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Evaluating the Financial Implications of Injectivity Risk in Compartmentalized Reservoirs for CCS

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Evaluating the Financial Implications of Injectivity Risk in Compartmentalized Reservoirs for CCS

by

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Thesis

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Abstract

Working Title: Evaluating Mitigation Options to Address Injectivity Risk in Compartmentalized Reservoirs for CCS

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Injectivity is a major driver of risk in CCS projects. Risk mitigation efforts are focused on leakage and well remediation, while operational issues from past CCS projects have shown injectivity is frequently caused by the mischaracterization of compartmentalized reservoirs Sub-seismic faults, misinterpreted facies changes and a host of other factors can induce unexpected compartmentalization. The financial penalty due to the disruption of CCS operations is a large, depending on the agreement between the site operator and capture source. This paper explores the effect of compartment size and boundary condition on injectivity, and the subsequent financial implications.

Risk profiles of injectivity are generated through reservoir simulations in CMG-GEM, constrained by preliminary statistics from a CCS prospect on the Gulf Coast. A financial tool is built to understand the impact on project value when an injectivity issue occurs and an offset well needs to be drilled. CO_2 offtake price and insurance

mechanisms are considered in the tool. We observe that even in relatively closed boundary conditions, pressure can dissipate in the reservoir to allow injection over the project life. The economic feasibility of a CCS project that does face an injectivity issue depends on the year of the injection issue, with projects able to overcome financial liability and mitigation costs if an injection issue occurs in the latter half of the project life.

To date, there is no CCS literature on financial risk specifically regarding injectivity. Making CCS projects bankable requires robust assurance, and thus understanding injectivity risk, project contingency, and the feasibility of mitigation options can help to expand CCS deployment.

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List of Acronyms

BHP Bottom-hole Pressure

CCS Carbon Capture and Storage

DOE Department of Energy

EOR Enhanced Oil Recovery

EPA Environmental Protection Agency

FOAK First of a kind

mD Milli-Darcy

MT Million Metric Ton

SCF Standard Cubic Feet

SWD Saltwater Disposal Well

WACC Weighted Average Cost of Capital

CHAPTER 1: INTRODUCTION

1.1 Introduction

Climate change mitigation requires anthropogenic emissions to be cut significantly to avoid the worst effects of a warming planet. Limiting global warming to 1.5°C, as outlined in the Paris Climate Agreement, requires emissions to be net zero by 2050, with significant reductions in carbon and methane emissions throughout the 2020s and 2030s (IPCC. (n.d.-b)). In 2022, global emissions grew 0.9% to 36.8 Gt (IEA. 2023). Globally, the energy transition will require decarbonizing every part of the economy that emits emissions.

Carbon capture and sequestration (CCS) technology can help reduce fossil fuel emissions. CCS is a process by which carbon dioxide that normally would be emitted is captured from the flue gas in industrial or power generation plants. The carbon is then heated and compressed into a supercritical phase, and injected deep underground in geologic formations, where it stays underground for millennia (Global CCS Institute, 2022). Industries like chemicals, steel, and cement rely on high temperatures and cheap power from natural gas and will be hard to continue operating on renewable energy technology. In hard-to-abate industries that cannot rely on renewable energy to operate, CCS is one of the only options to decarbonize (IEA, 2019). Additionally, new standards to decarbonize the US power sector by 2035 under the Clean Air Act have been proposed that would lean on CCS technology heavily for fossil-fuel power generation, particularly on natural gas plants (Volcovici, 2023). The IPCC has stated that scaling CCS technologies on a relatively short time horizon is required to meet net zero targets (IPCC Chapter 2 — Global Warming of 1.5., n.d.-b).

While the track record of CCS development is well known, scaling this technology to gigatons of CO_2 sequestered requires overcoming legal, financial, and technical challenges. Recent national legislation has focused on addressing these hurdles in the US. The Bipartisan Infrastructure Law passed in 2021 provides funding for research, testing, and development of CCS technologies, with funds specifically designed to de-risk and accelerate project deployment (Carbon Capture Coalition, 2022). In addition to research, the law provides millions of dollars to assist in permitting and establishing regional CCS hubs to assist in the project deployment. The Inflation Reduction Act of 2022 devotes significant funds in the form of an increased tax credit for sequestration through code 45Q of the IRS for carbon storage. Previously $50 and $35 for geologic sequestration and enhanced oil recovery (EOR), respectively, a ton of carbon dioxide captured and stored from anthropogenic emissions increased to $85 and $60, respectively. For direct air capture (DAC), the tax credit is now worth $180 per ton (Jones and Marples, 2023).

More specifically, the wave of government assistance towards large-scale CCS deployment comes in the form of an additional $2.5 billion in funds from the DOE (DOE, n.d.). These funds will be used to create demonstration projects that de-risk the first-of-a-kind (FOAK) CCS projects and provide assistance to ensure the technical and safety viability of these projects. Additionally, $45 million for CCS transport from the DOE's

Office of Fossil Energy and Carbon Management will be spent to develop transport pipelines, with the intention to create hubs across the U.S. that reduce the collective cost and risk of capture, transport and storage (DOE, 2023). Due to the favorable geology in the Gulf Coast, recent public land auctions have caused a ‘land grab’ in the past few years for companies to obtain pore space with good injection prospects (Johnson and Raines, 2023).

In the US, the EPA regulates CCS injection well applications and designates it as a Class VI well, unless a state has taken primacy of the process (EPA, n.d.). The permitting process requires detailed geologic and technical data that supports the basis for underground injection and requires a litany of project requirements such as financial assurance, social and governance considerations and environmental protection. The regulatory complexities involved with CCS are challenging from a project development and stakeholder engagement perspective. Currently, only Wyoming and Louisiana have obtained primacy for CCS well permitting, with Texas, South Dakota, and other states currently in the application process for primacy (Chemnick, 2023). Regulatory frameworks such as long-term liability are being addressed at the state level, and the hope is that primacy will accelerate project deployment.

To this end, maximizing the likelihood of success is crucial to pave the way for more CCS sequestration projects. The cost of CCS is projected to be highly variable and depends on geologic factors that affect storage capacity and injectivity, distance to the source of CO_2, purity of the CO_2 from the source, and infrastructure requirements. Risk and liability for injection is highly project-dependent, but also depends on the contracts between the CO_2 source and the CO_2 sequestration operator. Figure 1 below illustrates the storage potential in the continental U.S., with much of the CO_2 storage capacity located in the Gulf Coast region. CO_2 sequestration operators will have an obligation to ensure the carbon is sequestered for the CO_2 emitting source to earn the tax credit revenue. Managing operations in a cost-efficient and effective manner is crucial. Given subsurface uncertainty, initial estimated project conditions may not be sufficient to store the promised amount of CO_2.

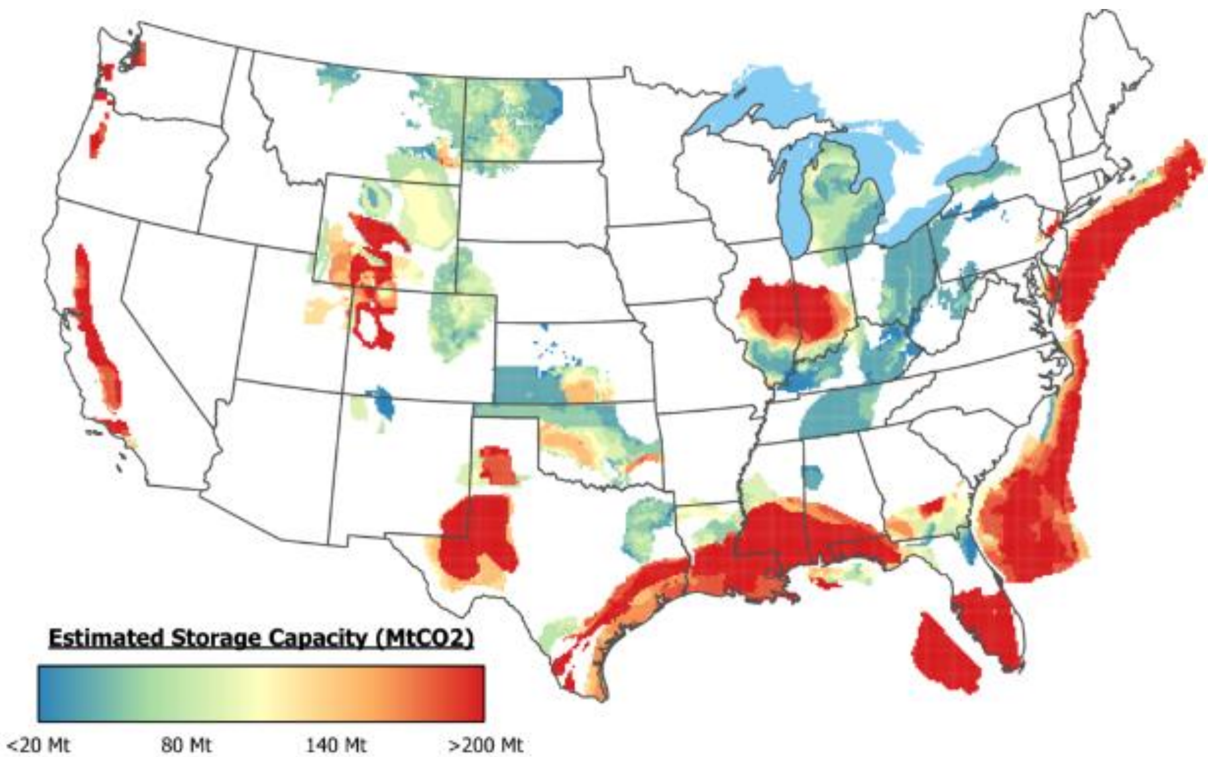

Figure 1: Geologic Carbon Storage Potential of the United States, as estimated by the SCO$_2$T^{PRO} Tool (Carbon Solutions LLC, 2023)

Evaluating this risk in the context of financial assurance mechanisms is important for policymakers and developers to consider as the bankability of CO_2 storage projects is still an open question in the industry. The EPA requires financial assurance tools for a Class VI permit only for emergency and remedial response purposes (EPA, 2022). However, the reliance of the 45Q tax credit and the substantial government funding underway to kick-start the CCS industry requires a plethora of other tools to ensure private industry is comfortable investing in CCS.

Sequestration relies on traps and compartments to hold the CO_2 in place. Understanding reservoir size for closed or semi-closed boundary projects determines the storage capacity of the site. Faults and other geologic heterogeneities not previously known to the operator or characterized incorrectly can unexpectedly diminish compartment size i.e., the area in which CO_2 can be injected consistently without pressure increases. This directly affects injectivity and the ability for a site to take the required CO_2, forcing the operator to abandon the project, or drill offset wells in a new formation. Given this uncertainty and high costs of failure, understanding how to best plan for failure is built into the contingency planning of a site operator. Activities such as data gathering, permitting, drilling, and monitoring take extensive planning and upfront capital to achieve project completion in a reasonable timeline for the project to remain profitable. Understanding the costs an operator faces in the case of failure, and subsequent liability, is essential in contingency planning and can help to give operators a sense of the viability of a project given the time and money it will cost the project to fix any issue that might arise with injection.

1.2 Problem Statement

Compartmentalization of a carbon sequestration reservoir poses a significant risk to CO_2 storage site operators by creating pressure limits that affect the performance of injection wells. The effect of the compartment size and the compartment boundary condition (i.e., how open, or transmissive, a boundary or gap between the faults are) is not well understood with respect to injection performance. Due to uncertainty in reservoir characterization, an operator will not fully understand the compartment issue until the project starts injecting CO_2. Uncertainty in the identification of faults that may cause compartmentalization is also possible. Taking this into account, the site operator must understand how to identify this injection risk and create mitigation options in the form of drilling an offset well, which is time and capital intensive. Contractual obligations between the storage site operator and the plant that captures the CO_2 create significant financial risks in the form of the loss of tax credits, which is the primary revenue source for CO_2 sequestration to make the project economically viable. The specific contractual agreements between the source and sink of a CCS project are unknown, usually private information and may be highly project dependent. A site operator must therefore balance the costs of mitigation options available with the risk of decreased injection performance.

1.3 Research objective

This study seeks to evaluate the economic costs and benefits of CO_2 injection in compartmentalized reservoirs in conditions with varying injectivity profiles, site characteristics and mitigation strategies.

I established a baseline of success by running computational fluid dynamic simulations on data modeled after Gulf Coast Carbon Center research in potential storage prospects in the nearshore Gulf of Mexico. I then calculated the economic impact of injectivity in case studies which exemplify (a) a range of compartment conditions - from the most challenging, where reservoir pressure and compartment size limit injection capacity and longevity, to a best-case scenario with ideal compartment conditions -- and (b) a variety of mitigation scenarios available to operators.

My analysis shows that injection in average Gulf Coast compartments has an economic potential to satisfy rate of return requirements for first-of-a-kind (FOAK) investments requiring high rates of return, as well as significant ability to manage injection risk. In extreme scenarios, the NPV project with a 15% discount rate can be as low as -$50,515,953 accounting for financial liability of lost tax credits and the requirement for the operator to drill an offset well outside the compartment. Operators need to understand how quickly they can get an offset well permitted, and ensure there is enough lease space close enough to the source to drill an offset permitted and are the factors that lead to the most economic loss. They should also take advantage of the opportunity to survey and characterize beyond their minimum area of review because it may be beneficial in the long term. Risk management is likely needed in the form of insurance or bonding.

CHAPTER 2: BACKGROUND

2.1 Injectivity in Carbon Sequestration

Injectivity in CCS is defined as the ability to inject CO_2 into the subsurface without causing the reservoir pressure to reach the maximum allowable limits. Mathematically, a simple explanation of injectivity is defined by the permeability and thickness of a reservoir, which represents the ease in which the plume of CO_2 injected into the subsurface can travel, thereby maintaining the proper pressure in the subsurface (Bakhshian, 2023). By exceeding the maximum allowable pressure in the subsurface there is a risk of induced seismicity, which can have negative second order effects of rock fracturing, which among consequential risks includes CO_2 migrating to the surface or to underground sources of drinking water, as well as induced seismicity (Simmenes, 2013). A reservoir rock fracture can also cause well control issues. Due to these risks, operators must constantly monitor the reservoir pressure and inject at lower pressures than the fracture pressure. If the maximum allowable reservoir pressure is reached, then operators must stop injecting.

As a result, this can have a negative impact on the economics of the project. Injectivity is an important factor for developers to consider when choosing a storage site. Maximizing CO_2 injection rate and overall storage capacity over a 30–50-year project window is the primary goal.

Injectivity index is a defined as:

$$I = \frac{q}{(P_{BH} - P_f)} \sim Kh \qquad (1)$$

Where q equals average CO_2 injection rate, P_{BH} is the well bottom-hole pressure, and P_f is the formation pressure. The denominator of the equation is, in simple terms, the pressure increases across the reservoir due to injection. This injection index is calculated at the outset of a project where the fracture gradient is calculated based on of the top seal rock type and depth (Bakhshian, 2022). The injectivity index as outlined in equation 1 is simply the CO_2 injection rate possible for a certain pressure increase (i.e., the difference between P_f, formation pressure, and P_{BH}, the well bottom-hole pressure during injection. K and h are reservoir permeability (mD) and the thickness (ft.), respectively, the product of the two broadly defining the physical ability to inject q amount average CO_2 over a given time period. Intuitively, permeability, or the ability for a gas/liquid to move through the pores of a rock within a given time period, and thickness, the amount of rock there is for CO_2 to move through, constrain the amount of CO_2 the operator can inject.

