of mineral rights over pore space rights 8. Value of escaped CO₂ 9. Elimination of current tax deductions for oil and gas 	<p>Legislation can have a significant impact on CCS project economics.</p> <p>Lack of, or gaps in, CO₂ legislation can create uncertainty for the project and make it more difficult to permit and finance the project.</p> <p>Concerns that enacted CO₂ legislation could be repealed or changed also contribute to uncertainty for the project and make it more difficult to finance.</p> <p>Elimination of certain oil and gas tax deductions could make it more costly to develop EOR and ECBM projects and negatively affect the financial conditions and results of operations.</p>
353	17.02.00.	CO ₂ regulations	<p>Some outstanding CO₂ regulation issues are as follows:</p> <ol style="list-style-type: none"> 1. CO₂ storage permitting and compliance requirements 2. Permitting and compliance for Class VI wells 3. Permitting and compliance for hybrid Class II and VI wells (wells used for both EOR and DSA) 4. Post-injection site care (monitoring) period - EPA proposing 50 years with some flexibility 5. Safety guidelines - DOE best practices guidelines 6. Monitoring and operational reporting requirements 7. Verification and accounting procedures 8. Classification of CO₂ as a pollutant rather than a commodity 9. CO₂ emission controls and reporting 10. CO₂ site straddling two states having to deal with differing regulations 11. Land use restrictions 12. Drilling bonds and other financial responsibility requirements 13. Spacing of wells 14. Reporting on emissions of greenhouse gases 15. Permitting of emissions of greenhouse gases and other regulated air pollutants 16. Utilization and pooling of properties 17. Well stimulation processes 18. Produced water disposal 19. Taxation 	<p>Regulations can have a significant impact on CCS project economics.</p> <p>Lack of, or gaps in, CO₂ regulations can create uncertainty for the project and make it more difficult to permit and finance the project.</p>
354	17.03.00.	CO ₂ liabilities	<p>Responsibility for the injected CO₂ and any associated liability, during and after active project phase, is currently an unresolved legal issue. Project participants could reduce their involvement if this issue remains unresolved, or is resolved in a manner that unacceptably increases their exposure.</p> <ol style="list-style-type: none"> 1. CO₂ ownership and custody 2. Tort-injury to a third-party (person or property) 3. Property-rights dispute 4. Trespass - contamination of third-party natural resources 5. Trespass - infringement on third-party pore space 6. Breach of duty - leakage sufficient to undermine the value of carbon credits 7. Frivolous lawsuits private or organizational based legal challenges 8. Surface ownership and associated liability 9. Assigning liability responsibility in a multi-party project 	<p>Liability for potential damages associated with sequestration or operational aspects could preclude the project from moving forward.</p> <p>Property-right disputes over surface rights, mineral rights or pore space could halt or restrict construction, CO₂ injection or monitoring operations for CCS projects.</p> <p>Under environmental, health and safety laws and regulations the owner/operator could be liable for:</p> <ol style="list-style-type: none"> 1. Personal injuries 2. Property and natural resource damages 3. Oil spills and releases or discharges of hazardous materials 4. Well reclamation costs 5. Remediation and clean-up costs and other government sanctions and fines. 6. Other environmental damages 7. Additional reporting permitting or other issues arising from emissions of greenhouse gases and other regulated air pollutants.

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355	17.03.01.	Insurance	<p>There are many kinds of insurance coverage. Some of those that pertain to CCS include:</p> <ol style="list-style-type: none"> 1. Physical damage 2. Machinery breakdown 3. Business interruption (advanced loss of profit) 4. Environmental 5. Third-party liability 6. Worker's compensation 7. Transportation 8. Closure and post-closure financial assurance 9. Operator's extra expense (OEE) 	Insurance coverage may not be available for CCS projects until there is a sufficient track record of performance (or failure) to determine the probability of failure occurring.
356	17.03.02	Transfer of long-term liability stewardship	Public companies cannot take on long-term liability for 50 years or more. There is no guarantee companies will stay in business that long. Therefore, it is up to a government entity to take on responsibility. The federal government would be preferred because it would level the playing field among states and spread the risks over more projects. A sinking fund could be used to cover the costs of such a program.	Companies are unlikely to invest in deep saline aquifer (DSA) sequestration projects without some assurance that the long-term liability is transferable or manageable.
357	18.00.00.	CO₂ CAPTURE RISKS		
358	18.01.00.	CO ₂ capture system performance	<p>Performance risks for CO₂ capture systems could include:</p> <ol style="list-style-type: none"> 1. Production below design capacity 2. Unable to meet product specification 3. Low CO₂ recovery 4. Low thermal efficiency - greater heat losses than expected, low heat recovery 5. Excess solvent or sorbent consumption 6. Excess power consumption 7. Excess steam consumption 8. Excess cooling water circulation required 9. Excess maintenance 10. Low process availability 11. Low mechanical availability 	Poor performance of the CO ₂ capture system can result in higher operating and maintenance costs, interruption of CO ₂ supply, and/or off spec CO ₂ .

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359	18.02.00.	CO ₂ capture system design	<p>Design deficiencies for CO₂ capture systems could include:</p> <ol style="list-style-type: none"> 1. Scale-up errors 2. Equipment undersized/oversized for proper residence time 3. Equipment undersized/oversized for proper surface area 4. Excess velocities 5. Inadequate expansion joints 6. System bottlenecks 7. Inadequate instrumentation 8. Inadequate process controls and alarms 9. Inadequate computer simulation models 10. Wrong sorption model for the contacting device 11. Insufficient winterization 12. Wrong materials of construction 13. Lack of emergency flare/vent 14. Lack of surge capacity 15. Lack of redundancy -backup systems 	Design deficiencies can result in poor performance, higher operating and maintenance costs, interruption of CO ₂ supply, and/or off-spec CO ₂ ..
360	18.03.00.	CO ₂ capture system scale up limitations	<p>The limits on scale up of the CO₂ capture system could include:</p> <ol style="list-style-type: none"> 1. Equipment size limits - manufacturing, transport, or structural load limits 2. Heat transfer limits 3. Mass transfer limits 4. Diffusion limits 5. Surface area limits 6. Reaction kinetics limits 	Limits in scale up of the CO ₂ capture system can lead to higher capital cost and higher operating costs.
361	18.04.00.	CO ₂ capture system operations	<p>System operating risks for CO₂ capture systems could include:</p> <ol style="list-style-type: none"> 1. Non-equilibrium or non-steady-state conditions 2. Exothermic reactions overheating the process 3. Endothermic reactions overcooling the process 4. Pressure/stress buildup 5. Non-uniform mass distribution/dispersion/mixing – dead zones, stratification 6. Non-uniform temperature distribution – hot/cold spots, stratification 7. Mass and energy imbalance 8. System imbalance 9. Pressure or temperature cycling 10. System upset – unexpected high flow rate/temperature, carryover of upstream contaminants 11. Off-spec or inconsistent feed and/or product 12. Abrasion/erosion 13. Corrosion 14. Fouling 15. Contactor plugging 16. CO₂ escape/leakage to the atmosphere 17. Scale build up causing heat exchanger failure 18. Air leakage - nitrogen dilution 19. Equipment failure due to defects, plugging, wear 20. Control system failure 	Operation and maintenance problems can result in higher operating and maintenance costs, CO ₂ supply interruptions and off-spec CO ₂ .

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362	18.05.00.	CO ₂ capture solvent or sorbent	<p>Solvent or sorbent risks for CO₂ capture could include:</p> <ol style="list-style-type: none"> 1. Off-spec or inconsistent solvent or sorbent 2. Unexpected contamination (SO_x, NO_x, Cl, H₂O, hydrocarbons, trace metals, chemical slip, particulate matter) 3. Gradual buildup of contaminants in circulating loads 4. Foaming 5. Chemical reactions with contaminants - precipitation of solids 6. Excess viscosities 7. Chemical degradation of solvent or sorbent 8. Thermal degradation of solvent or sorbent 10. Aging (deactivation) of solvent or sorbent 11. Hazardous material handling 	Off spec or degraded solvent or sorbent can result in poor CO ₂ capture, higher operating costs, CO ₂ supply interruptions, and off-spec CO ₂ .
363	19.00.00.	CO₂ DEHYDRATION RISKS		
364	19.01.00.	CO ₂ dehydration system performance	<p>Performance risks for CO₂ dehydration systems could include:</p> <ol style="list-style-type: none"> 1. Production below design capacity 2. Unable to meet product specification 3. Excess glycol consumption 4. Carryover of glycol into downstream systems 5. Excess utility consumption 6. Excess maintenance 7. Low plant process and/or mechanical availability 	Poor performance of the CO ₂ dehydration system can result in higher operating and maintenance costs, interruption of CO ₂ supply, off spec CO ₂ , and corrosion of downstream systems.
365	19.02.00.	CO ₂ dehydration system operation	<p>Operating risks for CO₂ dehydration systems could include:</p> <ol style="list-style-type: none"> 1. Upset conditions 2. Foaming in the contactor 3. Fouling 4. Buildup of liquid contaminants in recycled glycol 5. Buildup of solid contaminants in recycled glycol 6. Contactor plugging due to fouling 7. Reboiler tube failure due to fouling 8. Heat exchanger failure due to fouling 9. Pump seal failure due to fouling 10. Corrosion - wrong materials of construction 11. Oxidation degradation of glycol 12. Thermal degradation of glycol <p>Dehydration units are normally fairly reliable as long as they are maintained properly avoid process upsets and/or contamination.</p>	Operating problems in the CO ₂ dehydration system can result in higher operating and maintenance costs, interruption of CO ₂ supply, off spec CO ₂ , and corrosion of downstream systems.
366	20.00.00.	CO₂ COMPRESSION RISKS		
367	20.01.00.	CO ₂ compression system performance	<p>Performance risks for CO₂ compression systems could include:</p> <ol style="list-style-type: none"> 1. Output below design capacity 2. Unable to meet pressure specification 3. Excess power consumption 4. Excess maintenance 5. Low mechanical availability 	CO ₂ operating performance is critical to success of a CCS project.
368	20.02.00.	CO ₂ compression system EPC	<p>Engineering, procurement and construction (EPC) risks for compression systems could include:</p> <ol style="list-style-type: none"> 1. Procurement delays - Compressors are typically one of the longest lead items for equipment 2. High capital cost - compression systems are one of the major capital costs for CCS projects 3. Improper specification 4. Metallurgical defect 	Delays in project startup. Increased capital cost. Operating problems resulting from improper specification or installation.
369	20.03.00.	Compressor type	<ol style="list-style-type: none"> 1. Reciprocating compressors - lower capital, higher maintenance, may require spare capacity 2. Centrifugal compressors - higher capital, lower maintenance 3. Screw compressors (dry type) 	Type of compressors selected can impact capital costs, operating costs and operating availability.

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370	20.04.00.	Compression system operation	<p>Operating risks for CO₂ compression systems:</p> <ol style="list-style-type: none"> 1. Improper operation <ul style="list-style-type: none"> - Intermittent operation of the compressor - Operating above/below recommended limits - Upset conditions - Operating compressor with control valve closed - Fouling by dust or liquid droplets - Plugging relief valves during depressurization - Corrosion - due to water in CO₂ stream 2. Improper maintenance <ul style="list-style-type: none"> - Vibration - Noise - Overheating - Leakage 3. Wear and failure <ul style="list-style-type: none"> - Rod drop due to ring wear on recip. comp. - Rod run out or rod deflection on recip. comp. - Valve failure on recip. comp. - Bearing wear/failure - Tip wear on cent. comp. 	Downtime, loss of revenue, increased maintenance costs.
371	21.00.00.	CO₂ PIPELINE RISKS		
372	21.01.00.	Pipeline routing risks		
373	21.01.01.	New versus existing right-of-way (ROW)	<p>ROW issues include:</p> <ol style="list-style-type: none"> 1. Single or multiple pipeline rights 2. Width of ROW 3. Rights for above ground facilities 4. Access to site for repair/modification and inspections 5. Payment for original and continued use of ROW 6. Damage awards for the property owner 7. Requirement for pipeline removal upon abandonment of the pipeline. 8. Eminent domain - used as a last resort to gain access to ROW 	Developing a new ROW is significantly more riskier than using an existing utility ROW.
374	21.01.02.	Climate conditions	<p>Weather conditions can impact pipeline surface facilities</p> <ol style="list-style-type: none"> 1. Severe high or low temperatures 2. Significant winds (tornadoes) 3. Lightning - common cause of pipeline damage 4. Heavy rain fall - flooding 5. Severe winter storms 	Delays in construction and damage to surface facilities.
375	21.01.03.	Soil and terrain conditions	<ol style="list-style-type: none"> 1. Thin soil - insufficient to bury pipeline to depth 2. Corrosive soil - high moisture, high electrical conductivity, high acidity, and high dissolved salts 3. Rocky soil - special care needed in backfilling to protect pipeline 4. Unstable land <ul style="list-style-type: none"> - subsidence - uplift - landslides - earthquake area - active fault zone - high erosion areas - flood plains, dry wash - permafrost - frost heaves - high water table (marshes, swamps, peat bogs) - moving sand dunes - underground mine/coal mine areas - steep slopes >18% (landslides or erosion) 5. Rugged terrain/topography - mountains, hills, canyons, gorges 6. Significant elevation increase or variation over length of pipeline 7. Low lying areas 8. Exposed granite bedrock 	<ol style="list-style-type: none"> 1. Need to add soil to achieve 1.2 -1.8 m (4-6ft) burial depth 2. Accelerated external corrosion 3. Need fine backfill to protect pipeline 4. Can lead to unintended movement or abnormal loading of a pipeline resulting in mechanical damage, leakage or rupture. 5. Significantly higher installation cost 6. Increased compression or pumping costs due to higher pressure drop across pipeline 7. Potential for leaked CO₂ to accumulate in low lying areas if there is insufficient escape velocity or wind to disperse the leaked CO₂ to the atmosphere. 8. Very high costs for blasting a pipeline trench

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376	21.01.04.	Populated areas	<p>A high population area means an urbanized area, as defined by the Census Bureau, that contains 50,000 or more people and has a population density of at least 1000 people per square mile. This is designated a high consequence area. (49 CFR Part 195.450) Other populated areas are also designated as high consequence areas. Non rural areas categorized as high risk. Rural areas categorized as low risk. (49 CFR Part 195 Appendix B)</p> <p>Pipeline right-of-way must be selected to avoid, as far as practicable, areas containing private dwellings, industrial buildings, and places of public assembly. No pipeline may be located within 15 m (50 feet) of any private dwelling, or any industrial building or place of public assembly in which persons work, congregate or assemble, unless it is provided with at least 0.3 m (12 inches) of cover in addition to that prescribed in Section 195.238 (49 CFR Part 195.210). CO2-CRC recommends a 30 m (100 ft) wide easement restricting access to the buried pipeline, a distance of 100 m (330 ft) minimum distance from residential buildings and a 1,000 m (3,300 ft) consultation zone on either side of the pipeline for emergency notification.</p> <ol style="list-style-type: none"> High population density nearby Sensitive receptors (schools, hospitals, nursing homes, prisons) nearby Business/industry/mining nearby 	The greater the number of people, the greater the risk of exposure to CO2.
377	21.01.05.	Land crossings	<ol style="list-style-type: none"> Navigable water ways - Army Corp of Engineers permitting Protected areas - Wetlands, migratory water bird concentration, national parks, habitats for imperiled, threatened, endangered or protected species (aquatic and terrestrial), archeological sites. (49 CFR Part 195.6) Federal land - could trigger the need for permits from the US Army Corp of Engineers, the US Fish and Wildlife, the US Department of the Interior Bureau of Land Management (BLM), the US Department of Agriculture, Forest Service, the US Department of Defense. Also will trigger the National Environmental Policy Act (NEPA) and require Environmental Assessment (EA) or Environmental Impact Statement (EIS) Tribal land - would trigger NEPA (EA or EIS) and the need for a permit from the US Department of Interior Bureau of Indian Affairs (BIA) Transportation corridors - Railroads, highways, roads, bridges, other rights of way could trigger the need for permits from railroad companies, state/county departments of transportation. Drinking water resource areas - Non-navigable surface waters - lakes, rivers, streams 	Land crossing increase cost and the need for additional permits.
378	21.01.06.	Offshore pipeline	<p>The difficulty of offshore construction is roughly proportional to the depth multiplied by the pipeline diameter. (IPCC 2005). Some of the risks include:</p> <ol style="list-style-type: none"> Sea currents Uneven seabed Biological growth on pipeline Arctic conditions (ice gouging) 	Offshore pipeline have significantly higher costs.
379	21.02.00.	Pipeline design risks		
380	21.02.01.	Pipeline diameter	<ol style="list-style-type: none"> Large diameter Large diameter pipelines will release more CO2 in a rupture and are thus classified as having greater severity in the case of a failure such as a rupture. Insufficient diameter for capacity Increased pressure required may place too much stress on the pipeline and components. Limits future expansion. Excess diameter for capacity Resulting decreased pressure may put the CO2 at risk of changing from supercritical to two-phases. No room for 	High risk: Pipeline diameter 0.46 m (18 in) and above. Medium risk: Pipeline diameter from 0.25-0.4 m (10 to 16 in). Low risk: Pipeline diameter 0.2 m (8 in) and below. (49 CFR Part 195 Appendix B).
381	21.02.02.	Pipeline length	The longer the pipeline, the greater the risks.	Long pipeline more expensive, more potential for failure.
382	21.02.03.	Pipeline failure history (for existing pipeline)	Pipeline failure history for time-dependent defects can indicate probability of future failures.	High risk: >3 leaks in last 10 years. Low risk: ≤3 leaks in last 10 years. (49 CFR Part 195 Appendix B)

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383	21.02.04.	Pipeline age (for existing pipeline)	Safety risk increases with the age of the pipeline depending on the pipeline's coating and corrosion condition, and steel quality, toughness, welding.	High risk: >25 years old Low risk: <25 years old (49 CFR Part 195 Appendix C)
384	21.02.05.	Pipeline pressure	All pipeline components must be designed and tested for at least 125% of maximum operating pressure (MOP). If, within a pipeline system, two or more components are to be connected at a place where one will operate at a higher pressure than another, the system must be designed so that any component operating at the lower pressure will not be overstressed. (49 CFR Part 195.104) Pipelines should be designed with sufficient pressure to maintain CO ₂ as a supercritical fluid. 1. Operating pipeline in excess of maximum operating pressure (MOP). 2. Operating pipeline below the CO ₂ supercritical pressure (CSP). 3. Insufficient working range between MOP and CSP.	Components operating at excessive operating pressure will be overstressed and subject to failure. Operating the pipeline at or below the supercritical pressure of CO ₂ can lead to CO ₂ phase change in the pipeline. If the supercritical CO ₂ drops back into the liquid-vapor, two-phase region (which occurs below 6.9 MPa (1000 psig) at ambient temperature), there would be freeze-up issues and a much higher pressure drop in the pipeline.
385	21.02.06.	Pipeline external loads	Anticipated external loads (e.g., earthquakes, vibration, thermal expansion, and contraction must be provided for in designing a pipeline system. (See ASME B31.4). The pipe and other components must be supported in such a way that the support does not cause excess localized stresses (49 CFR Part 195.110). The pipe at each railroad and highway crossing must be installed so as to adequately withstand the dynamic forces exerted by anticipated traffic loads (49 CFR Part 195.256).	Insufficient design for external loads could lead to cracking and CO ₂ leakage.
386	21.02.07.	Pipeline wall thickness	Thicker pipe is typically used for sensitive areas like crossings. Wall thickness for 0.3 -0.36 m (12-14 in) pipe is typically 9.5 mm (0.375 in) except in sensitive areas like crossings where 12.7 mm (0.5 inch) wall thickness used for road crossings (up to 0.3 m (1 ft) past road right of way) and 15.9 mm (0.625 in) thickness used for railroad crossings. (DGC)	Thicker walls give a better safety margin.
387	21.02.08.	Pipeline steel grade	X65 carbon steel is typically used for CO ₂ pipeline if CO ₂ is dry and has low impurities such as H ₂ S.	Pipeline steel grade determines pipeline maximum operating pressure
388	21.02.09.	Pipeline temperature	CO ₂ increases in temperature as it is compressed and decreases in temperature as it expands. CO ₂ entering a pipeline may be in the range of 49°C (120°F) however, it will gradually conform to the ambient ground temperature which may be in the range of 10°C (50°F). Components of CO ₂ pipelines that are subject to low temperatures during normal operation because of rapid pressure reduction or during the initial fill of the line must be made of materials that are suitable for those low temperatures. (49 CFR Part 195.102)	Improper material selection for pipeline components that may experience extreme cold due to rapid pressure reduction may result in component failure and CO ₂ leakage.
389	21.02.10.	Piping type	Seamless pipe is typically used for sensitive areas like crossings or near residences; double submerged arc welded or electric resistance welded pipe is typically used for other areas. (DGC)	Proper piping selection is important in sensitive areas to prevent risk of CO ₂ leakage.

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390	21.02.11.	Pipeline coating	CO ₂ pipelines are typically coated with fusion bonded epoxy to prevent corrosion. In addition piping used at bored crossings is overcoated with an abrasion resistant coating to prevent damage to the epoxy coating during installation. (DGC) 1. External coating 2. Internal coating	Damage to pipeline coating during installation or due to third-party excavation can result in external corrosion.
391	21.02.12.	Pipeline cathodic protection	Cathodic protection on CO ₂ pipelines is maintained by rectifiers located at main-line valve stations every 32 km (20 miles) or less along the pipeline. Cathodic protection is measured in voltage at test posts located at 1.6 km (1 mi) intervals over the length of the pipeline. The rectifier output is adjusted to maintain voltage levels between 0.85 and 1.4 volts at each test station. (DGC)	Insufficient or lack of cathodic protection could lead to external corrosion and CO ₂ leakage.
392	21.02.13.	Pipeline booster stations or pumping stations	Booster or pumping stations are typically needed every 80-320 km (50 to 200 mi) depending on end-use pressure (EERC). Adequate ventilation must be provided in pumping station buildings to prevent the accumulation of CO ₂ gas. Warning devices must be installed to warn of the presence of CO ₂ gas in the pumping building. Safety devices to prevent over pressuring of primary and auxiliary pumping equipment and a device for emergency shutdown of each pumping station should be included. If power is necessary to actuate the safety devices, an auxiliary power supply should be included. (49 CFR Part 195.262)	Insufficient booster or pumping stations could lead to low pressure at the end of the pipeline.
393	21.02.14.	Pipeline future expansion	If there is potential for future expansion, it is practical to install taps for future branches, leave room for booster stations and design the pipeline to allow for expansion at higher pressure without having to replace piping and components. Pipeline diameter and pressure should take into account potential for future expansion through addition of booster stations and increased operating pressure.	Lack of reserved locations for booster stations, insufficient pipeline diameter, and excess operating pressure may make future expansion of pipeline capacity more difficult and more expensive.
394	21.02.15.	Pipeline flow velocity	Reported pipeline velocity varies from 0.9 to 4.6 m/s (3 to 15 ft/s). (IPCC 2005)	Excessive flow capacity could cause erosion in pipeline components.
395	21.02.16.	Pipeline SCADA system	Supervisory control and data acquisition (SCADA) system should have sufficient instrumentation for the central control room to monitor and control flow along the entire pipeline. The system should have built in redundancies to prevent loss of operational capability if a component fails. 1. IT security for SCADA system to protect against cyber-terrorism	Loss of the SCADA system could shut the pipeline down or result in pipeline failure and CO ₂ release.
396	21.02.17.	Pipeline CPM leak detection systems	Computational pipeline monitoring (CPM) leak detection system must comply with section 4.2 of API 1130. (49 CFR Part 195.134). CPM leak detection can be based on acoustics, measurement of chemical release, detecting pressure changes or small changes in mass balance.	Lack of a properly designed CPM leak detection system prevents the pipeline operator from rapid detection and response to CO ₂ leaks. Inaccurate modeling of CO ₂ dense phase can cause the computational leak detection system to malfunction.

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397	21.02.18.	Pipeline block valves or control valves	<p>Main-line valves (block or control valves) are located on either side of water crossings and approximately every 32 km (20 mi) overland in order to allow for quick isolation and to minimize the impact of a leak. (DGC) Valves must be installed at each of the following locations: on the suction end and discharge end of a pump station, on each mainline at locations along the pipeline system that will minimize damage or pollution from CO₂ discharge, on each lateral takeoff from the trunk line, on each side of a water crossing that is more than 30 m (100 ft) wide and on each side of a reservoir that is holding water for human consumption. (49 CFR Part 195.260)</p> <p>Each valve must be installed in a location that is accessible to authorized employees and that is protected from damage or tampering. (49 CFR Part 195.258)</p>	The distance between main-line valves determines the amount of CO ₂ released in a rupture. Longer spacing means a larger volume of CO ₂ is likely to escape.
398	21.02.19.	Pipeline internal inspection devices	<p>Pipelines must be designed and constructed to accommodate the passage of instrumented internal inspection devices (i.e. smart pig). 49 CFR Part 195.120)</p> <p>No operator may use a launcher or receiver that is not equipped with a relief device capable safely relieving pressure in the barrel before insertion or removal of scrapers or spheres. (49 CFR Part 195.426)</p>	Internal inspection devices are important tools for detecting corrosion or mechanical damage in pipelines before they fail.
399	21.02.20.	Pipeline seals	Teflon or nylon have been used for seals to prevent swelling. (Meyer 2007).	Improper sealing materials may react with CO ₂ and cause CO ₂ leakage
400	21.02.21.	Pipeline winterization	Winterization (protection from severe cold/ice) may be needed for above ground facilities in cold climates.	Lack of winterization can cause CO ₂ pipeline instrumentation lines and valves to freeze up in severe cold/icy weather.
401	21.02.22.	Pipeline burial depth	<p>CO₂ pipelines are typically buried a minimum of 1.2 m (4 ft) over the length of the pipeline, ≥1.5 m (5 ft) below roads, ≥3 m (10 ft) below railroads, ≥1.2 m (4 ft) below ditches and ≥3 m (10 ft) below water line on shores. (DGC).</p> <p>Minimum burial depth for pipeline is 0.9 m (36 in) for industrial commercial and residential areas, 1.2 m (48 in) for crossing of inland bodies of water, 0.9 m (36 in) for drainage ditches at public roads and railroads, 1.2 m (48 in) for deepwater port safety zones, 0.9 m (36 in) for offshore areas and 0.8 m (30 in) elsewhere. There are exceptions for rock excavation areas. (49 CFR Part 195.248)</p>	Insufficient burial depth makes pipeline more susceptible to excavation damage, sabotage, climate damage etc.
402	21.02.23	Pipeline bedding and foundation structures	Pipeline bedding and foundation structures are designed to hold a pipeline stable throughout its life. This is particularly important for offshore pipelines.	Improper design of pipeline bedding or foundation structures could result in pipeline shifting or buckling.
403	21.03.00.	Pipeline defects		

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404	21.03.01.	Pipeline material defects	<p>During the manufacturing of steel, impurities can sometimes remain in the molten steel. These impurities can cause an incomplete bonding of the material in the steel plate or solid round billet used to produce pipe and other pipeline components. reduce the wall thickness of the pipe or pipeline component, and, if large enough, can reduce the pressure-carrying capacity of the pipe or component.</p> <p>Some pipeline material defects include:</p> <ol style="list-style-type: none"> 1. Propagating cracks - very rapid propagating cracks can occur that "unzip" the pipeline along its length. 2. Laminations and inclusions - caused by oxides or impurities trapped in the steel 3. Blisters and scabs - raised spots on steel surface caused by expansion of trapped gases within the steel 4. Hard spots - created by localized cooling of the steel plate (ERW pipe) during rolling 5. Indentations - formed by the expanders or mandrels used to make seamless pipe 6. Transit fatigue - cracks formed when pipes are repeated flexed during transportation and handling 7. Cyclic fatigue - cracks caused by stress from repeated fluctuating operating pressure within the pipe 8. Elastomer and polymer - failure due to reaction with CO₂ 	<ol style="list-style-type: none"> 1. Propagating cracks can lead to pipeline rupture. 2. A lamination or inclusion can eventually lead to failure if they eventually grow to the inner or outer wall of the pipe or pipeline component through pressure cycles. 3. Blisters and scabs reduce the wall thickness of the pipe and, if large enough, can reduce the pressure-carrying capacity of the pipe or component. 4. Cracking can occur at hard spots that eventually grows in size over time. 5. Stress risers can occur at indentations if they are too deep, eventually leading to pipe failure. 6. Transit fatigue cracks are typically discovered during the hydrostatic pressure testing however, some can remain and grow during pipeline pressure cycles until a failure occurs. 7. Can lead to CO₂ leakage. 8. Failure of elastomers and/or polymers could lead to CO₂ leakage.
405	21.03.02.	Pipeline weld defects	<p>Some pipeline weld defects include:</p> <ol style="list-style-type: none"> 1. Pinholes - small, unwelded area extending through the entire thickness of the weld 2. Toe cracks - occur where the crown of the weld bead intersects the edge of the plate in pipe joined using the Double Submerged Arc Welding (DSAW) 3. Off seam welding - crack caused by the inside and outside welds of the DSAW process being offset 4. Undercutting - occurs when there is an inadvertent reduction in the wall thickness in the area of the weld 5. Incomplete fusion - occurs when there is a lack of complete fusion of the weld and the base metal 6. Porosity - occurs when one or more voids are created in the weld material from shrinkage of the material 7. Slag inclusions - exist when non-metallic material becomes trapped in the weld 8. Weld defects in older pipe <ul style="list-style-type: none"> - Burnt pipe edges - Incomplete fusion - Hook cracks - Cold welds 	Weld defects can lead to CO ₂ leakage
406	21.03.03.	Pipeline equipment defects	Equipment failures involve pumps, compressors, valves, meters, tanks, control/relief equipment and other components and devices on pipeline systems. (PHMSA). Can include broken couplings, stripped threads.	Equipment is often located on company property that is not accessible to the public. Equipment failure usually results in a CO ₂ release that is contained on public property, typically not resulting in injury to the general public. (PHMSA)
407	21.04.00.	Pipeline corrosion	About 15% of gas pipeline failures in Europe are caused by corrosion (EGIG 2008)	Corrosion can lead to pipe failure and CO ₂ leakage.
408	21.04.01.	External corrosion	Galvanic corrosion can take place when an unprotected metal pipeline comes in contact with water or soil. <ol style="list-style-type: none"> 1. External corrosion of buried pipe 2. External corrosion of surface pipe 	Corrosion can lead to pipe failure and CO ₂ leakage.

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409	21.04.02.	Internal corrosion	<p>There is potential for rapid corrosion of steel pipeline if free water becomes present in the CO₂ stream. There is currently insufficient data to adequately understand the effect of an accidental flow of high water content CO₂ into a pipeline and also the influence the various CO₂ impurities (O₂, H₂, SO_x, NO_x, H₂S TEG, MEG and amines/NH₃) will have on the corrosion rates. (DNV CO₂PIPETRANS Phase 2).</p> <p>Corrosion rate of carbon steel in dry supercritical CO₂ is low. For AISI 1080 values around 12.5 microns per year have been measured at 9-12 MPa (90-120 bar) and 160-180°C for 200 days. During 12 years, the corrosion rate in an operating pipeline amounted to 0.25-2.5 microns per year.</p>	Corrosion can lead to pipe failure and CO ₂ leakage.
410	21.04.03.	Microbial corrosion	Microbial corrosion is corrosion promoted by microorganisms such as chemoautotrophs which can produce hydrogen sulfide, sulfuric acids, other acids or ammonia. Some bacteria directly oxidize iron to iron oxide or iron hydroxide.	Hydrogen sulfide can cause corrosion and sulfide stress cracking.
411	21.04.05.	Selective seam corrosion	Selective seam corrosion (SSC) is a form of corrosion that tends to affect pipe manufactured prior to 1970 using low-frequency electric resistance welding (LR-ERW) or electric flash welding (EFW) processes. SSC is a localized corrosion attack along the weld bond line of ERW and EFW pipe, that leads to the development of a wedge shaped groove that is often filled with corrosion products. (PHMSA)	Risk for older LF-ERW or EFW pipe, not HF-ERW, DSAW or seamless pipe. (PHMSA)
412	21.0404.	Stress corrosion cracking	Stress corrosion cracking (SCC) is a form of corrosion that produces a marked loss of pipeline strength with little metal loss. The combined influence of pipeline stress due to its pressurized contents and a corrosive medium can occasionally result in the formation of interlinking crack clusters that can grow until the affected pipe fails. (PHMSA)	Stress corrosion cracking can result in pipe failure and CO ₂ leakage.
413	21.05.00.	Pipeline mechanical damage	Mechanical damage consists of dents, gouges, cracks, punctures, stress risers or ruptures.	Mechanical damage of a pipeline can lead to immediate or eventual/accelerated CO ₂ leakage.
414	21.05.01.	Excavation damage	About 50% of pipeline failures in Europe and 33% in the US are caused by excavation damage. Excavation damage can include damage to the external coating of the pipe, or dents, scrapes, cuts, or punctures directly into the pipeline itself. The damage can be caused by any type of excavation, including digging, grading, trenching and boring, road and highway maintenance, general construction and farming activities. It normally occurs when excavators fail to call their local one-call system to mark where underground facilities are located prior to excavating. (PHMSA)	Excavation can lead to pipeline damage and CO ₂ leakage.
415	21.05.02.	Natural force damage	Natural force damage includes damage from landslide, flood, heavy rains, riverbed scouring and washouts, dike breaks, subsidence, earthquakes, high winds, tornadoes, hurricanes, lightning, frost heaves, and frozen instrumentation lines. (PHMSA)	Can lead to unintended movement or abnormal loading of a pipeline resulting in mechanical damage, leakage or rupture.
416	21.05.03.	Other outside force damage	<p>Other outside force damage excludes excavation but include such things as vehicle accident (hitting above ground valve or booster station), electric arcing from nearby power lines, vandalism, sabotage, terrorist attack, theft, fires from other businesses or industries, etc. (PHMSA)</p> <p>Most susceptible to this particular type of damage are above ground pipeline facilities which are in close proximity to highways or large population and industrial centers.</p>	Mechanical damage of a pipeline can lead to immediate or eventual/accelerated CO ₂ leakage.

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417	21.05.04.	Mechanical damage requiring immediate repair	<p>Metal loss greater than 80% of nominal wall thickness.</p> <p>Dent located on the pipeline (above 4 and 8 o'clock positions) that has any indication of metal loss, cracking or a stress riser.</p> <p>Dent located on the pipeline (above 4 and 8 o'clock positions) with a depth greater than 6% of the nominal pipe diameter. (49 CFR Part 195.452)</p>	Mechanical damage can require immediate repair to prevent CO ₂ leakage.
418	21.05.05.	Mechanical damage requiring evaluation and remediation within 60 days of discovery	<p>Dent on the bottom of the pipeline that has any indication of metal loss, cracking or a stress riser.</p> <p>Dent located on the pipeline (above 4 and 8 o'clock positions) with a depth between 3% and 6% of the nominal pipe diameter. (49 CFR Part 195.452)</p>	Mechanical damage can require timely evaluation and remediation to prevent CO ₂ leakage.
419	21.06.00.	Pipeline procurement risks		
420	21.06.01.	Used pipe or old pipe	Used pipe must comply with the same quality requirements as new pipe. Used pipe must not have any mechanical damage (buckles, cracks, gouges, dents) or corroded areas that threaten the integrity of the pipe. (49 CFR Part 195.114).	Use of defective used pipe could result in pipe failure and CO ₂ leakage.
421	21.06.02.	Pipeline valves	Each valve must be of sound engineering design, compatible with pipe and fittings, successfully hydrostatically tested, clearly marked for open and closed positions (except check valves), properly marked (nameplate) and properly sized. (49 CFR Part 195.116)	<p>Defective or off-spec valves could result in valve failure and CO₂ leakage.</p> <p>Wrong sized valves could lead to additional pressure stress or failure.</p>
422	21.06.03.	Pipeline fittings	Fittings must be suitable for the intended service and be at least as strong as the pipe and other fittings in the pipeline system. There may not be any buckles, dents, cracks, gouges or other defects in the fittings that may reduce the strength of the fitting. (49 CFR Part 195.118)	Defective off-spec fittings could result in fitting failure and CO ₂ leakage.
423	21.06.04.	Other pipeline components	<p>Other components such as fabricated branch connections, closures, flange connections, station piping, and fabricated assemblies must meet applicable requirements. (49 CFR Part 195.122-195.130)</p> <p>Materials for bolts and nuts should be same as flange. At least one full thread of bolt should be exposed beyond the nut.</p> <p>Gasket material should be compatible with CO₂.</p>	Defective or off-spec pipeline components could result in component failure and CO ₂ leakage.
424	21.07.00.	Pipeline construction defects	About 16% of gas pipeline failures in Europe are caused by construction defect or material failure. (EGIG 2008)	Construction defects could result in pipeline failure and CO ₂ leakage.
425	21.07.01.	Pipe installation	<p>All pipeline installed in a ditch must be installed in a manner that minimizes the introduction of secondary stresses and the possibility of damage to the pipe. (49 CFR Part 195.246). This is of particular concern in rocky soil. When a ditch for a pipeline is backfilled, it must be done in a manner that provides firm support under the pipe, and prevents damage to the pipe and pipe coating from equipment or from the backfill material. (49 CFR Part 195.252)</p> <p>Pipeline coating can be damaged during installation by laying the pipeline on sharp rocks in the ditch, dropping rocks on it during backfill, rough contact with equipment or abrasion if installing pipe through a bored hole under a road or railroad crossing.</p>	<p>Pipe damage during installation could result in accelerated pipe failure and CO₂ leakage</p> <p>Significant incident rate due to equipment/material/weld failure based on PHMSA CO₂ pipeline data from 1986 - July 2012: 1.34E-04/mile/yr.</p>
426	21.07.02.	Valve and other equipment installation	Valves and other equipment must be properly seated and installed.	Valves that are not properly seated or improperly installed could lead to system failure.

