Integrated Pre-Feasibility Assessment for a Northern Michigan Basin CarbonSAFE CO_2 Storage Complex

Final Report

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List of Acronyms

Acronym	**Definition**
2D	Two-dimensional
3D	Three-dimensional
AoR	Area of review
BILD	Bass Islands Dolomite
BLM	United States Bureau of Land Management
Btu	British thermal unit
CarbonSAFE	Carbon Storage Assurance and Facility Enterprise
CMG-GEM	Computer Modeling Group-Generalized Equation of State Model
$^{\circ}C$	Degrees Celsius
CCS	Carbon capture and storage
CCUS	Carbon capture, utilization, and storage
CFR	Code of Federal Regulations
CO_2	Carbon dioxide
CO_2-EOR	Carbon dioxide enhanced oil recovery
CS-NMB	CarbonSAFE – Northern Michigan Basin
DCP	DCP Midstream Partners, LP
DOE	United States Department of Energy
EBIT	Earnings before interest and taxes
eGRID	U.S. EPA Emissions & Generation Resource Integrated Database
EGU	Electricity generating unit
EIA	DOE Energy Information Administration
EOR	Enhanced oil recovery
EPA	United States Environmental Protection Agency
EPCM	Engineering, procurement and construction management
ERR	Emergency and remedial response
FE	Fossil energy
FE/NETL	Fossil Energy/National Energy Technology Laboratory
FEED	Front-End Engineering & Design
FEMA	Federal Emergency Management Agency
FOA	Funding opportunity announcement
ft	Feet
FutureGen 2.0	Intended to be the world's first full-scale oxycombustion clean coal power plant with CCS
GAP	Gap Analysis Program
GEM	See CMG-GEM
GHG	Greenhouse gas
GHGRP	Greenhouse Gas Reporting Program
GT	Gigaton
IAM	Integrated assessment model
in	Inch
kh	Permeability thickness
km	Kilometer
km^2	Square kilometers
kTon	Kiloton
kW	Kilowatt
kWh	Kilowatt hour
LANL	Los Alamos National Laboratory
lb	Pound
LOC	Letter of credit
m	Meter
m^2	Square meters
m^3	Cubed meters
M	Million (when referring to dollars)
md	See mD
mD	Millidarcy
MDEQ	Michigan Department of Environmental Quality
MDNR	Michigan Department of Natural Resources
mi	Miles
mi^2	Square miles

MLP	Master Limited Partnership
MMBNGL	Million barrels of natural gas liquids
MMBtu	Million British thermal units
MMSTB	Million barrels of oil
MMT	Million metric tons (tonnes)
MMT/km^2	Million metric tons per kilometer squared
MOGA	Michigan Oil and Gas Association
MPa	Megapascal
MPSC	Michigan Public Service Commission
MRCSP	Midwest Regional Carbon Sequestration Partnership
MT	See MMT
MW	Megawatt
MWh	Megawatt hour
NEPA	National Environmental Policy Act
NETL	National Energy Technology Laboratory
NGCC	Natural gas combined cycle
NHPR	National Historic Places Registry
NLCD	National Land Cover Database
NMB	Northern Michigan Basin
NOL	Net operating loss
NPL	National Priority List
NPRT	Northern Pinnacle Reef Trend
NPS	United States National Park Service
NRAP	National Risk Assessment Program
NRAP-IAM-CS	Toolset for quantitative risk assessment of geologic sequestration of carbon dioxide
O&M	Operations and maintenance
P_5	5^{th} percentile
P_{10}	10^{th} percentile
P_{50}	50^{th} percentile
P_{90}	90^{th} percentile
P_{95}	95^{th} percentile
P&I	Principal and interest
PAB	Project activity bond
PAD-US	Protected Areas Database of the United States
PISC	Post injection site care
PNS	Potential new source
ppm	Parts per million
psi	Pounds per square inch
psi/ft	Pounds per square inch per foot
R&D	Research and development
ROM	Reduced-order model
ROW	Right of way
RROM-GEN	Reservoir Reduced-Order Model – Generator
s	Second
SC	Site closure
SCPC	Super-critical pulverized coal
SEM	Static Earth model
SPC	Sub-critical pulverized coal
SPSS	St. Peter Sandstone
TCFG	Trillion cubic feet of natural gas
TDS	Total dissolved solids
tonne	Metric ton (1,000 kilograms, 2,204.62 pounds)
TPC	Total plant cost
UIC	Underground Injection Control
U.S.	United States of America
USDW	Underground sources of drinking water
USFS	United States Forest Service
U.S. FWS	United States Fish and Wildlife Service
USGS	United States Geological Survey
VSP	Vertical seismic profile
WMU	Western Michigan University
yrs	Years

Executive Summary

One of the key gaps in the critical path toward carbon capture and storage (CCS) deployment is the development of commercial-scale (50+ million metric tons carbon dioxide [CO_2]) geologic storage sites for CO_2 from industrial sources. There has been relatively little effort by the private sector to identify and certify (i.e., regulatory permit) geologic storage sites that are capable of storing commercial-scale volumes of CO_2, primarily because of the lack of immediate economic incentives. As a result, commercial-scale CO_2 sources that want to develop CCS projects face the risk of not finding a suitable saline storage site for their captured CO_2.

Carbon Storage Assurance Facility Enterprise (CarbonSAFE) is a U.S. Department of Energy (DOE)-sponsored effort to develop an integrated CCS storage complex constructed and permitted for operation in the 2025 timeframe over a series of sequential phases of development: Integrated CCS Pre-Feasibility, Storage Complex Feasibility, Site Characterization, and Permitting and Construction. Subject to availability of funds, a series of funding opportunity announcements (FOAs) are planned to accomplish this mission.

This document describes a project that addresses DOE FOA-1584 Phase I: Integrated Carbon Capture and Storage (CCS) Pre-Feasibility. The objective of this project was to take the first step in developing an integrated commercial geologic CO_2 storage complex in the Northern Michigan Basin, herein referred to as the CarbonSAFE – Northern Michigan Basin (CS-NMB) storage complex. This includes demonstrating that the storage sites within the complex have the potential to store more than 50 million metric tons (MMT) of industrially-sourced CO_2 emissions safely, permanently and economically. To achieve the overall objective of the Phase I pre-feasibility study, FOA-1584 required three activities:

- Perform a high-level technical sub-basinal evaluation to identify a potential storage complex with storage site(s), including a description of the geology and risks associated with the potential storage site; identify and evaluate potential CO2 sources.
- Develop a plan for the storage complex and storage site(s) including a strategy that would enable an integrated capture and storage project to be economically feasible and publicly acceptable.
- Form a CCS coordination team capable of addressing regulatory, legislative, technical, public policy, commercial, financial, etc. challenges specific to commercial-scale deployment of the CO_2 storage project.

Figure ES-1 shows a cross-walk between these objectives and the section in the document where the information is provided. Below is a summary of accomplishments and findings under each of the DOE activities.

Perform a High-Level Technical Sub-Basinal Evaluation

- A study area was identified for the CS-NMB program, which includes a multi-county area in the lower Michigan peninsula. This region of the country has several promising deep saline intervals for large-scale CO_2 storage.
- The lateral extent, thickness, structure, properties and CO_2 storage capacity of two saline reservoirs, the St. Peter Sandstone (SPSS) and the Bass Island Dolomite (BILD), were characterized and mapped.
- Both formations are present across the entire study area and are viable candidates for hosting a 50 MMT CO_2 storage complex. Of the two, the SPSS is preferred because it occurs at greater depths below the primary zones of oil and gas production.
- In addition to the SPSS and BILD, Niagaran pinnacle reefs represent another viable CO_2 storage reservoir type. A total of 856 discrete pinnacle reefs have been identified across the NMB study

area. Most of them are hydrocarbon bearing and have been produced and now are in a pressure-depleted condition, making them attractive for CO_2 storage. Overall, the Niagaran reefs have 230 MMT of storage capacity across the NPRT and can be used for either CO_2-enhanced oil recovery (EOR) or CO_2 storage scenarios.

- State-owned land and private land are the two primary options for locating a saline reservoir storage site. Within the study area, there is considerable amount of state land, in particular forest land, including large contiguous tracts of land, and this was determined to be the most viable option for a saline storage site. Core Energy, LLC, an oil company in Traverse City Michigan with a long history conducting CO_2-EOR in the study, has experience acquiring land rights and permitting CO_2-EOR operations.

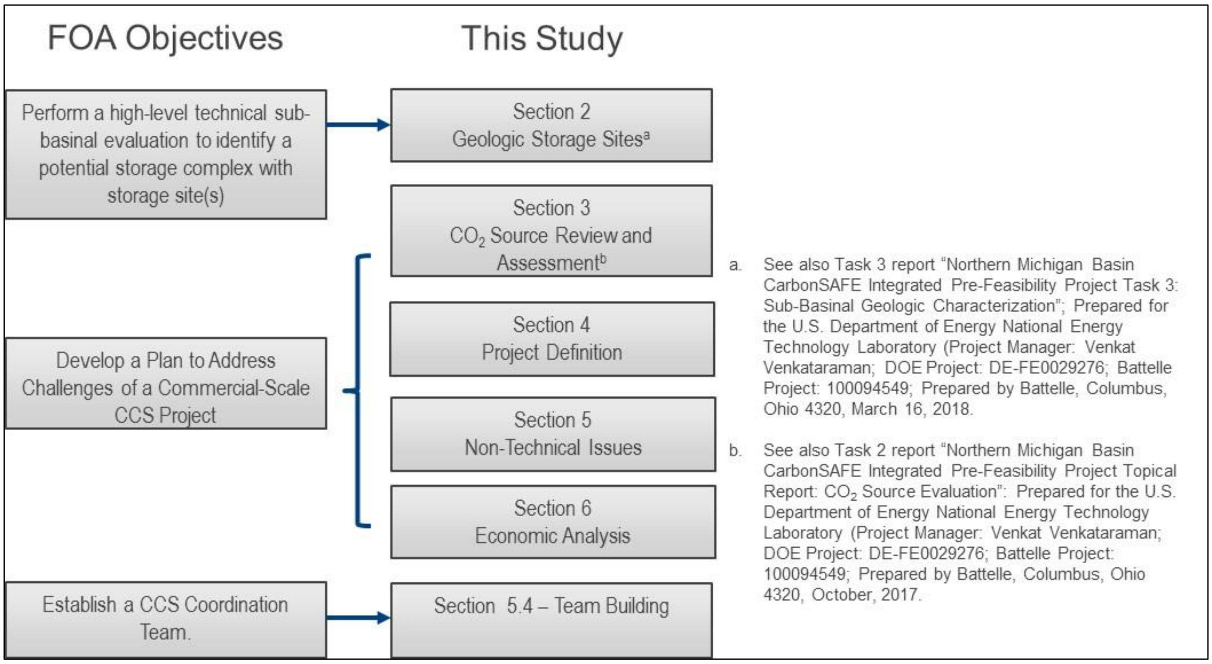

Figure ES-1. Cross-walk between FOA-1856 required activities and work performed.

Develop a Plan for the Storage Complex

- A modeling analysis demonstrated 50 MMT of CO_2 can be injected into the SPSS in 20 to 30 years using approximately three to five injection wells, depending on location, and that an area of approximately 15,000 acres is needed to accommodate the 50 MMT CO_2 plume.
- Eight (8) example locations with 15,000 acres of nearly contiguous state-owned forest land were identified that could support a saline reservoir storage site.
- A storage site design and cost estimate was developed for a 25 MMT storage scenario and a 50 MMT storage scenario for two of the example saline reservoir storage sites (Site 2 and Site 7) and carried forward into the economic analysis.
- A subset of 82 oil-bearing reefs with a combined storage capacity of 51 MMT were selected for this pre-feasibility study. The 82 reefs were selected because they can be used for CO_2-EOR and therefore bring added value to the project. Cost estimates were developed for a scenario in which all 50 MMT of CO_2 is stored in the reefs and another scenario in which 25 MMT is stored in the reefs and the other 25 MMT is stored in a SPSS saline reservoir at Site 2 or Site 7.
- 12 CO_2 emission sources were identified as the most promising existing or planned sources in the NMB for CO_2 capture as part of the regional storage complex. This list was further screened

based on receiving positive feedback from the source owner via networking and Team Building efforts in Task 5 to a list of four (4) sources that were carried forward into the economic analysis.

- A pipeline routing analysis, design, and cost estimate was performed for 12 pipeline scenarios including the four (4) CO_2 sources and three storage options for each (Site 2 50 MMT storage; Site 2 25 MMT storage; Niagaran reefs 50 MMT storage) and a 50 MMT reef storage scenario. A separate pipeline analysis was not performed for the eight (8) source-sink scenarios involving SPSS Saline reservoir Site 7 (4 sources x 50 MMT SPSS saline reservoir storage Site 7; 4 sources x 50 MMT SPSS saline reservoir storage Site 7).
- An economic analysis was performed for the 20 source-sink scenarios to determine revenue requirements for each scenario.

Form a CCS Coordination Team

Development of a commercial CO_2 storage complex requires a broad range of capabilities and expertise, as well participation of entities who are able to provide business framework across the entire CCS value chain. In addition to technical experts, the desired team members include CO_2 source and supply companies, pipeline developers, storage and EOR site operators, and financial investors. As the project evolves through development stages, these team members may become host sites, equity partners, technical consultants, advisors, or stakeholders. The objective of the team building task during Phase I was to start developing a project team that can move the project towards Phase II. The team building involved working with the existing partners and identification of the potential new partners/participants in the project.

- The existing team members for Phase I, included Core Energy, LLC (EOR site operator), Western Michigan University (geoscience expertise), Loomis, Ewert, Parsley, Davis & Gotting, P.C. (Loomis Law) (legal/regulatory expertise), Wade LLC (outreach), and PKM Energy Consulting (financial analysis). In addition, three national laboratories, Los Alamos National Laboratory, Pacific Northwest National Laboratory, and Lawrence Livermore National Laboratory provided support in the transport analysis and risk assessment task.
- Several project team meetings were held during the Phase I to review existing data, plan the technical approach, and develop the overall long-term strategy for the project.

1.0 Introduction

Carbon Storage Assurance Facility Enterprise (CarbonSAFE) is a U.S. Department of Energy (DOE)-sponsored effort to develop an integrated CCS storage complex constructed and permitted for operation in the 2025 timeframe over a series of sequential phases of development: Integrated CCS Pre-Feasibility, Storage Complex Feasibility, Site Characterization, and Permitting and Construction. Subject to availability of funds, a series of funding opportunity announcements (FOAs) are planned to accomplish this mission. This document describes a project that addresses DOE FOA-1584 Phase I: Integrated Carbon Capture and Storage (CCS) Pre-Feasibility. The objective of this project was to take the first step in developing an integrated commercial geologic carbon dioxide (CO_2) storage complex in the Northern Michigan Basin. The study area is shown in Figure 1-1.

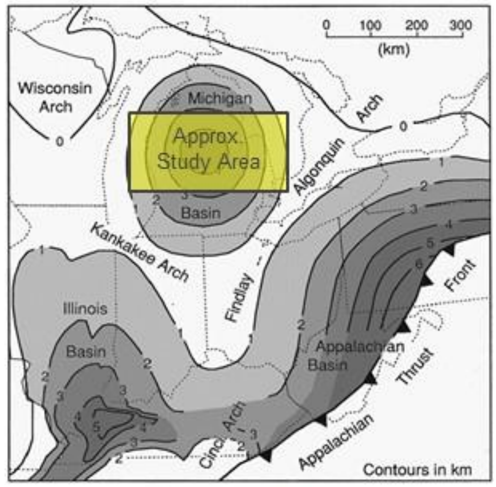

Figure 1-1. Study area within the Michigan Basin.

1.1 Objectives and Scope

The objective of this project was to take the first step in developing an integrated commercial geologic carbon dioxide (CO_2) storage complex in the Northern Michigan Basin, herein referred to as the CarbonSAFE – Northern Michigan Basin (CS-NMB) storage complex. This includes demonstrating that the storage sites within the complex have the potential to store more than 50 million metric tons (MMT) of industrially-sourced CO_2 emissions safely, permanently and economically. The project included five technical tasks which are identified in Figure 1-2 along with a list of the major outcomes of each task. The figure also identifies the section in this report where the information is documented.

1.2 Overview

This section provides a high-level overview of the progress made in the Phase I pre-feasibility study toward achieving the project goal of developing an integrated commercial geologic CO_2 storage complex in the Northern Michigan Basin. Progress is summarized by major aspects of the storage complex: geologic storage opportunities; public/stakeholder acceptance; legal and regulatory considerations; CO_2 sources; economic feasibility; and team building.

Geologic Storage Opportunities – A major focus of this pre-feasibility study was on defining the geologic storage complex. While there is a large potential for storing CO_2 in many geologic reservoirs, the process of identifying suitable sites with adequate storage site(s) involves methodical analysis of technical and non-technical challenges of promising areas (National Energy Technology Laboratory [NETL], 2010). Therefore, the process of defining a storage complex included a geologic characterization phase in which potential storage reservoirs and associated caprocks within the northern Michigan Basin were identified, characterized and screened, followed by a detailed evaluation of the preferred reservoirs at specific locations. The assessment included a computer modeling analysis of the preferred saline reservoir to define number of injection wells required to inject 50 MMT of CO_2 in 20 to 30 years, their spacing, and the size of the 50 MMT plume. The assessment also included an extensive land-ownership survey to identify specific locations that can accommodate the 50 MMT plume with the fewest number of landowners possible. The largest landowner in the study area, the Michigan Department

Task 2 – CO_2 Source Review and Assessment

- Identification of CO_2 emission sources for the Northern Michigan Basin area (3)[a]
- Down selection of most viable source-sink scenarios (3)[a]
- Review of capture technologies and costs (3)[a]

Task 3 – Sub-Basinal Geologic Storage Assessment

- Identification and characterization of deep saline formations for CO_2 storage reservoirs and calculation of CO_2 storage capacity of the SPSS and BILD saline reservoirs (2.1)[b]
- Identification and characterization of Niagaran pinnacle reefs that are candidate storage reservoirs and calculation of their individual and collective CO_2 storage capacity (2.1)[b]

Task 4 – Project Definition

- CO_2 injection modeling to determine number of injection wells required to inject 50 MMT and their spacing and plume area for multiple candidate SPSS storage sites (2.3)
- Calculation of Area of Review and Leakage risk using NRAP tools (2.4. Appendix A)
- Land ownership survey to identify public and private land for the storage complex (2.2)
- Regional proximity analysis to confirm that no environmental issues present significant (5.1) challenges for the CS-NMB project
- Pipeline routing analysis and preliminary pipeline design (sizing and supplemental compression) and costing (4)
- Development of the storage site design (6.2.1) (infrastructure, monitoring program, etc.) and cost estimate for two storage sites
- Economic analysis of 20 source-transport-sink scenarios to identify cost and revenue requirements (6, Appendix B)
- Identification of legal and regulatory aspects that facilitate or impede implementation of the NMB-CS CO_2 storage complex (5.2)
- Public outreach/stakeholder assessment to gauge public acceptance (5.3)

Task 5 – Team Building

- Involve operators, utilities, public stakeholders, and other team members to inform plans to complete a safe, effective, and economic CO_2 storage complex. (5.4)

Notes:

(3) Numbers in parenthesis indicate section number in this report where information is documented

a. See also Task 2 report "Northern Michigan Basin CarbonSAFE Integrated Pre-Feasibility Project Topical Report: CO_2 Source Evaluation": Prepared for the U.S. Department of Energy National Energy Technology Laboratory (Project Manager: Venkat Venkataraman; DOE Project: DE-FE0029276; Battelle Project: 100094549; Prepared by Battelle, Columbus, Ohio 4320, October, 2017.

b. See also Task 3 report "Northern Michigan Basin CarbonSAFE Integrated Pre-Feasibility Project Task 3: Sub-Basinal Geologic Characterization"; Prepared for the U.S. Department of Energy National Energy Technology Laboratory (Project Manager: Venkat Venkataraman; DOE Project: DE-FE0029276; Battelle Project: 100094549; Prepared by Battelle, Columbus, Ohio 4320, March 16, 2018.

Figure 1-2. Work performed and outcomes by task.

of Natural Resources (MDNR), indicated a strong willingness to use stand-owned land, particularly state forest land, for a storage site.

Two saline reservoirs, the St. Peter Sandstone (SPSS) and the Bass Island Dolomite (BILD) are both present across the entire study area and are both strong candidates for hosting a 50 MMT storage complex. Of the two, the SPSS is preferred because it occurs at greater depths below the primary zones of oil and gas production. The modeling analysis demonstrates 50 MMT of CO_2 can be injected into the SPSS in 20 to 30 years using approximately three to five injection wells, depending on location, and that an area of approximately 15,000 is needed to accommodate the 50 MMT CO_2 plume. The BILD was the focus of the Midwest Regional Carbon Sequestration Partnership (MRCSP) Phase II program, which included a pilot CO_2 injection test in which 60,000 tonnes of CO_2 were injected into the BILD and successfully monitored using a form of borehole geophysics (cross-well seismic).

In addition to the SPSS and BILD saline reservoirs, this region hosts the Northern Pinnacle Reef Trend, a collection of more than 800 Niagaran-age pinnacle reefs, many of which are oil or gas bearing. Most of the reefs were produced in the 1970s and 1980s and are now in a depleted condition that is conducive for storing CO_2. The fact that the reefs stored hydrocarbons for millions of years is evidence that they could securely store CO_2; CO_2 injection into pinnacle reefs is already occurring in the study area through a thriving CO_2-ehanced oil recovery (EOR) operation owned by Core Energy, LLC of Traverse City, Michigan. Core Energy has been conducting CO_2-EOR in the reefs for 15 years and has established methods and practices for safe CO_2 handling, injection, and processing. Since 2010, Core Energy's northern Michigan CO_2-EOR operation has been the host site for the DOE MRCSP Phase III program which is led by Battelle. During this time, the MRCSP has tested CO_2 monitoring methods in reefs, developed new protocols for CO_2 mass-balance accounting in an EOR operation, advanced the understanding of the geology of the reefs, and developed numerical models that can predict the long-term behavior of CO_2 injected into the reefs and their storage capacity. Collectively, this makes the reefs a low-risk, value-added CO_2 storage option that can be used in conjunction with saline storage.

Public/Stakeholder Acceptance – Equally important to demonstrating the technical feasibility of a geologic CO_2 storage complex is the need to demonstrate that it will be publicly acceptable. During the Phase I pre-feasibility study, an initial public outreach program was conducted to identify stakeholders and assess their "acceptability" for the storage complex concept. The outreach program included a social characterization study of the 17 counties that are collocated with the potential saline storage sites and are along the Niagaran Reef Trend and found that conditions are favorable for a commercial CO_2 storage site. actors that support this finding include:

- The region hosts a mature energy industry, which indicates public awareness of the basic operations for carbon capture, utilization and storage (CCUS; e.g., well drilling, CO_2 pipelines, CO_2 compression and separation).
- Energy is one the dominant economic drivers for the area. A recent Michigan Oil and Gas Association (MOGA) study showed that the 17 counties in the study area generated roughly $1.72 billion in total economic output in 2015, of which $485 million was in labor wages. This represents almost 20% of the state totals for economic output and labor wages. In addition, the energy sector in these counties contributed roughly $27.5 million in severance taxes and $21 million in local property taxes to the state. Despite this performance, the counties in the study area are still recovering from the economic recession and will likely find the potential economic benefits from the CS-NMB project attractive.

The likelihood of positive stakeholder support for the project has been borne out in the positive feedback obtained during the focused outreach conducted with key stakeholders. These stakeholders include public representatives, including Michigan Governor Rick Snyder, U.S. Representative Bergman and Michigan Representative Cole, who represent the project area at the Federal and state levels. They all have provided enthusiastic support letters for the project, along with the letter from MDNR indicating willingness to engage in pore space and site access discussions. These officials, agencies, and local operators will be engaged during Phase II. Some of the Michigan agencies have previously worked with

Battelle and Core Energy for such issues as site access and regulatory approvals for drilling. Throughout the remainder of Phase I and in Phase II, this direct outreach to influential stakeholders in the area will be built upon.

Legal and Regulatory Considerations – Team partner Loomis (Loomis, Ewert, Parsley, Davis & Gotting, P.C) prepared a legal analysis/assessment of Michigan policies, regulations, and practices that could affect the implementation of the CS-NMB project – either favorably or otherwise. The analysis demonstrates that Michigan has a regulatory climate that is generally favorable for CO_2 sequestration, although implementation of an authorized program for large-scale CO_2 storage will likely require modification of existing laws, policies or procedures and/or development of new statute. However, Michigan's Michigan Public Service Commission (MPSC), Michigan Department of Environmental Quality (MDEQ), and MDNR have the technical knowledge, experience, and institutional memory necessary to effectively regulate the new but related discipline of CO_2 large-scale storage and CO_2 storage incidental to CO_2 EOR. Favorable factors include:

- History of natural gas storage along with CO_2 EOR (including CO_2 transport) favors CS-NMB implementation
- Existing natural gas storage rules favor CS-NMB implementation; current statute/regulations may require modification to cover CO_2 storage.
- CO_2 EOR is already being implemented in Michigan; therefore, there is certainty that associated CO_2 storage can be implemented as a component of CS-NMB.
- There is high probability that state lands can be used for CO_2 storage. In addition to existing policies and procedures that allow use of state lands, the MDNR has indicated willingness to engage in CS-NMB assessment with a letter of support.
- Storage rights are well defined and include special provisions for natural gas storage that are good precedents for CO_2 storage.
- Underground Injection Control (UIC) Class VI permits would be implemented by the Environmental Protection Agency (EPA) Region 5, the only EPA office that has experience issuing UIC Class VI permits to date.
- MDNR, which manages large tracts of land where the CS-NMB project can be located, has a history of successfully stewarding oil and gas production and gas storage within public lands and has previously permitted drilling of MRCSP test wells on its lands.
- MDEQ has the authority to permit drilling of oil, gas, mineral, and test wells. MDEQ has also applied for primacy for authority to implement the UIC Class II permits that govern both EOR and brine disposal operations.

CO_2 Sources – A total of nine (9) existing and three (3) potential new CO_2-emission sources were determined to be attractive candidates for the establishment of a regional CCS hub based on total and potential future CO_2 emissions, location, industry-specific characteristics and cost of capture. These sources represent multiple industrial categories including electricity generation, cement production, and steel production. Potential new sources are limited to facilities that either: A) satisfy a clear need for a specific product or service as identified by the public sector, or B) are engaged in the environmental permitting process. Several large emitters were not included in this list as they were deemed to be non-viable because of their location or other specific factors. Four (4) of these 12 CO_2 emission sources were selected for further (economic) analysis based on interest expressed by the source owner/operator to participate in the CS-NMB project. These include:

- The Wolverine Alpine natural-gas power generation facility together with the DCP Midstream Partners natural gas processing plant, both located in Otsego County;
- Project TIM, a planned state-of-the-art steel-manufacturing facility in Shiawassee County;

- A potential new natural-gas power generation facility with the new NetPower technology, assumed location Otsego County; and
- A potential new natural-gas power generation facility with NGCC technology, assumed location Otsego County).

Economic Feasibility – The business case for a 30-year 50-MT CO_2 integrated source-transport-storage operation in northern Michigan under current legal and regulatory conditions was modeled using a comprehensive discounted cash flow financial analysis model developed as part of the FutureGen 2.0 integrated commercial CCS project. A total of 20 source-transport-storage scenarios were evaluated in the economic analysis, including the four (4) CO_2 emission sources down selected from the 84 CO_2 sources in the lower Michigan peninsula and five (5) storage options for each. As required by the FOA, a primary and secondary saline storage site was identified and modeled: the SPSS Site #2 and Site #7 (these are discussed further in Section 2 of this report). CO_2-EOR, in 50/50 combination with saline storage and alone, was also evaluated as an alternate storage mechanism. The results of this analysis demonstrate how an integrated capture and storage project can be economically viable and likely to be viewed positively by the public and other stakeholders. This most economically viable scenario is the emerging NET Power technology and 100% EOR storage. The sale of CO_2 for EOR alone covers the costs associated with CCS. Only transportation (pipeline) costs from the CO_2 source to the EOR field are necessary in this case because the incremental cost of capture is assumed to be zero for the Allam Cycle; the facility produces a pipeline-quality CO_2 as a byproduct. If only 50% of the CO_2 was to be sold for EOR operations and the other 50% stored in one of the proposed SPSS saline reservoirs, there would be a modest net revenue requirement of only approximately \$5 to \$7 per tonne in the low cost of capital case and \$10 to \$12 per tonne in the high cost of capital case. In this scenario, the net revenue requirement is defined as the amount of revenues obtained either from ratepayers or the market. This net revenue requirement could be further reduced if oil prices increase, or if costs savings can be found from the operations and monitoring of the pipeline or storage reservoir.

The economics of the other three sources is less favorable, due to two main factors: the incremental cost of capture for either a new gas-fired combined cycle facility (e.g., potential new source [PNS] with natural gas combined cycle [NGCC]) or a retrofit application (Wolverine)) is still the most significant CCS cost driver and exceeds the offsets that can be realized with revised Section 45Q tax credits and 100% EOR storage. Second, cost of pipeline transport becomes more significant with increasing distance from the source to the sink (i.e., either the saline reservoir storage site or EOR field). This is evident for Project TIM which is located over 100 miles from the proposed saline and EOR storage fields. Despite higher cost, Project TIM is attractive because it offers a combined advanced clean steel making with power generation, which can enable other manufacturing in the state. Overall, this economic analysis indicates that the availability of the recently enacted tax credits will go a long-way towards closing the cost and revenue gaps, especially when combined with value added options such as CO_2-EOR. For the saline storage scenarios, it is anticipated that capture technology improvements, detailed pipeline design optimization, storage and monitoring system optimizations, state and local incentives, and eventually a carbon reduction policy could help close the revenue shortfall over the next few years.

Team Building – A major emphasis of the work was to develop an effective team capable of addressing the technical, economic, legal, engineering, surface, and public acceptance related to implementation of a real-world CO_2 storage project in the Northern Michigan Basin. The team members for Phase I included Core Energy, LLC, Western Michigan University (geoscience expertise), Loomis Law (legal/regulatory expertise), Wade LLC (outreach), and PKM Energy Consulting (financial analysis). In addition, three national laboratories, Los Alamos National Laboratory, Pacific Northwest National Laboratory, and Lawrence Livermore National Laboratory provided support in the transport analysis and risk assessment tasks. A number of project team meetings were held during Phase I to review existing data, plan the technical approach, and develop the overall long-term strategy for the project.

2.0 Geologic Storage Sites

This section describes a geologic storage complex capable of storing at least 50 million tonnes (MMT) of CO_2 in saline formations over 20 to 30 years as per the requirements of the FOA by the DOE. The process of defining a 50 MMT storage complex included a geologic characterization phase in which potential storage reservoirs and associated caprocks within the Northern Michigan Basin (NMB) were identified, characterized and screened, followed by a feasibility evaluation (computer modeling analysis) of the preferred saline reservoir (SPSS saline reservoir) at specific locations. The feasibility study demonstrates that the selected formation has adequate storage capacity to accommodate 50 MMT CO_2 and defines the number of injection wells and land area required to achieve the 50 MMT CO_2 target in 20 to 30 years. The process is illustrated in Figure 2-1.

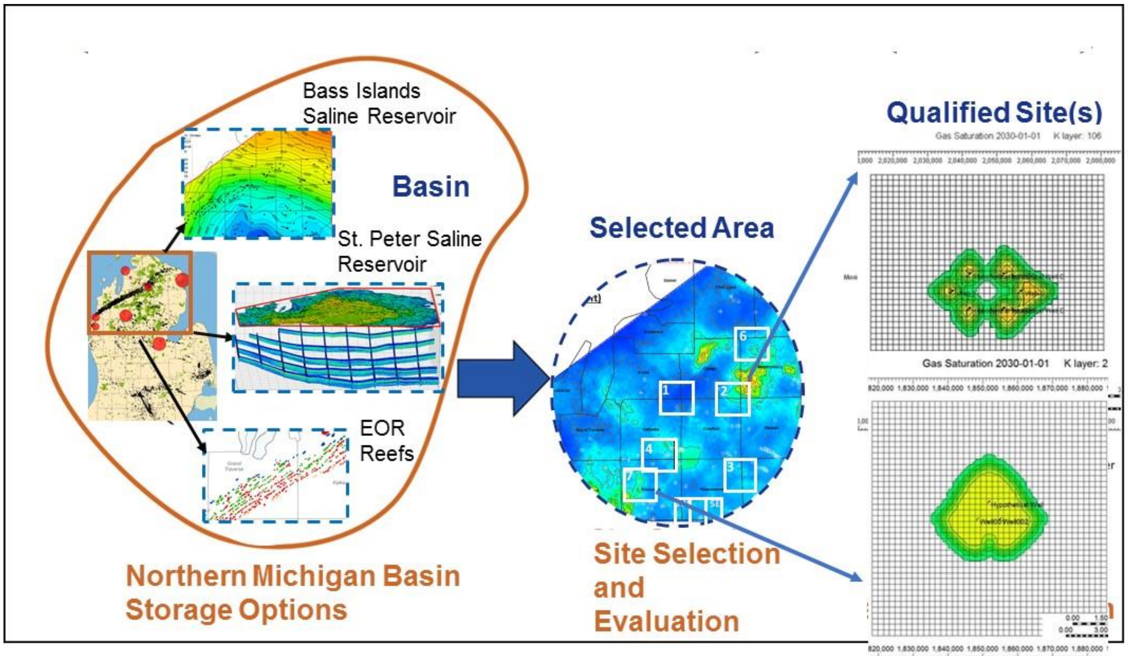

Figure 2-1. Process of basin-scale geologic characterization to identify candidate CO_2 storage reservoirs followed by site-scale feasibility assessment to determine injection well and land area requirements to achieve a 50 MMT injection target in 20 to 30 years.

Section 2.0 is divided into the following parts:

- Section 2.1 Sub-Basinal (Geology) Analysis Summary describes three geologic systems (the SPSS saline reservoir, Niagaran pinnacle reefs, and the BILD saline reservoir) that were determined to be viable candidate CO_2 storage reservoirs for a 50 MMT CarbonSAFE project. The SPSS and the Niagaran pinnacle reefs are considered to be the primary storage reservoirs and the BILD is considered to be a supplemental saline reservoir.
- Section 2.2 Land Access for Storage Sites describes land ownership in the study area and identifies example locations on state-owned land and private land that could host a 50 MMT geologic storage site.
- Section 2.3 SPSS Saline Reservoir Feasibility Study (CO2 Plume Modeling) describes a computer modeling analysis that was performed to estimate the size (area) of the 50 MMT CO_2 plume at two SPSS saline-reservoir storage site locations (Site 2 and Site 7) locations (as requested in the FOA). The modeled plume area(s) defines the minimum land area for which access must be approved and/or permitted for CO_2 storage and the minimum area that must be

monitored during the project. The modeling analysis also evaluated alternate injection strategies to minimize land area requirements, such as stacked storage (i.e., dividing CO_2 into SPSS saline reservoir and Niagaran reefs via carbon dioxide enhanced oil recovery [CO_2-EOR]). A modeling analysis was not performed for the Niagaran reefs because they are closed reservoir systems with well-defined boundaries and storage capacities; thus, the extent of the CO_2 plume(s) will be defined by the reef boundaries. A numerical modeling analysis was not performed for the BILD because it is a supplemental saline reservoir. The SPSS and the Niagaran pinnacle reefs are each capable of storing 50 MMT CO_2.

- In Section 2.4 Area of Review and Leakage Impacts Using the NRAP-IAM-CS Model, the DOE National Risk Assessment Program (NRAP) modeling tool was used to calculate the size of the 50 MMT area of review (AoR) for one of the two example SPSS saline reservoir storage sites (Site 7) and to calculate potential leakage impacts to a shallow drinking aquifer overlying the storage reservoir. The AoR is a critical parameter for the UIC Class VI permitting process.

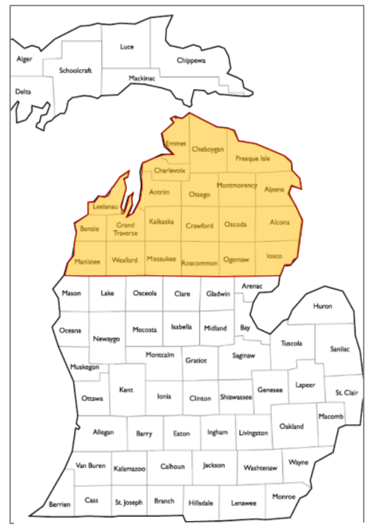

Figure 2-2. Multi-county study area indicated by shading.

2.1 Sub-Basinal (Geology) Analysis Summary

Study Area. The study area for the CS-NMB program includes a multi-county area in the lower Michigan peninsula (Figure 2-2). This region of the country has several promising deep saline intervals for large-scale CO_2 storage. In addition, CO_2-EOR operations provide a model for safe CO_2 handling, injection, and regulation. Therefore, the study area represents an attractive area for identifying candidate sites that meets DOE requirements for the CS-NMB concept.

The information presented in this section is taken from the (Task 3) report (Battelle, 2017) which was submitted previously as a stand-alone report.

2.1.1 Geologic Setting

The Michigan Basin is a major structural basin of more than 100,000 square miles (mi^2) in area, roughly elliptical and centered on the Lower Peninsula of the State of Michigan (Figure 2-3). The sedimentary formations in the basin attain a maximum thickness of nearly 16,000 feet (ft) and include sandstone, shale, carbonate, and evaporite rocks from Cambrian through Pennsylvanian age. A Pleistocene-age veneer of glacial deposits blankets the basin with thicknesses of up to 1,200 ft. The Michigan Basin is structurally stable with few known faults. No seismic events have been recorded in northern Michigan, and risk of seismic activity is low. Existing seismic data confirm the lack of major structural features in the study area.

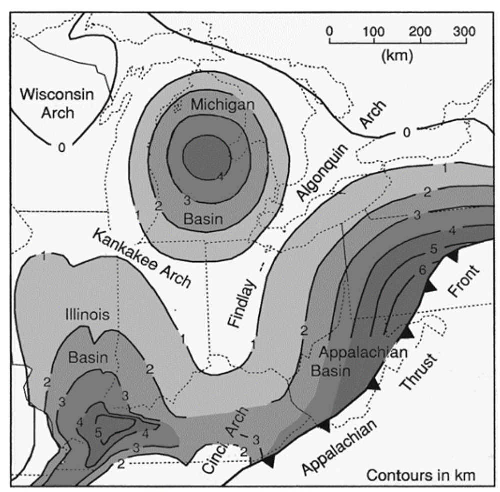

Figure 2-3. Generalized structural setting of the intracratonic Michigan Basin showing lateral extent and depth (in km) of the basin.

The stratigraphic position of the three geologic units that are viable candidates for providing safe, long-term geologic CO_2 storage in the NMB, in increasing depth, is BILD, the Silurian-age Niagaran reefs, and SPSS (Figure 2-4). The SPSS underlies the entire study area, occurs at depths below the main oil and gas producing zones in the NMB, and by itself has ample capacity to accommodate the 50 MMT CO_2 target; therefore, it is the primary saline reservoir storage target. The Niagaran reefs provide additional value-added storage opportunity through CO_2-EOR (associated storage); and, like the SPSS, can easily accommodate the 50 MMT CO_2 target. The BILD, the shallowest of the three, is also a saline reservoir that could be used to augment the SPSS saline reservoir. However, it has a lower storage capacity per unit area than the SPSS and it occurs above the main oil and gas producing formations in the basin (i.e., the Niagaran reefs) and therefore has been penetrated by numerous wells. Consequently, the BILD is considered to be a secondary saline storage reservoir to augment the SPSS if necessary – for example, to reduce overall CO_2 plume footprint and land area needed for the saline storage site. The NMB storage complex design that was developed for this Phase I pre-feasibility study includes only the SPSS and the Niagaran reefs.

2.1.1.1 St. Peter Sandstone

The SPSS occurs across a large portion of the midwestern United States including portions of Michigan, Indiana, western Kentucky, and northwestern Ohio. The SPSS is overlain by the Glenwood Shale and Black River Limestone which make up the immediate confining units. Directly above this are hundreds of feet of shale and tight carbonates. In Michigan, the SPSS unconformably overlies dolomitized carbonate rocks of the Prairie du Chien Group.

Throughout most of its regional occurrence, the SPSS is generally a coarse to fine, clean (i.e., mineralogically pure) quartz arenite sandstone (composed of greater than 90% detrital quartz, with limited amounts of other framework grains (feldspar, lithic fragments, etc.) and matrix. In Michigan, the SPSS has numerous interbeds of shale and shaley dolomite. In the central and eastern part of the Michigan Basin, multiple cycles of clean sandstone, clay-rich sandstone and shale or shaley carbonate are stacked on one another. The western margin of the basin generally has a thick section of clean sandstone that grades rapidly into the overlying Glenwood Formation.

Studies from the outcrop of the SPSS suggest that it was deposited in a terrestrial to shallow marine shelf facies belt that transgressed (spread over) the upper Midwest (Dott and Byers, 1981). In the Michigan Basin, the facies range from shoreface to inner and outer marine shelf.

The SPSS in the Michigan Basin has been subdivided into three lithofacies that can be recognized

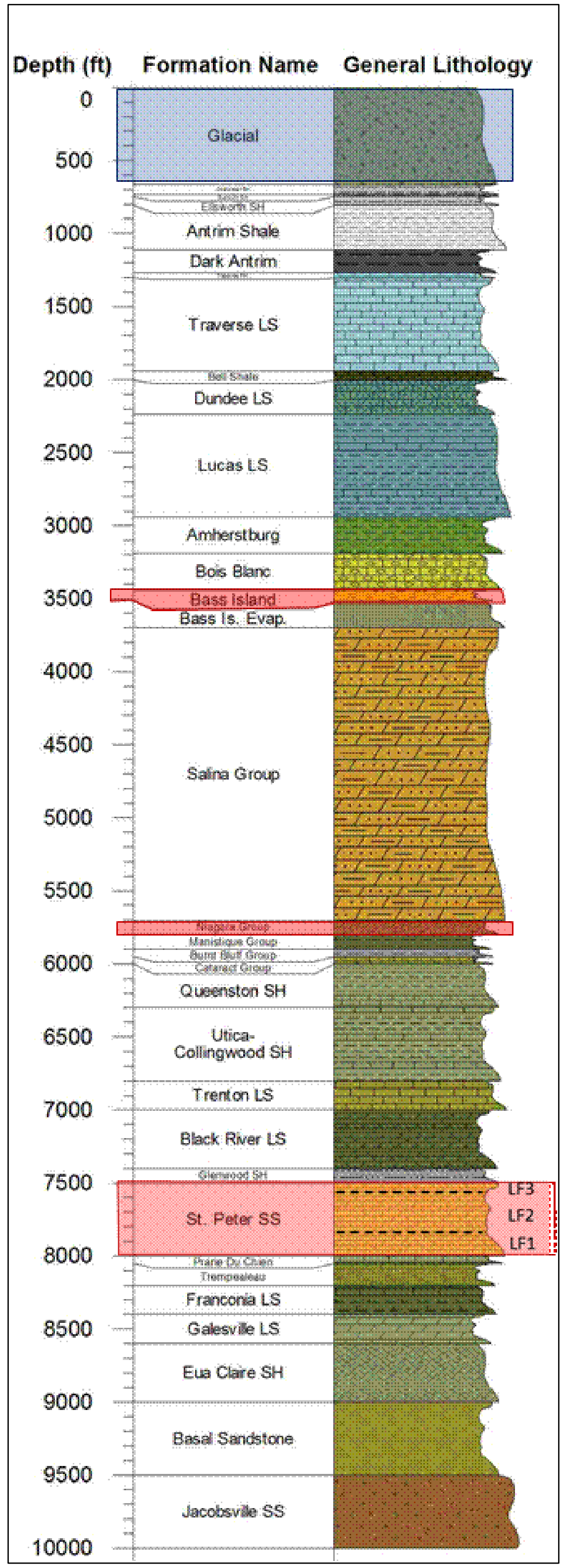

Figure 2-4. Geologic column showing SPSS and BILD saline reservoirs and Niagaran EOR reefs.

in cores and from wireline logs. From the base of the formation these lithofacies are LF1, LF2, and LF3. LF1 is a mixed sequence with coarse quartz sandstone, muddy sandstone and thin shale or carbonate beds (see photographs of example core in Figure 2-5). It directly overlies the Prairie du Chien Formation (Fisher and Barrett, 1985). LF2 is a cleaner quartz sandstone with occasional thin shale or carbonate beds. In the western part of the Michigan basin, this unit is usually a well-cemented quartz sandstone. LF3 comprises the uppermost member of the SPSS and is composed of finer-grained sandstone with both detrital and authigenic clay cement and matrix with high feldspar content.

Figure 2-5. Whole core photographs of Lithofacies 1 showing fine to medium-grained planar laminated sandstone (A), massive fine-grained sandstone (B), and coarse-grained cross-bedded sandstone (C).

2.1.1.1.1 Depth, Thickness and Porosity and Permeability

The depth of the SPSS ranges from 5,000 ft to more than 10,000 ft in the CS-NMB study area. It reaches a maximum thickness of more than 1,150 ft in the southern part of the study area and thins to a minimum of 350 ft along its northern/northeastern on-shore limit and to a minimum of 550 ft along its northwestern on-shore margin (Figure 2-6). Thickness data for the three lithofacies are summarized in Table 2-1.

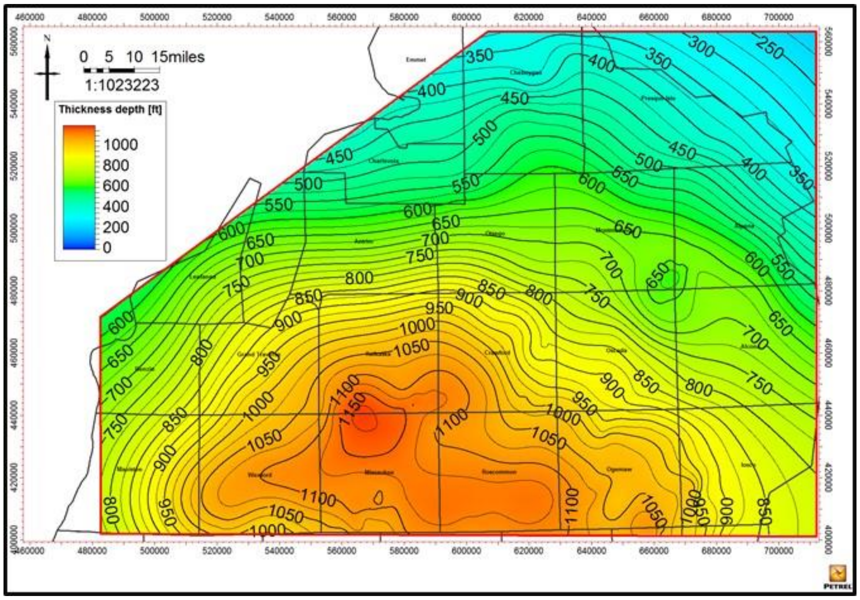

Figure 2-6. Thickness contour map (contour interval is 25 ft) of the St. Peter Sandstone.

Table 2-1. Thickness data for the three St. Peter lithofacies.

		LF1	LF2	LF3	Total
Thickness (ft)	Minimum	12	205	15	232
	Maximum	477	874	212	1563
	Average	232	523	72	827

Core-measured porosity and permeability data for the SPSS are available for 27 wells in the NMB. Porosity is very similar for the three lithofacies; whereas, permeability varies more between lithofacies, with LF3 having the highest permeability and LF2 having the lowest. Table 2-2 summarizes the porosity and permeability data for each lithofacies.

Table 2-2. St. Peter Sandstone Core-measured porosity and permeability data for wells in the NMB study area.

	Porosity (%)			Permeability (mD)		
Lithofacies	LF3	LF2	LF1	LF3	LF2	LF1
n wells	19	21	14	19	21	14
n samples	680	598	359	680	598	359
Min	0.5	0.7	0.7	0.01	0.01	0.01
Max	16.2	16.2	16.4	555	180	881
Mean	8.25	6.17	7.09	16.24	4.37	10.34
Geomean	--	--	--	1.4	0.40	1.32
P_5	3.2	2.6	1.99	0.03	0.02	0.08
P_{50}	8.5	5.8	7.2	1.13	0.29	1.25
P_{95}	12.6	10.43	12.4	74	22	40.3

Porosity values derived from geophysical logs (neutron porosity) are summarized in Table 2-3 for each lithofacies. Lithofacies 1 and 2 had an average neutron porosity of 4% while Lithofacies 3 was higher at 7%. Lithofacies 3 has the largest range in porosity while Lithofacies 2 has the smallest range, consistent with differences in rock matrix. In general, log-derived porosity is lower than core-derived porosity.

Porosity feet for the SPSS was mapped across the study area and is shown in Figure 2-7. Porosity feet is the thickness of the formation with a porosity above a lower threshold value that corresponds to a permeability of 1 millidarcy (mD). The threshold values for the three lithofacies are 7.8% (LF1), 7.2% (LF2), and 7.8% (LF3). Figure 2-7 shows the thickness of the SPSS with porosity above these values.

Table 2-3. Average and ranges of log porosity for the St. Peter lithofacies.

		LF1	LF2	LF3
Porosity (%)	Minimum	1	1	2
	Maximum	10	11	14
	Average	4	4	7

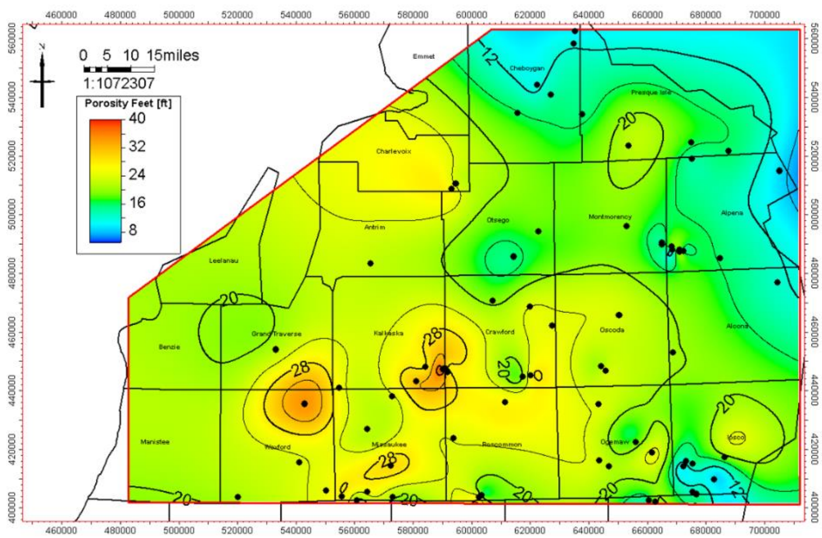

Figure 2-7. Map of the porosity feet for the total St. Peter sandstone showing isolated highs in Kalkaska, Wexford, and Grand Traverse counties.

2.1.1.1.2 Caprock

The SPSS is immediately overlain by the Glenwood Shale, a transitional unit composed of shale, sandstone, and limestone. The thickness varies from approximately 25 ft to 100 ft throughout the study area (Figure 2-8). The Glenwood Shale is overlain by the Black River Limestone, which is a tight limestone unit that has a thickness ranging from approximately 125 ft to 525 ft in the study area (Figure 2-8). This unit is considered to be the primary confining unit for the SPSS reservoir.

There are few well penetrations into the Black River confining unit. However, ten (10) core measurements of porosity and permeability are available from one well; these data are summarized in Table 2-4. Porosity ranges from 2.2% to 9.4% with a mean of 5.4%. Permeability ranges from 0.02 mD to 11 mD with a geometric mean of 0.36 mD. Reportedly, several of the core samples had fractures, so the reliability of these data is low. If a SPSS storage complex is developed in the future, it will be important to obtain additional core, log and other characterization data of the Black River Formation to demonstrate it has appropriate properties (e.g., thickness, porosity, permeability, etc.) to prevent upward CO_2 leakage out of the SPSS.

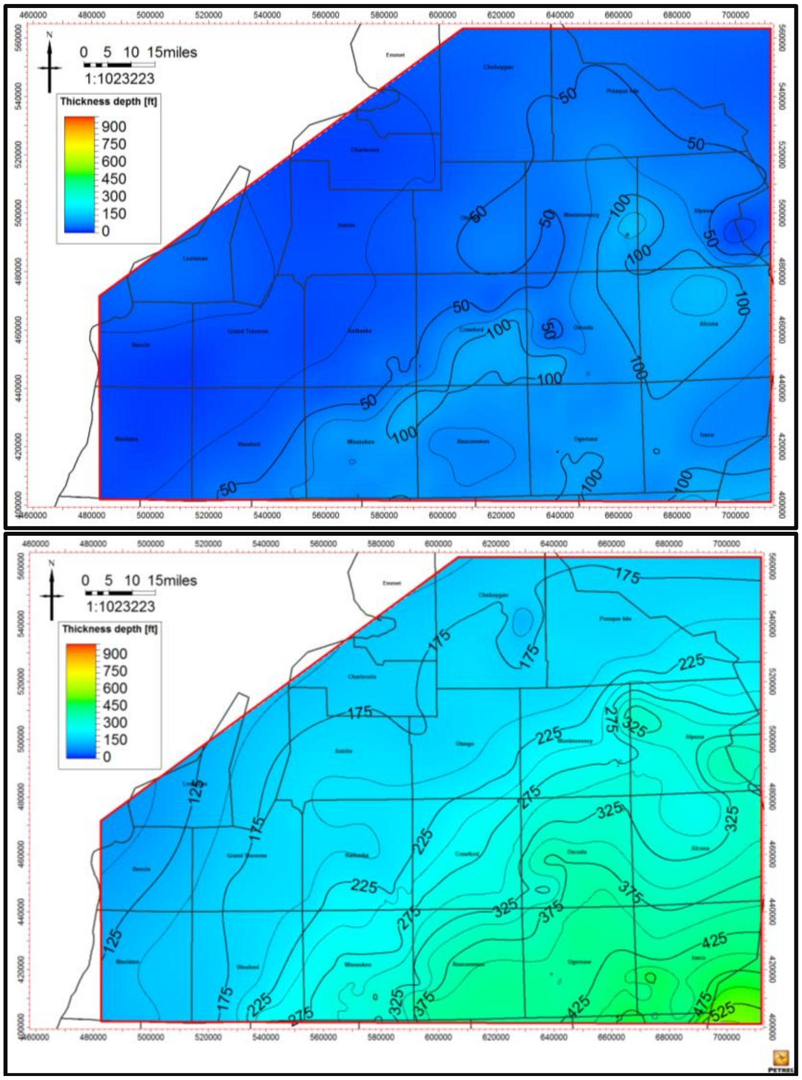

Figure 2-8. Thickness contour map of the Glenwood Shale (contour interval is 25 ft) (top) and the caprock Black River Limestone (contour interval is 10 ft) (lower).

Table 2-4. Glenwood Shale and Black River Core-measured porosity and permeability data.

	Glenwood Shale		Black River Limestone Caprock[a]	
	Permeability (mD)	Porosity (%)	Permeability (mD)	Porosity (%)
n wells	17		1	
n samples	189		10	
Minimum	0.01	0.3	0.02	2.2
Mean	---	5	---	5.4
Geo. mean	0.14	---	0.36	---
Maximum	153	16	11	9.4

a. Reportedly, several of the samples had fractures, so the reliability of these data is low.

2.1.1.1.3 St. Peter Sandstone Storage Capacity

A static earth computer model was built for the SPSS-Glenwood Shale-Black River Limestone system to facilitate calculating its CO_2 storage capacity. The total resource estimates range from 5.8 (P_{10}) to 20 (P_{90}) gigatons (GT), with a P_{50} of 11.3 GT. Lithofacies 2 (LF2) had the greatest storage potential because it is thicker than LF1 and LF3 (P_{50} ~7 GT), followed by LF1 (P_{50} ~2.7 GT) and LF3 (P_{50} ~1.5 GT). A contour map of storage capacity of the SPSS, for all three lithofacies combined, in MMT/0.25

square kilometers (km^2) is provided in Figure 2-9. The best total SPSS storage resource potential occurs in the west-central portion of the study area in Grand Traverse and Kalkaska Counties. The P_{50} resource estimate for the SPSS *net reservoir* within the study area is 2,937 MMT (2.94 GT) (net reservoir is the portion of the SPSS containing greater than 1 mD permeability). Total prospective CO_2 resource estimates for the SPSS total and net reservoir are shown in Table 2-5. By county, values range from 0.23 metric tons (tonnes)/km^2 (Cheboygan) to 0.77 tonnes/km^2 (Kalkaska), with an average value of 0.46 tonnes/km^2. These values translate to an area requirement to store 50 MMT CO_2 of 65 km^2 (25 mi^2 or 16,000 acres), 108 km^2 (42 mi^2 or 27,000 acres) and 217 km^2 (84 mi^2 or 54,000 acres).

Table 2-5. Total Prospective CO_2 Resource for the St. Peter Sandstone reservoir and net reservoir (portion of reservoir with permeability >1 mD).

Formation	Total Prospective CO_2 Storage Resource (MMT)		
	P_{10}	P_{50}	P_{90}
St. Peter sandstone	5,861	11,308	19,991
St. Peter Net Reservoir	1,522	2,937	5,193

1,000 MMT is equivalent to 1 giga(metric)ton (GT)

A map showing areas of the SPSS that have “notable” CO_2 prospective storage potential (notable areas have a P_{50} value of 0.3 MMT CO_2/0.25 km^2 or higher as indicated by data from two or more wells) is shown in Figure 2-10. Notable storage areas occur in Kalkaska, Wexford, Missaukee, Grand Traverse, and Crawford Counties.

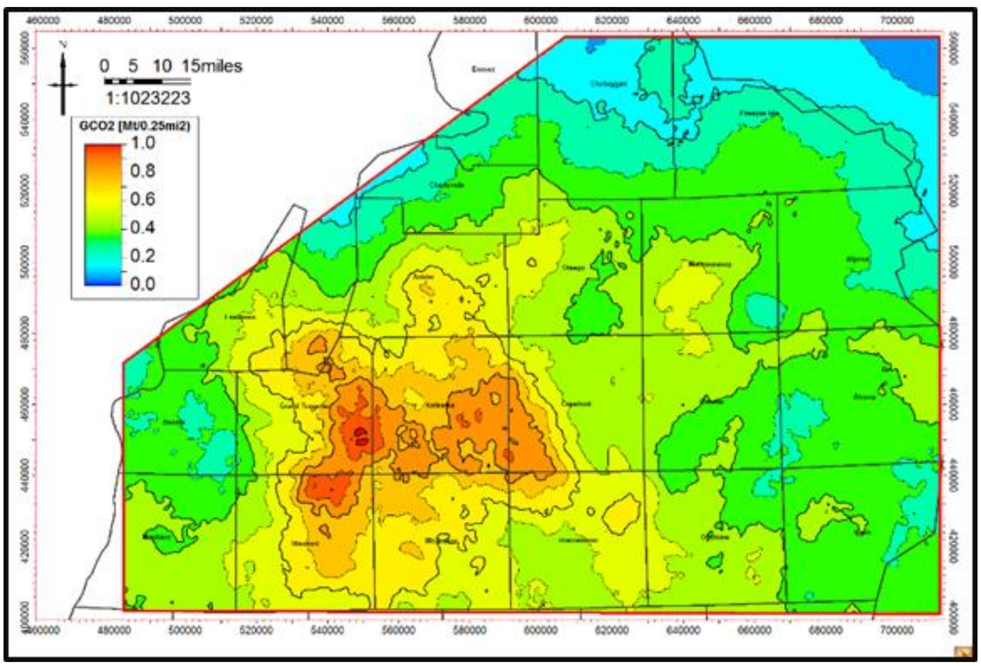

Figure 2-9. P_{50} prospective storage resource contour map (contour interval is 0.1 MMT/0.25 km^2) for the St. Peter sandstone (all three lithofacies combined) showing highest values in Grand Traverse and Kalkaska Counties (units are MMT/0.25 km^2).

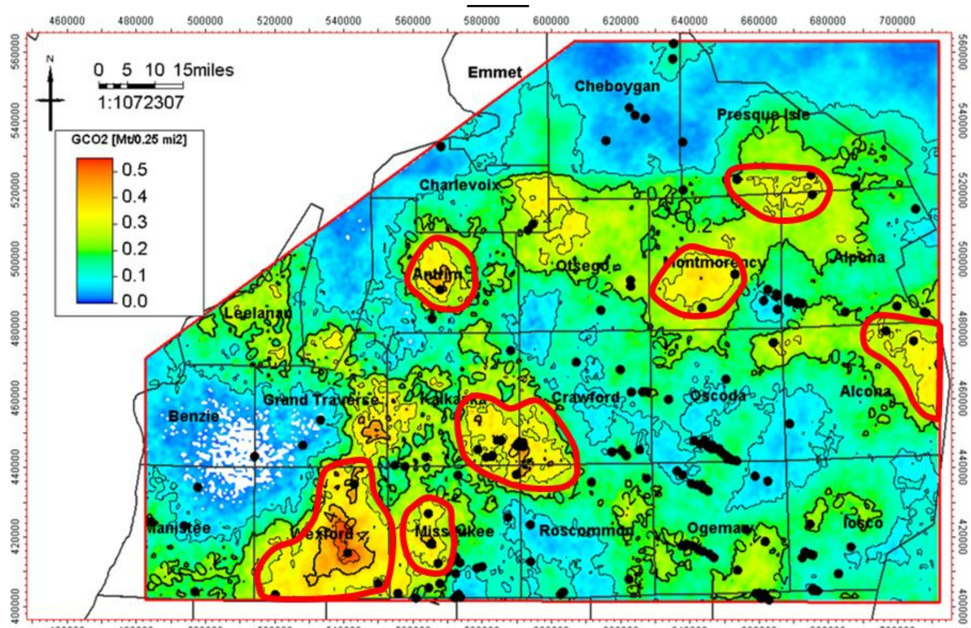

Figure 2-10. Net reservoir prospective storage resource map of the St. Peter sandstone (contour interval is 0.1 MMT/0.25 km²) showing areas with notable storage potential (P_{50}>0.3 MMT/km²) (units are MMT/0.25 km²).

2.1.1.2 Bass Islands Dolomite

The Bass Islands Group is a package of carbonate and evaporitic sedimentary rocks deposited during Late Silurian time and represent the youngest Silurian rocks in Michigan and the eastern Great Lakes region. The BILD, deposited in a shallow marine environment, is dominantly dolomite with locally high porosity and permeability due to grainstone and collapsed karst textures (see photographs of example core in Figure 2-11).

The Bass Islands dolomite is immediately overlain by the Bois Blanc formation which is composed of a mix of chert and cherty limestone or cherty dolostone. Porosity in the Bois Blanc can be high due to the chert, but permeability is usually negligible, making it a possible secondary storage zone through capillary trapping. The Amherstburg, composed of tight limestone, is the confining unit for the BILD. Above the Amherstburg are several hundred feet of tight carbonates, shales, and evaporites. Both units (Amherstburg and Bois Blanc) as well as the BILD are continuous across the study area.

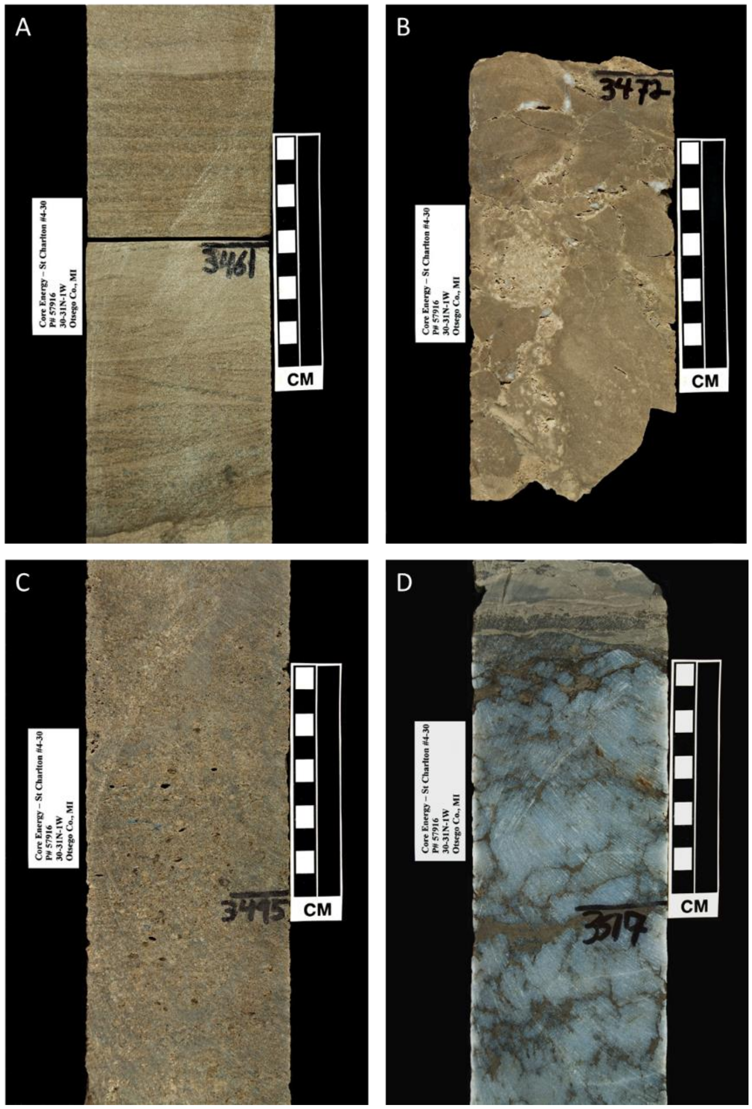

Figure 2-11. Photographs of Bass Islands core showing variability including interbedded grainstone (A), collapsed karst (B), grain supported dolostone (C) and anhydrite (D).

2.1.1.2.1 Depth, Thickness and Porosity and Permeability

The BILD is deepest towards the south-central part of the study area reaching depths greater than 4,800 ft. The formation becomes shallowest towards the north and approaches sea level. Consequently, the northernmost counties are considered too shallow to retain CO_2 as a liquid. However, over the major counties of interest (Otsego, Kalkaska, Grand Traverse, etc.), the depth of the BILD is sufficient (i.e., depth greater than 2,400 ft). The thickness of the BILD ranges from 24 to 124 ft throughout the study area but on average is 60 to 70 ft (Figure 2-12). The formation thins to the north and is thickest in Antrim County and towards the deeper basin center.

The Core Energy St. Charlton #4-30 well drilled through at least 188 ft of BILD and collected 78 ft of core from the uppermost part along with 42 ft of the overlying Bois Blanc Formation. This is the most complete subsurface core sample known for the BILD in Michigan. A total of 66 plugs were collected from the 78 ft of core for laboratory testing (Table 2-6 and Figure 2-13). Whole core contains highly dolomitized carbonate with some calcareous shale, nodular anhydrite, and silt. Porosity and permeability vary greatly and as cycles. Porosity ranges from 2% to 38% with an average of 13%. Permeability ranges from 0 mD to 684 mD with an average of 23 mD. Variations in core measurements are consistent with variations observed in lithology and textures. Log-derived porosity estimates for the BILD from geophysical logs range from 2% to 44%.

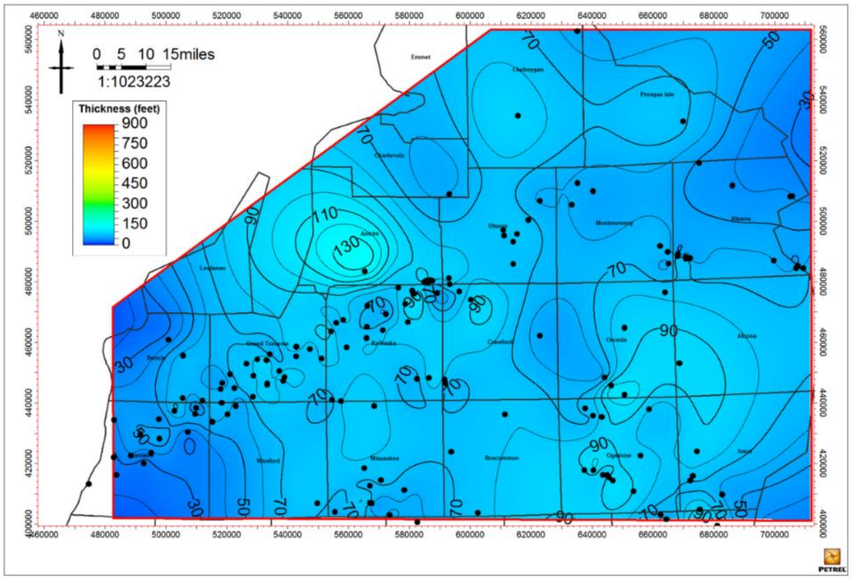

Figure 2-12. Thickness contour map of the BILD (contour interval is 10 ft).

Table 2-6. Core-measured porosity and permeability data for the BILD

	Bass Islands Dolomite	
	Porosity (%)	Permeability (mD)
n wells	1	
n samples	66	
Minimum	1.8	0.0002
Mean	13	NA
Geometric Mean	NA	0.56
Maximum	38	684

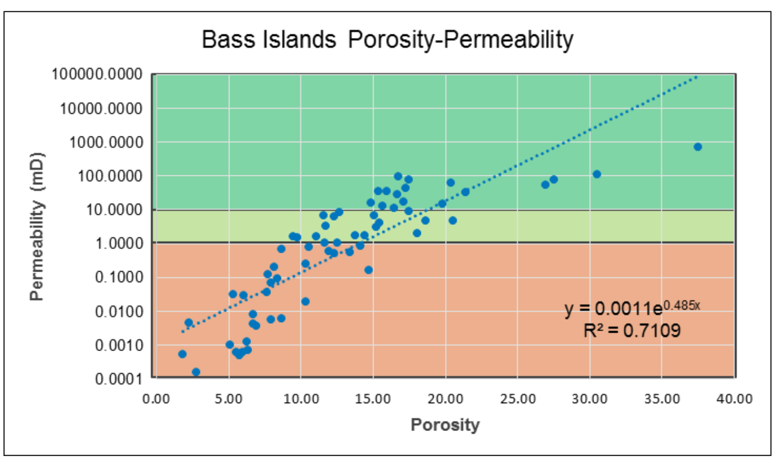

Figure 2-13. Core measured porosity and permeability for the BILD showing a strong correlation and highlighting ranges of high reservoir potential (green).

2.1.1.2.2 Bois Blanc-Amherstburg Containment Zone-Caprock

The thickness of the Bois Blanc reaches nearly 900 ft and thins to less than 150 ft in Manistee and Benzie counties (Figure 2-14). The Amherstburg is thickest in the center of the study area (Crawford/Otsego Counties), reaching a maximum of 350 ft, with an average thickness of 200 ft (Figure 2-14).

Core porosity and permeability data are available for one well in the study area (Table 2-7). Approximately 40 ft of whole core was previously collected from the lower Bois Blanc from the Core Energy St. Charlton #4-30 well near the contact with the BILD, and an additional four sidewall cores were collected. Five plugs were drilled from whole core and used for laboratory testing together with the four sidewall core samples. Whole core shows the Bois Blanc to have a mixed lithology of chert and cherty limestone or cherty dolostone. Occasional fractures were also noted. Porosity ranges from 5.7% to 16% with an average of 10.4%. Permeability ranges from 0.001 mD to 0.35 mD. The core porosity and permeability show some correlation (R^2 value of 0.64) (Figure 2-15), excluding the fractured sample (red).

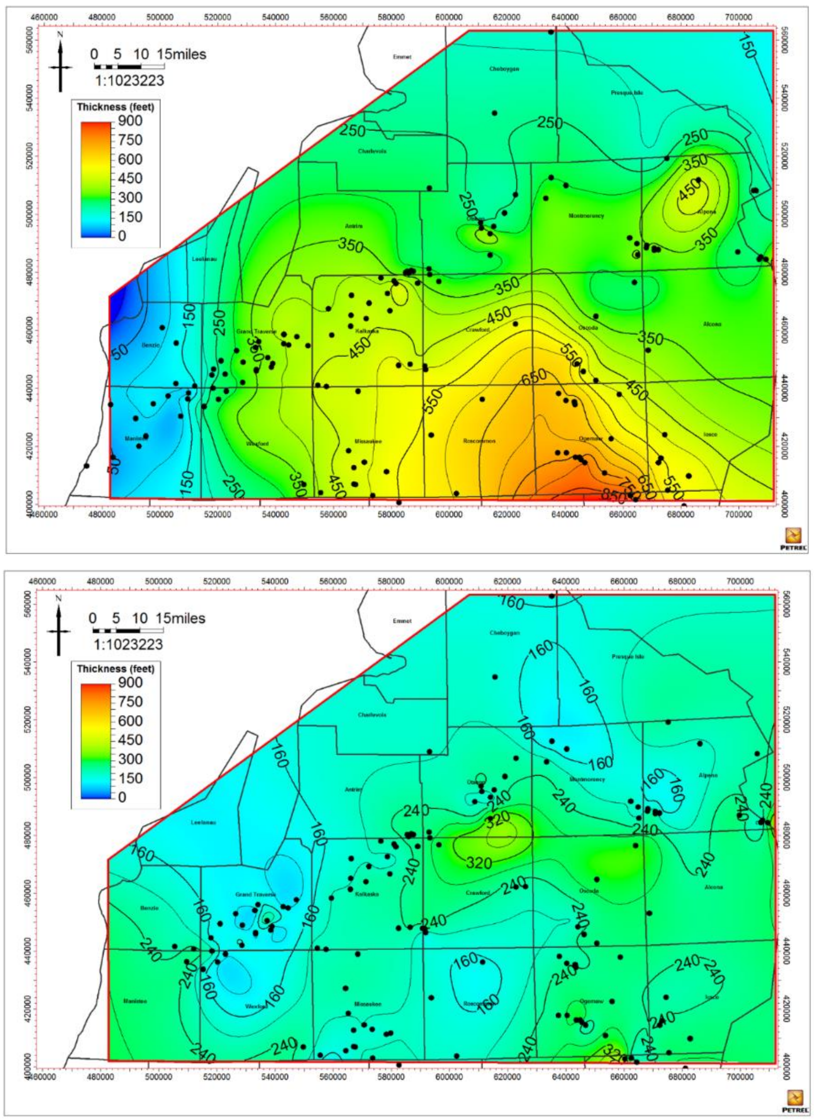

Figure 2-14. Thickness contour map of the Bois Blanc Formation (upper) (contour interval is 50 ft) and Amherstburg Limestone caprock (lower) (contour interval is 40 ft).

Table 2-7. Core-measured porosity and permeability data for the Bois Blanc Caprock.

	Porosity (%)	Permeability (mD)
n wells	1	
n samples	9	
Minimum	5.7	0.001
Mean	10.4	--
Geo. mean	--	0.009
Maximum	16	0.35

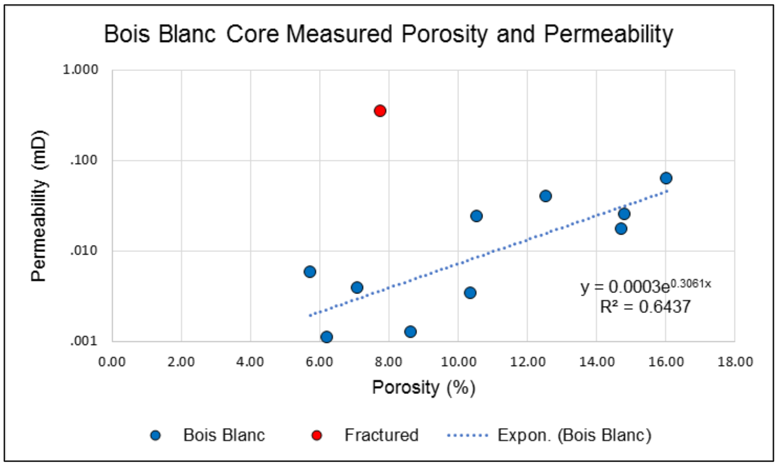

Figure 2-15. Core measured porosity and permeability for the Bois Blanc Formation.

Log and core analyses of the Amherstburg Limestone caprock showed consistently low porosity (<5%) and immeasurable permeability (data not shown).

2.1.1.2.3 BILD Storage Capacity

DOE-NETL's CO_2 SCREEN tool was used to compute prospective storage resource estimates for the BILD. Two-dimensional (2D) properties (depth, thickness, and average porosity maps) were re-gridded and used to input into CO_2 SCREEN. Default efficiency factors for dolomite were used for P_{10} (2.8%), P_{50} (5.68%), and P_{90} (9.63%) values. The resulting calculations produced a range of prospective CO_2 storage resource estimates of 3.5 GT (P_{10}) to 12 GT (P_{90}), with a P_{50} of 7 GT. The greatest prospective storage resource occurred in Antrim County, with surrounding counties (Otsego and Kalkaska) having relatively high storage. The northernmost counties (Emmet, Cheboygan, and Presque Isle) as well as Benzie and Manistee Counties have little to no prospective storage because the reservoir is too shallow in these areas to meet supercritical CO_2 conditions. On average across the study area, the P_{50} prospective storage estimate is 0.23 million metric tons per square kilometer (MMT/km^2), which translates to an approximate area of 220 km^2 (approximately 85 mi^2 or 54,400 acres) to store 50 MMT of CO_2. However, in Antrim County, the required storage area for 50 MMT is only about 100 km^2 (39 mi^2 or 25,000 acres) because the P_{50} prospective storage estimate in this area is higher (0.49 MMT/km^2). A map showing prospective storage resource in MMT/km^2 for the NMB study area is shown in Figure 2-16.

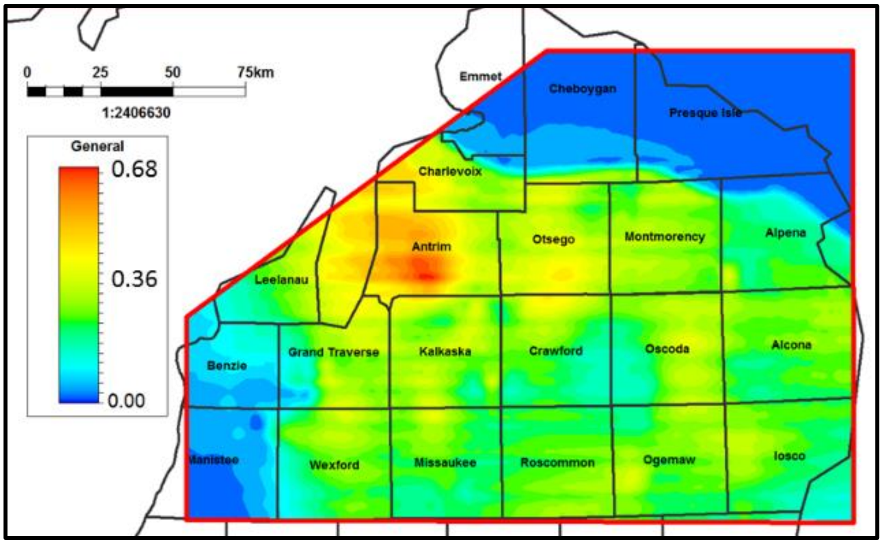

Figure 2-16. P_{50} prospective storage resource map for the Bass Island Dolomites showing highest values in Antrim County (units are MMT/km^2).

2.1.1.3 Niagaran Reefs

Niagaran pinnacle reefs are the third candidate CO_2 storage reservoir evaluated in the pre-feasibility study. Niagaran pinnacle reefs are developed primarily in the Brown Niagaran Formation. However, atop reef crests and higher portions of the reefs' flanks, the overlying A-1 carbonate occurs immediately above the Brown Niagaran Formation because the A-1 evaporite (halite and anhydrite) was not deposited in these positions. In these areas, the A-1 carbonate is often a continuous and effective part of the overall Niagaran reef reservoir system.

The formation of Niagaran reefs began by a carbonate mud-rich bioherm accumulation in warm, calm, shallow waters followed by multiple stages of growth, including: (Stage 1) vertical growth of bioherm and central reef core portions of the complexes by frame-building organisms as relative sea level rose due to a combination of eustatic sea level rise and basin center subsidence (Leibold, 1992); (Stage 2) an upper stromatolitic cap forms over top of the reef when relative sea level stabilizes and creates an intertidal, high energy depositional environment; (Stage 3) eustatic sea level fall results in a relative sea level drawdown in the Michigan Basin, resulting in exposure of all Niagaran Reef complexes; (Stage 4) as post-Niagaran sea level rises and falls, layers of carbonates and evaporites are deposited over the reef complex. The different stages of the reef development life cycle are illustrated in Figure 2-17. These processes resulted in the formation of a mound or "pinnacle" shaped geologic feature that is overlain and draped by the A-1 carbonate, A-1 evaporite, A-2 carbonate and A-2 evaporite.

A total of 856 discrete pinnacle reefs have been identified across the NMB study area (Figure 2-18). Over 85% (748) have been designated as producing pools by the State of Michigan and have a history of commercial oil and gas production. Through mid-2017, these fields collectively have produced over 422 million barrels of oil (MMSTB), 2.47 trillion cubic ft of natural gas (TCFG), and 3.8 million barrels of natural gas liquids (MMBNGL). Over 75% of the total reef count (both productive and total) and over 75% of the total cumulative production has come from four counties: Otsego, Kalkaska, Grand Traverse, and Manistee.