By ensuring that the injection parameters are within safe limits, project developers can significantly reduce the risks associated with CCS projects. Moreover, understanding injectivity can also help to identify potential challenges and develop contingency plans in case the injection process does not go as planned.

2.2 Compartmentalization

Compartmentalization of reservoirs was originally studied in the context of oil and gas applications. Unidentified reservoir compartmentalization has an adverse effect in oil and gas recovery due to poor drainage and efficiency reductions (Smalley and Muggeridge, 2010). In the case of CCS, the main concern is faults sealing or closing to create unexpected compartmentalization of a reservoir, raising reservoir pressures unexpectedly. Fluid samples, pressure gradient analysis, and 2D seismic data collection have been used in the past to characterize compartmentalization. However, limited number of well placements can make it difficult to verify pressure gradients (Nguyen et al., 2017). Oil production data can be used to analyze fluid flow between compartments, but these methods are not transferable to a greenfield CCS site. Additionally, sub-seismic faults, misinterpreted facies changes and a host of other uncertain geologic factors may contribute to unexpected compartmentalization.

2.3 Historical Precedent: Snohvit

Real-life compartmentalization issues have occurred in the brief history of CCS operations, with the primary example being the Snøhvit Norwegian natural gas refining project in the Barents Sea. CO_2 is separated from the natural gas extracted and injected into a separate formation (Chiaramonte et al, 2014). At Snøhvit, partial compartmentalization was discovered after injection due to a noticeable increase in the reservoir pressure. Injectivity was also found to be influenced by lower formation permeability and higher heterogeneity than initially estimated (Chiaramonte et al, 2014). Down-hole pressure measurements and seismic data acquisition eventually led to the injection wells and compartment being entirely abandoned for a more favorable formation, where injection continues to this day (Hansen et al, 2013). Bottom-hole pressure readings were frequently gathered through fall-off tests, in which the well is shut in to understand the reservoir pressure upon injection (Energy Glossary, n.d.). In the case of Snøhvit, faults visible by the baseline data may have been complemented by possible barriers near the injector. The project's backup plans were to perforate new zones or reservoirs within the structure (Hansen et al, 2013). Snøhvit is an important lesson for the industry to take the problem of compartmentalization seriously and to think about project contingencies as it relates to issues that might arise in injectivity.

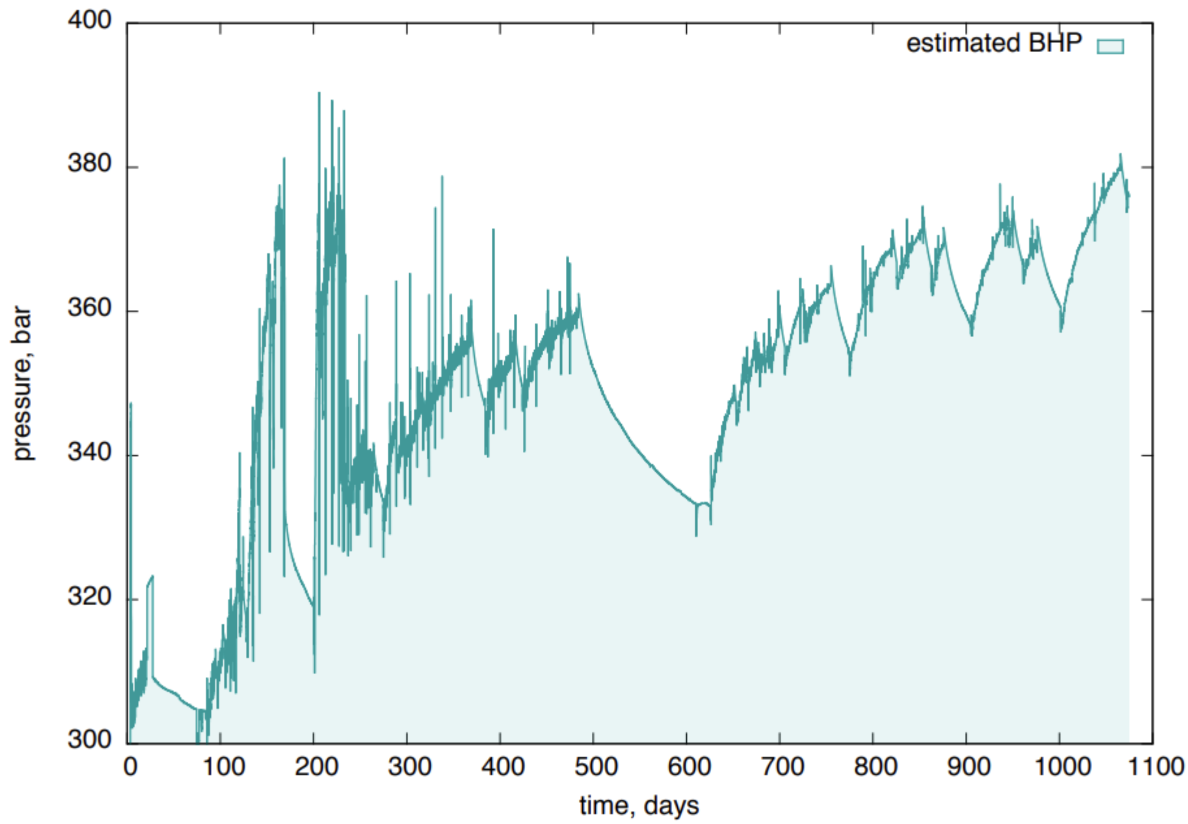

Figure 2: Estimated Bottom-hole Pressure at Snøhvit. Due to compartmentalization, pressure buildup, best exemplified by the BHP reaching just under 400 bar 200 days into the project, forces injection to stop periodically throughout the project. Periods of pressure decline, most notable 500-600 days into the project, are periods of injection cessation (from White et. al., 2014).

2.4 Injection Management Example: Paradox Valley Unit

As previously stated, there are a few famous examples of injectivity issues, with Snøhvit being the lone case in CCS. However, saltwater injection in West Texas provides an appropriate analog to injection management and liability. Saltwater is a fluid that is co-produced along with oil and gas. To avoid deleterious environmental effects, the saltwater must be injected back into the subsurface through Class II injection wells regulated by the EPA, or the Railroad Commission of Texas for the state of Texas. As of 2023, there are over 34,200 active injection and disposal wells in the state of Texas (the difference being injection is for EOR using produced saltwater, and disposal is reinjection for the purposes of subsurface storage) (Railroad Commission of Texas, n.d.). In 2022, 3.9 billion barrels of saltwater was produced in that year for the Permian Basin alone (Ramos, 2024). Injected fluids can cause induced seismicity through pressure increases, forcing faults to slip. In 2021, West Texas experienced around 2,000 earthquakes of magnitude 2.0 or higher (Hampton, 2022). This has caused injection to be reduced in current disposal wells and the Railroad Commission of Texas to pause dozens of permits and ban the practice in areas with increased seismicity (Ramos, 2024).

Curtailment is not well documented, and the cause for injection decline in many saltwater wells cannot be easily delineated. However, there is precedent for injection curtailment, as opposed to injection stoppage, like Snøhvit, to manage reservoir pressure increases. The Paradox Valley Unit is a saltwater disposal well in Western Colorado that seeks to inject naturally occurring brine into the subsurface before it enters the Colorado River. Microearthquakes soon followed injection, with a few significant earthquakes above M3.0 occurring throughout the life of the project (Mahrer et. al, 2005). The Bureau of Reclamation soon implemented shut-in periods, followed by reduced injection rates, with the result being stable bottom-hole pressure and reduced seismic events. The figure below summarizes the phases of decreased injection and associated seismic events.

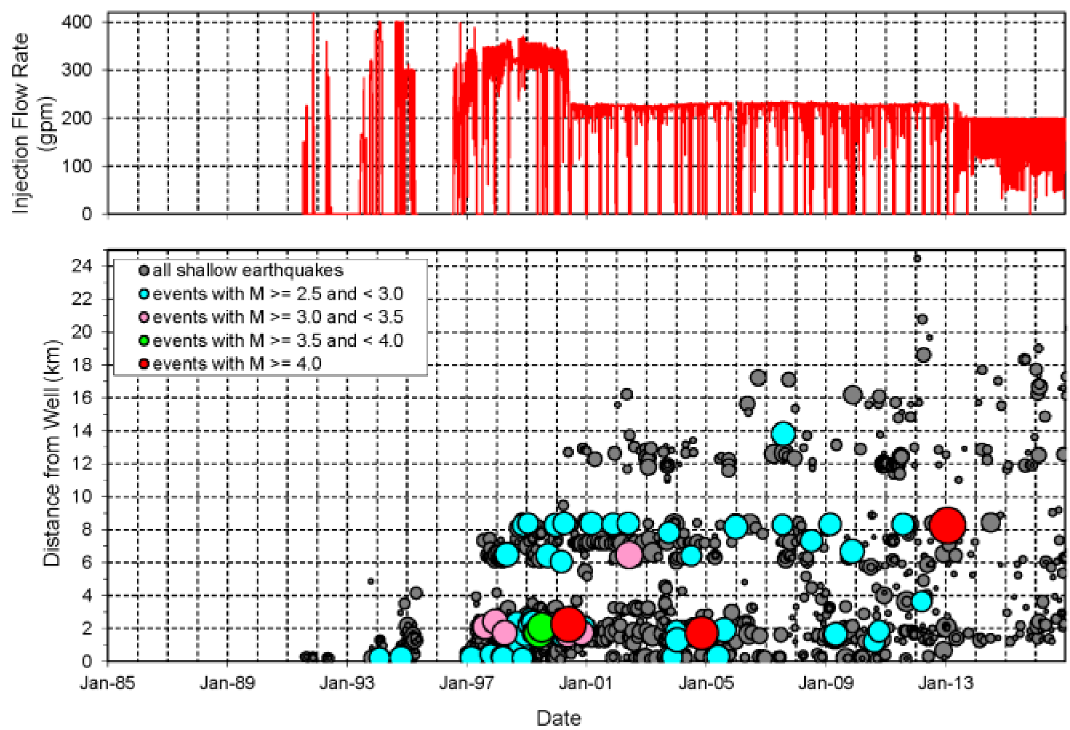

Figure 3: Injection Rate and Seismic Event Count at the Paradox Valley Unit from 1985 to 2016. Seismic events are sized and colored by magnitude of the event. Injection began in July 1991 with continuous, long-term disposal beginning in 1996 (taken from Block, 2017). Seismic frequency and size increased when injection began.

The effort to curtail injection and induced seismicity had 5 distinct phases:

- Phase 1: From May 1996 until June 1999, the well injected 345 gallons per minute (gpm) at 11,600 psi bottom-hole pressure (Mahrer et. al, 2005).
- Phase 2: Following a M3.6 event in June 1999, the units introduced a 20-day shut-in every 6 months with the intention to allow pressure to dissipate within the formation. Downhole pressure was approximately 11,750psi (Mahrer et. al, 2005).
- Phase 3: Following a M4.3 earthquake in May 2000, the injection rate was reduced 33% (~225 gpm), leading to a 10% reduced surface pressure but no change in bottom-hole pressure. Seismic events were reduced (Mahrer et. al, 2005).
- Phase 4: Following a M4.4 earthquake in January 2013, injection was ceased for 84 days, and resumed thereafter with a 36-hour shut-in every week. The injection rate was reduced to 200 gpm. The maximum downhole pressure was 12,261 psi. Since injection was resumed, the maximum down-hole pressure was 11,951 psi (Block, 2017).

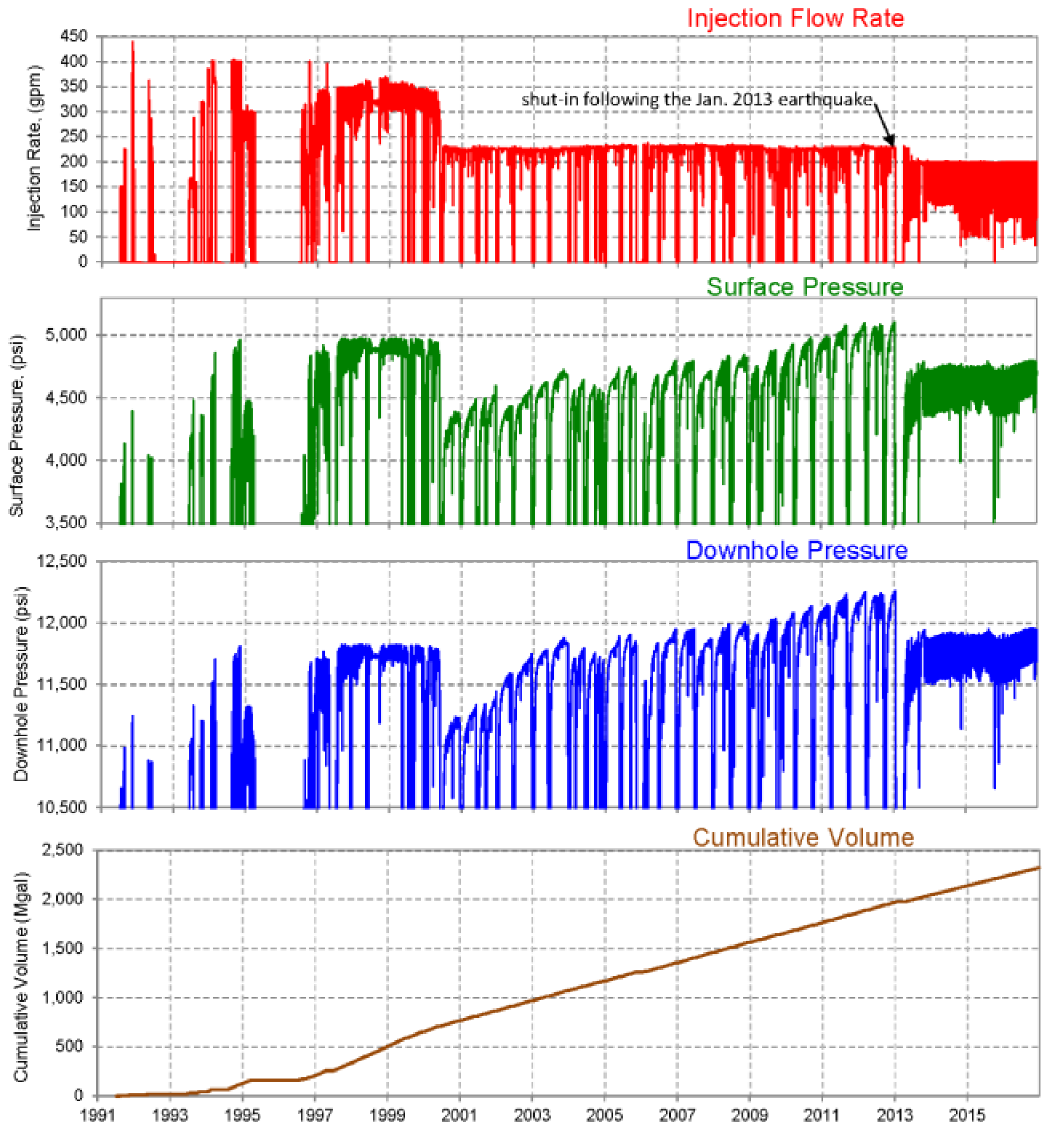

Figure 4: Time series of Injection Rate, Surface Pressure, Downhole Pressure, and Cumulative Volume at the Paradox Valley Unit from 1991 to 2016 (taken from Block, 2017)

Seismic events were reduced significantly with injection management. The evolution of the Paradox Valley Unit can serve as a lesson to the carbon storage industry on how to navigate increasing pressure due to partial compartmentalization. This example, coupled with the broader issue in saltwater disposal can serve as a warning that injection rates may not be constrained just by the fracture gradient of the reservoir, but also the pressure limits that trigger major seismic events. When managing liability, curtailing injection rates, rather than ceasing injection altogether, may save an operator money in the form of tax credit liability.