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427	21.07.03.	Pipe bending	Pipe must not have a wrinkle bend. A bend must not impair serviceability of the pipe. Each bend must have a smooth contour and be free from buckling, cracks, or any other mechanical damage. On pipe containing a longitudinal weld, the longitudinal weld must be as practicable to the neutral axis of the bend unless the bend is made with an internal bending mandrel or the pipe is 0.32 m (12.75 in) or less nominal outside diameter or has a diameter to wall thickness ratio less than 70. Each circumferential weld which is located where the stress during bending causes a permanent deformation in the pipe must be nondestructively tested either before or after the bending process. (49 CFR Part 195.212)	Pipe damage during bending could result in accelerated pipe failure and CO ₂ leakage
428	21.07.04.	Pipe welding (See 21.03.02.)	Welding must be performed by a qualified welder in accordance with welding procedures qualified under Section 5 of API 1104 or Section IX of the SASME Boiler and Pressure Vessel Code. Each welding procedure must be recorded in detail, including the results of the qualifying tests. 49 CFR Part 195.214-195.234)	Improper welding procedures could result in CO ₂ leakage.
429	21.07.06	Pipeline underground clearance	Any pipe installed underground must have at least 0.3 m (12 in) of clearance between the outside of the pipe and the extremity of any other structure, except that for drainage tile. (49 CFR Part 195.250).	Insufficient clearance could cause mechanical damage under load.
430	21.07.07.	Pipeline integrity inspection	No pipe or other component may be installed in a pipeline system unless it has been visually inspected at the site of installation to ensure that it is not damaged in a manner that could impair its strength or reduce its serviceability. (49 CFR Part 195.206)	Improper or lack of integrity inspection may fail to discover mechanical damage or defects before CO ₂ is fed to the pipeline.
431	21.07.08.	Protection for above ground components	Above ground components may be installed in areas under direct control of the operator but should be inaccessible to the public. (49 CFR 195.254)	Insufficient protection for above ground components could lead to vandalism, theft and equipment damage by third parties.
432	21.07.09.	Construction records	A complete record must be maintained by the operator for the life of each pipeline facility of girth welds (total, number tested, rejected, disposition), pipe installed (amount, location cover, size), locations of pipeline crossings, utility crossings, overhead crossings, valves, and corrosion test stations. (49 CFR Part 195.266) 1. Lack of final as-built drawings 2. Pipeline location not properly documented 3. Valves and other equipment not properly marked	Incomplete or inaccurate construction records or as-built drawings could result in error or confusion during operation, maintenance or emergency response. Improper documentation of pipeline location can lead to confusion when marking a pipeline location prior to excavation. Failure to properly mark valves and other equipment could lead to improper opening or closing of valves or improper equipment operation and/or maintenance.
433	21.08.00.	Pipeline operation risks		
434	21.08.01.	Operator error in pipeline operation	Operator error can include: 1. Leaving the wrong valve open or closed 2. Not following proper procedures 3. Using improper equipment or techniques to affect a repair 4. Improperly assessing a situation or condition resulting in inappropriate actions or decisions	Potential for pipeline failure and CO ₂ leakage.
435	21.08.02.	Pipeline over pressuring	Maximum operating pressure (MOP) is limited to 80% of pipeline design pressure. Isolating pipework or facilities with dense phase CO ₂ can result in doubling the pressure from 10 to 20 MPa (100 to 200 bar) as temperature raises from 25°C to 40°C.	Isolation of pipeline sections could lead to pipeline over pressuring. Operating the pipeline above maximum operating pressure (MOP) could place the pipeline at risk for failure.
436	21.08.03.	Pipeline re-pressurization	Re-pressurizing a pipeline results in isenthalpic flash across the re-pressurizing valve causing low temperature in the pipeline, no solid CO ₂ formation if the CO ₂ is warm enough. (Anderson 2008).	Low temperature across the re-pressurizing valve

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Line #	Index #	Risk Area/FEP	Description	Relevance
437	21.08.04.	Pipeline depressurization	Rapid depressurization on blowdown of a pipeline can lead to low temperatures (isentropic behavior) and possible solid CO ₂ formation at pressures below 5 bar. (Anderson 2008).	Rapid depressurization of facilities can lead to CO ₂ hydrate formation in vent system, possibly causing blockage and over pressurization. (Anderson 2008). Solidification of CO ₂ could lead to plugging of relief valves. Lowering depressurization rate of a compressor can lead to asphyxiation risk. (Anderson 2008).
438	21.08.05.	Pipeline flow modeling	There is a need for improved understanding of the effect contaminants (O ₂ , H ₂ , SO _x , NO _x , H ₂ S TEG, MEG and amines/NH ₃) have on the phase diagram and behavior of a CCS CO ₂ stream. (DNV CO ₂ PIPETRANS Phase 2) Nitrogen and oxygen in CO ₂ will shift the boundary of the two-phase region toward higher pressures and would require a higher operating pressure to avoid two-phase flow.	Improper understanding of the impact of CO ₂ impurities on the phase diagrams could lead to inaccurate pipeline flow modeling. Inaccurate modeling can cause the computational leak detection system to malfunction.
439	21.08.06.	Boiling liquid expanding vapor explosion (BLEVE)	Boiling liquid expanding vapor explosion (BLEVE) is a type of explosion that can occur when a vessel or pipeline containing a pressurized liquid is ruptured. Such explosions can be extremely hazardous. A BLEVE results from the rupture of a vessel containing a liquid substantially above its atmospheric boiling point. The substance is stored partly in liquid form, with a gaseous vapor above the liquid filling the remainder of the container. If the vessel is ruptured — for example, due to corrosion, or failure under pressure — the vapor portion may rapidly leak, lowering the pressure inside the container. This sudden drop in pressure inside the container causes violent boiling of the liquid, which rapidly liberates large amounts of vapor. The pressure of this vapor can be extremely high, causing a significant wave of overpressure (an explosion) which may completely destroy the storage vessel and project fragments over the surrounding area. (Wikipedia)	Supercritical CO ₂ can have significant density variations with changes in pressure and temperature. If a pipeline ruptures, this could lead to a boiling liquid expanding vapor explosion (Anderson 2008).
440	21.08.07.	Pipeline scheduled maintenance	Typical scheduled maintenance jobs and frequency: Aerial patrols 26 times per year. Population density survey every other year. ROW inspection 26 times per year. Emergency systems tested annually. Rectifier maintenance completed 6 times per year. Cathodic protection survey annually, Internal inspection of pipeline using an electronic tool, every 5 years or more frequently if necessary. Overpressure safety devices checked annually. Public awareness and damage prevention program reviewed annually. (DGC). Inspect each mainline valve twice a year 1. Pipeline cleaning	Failure to properly inspect and maintain the pipeline could lead to pipeline failure and CO ₂ leakage.
441	21.08.08.	Pipeline malfunctions	Some pipeline malfunctions could include: 1. Equipment malfunction or failure 2. Unintended valve closure or shutdown 3. Loss of communication (SCADA system) 4. Power outage 5. Pig stuck in pipeline causing a shutdown	Pipeline malfunctions could lead to unintended shutdown or CO ₂ leakage.

QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA)				
CarbonSAFE Rocky Mountains Phase I, CO ₂ -Storage Subsurface, Surface, Technical and Programmatic Risk Areas				
Line #	Index #	Risk Area/FEP	Description	Relevance
442	21.08.09.	Pipeline leak	<p>Pipeline leaks can include:</p> <ol style="list-style-type: none"> 1. Pinhole leak - small leak (visible due to dry ice forming on the surface) 2. Pipeline puncture small diameter leak 3. Pipeline puncture large diameter leak 	CO ₂ leakage.
443	21.08.10.	Pipeline rupture	Pipeline ruptures consist of a circumferential or longitudinal propagation fracture	CO ₂ leakage.
444	21.08.11.	Pipeline safety measures	<p>Pipeline safety measures can include:</p> <ol style="list-style-type: none"> 1. Emergency response plan 2. Reverse 911 call system - emergency alert 3. One-call system - prior to drilling or excavating 4. Supervision of excavation near pipelines 5. Regular inspection and maintenance of pipeline and ROW 6. CO₂ monitors and alarms at booster stations 7. Oxygen packs at booster stations 8. Fire fighting equipment at booster stations 9. Public emergency response plan 10. Fencing and barricades to protect above ground facilities 11. Markers for ROW, valves and equipment 	Lack of pipeline safety measures could lead to human injury and/or pipeline damage.
445	21.09.05	Pipeline hydraulic testing	Except as otherwise provided in this section ... no operator may operate a pipeline unless it has been pressure tested ... without leakage, (49 CFR Part 195.300-195.310)	Improper or lack of hydraulic testing may fail to discover leaks before CO ₂ is fed to the pipeline.
446	22.00.00.	CO₂ ON-SITE FACILITIES RISKS		
447	22.01.00.	On-site facilities for DSA	<p>On-site facilities for deep saline aquifer (DSA) CO₂ injection can include:</p> <ol style="list-style-type: none"> 1. Injection CO₂ distribution system trunk and laterals 2. Power supply 3. Injection and monitoring wells 4. Onsite CO₂ pumping stations 5. Water treatment facilities. 	Potential problems could include, blowout, equipment failure.

QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA)				
CarbonSAFE Rocky Mountains Phase I, CO ₂ -Storage Subsurface, Surface, Technical and Programmatic Risk Areas				
Line #	Index #	Risk Area/FEP	Description	Relevance
448	22.02.00.	On-site facilities for EOR	<p>On-site facilities for CO₂ enhanced oil recovery (EOR) can include:</p> <ol style="list-style-type: none"> 1. Recycle CO₂ compression system and building 2. Injection CO₂ distribution system trunk and laterals 3. Production gathering system 4. Oil, water and slop storage tanks 5. CO₂ dehydration system 6. CO₂ gas scrubber/knockout drum 7. Flare system 8. Circulation and transfer pumps 9. Instrument air system 10. Control room, motor control center and building 11. Power supply transformers, UPS, PLCs, cables 12. Injection, production, disposal and monitoring wells 13. Water treatment/disposal facilities 14. CO₂ separation and hydrocarbon recovery. 	Potential problems could include blowout, oil leaks/spills ignition/explosion, equipment failure, water quality, water disposal
449	22.03.00.	On-site facilities for ECBM	<p>On-site facilities for CO₂ enhanced coal bed methane (ECBM) can include:</p> <ol style="list-style-type: none"> 1. Recycle CO₂ compression system and building 2. Injection CO₂ distribution system trunk and laterals 3. Production gathering system 4. Water storage tanks 5. CO₂ dehydration system 6. CO₂ capture system - removal of CO₂ from nat. gas 7. Flare system 8. Circulation and transfer pumps 9. Instrument air system 10. Control room, motor control center and building 11. Power supply transformers, UPS, PLCs, cables 12. Injection, production, disposal and monitoring wells 13. Water treatment/disposal facilities 	Potential problems could include blowout, methane leaks ignition/explosion, equipment failure, water disposal.
450	22.04.00.	Injection well components	<p>CO₂ injection well components generally include:</p> <ol style="list-style-type: none"> 1. Wellhead and tree 2. Tubing and casing 3. Safety valve 4. Packer 5. Packer fluid 6. Elastomers 7. Perforations 8. Sand control - for unconsolidated reservoirs 	Component failure could result in CO ₂ leakage.

QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA)				
CarbonSAFE Rocky Mountains Phase I, CO ₂ -Storage Subsurface, Surface, Technical and Programmatic Risk Areas				
Line #	Index #	Risk Area/FEP	Description	Relevance
451	22.05.00.	Injection well materials of construction	<p>steel.</p> <p>Typical materials of construction for EOR CO₂ injection wells include:</p> <ul style="list-style-type: none"> - Upstream metering & piping runs: 316 SS, Fiberglass - Christmas tree (trim): 316 SS, Nickel, Monel - Valve packing and seals: Teflon, Nylon - Wellhead (trim): 316 SS, Nickel, Monel - Tubing hanger: 316 SS, Incoloy - Tubing: fiberglass lined (GRE) carbon steel, internally plastic coated carbon steel, corrosion resistant alloys - Tubing joint seals: Seal ring (fiberglass lined), coated threads and collars (internally plastic coated) - On/off tool, profile nipple: Nickel plated wetted parts, 316 SS - Packers: Internally coated hardened rubber of 80-90 durometer strength (Buna-N), Nickel plated wetted parts - Cements and cement additives: API cements and/or acid resistant specialty cements and additives - Production liner 316 SS, Incoloy - Casing: carbon steel J-55 and K-55 grades; corrosion resistant alloy used in intervals where potential potable water aquifers exist or where H₂S is present (Meyer 2007) Elastomers - Teflon or nylon have been used to prevent swelling 	<p>Corrosion can occur when tubulars are exposed to wet CO₂.</p> <p>Sufficient quantities of H₂S in CO₂ can cause corrosion or sulfide stress cracking. (CCP 2009)</p> <p>The reservoir fluid affects corrosivity near the wellbore and compaction resistance where formation dissolution has occurred. In significant dissolution cases, the well tubulars must be designed to resist column buckling in the injection interval. (CCP 2009)</p> <p>CO₂ phase behavior can impact velocity. High velocity of injection can cause erosion to materials exposed to the CO₂ stream (CCP 2009)</p>
452	22.05.01.	Elastomer seals	<p>Since supercritical CO₂ is a solvent, many elastomers, plastics, rubber, or resins present in a well could be subject to chemical attack or dissolution. When designing a CO₂ injector, material should be based on performance expectations.</p> <p>Elastomers, in particular, are a common part of well hardware used to seal different components. Elastomers must be made of material that is chemically compatible or inert to the injection fluid and must be of sufficient strength or adequately anchored to withstand the different pressure and explosive decompression that might exist across a seal. Since the physical and performance characteristics of many elastomer materials change with pressure and temperature, the elastomer must be able to perform reliably across the full range of differential pressures and temperatures expected through the design life of the well at the location of the seal within the well. (CCP 2009)</p> <p>Teflon or nylon have been used for seals to prevent swelling. (Meyer 2007).</p>	Elastomer seal failure can result in CO ₂ leakage.
453	22.06.00.	Injection well safety precautions	<p>Safety precautions for injection wells include:</p> <ol style="list-style-type: none"> 1. Casing corrosion protection <ul style="list-style-type: none"> - Impressed and passive currents - Oxygen, biocide corrosion inhibiting chemicals 2. Gentle handling to prevent damage to tubing coatings 3. Casing leak detection testing 4. Fencing, monitoring and atmospheric dispersion monitoring if near populated areas 5. Automatic shutdown controls for unsafe conditions 	Lack of safety precautions can lead to greater risk of CO ₂ leakage

QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA)				
CarbonSAFE Rocky Mountains Phase I, CO ₂ -Storage Subsurface, Surface, Technical and Programmatic Risk Areas				
Line #	Index #	Risk Area/FEP	Description	Relevance
454	22.07.00.	Production well submersible pump	While normally very reliable, the submersible pump in an EOR or ECBM production well can fail.	Failure of the submersible pump can result in operating delays and maintenance costs.
455	22.08.00.	Production well materials of construction	Production wells tend to be exposed to mixtures of CO ₂ , brine, hydrocarbons (oil and/or gas) and stripped gases such as H ₂ S. Production wells may also be exposed to hydrocarbon (asphaltene, paraffin or polyaromatic) deposition. Teflon coating has proven to help reduce hydrocarbon deposition. Scale buildup may also be a problem depending on brine chemistry.	The produced mixtures can be very corrosive. Hydrocarbon deposition or scale buildup may cause significant down time for cleaning out.
456	23.00.00.	CO₂ MONITORING RISKS		
457	23.01.00.	Data acquisition activities at the well	Activities include logging, drill stem tests, coring, hydrophone installation, etc.	May include some activities and procedures that are less familiar. Some techniques could limit other MMV techniques.
458	23.02.00.	Data acquisition activities away from the well	Many activities and procedures will be effectively new and newly trained for. Some monitoring techniques could present risk or barriers to the application or success of other techniques.	Off-site monitoring activities may incur risk of physical accidents and may make the project publicly prominent.
459	23.03.00.	Data acquisition conflicts	Data acquisition may involve many techniques including logging, fluid sampling, coring, surface and downhole geophones, surface seismic, surface air measurements, groundwater sampling, and others.	Use of some monitoring techniques can preclude or limit the applicability of other techniques.
460	23.04.00.	Seismic surveys	Vertical resolution of seismic imaging is inherently limited such that features less than 10 m thick can rarely be discerned. (CCP 2009) Subsurface CO ₂ is not seismically resolvable. Limited or absence of plume images via seismic. Seismic readings may be compromised by vibration from nearby heavy industrial facilities. 1. 2-D seismic survey 2. 3-D seismic survey 3. 4-D seismic survey 4. Vertical seismic profile (VSP)	Seismic techniques unable to pick up subsurface features or track CO ₂ plume.
461	23.05.00.	Gravity surveys	As a notional rule of thumb, CO ₂ filled reservoirs with less than 10% porosity, thicknesses of less than 10 m and depths greater than 2,500 m will be very difficult to resolve even with the best gravity data and mathematical inversion techniques. (CCP 2009) Current available standard gravimeters are capable of making repeat measurements valid to about 5 micro-gals. Fixed seal-floor gravimeters are essentially capable of the same. (CCP 2009) Corrections for motion are required for gravity data acquired from moving vessels. A change of only 1 cm of elevation will yield a difference of 3 micro-gals. Studies of oil fields have found that fixed permanent surface gravity monuments (i.e. stations) are essential to maximize repeatability (CCP	Gravity surveys unable to detect CO ₂ movement

QUANTITATIVE FAILURE MODES AND EFFECTS ANALYSIS (QFMEA)				
CarbonSAFE Rocky Mountains Phase I, CO ₂ -Storage Subsurface, Surface, Technical and Programmatic Risk Areas				
Line #	Index #	Risk Area/FEP	Description	Relevance
462	23.06.00.	InSAR surveys	InSAR is the current state-of-the-art satellite platform radar based technique to measure vertical ground elevations and relative elevation changes with time. (CCP 2009) Validation studies have shown that uplifts of 1-3 mm can be reliably and repeatedly measured when sites make use of special corner reflectors for calibration purposes. (CCP 2009)	InSAR may be unable to accurately measure vertical ground elevations and relative elevation changes over time due to high seasonal vegetation growth.
463	23.07.00.	Well monitoring	Well monitoring for CO ₂ storage seeks confident validation that: - Cement integrity and bond is maintained - Pressure isolation barriers are maintained and functioning - Corrosion is being controlled - The CO ₂ injection profile is being maintained - Barriers after plug and abandonment provide confidence. (CCP 2009)	Unexpected well failure due to lack of well monitoring.
464	23.07.00.	General monitoring risks	1. Weather conditions prevent using a monitoring method or retrieving data at a critical point in time 2. Injection site terrain too rugged for surface monitoring 3. Monitoring equipment not properly calibrated 4. Inappropriate monitoring suggests a false alarm for issues that do not exist (CCP 2009) 5. Inappropriate monitoring suggests a false sense of security (CCP 2009) 6. Difficulty of geophysical techniques monitoring below salt caprocks (CCP 2009) 7. Ineffective monitoring 8. Insufficient monitoring 9. Lack or loss of monitoring records 10. Accidental damage or breakdown of custom-made equipment, sensors or tools - repair/replacement delays and irretrievable data loss. 11. Conflicting results from different monitoring techniques. 12. Difficulty of monitoring stacked injection plumes	Ineffective or lack of monitoring can result in missed data. This leads to inadequate engineering control, raising costs and leakage risks; yields insufficient documentation to establish CO ₂ storage credits, etc.
465	23.08.00.	Pre-closure monitoring of storage (02.01.07.00.)	Processes related to any monitoring undertaken during the operational and closure phase. The extent and requirement for such monitoring activities may be determined by issues such as storage concept, geological setting, regulations, or public pressure. A number of monitoring techniques exist including seismic data, electrical resistance, soil gas and isotopic characteristics.	Monitoring during the operational phase contributes towards the amount and quality of information initially available after closure concerning the behavior and distribution of sequestered CO ₂ .
466	23.09.00.	Post-closure monitoring of storage	FEPs related to any monitoring undertaken during the post-closure phase. This includes monitoring of parameters related to the long-term safety and performance. The extent and requirement for such monitoring activities may be determined by issues such as storage concept, geological setting, regulations, or public pressure. A number of monitoring techniques exist including seismic data, electrical resistance, soil gas and isotopic characteristics.	Post-closure monitoring will provide information regarding the performance of the sequestration project and may trigger post-closure remedial actions, if necessary.



Rocky Mountain CarbonSAFE Phase I

Appendix K

Legal, Regulatory, and Liability Assessment CarbonSAFE Rocky Mountain Phase I

Legal, Regulatory, and Liability Assessment CarbonSAFE Rocky Mountain Phase I

Lincoln Davies,^I John Ruple,^{II} Candace Cady,^{III} Thomas Kessinger,^{IV} and Lisa Sledge^{IV}

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I. INTRODUCTION

Prior analyses have identified a wide variety of legal, regulatory, and other hurdles that Carbon Capture and Sequestration (CCS) projects may face. Many of these studies suggest that what limits CCS deployment is not always legal or regulatory in nature. Several early studies, for instance, suggested that the lack of commercial-scale CCS demonstration projects act as a key constraint on societal appetite for CCS generators.¹ However, subsequent research revealed that technology demonstration tends not to be the key impediment to commercial-scale CCS development. Rather, a 2013 survey of more than 200 experts² in the United States revealed that there are four key barriers to CCS commercialization:

- (1) cost and cost recovery;
- (2) the lack of price signal or financial incentive for using CCS;
- (3) liability risks; and
- (4) an overall lack of comprehensive CCS regulation.³

The 2013 study provided important context to the legal, regulatory, and social barriers that, at a broad scale, CCS projects face. Specifically, it showed that, above all else, the cost of CCS—including the energy penalty that CCS imposes on electricity generation as well as public resistance to higher energy prices—is the greatest impediment facing commercial-scale CCS deployment. Following cost, the experts surveyed in the 2013 study suggested that the lack of any clear price signal or other financial incentive for CCS use, such as a carbon tax or greenhouse gas cap-and-trade system, is the second most significant barrier to CCS commercialization. Following cost and the lack

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¹ *See generally, e.g.*, CARNEGIE-MELLON UNIV., DEPARTMENT OF ENGINEERING AND PUBLIC POLICY, CARBON CAPTURE AND SEQUESTRATION: FRAMING THE ISSUES FOR REGULATION, AN INTERIM REPORT FROM THE CCSREG PROJECT (2009); PETER FOLGER, CONG. RESEARCH SERV., CARBON CAPTURE AND SEQUESTRATION (CCS) (2009); GOV'T ACCOUNTABILITY OFFICE, REPORT TO THE CHAIRMAN OF THE SELECT COMMITTEE ON ENERGY INDEPENDENCE AND GLOBAL WARMING, HOUSE OF REPRESENTATIVES: FEDERAL ACTIONS WILL GREATLY AFFECT THE VIABILITY OF CARBON CAPTURE AND STORAGE AS A KEY MITIGATION OPTION (2008); INT'L ENERGY AGENCY, CARBON CAPTURE AND STORAGE: PROGRESS AND NEXT STEPS (2010); LARRY PARKER ET AL., CONG. RESEARCH SERV. CAPTURING CO₂ FROM COAL-FIRED POWER PLANTS: CHALLENGES FOR A COMPREHENSIVE STRATEGY (2009); WORLD RESOURCES INST., OPPORTUNITIES AND CHALLENGES FOR CCS (2007).

² These experts consisted of with experience as CO₂ emitters, CCS operators, consultants, regulators, researchers, and nonprofit organizations relevant to CCS.

³ Lincoln L. Davies et al., *Understanding Barriers to Commercial-Scale Carbon Capture and Sequestration in the United States: An Empirical Assessment*, 59 ENERGY POL'Y 745, 749 (2013).

of a price signal, those respondents found the most significant barrier to CCS to be liability risks associated with CO₂ storage, followed by the lack of an overall CCS regulatory framework.⁴

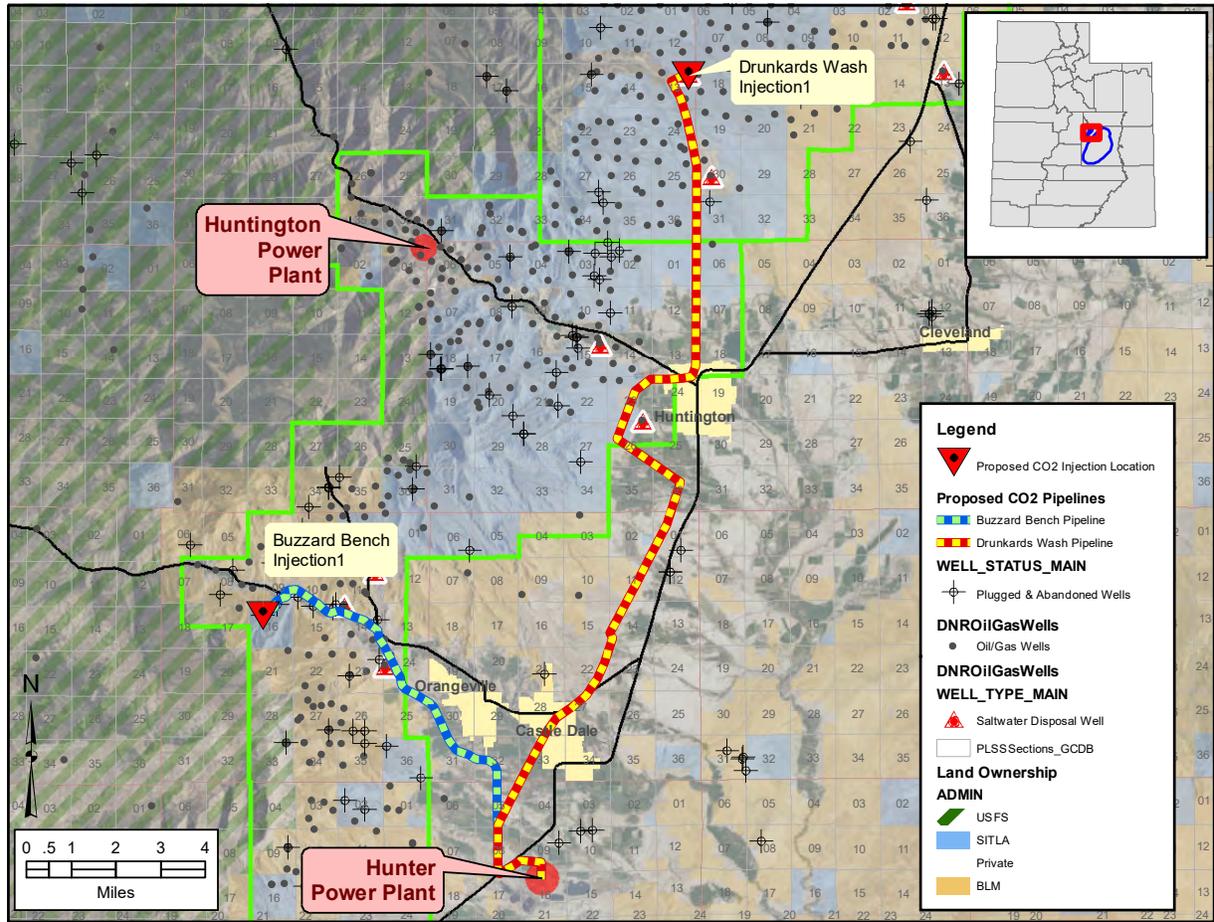


Figure 1. CarbonSAFE Rocky Mountain Location Map

This report seeks to identify the legal and regulatory structure that will govern development of any commercial-scale CCS project, including potential gaps in the legal and regulatory scheme. It does so in the context of the potential CarbonSAFE Rocky Mountain project, which would capture CO₂ from Rocky Mountain Power’s Hunter or Huntington power plants and geologically store the CO₂ in the geographically proximate Navajo sandstone saline formation. A rough schematic of the proposed project, as it is currently envisioned and on which this analysis is based, is shown below as Figure 1. The analysis herein is by necessity conceptual. It identifies and details overarching categories of applicable law and regulation, because more concrete application of that law to the

⁴ Subsequent research has broadly confirmed the 2013 study’s results. In a 2017 study, researchers evaluated expert views of CCS risk perception in three European countries. Perceived barriers across countries and experts included the high cost of implementing technologies, the slow development of policy and regulation, the absence of storage sites, and general liability. *See generally* Farid Karimi & Nadejda Komendantova, *Understanding Experts’ Views and Risk Perceptions on Carbon Capture and Storage in Three European Countries*, 82 GEOJOURNAL 185 (2017).

proposed project cannot be achieved until the specific contours and location of the project are delineated following more in-depth geologic analysis, at a later date.

CCS occurs in three industrial segments: first, *CO₂ capture*; second, *CO₂ transport*; and, finally, *CO₂ storage*. Consistent with the scope of this Phase I study, this portion of the report addresses legal, liability, and regulatory barriers for transport and storage.

This section of the report is organized as follows. It first addresses use of the land necessary for both CO₂ transport and storage, including surface land use, subsurface use, and Bureau of Land Management (BLM) regulation.⁵ It then discusses potential liability associated with geologic storage of CO₂ as part of CCS technology, including permitting under the Safe Drinking Water Act (SDWA). Because the proposed CarbonSAFE Rocky Mountain project is proximate to federal land and will likely require federal permits, we then discuss application of the National Environmental Policy Act (NEPA). Finally, other generally applicable legal and regulatory requirements are discussed, along with key lessons learned from parallel CCS projects.

II. LAND USE

Both surface and sub-surface access for CCS potentially implicate three general categories of land ownership near the CarbonSAFE Rocky Mountain project: privately owned lands, state owned lands, and federally owned lands. Surface uses include pipeline access connecting the CO₂ source to the injection site, as well as the injection site itself and associated infrastructure. Sub-surface use includes permanent geologic CO₂ sequestration within the receiving geologic formation, which is defined spatially by the extent of the CO₂ plume. We address surface and sub-surface rights in turn, for each type of ownership category, followed by general discussions of pore space ownership for the CarbonSAFE Rocky Mountain project as well as how to acquire access to such rights, including by negotiation (leasing, easement, or purchase) or exercise of governmental authority (eminent domain).

A. Surface Land Use

As noted, three different types of landowners possess surface property rights near the proposed CarbonSAFE Rocky Mountain project: private, state, and federal. Acquiring rights to use the surface of land owned or managed by these entities will necessarily involve different processes.

1. Private Ownership

Private landowners are generally free to alienate all or some subset of the rights that they hold. In the law, property often is referred to as a “bundle of sticks.” This means that a landowner may sell, lease, or otherwise grant rights to the use of the surface estate while still retaining overall ownership of the property. With respect to the CarbonSAFE Rocky Mountain project, then, if access is needed to privately owned surface lands, negotiated transactions would likely need to be used, particularly since eminent domain authority has not been developed fully in the CCS context, and the cost of such proceedings would likely be prohibitive both financially and in terms of potential project delays.

2. State Ownership

The Utah School and Institutional Trust Lands Administration (SITLA) manages most, if not all, of Utah’s surface and sub-surface estate within the vicinity of the proposed CarbonSAFE Rocky Mountain project area. State law provides mechanisms for the sale of state lands, but

⁵ CarbonSAFE Rocky Mountain is not anticipating use of the surface of National Forest System land.

obtaining a lease or easement would likely be a more efficient solution. With respect to pipelines transmitting CO₂ from the power plant to the injection site, rights-of-way may already be in place, depending on what transport path is selected. An existing easement could presumably be amended to accommodate additional pipeline infrastructure. Alternatively, a new easement could also be acquired.

3. Federal Ownership

The process for acquisition of rights to utilize federally managed surface resources is relatively well-defined. Indeed, over the last several decades, the Department of the Interior promulgated an extensive series of regulations that makes securing a surface lease or utility right-of-way on the type of federal lands proximate to the proposed CarbonSAFE Rocky Mountain project comparatively routine.

All federal lands (both surface and sub-surface) within the project area are believed to be under BLM administration. The Federal Land Policy and Management Act⁶ (FLPMA) requires the BLM to “prepare and maintain on a continuing basis an inventory of all public lands and their resource[s].”⁷ Based on this inventory, the BLM must “develop, maintain, and, when appropriate, revise land use plans which provide by tracts . . . for the use of the public lands.”⁸ These plans, commonly referred to as Resource Management Plans (RMPs), establish the management direction for a defined region of public land, although in practice such regions can be quite large, covering millions of acres. Critical RMP decisions include, among other things, which lands will be available for mineral development, which lands will be managed to emphasize resource protection, and what management stipulations are required to balance BLM’s multiple use and sustained yield mandates across the federal landscape.⁹

The Price RMP applies to the CarbonSAFE Rocky Mountain project area and was most recently revised in 2008. It contains management stipulations applicable to lands proximate to both the primary and secondary injection sites of the CarbonSAFE Rocky Mountain project, likely pipeline corridors and the injection site(s). The Price RMP contains mapped management stipulations for approximately eighty different resources. As RMP consistency is a central focus of any BLM lease or right-of-way approval, we reviewed¹⁰ the requirements contained in the Price RMP applicable to both the primary and secondary project sites.¹¹

⁶ 43 U.S.C. §§ 1701–1787 (2012).

⁷ *Id.* § 1711(a).

⁸ *Id.* § 1712(a).

⁹ *Id.* § 1701(a)(7).

¹⁰ To conduct the review, we mapped the approximate location of the Hunter and Huntington power plants, the primary and secondary injection sites, and the approximate route for a pipeline connecting the power plants with the associated injection site. We then compared those maps with resource maps contained in the Price RMP and identified the resources most likely to constrain project development. Only those resource that were identified as likely to impact project development are addressed here.

¹¹ As noted, our analysis is by necessity conceptual in nature, which is particularly pertinent with respect to BLM permitting. As the location and contours of the CarbonSAFE Rocky Mountain project are more clearly defined via further geologic study, evaluation of the applicable RMP will need to be updated based on that more detailed information, once that information becomes available and is needed for use, such as in a Phase II study of the proposal. CCS operators should also bear in mind that not all management constraints can be mapped at the scale or resolution considered in an RMP. Project proponents should meet with BLM officials to identify any additional constraints that may exist prior to project implementation and development.

4. *Hunter Power Plant (Primary CO₂ Source)*

The Hunter Power Plant is located on privately owned lands south of the town of Castle Dale. CO₂ injection and geologic sequestration would likely occur west of Castle Dale, at the Buzzards Bench site. Injection is likely to occur on state trust lands that are surrounded by BLM-managed public lands. CO₂ would be transported via pipeline as shown in Figure 1. Further investigation will be needed to confirm that this right-of-way could serve the project. Alternatively, CO₂ could be piped to the Drunkards Wash oil field approximately eighteen miles to the north, also as shown in Figure 1. Lands proximate to the Drunkards Wash injection site are largely managed by SITLA, with a parcel of BLM-managed lands existing immediately east of the injection site. The Drunkards Wash site is discussed in more detail below, in conjunction with the Huntington Power Plant.

The RMP includes oil and gas surface use stipulations that are uniquely important to the project, as these stipulations apply much more broadly than their name might suggest. The RMP explains:

The Approved RMP specifies restrictions for permitted activities to resolve concerns regarding the impacts of these uses. These conditions apply not only to oil and gas leasing, but also apply, where appropriate, to all other surface disturbing activities associated with land-use authorizations, permits, and leases, including other mineral resources.¹²

BLM-managed lands in the Buzzards Bench area are generally open to mineral development under “standard lease terms and conditions” or under “minor constraints.”¹³ Standard lease terms and conditions are the least restrictive category of stipulations and allow the BLM to require the operator to move proposed facilities by up to 200 meters and prohibit new surface disturbing operations for up to sixty days per year.¹⁴ “Minor constraints” may include timing limitations, controlled surface use stipulations, or lease notices that could result in a cumulative timing limitation of three to six months.¹⁵

The BLM applies a Visual Resource Management classification system to describe limits on visual impacts allowed across the landscape. Lands near Buzzards Bench are subject to Class 3 and Class 4 stipulations, which are generally facilitative of more intensive forms of development. Class 4 areas are managed to “provide for management activities which require major modification of the existing character of the landscape. The level of change to the characteristic landscape can be high.”¹⁶ The BLM manages Class 3 areas to “partially retain the existing character of the landscape. The level of change to the characteristic landscape should be moderate.”¹⁷

With respect to ecological considerations, few riparian areas are identified in the RMP as proximate to the injection site, with the exception of two riparian areas north of Orangeville and one riparian area west of Castle Dale. Impacts to riparian areas, wetlands, and waters of the United States

¹² BUREAU OF LAND MGMT., DEP’T OF THE INTERIOR, PRICE FIELD OFFICE RECORD OF DECISION AND APPROVED RESOURCE MANAGEMENT PLAN 40 (2008) (hereinafter the Price RMP).

¹³ *Id.* at Maps R-24 and R-26.

¹⁴ 43 C.F.R. § 3101.1-2 (2017).

¹⁵ Price RMP, *supra* note **Error! Bookmark not defined.**, at Map R-26.

¹⁶ *Id.* at Tbl. 3-12.

¹⁷ *Id.* at Map R-5.

are regulated under the Clean Water Act and may require additional permitting. Care should be taken to identify all wetland areas, surface waters, and intermittent drainages; to avoid such areas whenever possible; and to obtain appropriate permits for unavoidable impacts. Given the resolution of mapping contained in the RMP, CCS operators should not assume that RMP mapping of aquatic resources is complete or accurate.

Lands west of the Buzzards Bench injection site are characterized by a mix of sagebrush and Pinyon-Juniper cover. These lands provide mule deer habitat that is mapped as part of the Big Game Crucial Habitats layer contained in the Price RMP.¹⁸ The Price RMP does not identify either winter habitat or crucial value nesting or brood rearing habitat for the greater sage grouse in the general area.¹⁹ No crucial year-long white-tailed prairie dog habitat has been identified in the area.²⁰ Similarly, the Price RMP does not identify any designated critical habitat for threatened or endangered species, or state wildlife management areas in the immediate vicinity of Castle Dale.²¹ Areas of Critical Environmental Concern, Wilderness Study Areas, and Non-WSA Lands with Wilderness Characteristics have not been identified in the Orangeville area.²²

5. *Huntington Power Plant (Secondary CO₂ Source)*

The Huntington Power Plant, considered the secondary source for this proposed project, is located north of the Hunter Power Plant and northwest of the town of Huntington. The Huntington Power Plant is located on private land and ringed by private and SITLA-managed lands. The approximate CO₂ injection site is roughly thirteen miles northeast of the power plant, in the Drunkards Wash oil field. Lands proximate to the injection site are largely managed by SITLA, with a BLM-managed lands existing largely to the east of the injection site.

The Price RMP identifies a utility corridor extending to the southeast from the approximate location of the Huntington Power Plant, to points south and southwest of the town of Huntington. From there, rights-of-way extend to the northeast along Utah State Highway 10, and due north.²³ Either route could provide access to the Drunkards Wash Field, though transport distances would increase significantly over those associated with the Hunter Power Plant.

There is generally less BLM-managed land proximate to the Huntington Power Plant compared to the Hunter Power Plant. What BLM-managed lands do exist near the Drunkards Wash injection site are generally managed under “minor” surface constraints that could limit surface-disturbing activities for three to six months of the year.²⁴ Visual Resource Management stipulations for BLM-managed lands due east of the likely injection site are unlikely to pose a constraint, as they are managed to “provide for management activities which require major modification of the existing character of the landscape. The level of change to the characteristic landscape can be high.”²⁵ The Price RMP identifies riparian habitat near the likely injection site and, as with the Hunter Power Plant site, care should be taken to identify and avoid wetlands, surface waters, and intermittent drainages. Where these features cannot be avoided, additional permitting will be required.

¹⁸ *Id.* at Map R-8.

¹⁹ *Id.* at Map R-6.

²⁰ *Id.* at Map R-9.

²¹ *Id.* at Map R-7.

²² *Id.* at Maps R-11, R-28, and R-29.

²³ *Id.* at Map R-21.

²⁴ *Id.* at Maps R-25 and R-26.

²⁵ *Id.* at Map R-5.

The Huntington-Drunkards Wash area is classified as crucial habitat for both Rocky Mountain Elk and Mule Deer. This habitat extends from the Huntington Power Plant to the likely injection site.²⁶ CCS operators should consider ways to avoid, minimize, and mitigate unavoidable wildlife habitat impacts as they develop project plans. Crucial year-long habitat for white-tailed prairie dogs has been identified to the north of the likely CO₂ injection site.²⁷ The Price RMP does not identify greater sage grouse habitat near the likely injection site,²⁸ nor does it identify any designated critical habitat for threatened or endangered species or state wildlife management areas in the immediate vicinity of Orangeville.²⁹ As noted above, areas of Critical Environmental Concern, Wilderness Study Areas, and Non-WSA Lands with Wilderness Characteristics have not been identified in the area.³⁰

6. Greater Sage Grouse

Greater sage grouse pose an additional federal land use issue that is relevant to both the primary site and the secondary site. The greater sage grouse is a chicken-sized bird that lives in sagebrush steppe environments across the western United States. Greater sage grouse populations have declined precipitously, prompting a call to list the greater sage grouse under the Endangered Species Act (ESA). Faced with a court-ordered deadline to act on an ESA listing petition, and fearing that a listing decision could severely impact extractive industries across the West, a host of state and federal agencies developed a series of land use restrictions intended to protect the bird and preclude the need for ESA listing. These efforts were successful, culminating in a 2015 U.S. Fish and Wildlife Service (FWS) decision that ESA listing was not needed because other state and federal government actions adequately protect the bird.³¹ Relevant to this project, the BLM and the U.S. Forest Service issued programmatic amendments to all land and resource management plans within the state of Utah. The state of Utah also issued its own greater sage grouse management plan.

Greater sage grouse are known to inhabit lands in the vicinity of both the primary and secondary sites. Maps of greater sage grouse conservation areas that are contained in the programmatic amendments to BLM and Forest Service planning documents, however, lack the resolution needed to determine the extent of the constraint that the greater sage grouse could impose on the proposed CarbonSAFE Rocky Mountain project. While it is likely that greater sage grouse habitat could be avoided (if it exists within the project area), care must be taken to further evaluate this issue as more information becomes available relevant to pipeline and well locations. State protections for the greater sage grouse should also be considered, as they would apply on state and private land, including those in the vicinity of the secondary injection site.

Federal greater sage grouse management efforts are currently subject to litigation and are also undergoing administrative review that may result in less onerous protections. These administrative efforts will take several years and are likely to be mired by litigation, if they proceed at all. Proponents acting in areas with known greater sage grouse habitat are therefore advised to avoid habitat impacts to the extent possible.

Congress has temporarily prohibited the Fish and Wildlife Service from expending funds on the promulgation of a rule that lists the greater sage grouse under the ESA. While this prohibition is likely to remain in effect during the current Congress, there is no guarantee that these prohibitions

²⁶ *Id.* at Map R-8.

²⁷ *Id.* at Map R-9.

²⁸ *Id.* at Map R-6.

²⁹ *Id.* at Map R-7.

³⁰ *Id.* at Maps R-11, R-28, and R-29.

³¹ 80 Fed. Reg. 59858 (Oct. 2, 2015).

will persist in perpetuity. The lowest risk course of action, therefore, is to avoid greater sage grouse habitat.

7. *The Emery County Lands Bill*

On May 21, 2018, Representative John Curtis of Utah introduced House Resolution 5727, which would establish the 336,467-acre San Rafael Swell Western Heritage and Historic Mining National Conservation Area, designate 529,146 acres of wilderness within Emery County, create the Jurassic National Monument, and provide for certain conveyances of federal land to the state of Utah. The Hunter drill site is approximately twenty-miles west of the proposed National Conservation Area (NCA). The Drunkards Wash drill site is approximately twelve miles to the east of the proposed Candyland Mountain Wilderness Area, and approximately seventeen miles west of the proposed Jurassic National Monument.

The Emery County Lands Bill has not advanced to a vote and the likelihood of passage is uncertain. If the bill passes, there is significant distance between all CarbonSAFE Rocky Mountain facilities and the protective designations proposed under the bill. The CarbonSAFE team should, nonetheless, pay close attention to this pending legislation. Federal land management decisions within Utah attract significant attention and often prove to be very contentious. The San Rafael Swell has long been considered a potential site for a national monument designation, and the conservation community will likely oppose any development that they perceive as threatening resources within the Swell, including threats posed by visual or auditory impacts.