The highest value reservoirs have experienced some degree of regional porosity/permeability enhancement by dolomitization. Many of the pinnacle reefs have experienced minimal or no dolomitization and still have acceptable attributes as hydrocarbon traps (and sequestration targets). Other processes have had negative impacts on the development of the reservoir system in some reefs, including: formation of calcite cements that line, and may completely fill, the primary pore network; and, salt plugging and anhydrite plugging, which can also reduce porosity. The MRCSP Phase III project has studied both types of reefs, including injecting more than 1 MMT of CO_2 into multiple reefs, and found that injectivity can vary but is never zero, thereby demonstrating that reefs are viable injection targets.

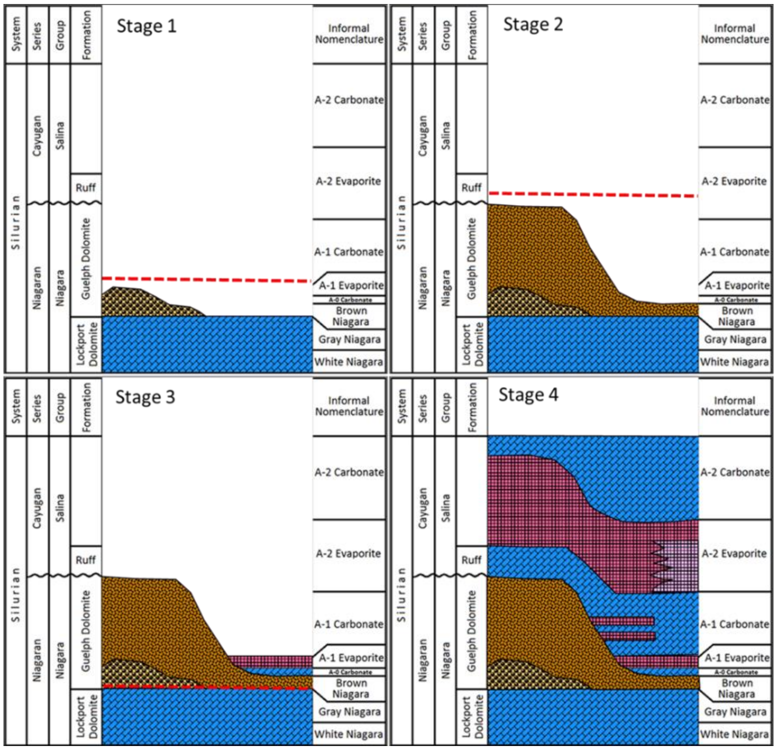

Figure 2-17. Conceptual model of the Stages of Niagaran reef development and demise demonstrating the initial building of the reef (Stage 1), the growth of the reef core during normal salinities and rising sea level (Stage 2); exposure of the reef and deposition of evaporite deposits during falling sea level (Stage 3), and burial of the karsted reef by transgressive A1 Carbonates and overlying A2 Evaporites (Stage 4). Red dashed line represents relative sea level position. Figure modified after Gill, 1973.

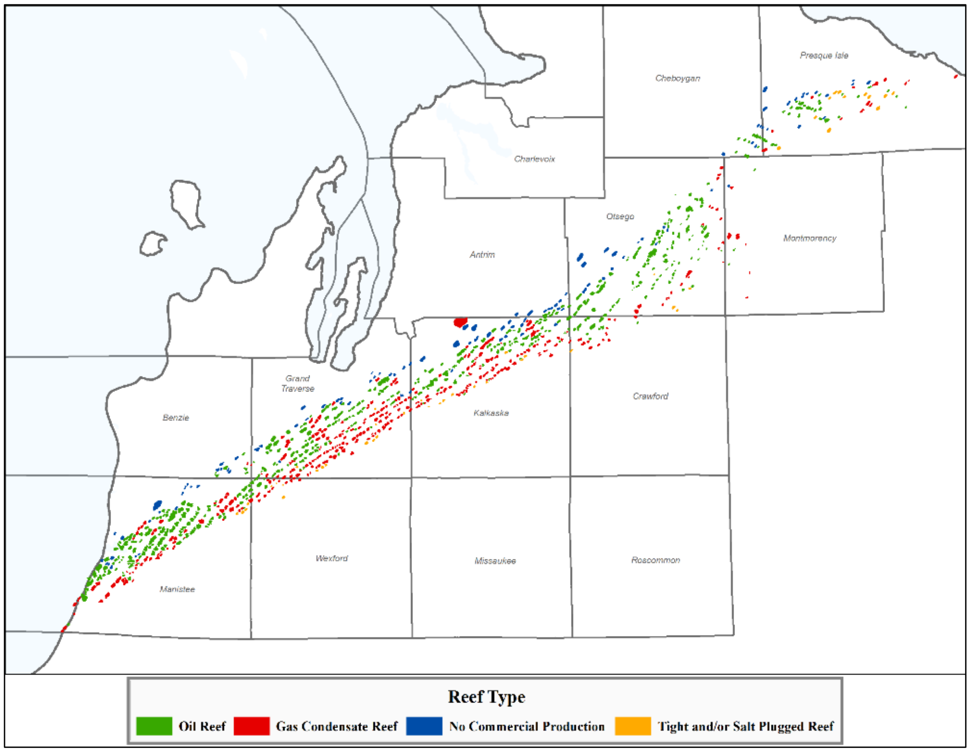

Figure 2-18. Regional map of the NPRT showing reef locations of 856 discrete pinnacle reefs in the NMB study area colored by reef type.

2.1.1.3.1 Depth, Thickness, Porosity and Permeability

The reefs occur at depths greater than 2,500 ft below ground surface across the entire Northern Pinnacle Reef Trend (NPRT), reaching depths close to 8,000 ft in places (Figure 2-19). The thickness (height) of the reefs (Brown Niagaran Formation) varies depending on the relative position of the reef along the basin rim. Shelfward pinnacles located up-dip on the Niagaran aged carbonate ramp (northward) are shorter (thinner) than those that occur farther down the ramp in a basinward (southward) position. Typical heights (thickness) of the reefs (Brown Niagaran) are 250 ft to 300 ft in the shelfward areas and in excess of 550 ft up to 700 ft in the basinward setting. In the areas between reefs, the Brown Niagaran thins to approximately 20 ft to 40 ft; however, the off-reef Brown Niagaran is not hydraulically connected to the on-reef Brown Niagaran (i.e., not part of the reservoir).

Reefs nearest the regional carbonate bank, or shelf (i.e., up-dip/north), typically show pervasive dolomitization (geological process by which the carbonate mineral dolomite is formed when magnesium ions replace calcium ions in the original carbonate mineral [calcite]). This dolomitization generally improves reservoir quality, although some reefs are tight from extensive and multiple-phased dolomitization and late dolomite cementation. In general, dolomitization is believed to be due to the development of sabkhas (an area of coastal flats subject to periodic flooding and evaporation which results in the accumulation of aeolian clays, evaporites, and salts) above the reefs during sea level low stands, which acted to focus fluids that subsequently infiltrated the underlying reefs and caused dolomitization. Pinnacles in the medial position between bankward (north) and basinward (south) commonly show an admixture of limestone and dolomitized intervals, and generally have favorable reservoir properties as well. Tall, basinward pinnacles typically show minimal or no dolomitization. These reefs still commonly produce hydrocarbons in commercial quantities, but reservoir properties are generally poorer than up-dip reefs and the economic quality of reef production in these basinward areas is far more variable.

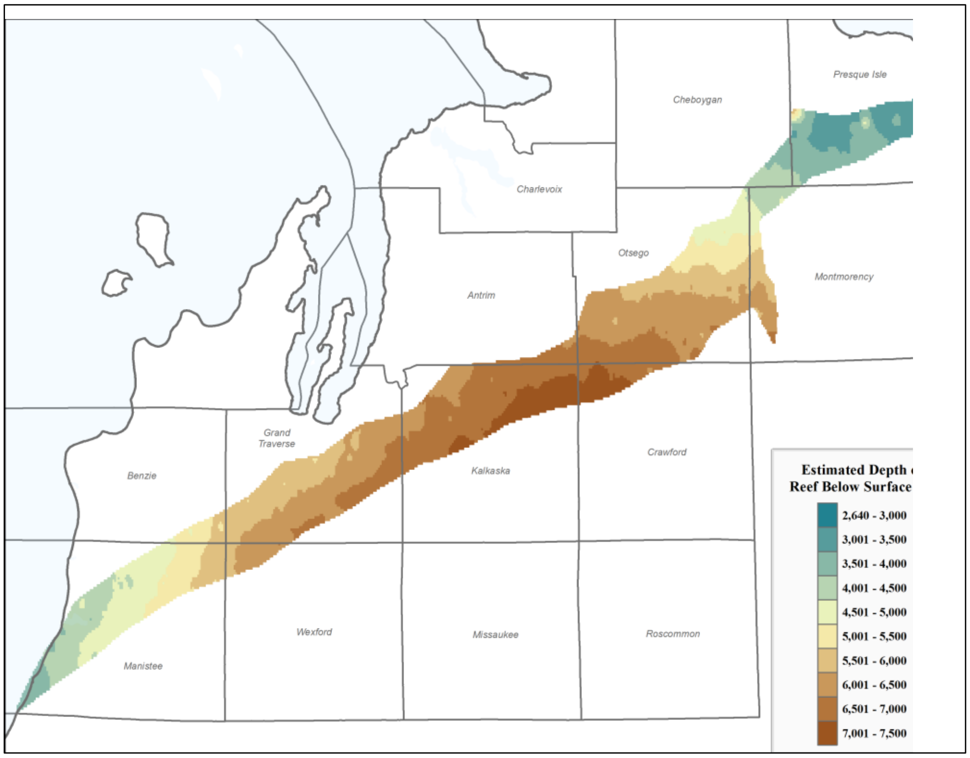

Figure 2-19. Map of the NPRT showing estimated depth to the top of the reef based on wells that penetrated known reef locations.

2.1.1.3.2 Caprock Assessment

The caprock for the Niagaran reefs is comprised of multiple intervals of thick bedded halite and associated evaporites, interspersed with tight carbonates, shaley carbonates, and shales of the Salina Group that overlies the Brown Niagaran Formation and A-1 carbonate. These poorly permeable rocks provide an ideal lateral and top seal for the reservoir system. The B-salt unit of the Salina Group (not differentiated in Figure 2-1) has been considered the ultimate confining unit; it is a ubiquitous, massive halite unit almost always in excess of 300 ft. This redundancy makes Niagaran Reefs ideal reservoirs for gas storage and CO_2 sequestration.

2.1.1.3.3 Storage Capacity

Due to the compartmentalization of the reefs and their history of oil and gas production, resource estimates were calculated based on a fluid substitution method rather than using the method applied to the SPSS and BILD saline reservoirs. This method assumes the reefs can store the equivalent amount of hydrocarbons produced. The methodology is conservative (underestimates capacity) because it does not account for the volume of water produced (water production records are incomplete), it uses volume of sold gas as an estimate of total produced gas (recorded values are sold gas), and it doesn't account for dissolution of CO_2 into oil or brine.

The analysis shows that there is approximately 230 MMT of storage across the NPRT, with the largest 15 reefs accounting for 50 MMT of storage. Classified gas reefs accounted for nearly 160 MMT of the 230 MMT and ranged from 780 metric tons (tonnes) to more than 5 MMT of storage per reef. On average, gas reefs have a capacity of 500,000 tonnes. The oil reefs account for approximately 73 MMT of the 230 MMT total storage capacity and ranged from negligible to 2.8 MMT per reef. On average, reefs have a capacity of 178,000 tonnes. Figure 2-20 is a map of the reefs in the northern trend colored by their estimated capacity. Overall, the Niagaran reefs have more than sufficient storage capacity across the

NPRT and can be used for either CO_2-EOR or CO_2 storage scenarios. Figure 2-21 is a map of a subset of 82 of the oil-bearing reefs in NPRT that are candidates for CO_2-EOR with a collective CO_2 storage capacity of 51 MMT CO_2. As mentioned above, the total storage capacity of all oil and gas reefs combined far exceeds the target 50 MMT CO_2 required for this pre-feasibility phase.

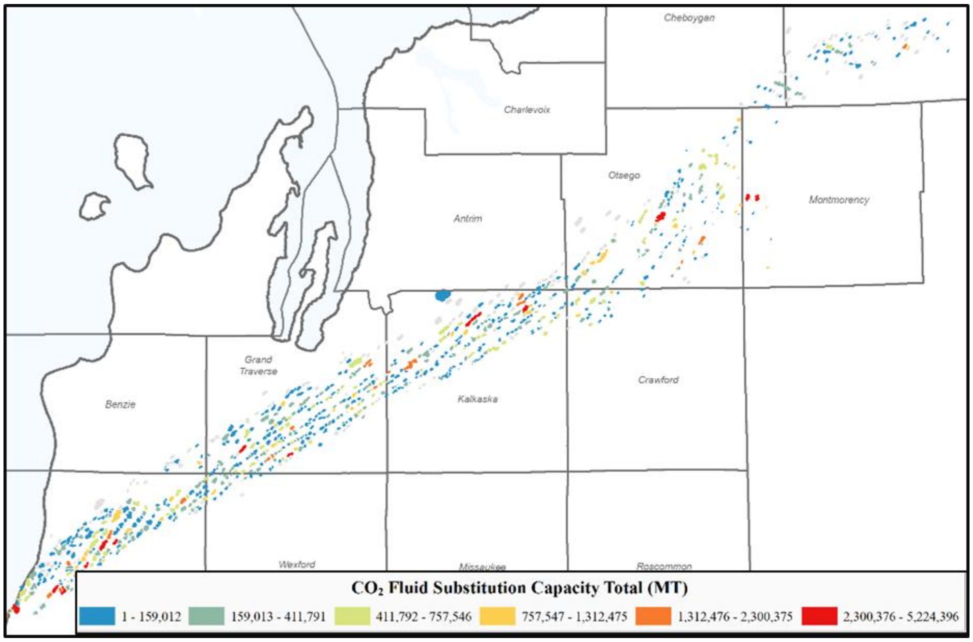

Figure 2-20. CO_2 storage resources for each reef as calculated using fluid substitution, showing reefs with higher resources along the trend.

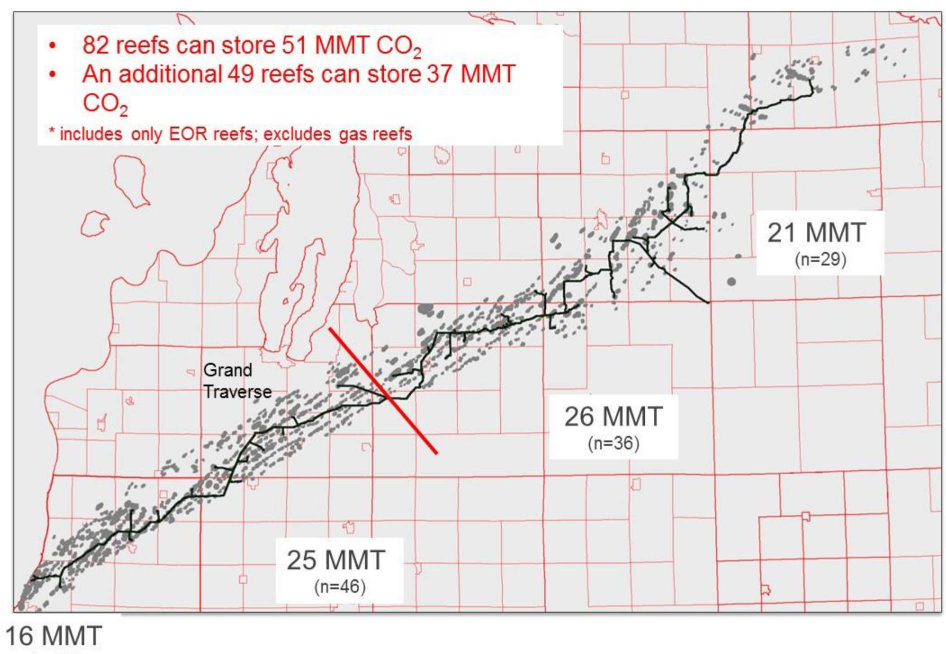

Figure 2-21. Map of a subset of the oil-bearing reefs in NPRT that are candidates for CO_2-EOR with a collective CO_2 storage capacity of 51 MMT.

2.2 Land Access for Storage Sites

The previous section demonstrates that there is considerably more CO_2 storage capacity than the 50 MMT target amount available in each of three geologic systems within the NMB study area (i.e., SPSS saline reservoir, BILD saline reservoir, Niagaran pinnacle reefs). In order to locate a storage site, access to land is required including subsurface storage rights for the area encompassing the CO_2 plume and surface access to selected locations within the CO_2 plume area for wells, monitoring systems, roads, and utility easements.

2.2.1 Land Options for SPSS and BILD Saline Reservoirs

State-owned land and private land are the two primary options for locating a saline reservoir storage site. Although there is federally-owned land in the study area, it was not explored as an option for hosting a storage site because of the perceived complexity of obtaining federal authorization compared to working with a state agency already familiar with subsurface CO_2 and brine injection and oil and gas production. Additionally, the location of the federally-owned lands further from the Niagaran pinnacle reefs don't coincide with the best storage areas within the saline reservoirs. Within the study area, there is a considerable amount of state-owned forest land, including large contiguous tracts of land, and this was determined to be the most viable option for a saline storage site based on the following rationale.

- A single contiguous tract of land owned by a single entity is preferred for a storage site because it minimizes the number of landowners involved in the project. State-owned forest land is the only land type that is available in contiguous tracts large enough to encompass the CO_2 plume or a significant portion of the CO_2 plume. There are no single privately-owned tracts large enough to encompass the CO_2 plume, although there are a few options controlled by a combination of a small number of private landowners and state land.
- The MDNR is the largest land owner in the CS-NMB study area and is supportive of the CS-NMB project, having provided a letter to the CS-NMB team indicating its interest and willingness to discuss the process for siting a CS-NMB project on state-owned land.
- The MDNR already manages and permits responsible use of the subsurface for oil and gas production and brine injection.

Figure 2-22 shows the extent of state-owned land in the CS-NMB study area. As can be seen, forest land (dark green) accounts for the largest proportion of state land types. Importantly, there is state-owned forest land in close proximity to the Niagaran reef trend, which means it may be possible to reduce infrastructure (e.g., pipelines) required to access both storage options (saline reservoirs and Niagaran reefs) by sharing.

In contrast, no single privately-owned contiguous tract of land was identified that is 10,000 acres in size; however, four areas (one in Montmorenecy County, two in Otsego County, and one in Missaukee County) were identified that include one or more relatively large private tracts plus a modest number of small private tracts and/or state-owned parcels covering an area of 10,000 acres. These are shown in Figure 2-23 and Figure 2-24. Due diligence was conducted for each of the four areas to assess likelihood of acquiring access to the needed area for hosting a saline reservoir storage site. The findings of the due-diligence investigation are summarized in Table 2-8. Of the four sites, Sites 1 and 3 would be most likely to support a storage site, and Sites 2 and 4 the least likely.

Table 2-8. Assessment of Privately Owned Land Areas for Hosting Potential Storage Sites.

Site/County		Determination
1.	Montmorency County	• Likely, particularly if the State is supportive • Two large primary private landowners • Both State and private owners appear to own minerals beneath most of their surface • Established communications with both private owners in the past • Existing infrastructure and pipeline corridors run through the site area
2.	Otsego County #1	• Somewhat unlikely or difficult due to many small tracts • Existing infrastructure and pipeline corridors run through the site area
3.	Missaukee County	• Somewhat likely, one very large private large owner adjacent to some State lands • Not close to existing pipeline corridors • Require potentially more Rights of Way acquisition to access
4.	Otsego County #2	• Unlikely due to many surface tracts • Not as close to existing infrastructure and pipeline corridors Horicon property

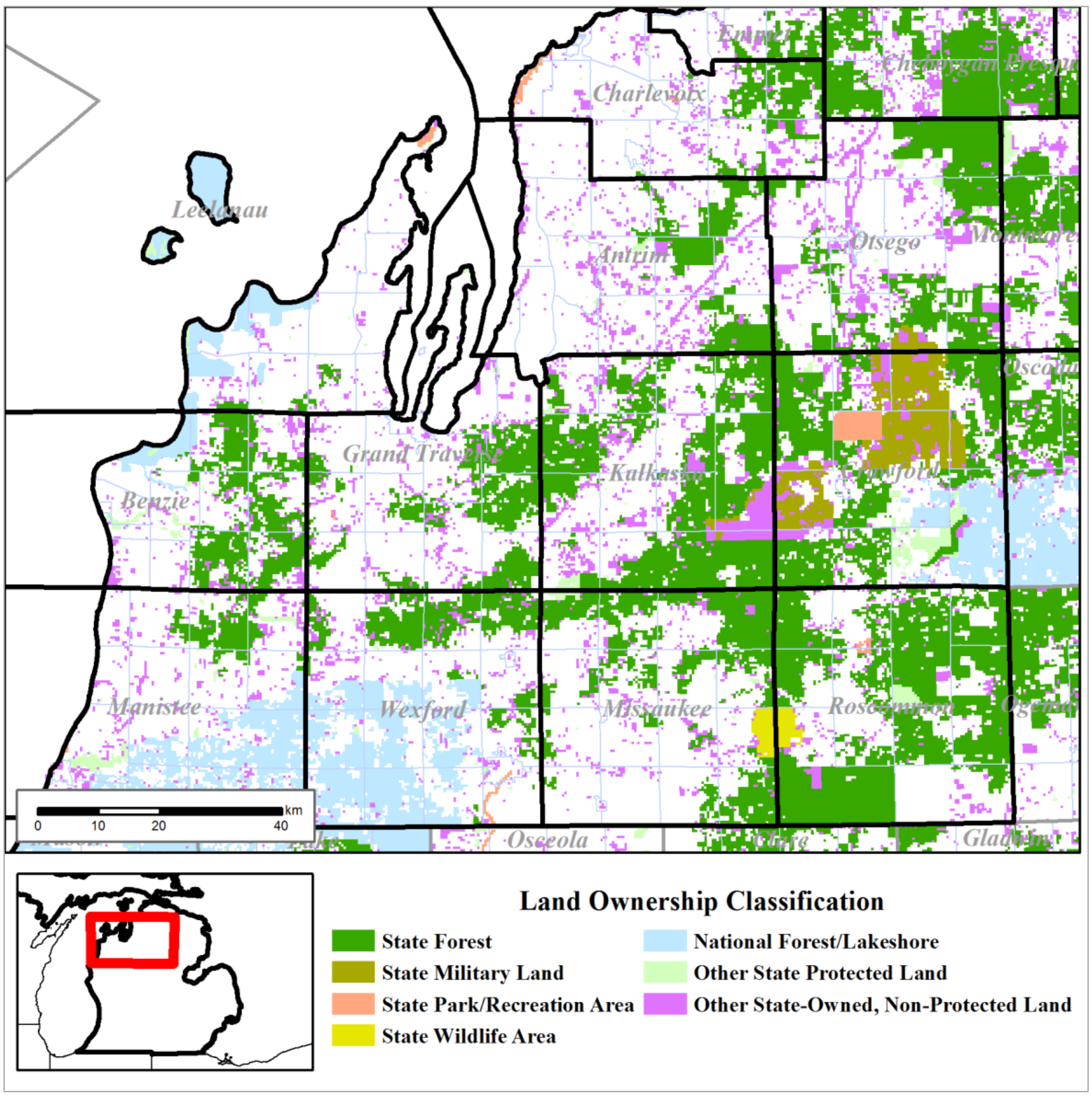

Figure 2-22. State-owned land in the CS-NMB study area.

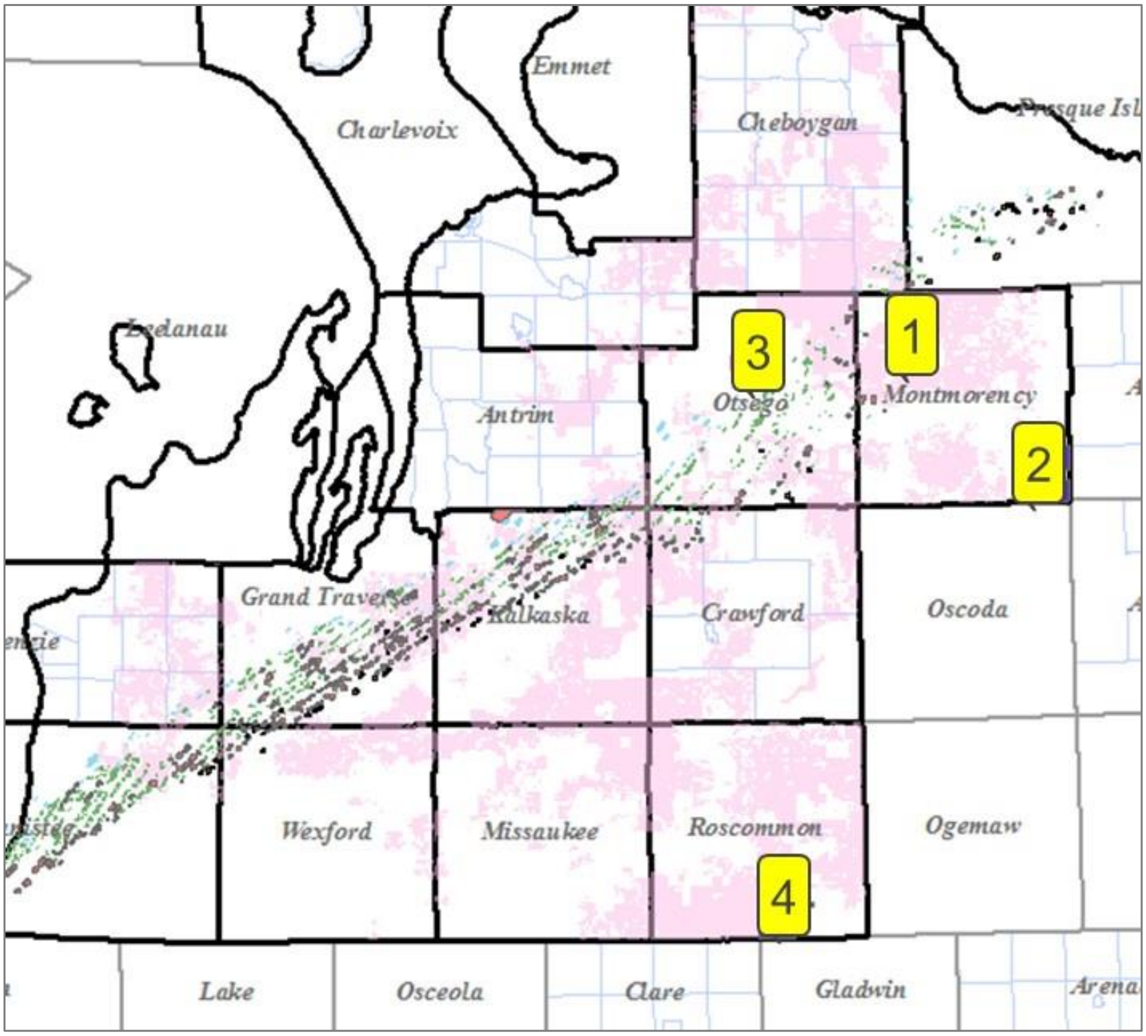

Figure 2-23. Areas with private land evaluated for hosting saline reservoir storage site.

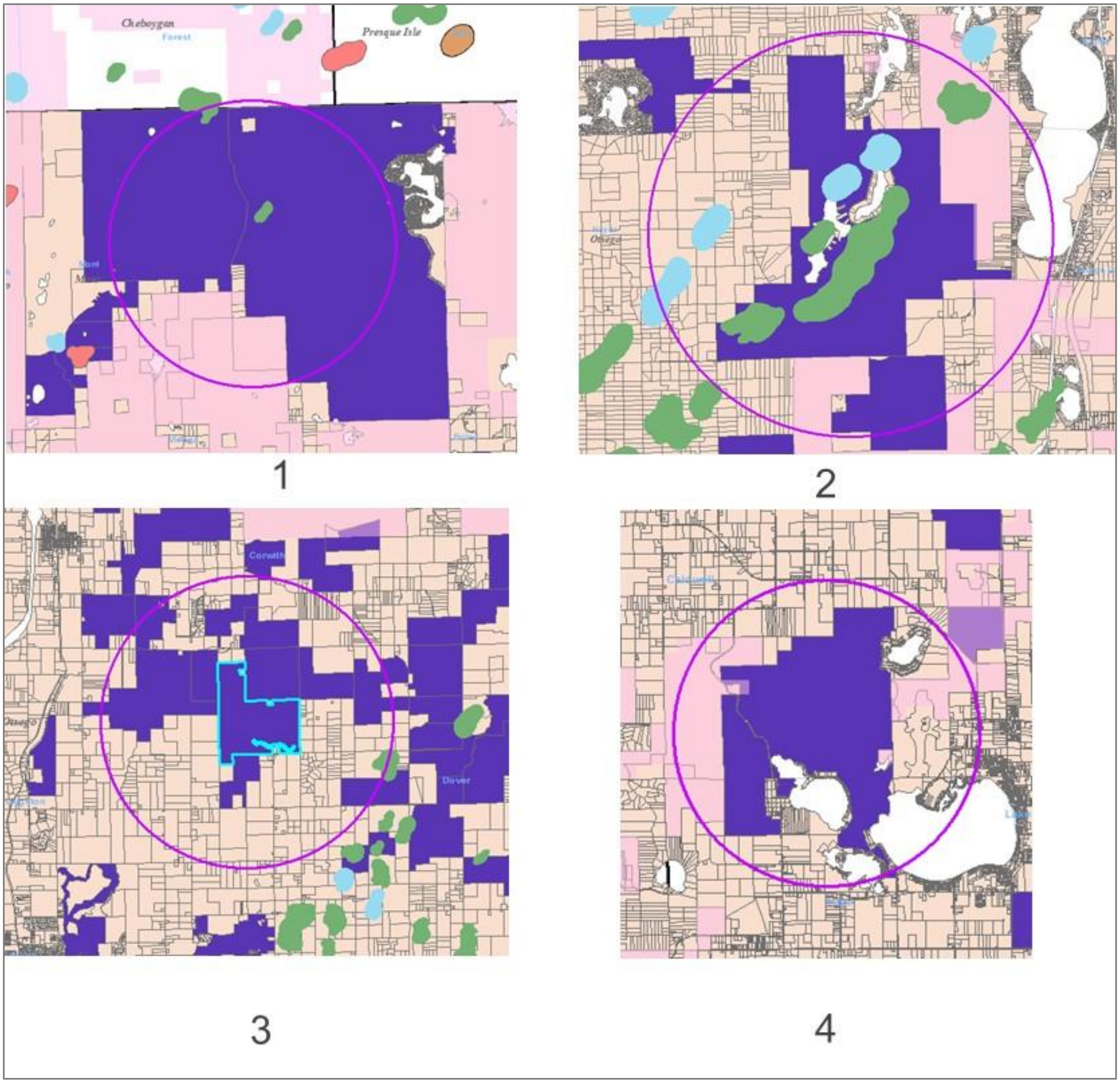

Figure 2-24. Four mostly privately-owned land areas that were considered for hosting saline reservoir storage sites. Pink circle is 10,000 acres (radius =2.23 miles).

2.2.2 Land Access for Niagaran Pinnacle Reefs

To secure access to the Niagaran reefs, it will be necessary to acquire mineral rights, surface rights, and storage (pore space) rights for the area overlying each reef. Storage rights are somewhat well defined in the state of Michigan and include special provisions for natural gas storage that are good precedents for CO_2 storage. Modifications to existing statutes and/or new regulation may be needed. The following information summarizes current requirements based on Michigan law (source: Loomis, Ewert, Parsley, Davis & Gotting, P.C). According to Michigan law,

- the underground storage space in rock absent of or evacuated of oil and gas belongs to the surface owner. The ownership of the storage space is not the same as the ownership of the oil and gas unless all interests in a parcel of property are owned by the same person or entity. (Department of Transportation v Goike, 220 Mich App 614; 560 NW2d 365 [1996]) The Court recognized that the right to store "foreign or extraneous minerals or gas" rests with the surface owner.
- most property rights are acquired by voluntary agreement between the proposed operator and the owner. However, in both MPSC gas storage and MDEQ CO_2-EOR proceedings, aspects of eminent domain and compulsory participation, respectively, are already in the statutes under which the agencies function. Amendments to the MPSC's and MDEQ's controlling statutes will be necessary for such aspects to be applicable to CO_2 storage.

In summary, in order to use the Niagaran reefs for CO_2 storage via CO_2-EOR, it will be necessary to acquire surface rights, mineral rights, and storage (pore space) rights for the area/volume encompassing each reef. If using the reefs for CO_2 storage without EOR (i.e., filling a depleted gas reef), it will be necessary to acquire surface rights and storage (pore space) rights for the area/volume encompassing each reef.

Amendments to current laws or a standalone CO_2 storage statute will be necessary to fully accommodate a large-scale CO_2 storage project. However, Michigan's MPSC, MDEQ, and MDNR have the technical knowledge, experience, and institutional memory necessary to effectively regulate the new but related discipline of CO_2 large-scale storage and CO_2 storage incidental to CO_2-EOR.

2.3 SPSS Saline Reservoir Feasibility Study (CO_2 Plume Modeling)

To demonstrate the viability of the SPSS to host a 50 MMT CO_2 storage complex, a three-dimensional (3D) numerical fluid-flow model was constructed for multiple example storage site locations (Figure 2-25) that coincide with large tracts of state-owned land in the NMB study area. This section presents the results for two sites (Site 2 and Site 7) which were selected for dynamic modeling because the SPSS in these areas has a higher permeability-thickness (kh) value than the other sites, which indicates a higher injectivity.

The objective of the dynamic modeling analysis was to determine the number of injection wells to inject 50 MMT CO_2 and their spacing, and to determine the size of the 50 MMT CO_2 volume. The predicted CO_2 plume size is important because this defines the land area that must be allotted (i.e., if using state-owned land) and/or permitted (i.e., if using private land). The modeled plume size was also used (together with the calculated pressure front) to determine the AoR for the UIC Class VI (CO_2) injection well permit. The AoR determination is discussed in Section 2.4 of this document. (A numerical modeling analysis was not performed for the Niagaran reefs because they are closed reservoir systems with well-defined boundaries and storage capacity, thus the extent of the CO_2 plume(s), will be defined by the reef boundaries. Similarly, a modeling analysis was not performed for the BILD because it is a supplemental saline reservoir.)

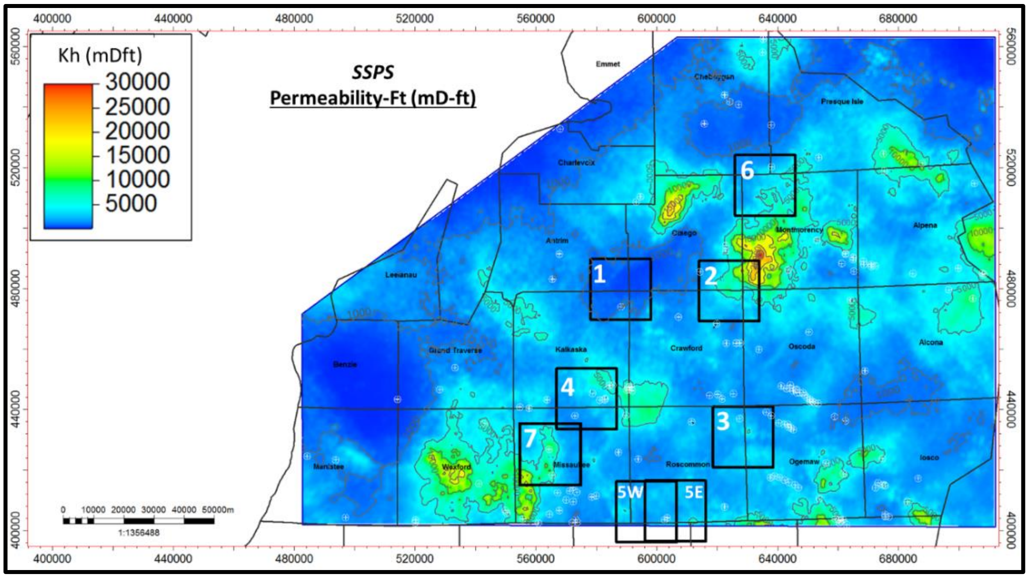

Figure 2-25. Locations of the sites that were evaluated using numerical modeling overlain on SPSS total permeability-thickness (kh), showing Site 2 and Site 7 as having the greatest kh.

2.3.1 Model Description

The computer model(s) were constructed using the Computer Modeling Group-Generalized Equation of State compositional reservoir simulator. A 3D geocellular grid was constructed for each site from a regional Static Earth Model (SEM) for the SPSS developed in the Petrel (Schlumberger) geologic modeling computer program. The SEM defines the spatial variation in the formation thickness, depth, and porosity for each site. Other model properties, such as permeability, initial pressure, and others, were specified directly in the GEM model. The model areal extent for each site was a square region measuring 41 kilometers (km) x 41 km, with grid cells measuring 500 meters (m) x 500 m laterally and 1 m to 2 m vertically (i.e., thick). Given the lateral continuity of the SPSS, each site was modeled with infinite-acting boundaries (except for Site 1, which is outside the extent of LF3). The heterogeneous porosity distribution within the area covered by each site model was reduced to a single value of porosity which preserved the true total pore volume for each lithofacies. Limited permeability data (from analysis of core samples) were available for the three lithofacies. Therefore, a single (i.e., homogenous) permeability equal to one geometric standard deviation above the geometric mean of the available data was used in the models. These values correspond to 4.9 mD, 1.3 mD, and 7 mD, for LF1, LF2, and LF3, respectively. Because of the limited porosity data, all sites that were evaluated used the same permeability value for each lithofacies but retained used porosity values unique to the site. Porosity and permeability values used in the Site 2 and Site 7 models are summarized in Table 2-9 and Table 2-10, respectively.

Table 2-9. Porosity Values Used in the Dynamic Models.

Facies	Site 2	Site 7
Lithofacies 1	6.0%	6.7%
Lithofacies 2	2.9%	3.3%
Lithofacies 3	4.1%	1.8%

Table 2-10. Permeability Used in the Dynamic Models.

Facies	Average (mD)	Geometric Standard Deviation (σ_{gm}) (mD)	Geometric Mean x σ^{1}_{gm} (mD)
Lithofacies 1	7.9	4.0	4.9
Lithofacies 2	3.1	4.0	1.3
Lithofacies 3	16.0	4.9	7.0

2.3.2 Model Results

Key results of the modeling analysis (number of injection wells, 30 MMT plume size, maximum pressure) are summarized in Table 2-11 and shown in Figure 2-26 and Figure 2-27 for Sites 2 and 7, respectively. The modeling demonstrates that 50 MMT CO_2 can be injected into both sites within 30 years, although more wells are required for Site 2 (six wells) than for Site 7 (three wells). Consequently, the 50 MMT plume size is larger for Site 2 because of the larger number of injection wells (Table 2-11). The initial reservoir pressure (gradient) in each model was specified as 0.48 pounds per square inch per foot (psi/ft), and the average reservoir pressure (gradient) at the end of injection was 0.67 and 0.60 psi/ft for Sites 2 and 7, respectively. The difference in the results for the two sites is due mainly to the fact that Site 7 has considerably higher injectivity (kh) because of a greater thickness of LF1 and LF3. However, Site 2 is still attractive because it has satisfactory injectivity and is considerably shallower (lower per well cost) than Site 7. Residual pressure is equal to the calculated fracture pressure for the reservoir minus the final pressure (i.e., pressure at 50 MMT CO_2). A positive value for residual pressure indicates that the maximum injection pressure is below the fracture pressure. Residual pressure is positive for both sites, indicating that 50 MMT CO_2 can be injected without fracturing the reservoir.

Table 2-11. Number of injection wells, modeled CO_2 plume area, and final reservoir pressure for two example storage site locations in the SPSS.

Site	Mass CO_2 Injection (MMT)	CO_2 Injection 30 years (MMT)	# Injection Wells	Well Pattern	Plume Area (acres)	Maximum Pressure at 30 years (psi/ft)
Site 2	50	30	6	Hexagon	18,200	0.67
Site 7	50	79	3	Triangle	13,900	0.60

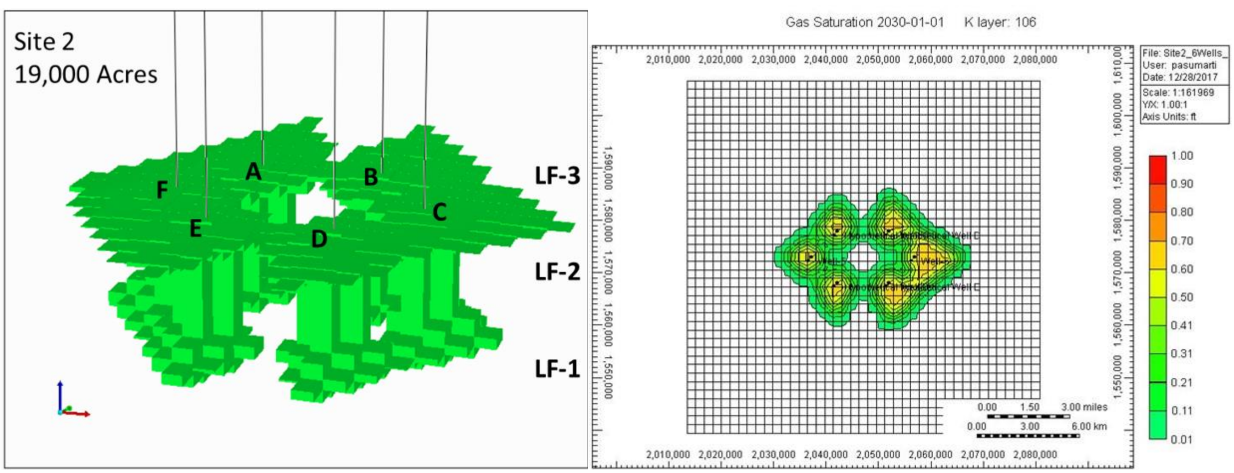

Figure 2-26a. Site 2 modeled 50 MMT CO_2 plume (% CO_2 saturation) in 3D (left) and plan view (right) showing largest areal extent in (Layer 253).

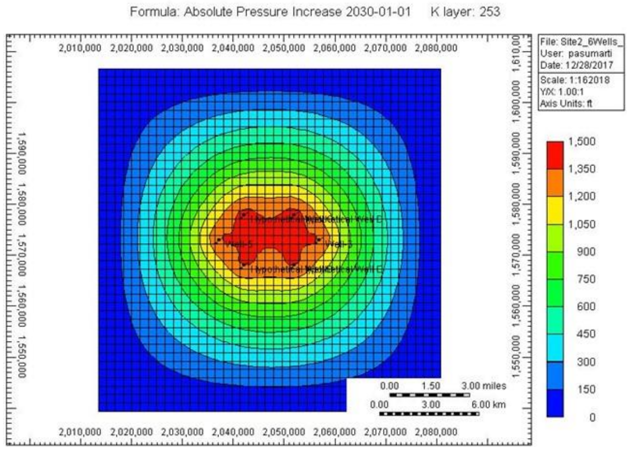

Figure 2-26b. Site 2 maximum pressure (psi) increase (modeled final – initial pressure) (Layer 253).

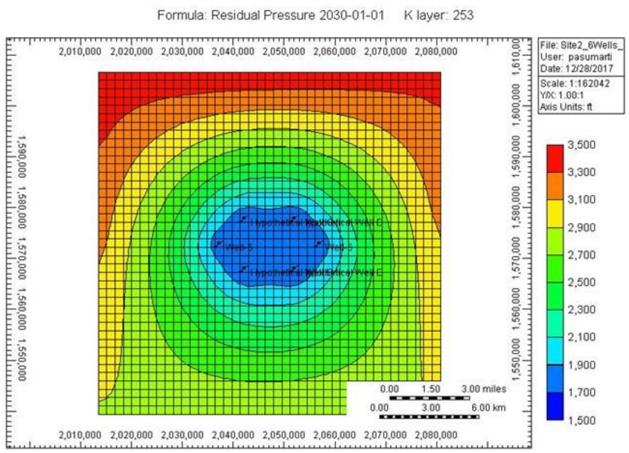

Figure 2-26c. Site 2 maximum pressure (psi) increase (modeled final – initial pressure) (Layer 253).

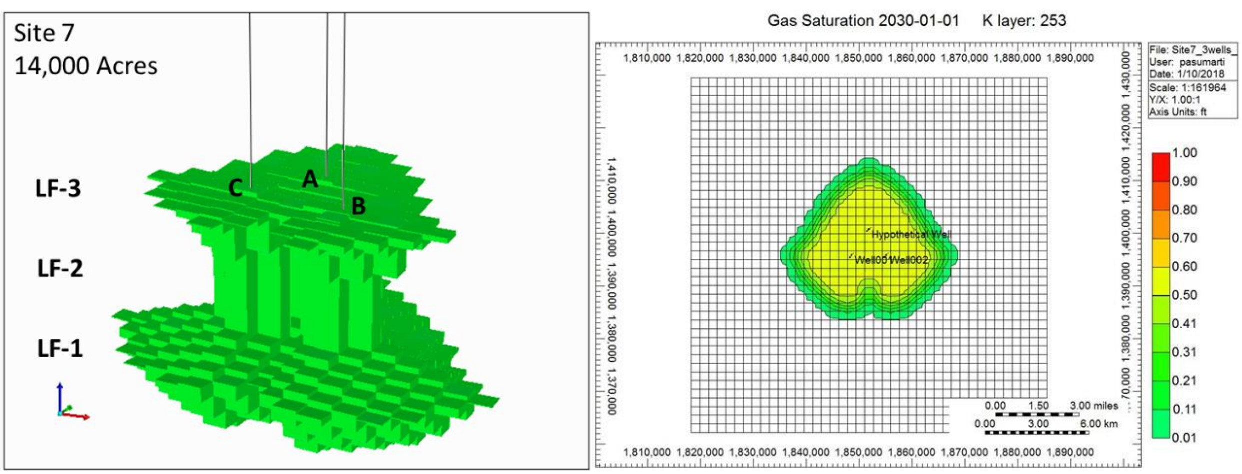

Figure 2-27a. Site 7 modeled 50 MMT CO_2 plume (% CO_2 saturation) in 3D (left) and plan view (right) showing largest areal extent in Layer 253.

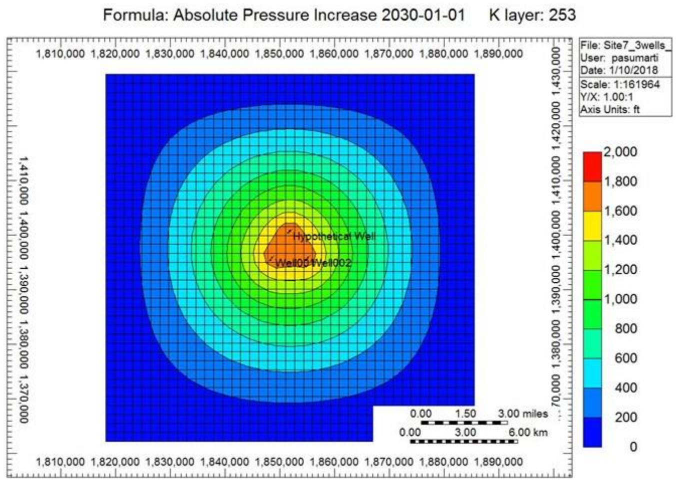

Figure 2-27b. Site 7 maximum pressure (psi) increase (modeled final – initial pressure) (Layer 253).

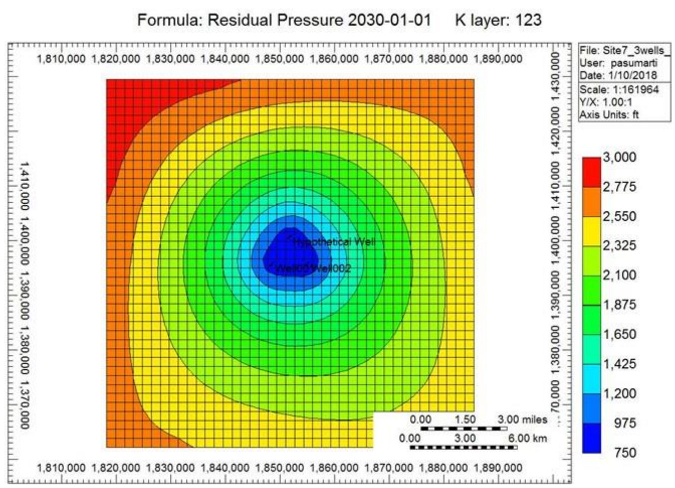

Figure 2-27c. Site 7 maximum pressure (psi) increase (modeled final – initial pressure) (Layer 253).

2.3.3 Conclusion

Fluid-flow modeling of a 30-year 50 MMT CO_2 injection scenario for two example SPSS storage site locations in the northern Michigan study area demonstrates that the SPSS is able to host a 50 MMT CO_2 storage complex in this area. Variability in SPSS properties (e.g., thickness) affect its injectivity and make some locations better than others. Based on this Phase I feasibility modeling, both sites are able to accommodate 50 MMT in 30 years, using a reasonable number of injection wells and requiring a reasonable amount of land area. The plume area for each of the two sites is 13,000 acres (Site 7) and 19,000 acres (Site 2). Consequently, Site 2 and Site 7 were both selected to carry forward into the financial (scenario) analysis to provide a range of storage site costs, rather than presenting only a best-case scenario.

2.4 Area of Review and Leakage Impacts Using the NRAP-IAM-CS Model

To further demonstrate the viability of specific storage reservoirs/sites for inclusion in the CS-NMB storage complex, an assessment of the AoR and leakage risks to shallow underground sources of groundwater (USDW) aquifers was conducted using software tools developed under the DOE National Risk Assessment Partnership (NRAP). NRAP tools are listed in Table 2-12.

An objective of the pre-feasibility study was to help validate the NRAP tools, which are still in the development phase, by applying them to real-world examples. In this study, the National Risk Assessment Partnership-Integrated Assessment Model-Carbon Storage (NRAP-IAM-CS) software tool was used for two purposes:

- determine the AoR using a risk-based approach that can be compared to an AoR determined using the EPA method, and
- estimate the potential of legacy wells located within the AoR to facilitate upward leakage of CO_2 and/or brine that could adversely impact groundwater quality in a shallow USDW aquifer at the SPSS saline storage Site 7.

Table 2-12. NRAP Integrated Assessment Model Tools.

Carbon Storage (NRAP-IAM-CS)[a,b]
Reservoir Evaluation and Visualization (REV) Tool
Reservoir ROM Generation Tool (RROM-Gen)[a]
Wellbore Leakage Analysis Tool (WLAT)
Natural Seal ROM (NSealR)
Aquifer Impact Model (AIM)
Design for Risk Evaluation and Monitoring (DREAM)
Term Seismic Forecasting (STSF)
Ground Motion Predictions for Induced Seismicity (GMPIS)
Multiple Source Leakage ROM for atmospheric leakage (MSLR)

a. Indicates NRAP Tool used in this study
b. Including built-in carbonate aquifer ROM and open borehole ROM

The NRAP-IAM-CS is a hybrid system model developed by the DOE for use in performance and quantitative risk assessment of geologic sequestration of CO_2 (Pawar et al., 2016). The model is divided into components representing different media, including a primary CO_2 injection reservoir, potential leakage pathways, and receptors, such as shallow aquifers. The model is designed such that it can be used to perform probabilistic simulations related to the long-term fate of a CO_2 sequestration operation. A stochastic framework at the system level allows NRAP-IAM-CS to be used to explore complex interactions among large numbers of uncertain variables and help evaluate the likely performance of potential sequestration sites. The model samples values for each uncertain parameter from probability distributions, leading to estimates of global uncertainty that accumulate as the coupled processes interact during a simulation. NRAP-IAM-CS is designed to link together many different processes (e.g., subsurface injection of CO_2, CO_2 migration, leakage, and shallow aquifer impacts) required in the analysis of long-term CO_2 storage in geologic reservoirs. The underlying processes can be simulated using reduced-order models (ROMs) developed for the components in the integrated assessment model (IAM). For the analysis conducted in this study, the system model consisted of a reservoir component, an open wellbore component, and a groundwater receptor component.

This section presents a summary of the work performed and results; a complete report on the subject is provided in Appendix B: Economic Analysis Figures. This work represents one of the first applications of the NRAP toolset for the screening of potential CO_2 storage sites.

2.4.1 Area of Review

The AoR was calculated using the EPA method and an alternate risk-based method using the NRAP-IAM-CS tool. The key steps involved in each method are shown in Figure 2-28.

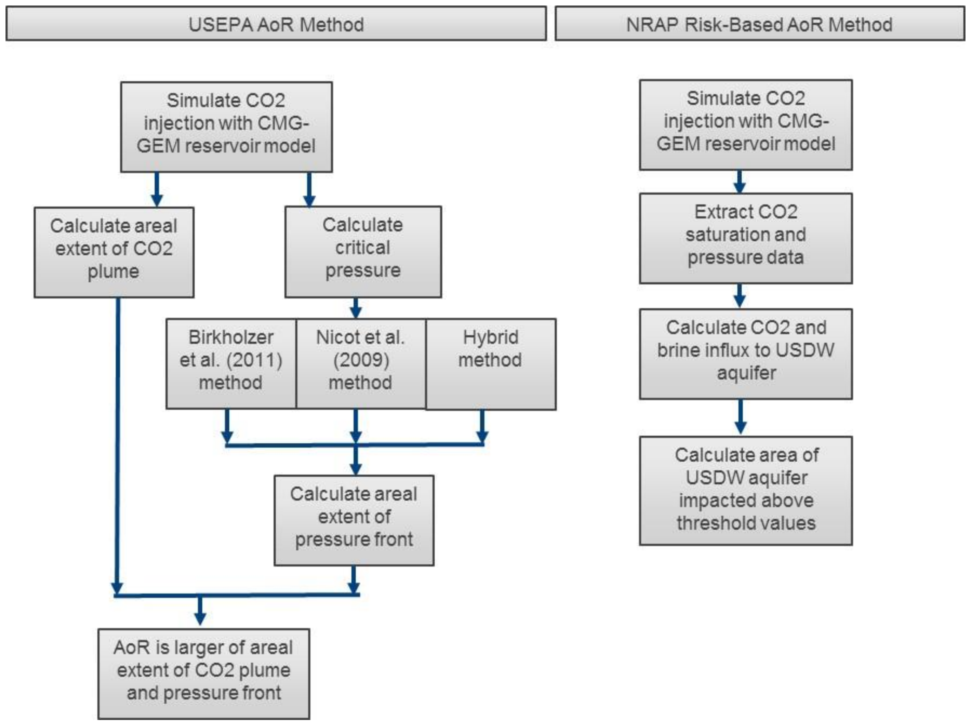

Figure 2-28. Key steps in USEPA and NRAP methods for calculating AoR.

2.4.1.1 U.S. EPA AoR Method

The U.S. EPA AoR is the larger of the areal extent of the CO_2 plume and the pressure front. The CO_2 plume areal extent is determined using an appropriate computer model (i.e., a porous media or fractured-media fluid-flow model with CO_2 equation of state). In this study, the CMG-GEM (Computer Modeling Group-Generalized Equation of State Model) computer model was used. The pressure front can be calculated by three methods:

- Birkholzer et al. (2011),
- Nicot et al., (2009)
- (Hybrid) – If the absolute value of critical pressure calculated with method 1 is less than critical pressure calculated with method 2, then the value of 2 minus the absolute value of 1 is used.

2.4.1.1.1 Predicted CO_2 Plume Area

The predicted (modeled) separate-phase CO_2 plume area for the 50 MMT CO_2 plume at SPSS Saline reservoir Site 7 is approximately 22 mi^2 or 13,900 acres (Figure 2-29; Table 2-13).

Table 2-13. Number of injection wells, modeled CO_2 plume area, and final reservoir pressure for storage Site 7.

Mass CO_2 Injection (MT)	CO_2 Injection 30 years (MT)	# Injection Wells	Well Pattern	Plume Area (mi^2; acres)	Maximum Pressure at 30 years (psi/ft)
50	79	3	Triangle	21.7; 13,900	0.60

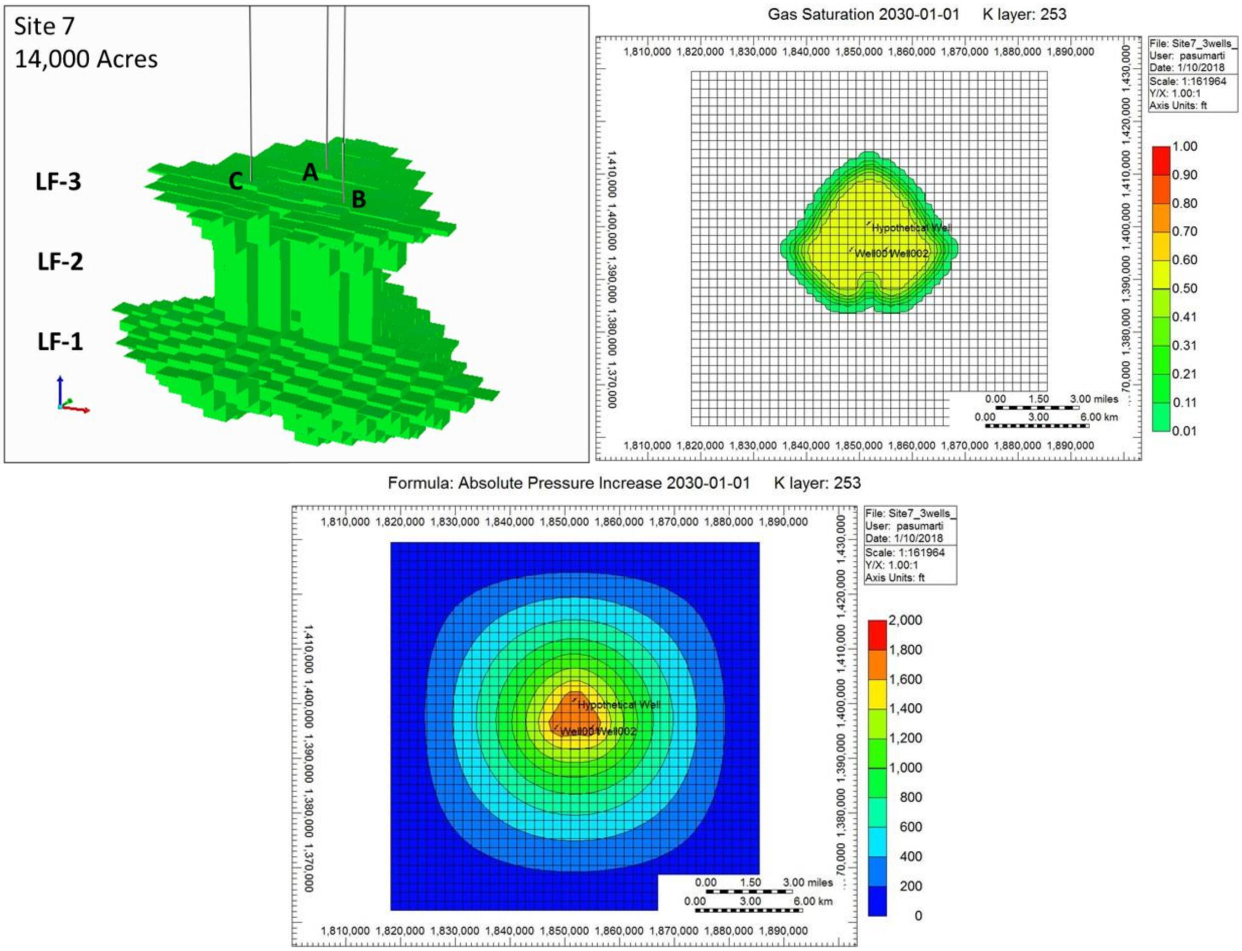

Figure 2-29. Site 7 modeled 50 MMT CO_2 Plume (% CO_2 saturation) in 3D view (upper left) and 2D plan view (upper right) showing largest areal extent (Layer 253); Site 7 maximum pressure (psi) increase (modeled final – initial pressure) (Layer 253) (lower).

2.4.1.1.2 Pressure Front

A critical pressure of -1.013 MPa (-147 psi) and 1.749 MPa (254 psi) was calculated for Site 7 using the Birkhlozer et al. (2011) method, and the Nicot et al. (2009) method, respectively. A negative value indicates an over-pressurized injection zone where reservoir brine has the potential to migrate to the drinking water aquifer prior to any CO_2 injection. Because the critical pressure using the Nicote et al. (2011) method is greater than the Birkholzer et al. (2011) critical pressure, the difference in magnitude between the two may be used as an estimate of the allowable pressure increase, subject to the assumptions used to derive Equation 2 (see Nicot et al., 2009). This results in an allowable pressure increase of 0.736 MPa (107 psi), (1.749 MPa to 1.013 MPa) which can be used to define the AoR[1]. The area with a pressure increase greater than or equal to 107 psi encompasses 104 mi^2 (66,560 acres) and is shown in Figure 2-30.

[1] Because the injection reservoir is over pressurized relative to the shallow drinking water aquifer, neither the critical pressure from methods 1 or 2 can be used to define the AoR. In this case, the allowable pressure increase (this is the term EPA uses) is used to delineate the AoR. The allowable pressure increase is the difference between the two critical pressures calculated with method 1 and 2.

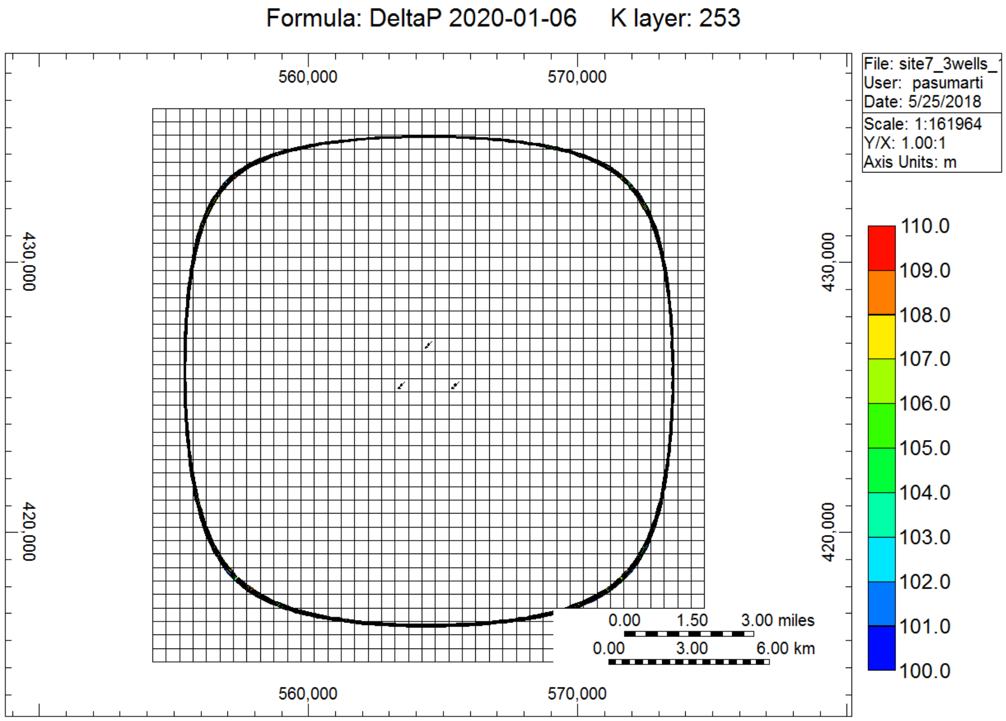

Figure 2-30. AoR as determined by the critical pressure method (0.736 MPa [107 psi]); Area =269 km^2 (104 mi^2; 66,560 acres).

2.4.1.1.3 Result

The pressure front (104 mi^2; 66,500 acres) is significantly larger than the CO_2 plume (22 mi^2; 13,900 acres) and therefore is used to define the AoR for Site 7.

2.4.1.2 NRAP Risk-Based AoR

2.4.1.2.1 Method

The risk-based AoR calculated using the NRAP-IAM-CS is the area where CO_2 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-net degradation” thresholds. The “no-net-degradation” thresholds are pH = 6.5 and total dissolved solids (TDS) = 500 ppm. The boundaries of the AoR were calculated by calculating pH and TDS in the shallow drinking water aquifer at hypothetical open wells located at increasing distances to the east, west, north, and south of the injection wells until no impact to the aquifer was observed. CO_2 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.

Figure 2-30 shows the locations of the hypothetical wells used to estimate the AoR. Wells 1, 2, and 3 are located within the CO_2 plume and Well 4 is located outside of the CO_2 plume but within the pressure front. Pressure buildup varies from approximately 11.9 MPa (1,726 psi) at the center of the injection area to about 1.8 MPa (261 psi) at Well 4.

CO_2 leakage to the USDW occurs at Wells 1, 2 and 3 and changes the shallow groundwater pH to below 6.5. Impacts to groundwater are used only to define the AoR; a full quantitative analysis would require updating the groundwater ROMs to handle large fluxes created by flow through an open wellbore. Qualitatively, the magnitude of the impact to groundwater decreases with distance from the injection center, and, the timing of the onset of impact increases in time with distance. There is no impact on groundwater pH at hypothetical well location 4 because the well is located outside the CO_2 plume. In contrast to CO_2 leakage, brine leakage to the USDW occurs at all four hypothetical well locations, resulting in impacts to groundwater at all locations, although the magnitude of impact decreases with increasing distance from the center of injection.

The ellipse in Figure 2-31 defines the risk-based AoR for Site 7. The estimated AoR has a radius between 8,295 m (27,215 ft) and 9,205 m (30,200 ft), corresponding to an area of 234 km^2 (90 mi^2; 57,600 acres). Although this method is conservative (because it assumes an open [uncemented]) well bore connects the injection zone to the USDW, the AoR is smaller than the EPA AoR (104 mi^2).

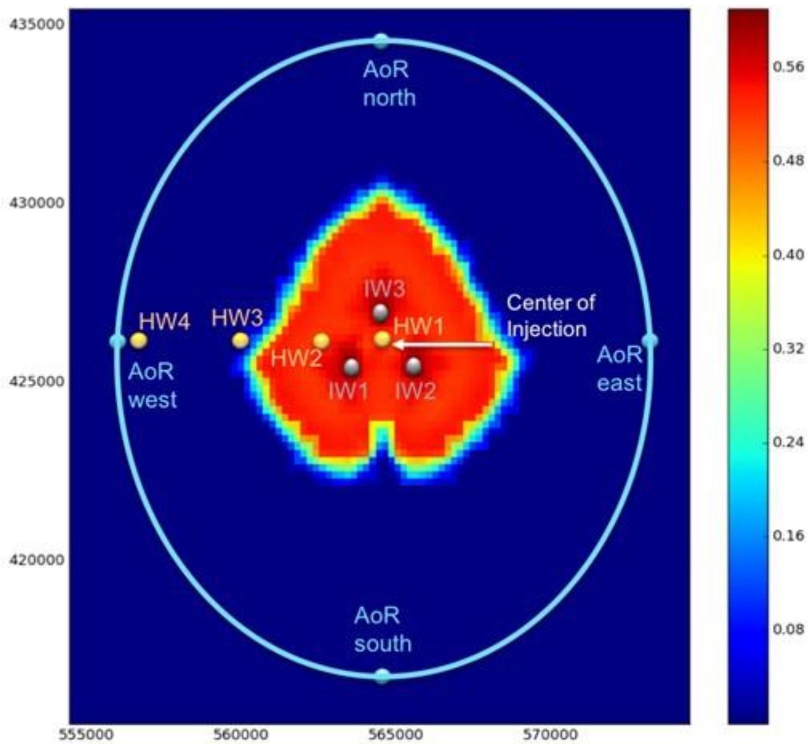

Figure 2-31. AoR as determined by the area inside which there is a predicted impact to the USDW from CO_2 or brine leakage through an open (uncemented) borehole.

2.4.2 Potential Impacts of CO_2 or Brine Leakage through Legacy Wells

The toolset provides a risk-based method of evaluating CO_2 or brine leakage through legacy wells. Groundwater impacts through cemented wellbores and known well locations were calculated using the same approach used to calculate the risk-based AoR; however, the open wellbore assumption was replaced with permeability data representative of cemented wellbores. A limited number of oil and gas wells are located around Site 7 and only two legacy wells were identified that were drilled to depths below the caprock (Figure 2-32). In this analysis, the two legacy wells that fall within the AoR and are likely to penetrate the CO_2 storage reservoir are considered. Figure 2-32 shows their location relative to the CO_2 and pressure plumes. One well is clearly within the CO_2 plume where CO_2 saturations are about 50%. The other well is to the south of the CO_2 plume close to the southern edge of the estimated AoR, where CO_2 saturations are low.

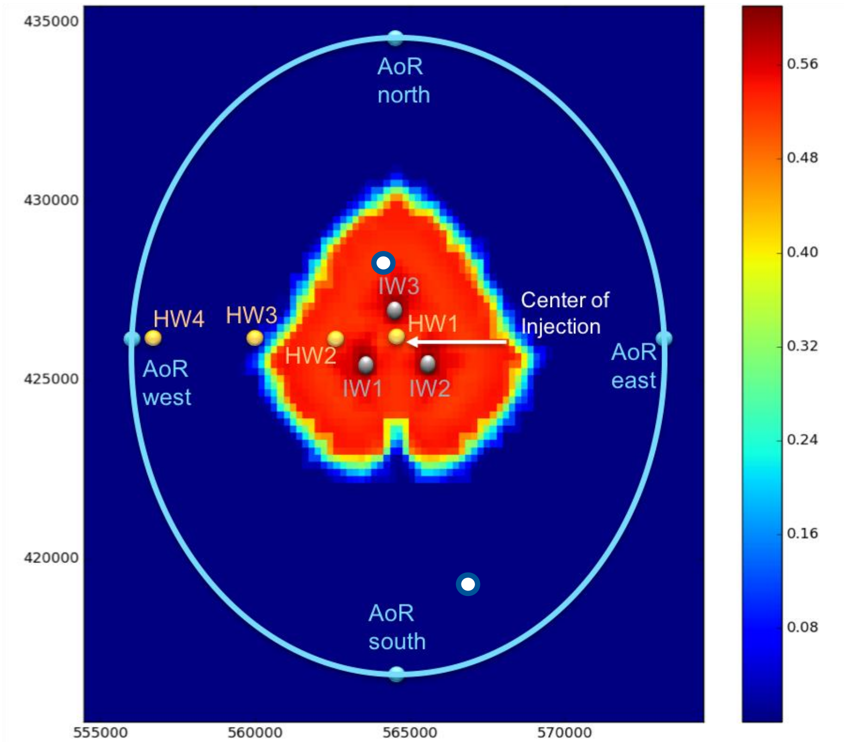

Figure 2-32. Approximate locations of the legacy wells (white circles) showing their penetration of the CO_2 plume (Well 1) and the pressure plume to the south of the CO_2 plume (Well 2). CO_2 plume is shown with colored contours of CO_2 saturation. The grid has units of meters.

A probabilistic assessment for known well locations was conducted using four predefined permeability distributions that are included in the NRAP-IAM-CS: the Alberta model; the Gulf of Mexico model; the FutureGen Low model; and the FutureGen High model. A total of 3,000 model realizations were run. Each realization calculated the mass of CO_2 and brine influx to the USDW, as well as the impact that influx would have on shallow groundwater quality. The probabilistic calculations using the default permeability distributions showed minimal influx, with most realizations yielding no influx and no impact to the groundwater. *Overall, the analysis suggests no risk to the overlying aquifer from CO_2 or brine leakage through these two legacy wells.*

2.4.3 Summary of AoR and Leakage Potential for SPSS Saline Storage Reservoir Site 7

Table 2-14 provides a summary of AoR estimates calculated for the SPSS Site 7 Saline Storage reservoir. The EPA critical pressure AoR and the NRAP AoR are similar to one another but both are considerably larger than the simulated CO_2 plume area. The NRAP AoR is overly conservative because it assumes an open borehole is present that connects the injection zone to the USDW aquifer. The probabilistic leakage analysis, which replaces the open borehole assumption with probability distributions of cement permeability, shows this to be the case and concludes there is no risk to the shallow USDW aquifer. The EPA critical pressure AoR also assumes a hypothetical open borehole is present that connects the injection zone to the USDW aquifer, and it assumes any amount of influx to the USDW aquifer is unacceptable (i.e., it does not account for mixing like the NRAP method). Furthermore, many of the parameters describing the USDW aquifer were unknown and had to be estimated. Therefore, the EPA critical pressure AoR is also likely to be overly conservative. It is recommended that the AoR be defined by the modeled CO_2 plume area, but that area should include the effect of uncertainty in model parameters that affect plume area.

Table 2-14. Summary of AoR estimates.

Method	Area	
	mi^2	acres
50 MMT CO_2 Plume Area	21.7	13,900
Pressure Front	104	66,560
NRAP Risk-Based AoR	90	57,600

3.0 Source Assessment

This section discusses large CO_2-atmospheric emission sources in the vicinity of the subsurface storage complex for the CS-NMB project. As discussed in Section 2.0: Geologic Storage Sites, the subsurface storage area is a multi-county area in the northern part of the lower peninsula of Michigan that is coincident with the Northern Pinnacle Reef Trend. This study considered large CO_2 sources in the lower Michigan peninsula because of proximity to the subsurface storage complex.

The Northern Michigan Basin project team assessed large CO_2 point sources for connection to a central CCS complex. This section summarizes the characteristics of existing and planned sources in the project area and presents a subset of the most feasible sources for a CS-NMB project. This information was used to support the project definition and integration effort (Task 4).

The project team identified prospective CO_2 sources using a semi-formalized process. First, the team identified all large CO_2 sources in the study area that are expected to be operating in the 2024-2030 timeframe. This list was then narrowed based on total emissions and proximity to prospective geological storage sites. Finally, the project team examined industry-specific capture costs and operator interest in CCS to determine the most suitable candidates for CCS.

3.1 Source Identification Approach

The primary source of information for identifying CO_2 sources was the EPA's Greenhouse Gas Reporting Program (GHGRP) (U.S. EPA, 2017), which collects greenhouse gas (GHG) emissions data from larger emitters (i.e., sources with the potential to emit more than 25,000 tonnes of CO_2 per year, per 40 Code of Federal Regulations [CFR] Part 98).

Michigan has approximately 84 large CO_2 point sources with the combined potential to emit more than 90 MMT of CO_2 per year. These sources are summarized in Figure 3-1 based on their 2015 annual CO_2 emissions (MMT/year) as reported to EPA. These sources are displayed according to the facility type. EPA's GHGRP is a useful resource for obtaining a snapshot of the major CO_2 sources in a given area and time. However, the latest available data from GHGRP (2015) does not always reflect the current status of major emissions sources, particularly for coal-fired power plants, due to frequent changes in operation, ownership, and fuel source. These changes are the direct result of the general increase in natural gas production and the associated reduction in the commodity price of natural gas and wholesale electricity price. As a result, many of the region's coal-fired power plants have shut down or converted to natural gas since the latest round of GHGRP reporting. Therefore, the work performed as part of the Task 2 source assessment also leveraged several additional sources to obtain current information on CO_2 sources in the area. These sources include:

- EPA Emissions & Generation Resource Integrated Database (eGRID)
- Trade journals and local news reports
- State of Michigan Department of Environmental Quality
- DOE Energy Information Administration (EIA) Form 923

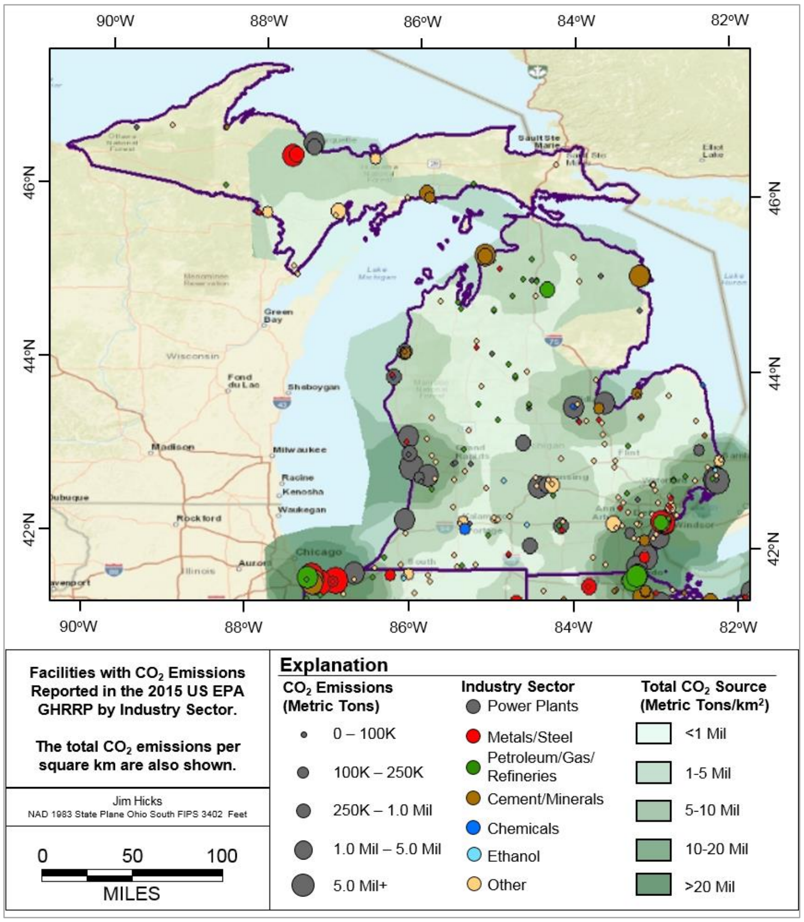

Figure 3-1. Facilities in the Northern Michigan Basin with 2015 CO_2 emissions reported in the U.S. EPA GHGRP. Facility type and the amount of CO_2 emissions per square kilometers (all facility types) are also shown. (U.S. EPA, 2016). In 2015, power plants accounted for over three quarters of the reported emissions in Michigan (77%) from 65 reporting facilities. Metal production was the next most CO_2 intense industry at 8% of the total emissions from 7 facilities followed by mineral production (6%) from 5 facilities. A total of eight reporting facilities account for the remaining 8% of the GHGRP reported emissions spread across several industrial types.

Information from these additional resources was used to update the list of sources and inform the project team's decision regarding which CO_2 sources were used in the economic analysis. More information on each of these data sources and their application to this effort is provided below.

- **EPA eGRID.** The eGRID is a comprehensive source of data on the environmental characteristics of almost all electric power generated in the United States. Unlike the GHGRP, these data are specific to each electricity generating unit (EGU) rather than aggregated for the entire facility. The environmental characteristics provided by eGRID include annual CO_2 emissions, net electricity generation, fuel type, annual hours of operation, and last reported EGU status (operational, retired, stand-by, etc.). The added resolution provided by eGRID data allows for more accurate quantification of CO_2 emission potential and capture costs compared to GHGRP data alone. The latest reported data, however, are for 2014, which means that there is still a data deficiency in terms of the current EGU status and ownership.
- **Trade journals and local news reports.** These sources provide useful information regarding changes in ownership, generation status, and fuel type for electricity generation in the study area. Events affecting the local community, such as plant closures or plant renovations, have a significant impact on the local economy and are generally well reported and readily available for

the intervening years since the latest GHGRP report. Industry trade journals provide specific information on the type of fuel conversion, affected EGUs, and planned changes in operation.

- **State of Michigan Department of Environmental Quality.** The MDEQ is the state agency responsible for permitting new emission sources and major changes to existing sources under Rule 201 of the Michigan Air Pollution Control Rules. As of this writing, 11 CO_2 sources are in various stages of the emissions permitting process, with potential CO_2 emissions calculated to be greater than 300,000 tonnes per year. The potential sources' stages in the permitting process range in maturity from the submittal of permit applications to the commencement of construction.
- **DOE/EIA**. DOE/EIA collects detailed monthly and annual electric power data on electricity generation, fuel consumption, fossil fuel stocks, and receipts at the power plant and prime mover level (Form EIA-923, Power Plant Operations Report and Instructions). The latest available data are from the August 28, 2017 release and detail the electricity generation for June 2017. The data contain up-to-date information about current facility and unit operators, fuel type, and operations but do not indicate planned changes of ownership or operation.

Using information collected from these data resources, the project team compiled a comprehensive list of major CO_2 sources in the region which are likely to remain active through 2030. A list of these industrial facilities and a review of CO_2 capture technology applicable to each industry is available in the Task 2 report of this project (Battelle, 2017).

3.2 CO_2 Capture Cost

Once the initial list of sources was developed, the cost of CO_2 capture was used to further sort the sources. The cost of capture was used as a main criterion for identifying large economically viable CO_2 sources located within a reasonable distance of the identified storage field candidates. The cost of CO_2 separation and compression is important to the viability of a CO_2 capture and storage project. A project with low capital and operating costs is more likely to attract investment at a lower risk premium and increases market competitiveness. For this reason, the cost of CO_2 capture and compression depends on several important factors, including the flue gas composition, pressure, and presence of competitively reactive gas constituents such as SO_2, NO_x, and particulate matter. For this initial screening, capture costs for candidate CO_2 sources were derived from two sources published by DOE/NETL.

The latest revision of the NETL Baseline Report (version 3) was used to estimate the cost of CO_2 capture and compression at coal-fired electricity generation facilities and NGCC units (DOE/NETL, 2015). These costs are shown in Table 3-1.