2.4 Financial Assurance in Class VI Permits

Part of a Class VI permit application requires operators to obtain and demonstrate a form of financial assurance, focusing on the protection of underground sources of drinking water (USDWs). The guidance from the EPA is quite vague, though 4 discrete actions are listed that need to be covered by assurance: corrective action on wells in the Area of Review (AOR), injection well plugging, post-injection site case and site closure (PISC), and emergency and remedial responses (Environmental Protection Agency, 2023). Dollar values for such activities must be provided by a third-party engineering firm and confirmed by the governing Class VI bond. (Environmental Protection Agency, 2023). There are a few options for the form the assurance can take and generally is chosen from the following: a trust fund, letter of credit, surety bond, insurance, or a financial test and corporate guarantee (Environmental Protection Agency, 2010).

A trust fund has a specified pay-in period to a fund specifically for the activities previously discussed. Oversight is already in place, and the only real risk is the financial institution providing the trust goes bankrupt. A letter of credit has the same strengths and weaknesses due to the same reason that it is a financial institution that guarantees this credit (Environmental Protection Agency, 2010). A surety bond is issued by an insurance company and guarantees performance of specific goods or services. (Environmental Protection Agency, 2010). It's triggered only when the owner or operator fails to comply with requirements. In oil and gas, there are well plugging and abandonment bonds, which lends itself well to carbon sequestration projects (CAC Specialty, 2021). Insurance is another option and is better suited for issues in emergency and remedial response items, like pollution (CAC Specialty, 2021). Insurance is only as effective as its coverage and limit of liability but is more customizable. Self-insurance and a corporate guarantee require rigorous financial testing, where the operator must have enough funds on hand for any of the required liabilities. Self-insurance has been successful in past oil and gas operations, and the EPA deems it an acceptable instrument for Class VI permits (CAC Specialty, 2021).

While certain financial mechanisms are appropriate for the liability delineated in the financial assurance requirements of a Class VI permit application, the liability the storage operator faces when an injection failure occurs is unexplored. Given most carbon storage operators are going to receive a tolling fee, with a "pay at the gate" contract structure with the CO_2 source, there is going to be some sort of liability the storage operator faces to guarantee the carbon capture source receives its tax credits. The purpose of this study is to understand the levels of financial and operational liability the storage operator can profitably take on under a variety of injectivity profiles.

The closest example of bonding requirements is natural gas bonding requirements. The natural gas boom in the past decade has renewed focus on environmental remediation capabilities of natural gas producers. The natural gas industry is highly fragmented, which is a cause for concern regarding a company's ability to pay for environmental remediation (Davis, 2012). Current bond requirements at the federal level have a minimum bond amount of $10,000 per well (Davis, 2012). While states can often have much higher minimum requirements, the environmental damage in the event of contamination can be millions of dollars. Given this extreme misalignment of incentives, policy researchers have long argued for higher bond requirements, or insurance. The difference between a bond and insurance is that a bond is returned with interest to the company if no damages occur, while insurance premiums are gone forever (Davis, 2012). While regulations make certain practices illegal, bonds ensure the resources are there to deal with environmental damage when it does occur. As noted later in this study, the EPA may have learned their lesson from the natural gas industry as CCS project bonding requirements are orders of magnitude higher. However, the guardrails that bonding provides is different than regulation policy or insurance and should not be viewed as necessarily a supplement for adequate regulation. CCS has multiple environmental and financial risks and given the risk of first-of-a-kind projects, should have bonding requirements that reflect this risk.

CHAPTER 3: METHODOLOGY

3.1 Methods Overview

This chapter first formalizes the steps taken to evaluate injectivity in compartments with varying size and boundary conditions. It then discusses how this injectivity risk can be evaluated through a financial liability model that considers a penalty for the failure to inject the contractual amount of CO_2 and the costs of an alternative offset well.

The result is an evaluation of scenarios selected to display the range of economic outcomes to the operator dependent upon the severity of compartmentalization and the operators' contingency plans.

3.2 Study Scope: The Gulf Coast

The scope of this study is within nearshore Gulf of Mexico along the Chemical Corridor. This coastal slice of the country stretching from the border of Louisiana to Corpus Christi, TX gets its name from the various heavy industry facilities active in the region. CCS is a popular solution proposed for emissions control in this region due to the proximity of the source emissions to favorable geology for sequestration. According to the EPA's FLIGHT database tracking greenhouse gas emissions, within the Chemical Corridor alone, there were approximately 2,700 million metric tons of CO_2 emitted in 2022 comprising 545 facilities (EPA, 2022). With so many emissions near world-class geology for carbon sequestration, taking advantage of easy-to-access pore space is key to rapid adoption. Additionally, uncertainty regarding the permitting of CO_2 pipelines makes pore space as close as possible to the source extremely important. In Fall 2023, the Heartland Greenway pipeline project expected to carry 15 million metric tons of CO_2 annually to sequestration sites in the U.S. was cancelled due to insurmountable regulatory hurdles and public opposition (Lavinsky, 2023). Such uncertainty will force developers to prize sequestration sites extremely close to the source. In the Chemical Corridor, this will require developers to deal with the large fault network as seen in Figure 5 below and emphasizes the need to understand the pressure space available and injectivity.

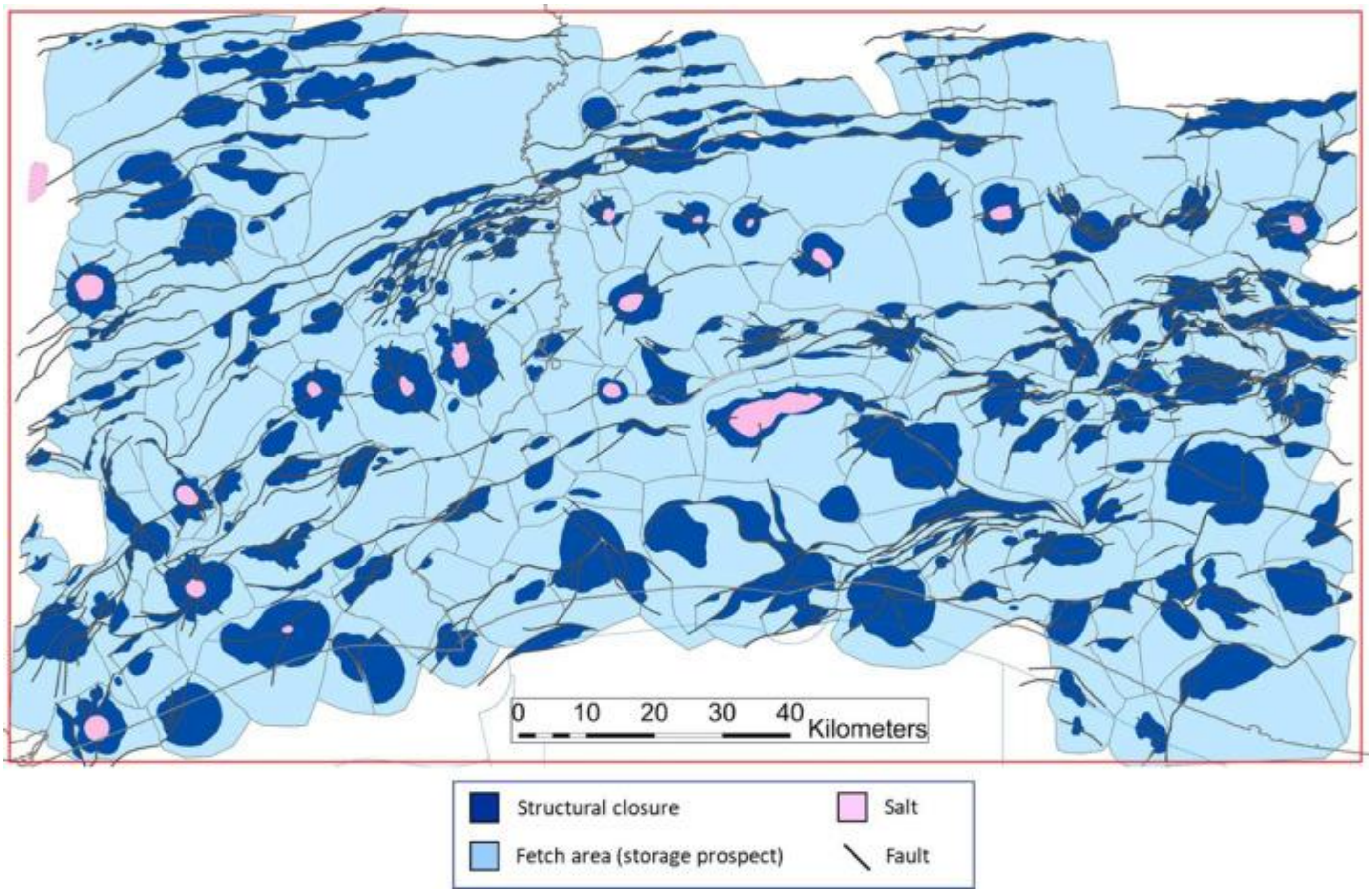

Figure 5: Map of the Fracture Network that creates reservoir compartments in the Gulf Coast (taken from Bump, Hovorka, 2023)

3.3 Compartment Risk Profiling

In the first part of the analysis, I evaluate injection risk based on reservoir size and boundary conditions (i.e., how open the gap is at the edge of the reservoir). Using data collected by the Gulf Coast Carbon Center on the Miocene section of a Gulf Coast prospect, compartment size and thickness distributions are calculated for each compartment (Zheng et. al., 2023). I use this data to bound scenarios to simulate in

CMG-GEM. CMG-GEM is a commercial 3D reservoir simulator used for modeling of carbon dioxide injection in geologic formations (CMG-GEM, 2012). For each simulation, I inject for 40 years and determine whether the project runs into an injection issue. For simplicity, I assume the reservoir to be homogenous, meaning the geologic characteristics (permeability, porosity, etc.) are the same in each grid block. I also keep the grid block setup the same across all simulations, using a 30x30x20 grid block reservoir. The primary output data from these simulations are bottom-hole pressure (psi) and the injection rate (SCF/day) of CO_2 into the reservoir to determine the month and year of an injection issue (if there is any), the cumulative CO_2 injected into the reservoir, and the pressure increase throughout the injection period for a given boundary condition.

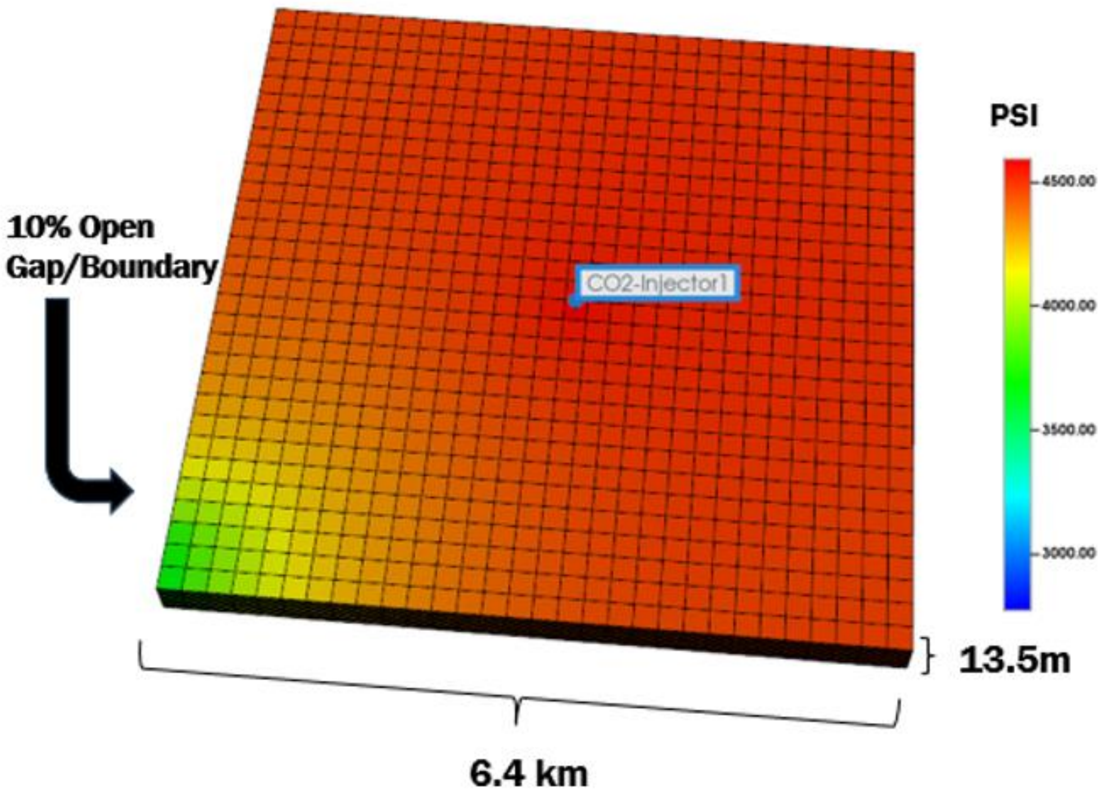

Figure 6: Example of a CMG-GEM simulation representing pressure in a reservoir with a 10% open boundary (on the left-hand side of the block reservoir only). Injected CO_2 and reservoir pressure dissipates through open boundary simulations (CMG-GEM, 2012).

The study seeks to understand the sensitivity of the compartment size and boundary conditions on the injection performance of the compartment. Table 1 below shows the assumptions used for the reservoir base case and are typical of a net sand interval that is commercial-grade for CCS. Lithostatic pressure, defined as the overburden of surrounding rock, of the reservoir is calculated by the depth of the reservoir using a gradient of 1psi/ft (Bakhshian, 2023). This pressure may not be exceeded at the risk of induced seismicity or rock fracturing (creating pathways for leakage and environmental damage). For this reason, operators usually inject at bottom-hole pressures at 80-90% of this fracture gradient. In this study 80% is used as a conservative estimate. Table 1 below outlines the base case geologic and injection parameters I use in my simulations.