While direct impacts to the San Rafael Swell appear unlikely to result from implementation of the CarbonSAFE Rocky Mountain project, perceptions and fears or adverse impacts may necessitate careful articulation of how the project was designed to avoid impacting resources within or near the Swell. The CarbonSAFE team should also anticipate that intense public scrutiny will be directed towards this project.

B. Subsurface Land Use

In addition to use of surface land for CO₂ transport and injection, CCS projects also implicate use of the subsurface. These issues are somewhat more complicated than the surface land issues. Typically, the question boils down to ownership of the subsurface lands. However, this ownership question can be complicated for a variety of reasons. First, a situation may arise where there is a different owner of the surface land than the subsurface land—a situation known as the “split estate” question. Second, the subsurface estate itself may be subdivided further into component estates based on the existence of specific minerals or other geological characteristics. Third, the subsurface owner may have leased some or all of the subsurface estate, potentially creating overlapping mineral interests. Ownership of the subsurface estate often is referred to as ownership of the “pore space”: the “spaces within a rock body that are unoccupied by solid material.”³² This is the portion of the subsurface that geologically stored CO₂ will occupy.

Historically, property rights have been referred to as “sticks” in a “bundle” of various rights.³³ Different rights can be separated from each other in a legal sense; each such right is referred

³² *Definition: Pore Space*, www.idahogeology.org/services/hydrogeology/portneufgroundwaterguardian/my_aquifer/vocab/vocab_text/pore_space.html (last visited Jul 29, 2017).

³³ See M. GRANGER MORGAN & SEAN T. MCCOY, CARBON CAPTURE AND SEQUESTRATION 95 (2012).

to as a “stick” in the overall “bundle” of property rights, and it is appropriate to look at pore space ownership as its own “stick” in the property bundle.³⁴

Generally, the owner of a fee simple estate (*i.e.*, full ownership of the surface and sub-surface land) will own the pore space beneath their land.³⁵ This is an application of the *ad coelum* doctrine, which historically stood for the proposition that an owner of a surface estate owns from the depths of the earth to the extent of the universe. As society has evolved, courts have recognized limits on the *ad coelum* doctrine. For instance, courts typically now place a ceiling on the ownership of a surface owner’s airspace. However, judicial decisions have not attempted to place a floor on the ownership of the subsurface estate underlying a fee-simple property owner’s land. Therefore, generally, the owner of a fee-simple estate will own the pore space that lies underneath a given tract of land.

This quickly becomes murkier in split estate or competing use issues, situations very familiar to the oil and gas arena. Split estates are created “when the surface estate and all or part of the mineral estate in a particular parcel are not owned by the same party.”³⁶ Internationally, the majority of countries reserve ownership of the mineral and other subsurface estates to the sovereign government. In the United States, however, there is widespread private ownership of subsurface estates.³⁷ The rise in usage of pore space outside of the context of CCS necessitated resolution first in the courts and later, in a minority of states, by legislation. Typically, two distinct rules guide the analysis for resolving split estate questions: the American Rule and the English Rule. Understanding these rules is important because ownership of pore space is not a settled issue, particularly with respect to ownership of pore space for CCS.³⁸

1. *The American Rule*

The American Rule cleaves the mineral estate from the pore space,³⁹ regardless of whether they are physically bound together, and vests ownership of the pore space with the surface estate owner.⁴⁰ This rule developed through applying common maxims used to determine the ownership of the subsurface generally.⁴¹ These maxims include the *ad coelum* doctrine, the narrow drafting of conveyances and narrow interpretation of those conveyances by courts,⁴² and a presumption of a

³⁴ See Trae Gray, *A 2015 Analysis and Update on U.S. Pore Space Law—The Necessity of Proceeding Cautiously With Respect to the “Stick” Known as Pore Space*, 1 OIL & GAS, NAT. RESOURCES & ENERGY J. 277, 279 (2015).

³⁵ See MORGAN & MCCOY, *supra* note 33, at 95

³⁶ Kendor P. Jones et al., *Split Estates and Surface Access Issues*, in LANDMAN’S LEGAL HANDBOOK, ch. 9 (Rocky Mt. Min. L. Fdn., 5th ed. (2013)).

³⁷ *Id.*

³⁸ This report draws heavily from MORGAN & MCCOY, *supra* note 33; Alexandra B. Klass & Elizabeth J. Wilson, *Climate Change, Carbon Sequestration, and Property Rights*, 2010 U. ILL. L. REV. 363, 381 (2010); STEFANIE L. BURT, WHO OWNS THE RIGHT TO STORE GAS: A SURVEY OF PORE SPACE OWNERSHIP IN U.S. JURISDICTIONS (2012); and Gray, *supra* note 34.

³⁹ *Ellis v. Arkansas Louisiana Gas Co.*, 450 F. Supp. 412, 421 (1978), *aff’d*, 609 F.2d 436 (10th Cir. 1979).

⁴⁰ This principle is likened to excavating a basement. If party A contracts with party B to remove the dirt underneath a tract of land owned by party A, party B does not obtain title to the newly created space. Accordingly, the owner of a mineral estate cannot lay claim to the pore space they create after extraction of gas or other mineral deposits, or even when the space is naturally occurring rather than created through extraction. See, e.g., *Burlington Res. Oil & Gas Co., LP v. Lang & Sons Inc.*, 259 P.3d 766, 771 (Mont. 2011).

⁴¹ See Owen L. Anderson, *Geologic CO₂ Sequestration: Who Owns the Pore Space?*, 9 WYO. L. REV. 97 at 99–100 (2009); see also MORGAN & MCCOY, *supra* note 33, at 95–96.

⁴² See *Ellis*, 450 F. Supp. at 420.

reservation of rights by surface holders when they are not expressly conveyed or necessary to reduce and capture a given mineral resource.⁴³

Because no court has dealt with the issue of pore space solely in the CCS context, application of the American Rule to CCS must be guided by other subsurface storage uses, such as natural gas storage. The case of *Ellis v. Arkansas Louisiana Gas Co.* provides an example⁴⁴ There, the court was asked to determine from whom a natural gas storage injector needed to obtain permission to store its natural gas, where a split estate existed. Plaintiffs owned seventy-eight acres of a surface estate in Oklahoma.⁴⁵ The mineral estate had been severed through a series of deeds. The gas reservoir had been depleted, so the mineral estate holder had been using the reservoir to store gas. The court held that the surface estate owned the subsurface pore space created by the depleted gas reservoir. This was because the legal instruments that severed the mineral estate conveyed the right to explore and develop the minerals in the estate but said nothing about who owned the depleted reservoir.⁴⁶ As a result, under the American rule, ownership of that space remained with the surface estate owner—and that was from whom the gas storage operation needed to acquire storage rights.

a. Mineral Estate Dominance

Courts have repeatedly held that the subsurface estate implicitly comes with certain additional rights. This typically is referred to as the “dominance” of the mineral estate over the subsurface estate.⁴⁷ In the oil and gas context, for instance, courts have long held that the mineral estate is dominant over the surface estate because the development of a mineral estate necessarily requires some surface access.⁴⁸ Thus, generally, when a mineral estate is severed from the surface estate, there exists either an express or implicit reservation that the mineral estate holder is allowed to use portions of the surface estate needed to facilitate development of the mineral estate.⁴⁹

b. The Accommodation Doctrine

In response to the idea of mineral estate dominance, courts also developed the accommodation doctrine. This doctrine attempts to balance the interests of the surface and subsurface estates. First announced in *Getty Oil Co. v. Jones*,⁵⁰ the accommodation doctrine imposes a requirement on the mineral estate that all mineral-estate-surface-uses must be “reasonably necessary” and accommodate the existing uses of the surface estate. The Utah Supreme Court summarized this doctrine in *Flying Diamond Corp. v. Rust*.⁵¹

[M]ineral rights [are] dominant over the rights of the owner of the [surface estate] to the extent reasonably necessary to extract the minerals therefrom. This dominance is limited in that the mineral owner may exercise that right only as reasonably necessary

⁴³ See MORGAN & MCCOY, *supra* note 33, at 95–96; see also *Ellis*, 450 F. Supp. at 421.

⁴⁴ *Ellis*, 450 F. Supp. 412 at 414.

⁴⁵ See *Ellis*, 609 F.2d at 439.

⁴⁶ *Ellis*, 450 F. Supp. at 421.

⁴⁷ See *Smith v. Linmar Energy Corp.*, 790 P.2d 1222, 1224 (Utah Ct. App. 1990).

⁴⁸ See generally 4 SUMMERS OIL AND GAS § 40:4 (3d ed.).

⁴⁹ *Smith v. Linmar Energy Corp.*, 790 P.2d at 1224 (“[A]s a general matter, ownership of mineral rights in land is dominant over the rights of the owner of the fee title to the extent reasonably necessary to extract minerals.”).

⁵⁰ *Getty Oil Co. v. Jones*, 470 S.W.2d 618, 621 (Tex. 1971).

⁵¹ 551 P.2d 509, 511 (Utah 1976)

for that purpose and consistent with allowing the fee owner the greatest possible use of his property consistent therewith. . . . [W]herever there exist separate ownerships of interests in the same land, each should have the right to the use and enjoyment of his interest in the property to the highest degree possible not inconsistent with the rights of the other.⁵²

In other words, while the mineral estate's dominance may impinge somewhat on how the surface estate is used, the accommodation doctrine limits that effect. It may mean that development of a subsurface pore space estate can be constrained by the surface estate rights as well.

For instance, in *Sunray Oil Co. v. Cortez Oil Co.*,⁵³ relied on by the *Ellis* court, the Oklahoma Supreme Court addressed ownership of pore space rights in a salt water disposal well. To resolve the dispute, the court relied on the accommodation doctrine. It reasoned that unless a mineral conveyance expressly grants more than the right to develop and explore for minerals such as oil and gas, the surface owner retains the right to use the pore space—and, thus, to grant its use to a third party.

2. *The English Rule*

In contrast to the American rule, the English rule vests ownership of the pore space with the mineral estate owner. That is, an entity that acquires the right to extract subsurface minerals—such as an oil and gas driller—also obtains the right to use the pore space by virtue of obtaining the mineral rights. The English rule states: “[T]he mineral interest owner has the exclusive right of possession of the whole space and, after all minerals have been extracted, the owner is entitled to the entire and exclusive use of that space for all purposes.”⁵⁴

Central Kentucky Natural Gas Co. v. Smallwood is an illustrative case. There, the court needed to determine whether the surface owner or the mineral estate was entitled to lease an exhausted reservoir to store natural gas.⁵⁵ The court found that the mineral estate held the right not only to explore and develop those minerals but also the right to exclude others from exploring and developing such minerals. In accord with these exclusive rights, the court ruled, the mineral estate held the right to lease storage rights to others.⁵⁶

The Kentucky Supreme Court subsequently overruled *Central Kentucky Natural Gas Co.* on other grounds. In *Texas American Energy Corp. v. Citizens Fidelity Bank & Trust Co.*, the Kentucky court held that an entity that reinjects natural gas into an underground formation for storage does not abandon ownership of the injected gas.⁵⁷ The *Texas American Energy* opinion, however, did not address ownership of the pore space. *Central Kentucky Natural Gas Co.*'s holding that pore space ownership is vested with the mineral estate owner therefore appears to remain intact. The case, moreover, illustrates the difference in approach between the American rule and the English rule. Where the American rule turns on the idea that conveyance of subsurface rights typically should be narrowly construed, the English Rule hinges on the idea that pore space itself is mineral in character and, therefore, part of the mineral estate.

⁵² *Id.* (citations and footnotes omitted).

⁵³ 112 P.2d 792 (Okla. 1941).

⁵⁴ Elizabeth Lokey Aldrich & Cassandra Koerner, *Analysis of Carbon Capture and Sequestration Pore Space Legislation: A Review of Existing and Possible Regimes*, 24 *ELECTRICITY J.* 22–33, 22–33 (2011).

⁵⁵ *See* 252 S.W.2d 866 (1952).

⁵⁶ *Id.*

⁵⁷ 736 S.W.2d 25, 27 (Ky. 1987).

The English rule stands in contrast to the American rule in another way. It is a minority position. Only a limited number of jurisdictions within the United States follow the English rule. In fact, in the context of natural gas storage, only three states appear to continue to apply the English rule: Alaska, Kentucky, and Texas.⁵⁸

C. Pore Space Ownership for a Utah CCS Project

A majority of oil-producing states follow the American rule.⁵⁹ This is often via development of the common law. Many jurisdictions have yet to codify this principle, instead resolving pore space issues in court. A small number of states have enacted legislation that places pore space ownership in the surface estate. Utah, however, has not adopted legislation defining pore space ownership, and no case law from Utah directly addresses ownership in the CCS context.

While Utah law is not entirely clear which entity owns the pore space into which CO₂ would be injected, the surface estate owner or the mineral estate holder, the Utah Legislature has enacted legislation regarding natural gas storage which implies that pore space should be considered part of the surface estate. The Utah Legislature has directed the state Department of Natural Resources, to create pore space ownership and other rules for CCS.⁶⁰ Utah began to undertake an effort to adopt such rules in 2009 and 2010. However, after the EPA announced its final rule for Class VI Underground Injection Control wells under the Safe Drinking Water Act, Utah put its plans to adopt CCS rules on indefinite hold. Notwithstanding that hold, recommendations from the state's CCS Rules Working Group⁶¹ suggest that Utah likely would have adopted the American rule with respect to CCS pore space ownership.⁶²

Further, Utah Code § 78B-6-501(6)(d) grants the mineral estate owner the right to condemn “any subsurface stratum or formation” for natural gas storage. By granting the mineral estate owner the power of condemnation for pore space to store natural gas, the legislature necessarily concluded that the mineral estate owner did not already own the pore space—if they did, there would be no need for the power of condemnation. Since the strong implication from § 78B-6-501(6)(d) is that pore space does not belong to the mineral estate owner, it logically follows that, in accord with the American rule, pore space is owned by the surface estate owner in Utah.

In Utah, an argument could also be made that, as at least as applied to state lands, conveyance of pore rights must be express—a position again consistent with the American rule. Under SITLA's mineral reservation statutes, pore space must be reserved to the state when SITLA sells lands to private parties. Utah Code § 53C-1-102 imposes several “fiduciary duties” on SITLA, including a duty to “manage the lands . . . in the most prudent and profitable manner possible[.]”⁶³

⁵⁸ See BURT, *supra* note 38, at 5. See also *City of Kenai v. Cook Inlet Nat. Gas Storage Alaska, LLC*, 373 P.3d 473, 480–81 (Alaska 2016) (holding that a reservation of a mineral right implied the reservation of the right to use pore space to store natural gas).

⁵⁹ See generally BURT, *supra* note 38; see also Gray, *supra* note 34.

⁶⁰ See UTAH CODE § 54-17-701.

⁶¹ See UTAH CODE § 54-17-701 (creating this CCS Rules Working Group); see also Utah Dep't of Envtl. Quality, Utah Dep't of Natural Resources, Recommended Rules for Carbon Capture and Geologic Sequestration (Nov. 15, 2010), <https://pscdocs.utah.gov/misc/miscindx/documents/RecommendedRulesforCarbonCaptureandGeologicSequestration11-15-2010.pdf> (hereinafter Utah Rec. Rules).

⁶² See Utah Rec. Rules, *supra* note 61. It appears that no further action is being taken regarding adoption of the rules.

⁶³ UTAH CODE § 53C-1-102.

Further, sales of stand lands “[must] contain . . . a [coal and mineral] reservation.”⁶⁴ Excepted from that reservation are “common varieties of sand, gravel, and cinders”—but not exempted are “deposits which are valuable because the[y] contain[] characteristics which give it distinct and special value.”⁶⁵ Therefore, if pore space is of distinct and special value, it may be statutorily reserved to SITLA. While this provision applies only to land sales, SITLA may apply the same principle when issuing mineral leases.

As part of Phase II, the CarbonSAFE Rocky Mountain Team should review all existing mineral leases proximate to the injection site, whether those leases were issued by the BLM, SITLA, or a private entity, and determine whether any of these leases address pore space use. If leases fail to indicate pore space ownership, the weight of authority implies that the surface owner also owns the pore space, and that ownership must be addressed in turn as part of legal approval for CCS operations.

D. Obtaining Land Use Rights

Because accessing private, state, and federal lands—both at the surface and subsurface—may be necessary to execute the proposed CarbonSAFE Rocky Mountain project, it is necessary to understand the process for obtaining such rights. This subsection describes available processes. At the outset, however, it is worth noting that particularly with respect to subsurface property rights, obtaining pore space remains a rather novel legal question. The state of Utah and the BLM have never granted an interest in pore space solely for the purpose of injecting CO₂ for permanent geologic sequestration. Therefore, each of the avenues presented below should be considered as options only, and not necessarily the only way to obtain an interest in pore space, while also recognizing that the processes could be altered when relevant decisional bodies are faced with the new situation of CO₂ injection and storage.

1. Acquiring Private Land Use Rights

Generally, fee-simple landowners are free to alienate or dispose of their property, including a subset of their rights. There are several ways to go about this, but they break down into two broad categories: agreement via negotiation and acquisition via governmental authority (*i.e.*, eminent domain).

a. Agreement

Three primary mechanisms tend to be used to acquire property rights from a fee simple landowner: leases, easements, and outright conveyances. Each of these could be used for both surface and subsurface rights acquisition.

Leases have been used in the mineral context for some time and are particularly common in the oil and gas context. Adapting this established framework could facilitate a CCS project. A lease for surface access would allow for ingress and egress, and use of the land to, for instance, transport CO₂ or inject it. For subsurface rights, obtaining a right to occupy the pore space would require the drafting and execution of a pore space lease. When using a lease, the operator should be mindful of the permanence of the sequestered CO₂ and the potential for interference with other uses. Presumably, oil and gas leases could serve as a starting point for tailoring a CO₂ storage lease.

An easement may provide a more permanent and elegant solution than a lease. Easements are particularly common in the energy and utility infrastructure context, where they are typically

⁶⁴ *Id.* § 53C-2-401.

⁶⁵ *Id.*

referred to as rights-of-way (ROW). Easements are “created by express words of either a formal grant or of a reservation or exception in a conveyance of land.”⁶⁶ Like a lease, an easement does not create an ownership interest in the subject property, but rather, only the mere right to use the property in a given manner. The advantage of an easement is that it could exist in perpetuity until abandoned. This could be beneficial at the surface and subsurface level, and for pore space rights, may help navigate around the issue of permanence.

Lastly, a CCS operator could obtain the right to use land from an outright conveyance through a deed or other similar instrument. Use of such a mechanism is rather uncommon in the surface land context where the land is of significant value, and particularly where the property in question is large or the acquisition of the property will split the larger tract. In the subsurface context, however, the advantage of this route would be that ownership of the pore space will remain with the CCS operator in perpetuity. Still, this could be a costlier approach than the lease or easement options.

b. Eminent Domain

Eminent domain allows the taking of private property for public use by the state, municipalities, private individuals, or corporations that are authorized to exercise functions of a public character. Eminent domain can be utilized to obtain surface rights, subsurface rights, or both. Eminent domain authority is not available against the federal government unless expressly authorized by an act of Congress.⁶⁷

Utah’s eminent domain statute does not expressly grant a CCS operator authority to condemn certain real property.⁶⁸ The touchstone of eminent domain authority is a taking for a public use. Utah’s eminent domain statute lists several statutory public uses, including “any subsurface stratum or formation in any land for the underground storage of natural gas.”⁶⁹ Uses identified in the statute are “not exclusive . . . and merely establish a general starting point.”⁷⁰ Therefore, if a CCS operation could demonstrate that geologic sequestration is a public use, the operator could conceivably claim authority to condemn property.⁷¹ It is also noteworthy that the CCS Rules Working Group recognized the lack of express eminent domain authority for CCS operators, and recommended expansion of several areas of the eminent domain statute.⁷²

Second, Utah law also provides that “the right of eminent domain may be exercised on behalf of . . . any occupancy in common by the owners or possessors of different mines, quarries, coal mines, mineral deposits, mills, smelters, or other places for the reduction of ores, or *any place for*

⁶⁶ UTAH REAL PROPERTY LAW § 12.02 (Lexis).

⁶⁷ *Utah Power & Light Co.*, 243 U.S. 389, 405 (1914). While the Utah Legislature has enacted legislation authorizing the use of eminent domain against the federal government, *see* UTAH CODE § 78B-6-503.5, this statute is almost certainly unconstitutional. As the Utah Office of Legislative Research and General Counsel warned the Legislature before enactment, “[T]he state has no standing as sovereign to exercise eminent domain or assert any other state law that is contrary to federal law on land or property that the federal government holds under the Property Clause.” H.R. 143, 2012 Gen. Sess. (Utah 2012) (fiscal note appended to the introduced version of the bill).

⁶⁸ *See generally* UTAH CODE §§ 78B-6-501 *et seq.* (2017)

⁶⁹ *Id.* § 78B-6-501(6)(d).

⁷⁰ *Utah Dep’t of Transp. v. Carlson*, 2014 UT 24, ¶ 20, 332 P.3d 900, 904; *Salt Lake City Corp. v. Evans Dev. Grp., LLC*, 2016 UT 15, ¶ 11, 369 P.3d 1263, 1266.

⁷¹ *See, e.g., Watkins v. Somonds*, 354 P.2d 852 (Utah 1960); *Jacobsen v. Memmott*, 354 P.2d 569 (Utah 1960).

⁷² *See* Utah Rec. Rules, *supra* note 61, at att. 2.

the flow, *deposit* or conduct of tailings or *refuse matter*.”⁷³ While tenuous, a CCS operator—or coal mine operator—could argue that CO₂ should be classified as refuse matter to coal production. The argument would be that what is being sought is a place to dispose a product that, for commercial purposes, has little value. Thus, by analogy, CO₂ arguably could be considered akin to waste or, in statutory terms, “refuse matter.” In response, an owner of condemned property would argue that such a reading of the statute is not in character with its intended meaning and, further, that CO₂ storage is not in the public use.

Given the untested nature of these arguments, the much safer route for a CCS operator seeking to use eminent domain authority would be to obtain a legislative amendment of the existing law, in accord with the CCS Rules Working Group’s recommendation.⁷⁴ That is, an attempt to exercise eminent domain authority without such a legislative enactment would carry a high risk of litigation.

Another downside of using eminent domain bears mention. Eminent domain proceedings tend to provoke litigation and delay. Further, even if successful, they require payment for the resources seized, and valuation can invite further litigation. Negotiated transactions therefore appear highly preferable for CCS purposes.

2. Acquiring State Land Use Rights

A portion of the land granted to Utah at statehood is held by the state in trust for the benefit of the public schools and institutions.⁷⁵ These lands are now managed under the authority of the State of Utah School and Institutional Trust Lands Administration (SITLA).⁷⁶ SITLA lands are ubiquitous in and around the location of the proposed CarbonSAFE Rocky Mountain project.

There are several ways in which a private entity could obtain ownership or an interest in SITLA-managed lands. These fall into three broad categories that track the negotiation-based options for obtaining access to private lands: easements, leases, and land sales.

Notably, of these three avenues, private parties typically obtain an interest in SITLA lands through a variety of leases, including agricultural, grazing, and mineral leases. Commercial and renewable energy leases are also common. Obtaining the right to pore space under current SITLA regulations, however, would be a matter of first impression and would necessarily involve conferring and negotiating directly with SITLA.

a. Easement

To obtain an easement, a CCS operator would need to apply to SITLA under the procedures delineated in Utah Admin. Code R850-40 *et. seq.* Much of the language in these provisions suggests that these easements are not permanent, but it appears that SITLA may extend the life of an easement into perpetuity.⁷⁷ The minimum cost to the CCS operator would be the cost of administering the easement. If a CCS operator obtains an easement, the operator can assign the easement, but only with approval from SITLA.⁷⁸ Easements are managed by the Surface Group at SITLA and are commonly used for electrical lines, pipelines, and roads.

While technically allowable under SITLA’s authority, easements are not commonly used when developing a resource. Instead, an entity typically requests a lease or a permit. A CCS operator

⁷³ UTAH CODE § 78B-6-501(6)(f).

⁷⁴ See Utah Rec. Rules, *supra* note 61, at Att. 2.

⁷⁵ See UTAH CODE § 53C-1-102.

⁷⁶ See *id.* §§ 53C-1-101 *et seq.*

⁷⁷ UTAH ADMIN. CODE R850-40-800 (2016).

⁷⁸ *Id.* R850-40-1600.

is arguably developing the pore space estate, not merely using it passively, as is done for utility lines or roads. After the CO₂ is injected, no one could further use the pore space, meaning that it is depleted, whereas after a pipeline is no longer needed, the land it has been occupying can be used for other purposes since the pipeline can be removed. Therefore, a lease would be a more logical—and perhaps more likely—way to develop a CCS project on SITLA lands, particularly with respect to subsurface rights as opposed to CO₂ transport.

b. Lease

Utah Admin. Code R850-30-100 *et seq.* defines SITLA’s authority to issue special use leases. Special use leases may be required for pipelines or other infrastructure needed for CCS operations. Industrial special use leases are issued for periods of up to fifty-one years,⁷⁹ but in extraordinary circumstances, the lease term can be extended to ninety-nine years.⁸⁰ A lease for CCS use of pore space would most likely be classified as a special use lease because it is not within the standard definition of a mineral lease.⁸¹ To obtain a special use lease, the applicant must follow procedures listed in Utah Admin. Code R850-30-500. The applicant may be required to submit a bond for reclamation as well as lease payments.⁸² The lease rate will be based on market value and income-producing capability.⁸³

c. Land Sale

State law vests SITLA with authority to sell trust lands under its management. There are two avenues by which SITLA may sell trust lands: a public sale or a negotiated sale.⁸⁴ SITLA commonly reserves the mineral estate during land sales, and most sales involve developable lands rather than linear features. Whether SITLA would entertain a proposal to sell lands for either CCS or for a pipeline is unclear, but it appears less likely than a lease. This is because a land sale permanently divests the property from SITLA, whereas a lease extracts income from the property while preserving the corpus of the land for future income-generating activity. As a trustee for the state’s lands, SITLA has a fiduciary obligation to maximize benefit to the state from the trust lands. This likely explains why SITLA tends to reserve mineral rights when it engages in land sales.

3. *Acquiring Federal Land Use Rights*

Several different entities manage federally owned lands within the United States. In Utah, most federally owned land is managed by the Bureau of Land Management (BLM) and the U.S. Forest Service, and the BLM is responsible for the management of the federal subsurface mineral estates.

Both the BLM and the Forest Service manage lands under the broad and flexible principles of multiple use. That is, the statutes governing these agencies require them to seek to accommodate a balance of uses on federal lands, with the general idea in mind that the lands will produce a “sustained yield.”⁸⁵

⁷⁹ *Id.* R850-80-200(3)(e); R850-80-200(2).

⁸⁰ *Id.* R850-80-200(2).

⁸¹ *Id.* R850-80-100.

⁸² *Id.* R850-80-800.

⁸³ *Id.* R850-80-400(1).

⁸⁴ *See id.* R850-80-610–615.

⁸⁵ 43 U.S.C. §§ 1701(a)(7), 1712(c)(1); 16 U.S.C. § 529.

Two primary authorities govern which lands the BLM can dispose of or grant usage rights to: The Federal Land Planning and Management Act (FLPMA)⁸⁶ and the Mineral Leasing Act (MLA).⁸⁷ FLPMA would govern rights-of-way needed for the transport phase of a CCS operation on federal lands managed by the BLM. Likewise, a CCS operator that is not pursuing an enhanced oil recovery project would obtain the right to use pore space under FLPMA. If the project also involves oil and gas development, the rights would be obtained under the MLA. The National Forest Management Act governs surface uses of lands managed by the Forest Service while the BLM manages minerals beneath Forest Service managed land surface pursuant to the MLA.

As in the state context, acquisition of rights of way for pipeline or other utility or transport uses is quite common on federal lands. However, use of federal lands for CO₂ storage would be a rather novel proposition. To our knowledge, no entity operates a CCS project on BLM land for the sole purpose of CO₂ sequestration.⁸⁸ The lack of clear precedent for the CarbonSAFE Rocky Mountain project could complicate permitting efforts.

A CCS operator could obtain a right-of-way to transport or store CO₂ under FLPMA, which gives the BLM broad authority to issue rights-of-way. FLPMA states:

The Secretary . . . [is] authorized to grant, issue, or renew rights-of-way over, upon, under, or through such lands for . . . such other necessary transportation or other systems or facilities which are in the public interest and which require rights-of-way over, upon, under, or through such lands.⁸⁹

To obtain a right of way from the BLM, a CCS operator would need to meet with the local BLM office, conduct a pre-planning meeting, complete a Standard Form 299 (SF299),⁹⁰ and pay a processing fee.⁹¹ If the application is approved, the BLM may require a bond, and the CCS operator would need to pay monitoring fees during development, plus annual rent for the life of the project.

According to employees at the BLM's Utah office, FLPMA could be a means of obtaining a right not only to transport CO₂ across BLM lands but also potentially to use BLM pore space for CO₂ storage (so long as the project is outside of an oil and gas context, such as enhanced oil recovery). Although BLM officials have preliminarily indicated that the FLPMA right-of-way process could possibly be used for CO₂ storage, to date the BLM has not issued any ROW for a project of this nature. Such a first-of-kind ROW grant could be seen by the BLM as having a potential precedent-setting effect, and thus, would likely require input from high-ranking BLM or Department of the Interior officials. This could delay ROW issuance.

⁸⁶ 43 U.S.C. §§ 1701 *et seq.*

⁸⁷ 30 U.S.C. §§ 181 *et seq.*

⁸⁸ Our analysis assumes that the sole purpose of the proposed CarbonSAFE Rocky Mountain CCS operator is to sequester CO₂ rather than to engage in further mineral development, such as through enhanced oil recovery.

⁸⁹ 43 U.S.C. § 1761(a)(7).

⁹⁰ See GSA Forms Library, Form: SF299, www.gsa.gov/portal/forms/download/117318 (last visited Aug 14, 2017).

⁹¹ See Bureau of Land Mgmt., Division of Lands and Realty, *Obtaining a Right-of-Way on Public Lands* (Mar. 10, 2009), www.blm.gov/sites/blm.gov/files/ObtainingaROWPamphlet.pdf.

III. LIABILITY RISK

Any activity involves an element of risk. For the proposed CarbonSAFE Rocky Mountain project, these risks exist for both the transport and storage phases of CCS. With respect to transport, the primary risk is that there will be some kind of accident as CO₂ is being moved. Such an accident could, for instance, harm employees or contractors involved in achieving transport, or the general public or surrounding lands, if a leak occurred. Transport of CO₂ is governed by safety regulations implemented by the Pipeline and Hazardous Materials Safety Administration (PHMSA). This section of the report focuses on that regulation, recognizing that other legal frameworks for liability might apply, particularly under tort law and property law. With respect to geologic storage of CO₂, a host of issues could impact long-term liability exposure. The three main issues are ownership of injected CO₂, permitting requirements for underground injection control under the Safe Drinking Water Act, and long-term liability exposure under other environmental laws. This section addresses each in turn.⁹²

A. Transport Regulation

The Pipeline and Hazardous Materials Safety Administration (PHMSA) within the Department of Transportation regulates the movement of a large array of materials via pipeline. This includes CO₂, which PHMSA regulations define as “a fluid consisting of more than 90 percent carbon dioxide molecules compressed to a supercritical state.”⁹³ PHMSA regulation of CO₂ transport is extensive and focused on ensuring safety and the lack of accidents.⁹⁴ Here, we overview six key aspects of these regulations.

1. *Minimum Design Requirements*

The PHMSA imposes minimum design requirements for new, relocated, replaced, or modified CO₂ pipeline systems. The pipeline must be “made of steel of the carbon, low alloy-high strength, or alloy type that is able to withstand the internal pressures and external loads and pressures anticipated for the pipeline system.”⁹⁵ If there are segments of the system that operate under different pressure levels, the system must be designed so that components operating at lower pressures will not be overstressed.⁹⁶ The system must also account for possible external pressures, such as earthquakes, vibration, and thermal expansion and contraction.⁹⁷ All materials in the system also must be chemically compatible with CO₂ and selected for the temperature environment in which the system will operate, maintaining structural integrity.⁹⁸ The pipeline also must be designed and constructed to accommodate internal inspection devices.⁹⁹

⁹² Other sources of liability exist, including but not limited to liability for an inadvertent CO₂ release from compression, transport, or injection infrastructure or from the reservoir itself. These issues are treated as the kind of generalized liability that is associated with more routine energy industry development and therefore beyond the scope of this analysis.

⁹³ 49 C.F.R. § 195.2.

⁹⁴ For an overview of regulatory issues of CO₂ transport for CCS, see Jennifer Skougard Horne, *Getting from Here to There: Devising an Optimal Regulatory Model for CO₂ Transport in a New Carbon Capture and Sequestration Industry*, 30 J. LAND RESOURCES & ENVTL. L. 357 (2010).

⁹⁵ 49 C.F.R. § 195.112(a).

⁹⁶ *Id.* § 195.104.

⁹⁷ *Id.* §§ 195.108, 195.112.

⁹⁸ *Id.* § 195.102.

⁹⁹ *Id.* § 195.120.

2. Construction, Inspection, and Testing

Each phase of pipeline construction and repair must be inspected by a person trained and qualified in the specific aspect of construction.¹⁰⁰ Beginning with initial construction, the operator is responsible for maintaining a complete inspection record for the life of the system.¹⁰¹ Pipeline location, materials, components, welds, valves, and pumping equipment must all be inspected at the time of installation or construction of each segment. Likewise, breakout tanks must be inspected for adequate emergency venting or pressure relief.¹⁰² Further, no owner may operate a pipeline or return to service any segment unless it has been pressure tested without leakage.¹⁰³ The test pressure must be maintained for at least four continuous hours at a pressure equal to 125 percent or more of the maximum operating pressure.¹⁰⁴ The operator must keep records of every pressure test and retain the records as long as the pipeline facility is in use.¹⁰⁵

3. Operation and Maintenance

Each operator is responsible for the maintenance and safe operation of its pipeline system. If the operator discovers an adverse condition within the system, it must correct the condition within a reasonable time. If the condition presents an immediate hazard, the operator must cease use of the affected part of the pipeline system until it corrects the condition.¹⁰⁶

The operator must maintain a manual with written procedures for conducting normal operations and maintenance, as well as protocols for abnormal operations and emergencies. The manual must be reviewed and updated annually and kept in locations where operations and maintenance activities are conducted.¹⁰⁷

Each operator also must keep adequate firefighting equipment at each pump station and breakout tank area, prohibit smoking and open flames, develop and implement a written continuing public education program, establish and conduct a training program for emergency personnel, maintain current maps and records of its pipeline systems, maintain a system of communication for the transmission of information regarding the safe operation of the pipeline system, and place and maintain line markers over each buried pipeline.¹⁰⁸ Signs visible to the public must be maintained around each pumping station and each breakout tank area.¹⁰⁹

At least 26 times per year, at intervals of no more than 3 weeks, the operator must inspect the surface conditions on or adjacent to each pipeline right-of-way.¹¹⁰ Operators must also inspect all overpressure safety devices and overflow protection systems at intervals not to exceed 7.5 months, at least twice a year, to ensure that all pressure control equipment is properly functioning, remains in good mechanical condition, and is adequate for capacity and reliability.¹¹¹ Repairs must be made in a

¹⁰⁰ *Id.* § 195.204.

¹⁰¹ *Id.* § 195.266.

¹⁰² *Id.* § 195.264.

¹⁰³ *Id.* § 195.302.

¹⁰⁴ *Id.* § 195.304.

¹⁰⁵ *Id.* § 195.310.

¹⁰⁶ *Id.* § 195.401.

¹⁰⁷ *Id.* § 195.402.

¹⁰⁸ *Id.* §§ 195.403-.404.

¹⁰⁹ *Id.* § 195.434.

¹¹⁰ *Id.* § 195.412(a).

¹¹¹ *Id.* § 195.428.

safe manner so as to prevent damage to persons or property.¹¹² Each operator must also carry out a written program to prevent damage to pipeline from excavation activities, including blasting, boring, tunneling, backfilling, removal of aboveground structures, and other earth moving operations.¹¹³

4. Corrosion Control

CO₂ pipeline operators also must comply with PHMSA regulations ensuring against corrosion. Each buried or submerged pipeline must have an external coating for external corrosion control.¹¹⁴ The coating material must be designed to mitigate corrosion, have sufficient adhesion, be sufficiently ductile, resist damage due to handling and soil stress, and support any supplemental cathodic protection.¹¹⁵ Each buried pipeline must have cathodic protection in operation no later than one year after the pipeline is constructed as well as electrical test leads for external corrosion control.¹¹⁶

Corrosion control must be conducted regularly, with tests for external corrosion at least once every 15 months.¹¹⁷ Whenever any portion of a buried pipeline is exposed, the operator must examine the exposed portion.¹¹⁸ Likewise, pipeline interior must be investigated at least every 7.5 months. If corrosion reduces sufficient wall thickness, the pipe must be replaced.¹¹⁹ When corrosion requiring corrective action is found, the operator must investigate circumferentially and longitudinally beyond the removed pipe to determine that further corrosion does not exist.¹²⁰

Unless electrically interconnected and cathodically protected, all buried pipeline must be electrically isolated from other metallic structures. One or more insulating devices must be installed wherever electrical isolation of a portion of pipeline is necessary to facilitate corrosion control. Each electrical isolation must be inspected and electronically tested to assure the isolation is adequate. If an insulating device is installed in an area where a combustible atmosphere is reasonably foreseeable, precautions must be taken to prevent arcing.¹²¹ Operators must have a program to identify, test for, and minimize damage to pipelines exposed to stray currents.¹²²

Records of corrosion control must be maintained. An operator must keep current maps or records showing the location of cathodically protected pipelines, cathodic protection facilities, and neighboring structures bonded to cathodic protection systems. Records of each analysis, check, demonstration, examination, inspection, investigation, review, survey, and test must be kept with sufficient detail to demonstrate the adequacy of corrosion control measures for at least 5 years.¹²³

5. Annual, Accident, and Safety-Related Reporting

PHMSA regulations require pipeline operators to submit a variety of regular and incident-specific reports. Annual safety reports are due no later than June 15 for each previous year.¹²⁴

¹¹² *Id.* § 195.422.

¹¹³ *Id.* § 195.442.

¹¹⁴ *Id.* § 195.557.

¹¹⁵ *Id.* § 195.559(a)-(e).

¹¹⁶ *Id.* §§ 195.563(a), 195.567.

¹¹⁷ *Id.* § 195.573(a)(1).

¹¹⁸ *Id.* § 195.569.

¹¹⁹ *Id.* § 195.585(a).

¹²⁰ *Id.* § 195.579(c).

¹²¹ *Id.* § 195.575(a)-(e).

¹²² *Id.* § 195.577(a).

¹²³ *Id.* § 195.589.

¹²⁴ *Id.* § 195.49.

Written accident reports, along with updates on the status of an accident, must be submitted within 30 days of the occurrence. Separate reports must be submitted for each failure that results in any (1) unintentional explosion or fire, (2) release of 5 gallons or more of CO₂, (3) death of any person, (4) injury to any person that requires hospitalization, (5) damages estimated to exceed \$50,000.¹²⁵ In addition to the written report, operators must provide telephonic notice of qualifying accidents as soon as reasonably possible following the discovery of the accident. Accidents that result in the pollution of any stream, river, lake, reservoir, or other similar body of water also requires immediate telephonic notice.¹²⁶ If an accident is investigated by PHSMA or other government regulator, the operator has a duty to provide all records, information, and assistance reasonably available or necessary.¹²⁷

6. Qualifications of Pipeline Personnel

Each operator must have and follow a written personnel qualification program that will, among other things, identify covered tasks, evaluate the qualifications of individuals assigned to covered tasks, provide training, allow individuals who are not yet qualified to perform a covered task under supervision of a qualified individual, and communicate changes that affect covered tasks to the individuals responsible for performing those covered tasks.¹²⁸ Additionally, each operator must maintain records that contain (1) the identification of qualified individuals, (2) the identification of the covered tasks each individual is qualified to perform, (3) the dates of the individual's current qualification, and (4) the methods of training the individual received. Records of prior/expired qualifications and of individuals no longer performing covered tasks must be retained for 5 years.¹²⁹

B. Storage Liability

Three key issues outline the likely scope of liability for permanently sequestered CO₂. These relate to who owns the CO₂, permitting under the Safe Drinking Water Act, and potential long-term liability under both environmental and other statutory and common law.

1. CO₂ Ownership

A threshold question for possible liability from the storage phase of CCS is who owns the geologically deposited CO₂. That is, once the CO₂ is injected into the ground, does the injector maintain ownership of it and thus risk liability from any harm that may arise from the injected CO₂?

The law is not clear on this question, although analogous reasoning from other areas suggests that an injector of CO₂ is likely to retain title to the gas. Indeed, ownership of injected CO₂ is not a settled issue. It has not been addressed in a published court opinion, and Utah statutory law does not address the question. However, applying property law doctrines from the natural gas context may help delineate ownership of sequestered CO₂.