Costs for CO_2 separation and compression applied to industrial sources were derived from a DOE/NETL study published in 2014 (DOE/NETL, 2014). The costs shown in

Table 3-2 represent the retrofit costs for existing sources.

It is worth noting that multiple point sources may be present at a single facility and would require additional infrastructure (and possibly multiple process trains) to capture, dewater, and compress CO_2. Hence, facilities with larger point sources are most suitable to serve as CO_2 sources. Detailed information about specific point sources within a facility may not be available in all cases, such as with non-utility industrial sources.

Table 3-1. Cost estimates for CO_2 separation and compression from coal-fired and NGCC EGUs (DOE/NETL, 2015).

Technology	Cost ($/tonne of CO_2)
Sub-critical coal-fired facilities	$57
NGCC units	$72

Table 3-2. Cost of CO_2 capture from industrial sources (DOE/NETL, 2014).

Process	Retrofit Break-even Cost ($/tonne of CO_2)
High-Purity Sources	
Ethanol	$30
Ammonia	$27
Natural gas processing	$18
Ethylene oxide	$25
Low-Purity Sources	
Cement	$127
Lime manufacturing (aggregate processing)*	$127
Refinery hydrogen	$118
Steel/iron coke oven gas + power plant stack (COG+PPS)	$99
Coke manufacturing*	$72

*Inferred values based on similarities in flue gas composition to other processes for which better information is available.

3.3 Selected CO_2 Sources for the Establishment of a Regional CCS Hub

Following the capture cost analysis, a total of nine (9) existing and three (3) potential new CO_2 sources were determined to be attractive candidates for the establishment of a regional CCS hub based on total and potential future CO_2 emissions, location, and industry-specific characteristics. These sites span multiple industrial categories including electricity generation, cement production, and steel production. Several large emitters were not included in this list as they are deemed to be non-viable because of their location or other specific factors. The petroleum refinery in Detroit, for example, is not a likely candidate for CO_2 capture for this project because of the difficulties in establishing a CO_2 transport pipeline through an urban setting. Even in the selected shortlist, the high cost of capture from some industrial sources, such as cement plants, could make them less attractive as a potential source, despite suitable location. It is also possible that the capture system installation may be preferred only for new sources, where a fully integrated and cost-effective system can be developed as part of initial facility design. The nine (9) existing sources are summarized in Table 3-3. Three (3) new sources meeting these criteria are described in Table 3-4. The location of these 12 sources is shown in Figure 3-2.

The 12 CO_2 emission sources listed in Table 3-3 and Table 3-4 are the most promising existing or planned sources in the NMB for CO_2 capture as part of the regional storage hub. This list was further screened based on receiving positive feedback from the source owner via networking and team building efforts in Task 5. Based on these efforts, four (4) sources from the list of 12 were selected to carry forward into the economic analysis. The networking and team building task will continue beyond this initial pre-feasibility phase and attempt to attract interest from additional CO_2 sources. The four (4) sources include:

- The Wolverine Alpine natural-gas power generation facility together with the DCP Midstream Partners natural gas processing plant, both located in Otsego County;
- Project TIM, a planned state-of-the-art steel-manufacturing facility in Shiawassee County;
- A potential new natural-gas power generation facility with the new NetPower technology, assumed location Otsego County; and
- A potential new natural-gas power generation facility with NGCC technology, assumed location Otsego County.

Table 3-3. Nine existing CO_2 semi-finalist sources that were evaluated to identify candidate sources for the establishment of a regional CCS hub.

Name	Type	Description	Annual CO_2 Emissions (tonnes/yr)	Eliminated/Retained in Final Scenario Analysis
Dan E Karn Generating Station	Coal-fired and natural-gas fired power plant	The Karn generation station is located near Bay City, MI. This facility consists of two coal-fired units and two oil and natural gas-burning units.	The two coal units each have the potential to emit around 1.7 MMT of CO_2 per year (i.e., each unit produces the target CO_2 output for this project). Only one of the four natural gas units has had significant operation time in the past five years. This unit emitted 1.3 MMT of CO_2 in 2015. The other three units have minimal emissions (less than 300 thousand tonnes per year).	Eliminated due to high likelihood of generation unit closure.
LaFarge Cement	Cement manufacturing	Located near Alpena, Michigan, on the eastern shore of Michigan's Lower Peninsula. Although the LaFarge plant is a large CO_2 source, the cost of capture from a cement plant is high due to the degradation of amine and ammonia solvent by SO_x, NO_x, and particulate matter. The plant is owned and operated by LaFarge North America.	The plant has total emissions of approximately 2.3 MMT of CO_2 per year.	Eliminated due to high CO_2 capture cost
St. Marys Cement Plant	Cement manufacturing	Located near Charlevoix Michigan, in the northern reaches of the study area. Capturing CO_2 from the St. Marys facility would require a large investment in pollution control equipment to reduce amine degradation similar to the LaFarge Plant. The St. Marys facility is owned by Votorantim Cimentos North America	The plant emits about 1.0 MMT of CO_2 per year.	Eliminated due to high CO_2 capture cost
DCP Midstream Partners	Natural gas processing and separation facility	Located near Gaylord, Michigan, in Otsego County. DCP's facility is a likely candidate for future discussions regarding the capture and sequestration of a greater proportion of their CO_2 stream	The facility currently emits approximately 400 thousand tonnes of CO_2 per year, although emissions are expected to decline with reduced upstream production. The vast majority of CO_2 emissions is currently utilized for EOR in the region.	Eliminated due to limited additional CO_2 availability beyond current capacity.
TES Filer City Station	Combined heat and power facility utilizing two boiler	The electric output is sold pursuant to a long-term power purchase agreement with Consumers Energy Company.	Capable of producing an approximate 400 thousand tonnes of CO_2 per year. Since a portion of the fuel is biogenic, there is	Eliminated due to high number of facility

Table 3-3 (continued). Nine existing CO_2 semi-finalist sources that were evaluated to identify candidate sources for the establishment of a regional CCS hub.

Name	Type	Description	Annual CO_2 Emissions (tonnes/yr)	Eliminated/Retained in Final Scenario Analysis
	units burning both coal and wood.	Process steam is sold to an adjacent industrial customer (Louisiana Iron Works). The facility is owned by CMS Energy, KCR Power, Western Michigan Cogeneration, and Louisiana Iron Works.	potential for achieving net negative emissions	stakeholders and limited capture capacity.
Michigan Power	NGCC heat and power plant	Located in Ludington, Michigan. and is owned by Arclight Capital Partners.	The facility has a potential emission capacity of approximately 600 thousand tonnes of CO_2 per year	Eliminated due to high number of facility stakeholders and limited capture capacity.
Alpine Simple Cycle (NGCC Retrofit)	Natural-gas (simple cycle) fired power generation	Located near Elmira Township, in Otsego County, Michigan and owned by Wolverine Power Supply Cooperative operates two simple-cycle natural gas EGUs Wolverine has indicated to members of the project team that there are plans to refit these two units as a combined-cycle facility before the 2025 project start date. The facility upgrade would allow for the capture of CO_2 emissions from the plant.	The combined potential emissions from these two units is approximately 1.9 MMT per year based on a maximum capacity factor.	Retained
Midland Cogeneration Venture	NGCC power plant	Located near Midland, Michigan, The Midland Cogeneration Venture facility is one of the largest NGCC operations in the country. The owner and operator of this facility is Midland Cogeneration Venture.	The facility contains 18 EGUs which produced a combined 2.8 MMT of CO_2 in 2015 but have an estimated potential to produce 5.8 MMT per year. However, individual EGUs have the potential to emit a maximum of 0.5 tonnes of CO_2 per year. Hence, this facility could serve as a single source of the total CO_2 requirement but would require adding CO_2 capture to multiple units.	Eliminated due to high combined cost of capture and transport.
J H Campbell	Coal-fired power plant	Located in Port Sheldon, Michigan. The facility is owned and operated by CMS Energy with the exception of a 4% stakeholder share split between Michigan Public Power Agency and Wolverine Power Supply Cooperative.	Three remaining EGUs with emissions potential range from 1.9 to 6.3 MMT of CO_2 per year, for a combined emission capacity of approximately 10.5 MMT per year.	Eliminated due to high combined cost of capture and transport.

Table 3-4. Three potential new CO_2 sources that are candidates for the establishment of a regional CCS hub.

Name	Type	Description	Annual CO_2 Emissions (tonnes/yr)	Included/Retained in Final Scenario Analysis
Project TIM	Iron and steel manufacturing	Proposed location is in Shiawassee County. The new facility would be a 24M ft^2 facility that would be the “greenest facility of its kind anywhere in the world” (Livengood, 2017). Although this project is in the early stages of development, the new facility has potential to be a significant source of CO_2 requiring an approximately 200-mile-long pipeline to link the source to storage sites in the Michigan Basin study area	Minimal facility-specific information is available at this time. However, verbal communications with Project TIM staff confirm that the facility will produce sufficient emissions to meet the 1.7 MMT per year goal for CO_2 capture.	Retained
Potential New Source (Net Power)	Power generation, innovative natural gas combustion process	Net Power is a technology company based on an innovative natural gas combustion process, the Allam Cycle, which burns natural gas in a pure oxygen environment. Although the process has yet to be demonstrated at scale, the company’s early success suggests that the process may be used to produce electricity as well as a relatively pure, pressurized CO_2 by-product. This technology may be incorporated into a new electricity generation facility located near the selected CO_2 storage site.	A new facility located in Michigan could be sized to provide adequate CO_2 for a capture project. However, specific information about a project design would be needed in order to estimate potential emissions.	Retained
Potential New Source (NGCC)	Power generation, natural gas combined cycle	Natural gas combined cycle units are an attractive option for replacing Michigan’s aging fleet of coal fired generators. As such, a new NGCC facility equipped with CO_2 capture is a potentially viable option in the NMB region. This new potential source could be sited near the storage field.	Based on performance modeling using the Integrated Environmental Control Model, a NGCC unit would need to produce approximately 700 MW_{net} to provide the requisite 1.7 MMT of CO_2.	Retained

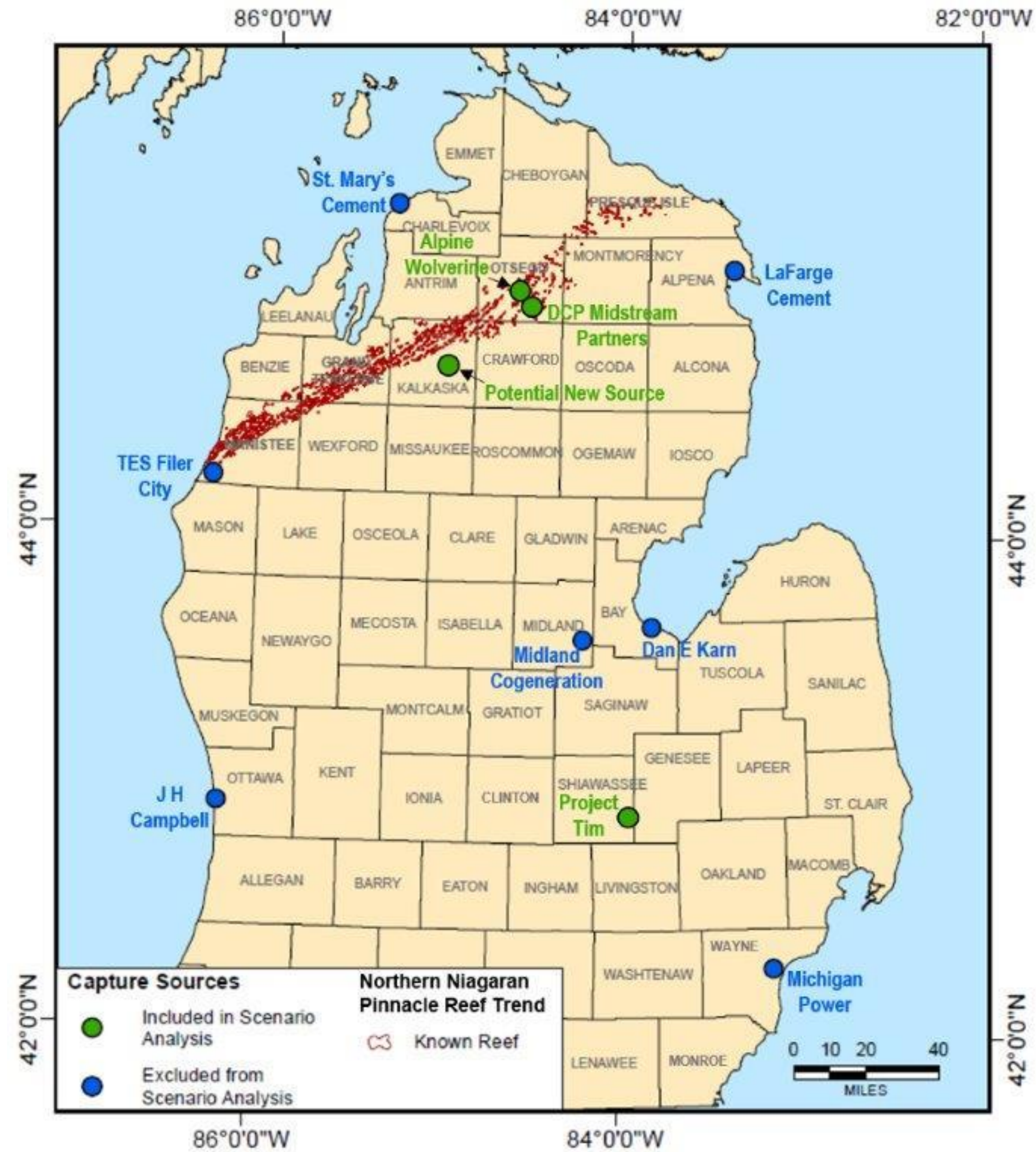

Figure 3-2. Twelve most promising existing or planned CO_2 emission sources in the Northern Michigan Basin for the CS-NMB regional storage hub.

4.0 CO_2 Pipeline Routing and Preliminary Design

As discussed in Section 3.0 Source Assessment, four CO_2 sources were identified from a total of 84 sources in the lower Michigan peninsula as potential CO_2 sources for the CS-NMB storage complex. These four sources were carried forward to the CS-NMB cost estimate and economic analysis (Section 6). Implementing CCS requires infrastructure (i.e., pipelines) to move the CO_2 from the source to the storage site. This section describes a preliminary pipeline routing analysis performed to provide a basis for the cost estimate and economic analysis.

4.1 Scope

A preliminary pipeline routing analysis was performed for each source-storage scenario listed in Table 4-1 and Table 4-2. A separate pipeline analysis was not performed for the source-sink scenarios that use SPSS Saline Storage Site 7 (see Table 4-3); instead, the economic analysis (see Section 6.0 in this document) assumed pipeline costs for Site 7 are equivalent to the Site 2 pipeline costs.

Table 4-1. Eight (8) CO_2 source and storage options that include SPSS Saline Reservoir Site 2

CO_2 Source	CO_2 Storage Options[a]
Wolverine (natural gas power) + DCP (gas separation plant)	Saline SPSS Site 2 (100%)
	Saline Site 2 (50%)/EOR (50%)
Potential New Source (NET Power)	Saline SPSS Site 2 (100%)
	Saline Site 2 (50%)/EOR (50%)
Potential New Source (NGCC)	Saline SPSS Site 2 (100%)
	Saline Site 2 (50%)/EOR (50%)
Project TIM (steel and power)	Saline SPSS Site 2 (100%)
	Saline Site 2 (50%)/EOR (50%)

Table 4-2. Four (4) CO_2 source and storage options that include 100% EOR storage

CO_2 Source	CO_2 Storage Options[a]
Wolverine (natural gas power) + DCP (gas separation plant)	Niagaran Pinnacle Reefs CO_2-EOR (100%)
Potential New Source (NET Power)	Niagaran Pinnacle Reefs CO_2-EOR (100%)
Potential New Source (NGCC)	Niagaran Pinnacle Reefs CO_2-EOR (100%)
Project TIM (steel and power)	Niagaran Pinnacle Reefs CO_2-EOR (100%)

4.2 Method

Pipeline routing was conducted for this study using the SimCCS Software (Middleton and Bielecki, 2009). The SimCCS program is designed to select a set of pipelines and/or pipeline routes from existing pipelines and rights of ways (ROWs) to connect a set of CO_2 sources to a set of storage sites for minimal possible cost. This feature of CCS was not used because the selected sources can individually meet the 1.7 MMT/year CO_2 emission target; therefore, the program was used to determine the optimal pipeline route from each individual CO_2 source to each storage option.

4.3 Results

The SimCCS model provided pipeline length for each source-sink scenario together with the elevation difference and required pressure change between pipeline inlet and outlet was used to develop a preliminary pipeline specification (diameter, supplemental compression) for 12 source-sink scenarios (Table 4-1 and Table 4-2) using the DOE NETL CO_2 Transport Cost Model (DOE/NETL-2014/1667).

This model was also used to calculate pipeline capital and operating costs. Costs are not presented in this section but are presented in Section 6.0 Economic Analysis of this document.

The resulting pipeline routes for the SPSS saline reservoir Site 2 and the 100% EOR storage scenarios are provided in Figure 4-1 through Figure 4-3. Table 4-3. Pipeline Design Assumptions and Calculated Diameter and Supplemental Compression Requirement summarizes the calculated pipeline diameter and number of booster pumps required for each scenario. It also provides the input assumptions for each scenario – i.e., pipeline length, elevation change, inlet pressure, outlet pressure requirement. Outlet pressure requirement is normally determined from CO_2 injection modeling which provides an estimate of the necessary bottom-hole pressure in the CO_2 injection well and in turn is used to calculate required wellhead (injection) pressure (i.e., pipeline outlet pressure). Since a CO_2 injection model was not developed for each storage site scenario, the outlet pressure requirement was assumed to be 1,850 psi for all scenarios, and inlet pressure was assumed to be 2,200 psi for all scenarios. The latter assumption follows the assumptions used by NETL's Baseline Report (DOE/NETL, 2015). The initial compression minimizes the risk of phase changes during transportation and reduces compression or pumping costs during transit. The high initial pressure means that the CO_2 pressure at the storage end of the pipeline will exceed the wellhead pressure required for storage in either storage formation (SPSS or Niagaran reefs), despite the pressure decline caused by friction during transport. The costs associated with compression are, therefore, relatively conservative but will require additional optimization, including the potential for lower initial compression and installation of booster pumps, based on more extensive routing studies.

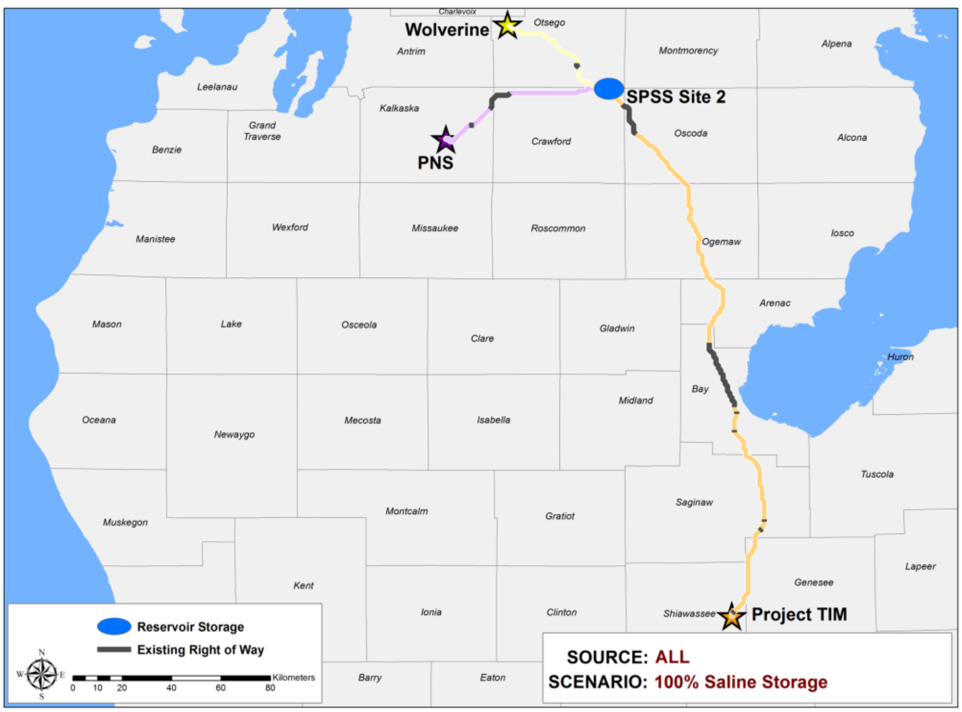

Figure 4-1. Illustration of pipeline routing for (left) 100% (50 MT CO_2) Saline Storage Scenario for SPSS Site 2 and four sources (Wolverine, Potential New Sources [PNS [NGCC and NetPower], and Project TIM).

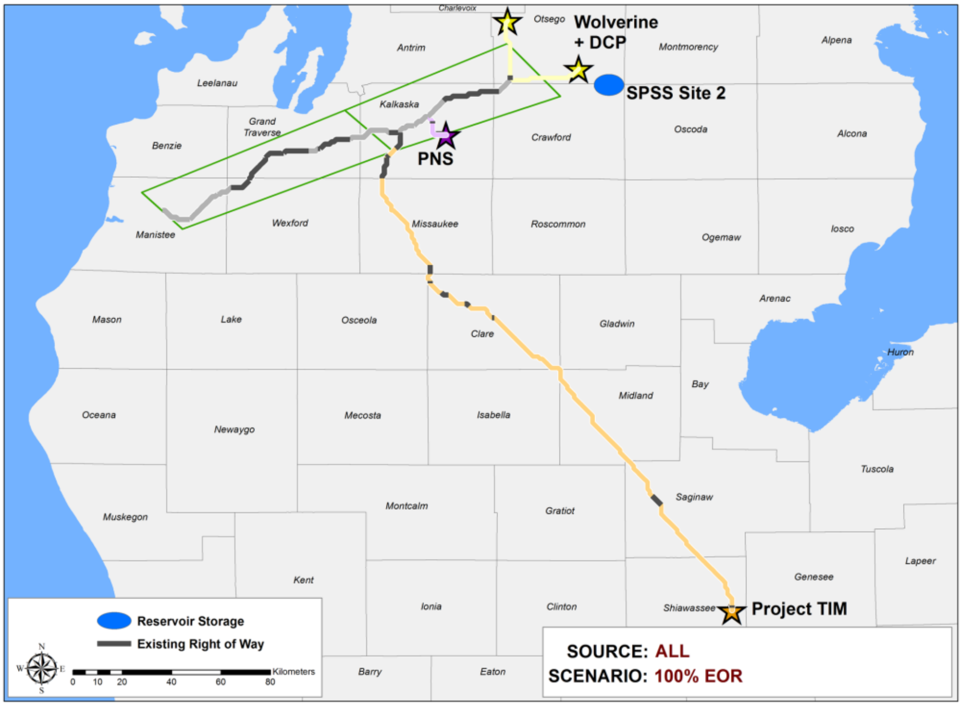

Figure 4-2. Illustration of pipeline routing for 100% (50 MMT CO_2) EOR storage scenario for four sources (Wolverine, PNS [NGCC and NetPower], and Project TIM); each green rectangle represents an area with Niagaran Reef storage capacity of 25 MMT. Not shown is a hybrid case in which the CO_2 is divided between saline storage and CO_2-EOR; in this case, only one group of EOR reefs (one green rectangle) is needed to store 25 MMT CO_2.

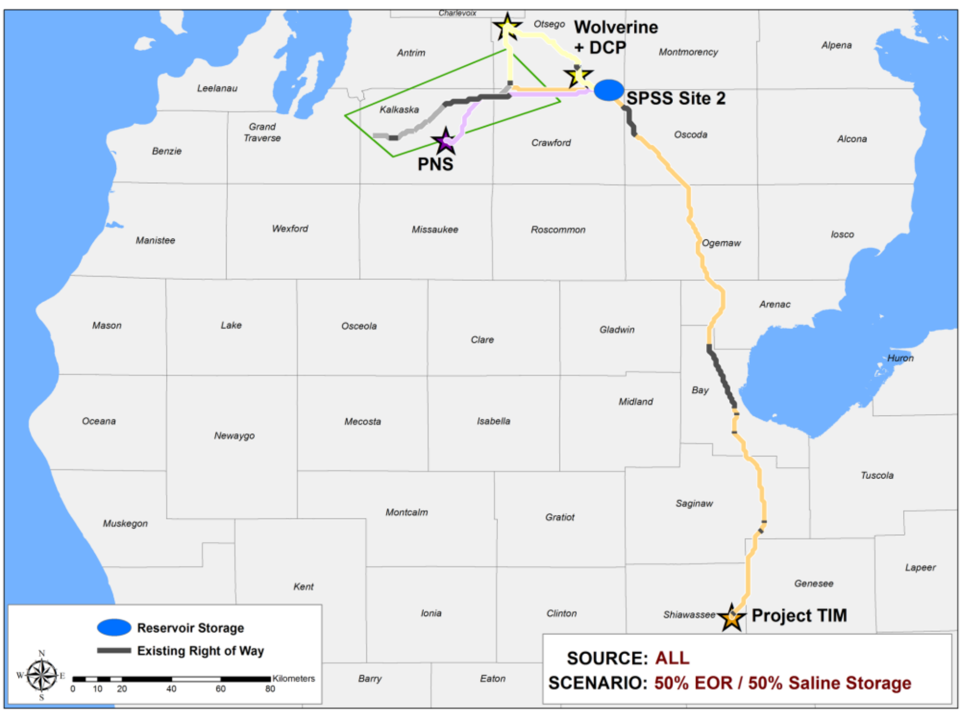

Figure 4-3. Illustration of pipeline routing for hybrid storage case in which the CO_2 is divided equally between saline storage and CO_2-EOR; in this case, only one group of EOR reefs (one green rectangle) is needed to store 25 MMT CO_2.

Table 4-3. Pipeline Design Assumptions and Calculated Diameter and Supplemental Compression Requirement

CO_2 Source	CO_2 Storage Option[a]	Distance (mi)	Pinlet/Pout (psi)	ΔElev (ft)	ID/OD (in)	Booster Pumps
Wolverine (natural gas power) + DCP (gas separation plant)	Saline SPSS Site 2 (100%)	21	2200/1850	728.4	8.78/12	0
	Saline Site 2 (50%)/EOR (50%)	74	2200/1850	-49	11.41/12	0
	Saline SPSS Site 7 (100%)	a.	a.	a.	a.	a.
	Saline Site 7 (50%)/EOR (50%)	a.	a.	a.	a.	a.
	Niagaran Pinnacle Reefs CO_2-EOR (100%)	105	2200/1850	23	10.78/12	1
Potential New Source (NET Power)	Saline SPSS Site 2 (100%)	17	2200/1850	223	8.78/12	0
	Saline Site 2 (50%)/EOR (50%)	46	2200/1850	223	10.64/12	0
	Saline SPSS Site 7 (100%)	a.	a.	a.	a.	a.
	Saline Site 7 (50%)/EOR (50%)	a.	a.	a.	a.	a.
	Niagaran Pinnacle Reefs CO_2-EOR (100%)	83.2	2200/1850	68.9	11.82/12	0
Potential New Source (NGCC)	Saline SPSS Site 2 (100%)	17	2200/1850	223	8.78/12	0
	Saline Site 2 (50%)/EOR (50%)	46	2200/1850	223	10.64/12	0
	Saline SPSS Site 7 (100%)	a.	a.	a.	a.	a.
	Saline Site 7 (50%)/EOR (50%)	a.	a.	a.	a.	a.
	Niagaran Pinnacle Reefs CO_2-EOR (100%)	83.2	2200/1850	68.9	11.82/12	0
Project TIM (steel and power)	Saline SPSS Site 2 (100%)	154	2200/1850	534.8	11.15/12	2
	Saline Site 2 (50%)/EOR (50%)	183	2200/1850	534.8	11.52/12	2
	Saline SPSS Site 7 (100%)	a.	a.	a.	a.	a.
	Saline Site 7 (50%)/EOR (50%)	a.	a.	a.	a.	a.
	Niagaran Pinnacle Reefs CO_2-EOR (100%)	225	2200/1850	285.4	11.76/12	2

a. A SimCCS pipeline routing analysis was not performed for SPSS Saline Storage Site 7; instead, the economic analysis (see Section 6 in this document) assumes pipeline costs for Site 7 are equivalent to the Site 2 pipeline costs.

5.0 Non-Technical Considerations

This section discusses important non-technical issues that affect the viability of the CS-NMB project, including: environmentally sensitive areas; legal and regulatory considerations; and public acceptance, and formation of a team capable of addressing technical and non-technical challenges specific to commercial-scale deployment of the CO_2 storage project (team building). An analysis of these issues during Phase I did not identify any major issues or barriers that would preclude furthering the development of the CS-NMB storage site complex concept.

5.1 Regional Proximity Analysis

A regional proximity analysis was completed for the selected areas to confirm that sensitive environmental areas, pore space ownership, population centers, resource development, and pipeline routing issues would not present significant challenges for the CS-NMB project. The analysis considered future project development, based on typical National Environmental Policy Act (NEPA) environmental assessment factors. Overall, the low population density, existing oil and gas operations, and regulatory experience provide a favorable setting for the project. Minor issues related to wetlands, endangered species, and land use will require consideration for development; however, major obstacles to the project do not exist. Ultimately, the study area was determined to contain many viable storage areas that will not interfere with environmentally sensitive areas.

Protected Sensitive Areas. Environmentally sensitive areas were ordered into one of five categories, based on land characteristics and associated project requirements.

1. Open areas include National Land Cover Database (NLCD) (United States Geological Survey [USGS], 2014) designations of grassland, cultivated crops, pasture, or shrubland/scrubland. They are preferred for siting wells, equipment, or pipelines.
2. Wooded areas include NLCD designations of deciduous evergreen or mixed forests (USGS, 2014). They can be used to stage wells, equipment, or pipelines.
3. Surface obstacles include wetlands (United States Fish and Wildlife Service [U.S. FWS], 2017a) and 100-year floodplains (Federal Emergency Management Agency [FEMA], 2017). They can be used to site wells, equipment, or pipelines with a permit or other consideration.
4. Surface barriers include areas with a Protected Areas Database of the United States (PAD-US) Gap Analysis Program (GAP) designation of #1 or #2 (protected for wildlife/biodiversity) (USGS, 2016a); conservation easements (MDEQ, 2009); critical habitats (U.S. FWS, 2017b); critical dunes (MDEQ, 1989); NLCD light, medium, and heavy developed areas (USGS, 2014); scenic rivers (Bureau of Land Management [BLM], National Park Service [NPS], U.S. FWS, and U.S. Forest Service [USFS], 2017); surface water (USGS, 2016b); National Historic Places Registry (NHPR) sites (National Parks Service, 2017); wellhead protection areas (MDEQ, 2015); or existing surface mineral extraction (MDEQ, 2015). These areas should be considered when siting, either by legal requirement and/or potential complications with public acceptance.
5. Subsurface obstacles include gas storage fields (MDEQ, 2015). These areas can be used to site wells with additional diligence but do not affect siting surface equipment or pipelines.

Storage Area Environmental Status and Planning. The storage areas of interest were also evaluated based on their classification and current standing, with respect to an array of environmental issues and standards.

Air Quality. The study areas are not listed as EPA National Ambient Air Quality Standards non-attainment for ozone, particulate matter, sulfur dioxide, or other multi-pollutants (EPA, 2016). The study area is not considered a sensitive location for climate and/or GHG emissions.

Geology and Soils. The study areas are in the northern High Plains physiographic province where moderate stream valleys or fingers are incised into glacial drift, which can have a thickness of several hundred feet and directly overlies bedrock. Soils in the study areas are mainly sand, loam, sandy loam, muck, peat, marl, and silt loam. Peat, muck, and marl may present difficulties for drilling, but most of these areas are wetlands where drilling and construction activities would require an additional permit.

Water Resources. Groundwater and surface water resources are widespread in the study areas. Small- to moderate-sized lakes are found throughout the area. The Au Sable, the largest river in the area, drains to the south. A reach of the Au Sable in Oscoda/Alcona counties is a scenic river (BLM, NPS, U.S. FWS, and USFS, 2017). The Cheboygan or Black River watersheds, north of Gaylord, drains to the north. Other smaller streams and creeks form a dendritic stream network. Numerous groundwater wells are drilled in the study area. The lowermost underground source of groundwater is generally the base of the glacial drift (400 to 700 ft) with yields of 200 to more than 1,000 gallons per minute (GWIM, 2006). Bedrock is used for drinking water in Kalkaska County, but most bedrock has high dissolved solids. No sole source aquifers for drinking water are in the area; however, wellhead protection areas are located near Gaylord, Grayling, and adjacent areas.

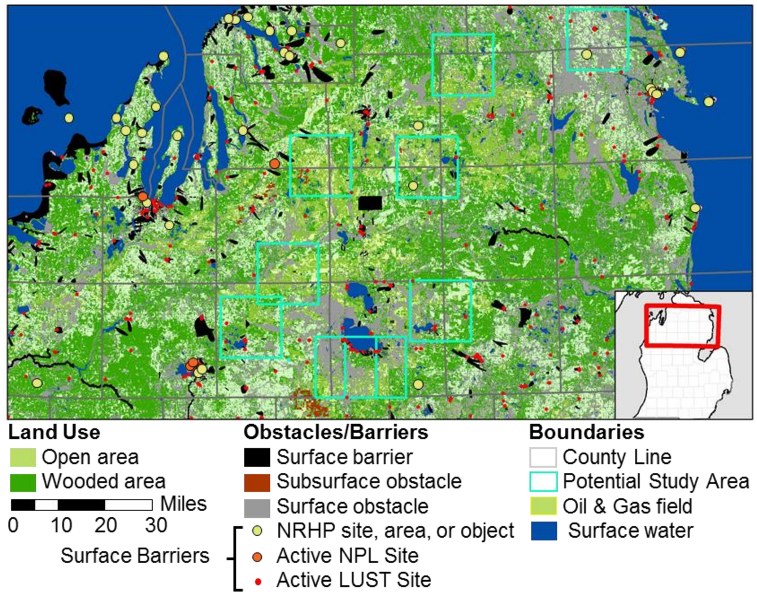

Figure 5-1. Map of simplified land use and project obstacles and barriers.

Wetlands and Critical Habitat. Wetlands are present throughout the study area, along streams and rivers and near peat and bog soil types (U.S. FWS, 2017a). Michigan's regulations allow land modifications in a wetland with a permit. Thus, wetlands areas can be considered for construction but are usually avoided for drilling oil and gas wells.

Protected Faunae and Plant Species. Five federally listed endangered species (Indiana myotis, Hungerford's crawling water beetle, Hine's emerald dragon fly, piping plover, and Kirtland's warbler) and three threatened species (northern long-eared bat, red knot, and eastern Massassauga rattlesnake) are found in the study area. Care will be taken to ensure that project activities do not exacerbate habitat loss and sedimentation and/or foster the expansion of invasive species for these and the florae and faunae protected by the state.

Parks and Recreation and Visual Resources. Large tracts of state and Federal lands are found near the potential sinks. In addition, several sites listed in the NHPR are in northern Michigan. Although there are parks and significant places in the area, the presence of oil and gas operations suggests that a CCS project is viable here. Care will be taken to limit the effect the project has on recreational areas or visual resources.

Contaminated Sites. All environmentally contaminated sites will be avoided when siting project infrastructure. Four active Superfund National Priorities List (NPL) sites are within the sinks area: Tar Lake in Antrim County, Northernaire Plating and Kysor Industrial Corp. in Wexford County, and Grand Traverse Overall Supply Company in Leelanau County (U.S. EPA, 2018). In addition, several open leaking underground storage tank sites can be found in the sinks area (MDEQ, nd). These sites are often in developed areas and are, thus, not targets for project infrastructure anyway. No nuclear contamination sites exist in the sinks area (Wall Street Journal, nd).

Population Centers. Many of the census block groups in northern Michigan have a population density of less than 50 people per square mile. The larger population centers around the potential study areas are Gaylord (Otsego County) and Denton Township (Roscommon County).

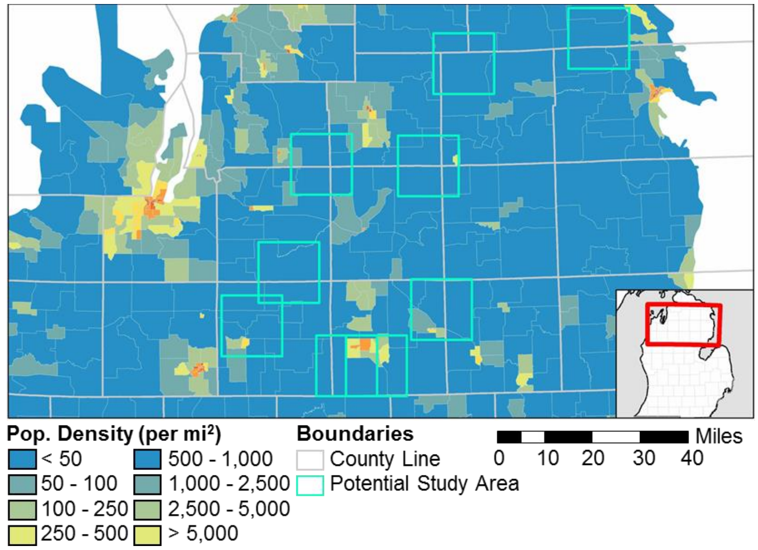

Figure 5-2. Population density of the study area (U.S. Census Bureau, 2016a, b).

Pore Space Ownership. The CS-NMB storage complex is in an active oil and gas production area, with almost all the natural gas production from the Antrim Shale and oil production from Niagaran reefs. In addition, several gas storage fields are located in the isolated Niagaran reefs. There is almost no production activity in the deeper SPSS in the area, which will help mitigate conflicts with mineral right owners. These activities are synergistic with the CS-NMB concept, wherein the Antrim Shale gas processing is the current source of CO_2, while the Niagaran depleted oil fields are used for CO_2-EOR and associated storage. Some large depleted gas reefs can also be used for CO_2 storage. The MDNR is the largest surface and pore space owner for the storage horizons. It manages and permits responsible use of subsurface and has provided a letter indicating its willingness to discuss the CS-NMB project siting. In the past, MDNR has permitted drilling of MRCSP test wells on its land for planned CCS projects. The project has identified other large property owners, who could offer additional storage space. As previously discussed, the well layout and site selection will be designed to maximize the surface and subsurface footprint in the MDNR and other larger properties and minimize the number of smaller pore space owners in the plume areas.

Resource Development. There is little risk of resource development conflicts for the project. The proposed storage zones include a combination of deep SPSS deep saline formation (isolated from oil and gas plays) and Niagaran Reef enhanced oil reservoirs. The only hydrocarbon interval deeper than the SPSS is the marginally producing Prairie du Chien, and unlikely to be targeted for future production. The Niagaran Reef EOR operations would supplement existing oil production in the region. Brine disposal injection wells in the region typically target shallower intervals like the Detroit River Group, mostly less than 3,000 ft deep. Solution mining is limited and focused on other zones. Geothermal is not well established and is unlikely to be over 8,000 ft deep. Mining is limited in the study area, and coal development was confined to areas mostly south of the sinks study area.

Pipeline Right of Ways. An evaluation of potential pipeline routes to proposed storage locations was completed based on publicly available information and contractors' industry knowledge. The analysis included identification of all major permit and regulatory requirements and regulatory gaps relevant to the constriction, ownership, and operation of the pipeline system. Major environmental considerations were also identified for the potential pipeline routes to potential storage areas within Michigan. A preliminary design basis for the pipeline system configuration was developed, including estimates on capital and operating cost methodology to be used in evaluating each of the pipeline system routes. In association with NRAP research, a preliminary capital and operating cost model was developed to estimate the net present value economics of the potential pipeline system routes, based on the CO_2 specification provided.

The pipeline routing analysis is also concentrated on using the existing ROWs. As a significant boost for CO_2-EOR and storage, Michigan has already amended its pipeline statutes to enable ROW acquisition for CO_2 pipelines in 2014 (Michigan House Bills 5254, 5255, and 5274).

5.2 Legal and Regulatory Considerations

This section addresses public acceptance, pore space rights, and long-term liability. It also presents information about current legal and regulatory conditions in Michigan that favor successful development of such a project. The project benefits from the fact that UIC Class VI permits would be implemented by EPA Region 5, the only EPA office that has experience issuing UIC Class VI permits to date. The project benefits strongly from a state agency, MDNR, willing to consider using state land for the saline reservoir storage site. MDNR manages large tracts of land where the CS-NMB project can be located, has a history of successfully stewarding oil and gas production and gas storage within public lands and has previously permitted drilling of MRCSP test wells on its lands. Similarly, MDEQ with authority to permit drilling of oil, gas, mineral, and test wells is also aware of the CS-NMB project. MDEQ has applied for primacy for authority to implement the UIC Class II permits that govern both EOR and brine disposal operations.

5.2.1 Role of State Policies towards Public Acceptance

The CS-NMB project is in an area of oil and gas production, including gas storage and brine disposal. Michigan's policies allow the use of state lands for subsurface activities, under MDNR and MDEQ regulations, with local public support. The State policies also provide legal framework for unitization and easements needed for oil/gas production, while protecting public and private property interests.

5.2.2 Pore Space Rights

Michigan law states that the underground storage space in rock absent of/evacuated of oil and gas belongs to the ***surface owner***. The ownership of the storage space is not the same as the ownership of the oil and gas unless all interests in a parcel of property are owned by the same person or entity. The court recognized that the right to store "foreign or extraneous minerals or gas" rests with the surface owner.

Michigan law also states that the property rights required to operate an underground field for gas storage are (1) access to the surface, (2) the right to use of the container, and (3) permission from the owner of the contents of the container, if any (whatever native gas and oil may remain in the container).

Most property rights are acquired by voluntary agreement between the proposed operator and the owner. However, aspects of eminent domain and compulsory participation are already in the statutes for EOR and pipelines. Amendments to the MPSC's and MDEQ's controlling statutes will be requested to extend these to CO_2 storage.

5.2.3 Strategy for Securing Any Necessary Pore Space Rights

The largest landowner in Michigan is the State of Michigan. Because of the vastness of the lands it administers, the proposed large-scale CO_2 storage project will very likely involve State of Michigan lands. The MDNR has established policies and procedures in place regulating operations on the surface and in the subsurface of the State of Michigan's lands, as well as trained and experienced technical staff. The MDNR staff's experience with MPSC-regulated natural gas storage operations and MDEQ-regulated CO_2 EOR operations will facilitate MDNR staff's evaluation of, and participation in, a large-scale CO_2 storage project. In addition to existing policies and procedures that allow use of state lands, the MDNR has indicated support for the CS-NMB project. There is a high probability state lands can be used for locating a CO_2 storage site.

In Phase I, the Battelle team initiated the process of securing MDNR approval for use of state-owned land, and this process would have been continued in Phase II, with the goal of securing state approval or, at a minimum, increasing the certainty that this will be possible. Private property is another alternative for the storage site. However, using private property can be more challenging because of the need to secure permission from multiple landowners.

5.2.4 Plan for Assumption of Long-Term Liability for Stored CO_2

Michigan does not have a regulatory mechanism to cover the long-term liability of CO_2 storage projects beyond the 30-year injection operations and 50-year post injection site care (PISC+SC) period, but a successful project is not anticipated to require significant liability coverage beyond this time span. CO_2 used for EOR is considered to be sequestered under existing state statutes. For this prefeasibility analysis, Battelle assumes that when the CFR requirements have been fulfilled and the site has been closed following approval by the EPA administrator, the owner and operator will have no further liability for the stored CO_2.

The economic analysis includes the costs associated with the CFR requirements in EPA's Class VI regulations. The owner or operator of a Class VI injection project is required to provide EPA with assurance that the costs for corrective action, injection well plugging, emergency and remedial response (ERR), and post injection site care (PISC+SC) are provided for, if the owner or operator fails to fulfill regulatory obligations. These cost assurances can be met through one or more allowed financial instruments. The financial instruments currently recognized in the regulations include self-insurance (corporate guarantee), trust funds, escrow accounts, insurance, surety bonds, and letters of credit.

5.3 Public Acceptance

During Phase I, the CS-NMB team assessed the viability of a commercial CO_2 storage complex by conducting a stakeholder analysis, in addition to developing a community outreach plan to ensure viability in future phases. The stakeholder analysis included a social characterization study of the 17 counties that are collocated with the potential saline storage sites and are along the Niagaran Reef trend and found conditions favorable for a commercial CO_2 storage site. Additionally, a community outreach plan was developed. The outreach plan was designed to enable the CS-NMB team to gain momentum with stakeholders for current and future phases of the CS-NMB project and ensure continued viability.

Social Characterization Study. During Phase I, Wade LLC conducted a preliminary social characterization of 17 counties in the NMB that are located in the general area where saline storage sites are most likely to be located. This work was based on online research and interviews with members of the project team who have experience in those counties. The final report presents a summary of findings for the entire 17-county study area, as well as a focused report for each county. The topics addressed in the study include political, economic, social, technological, environmental, and legal factors that could indicate or influence public attitudes toward the CS-NMB project.

Based on the assessment, it appears that the CS-NMB project could play a welcome and useful role as part of an integrated energy system. This part of the state already hosts growing EOR operations and contains several sources of CO_2. There is also a call to develop additional power sources to meet the growing demand for energy in the region. One of the challenges with large CO_2-EOR operations is that there is not always a constant, steady demand for CO_2. The CS-NMB project could provide some operational flexibility by providing in effect, buffer capacity. Socially, the 17-county area has a demonstrated suitability to host a large-scale CCS project.

- The region hosts a mature energy industry, which indicates public awareness of the basic operations for CCUS (e.g., well drilling, CO_2 pipelines, CO_2 compression and separation).
- Energy is one of the dominant economic drivers for the area. A recent MOGA study showed that the 17 counties in the study area generated roughly $1,720 million in total economic output in 2015, of which $485 million was in labor wages. This represents almost 20% of the state totals for total economic output and labor wages. In addition, the energy sector in these counties contributed roughly $27.5 million in severance taxes and $21 million in local property taxes to the state. Despite this performance, the counties in the study area are still recovering from the

economic recession and will likely find the potential economic benefits from the CS-NMB project attractive.

Other Information in Support of a CS-NMB Project. Stakeholder acceptance will be bolstered by the presence and work experience of the CS-NMB team, particularly Core Energy. Core Energy is a multigenerational oil business in Traverse City, Michigan, with a good reputation at the local and state levels. Battelle, as project lead for the MRCSP, has been successfully engaged with Core Energy in CCUS projects in the region for well over a decade. The CS-NMB project leaders bring a long-standing business presence, good reputation, and recognized technical expertise to the project that will facilitate stakeholder acceptance at the local and state levels.

The analysis of CO_2 sources and storage sites done for Phase I suggests that all counties in the study area could host a 50 MMT CO_2 storage site using the SPSS, a saline reservoir, as the host injection reservoir. In addition to the storage capacity available in the SPSS, the analysis also showed that there is additional CO_2 storage capacity (>200 MMT) in Niagaran reefs, which are present in a band crossing several counties in the study area. The social characterization shows that the counties where the reefs exist do not stand out as particularly attractive or unattractive in comparison to the other counties studied. They have a very strong energy presence and are grouped with the rest of the counties in terms of other economic indicators, such as average household income, poverty rates, and education levels.

No special social issues appear to exist with regard to the viability of the transportation or storage aspects of the project in either county. Indeed, given the strong presence of the energy industry, the demand for jobs, and the potential role that CO_2 storage could play in the energy industry, it is anticipated the project will be favorably perceived.

The likelihood of positive stakeholder support for the project has been borne out in the positive feedback obtained during the focused outreach conducted with key stakeholders. These stakeholders include public representatives, including Michigan Governor Rick Snyder, U.S. Representative Bergman and Michigan Representative Cole, who represent the project area at the Federal and state levels. They all provided enthusiastic support letters for the project. Some of the Michigan agencies have previously worked with Battelle and Core Energy for such issues as site access and regulatory approvals for drilling. The project team had planned to engage with these agencies during Phase II to address any regulatory gaps in acquisition of pore space rights, use of state lands for CCS operations, use of unitization for pore space, and options for managing long-term liability of the injected CO_2.

Outreach Plan. An outreach plan was developed for Phase II that was designed to build momentum with stakeholders and to serve as the foundation for future outreach efforts. There outreach plan has four main tasks: (1) finalize outreach goals and objectives, (2) establish an outreach team, (3) assess stakeholder perceptions and potential community issues, and (4) finalize and implement an outreach program.

The outreach team would have consisted of technical experts from Core Energy, Battelle, and other project partners; outreach experts from the project team; and potentially a local communications firm. The project would also draw on its advisors to assist with outreach. During Phase I, an assessment of stakeholder perceptions was initiated. The initial focus was on opinion leaders and stakeholders involved in the potential legal efforts. This focus would be expanded to those stakeholders directly involved with the project location. If the project moved ahead, the full range of stakeholders, their concerns, and perceptions of CCS and the project would be identified.

The outreach program was tailored to the needs of the project and the host communities. It would have involved such activities as the development of fact sheets and other communication materials, engagement with stakeholders, convening of meetings that include stakeholders and technical experts from the project team, other communications and engagement endeavors, and initial planning for the steps that would need to be taken in Phase III.

5.4 Team Building Activities

Development of a commercial CO_2 storage complex requires a broad range of capabilities and expertise, as well participation of entities who are able to provide business framework across the entire CCS value chain. In addition to technical experts, the desired team members include CO_2 source and supply companies, pipeline developers, storage and EOR site operators, and financial investors. As the project evolves through development stages, these team members may become host sites, equity partners, technical consultants, advisors, or stakeholders. The objective of the team building task during Phase I was to start developing a project team that can move the project towards Phase II. The team building involved working with the existing partners and identification of the potential new partners/participants in the project.

The existing team members for Phase I, included Core Energy, LLC (likely host company), Western Michigan University (geoscience expertise), Loomis Law (legal/regulatory expertise), Wade LLC (outreach), and PKM Energy Consulting (financial analysis). In addition, three national laboratories, Los Alamos National Laboratory, Pacific Northwest National Laboratory, and Lawrence Livermore National Laboratory provided support in the transport analysis and risk assessment tasks only. A number of all project team meetings were held during the Phase I to review existing data, plan the technical approach, and develop the overall long-term strategy for the project. These meetings are listed in Table 5-1 below.

Table 5-1. Scheduled Project Team-Building Meetings

Meeting	Description	Date
Internal Project Team Kickoff Meeting	Face-to-face meeting among Battelle task leads	2/28/2017
DOE Kickoff meeting	Face-to-face meeting hosted at NETL Pittsburgh site	4/14/2017
Project Technical Working Group Meeting	Internal discussion with task leads for planning	3/24/2017
Project Technical Working Group Meeting	Web conference with LANL	4/14/2017
Project Technical Working Group Meeting	Web conference with PNNL and LLNL	4/14/2017
Project Team Kickoff Meeting	Face-to-face with Battelle and team members (except National Labs)	4/27/2017
Project Technical Working Group Meeting	Face-to-face meeting at Western Michigan University	6/28-29/2017
Project Technical Working Group Meeting	Face-to-face with Battelle and team members (except National Labs)	7/11/2017
Project Technical Working Group Meeting	Face-to-face with Battelle and team members (except National Labs)	8/30/2017
Task 3 Collaborative Meeting	Wayne Goodman face-to-face meeting with Task 3 team for geologic analysis	9/26-27/2017
Project Technical Meeting with DOE-NETL	All Battelle CarbonSAFE Project meeting with Venkat for project overviews	10/4/2017
Collaborative Meeting with Core Energy	Face-to-face meeting with a potential source to discuss collaboration and working meeting with Core Energy	12/1/2017

Identification and outreach to the potential new team members was a second key aspect of the team building activities. This was specifically aimed at filling the gaps in CCS value chain from capture and transport to storage and engaging key stakeholders.

The identification of potential sources of CO_2 is the most critical gap in the team. Therefore, based on the findings of the source analysis task and networking through existing team members, several potential

CO_2 sources were identified. Battelle and/or Core Energy coordinated this outreach strategy. Discussions were held with the owners of existing sources such as the Wolverine natural gas fired plant in Otsego County, Tondu Corporation, and potential future source owners, such as the Project TIM steel plant, and NetPower Corporation. These discussions were successful in informing the companies about the overall CarbonSAFE project objectives and long-term plans. As a result, support letters for participation in Phase II were received from these companies. Involvement of companies with CO_2 capture expertise, such as the Mitsubishi Heavy Industry (MHI) was also sought for the CO_2 supply evaluation.

The CO_2 transport and pipeline development expertise are also a key factor in project success. This requires both the technical expertise in pipeline design and construction, and the regulatory and legal expertise for obtaining pipeline rights-of-way. Discussions were held with several companies with such expertise and one company with specific CO_2 pipeline experience was selected for participation in Phase II.

Development of CO_2 storage complex involves a team with diverse expertise. The existing team members already provide significant resources for evaluating and addressing geologic, legal, regulatory, financial analysis, and outreach issues. The participation of Core Energy represents the potential host site and operator for the project. The most critical remaining gaps were related to obtaining surface and subsurface access. As discussed in Section 5.2.2, the most attractive option for this is to work with MDNR to determine feasibility of using state lands for CO_2 injection wells. There is already a strong precedent in Michigan for environmentally responsible use of such lands for oil and gas related activities, including CO_2 injection for EOR, gas storage, and wastewater disposal. However, the exact processes for extending these activities to long-term CO_2 storage needs to be evaluated. For this purpose, MDNR was briefed about the project and they agreed to engage in further dialogue and discussions as the project evaluation continued. The storage complex development team building also included identification of vendors and subcontractors for the next feasibility analysis phase of the project, including companies for drilling, coring, logging, well testing, and seismic surveys.

Finally, as part of the stakeholder outreach, other state and local entities were also briefed on the project where relevant. Public officials including the local, state, and national elected representatives were briefed on the project goals and objectives and to obtain their feedback at an early stage.

6.0 Economic Analysis

This section describes the economic analysis methodology, assumptions and results for the integrated CO_2 source-transport-storage opportunities identified in northern Michigan as part of the CS-NMB program. Also discussed in this section are estimated financing needs and strategies necessary to develop, own and operate a successful project in this region. The economic analysis for CS-NMB focused on developing source-to-sink business case scenarios which were modeled using a comprehensive discounted cash flow financial model adapted from the FutureGen 2.0 integrated commercial CCS project. The results of this analysis help to demonstrate how an integrated capture and storage project can be economically viable and likely to be viewed positively by the public and other stakeholders.

6.1 Scenarios Analyzed

A source-to-sink business case scenario for the CS-NMB program consisted of a CO_2 source, pipeline, and storage site(s). The scenarios identified for the pre-feasibility phase (Phase I) of the project are listed in Table 6-1. CO_2 source and storage options evaluated in the economic analysis. Multiple CO_2 sources, rather than a single source, were considered in the analysis. These include: 1) the existing Wolverine natural gas-fueled power station in Otsego County that will be retrofitted to a combined cycle facility with CO_2 capture supplemented by CO_2 from the DCP natural-gas separation facility, also located in Otsego County (the Wolverine plant alone doesn't produce the required annual amount of CO_2); 2) a potential new source (PNS) assumed to be located close to the saline storage site(s) and the EOR fields that is a conventional NGCC facility with capture; 3) a second variation of the PNS that incorporates the emerging natural gas-fired technology being developed and built by NET Power, LLC, based on the Allam Cycle; and 4) Project TIM, a proposed steel manufacturing facility by New Steel, Inc. in Shiawassee County. Note that it was assumed that both variations of the PNS would be located at the same location (therefore, maps in this section showing source locations only show one location for the [two] PNS).

As required by the FOA a primary and secondary saline storage site was identified and modeled for the pre-feasibility phase. The two saline storage sites down-selected for detailed economic analysis are the SPSS Site 2 and Site 7 (these were discussed further in Section 3 of this report). CO_2-EOR, in 50/50 combination with saline storage and alone, was also evaluated as an alternate storage mechanism. CO_2-EOR is a thriving business in the study area and Core Energy, a key member of the Battelle CS-NMB team, could easily expand its existing operations to utilize and store up to the anticipated total 1.67 MMT per annum of CO_2 produced from the identified sources. Thus, a total of 20 business case scenarios (4 sources x 5 storage options), identified in Table 6-1. CO_2 source and storage options evaluated in the economic analysis., were evaluated in the economic feasibility analysis.

Table 6-1. CO_2 source and storage options evaluated in the economic analysis.

Project CO_2 Sources	CO_2 Storage Options[a]
Wolverine (NGCC retrofit) +DCP[b] Potential New Source (NET Power) Potential New Source (NGCC) Project TIM (steel and power)	Saline SPSS Site 2 (100%)
	Saline SPSS Site 2 (50%)/EOR (50%)
	Saline SPSS Site 7 (100%)
	Saline SPSS Site 7 (50%)/EOR (50%)
	EOR (100%)

a. % indicates portion of CO_2 going to saline storage and/or to EOR
b. DCP CO_2 can only be used for CO_2-EOR therefore, the two storage options that include 100% saline storage would acquire CO_2 only from the Wolverine Plant which produces slightly less than 1.67 MMT/yr.

Figure 6-1 and Figure 6-2 illustrate selected scenarios, including 100% saline storage at Site 2 for each of the identified sources (Figure 6-1) and 100% CO_2-EOR in the EOR fields (i.e., carbonate reefs) (Figure 6-2). The location of the EOR reefs are shown in Figure 6-1 by two green rectangles, each of which represent an area with sufficient number of reefs to store 25 MMT CO_2. The hybrid case in which the CO_2 is divided between saline storage (50%) and CO_2-EOR (50%) is not shown; in this case, only one group of EOR reefs (a single green rectangle from Figure 6-2) is needed to store 25 MMT CO_2. The availability of EOR (ongoing and expanded) as an option for stacked storage with saline storage is an attractive feature for the CS-NMB area, as this can help defray some of the capital and operating costs for saline storage, increasing the feasibility of the project.

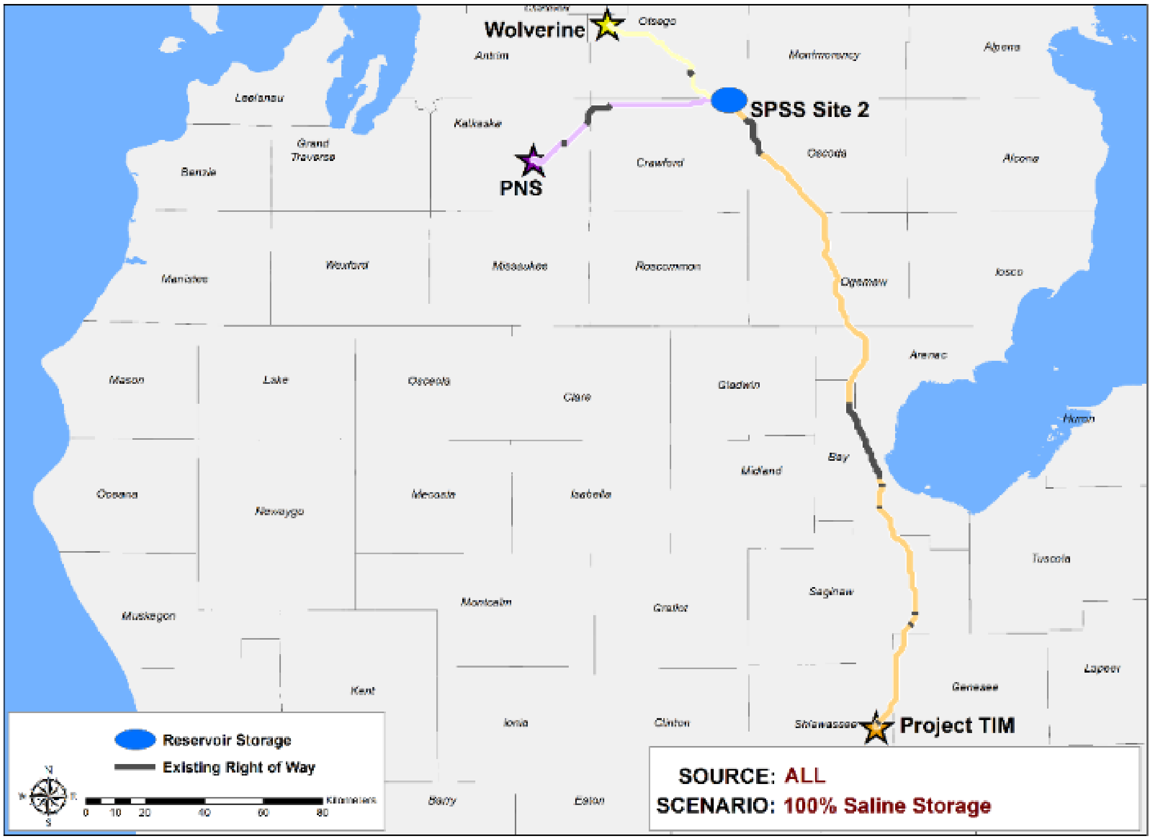

Figure 6-1. Illustration of source-to-sink scenarios with pipeline routing for 100% (50 MMT CO_2) saline storage at SPSS Site 2 from the four potential sources (Wolverine, PNS, and Project TIM).

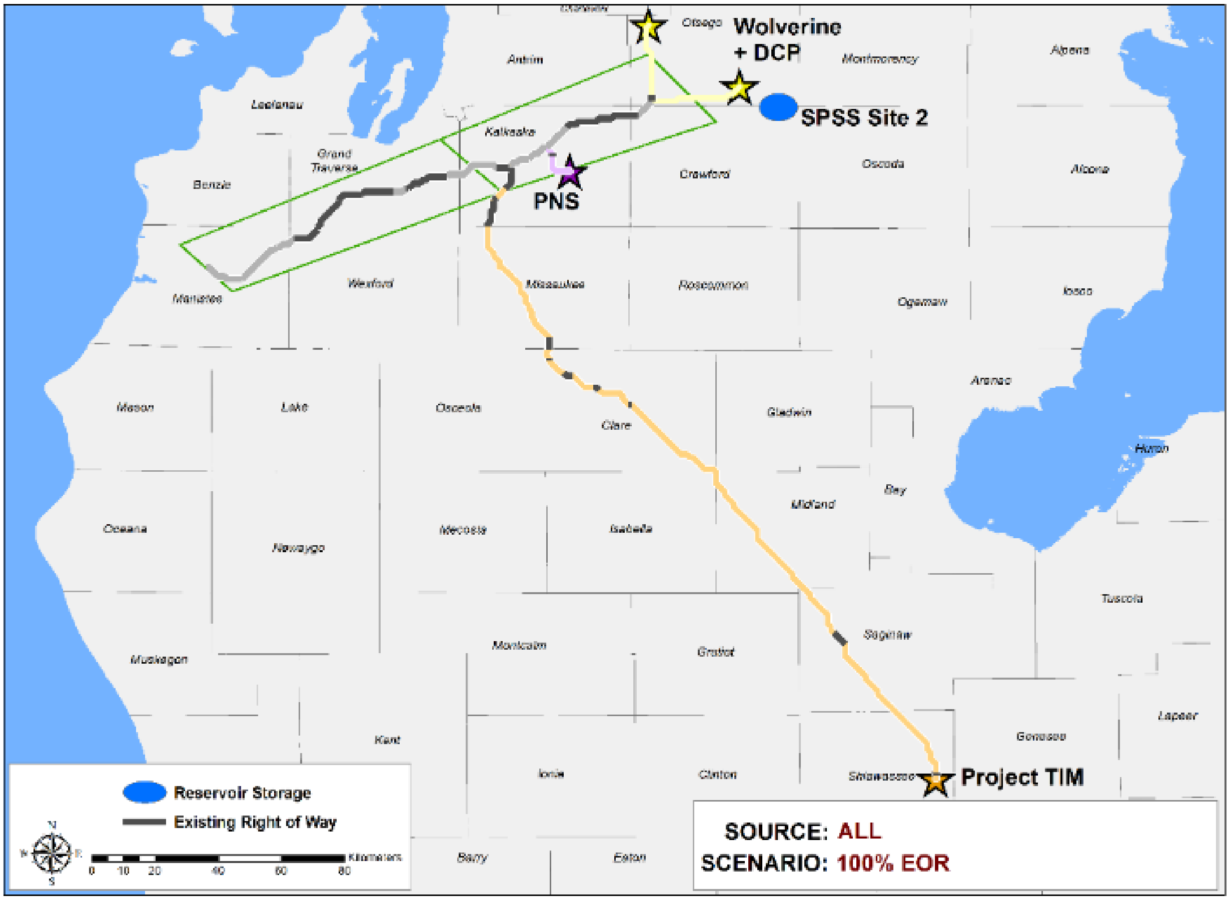

Figure 6-2. Illustration of source-to-sink scenarios with pipeline routing for 100% EOR storage scenario for the four potential sources (Wolverine, PNS, and Project TIM); each of the two green rectangles represents an area with Niagaran Reef storage capacity of 25 MMT.

6.2 Cost Analysis Methodology and Assumptions

The economic analysis for the CS-NMB pre-feasibility study relied on publicly available cost and performance information from DOE/NETL, Battelle in-house expertise, information from FutureGen 2.0, and expert judgement from members of the project team. In addition, information regarding proposed CO_2 pipeline routes and distances was developed using the Los Alamos National Laboratory's (LANL's) SimCCS program (Middleton and Bielicki, 2009). The cost estimating sources and method used for each component (source, pipeline and storage reservoir) of a scenario is described below.

6.2.1 Saline Storage Costs

Preliminary capital, operating, and Class VI permit financial responsibility costs were estimated using the Fossil Energy (FE) National Energy Technology Laboratory FE/NETL CO_2 OnShore Saline Storage Cost Model (DOE/NETL-2017/1669). Cost estimates were developed for a 50 MMT and a 25 MMT storage scenario for Site 2 and Site 7, respectively. The cost estimates derived from the NETL model reflect the input of site-specific geologic conditions from data collected by Battelle under the MRCSP project and the CS-NMB Phase I program and by academic institutions, such as Western Michigan University (WMU). Capital and operating costs estimated by this model were in constant 2008 dollars. Each scenario that incorporated saline storage assumed the project lifecycle (i.e., phases and durations) shown in Table 6-2.

Table 6-2. Project lifecycle used to calculate sequestration costs.

Project Phases	Duration (yrs)	Begin Year	End Year	Calendar Years:
Site Screening	1	1	1	2018 - 2018
Site Selection & Site Characterization	3	2	4	2019 - 2021
Permitting & Construction	3	5	7	2022 - 2024
Operations	30	8	37	2025 - 2054
PISC and Site Closure	25	38	62	2055 - 2079

Figure 6-3 and Figure 6-4 summarize the capital, operating and PISC and PISC/SC cost components estimated from the NETL storage model for 50 MMT and 25 MMT of storage capacity for SPSS Site 2 and 7. The operations and PISC/SC costs presented are the total over the 30-year forecasted operating period and proposed 25-year post-injection period, respectively. The difference in the cost for the two sites is due to variability in geologic properties of the SPSS across the northern Michigan storage complex study area. Site 2 requires six injection wells to inject 50 MMT of CO_2 and has a projected 50 MMT CO_2 plume area of 18,200 acres. Site 7 requires only three injection wells and has a projected plume area of 14,000 acres. These projected plume areas could potentially be further reduced by optimizing well configurations based on Phase II data (had Phase II been awarded). Additional avenues to be explored for significant cost reductions include use of state land and incentives for storage.

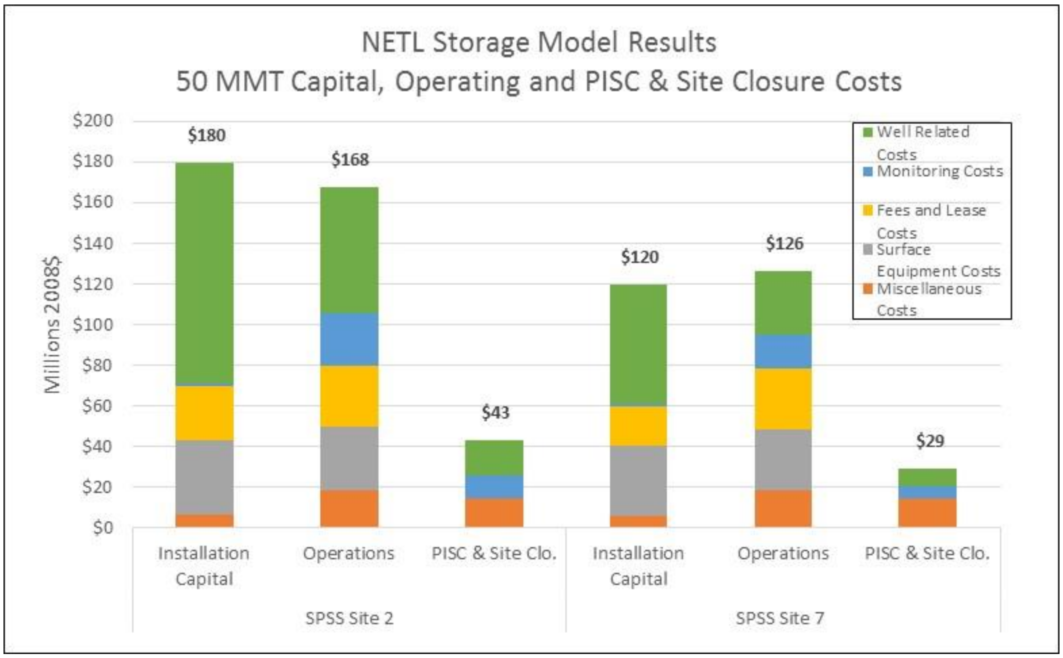

Figure 6-3. SPSS 50 MMT Site 2 and 7 capital, operating, and PISC/SC costs in constant 2008$.

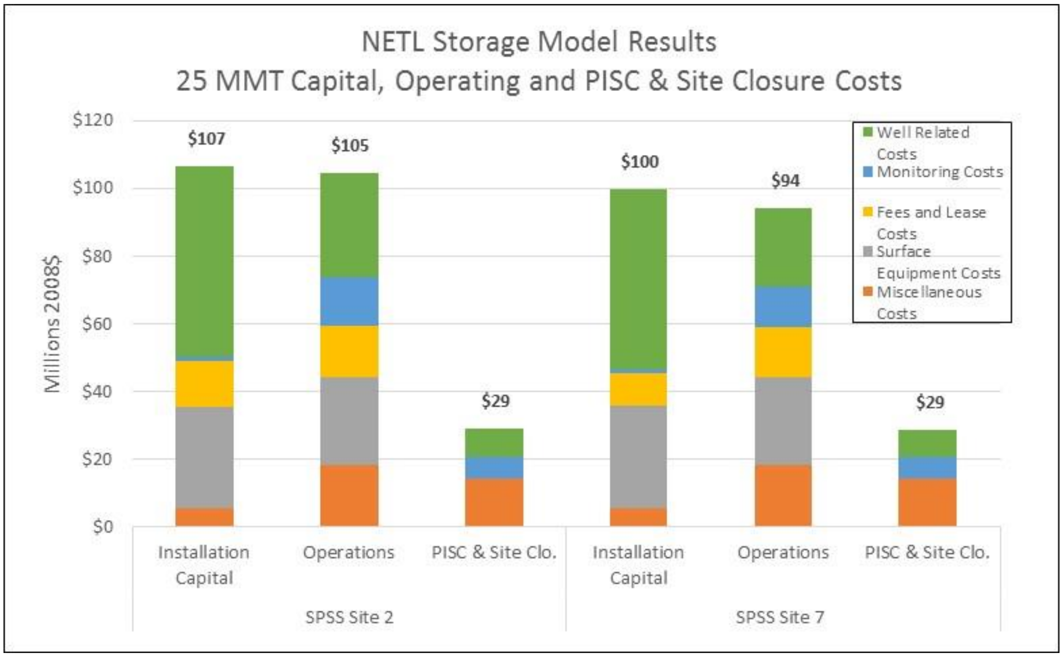

Figure 6-4. SPSS 25 MMT Site 2 and 7 capital, operating, and PISC/SC costs in constant 2008$.

6.2.2 Pipeline Costs

Preliminary CO_2 pipeline capital and operating costs were developed using the NETL FE/NETL CO_2 Transport Cost Model (DOE/NETL-2014/1667). Inputs to this model were developed from the LANL SimCCS simulation of each source-to-sink pipeline route as shown in Figure 6-1 and Figure 6-2 above. These inputs included both expected pipeline distance for the route and anticipated elevation changes. This model calculated costs in constant 2011 dollars.

Table 6-3 provides the estimated pipeline distance and elevation changes determined using the LANL SimCCS model for each project source and CO_2 sequestration scenario. These pipeline distances and elevation changes were input into the NETL Transport Model to estimate the pipeline capital and operating costs summarized in Figure 6-5 and Figure 6-6 below.

Table 6-3. CO_2 Pipeline distances and elevation change between sources and storage options.

Project CO_2 Source	Scenario	Distance (mi)[a]	Elevation Change (ft)
Wolverine	50 MMT of Saline Storage	21	49
	25 MMT of Saline Storage and EOR	74	49
	50 MMT of EOR	105	23
Potential New Source	50 MMT of Saline Storage	17	223
	25 MMT of Saline Storage and EOR	46	223
	50 MMT of EOR	83	68
Project TIM	50 MMT of Saline Storage	154	534
	25 MMT of Saline Storage and EOR	183	534
	50 MMT of EOR	225	285

a. pipeline distances for saline storage option are for SPSS Site 2; the same values were used for Site 7.

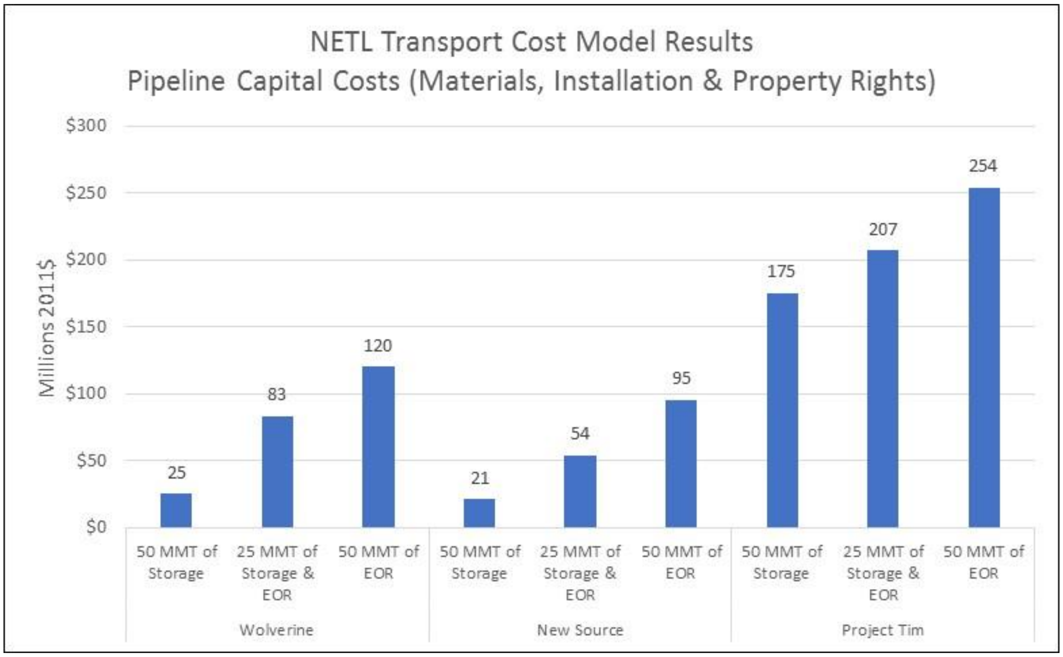

Figure 6-5. CO_2 pipeline capital costs in constant 2011$.

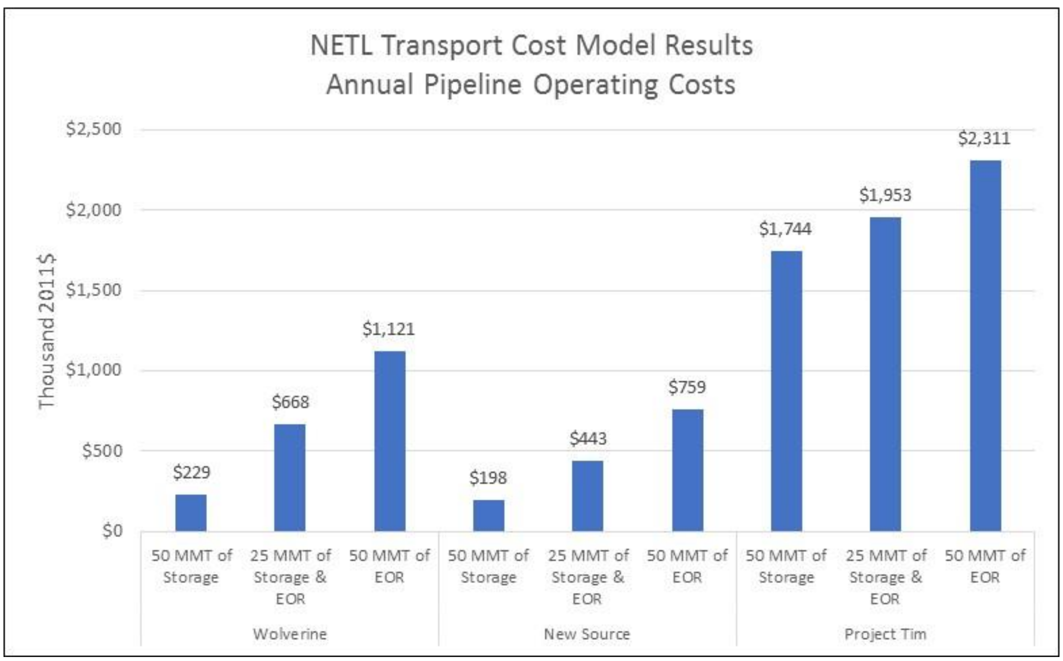

Figure 6-6. CO_2 pipeline annual operating costs in constant 2011$.

6.2.3 Capture Costs

Preliminary CO_2 capture capital and operating costs were derived from several DOE/NETL studies and presentation materials. For electric generation CO_2 sources, capital and operating costs were developed using Cost and Performance Baseline for Fossil Energy Plants Volume 1a: Bituminous Coal (PC) and Natural Gas to Electricity Revision 3 (DOE/NETL-2015/1723) and Post-Combustion Capture Retrofit: Eliminating the Derate (DOE/NETL-2017). Table 6-4 summarizes the capital and operating cost components and projected performance of NGCC, sub-critical pulverized coal (SPC), and super-critical pulverized coal (SCPC) facilities with and without CO_2 capture from the DOE/NETL reports. However, since the CO_2 emissions from the SPC and SCPC facility designs were significantly greater than the 1.67 MMT per year required for the storage project in this analysis, the costs and performance parameters were scaled down to capture approximately 45% and 46% of the emissions, respectively. The scaled SPC and SCPC costs and performance parameters are shown in Table 6-5. All costs listed are in constant 2011 dollars.

The cost and performance parameters in Table 6-4 and Table 6-5 were used to estimate the incremental capital and operating cost of capture for the scenarios described in Table 6-1. The NGCC costs were used for the retrofitted existing Wolverine facility and for the PNS with NGCC. The scaled SCPC costs and performance parameters were used to estimate the incremental cost for capture associated with Project TIM. This assumption was based on discussions with the project sponsors regarding the power generation source to be developed to support the operations of the proposed steel mill. However, it must be noted that actual capture technology costs are likely to be significantly lower as a result of cost reductions realized from investments made by DOE's CO_2 capture research and development (R&D) program and current and next generation technologies proceed from pilot to commercial deployment.

No incremental capital or operating costs for CO_2 capture were assumed for the PNS with the NET Power Allam cycle technology. Based on a review of the NET Power information, the proposed facility would produce pipeline quality CO_2 as a standard byproduct with no additional infrastructure required for cleanup or compression.

Table 6-4. Performance and cost parameters for new NGCC, Sub-PC and Super-critical PC with and without CO_2 Capture.

Category	NGCC	NGCC w/ Capture	Sub-Critical PC	Sub-Critical PC w/ Capture	Super-Critical PC	Super-Critical PC w/ Capture
Gross Output - MW	641	601	580	642	580	612
Net Output (including capture) - MW	630	559	550	550	550	550
Net Plant Heat Rate - Btu/kWh	6,629	7,466	8,740	10,953	8,379	10,508
Capacity Factor - %	85%	85%	85%	85%	85%	85%
Total Plant Cost - $x000s	430,931	827,904	1,078,113	1,906,174	1,114,361	1,939,143
Total Plant Cost - $/kW, net	684	1,481	1,960	3,466	2,026	3,526
Fixed O&M – $/kW	25.21	48.96	69.25	112.70	71.46	114.67
Variable O&M - $/MWh	1.66	3.96	9.23	15.09	9.05	14.73
Fuel Consumption - $/MWh	40.70	45.87	25.67	32.18	24.61	30.87
CO_2 Emitted – lb CO_2/MMBtu	118.50	118.50	204.00	204.00	204.00	204.00
Capture Rate - %	N/A	90%	N/A	90%	N/A	90%
CO_2 Captured – tonne/MWh	N/A	106.65	N/A	187.20	N/A	187.20

Table 6-5. Performance and cost parameters for new Sub-PC and Super-critical PC facilities scaled for 1.67 MMT for CO_2 capture.