Porosity (%)	20%
Permeability (mD)	1000
Injection Rate (SCF/day)	92,000,000 (1.9MT/yr)
Maximum allowable pressure (psi), as a % of lithostatic pressure	80%
Reservoir Thickness (m)	13.4 (44ft)
Well location - grid blocks (out of 30)	15 (center of the reservoir)
Depth (m)	1,828 (6,000 ft)
Areal Extent (km^2)	37

Table 1: Variables in the base case scenario.

Over 350 simulations in CMG-GEM were ran, accounting for over 30 unique scenarios, each having 11 simulations testing boundary openness. The boundary conditions are tested at 0-100% open, in 10% step progressions. Table 2 below shows the range of values for each parameter tested in the sensitivity analysis of the ability to inject

CO_2 in the reservoir for 40 years. To emulate a partially open boundary, I use the *VOLMOD function in the CMG files to make the block size at the boundary extremely large, rendering the grid blocks at the boundary to act as virtually open.

Variable	Range of Sensitivity Analysis
Boundary Openness of the Reservoir	0-100%
Thickness (m)	1.37-69.8 (4.5-229 ft)
Areal Extent (km^2)	3.2-254
Permeability (mD)	100-1,000
Depth of the Reservoir (m)	1,219-2438 (4,000-8,000 ft)
Well Location (grid block number in the simulations, 1 is directly on the open boundary, 15 is the center of the reservoir, 30 is the farthest away from the open boundary)	2-29

Table 2: Range of values for each parameter of the reservoir used for sensitivity analysis of injectivity.

The base injection rate of 92,000,000 SCF/day, or 1.9 MtCO_2/yr is more than the average historic injection rate of 0.7 MtCO_2/yr per well as calculated by Rinrose and Meckel (Ringrose and Meckel, 2019). The purpose of injecting more than the typical well is to test the upper limits of reservoir pressurization in a single well. In a real-world application, it may be two or three wells that may inject into the same compartment to reach the same rate of injection. In my financial analysis I account for this correction.

Sensitivity analysis of reservoir variables including thickness (m), areal extent (km^2), depth (m), injection rate (SCF/day), well placement, and distance to the boundary gap are tested (m). Changing the areal extent of the reservoir site in CMG inherently changes the distance to the gap with a well at the center of the reservoir. However, the well placement sensitivity seeks to understand the asymmetric pressure dissipation that occurs when the well is not directly in the center of the compartment (whether open, closed or partially open boundary conditions).

Through these simulations, injectivity risk can be understood depending on the compartment size and boundary conditions of the reservoir. As the reservoir pressure increases, the bottom-hole pressure of the well can be seen to increase upwards towards the maximum allowable pressure, as seen in the chart below exported directly from CMG:

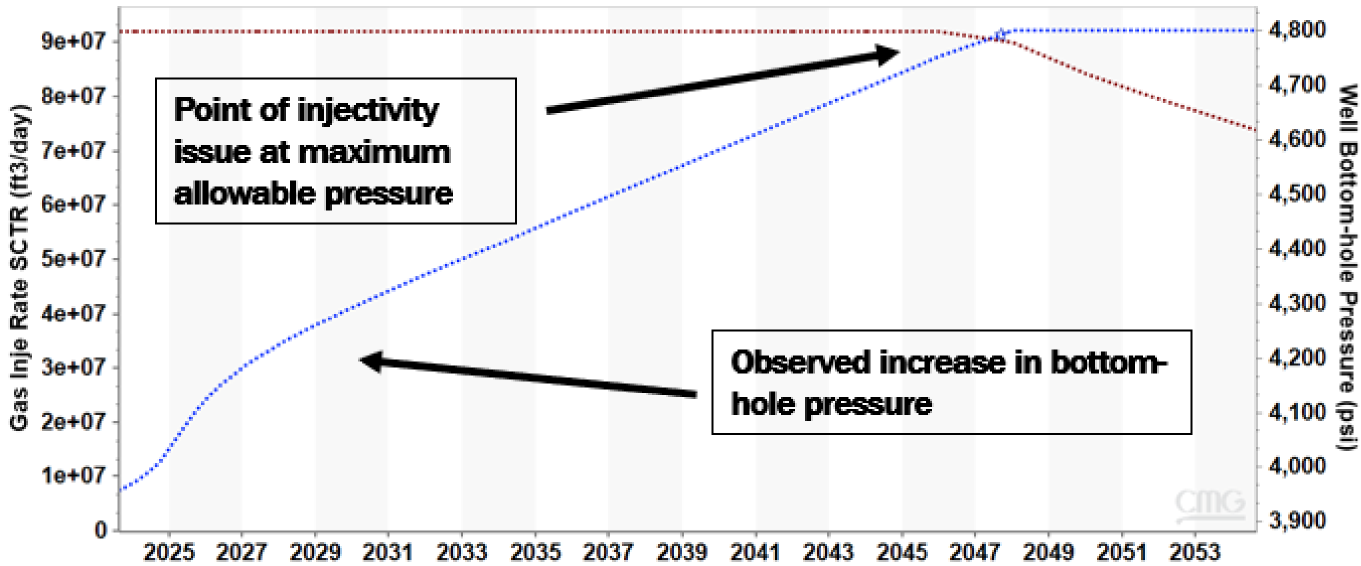

Figure 7: Example result exported from CMG-GEM. The dotted red line is the injection rate and the dotted blue line is the bottom-hole pressure. The Bottom-hole pressure trend is evident before the injection issue occurs in 2046 (CMG-GEM).

Based on the rate of the pressure increase and predicted trend of bottom-hole pressure at any given point in time, the operator can extrapolate the timing and severity of the injection issue before it happens. In this sense, the risk is minimized significantly if the pressure trend can be established ahead of time to know when the injection issue will occur. Preparations can be made to drill an injection well in another part of the site outside the compartment before the maximum allowable pressure is reached. The time towards the maximum allowable pressure is a straight line in the scenarios because information access is assumed to be perfect in CMG. However, in the real world, bottom-hole pressure is not as smooth. Observing bottom-hole pressure whether a well is shut in or not greatly varies the measured reading. To evaluate the effect this variability of pressure readings may have on the pattern, I use real bottom-hole pressure data given to me by my GCCC colleague Angela Luciano, who gathered bottom-hole pressure data from historical Class I and Class II injection wells (Luciano, 2023). The average standard deviation from these wells was calculated and applied to the CMG bottom-hole pressure data to simulate noise in the scenarios. I apply Gaussian noise such that the mean is 0, and the standard deviation is the observed standard deviation from the Class I and II wells, which was 25 psi. As seen in the Figure 8 below, bottom-hole pressure variability does not greatly impact the slope or shape of an injection well that is facing increasing reservoir pressure. To this end, it can be reasonably concluded that the operator, with correct monitoring equipment, will be able to predict the date of the injection issue when the trend of bottom-hole pressure is established.

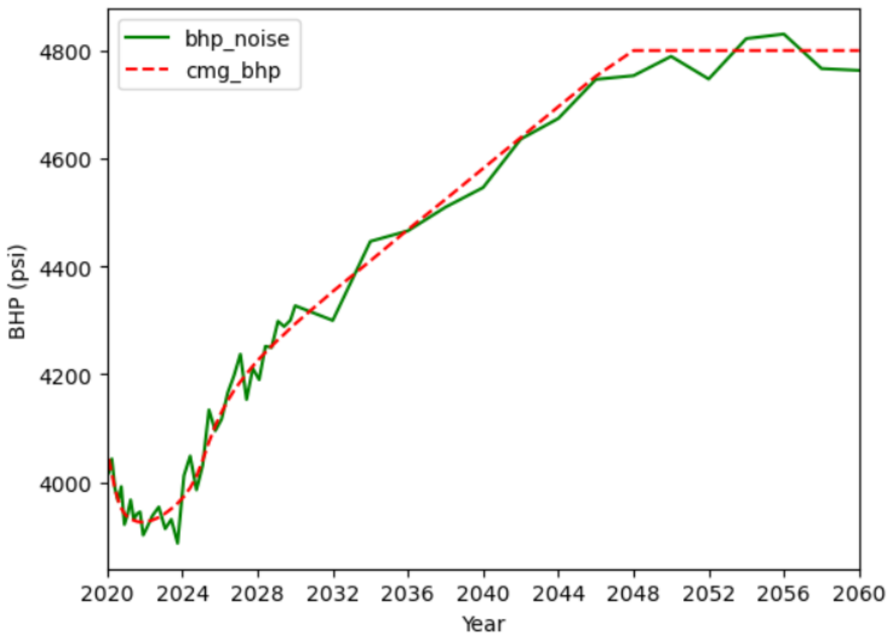

Figure 8: CMG Bottom-Hole Pressure Output with Gaussian noise added from Class I and II injection well data (data from Luciano, 2023).

3.4 Mitigation Options for CCS

If an operator experiences an injection issue, they face an obligation to find another area in the reservoir to inject CO_2 that was contractually promised to the CO_2 capture source. The storage operators' offtake contract with the CO_2 emitter will include an agreed-upon amount of CO_2 for storage. The structure of the contract will typically be a tolling fee, with the CO_2 emitter paying the site operator a dollar/ton fee to store the carbon underground over an agreed upon amount of time. This is consistent with CO_2 market operations today for enhanced oil recovery, where CO_2 is sold from certain industrial sites to oil and gas companies. In this structure, the capture firm does not need to develop storage expertise, but rather uses this "pay at the gate" model (Cai et. al, 2014). This study only considers this contract structure. Under the 45Q tax credit established by the IRS and most recently updated in the Inflation Reduction Act, the carbon tax credit is not received by the CO_2 source until after permanent geologic storage is proven (Congressional Research Service, 2023). Therefore, in the contract with the CO_2 storage operator it is reasonable to assume there will be language that elucidates the penalty if the site operator is unable to inject CO_2. Upon speaking with a climate technology insurance company that is actively insuring CCS projects, I was told a reasonable financial liability to assume for the site operator's inability to inject CO_2 is 10% of the total amount that was originally promised, with CO_2 source company bearing the risk for the remaining value of the tax credit in this "pay at the gate" contract structure (K. Sutton, personal communication, October 26, 2023). The operator must therefore take this risk into account when examining the broader injectivity risk of a reservoir and how to plan for it.

As learned in the Snøhvit project, alternative plans need to be created at the onset of the project since issues with compartmentalization and reservoir pressure will not be known until after the injection starts. It's therefore crucial for the site operator to evaluate potential backup sites and site remediation needs. The most important factor of site remediation is accounting for legacy oil and gas wells (Ide et. al., 2006). This adds significant monitoring and preparation costs for an alternative site near old oil and gas wells.

What is entailed in these potential backup plans will include a litany data acquisition, permitting and construction that is both time and capital intensive to an operator. It is therefore important for the operator to consider which activities to engage in that are cost effective and advances a construction schedule of an alternative site if an injectivity issue ever occurs. Water production is often seen as a potential mitigation strategy. However, water production is not considered in this study due to the high costs and uncertainty of conducting water production operations at a CCS site. Given this fact, this study focuses on new offset wells drilled outside the compartment as the primary mitigation scenario.

3.5 Discounted Cash Flow Model

To construct a cash flow model of each scenario, I use the NETL CO_2 Saline Storage cost model (National Energy Technology Laboratory, 2017). This model contains detailed line items for the cost of acquiring data, permits and land as well as drilling and operations costs of an onshore carbon sequestration site. In the base case, there are six years at the project start associated with the preparation of a site prior to CO_2 injection. My case studies seek to understand what site parameters most affect the costs of an offset well that needs to be drilled if an injectivity issue is discovered in the primary reservoir. The primary stages of the project are site screening, site selection and characterization, permitting and construction, operations, and post-injection site care (PISC).

Appendix C illustrates the cost and revenue assumptions made in the free cash flow model such that:

$$FCF_i = (Rev_i - OpEx_i - Dep_i) \times (1 - tax_{rate}) + Dep_i - CapEx_i + \triangle NW$$

(2)

Where *FCF* is free cash flow for *i* year, *Revn* is the top line revenue, *OpEx* being operational costs, *Dep* being depreciation, *tax_rate* the combined federal and state tax rate, *CapEx* being capital cost, and *△NW* being change in net working capital.

Under the 45Q tax code, the carbon source that implements the carbon capture equipment qualifies for the credit (Legal Information Institute, 2021). In most cases outside of a joint venture agreement between the storage operator and capture source, a per ton tolling fee will be paid to the storage operator for CO_2 offtake. The capture costs constitute the most expensive part of the CCUS process and the most variable. Costs from pure CO_2 sources range from $15-25/ton while more dilute sources can cost anywhere from $40-$125/ton. Figure 9 shows the bulk of capture sources (~90%) fall under $20/ton. Transport costs largely depend on the pipeline length from source to sink, but the IEA estimates costs range from $2-14/ton for onshore pipelines. For storage, it's estimated that more than half of onshore storage capacity in the U.S. is estimated at $10/ton or below (Baylin-Stern and Bergout, 2021). I consider a range of prices in my financial model but use a base case of $15/ton for CO_2 offtake.

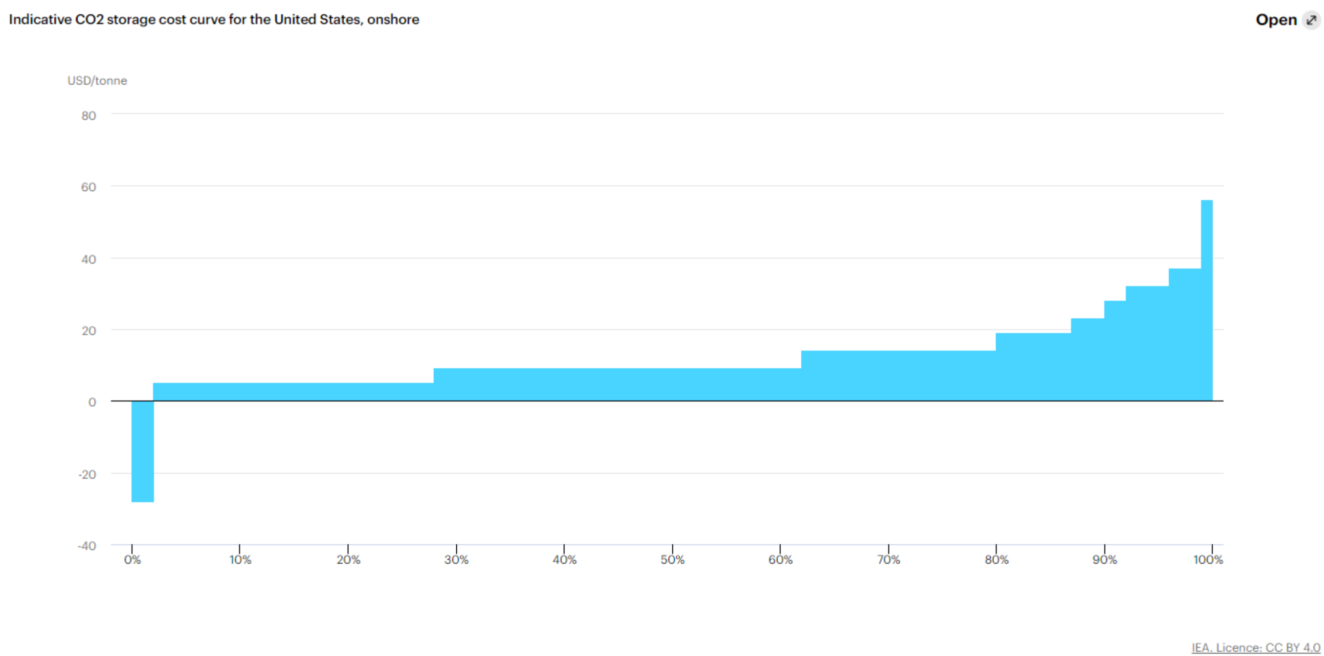

Figure 9: IEA Cost Curve for CO_2 Geologic Storage. The y-axis is estimated USD/ton CO_2 sequestered and the x-axis is the percentage of storage area in the U.S. that can store CO_2 at a given cost. 80% of the storage capacity in the U.S. can storage a ton of CO_2 at below $20 (Baylin-Stern and Bergout, 2021)

A flexible discounted cash flow model is built that illustrates the liability facing an operator when an injection issue is faced. A user can select mitigation scenarios that include backup well sites, distance from the original site (for distribution pipelines), capacity and number of wells. As illustrated in Figure 10 below, these mitigation scenarios are coupled with the bottom-hole pressure profiles from the CMG simulations. A decision threshold is then chosen by the user to determine when to begin a given mitigation strategy. This is expressed as a percentage of the maximum allowable pressure (e.g. the user may decide at 80% maximum allowable pressure to begin offset well activities). Once this threshold is reached, both the year of the injectivity issue occurring and the year the operator takes action is fed into the schedule of activities that impacts the cash flow model. If bottom-hole pressure reaches the fracture gradient (i.e., maximum allowable pressure) before operations begin in the offset well, then a financial penalty is applied for failure to inject in terms of percentage of the 45Q tax credit (in this case, $85/ton) multiplied by the difference between the actual amount of CO_2 injected and the promised amount of CO_2. In this study, I use 1.9MT/yr as the contractually obligated amount of CO_2 the operator must inject. Figure 10 below illustrates the flow of the tool.