Two theories have been suggested to address ownership of injected natural gas: the so-called “non-ownership” and “ownership” theories. Under the non-ownership theory, it can be reasoned that once natural gas is injected into the ground, the injector loses ownership of the resource because it is available for anyone to take. This reasoning derives from the longstanding “rule of capture,” which serves as the foundation of oil and gas law. The rule of capture holds that, because

¹²⁵ *Id.* § 195.50.

¹²⁶ *Id.* § 195.52.

¹²⁷ *Id.* § 195.60.

¹²⁸ *Id.* § 196.505(a)-(e).

¹²⁹ *Id.* § 195.507.

oil and gas are fugitive minerals and can transverse subterranean property boundaries, the first person to reduce that mineral to its possession can claim ownership of it.¹³⁰ Building on this idea, which has long been invoked in oil and gas law in part to encourage exploration and extraction, the theory of non-ownership would hold that once the resource—here, CO₂—is injected into the ground, the releaser cannot continue to claim ownership because possession has ceased.¹³¹ The problem with this non-ownership theory is that, in the natural gas context, it has been rejected by all states.¹³²

In place of the non-ownership theory, states instead have adopted the ownership theory. Under this theory, “title to natural gas once having been reduced to possession is not lost by the injection of such gas into a natural underground reservoir for storage purposes.”¹³³ The rationale for this theory should be plain. It would be incongruous to promote natural gas extraction under the rule of capture, only to turn around and limit the producing party’s incentive to extract by restricting its ability to feasibly store the extracted resource. To reach such holdings, courts have thus distinguished the geological context of injected gas from naturally occurring gas. Whereas the latter can be pulled across property boundaries through extraction techniques, the former is unlike releasing an animal into the wild because there is a “well[-]defined storage field . . . subject to the control of the storage companies[.]”¹³⁴ Accordingly, in cases where a gas has previously been reduced to possession but is later injected into a well-defined underground space capable of being maintained with integrity, title to the gas remains with the original owner.

While sequestered CO₂ is distinguishable from natural gas in that the former is part of the waste stream while the latter is an economically valuable commodity, a formidable argument can be made that the ownership theory should also apply to geologically stored CO₂. Because CO₂ is sequestered in a similar manner as natural gas is stored, application of the ownership theory would appear appropriate. Indeed, the mirror image of the policy incentives created by applying the ownership theory to natural gas exist for stored CO₂ as well. For natural gas, the ownership theory preserves the incentive to extract the resource in the first instance. That is, the theory avoids the inequity of a gas producer incurring the cost of extraction but allowing another party to profit from that by taking the gas once it is stored. Similar reasoning could apply in the stored CO₂ context. It would seem incongruous to require the CO₂ owner to incur liability while the CO₂ is above ground but remove the potential of such obligations simply because the CO₂ is moved underground.

Nonetheless, a possible limit on the application of the ownership theory to stored CO₂ might derive from a factual difference between it and natural gas. Injected CO₂ could mineralize within as little as two years, depending upon the medium into which it is injected.¹³⁵ This could have significant implications for legal liability, because once the CO₂ turns into a solid, an argument could be made that any possibility of liability should be curtailed since solid rock will not leak or spread.

¹³⁰ *Westmoreland & Cambria Nat. Gas Co. v. De Witt*, 130 Pa. 235, 249 (1889).

¹³¹ *Hammonds v. Cent. Kentucky Nat. Gas Co.*, 75 S.W.2d 204, 206 (1934), *overruled by Texas Am. Energy Corp. v. Citizens Fid. Bank & Trust Co.*, 736 S.W.2d 25 (Ky. 1987)

¹³² Mark deFigueiredo, *The Liability of Carbon Dioxide Storage* 304 (Feb. 2007) (unpublished Ph.D. dissertation, Massachusetts Institute of Technology), http://sequestration.mit.edu/pdf/Mark_de_Figueiredo_PhD_Dissertation.pdf.

¹³³ *White v. N.Y. State Nat. Gas Corp.*, 190 F. Supp. 342, 349 (W.D. Pa. 1960).

¹³⁴ *Id.* at 348.

¹³⁵ J.M. Matter et al., *Rapid Carbon Mineralization for Permanent Disposal of Anthropogenic Carbon Dioxide Emissions*, 352 *SCIENCE* 1312 (2016).

2. *Safe Drinking Water Act Permitting*

The Safe Drinking Water Act (SDWA) requires operators to obtain permits before conducting underground injection of certain materials. The Act relies on a cooperative federalism model whereby the EPA sets minimum standards and states develop programs to attain those objectives in light of local conditions. One such program under the Act is the Underground Injection Control (UIC) program. The UIC program aims to “protect public health and prevent contamination of underground sources of drinking water (USDWs).”¹³⁶ The program specifies six classes of well permits that may be granted to inject underground materials subject to the Act. Class VI permits are the relevant permit for CCS operations.

In Utah, the Utah Department of Environmental Quality and the Department of Natural Resources issue Class I-V UIC permits.¹³⁷ That is, these state-level agencies have received primacy from the EPA to administer permits for wells within classes I-V. Utah has not petitioned for authorization to administer Class VI UIC permits. That authority rests solely with the EPA. A CCS operator must therefore obtain a Class VI UIC permit from the EPA prior to injecting CO₂.¹³⁸

a. Class VI Well Requirements Under the SDWA

Class VI wells are used exclusively for the injection of CO₂ into the subsurface in aid to a geologic sequestration (GS) or CCS projects. The EPA’s main health and environmental concerns regarding CCS are the “[l]arge CO₂ injection volumes associated with GS, the buoyant and mobile nature of the [CO₂ stream], the potential presence of impurities in the CO₂ stream, and its corrosivity in the presence of water.”¹³⁹ In addition, EPA has expressed concern about the “pressures induced by injection” from CCS, as those pressures “may force naturally occurring salty water (brine) into USDWs, causing degradation of water quality and affecting drinking water treatment processes.”¹⁴⁰

Class VI permits address a wide range of issues: site characterization, computational modeling of the Area of Review (AoR), periodic reevaluation of the AoR, well construction, project monitoring, comprehensive post-injection monitoring and site care, and financial responsibility requirements.¹⁴¹

Obtaining and complying with a Class VI permit under the SDWA provides important liability protection for CCS project operators. This liability protection, however, is far from universal and addresses only SDWA liability. EPA regulations make clear that “compliance with a permit during its term constitutes compliance, *for purposes of enforcement*, with Part C of the SDWA.”¹⁴² This

¹³⁶ Underground sources of drinking water are defined as “an aquifer or its portion: (a)(1) Which supplies any public water system; or (2) Which contains a sufficient quantity of ground water to supply a public water system; and (i) Currently supplies drinking water for human consumption; or (ii) Contains fewer than 10,000 mg/l total dissolved solids; and (b) Which is not an exempted aquifer.” 40 C.F.R. § 144.3 (2017).

¹³⁷ Each class of UIC permits covers a different use. Class I deals with industrial and municipal waste. Class II covers enhanced oil recovery, salt water disposal, and storage of hydrocarbons that are liquid at standard temperature and pressure. Class III covers solution mining. Class IV covers hazardous wastes. And Class V covers injection of fluids not covered in other well classes.

¹³⁸ 40 C.F.R. § 144.18.

¹³⁹ See U.S. EPA, *Class VI - Wells Used for Geologic Sequestration of CO₂*, www.epa.gov/uic/class-vi-wells-used-geologic-sequestration-co2#well_def (last visited Sept. 15, 2017).

¹⁴⁰ *Id.* at II(A)(3).

¹⁴¹ *Id.*

¹⁴² 40 C.F.R. § 144.35 (emphasis added).

rule, commonly referred to as a “permit shield” provision, is echoed in EPA’s site closure¹⁴³ guidance documents:

[O]nce an owner or operator has met all regulatory requirements under the UIC program for Class VI wells [at 40 C.F.R. § 146] and the UIC Program Director has approved site closure pursuant to requirements at 40 C.F.R. § 146.93, the owner or operator will generally no longer be subject to enforcement for regulatory noncompliance. However, following site closure, the owner or operator is financially responsible for any remedial action deemed necessary for USDW endangerment caused by the injection operation.¹⁴⁴

In short, the EPA will not bring enforcement actions under Part C of the SDWA, which addresses protection of USDWs, once a CCS site has undergone official site closure. However, as discussed in more detail below, the rule does not shield enforcement of Part D of the SDWA, which addresses the EPA Administrator’s emergency powers to address imminent and substantial endangerment to health. Nor does compliance with Part C preclude other enforcement mechanisms or different kinds of liability. As the above guidance document makes clear, CCS owners/operators remain “financially responsible for any remedial action” that becomes necessary even after site closure.¹⁴⁵ Another portion of EPA’s SDWA guidance further reinforces this point:

[S]ite closure does not eliminate any potential responsibility or liability of the owner or operator under other provisions of law[, or § 1431 of the SDWA¹⁴⁶]. . . . Furthermore, after site closure, an owner or operator may remain liable under tort and other remedies, or under other federal statutes including, but not limited to, the Clean Air Act (CAA); the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA); and the Resource Conservation and Recovery Act (RCRA).¹⁴⁷

Stiff penalties may be imposed for violating the SDWA’s USDW protections. Violators are subject to civil penalties of up to \$25,000 for each day of violation. If the violation was “willful,” the violator may also be subject to criminal prosecution and imprisonment of not more than three years.¹⁴⁸

¹⁴³ See U.S. EPA, Geologic Sequestration of Carbon Dioxide Underground Injection Control (UIC) Program Class VI Well Plugging, Post Injection Site Care, and Site Closure Guidance (Dec. 2016), www.epa.gov/sites/production/files/2016-12/documents/uic_program_class_vi_well_plugging_post-injection_site_care_and_site_closure_guidance.pdf.

¹⁴⁴ *Id.* § 4.4.

¹⁴⁵ *Id.*

¹⁴⁶ See *id.* Under Section 1431 of SDWA, the Administrator may require an owner or operator to take necessary response measures if he or she receives information that a contaminant is present or is likely to enter a public water system or USDW and may present an imminent and substantial endangerment to the health of persons, and the appropriate state and local authorities have not acted to protect the health of such persons. The action may include issuing administrative orders or commencing a civil action for appropriate relief against the owner or operator of a Class VI well. If the owner or operator fails to comply with the order, he or she may be subject to a civil penalty for each day in which such violation occurs or failure to comply continues.

¹⁴⁷ *Id.* (internal citations omitted).

¹⁴⁸ 42 U.S.C. § 300h-2(b).

b. Lessons Learned from SDWA Permitting for CCS Facilities

We reviewed permitting documents for three other CCS facilities in order to identify lessons learned from those experiences. While the CarbonSAFE Rocky Mountain project will be subject to the same procedural requirements, factual differences between the project at hand and prior CCS facilities need to be acknowledged when considering the experience at other CCS facilities.

1. *FutureGen*

FutureGen involved CO₂ capture from Unit 4 of Ameren’s Meredosia Energy Center, approximately 20 miles west of Jacksonville, Illinois, and was intended to be the world’s first full-scale oxy-combustion clean coal repowering of an existing power plant fully integrated with CO₂ transport and permanent geologic storage. CO₂ would have been transported approximately thirty miles from the plant site to the storage location, where approximately one million metric tons per year of compressed and purified CO₂ would have been injected into the Mt. Simon saline formation for a projected twenty-year period.

FutureGen was the first full-scale CCS project in the United States to undergo SDWA Class VI permitting, and twenty-nine parties submitted comments on the draft permit to EPA. After responding to the comments, the EPA issued FutureGen a Class VI permit on March 31, 2014. As the first of such permits issued by the EPA, the agency stated throughout the permit file that particular care was taken to ensure protection of underground sources of drinking water. In addition, the EPA stated that modifications to the permit may be required as the project developed and therefore more data was acquired, despite all of requirements prior to issuing the permit. However, FutureGen 2.0 was discontinued due to funding limitations resulting from the expiration of American Recovery and Reinvestment Act funds on September 30, 2015. Despite the project’s failure, the comments received may provide some indication of the kinds of issues that are likely to arise for the CarbonSAFE project.

Notably, the EPA took an exceedingly narrow view of the issues that it needed to consider during the FutureGen 2.0 UIC permitting process, focusing exclusively on protection of USDW. Whether plume migration had ceased prior to closure was oddly considered outside the scope of the permit analysis. Similarly, the EPA took the approach that Class VI rules were not concerned with pore space rights, just safety and project operation. The EPA therefore did not address pore space ownership, concluding that the permit does not prevent private rights from being asserted.

Also, of note, by statute and as acknowledged in the permit, Illinois would have taken ownership of the site ten years after the site closure. Therefore, any long-term liability associated with the project would rest with Illinois. Utah does not have such a statute and it appears that ownership of the site would remain with the operator until it disposes of the site in some way upon site closure. EPA appeared to acknowledge this in issuing the FutureGen 2.0 permit. It stated that “any remediation costs incurred in the very long term (i.e., after the non-endangerment determination and the release from post-injection site care responsibilities) is beyond the scope of the Class VI financial responsibility requirements and the UIC permitting process.”

2. *ADM*

The Archer Daniels Midland Company (ADM) Illinois ICCS project involves sequestration of CO₂ generated as a byproduct of processing corn into ethanol at ADM’s biofuels plant adjacent to the storage site in Decatur, Illinois. The CO₂ is collected at atmospheric pressure, compressed, and dehydrated to deliver supercritical CO₂ to the injection wellhead for storage. Injection occurs on a 200-acre site adjacent to the ethanol plant, which is also owned by ADM. While not addressed

in detail in permitting documents, it appears that ADM owns the pore space into which the CO₂ would be injected. The project is designed to sequester 2.5 million tons of CO₂ over a 2.5-year period.

On May 3, 2011, the Department of Energy concluded its NEPA analysis¹⁴⁹ for the ADM project and issued a Finding of No Significant Impact.¹⁵⁰ The ADM project received the U.S. EPA's UIC Class VI injection well permit effective March 6, 2017 and started commercial operations accordingly. ADM characterized the CO₂ streams generated by this project as liquids, supercritical fluids, or gas. It will be injected into the Mount Simon at depths between 5,553 feet and 7,043 feet.

Class VI injection well permitting appeared to generate very little controversy, with only one member of the public submitting comments on the draft permit. Most relevant to the CarbonSAFE project, the commenter asserted that pore space rights must be taken into account when issuing the permit. The EPA, however, responded that under Class VI rules, it need not consider pore space rights, and the permit does not grant any real property rights. As noted above, CarbonSAFE Rocky Mountain would be wise to anticipate a higher level of scrutiny and that other federal approvals will need to address pore space ownership, even if the EPA does not address the issue directly.

3. *Potential Liability Outside of SDWA Part C*

As noted, SDWA Part C addresses protection of USDWs. SDWA Part D addresses the EPA Administrator's authority to respond to imminent and substantial threats to public health. Because compliance with a Class VI well permit does not act as a complete shield to liability,¹⁵¹ it is important to understand how other types of liability may arise. Although not exhaustive, there are three key areas to consider: other provisions of the SDWA, RCRA and CERCLA, and the common law.

a. SDWA Part D

Section 1431 of the SDWA authorizes the EPA to take action against a CCS operator upon a finding of an "imminent and substantial endangerment to the health of persons" where "appropriate State and local authorities have not acted to protect the health of such persons."¹⁵² The statute refers to this authority as "[e]mergency powers." The actions that EPA may take include but are not limited to:

- (1) issuing such orders as may be necessary to protect the health of persons who are or may be users of such system (including travelers), including orders requiring the provision of alternative water supplies by persons who caused or contributed to the endangerment, and (2) commencing a civil action for appropriate relief, including a restraining order or permanent or temporary injunction.¹⁵³

¹⁴⁹ U.S. Dep't of Energy, Final Environmental Assessment of Industrial Carbon Capture and Sequestration (ICCS) Area 1 Project, "CO₂ Capture from Biofuels Production and Sequestration into the Mt. Simon Sandstone," Archer Daniels Midland Company Decatur, Illinois (2011).

¹⁵⁰ U.S. Dep't of Energy, Finding of No Significant Impact for Archer Daniels Midland Company's "CO₂ Capture from Biofuels Production and Sequestration into the Mt. Simon Sandstone," Decatur, Illinois (2011).

¹⁵¹ See 75 Fed. Reg. 77230, 77270 (Dec. 10, 2010); see also Geologic Sequestration of Carbon Dioxide: Underground Injection Control (UIC) Program Class VI Well Plugging, Post Injection Site Care, and Site Closure Guidance (Dec. 2016), available at www.epa.gov/sites/production/files/2016-12/documents/uic_program_class_vi_well_plugging_post-injection_site_care_and_site_closure_guidance.pdf.

¹⁵² 42 U.S.C. § 300i.

¹⁵³ *Id.*

If EPA does issue an order under this provision, failure to comply with the order may result in civil penalties of up to \$15,000 per day of noncompliance.¹⁵⁴

b. RCRA / CERCLA

Because CO₂ streams that may be used for geologic sequestration are likely to contain impurities, there is a risk that a contaminated CO₂ stream may be considered toxic or hazardous waste regulated under the Resource Conservation and Recovery Act (RCRA). There is also a risk that, depending on the scope of any environmental contamination caused by impurities in the CO₂, liability could arise under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA or Superfund).¹⁵⁵ Industry specifically raised this concern to EPA during the rulemaking process for UIC Class VI wells, but EPA chose not to address the issue there.¹⁵⁶

Instead, in a separate rulemaking,¹⁵⁷ EPA clarified that CO₂ injected underground for CCS purposes will not create RCRA liability so long as certain conditions are followed. In adopting this rule, EPA specifically acknowledged the need for CCS industry certainty, noting that its objective is to “substantially reduce the uncertainty associated with defining and managing . . . CO₂ streams under RCRA subtitle C and [to] facilitate the deployment of GS.”¹⁵⁸

In order to qualify for RCRA liability exclusion under this rule, CCS owners and operators must comply with four key conditions:

- (1) Transportation of the carbon dioxide stream must be in compliance with U.S. Department of Transportation requirements, including the pipeline safety laws and regulations of the U.S. Department of Transportation, and pipeline safety regulations adopted and administered by a state authority pursuant to a certification, as applicable.
- (2) Injection of the carbon dioxide stream must be in compliance with the applicable requirements for Class VI Underground Injection Control wells, including the applicable requirements;
- (3) No hazardous wastes shall be mixed with, or otherwise co-injected with, the carbon dioxide stream; and
- (4)(i) Any generator of a carbon dioxide stream, who claims that a carbon dioxide stream is excluded under this paragraph (h), must have an authorized representative sign a certification.¹⁵⁹

¹⁵⁴ *Id.* § 300i(b).

¹⁵⁵ In broad terms, RCRA governs handling and disposal of hazardous and toxic wastes. CERCLA governs liability for cleanup of the nation’s most polluted sites.

¹⁵⁶ Hazardous Waste Management System: Conditional Exclusion for Carbon Dioxide (CO₂) Streams in Geologic Sequestration Activities, 79 Fed. Reg. 350-01 (Jan. 3, 2014).

¹⁵⁷ *Id.*

¹⁵⁸ *Id.*

¹⁵⁹ 40 C.F.R. § 261.4; *see also id.* § 261.4(h)(4).

Thus, under RCRA, a CO₂ stream that is connected to coal power plant will not be considered waste for RCRA purposes as long as the CCS owner and operator complies with all relevant regulations.

Presumably, the EPA's Conditional Exclusion Rule also should remove the specter of CERCLA liability for CCS operators. This is because of how CERCLA liability attaches. In broad terms, CERCLA liability attaches when there is a "release of a hazardous substance, from a facility, that results in response costs."¹⁶⁰ CERCLA categorically defines hazardous waste as "any hazardous waste having the characteristics identified under or listed pursuant to RCRA."¹⁶¹ Because EPA's rule excludes CO₂ streams from RCRA so long as the specified conditions are met, CERCLA liability also presumptively should be precluded because the CO₂ stream would not meet the definition of hazardous waste under RCRA, and thus, CERCLA.

c. Common Law

The United States has a long and rich tradition of judicially made law (now, often codified) that may give rise to liability. This is typically referred to as the "common law." The two most prominent areas in this regard are property law and tort law. These generally are areas of state law, and vary from jurisdiction to jurisdiction, although some federal common law also exists.

Accordingly, this section discusses several causes of action that may give rise to liability under common law theories for CCS operation. In particular, we address five key areas of common law: trespass, nuisance, negligence, negligence per se, and strict liability.

All of these causes of action require a judge (and/or jury) to balance the interests of CCS operation and CO₂ sequestration with the harm or harmful conduct alleged. Currently, there is no judicial precedent declaring the importance of CCS, and the exact harms that could occur are still speculative. Another relevant factor is the interaction of federal and state law. Generally, under the Supremacy Clause of the U.S. Constitution, federal law trumps state law. Parties to disputes sounding in common law thus regularly invoke federal law as a way to seek to defend against potential liability. As more federal legislation arises in the context of CCS, the availability of such defenses—referred to as "preemption"—could also arise, just as the imposition of federal standards of care may give rise to new legal theories for litigants. Further, when statutes of limitation bar claims will impact when and under what conditions liability for CCS projects may arise, especially for the sequestration phase of CCS.

Numerous courts also recognize that a tort defendant's compliance with regulatory requirements can provide a defense to certain tort or personal injury claims. Generally, however, a party whose conduct comports with regulatory requirements is not automatically protected from tort liability for harm resulting from that conduct. Rather, regulatory compliance is treated as non-conclusive evidence of an actor's non-negligent conduct.¹⁶²

1. *Trespass*

In the context of CCS, trespass may occur either when transported CO₂ (and the other chemicals it contains) contaminates the surface or subsurface estate owned by another entity. Because the quantity of injected CO₂ is vast, and how long the CO₂ remains mobile underground depends on myriad factors, there is a chance that CO₂ may migrate beyond acquired property interests. In that case, there may be actionable trespass claims against a CCS operator.

¹⁶⁰ Alexandra B. Klass & Elizabeth J. Wilson, *Climate Change and Carbon Sequestration: Assessing a Liability Regime for Long-Term Storage of Carbon Dioxide* 58 EMORY L.J. 103 (2008).

¹⁶¹ 42 U.S.C. § 9601(14).

¹⁶² THOMAS A. DICKERSON ET AL., 2 LAW OF TOXIC TORTS § 11:5.20 (2017).

Applying analogous principles from oil and gas law helps clarify the potential extent of such liability for trespass. Scholars have identified two factors that may limit a cause of action for trespass in the oil and gas context: (1) ascertaining actual damages and (2) overcoming public policy that favors the trespass.¹⁶³

First, ascertaining actual damages could be difficult, largely because of the fact that everything takes place deep beneath the surface. Thus, in the absence of catastrophic releases of stored CO₂, adjacent subsurface owners would most likely be unable to detect any trespass. Further, when the trespass is detected, plaintiffs typically bear the burden of proving their damages.¹⁶⁴ Therefore, a CCS operator should only anticipate trespass liability where there are “reasonably foreseeable” competing uses proximate to the CO₂ plume, such as natural gas extraction or storage.¹⁶⁵

Second, even if damages are capable of being ascertained and proven, courts weigh public policy against property law concerns.¹⁶⁶ This is particularly true in the oil and gas context, because many states have laws on the books specifically promoting the extraction of these resources. By contrast, state policy favoring CO₂ sequestration is much less established. Moreover, courts are less likely to weigh the public interest in cases of imminent danger to public health, because the damage is readily ascertainable, and the fundamental purpose of tort law is to redress private injury.¹⁶⁷

2. Nuisance

Nuisance actions arise even when there has been no physical trespass and the operator is in full regulatory compliance. Two different types of nuisance theories exist at common law: private nuisance and public nuisance. They differ as follows:

A public nuisance is an unreasonable interference with a right common to the general public and may only be asserted by a public body (such as a state or local government) or by a private party who has suffered a unique or special injury that differentiates his or her harm from that suffered by the general public. A private nuisance is a nontrespassory invasion of another’s interest in the private use and enjoyment of land and may be brought by anyone with an ownership or possessory interest in land.¹⁶⁸

Generally, under either theory, a cause of action sounding in nuisance arises when “the invasion of the private use and enjoyment of land [is] (1) intentional and unreasonable or (2) unintentional but negligent, reckless, or subject to strict liability because it is an abnormally dangerous activity.”¹⁶⁹ Once a cause of action in nuisance is shown, the question then becomes how to compensate the harmed party for it. In this regard, “the court balances the benefits of the alleged nuisance activity, the harm to the plaintiff and others, and other equitable factors to determine

¹⁶³ See Klass & Wilson, *supra* note 160, at 135.

¹⁶⁴ See, e.g., Raymond v. Union Texas Petroleum Corp., 697 F. Supp. 270, 274 (D. La. 1988); see also Mongrue v. Monsanto Co., No. 98-2531, 1999 WL 970354 (E.D. La. 1999).

¹⁶⁵ Chance v. BP Chems., Inc., 670 N.E.2d 985, 992 (Ohio 1996).

¹⁶⁶ See Klass & Wilson, *supra* note 160, at 135.

¹⁶⁷ *Id.*

¹⁶⁸ *Id.* at 139. (internal quotations and citations omitted).

¹⁶⁹ *Id.* (internal quotations and citations omitted).

whether the defendant should pay damages to the plaintiff or whether the plaintiff is entitled to enjoin the conduct causing the nuisance.¹⁷⁰

Nuisance liability could occur in ways similar to how trespass liability might arise. If a CCS operation contaminates (or forecloses or limits use of land) underground drinking water, soil or other surface resources, or subsurface resources, nuisance liability may exist. As with each of the common law liability theories at issue here, the resulting response from a court could include monetary damages and/or an injunction prohibiting future activities (or dictating how they proceed).

3. *Negligence*

A CCS operator potentially may be liable under common law theories of negligence as well, during both the transport and storage phases of the project. In general, negligence occurs when, by a preponderance of the evidence, a plaintiff shows that a

defendant owed a duty of care to the plaintiff, that the defendant breached that duty of care, that the defendant's breach of the duty was the actual and proximate cause of the plaintiff's harm, and that the plaintiff suffered damages (based on injury to person or property) as a result of the defendant's conduct.¹⁷¹

For many types of activities, duties of care are well-settled. For more novel activities, it can take some time for the law to coalesce around what, precisely, the duty of care is. Typically, the duty of care calculation weighs the utility of a defendant's action against its risk. Also taken into consideration is how reasonable the defendant's actions were.¹⁷² Because CO₂ transport is well-established and governed heavily by extant regulations, violations of those regulations likely would be considered a breach of the duty of care for purposes of negligence. By contrast, because the storage portion of CCS operations is more novel, plaintiffs may have an uphill battle demonstrating what level of care is required in, for example, selecting a site, injecting CO₂, ensuring its safe sequestration, and monitoring it for decades.¹⁷³ Of course, compliance with the terms of permits for these activities is at least some evidence of reasonableness, although it is not conclusive. Another key issue for CCS is proving who caused the damage in question. Because that could be difficult if there is more than one CCS operation underway in the same formation, plaintiffs, as with trespass, may face evidentiary challenges if they choose to bring a negligence claim. This issue runs to the heart of any claim for relief under a negligence theory, particularly if harm is difficult to quantify or monetize.

4. *Negligence Per Se*

A plaintiff may also bring an action under a theory of negligence per se. "Under negligence per se, a plaintiff can establish negligence if he or she can show that the defendant violated a statute 'designed to protect against the type of accident the actor's conduct causes and if the accident victim is within the class of persons the statute was designed to protect.'"¹⁷⁴ The UIC rules, promulgated under the SDWA, would likely fall into this category. It is possible that other applicable Utah statutes also could give rise to negligence per se liability. Such a liability theory would provide a more

¹⁷⁰ *Id.* (internal quotations and citations omitted).

¹⁷¹ *Id.* at 136 (quoting 1 DAN B. DOBBS, *THE LAW OF TORTS* § 114, at 269-70 (2001)).

¹⁷² *See* RESTATEMENT (SECOND) OF TORTS § 291.

¹⁷³ *See, e.g.*, N.J. Dep't of Env'tl. Prot. v. Ventron Corp., 468 A.2d 150 (N.J. 1983).

¹⁷⁴ Klass & Wilson, *supra* note 160, at 138 (quoting RESTATEMENT (THIRD) OF TORTS § 14 (Proposed Final Draft 2005)).

convenient path for plaintiffs, although they may face the same evidentiary challenges in bringing this cause of action as they would under a standard theory of negligence.¹⁷⁵

5. *Strict Liability*

Strict liability attaches when a project involves abnormally dangerous activities. Utah applied the *Rylands* test in *Branch v. W. Petroleum, Inc.*¹⁷⁶ and imposes strict liability when an operator “engages in a ‘non-natural’ or ‘abnormal’ use of the land which results in harm.”¹⁷⁷

Whether a CCS operator could be held strictly liable for their actions is uncertain. Klass and Wilson analyzed use of strict liability theories and concluded that such liability has been found applicable over time to “a broad range of activities.”¹⁷⁸ These include, for example, contamination of groundwater via petroleum products, release of “toxic wastes from . . . industrial operations,” and contamination of adjacent property with polychlorinated biphenyl (PCBs).¹⁷⁹ A strong argument can be made that CCS is a non-natural or abnormal land use, though abnormality may be somewhat more difficult to prove in areas undergoing extensive EOR. As with the tort remedies discussed above, strict liability could be an attractive path for plaintiffs, provided that plaintiffs can overcome the requirements to establish that the harm they experienced was caused by the operator.

C. **Managing Financial Risk and Long-Term Liability**

Risk exposure is a function of the likelihood of harmful event combined with the consequences of such an event, both of which are influenced by numerous site-specific factors. In this section, we treat financial risk as the economic cost of mitigating the injuries caused by a harmful event as well as compensation for unmitigable injuries associated with any such event. For purposes of risk assessment, CCS operations can be broken into four discrete phases: (1) capture, (2) transport, (3) injection and CO₂ plume stabilization, and (4) post-closure stabilization and monitoring. This analysis focuses on the transport, injection and CO₂ plume stabilization, and post-closure stabilization and monitoring phases.

Events giving rise to financial liability could take many forms, the most likely of which involve damage caused by: (1) the puncture of a CO₂ pipeline or failure of other pipeline infrastructure, (2) seismicity induced by CO₂ injection, (3) ground surface damage or surface heaving caused by injected CO₂, (4) interference with a surface owner’s rights to occupy or use the ground surface (trespass), (5) interference with a sub-surface owner’s rights to occupy or use the sub-surface, or infringement with development of their mineral rights (trespass on minerals), (6) contamination of an underground source of drinking water or other water source, and (7) an atmospheric release of CO₂. Loss of CO₂ containment and failure to maintain permanent

¹⁷⁵ For a thorough discussion of negligence per se and environmental regulations, see Alexandra B. Klass, *Common Law and Federalism in the Age of the Regulatory State*, 92 IOWA L. REV. 545, 585 (2007).

¹⁷⁶ 657 P.2d 267 (Utah 1982). *W. Petroleum* dealt with an oil well water disposal service, which disposed of formation water in ponds adjacent to plaintiffs’ farm. The court held the defendant strictly liable for pollution of subterranean water system that fed plaintiffs’ culinary wells, determining that liability could be based on the theory that ponding of toxic formation water in an area adjacent to the wells constituted an abnormally dangerous and inappropriate use of the land.

¹⁷⁷ See *id.* at 141 (quoting W. PAGE KEETON ET AL., PROSSER AND KEETON ON THE LAW OF TORTS § 75, at 534 (5th ed. 1984)).

¹⁷⁸ Klass & Wilson, *supra* note 160, at 142.

¹⁷⁹ *Id.* For a full discussion of strict liability cases, see generally Alexandra B. Klass, *From Reservoirs to Remediation: The Impact of CERCLA on Common Law Strict Liability Environmental Claims*, 39 WAKE FOREST L. REV. 903, 942-961 (2004).

sequestration, as required by regulation or contract, could also require the operator to refund payments received for sequestration. Damage to property, damage to natural resources or livestock, and injury to humans also involve potential economic costs to an operator.

The risk profile for each stage of operation underpins the range of costs and loss values associated with potential mitigation, remediation, and, as necessary, compensation for damages. The risk profile is a function of numerous phase-specific considerations. With respect to CO₂ transport, pipeline length, period of pipeline operation, CO₂ pressure, CO₂ purity, and proximate land use activities are examples of factors that could contribute to the risk associated with an unintended release. The location of an unintended release of CO₂ could also directly impact the consequences of such a release. A CO₂ release would be more likely to cause injury or property damage if it occurred in a populated area, for example.

During the injection and plume stabilization phase, the volume of CO₂ injected, the injection pressure, the length of the injection period, the geology of the receiving formation, the number and integrity of other wells penetrating the receiving formation, and the existence of underground sources of drinking water or valuable minerals all contribute to the risk profile. As with the risk profile associated with CO₂ transportation, the proximity to populated areas is also a critical factor in assessing risk. This necessarily requires consideration of current population as well as anticipated population growth.

Many of the same factors that shape injection and plume stabilization period risks impact the risk profile during the post-closure and post-CO₂-plume-stabilization period. However, in contrast to the risk profile during the injection and stabilization phase, which increases with injection volume and pressure until stabilization occurs, the post-stabilization and closure risk profile is likely to decline¹⁸⁰ as reservoir pressures stabilize, plume migration slows or stops, and as CO₂ reacts with brine and minerals in the rock to form bicarbonate that permanently traps that portion of the injected CO₂, as shown in Figure 2.¹⁸¹

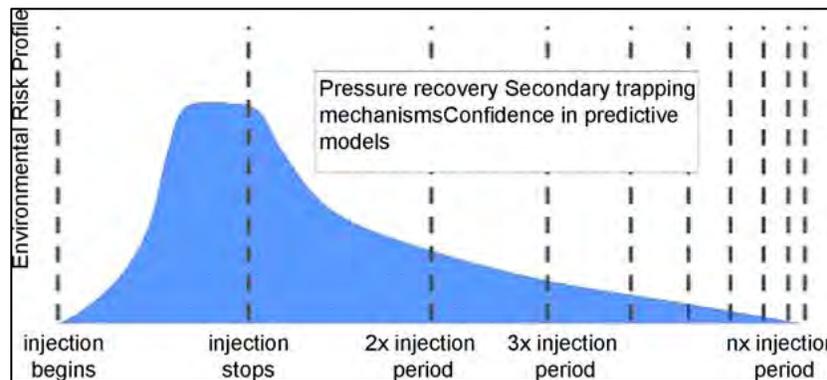


Figure 2. Life-Cycle Risk Profile for Geologic CO₂ Storage¹⁸²

¹⁸⁰ See, e.g., James J. Dooley et al., *Design Considerations for Financing a National Trust to Advance the Deployment of Geologic CO₂ Storage and Motivate Best Practices*, 4 INT'L J. GREENHOUSE GAS CONTROL 381, 382 (2010).

¹⁸¹ For a summary of CO₂-trapping mechanisms, see National Energy Technology Lab, U.S. Dept. of Energy, *How Is CO₂ Trapped in the Subsurface?*, <https://www.netl.doe.gov/research/coal/carbon-storage/carbon-storage-faqs/how-is-co2-trapped-in-the-subsurface> (last visited Apr. 25, 2018).

¹⁸² Figure 2 is from S.M. Benson, *Multi-Phase Flow and Trapping of CO₂ in Saline Aquifers* (Paper No. OTC 19244) in PROCEEDINGS OF 2008 OFFSHORE TECHNOLOGY CONFERENCE (2008).

Other factors further underscore how quantifying CCS financial risks necessarily requires site-specific risk assessments. Reservoir size and permeability, injection volume and pressure, CO₂ stream purity, structural geology, faulting and reservoir perforations (including existing and abandoned wells), proximity to groundwater, proximity to valuable mineral resources, proximity to populated areas, proximity to sensitive surface resources, and pipeline length are all examples of the kinds of factors that must be considered on a case-by-case basis. Should the CarbonSAFE Rocky Mountain project proceed past Phase I, then, a quantitative risk assessment specific to the project, taking into account this site-specific information, would be necessary.

While a precise quantification of financial risk for the CarbonSAFE Rocky Mountain project is not currently possible, a review of other CCS projects may provide a rough indication of the scale of financial risk at hand. A 2011 study in ENERGY PROCEDIA provides preliminary estimates of potential public health damages during the operational phases at three proposed FutureGen sites: Tuscola, Illinois; Jewett, Texas; and Odessa, Texas.¹⁸³ As the authors explain:

[A]ll three sites are in highly rural areas and have favorable geologic and geographic characteristics that result in relatively low damages relative to the expected cost of these facilities. Notably, the Odessa damages estimate is particularly low, reflecting the near absence of human receptors near the plant site, CO₂ pipeline, and sequestration site.¹⁸⁴

Specifically, damage estimates ranged from \$50,000 to \$7,400,000. These estimates equate to less than \$0.20 per ton of CO₂, assuming a 50-year injection period and 50 million metric tons of CO₂ stored per site. Critically, however, these valuation estimates are limited to valuation of events arising during the operational period through a defined post-injection period for each site. It is also important to note that these estimates relate only to damages associated with injuries involving public health and do not contemplate damages associated with environmental resources, such as groundwater or atmospheric releases of CO₂.

A 2014 study involving two of the same authors and also published in ENERGY PROCEDIA used a risk-based probabilistic model to estimate several categories of potential financial damages on a site-specific basis.¹⁸⁵ This model estimated the financial consequences arising from potential human health, safety, environmental, and business interruption events associated with CCS, in light of their anticipated site-specific likelihood and magnitude.

The authors utilized this model to quantify financial risk at the Alabama Gulf Coast-Plant Barry pilot project in Mobile, Alabama based on forty-eight potential site-specific CCS-related events at the site. The authors contemplated two scenarios: an “experimental injection well” that operated for nine years and a theoretical commercial injection well that operate for 103 years (including ten years of post-injection monitoring). Damages under the experimental injection well scenario were estimated to range up to \$27 million, with a median damage estimate of \$3.3 million.¹⁸⁶ The five events contributing the highest potential damage for the experimental scenario were:

¹⁸³ Michael Donlan & Chiara Trabucchi, *Valuation of Consequences Arising from CO₂ Migration at Candidate CCS Sites in the U.S.*, 4 ENERGY PROCEDIA 2222 (2011).

¹⁸⁴ *Id.* at 2228.

¹⁸⁵ Chiara Trabucchi et. al, *Application of a Risk-Based Probabilistic Model (CCSvt Model) to Value Potential Risks Arising from Carbon Capture and Storage*, 63 ENERGY PROCEDIA 7608 (2014).

¹⁸⁶ *Id.* at 7612.

- Failure to maintain sustained operation of capture unit, pipeline, and injection to enable storage of sufficient volumes of CO₂ (100-300 kt) to meet project goals;
- Unexpected transport requirements;
- Monitoring program unable to meet monitoring intents due to movement of CO₂ and demonstration of containment;
- Decreased performance of capture unit based on fuel switch; and
- Injection pump failure or downtime.

Together, these five categories of events represented 66.5 percent of total costs across all model runs.¹⁸⁷

Modeling for the commercial scenario produced damage estimates of up to \$131 million, with a median damage estimate of \$6 million. The five events contributing to the highest potential damage estimated under the commercial scenario were:

- Monitoring program unable to meet monitoring intents due to movement of CO₂ and demonstration of containment;
- Unexpected transport requirements;
- Unexpected size of plume expansion (larger than anticipated) triggering permit review, expanded monitoring activities, and implementation of preventive measures on wells;
- Loss of containment due to migration along transmissive faults; and
- Return of low quality condensate that could impact water chemistry and cause problems at the plant.

Together, these five categories of events represented 83.7 percent of the total costs across all model runs.¹⁸⁸ The authors also compared the cost per ton of sequestered CO₂ to those projected for the non-selected FutureGen site in Jewett, Texas, as shown in Figure 3.

Category	Commercial Well Scenario - Plant Barry				Non-Selected FutureGen Site Jewett, TX
	30-Year Post-Injection Monitoring		10-Year Post-Injection Monitoring		
	All Events	Business Risks Excluded	All Events	Business Risks Excluded	
Minimum \$/ton cost	\$0.00	\$0.00	\$0.00	\$0.00	\$0.00
50th percentile \$/ton cost	\$0.17	\$0.12	\$0.12	\$0.07	\$0.17
95th percentile \$/ton cost	\$1.05	\$1.01	\$0.92	\$0.88	\$0.37
99th percentile \$/ton cost	\$1.54	\$1.49	\$1.36	\$1.32	\$0.48
Maximum \$/ton cost	\$2.67	\$2.85*	\$2.63	\$2.56	\$0.74

* All Monte Carlo simulations across scenarios were conducted independently. In this case, the highest-cost trial for the "business risks excluded" scenario exceeded the costs of the highest-cost trial for the scenario where no events were excluded. This outcome has a very low probability of occurrence. \$/ton assume 50MM tons CO₂ injected.

**Figure 3. Cost Per Ton Summary
Model Outputs for Commercial Well Scenario
and Non-Selected FutureGen Site in Jewett, TX¹⁸⁹**

¹⁸⁷ *Id.*

¹⁸⁸ *Id.*

¹⁸⁹ Figure 3 is from Trabucchi et al., *supra* note 185.