Category	Sub-Critical PC w/ Capture	Super-Critical PC w/ Capture
Gross Output - MW	612	612
Net Output (including capture) - MW	550	550
Net Plant Heat Rate - Btu/kWh	9,839	9,477
Capacity Factor - %	85%	85%
Total Plant Cost - $x000s	1,588,400	1,635,150
Total Plant Cost - $/kW, net	2,888	2,973
Fixed O&M – $/kW	90.81	93.77
Variable O&M - $/MWh	12.14	11.98
Fuel Consumption - $/MWh	28.90	27.85
CO_2 Emitted – lb CO2/MMBtu	204.00	204.00
Capture Rate - %	44.70%	46.41%
CO_2 Captured – tonne/MWh	91.19	94.67

6.2.4 Aggregating Costs

Various ownership structures for the CO_2 capture, pipeline, and storage facilities were evaluated based on possible financing arrangements, regulatory schemes (e.g., rate regulated versus independent power producer) and risk management considerations and are summarized in

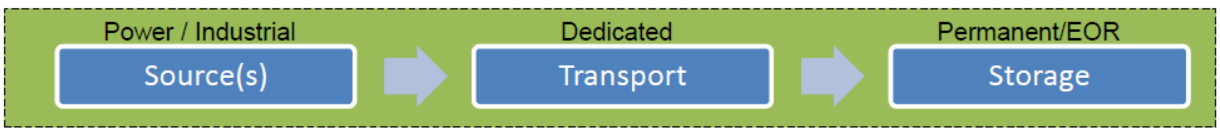

Figure 6-7. Some of these ownership models have been used by CCS projects currently operating, in construction, or previously proposed. For example, the Illinois Industrial Carbon Capture and Storage project in Decatur, Illinois, is a fully integrated capture and deep saline storage facility jointly owned by Archer Daniel Midlands with other regional partners. FutureGen, Kemper County and Petro Nova are examples of projects that divided the ownership between the capture, transport and storage or EOR facilities.

The ownership model may also depend on whether the capture facility is part of a regulated utility. For example, in the case of Kemper County, the capture facility and pipeline were both to be included in the rate base of Mississippi Power; whereas, the FutureGen project aimed to recover the costs of CCS through long-term power purchase agreements with rate regulated distribution utilities in Illinois.

To successfully finance an integrated CO_2 capture and storage project from rate regulated natural gas or coal-fired electric generating stations, the State of Michigan will likely need to pass legislation to enable cost recovery by either allowing long-term power purchase agreements to be signed that cover such costs and/or allow the MPSC to include such costs in electricity consumer rates. These types of cost recovery mechanisms are critical to the success of any CO_2 capture and storage project in the absence of a value for carbon in the wholesale electricity markets or federally mandated carbon reduction, even with the potential for EOR revenues included in this project.

At this pre-feasibility stage of the CS-NMB project, the single owner model (

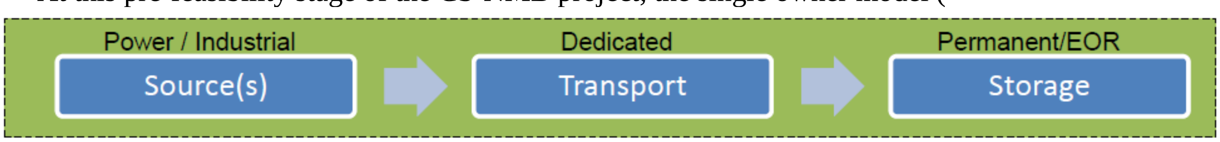

Figure 6-7a) was considered the best opportunity for a project scenario with deep saline storage to be successfully developed and financed. This fully integrated approach eliminates the financial,

performance, and contractual offtake risks of having multiple entities involved in a complex project. Project lenders also have a single accountable project sponsor to ensure the facilities are constructed and operated properly. Revenues required to support the incremental costs associated with the CCS were assumed to be available either through the wholesale power market or recovered through a long-term power purchase agreement with one of the rate regulated utilities in Michigan.

Alternative scenarios, such as ownership of pipelines and/or saline and/or EOR storage sites by separate entities, were also considered potentially attractive options. However, this approach would require off-take agreements with the owner of the capture process to manage CO_2 liability issues.

Arrangements for CCS system cost recovery, whether from rate payers, the wholesale power markets or third-party sales of CO_2, along with allocation of federal and state tax and other incentives must be decided prior to final investment decisions regarding the ownership structure.

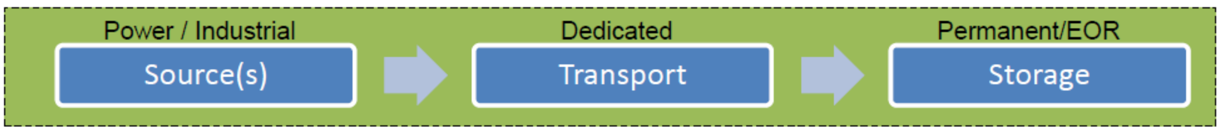

Figure 6-7a. Integrated CCS project ownership structure in which all project elements are owned by a single entity (Illinois Industrial Carbon Capture and Storage project).

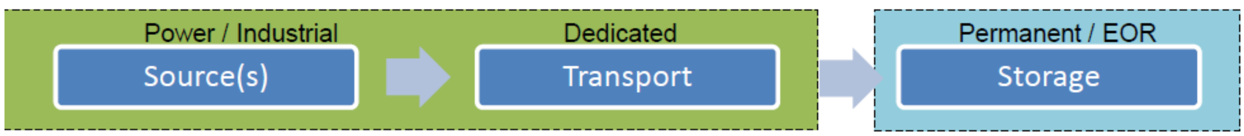

Figure 6-7b. Single owner of the capture and transport facilities transferring CO_2 to a separately owned storage project or EOR field (Kemper County model).

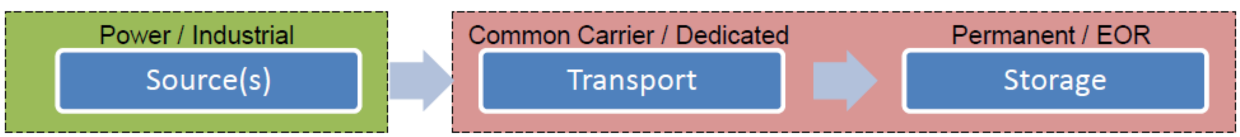

Figure 6-7c. Separately owned capture facility transferring CO_2 to a single owner of transport and storage project elements (FutureGen and Petro Nova model).

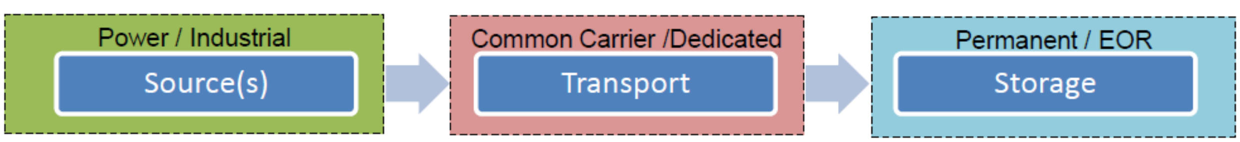

Figure 6-7d. Fully disaggregated CCS project structure in which all project elements are owned by separate entities.

6.2.5 Assumptions

Key macro-economic and financial assumptions used in the cost analysis are summarized in Table 6-6. Escalation factors for capture, pipeline, and storage capital costs were derived from the Chemical Engineering Plant Cost Index and the North America Power Capital Cost Index published by IHS Markit. Escalation assumptions for revenue operating costs were developed using data published by the Federal Reserve Bank of Philadelphia. All scenarios included the benefits and rules from the recently enacted changes to the Federal tax code and to the Section 45Q tax credits.

Financing assumptions were based on possible business ownership structures, whether the project was subject to rate regulation, and differentiated between low and high costs of capital. These assumptions are listed in Table 6-7. The resulting pre-tax and after-tax costs of capital for each business structure are provided in Table 6-8 through Table 6-10.

The discounted cash flow analysis of the scenarios listed in Table 6-1 assumed that the projects were all structured as independent power producers as none of the capture facilities are or are projected to be included in the rate base of a regulated utility.

Table 6-6. Macro-economic and financial assumptions.

Category	Value
ANALYSIS TIME PERIODS	
Project Start Date:	January 1, 2018
Project Commercial Operation Date	January 1, 2025
Capital Expenditures (including development and permitting)	Storage facility: 7-yrs Pipeline: 3-yrs (<25 mi); 4 years (>25 mi) Capture facility: 4-yrs
Operations	30 yrs
Post Injection Site Care & Site Closure	25 yrs
TAXES & TAX CREDITS	
Federal Income Taxes[a]	21%
State Income Taxes	6% Michigan statutory corporate rate
State Sales Tax	100% exemption
Local Property Taxes	1% of Pre-finance capital expenditures
Tax Depreciation[b]	Storage Facility: 5-yr MACRS (wells); 15-yr MACRS (equipment and other costs) Pipelines: 15-yr MACRS Capture Facility: 20-yr MACRS
Federal Tax Credits: Section 45Q	Permanent sequestration: 50$/tonne Enhanced oil recovery: 35$/tonne Credit duration: 12-yrs
% of Capital Cost Depreciated	100%
ESCALATION FACTORS	
Capital Expenditures	3.42% Sources: *Chemical Engineering* Plant Cost Index. Nominal average annual escalation rate between 1950 and 2016
Revenues & Operating Expenditures	2.32% Source: Philadelphia Federal Reserve *Livingston Survey* long-term inflation forecast
COMMODITY PRICES	
Sale of CO_2 for EOR	20$/tonne (2018$)

a. The calculation of Federal income tax liability included the limitation on interest deduction of 30% of EBIT starting in 2022. However, this limitation does not apply to regulated utilities. Also included in the tax calculations was the limitation on net operating loss (NOL) utilization of 80%.

b. 40% bonus depreciation was included based on the assumed project commercial operation date of January 1, 2025.

Table 6-7. Financing and Owners Cost Assumptions.

Category	Regulated Utility		Independent Power Producer		Industrial Facility	
	LCC	HCC	LCC	HCC	LCC	HCC
FINANCING						
Assumed credit rating	A	BBB	BBB	BBB-	BBB	BBB-
Construction financing all-in interest rate	3.14%	3.84%	3.84%	4.69%	3.84%	4.69%
12-month LIBOR Rate	1.77%	1.77%	1.77%	1.77%	1.77%	1.77%
Credit spread – long term average	1.37%	2.07%	2.07%	2.92%	2.07%	2.92%
Commitment fee	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
Up-front fees	2.50%	2.50%	2.50%	2.50%	2.50%	2.50%
Legal & other consultant costs (% of debt)	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%
Term financing – all-in interest rate	4.27%	4.97%	4.97%	5.82%	4.97%	5.82%
Treasury Rate (30-yr)	2.90%	2.90%	2.90%	2.90%	2.90%	2.90%
Credit spread – long term average	1.37%	2.07%	2.07%	2.92%	2.07%	2.92%
Tenor (yrs)	30	30	30	30	30	30
P&I repayment schedule	Mortgage Style	Mortgage Style	Mortgage Style	Mortgage Style	Mortgage Style	Mortgage Style
Debt service reserve (months of P&I)	0	0	0	0	0	0
Working capital (months of OPEX)	2	2	2	2	2	2
LOC Fee on debt reserve + working capital	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%

Table 6-7 (continued). Financing and Owners Cost Assumptions.

After-tax cost of equity	10%	11%	10%	15%	15%	20%
OWNERS COSTS						
Insurance (% of Pre-financing CAPEX)						
Builders risk (construction period)	1%	1%	1%	1%	1%	1%
Operating period	1%	1%	1%	1%	1%	1%
Commissioning & start-up (months of O&M)						
Capture facility	12	12	12	12	12	12
Pipeline and storage reservoir	6	6	6	6	6	6
Capital spares (% of Pre-financing CAPEX)	0.50%	0.50%	0.50%	0.50%	0.50%	0.50%
Owners management reserve (% of Pre-financing CAPEX + financing costs)	15%	15%	15%	15%	15%	15%

Table 6-8. Pre-tax and after-tax costs of capital – Regulated Utility.

Category	% of Total	Cost of Funds	Pre-Tax Weighted Cost of Funds	After-Tax Weighted Cost of Funds
LOW COST OF CAPITAL				
Equity	45	10%	4.50%	4.50%
Debt	55	4.27%	2.35%	1.74%
Total	100		6.85%	6.24%
HIGH COST OF CAPITAL				
Equity	50	11%	5.50%	5.50%
Debt	50	4.97%	2.49%	1.85%
Total	100		7.99%	7.35%

Table 6-9. Pre-tax and after-tax costs of capital – Independent Power Producer.

Category	% of Total	Cost of Funds	Pre-Tax Weighted Cost of Funds	After-Tax Weighted Cost of Funds
LOW COST OF CAPITAL				
Equity	30	10%	3.00%	3.00%
Debt	70	4.97%	3.48%	2.58%
Total	100		6.48%	5.58%
HIGH COST OF CAPITAL				
Equity	40	15%	6.00%	6.00%
Debt	60	5.82%	3.49%	2.76%
Total	100		9.49%	8.76%

Table 6-10. Pre-tax and after-tax costs of capital – Industrial Facility.

Category	% of Total	Cost of Funds	Pre-Tax Weighted Cost of Funds	After-Tax Weighted Cost of Funds
LOW COST OF CAPITAL				
Equity	30	15%	4.50%	4.50%
Debt	70	4.97%	3.48%	2.58%
Total	100		7.98%	7.08%
HIGH COST OF CAPITAL				
Equity	40	20%	8.00%	8.00%
Debt	60	5.82%	3.49%	2.76%
Total	100		11.49%	10.76%

6.2.6 Cost Build-Up Methodology

The capital cost estimates for the CO_2 storage and pipeline facilities that were developed using NETL models described above were adjusted to include appropriate owner's costs including: startup and commissioning, working capital, builders risk insurance, upfront financing costs and related fees. An owner's management reserve of 15% was also included. These constant dollar cost estimates were then escalated at the capital cost escalation rate listed in Table 6-6 from 2008 and 2011 dollars, respectively, to arrive at a total "overnight" estimate for both the storage and pipeline facilities at the project start date of January 1, 2018.

The starting point for developing the overall total capital costs for the CO_2 capture facilities was the total plant cost (TPC) for the various capture technologies listed in Table 6-4 and Table 6-5. As described above for the storage and pipeline estimates, the TPC was adjusted to include appropriate owner's costs including: startup and commissioning, working capital, capital spares, builders risk insurance and upfront financing costs and related fees. In addition to process and project contingencies included in the TPC, an owner's management reserve of 15% was added to the total. These constant dollar cost estimates were also escalated from 2011 dollars to arrive at a total "overnight" estimate for the capture facility at the project start date of January 1, 2018.

This cost build-up methodology assumes that an engineering, procurement and construction management (EPCM) strategy will be utilized by the project owners. Use of an EPCM approach is typically more cost effective (compared to a fully wrapped turnkey approach which is referred to as an EPC agreement) because it eliminates the premium paid to contractors for assuming overall performance, schedule and cost risk. An EPCM contract would transfer the overall project completion, integration and performance risk to the owner, and typically requires stronger financial backing from the owner for lenders to support such an arrangement. No matter the contracting scenario, it is incumbent upon the project owner to ensure that thorough scope definition and engineering is completed prior to the commencement of construction. A phased engineering approach that includes a front-end engineering and design (FEED) phase followed by detailed final engineering is considered advisable to minimize scope changes and cost increases. This approach can produce a level of design and cost certainty that helps to reduce the risk associated with obtaining the necessary financing.

Interest during construction and escalation were included for each of the storage, pipeline and capture facilities during the construction period to arrive at an as-spent mixed-year dollars final estimate prior to the commencement of operations on January 1, 2025.

6.3 Capital and Operating Costs Results

6.3.1 Capital Costs

The all-in storage project capital costs in constant 2018 dollar and mixed, as-spent dollars for SPSS sites 2 and 7 assuming a low cost of capital and a high cost of capital are shown in Figure 6-8 through Figure 6-11. The all-in pipeline project capital costs in constant 2018 dollar and mixed, as-spent dollars for each project scenario listed in Table 6-1 assuming either a low cost of capital or high cost of capital are shown in Figure 6-12 through Figure 6-17. The all-in incremental capture project capital costs in constant 2018 dollar and mixed, as-spent dollars for each project scenario listed in Table 6-1 assuming either a low cost of capital or high cost of capital are shown in Figure 6-18 through Figure 6-20.

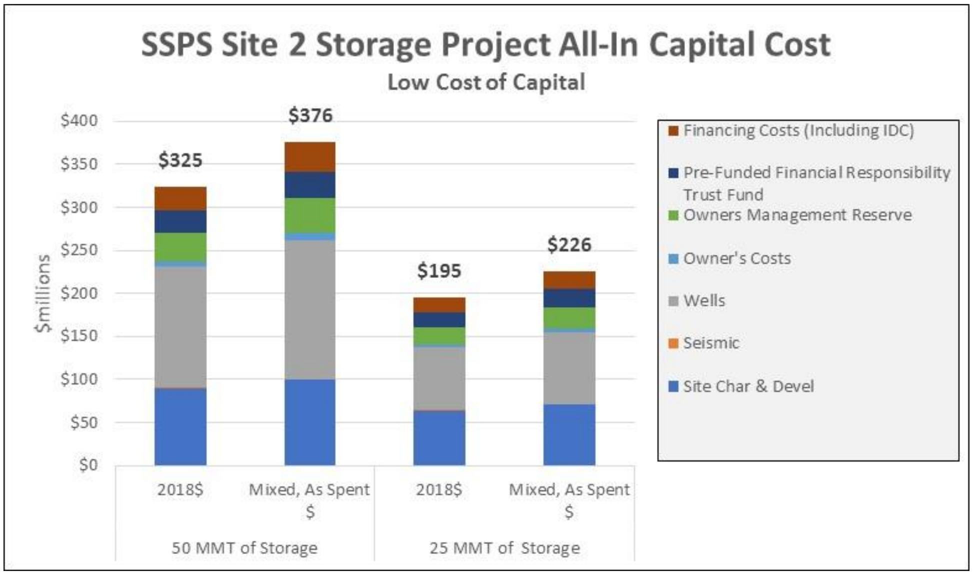

Figure 6-8. SPSS Site 2 total project capital costs for 50 MMT and 25 MMT storage in 2018$ and mixed, as spent dollars assuming a low cost of capital.

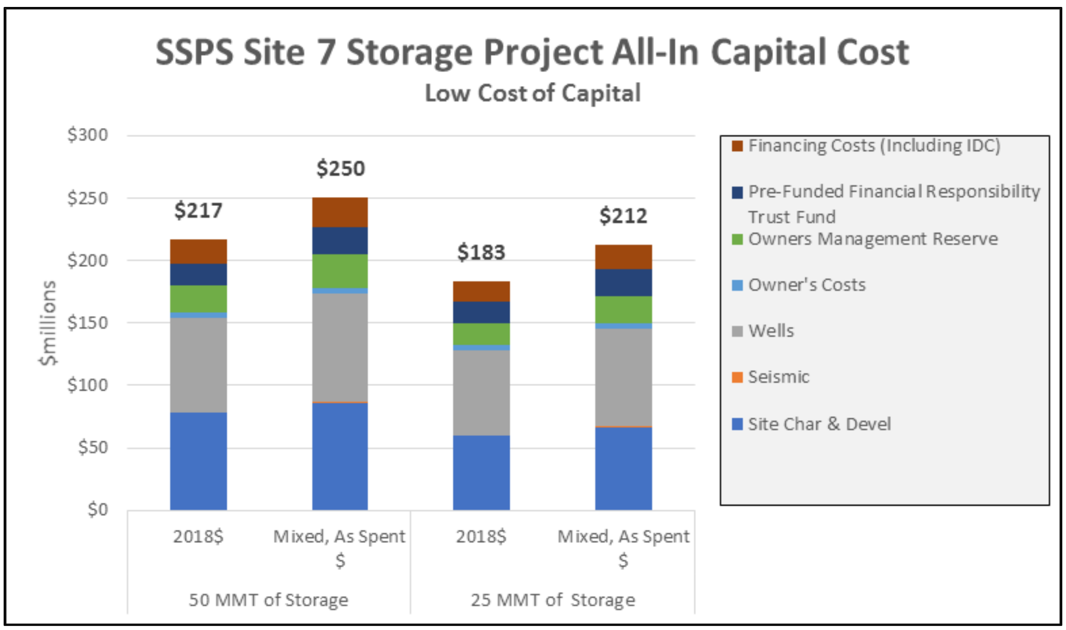

Figure 6-9. SPSS Site 7 total project capital costs for 50 MMT and 25 MMT storage in 2018$ and mixed, as spent dollars assuming a low cost of capital.

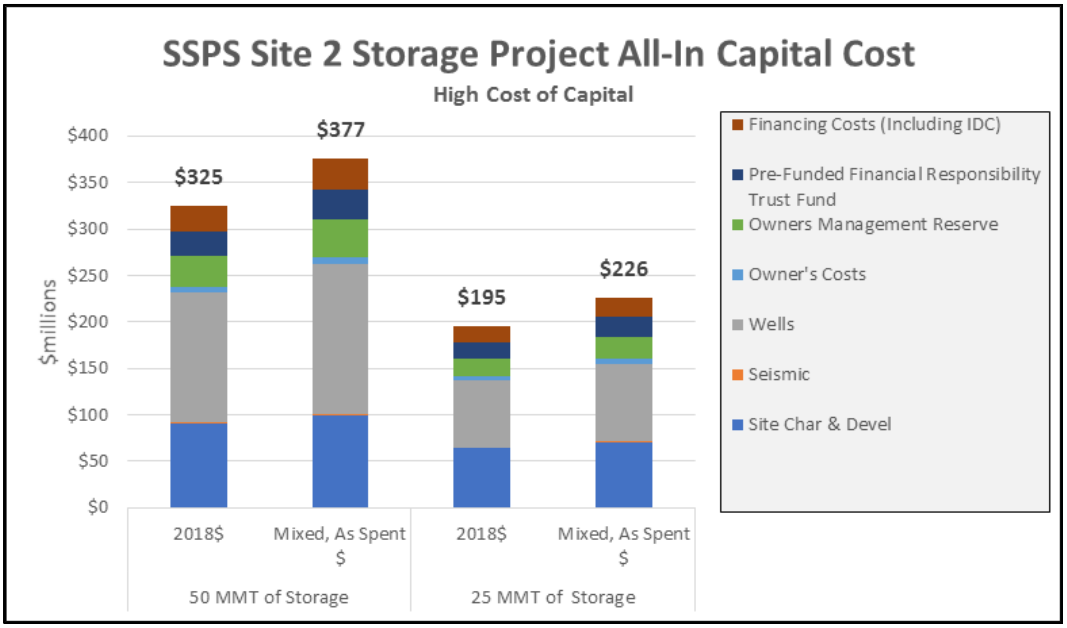

Figure 6-10. SPSS Site 2 total project capital costs for 50 MMT and 25 MMT storage in 2018$ and mixed, as spent dollars assuming a high cost of capital.

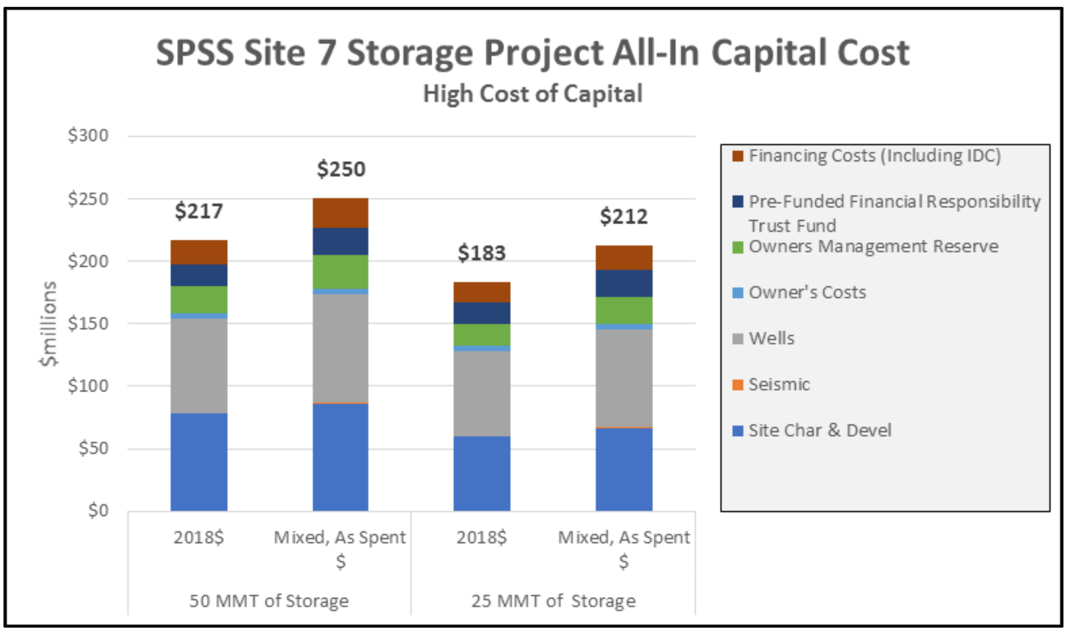

Figure 6-11. SPSS Site 7 total project capital costs for 50 MMT and 25 MMT storage in 2018$ and mixed, as spent dollars assuming a high cost of capital.

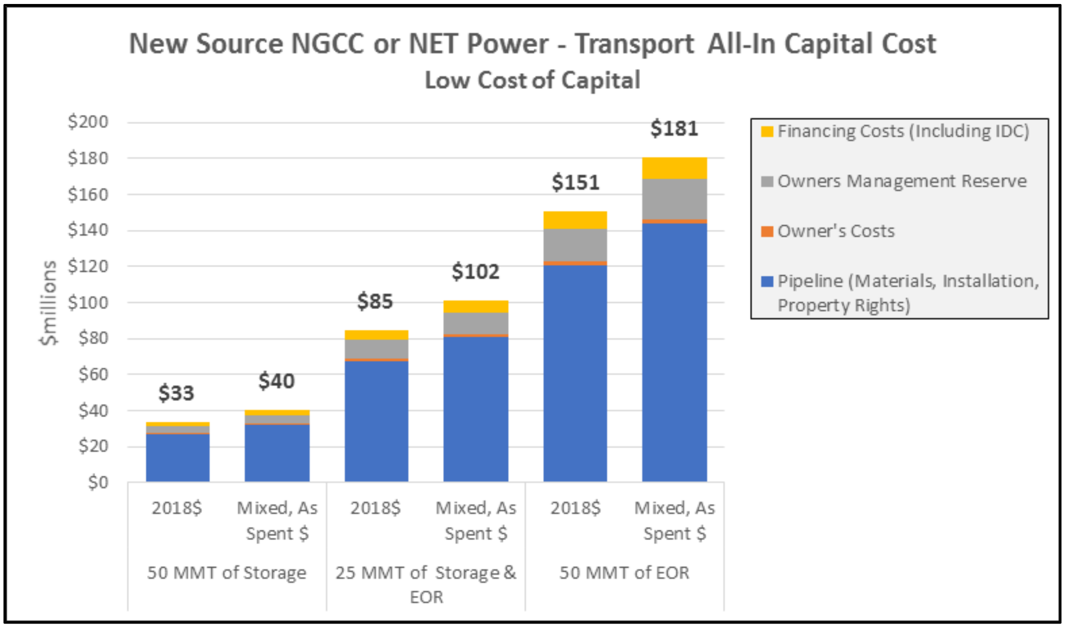

Figure 6-12. New Source NGCC or NET Power scenario transport all-in capital costs in 2018$ and mixed, as spent dollars with a low cost of capital.

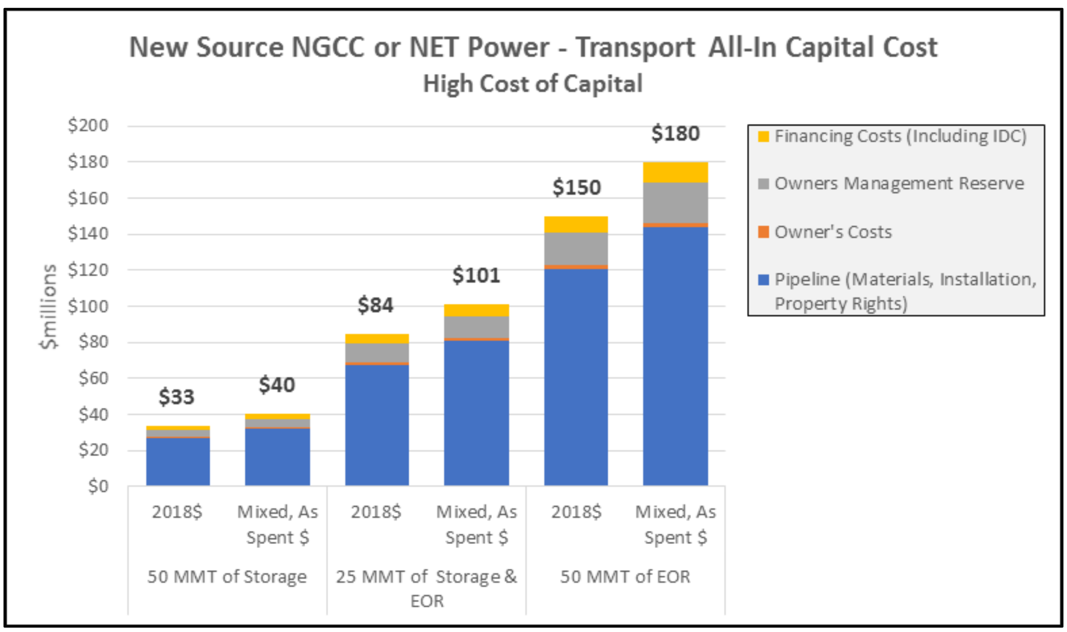

Figure 6-13. New Source NGCC or NET Power scenario transport all-in capital costs in 2018$ and mixed, as spent dollars with a high cost of capital.

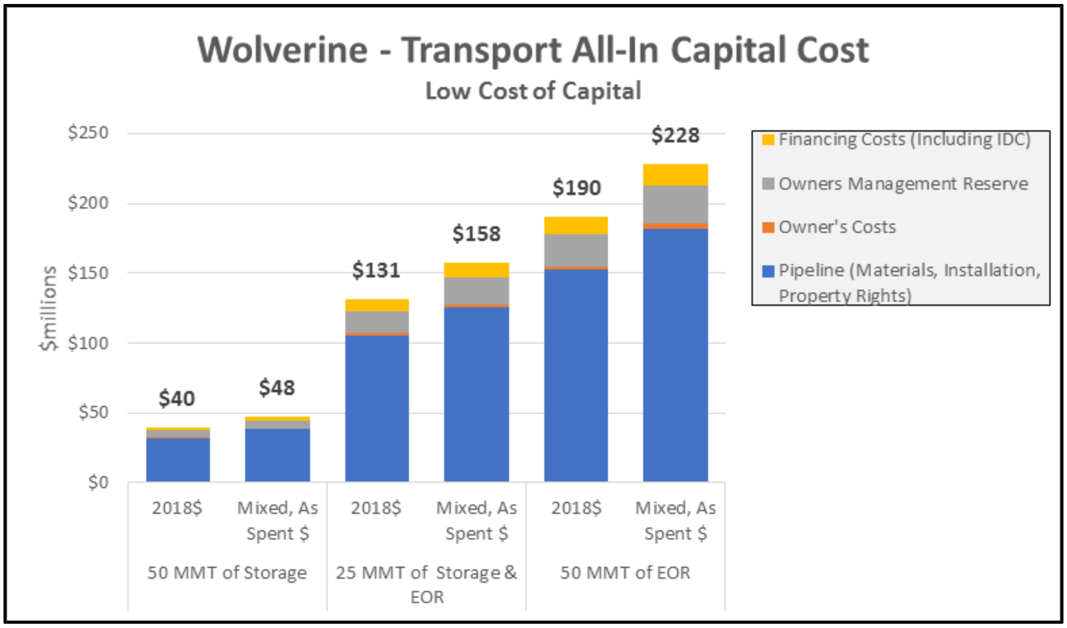

Figure 6-14. Wolverine transport all-in capital costs in 2018$ and mixed, as spent dollars with a low cost of capital.

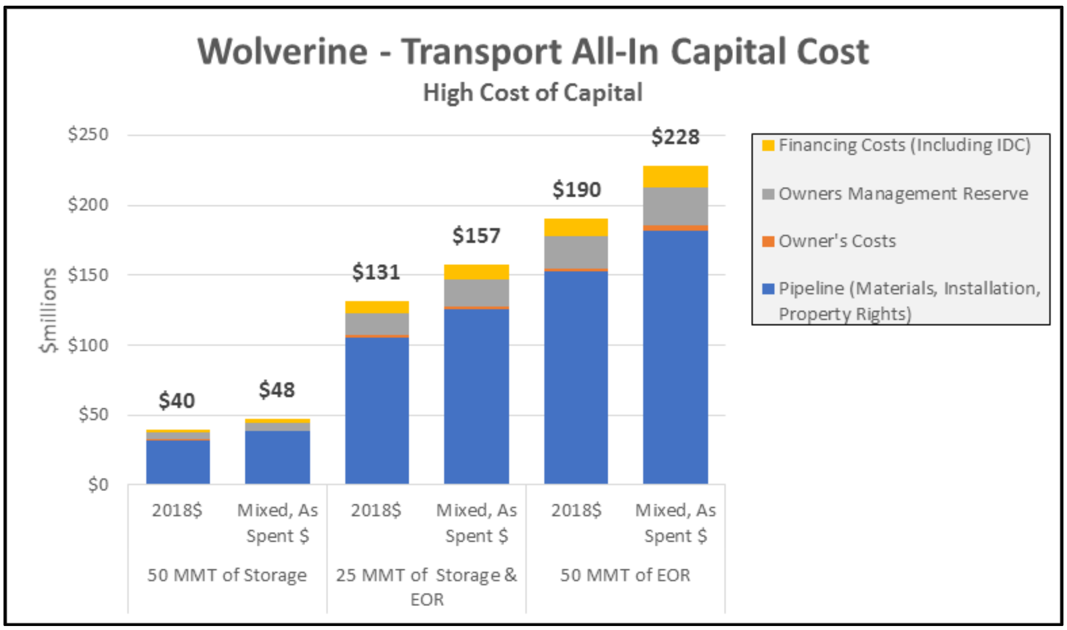

Figure 6-15. Wolverine transport all-in capital costs in 2018$ and mixed, as spent dollars with a high cost of capital.

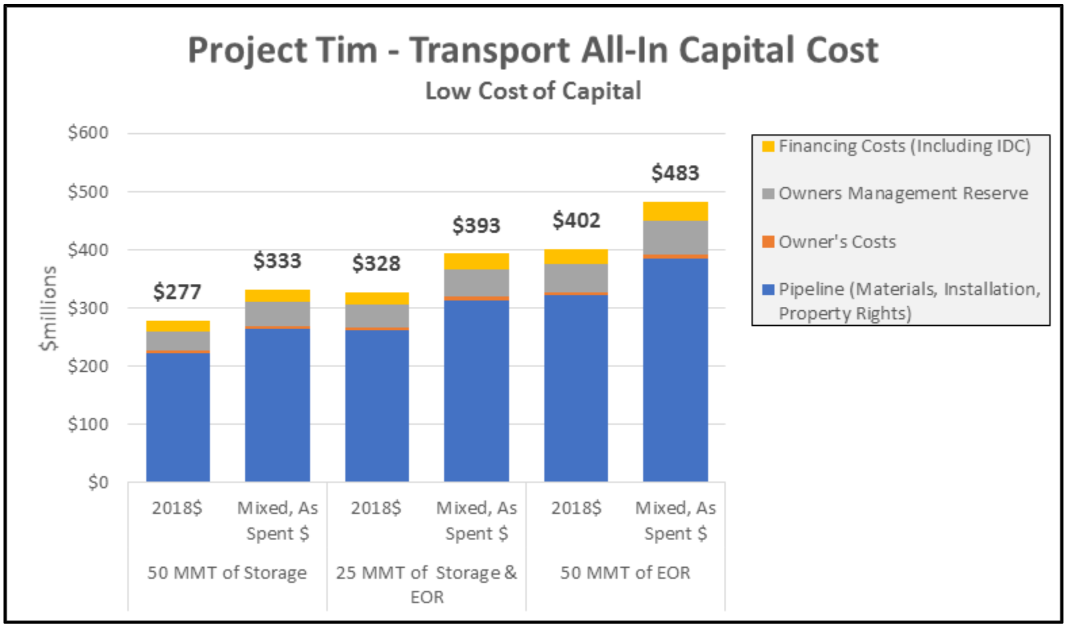

Figure 6-16. Project Tim transport all-in capital costs in 2018$ and mixed, as spent dollars with a low cost of capital.

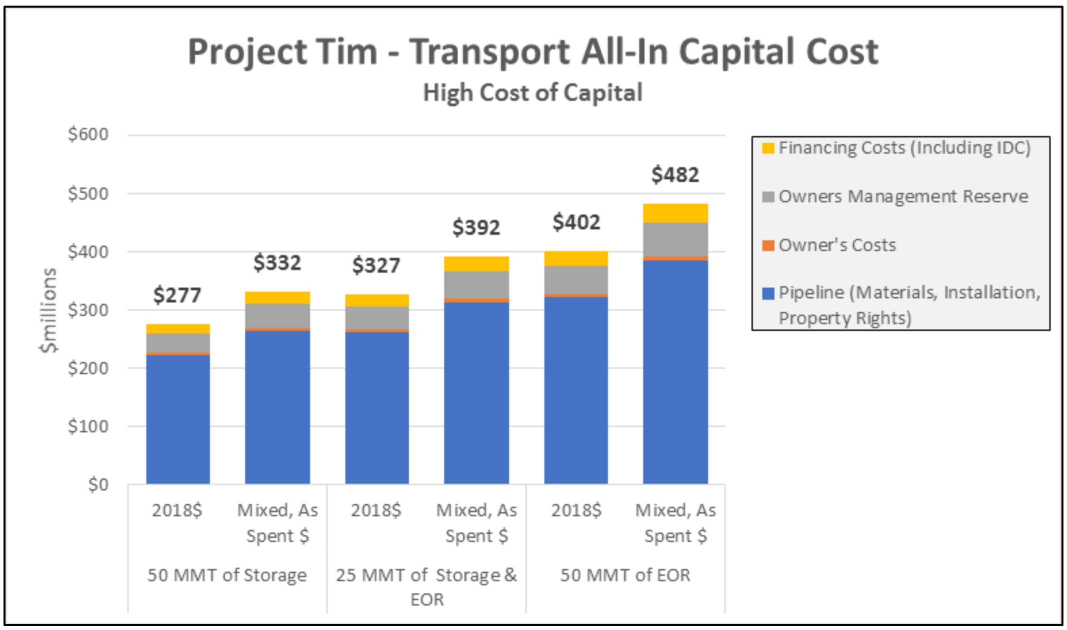

Figure 6-17. Project Tim transport all-in capital costs in 2018$ and mixed, as spent dollars with a high cost of capital.

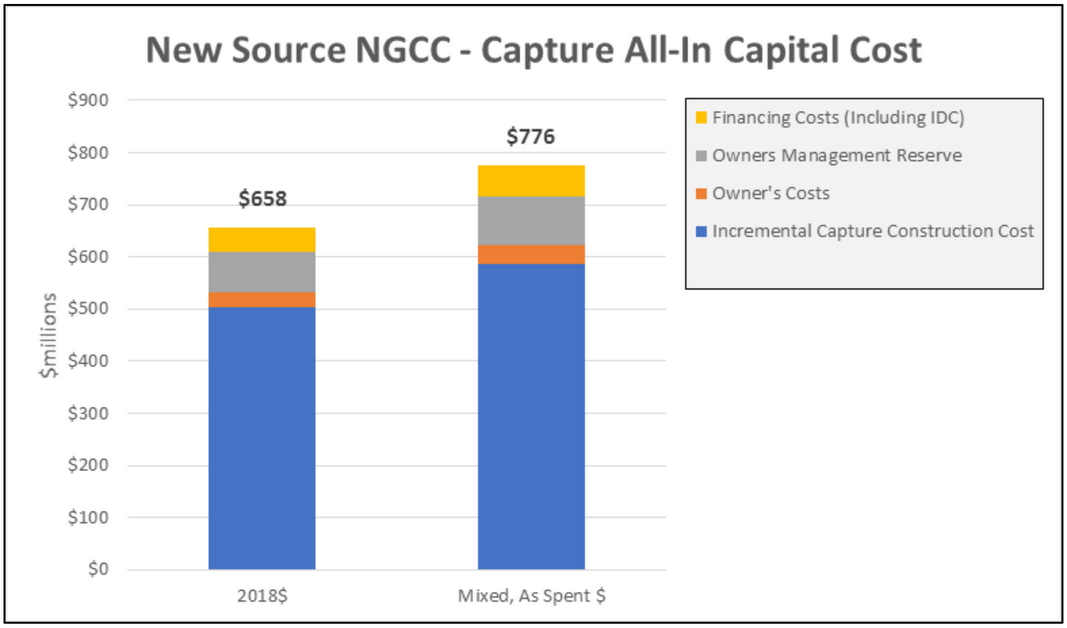

Figure 6-18. New Source NGCC incremental capture all-in capital costs in 2018$ and mixed, as spent dollars with a low or high cost of capital.

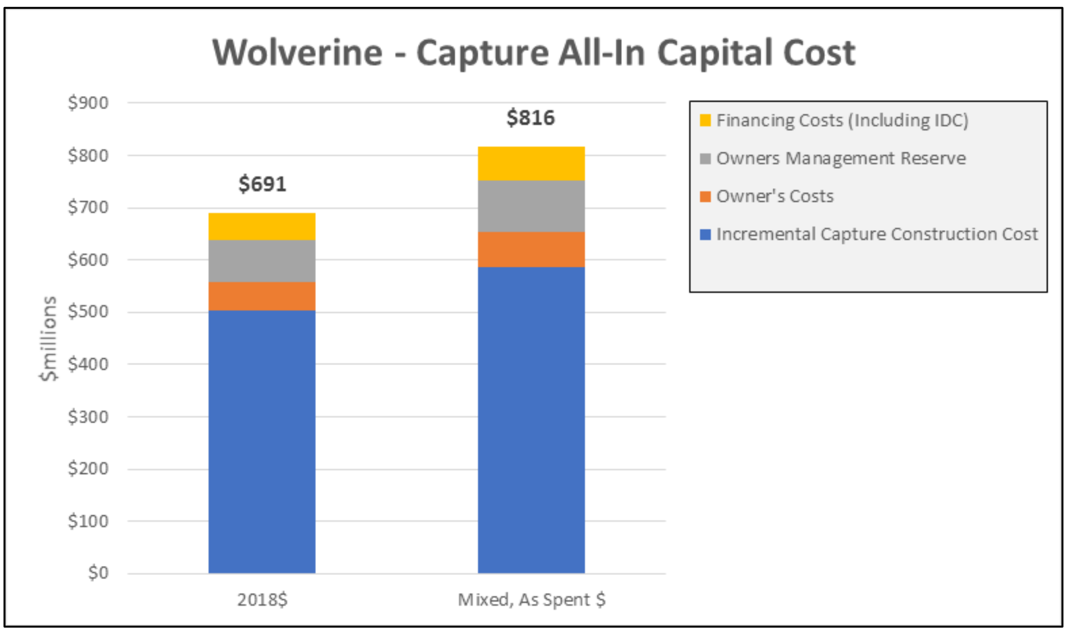

Figure 6-19. Wolverine NGCC retrofit incremental capture all-in capital costs in 2018$ and mixed, as spent dollars with a low or high cost of capital.

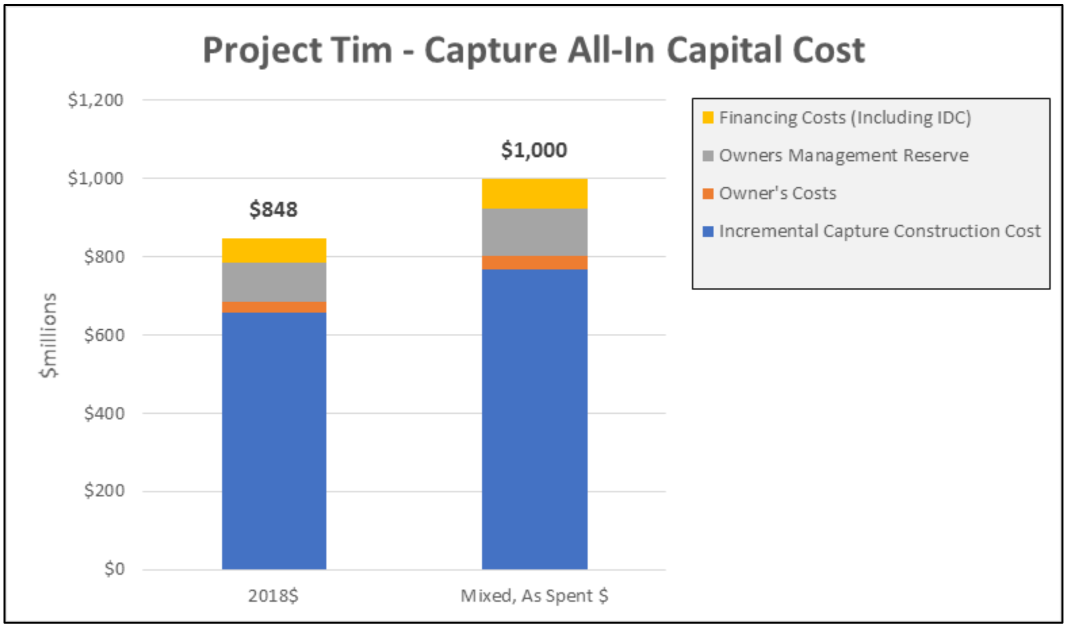

Figure 6-20. Project Tim incremental capture all-in capital costs in 2018$ and mixed, as spent dollars with a low or high cost of capital.

6.3.2 Operating Costs

Operating period costs for the CO_2 storage facility and pipeline were also escalated from 2008 and 2011 dollars, respectively, to the appropriate year of operation based on operating cost escalation rate in Table 6-6. PISC/SC costs were estimated using the NETL storage model and information from Battelle based on the UIC Class VI permitting experience for FutureGen 2.0. These PISC/SC costs were included as part of the estimate of the financial responsibility (FR) requirements in EPA's Class VI regulations (40 CFR §146.85). Fixed and variable operating costs, including fuel and power related costs included in the DOE studies for the capture technologies, were also escalated from 2011 dollars to the appropriate year during the expected 30-year operating period.

6.3.3 Levelized Costs for Each Scenario

The results of the cost and economic analyses for the 20 scenarios described in Table 6-1 are summarized in Figure 6-21 through Figure 6-36 (there are four figures for each of the four sources: costs levelized in 2018 [start of project] dollars; costs levelized in 2025 [first year of injection] dollars; low cost of capital finance cost; high cost of capital finance cost). The appendix contains a separate plot for each scenario, showing the capture, transport, and storage costs, levelized to 2025, associated with each scenario.

Each plot in Figure 6-21 through

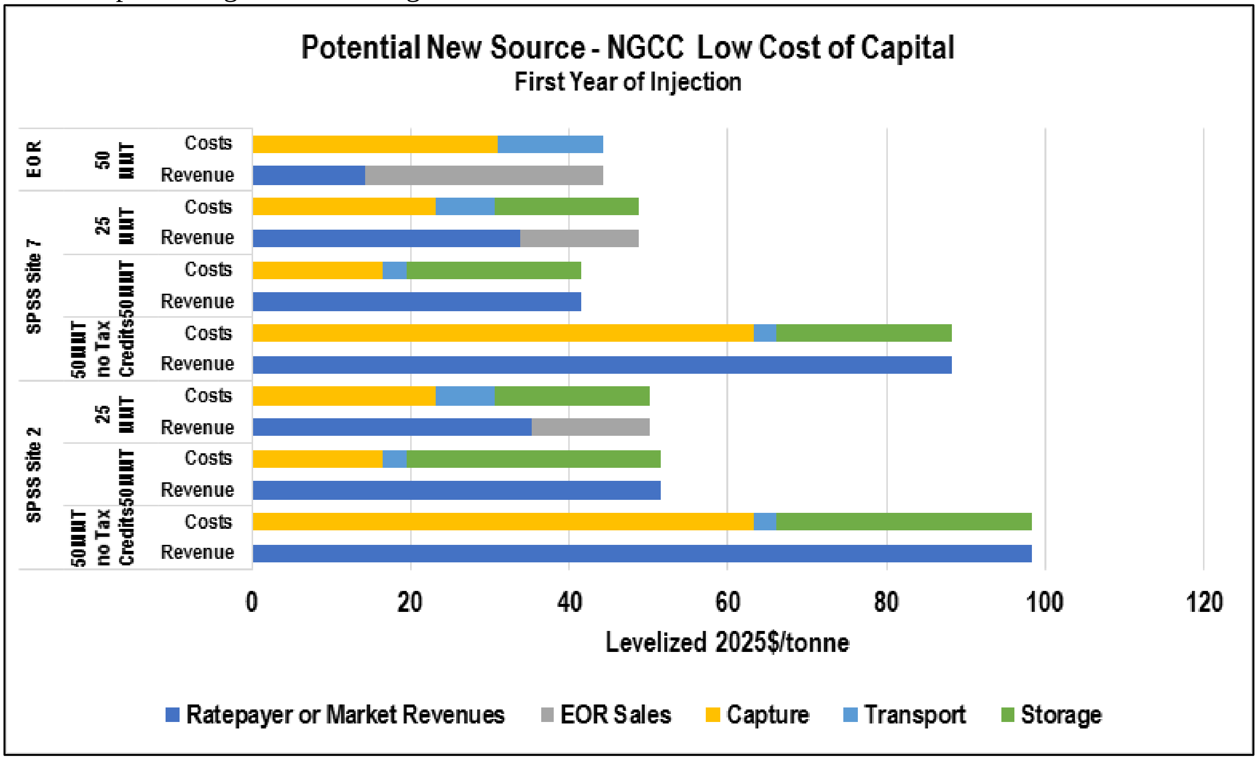

Figure 6-26 shows the cost components and anticipated amount of revenue for a scenario on a 30-year levelized basis, expressed in either 2018$/tonne (the project-start date) or in 2025$/tonne (the first year of injection) on a low or high cost of capital basis. Furthermore, each cost bar is divided into capture (yellow), transport (blue), and storage (green) components, where applicable. A companion bar of equal value shows the levelized revenue requirement necessary to cover the integrated cost of capture, transport, and storage. In all cases, the primary revenue source is assumed to be either from the market or a ratepayer-based (light blue) source. In cases where EOR sales were considered, the EOR revenue (gray) is differentiated from the market- or ratepayer-based revenues and reduces the overall amount of revenue to be collected from either the market or ratepayers.

On some plots in Figure 6-21 through Figure 6-36, it appears that capture costs vary within the same CO_2 source and CO_2 capture quantity, when it seems that cost should be the same. However, this is not an error. The reason the levelized cost of capture varies for the same source depends on the amount of and benefit attributed to the federal tax credits.

- In the case of 50 MMT of storage without EOR, the value of the tax credits is $50/tonne.
- In the case of 25 MMT of storage and 25 MMT of EOR, the value of the tax credits is a weighted average of $50/tonne and $35/tonne.
- In the case of 50 MMT of EOR, the value of the tax credits is $35/tonne.

However, in all the cases, the upfront capital cost, the ongoing operating costs, and the expected return on equity over the 30-year operating period are the same. What changes is how much benefit the tax credits provide to lower the overall cost of capture.

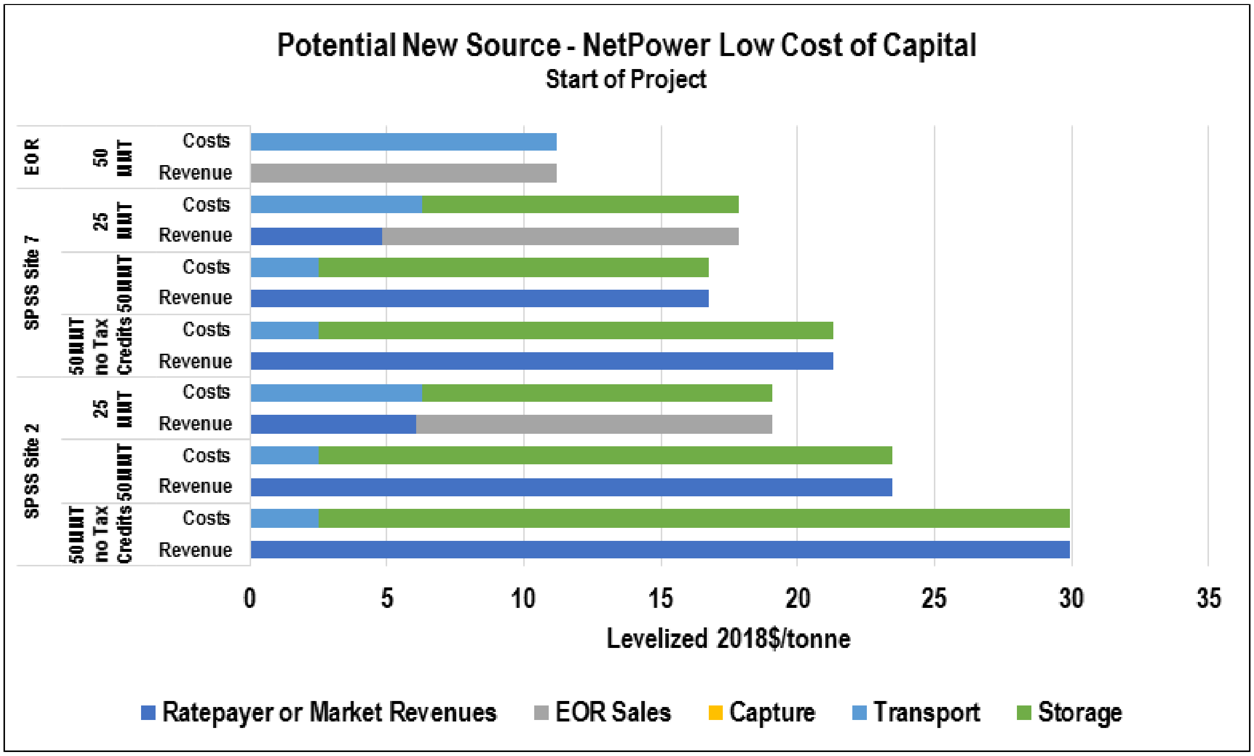

Figure 6-21. New Source NET Power - levelized cost of CCS and revenue requirements low cost of capital; 2018$/tonne (start of project).

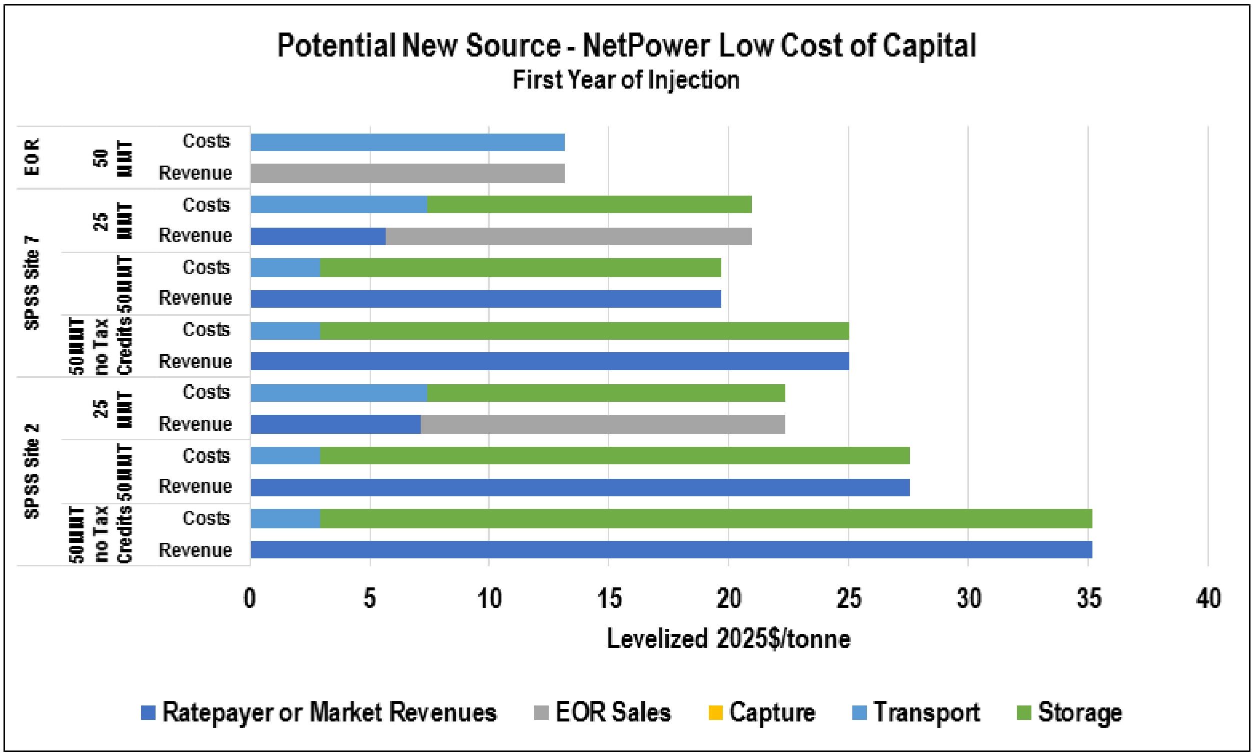

Figure 6-22. New Source NET Power - levelized cost of CCS and revenue requirements low cost of capital; 2025$/tonne (first year of injection).

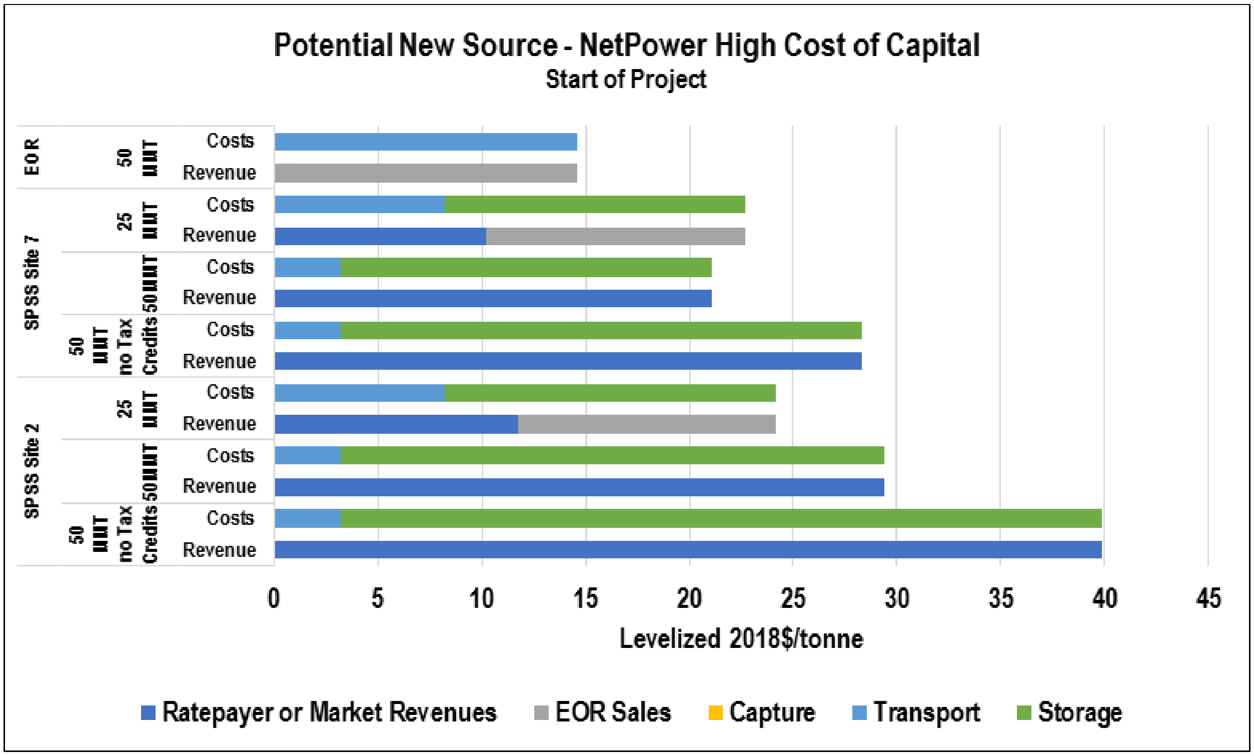

Figure 6-23. New Source NET Power - levelized cost of CCS and revenue requirements high cost of capital; 2018$/tonne (start of project).

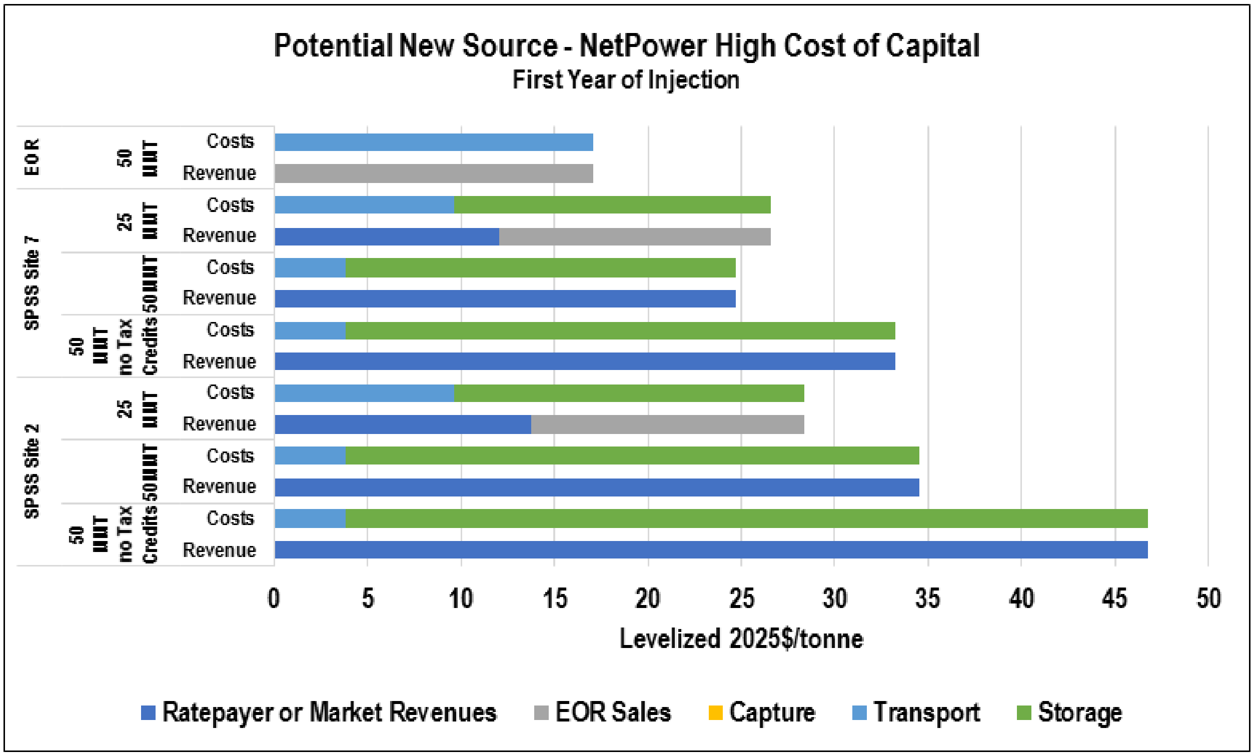

Figure 6-24. New Source NET Power - levelized cost of CCS and revenue requirements high cost of capital; 2025$/tonne (first year of injection).

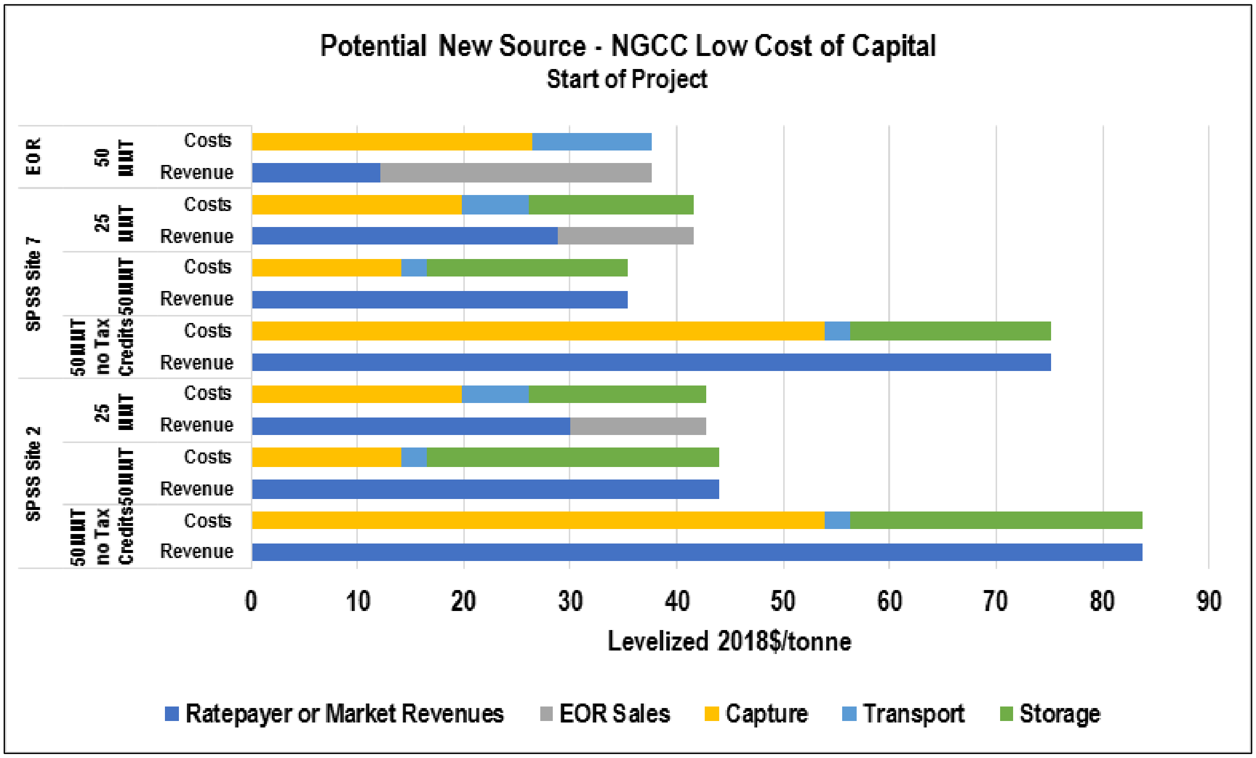

Figure 6-25. New Source NGCC - levelized cost of CCS and revenue requirements low cost of capital; 2018$/tonne (start of project).

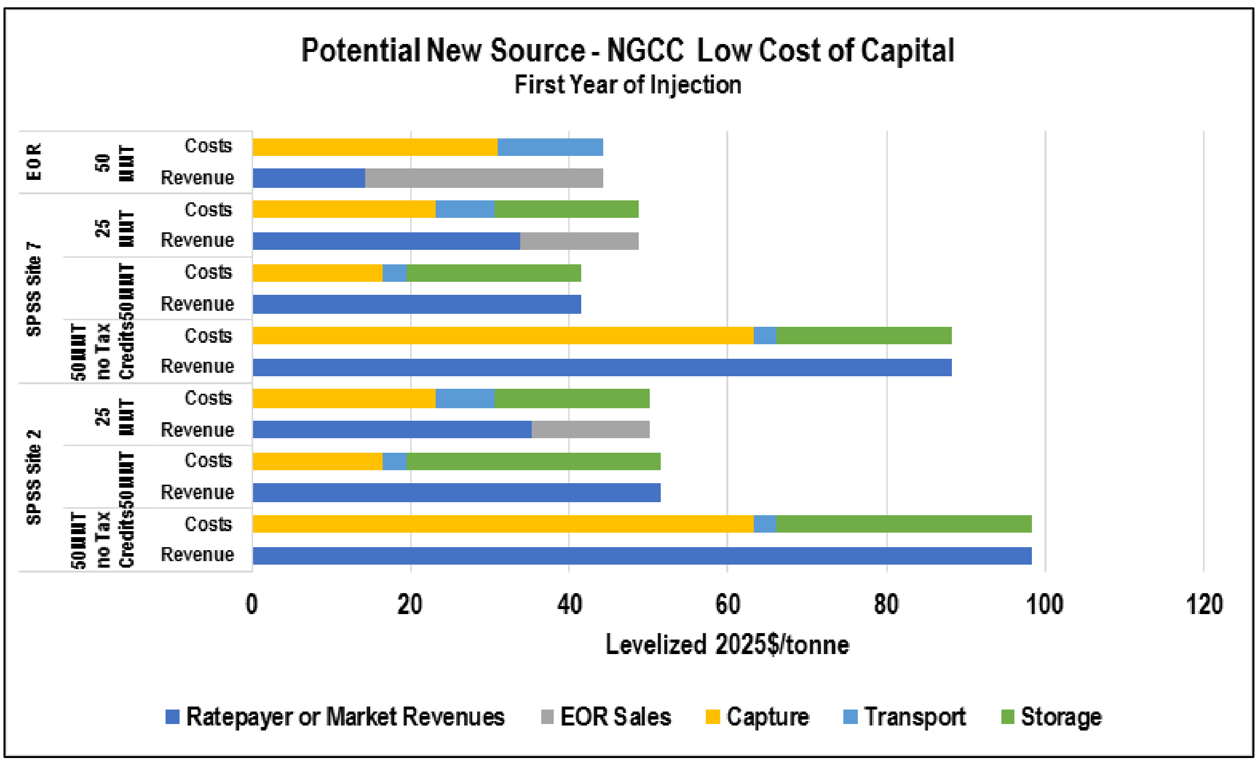

Figure 6-26. New Source NGCC - levelized cost of CCS and revenue requirements low cost of capital; 2025$/tonne (first year of injection).

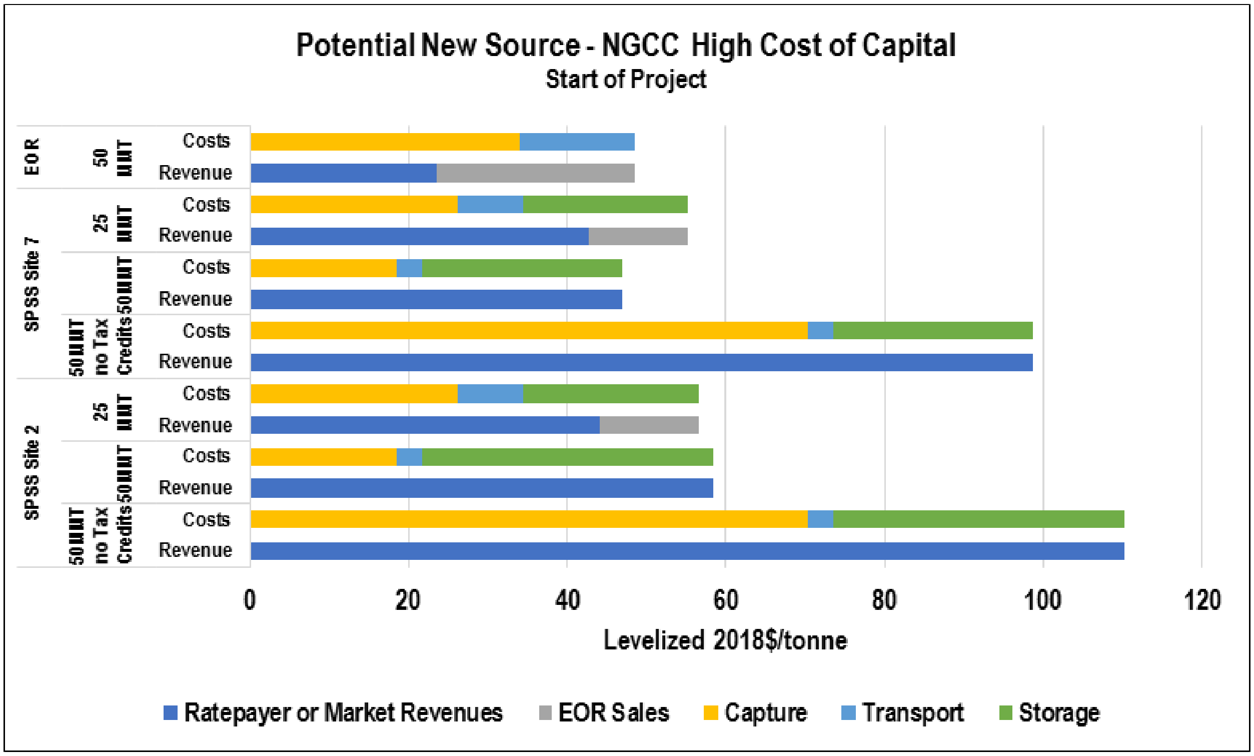

Figure 6-27. New Source NGCC - levelized cost of CCS and revenue requirements high cost of capital; 2018$/tonne (start of project).

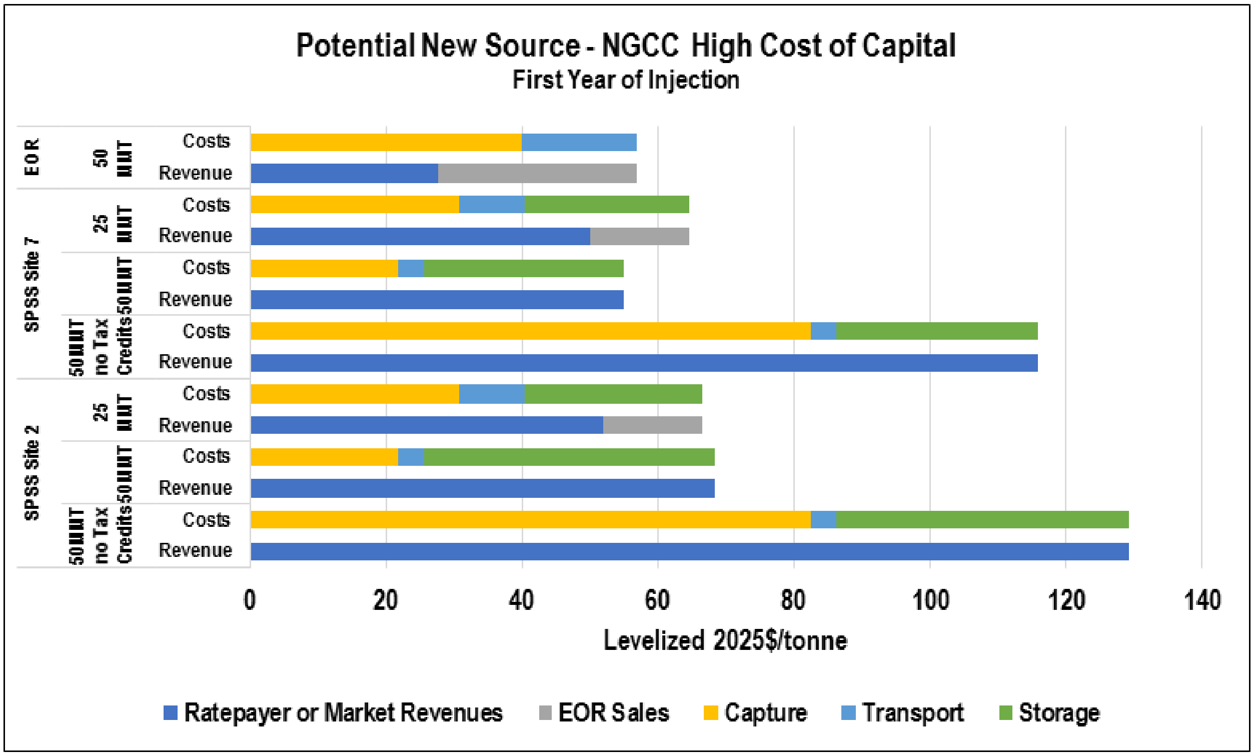

Figure 6-28. New Source NGCC - levelized cost of CCS and revenue requirements high cost of capital; 2025$/tonne (start of project).

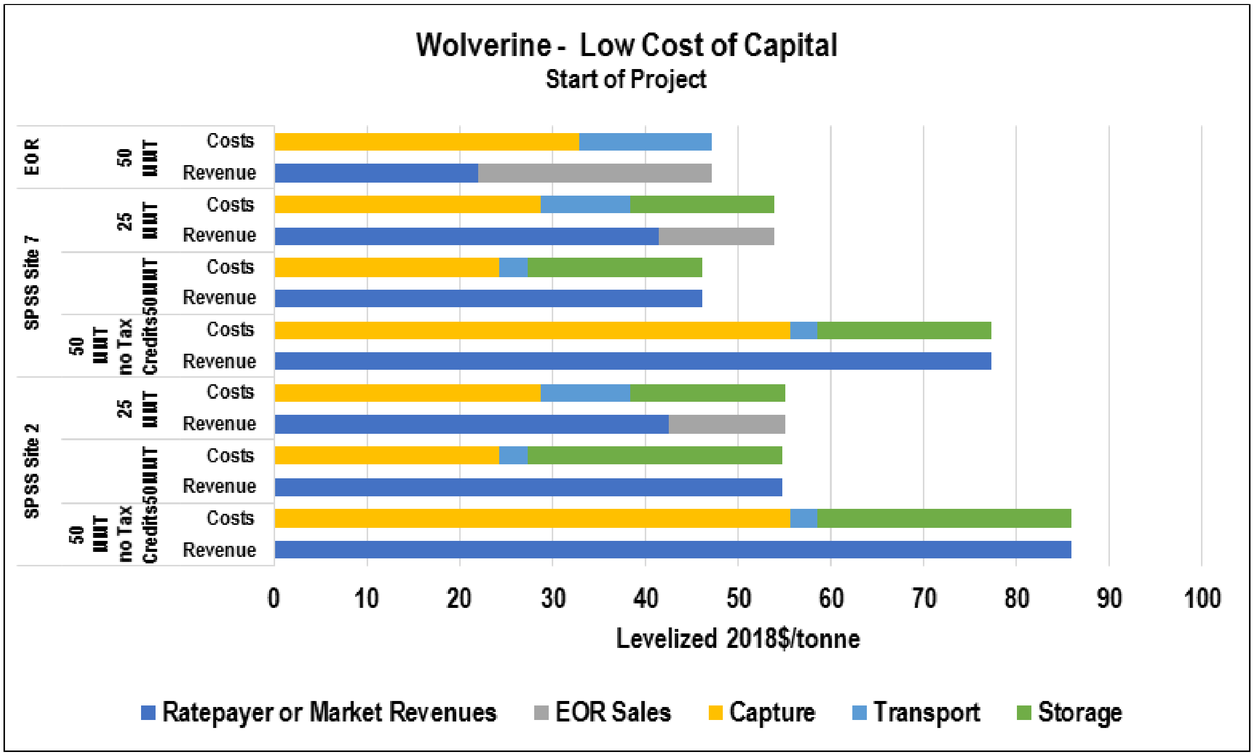

Figure 6-29. Wolverine - levelized cost of CCS and revenue requirements low cost of capital; 2018$/tonne (start of project).

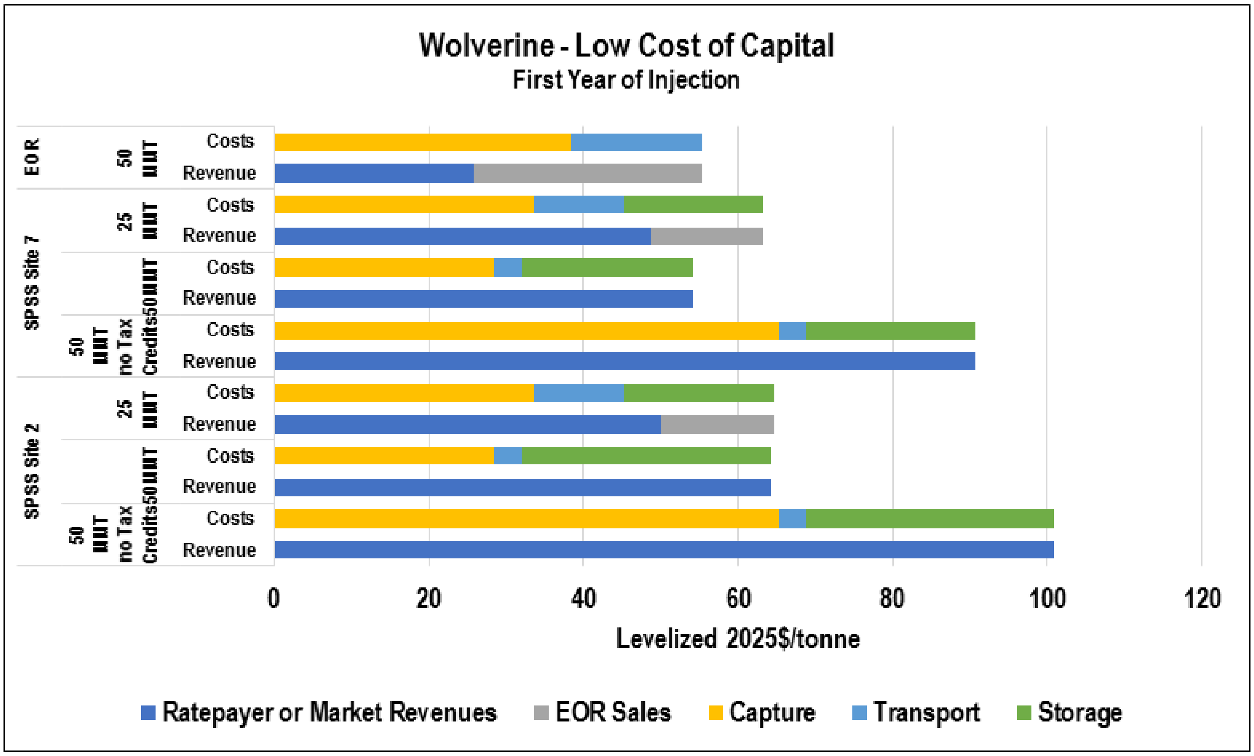

Figure 6-30. Wolverine - levelized cost of CCS and revenue requirements low cost of capital; 2025$/tonne (first year of injection).