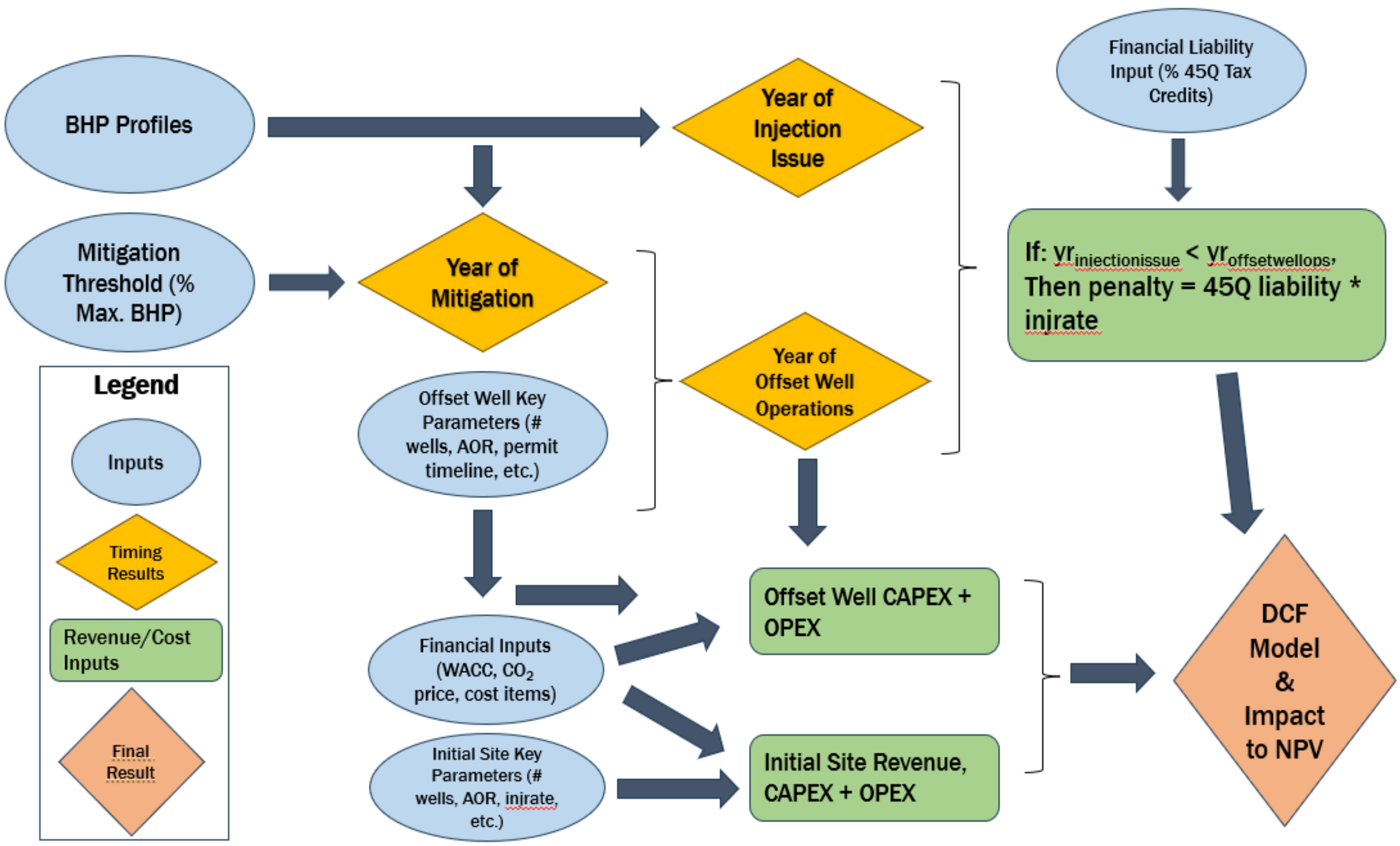

Figure 10: Process Diagram for the Financial Liability Tool. CMG BHP Inputs, coupled with user inputs determine the financial liability and project costs for an offset well. WACC is the weighted average cost of capital i.e., the discount rate.

3.5.1 Financial Liability Tool

A flexible financial tool is built in Excel that uses the simulation outputs from CMG-GEM to evaluate the additional costs and liabilities a CCS site operator may incur given unexpected reservoir compartmentalization and subsequent injection curtailment. The first goal of this tool is to understand the nominal costs associated with drilling an offset well to counteract compartmentalization of a CCS reservoir. The second goal is to understand the sensitivities of the CO_2 offtake price (revenue) and liability of lost 45Q tax credit revenues (penalty for failure to inject) to overall project value. The results from this tool help to evaluate potential possibilities for an adequate financial assurance mechanism and insurance structure to address the relevant risks. A wide range of mitigation parameter values can be tested in best and worst-case scenarios to determine whether a specific financial assurance mechanism is feasible.

The well's bottom-hole pressure profiles from CMG-GEM are imported into Excel. A user selects the specific compartment simulation, and the year that the maximum bottom-hole pressure is reached is reflected in a project schedule and discounted cash flow analysis. The user selects a mitigation threshold, which is reflected as a percentage of the maximum bottom-hole pressure that is tolerable before the fracture pressure gradient is reached (and injection in the original well stops). The user selects the number of years it will take for each stage of the new offset site. The stages are site characterization, permitting and construction, operations, and post-injection site care. Based on the simulation output selected, the year this threshold is reached (i.e., the year the operator decides to begin mitigation), and the project schedule, the relevant costs are thus dynamically calculated for each year in the tool. The user then selects the key parameters pertinent to the overall cost of the offset well, which includes variables like depth (m), area of review (square km), # injection wells and the monitoring regime (fluid sampling, seismic surveying, etc.).

Offset Well Variable	**Range of Inputs**	**Cost Parameter(s) Affected**
Depth (m)	1,219-2,438 **(**4,000-8,000 ft)	Well drilling capital costs
Area of Review (km^2)	3.25-255	Surveying, pore lease, area of review for monitoring operating costs
# Injection Wells	2-6	Injection well capital and operating Costs
# Monitoring Wells	1-10	Monitoring well capital and operating Costs
3D Seismic Frequency (# times throughout project life)	Twice (baseline and after injection operations) to Once Every 5 Years	3D Seismic capital and operating costs

Table 3: Range of values for each parameter of the offset well site and the specific costs each parameter effects in the cost model.

Using the mitigation threshold year and this schedule, a penalty for failure to inject the required amount of CO_2 is assessed only if the operations for the mitigation well do not commence before the injection issue in the original well occurs. This penalty is assessed as a percentage of the value of the 45Q tax credit ($85/ton) multiplied by the obligated injection rate the site operator contractually promised to the carbon capture source. As stated previously, 10% of the credit amount is the base case based on personal communication with an insurance company, though I evaluate the full range of potential financial liability. When an injection issue occurs, the initial well begins shutdown operations since the well needs to be shut in and stringent environmental measures are required.

The tool dynamically changes the costs in the cash flow model based on the injection issue year, mitigation schedule and site parameter/financial inputs. The aggregated discounted cash flow model based on this tool can thus evaluate the impact to the project value and nominal costs based on each of the 350+ scenarios ran in CMG-GEM, and the feasibility of self-insurance structures can thus be evaluated. This tool is deterministic, meaning there is no uncertainty for each set of inputs, though sensitivity analysis is conducted across input parameters.

The tool has 5 main components: inputs (reservoir characteristics and mitigation scenarios), a schedule that outlines both the year of the injection issue and the year mitigation efforts are commenced, the site costs for the target reservoir, the site costs for the backup reservoir, and a discounted cash flow analysis. Initial inputs, as seen in

Section 3.6 where the specific scenarios are illustrated, include:

- Compartment scenario: the name of the specific simulation file ran in CMG-GEM. The bottom-hole pressure profile is indexed.
- The mitigation threshold and override inputs: the value used to commence mitigation efforts, as expressed as a percentage of the maximum bottomhole pressure (i.e., the fracture pressure). An override is also available to set the maximum pressure below the frac gradient pressure to simulate the cessation of injection due to induced seismicity.
- Mitigation Scenario: An offset well is drilled based on the mitigation threshold. Injection rate management is also explored.
- Curtailment option (Y/N): The option to continue to inject whatever amount of CO_2 the reservoir can take once it reaches maximum pressure. This is relevant in partially open boundary scenarios where pressure may dissipate when injection stops.
- Compartment characteristics that dictate specific cost-line items. Variables include
    - Areal extent (km^2)
    - Distance from the main transportation pipeline to the reservoir (km)
    - Distance of the feeder pipeline to each well (km)
    - Number of wells to drill (for injection, stratigraphy, and monitoring wells)

    - Number of legacy wells to plug and abandon
    - New lease costs
- Mitigation Schedule: The number of years it takes for the first three stages of the mitigation scenario (site screening, site characterization, and permitting/construction). The base case assumes 0 years of site screening, 1 year of site characterization and selection, 1 year of permitting, the remaining years of injection left in the 40-year project once an injection issue occurs, and 50 years of PISC. For practical purposes, I only increase the time in the permitting and construction stage to emulate delays in permitting administration.

The next component is the initial site costs, where a business-as-usual cost schedule with the 5 stages (site characterization, site surveying, construction and permitting, operations, post-site care) of the project are broken out into capital and operating expenses. The specific cost items associated with the reservoir characteristics are described in the sections below. If an injection issue occurs, then the post-injection stage of the project is moved forward in the schedule as operations shut down in the primary reservoir and post-site care commences.

From these two separate cost schedules, the discounted cash flow (DCF) is derived using the injection rate and CO_2 price for revenue, a liability incurred if operations in the mitigation scenario do not commence before the injection issue is reached, operating costs for both the primary and mitigation sites, taxes (if applicable), depreciation (assume a 15 straight-line schedule, where the capital costs are spread evenly over a 15 year period for depreciation), and capital expenditures to yield the free cash flow in each year of the project over 100 years). These final free cash flows are used to generate internal rate of return and NPV metrics. I assume a base case of 10% of the lost 45Q tax credit revenue the site operator is liable to pay to the carbon capture source for failure to inject, though I evaluate the sensitivity of this penalty to the overall value of the project for policy analysis purposes. I use 3% as the annual escalations in both the CO_2 price (i.e., the 45Q tax credit) and site costs to account for inflation.

3.5.2 Cost of Monitoring and Plugging Abandoned Wells

A significant cost site operators need to consider is the monitoring and remediation of legacy oil and gas wells within the Area of Review (AOR). Unplugged or improperly plugged oil and gas wells pose environmental and health risks. However, for CCS, the largest risk of orphaned or abandoned wells is that it creates a potential leakage pathway for CO_2. Millions of oil and gas wells have been drilled in the U.S. since the late 1800s (Cutler, 2023). Limited information exists on the condition of older decommissioned wells, meaning a site operator will need to inspect each one and plug with cement if necessary, costing time and money. The Class VI permit application guidance states that "after all the available records have been reviewed, any wells located within the AOR that cannot be proven to have plugs adequate to prevent migration of carbon dioxide or formation fluids out of the injection zone must be evaluated by field tests in order to determine the quality of plugging" (EPA, 2013). The EPA denotes that a strategy to manage leakage risk in orphaned or abandoned wells must be listed in a Class VI permit application and improved iteratively throughout the project (Lackey et. al, 2019).

Using data collected from Raimi et. al. on 448 decommissioned wells in Texas, I use the average cost of $75,307 per well as the cost to plug and abandon (Raimi et. al, 2021). The costs of plugging all wells inside the area of review that need to be plugged and abandoned area considered in the total capital cost in years 2-4 of planning in the project.

3.5.3 Drilling Costs

Drilling costs in the 2017 NETL model were taken from the American Petroleum Institute's 2006 Join Association Survey on Drilling Costs (National Energy Technology Laboratory, 2017). The option to choose between fitted models based on the survey are available, where one can pick an exponential, polynomial, power or linear function based on depth is used for the costs. For simplicity, I use the polynomial function for the state of Texas where:

$$Cost_{drill} = 0.0003 \times dep^2 \times 0.091 \times \ dep + 162.68 \qquad (3)$$

Where $Cost_{drill}$1 is the total capital cost of drilling and completing a well and dep being the depth of drilling, in feet. In 2024 dollars, this translates to $1,889,342 for a 6,000 ft. well (the base case depth used). The same methodology is applied for stratigraphy and monitoring wells. Costs include everything through well completion for a drilled well.

Completion costs are typically casing and production tubing, perforation, packers, safety devices, kits at the reservoir sands and a tree at the top of the well (National Energy Technology Laboratory, 2017).