While the costs and risks associated with the CarbonSAFE Rocky Mountain project will undoubtedly differ from those associated with either the Plant Berry or Jewett, Texas facilities, it seems reasonable at this preliminary phase to plan for financial risks in the range of \$1.00 to \$1.50 per ton of CO₂ injected. This represents approximately the ninety-fifth to ninety-ninth percentile for the Plant Berry Facility and is more than the estimate for the Jewett, Texas site.

Insurance for CCS operations needs to consider all of the risks associated with more traditional industrial operations as well as the risks associated with long-term sequestration. Insurance markets for post sequestration and stabilization liability remain undeveloped. The possibility of open-ended liability—including the potential for a large payout—has discouraged investment in this area, as has the slow development of commercial scale CCS facilities. There may also be a mismatch between the real and perceived risk profile for long-term CCS, as reservoir pressures are anticipated to decrease over time, especially given that CO₂ is likely to react with brine and minerals in the rock to form bicarbonate and permanently trap a significant portion of the injected CO₂. This may, in turn, result in reliance on less accurate analogues for insurance model development.

Legislation at either the state or federal level that assumes long-term responsibility once injection has ceased and the CO₂ plume has stabilized may help in addressing these issues. This is what Congress has done for other industries, including, for example, for the nuclear power industry through the Price-Anderson Act. Otherwise, operators may need to explore more creative ways of developing insurance options.

IV. FEDERAL ENVIRONMENTAL IMPACT REVIEW

The National Environmental Policy Act (NEPA)¹⁹⁰ has been described as the Magna Carta of environmental laws.¹⁹¹ Notably, however, the law does not require the federal government to do anything substantive with respect to the environment. Rather, the statute requires the government to consider what impact different actions that it takes will have on the environment before taking those actions. The idea is that NEPA facilitates federal agencies making informed decisions because they consider the consequences of various alternative courses of action before proceeding. Indeed, NEPA does not require selection of the least damaging alternative, only that agencies take a hard look at tradeoffs before moving forward. Where an action involves approvals from multiple agencies, those agencies can combine their NEPA analyses. While several states have adopted state environmental policy acts that involve procedural mandates similar to NEPA, Utah is not one of those states.

A. The NEPA Process

NEPA requires that, prior to authorizing or undertaking any “major Federal action significantly affecting the quality of the human environment,” the lead federal agency must analyze the likely impacts of that action on the environment. This often results in a detailed statement discussing the purpose and need for the proposed action, alternative means of satisfying the purpose and need, and the environmental impacts that are anticipated to result from each considered alternative, including an alternative of “no action.”¹⁹² Under NEPA, the “human environment” is defined broadly to include “the natural and physical environment and the relationship of people with

¹⁹⁰ 42 U.S.C. §§ 4321–4370(h).

¹⁹¹ DANIEL R. MANDELKER, *NEPA LAW AND LITIGATION* § 1:1 (2d ed. 2014).

¹⁹² 42 U.S.C. § 4332(2)(C).

that environment.”¹⁹³ Major federal actions typically include the issuance of project permits, such as mineral leases on federal lands.

Not all federal actions have a “significant” impact, and the scope and intensity of impacts associated with the proposed action determine the level of analysis required. Where impacts are “significant” in both their context and intensity, an Environmental Impact Statement (EIS) is required. “Context” varies by project and is evaluated at multiple scales.¹⁹⁴ “Intensity” may reflect a wide array of factors, including but not limited to controversy surrounding the nature of the effects¹⁹⁵ and the degree to which the action may establish a precedent for future actions with significant effects.¹⁹⁶

Where the significance of impact is uncertain, the lead federal agency may elect to prepare either an EIS or a less onerous Environmental Assessment (EA).¹⁹⁷ If the agency chooses the latter path and the EA shows that the impacts are significant, then the agency must prepare a full-fledged EIS. If, however, the EA shows that the impacts are not significant, the agency may issue a finding of no significant impact (FONSI) and a record of decision (ROD) on that determination.

Agencies are also authorized to promulgate regulations identifying categories of action that “do not individually or cumulatively have a significant effect on the human environment.”¹⁹⁸ Agencies can then categorically exclude these actions from further NEPA review. However, even if a categorical exclusion (CE) has been established by rule, the existence of “extraordinary circumstances” may prevent its application.¹⁹⁹ Under Department of Energy regulations, certain small-scale CO₂ injection wells are categorically exempt from NEPA analysis.²⁰⁰ CarbonSAFE, however, is likely to inject more than the 500,000-ton limit allowed under these regulations.

EISs are part of an iterative analytical decision making process that begins with publication of a Notice of Intent (NOI) to prepare an EIS.²⁰¹ The NOI kicks off a public scoping period in which the public is invited to submit comments about the proposal, the environmental issues the proposal raises, and potential alternative means of achieving the purpose of the proposed action.²⁰² Those comments help the lead federal agency identify issues, formulate alternatives, and collect or conduct necessary research. The reasonably foreseeable direct, indirect, and cumulative impacts anticipated to result from implementation of each alternative (including a “no action alternative”) are then analyzed and disclosed in a Draft EIS (DEIS).²⁰³ The DEIS is made available for public review and comment.²⁰⁴ After considering public input, the lead federal agency releases a Final EIS (FEIS) that reflects public input on the agency’s methods and analysis.²⁰⁵ Following a period in which the governor of the state within which the project occurs can comment on consistency with state requirements, the lead federal agency then issues a ROD stating the agency’s decision and initiating a protest or appeals period.²⁰⁶ Figure 4 details this process.

¹⁹³ 40 C.F.R. § 1508.14.

¹⁹⁴ *Id.* § 1508.27(a).

¹⁹⁵ *Id.* § 1508.27(b)(4).

¹⁹⁶ *Id.* § 1508(b)(6).

¹⁹⁷ *Id.* § 1508.9.

¹⁹⁸ *Id.* § 1508.4.

¹⁹⁹ *Id.* § 1508.4.; *see e.g.*, 43 C.F.R. § 46.215 (2017) (listing extraordinary circumstances for BLM NEPA).

²⁰⁰ 10 C.F.R. § Pt. 1021. Subpt. D App. B § B5.13 (2017).

²⁰¹ 40 C.F.R. § 1501.7.

²⁰² *Id.* § 1501.7(a).

²⁰³ *Id.* §§ 1502.9(b), 1508.8.

²⁰⁴ *Id.* § 1503.1(a)(4).

²⁰⁵ *Id.* § 1502.9(b).

²⁰⁶ *Id.* § 1505.2.

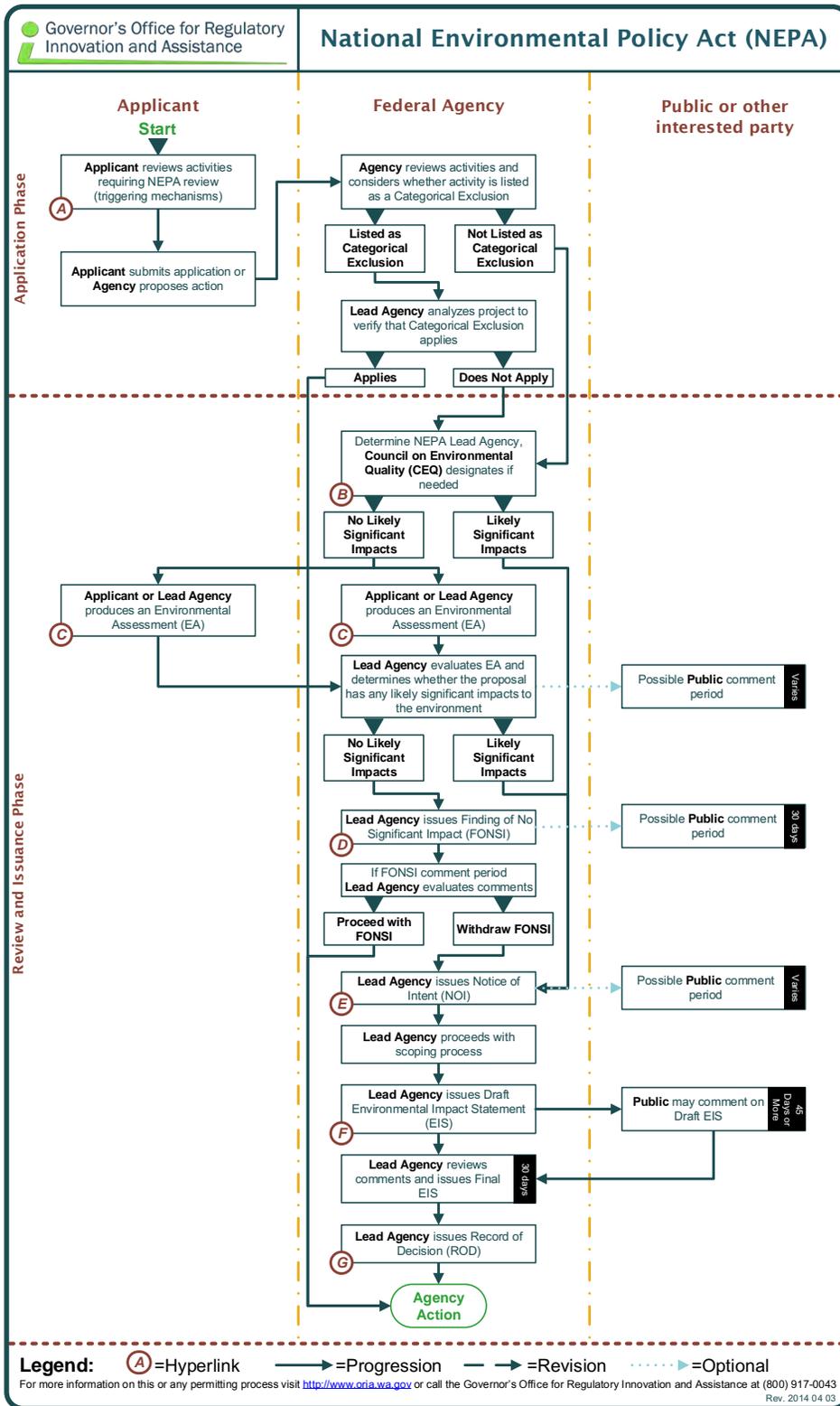


Figure 4. The NEPA Process²⁰⁷

Agencies are directed not to speculate when conducting their NEPA analysis, and therefore frequently choose to undertake a phased approach to NEPA implementation. The BLM, for example, may undertake a NEPA analysis as part of a planning-level decision to determine which lands are available for oil and gas development and which surface use stipulations will apply to those broad areas. Not all lands that are available for leasing will be of interest to industry, and the BLM may therefore need to review or update NEPA determinations in response to an expression of interest prior to leasing an individual parcel, if project-scale information was not considered at the multi-million-acre planning scale. The BLM may also need to conduct NEPA reviews on, for instance, the actual development of the well or well field if the viability of the field, the number of wells, likely field and pipeline layouts, or other associated impacts that were not discernable at the time of leasing. The federal agency, however, cannot segment one project into its component parts in order to reduce the level of analysis required under NEPA.²⁰⁸

B. NEPA Considerations for the CarbonSAFE Rocky Mountain Project

Multiple federal actions associated with the CarbonSAFE Project are likely to trigger NEPA review. If the CO₂ plume is anticipated to migrate into pore space that is under federal ownership or control, issuance of a federal lease to utilize the pore space will likely require NEPA analysis by the Bureau of Land Management. If the injection well compressors, pipelines, or other infrastructure are located on federal lands, obtaining rights to use these lands (leases or rights-of-way) will also require NEPA review. Issuance of federal permits that may be required by other laws may also require analysis under NEPA, including, potentially, for a CCS pipeline.²⁰⁹ Finally, future funding of project implementation by the Department of Energy would also likely require NEPA analysis.²¹⁰

Notably, Class VI injection well permitting, which is conducted by the EPA and occurs pursuant to the Safe Drinking Water Act, is likely exempt from NEPA review. Safe Drinking Water Act permitting is exempt from NEPA because the SDWA's requirements to consider the environment are "functional equivalents" of the impact statement process.²¹¹

With respect to the level of review that agencies are likely to employ, we believe that federal agencies are likely to conclude that an EIS is required for any possible CCS project like CarbonSAFE in light of the context and intensity of potential impacts. If a less rigorous level of analysis is available, permitting could move forward more expeditiously. A less rigorous approval process, however, may be more difficult to defend in the face of potential legal challenges. This is because, when challenging an EA, a party must show that impacts were either inadequately considered or that impacts exceed the "significance" threshold. By contrast, in legal challenges to EISs, significance of impact is not an issue. Instead, the litigant must demonstrate that the agency

²⁰⁷ Schematic from Washington State, Governor's Office of Regulatory Innovation and Assistance https://www.oria.wa.gov/Portals/_oria/VersionedDocuments/Schematics_N-Z/National-Environmental-Policy-Act-Schematics.pdf.

²⁰⁸ *Coalition on Sensible Transportation v. Dole*, 826 F.2d 60, 68 (D.C. Cir. 1987) ("Agencies may not evade their responsibilities under NEPA by artificially dividing a major federal action into smaller components, each without 'significant' impact.").

²⁰⁹ Most Clean Water Act permitting is exempt from NEPA, *see* 33 U.S.C. § 1371(c), as are most Clean Air Act permits, *see* 15 U.S.C. § 793(c)(1).

²¹⁰ Under DOE regulations, certain small-scale CO₂ injection wells are categorically exempt from NEPA analysis. 10 C.F.R. § Pt. 1021. Subpt. D App. B § B5.13.

²¹¹ *Western Nebraska Resource Council v. EPA*, 943 F.2d 867, 871 (8th Cir. 1992).

failed to take the requisite “hard look” at potential impacts.²¹² Proceeding as if an EIS is required therefore represents a conservative assumption for a project such as CarbonSAFE.

To expedite the NEPA process and reduce paperwork, federal agencies may integrate the NEPA review with other environmental reviews and consultation processes,²¹³ incorporate other NEPA documents by reference,²¹⁴ or “tiering from statements of broader scope to those of narrower scope, to eliminate repetitive discussions of the same issues.”²¹⁵ Accordingly, CarbonSafe may be able to utilize the information contained in the Class VI injection well permit application to satisfy much of their NEPA obligation.

A recent review of EISs prepared for large oil and natural gas field development projects in the Intermountain West found that it takes an average of 4.4 years to complete an oil and gas field EIS, as measured from the NOI to ROD (the range was 1,057 to 2,556 days).²¹⁶ This represents a rough estimate of the time likely involved in obtaining NEPA approval for the CarbonSAFE Project, as the smaller geographic scope of the CarbonSAFE Project is likely to minimize the level of analysis required. However, as a first-of-kind project associated with a highly scrutinized industry and located proximate to areas that are of great interest to the environmental community, intense public scrutiny should be anticipated.

Notably, on September 1, 2017, the Secretary of the Interior issued an order to all agencies within the Department, including the Bureau of Land Management, directing them to complete their NEPA analyses within a one-year limit. The order also directs agencies to limit their EISs to 150 pages normally, or 300 pages for unusually complicated projects.²¹⁷

Operators should not assume that the Department of the Interior will adhere to either time limits or page restrictions. Accelerating the NEPA process may impact the quality of the analysis and invite litigation. Rushing may, in short, prove to be counterproductive. We anticipate that the BLM will work hard to comply with the Secretarial Order without compromising document defensibility. The best way to do this is to frontload the NEPA analysis by completing requisite studies before publishing a NOI. This will result in delayed initiation of the formal NEPA process.

More importantly, when a federal agency is sued for failing to comply with NEPA’s procedural requirements, the reviewing court will still ask whether the agency took the requisite “hard look” at the environmental consequences of the project and a reasonable range of alternatives.²¹⁸ This standard of review has not changed. The BLM has a strong incentive to ensure that EISs are defensible in court and is therefore likely to move text from the EIS into an appendix. This practice will change the formatting of NEPA documents but not reduce the overall analysis. The BLM likewise has a similar incentive to delay document completion in order to increase defensibility.

A final consideration involves the potential scope of review that would be required if the CCS operator intends to use only state or private pore space, but where that operator needs to acquire limited surface use rights for pipelines, monitoring wells, or other infrastructure. If such a question arises, the issue becomes the scope of the analysis required pursuant to NEPA. NEPA

²¹² *Citizens to Preserve Overton Park, Inc. v. Volpe*, 401 U.S. 402 (1971).

²¹³ 40 C.F.R. § 1500.4(k) (2017).

²¹⁴ *Id.* § 1500.4(j).

²¹⁵ *Id.* § 1500.4(i).

²¹⁶ John Ruple & Mark Capone, *NEPA—Substantive Effectiveness Under a Procedural Mandate: Assessment of Oil and Gas EISs in the Mountain West*, 7 G. WASH. J. ENERGY & ENVTL. L. 39, 43 (2016).

²¹⁷ U.S. Dep’t of the Interior Secretarial Order 3355 (Sept. 1, 2017).

²¹⁸ *Citizens to Preserve Overton Park, Inc. v. Volpe*, 401 U.S. 402 (1971).

requires analysis of the direct, indirect, and cumulative effects of the various alternatives regardless of whether those impacts occur on federal land. “Direct” environmental effects are those “which are caused by the action and occur at the same time and place.”²¹⁹ Indirect effects are those “which are caused by the action and are later in time or farther removed in distance, but are still reasonably foreseeable.”²²⁰ A cumulative impact is “the impact on the environment which results from the incremental impact of the action when added to other past, present, and reasonably foreseeable future actions. . . . Cumulative impacts can result from individually minor but collectively significant actions taking place over a period of time.”²²¹ Connected actions cannot be divided into their component parts in order to narrow or expedite the analysis.²²²

While NEPA compliance can be costly and time-consuming, it will likely be a necessary component of CarbonSAFE Rocky Mountain implementation. Possibly the best advice that we can provide regarding NEPA compliance is to coordinate closely with the BLM, be patient, and avoid the temptation to cut corners. A rushed NEPA analysis is more likely to contain errors or omissions that would cause a reviewing court to require a supplemental analysis. Any time saved by streamlining analysis on the front end will likely be more than consumed by litigation and revisions on the back end.²²³

C. The National Historic Preservation Act

Enacted in 1966, the National Historic Preservation Act²²⁴ (NHPA) was intended, in part, to preserve historical and archaeological sites. Section 106 of the NHPA requires that federal agencies complete a review process for all federally funded and permitted projects that will impact sites listed on, or that are eligible for listing on, the National Register of Historic Places.²²⁵ Under section 106, federal agencies must “take into account” the effect a project may have on historic properties. Section 106 allows interested parties an opportunity to comment on the potential impact that projects may have on significant archaeological or historic sites. Like NEPA, the NHPA is a procedural statute that does not require substantive protections. Rather, both statutes require federal agencies to “look before they leap.”

Any federal agency whose project, funding, or permit may affect a historic property that is either listed or eligible for inclusion in the National Register of Historic Places must consider project effects and seek to avoid, minimize, or mitigate any adverse effects on historic properties. NHPA compliance will require early consultation with BLM archaeologists and the State Historic Preservation Officer. These individuals will be able to search agency records and identify known cultural and historic sites. Surveys and tribal consultation may be required to determine whether additional cultural or historic sites are found within the project area and, if so, whether these sites are potentially eligible for inclusion on the National Register of Historic Places.

Of note for the CarbonSAFE Rocky Mountain project, oil and natural gas lease sales in the region have been challenged and sometimes deferred because of possible impacts to petroglyphs and pictographs that are known to exist near the San Rafael Swell. These sites, which are almost certainly eligible for inclusion on the National Register of Historic Places, have not been the subject of

²¹⁹ 40 C.F.R. § 1508.8(a).

²²⁰ *Id.* § 1508.8(b).

²²¹ *Id.* § 1508.7.

²²² *Id.* § 1508.25(a)(1).

²²³ See John Ruple & Mark Capone, *NEPA, FLPMA, and Impact Reduction: An Empirical Assessment of BLM Resource Management Planning and NEPA in the Mountain West*, 46 ENVTL. L. 952 (2017).

²²⁴ 16 U.S.C. §§ 470 *et seq.*

²²⁵ *Id.* § 470f.

comprehensive surveys and are therefore not well documented. While the project at hand has a limited geographic footprint and is therefore less likely to impact sites across a broad area, the project team should still consult with the BLM and Utah State Historic Preservation Officer to identify archaeological sites, historic mining properties, homesteads, or other sites that may warrant special attention.

D. Lessons Learned from Permitting Other CCS Facilities

We reviewed permitting documents for other CCS facilities in order to identify lessons that could be learned from those experiences, as detailed above. While the CarbonSAFE Rocky Mountain project will be subject to many of the same procedural requirements, factual differences between the project at hand and prior CCS facilities need to be acknowledged when considering the experience at other CCS facilities. Nonetheless, the experience of the other projects is useful when appraising the path forward for a potential CarbonSAFE Rocky Mountain project.

1. *NRG Energy (W.A. Parish Post Combustion Project)*

NRG Energy's proposed W.A. Parish PCCS Project involved construction of a CO₂ capture facility at NRG's 4,880-acre W.A. Parish Plant in rural Fort Bend County, Texas (sometimes also referred to as the Petra Nova Project). The capture facility would use an amine-based absorption technology to capture at least 90% of the CO₂ from a 250-megawatt equivalent portion of the flue gas exhaust from Unit 8 at the plant. The project would be designed to capture approximately 1.6 million tons of CO₂ per year, and the captured CO₂ would be compressed and transported via a new, 81-mile-long, 12-inch-diameter underground pipeline to the existing West Ranch oil field in Jackson County, Texas. There, the CO₂ would be used for enhanced oil recovery and ultimately sequestered in geologic formations approximately 5,000 to 6,300 feet below the ground surface.

The DOE completed an EIS for the W.A. Parish Project, addressing the following issues: air quality and climate, greenhouse gas emissions, geology, physiography and soils, surface waters, ground water, floodplains, wetlands, biological resources, cultural resources, land use, aesthetics, traffic, transportation, noise, materials and waste management, human health and safety, utilities, community services, socioeconomics, and environmental justice. For purposes of the EIS, the DOE assumed that the project would continue for twenty years. The DOE was required to conduct a NEPA analysis because the project involved DOE funding.

The W.A. Parish Project did not generate significant controversy; there were just four comments on the Draft EIS. Of the four comments received, three came from government agencies, and one was from a member of the general public. Comments from the public focused on air quality impacts associated with the continued combustion of coal and how conversion to a natural gas-fired facility would help reduce both VOC and NO_x emissions. The EPA was concerned about damage to navigable waters and jurisdictional wetlands. The DOE asserted that all navigable water would be identified and that any wetland permanently impacted would be mitigated. The FWS was concerned with impacts to listed species under the ESA. The DOE amended the EIS to ensure that more migrating birds would not be impacted during pipeline construction. The Texas Parks and Wildlife Department echoed the FWS and the DOE ensured their concerns were addressed. Pore space ownership was not an issue, as CO₂ was injected into an existing field for EOR.

2. *ADM*

The ADM project was considered a "federal action" and therefore subject to NEPA because of DOE funding. The NEPA analysis considered only two alternatives, the proposed action and a no action alternative under which the DOE would not contribute any funds. EPA permitting documents do not mention public comments received in response to the ADM proposal. The

narrow range of alternatives and absence of a discussion of public comments likely indicate that the project received little public scrutiny. While the reasons for limited public interest are difficult to identify, the setting and short duration of the project were likely contributing factors. Notably, ADM appears to own the pore space into which the CO₂ is injected, thus limiting potential impacts to public lands and removing a major concern that is likely to face the CarbonSAFE project.

As noted in the earlier discussion of SDWA permitting for the ADM project, the EPA did not address pore space ownership as part of its analysis. It also appears that no claim of federal pore space ownership was implicated by the ADM project. CarbonSAFE Rocky Mountain is therefore distinguishable from the ADM permit because the BLM will need to complete a NEPA review before granting rights to utilize the federal surface or sub-surface, and this analysis will necessarily consider pore space ownership. This NEPA analysis will be independent of the EPA's NEPA analysis for the Class VI injection permit. Proximity to the San Rafael Swell is also likely to attract a level of public attention that was absent from the ADM project.

With respect to the ADM project, the EPA also disclaimed any need to consult with the Fish and Wildlife Service regarding impacts to species protected pursuant to the Endangered Species Act. The EPA stated that they found there was no jeopardy to listed species or critical habitat, thus ending the inquiry. Further, EPA disclaimed any need for NEPA review because the action was "administrative in nature." Again, CarbonSAFE should not assume such expedient treatment of its project. While the EPA may consider impacts to wildlife to be beyond the scope of their permitting analysis, the likely use of federal surface or sub-surface for either infrastructure or sequestration will necessitate BLM involvement, and as issuance of a right-of-way or permit to utilize federal lands could represent an irretrievable commitment of resources, the BLM will almost certainly need to consider wildlife impacts before rendering a decision.

V. ADDITIONAL LEGAL AND REGULATORY CONSIDERATIONS

The above analysis highlights the key legal issues that tend to be focused on with respect to CCS projects. However, there are several other issues that may arise, and that would need to be addressed depending on the particular facts of the project. Those facts should come into clearer focus should the CarbonSAFE Rocky Mountain project proceed beyond Phase I.

A. Public Utility Regulation

One key regulatory approval that the CarbonSAFE Rocky Mountain project would have to obtain is a determination that the cost imposed by the project on electricity customers is not too great. This involves six determinations, not one. Rocky Mountain Power is a subsidiary of PacifiCorp. In turn, PacifiCorp allocates portions of its broad generation portfolio among its various utility subsidiaries serving customers in six states: California, Idaho, Oregon, Utah, Washington, and Wyoming. Unless PacifiCorp chose to alter this allocation, conceivably the public service commission in each of those states would need to pass on the cost impacts of the CarbonSAFE project at some point.

At one level, this form of regulation would not appear to pose too high of a burden for the CarbonSAFE project. Although regulatory approval eventually would be needed, utility law generally does not require electricity providers to file a new rate case every time they incur some new cost. Rather, they must only do so when they seek a general rate increase or change.²²⁶ So, the CarbonSAFE project theoretically could be operational before such a rate approval were sought.

²²⁶ See, e.g., UTAH CODE § 54-7-12.

However, two caveats limit how much leeway the proponents of the CarbonSAFE project might actually enjoy. First, public utility commissions typically can start their own investigations of a utility, if they see fit. Thus, if the CarbonSAFE project raised concerns for any of these states' public service commissions, regulatory oversight could arrive more quickly than planned. Second, when a rate case is brought, even by the utility itself, the utility must justify the cost as both “just and reasonable”—that is, not too expensive—as well as “prudent”—that is, an economically efficient investment that a reasonable or prudent manager of the company would make.²²⁷

Under this substantive standard, the two biggest hurdles to the CarbonSAFE project likely would be economic and policy-based. The economic obstacle is obvious and relates back to the cost barrier to commercial-scale deployment that CCS technology faces. Since the objective of utility regulation is to ensure that companies only incur necessary (and economically efficient) costs in providing service, there is a risk that parties would argue the comparatively high cost of CCS is neither. Of course, were some kind of greenhouse gas emission limit placed on PacifiCorp or Rocky Mountain Power, this might be easier to show, but the receding nature of federal regulation in that context and the absence of it in many state contexts renders that argument more difficult to make. Moreover, even with climate regulation of the electricity sector in place, proponents of the CarbonSAFE project arguably would need to either show that CCS technology is as cost-effective as other ways of mitigating climate emissions (such as solar or wind) or point to a CCS-specific mandate of some kind. This may be difficult.

From a policy-based perspective, the CarbonSAFE project also could face challenges. Many of the states from which PacifiCorp would need regulatory approvals have renewable energy requirements for the electricity sector in place.²²⁸ This could raise questions about why the CarbonSAFE project is appropriate in light of those statutory mandates. Further, two of the states—California and Washington—have climate regulations in place that affect the electricity sector,²²⁹ and one of the states—Oregon—has an outright ban on coal generation beginning in 2030.²³⁰ Again, PacifiCorp potentially could eliminate these concerns by reallocating how it operates its generation fleet, but in the absence of that step, this state-level regulation would appear to create challenges for the CarbonSAFE project, if the electricity generation associated with it is allocated to any of these states. These are concerns for which the project team would want to have a plan before proceeding to implementation of the CarbonSAFE Rocky Mountain project.

B. Brine Disposal

The Navajo sandstone into which the CarbonSAFE Rocky Mountain would inject CO₂ contains saline brine. CO₂ will react with brine to form carbonate, but some brine may be displaced by injected CO₂. The extent to which brine would be displaced was uncertain at the time this report was written. Displacement of brine must be considered as noted in SDWA permitting and tort liability discussions, above. If brine must be extracted to increase storage capacity, extracted brine will need to be dealt with, possibly by using brine for EOR. Use of brine for EOR would trigger the SDWA's UIC class II permitting requirements.

If brine cannot be utilized for EOR, it will need to be disposed of in accordance with applicable environmental laws and regulations. In that case, permits would need to be obtained in

²²⁷ See, e.g., UTAH CODE § 54-3-1.

²²⁸ See CAL. PUB. UTIL. CODE § 399.11; OR. REV. STAT. § 469A.052; UTAH CODE § 10-19-201; WASH. REV. CODE § 19.285.040.

²²⁹ See, e.g., CAL. HEALTH & SAFETY § 38566; Code CAL. PUB. UTIL. § 8341; WASH. REV. CODE § 80.80.040.

²³⁰ See OR. REV. STAT. § 757.518.

accordance with the Clean Water Act and other applicable requirements before brine could be discharged into a receiving water or via land application. Any water treatment that results in sludge or contaminated filter materials could trigger hazardous waste disposal permitting requirements.

Alternatively, brine could be disposed of in evaporative ponds, though this could pose additional regulatory challenges, and highly concentrated minerals would require additional processing and disposal. Portions of Eastern Utah suffer from elevated ozone levels, which have been attributed, in part, to oil and gas development activities. Evaporation of oil and gas product water has been identified as a contributor to elevated ozone levels because product water often contains volatile organic compounds (VOCs). VOCs evaporate readily and are subject to atmospheric photochemical reactions that produce ground-level ozone. Any brine that is removed from the storage reservoir may therefore need to be treated to remove VOCs, if VOCs are present in the brine, before evaporation could proceed. Similar concerns could arise if the brine contains trace quantities of radionuclides, or hazardous chemical elements such as arsenic.

Surface disposal could also raise environmental concerns if brine is stored in evaporation ponds that attract wildlife. Hydrocarbons in the brine could coat the wings of migratory birds that are attracted to the water surface. Similarly, salts or other minerals that are toxic to migratory birds can cause avian mortality. Mortality that is attributable to surface disposal operations could trigger liability under the Migratory Bird Treaty Act, the Bald and Gold Eagle Protection Act, the Endangered Species Act, or other state and federal statutes.



Rocky Mountain CarbonSAFE Phase I

Appendix L

CarbonSAFE Class VI Requirement Matrix

DRAFT	EPA Class VI Guidance Document / Sections	CarbonSAFE Phase I Project Plan	Phase I Task	Phase I Subtask	Responsible Person(s)
40 CFR 146.82 - Required Class VI Permit Information					
(a) Prior to the issuance of a permit for the construction of a new Class VI well or the conversion of an existing Class I, Class II, or Class V well to a Class VI well, the owner or operator shall submit, pursuant to §146.91(e), and the Director shall consider the following:					
(1) Information required in §144.31 (e)(1) through (6) of this Section;			2.0	2.1	DEQ/DWQ
144.31 (e) (1) The activities conducted by the applicant which require it to obtain permits under RCRA, UIC, the National Pollution Discharge Elimination System (NPDES) program under the Clean Water Act, or the Prevention of Significant Deterioration (PSD) program under the Clean Air Act.					
144.31 (e) (2) Name, mailing address, and location of the facility for which the application is submitted.					
144.31 (e) (3) Up to four SIC codes which best reflect the principal products or services provided by the facility.					
144.31 (e) (4) The operator's name, address, telephone number, ownership status, and status as Federal, State, private, public, or other entity.					
144.31 (e) (5) Whether the facility is located on Indian lands.					
144.31 (e) (6) A listing of all permits or construction approvals received or applied for under any of the following programs:					
(i) Hazardous Waste Management program under RCRA.					
(ii) UIC program under SDWA.					
(iii) NPDES program under CWA.					
(iv) Prevention of Significant Deterioration (PSD) program under the Clean Air Act.					
(v) Nonattainment program under the Clean Air Act.					
(vi) National Emission Standards for Hazardous Pollutants (NESHAPS) preconstruction approval under the Clean Air Act.					

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(vii) Ocean dumping permits under the Marine Protection Research and Sanctuaries Act.					
(viii) Dredge and fill permits under section 404 of CWA					
(ix) Other relevant environmental permits, including State permits.					
(2) A map showing the injection well for which a permit is sought and the applicable area of review consistent with § 146.84. Within the area of review, the map must show the number or name, and location of all injection wells, producing wells, abandoned wells, plugged wells or dry holes, deep stratigraphic boreholes, State- or EPA-approved subsurface cleanup sites, surface bodies of water, springs, mines (surface and subsurface), quarries, water wells, other pertinent surface features including structures intended for human occupancy, State, Tribal, and Territory boundaries, and roads. The map should also show faults, if known or suspected. Only information of public record is required to be included on this map;	Site Characterization / Sect. 2.2	CarbonSAFE Site Pre-Feasibility Plan	3.0	3.1, 3.2, 3.3, 3.4	UGS - Morgan; UU - Chan
(3) Information on the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations, including:		CarbonSAFE Site Pre-Feasibility Plan	3.0	3.1, 3.2, 3.3	UGS - Morgan; UU - Chan
(i) Maps and cross sections of the area of review;	Site Characterization / Sect. 2.3.1			3.1, 3.2	
(ii) The location, orientation, and properties of known or suspected faults and fractures that may transect the confining zone(s) in the area of review and a determination that they would not interfere with containment;	Site Characterization / Sect. 2.3.2				
(iii) Data on the depth, areal extent, thickness, mineralogy, porosity, permeability, and capillary pressure of the injection and confining zone(s); including geology/facies changes based on field data which may include geologic cores, outcrop data, seismic surveys, well logs, and names and lithologic descriptions;	Site Characterization / Sect. 2.3.3, 3.1, 2.3.4, 2.3.5, 2.3.10				
(iv) Geomechanical information on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone(s);	Site Characterization / Sect. 2.3.6				

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(v) Information on the seismic history including the presence and depth of seismic sources and a determination that the seismicity would not interfere with containment; and	Site Characterization / Sect. 2.3.7				
(vi) Geologic and topographic maps and cross sections illustrating regional geology, hydrogeology, and the geologic structure of the local area.	Site Characterization / Sect. 2.1				
(4) A tabulation of all wells within the area of review which penetrate the injection or confining zone(s). Such data must include a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require;	AoR & CA / Sect. 4	CarbonSAFE Site Pre-Feasibility Plan			
(5) Maps and stratigraphic cross sections indicating the general vertical and lateral limits of all USDWs, water wells and springs within the area of review, their positions relative to the injection zone(s), and the direction of water movement, where known;	Site Characterization / Sect. 2.3.8	CarbonSAFE Site Pre-Feasibility Plan			
(6) Baseline geochemical data on subsurface formations, including all USDWs in the area of review;	Site Characterization / Sect. 2.3.9	CarbonSAFE Site Pre-Feasibility Plan			
(7) Proposed operating data for the proposed geologic sequestration site:		Task 4.0 Plan	4.0, 3.0		UU: Miland Deo / PacifiCorp
(i) Average and maximum daily rate and volume and/or mass and total anticipated volume and/or mass of the carbon dioxide stream;					
(ii) Average and maximum injection pressure;					
(iii) The source(s) of the carbon dioxide stream; and					
(iv) An analysis of the chemical and physical characteristics of the carbon dioxide stream.				4.1	
(8) Proposed pre-operational formation testing program to obtain an analysis of the chemical and physical characteristics of the injection zone(s) and confining zone(s) and that meets the requirements at § 146.87;		Not Phase I			
(9) Proposed stimulation program, a description of stimulation fluids to be used and a determination that stimulation will not interfere with containment;		Not Phase I			

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(10) Proposed procedure to outline steps necessary to conduct injection operation;		Not Phase I			
(11) Schematics or other appropriate drawings of the surface and subsurface construction details of the well;		Not Phase I			
(12) Injection well construction procedures that meet the requirements of § 146.86;		Not Phase I			
(13) Proposed area of review and corrective action plan that meets the requirements under § 146.84;	AoR & CAP / All Sections	AoR & CAP			
(14) A demonstration, satisfactory to the Director, that the applicant has met the financial responsibility requirements under § 146.85;		Not Phase I; Economic Assess.			
(15) Proposed testing and monitoring plan required by § 146.90;		Not Phase I; Economic Assess.			
(16) Proposed injection well plugging plan required by § 146.92(b);		Not Phase I; Economic Assess.			
(17) Proposed post-injection site care and site closure plan required by § 146.93(a);		Not Phase I; Economic Assess.			
(18) At the Director's discretion, a demonstration of an alternative post-injection site care timeframe required by § 146.93(c);		Not Phase I; Economic Assess.			
(19) Proposed emergency and remedial response plan required by § 146.94(a);		Not Phase I			
(20) A list of contacts, submitted to the Director, for those States, Tribes, and Territories identified to be within the area of review of the Class VI project based on information provided in paragraph (a)(2) of this section; and		Not Phase I, Public Outreach			
(21) Any other information requested by the Director.					
(b) The Director shall notify, in writing, any States, Tribes, or Territories within the area of review of the Class VI project based on information provided in paragraphs (a)(2) and (a)(20) of this section of the permit application and pursuant to the requirements at § 145.23(f)(13) of this chapter.		EPA Responsibility			
(c) Prior to granting approval for the operation of a Class VI well, the Director shall consider the following information:		Not Phase I			

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(1) The final area of review based on modeling, using data obtained during logging and testing of the well and the formation as required by paragraphs (c)(2), (3), (4), (6), (7), and (10) of this section;		Not Phase I			
(2) Any relevant updates, based on data obtained during logging and testing of the well and the formation as required by paragraphs (c)(3), (4), (6), (7), and (10) of this section, to the information on the geologic structure and hydrogeologic properties of the proposed storage site and overlying formations, submitted to satisfy the requirements of paragraph (a)(3) of this section;	Site Characterization / Sect. 4	Not Phase I			
(3) Information on the compatibility of the carbon dioxide stream with fluids in the injection zone(s) and minerals in both the injection and the confining zone(s), based on the results of the formation testing program, and with the materials used to construct the well;	Site Characterization / Sect. 3.3		3.0	3.1	UU: Chan; UGS: Morgan
(4) The results of the formation testing program required at paragraph (a)(8) of this section;	Site Characterization / Sect. 4.1	Not Phase I			
(5) Final injection well construction procedures that meet the requirements of § 146.86;		Not Phase I			
(6) The status of corrective action on wells in the area of review;		Not Phase I			
(7) All available logging and testing program data on the well required by § 146.87;	Site Characterization / Sect. 4.2, 4.3, 4.4, 4.5	Not Phase I			
(8) A demonstration of mechanical integrity pursuant to § 146.89;		Not Phase I			

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(9) Any updates to the proposed area of review and corrective action plan, testing and monitoring plan, injection well plugging plan, post-injection site care and site closure plan, or the emergency and remedial response plan submitted under paragraph (a) of this section, which are necessary to address new information collected during logging and testing of the well and the formation as required by all paragraphs of this section, and any updates to the alternative post-injection site care timeframe demonstration submitted under paragraph (a) of this section, which are necessary to address new information collected during the logging and testing of the well and the formation as required by all paragraphs of this section; and		Not Phase I			
(10) Any other information requested by the Director.					
(d) Owners or operators seeking a waiver of the requirement to inject below the lowermost USDW must also refer to § 146.95 and submit a supplemental report, as required at § 146.95(a). The supplemental report is not part of the permit application.			3.0	3.1	
40 CFR § 146.83 - Minimum criteria for siting. NOTICE: Section 3 of the Site Characterization Guidance entitled 'Data Synthesis for Demonstration of Site Suitability' contains more detail than indicated below.	Site Characterization		3.0	3.1 3.2 3.3 3.4	UU: Chan; UGS: Morgan
(a) Owners or operators of Class VI wells must demonstrate to the satisfaction of the Director that the wells will be sited in areas with a suitable geologic system. The owners or operators must demonstrate that the geologic system comprises:	Site Characterization		3.0	3.1 3.2	
(1) An injection zone(s) of sufficient areal extent, thickness, porosity, and permeability to receive the total anticipated volume of the carbon dioxide stream;	Site Characterization		3.0	3.1 3.2	

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(2) Confining zone(s) free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected carbon dioxide stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in the confining zone(s).	Site Characterization		3.0	3.1 3.2	
(b) The Director may require owners or operators of Class VI wells to identify and characterize additional zones that will impede vertical fluid movement, are free of faults and fractures that may interfere with containment, allow for pressure dissipation, and provide additional opportunities for monitoring, mitigation, and remediation.	Site Characterization		3.0	3.1 3.2	
40 CFR § 146.84 - Area of review and corrective action.	AoR Evaluation & Corrective Action (AoR & CA)				
(a) The area of review is the region surrounding the geologic sequestration project where USDWs may be endangered by the injection activity. The area of review is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization, monitoring, and operational data.	AoR & CA				
(b) The owner or operator of a Class VI well must prepare, maintain, and comply with a plan to delineate the area of review for a proposed geologic sequestration project, periodically reevaluate the delineation, and perform corrective action that meets the requirements of this section and is acceptable to the Director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. As a part of the permit application for approval by the Director, the owner or operator must submit an area of review and corrective action plan that includes the following information:	AoR & CA	AoR & CA Plan			

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(1) The method for delineating the area of review that meets the requirements of paragraph (c) of this section, including the model to be used, assumptions that will be made, and the site characterization data on which the model will be based;	AoR & CA / Sect. 2 & 3		3.0	3.2	
(2) A description of:					
(i) The minimum fixed frequency, not to exceed five years, at which the owner or operator proposes to reevaluate the area of review;	AoR & CA / Sect. 5	Not Phase I			
(ii) The monitoring and operational conditions that would warrant a reevaluation of the area of review prior to the next scheduled reevaluation as determined by the minimum fixed frequency established in paragraph (b)(2)(i) of this section.	AoR & CA / Sect. 5	Not Phase I			
(iii) How monitoring and operational data (e.g., injection rate and pressure) will be used to inform an area of review reevaluation; and	AoR & CA / Sect. 5	Not Phase I			
(iv) How corrective action will be conducted to meet the requirements of paragraph (d) of this section, including what corrective action will be performed prior to injection and what, if any, portions of the area of review will have corrective action addressed on a phased basis and how the phasing will be determined; how corrective action will be adjusted if there are changes in the area of review; and how site access will be guaranteed for future corrective action.	AoR & CA / Sect. 5	Not Phase I			
(c) Owners or operators of Class VI wells must perform the following actions to delineate the area of review and identify all wells that require corrective action:			3.0		
(1) Predict, using existing site characterization, monitoring and operational data, and computational modeling, the projected lateral and vertical migration of the carbon dioxide plume and formation fluids in the subsurface from the commencement of injection activities until the plume movement ceases, until pressure differentials sufficient to cause the movement of injected fluids or formation fluids into a USDW are no longer present, or until the end of a fixed time period as determined by the Director. The model must:	AoR & CA / Sect. 2 & 3		3.0	3.1, 3.2	

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(i) Be based on detailed geologic data collected to characterize the injection zone(s), confining zone(s) and any additional zones; and anticipated operating data, including injection pressures, rates, and total volumes over the proposed life of the geologic sequestration project;	AoR & CA / Sect. 2 & 3		3.0	3.1	
(ii) Take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and	AoR & CA / Sect. 2 & 3		3.0	3.1	
(iii) Consider potential migration through faults, fractures, and artificial penetrations.	AoR & CA / Sect. 2 & 3		3.0	3.1	
(2) Using methods approved by the Director, identify all penetrations, including active and abandoned wells and underground mines, in the area of review that may penetrate the confining zone(s). Provide a description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Director may require; and	AoR & CA / Sect. 4.2		3.0		
(3) Determine which abandoned wells in the area of review have been plugged in a manner that prevents the movement of carbon dioxide or other fluids that may endanger USDWs, including use of materials compatible with the carbon dioxide stream.	AoR & CA / Sect. 4.3				
(d) Owners or operators of Class VI wells must perform corrective action on all wells in the area of review that are determined to need corrective action, using methods designed to prevent the movement of fluid into or between USDWs, including use of materials compatible with the carbon dioxide stream, where appropriate.	AoR & CA / Sect. 4.4	Not Phase I			
(e) At the minimum fixed frequency, not to exceed five years, as specified in the area of review and corrective action plan, or when monitoring and operational conditions warrant, owners or operators must:	AoR & CA / Sect. 5	Not Phase I			
(1) Reevaluate the area of review in the same manner specified in paragraph (c)(1) of this section;					
(2) Identify all wells in the reevaluated area of review that require corrective action in the same manner specified in paragraph (c) of this section;					

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(3) Perform corrective action on wells requiring corrective action in the reevaluated area of review in the same manner specified in paragraph (d) of this section; and					
(4) Submit an amended area of review and corrective action plan or demonstrate to the Director through monitoring data and modeling results that no amendment to the area of review and corrective action plan is needed. Any amendments to the area of review and corrective action plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at § 144.39 or § 144.41 of this chapter, as appropriate.					
(f) The emergency and remedial response plan (as required by § 146.94) and the demonstration of financial responsibility (as described by § 146.85) must account for the area of review delineated as specified in paragraph (c)(1) of this section or the most recently evaluated area of review delineated under paragraph (e) of this section, regardless of whether or not corrective action in the area of review is phased.		Not Phase I			
(g) All modeling inputs and data used to support area of review reevaluations under paragraph (e) of this section shall be retained for 10 years.					
40 CFR § 146.85 - Financial responsibility.	Financial Responsibility (FR)		2.0	2.2	UU: Ruple, Davies
(a) The owner or operator must demonstrate and maintain financial responsibility as determined by the Director that meets the following conditions:					
(1) The financial responsibility instrument(s) used must be from the following list of qualifying instruments:	FR / Sect. 3 A				
(i) Trust Funds.					
(ii) Surety Bonds.					
(iii) Letter of Credit.					
(iv) Insurance.					