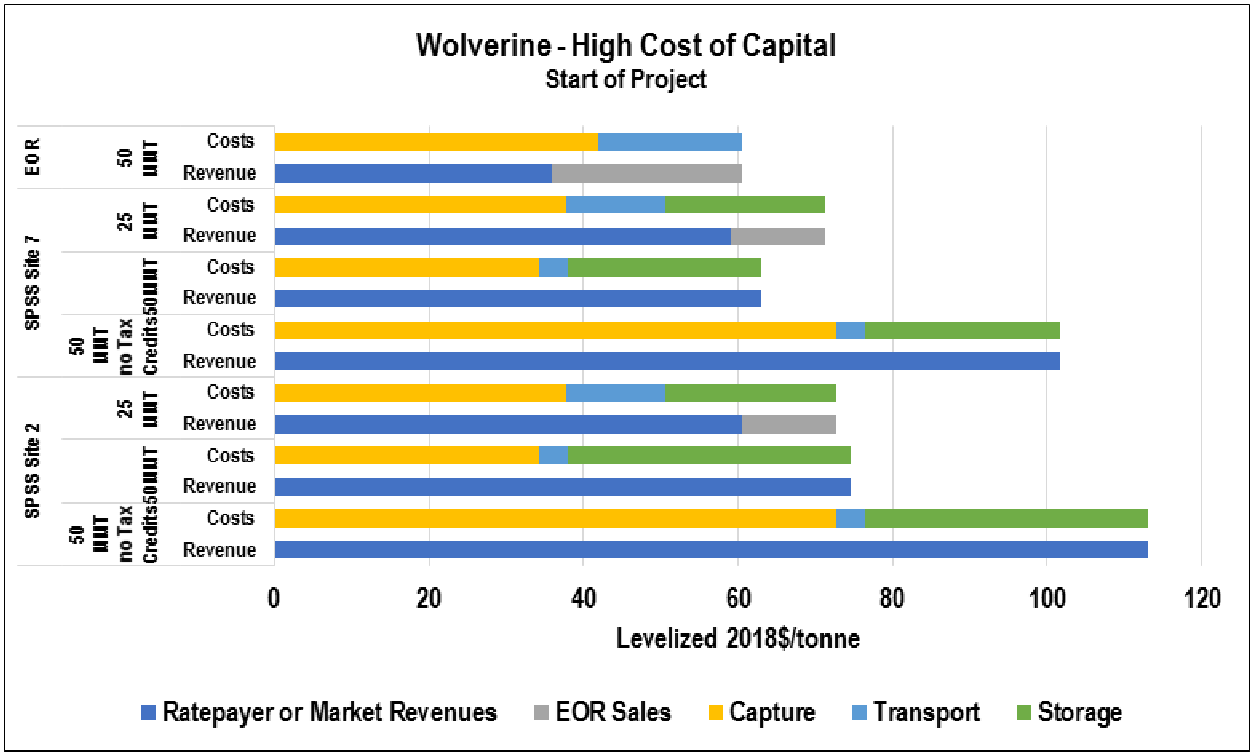

Figure 6-31. Wolverine - levelized cost of CCS and revenue requirements high cost of capital; 2018$/tonne (start of project).

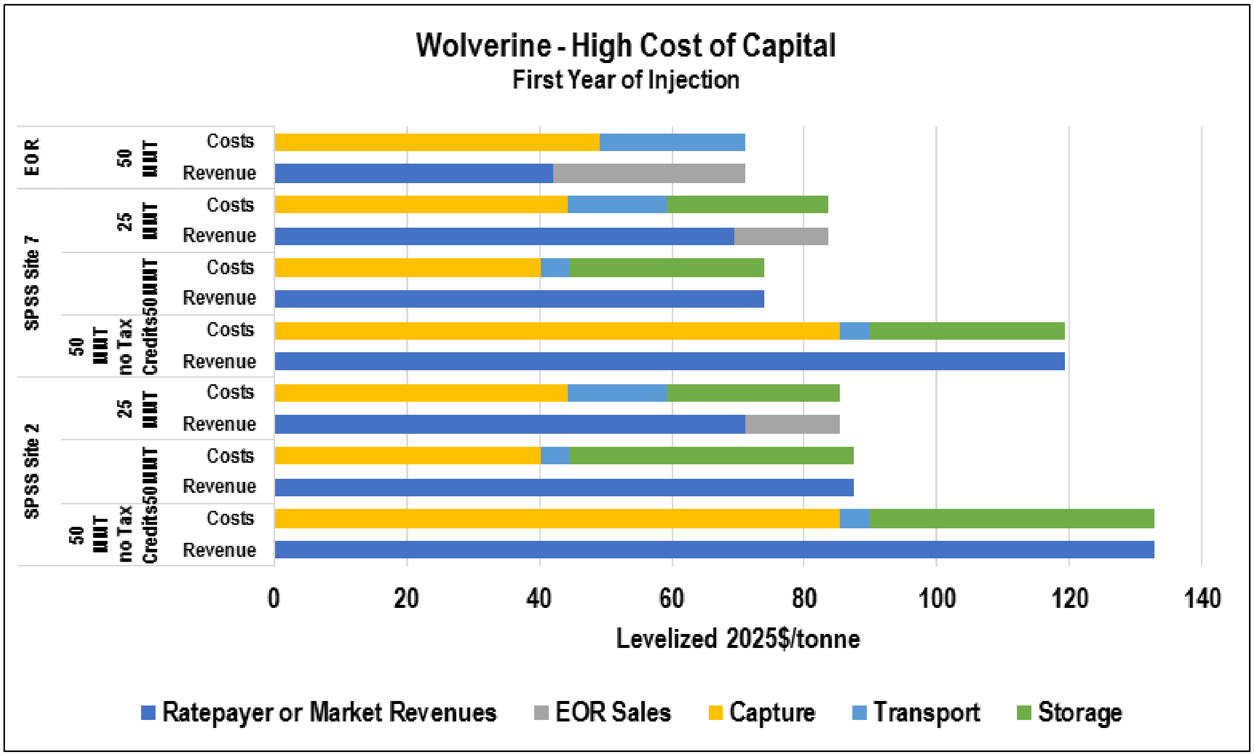

Figure 6-32. Wolverine - levelized cost of CCS and revenue requirements high cost of capital; 2025$/tonne (first year of injection).

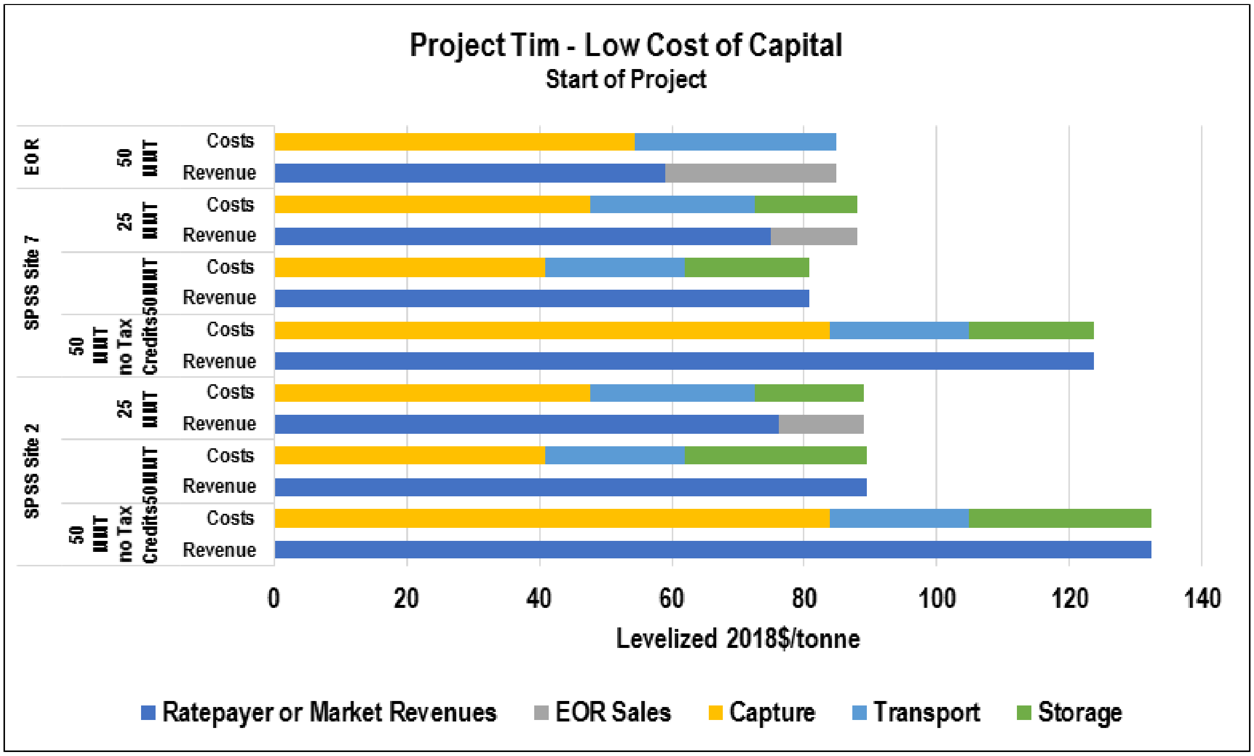

Figure 6-33. Project Tim - levelized cost of CCS and revenue requirements low cost of capital; 2018$/tonne (start of project).

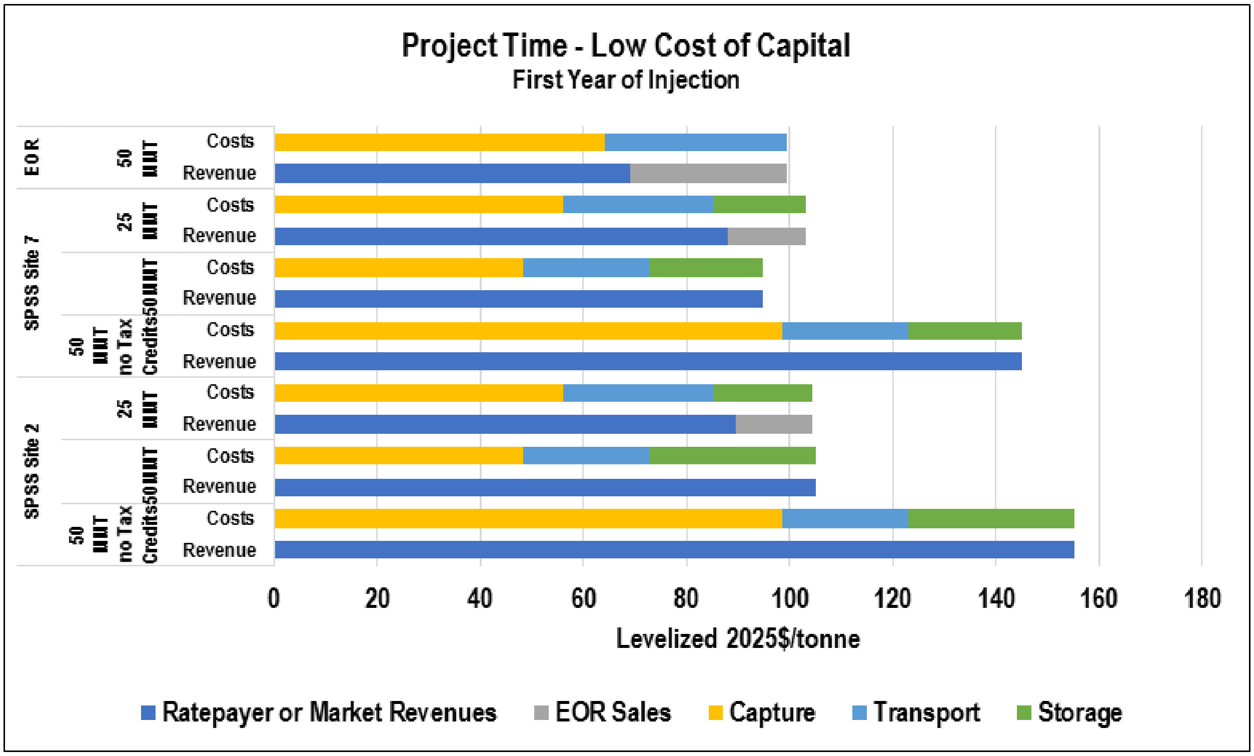

Figure 6-34. Project Tim - levelized cost of CCS and revenue requirements low cost of capital; 2025$/tonne (first year of injection).

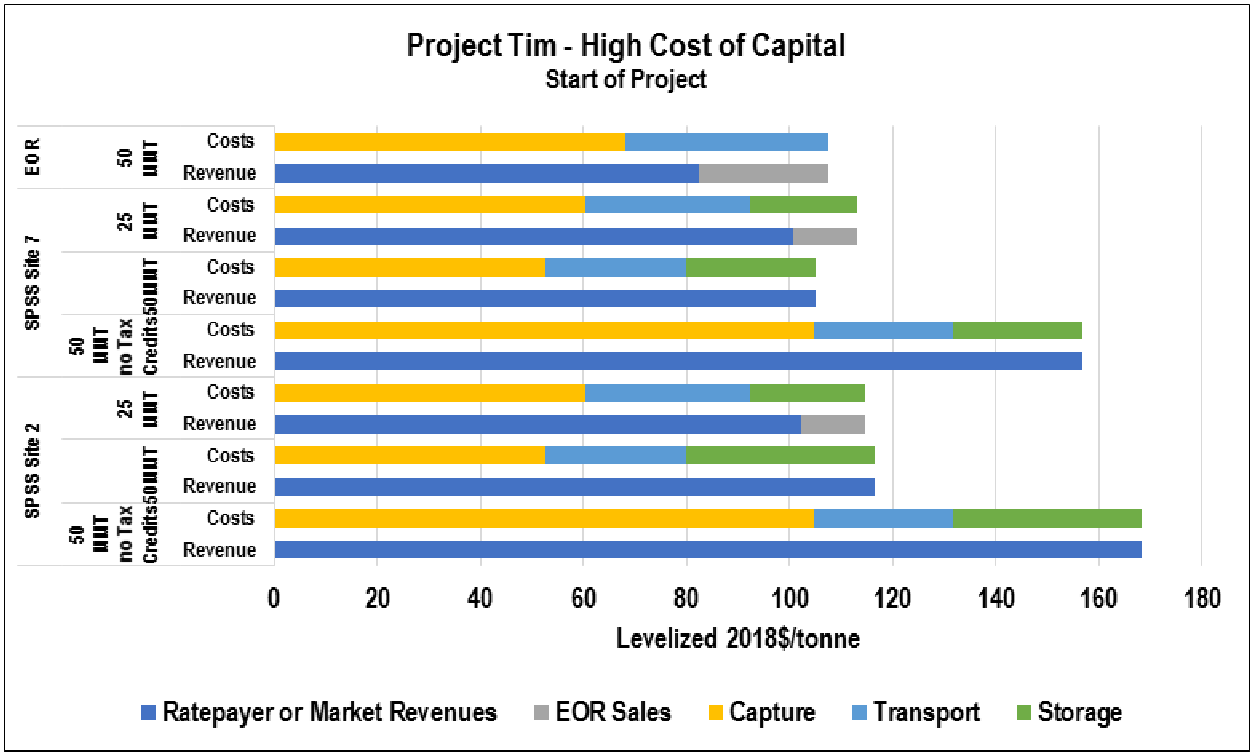

Figure 6-35. Project Tim - levelized cost of CCS and revenue requirements high cost of capital; 2018$/tonne (start of project).

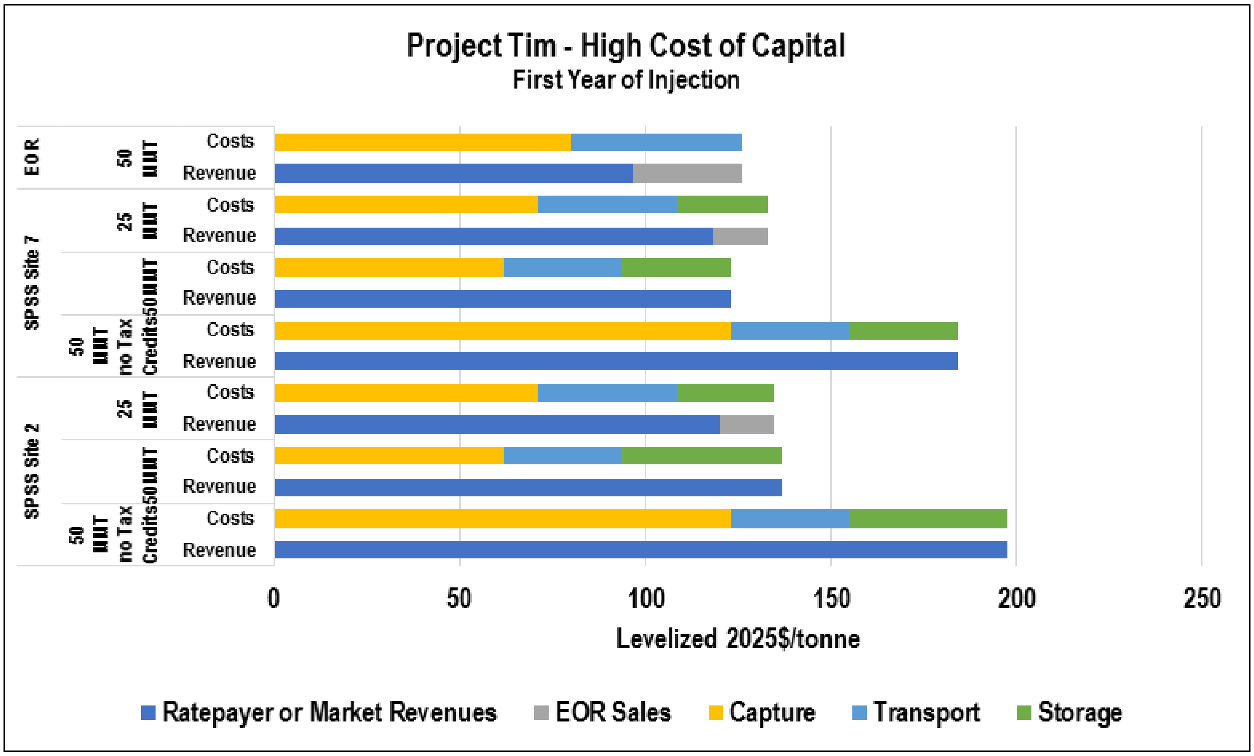

Figure 6-36. Project Tim - levelized cost of CCS and revenue requirements high cost of capital; 2025$/tonne (first year of injection).

6.3.4 Summary

This preliminary analysis indicates that the most economically viable scenario is the emerging NET Power technology and 100% EOR storage (see Figure 6-21 through

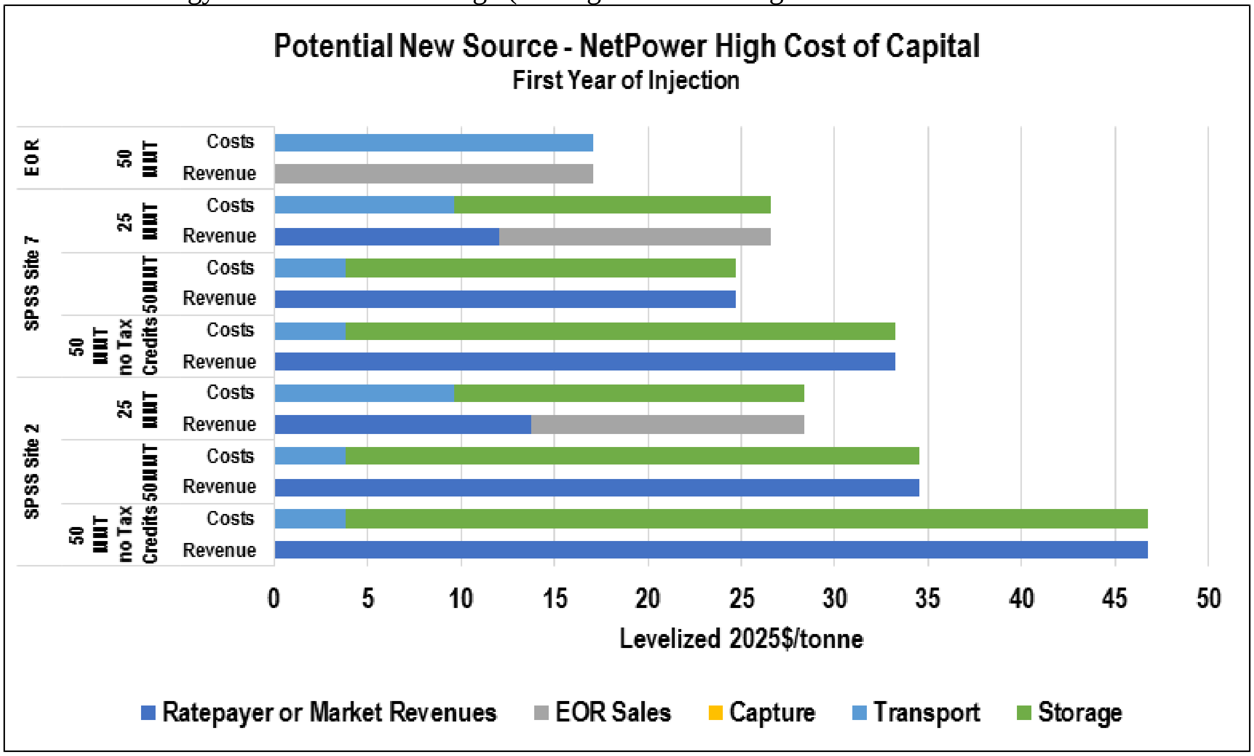

Figure 6-24). As these charts illustrate for this scenario, the sale of CO_2 for EOR alone covers the costs associated with CCS. Only transportation (pipeline) costs from the CO_2 source to the EOR field are necessary in this case because the incremental cost of capture is assumed to be zero for the Allam Cycle; the facility produces a pipeline-quality CO_2 as a byproduct. If only 50% of the CO_2 was to be sold for EOR operations and the other 50% stored in one of the proposed SPSS saline reservoirs, there would be a modest net revenue requirement of only approximately $5 to $7 per tonne in the low cost of capital case and $10 to $12 per tonne in the high cost of capital case. (The net revenue requirement being defined as the amount of revenues obtained either from ratepayers or the market.) This net revenue requirement could be further reduced if oil prices increase, or if costs savings can be found from the operations and monitoring of the pipeline or storage reservoir.

Following the PNS with NET Power source-sink combination, the other three source-to-sink combinations are presented in economic order from least to most costly in

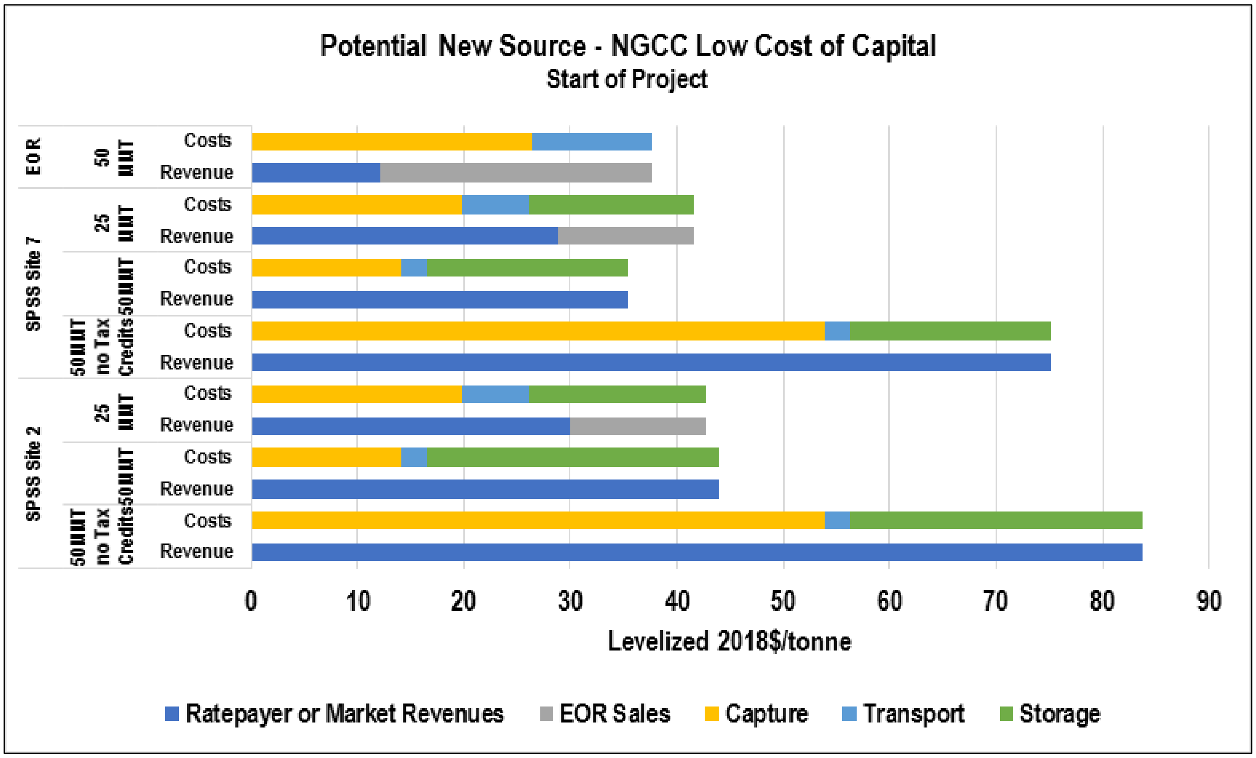

Figure 6-25 through Figure 6-36 – i.e.,

- PNS with NGCC (

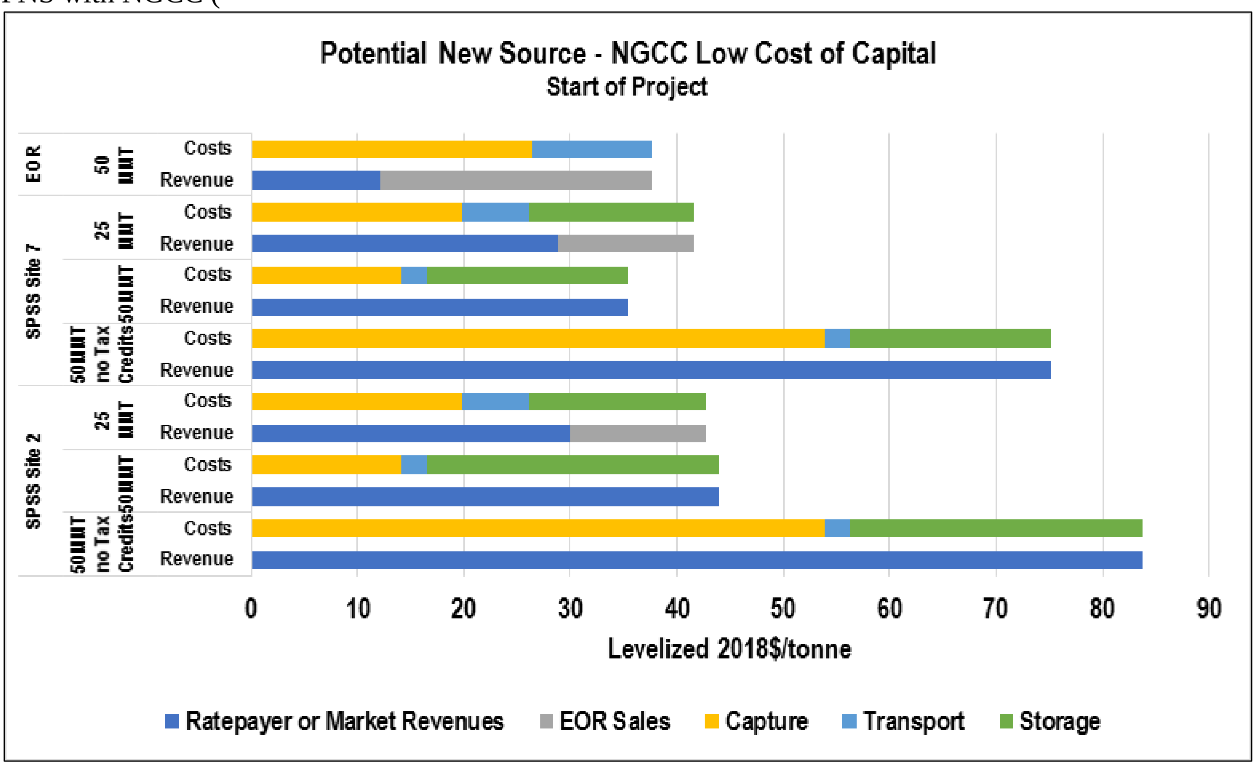

Figure 6-25 through

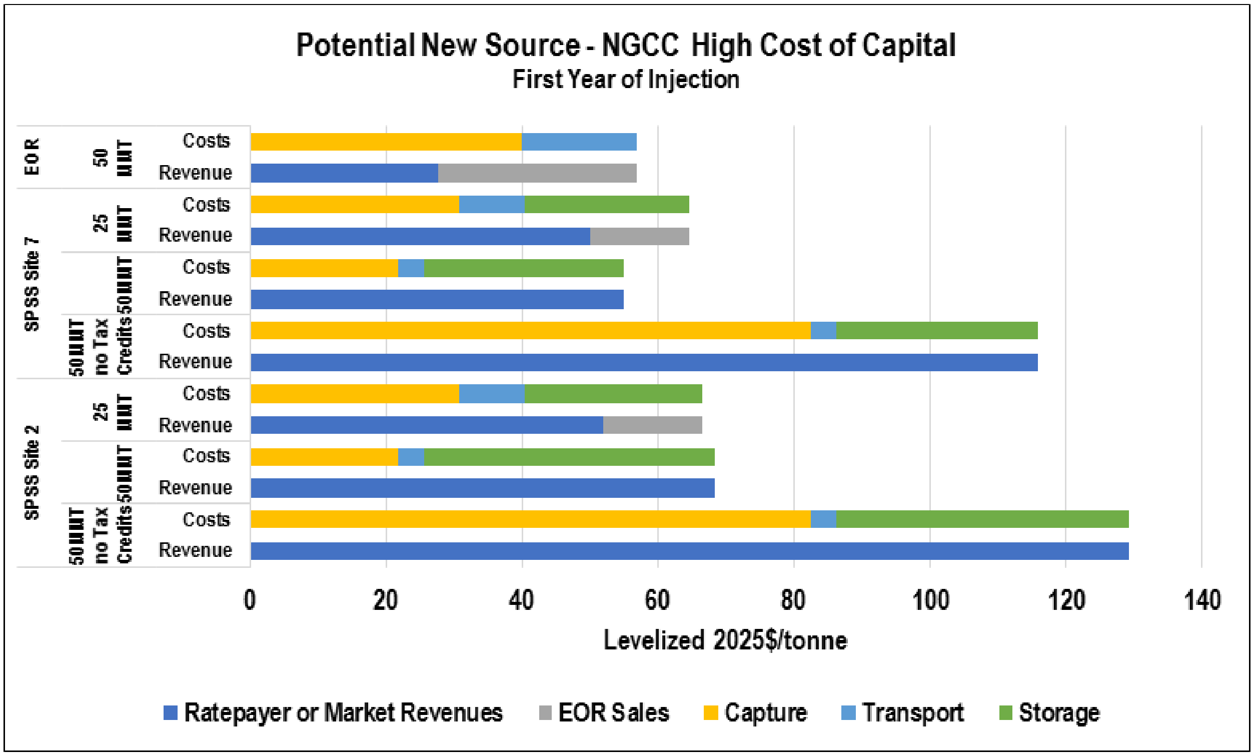

Figure 6-28);

- Wolverine (

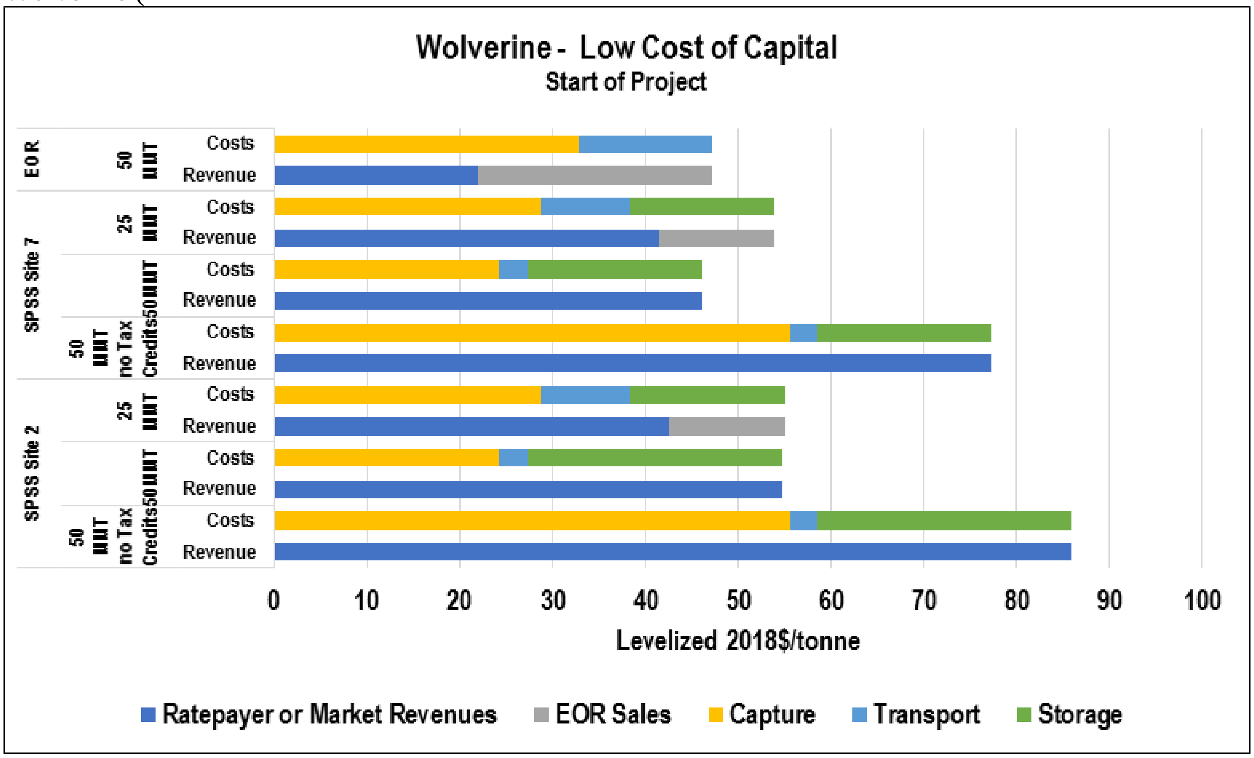

Figure 6-29 through Figure 6-32);

- Project TIM (Figure 6-33 through Figure 6-36).

As these figures illustrate, these other scenarios are less attractive for two reasons. Mainly, the incremental cost of capture for either a new gas-fired combined cycle facility (as shown by the PNS with NGCC in

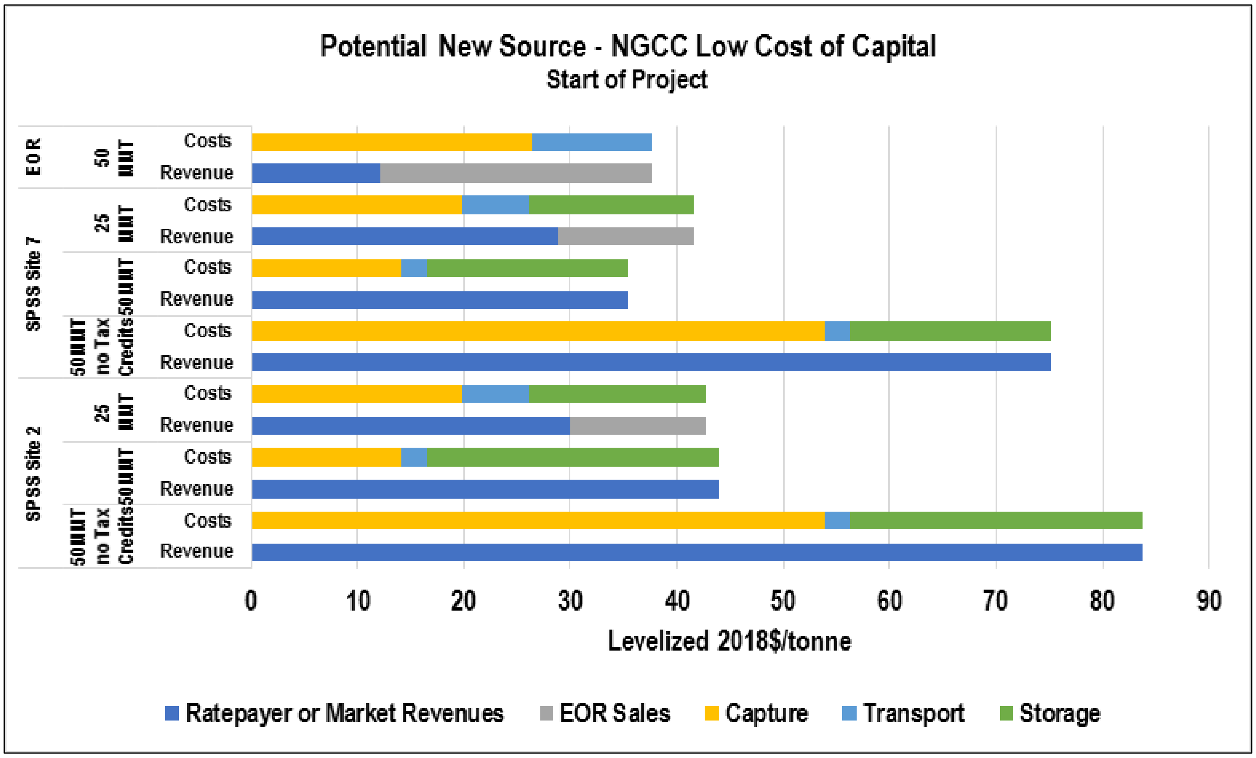

Figure 6-25 through

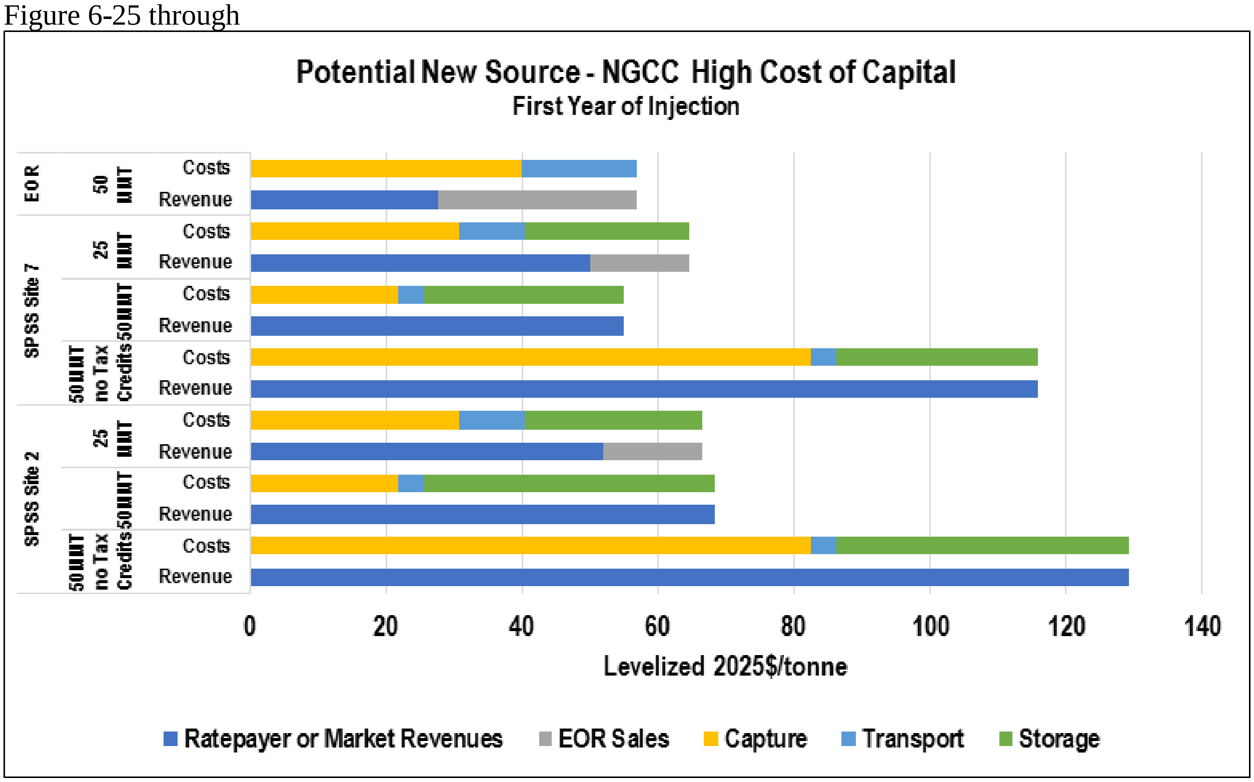

Figure 6-28) or a retrofit application (as shown by the results for the Wolverine scenario in

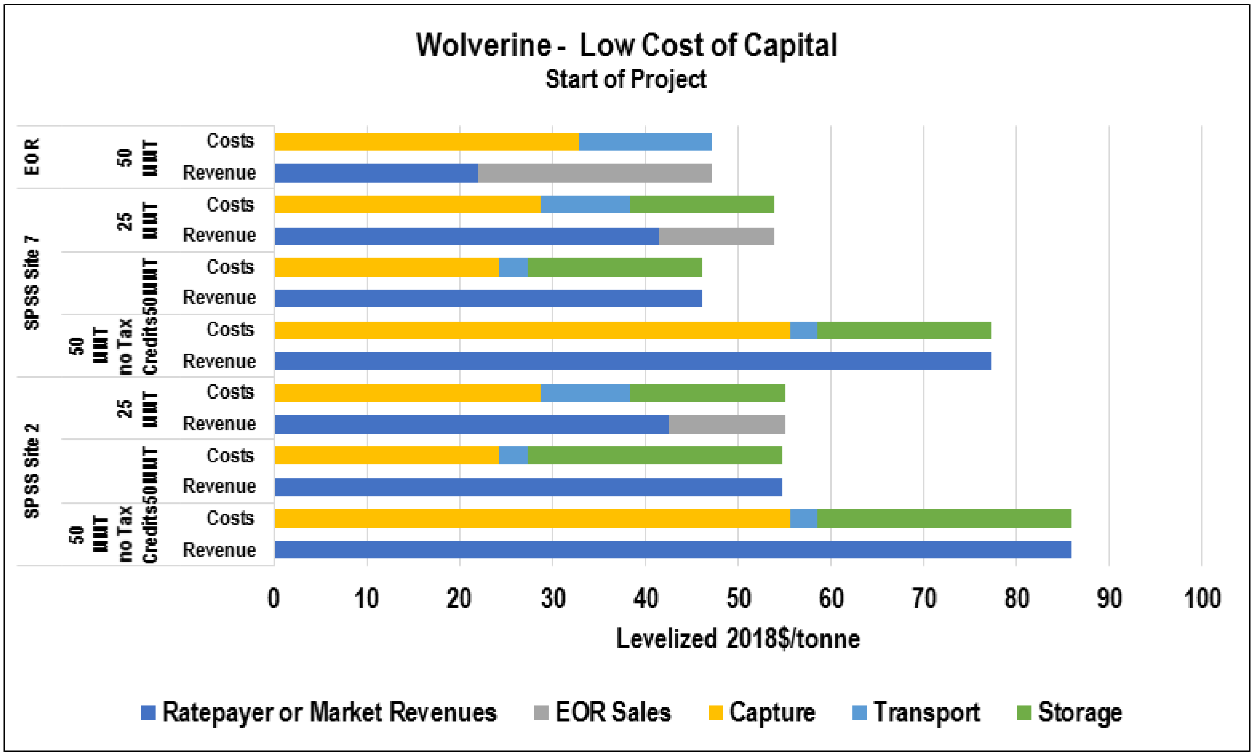

Figure 6-29 through Figure 6-32), is still the most significant CCS cost driver and cannot be overcome even with the addition of the revised Section 45Q tax credits and 100% EOR storage. The cost of capture is a greater impediment on the economics of CCS for a new coal-fired facility as proposed in the Project TIM scenario (Figure 6-33 through Figure 6-36). As shown in Figure 6-37 below, a >20% reduction in the cost of capture is necessary for a new natural gas-fired combined cycle with 100% CO_2-EOR storage to achieve a breakeven net revenue requirement. However, it should be noted that capture technology costs are likely to be significantly lower in the future as the investments made by the DOE CO_2 capture R&D program mature and the deployment of current and next generation technologies proceeds from pilot to commercial deployment. Such advances could make a 20% savings in capture costs a possibility. Also, if additional EOR revenues could be realized as shown in Figure 6-38, the net revenue gap will shrink considerably for a natural gas plant with 100% EOR storage making this option more viable.

Second, the greater the distance from either the saline reservoir or EOR field the source is located, the cost of transport becomes a more significant negative factor for the scenario economics. This is again very evident for Project TIM, which is located over 100 miles from the proposed saline and EOR storage fields. Despite higher cost, Project TIM could be potentially attractive because it offers a combined advanced clean steel making with power generation, which can enable other manufacturing in the state.

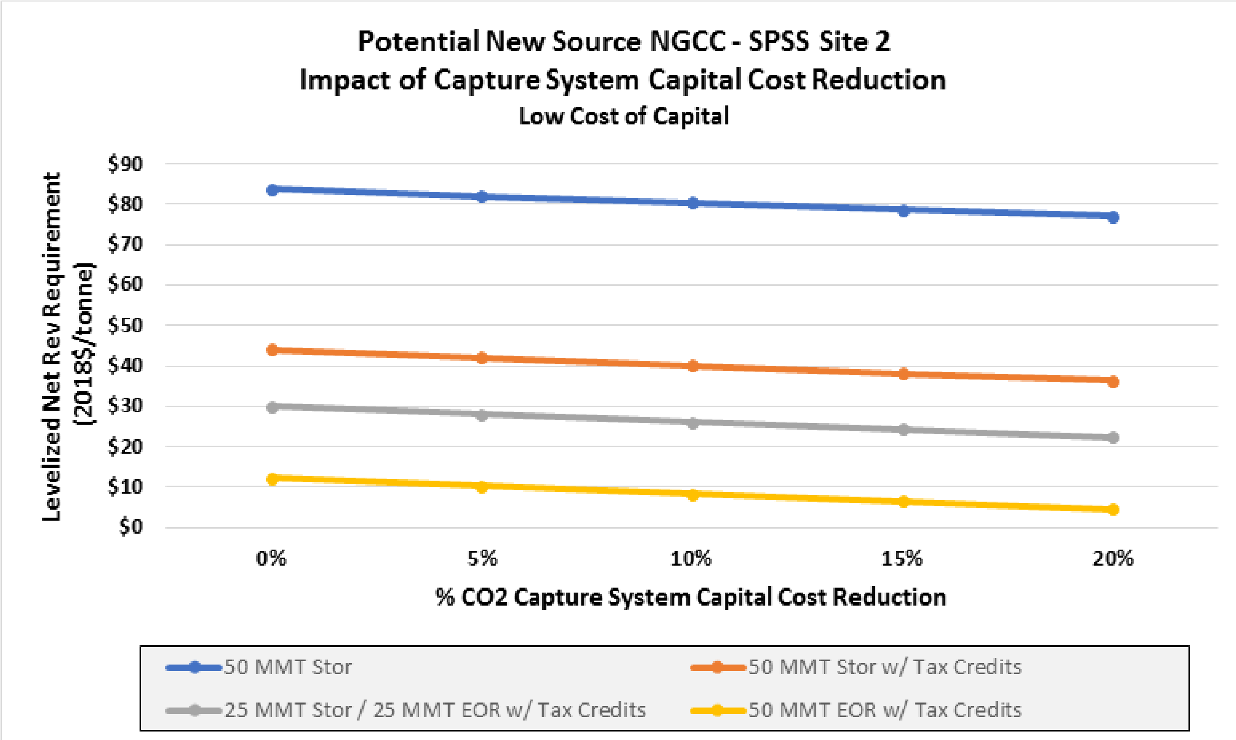

Figure 6-37. Impact of capture capital cost reduction on levelized net revenue requirement for a natural gas-fired combined cycle.

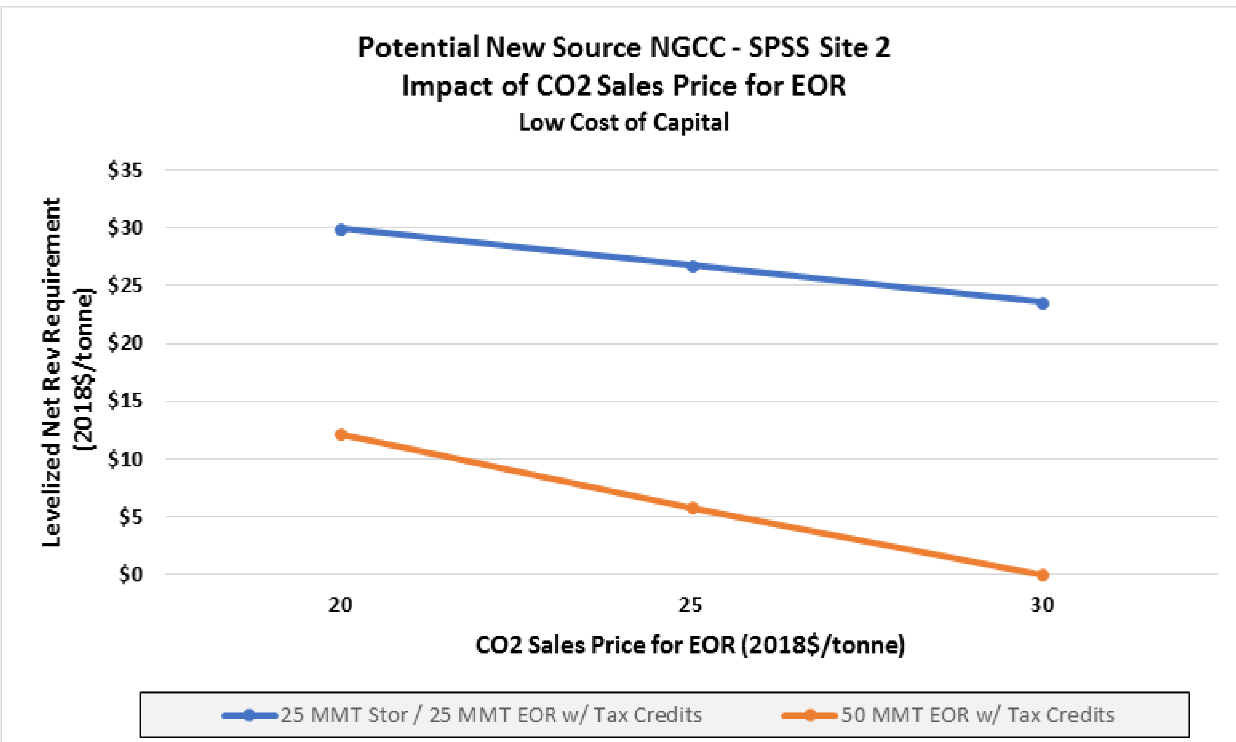

Figure 6-38. Impact of CO_2 sales price for EOR on levelized net revenue requirement for a natural gas-fired combined cycle.

Overall, this analysis indicates that the availability of the recently enacted tax credits will go a long way towards closing the cost and revenue gaps, especially when combined with value added options such as CO_2-EOR. For the saline storage scenarios, it is anticipated that capture technology improvements, detailed pipeline design optimization, storage and monitoring system optimizations, state and local incentives, and eventually a carbon reduction policy could help close the revenue shortfall over the next few years.

6.4 Anticipated Financing Needs and Strategies

The ability to secure lower cost equity and debt financing for deployment of CCS will depend on future policy and incentives because the current environment does not support significant market-based investment. Research by the Clean Air Task Force suggests that without a carbon reduction mandate, the passage of proposed reforms allowing CCS projects to take advantage of the lower cost of capital through Master Limited Partnerships (MLPs) and Project Activity Bonds (PABs) is still needed. These reforms, coupled with the changes to the Section 45Q program, make it more likely that investors and lenders will be attracted to CCS opportunities.

The recent passage of enhancements to the Section 45Q tax credits is a positive development to help support the financing of CCS projects. As has been demonstrated in the wind and solar energy sector, the use of federal tax incentives has created a thriving market for development and investment in such projects using innovative tax equity structures. A similar market for CCS projects could very well develop first for EOR-supported opportunities and then for saline storage projects as reductions in the cost for capture technologies accelerates. During Phase 2, Battelle and its project partners will work to develop a comprehensive financial plan to support the implementation of any of the six scenarios listed above. This plan would include identifying potential equity sponsors who could maximize the use of the federal tax credits, commercial bank lenders, and capital market debt financing alternatives. As the acceptance of CCS projects increases, more potential equity and debt financing options may be available.

With significant uncertainty surrounding the ultimate outcome of EPA's Clean Power Plan, state-level incentives to promote carbon-free power generation and industrial facilities are also necessary. To successfully finance an integrated CO_2 capture and storage project from a natural gas or coal-fired generating station, the State of Michigan may need to pass legislation to enable cost recovery by either allowing long-term power purchase agreements to be signed that cover such costs and/or allow the MPSC to include such costs in electricity consumer rates. These types of cost recovery mechanisms are critical to the success of any CO_2 capture and storage project in the absence of a value for carbon in the wholesale electricity markets or federally mandated carbon reduction, even with the potential for EOR revenues from companies, such as Core Energy, on this project. In addition to legislation that allows for cost recovery, other incentives, such as exemption to state sales tax during construction, property tax abatement, and the possible reduction in state income taxes, should be considered by policymakers to enable the growth of CCS projects. Additional incentives could include rebates on easements for pipelines and surface access for a storage complex and enabling access to state-owned pore space through reduced access fees, similar to the reduction in severance taxes for CO_2-EOR already offered by Michigan.

The project team's commercial and financial experience on FutureGen 2.0 and other complex CCS projects provides the firsthand knowledge necessary to develop and finance a successful CCS project. The team also started developing plans for garnering legislative and community support to help advance the CCS industry in Michigan.

7.0 Path Forward

The primary objective of the CarbonSafe program in the Northern Michigan basin is to develop a commercial-scale (50 MT over 20-30 years) CO_2 storage complex with demonstrated safe, permanent, and economic storage. This development can be undertaken with progressively more decisive steps over several years as conceptualized in the DOE's CarbonSafe program roadmap. The progressive steps involve feasibility analysis (Phase II), detailed characterization (Phase III), and final permitting and construction (Phase IV). Each step is associated with decision points related to reducing surface, subsurface, and business uncertainties, so that appropriate business and investment decisions can be made. Furthermore, the complete realization of the storage complex development will also require a strong partnering between public and private entities for financial support and equitable risk management instruments.

The pre-feasibility analysis presented in this report has demonstrated that the NMB region is attractive for geologic storage based on favorable geology, history of CO_2-EOR, stakeholder acceptance, and regulatory atmosphere. Therefore, it is advisable to move the project into a detailed feasibility analysis under Phase II. This future phase can be primarily aimed at reducing the remaining geologic uncertainties, which could influence operational and long-term performance and should lead to a clear roadmap for addressing any remaining non-technical issues. The feasibility analysis will rely heavily on the past 13 years of DOE investments in the MRCSP research in the CS-NMB area; on the prefeasibility work done under Phase I; and especially on the site access, assets, local relationships, and knowhow provided by Core Energy.

The feasibility study should involve performing commercial-scale initial characterization of the storage complex and developing comprehensive datasets of formation characteristics (such as porosity, permeability, injectivity, mineralogy, fluid composition, geochemical conditions, stratigraphy, cap rock integrity, etc.) and performing analyses of the data to determine the suitability of the potential geologic storage site(s) within the storage complex. The feasibility study should also further develop the public acceptance and economic feasibility of a CO_2 storage complex in the Northern Michigan Basin study area.

The key challenges to be addressed during feasibility study are discussed in the following sections.

Challenge #1 – Additional subsurface data are needed to reduce the geologic uncertainties related to designing and operating a CO_2 storage complex.

During Phase II, the remaining geologic data gaps should be addressed by conducting a comprehensive characterization and testing program focused on the SPSS and its caprock/seals.

Surface Reflection Seismic Data – The sub-basinal characterization must be able to assess the geologic continuity of the reservoirs and cap rocks at the well sites and in the larger sub-basin for commercial deployment. The project will use existing and new seismic data to help overcome the data quality issues with the older available 2D lines in the region. Several thousand miles of 2D lines are available from seismic brokers, albeit many of these are shorter segments acquired for small local plays. Battelle can review selected lines and select an appropriate length (~200 miles) for reprocessing and incorporation into the sub-regional geologic framework model developed in Phase I. The 2D lines should be supplemented with selected newer 3D seismic data, which cover smaller areas around existing EOR operations and have been integrated with wellbore data from the Niagaran Reefs. The relevant portions of these data may need reprocessing for mapping the deeper SPSS layers. Finally, the surface seismic data can be integrated with the wellbore vertical seismic profile (VSP) collected from one or both planned Phase II characterization wells.

Borehole/Well Test Data – The CS-NMB team can deepen two existing wells (MRCSP1 and Charlton 3-6) through the SPSS, collect rock core and log data, and conduct in situ testing of the SPSS and overlying cap rocks. Having access to two wells is significant for reducing uncertainty in geologic properties that affect predictions of injectivity, capacity, and containment. The MRCSP1 was drilled to about 7,100 feet in 2011 with DOE funds but was left incomplete and in temporary abandonment status due to the impact of the EPA Class VI well requirements. The Charlton 3-6 is a vertical well drilled to the base of the reefs and can be deepened in the current configuration. Using these partially cased wells also helps avoid lost circulation zones in the shallower sections and provides benefits of more than $5M in prior investments in the wells.

A common set of characterization data should be obtained from both wells, including a mud log, routine and specialized geophysical logs, and sidewall core samples. In addition, an enhanced characterization program can be conducted in one well, including collection of whole core from the SPSS reservoir and cap rock for laboratory testing and a series of reservoir tests. The common dataset will allow an assessment of spatial variability of key reservoir and cap rock properties within the storage complex that cannot be obtained from a single characterization well.

The reservoir testing program should be conducted after the drilling, coring, and logging is completed for both wells. The planned tests and their objectives are given in Table 7-1. Reservoir hydraulic tests are a preferable method for deriving reservoir hydraulic properties because they provide results for a much larger reservoir volume compared to log data and core data. The in situ hydraulic fracture (mini-frac) tests are the only reliable method for constraining maximum horizontal stress. In situ test data can also be used to calibrated log data. Fluid samples from the SPSS can be collected in conjunction with the multi-day pumping test and analyzed for isotopic and geochemical parameters.

Table 7-1. Reservoir and Caprock Testing Objectives and Approaches

Characterization Objectives		Test Approaches/Options
1	Assess the intermediate- to large-scale composite permeability-thickness (injectivity) and presence of hydrologic boundaries of the entire SPSS (i.e., presence of lateral hydrologic boundaries or facies changes that may impact long-term injection potential)	Multi-day pumping test (drawdown/recovery)
2	Obtain an intermediate-scale, reconnaissance-level vertical permeability profile of the SPSS reservoir to define potential injection layers	Dynamic mechanical (spinner) flowmeter surveys performed in a constant-rate injection test mode
3	Assess the small- to intermediate-scale transmissivity (kh) and presence of local hydrologic boundaries that may impact injection potential of specific layers within the SPSS	Slug/DST test using a straddle packer with adjustable, test interval spacing. Drawdown/buildup testing using wireline-deployed testing tool, with 3-foot fixed straddle packer spacing
4	Establish the minimum and maximum horizontal stress (fracture-gradient) for the SPSS and overlying cap rocks	Open borehole injection/fall-off (mini-frac) testing using straddle packer with adjustable test interval capabilities or wireline-deployed tool with 1- or 3-foot straddle packer spacing
5	Obtain representative reservoir fluid hydrochemistry sample	Achieved in conjunction with the multi-day pumping test (Objective 1)

Borehole Seismic Data – Vertical Seismic Profile (VSP) – Borehole seismic acquisition can be collected for geophysical images of the lateral architecture, continuity, and structure of the SPSS and overlying cap rock formations in the vicinity of one or both characterization wells. VSP is advantageous over surface reflection seismic in the northern Michigan study area because of the thick layer of glacial deposits at surface that attenuate energy. By placing geophone receivers in the borehole, VSP can provide much higher resolution images of the subsurface geology. The VSP survey can include four walk-away transects at the well, each extending approximately 8,000 feet from the well, and oriented 90 degrees from one another, with sources spaced 100 to 250 feet apart. This configuration, which can be finalized for execution, should allow imaging two vertical cross sections through the well(s), each with a lateral coverage of approximately 5,000 feet at the base of the SPSS (**Error! Reference source not found.**). These higher resolution VSP lines can be tied to the older 2D lines so that the seismic framework can be extended along the sub-basin beyond the immediate VSP lines. Depending on data quality, an attempt can also be made to process the seismic data to estimate the reservoir porosity distribution and geomechanical stress parameters variability in the coverage area.

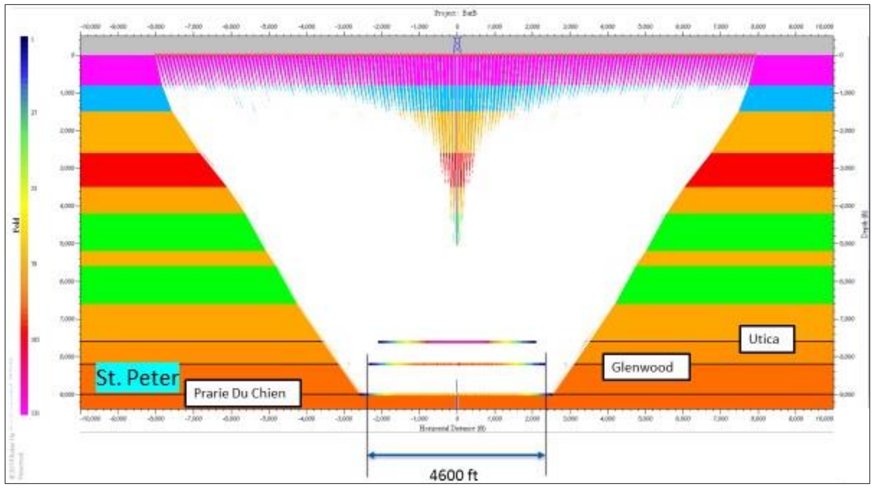

Figure 7-1. Estimated image area (white shading) (approximately 5,000 ft) at base of St. Peter based on preliminary VSP acquisition designs.

Cross-Formation Pressure Monitoring for Testing Cap Rock Integrity

Monitoring of pressure response in the first porous and permeable zones(s) above the cap rock overlying a CO_2 storage reservoir has been suggested by U.S. EPA as a means for detecting vertical migration of fluids (leakage) out of the reservoir. The carbonate Niagaran reefs represent the first porous and permeable zone overlying the SPSS. After the conclusion of the borehole characterization program in the Charlton 3-6 well, a pressure gauge can be installed in the well and in one or two existing wells in the overlying Charlton 6 Niagaran reef (one of Core Energy's active EOR fields). The pressure gauges should be left in place for a period of time (months) to monitor potential pressure response in the SPSS from hydraulic stress perturbations caused by injection and/or production in the overlying Charlton 6 field, as way to assess the potential for upward cross-formational flow. The pressure data from the Charlton 6 Niagaran reef wells will provide a reference for comparing the pressure data from the deeper SPSS well to determine if a pressure response is detected and, if so, whether a correlation exists with the stress signal in the reef.

Integrating and Interpreting the Data

The geologic characterization data collected in Phase II should be integrated with already existing data used in the Phase I prefeasibility assessment to develop a storage complex design. A generalized workflow from field characterization to modeling to the storage complex design is shown in Figure 7-2. While much of this work does not require development of new technologies, it does require innovative use of existing assets, characterization tools and methodologies, and data integration and modeling workflows to address the key questions.

Reservoir modeling and analysis can be used to advance the state of the art for using the field data to simulate the storage complex for commercial-scale design, optimized pore space utilization, and assessing and mitigating risks. The Phase II data from two wells can be used to constrain the range of uncertainty in the static and dynamic storage resources. A key outcome of this analysis will be a narrower gap between P_{10} and P_{90} resource estimates for the storage zone. The compositional flow models for CO_2 injection in brine have been used extensively by Battelle for projects, such as FutureGen and the AEP Mountaineer sites. Innovative well designs have been developed to mitigate risks of plume trespass into unlicensed areas. Battelle has also conducted coupled geomechanical and geochemical modeling, especially to evaluate risks for fracturing of cap rock and migration along fracture networks. Finally, the NRAP modeling tools can be used to evaluate risks and extend the work done during Phase I of the project. These will advance the technology by testing the tools and developing methodologies for commercial-scale applications.

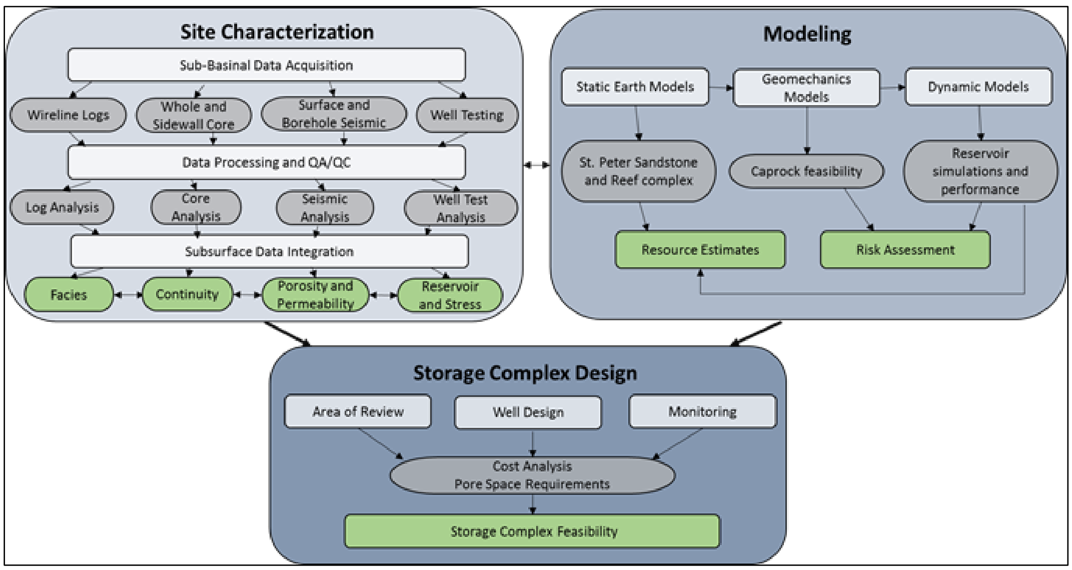

Figure 7-2. Workflow for data collection, modeling, and storage complex design.

Challenge #2 – Linking CO_2 sources to local sinks relies on CO_2 emitters installing capture technologies in an economically viable manner.

Engagement of CO_2 source companies shows a diversity of potential supply options with new generation technologies, such as a planned state-of-the-art steel mill with cogeneration from coal and other fuels; revolutionary generation technologies, such as NET Power, offering high-purity, compressed CO_2; natural gas-based power plants (such as the Wolverine plant in Otsego County); and cogeneration being converted to natural gas combined cycle (Tondu Corporation). Extensive dialogue and collaboration with CO_2 sources are needed to fully evaluate the diversity of choices and innovative technologies.

Challenge #3 – Legal/Regulatory Challenges

In Phase II, the CS-NMB team, assisted by team member Loomis Law, should engage with the appropriate regulatory agencies to define all legal/regulatory requirements for a commercial-scale geologic storage facility and endeavor to resolve or begin the process of resolving issues that could be barriers to successfully developing the CS-NMB program. Some of the key issues and questions that can be addressed during Phase II include:

- Obtaining state authorization for using state land for CO_2 storage.
- Determining if current statutes controlling pore space rights need to be amended for CO_2 storage.

- Determining if the MDEQ's empowering statutes need to be amended to expand the MDEQ's jurisdiction to cover the storage of CO_2 incidental to ongoing enhanced oil recovery operations and the conclusion of the CO_2 EOR operations.
- Determining if MPSC's current statute and regulations governing natural gas storage can be amended to empower the MPSC with jurisdiction to regulate CO_2 storage.
- Data generated and/or obtained during Phase II should be organized to support development of a draft Class VI (and Class II) UIC permit application, starting in Phase II.
- A regulatory roadmap will be developed that defines all permitting requirements for the storage complex.

Challenge #4 – More financial mechanisms to establish a commercial CO_2 storage complex are needed.

The recent passage of the Future Act tax credits will help make commercial-scale CO_2 storage more economical. The tax credits alone may not do enough to make it economically possible, except in rare cases where the cost of capture (usually the largest cost) can be significantly reduced or avoided (e.g., NET Power, ethanol plants) and transportation costs can be minimized by having collocated sources and storage sites. For other more typical cases, other financial mechanisms will be required, such as passage of reforms allowing CCS projects to take advantage of the lower cost of capital through MLPs and PABs. These reforms coupled with changes to the Section 45Q program make it more likely that investors and lenders will be attracted to CCS opportunities.

Combining saline storage with CO_2-EOR is another mechanism that may help make a commercial-scale storage complex feasible. As shown in the economic analysis section, combining CO_2 storage in a saline reservoir with storage in depleted oil fields through CO_2-EOR is more economically feasible than saline storage alone. Also, CO_2-EOR alone may be the most economically feasible storage alternative, depending on the sale cost of CO_2 for CO_2-EOR and other factors that affect the cost of these alternative storage options. When used in tandem, the saline reservoir can provide buffer storage when CO_2 is not needed for EOR operations, and the EOR fields can offer storage with a potential value-added benefit.

The Future Act tax credits will require careful economic analysis/modeling to accurately determine the cost/benefit trade-offs of saline storage vs. combined saline storage and CO_2-EOR vs. CO_2-EOR alone. With a per tonne credit of $50 for saline storage vs. $35 per tonne for EOR, the economic winner is not obvious without an accurate understanding of all costs for each scenario and careful financial modeling. The CS-NMB project offers a perfect test bed for evaluating the economics of these different storage options. Some of the groundwork has already been done under Phase I and MRCSP.

In Phase II, the team can further refine the cost/business model developed in Phase I for expanding its current operations along the reef complex to include a sufficient number of EOR reefs to accommodate up to 50 MT of CO_2 in a 30-year period. A backbone pipeline system along the reef trend (already existing) connects the EOR reefs to the main supply line from one or more CO_2 sources, which is also connected to one or more saline reservoir storage sites. Preliminary modeling of this scenario shows that only about 82 of the more than 700 reefs can provide 50 MT of storage capacity through associated and end-of-EOR storage. Core Energy and Battelle can further develop this scenario to determine the best operational practices to optimize CO_2 storage while also improving oil production. The ongoing CO_2-EOR operations in 10 reefs and the 13 years of MRCSP research in NMB provide a solid foundation for business models that optimize CO_2 storage and utilization between saline reservoirs and associated storage in depleted oil fields.

Challenge #5 – Ensuring regional and site-specific stakeholder acceptance.

Phase II can further advance stakeholder outreach to ensure public acceptance of the CS-NMB program and enable project development. The outreach team, developed in Phase I, should be finalized and with the inclusion of a local and regional public relations firm. Outreach materials should be prepared, such as flyers and/or fact sheets. Stakeholder and social climate should be monitored throughout the project and selected outreach conducted to secure key stakeholder support and address policy gaps.

Ultimate success of the CS-NMB project will depend on a geologically acceptable storage complex, along with the availability of mechanisms to address key non-technical issues. Very often, such issues, especially the lack of public support, the absence of financial or policy drivers, and the inability to manage long-term liability have derailed many projects. The CS-NMB project attempts to address these issues as part of a business model development strategy.

The Phase II feasibility assessment will advance the state of development for the CS-NMB storage complex so that an investment decision to proceed to the detailed site characterization (Phase III) and site acquisition (Phase IV) can be made with confidence. In addition to advancing the technical design of the CS-NMB storage complex from conceptual toward a commercial-scale design, the Phase II effort will also make advancements in addressing non-technical issues relevant to commercial deployment.

The project will also contribute to the advancement of all four goals of the DOE Carbon Storage R&D program: ensure 99% storage permanence; improve storage efficiency and performance; predict storage capacity; and contribute to best practice manuals. This will be done through sub-basinal characterization and use of NRAP tools; integration of reservoir data into modeling tools; and using results to support future versions of best practice manuals.

8.0 Summary

The document summarizes initial work performed to investigate and demonstrate the feasibility of an integrated commercial geologic CO_2 storage complex in the Northern Michigan Basin. The study, which was the first phase (pre-feasibility phase) of a multi-phase program envisioned by the DOE NETL, was conducted under DOE Award DE-FE0029276 in response to FOA DE-FOA-0001584. The project was performed during an 18-month period from January 2017 through June 2018. The CS-NMB concept represents a highly viable opportunity that could be advanced and brought closer to realization with additional support from the DOE. Major outcomes of the Phase I pre-feasibility study are summarized below. Figure 8-1 illustrates the CS-NMB storage complex concept.

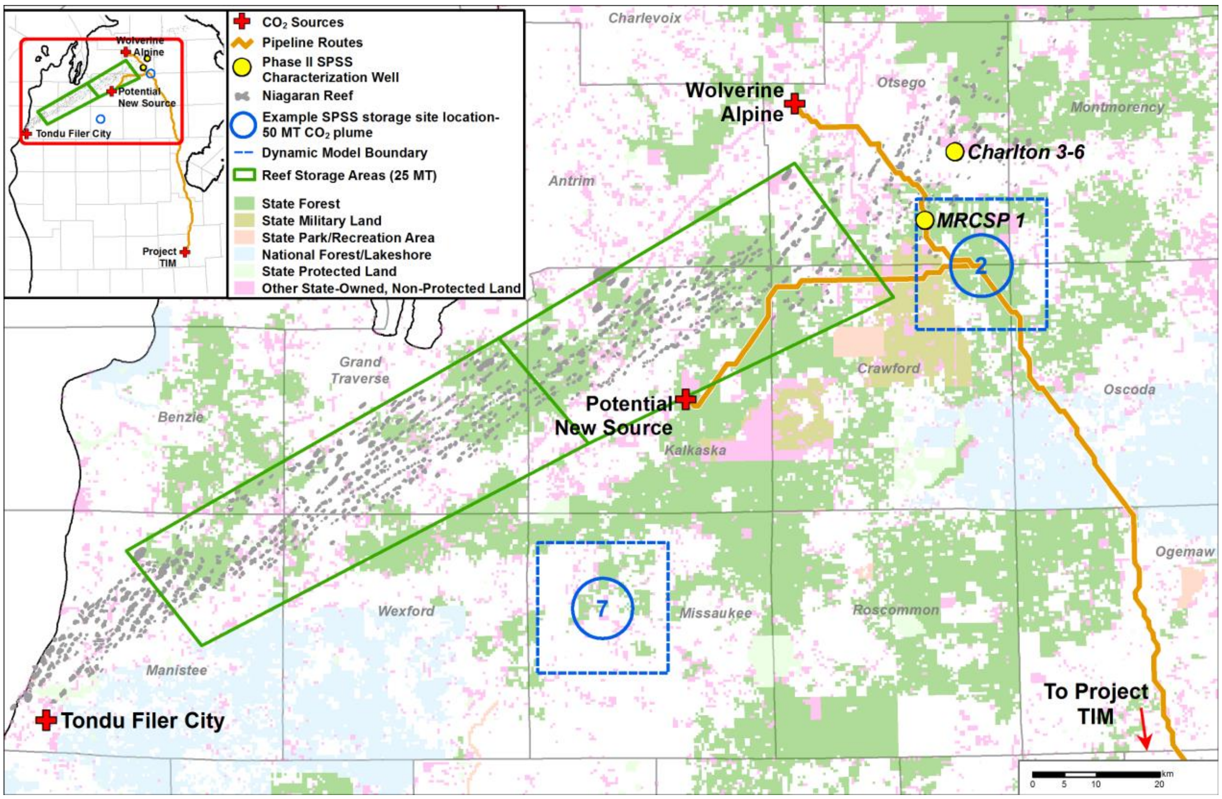

Figure 8-1. CS-NMB storage complex concept area showing example saline storage sites (blue square) with modeled 50-MT CO_2 plume to scale, shown by circle inside square; two characterization wells, Niagaran reef trend (gray features trending NW-SE across the figure), state owned lands, CO_2 sources, and pipeline routing to saline storage Site 2. The two green rectangles each include a sufficient number of reefs to store 25 MT of CO_2; the yellow circles represent existing wells that can be deepened to the SPSS to obtain additional characterization data).

Key Results of Phase I Pre-Feasibility Study:

1. Two saline reservoirs, the SPSS and the BILD, are both present across the entire study area (a multi-county area in the norther portion of the lower peninsula of Michigan) and are both strong candidates for hosting a 50 MMT storage complex. Of the two, the SPSS is preferred because it occurs at greater depths below the primary zones of oil and gas production.

   - Computer modeling simulations of CO_2 injection demonstrated that 50 MMT of CO_2 can be injected into the SPSS in 20 to 30 years using approximately three to five injection wells, depending on location, and that an area of approximately 15,000 acres is needed to accommodate the 50 MMT CO_2 plume.

- The BILD could be used as a supplemental saline reservoir in addition to the SPSS to reduce the land area needed to accommodate the 50 MMT CO_2 plume.

2. In addition to the two saline reservoirs, the NMB region hosts the Northern Pinnacle Reef Trend, a collection of more than 800 Niagaran-age pinnacle reefs. Several factors combine to make the reefs a low-risk, value-added CO_2 storage option that can be used in conjunction with saline storage in the CS-NMB storage complex.
   - Most reefs are oil- or gas-bearing and were produced in the 1970s and 1980s and are now in a pressure-depleted condition that is conducive for storing CO_2. Fluids do not have to be removed to make space for the CO_2.
   - The reefs are proven reservoirs for storing hydrocarbons and thus are excellent candidates for storing CO_2. Stratigraphically positioned below the BILD but above the SPSS, the reefs are overlain by massive salt and low permeability carbonates.
   - Work performed in this study shows that of the more than 800 reefs present, only 82 oil-bearing reefs are required to store 50 MMT of CO_2. Thus, the total storage capacity of the reefs is several times higher.
   - Subsurface CO_2 injection is already occurring in the CS-NMB study area and is a well-understood process. Core Energy, LLC has been conducting EOR with CO_2 in several Niagaran pinnacle reefs for the past 15 years and has established a CO_2 pipeline system that could be expanded to connect additional CO_2 source(s) and additional reefs. Core Energy has already developed a preliminary plan for expanding their current operation to be able to store 50 MMT in a 25-year period.
   - Through their years of demonstrated success in CO_2-EOR, Core Energy has established methods and practices for safe CO_2 handling, metering/tracking, injection, and processing that are directly applicable to the CS-NMB storage complex.
   - Extensive experience and knowledge in the areas of subsurface monitoring and modeling of CO_2 in the reefs has been acquired by the Battelle-led project team, which is conducting the MRCSP Phase III project in the Core Energy-operated reefs. The Battelle-led team has successfully injected more than one million metric tons of CO_2 into a group of Niagaran pinnacle reefs during the MRCSP Phase III program.
   - Because CO_2-EOR is already a thriving business in the area, CO_2-EOR represents a real source of revenue that can help offset the cost of CCS in the area immediately.
3. The MDNR, which manages large tracts of land where the CS-NMB project can be located, has indicated interest in allowing state-owned land to be used for a geologic CO_2 storage site. MDNR has a history of successfully stewarding oil and gas production and gas storage within public lands and has previously permitted drilling of MRCSP CO_2 test wells on its lands. Further team-building with the MDNR is needed to finalize the process for using state land for CO_2 storage. Some opportunities may also exist to use private-land for CO_2 storage sites.
4. Team partner Loomis (Loomis, Ewert, Parsley, Davis & Gotting, P.C) prepared a legal analysis/assessment of Michigan policies, regulations, and practices that could affect the implementation of the CS-NMB project and found that Michigan has a regulatory climate that is generally favorable for CO_2 sequestration. MPSC, MDEQ, and MDNR have the technical knowledge, experience, and institutional memory necessary to effectively regulate the new but related discipline of CO_2 large-scale storage and CO_2 storage incidental to CO_2 EOR:

5. Results of a focused outreach program conducted with key stakeholders during the Phase I pre-feasibility project demonstrate a high level of support for the CS-NMB storage complex concept. Key stakeholders include public representatives Michigan Governor Rick Snyder, U.S. Representative Bergman and Michigan Representative Cole, who represent the project area at the Federal and state levels. They all have provided enthusiastic support letters for the project.
6. At least nine (9) existing and three (3) potential new CO_2 sources were determined to be attractive candidates for the establishment of a regional CCS hub based on total and potential future CO_2 emissions, location, industry-specific characteristics, and capture costs. These sources represent multiple industrial categories including electricity generation, cement production, and steel production. Four (4) of these 12 CO_2 emission sources were selected for further (economic) analysis based on interest expressed by the source owner/operator to participate in the CS-NMB project. These include:
   - The Wolverine Alpine natural-gas power generation facility together with the DCP Midstream Partners natural gas processing plant, both located in Otsego County;
   - Project TIM, a planned state-of-the-art steel-manufacturing facility in Shiawassee County;
   - A potential new natural-gas power generation facility with the new NetPower technology, assumed location Otsego County;
   - A potential new natural-gas power generation facility with NGCC technology, assumed location Otsego County)
7. The economics of a 30-year 50-MT CO_2 integrated source-transport-storage operation in northern Michigan under current legal and regulatory conditions was modeled using a comprehensive discounted cash flow financial analysis model, 20 source-transport-storage scenarios were modeled that included the following five storage options for each of four (4) CO_2 emission sources:
   - 100% (50 MMT CO_2) storage in the SPSS saline reservoir (Site 2 and Site 7);
   - 50% (25 MMT CO_2) storage in the SPSS saline reservoir (Site 2 and Site 7) and 50% (25 MMT CO2) storage in Niagaran pinnacle reefs via CO_2-EOR; and,
   - 100% (50 MMT CO_2) storage in Niagaran pinnacle reefs via CO_2-EOR.