3.5.4 Compression Costs

A carbon capture operation from source to sink requires several steps of compression. At the source, CO_2, once separated from its waste gas, needs to be compressed from atmospheric pressure (0.1MPa) to a pressure that forces the gas to be in a liquid or 'dense phase' state suitable for transport (15MPa) (National Energy Technology Laboratory, 2017) A compressor is needed for CO_2 to undergo this transition, but a pump can be used to boost the pressure. Assuming the entry pressure of a pipeline is 15MPa, then the power requirement for a pump using depth and injection rate is defined by:

$$W_{pump} = m_{CO2} \times (P_{out} - P_{in}) \times \ 1e6 \frac{Pa}{MPa} \times 1e - 3(\rho_{CO2} \ \times eff) \qquad (4)$$

Where $W_{pump}$is the final pump power requirement, m_{CO2} is flow rate of the CO_2, which at 1.9 MT/yr (the target injection rate) is 67.38kg/sec, P_{out} is the desired pressure at the pump outlet, P_{in} is 15MPa, ρ_{CO2} is the density of CO_2 at average pressure and surface temperature, and eff is the efficiency of the pump, which is assumed to be 75%. This power requirement is multiplied by a base price of $1,400/kW and a fixed capital cost of $87,000, as taken from McCollum and Ogden (2006). For operating costs, I assume the pump runs year-round at an electricity price of $0.1036/kWh and a fixed operating cost of 4% of the capital costs (assumed in the NETL model).

In this study, I assume scenarios in which the operator sets the pump specifications to the maximum pressure possible, which in my simulations is 80% of the fracture pressure (where injection would stop). There would be an entire system failure when the pressure needed for injection is raised higher than the pump specifications due to the increasing reservoir pressure. However, as discussed in later sections, the data from Class VI permits to-date suggests operators are designing their pumps to handle the maximum pressure that may be required (EPA, 2024).

3.5.6 Permitting

The EPA and states with primacy have worked to streamline the permit application process to give more transparency to the timeline expected. The EPA's guidance is that the total permit timeline is around a 25-month process from application to final permit, divided into 5 phases (Pickerill et. al., 2023):

- 30-day completeness review
- 18-month technical review
- 60-day preparation of draft permit
- 30-45-day public comment period
- 90-day preparation of final permit.

Construction can begin once the final permit is issued, though more testing is required to be submitted to the EPA before injection can commence. From the permit tracker on the EPA website seen in Figure 11, as of February 5th, 2024 a total of 43 projects were in the permit queue (EPA, 2024). This does not include North Dakota and Louisiana, who have been granted primacy over carbon sequestration permitting. At the time of this publication, there were 23 applications transferred to Louisiana Department of Energy and Natural Resources, though their permit details were not available. There were 6 permits issued in North Dakota whose permit details were readily available (Department of Mineral Resources, North Dakota, 2024). Many projects' technical review process has already exceeded 18 months, noticeably due requests for additional information (RAI) or a notice of deficiency (NOD) being sent to the applicant. Most applicants' response time to RAIs and NODs are typically only a few months, but as seen in Figure 11 below, these pauses in review have a substantial effect on the permit application time. Due to this uncertainty in permitting, I test a wide range of permitting timelines in the mitigation scenarios to understand the impact of permit delays on the value of the project, given the operator will face financial penalties for each year they fail to inject the obligated amount of CO_2.

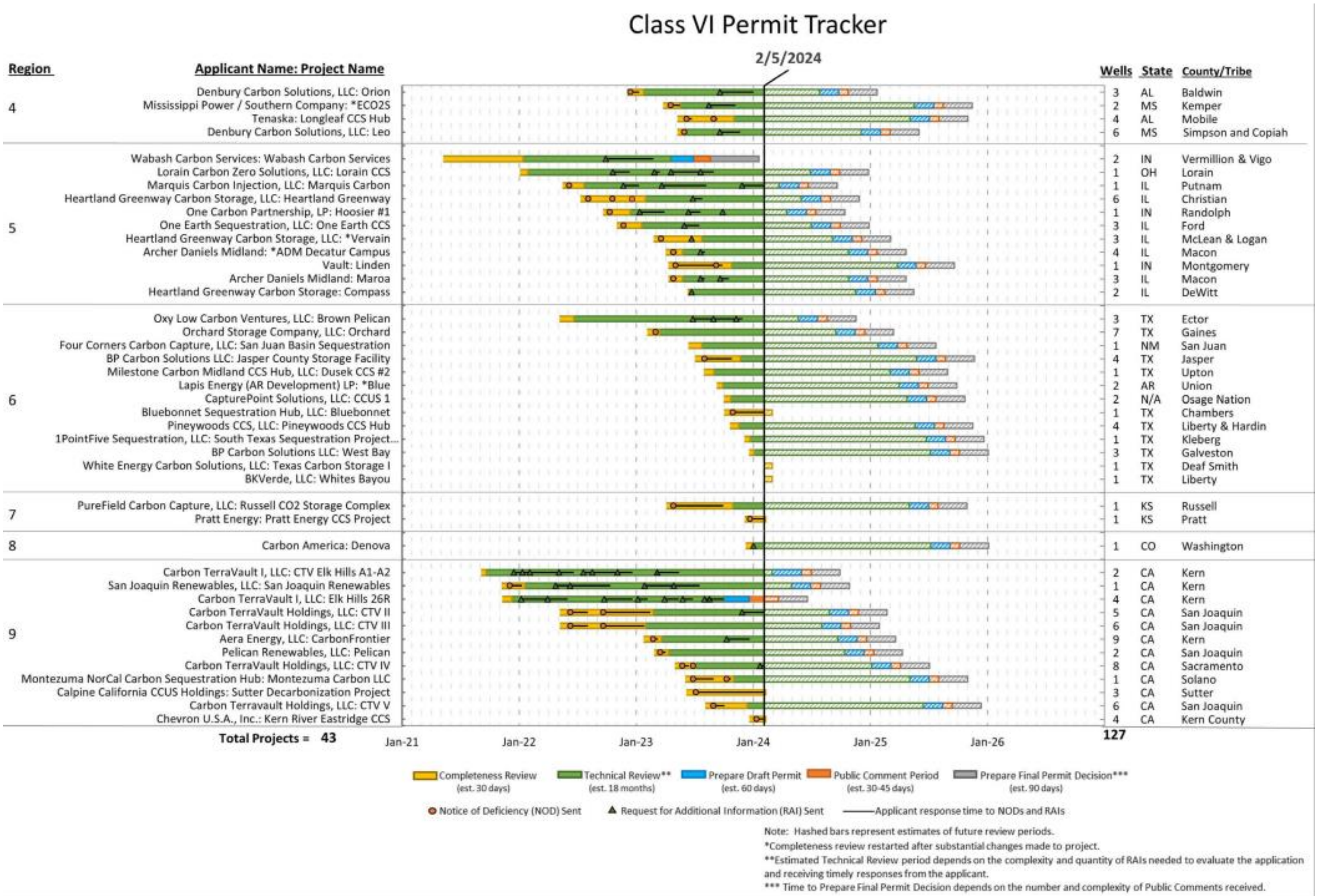

Figure 11: Class VI Permit Tracker as of 2/4/24. Status and length of time of permit review helps to constrain test cases of permitting delays (from EPA, 2024)

3.5.7 Monitoring Requirements

As described in the next section, the values for the parameters in the financial liability tool are meant reflect realistic situations to ascertain the influence of a given variable on project viability. Monitoring is one of the costliest components of the annual cost of sequestration. Vertical seismic profiling and 3D seismic profiling costs up to $500,000 per square mile but gives the most accurate picture in what is occurring in the subsurface (National Energy Technology Laboratory, 2017). Not only does the CO_2 plume need to be monitored, but the extent and magnitude of the pressure in the area of review, groundwater quality, legacy wells, and well mechanical integrity all need constant monitoring. Additionally, what is to be considered adequate monitoring is still very much a topic of debate in the CCS industry. The NETL Saline Storage Cost Model currently allocates yearly air-magnetic surveys for geological mapping and exploration, aerial surveys, groundwater sampling and 2D seismic surveys on an annual basis, while 3D seismic surveys are done every 5 years. The NETL model also allocates monitoring wells on a per square mile basis. Given a large AOR, these costs are extremely punitive to a project.

Based on the ongoing conversation in the industry around monitoring, as well as public Class VI permit data available to-date, the monitoring requirements are less stringent. Table 4 below summarizes the three projects available on the EPA website that have been approved, or in the process of being approved, to-date. While there are many more permits in the queue that are awaiting review and approval, the relevant information is redacted and unavailable in the permit applications online.

In Table 4 below, the three projects all have similar target injection rates to my simulation target of 1.9MTa, which requires a minimum of two wells. In each of the projects, only 2-4 monitoring wells are planned for an AoR roughly the size of my injection profile base case of 37 km^2. Regarding seismic profiling, passive seismic, or 2D seismic, is expected to occur annually, as it does in the NETL model. However, plans for 3D seismic profiling vary. In the ADM Midland CCS project in Illinois, 3D seismic profiling occurs once as a baseline in project planning, twice during operations, and twice in post-site closure. In the Vigo and Vermillon County project planned by Wabash Carbon Services in Indiana, as well as the Elk Hills Storage Project in CA by Carbon TerraVault, 3D seismic occurs once every five years (EPA, 2024). This 3D seismic frequency is what I use in my study.

3.5.8 Pipeline costs

Pipeline costs are defined by the NETL cost model and include two separate pipelines: the feeder pipeline and the distribution pipelines. The feeder pipeline is the pipeline from the main transport pipeline to the site. The distribution pipeline is from the feeder pipeline to each individual injection well. The NETL model uses assumptions from Godec, 2014 and Heddle, et. al, 2003 for these costs, which is based on injection rate and length of pipeline (Godec, 2014, Heddle et. al., 2003). At 1.9MT/yr, there is $200,000 fixed cost and $900,000/mi. variable cost for the feeder pipeline CAPEX and $9,000/mi-yr for operating costs. I assume a 3-mile feeder pipeline for this site. For distribution pipelines, I assume 1 mile for pipes to each well.

Site	**ADM Midland CCS**	**Vigo and Vermillon County**	**Elk Hills 26R Storage Project**
Company	ADM	Wabash Carbon Services	Carbon TerraVault JV Storage Company
State	IL	IN	CA
Injection Rate Proposed (MT/yr)	1.3	0.834	1.6
Stage	Operations	Pre-operations	Pending
# Injection Wells	2	2	4
Thickness (ft)	N/A	408	N/A
Max Injection Pressure - Surface (psi)	2,284	1,296	1,888
Permeability (mD)	194	2400	100
frac gradient (psi/ft)	0.715	0.71	0.71
Depth (ft)	6670	4300	6000
Max. injection pressure, as submitted (psi)	4,489.06	2,537	3,847
boundary conditions	open	N/A	N/A
AOR	34.17	32	N/A
Total Legacy O&G wells	10	N/A	157
Not plugged	0	N/A	157
AOR reevaluation trigger 1	Three standard deviations from bottom-hole pressure	Three standard deviations from bottom-hole pressure	10% deviation from computational pressure model
AOR reevaluation trigger 2	Seismic event M3.5 or greater within 8 miles of well	Seismic event M3.5 or greater within 100 km	Seismic event M3.5 or greater
Fluid Sampling frequency	annual	annual	annual
3d seismic frequency	once (baseline), once in ops, twice in PISC	every 5 years (16 sq. mi per inj well)	every 5 years
Passive seismic frequency	annual	annual	annual
Financial Responsibility (millions)	$ 33.81	$ 35.21	$33.67
# Groundwater Monitoring Wells	4	10	N/A
# Monitoring Wells	4	2	4

CO_2 feeder pipe length (mi)	0.2	N/A	N/A
CO_2 distribution. pipe length (mi)	0.6	N/A	N/A

Table 4: EPA Class VI Permit Information (EPA, 2024)

3.5.9 Other Relevant Project Information from Class VI Permits

These early projects reflect other operational parameters like what might be found in the Gulf Coast compartmentalized network. CO_2 pipelines are extremely short (< 1 mi.), with the storage site right next to the sequestration site. Groundwater monitoring wells vary, but do not exhibit the unnecessarily large number of wells present in the NETL model. Financial assurance for emergency remediation is similar in each project, with total responsibility ranging from $33.67 million to $35.21 million (EPA, 2024). The responsibility required in the Class VI permits covers the same remedial response and post-site closure activities, so it’s no surprise that these costs do not vary between projects.

3.6 Case Study Scenarios

The cases ran in the financial liability tool are created to evaluate realistic possibilities for each factor of a sequestration project in order to consider relevant policy considerations for CO_2 project management and administration. As it is described in section 4.1, the CMG-GEM simulation results, I do not need to evaluate every single scenario ran, but rather the distinct pressure profiles presented from the results. In other words, the results dictate that only a few categories of injectivity issues need to be explored: immediate injection issues, mid-operations injection issues, and late-operations injection issues. Each category of results has their own rate of pressure increase.

For the initial project parameters, I evaluate the base scenario for the model on table 5 below.

Variable	**Base Case Scenario**	**Range of Values Tested**
Areal Extent (km^2)	37	3.25-250
Permeability (mD)	1,000	100-1,000
Depth (m)	1,828 (6,000 ft)	1,219-2,438 (4,000-8,000 ft)
Distance to compartment (km)	4.28 (3 miles)	0-15 (0-9.23 miles)
No. Stratigraphy Wells	2	0-6
Monitoring Wells - In Reservoir	2	0-15
Injection Wells	2	2-6
# Legacy Wells	15	0-200
Total Injection Rate (MT/yr)	1.9	1.9-1.9
Pressure rating in transport pipelines (PSI)	2,200	2,200-2,200
Feeder Pipeline Length (km)	3.2 (2 miles)	0-15 (0-9.23 miles)
AOR (km^2)	46.25	4-312
Stage 1: Acquire/purchase/analyze existing data (years)	1	0-1
Stage 2: Site Selection and Characterization (years)	3	0-5
Stage 3: Permitting and Construction (years)	2	0-5
Stage 4: Operations/Injection Period (years)	40	N/A
Stage 5: Post-Injection Site Care (years)	50	N/A

Table 5: Base Case Site Inputs/Parameters for financial analysis

The project-specific parameters and costs are also evaluated in a realistic fashion to understand the effect on project value each parameter has. For the mitigation scenarios, where an offset well is drilled, I evaluate the model with the base conditions as follows:

- The Area of Review (AOR) is 37km^{2,} based on the base case scenario for the CMG-GEM simulations, where the project operator does not need to purchase additional land, however, a new offset well requires pre-injection characterization and permitting. Monitoring, site characterization, legacy wells, etc. do not change from the initial project conditions.
- Depth is 6,000 ft, where the net-sands and geology for injection do not structurally change.
- Site Selection and Characterization takes 1 year for detailed seismic to better characterize the fault network causing compartmentalization.
- Permitting and Construction takes 1 year. I evaluate scenarios where permitting and construction takes up to 5 years.
- Operations is 40 years less the number of successful years of injection before compartmentalization.
- PISC takes 50 years.

I evaluate scenarios where the area of review does change, and new monitoring wells, lease bonuses, and characterization is needed. I conduct a sensitivity analysis using the best and worst cases for each variable to understand the effect on NPV the range of possibilities have.

Given I am evaluating a saline aquifer, and not an oilfield, I assume the 45Q tax credit is $85/ton and increases each year with inflation. For liability for failure to inject, I assume 10% of this credit is applied in years full injection does not occur. As stated earlier in this paper, I assume this value based on conversations with insurance companies who have seen 10% as the value of the credit sequestration projects may be liable for in the scenario CO_2 leaks from the subsurface the tax credits are recaptured. I evaluate the full range of what this liability may be, from 0-100% of the tax credit liability. The primary policy and operational question I'm exploring is whether injection management or injection cessation given a certain pressure threshold, coupled with this liability, fundamentally changes project economics and if so, by how much.