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(v) Self Insurance (i.e., Financial Test and Corporate Guarantee).					
(vi) Escrow Account.					
(vii) Any other instrument(s) satisfactory to the Director.	FR / Sect. 3 B				
(2) The qualifying instrument(s) must be sufficient to cover the cost of:	FR / Sect. 4				
(i) Corrective action (that meets the requirements of § 146.84);					
(ii) Injection well plugging (that meets the requirements of § 146.92);					
(iii) Post injection site care and site closure (that meets the requirements of § 146.93); and					
(iv) Emergency and remedial response (that meets the requirements of § 146.94).					
(3) The financial responsibility instrument(s) must be sufficient to address endangerment of underground sources of drinking water.	FR / Sect. 6				
(4) The qualifying financial responsibility instrument(s) must comprise protective conditions of coverage.	FR / Sect. 5				
(i) Protective conditions of coverage must include at a minimum cancellation, renewal, and continuation provisions, specifications on when the provider becomes liable following a notice of cancellation if there is a failure to renew with a new qualifying financial instrument, and requirements for the provider to meet a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable.					

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<p>(A) Cancellation—for purposes of this part, an owner or operator must provide that their financial mechanism may not cancel, terminate or fail to renew except for failure to pay such financial instrument. If there is a failure to pay the financial instrument, the financial institution may elect to cancel, terminate, or fail to renew the instrument by sending notice by certified mail to the owner or operator and the Director. The cancellation must not be final for 120 days after receipt of cancellation notice. The owner or operator must provide an alternate financial responsibility demonstration within 60 days of notice of cancellation, and if an alternate financial responsibility demonstration is not acceptable (or possible), any funds from the instrument being cancelled must be released within 60 days of notification by the Director.</p>					
<p>(B) Renewal—for purposes of this part, owners or operators must renew all financial instruments, if an instrument expires, for the entire term of the geologic sequestration project. The instrument may be automatically renewed as long as the owner or operator has the option of renewal at the face amount of the expiring instrument. The automatic renewal of the instrument must, at a minimum, provide the holder with the option of renewal at the face amount of the expiring financial instrument.</p>					
<p>(C) Cancellation, termination, or failure to renew may not occur and the financial instrument will remain in full force and effect in the event that on or before the date of expiration: The Director deems the facility abandoned; or the permit is terminated or revoked or a new permit is denied; or closure is ordered by the Director or a U.S. district court or other court of competent jurisdiction; or the owner or operator is named as debtor in a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code; or the amount due is paid.</p>					
<p>(5) The qualifying financial responsibility instrument(s) must be approved by the Director.</p>	FR / Sect. 7				

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(i) The Director shall consider and approve the financial responsibility demonstration for all the phases of the geologic sequestration project prior to issue a Class VI permit (§ 146.82).					
(ii) The owner or operator must provide any updated information related to their financial responsibility instrument(s) on an annual basis and if there are any changes, the Director must evaluate, within a reasonable time, the financial responsibility demonstration to confirm that the instrument(s) used remain adequate for use. The owner or operator must maintain financial responsibility requirements regardless of the status of the Director's review of the financial responsibility demonstration.					
(iii) The Director may disapprove the use of a financial instrument if he determines that it is not sufficient to meet the requirements of this section.					
(6) The owner or operator may demonstrate financial responsibility by using one or multiple qualifying financial instruments for specific phases of the geologic sequestration project.	FR / Sect. 5 H				
(i) In the event that the owner or operator combines more than one instrument for a specific geologic sequestration phase (e.g., well plugging), such combination must be limited to instruments that are not based on financial strength or performance (i.e., self insurance or performance bond), for example trust funds, surety bonds guaranteeing payment into a trust fund, letters of credit, escrow account, and insurance. In this case, it is the combination of mechanisms, rather than the single mechanism, which must provide financial responsibility for an amount at least equal to the current cost estimate.					
(ii) When using a third-party instrument to demonstrate financial responsibility, the owner or operator must provide a proof that the third-party providers either have passed financial strength requirements based on credit ratings; or has met a minimum rating, minimum capitalization, and ability to pass the bond rating when applicable.					

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(iii) An owner or operator using certain types of third-party instruments must establish a standby trust to enable EPA to be party to the financial responsibility agreement without EPA being the beneficiary of any funds. The standby trust fund must be used along with other financial responsibility instruments (e.g., surety bonds, letters of credit, or escrow accounts) to provide a location to place funds if needed.					
(iv) An owner or operator may deposit money to an escrow account to cover financial responsibility requirements; this account must segregate funds sufficient to cover estimated costs for Class VI (geologic sequestration) financial responsibility from other accounts and uses.					
(v) An owner or operator or its guarantor may use self insurance to demonstrate financial responsibility for geologic sequestration projects. In order to satisfy this requirement the owner or operator must meet a Tangible Net Worth of an amount approved by the Director, have a Net working capital and tangible net worth each at least six times the sum of the current well plugging, post injection site care and site closure cost, have assets located in the United States amounting to at least 90 percent of total assets or at least six times the sum of the current well plugging, post injection site care and site closure cost, and must submit a report of its bond rating and financial information annually. In addition the owner or operator must either: Have a bond rating test of AAA, AA, A, or BBB as issued by Standard & Poor's or Aaa, Aa, A, or Baa as issued by Moody's; or meet all of the following five financial ratio thresholds: A ratio of total liabilities to net worth less than 2.0; a ratio of current assets to current liabilities greater than 1.5; a ratio of the sum of net income plus depreciation, depletion, and amortization to total liabilities greater than 0.1; A ratio of current assets minus current liabilities to total assets greater than -0.1; and a net profit (revenues minus expenses) greater than 0.					

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(vi) An owner or operator who is not able to meet corporate financial test criteria may arrange a corporate guarantee by demonstrating that its corporate parent meets the financial test requirements on its behalf. The parent's demonstration that it meets the financial test requirement is insufficient if it has not also guaranteed to fulfill the obligations for the owner or operator.					
(vii) An owner or operator may obtain an insurance policy to cover the estimated costs of geologic sequestration activities requiring financial responsibility. This insurance policy must be obtained from a third party provider.					
(b) The requirement to maintain adequate financial responsibility and resources is directly enforceable regardless of whether the requirement is a condition of the permit.					
(1) The owner or operator must maintain financial responsibility and resources until:					
(i) The Director receives and approves the completed post-injection site care and site closure plan; and					
(ii) The Director approves site closure.					
(2) The owner or operator may be released from a financial instrument in the following circumstances:					
(i) The owner or operator has completed the phase of the geologic sequestration project for which the financial instrument was required and has fulfilled all its financial obligations as determined by the Director, including obtaining financial responsibility for the next phase of the GS project, if required; or					
(ii) The owner or operator has submitted a replacement financial instrument and received written approval from the Director accepting the new financial instrument and releasing the owner or operator from the previous financial instrument.					
(c) The owner or operator must have a detailed written estimate, in current dollars, of the cost of performing corrective action on wells in the area of review, plugging the injection well(s), post-injection site care and site closure, and emergency and remedial response.					

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(1) The cost estimate must be performed for each phase separately and must be based on the costs to the regulatory agency of hiring a third party to perform the required activities. A third party is a party who is not within the corporate structure of the owner or operator.					
(2) During the active life of the geologic sequestration project, the owner or operator must adjust the cost estimate for inflation within 60 days prior to the anniversary date of the establishment of the financial instrument(s) used to comply with paragraph (a) of this section and provide this adjustment to the Director. The owner or operator must also provide to the Director written updates of adjustments to the cost estimate within 60 days of any amendments to the area of review and corrective action plan (§ 146.84), the injection well plugging plan (§ 146.92), the post-injection site care and site closure plan (§ 146.93), and the emergency and remedial response plan (§ 146.94).					
(3) The Director must approve any decrease or increase to the initial cost estimate. During the active life of the geologic sequestration project, the owner or operator must revise the cost estimate no later than 60 days after the Director has approved the request to modify the area of review and corrective action plan (§ 146.84), the injection well plugging plan (§ 146.92), the post-injection site care and site closure plan (§ 146.93), and the emergency and response plan (§ 146.94), if the change in the plan increases the cost. If the change to the plans decreases the cost, any withdrawal of funds must be approved by the Director. Any decrease to the value of the financial assurance instrument must first be approved by the Director. The revised cost estimate must be adjusted for inflation as specified at paragraph (c)(2) of this section.					

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(4) Whenever the current cost estimate increases to an amount greater than the face amount of a financial instrument currently in use, the owner or operator, within 60 days after the increase, must either cause the face amount to be increased to an amount at least equal to the current cost estimate and submit evidence of such increase to the Director, or obtain other financial responsibility instruments to cover the increase. Whenever the current cost estimate decreases, the face amount of the financial assurance instrument may be reduced to the amount of the current cost estimate only after the owner or operator has received written approval from the Director.					
(d) The owner or operator must notify the Director by certified mail of adverse financial conditions such as bankruptcy that may affect the ability to carry out injection well plugging and post-injection site care and site closure.					
(1) In the event that the owner or operator or the third party provider of a financial responsibility instrument is going through a bankruptcy, the owner or operator must notify the Director by certified mail of the commencement of a voluntary or involuntary proceeding under Title 11 (Bankruptcy), U.S. Code, naming the owner or operator as debtor, within 10 days after commencement of the proceeding.					
(2) A guarantor of a corporate guarantee must make such a notification to the Director if he/she is named as debtor, as required under the terms of the corporate guarantee.					
(3) An owner or operator who fulfills the requirements of paragraph (a) of this section by obtaining a trust fund, surety bond, letter of credit, escrow account, or insurance policy will be deemed to be without the required financial assurance in the event of bankruptcy of the trustee or issuing institution, or a suspension or revocation of the authority of the trustee institution to act as trustee of the institution issuing the trust fund, surety bond, letter of credit, escrow account, or insurance policy. The owner or operator must establish other financial assurance within 60 days after such an event.					

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(e) The owner or operator must provide an adjustment of the cost estimate to the Director within 60 days of notification by the Director, if the Director determines during the annual evaluation of the qualifying financial responsibility instrument(s) that the most recent demonstration is no longer adequate to cover the cost of corrective action (as required by § 146.84), injection well plugging (as required by § 146.92), post-injection site care and site closure (as required by § 146.93), and emergency and remedial response (as required by § 146.94).					
(f) The Director must approve the use and length of pay-in-periods for trust funds or escrow accounts.					
40 CFR § 146.86 - Injection well construction requirements.	Well Construction / Sect. 2	Not Phase I			
(a) General. The owner or operator must ensure that all Class VI wells are constructed and completed to:					
(1) Prevent the movement of fluids into or between USDWs or into any unauthorized zones;	Well Construction / Sect. 2.1				
(2) Permit the use of appropriate testing devices and workover tools; and	Well Construction / Sect. 2.2				
(3) Permit continuous monitoring of the annulus space between the injection tubing and long string casing.	Well Construction / Sect. 2.2.2				
(b) Casing and cementing of Class VI wells.	Well Construction / Sect. 2.4, 2.5				

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(1) Casing and cement or other materials used in the construction of each Class VI well must have sufficient structural strength and be designed for the life of the geologic sequestration project. All well materials must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director. The casing and cementing program must be designed to prevent the movement of fluids into or between USDWs. In order to allow the Director to determine and specify casing and cementing requirements, the owner or operator must provide the following information:	Well Construction / Sect. 2.4.1				
(i) Depth to the injection zone(s);					
(ii) Injection pressure, external pressure, internal pressure, and axial loading;					
(iii) Hole size;					
(iv) Size and grade of all casing strings (wall thickness, external diameter, nominal weight, length, joint specification, and construction material);					
(v) Corrosiveness of the carbon dioxide stream and formation fluids;					
(vi) Down-hole temperatures;					
(vii) Lithology of injection and confining zone(s);					
(viii) Type or grade of cement and cement additives; and					
(ix) Quantity, chemical composition, and temperature of the carbon dioxide stream.					
(2) Surface casing must extend through the base of the lowermost USDW and be cemented to the surface through the use of a single or multiple strings of casing and cement.	Well Construction / Sect. 2.5				
(3) At least one long string casing, using a sufficient number of centralizers, must extend to the injection zone and must be cemented by circulating cement to the surface in one or more stages.	Well Construction / Sect. 2.5				

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(4) Circulation of cement may be accomplished by staging. The Director may approve an alternative method of cementing in cases where the cement cannot be recirculated to the surface, provided the owner or operator can demonstrate by using logs that the cement does not allow fluid movement behind the well bore.	Well Construction / Sect. 2.5				
(5) Cement and cement additives must be compatible with the carbon dioxide stream and formation fluids and of sufficient quality and quantity to maintain integrity over the design life of the geologic sequestration project. The integrity and location of the cement shall be verified using technology capable of evaluating cement quality radially and identifying the location of channels to ensure that USDWs are not endangered.	Well Construction / Sect. 2.5.3				
(c) Tubing and packer.					
(1) Tubing and packer materials used in the construction of each Class VI well must be compatible with fluids with which the materials may be expected to come into contact and must meet or exceed standards developed for such materials by the American Petroleum Institute, ASTM International, or comparable standards acceptable to the Director.	Well Construction / Sect. 2.6				
(2) All owners or operators of Class VI wells must inject fluids through tubing with a packer set at a depth opposite a cemented interval at the location approved by the Director.	Well Construction / Sect. 2.6				
(3) In order for the Director to determine and specify requirements for tubing and packer, the owner or operator must submit the following information:	Well Construction / Sect. 2.7				
(i) Depth of setting;					
(ii) Characteristics of the carbon dioxide stream (chemical content, corrosiveness, temperature, and density) and formation fluids;					
(iii) Maximum proposed injection pressure;					
(iv) Maximum proposed annular pressure;					
(v) Proposed injection rate (intermittent or continuous) and volume and/or mass of the carbon dioxide stream;					

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(vi) Size of tubing and casing; and					
(vii) Tubing tensile, burst, and collapse strengths.					
40 CFR § 146.87 - Logging, sampling, and testing prior to injection well operation.					
(a) During the drilling and construction of a Class VI injection well, the owner or operator must run appropriate logs, surveys and tests to determine or verify the depth, thickness, porosity, permeability, and lithology of, and the salinity of any formation fluids in all relevant geologic formations to ensure conformance with the injection well construction requirements under § 146.86 and to establish accurate baseline data against which future measurements may be compared. The owner or operator must submit to the Director a descriptive report prepared by a knowledgeable log analyst that includes an interpretation of the results of such logs and tests. At a minimum, such logs and tests must include:					
(1) Deviation checks during drilling on all holes constructed by drilling a pilot hole which is enlarged by reaming or another method. Such checks must be at sufficiently frequent intervals to determine the location of the borehole and to ensure that vertical avenues for fluid movement in the form of diverging holes are not created during drilling; and	Well Construction / Sect. 2.2.3				
(2) Before and upon installation of the surface casing:					
(i) Resistivity, spontaneous potential, and caliper logs before the casing is installed; and	Well Construction / Sect. 2.2.4				
(ii) A cement bond and variable density log to evaluate cement quality radially, and a temperature log after the casing is set and cemented.	Well Construction / Sect. 2.5.4				
(3) Before and upon installation of the long string casing:					
(i) Resistivity, spontaneous potential, porosity, caliper, gamma ray, fracture finder logs, and any other logs the Director requires for the given geology before the casing is installed; and					

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(ii) A cement bond and variable density log, and a temperature log after the casing is set and cemented.					
(4) A series of tests designed to demonstrate the internal and external mechanical integrity of injection wells, which may include:	Testing & Monitoring Sect. 2, 2.2, 2.3.4				
(i) A pressure test with liquid or gas;					
(ii) A tracer survey such as oxygen-activation logging;					
(iii) A temperature or noise log;					
(iv) A casing inspection log; and					
(5) Any alternative methods that provide equivalent or better information and that are required by and/or approved of by the Director.	Testing & Monitoring Sect. 2, 2.2, 2.3.4				
(b) The owner or operator must take whole cores or sidewall cores of the injection zone and confining system and formation fluid samples from the injection zone(s), and must submit to the Director a detailed report prepared by a log analyst that includes: Well log analyses (including well logs), core analyses, and formation fluid sample information. The Director may accept information on cores from nearby wells if the owner or operator can demonstrate that core retrieval is not possible and that such cores are representative of conditions at the well. The Director may require the owner or operator to core other formations in the borehole.			3.0	3.1	UGS: Morgan
(c) The owner or operator must record the fluid temperature, pH, conductivity, reservoir pressure, and static fluid level of the injection zone(s).					
(d) At a minimum, the owner or operator must determine or calculate the following information concerning the injection and confining zone(s):					
(1) Fracture pressure;	Site Characterization / Sect. 4.4				
(2) Other physical and chemical characteristics of the injection and confining zone(s); and					
(3) Physical and chemical characteristics of the formation fluids in the injection zone(s).					

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(e) Upon completion, but prior to operation, the owner or operator must conduct the following tests to verify hydrogeologic characteristics of the injection zone(s):					
(1) A pressure fall-off test; and,					
(2) A pump test; or					
(3) Injectivity tests.					
(f) The owner or operator must provide the Director with the opportunity to witness all logging and testing by this subpart. The owner or operator must submit a schedule of such activities to the Director 30 days prior to conducting the first test and submit any changes to the schedule 30 days prior to the next scheduled test.					
40 CFR § 146.88 - Injection well operating requirements.	Well Construction / Sect. 4				
(a) Except during stimulation, the owner or operator must ensure that injection pressure does not exceed 90 percent of the fracture pressure of the injection zone(s) so as to ensure that the injection does not initiate new fractures or propagate existing fractures in the injection zone(s). In no case may injection pressure initiate fractures in the confining zone(s) or cause the movement of injection or formation fluids that endangers a USDW. Pursuant to requirements at § 146.82(a)(9), all stimulation programs must be approved by the Director as part of the permit application and incorporated into the permit.	Well Construction / Sect. 4.1				
(b) Injection between the outermost casing protecting USDWs and the well bore is prohibited.	Well Construction / Sect. 4.1				
(c) The owner or operator must fill the annulus between the tubing and the long string casing with a non-corrosive fluid approved by the Director. The owner or operator must maintain on the annulus a pressure that exceeds the operating injection pressure, unless the Director determines that such requirement might harm the integrity of the well or endanger USDWs.	Well Construction / Sect. 4.2				

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(d) Other than during periods of well workover (maintenance) approved by the Director in which the sealed tubing-casing annulus is disassembled for maintenance or corrective procedures, the owner or operator must maintain mechanical integrity of the injection well at all times.					
(e) The owner or operator must install and use:					
(1) Continuous recording devices to monitor: The injection pressure; the rate, volume and/or mass, and temperature of the carbon dioxide stream; and the pressure on the annulus between the tubing and the long string casing and annulus fluid volume; and	Testing & Monitoring Sect. 3.2, 3.3				
(2) Alarms and automatic surface shut-off systems or, at the discretion of the Director, down-hole shut-off systems (e.g., automatic shut-off, check valves) for onshore wells or, other mechanical devices that provide equivalent protection; and					
(3) Alarms and automatic down-hole shut-off systems for wells located offshore but within State territorial waters, designed to alert the operator and shut-in the well when operating parameters such as annulus pressure, injection rate, or other parameters diverge beyond permitted ranges and/or gradients specified in the permit.					
(f) If a shutdown (i.e., down-hole or at the surface) is triggered or a loss of mechanical integrity is discovered, the owner or operator must immediately investigate and identify as expeditiously as possible the cause of the shutoff. If, upon such investigation, the well appears to be lacking mechanical integrity, or if monitoring required under paragraph (e) of this section otherwise indicates that the well may be lacking mechanical integrity, the owner or operator must:					
(1) Immediately cease injection;					
(2) Take all steps reasonably necessary to determine whether there may have been a release of the injected carbon dioxide stream or formation fluids into any unauthorized zone;					
(3) Notify the Director within 24 hours;					

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(4) Restore and demonstrate mechanical integrity to the satisfaction of the Director prior to resuming injection; and					
(5) Notify the Director when injection can be expected to resume.					
40 CFR § 146.89 - Mechanical integrity.	Testing & Monitoring				
(a) A Class VI well has mechanical integrity if:					
(1) There is no significant leak in the casing, tubing, or packer; and	Testing & Monitoring Sect. 2.2				
(2) There is no significant fluid movement into a USDW through channels adjacent to the injection well bore.	Testing & Monitoring Sect. 2.3				
(b) To evaluate the absence of significant leaks under paragraph (a)(1) of this section, owners or operators must, following an initial annulus pressure test, continuously monitor injection pressure, rate, injected volumes; pressure on the annulus between tubing and long-string casing; and annulus fluid volume as specified in § 146.88 (e);	Testing & Monitoring Sect. 2.1				
(c) At least once per year, the owner or operator must use one of the following methods to determine the absence of significant fluid movement under paragraph (a)(2) of this section:	Testing & Monitoring Sect. 2.3				
(1) An approved tracer survey such as an oxygen-activation log; or					
(2) A temperature or noise log.					
(d) If required by the Director, at a frequency specified in the testing and monitoring plan required at § 146.90, the owner or operator must run a casing inspection log to determine the presence or absence of corrosion in the long-string casing.	Testing & Monitoring Sect. 3.4				

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<p>(e) The Director may require any other test to evaluate mechanical integrity under paragraphs (a)(1) or (a)(2) of this section. Also, the Director may allow the use of a test to demonstrate mechanical integrity other than those listed above with the written approval of the Administrator. To obtain approval for a new mechanical integrity test, the Director must submit a written request to the Administrator setting forth the proposed test and all technical data supporting its use. The Administrator may approve the request if he or she determines that it will reliably demonstrate the mechanical integrity of wells for which its use is proposed. Any alternate method approved by the Administrator will be published in the Federal Register and may be used in all States in accordance with applicable State law unless its use is restricted at the time of approval by the Administrator.</p>	<p>Testing & Monitoring Sect. 2.1</p>				
<p>(f) In conducting and evaluating the tests enumerated in this section or others to be allowed by the Director, the owner or operator and the Director must apply methods and standards generally accepted in the industry. When the owner or operator reports the results of mechanical integrity tests to the Director, he/she shall include a description of the test(s) and the method(s) used. In making his/her evaluation, the Director must review monitoring and other test data submitted since the previous evaluation.</p>					
<p>(g) The Director may require additional or alternative tests if the results presented by the owner or operator under paragraphs (a) through (d) of this section are not satisfactory to the Director to demonstrate that there is no significant leak in the casing, tubing, or packer, or to demonstrate that there is no significant movement of fluid into a USDW resulting from the injection activity as stated in paragraphs (a)(1) and (2) of this section.</p>	<p>Testing & Monitoring Sect. 2.2, 2.3.4</p>				
<p>40 CFR § 146.90 - Testing and monitoring requirements.</p>	<p>Testing & Monitoring</p>				

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The owner or operator of a Class VI well must prepare, maintain, and comply with a testing and monitoring plan to verify that the geologic sequestration project is operating as permitted and is not endangering USDWs. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. The testing and monitoring plan must be submitted with the permit application, for Director approval, and must include a description of how the owner or operator will meet the requirements of this section, including accessing sites for all necessary monitoring and testing during the life of the project. Testing and monitoring associated with geologic sequestration projects must, at a minimum, include:	Testing & Monitoring Sect. 1.2				
(a) Analysis of the carbon dioxide stream with sufficient frequency to yield data representative of its chemical and physical characteristics;	Testing & Monitoring Sect. 3.1				
(b) Installation and use, except during well workovers as defined in § 146.88(d), of continuous recording devices to monitor injection pressure, rate, and volume; the pressure on the annulus between the tubing and the long string casing; and the annulus fluid volume added;	Testing & Monitoring Sect. 3.2, 3.3				
(c) Corrosion monitoring of the well materials for loss of mass, thickness, cracking, pitting, and other signs of corrosion, which must be performed on a quarterly basis to ensure that the well components meet the minimum standards for material strength and performance set forth in § 146.86(b), by:	Testing & Monitoring Sect. 3.4				
(1) Analyzing coupons of the well construction materials placed in contact with the carbon dioxide stream; or					
(2) Routing the carbon dioxide stream through a loop constructed with the material used in the well and inspecting the materials in the loop; or					
(3) Using an alternative method approved by the Director;					
(d) Periodic monitoring of the ground water quality and geochemical changes above the confining zone(s) that may be a result of carbon dioxide movement through the confining zone(s) or additional identified zones including:	Testing & Monitoring Sect. 4				

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(1) The location and number of monitoring wells based on specific information about the geologic sequestration project, including injection rate and volume, geology, the presence of artificial penetrations, and other factors; and					
(2) The monitoring frequency and spatial distribution of monitoring wells based on baseline geochemical data that has been collected under § 146.82(a)(6) and on any modeling results in the area of review evaluation required by § 146.84(c).					
(e) A demonstration of external mechanical integrity pursuant to § 146.89(c) at least once per year until the injection well is plugged; and, if required by the Director, a casing inspection log pursuant to requirements at § 146.89(d) at a frequency established in the testing and monitoring plan;	Testing & Monitoring Sect. 2.3				
(f) A pressure fall-off test at least once every five years unless more frequent testing is required by the Director based on site-specific information;	Testing & Monitoring Sect. 3.5				
(g) Testing and monitoring to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure (e.g., the pressure front) by using:	Testing & Monitoring Sect. 5				
(1) Direct methods in the injection zone(s); and,	Testing & Monitoring Sect. 5.2				
(2) Indirect methods (e.g., seismic, electrical, gravity, or electromagnetic surveys and/or down-hole carbon dioxide detection tools), unless the Director determines, based on site-specific geology, that such methods are not appropriate;	Testing & Monitoring Sect. 5.3				
(h) The Director may require surface air monitoring and/or soil gas monitoring to detect movement of carbon dioxide that could endanger a USDW.	Testing & Monitoring Sect. 6				
(1) Design of Class VI surface air and/or soil gas monitoring must be based on potential risks to USDWs within the area of review;					
(2) The monitoring frequency and spatial distribution of surface air monitoring and/or soil gas monitoring must be decided using baseline data, and the monitoring plan must describe how the proposed monitoring will yield useful information on the area of review delineation and/or compliance with standards under § 144.12 of this chapter;					

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(3) If an owner or operator demonstrates that monitoring employed under §§ 98.440 to 98.449 of this chapter (Clean Air Act, 42 U.S.C. 7401 et seq.) accomplishes the goals of paragraphs (h)(1) and (2) of this section, and meets the requirements pursuant to § 146.91(c)(5), a Director that requires surface air/soil gas monitoring must approve the use of monitoring employed under §§ 98.440 to 98.449 of this chapter. Compliance with §§ 98.440 to 98.449 of this chapter pursuant to this provision is considered a condition of the Class VI permit;					
(i) Any additional monitoring, as required by the Director, necessary to support, upgrade, and improve computational modeling of the area of review evaluation required under § 146.84(c) and to determine compliance with standards under § 144.12 of this chapter;					
(j) The owner or operator shall periodically review the testing and monitoring plan to incorporate monitoring data collected under this subpart, operational data collected under § 146.88, and the most recent area of review reevaluation performed under § 146.84(e). In no case shall the owner or operator review the testing and monitoring plan less often than once every five years. Based on this review, the owner or operator shall submit an amended testing and monitoring plan or demonstrate to the Director that no amendment to the testing and monitoring plan is needed. Any amendments to the testing and monitoring plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at § 144.39 or § 144.41 of this chapter, as appropriate. Amended plans or demonstrations shall be submitted to the Director as follows:					
(1) Within one year of an area of review reevaluation;					
(2) Following any significant changes to the facility, such as addition of monitoring wells or newly permitted injection wells within the area of review, on a schedule determined by the Director; or					
(3) When required by the Director.					
(k) A quality assurance and surveillance plan for all testing and monitoring requirements.					

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40 CFR § 146.91 - Reporting requirements. NOTICE: There are additional reporting requirements pertaining to the development of CCS Project Plans that are not detailed below. READ THE RECORDKEEPING, REPORTING & DATA MANAGEMENT GUIDANCE.	Recordkeeping, Reporting & Data Management (R R & DM)				
The owner or operator must, at a minimum, provide, as specified in paragraph (e) of this section, the following reports to the Director, for each permitted Class VI well:					
(a) Semi-annual reports containing:	RR & DM / Sect. 5.1				
(1) Any changes to the physical, chemical, and other relevant characteristics of the carbon dioxide stream from the proposed operating data;	RR & DM / Sect. 5.1.1				
(2) Monthly average, maximum, and minimum values for injection pressure, flow rate and volume, and annular pressure;	RR & DM / Sect. 5.1.2				
(3) A description of any event that exceeds operating parameters for annulus pressure or injection pressure specified in the permit;	RR & DM / Sect. 5.1.3				
(4) A description of any event which triggers a shut-off device required pursuant to § 146.88(e) and the response taken;	RR & DM / Sect. 5.1.3				
(5) The monthly volume and/or mass of the carbon dioxide stream injected over the reporting period and the volume injected cumulatively over the life of the project;	RR & DM / Sect. 5.1.2				
(6) Monthly annulus fluid volume added; and	RR & DM / Sect. 5.1.2				
(7) The results of monitoring prescribed under § 146.90.	RR & DM / Sect. 5.1.4				
(b) Report, within 30 days, the results of:	RR & DM / Sect. 5.2				
(1) Periodic tests of mechanical integrity;					

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(2) Any well workover; and,					
(3) Any other test of the injection well conducted by the permittee if required by the Director.					
(c) Report, within 24 hours:	RR & DM / Sect. 5.4.1				
(1) Any evidence that the injected carbon dioxide stream or associated pressure front may cause an endangerment to a USDW;					
(2) Any noncompliance with a permit condition, or malfunction of the injection system, which may cause fluid migration into or between USDWs;					
(3) Any triggering of a shut-off system (i.e., down-hole or at the surface);					
(4) Any failure to maintain mechanical integrity; or.					
(5) Pursuant to compliance with the requirement at § 146.90(h) for surface air/soil gas monitoring or other monitoring technologies, if required by the Director, any release of carbon dioxide to the atmosphere or biosphere.					
(d) Owners or operators must notify the Director in writing 30 days in advance of:	RR & DM / Sect. 5.2				
(1) Any planned well workover;					
(2) Any planned stimulation activities, other than stimulation for formation testing conducted under § 146.82; and					
(3) Any other planned test of the injection well conducted by the permittee.					
(e) Regardless of whether a State has primary enforcement responsibility, owners or operators must submit all required reports, submittals, and notifications under subpart H of this part to EPA in an electronic format approved by EPA.	RR & DM / Sect. 2				
(f) Records shall be retained by the owner or operator as follows:	RR & DM / Sect. 2.5				

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(1) All data collected under § 146.82 for Class VI permit applications shall be retained throughout the life of the geologic sequestration project and for 10 years following site closure.					
(2) Data on the nature and composition of all injected fluids collected pursuant to § 146.90(a) shall be retained until 10 years after site closure. The Director may require the owner or operator to deliver the records to the Director at the conclusion of the retention period.					
(3) Monitoring data collected pursuant to § 146.90(b) through (i) shall be retained for 10 years after it is collected.					
(4) Well plugging reports, post-injection site care data, including, if appropriate, data and information used to develop the demonstration of the alternative post-injection site care timeframe, and the site closure report collected pursuant to requirements at §§ 146.93(f) and (h) shall be retained for 10 years following site closure.					
(5) The Director has authority to require the owner or operator to retain any records required in this subpart for longer than 10 years after site closure.					
40 CFR § 146.92 - Injection well plugging.	Well Plugging, PISC, Site Closure (WP PISC & SC) / Sect. 2				
(a) Prior to the well plugging, the owner or operator must flush each Class VI injection well with a buffer fluid, determine bottomhole reservoir pressure, and perform a final external mechanical integrity test.	WP PISC & SC / Sect. 2.4				

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(b) Well plugging plan. The owner or operator of a Class VI well must prepare, maintain, and comply with a plan that is acceptable to the Director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit. The well plugging plan must be submitted as part of the permit application and must include the following information:	WP PISC & SC / Sect. 2.3				
(1) Appropriate tests or measures for determining bottomhole reservoir pressure;					
(2) Appropriate testing methods to ensure external mechanical integrity as specified in § 146.89;					
(3) The type and number of plugs to be used;					
(4) The placement of each plug, including the elevation of the top and bottom of each plug;					
(5) The type, grade, and quantity of material to be used in plugging. The material must be compatible with the carbon dioxide stream; and					
(6) The method of placement of the plugs.					
(c) Notice of intent to plug. The owner or operator must notify the Director in writing pursuant to § 146.91(e), at least 60 days before plugging of a well. At this time, if any changes have been made to the original well plugging plan, the owner or operator must also provide the revised well plugging plan. The Director may allow for a shorter notice period. Any amendments to the injection well plugging plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at § 144.39 or § 144.41 of this chapter, as appropriate.	WP PISC & SC / Sect. 2.2				
(d) Plugging report. Within 60 days after plugging, the owner or operator must submit, pursuant to § 146.91(e), a plugging report to the Director. The report must be certified as accurate by the owner or operator and by the person who performed the plugging operation (if other than the owner or operator.) The owner or operator shall retain the well plugging report for 10 years following site closure.	WP PISC & SC / Sect. 2.7				

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40 CFR § 146.93 - Post-injection site care and site closure.	Well Plugging, PISC, Site Closure (WP PISC & SC)	Liability Plan	2.0	2.3 + input from others	
(a) The owner or operator of a Class VI well must prepare, maintain, and comply with a plan for post-injection site care and site closure that meets the requirements of paragraph (a)(2) of this section and is acceptable to the Director. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit.	WP PISC & SC / Sect. 3				
(1) The owner or operator must submit the post-injection site care and site closure plan as a part of the permit application to be approved by the Director.	WP PISC & SC / Sect. 3.1				
(2) The post-injection site care and site closure plan must include the following information:	WP PISC & SC / Sect. 3.1.1				
(i) The pressure differential between pre-injection and predicted post-injection pressures in the injection zone(s);					
(ii) The predicted position of the carbon dioxide plume and associated pressure front at site closure as demonstrated in the area of review evaluation required under § 146.84(c)(1);					
(iii) A description of post-injection monitoring location, methods, and proposed frequency;					
(iv) A proposed schedule for submitting post-injection site care monitoring results to the Director pursuant to § 146.91(e); and,					
(v) The duration of the post-injection site care timeframe and, if approved by the Director, the demonstration of the alternative post-injection site care timeframe that ensures non-endangerment of USDWs.					

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DRAFT	EPA Class VI Guidance Document / Sections	CarbonSAFE Phase I Project Plan	Phase I Task	Phase I Subtask	Responsible Person(s)
(3) Upon cessation of injection, owners or operators of Class VI wells must either submit an amended post-injection site care and site closure plan or demonstrate to the Director through monitoring data and modeling results that no amendment to the plan is needed. Any amendments to the post-injection site care and site closure plan must be approved by the Director, be incorporated into the permit, and are subject to the permit modification requirements at § 144.39 or § 144.41 of this chapter, as appropriate.	WP PISC & SC / Sect. 3.1.1				
(4) At any time during the life of the geologic sequestration project, the owner or operator may modify and resubmit the post-injection site care and site closure plan for the Director's approval within 30 days of such change.					
(b) The owner or operator shall monitor the site following the cessation of injection to show the position of the carbon dioxide plume and pressure front and demonstrate that USDWs are not being endangered.	WP PISC & SC / Sect. 3.3				
(1) Following the cessation of injection, the owner or operator shall continue to conduct monitoring as specified in the Director-approved post-injection site care and site closure plan for at least 50 years or for the duration of the alternative timeframe approved by the Director pursuant to requirements in paragraph (c) of this section, unless he/she makes a demonstration under (b)(2) of this section. The monitoring must continue until the geologic sequestration project no longer poses an endangerment to USDWs and the demonstration under (b)(2) of this section is submitted and approved by the Director.	WP PISC & SC / Sect. 3.3				

DRAFT	EPA Class VI Guidance Document / Sections	CarbonSAFE Phase I Project Plan	Phase I Task	Phase I Subtask	Responsible Person(s)
(2) If the owner or operator can demonstrate to the satisfaction of the Director before 50 years or prior to the end of the approved alternative timeframe based on monitoring and other site-specific data, that the geologic sequestration project no longer poses an endangerment to USDWs, the Director may approve an amendment to the post-injection site care and site closure plan to reduce the frequency of monitoring or may authorize site closure before the end of the 50-year period or prior to the end of the approved alternative timeframe, where he or she has substantial evidence that the geologic sequestration project no longer poses a risk of endangerment to USDWs.	WP PISC & SC / Sect. 3.4				
(3) Prior to authorization for site closure, the owner or operator must submit to the Director for review and approval a demonstration, based on monitoring and other site-specific data, that no additional monitoring is needed to ensure that the geologic sequestration project does not pose an endangerment to USDWs.	WP PISC & SC / Sect. 3.4				
(4) If the demonstration in paragraph (b)(3) of this section cannot be made (i.e., additional monitoring is needed to ensure that the geologic sequestration project does not pose an endangerment to USDWs) at the end of the 50-year period or at the end of the approved alternative timeframe, or if the Director does not approve the demonstration, the owner or operator must submit to the Director a plan to continue post-injection site care until a demonstration can be made and approved by the Director.					