The results of this analysis demonstrate how an integrated capture and storage project can be economically viable, which scenarios are most/least economically viable, and approximate revenue (cost) requirements for scenarios that are not capable of being self funded. Overall, the economic analysis indicates that the availability of the recently enacted tax credits will go a long-way towards closing the cost and revenue gaps, especially when combined with value added options such as CO_2-EOR.

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Appendix A: Assessment of the Area of Review and Leakage Impact for Site 7 Using the NRAP-IAM-CCS Tool, Northern Michigan Basin-CarbonSAFE Phase 1 Pre-Feasibility Study

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Executive Summary

U.S. Environmental Protection Agency's (EPA's) Class VI regulations require owners or operators of carbon storage projects to determine an AoR representative of project risk to underground sources of drinking water (USDWs). The AoR is an estimate of the project footprint and is used to develop monitoring plans to ensure protection of USDWs. In this study, the NRAP-IAM-CS software tool was applied to estimate the AoR and the leakage potential of legacy wells located within the AoR to impact groundwater quality at a carbon storage screening site for the CS-NMB, Phase 1 project. The NRAP-IAM-CS is a science-based toolset developed by the U.S. Department of Energy for quantitative risk assessment of geologic sequestration CO_2 (Pawar et al., 2016). The toolset adopts a stochastic approach in which predictions include site uncertainties using storage reservoir, leakage scenario, and shallow groundwater impact reduced order models (ROMs).

Risk-based analysis done using the NRAP-IAM-CS yielded an AoR that was comparable to estimates defined by the critical pressure needed move fluid from the reservoir to the overlying USDW through an open wellbore. The risk-based AoR was slightly smaller than that based on the critical pressure (234 km^2 compared to 269 km^2), because small fluxes did not impact groundwater quality. Leakage from two legacy wells located within the AoR should not impact groundwater quality over the 30-year injection period. Legacy Well 1 penetrates the simulated CO_2 plume and would require a permeability of 5 x 10^{-12} m^2 (~5 Darcy) to impact groundwater quality after about 20 years of injection. Legacy Well 2 falls outside of the CO_2 plume footprint, where reservoir pressures are too small to generate large enough leakage flux to change groundwater quality even with well permeabilities as high as 5 x 10^{-11} m^2 (~50 Darcy).

This work represents one of the first applications of the NRAP toolset for the screening of potential CO_2 storage sites. The toolset provides a risk-based method of evaluating the AoR and the impact of CO_2 or brine leakage through legacy wells. The following recommendations will strengthen the use of probabilistic assessments for site selection and permitting of Class VI CO_2 injection wells.

- The AoR calculations would be more robust if the toolset sampled pressures and CO_2 saturations from many horizontal planes within the reservoir. This is particularly important for stacked storage reservoirs where geologic heterogeneity will control pressure and CO_2 gas saturations. A reduced order model (ROM) specific to the site reservoir would further improve a probabilistic assessment of the AoR.
- USDW ROMs need to be calibrated against the high leakage fluxes generated from open wellbores. All USDW ROMs were calculated for cemented wellbores, which assumes leakage is controlled by the permeability of a damaged cemented zone within the well's casing-borehole annulus; this results in a much lower leakage rate than the rate for a hypothetical open (uncemented) well.
- The NRAP-IAM-CS currently has one option for a UDSW ROM, the unconfined carbonate aquifer ROM, which simulates CO_2 leaks to the aquifer and to the atmosphere. NRAP is updating

the toolset with a confined alluvium aquifer in which all CO_2 leaked will stay within the aquifer system.

- Any AoR and groundwater impact assessments should be made over the injection and post-injection periods. This is important for AoR assessments to demonstrate that the CO_2 plume has stabilized and that the reservoir pressures have returned to pre-injection levels. Post-injection assessments of CO_2 leakage are important because buoyancy will continue to move the CO_2 along leakage pathways. Conclusions in this study were based only on the injection period.

A.1 Introduction

U.S. Environmental Protection Agency's (EPA's) Class VI regulations require owners or operators of carbon storage projects to determine an AoR representative of project risk to underground sources of drinking water (USDWs). The AoR is an estimate of the region potentially impacted by the CO_2 injection and is used to develop monitoring plans to ensure protection of USDWs. Estimates of the AoR need to account for the physical and chemical properties of all phases of the injected carbon dioxide stream, are based on available site characterization, monitoring, and operational data, and are to be made with computational models (40 CFR 146.84). Permitting also requires an understanding of the leakage risks from leakage pathways, such as wells and/or faults connecting the storage reservoir with any overlying underground sources of drinking water (USDWs). Environmental Protection Agency's (EPA's) Class VI Rule requires groundwater geochemistry monitoring above the lowermost confining zone overlying the storage reservoir to detect changes in aqueous geochemistry resulting from fluid leakage out of the injection zone [40CFR 146.90(d)] (U.S. Environmental Protection Agency, 2012).

The NRAP-IAM-CS is a science-based toolset developed by the U.S. Department of Energy (DOE) for quantitative risk assessment of geologic sequestration of CO_2 (Pawar et al., 2016). The toolset 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 ROMs, for each component of the system. These tools can be used to help regulators and operators define the AoR and better understand the expected sizes and longevity of changes in water quality caused by CO_2 and brine leakage from a storage reservoir into drinking water aquifers.

The EPA defines the AoR as the maximum extent of the separate-phase CO_2 plume or the pressure front over the lifetime of the project as measured by numerical model simulations. Generally, the maximum pressure front defines the AoR because it is larger than the supercritical CO_2 plume. The AoR is often delineated by the area within which the maximum pressure buildup is above that needed to move the reservoir fluids through an open wellbore (U.S. EPA, 2013). This approach is conservative and assumes that any leakage will impact USDW quality regardless of the magnitude and duration of the leak.

Wells are considered to be high-risk pathways for fluid leakage from geologic CO_2 storage reservoirs because breaches in this engineered system have the potential to connect the reservoir to drinking water resources and the atmosphere. Well integrity is often difficult to measure due to a lack of well data such as permeability of the annular material between the outermost well casing and the borehole wall, a potential avenue for upward fluid migration. For such cases, the NRAP-IAM-CS can be used to evaluate the probability of CO_2 and brine leakage and its impact on drinking water quality from known well locations using default permeability distributions based on oil and gas wells in the Alberta and Gulf Coast basins and the greenfield FutureGen Site.

A.1.1 Organization

This section discusses the use of the NRAP-IAM-CS model to estimate the AoR and the impact of leakage through legacy wells to overlying drinking waters for Site 7, one of two example St. Peter

Sandstone saline reservoir storage sites evaluated as part of the CS-NMB Phase 1 project[2]. The section is organized into the following sections:

- Section A.1.2 presents a risk-based AoR calculated using the NRAP-IAM-CS tool based on leakage impacts to groundwater quality in a shallow drinking water aquifer overlying the storage reservoir from hypothetical open (uncemented) wells.
- Section A.1.3 presents an AoR calculated using the U.S. EPA critical pressure method;
- Section A.1.4 presents an assessment of leakage impacts to groundwater quality in a shallow drinking water aquifer overlying the storage reservoir from known legacy wells in the AoR calculated using the NRAP-IAM-CS tool.

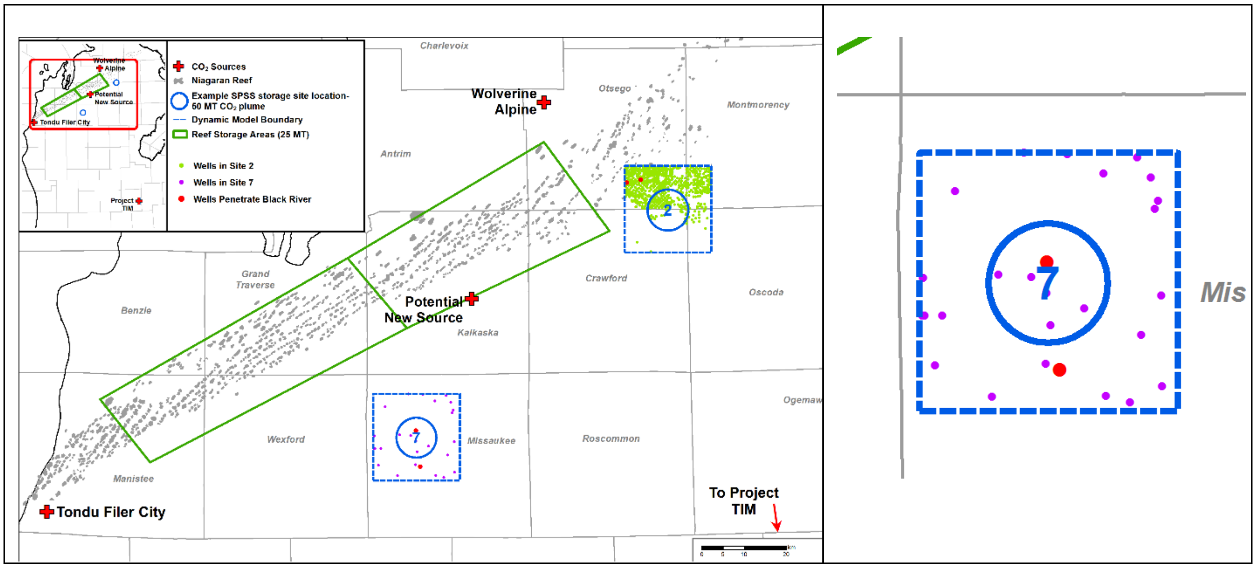

Figure A-1. Location of Sites 2 and 7, two St. Peter Sandstone (saline reservoir) CO_2 storage site locations considered in the CS-NMB Phase 1 project, the Niagaran reefs proposed for associated storage (each group of reefs within a green rectangle has a storage capacity of 25 MMT). Only Site 7 is evaluated in the AoR analysis in this section. Dashed blue line indicates extent of CMG-GEM reservoir model area; solid blue circles indicate approximate extent of modeled 50 MMT CO_2 plume in the St. Peter Sandstone. Two legacy wells that penetrate the St. Peter Sandstone are present in the Site 7 model area and are shown as solid red circles in the Site 7 box (enlarged in the righthand image). Purple circles are wells that do not reach the St. Peter Sandstone.

A.1.2 Risk-Based Approach for Determining the Area of Review (AoR)

The risk-based AoR calculated using the NRAP-IAM-CS is the area where CO_2 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-net degradation" thresholds. The "no-net-degradation" thresholds are pH = 6.5 and total dissolved solids (TDS) = 500 parts per million (ppm). The boundaries of the AoR were calculated by calculating pH and TDS in the shallow drinking water aquifer at hypothetical open wells located at increasing distances to the east, west, north, and south of the injection wells until no impact to the aquifer was observed. CO_2 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

[2] Site 2 was not considered because the simulation results for that site could not be converted to the format needed for the NRAP-IAM-CS.

A.1.2.1 Description of NRAP-IAM-CS and Assumptions

The NRAP-IAM-CS is an integrated system model developed by the U.S. Department of Energy for use in performance and quantitative risk assessment of geologic sequestration of CO_2 (Pawar et al., 2016). The model components include a primary CO_2 injection reservoir, potential leakage pathways, and receptors such as shallow aquifers. The model is designed to perform probabilistic simulations related to the long-term fate of a CO_2 sequestration operation. A stochastic framework at the system level allows NRAP-IAM-CS to be used to explore complex interactions among large numbers of uncertain variables and helps evaluate the likely performance of potential sequestration sites. The model samples values for each uncertain parameter from probability distributions, leading to estimates of global uncertainty that accumulate as the coupled processes interact during a simulation. NRAP-IAM-CS is designed to link together many different processes (e.g., subsurface injection of CO_2, CO_2 migration, leakage, and shallow aquifer impacts) required in the analysis of long-term CO_2 storage in geologic reservoirs. The underlying processes can be simulated using ROMs developed for the components in the integrated assessment model (IAM). Details of the NRAP-IAM-CS are provided in the manual (Stauffer, et al., 2016). The risk-based AoR for Site 7 was calculated using spatial and temporal distributions of CO_2 saturations and pressures within the storage reservoir from a multi-phase numerical reservoir flow simulator (Computer Modeling Group-Generalized Equation of State Model [CMG-GEM] that was used to predict CO_2 plume boundaries as input to a site-specific open wellbore ROM and a shallow groundwater ROM developed with NRAP-IAM-CS (Figure A-2).

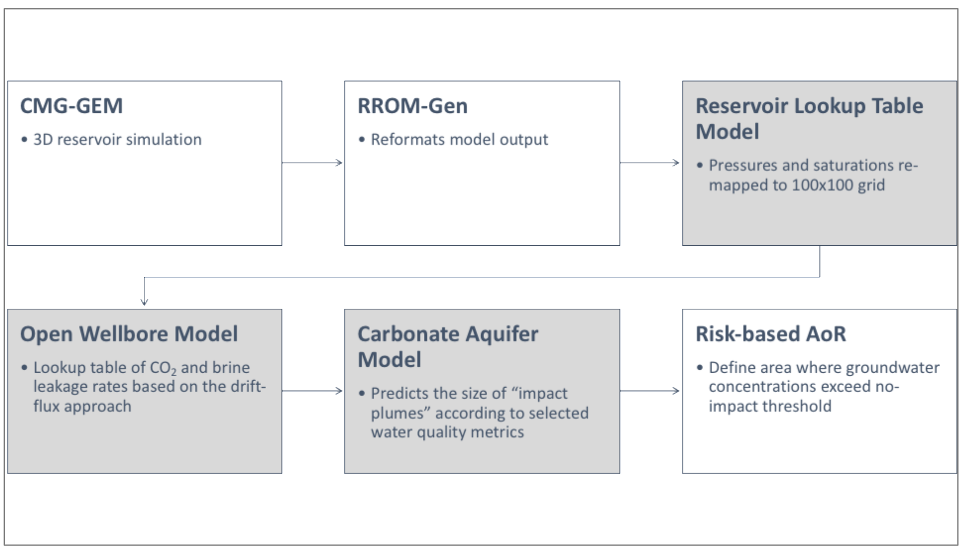

Figure A-2. Components of the risk-based AoR approach for Site 7 (grey components are part of the NRAP-IAM-CS system model).

The ***open wellbore model*** is a multiphase and non-isothermal model that couples wellbore and reservoir flow of CO_2 and variable salinity brine to calculate CO_2 and brine leakage rates into a shallow USDW aquifer and to the atmosphere (Pan et al., 2011). The model allows for the phase transition of CO_2

from supercritical phase to gaseous phase and accompanying Joule-Thompson cooling and exsolution of CO_2 from the brine phase. The model simulates CO_2 and/or brine leakage from the storage reservoir using inputs of pressure and CO_2 saturations from the Reservoir Reduced-Order Model – Generator (RROM-GEN) generated look-up tables. The CO_2 and brine fluxes from the open wellbore ROM used to calculate groundwater impacts are qualitative, because leakage rates from the open wellbore ROM may exceed the range of values to which the carbonate aquifer ROM was calibrated (Table A-1). Additional parameters needed for the wellbore leakage and aquifer impact calculations are shown in Table A-2.

It is very important to note that ***open wellbore model*** assumes that the wellbore is completely open – meaning that the annular space outside the casing is completely devoid of cement or other material. The assumption of a completely open borehole that penetrates the storage reservoir and connects it to the shallow drinking water aquifer can lead to unrealistically high leakage rates (flux of brine and CO_2) and aquifer impacts (resulting from chemical constituent concentrations in the shallow drinking water aquifer). However, this assumption is consistent with EPA's guidance for calculating the Area of Review.

The ***unconfined carbonate aquifer ROM*** predicts the volume of impacted groundwater in a shallow drinking water from CO_2 and brine leaks using nine water quality parameters (Keating et al., 2016a). The unconfined carbonate aquifer ROM is the only USDW ROM available in NRAP-IAM-CS. NRAP is currently adding a confined alluvium aquifer ROM. In this analysis two of the nine parameters (pH and TDS) were used. pH and TDS plume volumes below the no-impact threshold were assumed to be consistent with EPA guidelines for no-net degradation. More information on how the threshold values were determined can be found in Last et al (2016). Adjustable model input parameters, including permeability mean, variance, correlation length and anisotropy, aquifer thickness and horizontal hydraulic gradient were based on site characterization data where possible.

Table A-1. Carbonate Aquifer ROM wellbore leakage parameter maximum values

Parameter	Maximum Value	Unit
CO_2 leak rate	500	gram/s
Brine leak rate	75	gram/s
Cumulative CO_2 mass leaked	500	kTon
Cumulative Brine mass leaked	100	kTon

Table A-2: NRAP-IAM-CS Input Parameters for Site 7

	Site 7 – Model Layer 253	
Parameter	**Reservoir**	**USDW**
Surface Elevation (m)	381	381
Initial Pressure (MPa)	32.57	2.96
Elevation of Top (m)	-2777.34 3032	76.2
Temperature (◦C)	65 (Footnote a)	15.56
Mean Permeability (m^2)	4.8×10^{-5} (Footnote a)	9.8692×10^{-15}
Mean Porosity (fraction)	0.018 (Footnote a)	0.1
Thickness (m)	Footnote a	304
Salinity (ppm)	200,000	0

a. These parameters are incorporated in the 3D CMG-GEM reservoir model.

For the reservoir component, the RROM-Gen (King, 2016) was used to create NRAP-IAM-CS reservoir ROM look-up tables from the 3D reservoir simulations performed with the CMG-GEM code. Simulated CO_2 saturations and pressures for Site 7 for 30-years of CO_2 injection and a total injection of 50 MMT CO_2 were converted to a format acceptable to the NRAP-IAM-CS. The tool defines a new (100 x 100 cells) grid based on user input options, then uses piecewise bi-linear interpolation to convert the reservoir data from the original grid to the new grid. The gridded results are then written to specified file format reservoir lookup tables. Only one horizontal plane (layer) is extracted from the reservoir simulation results for use in the NRAP-IAM-CS calculations. For this application, reservoir pressures and CO_2 saturations for all nodes in Layer 253 of the Site 7 GEM model at yearly time steps from 0 to 30 years were used. This layer was selected because it had the highest pressure (gradient) and largest CO_2 plume. The top of the reservoir is defined at an elevation of -2,777.34 m (9,112 ft), corresponding to a depth of 3,158.34 m (10,362 ft). Interpolated pressures and CO_2 saturations are shown at years 0 and 30 in Figures A-3 to A-6.

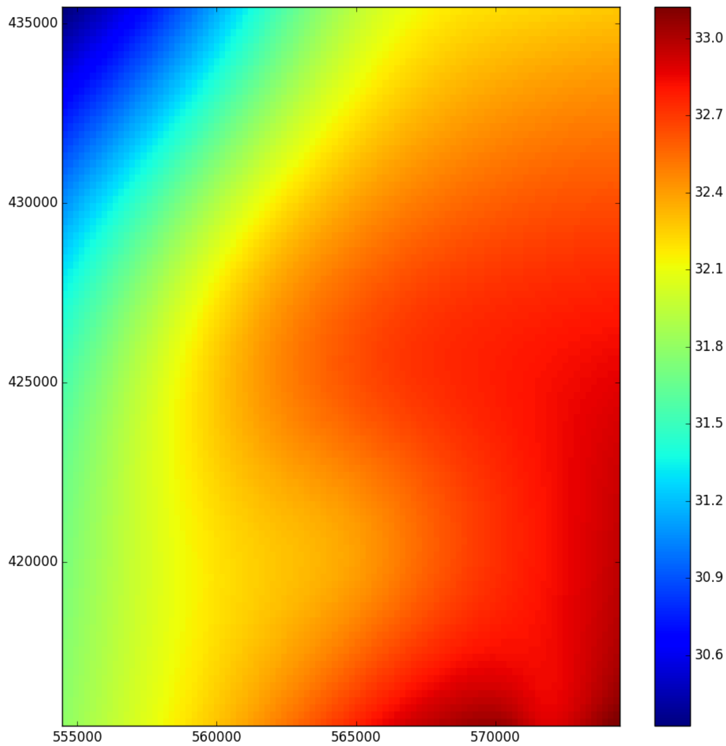

Figure A-3. Pressure distribution in MPa for CMG-GEM model layer 253 at time 0 years interpolated to a 100x100 grid. The grid has units of meters.

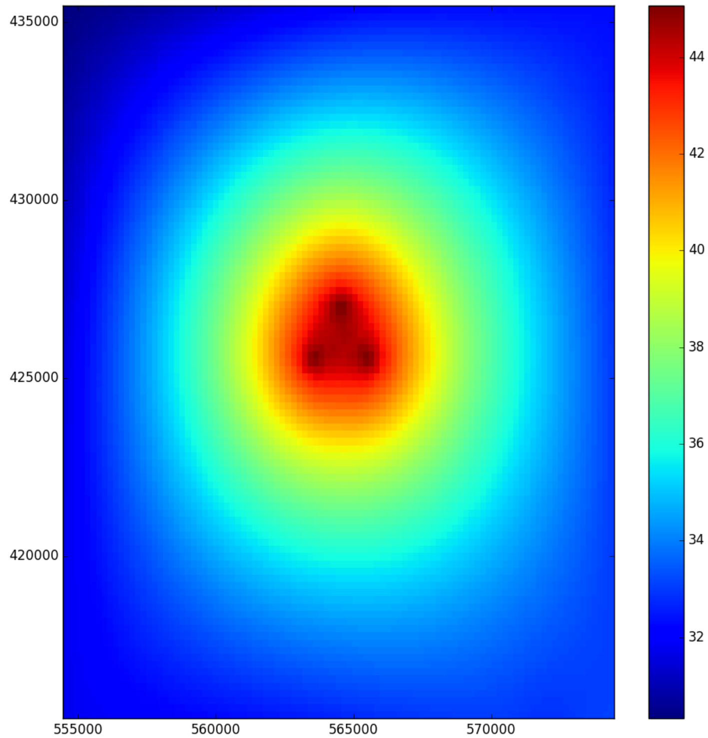

Figure A-4. Pressure distribution in MPa for CMG-GEM model layer 253 at time 30 years interpolated to a 100x100 grid (the three injection-well locations can be seen in the center of grid). The grid has units of meters.

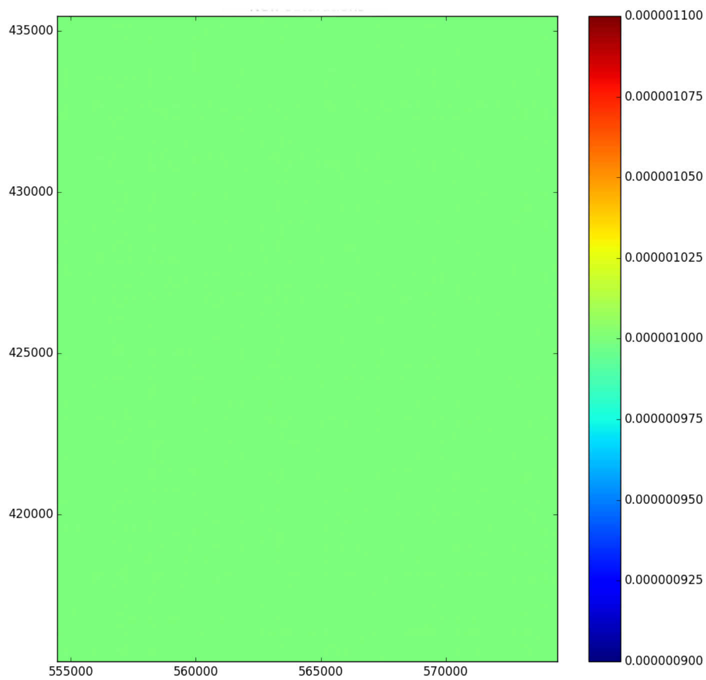

Figure A-5. CO_2 gas saturation distribution for CMG-GEM model layer 253 at time 0 years interpolated to a 100x100 grid. The grid has units of meters.

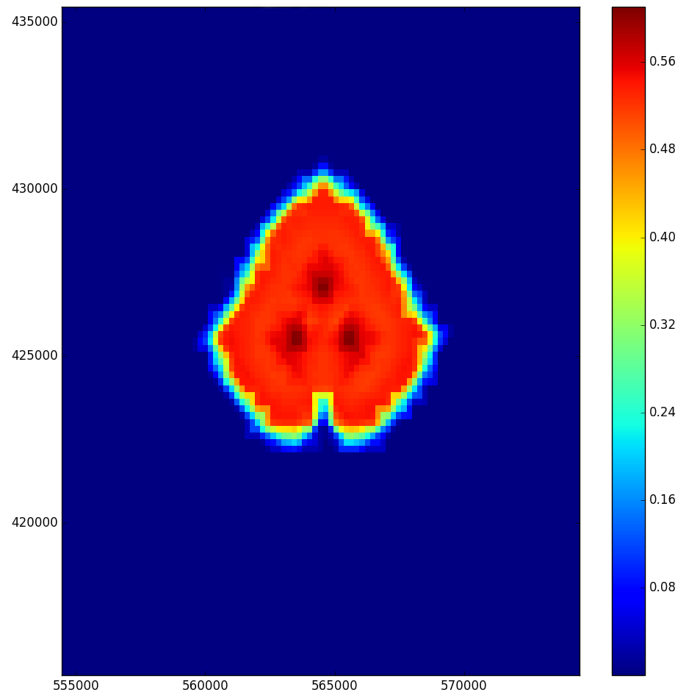

Figure A-6. CO_2 gas saturation distribution for CMG-GEM model layer 253 at time 30 years interpolated to a 100x100 grid. The grid has units of meters.

A.1.2.2 Risk-Based AoR Results

Figure A-7 shows the locations of the hypothetical wells used to estimate the AoR. The modeled reservoir pressure and CO_2 saturation vs. time for each of the four hypothetical well locations are shown in Figures A-8 and A-9. These values were used to calculate the CO_2 and brine leakage fluxes with time at each location. Wells 1, 2, and 3 are located within the CO_2 plume and Well 4 is located outside of the CO_2 plume but within the pressure front. Pressure buildup varies from approximately 11.9 megapascals (MPa) (1,726 psi) at the center of the injection area to about 1.8 MPa (261 psi) at Well 4.

CO_2 leakage to the USDW occurs at Wells 1, 2 and 3 and changes the shallow groundwater pH to below pH 6.5 (Figures A-10, A-11). Impacts to groundwater are used only to define the AoR; a full quantitative analysis would require updating the groundwater ROMs to handle large fluxes created by flow through an open wellbore. Qualitatively, the magnitude of the impact to groundwater decreases with distance from the injection center; and, the timing of the onset of impact increases in time with distance. There is no impact on groundwater pH at Well 4 because the well is located outside the CO_2 plume. In contrast to CO_2 leakage, brine leakage to the USDW occurs at all four hypothetical well locations resulting in impacts to groundwater at all locations, although the magnitude of impact decreases with increasing distance from the center of injection (Figures A-12, A-13).

The ellipse in Figure A-14 defines the risk-based AoR for Site 7. Table A-3 specifies the boundary points for the AoR and Figures A-15 and A-16 show the brine flux during the 30-year CO_2 injection period. The estimated AoR has a radius from 8,295 m (27,215 ft) to 9,205 m (30,200 ft), corresponding to an area of 234 km^2 (90 mi^2).

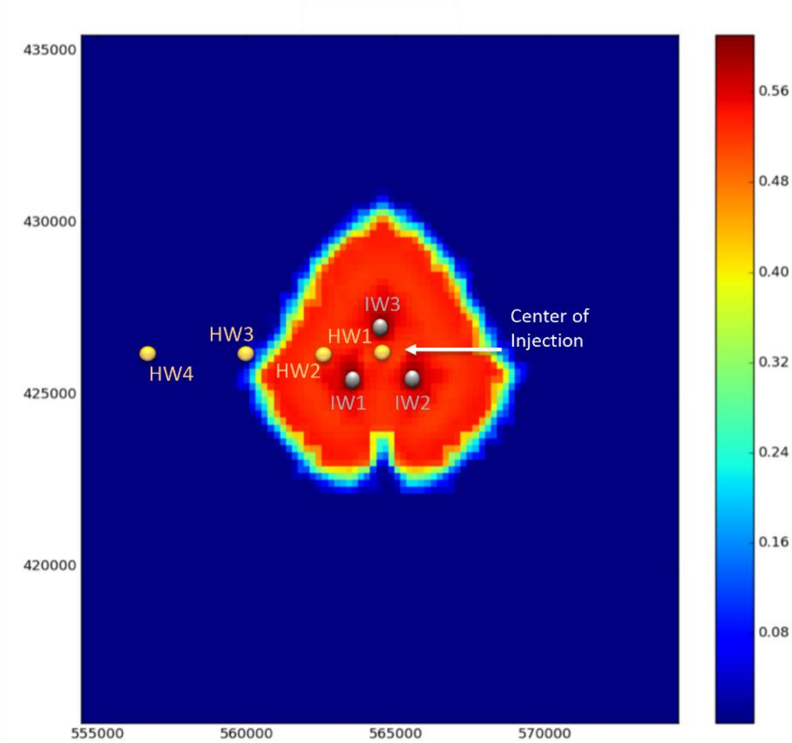

Figure A-7. Locations of hypothetical wells superimposed on the CO_2 saturation contour plot for year 30. The grid has units of meters.

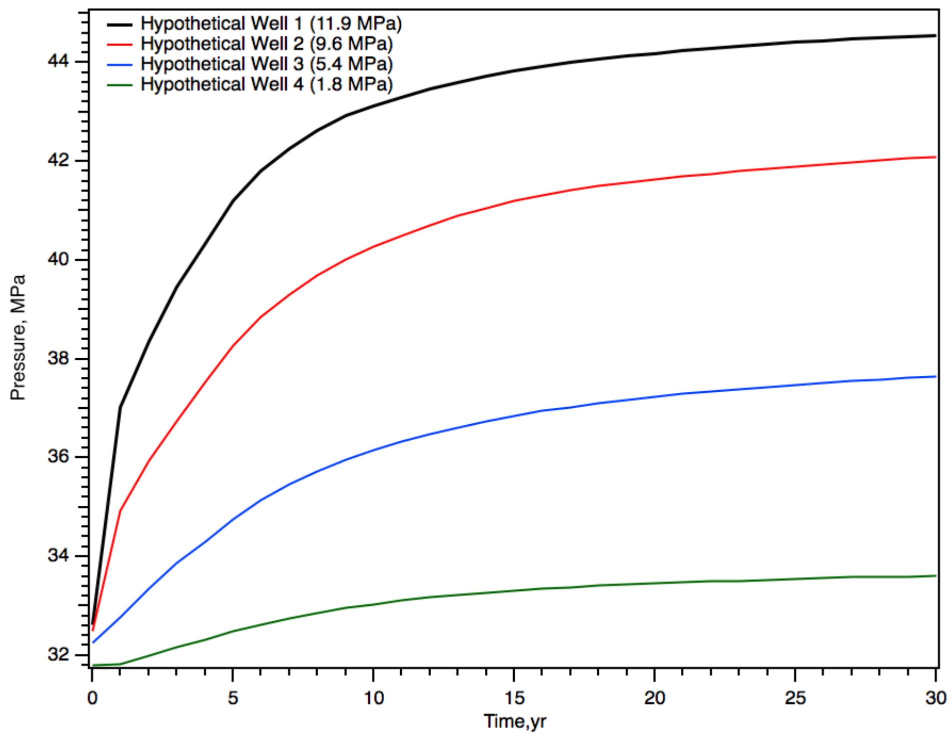

Figure A-8. Pressure vs. time at each hypothetical well location. The maximum pressure difference is shown in parenthesis for each well.

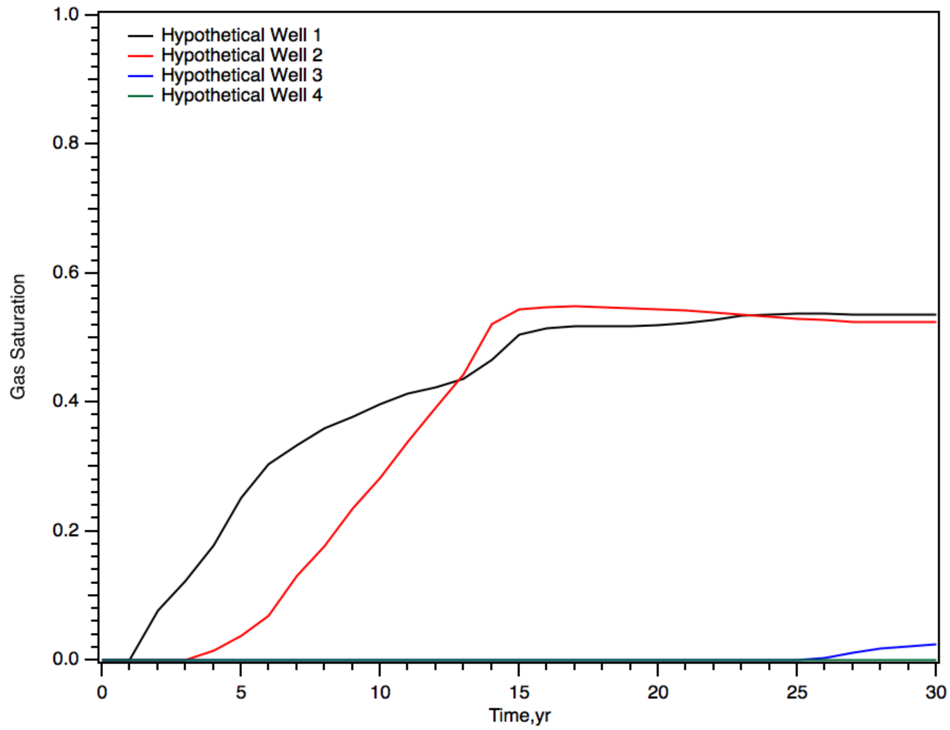

Figure A-9. CO_2 saturation vs. time at each hypothetical well location

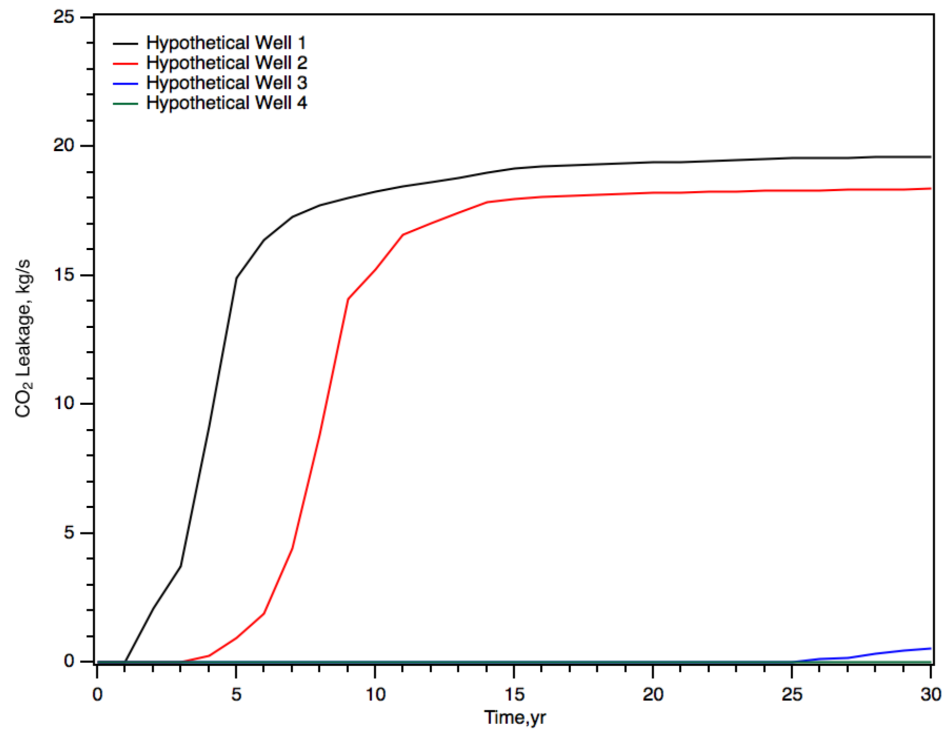

Figure A-10. CO_2 leakage rates over time at hypothetical well locations within (Wells 1, 2, and 3) and outside (Well 4) the CO_2 plume footprint

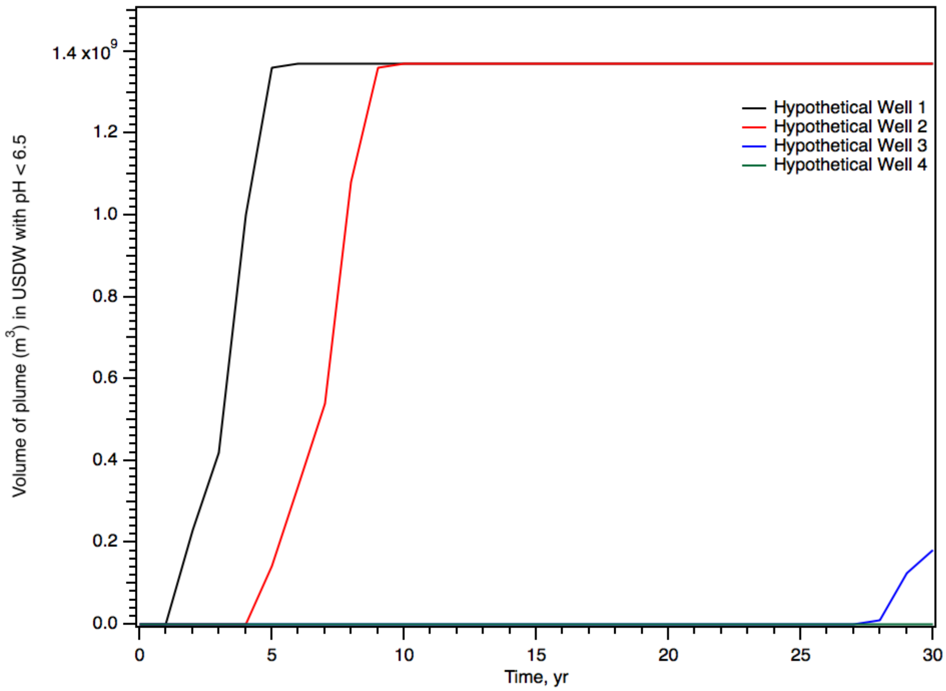

Figure A-11. Impact to the USDW in terms of pH changes at hypothetical well locations within (Wells 1, 2, and 3) and outside (Well 4) the CO_2 plume footprint

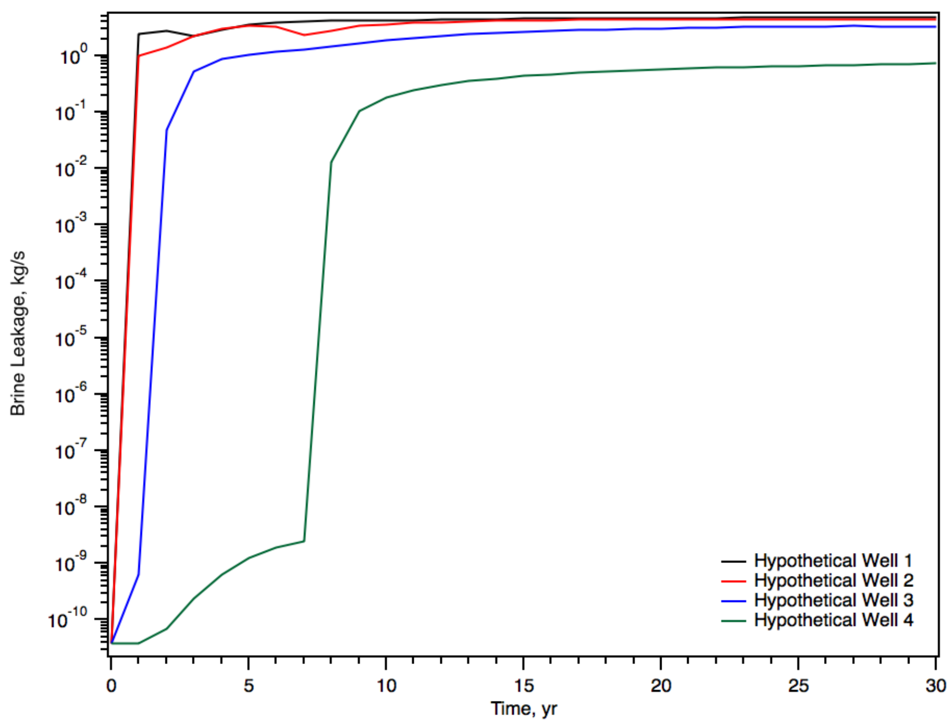

Figure A-12. Brine leakage rates over time at hypothetical well locations within (Wells 1, 2, and 3) and outside (Well 4) the CO_2 plume footprint

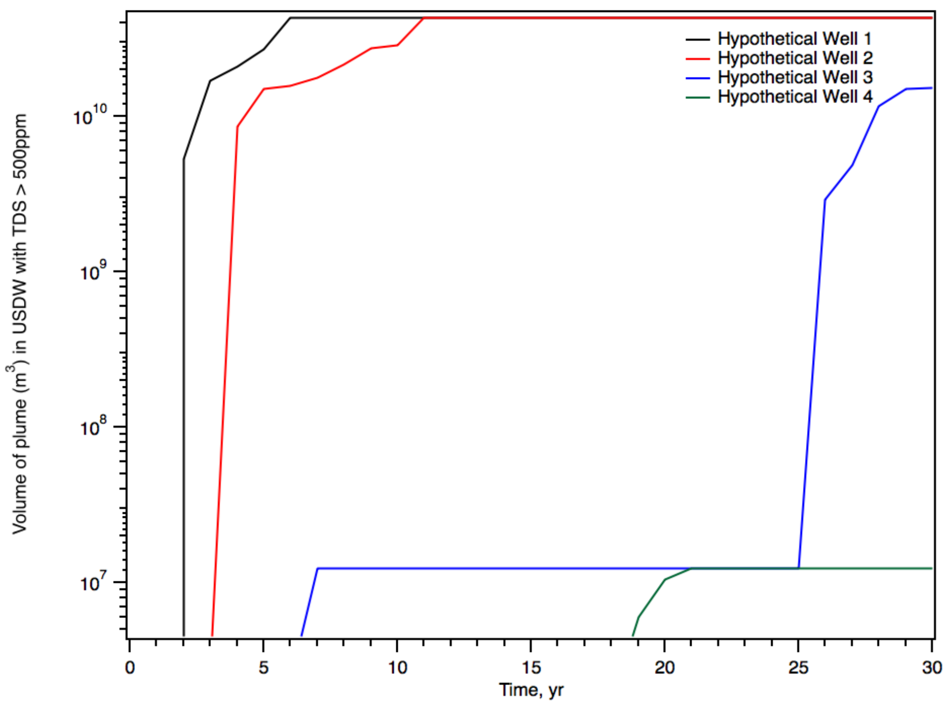

Figure A-13. Impact to the USDW in terms of TDS at hypothetical well locations within (Wells 1, 2, and 3) and outside (Well 4) the CO_2 plume footprint

Table A-3. Locations of hypothetical wells defining the boundary of the risk-based AoR

AoR Boundary Points			Distance from Center of Injection Well Field
	X (m)	Y (m)	m
North	564461	434500	8295
East	573000	426205	8539
South	564461	417000	9205
West	556000	426205	8461

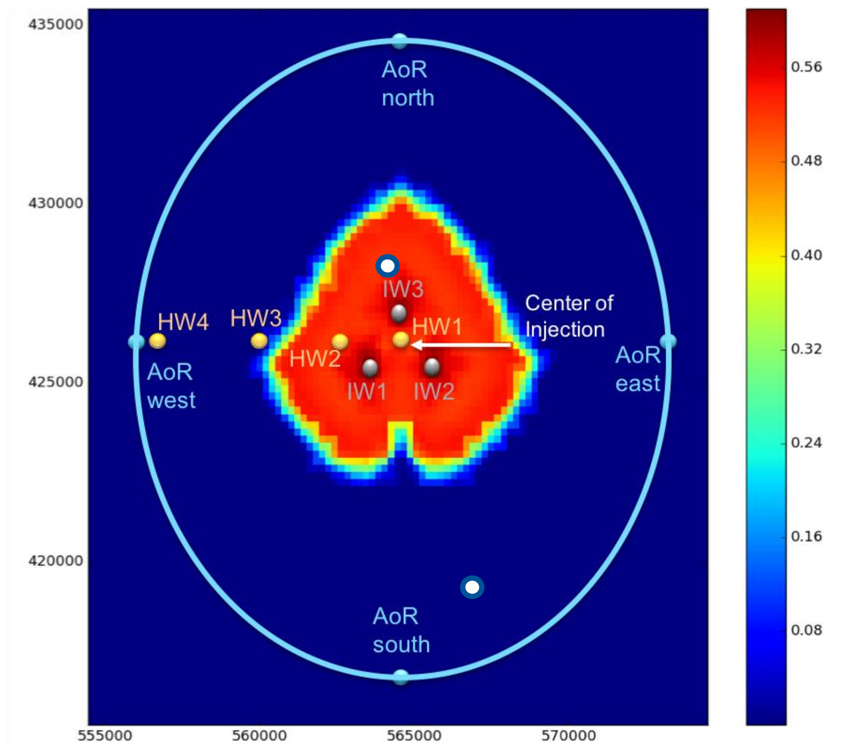

Figure A-14. AoR as determined by the area inside which there is impact to the USDW from CO_2 or brine leakage. Approximate locations of the legacy wells (white circles) showing their penetration of the CO_2 plume (Well 1) and the pressure plume to the south of the CO_2 plume (Well 2). CO_2 plume is shown with colored contours of CO_2 saturation. The grid has units of meters.

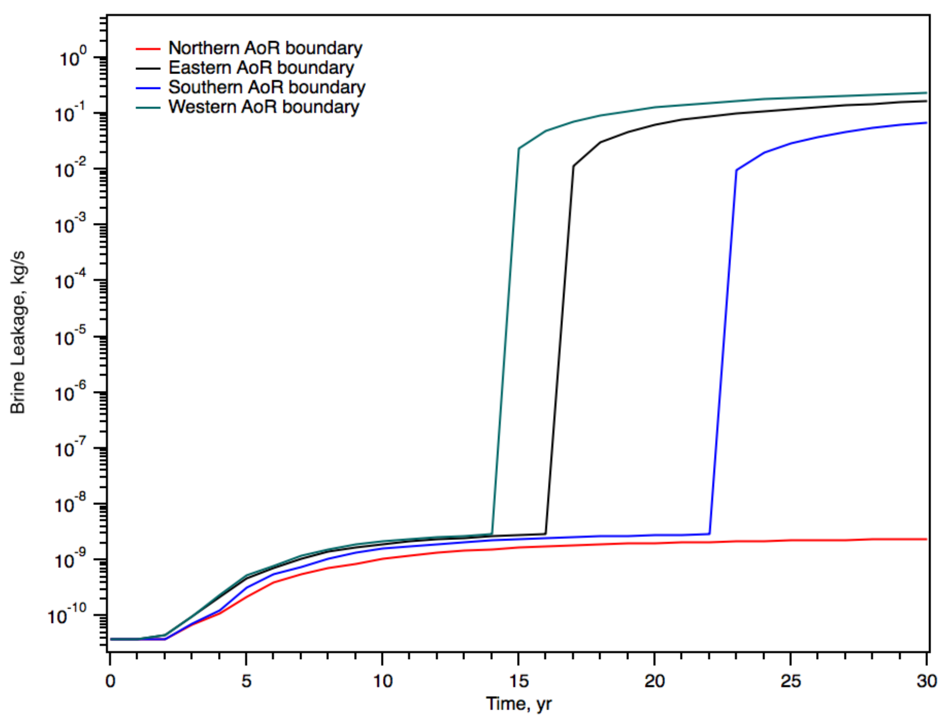

Figure A-15. Brine leakage at points representing the northern, eastern, southern, and western limits of the AoR as determined by estimated zero risk to the USDW

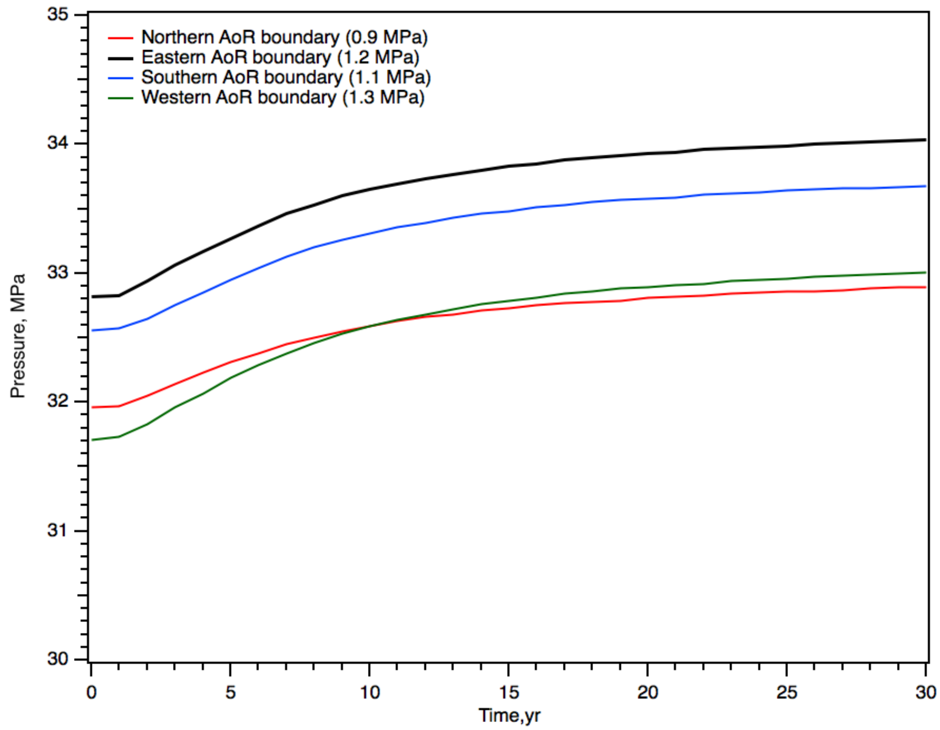

Figure A-16. Pressure vs. time at points representing the northern, eastern, southern, and western limits of the AoR as determined by estimated zero risk to the USDW. Maximum pressure buildup is indicated in parenthesis for each location.

A.1.3 Critical Pressure Based AoR

Currently, the EPA provides guidance to operators of CO_2 storage sites for approaches to determining the critical pressure that should be used to define the pressure front that is considered in the AoR delineation (U.S. EPA, 2012). Comparison of the risk-based and critical pressure approaches yielded very similar AoR, with the risk-based AoR being equal to 234 km^2 and the critical pressure AoR being equal to 269 km^2. The approach taken to determine a critical pressure AoR for Site 7 is discussed below.

The critical pressure corresponds to the critical (minimal) pressure needed to move fluids from the reservoir into a USDW through a hypothetical open conduit, such as an uncemented well (U.S. EPA, 2012). The first step is to use a method that is applicable to reservoirs that are hydrostatic or underpressurized prior to the injection of CO_2 (Birkholzer et al., 2011). This method assumes that the density of the fluid in the wellbore is uniform and equal to the density in the injection zone. Equation A-1 can be used to calculate the necessary increase in pressure in the reservoir to equalize the hydraulic head between the injection zone and the USDW.

$$\Delta P_{if} = P_u + \rho_i g \cdot (z_u - z_i) - P_i \qquad \text{Equation A-1}$$

where:
P_u is the initial pressure in the USDW (Pa= kg·m^{-1}·s^{-2}),
ρ_i is the density of the injection zone fluid (kg/m^3),
g is the acceleration of gravity (m/s^2),
z_u is the depth to the base of the lowermost USDW (m),
z_i is the depth to the top of the injection zone (m), and
P_i is the initial pressure in the injection zone (Pa)

A positive value of $\Delta P_{i,f}$ (Equation A-1) corresponds to an injection reservoir that is under-pressurized relative to the USDW (i.e., a downward hydraulic gradient exists between the USDW and the injection zone). The reservoir overpressure would need to increase to values equal to or above $\Delta P_{i,f}$ to move reservoir fluid into the drinking water aquifer. A $\Delta P_{i,f}$ value of zero corresponds to the hydrostatic case. A negative value of $\Delta P_{i,f}$ indicates an over-pressurized injection zone where reservoir brine has the potential to migrate to the drinking water aquifer prior to any CO_2 injection.

Using Equation A-1 and the parameters in Table A-4, a critical pressure of -1.013 MPa (-147 psi) was calculated for Site 7. The negative critical pressure indicates that the reservoir is over-pressurized relative to the USDW. Some over-pressurization within the injection zone may be allowable without causing sustained fluid leakage, owing to the density differential between the fluids in the injection zone and USDW. In such cases, a second method, shown in Equation A-2, can be used to estimate the pressure needed to displace the existing fluid in the borehole and create leakage into the USDW. Equation A-2 assumes that below the calculated "threshold" pressure, no leakage into the USDW will occur (Nicot et al, 2009). Using Equation A-2, a threshold pressure of 1.749 MPa (254 psi) was calculated for Site 7. Because the value of ΔP_c using Equation A-2 is greater than the value of $\Delta P_{i,f}$ using Equation A-1, the difference in magnitude between the two may be used as an estimate of the allowable pressure increase, subject to the assumptions used to derive Equation A-2 (see Nicot et al, 2009). This results in an allowable pressure increase of 0.736 MPa (107 psi), (1.749 MPa - 1.013 MPa) which can be used to define the AoR (Figure A-17)[3].

$$\Delta P_c = \frac{1}{2} \cdot g \cdot \xi \cdot (z_u - z_i)^2$$

Equation A-2

where:
g is the acceleration of gravity (m/s^2),
z_u is the depth to the base of the lowermost USDW (m),
z_i is the depth to the top of the injection zone (m),
ρ_i is the fluid density in the injection zone (kg/m^3),
ρ_u is the fluid density in the USDW (kg/m^3), and
$\xi = \frac{\rho_i - \rho_u}{z_u - z_i}$ (kg/m^2)

Table A-4. Inputs for Critical Pressure and Threshold Pressure Calculation (Equations A-1 and A-2)

Input Parameter	Value
Depth to top of injection zone (m)	3,158
Depth at base of the lowermost USDW (m)	609
Initial Pressure in Injection Zone (MPa)	32.572
Initial Pressure at the base of the lowermost USDW (MPa)	2.964
Fluid Density in the Injection Zone (kg/m^3)	1,144
Fluid Density in the USDW (kg/m^3)	1,004
Critical Pressure from Equation 1 (MPa)	-1.013
Threshold Pressure Increase from Equation 2 (MPa)	1.749

[3] Because the injection reservoir is over pressurized relative to the shallow drinking water aquifer, neither the critical pressure from Equations A-1 or A-2 can be used to define the AoR. In this case, the allowable pressure increase (this is the term EPA uses) is used to delineate the AoR. The allowable pressure increase is the difference between the two critical pressures calculated with Equations A-1 and A-2. This likely would need to be negotiated with EPA. Figure A-17 uses the allowable pressure of 0.736 MPa (107 psi) to define the AoR.

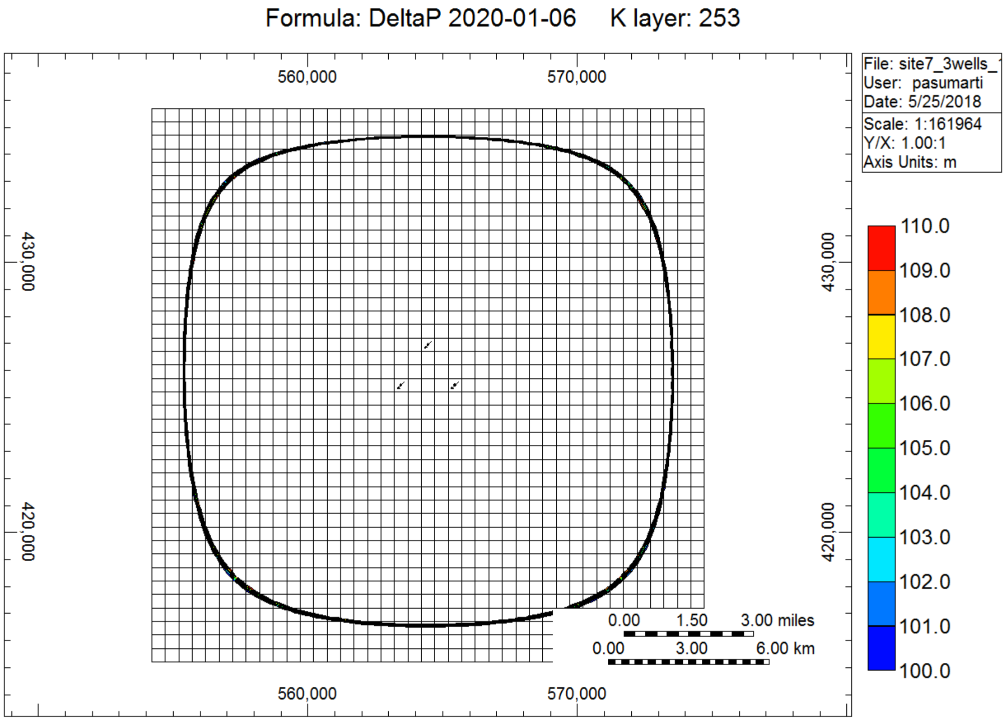

Figure A-17. Area of Review as determined by the critical pressure calculated using the analytical approaches (0.736 MPa [107 psi]); Area =269 km^2 (104 mi^2).

A.1.4 Assessment of Leakage Impacts from Known Legacy Well Locations

The NRAP-IAM-CS was also used to evaluate the probability and impacts of CO_2 and brine leakage from known well locations at Site 7. Groundwater impacts through cemented wellbores and known well locations were calculated using the same approach used to calculate the risk-based AoR; however, the open wellbore assumption was replaced with permeability data representative of cemented wellbores (Figure A-2). There are a limited number of oil and gas wells around Site 7 and only two legacy wells were identified that were drilled to depths below the caprock (Figure A-1). In this analysis, only the two legacy wells that fall within the AoR and are likely to penetrate the CO_2 storage reservoir are considered. Table A-5 lists the location of the two legacy wells and Figure A-14 shows their location relative to the CO_2 and pressure plumes. One well is clearly within the CO_2 plume where CO_2 saturations are about 50%. The other well is to the south of the CO_2 plume close to the southern edge of the estimated area of review, where CO_2 saturations are low.

Table A-5. Locations of the Site 7 legacy wells

	API Number	Latitude	Longitude	X (m)	Y (m)
Legacy Well 1	21113397250000	-85.1899	44.39144	564360.44	426977.23
Legacy Well 2	21113386820000	-85.1787	44.31443	565341.13	418432.1

A probabilistic assessment for known well locations was conducted using predefined permeability distributions that are included in the NRAP-IAM-CS. These are described below:

1. The Alberta model – a uniform distribution with permeability between 10^{-12} to 10^{-13} m^2 for 0.2% of the wells, 10^{-14} to 10^{-17} m^2 for 4.4 % of the wells, and 10^{-20} m^2 for 95.4% of the wells.

The Gulf of Mexico model – a uniform distribution with permeability between 10^{-12} to 10^{-13} m^2 for 0.6% of the wells, 10^{-14} to 10^{-17}m^2 for 11.4 % of the wells, and 10^{-20} m^2 for 88% of the wells.

The FutureGen Low models – assumes a log normal distribution, where 10% of the wells are assumed to have of permeability of 10^{-15} to 10^{-17} m^2 and 90% of the wells have a much lower permeability of 10^{-20} m^2 for low rates of failure.

The FutureGen High model – assumes a log normal distribution, where 10% of the wells have a permeability of 10^{-13} to 10^{-15} m^2 and 90% of the wells a much lower permeability of 10^{-18} to 10^{-20} m^2.

The number of realizations was limited to 3000. Each realization calculated the mass of CO_2 and brine leaked to the USDW, as well as the impact that leakage would have on shallow groundwater quality. The probabilistic calculations using the default permeability distributions showed minimal leakage, with most realizations yielding no leakage and no impact to the groundwater. *Overall, the analysis suggests no risk to the overlying aquifer from CO_2 or brine leakage through these two legacy wells.*

Because the probabilistic assessment using the default permeability distributions yielded no leakage from the two legacy wells for Site 7, the NRAP-IAM-CS was used to estimate the permeability each well would need to have to cause an unacceptable impact to groundwater quality. The leakage profiles are different for the two legacy wells reflecting their locations relative to the CO_2 plume in the storage reservoir. Figure A-18 shows the mass of CO_2 and brine leaked into the shallow groundwater assuming fixed well permeabilities for Legacy Well 1, which is located within the CO_2 plume. Modeling results indicate that leakage from Legacy Well 1 may change the groundwater below the pH 6.5 threshold if the well permeability is 5 x 10^{-12} m^2 or higher[4]. Figure A-19 indicates that impacted volumes would be delayed for 10 to 20 years and would exceed 200,000 to 700,000 m^3 after 30 years. CO_2 leakage from a legacy well with permeabilities between 5 x 10^{-13} m^2 and 5 x 10^{-18} m^2 does not impact groundwater and no leakage occurs at permeability of 5 x 10^{-19} m^2 and below[5]. These estimates may under predict the magnitude of impact (i.e., change in pH) because NRAP-IAM-CS uses an open (i.e., unconfined) aquifer to estimate leakage, allowing a large fraction of the CO_2 to move to the vadose zone and out to the atmosphere, rather than into the shallow groundwater where it could alter the pH. If a confined aquifer is used to represent the shallow groundwater, then the volume of impacted water would be greater. Brine leakage from Legacy Well 1 does not impact the shallow groundwater above the TDS threshold.

Legacy Well 2 is south of the CO_2 plume. As expected, the NRAP-IAM-CS predicts only brine leakage at this location. The amount of brine leaked does not impact the shallow groundwater above the TDS threshold. Results of the fixed permeability analysis of Legacy Well 1 and 2 supports the null outcome of probabilistic analysis using the default well permeability distributions provided with the NRAP-IAM-CS. Although two of the four distributions include permeabilities as high as 10^{-12} m^2, these higher values make up a small fraction of the sampled permeabilities. Permeabilities sampled by the FutureGen models are all below 10^{-12} m^2 and leakage would not be expected.

[4] Approximately 5 Darcy
[5] Approximately 500 to 0.05 millidarcy

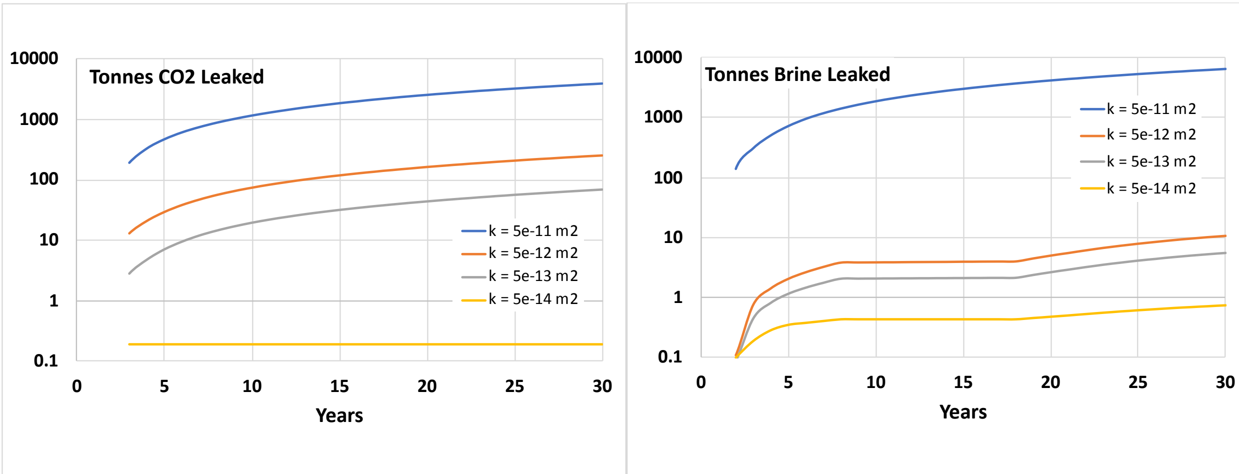

Figure A-18. Mass of CO_2 (left) and brine (right) leaked estimated to leak into a shallow groundwater from Legacy Well 1 for four values of wellbore permeability.

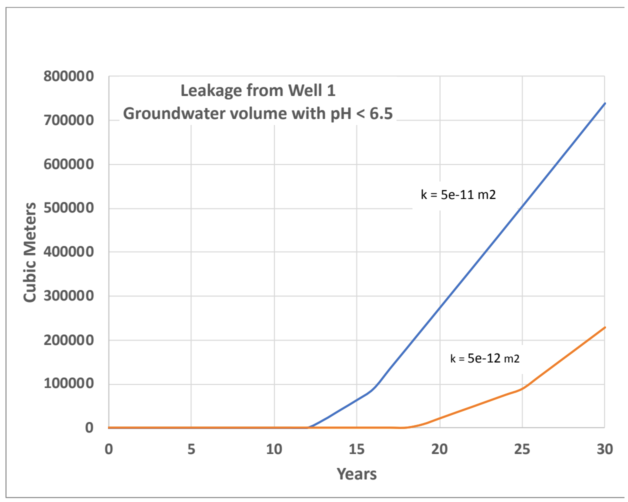

Figure A-19. Shallow groundwaters are estimated to impact groundwater because leaking CO_2 will change the pH above the threshold if the permeability of Legacy Well 1 is 5 x 10^{-12} m^2 (~5 Darcy) or higher.

A.1.5 Summary and Conclusions

The NRAP-IAM-CS was used to estimate the AoR and the impact of leakage from legacy wells located within the AoR at a representative carbon storage site for the Michigan CarbonSAFE, Phase 1 project. The risk-based analysis yielded an AoR of 234 km^2 (90 mi^2), which is slightly smaller in size to the AoR defined using the critical pressure approach (269 km^2, 104 mi^2) because small fluxes did not impact groundwater quality.

Leakage from two legacy wells located within the AoR should not adversely impact groundwater quality over the 30-year injection period. Legacy Well 1 penetrates the simulated CO_2 plume and would require permeability of 5 x 10^{-12} m^2 or 5 Darcy to impact groundwater quality after about 20 years of injection. Legacy Well 2 falls outside of the CO_2 plume, where reservoir pressures are too small to generate large enough leaks to change groundwater quality even with well permeabilities as high as 5 x 10^{-11} m^2 or 50 Darcy.

A.1.6 Recommendations

The NRAP-IAM-CS toolset was released in 2017. The strength of the toolset is the ability to perform probabilistic assessments that account for the uncertainty of the storage complex. This work represents some of the first applications of the tools to potential CO_2 storage sites. The following recommendations to the toolset could advance its use for the determination of probabilistic assessments of risk-based AoR and leakage from legacy wells on quality to USDWs.

1. The AoR calculations would be more robust if the toolset could sample pressures and CO_2 saturations from many 2D planes within the reservoir. This is particularly important for stacked storage reservoirs where stratigraphic heterogeneity will control pressure and CO_2 gas saturations. A ROM specific to the site reservoir would further improve a probabilistic assessment of the AoR.

USDW ROMs need to be calibrated against the high leakage fluxes generated from open wellbores. All USDW ROMs were calculated for cemented wellbores, where leakage is controlled by the permeability of damage zones within the completed wells.

The NRAP-IAM-CS currently has one option for a UDSW ROM, the unconfined carbonate aquifer, where CO_2 leaks to aquifer and to the atmosphere. NRAP is updating the toolset with a confined alluvium aquifer in which all CO_2 leaked stays within the aquifer system.

Any AoR and groundwater impact assessments should include both the injection and post-injection periods. This is important to demonstrate that the CO_2 plume has stabilized and that the reservoir pressures have returned to pre-injection levels. Post-injection assessments of CO_2 leakage are important because buoyancy will continue move the CO_2 along leakage pathways even after the reservoir pressure has relaxed to its pre-injection levels. Conclusions in this study were based only on the injection period.

A.1.7 References

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Appendix B: Economic Analysis Figures

This appendix contains 56 plots (figures), including 14 for each of the four sources evaluated.