3.6.2 Injection Management Scenarios

Injection management may be a necessary tool in project operators' set of options to manage injectivity risk due to unexpected compartmentalization. Using the Paradox Valley saltwater disposal well as an example, multiple adjustments may need to be made to the injection rate to properly manage reservoir pressure. Reasons for curtailed injection or regular pauses in injection, rather than full abandonment, may have to do with the nature of the pressure issue and exact geologic properties of the reservoir (e.g. faulting, seismicity, etc.). Financially, storing a fraction of the promised CO_2 may be enough to justify the viability of a project. Additionally, the proliferation of regional CO_2 sequestration hubs may make injection management feasible due to having multiple sites to route the CO_2 to. In this sense, it is plausible to anticipate injection management being a tool in a site operator's belt to manage reservoir pressure.

To this end, I create simulations that emulate the techniques taken by Paradox Valley to evaluate if injection issues are resolved compared to their base case scenarios without injection management. Due to time and computational constraints, I only evaluate scenarios of 300mD and above since successful injection can occur with only two wells. I propose two injection strategies

- Introduce a regular cadence of injection curtailment, where 1 or 2 of the wells are shut off completely for 1 month every 6 months. This reduces annual injection for each well regulated by 1/6 (2 months per year the well is shut off).
- Reduce the injection rate by 30%, as Paradox Valley did, when the injection rate reaches a certain threshold. In the base case scenario, the 10% open simulation reaches 80% of fracture pressure (the maximum allowable pressure) in 2026, so this is the year the injection rate is curtailed.

The results of the simulation will be plugged into the financial tool to understand the tradeoff between revenue loss and financial penalties with the ability to inject for the full project period. While the full range of scenarios is not tested, the purpose of this exercise is to illustrate the concept of injection management and its impact on project economics.

3.6.3 Self-Insurance

Once I explore the range of liability and NPV outcomes from the tool for the range of injection profile scenarios, I will find the break-even price to self-insure against the given financial liability for a scenario. I will do this by assigning a dollar per ton amount in a separate line item in the tool, as that is the traditional way of self-insurance. I will also explore the present value needed to self-insure instead of a dollar-per-ton strategy to evaluate contingency funds needed. Through this exercise, the break-even self-insurance amounts can be compared to the financial responsibility the operator is already claiming for emergency remedial responses.

3.6.4 45Q Tax Credit Expiration Considerations

The 45Q tax credit is currently slated to offer 12 years of tax credits for carbon sequestration if the site is in operation by 2032 (Congressional Research Services, 2023). In this study, I assume the tax credit will be extended indefinitely at some point in the future. The industry is struggling with this question of if tax credit extensions as a basis for investment decisions and is an important policy element to consider in this study. I evaluate the project viability under the range of 12 years, the minimum guaranteed length of the credit, to indefinite periods of time. For projects with immediate compartmentalization requiring an offset well with an uncertain well permitting schedule, understanding the range of outcomes via this policy is important for long-term contingency consideration.

CHAPTER 4: ANALYSIS AND RESULTS

4.1 Establishing the baseline of injectivity in compartmentalized reservoirs

Of the results from the sensitivity analysis ran through CMG-GEM, most of the simulations display the same relationship of the boundary condition to injection performance as shown in Figure 12 below, which shows the results for the base scenario.

The initial finding is that performance of the reservoir is stable over 40 years of injection in boundary conditions that are 20% open or above. In the base scenario displayed in Appendix A, the full capacity of the reservoir can be used, and 7 million tons of CO_2 is injected over 40 years. Injection performance is affected in the 10% open and 0% open boundary simulations, where 5 million tons and less than 1 million ton are injected before the pressure limit (and therefore an injection issue) is reached, respectively. Results for all of the simulation scenarios elucidate that this pattern holds across varying geologic parameters. The initial conclusion that can be drawn from this result is that if an operator faces unexpected compartmentalization, which is not detected in the characterization stage, their risk of facing injection issues is contained only in very closed boundary conditions. In all other cases, pressure can dissipate enough through the gap or fracture network to allow the operator to continue injecting for the full project life.

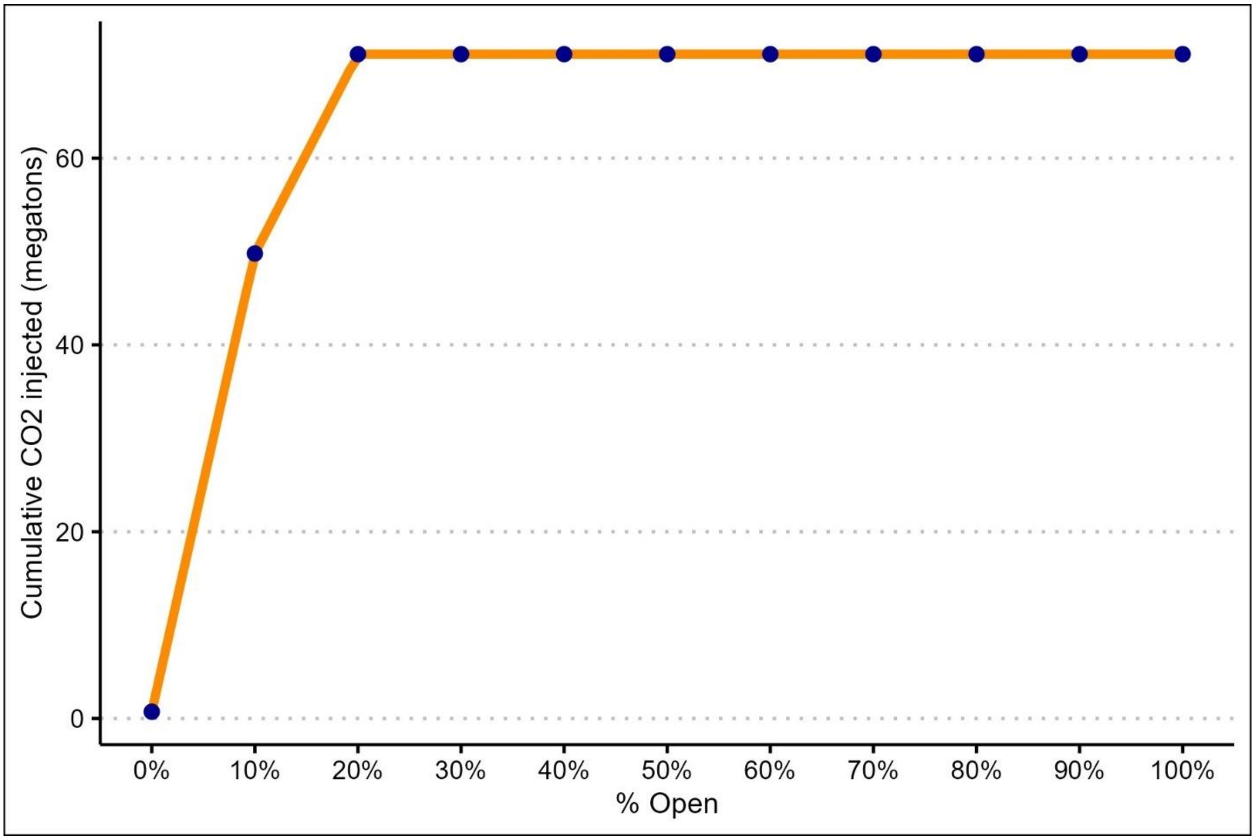

Figure 12: Initial results from the base case simulation. Injection performance is affected in the 10% open and 0% open boundary cases, but not in 20% or above openness of the boundary.

As shown in Figure 13 below, this pattern holds true across most scenarios comparing the depth of the reservoir. In all cases except the 4,000 foot-depth simulations, injection performance is unaffected by reservoirs with boundary conditions 20% open or above. At 4,000 feet, injection rates over 40 years are affected in 30% or below open boundary conditions. This result is reassuring to a project developer that pressure can dissipate in even relatively closed boundary reservoirs to continue injecting.

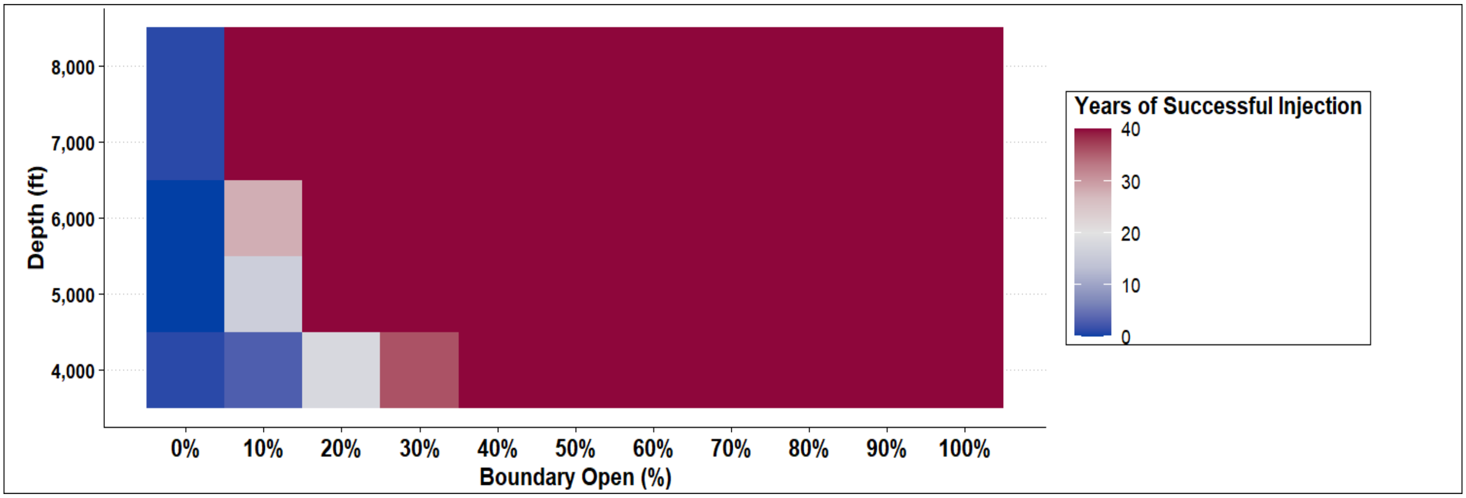

Figure 13: Depth (ft) vs Boundary Condition (% Open), colored by years of adequate injection performance. The yellow (40 years) indicates no injection issue throughout the life of the project.

Permeability dependence of the injectivity results is shown in Figure 14 below. As the permeability decreases, the tolerance for full injection decreases. At 500 mD and above, full injection is possible with 30% open boundary conditions. The results show a linear trend of injectivity decreasing as permeability decreases, holding the boundary condition constant. The number of wells needed for injection increases in the low permeability scenarios (300 mD and below) and results in a greater sensitivity to injection issues since only 1 well needs to encounter a pressure issue to be forced to stop injection.

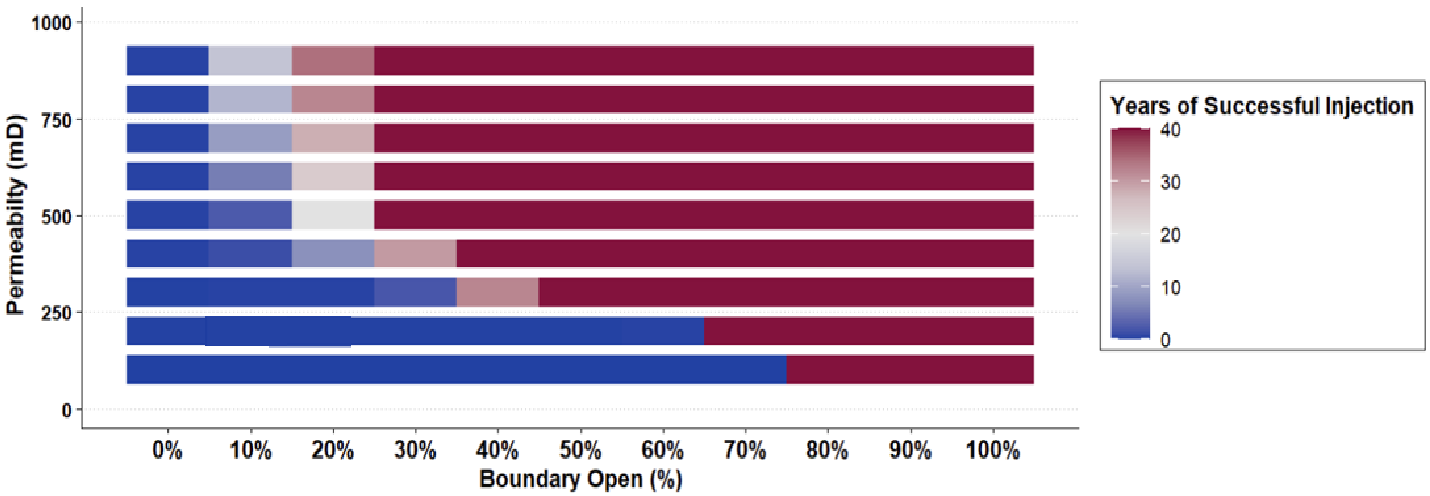

Figure 14: Successful Years of Injection Heat Map. X-axis is boundary openness (%) and y-axis is permeability (mD) for the base case scenario. 100mD requires 6 wells, 200mD requires 3 wells, and 300mD or more requires 2 wells.

4.2 Case Study Results

4.2.1 Base Case Results

In the base case results, using the base case parameters for the offset well and a 10% financial liability for failure to inject, the NPV for each of the three distinct scenarios characterizing pressure increase in the reservoir (0%, 10%, 100% open boundary) are in Figure 15 below. If no injectivity issue occurs and the operator can inject the full 1.9MT of CO_2 per year over 40 years of the project, meaning no offset well is required, the net present value of the project is $36,910,986 using a 15% discount rate. In the worst-case scenario, the 0% open scenario, an injection issue occurs in the first year of operations. Based on the additional upfront costs of building an offset well and the operator facing a 10% liability for lost tax credits, this causes the net present value of the project to be -$50,515,953. This represents the worst-case scenario for project value. Total nominal costs of an offset well over a 100-year period, assuming the operator is responsible for post-injection site care during this period is $203,835,520, nominally.

In the 10% open boundary scenario, an injection issue occurs in year 33 of the 40-year injection phase of the project. Based on the threshold for pressure increase when the operator ultimately reacts and decides to build an offset well, the net present value of the project varies, but is positive in all scenarios. At a pressure mitigation threshold of 80% of maximum bottom-hole pressure or less, the NPV of the project is, $6,772,461. When the operator begins drilling an offset well at 100% of maximum tolerable bottom-hole pressure (when the injection issue actually occurs), the NPV of the project is $7,233,126, as opposed to $9,207,129 when the operator begins mitigation efforts at 90% of maximum BHP. A 90% threshold makes the operator act in year 8 of the injection phase, while an 80% threshold forces the operator to react in the first year of injection. This result suggests that to the operator’s best ability, delaying mitigation effort adds value to the project in lieu of the fact that an injectivity issue still occurs. This follows the rule of the time value of money where a dollar today is worth more than a dollar tomorrow, though when the operator acts too late at 100% mitigation threshold (when the injection issue occurs), project value is diminished.