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DRAFT	EPA Class VI Guidance Document / Sections	CarbonSAFE Phase I Project Plan	Phase I Task	Phase I Subtask	Responsible Person(s)
(c) Demonstration of alternative post-injection site care timeframe. At the Director's discretion, the Director may approve, in consultation with EPA, an alternative post-injection site care timeframe other than the 50 year default, if an owner or operator can demonstrate during the permitting process that an alternative post-injection site care timeframe is appropriate and ensures non-endangerment of USDWs. The demonstration must be based on significant, site-specific data and information including all data and information collected pursuant to §§ 146.82 and 146.83, and must contain substantial evidence that the geologic sequestration project will no longer pose a risk of endangerment to USDWs at the end of the alternative post-injection site care timeframe.	WP PISC & SC / Sect. 3.2.2				
(1) A demonstration of an alternative post-injection site care timeframe must include consideration and documentation of:					
(i) The results of computational modeling performed pursuant to delineation of the area of review under § 146.84;					
(ii) The predicted timeframe for pressure decline within the injection zone, and any other zones, such that formation fluids may not be forced into any USDWs; and/or the timeframe for pressure decline to pre-injection pressures;					
(iii) The predicted rate of carbon dioxide plume migration within the injection zone, and the predicted timeframe for the cessation of migration;					
(iv) A description of the site-specific processes that will result in carbon dioxide trapping including immobilization by capillary trapping, dissolution, and mineralization at the site;					
(v) The predicted rate of carbon dioxide trapping in the immobile capillary phase, dissolved phase, and/or mineral phase;					
(vi) The results of laboratory analyses, research studies, and/or field or site-specific studies to verify the information required in paragraphs (iv) and (v) of this section;					

DRAFT	EPA Class VI Guidance Document / Sections	CarbonSAFE Phase I Project Plan	Phase I Task	Phase I Subtask	Responsible Person(s)
(vii) A characterization of the confining zone(s) including a demonstration that it is free of transmissive faults, fractures, and micro-fractures and of appropriate thickness, permeability, and integrity to impede fluid (e.g., carbon dioxide, formation fluids) movement;					
(viii) The presence of potential conduits for fluid movement including planned injection wells and project monitoring wells associated with the proposed geologic sequestration project or any other projects in proximity to the predicted/modeled, final extent of the carbon dioxide plume and area of elevated pressure;					
(ix) A description of the well construction and an assessment of the quality of plugs of all abandoned wells within the area of review;					
(x) The distance between the injection zone and the nearest USDWs above and/or below the injection zone; and					
(xi) Any additional site-specific factors required by the Director.					
(2) Information submitted to support the demonstration in paragraph (c)(1) of this section must meet the following criteria:					
(i) All analyses and tests performed to support the demonstration must be accurate, reproducible, and performed in accordance with the established quality assurance standards;					
(ii) Estimation techniques must be appropriate and EPA-certified test protocols must be used where available;					
(iii) Predictive models must be appropriate and tailored to the site conditions, composition of the carbon dioxide stream and injection and site conditions over the life of the geologic sequestration project;					
(iv) Predictive models must be calibrated using existing information (e.g., at Class I, Class II, or Class V experimental technology well sites) where sufficient data are available;					

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DRAFT	EPA Class VI Guidance Document / Sections	CarbonSAFE Phase I Project Plan	Phase I Task	Phase I Subtask	Responsible Person(s)
(v) Reasonably conservative values and modeling assumptions must be used and disclosed to the Director whenever values are estimated on the basis of known, historical information instead of site-specific measurements;					
(vi) An analysis must be performed to identify and assess aspects of the alternative post-injection site care timeframe demonstration that contribute significantly to uncertainty. The owner or operator must conduct sensitivity analyses to determine the effect that significant uncertainty may contribute to the modeling demonstration.					
(vii) An approved quality assurance and quality control plan must address all aspects of the demonstration; and,					
(viii) Any additional criteria required by the Director.					
(d) Notice of intent for site closure. The owner or operator must notify the Director in writing at least 120 days before site closure. At this time, if any changes have been made to the original post-injection site care and site closure plan, the owner or operator must also provide the revised plan. The Director may allow for a shorter notice period.	WP PISC & SC / Sect. 4.1				
(e) After the Director has authorized site closure, the owner or operator must plug all monitoring wells in a manner which will not allow movement of injection or formation fluids that endangers a USDW.	WP PISC & SC / Sect. 4.2				
(f) The owner or operator must submit a site closure report to the Director within 90 days of site closure, which must thereafter be retained at a location designated by the Director for 10 years. The report must include:	WP PISC & SC / Sect. 4.3				
(1) Documentation of appropriate injection and monitoring well plugging as specified in § 146.92 and paragraph (e) of this section. The owner or operator must provide a copy of a survey plat which has been submitted to the local zoning authority designated by the Director. The plat must indicate the location of the injection well relative to permanently surveyed benchmarks. The owner or operator must also submit a copy of the plat to the Regional Administrator of the appropriate EPA Regional Office;					

DRAFT	EPA Class VI Guidance Document / Sections	CarbonSAFE Phase I Project Plan	Phase I Task	Phase I Subtask	Responsible Person(s)
(2) Documentation of appropriate notification and information to such State, local and Tribal authorities that have authority over drilling activities to enable such State, local, and Tribal authorities to impose appropriate conditions on subsequent drilling activities that may penetrate the injection and confining zone(s); and					
(3) Records reflecting the nature, composition, and volume of the carbon dioxide stream.					
(g) Each owner or operator of a Class VI injection well must record a notation on the deed to the facility property or any other document that is normally examined during title search that will in perpetuity provide any potential purchaser of the property the following information:	WP PISC & SC / Sect. 4.3				
(1) The fact that land has been used to sequester carbon dioxide;					
(2) The name of the State agency, local authority, and/or Tribe with which the survey plat was filed, as well as the address of the Environmental Protection Agency Regional Office to which it was submitted; and					
(3) The volume of fluid injected, the injection zone or zones into which it was injected, and the period over which injection occurred.					
(h) The owner or operator must retain for 10 years following site closure, records collected during the post-injection site care period. The owner or operator must deliver the records to the Director at the conclusion of the retention period, and the records must thereafter be retained at a location designated by the Director for that purpose.	WP PISC & SC / Sect. 4.3				
40 CFR § 146.94 - Emergency and remedial response.	No EPA Guidance	Emergency & Remedial Response Plan			PacifiCorp

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DRAFT	EPA Class VI Guidance Document / Sections	CarbonSAFE Phase I Project Plan	Phase I Task	Phase I Subtask	Responsible Person(s)
(a) As part of the permit application, the owner or operator must provide the Director with an emergency and remedial response plan that describes actions the owner or operator must take to address movement of the injection or formation fluids that may cause an endangerment to a USDW during construction, operation, and post-injection site care periods. The requirement to maintain and implement an approved plan is directly enforceable regardless of whether the requirement is a condition of the permit.		Not Phase I			
(b) If the owner or operator obtains evidence that the injected carbon dioxide stream and associated pressure front may cause an endangerment to a USDW, the owner or operator must:					
(1) Immediately cease injection;					
(2) Take all steps reasonably necessary to identify and characterize any release;					
(3) Notify the Director within 24 hours; and					
(4) Implement the emergency and remedial response plan approved by the Director.					
(c) The Director may allow the operator to resume injection prior to remediation if the owner or operator demonstrates that the injection operation will not endanger USDWs.					
(d) The owner or operator shall periodically review the emergency and remedial response plan developed under paragraph (a) of this section. In no case shall the owner or operator review the emergency and remedial response plan less often than once every five years. Based on this review, the owner or operator shall submit an amended emergency and remedial response plan or demonstrate to the Director that no amendment to the emergency and remedial response plan is needed. Any amendments to the emergency and remedial response plan must be approved by the Director, must be incorporated into the permit, and are subject to the permit modification requirements at § 144.39 or § 144.41 of this chapter, as appropriate. Amended plans or demonstrations shall be submitted to the Director as follows:					
(1) Within one year of an area of review reevaluation;					

DRAFT	EPA Class VI Guidance Document / Sections	CarbonSAFE Phase I Project Plan	Phase I Task	Phase I Subtask	Responsible Person(s)
(2) Following any significant changes to the facility, such as addition of injection or monitoring wells, on a schedule determined by the Director; or					
(3) When required by the Director.					
40 CFR § 146.95 - Class VI injection depth waiver requirements.	No EPA Guidance		3.0	3.1	UU: Chan, UGS: Morgan
This section sets forth information which an owner or operator seeking a waiver of the Class VI injection depth requirements must submit to the Director; information the Director must consider in consultation with all affected Public Water System Supervision Directors; the procedure for Director—Regional Administrator communication and waiver issuance; and the additional requirements that apply to owners or operators of Class VI wells granted a waiver of the injection depth requirements.					
(a) In seeking a waiver of the requirement to inject below the lowermost USDW, the owner or operator must submit a supplemental report concurrent with permit application. The supplemental report must include the following,					
(1) A demonstration that the injection zone(s) is/are laterally continuous, is not a USDW, and is not hydraulically connected to USDWs; does not outcrop; has adequate injectivity, volume, and sufficient porosity to safely contain the injected carbon dioxide and formation fluids; and has appropriate geochemistry.					
(2) A demonstration that the injection zone(s) is/are bounded by laterally continuous, impermeable confining units above and below the injection zone(s) adequate to prevent fluid movement and pressure buildup outside of the injection zone(s); and that the confining unit(s) is/are free of transmissive faults and fractures. The report shall further characterize the regional fracture properties and contain a demonstration that such fractures will not interfere with injection, serve as conduits, or endanger USDWs.					

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DRAFT	EPA Class VI Guidance Document / Sections	CarbonSAFE Phase I Project Plan	Phase I Task	Phase I Subtask	Responsible Person(s)
(3) A demonstration, using computational modeling, that USDWs above and below the injection zone will not be endangered as a result of fluid movement. This modeling should be conducted in conjunction with the area of review determination, as described in § 146.84, and is subject to requirements, as described in § 146.84(c), and periodic reevaluation, as described in § 146.84(e).					
(4) A demonstration that well design and construction, in conjunction with the waiver, will ensure isolation of the injectate in lieu of requirements at 146.86(a)(1) and will meet well construction requirements in paragraph (f) of this section.					
(5) A description of how the monitoring and testing and any additional plans will be tailored to the geologic sequestration project to ensure protection of USDWs above and below the injection zone(s), if a waiver is granted.					
(6) Information on the location of all the public water supplies affected, reasonably likely to be affected, or served by USDWs in the area of review.					
(7) Any other information requested by the Director to inform the Regional Administrator's decision to issue a waiver.					
(b) To inform the Regional Administrator's decision on whether to grant a waiver of the injection depth requirements at §§ 144.6 of this chapter, 146.5(f), and 146.86(a)(1), the Director must submit, to the Regional Administrator, documentation of the following:					
(1) An evaluation of the following information as it relates to siting, construction, and operation of a geologic sequestration project with a waiver:					
(i) The integrity of the upper and lower confining units;					
(ii) The suitability of the injection zone(s) (e.g., lateral continuity; lack of transmissive faults and fractures; knowledge of current or planned artificial penetrations into the injection zone(s) or formations below the injection zone);					
(iii) The potential capacity of the geologic formation(s) to sequester carbon dioxide, accounting for the availability of alternative injection sites;					

DRAFT	EPA Class VI Guidance Document / Sections	CarbonSAFE Phase I Project Plan	Phase I Task	Phase I Subtask	Responsible Person(s)
(iv) All other site characterization data, the proposed emergency and remedial response plan, and a demonstration of financial responsibility;					
(v) Community needs, demands, and supply from drinking water resources;					
(vi) Planned needs, potential and/or future use of USDWs and non-USDWs in the area;					
(vii) Planned or permitted water, hydrocarbon, or mineral resource exploitation potential of the proposed injection formation(s) and other formations both above and below the injection zone to determine if there are any plans to drill through the formation to access resources in or beneath the proposed injection zone(s)/formation(s);					
(viii) The proposed plan for securing alternative resources or treating USDW formation waters in the event of contamination related to the Class VI injection activity; and,					
(ix) Any other applicable considerations or information requested by the Director.					
(2) Consultation with the Public Water System Supervision Directors of all States and Tribes having jurisdiction over lands within the area of review of a well for which a waiver is sought.					
(3) Any written waiver-related information submitted by the Public Water System Supervision Director(s) to the (UIC) Director.					
(c) Pursuant to requirements at § 124.10 of this chapter and concurrent with the Class VI permit application notice process, the Director shall give public notice that a waiver application has been submitted. The notice shall clearly state:					
(1) The depth of the proposed injection zone(s);					
(2) The location of the injection well(s);					
(3) The name and depth of all USDWs within the area of review;					
(4) A map of the area of review;					

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DRAFT	EPA Class VI Guidance Document / Sections	CarbonSAFE Phase I Project Plan	Phase I Task	Phase I Subtask	Responsible Person(s)
(5) The names of any public water supplies affected, reasonably likely to be affected, or served by USDWs in the area of review; and,					
(6) The results of UIC-Public Water System Supervision consultation required under paragraph (b)(2) of this section.					
(d) Following public notice, the Director shall provide all information received through the waiver application process to the Regional Administrator. Based on the information provided, the Regional Administrator shall provide written concurrence or non-concurrence regarding waiver issuance.					
(1) If the Regional Administrator determines that additional information is required to support a decision, the Director shall provide the information. At his or her discretion, the Regional Administrator may require that public notice of the new information be initiated.					
(2) In no case shall a Director of a State-approved program issue a waiver without receipt of written concurrence from the Regional Administrator.					
(e) If a waiver is issued, within 30 days of waiver issuance, EPA shall post the following information on the Office of Water's Web site:					
(1) The depth of the proposed injection zone(s);					
(2) The location of the injection well(s);					
(3) The name and depth of all USDWs within the area of review;					
(4) A map of the area of review;					
(5) The names of any public water supplies affected, reasonably likely to be affected, or served by USDWs in the area of review; and					
(6) The date of waiver issuance.					
(f) Upon receipt of a waiver of the requirement to inject below the lowermost USDW for geologic sequestration, the owner or operator of the Class VI well must comply with:					
(1) All requirements at §§ 146.84, 146.85, 146.87, 146.88, 146.89, 146.91, 146.92, and 146.94;					

DRAFT	EPA Class VI Guidance Document / Sections	CarbonSAFE Phase I Project Plan	Phase I Task	Phase I Subtask	Responsible Person(s)
(2) All requirements at § 146.86 with the following modified requirements:					
(i) The owner or operator must ensure that Class VI wells with a waiver are constructed and completed to prevent movement of fluids into any unauthorized zones including USDWs, in lieu of requirements at § 146.86(a)(1).					
(ii) The casing and cementing program must be designed to prevent the movement of fluids into any unauthorized zones including USDWs in lieu of requirements at § 146.86(b)(1).					
(iii) The surface casing must extend through the base of the nearest USDW directly above the injection zone and be cemented to the surface; or, at the Director's discretion, another formation above the injection zone and below the nearest USDW above the injection zone.					
(3) All requirements at § 146.90 with the following modified requirements:					
(i) The owner or operator shall monitor the groundwater quality, geochemical changes, and pressure in the first USDWs immediately above and below the injection zone(s); and in any other formations at the discretion of the Director.					
(ii) Testing and monitoring to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure (e.g., the pressure front) by using direct methods to monitor for pressure changes in the injection zone(s); and, indirect methods (e.g., seismic, electrical, gravity, or electromagnetic surveys and/or down-hole carbon dioxide detection tools), unless the Director determines, based on site-specific geology, that such methods are not appropriate.					
(4) All requirements at § 146.93 with the following, modified post-injection site care monitoring requirements:					
(i) The owner or operator shall monitor the groundwater quality, geochemical changes and pressure in the first USDWs immediately above and below the injection zone; and in any other formations at the discretion of the Director.					

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DRAFT	EPA Class VI Guidance Document / Sections	CarbonSAFE Phase I Project Plan	Phase I Task	Phase I Subtask	Responsible Person(s)
(ii) Testing and monitoring to track the extent of the carbon dioxide plume and the presence or absence of elevated pressure (e.g., the pressure front) by using direct methods in the injection zone(s); and indirect methods (e.g., seismic, electrical, gravity, or electromagnetic surveys and/or down-hole carbon dioxide detection tools), unless the Director determines based on site-specific geology, that such methods are not appropriate;					
(5) Any additional requirements requested by the Director designed to ensure protection of USDWs above and below the injection zone(s).					



Rocky Mountain CarbonSAFE Phase I

Appendix M

Area of Review (AoR) Evaluation and Corrective Action Guidance

UIC Class VI Requirements

Area of Review (AoR) Evaluation and Corrective Action Guidance

Prepared by Candace Cady

(Condensation of EPA's UIC Class VI Well
Area of Review Evaluation and Corrective Action Guidance)



!! DISCLAIMER !!

This document is meant to make the CarbonSAFE Rocky Mountains team aware of EPA's Class VI injection well requirements as they are presented in the several guidance documents prepared by EPA. It is NOT meant to be a stand-alone document. I encourage you, I implore you to read the relevant sections of the guidance documents, the final Class VI rule, and all references contained therein which pertain to your particular task on the CarbonSAFE team!



Overview of AoR & CA Requirements

- Prepare, maintain, and comply with an AoR and Corrective Action Plan that includes all of the required elements of the plan [40 CFR 146.84(b)];
- Delineate the AoR using computational modeling and identify all wells that require corrective action [40 CFR 146.84(c)];
- Perform all required corrective action on wells in the AoR [40 CFR 146.84(d)];
- Re-evaluate the AoR throughout the life of the project [40 CFR 146.84(e)];
- Ensure that the Emergency and Remedial Response Plan and financial responsibility demonstration account for the most recently approved AoR [40 CFR 146.84(f)]; and
- Retain modeling inputs and data used to support AoR re-evaluations for 10 years [40 CFR 146.84(g)].



Organization of this Guidance

- Computational Modeling for Geologic Sequestration (pages 7 – 29)
- AoR Delineation Using Computational Models (pages 30 – 49)
- Identifying Artificial Penetrations and Performing Corrective Action (pages 50 – 67)
- AoR Re-evaluation (pages 68 – 77)



Activities Relating to AoR

- Prior to Issuance of a Class VI Permit:
 - ⚙ Collection of relevant site characterization and operational data
[40 CFR 146.82(a)(3), 146.82(a)(5), 146.82(a)(6), and 146.83];
 - ⚙ Determination of relevant operational data that will inform the AoR modeling
[40 CFR 146.82(a)(7), and 146.82(a)(10)-(11)];
 - ⚙ Development of an AoR and Corrective Action Plan
[40 CFR 146.82(a)(13) and 146.84(b)];
 - ⚙ Performing AoR modeling and delineation
[40 CFR 146.82(a)(2)]; and
 - ⚙ Identification and assessment of artificial penetrations within the AoR
[40 CFR 146.82(a)(4)].



Activities Relating to AoR (cont.)

- Prior to Being Granted Authorization to Inject into Class VI Well:
 - ⚙ Collection and/or updating of relevant site characterization and operational data that will inform AoR modeling
[40 CFR 146.82(c)(2)-(5), 146.82(c)(7), and 146.83];
 - ⚙ Identification of any needed updates to the AoR and Corrective Action Plan
[40 CFR 146.82(c)(9)];
 - ⚙ Finalizing AoR modeling and delineation
[40 CFR 146.82(c)(1)]; and
 - ⚙ Performing corrective action on those penetrations that may serve as a conduit for fluid movement
[40 CFR 146.82(c)(6) and 146.84(d)].

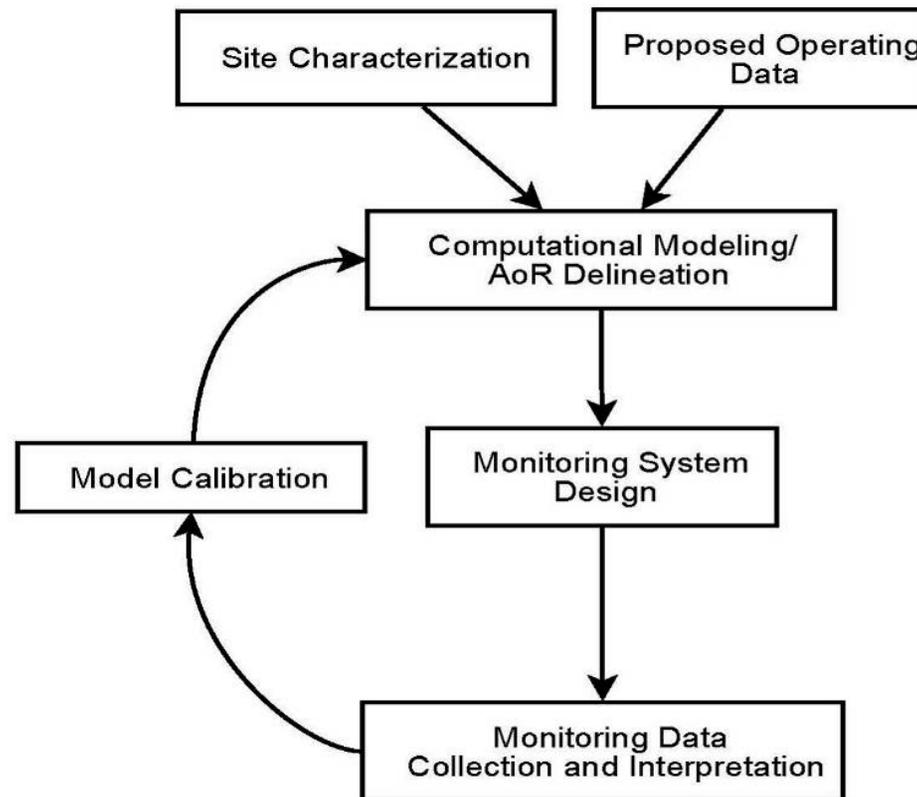


Activities Relating to AoR (cont.)

- During Injection and Post-Injection Site Care (PISC):
 - ⚙ Re-evaluation of the AoR periodically, at least once every five (5) years
[40 CFR 146.82(c)(9) and 146.84(e)],
and updating the AoR and Corrective Action Plan; and
 - ⚙ If phased corrective action is approved or when additional corrective action is warranted based on AoR re-evaluations, performing corrective action
[40 CFR 146.82(c)(6) and 146.84(d)].



Relationship between Site Characterization, Modeling, & Monitoring



Computational Modeling for Geologic Sequestration

- Modeled Processes
- Model Parameters
- Computational Approaches
- Model Uncertainty & Sensitivity Analyses
- Model Calibration
- Existing Codes used for Development of GS Models



Computational Modeling for Geologic Sequestration

Modeled Processes

- Modeled Processes
 - ⚙ multiphase flow – **Class VI Rule requires inclusion in computational modeling.**
 - ⚙ reactive transport
 - ⚙ geomechanical processes
 - ⚙ coupled multiphase flow & geomechanical processes
 - ⚙ coupled multiphase flow & geochemical processes
 - ⚙ interactive coupling of all 3 processes where geochemical & geomechanical processes are significant



Computational Modeling for Geologic Sequestration
Model Parameters



Computational Modeling for Geologic Sequestration

Computational Approaches

- the guidance discusses the ‘numerical formulation of the governing equations applied over a spatially discretized model domain that defines the spatial extent and resolution of the problem (i.e., the model grid). This formulation is solved by a numerical method, such as finite element or finite difference approximation.’
- the guidance further discusses the processes which are most suitably addressed by numerical methods some of which are:
 - ⚙ fluid and heat flow;
 - ⚙ phase changes, mass transfer, and chemical reactions;
 - ⚙ steady-state and transient problems relative to injection & withdrawal rates.



Computational Modeling for Geologic Sequestration

Computational Approaches (cont.)

- the guidance also discusses the use of analytical, semi-analytical and hybrid methods to complement numerical modeling efforts in AoR delineation
- these methods may be useful:
 - ⚙ for assessing transport of carbon dioxide through abandoned well bores;
 - ⚙ as screening tools to quickly assess potential storage sites;
 - ⚙ as a relatively simple comparative check on numerical modeling results.



Computational Modeling for Geologic Sequestration

Model Uncertainty & Sensitivity Analyses

- the guidance discusses model uncertainty due to:
 - ⚙ uncertainties in governing equations and model framework due to incomplete scientific data or lack of knowledge or data on the behavior of supercritical CO₂ in the subsurface or simplifications
 - ⚙ parameter uncertainties due to lack of data, poor data quality, inherent variability in natural systems
 - ⚙ process and scale dependency



Computational Modeling for Geologic Sequestration Model Uncertainty & Sensitivity Analyses (cont.)

- the guidance also discusses characterization of parameter uncertainty by conducting a model sensitivity analysis
 - ⚙ provides indication of those modeling parameters that are most sensitive (i.e., that most impact predictions of carbon dioxide migration, trapping, and pressure changes), and
 - ⚙ provides guidance for what parameters to focus on during data collection, parameter estimation, and model calibration.



Computational Modeling for Geologic Sequestration

Model Calibration

- the guidance discusses the concept of model calibration and the use of manual and automated manual calibration
- model calibration of the Frio Brine Pilot Project is presented



Computational Modeling for Geologic Sequestration

Existing Codes used for Development of GS Models

- the guidance briefly discusses existing codes used for development of GS models
 - ⚙ petroleum reservoir codes: STARS, GEM, ECLIPSE, CHEARS
 - ⚙ US DOE: STOMP, CRUNCH, TOUGH-series



AoR Delineation Using Computational Models

- AoR Delineation Class VI Rule Requirements
- Data Collection and Compilation
- Model Development
- AoR Delineation Based on Model Results
- Reporting AoR Delineation Results to the UIC Program Director



AoR Delineation Using Computational Models

AoR Delineation Class VI Rule Requirements

- 40 CFR 146.84(a): The AoR is the region surrounding the GS project where USDWs may be endangered by the injection activity. The AoR is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization, monitoring, and operational data.



AoR Delineation Using Computational Models

AoR Delineation Class VI Rule Requirements (cont.)

- 40 CFR 146.84(c)(1): Owners or operators of Class VI wells must predict, using existing site characterization, monitoring and operational data, and computational modeling, the projected lateral and vertical migration of the carbon dioxide plume and formation fluids in the subsurface from the commencement of injection activities until the plume movement ceases, until pressure differentials sufficient to cause the movement of injected fluids or formation fluids into a USDW are no longer present, or until the end of a fixed time period as determined by the UIC Program Director. The model must:



AoR Delineation Using Computational Models

AoR Delineation Class VI Rule Requirements (cont.)

- (i) Be based on detailed geologic data collected to characterize the injection zone(s), confining zone(s), and any additional zones; and anticipated operating data, including injection pressures, rates, and total volumes over the proposed life of the GS project;
- (ii) Take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and
- (iii) Consider potential migration through faults, fractures, and artificial penetrations.



AoR Delineation Using Computational Models

Data Collection and Compilation

- the guidance emphasizes that the extent to which site and operational conditions are realistically represented determines the validity of the resulting model predictions. (aka: Avoid garbage in, garbage out syndrome!)
 - ⚙ Site Hydrology - Regional and site-specific geology provide the foundations of the computational model used to delineate the AoR.
 - ⚙ Operational Data - 40 CFR 146.84(c)(1)(i) requires that the model be based on and anticipated operating data, including injection pressures, rates, and total volumes over the proposed life of the geologic sequestration project;



AoR Delineation Using Computational Models

Model Development

- with regards to the development of computational models, the guidance discusses the following major points:
 - ⚙️ Conceptual Model of the Proposed Injection Site
 - ⚙️ Determination of Physical Processes to be Included in the Computational Model
 - ⚙️ Computational Model Design
 - Computational Code Determination
 - Model Spatial Extent, Discretization, and Boundary Conditions
 - Model Timeframe
 - Parameterization
 - ⚙️ Executing the Computational Model



AoR Delineation Using Computational Models

AoR Delineation Based on Model Results

- 40 CFR 146.84(a) and 40 CFR 146.84(c)(1) require that the predicted AoR, which is based on the computational modeling, submitted with the Class VI permit application be based on a delineation of the area where the GS project may cause endangerment of USDWs
- at the discretion of the UIC Program Director, a single AoR modeling exercise may be conducted for a single GS project with multiple wells
- boundaries of AoR are based on simulated predictions of the extent of the separate-phase (i.e. supercritical, liquid, or gaseous) plume and pressure front.



AoR Delineation Using Computational Models

AoR Delineation Based on Model Results (cont.)

- EPA recommends that the AoR encompass the maximum extent of the separate-phase plume or pressure front over the lifetime of the project and entire timeframe of the model simulations.
- definition of pressure front - the minimum pressure within the injection zone necessary to cause fluid flow from the injection zone into the formation matrix of the USDW through a hypothetical conduit (i.e., artificial penetration) that is perforated in both intervals (the injection interval and the USDW interval).



AoR Delineation Using Computational Models

AoR Delineation Based on Model Results (cont.)

- the guidance describes the following several methods for estimating the pressure front based on various assumptions
 - ⚙ *Pressure front based on bringing injection zone and USDW to equivalent hydraulic heads (applicable to under-pressurized case only).*
 - ⚙ *Pressure front based on displacing fluid initially present in the borehole (applicable to hydrostatic case only).*
 - ⚙ *Methods for over-pressurized cases.*
- the guidance presents, in detail, a hypothetical example of an AoR delineation



AoR Delineation Using Computational Models

Reporting AoR Delineation Results to the UIC Program Director

- 40 CFR 146.82(a)(13) requires the submittal of the AoR and Corrective Action Plan with the initial permit application
- Information pertaining to how this plan should be submitted is provided in the *UIC Program Class VI Well Project Plan Development Guidance*.
- the guidance lists the 10 data elements EPA recommends be submitted with the permit application
- 40 CFR 146.82(c)(1) requires that the final delineated AoR based on computational modeling is submitted to the UIC Program Director prior to receiving authorization to inject.



Identifying Artificial Penetrations & Performing Corrective Action

- Rule Requirements
- Identifying Artificial Penetrations within the AoR
- Assessing Identified Abandoned Wells
- Performing Corrective Action on Wells within the AoR
- Reporting Well Identification, Assessment, and Corrective Action to the UIC Program Director



Identifying Artificial Penetrations & Performing CA Rule Requirements

- 40 CFR 146.84(c)(2): Using methods approved by the UIC Program Director, identify all penetrations, including active and abandoned wells and underground mines, in the AoR that may penetrate the confining zone(s). Provide a description of each well's type, construction, date drilled, location, depth, record of plugging and/ or completion, and any additional information the UIC Program Director may require;
- 40 CFR 146.84(c)(3): Determine which abandoned wells in the AoR have been plugged in a manner that prevents the movement of carbon dioxide or other fluids that may endanger USDWs, including use of materials compatible with the carbon dioxide stream;



Identifying Artificial Penetrations & Performing CA Rule Requirements (cont.)

- 40 CFR 146.84(d): Perform corrective action on all wells in the AoR that are determined to need corrective action, using methods designed to prevent the movement of fluid into or between USDWs, including use of materials compatible with the carbon dioxide stream, where appropriate;
- 40 CFR 146.84(e)(2): During the AoR reevaluation process, identify all wells in the reevaluated AoR that require corrective action in the same manner specified in 40 CFR 146.84(c);
- 40 CFR 146.84(e)(3): Perform corrective action on wells requiring corrective action in the reevaluated AoR in the same manner specified in 40 CFR 146.84(d);
- 40 CFR 146.84(e)(4): Revise the AoR and Corrective Action Plan as necessary whenever the AoR is reevaluated.



Identifying Artificial Penetrations & Performing CA

Identifying Artificial Penetrations within the AoR

- 40 CFR 146.84(d) requires identified abandoned wells that have been improperly plugged or not plugged at all (such penetrations can provide unimpeded flow conduits out of the injection zone) must be properly plugged in order to prevent endangerment of USDWs.
- the guidance describes the following methods for identifying artificial penetrations:
 - ⚙ historical research
 - ⚙ site reconnaissance
 - ⚙ aerial and satellite imagery review
 - ⚙ geophysical surveys – magnetic methods, electromagnetic methods, ground penetrating radar,



Identifying Artificial Penetrations & Performing CA Assessing Identified Abandoned Wells

- the guidance discusses the process of assessing each identified artificial penetration for the potential to serve as a conduit for fluid movement.
 - ⚙ abandoned well plugging records review
 - ⚙ abandoned well field testing
 - after all the available records have been reviewed, any wells located within the AoR that cannot be proven to have plugs adequate to prevent migration of carbon dioxide or formation fluids out of the injection zone must be evaluated by field tests in order to determine the quality of plugging, as required by 40 CFR 146.84(c)(3).
 - the guidance describes several tools used for assessing the integrity of abandoned wells.



Identifying Artificial Penetrations & Performing CA

Performing Corrective Action on Wells within the AoR

- the guidance includes a graphical well evaluation decision tree – Fig. 4-3
- the Class VI Rule allows for corrective action on a phased basis
- acceptable forms of corrective action include well plugging and/or remedial cementing of the improperly abandoned wells. Both are described in the guidance.
- EPA recommends performing enhanced monitoring in the vicinity of improperly abandoned wells, including ground water monitoring and using indirect geophysical techniques for obtaining monitoring results. (See the *UIC Program Class VI Well Testing and Monitoring Guidance* for appropriate monitoring.)



Identifying Artificial Penetrations & Performing CA

Reporting Well Identification, Assessment, and CA to the UIC Program Director

- the guidance emphasizes that the AoR and Corrective Action Plan (see the *UIC Program Class VI Well Project Plan Development Guidance* for details in the development of this plan) must indicate what well identification and assessments will be used and how corrective action will be conducted.



AoR Re-Evaluation

- Class VI Rule Requirements Related to AoR Re-evaluation
- Conditions Warranting an AoR Re-evaluation
- Performing an AoR Re-evaluation



AoR Re-Evaluation

Class VI Rule Requirements Related to AoR Re-evaluation

- 40 CFR 146.84(e): At the minimum fixed frequency, not to exceed five years, as specified in the AoR and Corrective Action Plan, or when monitoring and operational conditions warrant, owners or operators must:
 - (1) Re-evaluate the AoR in the same manner specified in 40 CFR 146.84(c)(1);
 - (2) Identify all wells in the re-evaluated AoR that require corrective action in the same manner specified in 40 CFR 146.84(c);
 - (3) Perform corrective action on wells requiring corrective action in the re-evaluated AoR in the same manner specified in 40 CFR 146.84(d); and



AoR Re-Evaluation

Class VI Rule Requirements Related to AoR Re-evaluation (cont.)

(4) Submit an amended AoR and Corrective Action Plan or demonstrate to the UIC Program Director through monitoring data and modeling results that no amendment to the AoR and Corrective Action Plan is needed. Any amendments to the AoR and Corrective Action Plan must be approved by the UIC Program Director, must be incorporated into the permit, and are subject to the permit modification requirements at 40 CFR 144.39 or 144.41, as appropriate.



AoR Re-Evaluation

Conditions Warranting an AoR Re-evaluation

- AoR re-evaluation is required at a minimum fixed frequency of at least once every five years, or when monitoring and operational conditions warrant. EPA recommends, and the guidance describes, that monitoring and operational conditions that may warrant a re-evaluation of the AoR include:
 - ⚙ Significant changes in site operations that may alter model predictions and the AoR delineation;
 - ⚙ Monitoring results for the injected carbon dioxide plume and/or the associated pressure front that differ significantly from model predictions; or
 - ⚙ New site characterization data obtained that may significantly change model predictions and the delineated AoR.



AoR Re-Evaluation

Performing an AoR Re-evaluation

- the guidance describes the steps in performing an AoR re-evaluation including:
 - ⚙ comparison of plume monitoring data with model predictions
 - ⚙ comparison of pressure monitoring data with model predictions
 - ⚙ evaluate outcome of monitoring data and model comparison
 - ⚙ revise the AoR delineation (and model) and AoR and Corrective Action Plan, if necessary
- the guidance presents a hypothetical example of an AoR re-evaluation and a presentation of the revised AoR





Rocky Mountain CarbonSAFE Phase I

Appendix N

Site Characterization Guidance

UIC Class VI Requirements

Site Characterization Guidance

Prepared by Candace Cady

(Condensation of EPA's UIC Class VI Well
Site Characterization Guidance)



!! DISCLAIMER !!

This document is meant to make the CarbonSAFE Rocky Mountains team aware of EPA's Class VI injection well requirements as they are presented in the several guidance documents prepared by EPA. It is NOT meant to be a stand-alone document. I encourage you, I implore you to read the relevant sections of the guidance documents, the final Class VI rule, and all references contained therein which pertain to your particular task on the CarbonSAFE team!

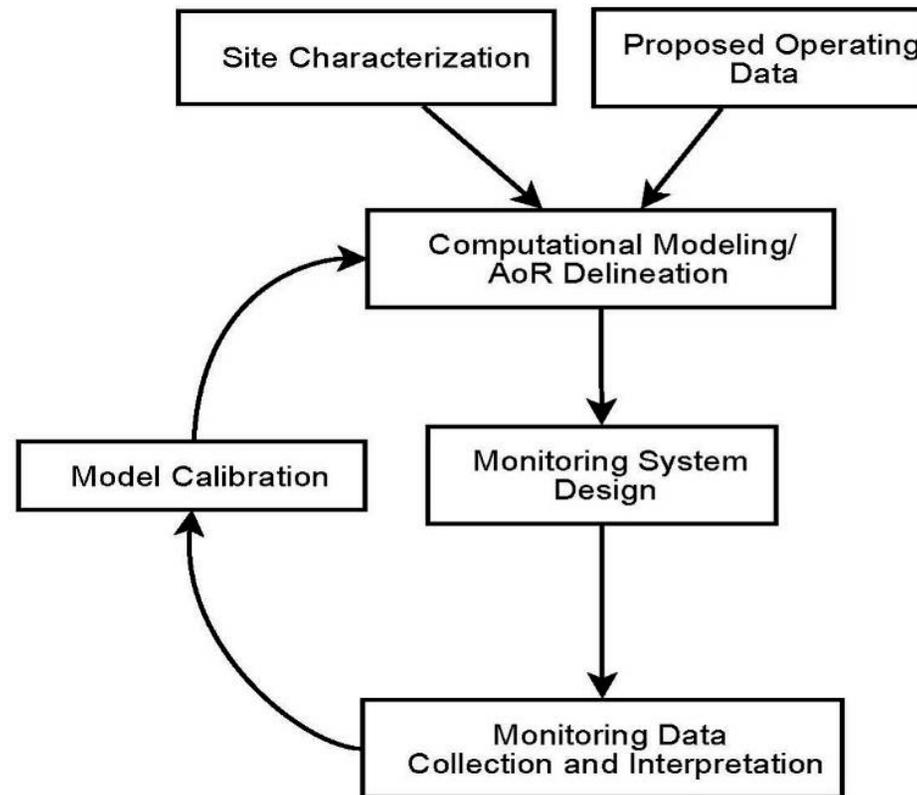


Organization of this Guidance

- Activities Performed Prior to Construction of a Class VI Well
 - ✓ information required for Class VI permit application
 - ✓ meet requirements of 40 CFR 146.82(a)(2), (3), (5), and (6)
- Data Synthesis for Demonstration of Site Suitability
- Activities Performed Prior to Operation of a Class VI Well
 - ✓ activities & information before injection may be authorized
 - ✓ meet requirements of 40 CFR 146.82(c)(2)–(4) and (7), and 146.87(b)–(e).



Relationship between Site Characterization, Modeling, & Monitoring



Prior to Construction

- Regional Geology, Hydrogeology, & Local Structural Geology (pages 9 - 11)
- Map of Injection Well, Area of Review (AoR), Surface Water Bodies, Artificial Penetrations, & Faults (page 11 - 13)
- Detailed Geology & Hydrogeologic Site Characterization within AoR (page 13 - 44)



Class VI AoR Delineation Requirements

- 40 CFR 146.84(a): The AoR is the region surrounding the GS project where USDWs may be endangered by the injection activity. The AoR is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization, monitoring, and operational data.



Class VI AoR Delineation Requirements (cont.)