Source	Saline Storage Site	Cost of Capital	Scenario and Figure Number
Wolverine	2	Low	1. 50 MMT Storage no tax credits 2. 50 MMT Storage w/ tax credits 3. 25 MMT Storage / 25 MMT EOR w/ tax credits
		High	4. 50 MMT Storage no tax credits 5. 50 MMT Storage w/ tax credits 6. 25 MMT Storage / 25 MMT EOR w/ tax credits
	7	Low	7. 50 MMT Storage no tax credits 8. 50 MMT Storage w/ tax credits 9. 25 MMT Storage / 25 MMT EOR w/ tax credits
		High	10. 50 MMT Storage no tax credits 11. 50 MMT Storage w/ tax credits 12. 25 MMT Storage / 25 MMT EOR w/ tax credits
	none	Low	13. 50 MMT EOR w/ tax credits
		High	14. 50 MMT EOR w/ tax credits
Potential New Source – Net Power	2	Low	15. 50 MMT Storage no tax credits 16. 50 MMT Storage w/ tax credits 17. 25 MMT Storage / 25 MMT EOR w/ tax credits
		High	18. 50 MMT Storage no tax credits 19. 50 MMT Storage w/ tax credits 20. 25 MMT Storage / 25 MMT EOR w/ tax credits
	7	Low	21. 50 MMT Storage no tax credits 22. 50 MMT Storage w/ tax credits 23. 25 MMT Storage / 25 MMT EOR w/ tax credits
		High	24. 50 MMT Storage no tax credits 25. 50 MMT Storage w/ tax credits 26. 25 MMT Storage / 25 MMT EOR w/ tax credits
	none	Low	27. 50 MMT EOR w/ tax credits
		High	28. 50 MMT EOR w/ tax credits
Potential New Source – NGCC	2	Low	29. 50 MMT Storage no tax credits 30. 50 MMT Storage w/ tax credits 31. 25 MMT Storage / 25 MMT EOR w/ tax credits
		High	32. 50 MMT Storage no tax credits 33. 50 MMT Storage w/ tax credits 34. 25 MMT Storage / 25 MMT EOR w/ tax credits
	7	Low	35. 50 MMT Storage no tax credits 36. 50 MMT Storage w/ tax credits 37. 25 MMT Storage / 25 MMT EOR w/ tax credits
		High	38. 50 MMT Storage no tax credits 39. 50 MMT Storage w/ tax credits 40. 25 MMT Storage / 25 MMT EOR w/ tax credits
	none	Low	41. 50 MMT EOR w/ tax credits
		High	42. 50 MMT EOR w/ tax credits
Project TIM	2	High	43. 50 MMT Storage no tax credits 44. 50 MMT Storage w/ tax credits 45. 25 MMT Storage / 25 MMT EOR w/ tax credits
		Low	46. 50 MMT Storage no tax credits 47. 50 MMT Storage w/ tax credits 48. 25 MMT Storage / 25 MMT EOR w/ tax credits
	7	High	49. 50 MMT Storage no tax credits 50. 50 MMT Storage w/ tax credits 51. 25 MMT Storage / 25 MMT EOR w/ tax credits
		Low	52. 50 MMT Storage no tax credits 53. 50 MMT Storage w/ tax credits 54. 25 MMT Storage / 25 MMT EOR w/ tax credits
	none	Low	55. 50 MMT EOR w/ tax credits
		High	56. 50 MMT EOR w/ tax credits

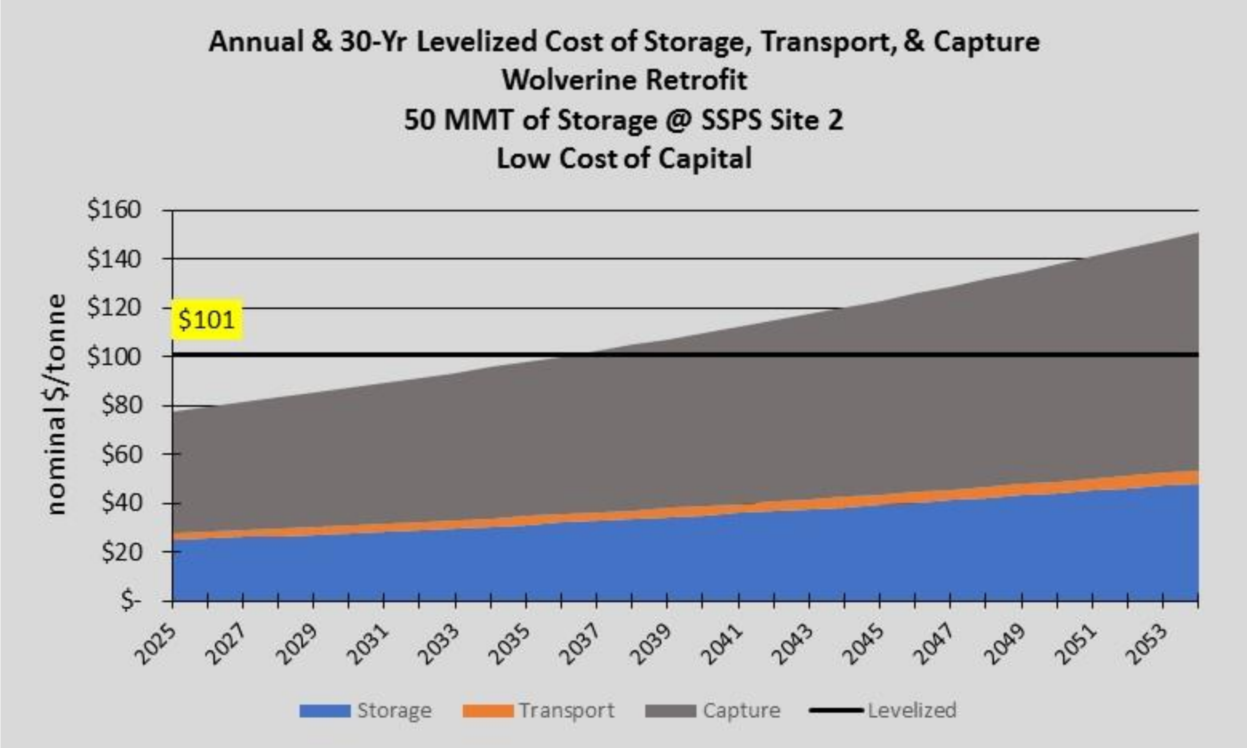

Figure B-1. Wolverine retrofit at SSPS site 2 at low cost of capital with 50 MMT storage and no tax credits

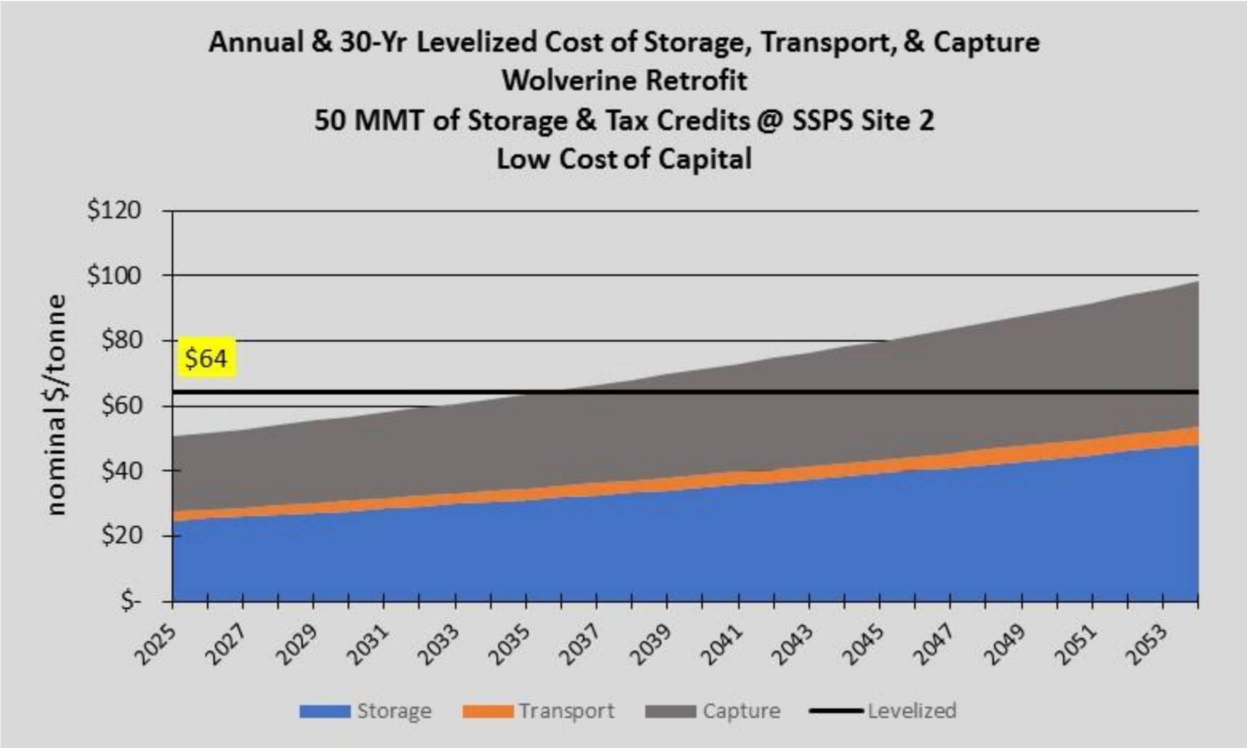

Figure B-2. Wolverine retrofit at SSPS site 2 at low cost of capital with 50 MMT storage and tax credits

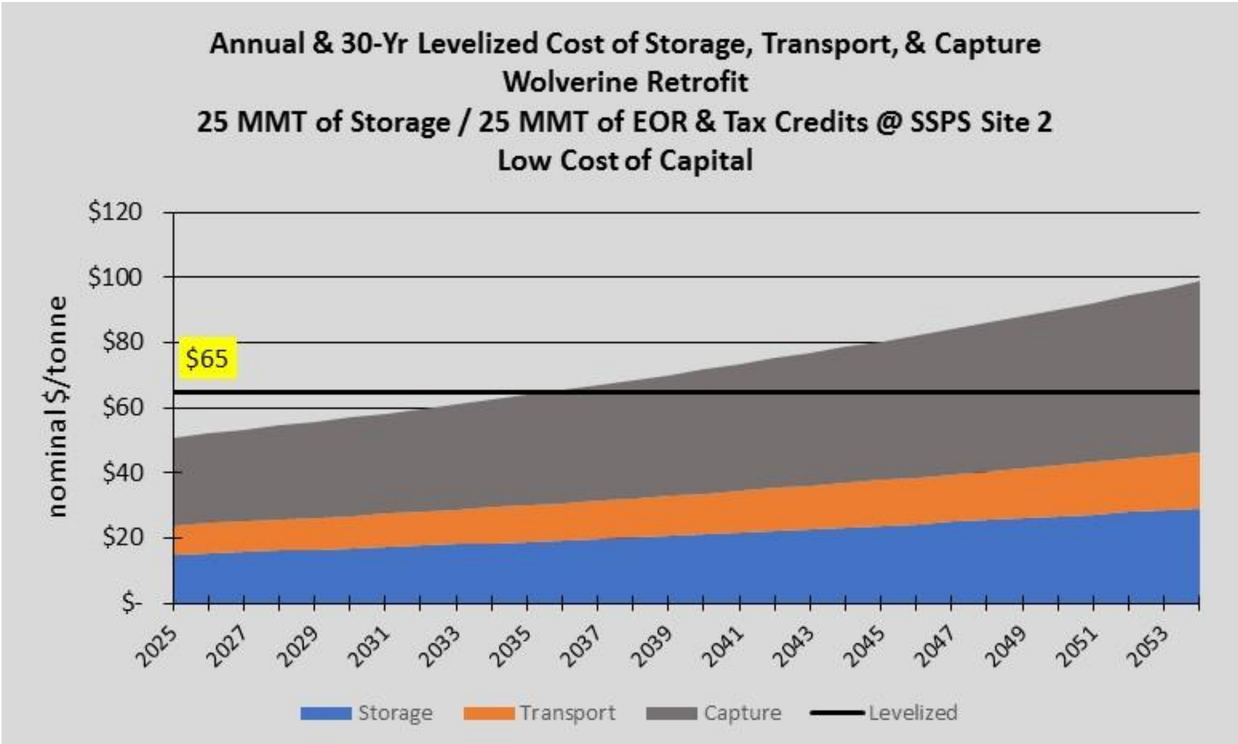

Figure B-3. Wolverine retrofit at SSPS site 2 at low cost of capital with 25 MMT storage/25 MMT of EOR with tax credits

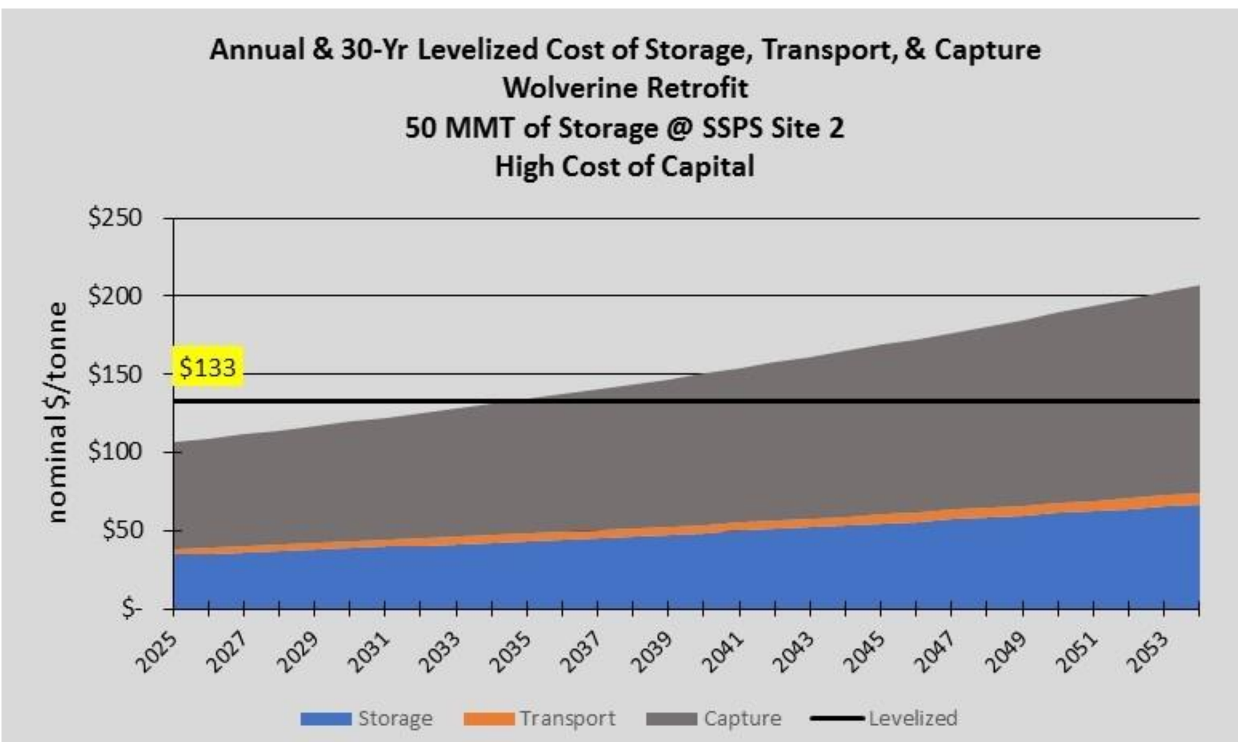

Figure B-4. Wolverine retrofit at SSPS site 2 at high cost of capital with 50 MMT storage and no tax credits

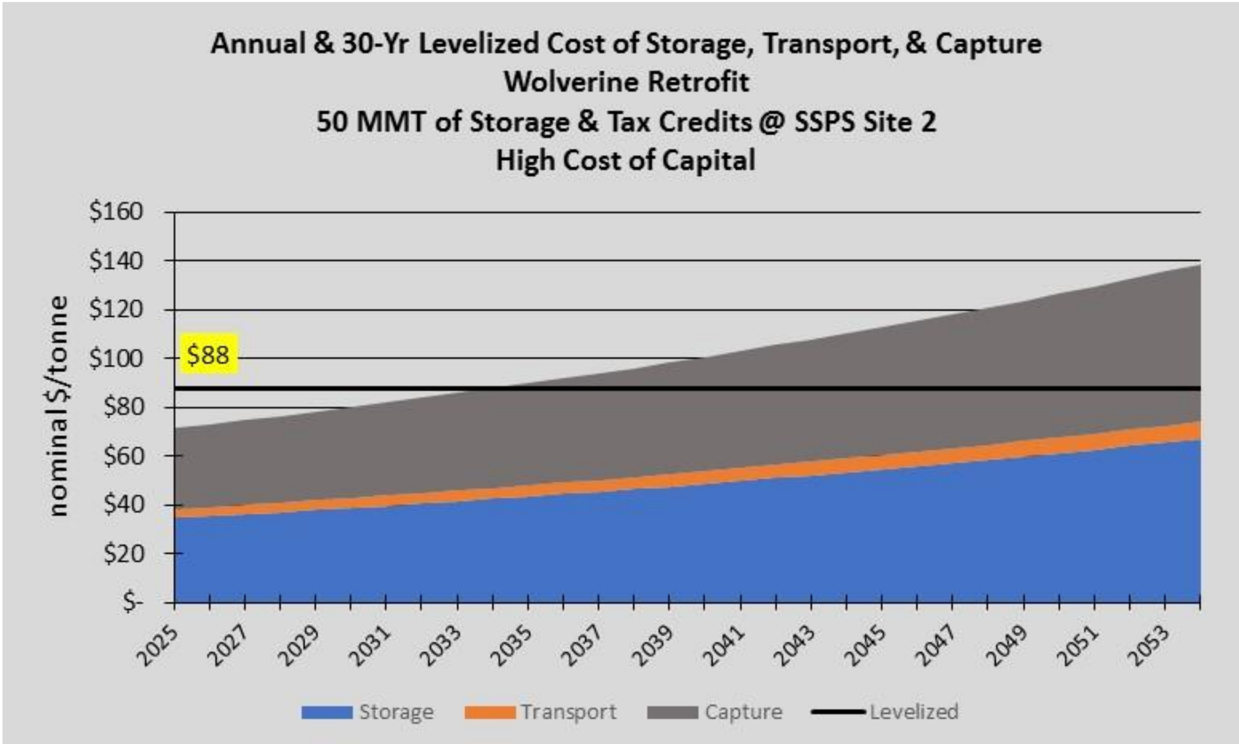

Figure B-5. Wolverine retrofit at SSPS site 2 at high cost of capital with 50 MMT storage and tax credits

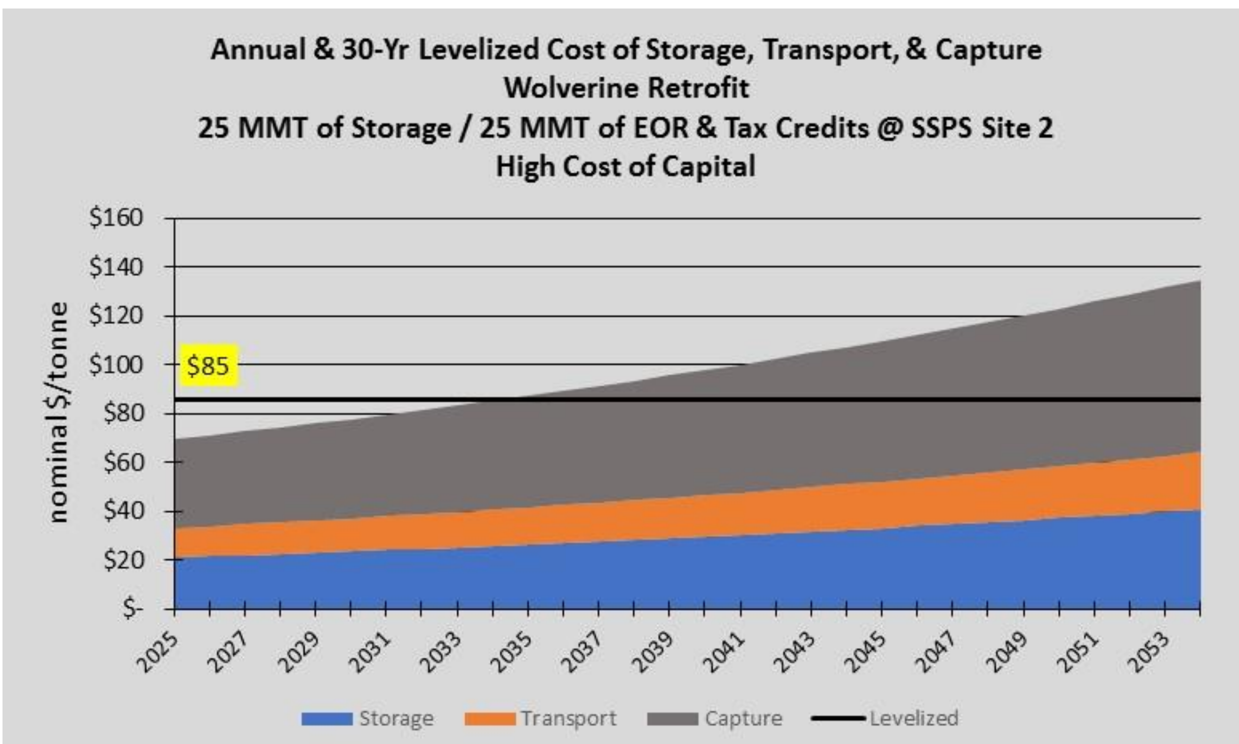

Figure B-6. Wolverine retrofit at SSPS site 2 at high cost of capital with 25 MMT storage/25 MMT of EOR and tax credits

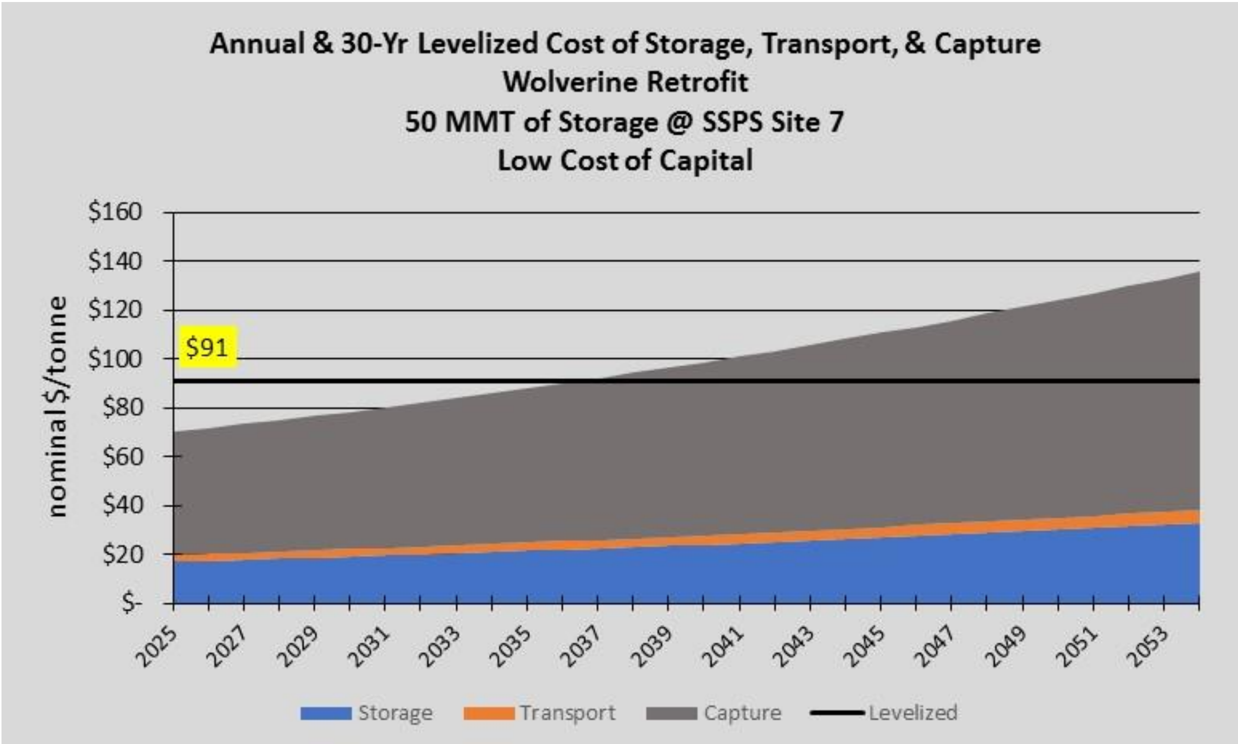

Figure B-7. Wolverine retrofit at SSPS site 7 at low cost of capital with 50 MMT storage and no tax credits

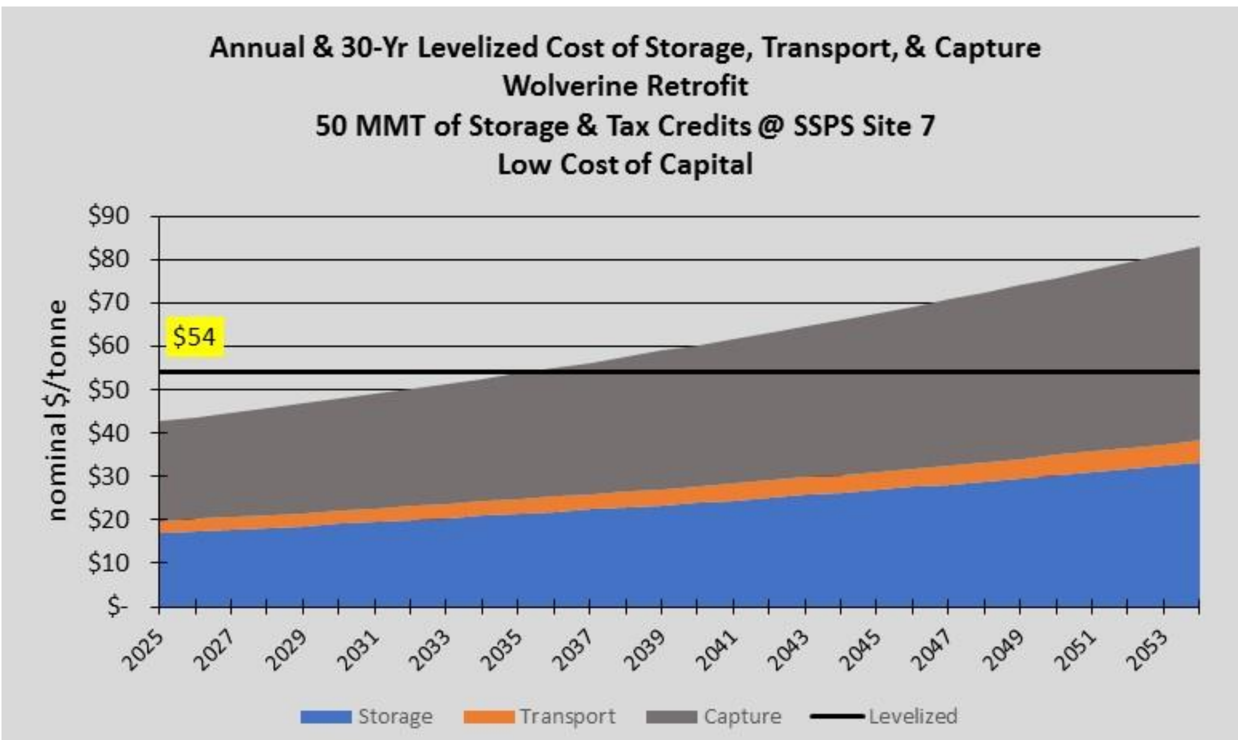

Figure B-8. Wolverine retrofit at SSPS site 7 at low cost of capital with 50 MMT storage and tax credits

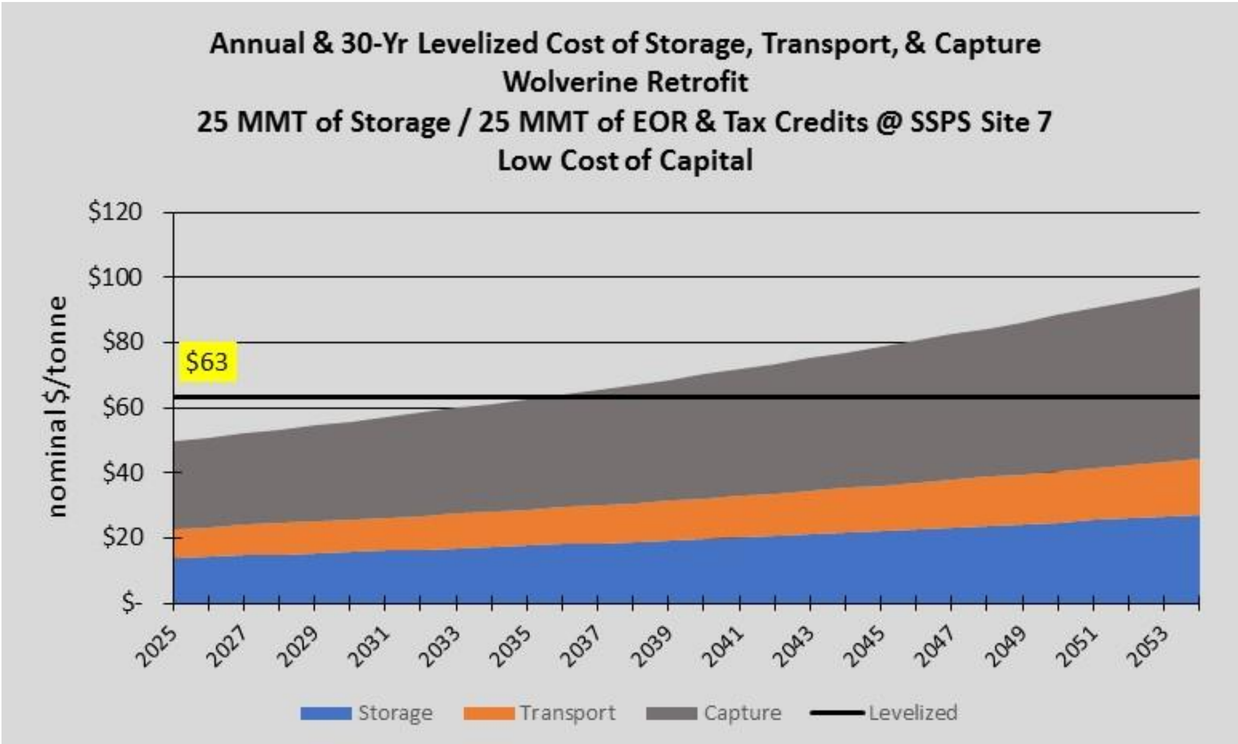

Figure B-9. Wolverine retrofit at SSPS site 7 at low cost of capital with 25 MMT storage/25 MMT of EOR and tax credits

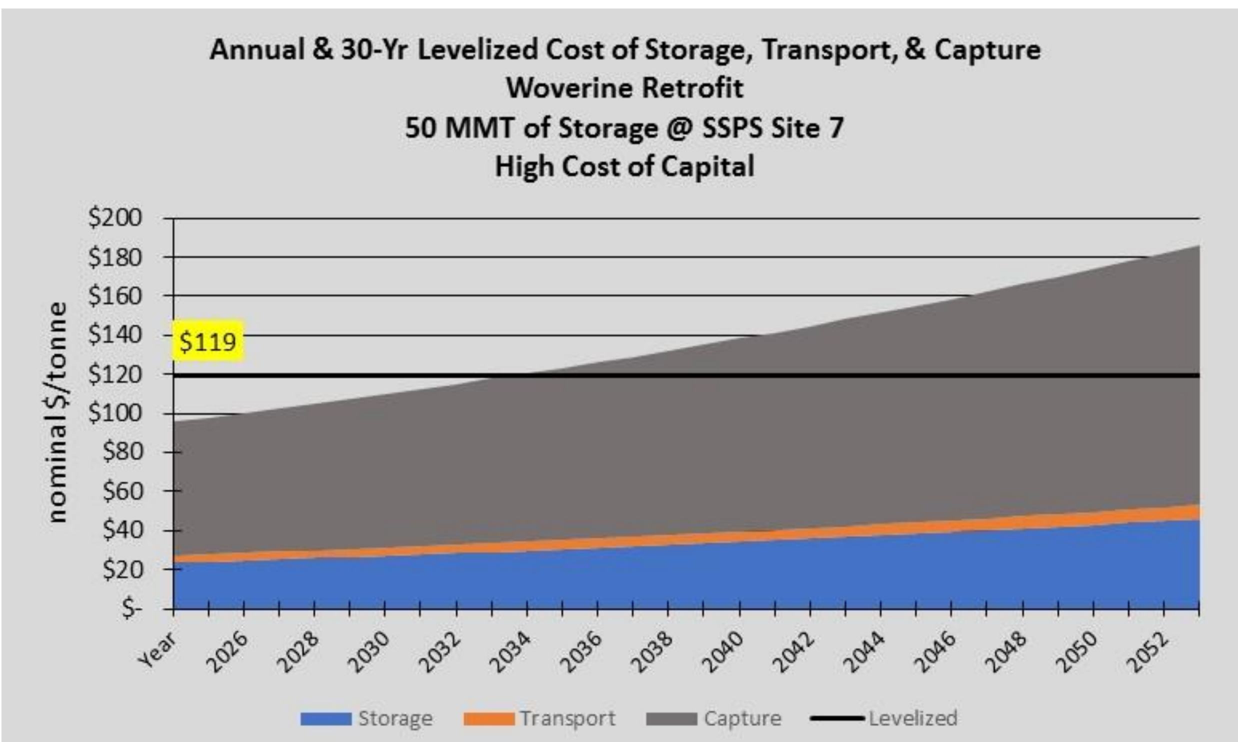

Figure B-10. Wolverine retrofit at SSPS site 7 at high cost of capital with 50 MMT storage and no tax credits

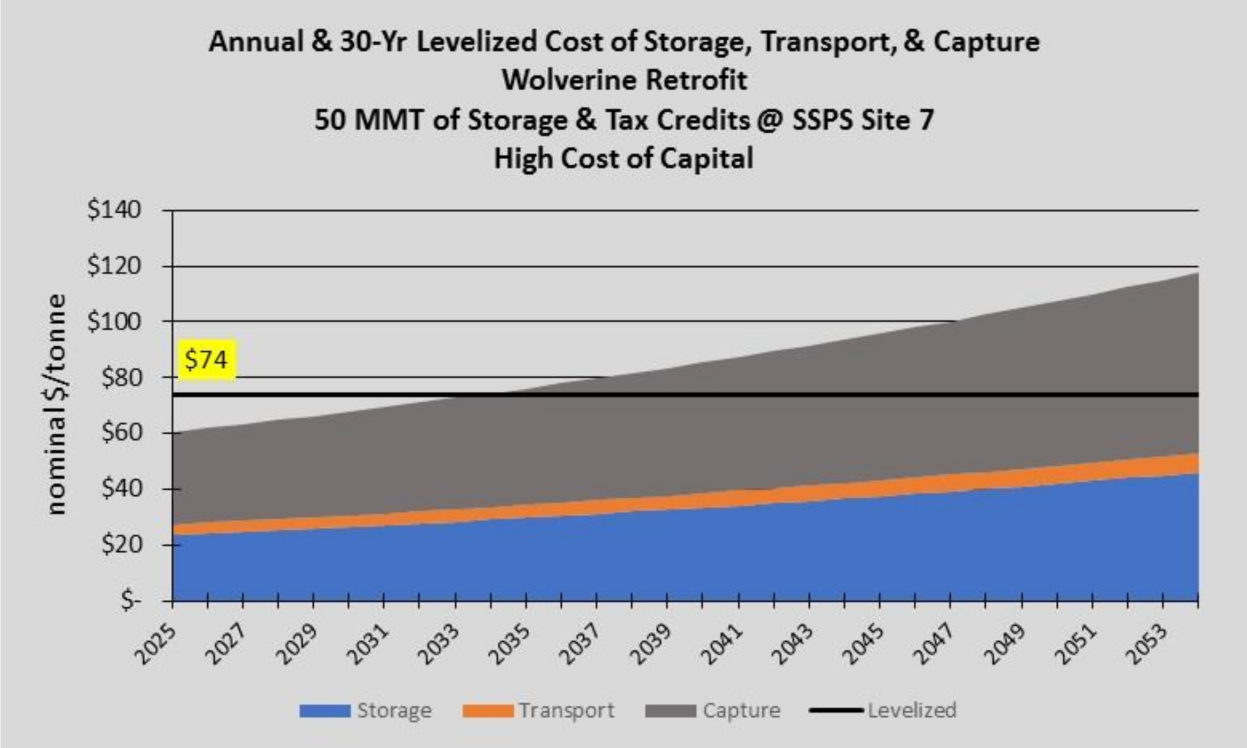

Figure B-11. Wolverine retrofit at SSPS site 7 at high cost of capital with 50 MMT storage and tax credits

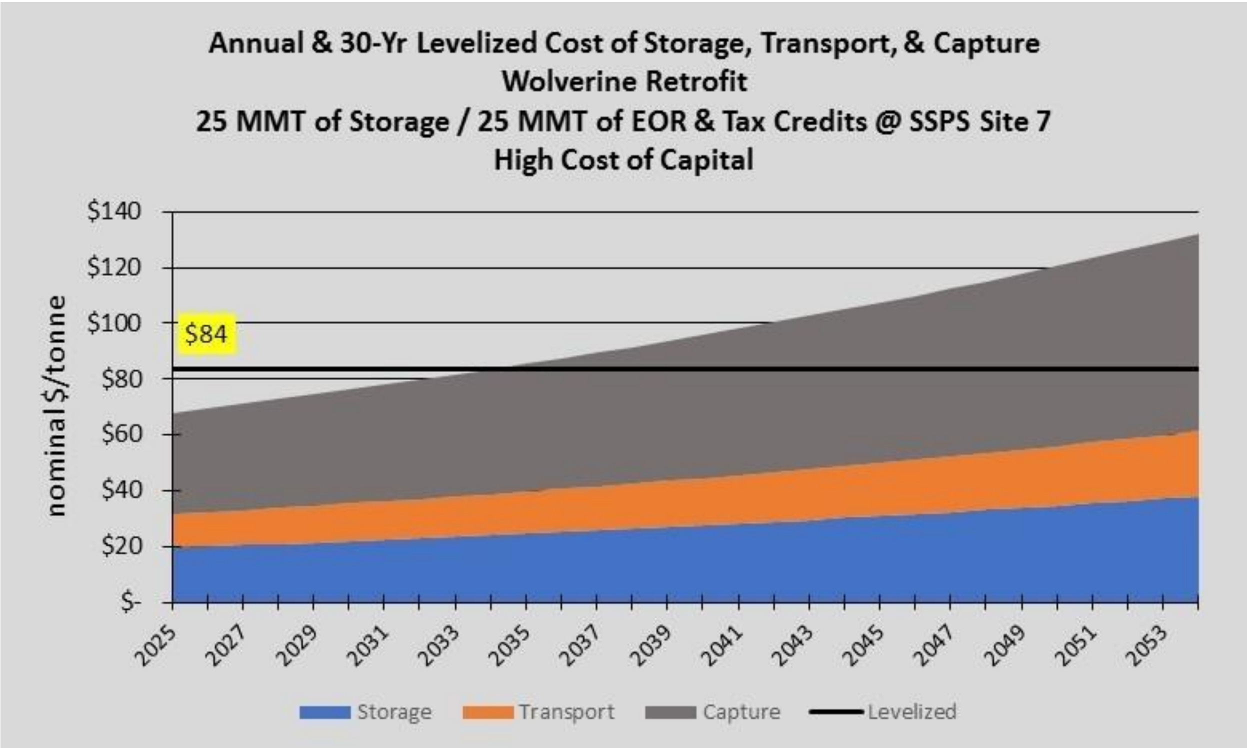

Figure B-12. Wolverine retrofit at SSPS site 7 at high cost of capital with 25 MMT storage/25 MMT of EOR and tax credits

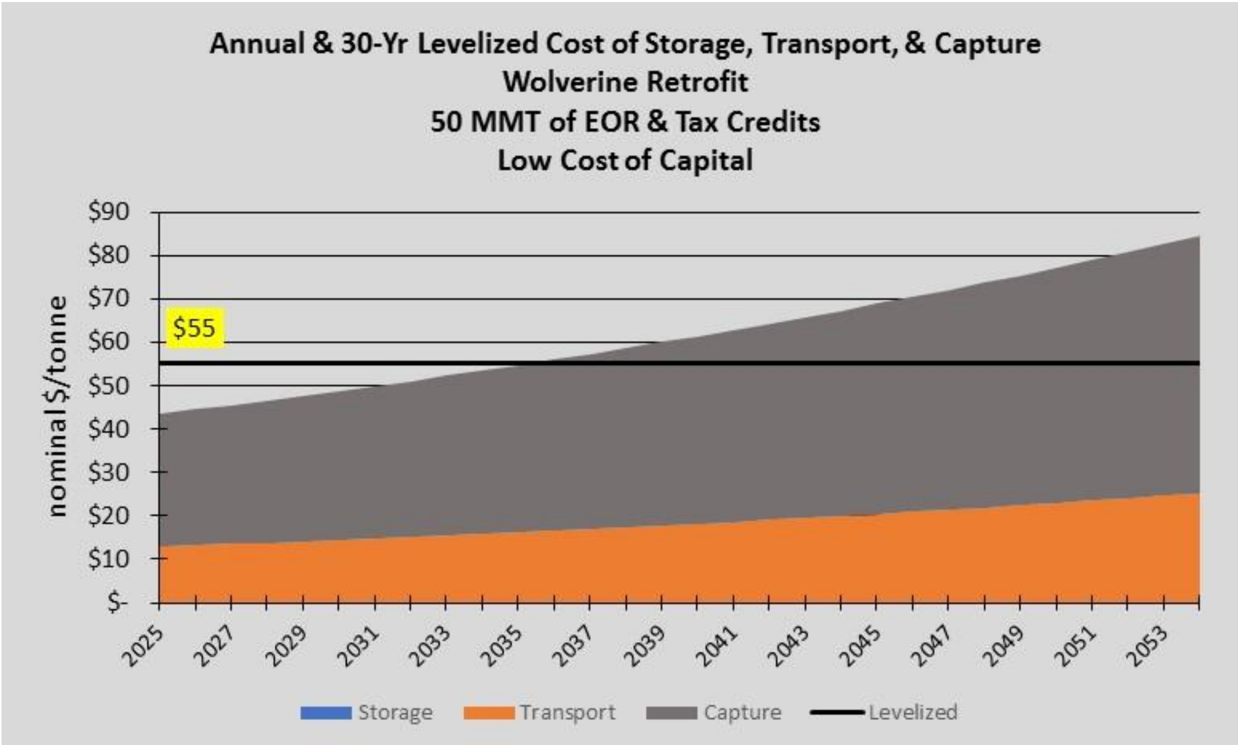

Figure B-13. Wolverine retrofit at low cost of capital with 50 MMT of EOR and tax credits

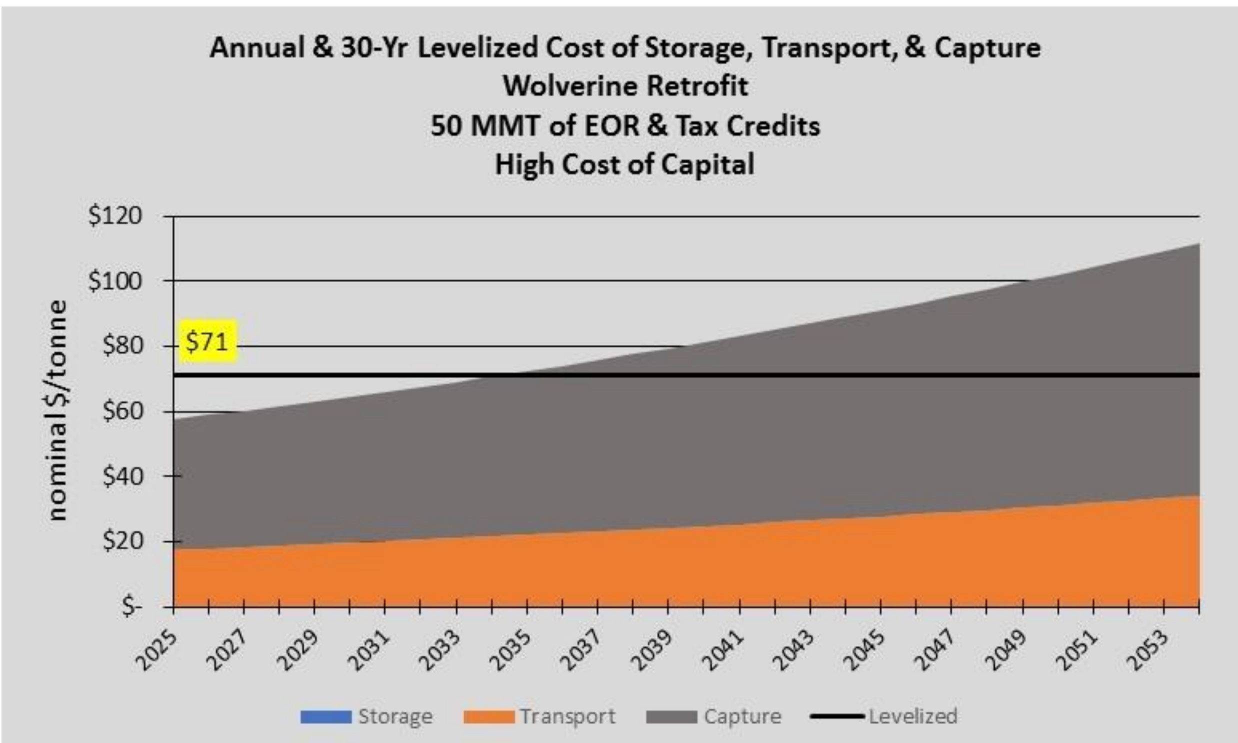

Figure B-14. Wolverine retrofit at high cost of capital with 50 MMT of EOR and tax credits

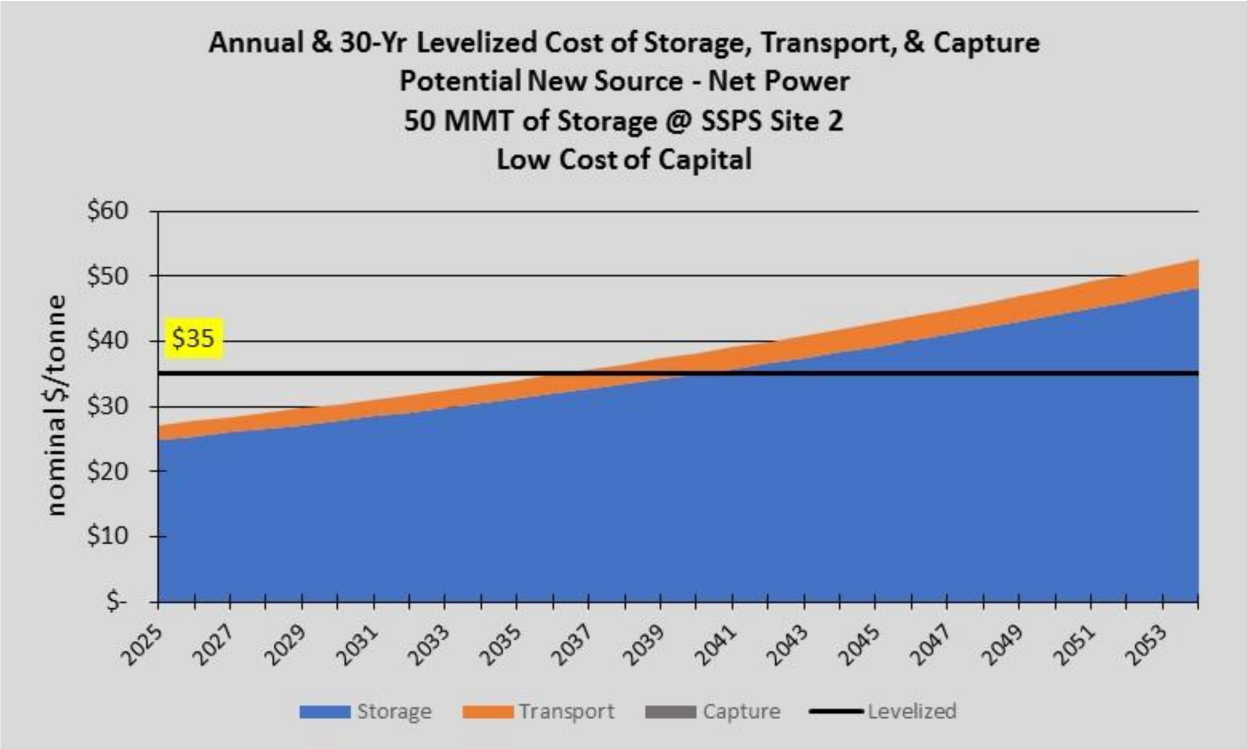

Figure B-15. Potential new source – net power at SSPS site 2 at low cost of capital with 50 MMT storage and no tax credits

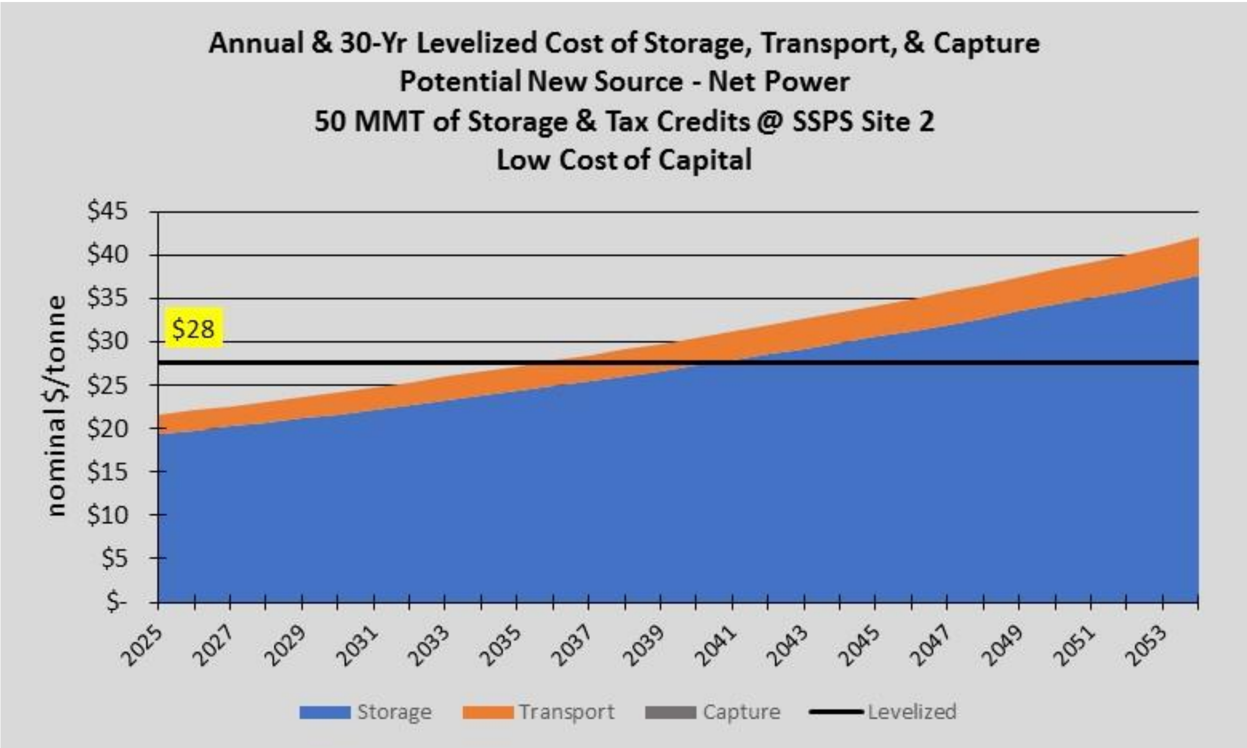

Figure B-16. Potential new source – net power at SSPS site 2 at low cost of capital with 50 MMT storage and tax credits

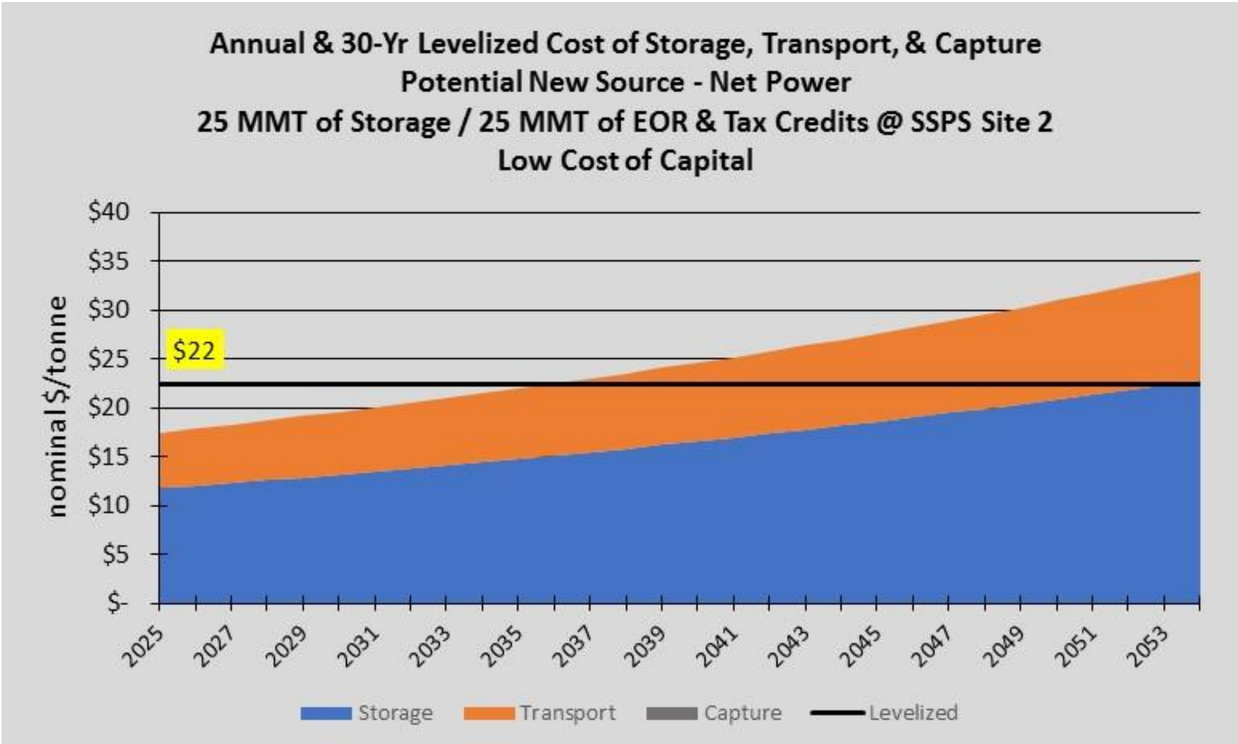

Figure B-17. Potential new source – net power at SSPS site 2 at low cost of capital with 25 MMT storage/25 MMT of EOR and tax credits

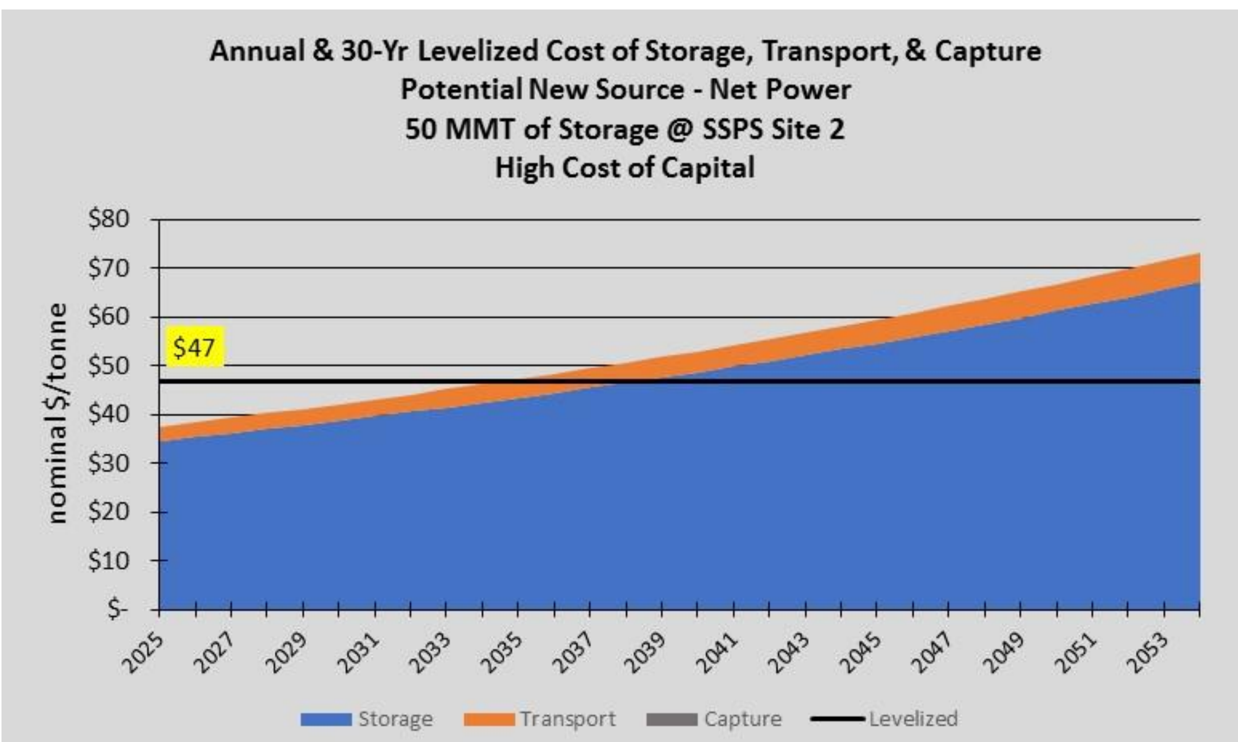

Figure B-18. Potential new source – net power at SSPS site 2 at high cost of capital with 50 MMT storage and no tax credits

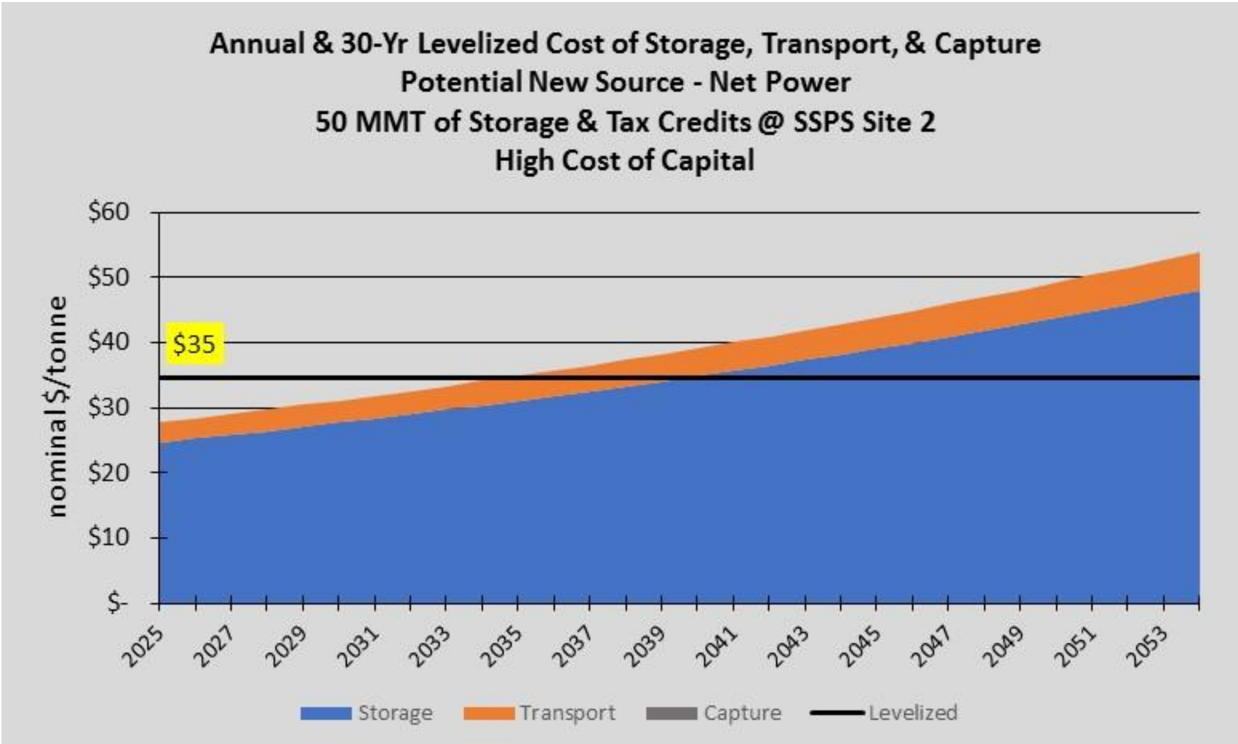

Figure B-19. Potential new source – net power at SSPS site 2 at high cost of capital with 50 MMT storage and tax credits

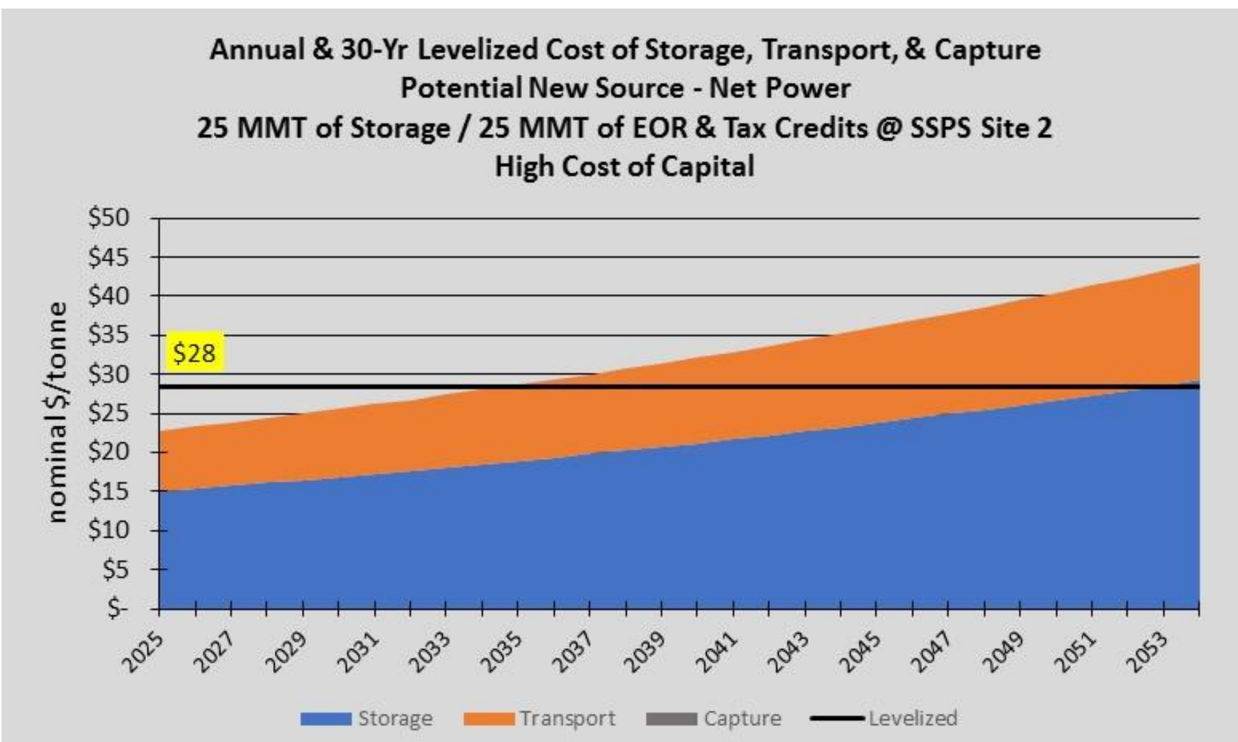

Figure B-20. Potential new source – net power at SSPS site 2 at high cost of capital with 25 MMT storage/25 MMT of EOR and tax credits

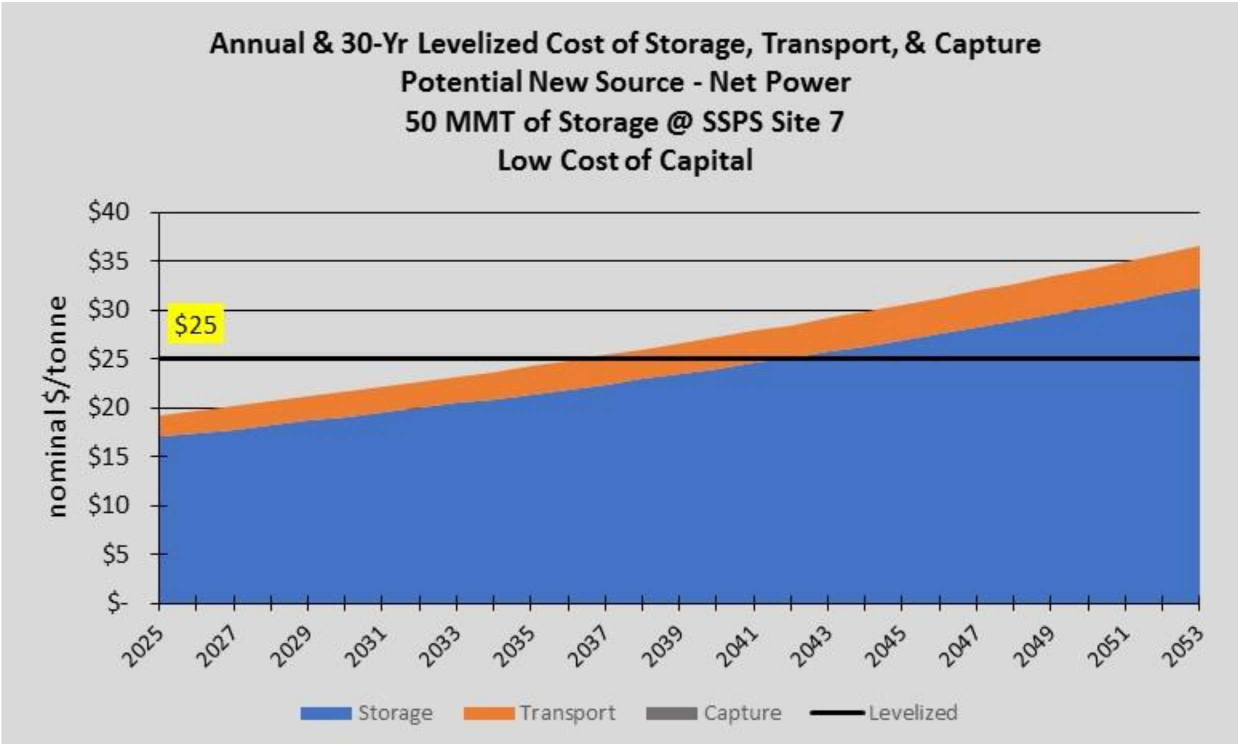

Figure B-21. Potential new source – net power at SSPS site 7 at low cost of capital with 50 MMT storage and no tax credits

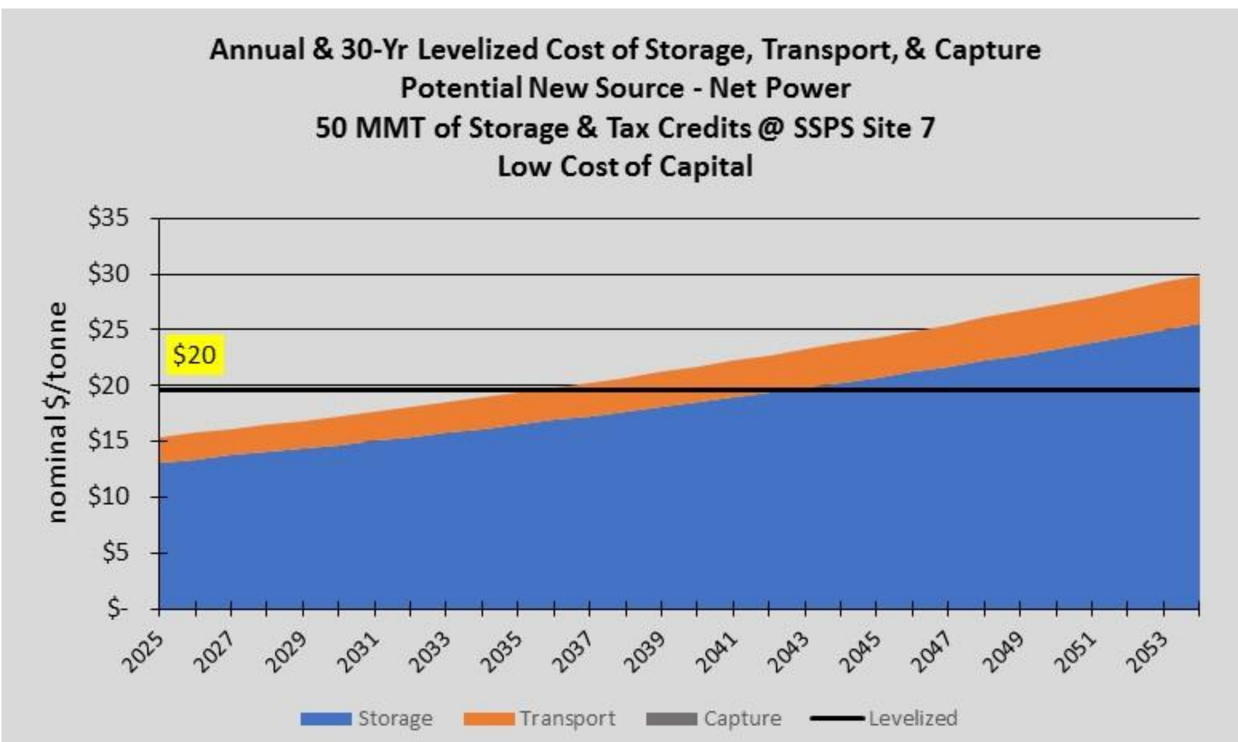

Figure B-22. Potential new source – net power at SSPS site 7 at low cost of capital with 50 MMT storage and tax credits

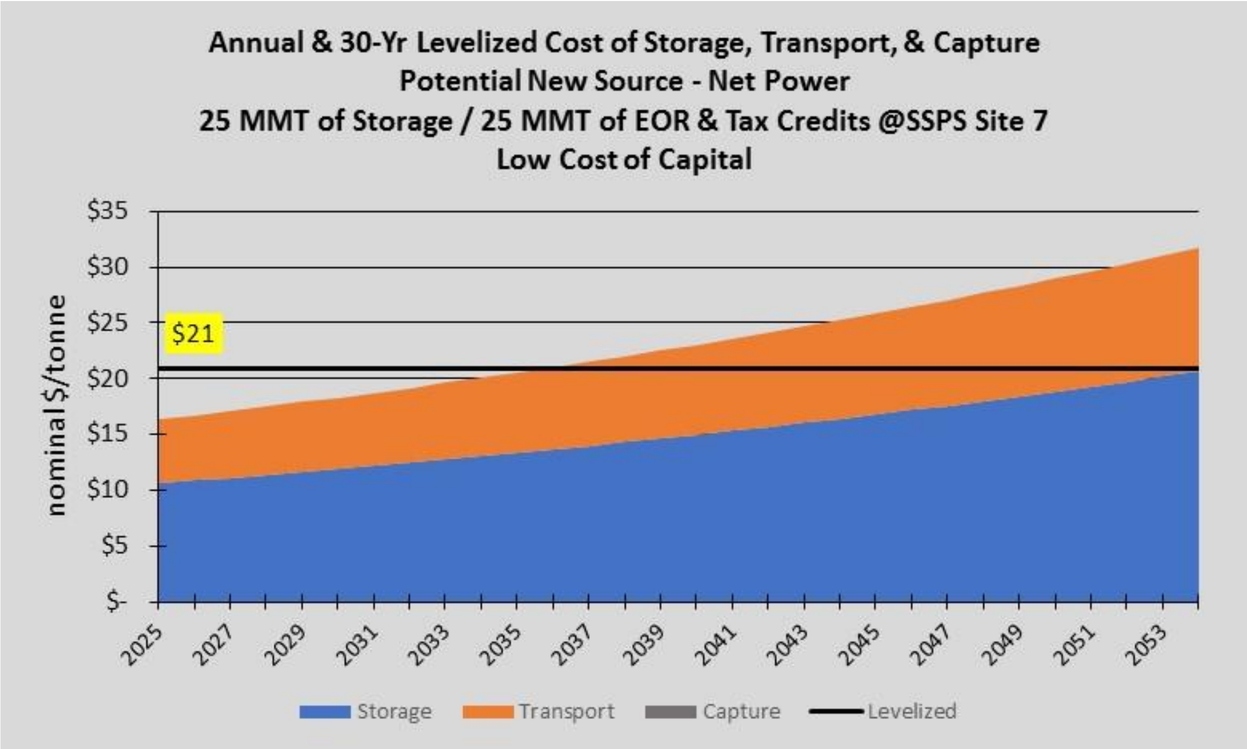

Figure B-23. Potential new source – net power at SSPS site 7 at low cost of capital with 25 MMT storage/25 MMT of EOR and tax credits

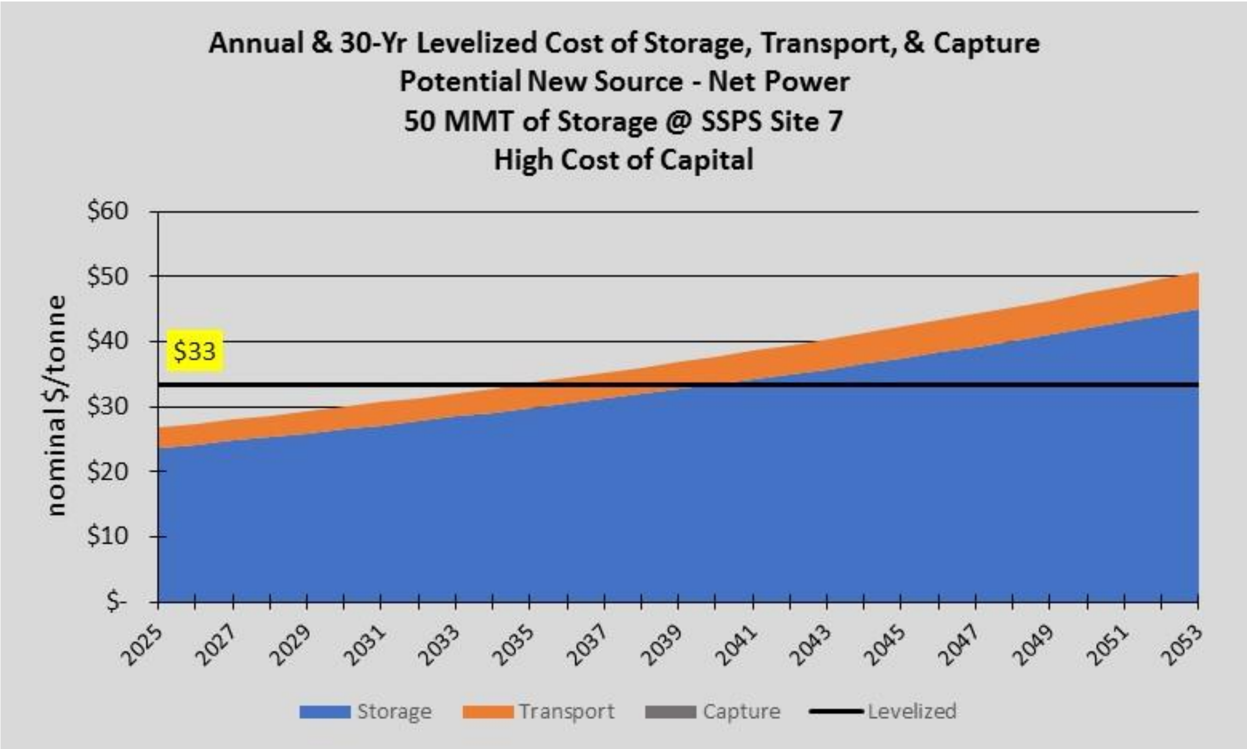

Figure B-24. Potential new source – net power at SSPS site 7 at high cost of capital with 50 MMT of storage and no tax credits

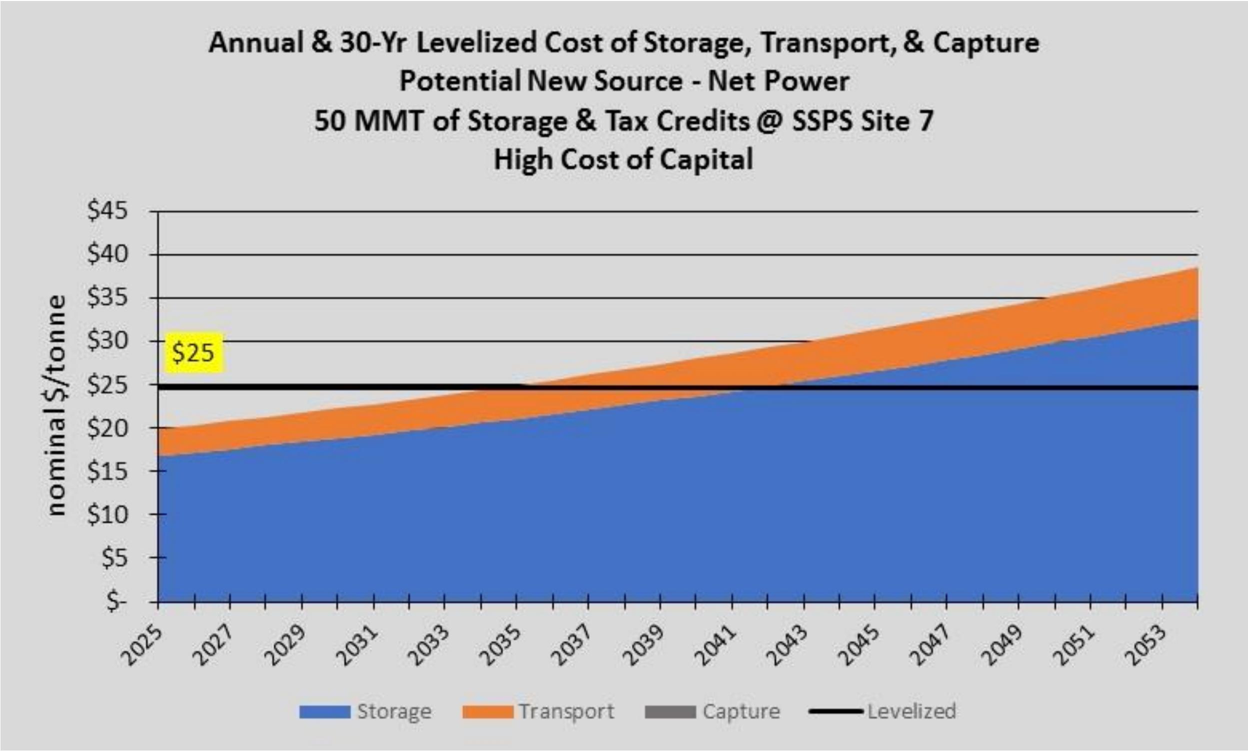

Figure B-25. Potential new source – net power at SSPS site 7 at high cost of capital with 50 MMT storage and tax credits

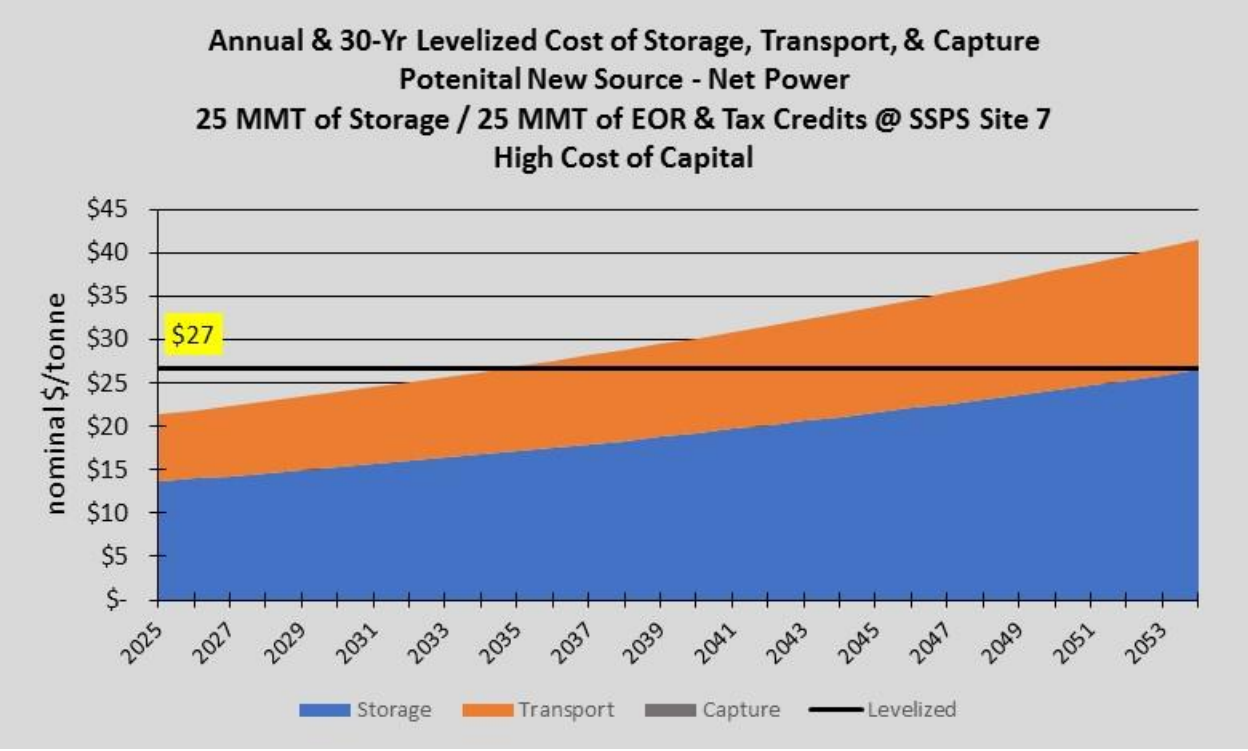

Figure B-26. Potential new source – net power at SSPS site 7 at high cost of capital with 25 MMT storage/25 MMT of EOR and tax credits

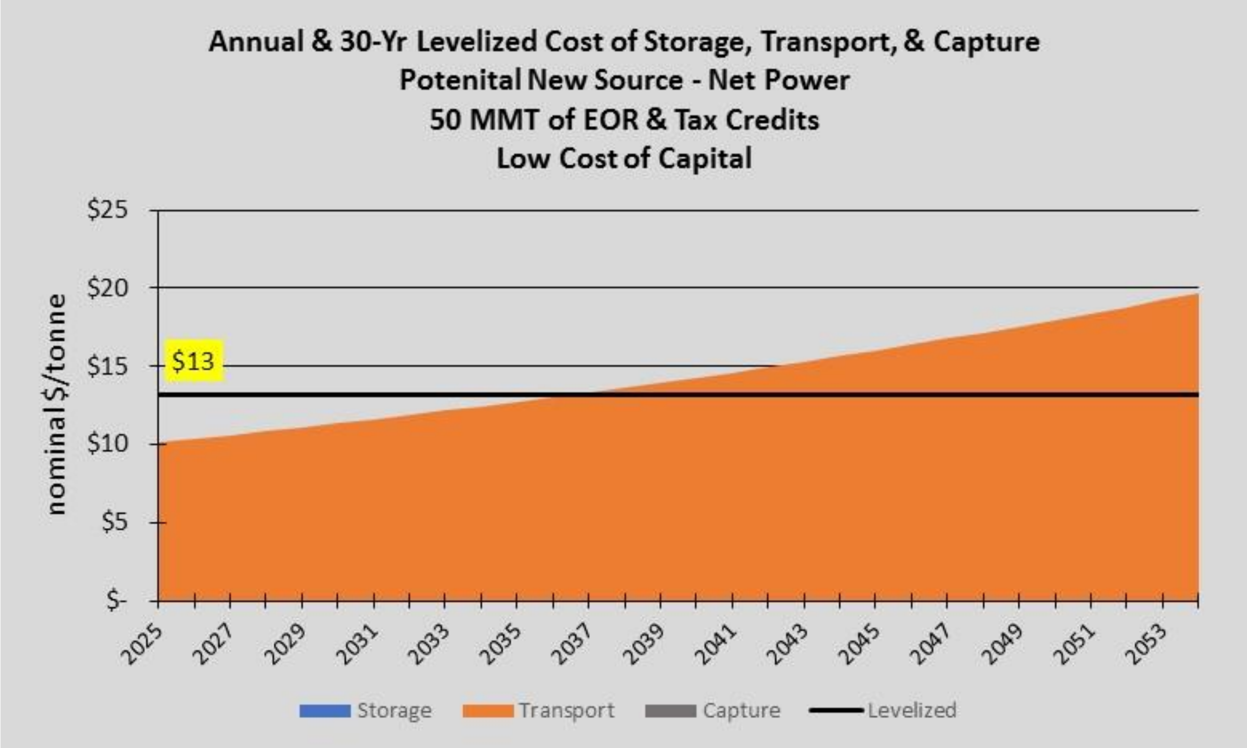

Figure B-27. Potential new source – net power at low cost of capital with 50 MMT of EOR and tax credits

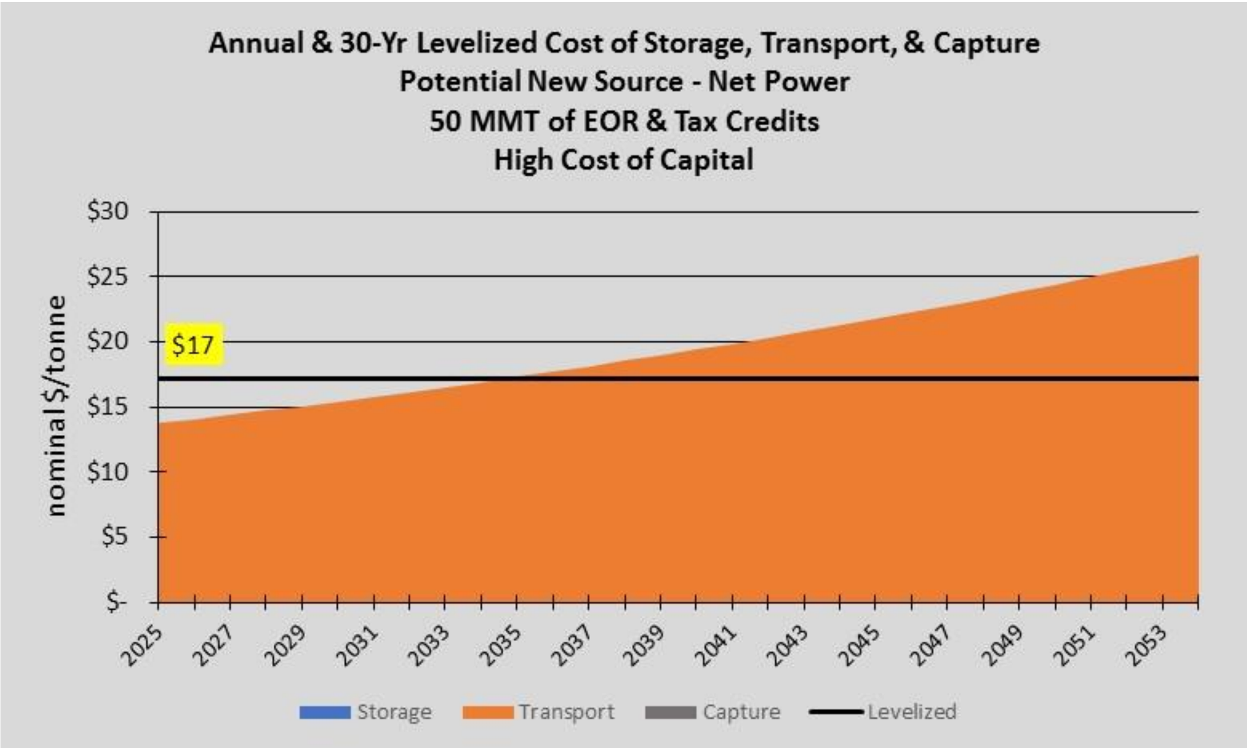

Figure B-28. Potential new source – net power at high cost of capital with 50 MMT of EOR and tax credits

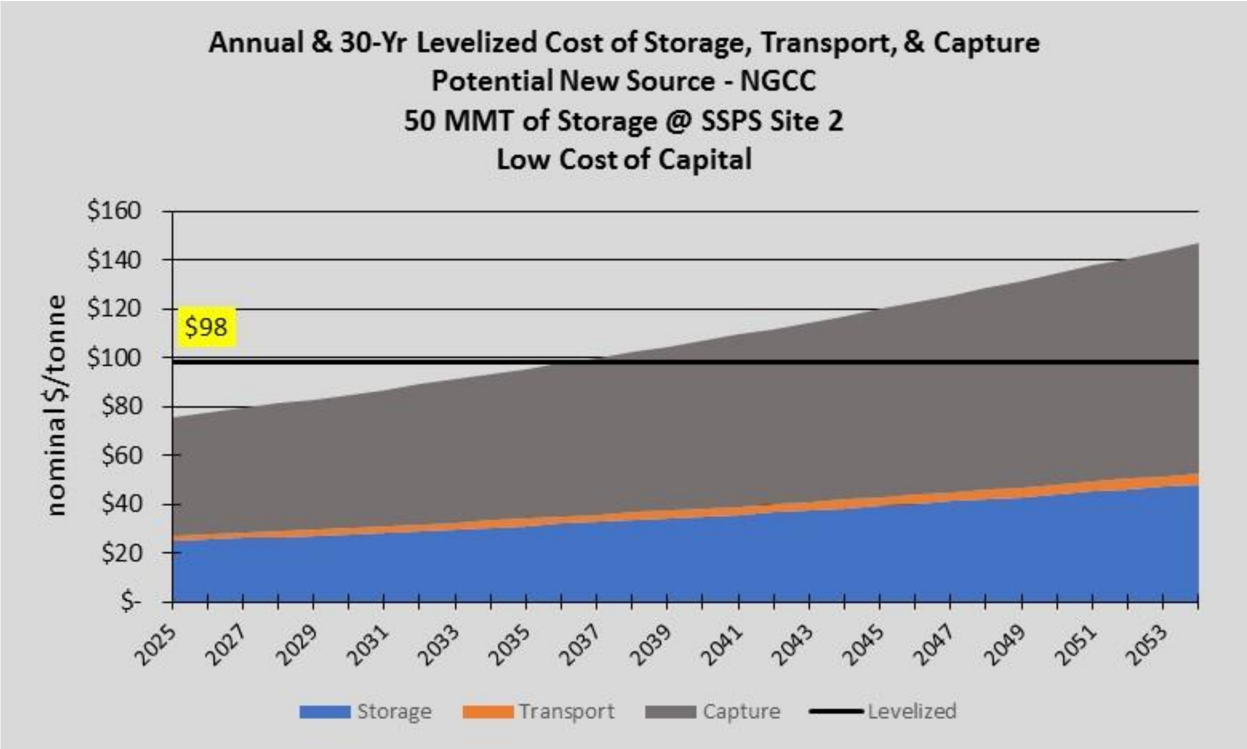

Figure B-29. Potential new source – NGCC at SSPS site 2 at low cost of capital with 50 MMT of storage and no tax credits

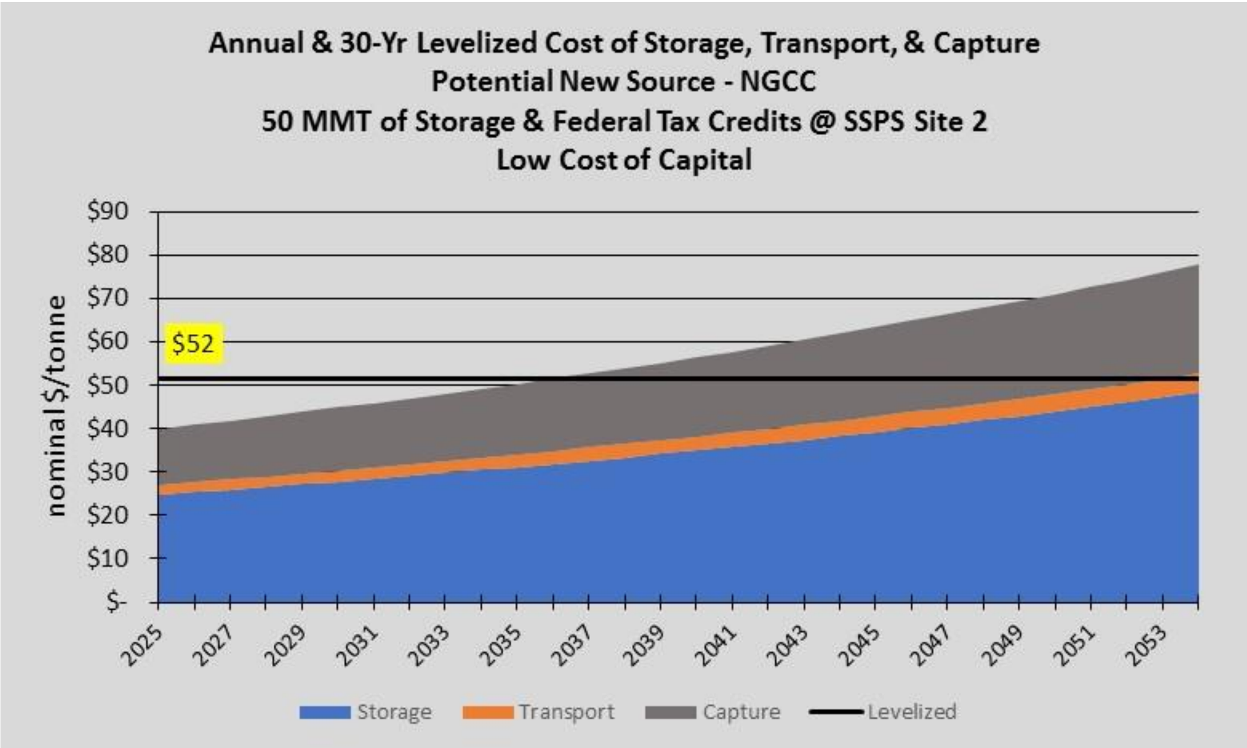

Figure B-30. Potential new source – NGCC at SSPS site 2 at low cost of capital with 50 MMT storage and federal tax credits

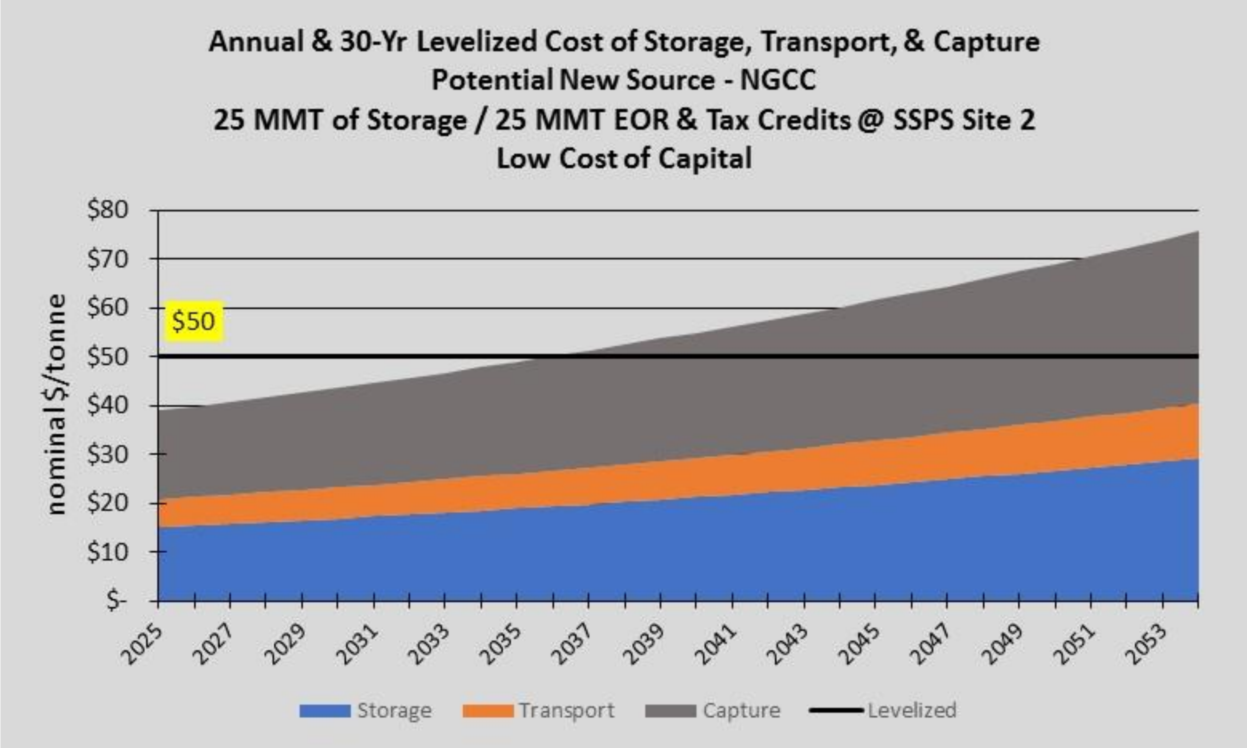

Figure B-31. Potential new source – NGCC at SSPS site 2 at low cost of capital with 25 MMT storage/25 MMT of EOR and tax credits

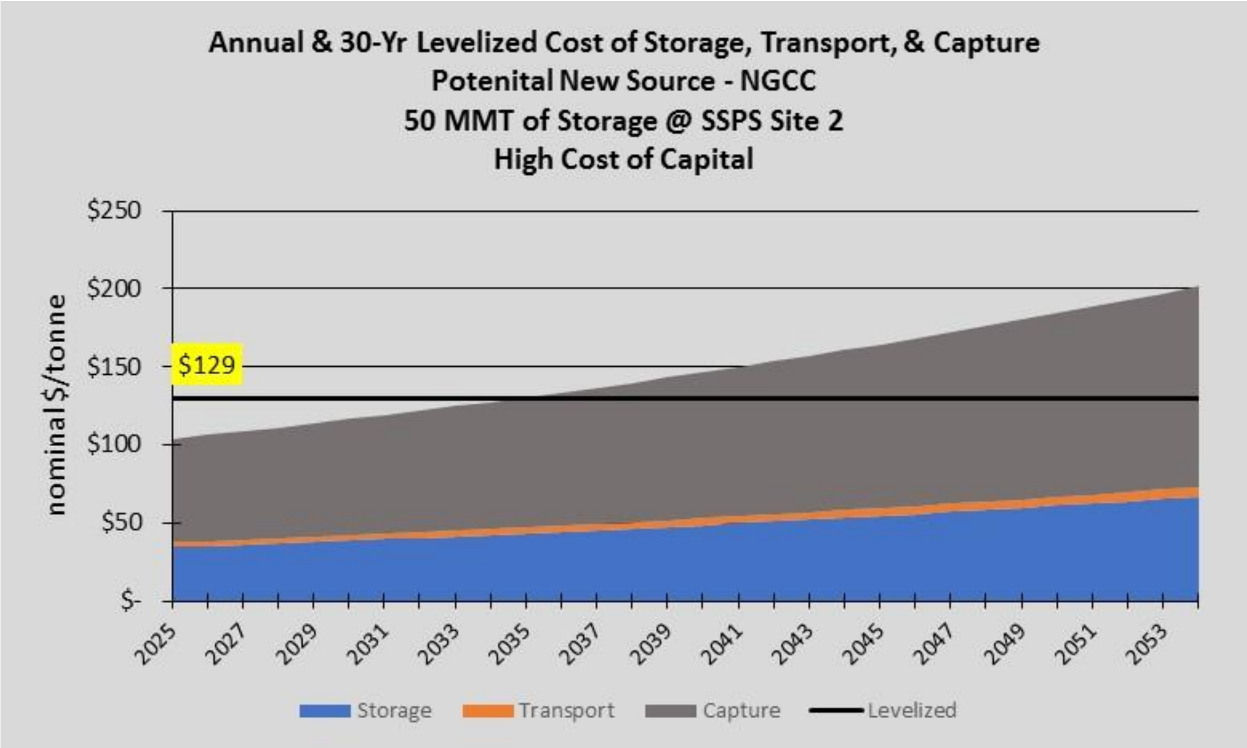

Figure B-32. Potential new source – NGCC at SSPS site 2 at high cost of capital with 50 MMT storage and no tax credits

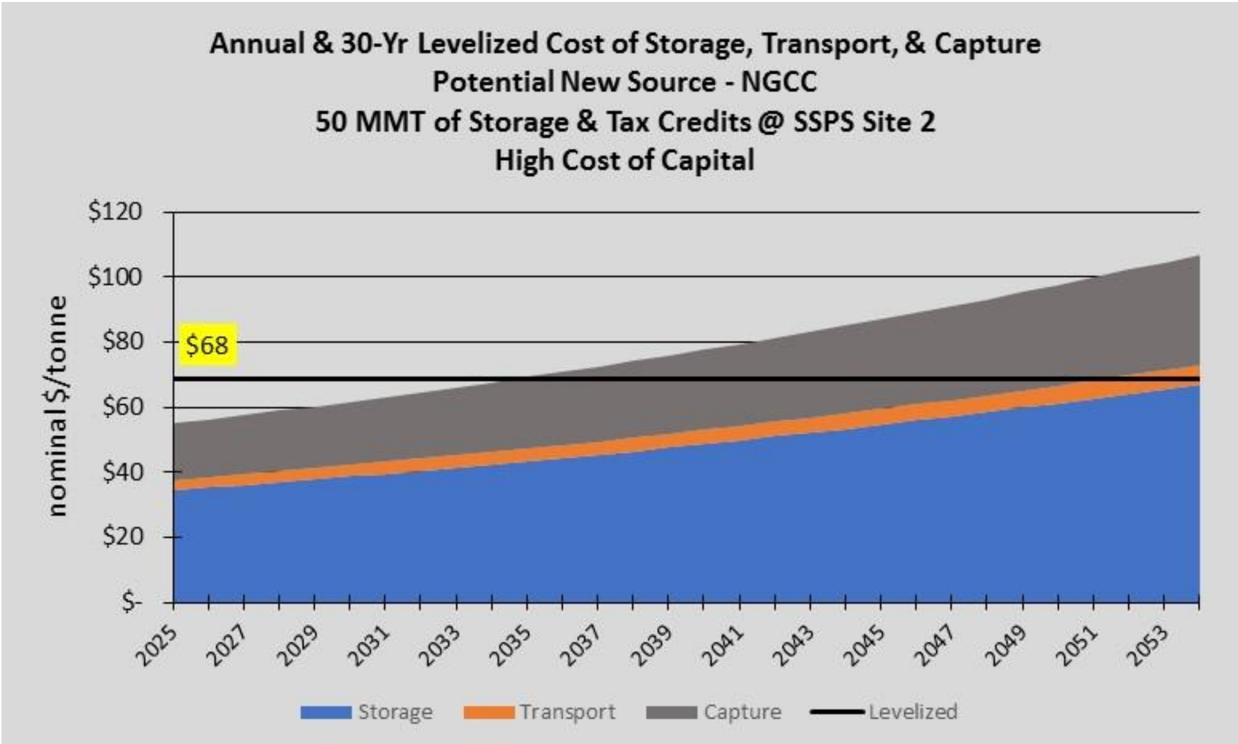

Figure B-33. Potential new source – NGCC at SSPS site 2 at high cost of capital with 50 MMT storage and tax credits

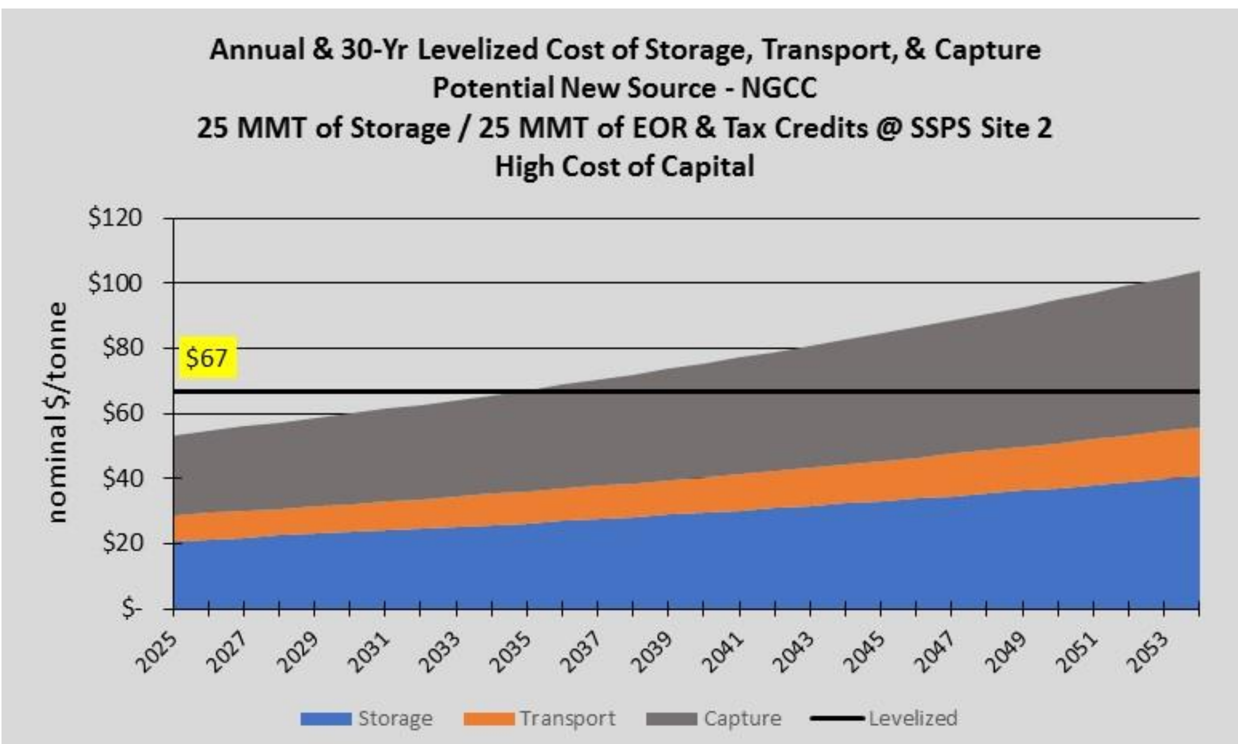

Figure B-34. Potential new source – NGCC at SSPS site 2 at high cost of capital with 25 MMT storage and 25 MMT of EOR and tax credits

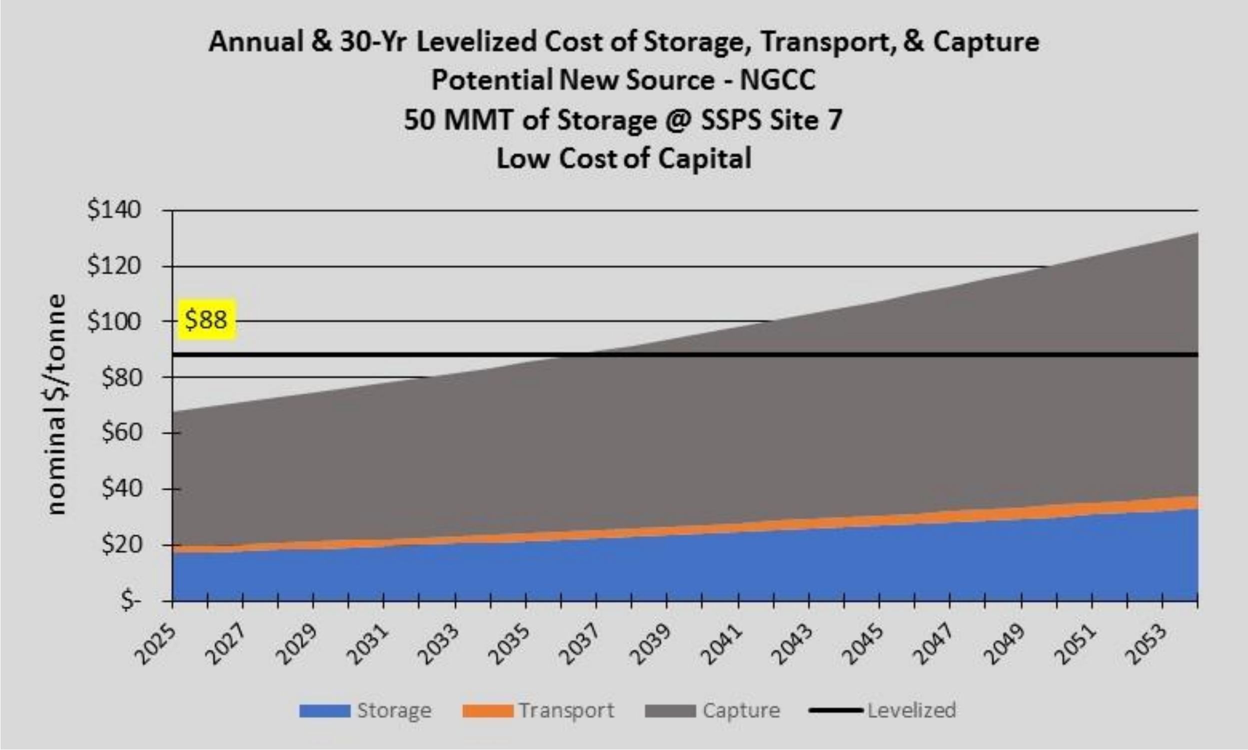

Figure B-35. Potential new source – NGCC at SSPS site 7 at low cost of capital with 50 MMT storage and no tax credits

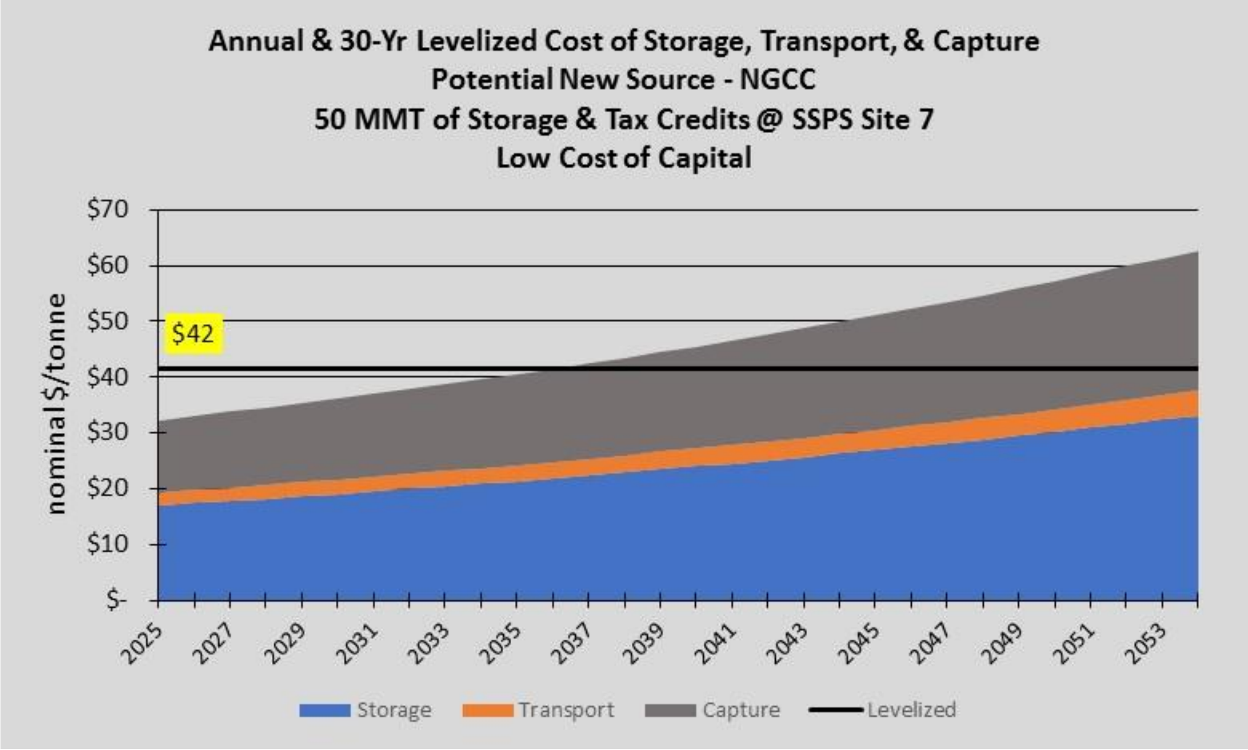

Figure B-36. Potential new source – NGCC at SSPS site 7 at low cost of capital with 50 MMT storage and tax credits

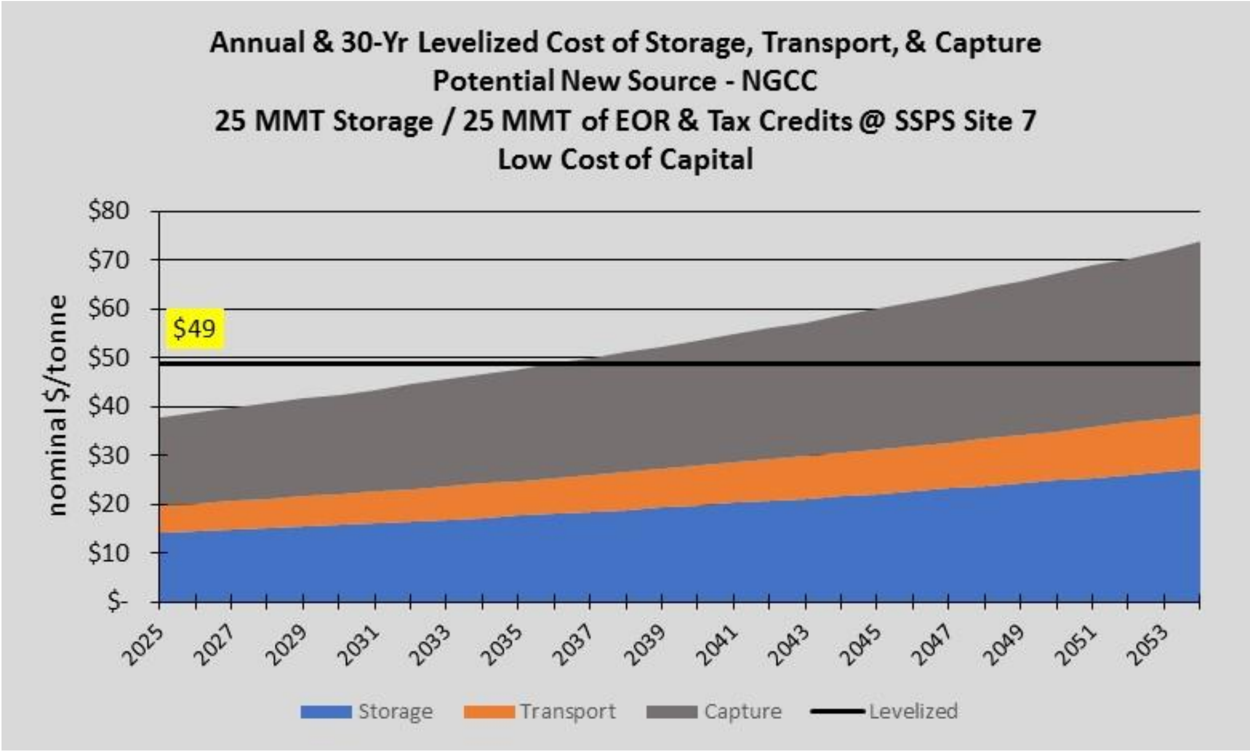

Figure B-37. Potential new source – NGCC at SSPS site 7 at low cost of capital with 25 MMT storage/25 MMT of EOR and tax credits

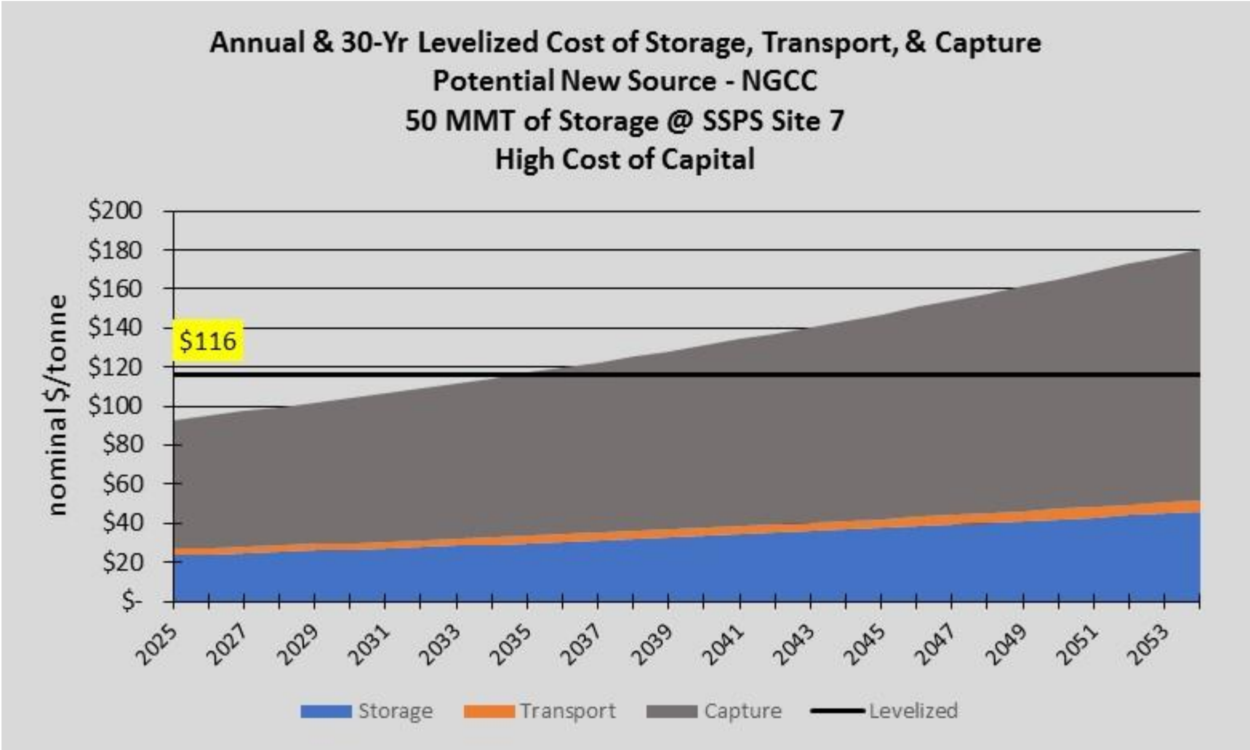

Figure B-38. Potential new source – NGCC at SSPS site 7 at high cost of capital with 50 MMT storage and no tax credits

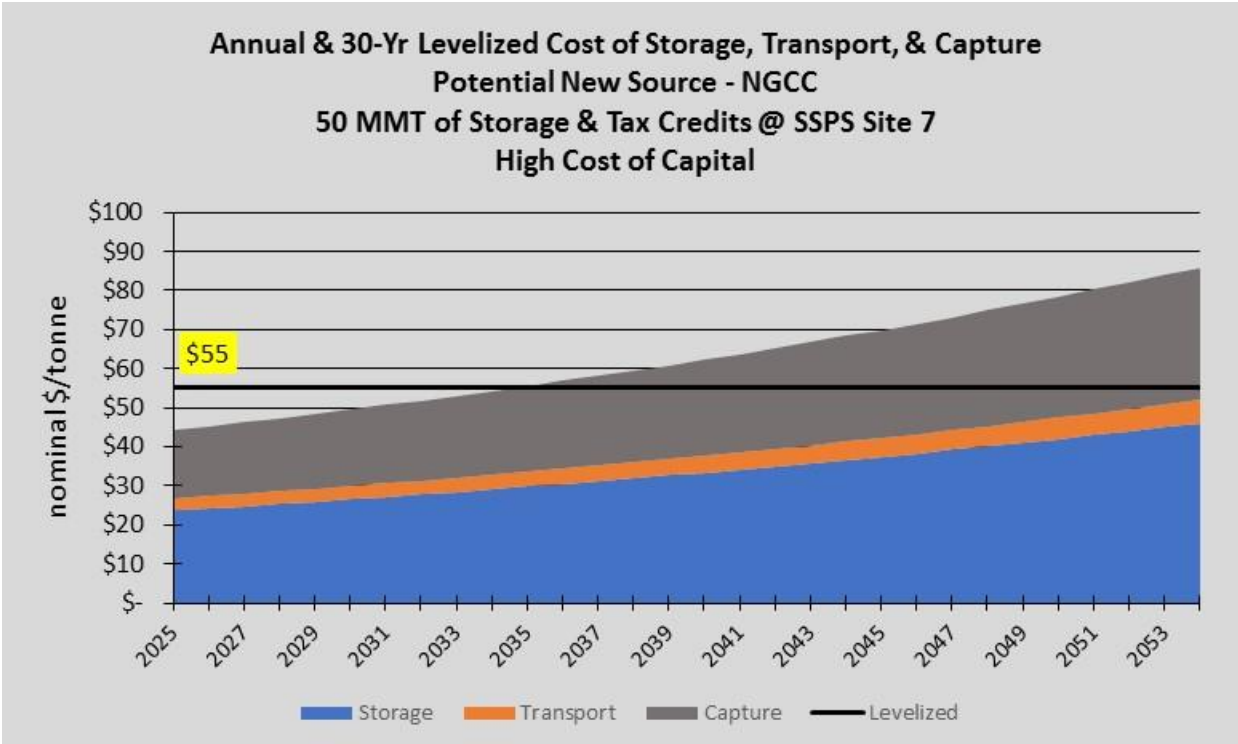

Figure B-39. Potential new source – NGCC at SSPS site 7 at high cost of capital with 50 MMT storage and tax credits

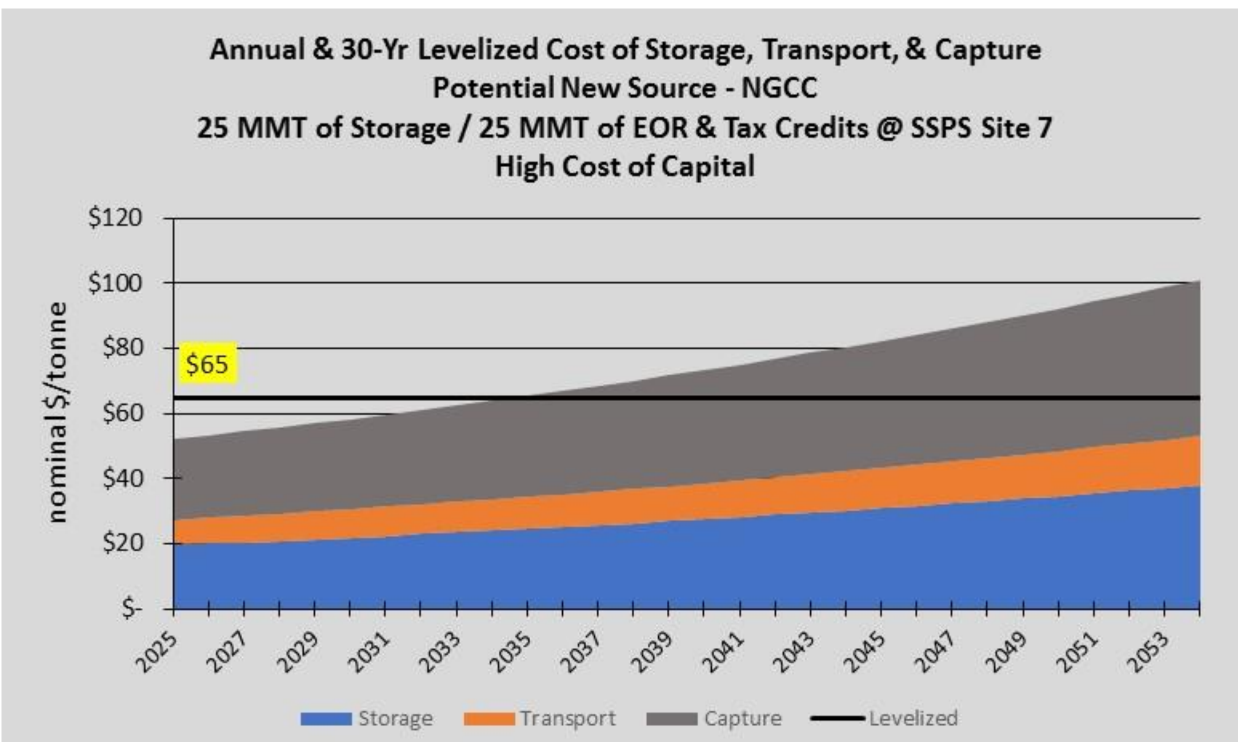

Figure B-40. Potential new source – NGCC at SSPS site 7 at high cost of capital with 25 MMT storage/25 MMT of EOR and tax credits

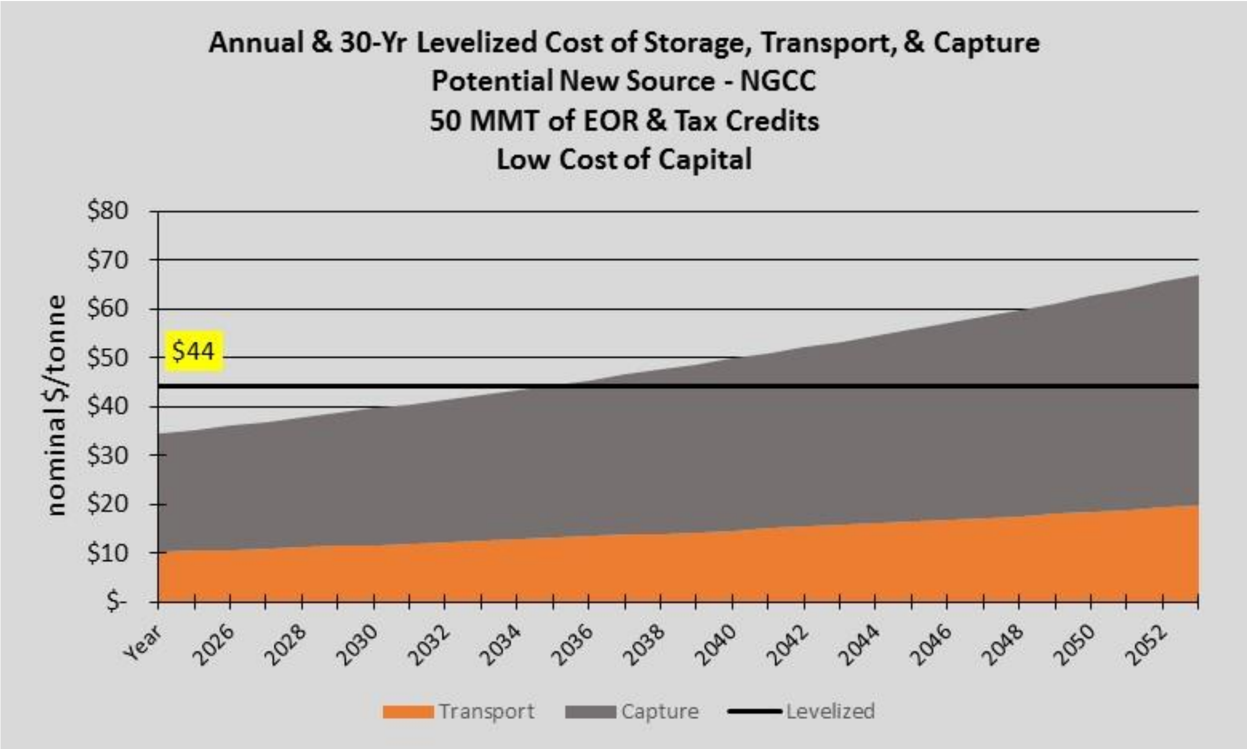

Figure B-41. Potential new source – NGCC at low cost of capital with 50 MMT of EOR and tax credits

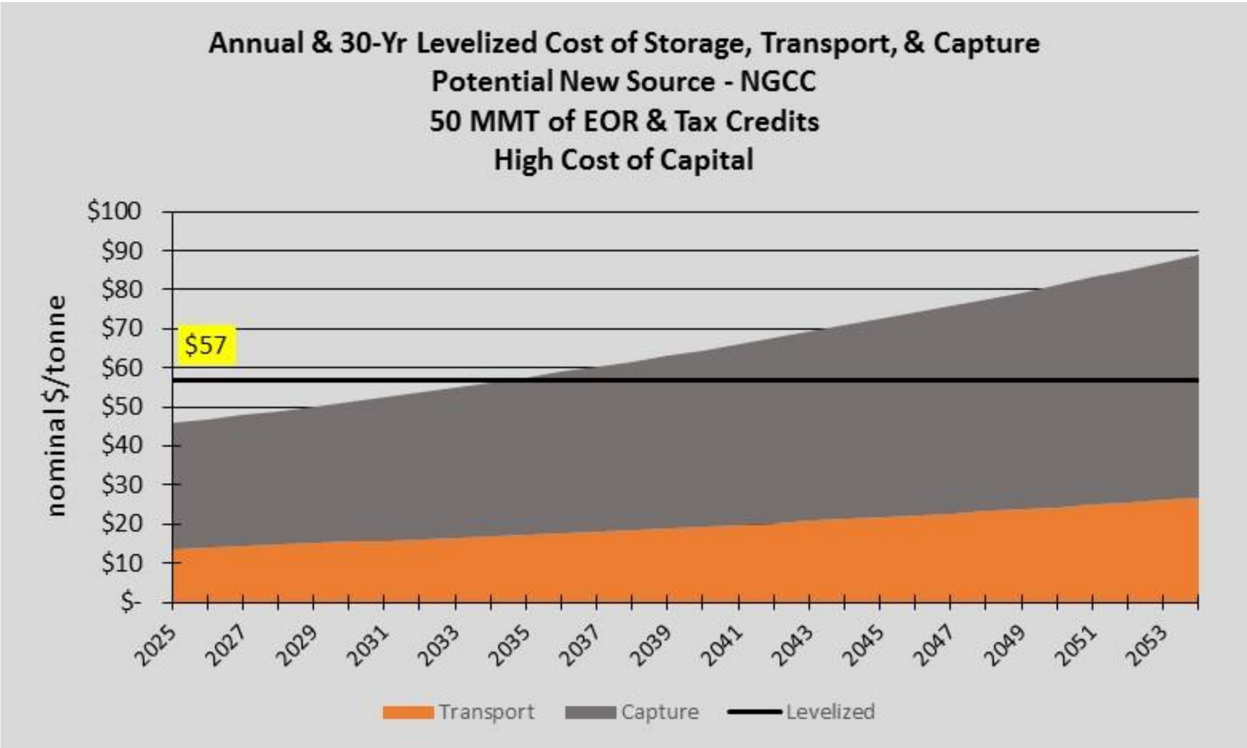

Figure B-42. Potential new source – NGCC at high cost of capital with 50 MMT of EOR and tax credits

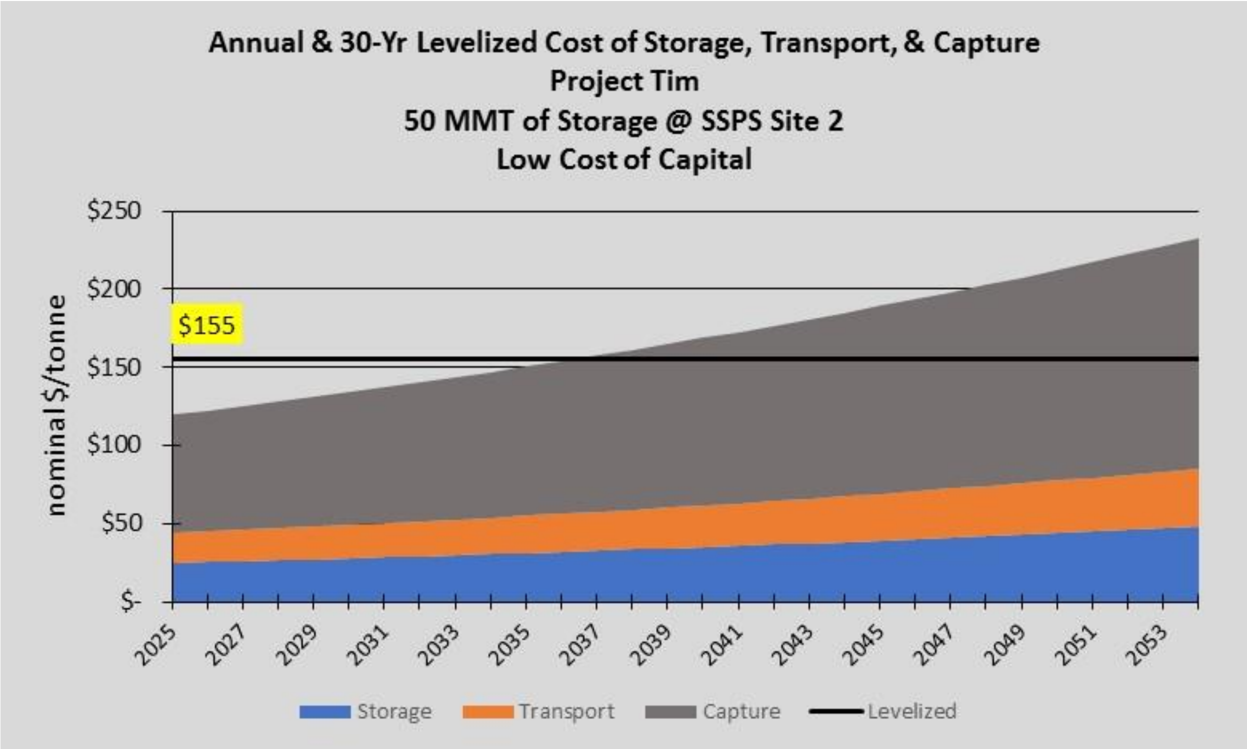

Figure B-43. Project Tim at SSPS site 2 at low cost of capital with 50 MMT storage and no tax credits

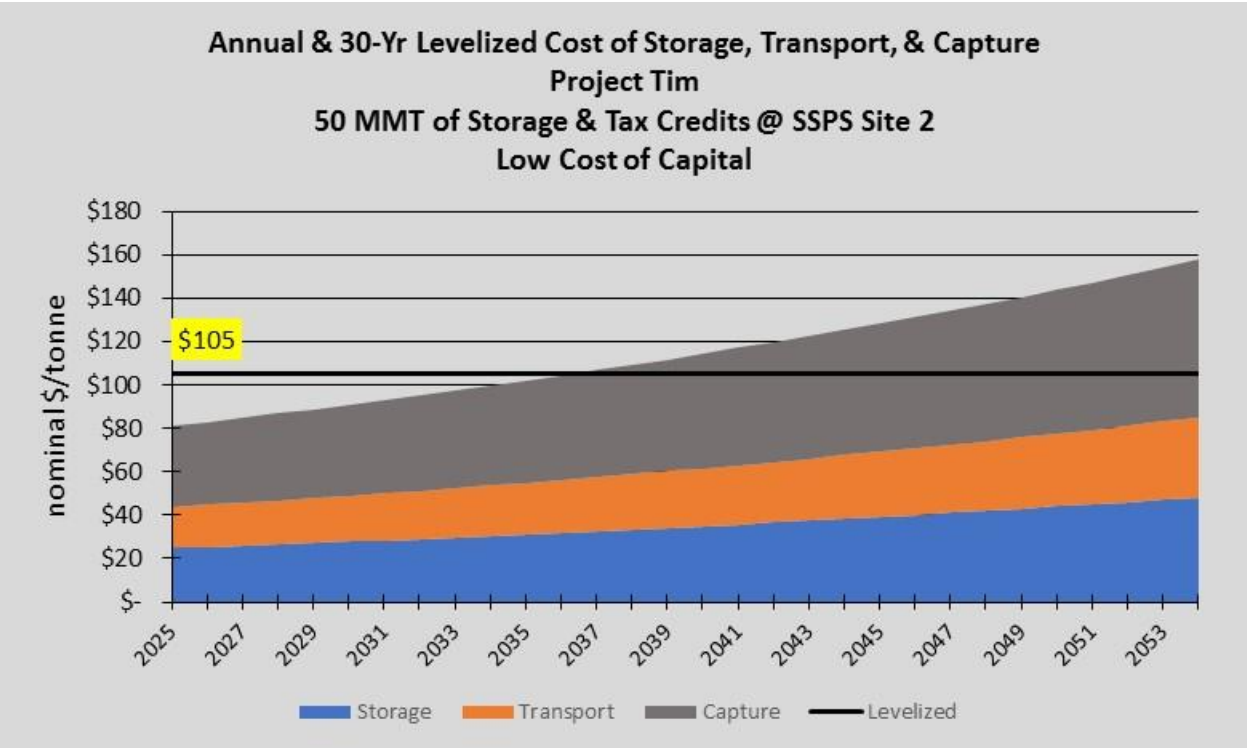

Figure B-44. Project Tim at SSPS site 2 at low cost of capital with 50 MMT storage and tax credits

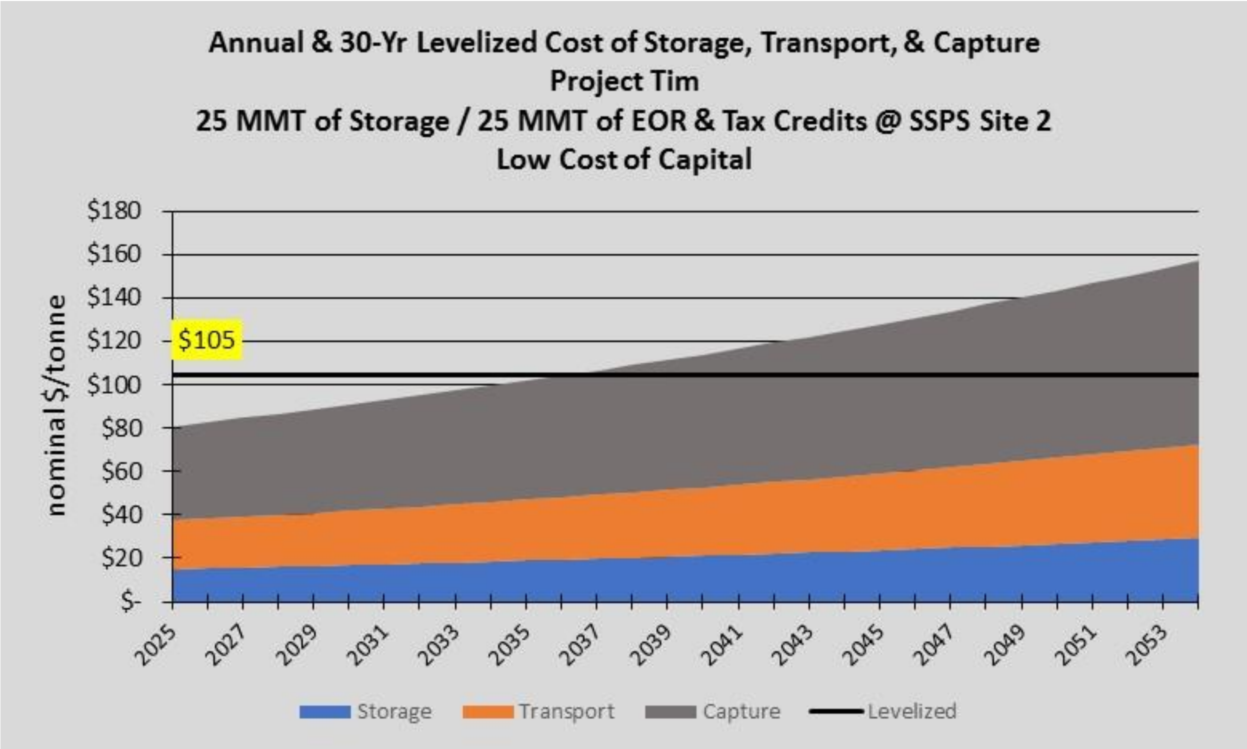

Figure B-45. Project Tim at SSPS site 2 at low cost of capital with 25 MMT storage and 25 MMT of EOR and tax credits

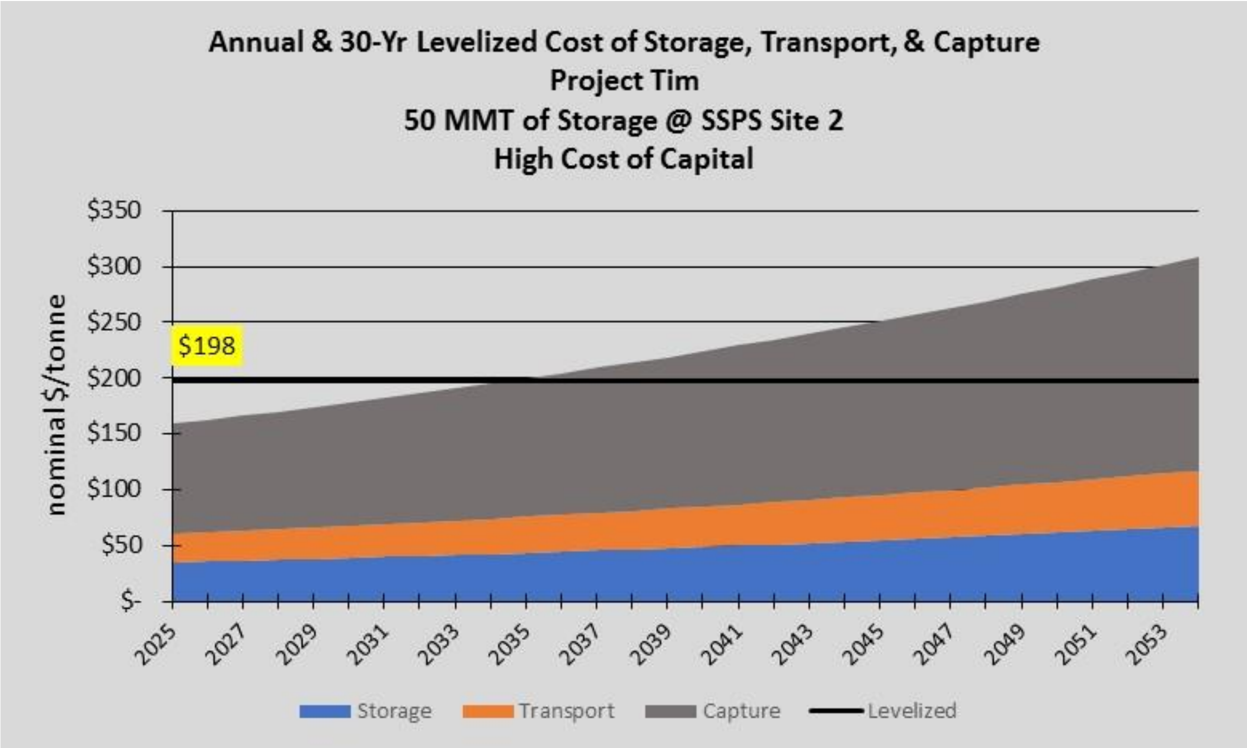

Figure B-46. Project Tim at SSPS site 2 at high cost of capital with 50 MMT storage and no tax credits

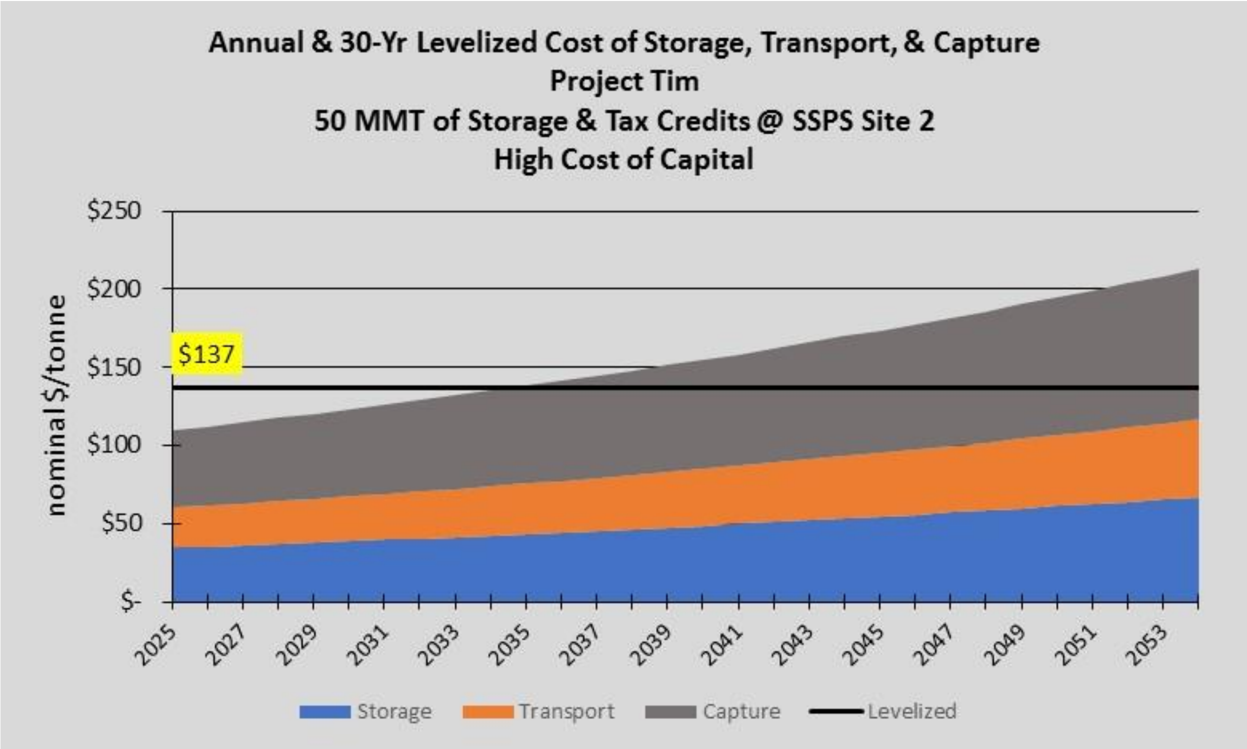

Figure B-47. Project Tim at SSPS site 2 at high cost of capital with 50 MMT storage and tax credits

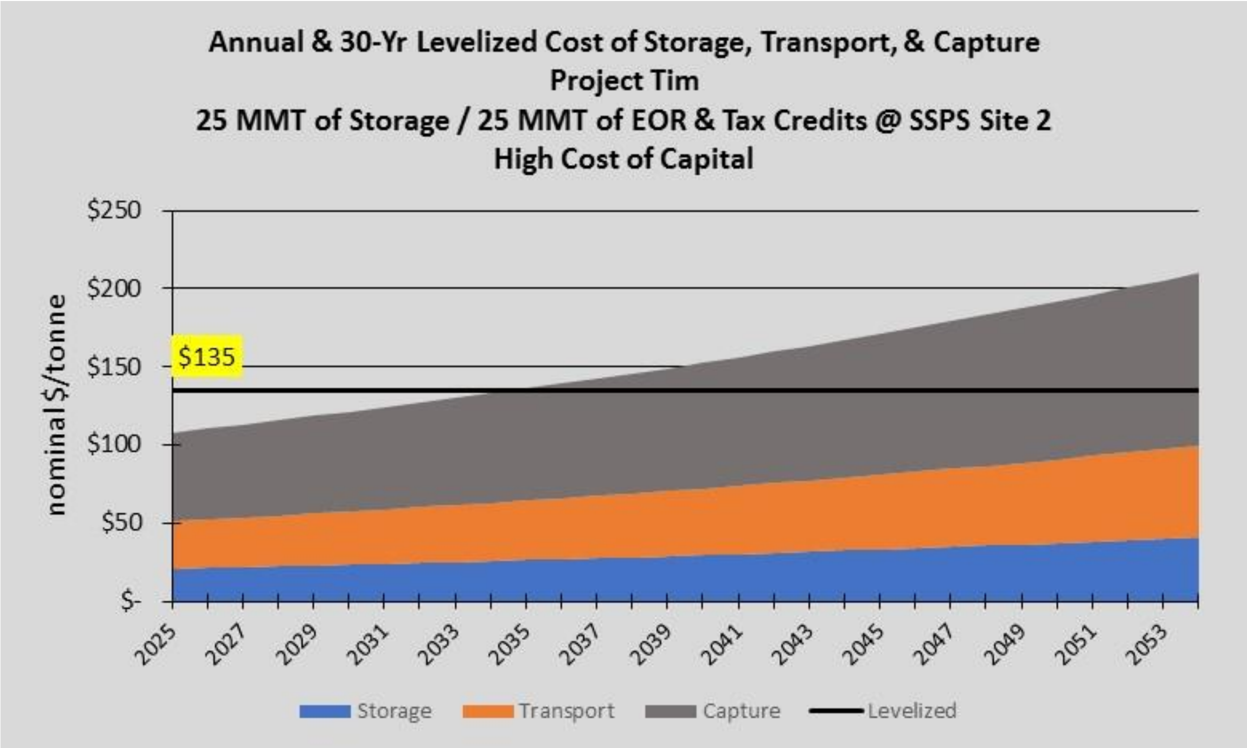

Figure B-48. Project Tim at SSPS site 2 at high cost of capital with 25 MMT storage/25 MMT of EOR and tax credits

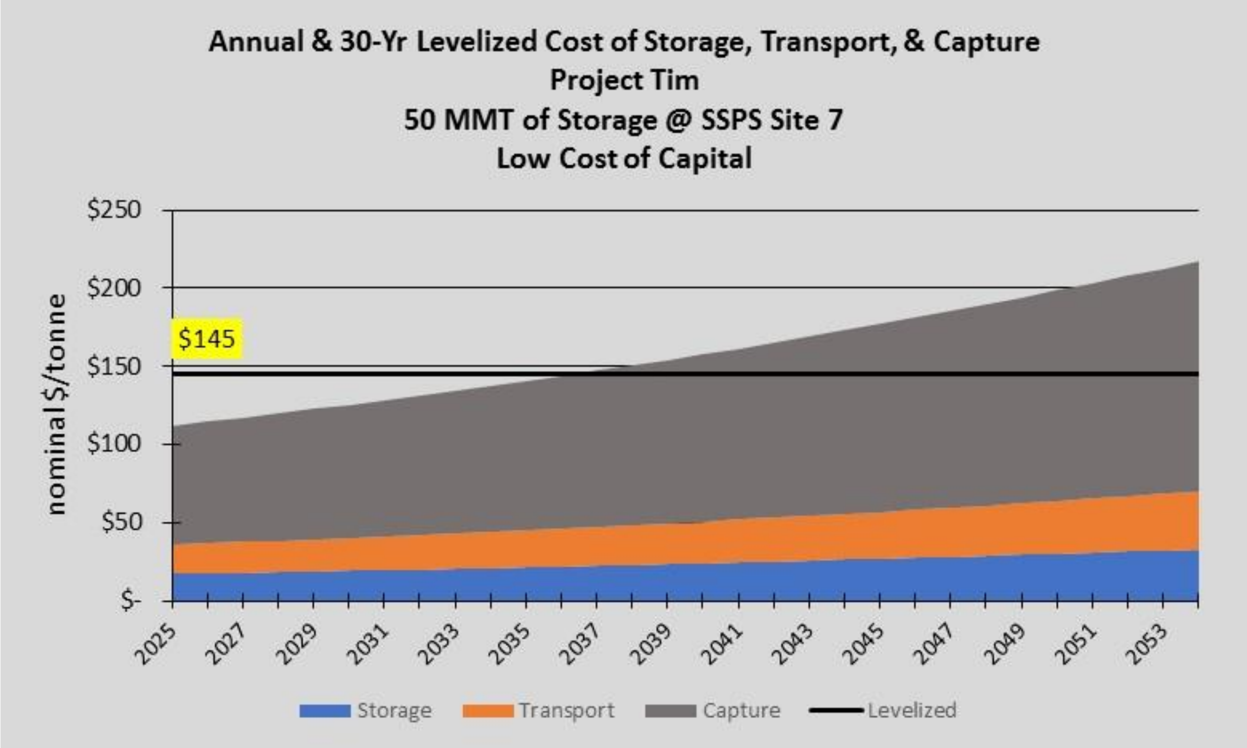

Figure B-49. Project Tim at SSPS site 7 at low cost of capital with 50 MMT storage and no tax credits

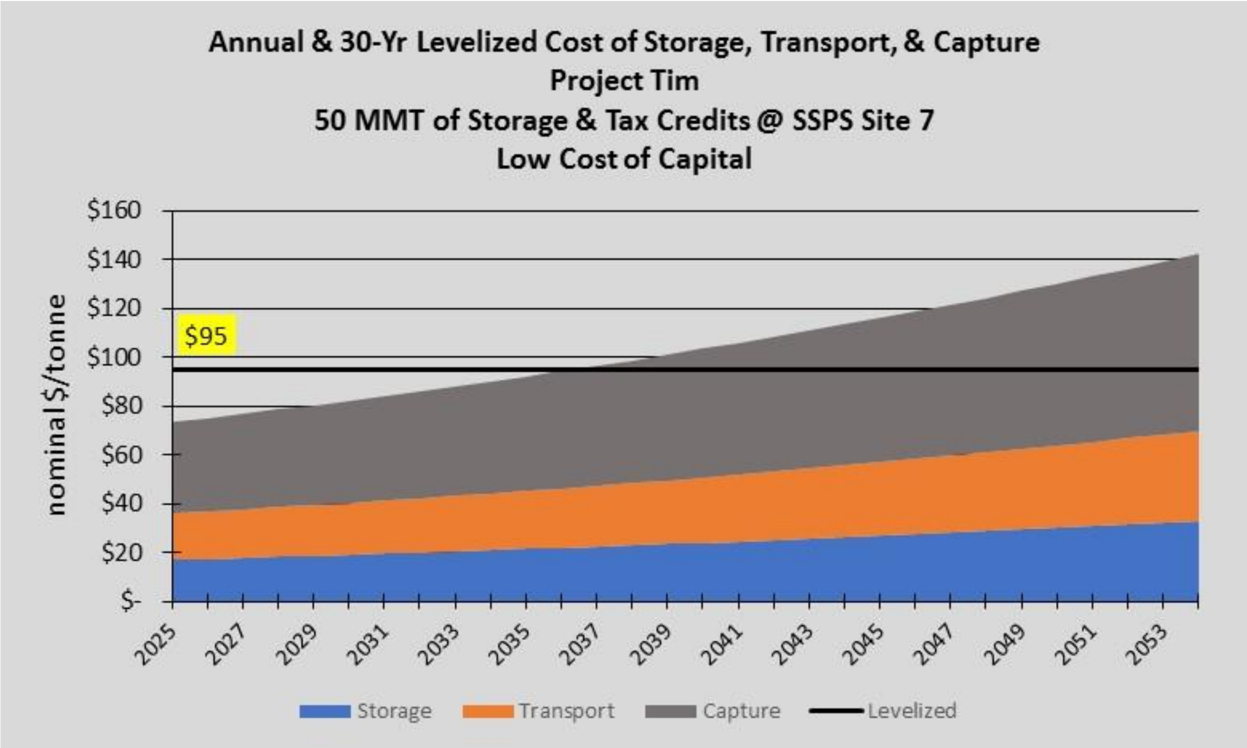

Figure B-50. Project Tim at SSPS site 7 at low cost of capital with 50 MMT storage and tax credits

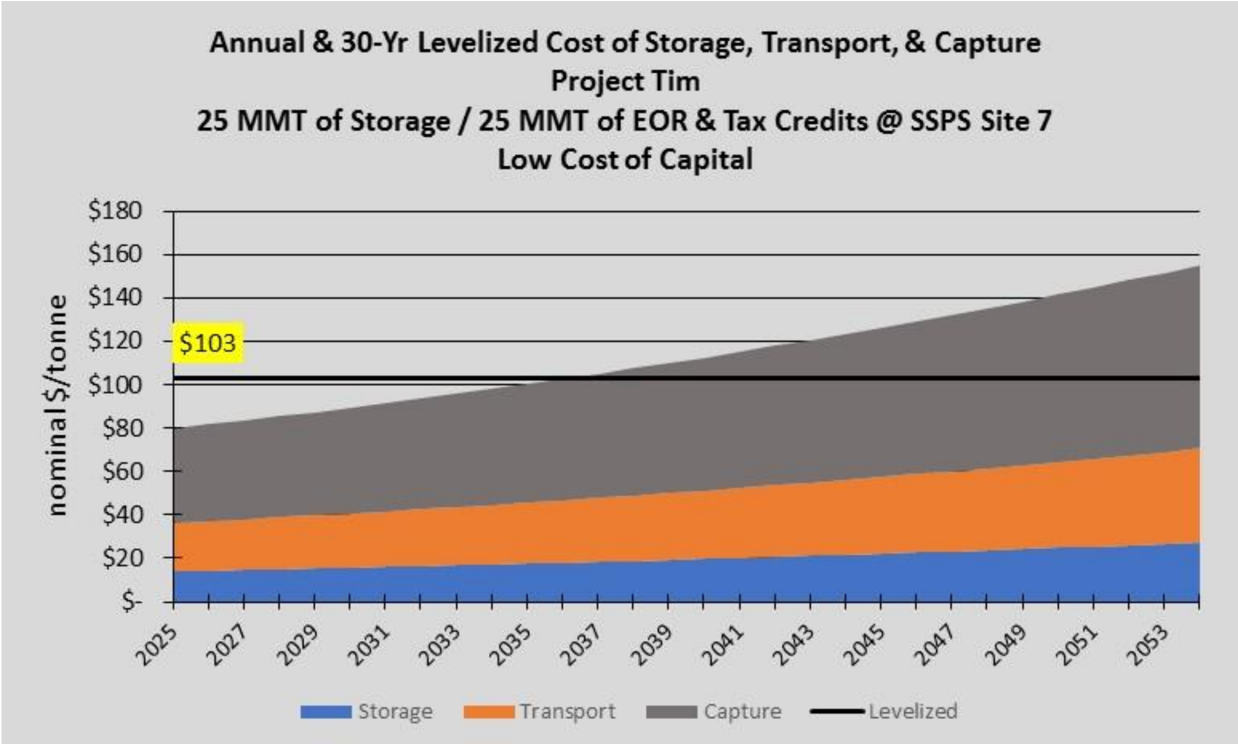

Figure B-51. Project Tim at SSPS site 7 at low cost of capital with 25 MMT storage/25 MMT of EOR and tax credits

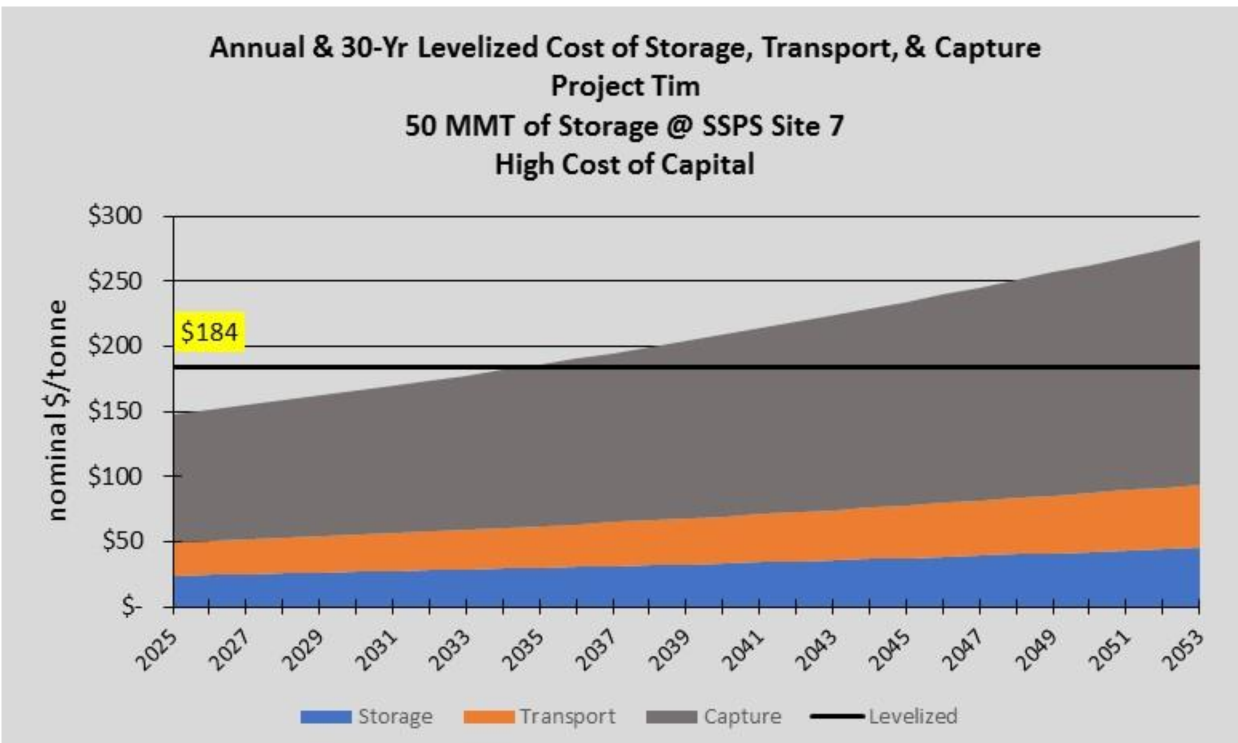

Figure B-52. Project Tim at SSPS site 7 at high cost of capital with 50 MMT storage and no tax credits

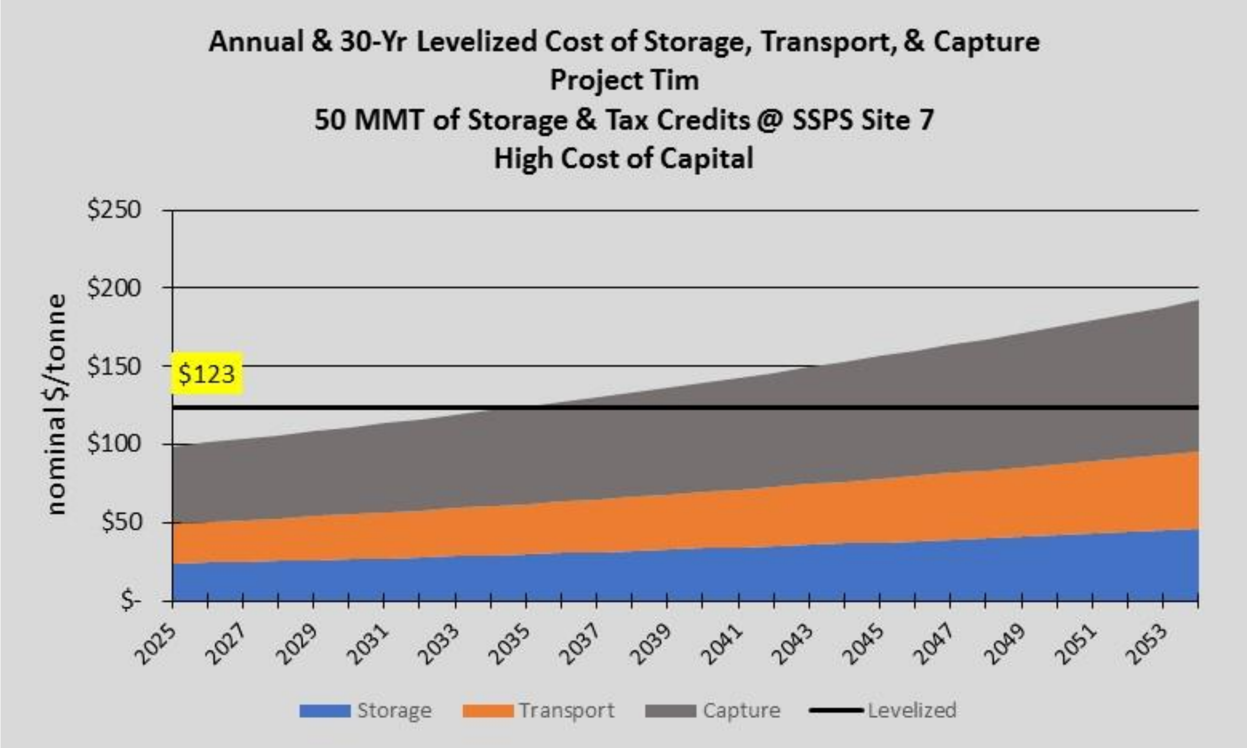

Figure B-53. Project Tim at SSPS site 7 at high cost of capital with 50 MMT storage and tax credits

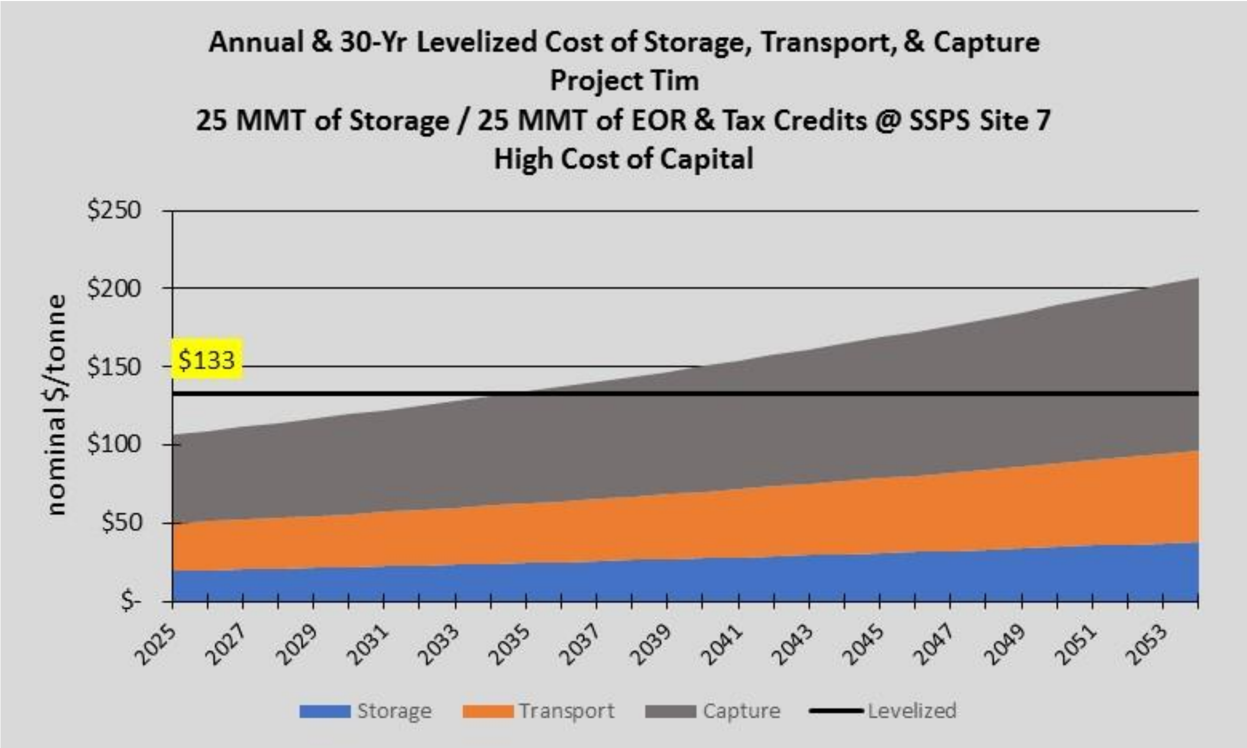

Figure B-54. Project Tim at SSPS site 7 at high cost of capital with 25 MMT storage/25 MMT of EOR and tax credits

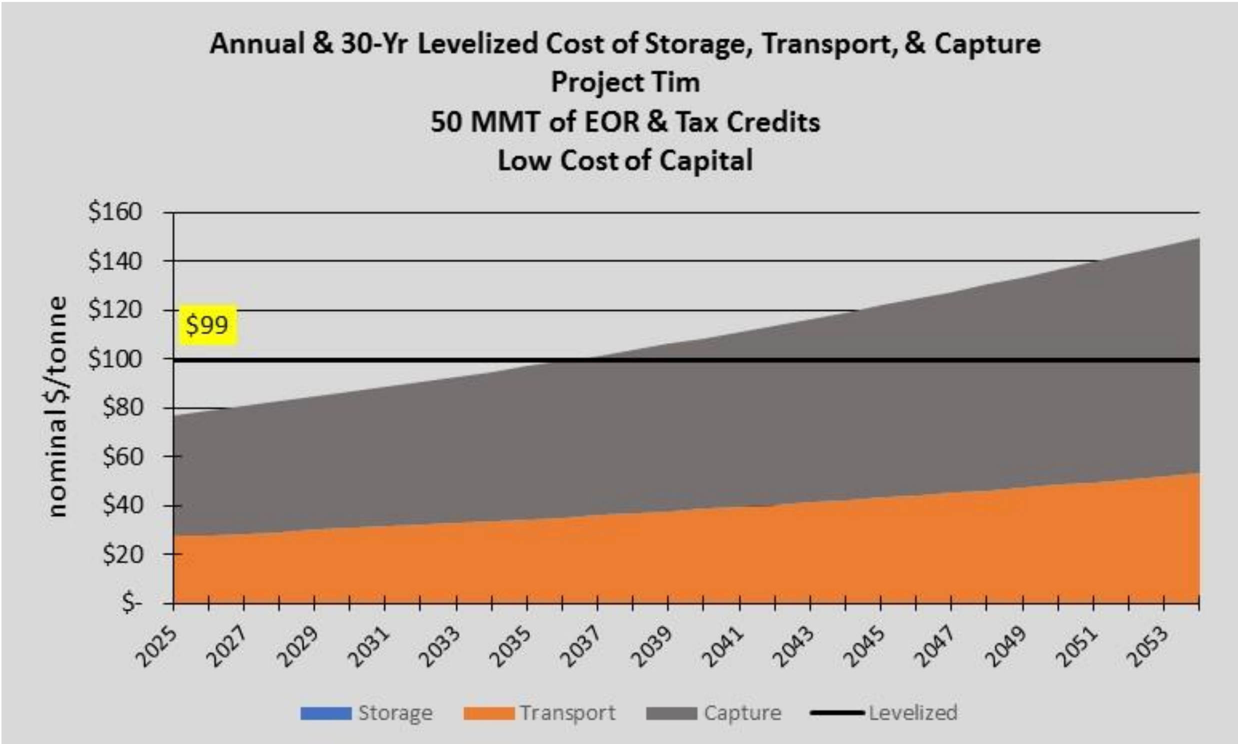

Figure B-55. Project Tim at low cost of capital with 50 MMT of EOR and tax credits

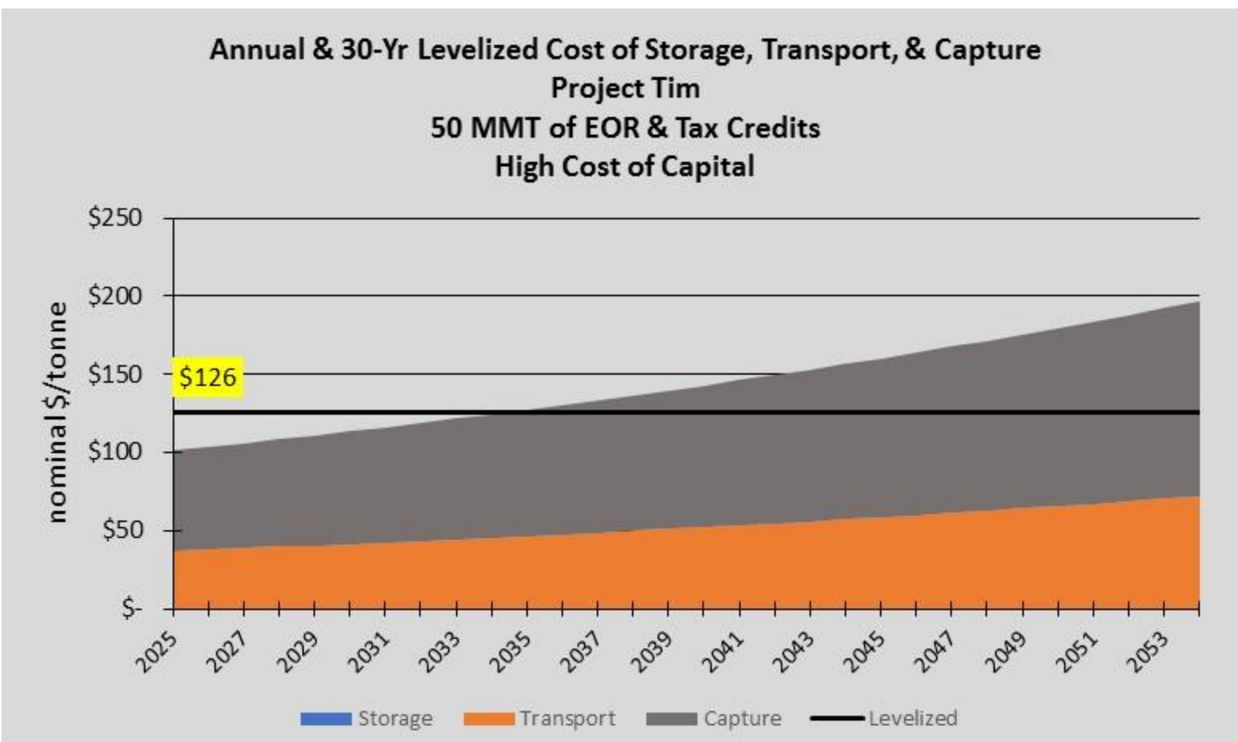

Figure B-56. Project Tim at high cost of capital with 50 MMT of EOR and tax credit