- 40 CFR 146.84(c)(1): Owners or operators of Class VI wells must predict, using existing site characterization, monitoring and operational data, and computational modeling, the projected lateral and vertical migration of the carbon dioxide plume and formation fluids in the subsurface from the commencement of injection activities until the plume movement ceases, until pressure differentials sufficient to cause the movement of injected fluids or formation fluids into a USDW are no longer present, or until the end of a fixed time period as determined by the UIC Program Director. The model must:



Class VI AoR Delineation Requirements (cont.)

- (i) Be based on detailed geologic data collected to characterize the injection zone(s), confining zone(s), and any additional zones; and anticipated operating data, including injection pressures, rates, and total volumes over the proposed life of the GS project;
- (ii) Take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and
- (iii) Consider potential migration through faults, fractures, and artificial penetrations.



Regional Geology, Hydrogeology, & Local Structural Geology

- 40 CFR 146.82(a)(3)(vi) requires submittal of geologic & topographic maps & cross sections illustrating regional geology, hydrogeology, geologic structure of local area surrounding the project area
- the guidance discusses the features to highlight in maps & accompanying narrative:
 - ✓ names, lithologies, & depths of injection formation(s) & confining zone(s)
 - ✓ depths, extent, & groundwater flow patterns of regional USDW
 - ✓ brief synopsis of geologic history of project site
 - ✓ regional faults, fault types, trends, & whether they transect the injection formation(s) and/or confining zone(s)



Regional Geology, Hydrogeology, & Local Structural Geology (cont.)

- ✓ structural geology of the local area
 - presence & trends of folds
 - whether proposed storage site will be bounded by faults or other structural features.
- UIC Director may require characterization of secondary confining zone [40 CFR 146.83(b)].



Map of Injection Well, Area of Review, Surface Water Bodies, Artificial Penetrations, & Faults

- 40 CFR 146.82(a)(2) requires submittal of an Area of Review (AoR) map showing existing information in the public record regarding:
 - ✓ surface bodies of water & springs
 - ✓ mines (both surface & subsurface) & quarries
 - ✓ surface features, including structures intended for human occupancy
 - ✓ political boundaries such as state, tribal & territorial boundaries
 - ✓ surface trace of all known & suspected faults
 - ✓ number or name, & location of all injection wells, producing wells, abandoned wells, plugged wells, dry holes, or deep stratigraphic holes
 - ✓ state- or EPA-approved subsurface cleanup sites.



Map of Injection Well, Area of Review, Surface Water Bodies, Artificial Penetrations, & Faults (cont.)

- 40 CFR 146.82(a)(4) requires tabulation of all wells within AoR that penetrate the injection or confining zone(s) – artificial penetrations – to include:
 - ✓ description of each well's type, construction, date drilled, location and depth
 - ✓ record of plugging and/or completion
 - ✓ any additional information UIC Director may require.



Detailed Geology & Hydrogeologic Site Characterization

- Maps & Cross Sections of AoR
- Fault & Fractures in AoR
- Depth, Areal Extent, & Thickness of Injection & Confining Zones
- Petrology & Mineralogy of Injection & Confining Zones
- Porosity, Permeability, & Capillary Pressure of Injection & Confining Zones
- Geomechanical Characterization
- Seismic History
- Hydrology & Hydrogeology of AoR
- Baseline Geochemical Characterization
- Geophysical Characterization
- Surface Air & Soil Gas Monitoring



Detailed Geology & Hydrogeologic Site Characterization

Maps & Cross Sections of AoR

- 40 CFR 146.82(a)(3)(i) requires submittal of maps & cross sections of AoR
 - ✓ topographic maps
 - ✓ geologic maps w/ cross sections & stratigraphic columns summarizing lithology, sequence of geologic units (including injection & confining zones and USDWs), approximate formation thicknesses, lateral extent of units, and correlation of units in vicinity of project and across region



Detailed Geology & Hydrogeologic Site Characterization

Maps & Cross Sections of AoR (cont.)

- narrative accompanying maps and cross sections of the AoR should be similar in scope to the evaluation of regional geology, but provide more detail on the AoR; narrative should highlight lateral extent of injection formation and show that it is continuous throughout proposed site; at a minimum, the following should be described:
 - ✓ formation names, lithologies, and depths of the injection formation(s), confining zone(s), and USDWs within the proposed AoR;
 - ✓ general description of stratigraphy, including the vertical distance and formations separating the injection formation from USDWs; and
 - ✓ structural geology of the project site, including whether the proposed storage site will be bounded or influenced by a structural trap (e.g., faults or a dome).



Detailed Geology & Hydrogeologic Site Characterization

Faults & Fractures in the AoR

- 40 CFR 146.82(a)(3)(ii) requires submittal of information on location, orientation, and properties of known or suspected faults & fractures that may transect the confining zone(s) in the AoR and a determination that they would not interfere with containment.
- This information is needed to demonstrate that the site has a confining zone(s) free of transmissive faults or fractures and that will allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in the confining zone(s). Evaluation of fault stability and fault or fracture sealing capacity is needed to demonstrate that faults will not interfere with containment of the carbon dioxide.



Detailed Geology & Hydrogeologic Site Characterization

Faults & Fractures in the AoR (cont.)

- EPA recommends obtaining information on fault in injection zone including whether a fault zone consists of one major plane or a series of faults that may collectively provide a conduit for fluid movement through confining zone, especially if faults intersect lenses of high permeability.
- faults and fractures shall be assessed for stability and the likelihood that they are sealing



Detailed Geology & Hydrogeologic Site Characterization

Faults & Fractures in the AoR (cont.)

- in describing faults & fractures, EPA recommends the following information:
 - ✓ location and characteristics of the fault or fracture (e.g., geometry, depth, fault displacement, units juxtaposed by fault);
 - ✓ formations intersected or transected by the fault or fracture;
 - ✓ methods and results of fault stability analyses and comparison to preliminary anticipated (modeled) pressures during the injection phase of the project; and
 - ✓ information on faults and fractures in the lower confining zone (in cases where an injection depth waiver is sought).



Detailed Geology & Hydrogeologic Site Characterization

Faults & Fractures in the AoR (cont.)

- in demonstrating non-transmissivity of faults and fractures, EPA recommends the following information:
 - ✓ description of the approach used to infer whether a fault or fracture is transmissive;
 - ✓ summary table of data used to formulate the estimate;
 - ✓ supporting data and information (e.g., analyses of core samples, results of geophysical surveys, pore pressure data, maps, and cross sections) and any relevant calculations (e.g., calculation of shale gouge ratio);
 - ✓ narrative that describes and integrates the relevant information, including a discussion of any spatial heterogeneity in sealing properties and whether a fault or fracture is likely to be transmissive in the project area; and
 - ✓ discussion of uncertainties in the data.



Detailed Geology & Hydrogeologic Site Characterization

Depth, Areal Extent, and Thickness of Injection & Confining Zones

- 40 CFR 146.82(a)(3)(iii) requires submittal of information on the depth, areal extent & thickness of the injection formation & confining zone(s)
- in illustrating this information, EPA suggests the following:
 - ✓ isopach maps
 - ✓ isochore maps supported by available well logs and cores
 - ✓ seismic or other geophysical survey results w/ relevant info highlighted
 - ✓ well log data, if available, w/ injection & confining zones highlighted
- narrative about required information including discussion of variability of thickness of injection formation & confining zone(s); data quality & uncertainties.



Detailed Geology & Hydrogeologic Site Characterization

Petrology & Mineralogy of Injection & Confining Zones

- 40 CFR 146.82(a)(3)(iii) requires submittal of data on mineralogy of injection & confining zone(s).
- supports identification of any geochemical reactions that may affect storage and containment of injected carbon dioxide which could result from potential changes in properties of injection or confining zones (e.g., porosity, permeability, injectivity).
- provides information on mobilization of trace elements from formation matrix if minerals known to contain trace elements are identified, which informs decisions regarding parameters to analyze as part of a testing and monitoring program.



Detailed Geology & Hydrogeologic Site Characterization

Petrology & Mineralogy of Injection & Confining Zones (cont.)

- evaluation of minerals and potential geochemical reactions is the basis of the required demonstration of compatibility of the carbon dioxide stream with fluids in the injection zone and minerals in the injection and confining zones required prior to commencement of injection
- if evaluation of potential geochemical processes suggests long-term storage and confinement of carbon dioxide may be affected by changes in the injection formation and confining zone(s), the AoR delineation may need to account for geochemical reactions through the use of reactive transport models



Detailed Geology & Hydrogeologic Site Characterization

Petrology & Mineralogy of Injection & Confining Zones (cont.)

- any potential effects on storage and confinement due to mechanisms such as precipitation and dissolution may also affect the post-injection site care (PISC) time frame.
- data collection & analysis
 - ✓ existing data within AoR? sufficient quality & completeness?
 - ✓ discuss possible need for stratigraphic test well with UIC Director
 - ✓ basic lithology from mud logging & cores; polarized light microscopy, SEM, powder XRD



Detailed Geology & Hydrogeologic Site Characterization

Petrology & Mineralogy of Injection & Confining Zones (cont.)

- EPA recommends a narrative report that includes the following information:
 - ✓ methods used in examining samples;
 - ✓ locations (on maps) and depths of samples and the names of the formations sampled;
 - ✓ lithologies and descriptions (e.g., color, texture) from cores or hand samples;
 - ✓ mineralogic and petrologic descriptions obtained via microscopy (with approximate percentages of minerals);
 - ✓ cementation minerals and dissolution features; and
 - ✓ preliminary discussion of geochemical reactions that may affect the storage, confinement, and/or overall performance of the project.



Detailed Geology & Hydrogeologic Site Characterization

Porosity, Permeability, & Capillary Pressure of Injection & Confining Zones

- 40 CFR 146.82(a)(3)(iii) requires submittal of data on porosity, permeability & capillary pressure of injection & confining zones
 - ✓ crucial for a number of aspects of site characterization including determination of storage capacity, injectivity, & integrity of confining zone
 - ✓ also needed for multiphase modeling to predict plume & pressure front behavior & to delineate AoR.



Detailed Geology & Hydrogeologic Site Characterization

Geomechanical Characterization

- 40 CFR 146.82(a)(3)(iv) requires that geomechanical information be submitted on fractures, stress, ductility, rock strength, and in situ fluid pressures within the confining zone.
- geomechanical characterization is important for evaluating confining zone integrity as well as setting safe operational parameters
- information to provide:
 - ✓ test(s) performed, dates, and locations (on maps);
 - ✓ sample collection procedures for cores;
 - ✓ test conditions (as appropriate);
 - ✓ results in tabular and/or graphical form;



Detailed Geology & Hydrogeologic Site Characterization

Geomechanical Characterization (cont.)

- ✓ narrative of test results, including any anomalies or uncertainties in the data;
- ✓ comparison of data from different tests if more than one type of test is used for a particular parameter; and
- ✓ any issues with sample procurement, e.g., disintegration of poor quality rocks during transport or sample retrieval, the existence of discontinuities (fractures, fossils, etc.) in tested samples.



Detailed Geology & Hydrogeologic Site Characterization

Seismic History

- 40 CFR 146.82(a)(3)(v) requires a report on the seismic history of the project site, including the presence and depth of all seismic sources
- information to submit:
 - ✓ tabulation and/or map of seismic sources and their depths;
 - ✓ tabulation of seismic events, their hypocenters, and magnitudes for as far back as data are available;
 - ✓ sources of all seismic history data;
 - ✓ information on any seismic risk models used and the results; and
 - ✓ discussion of the degree of seismic risk in the region and information to support a determination that the confining system and wells at the project site are not vulnerable to damage from seismic activity.



Detailed Geology & Hydrogeologic Site Characterization

Hydrology & Hydrogeology of AoR

- 40 CFR 146.82(a)(5) requires submission of maps and stratigraphic cross sections indicating the general vertical and lateral limits of all USDWs, water wells, and springs within the AoR, their positions relative to the injection zone(s) and confining zone(s), and the direction of water movement, where known
- to meet this requirement, EPA recommends the following information:
 - ✓ numbers, thicknesses, and lithologies of USDWs (including interbedded low permeability zones);
 - ✓ information on all USDWs in the AoR and the region, and whether they are currently being used for drinking water; and
 - ✓ location of water wells and springs within the AoR.



Detailed Geology & Hydrogeologic Site Characterization

Baseline Geochemical Characterization

- 40 CFR 146.82(a)(6) requires baseline geochemical information on subsurface formations including all USDWs in the AoR including both fluid and solid phase chemical analysis.
 - ✓ information on water chemistry indicates which formations in the stratigraphic column qualify as USDWs and confirms that the proposed injection formation is not a USDW.
 - ✓ geochemical information on both solids and fluids is also needed, in combination with the mineralogic data required at 40 CFR 146.82(a)(3)(iii), to determine whether the interaction of the formation fluids with the injectate and solids will cause changes in injectivity, changes in the properties of the confining zone, or the release of trace elements.



Detailed Geology & Hydrogeologic Site Characterization

Geophysical Characterization

- the guidance discusses the use of geophysical methods for obtaining subsurface information in lieu of direct physical sampling. These methods include:
 - ✓ Seismic Methods – 2D, 3D, Vertical Seismic Profile (VSP), 3D-VSP, Cross-well, Borehole Microseismic
 - ✓ Gravity Methods – Aerial & Surface Gravity, Borehole Gravity
 - ✓ Electrical / Electromagnetic Geophysical Methods – Natural Source, Controlled Source, Electrical Resistance Tomography (ERT)
 - ✓ Magnetic Methods – Aerial & Surface Magnetic



Detailed Geology & Hydrogeologic Site Characterization

Surface Air & Soil Gas Monitoring

- 40 CFR 146.90(h) – at the discretion of the UIC Program Director, monitoring of surface air and/or soil gas for CO₂ leakage may be required.
 - ✓ Baseline surface air and soil gas data should be collected if the UIC Program Director requires surface air and soil gas monitoring as part of the Testing and Monitoring Plan.
 - ✓ in the guidance, EPA makes recommendations regarding the selection of monitoring parameters and the location of monitoring sites
 - ✓ Further information on technologies that can be used for soil gas and surface air monitoring can be found in the *UIC Program Class VI Well Testing and Monitoring Guidance* and the *Subpart RR General Technical Support Document for Injection and Geologic Sequestration of Carbon Dioxide* (USEPA, 2010).



Demonstration of Site Suitability

The information required at 40 CFR 146.82 and described in this guidance provide comprehensive data and descriptions for many properties of the proposed project site (e.g., porosity, geochemistry).

These data do not individually provide a complete picture of the site to demonstrate that it can safely receive and confine the carbon dioxide.

Together, however, this information can form a comprehensive picture of the site and demonstrate whether it is a good candidate for GS and meets the requirements at 40 CFR 146.83.

This section describes how the owner or operator can synthesize the information collected during site characterization to demonstrate site suitability.



Demonstration of Site Suitability

- Facies Analysis for Project Site
- Structure of Injection & Confining Zones
- Compatibility of CO₂ Stream w/ Subsurface & Well Materials
- Demonstration of Storage Capacity
- Demonstration of Confining Zone Integrity
- Considerations for Secondary Confinement
- Reporting Process



Facies Analysis for Project Site

- 40 CFR 146.82(a)(3)(iii) requires owners or operators to provide information on facies changes in the injection and confining zones.
- prepare narrative of the inferred depositional environment(s) at the project site in the context of the site geologic conceptual model; narrative should reference appropriate data, maps, geophysical images, cross sections, and stratigraphic columns and should address, at a minimum:
 - ⚙ implications for connectivity within the injection formation and the suitability of the confining zone;
 - ⚙ lithofacies distributions mapped in the injection and confining formations, including the distributions of properties such as porosity and permeability for each lithofacies;
 - ⚙ potential for preferential flow paths;
 - ⚙ diagenetic processes that may affect present-day hydrogeologic properties; and
 - ⚙ uncertainties associated with the data and with the resulting facies model.



Structure of Injection & Confining Zones

- 40 CFR 146.82(a)(3)(vi) requires that geologic and topographic maps and cross sections illustrate the geologic structure of the local area.
- prepare narrative that clearly describes how the local and regional geologic structure are conducive to GS and that an adequate confining system is present. The narrative should:
 - ⚙ describe how the structure of the injection and confining zones fit into and support the development of the site conceptual model developed for delineation of the AoR.
 - ⚙ identify which features support the capacity of the site to contain carbon dioxide, including the role of structural traps.
 - ⚙ address potential weaknesses (e.g., if faults are present, whether data indicate that they are sealing).
 - ⚙ discuss whether there are alternative interpretations to the data.



Compatibility of CO₂ Stream with Subsurface & Well Materials

- 40 CFR 146.82(c)(3) requires a report demonstrating the compatibility of the carbon dioxide stream with fluids in the injection zone(s) and minerals in both the injection and the confining zone(s), based on the results of the formation testing program, and with the materials used to construct the well; needed to support an understanding of the following:
 - 1) whether subsurface interactions among the injectate, fluids, and solids will lead to precipitation or dissolution of minerals such that permeability, porosity, and injectivity may change;
 - 2) if geochemical changes due to the introduction of large amounts of carbon dioxide into the subsurface might cause trace elements such as lead or arsenic to be liberated from subsurface solids; and
 - 3) if interactions among the fluid, carbon dioxide, and cement might cause deterioration of the cement such that the cement sheath would become a conduit for fluid migration.



Compatibility of CO₂ Stream with Subsurface & Well Materials (cont.)

- Demonstration of Compatibility of the Carbon Dioxide Stream with Fluids and Minerals will use information gathered during site characterization and during execution of formation testing program, including:
 - ⊗ chemical analyses of fluids in the injection zone and, if available, the confining zone;
 - ⊗ mineralogy of the injection and confining zones;
 - ⊗ bulk chemical analyses of solids in the injection and confining zones;
 - ⊗ pressure, temperature, and pH in the injection zone and, if available, the confining zone; and
 - ⊗ chemical characteristics of the injectate .



Compatibility of CO₂ Stream with Subsurface & Well Materials (cont.)

- Demonstration of Compatibility with Well Materials showing that reactions between the cement, formation fluids, and carbon dioxide will not lead to deterioration in the strength of the cement sheath or increases in the porosity and permeability that could result in the cement sheath becoming a conduit for carbon dioxide or carbon dioxide-rich fluids. Information gathered during site characterization and during well construction will be used, including :
 - ⚙ chemical analyses of fluids in the injection zone and, if available, the confining zone;
 - ⚙ cement type and additives;
 - ⚙ pressure, temperature, and pH in the injection zone and, if available, the confining zone;
 - ⚙ chemical characteristics of the injectate, including impurities that may result in an especially low pH (e.g., sulfur dioxide); and
 - ⚙ mineralogy of the injection and confining zones.



Demonstration of Storage Capacity

- 40 CFR 146.83(a)(1) requires a demonstration that the geologic system is comprised of an injection zone(s) of sufficient areal extent, thickness, porosity and permeability to receive the total anticipated volume of the carbon dioxide stream.
- the guidance discusses the geologic and project-specific (e.g. injection well configuration, CO₂ stream composition, etc.) characteristics that influence the estimation of storage capacity
- the guidance also discusses static and dynamic models and how they are used to make estimations of carbon dioxide storage capacity.



Demonstration of Storage Capacity (cont.)

- In reporting storage capacity estimates, the owner or operator should submit:
 - ⚙ description of the selected estimation method, including a discussion of its suitability for the type of formation;
 - ⚙ tabulation of any input data used, along with estimates of uncertainty in those data;
 - ⚙ results in tabular or graphic format;
 - ⚙ discussion of the results, relating them to proposed operational parameters and the anticipated total volume of carbon dioxide to be injected and the duration of the project and any identified site-specific vulnerabilities (e.g., faults, fractures, etc.);
 - ⚙ discussion of assumptions and limitations of the method used;
 - ⚙ discussion of uncertainty based on the results of a sensitivity analysis; and
 - ⚙ discussion of how the results are consistent with and/or supported by the AoR delineation modeling.



Demonstration of Confining Zone Integrity

- 40 CFR 146.83(a)(2) requires a demonstration that the geologic system is comprised of confining zone(s) free of transmissive faults or fractures and of sufficient areal extent and integrity to contain the injected carbon dioxide stream and displaced formation fluids and allow injection at proposed maximum pressures and volumes without initiating or propagating fractures in the confining zone(s).
- confining zone(s) may not allow migration of carbon dioxide, either through interconnected pore spaces across the thickness of the seal or through the confining zone along faults or fractures. In particular, analyses may be needed to ensure that existing non-transmissive faults will not become transmissive under anticipated injection and storage pressures.



Demonstration of Confining Zone Integrity (cont.)

- to demonstrate competence of confining zone(s), synthesis of several types of data gathered through the site characterization process will be required. examples of such data are:
 - ⚙ **Lithologic and stratigraphic data**, e.g., on the depth, thickness, and mineralogy of the confining zone;
 - ⚙ **Structural data**, e.g., on faults and fractures, including fault geometry, depth of origin and termination, and the amount of displacement along the fault, including determinations of whether slip is consistent or variable along the fault and where such variations occur;
 - ⚙ **Data from core analysis**, e.g., the capillary pressure, rock strength, permeability, and porosity;
 - ⚙ **Field formation testing data**, e.g., in situ fluid pressures, the magnitudes of principal stresses, and temperature ; and
 - ⚙ **Geophysical survey data**, e.g., seismic, gravity, magnetic, or other geophysical methods



Demonstration of Confining Zone Integrity (cont.)

- the guidance discusses movement of carbon dioxide through a continuous confining zone lacking faults or fractures in terms of capillary pressure and permeability
- the guidance discusses transmission of carbon dioxide through faults which can be generated when capillary entry pressure and pore pressure exceed the rock strength
- the guidance discusses the characterization of the sealing potential of existing faults and fractures in terms of juxtaposition of units, cataclasis (misspelled as ‘catalysis’ in the guidance), diagenetic sealing, calculation of shale gouge ratio (SGR), and pressure compartmentalization
- special considerations for characterizing lower confining zones are discussed for those applying for an injection depth waiver.



Considerations for Secondary Confinement

- 40 CFR 146.83(b) provides the UIC Program Director with discretion to require identification and characterization of additional confining zones if:
 - ⚙ primary confining zone does not exhibit sufficient strength to allow injection at the proposed pressures;
 - ⚙ known or suspected faults or fractures transect the primary confining zone and would interfere with containment of carbon dioxide;
 - ⚙ primary confining zone is not sufficiently extensive to cover the entire maximum extent of the carbon dioxide plume and pressure front or it is not sufficiently thick and homogeneous over the entire area; or
 - ⚙ insufficient information or conflicting data about the primary confining zone.



Reporting Process

- 40 CFR 146.82(a) and (c) requires submittal of site characterization data with permit application or prior to receiving authorization to begin injection, respectively.
 - ⚙ submitted in electronic format approved by EPA
 - ⚙ data and supporting documents - submitted as PDF files, including charts, graphs, and tabular data.
 - ⚙ raw data - submitted in separate files (e.g., LAS, Excel).
 - ⚙ maps - submitted in a GIS-compatible format.
 - ⚙ for additional information on complying with reporting requirements, see the *UIC Program Class VI Well Recordkeeping, Reporting, and Data Management Guidance for Owners and Operators*.



Prior to Injection

- 40 CFR 146.82(c) requires submittal of extensive geologic and hydrogeologic data collected during the construction of a Class VI well to demonstrate that the injection and confining zones are suitable for receiving and containing the injected fluids
- This section of the guidance focuses on the formation and well testing and logging activities that the owner or operator must conduct to generate the information and data required to receive authorization to inject at a Class VI well.



Prior to Injection

- Well Logging
- Core Analyses
- Characterization of Injection Formation Fluid Chemical & Physical Properties & Downhole Conditions
- Fracture Pressure of Injection & Confining Zones
- Hydrogeologic Testing



Well Logging

- 40 CFR 146.87 requires that, during the drilling and construction of a Class VI injection well, the owner / operator must run logs, conduct surveys, and perform tests when appropriate to determine or verify the depth, thickness, porosity, permeability, lithology, and salinity of any formation fluids in all relevant geologic formations.
- The *UIC Program Class VI Well Construction Guidance* provides information on how owners / operators can meet the injection well testing requirements.
- These post-well construction / pre-operational testing and logging data will provide updates to and can be synthesized with related injection and confining formation data obtained during the GS site characterization and submitted earlier as part of the Class VI permit application.



Well Logging (cont.)

- at a minimum, well logs must include resistivity, spontaneous potential, gamma ray, porosity, fracture finder logs, and any other logs the UIC Program Director requires based on the geology of the site. These logs must be conducted before installation of the surface casing and before installation of the long-string casing. Any alternative methods that provide equivalent or better information must be approved by the UIC Program Director prior to implementation.
- the guidance describes the information that must be submitted in fulfilling the well logging requirement



Core Analyses

- 40 CFR 146.87(b) requires the owner / operator to take whole cores or sidewall cores of the injection and confining zones and formation fluid samples from the injection zone(s) and to submit to the UIC Program Director a detailed report prepared by a log analyst.
- the guidance discusses the nature of the core sampling and the information that should be included in the core logs: lithology, thickness, grain size, sedimentary structures, diagenetic features, contacts, textural maturity, oil staining, fracturing, and porosity.
- laboratory analysis of cores should include petrology and mineralogy; petrophysical properties; and geomechanical properties
- the guidance discusses special core analysis (SCAL) to obtain an in-depth suite of tests for parameters relevant to GS, such as relative permeability, capillary pressure, fluid compatibility, wettability, and pore volume compressibility.



Characterization of Injection Formation Fluid Chemical & Physical Properties & Downhole Conditions

- 40 CFR 146.82(a)(8) and 146.87(b) require the sampling and characterization of the chemical and physical properties of the formation fluids in the injection zone.
- 40 CFR 146.87(c) requires the recording of the fluid temperature, pH, specific conductivity (SC), reservoir pressure, and static fluid level
- the guidance discusses methods for collecting required data
- see the *UIC Program Class VI Well Testing and Monitoring Guidance* for additional information



Fracture Pressure of Injection & Confining Zones

- 40 CFR 146.87(d)(1)] requires owners or operators to determine or calculate the fracture pressure of the injection and confining zones
- the guidance discusses the common method for obtaining the required information – step rate test – and recommended test set up (EPA Region 8 Step-Rate Test Procedure).



Hydrogeologic Testing

- 40 CFR 146.87(e)(1)–(3) requires verification of the hydrogeologic characteristics of the injection zone(s) by performing a pressure fall-off test and either a pump test or an injectivity test.
- the guidance discusses the recommended test procedures (EPA Region 6 ‘The Nuts and Bolts of Falloff Testing’) and how these tests are used to determine the transmissibility of the reservoir, the skin factor, and to identify nearby faults or fractures





Rocky Mountain CarbonSAFE Phase I

Appendix O

Stakeholders

Officials/Government Agencies	Organization	Contact Name	Potential Benefits	Potential Concerns	Email	Phone	Postal Address	Website	Notes
	USTAR	Andrew Sweeney	Economic stability. As market forces and legislation require decreased carbon emissions, the project may provide	Increased electrical rates could slow economic growth.	asweeney@utah.gov		60 E. South Temple, Third Floor, Salt Lake City, UT 84111	https://ustar.org/	Utah Science Technology and Research Initiative. "leverage science and technology innovation to expand and diversify the State's economy"
	Utah's Governor's Office of Energy Development	Alair Emory	The project falls under the offices purview to facilitating the development of the Utah's diverse energy sector.	Environmental issues.	alairemory@utah.gov	801-538-8722	P.O. Box 144845, Salt Lake City, UT 84114	http://energy.utah.gov/	
	CoalBlue	Jonathan Wood	Energy production with "clean, low-carbon coal."		jwood@coalblue.org	410-662-2130	1110 Vermont Ave, NW Suite 1000, Washington DC 20005	http://coalblue.org/	Group founded by Democrats to promote 'clean, low-carbon coal.'
	Sandia National Laboratories, Center for Experimental Geosciences	Charles Choens			rcchoen@sandia.gov		MS 0735, Sandia National Laboratories, 1515 Eubank SE, Albuquerque, NM, 87123		
	PRRC, New Mexico Tech / SWP	Martha Cather			martha@prrc.nmt.edu	575-835-6916	801 Leroy Place, Socorro, NM 87801	http://www.prrc.nmt.edu/	Petroleum Recovery Research Center, Industry Service & Outreach Group. Martha heads up the outreach component of the Southwest Regional Partnership on Carbon Sequestration.
	Emery County	Lynn Sitterud	Direct jobs. As market forces and legislation require decreased carbon emissions, the project may provide economic stability by stabilizing the region's coal mines and power plants.	Increased consumer electrical rates. Increased power production costs resulting in non-competitive wholesale pricing. Induced seismicity.	lynn@emery.utah.gov	435-381-3570	P.O. Box 629, Castle Dale, UT 84513	http://www.emerycounty.com	Chairman - Lynn Sitterud Commissioners - Paul Cowley, Kent Wilson
	Castle Dale City Town Council		same as above	same as above	mayor@castledalecity.org	435-381-2115	P.O. Box 728, Castle Dale, UT 84513	http://www.getdirtywithus.org	Mayor - Danny VanWagoner City Council - Bradley Giles, Joel Dorsch, Doug Weaver, Jacob Barnett, Julie Johansen
	Orangeville City		same as above	same as above	orange@etv.net	435-748-2651	P.O. Box 677, Orangeville, UT 84537	http://www.ovcity.info	Mayor Roger Swenson City Council- Carol Stilson, Carole Larsen, Brandon Hoffman, Janet Tuttle, Kirk McQuivey
	The Seven County Infrastructure Coalition	Mike McKee Executive Director			mmckee@7county.utah.gov	435-823-5010	5995 S. Redwood Road Salt Lake City, UT 84123	http://scic.utah.org	The Coalition includes Carbon, Daggett, Duchesne, Emery, San Juan, Sevier, and Uintah Countys. Its main role is to identify revenue-producing infrastructure assets benefitting the region. Its mission is to plan infrastructure corridors, procure funding, permit, design, secure rights-of-way and own such facilities.
	UT House of Representatives R-Bountiful	Rep. Raymond Ward	Reducing atmospheric CO2 will address climate change.		rayward@je.utah.gov	801-440-8765	954 E. MILLBROOK WAY, BOUNTIFUL, UT, 84010	http://house.utah.gov/rep/WARDR	2018, Sponsored H.C.R. 1, Concurrent Resolution on Climate Change, which acknowledges climate change and "states that the Legislature and Governor will continue to base decisions regarding state energy policies on the best scientific evidence available..."
	UT House of Representatives R-North Salt Lake	Rep. Rebecca Edwards	Reducing atmospheric CO2 will address climate change.		beckyedwards@je.utah.gov	801-554-1968	1121 EAGLEWOOD LOOP, NORTH SALT LAKE, UT, 84054	http://house.utah.gov/rep/EDWARRP	2018, Sponsored H.C.R. 7, Concurrent Resolution on Economic and Environmental Stewardship, which "recognizes the impacts of a changing climate on Utah citizens; expresses commitment to create and support economically viable and broadly supported solutions, including in rural communities..."
		Robert Finley			finleygeology@gmail.com	217-649-1744			Formerly with the IL Geological Survey, where he went through, as part of the FutureGen project, everything you now face with CarbonSAFE. He can speak authoritatively about the safety of CCS (for a project done right). Believe he could be very helpful in addressing, and hopefully calming, concerns/fears about leakage and contamination.
Environmental health directors from the local health departments around the state				Worker health and safety. Any local environmental impacts from infrastructure. Induced seismicity.				https://deq.utah.gov/Topics/Resources/healthdptsdw.htm	Suggested by Candice Caday.
	Bear River Health Department	Grant Koford		same as above	skoford@brhd.org	435-792-6575	85 East 1800 North, Logan, Utah 84341	http://www.brhd.org/	
	Central Utah Public Health	Nathan Selin		same as above	nselin@utah.gov	435-896-5451 ext 342	70 Westview Dr., Richfield, Utah, 84701	http://www.centralutahpublichealth.com/index.html	
	Davis County Health Dept.	Dennis Keith		same as above	dkeith@daviscountyutah.gov	801-525-5100	Davis County Health Department, Environmental	http://www.daviscountyutah.gov/health/about-	
	Salt Lake Valley Health Dept.	Royal DeLegge		same as above	rdelegge@slco.org	385-468-3860	788 East Woodoak Lane (5380 South), Murray, UT 84117	http://slco.org/health/	
	San Juan Health	Rick Meyer		same as above	rmeyer@sanjuancounty.org	435-678-2723 ext. 1005	196 East Center Street, Blanding UT 84511	http://www.sanjuanpublichealth.org/index.html	
	Southeastern Utah District Health Dept.	Brady Bradford		same as above	bbradfor@utah.gov	435-637-3671	28 South 100 East, Price UT 84501	https://www.seuhealth.com/program	
	Southwest Utah Public Health Dept	Gary House		same as above	ghouse@swuhealth.org	435-673-3528	620 South 400 East, Suite 400, St. George, UT 84770	https://swuhealth.org/southwest-utah-environmental-health/	
	Summit County Health Dept	Phil Bondurant		same as above	pbondurant@summitcounty.org	435-333-1584	650 Round Valley Drive, Park City, Utah 84060	http://summitcountyhealth.org/environmental-health/	
	Tooele County Health Dept.	Wade Tolebert		same as above	wtolebert@tooelehealth.org	435-277-2440	151 N. Main Street, Tooele, UT 84074	http://tooelehealth.org/environmental-health/	
	TriCounty Health Department	Darrin Brown		same as above	dbrown@tricountyhealth.com	435-247-1163	133 South 500 East Vernal, UT 84078	https://tricountyhealth.com/environmental-health/	
	Utah County Health Dept.	Bryce Larsen		same as above	brysel@utahcounty.gov	801-851-7525	151 S. University Ave., Provo, UT 84601	http://www.utahcountyonline.org/Dept2/Health/Environmental%20Health/home.aspx	
	Wasatch County Health Dept.	Dwight Hill		same as above	dhill@wasatch.utah.gov	435-657-3261	55 South 500 East Heber City, Utah 84032	http://www.wasatchcountyhd.org/Programs/EnvironmentalHealth.aspx	
	Weber County Health Dept.	Michela Gladwell		same as above	mgladwell@co.weber.ut.us	801-399-7160	477 23rd Street, Ogden, UT 84401	http://www.weberorganhealth.org/environmental-health-services/	
Regulators	Utah Division of Oil, Gas and Mining	John Baza			johnbaza@utah.gov	801-5385340	1594 W North Temple, Suite 1210, Salt Lake City, UT 84116	https://www.ogm.utah.gov	Director- John Baza
Business Interests	PacifiCorp	Ian Andrews	Public acceptance of continued use of coal-fired power plants. Future legislation may mandate some sort of CO2 capture	Infrastructure and operating costs. Decreased capacity.	Ian.Andrews@PacifiCorp.com	888-221-7070	1407 West North Temple, Ste 310, SLC, UT 84116		
	PacifiCorp (Hunter)	Larry Bruno			Larry.Bruno@pacificorp.com	435-748-5114	UT-10, Castle Dale, UT 84513		

	PacifiCorp (Hunter) HBW Resources Schlumberger outreach	Quinn Healy Andrew Browning Wayne Rowe	Quinn.Healy@pacificorp.com abrowning@hbwresources.com rowe5@slb.com	435-748-5114 713-337-8810 303-594-1219	UT-10, Castle Dale, UT 84513 2211 Norfolk Street #410, Houston, TX 77098 1875 Lawrence St. Ste. 500, Denver, CO 80202	https://hbwresources.com/ https://hbwresources.com/	Energy industry consultant Western U.S. Program Manager for Schlumberger Carbon Services		
Locals/ Interested Citizens		Paul Anderson	via email- Project would help reduce CO2 emissions and bring jobs.	via email- long-term leakage, who bears costs of construction and operation? Concerns addressed via email reply.	paul@pbageo.com	801-364-6613	PO Box 101, Emery, UT 84522	Consulting geologist. Ferron specialist. Involved with many UGS projects.	
		Mary Ann Wright Ken Fleck			MAW@pbageo.com Ken.Fleck@pacificorp.com	801-502-9611 435-650-0386	PO Box 101, Emery, UT 84522 280 N 1280 W, Price, UT 84501	Retired Utah Division of Oil, Gas and Mining UGS Board member / Geology and Environmental Affairs Manager PacifiCorp - Interwest Mining Company UGS Board member / PKGeography LLC	
		Pete Kilbourne			pkegor@gmail.com	435-650-8041	140 Hillcrest Dr Price, UT 84501		
Environmental Groups (local/regional)	Southern Utah Wilderness Alliance	Karin Duncker Associate Director	Reducing atmospheric CO2 will address climate change.	Any impacts to "wilderness	karin@suwa.org	801-428-3971	425 E 100 S, SLC, UT 84111	https://suwa.org/	"...defend America's redrock wilderness from oil and gas development, unnecessary road construction, rampant off-road vehicle use, and other threats to Utah's wilderness-quality lands.
		Joro Walker	same as above	Air quality degradation due to continued coal-fired powerplant operation. Any potential impacts to sage grouse habitat. Any potential impacts to San Rafael Swell	joro.walker@westernresources.org	801-413-7353	150 South 600 East, Suite 2A, SLC, UT 84102	http://westernresourceadvocates.org/regions/utah/	likely concerned about coal, sage grouse, and the Swell
	Western Resource Advocates								
		Allison Jones	same as above	Any potential impacts to sage grouse, wildlife habitat connectivity, or endemic plants	info@wildutahproject.org	801-328-3550	824 S 400 W, Suite B117, SLC, UT 84101	https://www.wildutahproject.org/	likely concerned about sage grouse, wildlife habitat connectivity, and endemic plants
	Wild Utah Project								
	Sierra Club of Utah	Mark Clemens	Reducing atmospheric CO2 will address climate change. (The Sierra Club Foundation's Forward Fund supports "Identifying and supporting new opportunities to bring ecologically sound carbon capture and sequestration processes to scale.")	Any potential impacts to sage grouse habitat. Concerns about continued reliance on coal.	mark.clemens@sierraclub.org	801-467-9294	423 West 800 South, Ste A103, SLC, UT 84101-223	http://utah.sierraclub.org/	likely concerned about coal and sage grouse
	National Parks Conservation Association	Britte Kirsch Regional Coordinator	Reducing atmospheric CO2 will address climate change.	Regional air quality degradation due to continued coal-fired powerplant operation.	ekirsch@npca.org	801-521-0785	307 West 200 South, Ste. 5000, SLC, UT 84101	https://www.npca.org/regions/southwest	interested in coal fired power plant emissions and downwind air quality that could impact national parks
	Physicians for a Healthy Environment	Denni Cawley	same as above	Air quality degradation due to continued coal-fired powerplant operation.	dcawleyuphe@gmail.com	385-707-3677	423 W. 800 S., Suite A108, SLC, UT 84101	http://uphe.org/	possibly concerned about coal and indirect impacts to air quality
Environmental Groups (national)	Natural Resources Defense Council	George Peridas	Reducing atmospheric CO2 will address climate change.		gperidas@nrdc.org	415-875-6100	111 Sutter Street, 21st Floor, San Francisco, CA 94104	https://www.nrdc.org/	supports CCS
	National Audubon Society	David Yarnold, President	same as above	Any potential impacts to sage grouse habitat or other ground nesting birds	mhsicla@audubon.org -executive assistant	212-979-3196	225 Varick St, 7th Fl., NY, NY 10014		
	National Audubon Society	Heather Dove Great Salt Lake Chapter	same as above	Any potential impacts to sage grouse habitat or other ground nesting birds	president@greatsaltlakeaudubon.org	801-201-3637	PO Box 520867, SLC, UT 84152-0867	http://www.greatsaltlakeaudubon.org/about-us/directory	because of potential impacts to greater sage grouse
	Wilderness Society	Scott Miller	same as above	Any potential impacts to San Rafael Swell	Scott_Miller@twsw.org	303-468-1961	1660 Wynkoop Street, Suite 850, Denver, CO 80202	http://wilderness.org/	interested in the Swell
	Teddy Roosevelt Conservation Partnership	Kevin Farron Western Field Associate	same as above	Any potential impacts to upland bird and big game habitat in the area	kfarron@trcp.org	406-926-3201	725 W. Alder St., Suite 1, Missoula, MT 59802	http://www.trcp.org/leadership/	upland bird and big game habitat in the area
	Sportsmen for Fish and Wildlife	Troy Justensen President	same as above	Any potential impacts to upland bird and big game habitat in the area	xtremeoutfitter@msn.com	801-557-3362	215 North Redwood Road #1, North Salt Lake, UT 84054	https://sfw.net/	upland bird and big game habitat in the area
Educators	Utah State University Eastern	Michelle Fleck	Post-secondary educational opportunities		michelle.fleck@usu.edu	435-613-5232	Utah State University Eastern 263 Reeves Building 451 East 400 North Price, Utah 84501	https://geology.usu.edu/people/faculty/index	
	Emery High School	Steven Gordon	High school educational opportunities		Stevens@emerschools.org	435-381-2689	955 North Center St, P.O. Box 499, Castle Dale, UT 84513	http://ehs.emerschools.org/About-Us/Meet-the-Faculty	Principal
	Emery High School	Lee Moss	High school science teaching opportunities		Moss@emerschools.org	435-381-2689	955 North Center St, P.O. Box 499, Castle Dale, UT 84513	http://ehs.emerschools.org/About-Us/Meet-the-Faculty	Chemistry and physics teacher