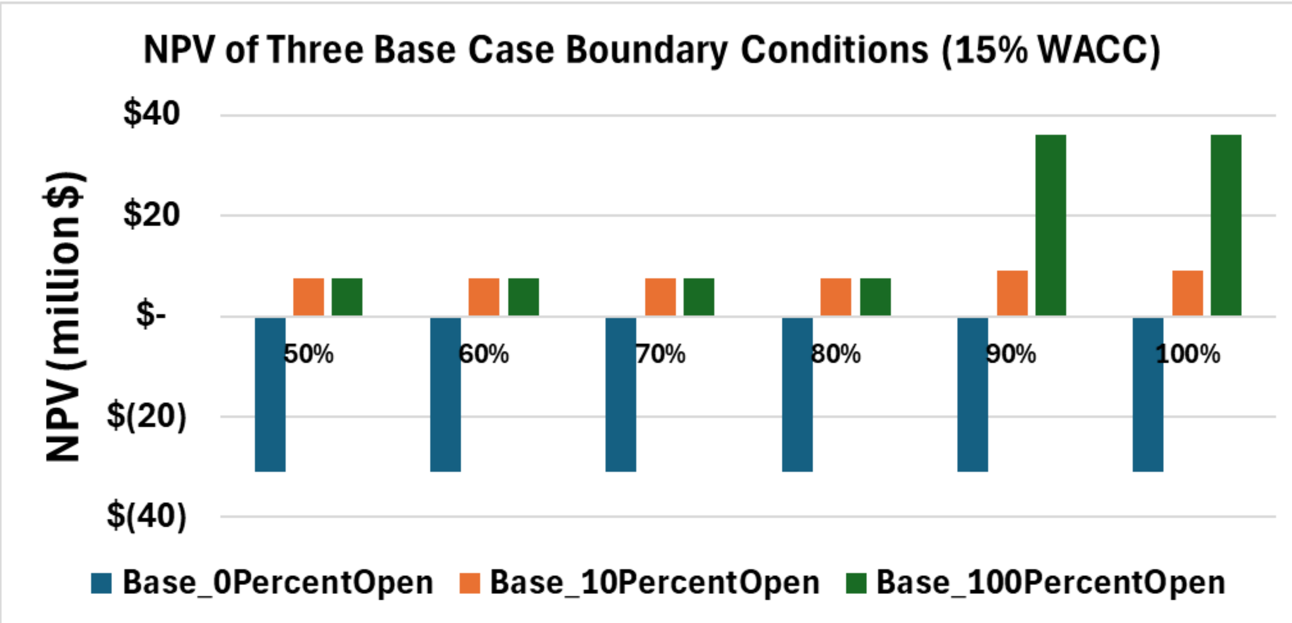

Figure 15: NPV of the distinct base case BHP profiles. X-axis is the bottom-hole pressure threshold i.e., the point where the operator decides to build an offset well, based on the percent of the maximum allowable pressure. An injection issue occurs in year 1, year 8, and never for the 0%, 10%, and 100% open boundary scenarios, respectively.

Figure 15 illustrates the project value change depending on when the operator decides to act as reservoir pressure increases. In the 0% open boundary scenario (closed boundary), the NPV is always negative. Figure 16 below is the base case 10% open boundary scenario's NPV sensitized to both the BHP mitigation threshold and the 45Q tax credit liability. In the base mitigation scenario, I assume it will take the operator two years to get an offset well permitted and ready for operations. In this scenario where the operator waits until an injection issue occurs, the operator faces two years of financial liability for tax credits that were not earned due to failure to inject. In less extreme penalty conditions, where the percentage of the 45Q credit the operator is liable for is small, the

NPV of the project does not vary significantly. If the operator waits until an injection issue (100% mitigation threshold), the value of the project is nearly $8 million less and $5 million less than if they act at 90% or 80% of the maximum BHP, respectively. From the standpoint of the service agreement between the capture source and the injection site operator, understanding the incentives one has to act quickly, or not act quickly, matters greatly an operator when faced with an injectivity issue.

		BHP Mitigation Threshold					
NPV15	$9,207,129	50%	60%	70%	80%	90%	100%
% 45Q Tax Credit Liability	0%	$ 6,772,461	$ 6,772,461	$ 6,772,461	$ 6,772,461	$ 9,207,129	$ 8,775,091
	10%	$ 6,772,461	$ 6,772,461	$ 6,772,461	$ 6,772,461	$ 9,207,129	$ 8,004,108
	20%	$ 6,772,461	$ 6,772,461	$ 6,772,461	$ 6,772,461	$ 9,207,129	$ 7,233,126
	30%	$ 6,772,461	$ 6,772,461	$ 6,772,461	$ 6,772,461	$ 9,207,129	$ 6,462,143
	40%	$ 6,772,461	$ 6,772,461	$ 6,772,461	$ 6,772,461	$ 9,207,129	$ 5,691,160
	50%	$ 6,772,461	$ 6,772,461	$ 6,772,461	$ 6,772,461	$ 9,207,129	$ 4,920,177
	60%	$ 6,772,461	$ 6,772,461	$ 6,772,461	$ 6,772,461	$ 9,207,129	$ 4,149,195
	70%	$ 6,772,461	$ 6,772,461	$ 6,772,461	$ 6,772,461	$ 9,207,129	$ 3,378,212
	80%	$ 6,772,461	$ 6,772,461	$ 6,772,461	$ 6,772,461	$ 9,207,129	$ 2,607,229
	90%	$ 6,772,461	$ 6,772,461	$ 6,772,461	$ 6,772,461	$ 9,207,129	$ 1,836,247
	100%	$ 6,772,461	$ 6,772,461	$ 6,772,461	$ 6,772,461	$ 9,207,129	$ 1,065,264

Figure 16: 2-way sensitivity table comparing the NPV of the 10% open boundary scenario against both the BHP mitigation threshold (x-axis) and % Liability of the 45Q Tax Credit (y-axis).

While BHP profiles that have sharp slopes and cause immediate injection issues is a straightforward case to determine the costs and benefits of mitigation, gradual increases in BHP and the subsequent optimal action taken by the operator to appropriately plan for mitigation is more ambiguous. In Figure 17 below, permit time is plotted against NPV and broken out by the mitigation threshold. In scenarios where permitting time is 0-2 years, it makes economic sense for the operator to wait until BHP reaches 90% or 100% of the maximum allowable pressure. The penalties are limited temporally since an operator can build a backup well without regulatory burden. However, if permitting time takes between 3 and 5 years, it makes sense for the operator to act at 80%, or even below 80%, of the maximum allowable pressure to allow enough time to account for delays while the original well can still inject. Doing so gives enough time for the operator to be granted a permit for the new backup well before the injection issue occurs in the compartmentalized reservoir. In addition to permitting, delays may also include the time it takes to negotiate a new lease and define the area of review for the offset well. There is no improvement in project value acting at less than 80% of the project value when the permit years are 0-2 years. When the permitting timeline is above 2 years, due to

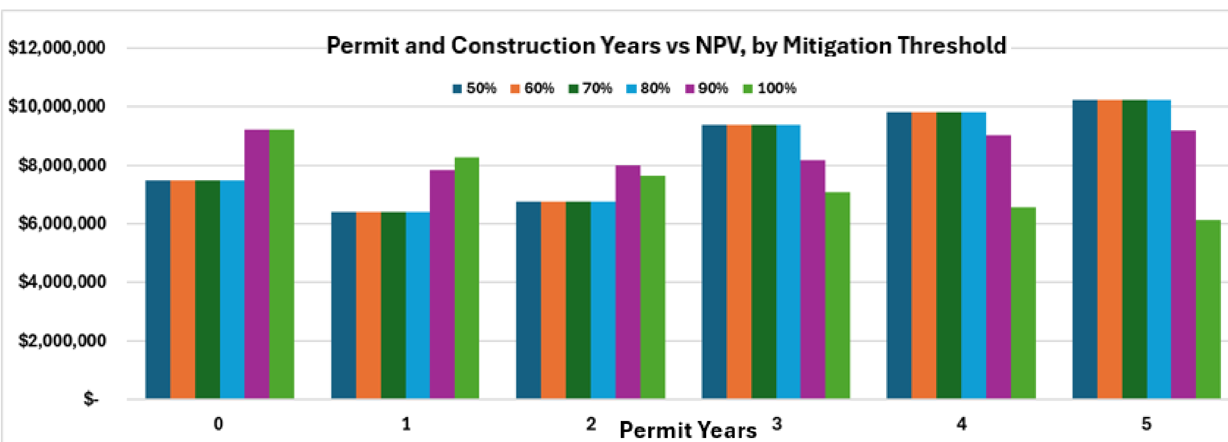

Figure 17: NPV vs. Length of Permit for a New Class VI Well, colored by BHP mitigation threshold. When the time to a permit granted is less than 3 years, the project is more valuable to wait until BHP is closer to the maximum allowable pressure.

additional potential years of financial liability for lost tax credits if the operator acts too late, project value is maximized when the operator reacts at 80% or below of the maximum allowable pressure. This gives the operator more time to account for the additional permit years while continuing to inject in the original well (until it reaches the maximum allowable pressure).

In the permeability sensitivity analysis, it was determined that the 20% open boundary scenario had the widest distribution of the number of years of successful injection, based on the range of values tested. As seen in the figure below, it's only when there is at least 5 years of successful injection at 400 mD, does the project experience a positive NPV. Before that, especially at 100 mD and 200 mD which required 6 and 3 wells, respectively (and 2 for the rest of the scenarios), the cost to build an offset well so quickly after the project commences operations causes steep losses for the project. Given subsurface modeling requires extreme uncertainty, these results will make an operator more risk averse if their prospective reservoir contains highly heterogenous permeability.

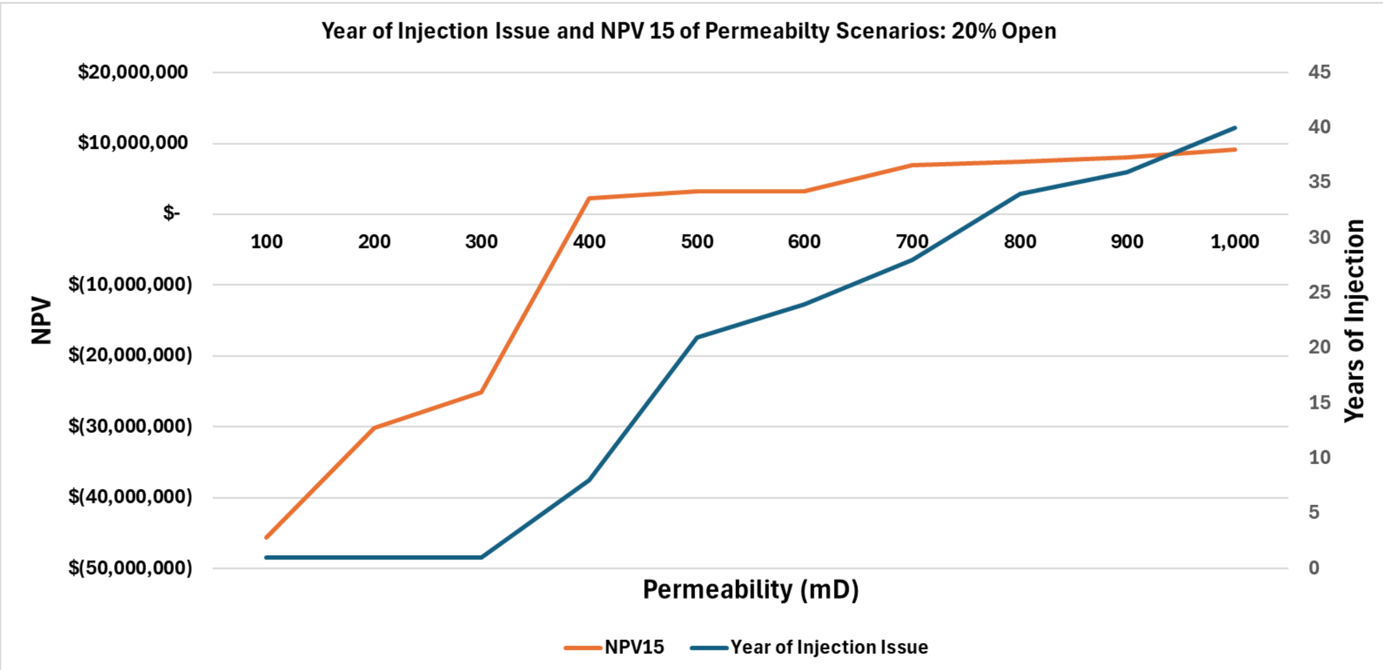

Figure 18: NPV vs. Permeability in the Base Case Scenario, 20% open boundary. 100mD requires 6 wells, 200mD requires 3 wells, and 300-1000mD requires 2 wells. Breakeven economics occur at 400mD with 7 years of injection. NPV15 is the NPV of the project with a 15% discount rate.

4.2.2: CO_2 Price

The base case for CO_2 stored that the operator receives is $15/ton. Outside of the emergency response costs covered by current Class VI bond requirements, it's important to understand the sensitivity of the price needed depending on the financial liability the operator faces due to failure to inject. In most cases, the project is unprofitable in the completely closed compartment conditions (0% open) and profitable with no injection issue at the base price of $15/ton. In the 10% open boundary scenario, where there an injection issue occurs in year 33 of injection operation, the break even price, regardless of the level of liability incurred by the operator for failure to inject is $14/ton. This was tested at 1-5 years of permitting and construction delays, with the result consistently around the same $14 break-even price regardless of delay periods. This confirms the fact that injection issues occurring in the beginning of the project destroys its profitability while costs incurred later in the project (like in the 10% open boundary scenario) are more manageable, as the discount rate and time value of money implies less costs in today's dollars. The operator can spread this discounted cost over the life of the project with no price increase. At complete compartment closure (0% open) where the injection issue occurs in the beginning of the project, the break-even price for an NPV of 0 ranges from $18/ton for no tax credit liability to $43/ton for 100% tax credit liability.

NPV15 @ 5 years of P&C		Liability of the 45Q Tax Credit										
	$9,381,425	0%	10%	20%	30%	40%	50%	60%	70%	80%	90%	100%
CO2 Price (%/ton)	10	$ (17,751,623)	$ (17,826,117)	$ (17,900,612)	$ (17,975,106)	$ (18,049,600)	$ (18,130,167)	$ (18,216,357)	$ (18,306,791)	$ (18,399,457)	$ (18,496,710)	$ (18,593,962)
	11	$ (12,310,115)	$ (12,384,609)	$ (12,459,103)	$ (12,533,597)	$ (12,608,092)	$ (12,683,136)	$ (12,765,858)	$ (12,853,421)	$ (12,943,855)	$ (13,036,050)	$ (13,133,303)
	12	$ (6,868,606)	$ (6,943,100)	$ (7,017,595)	$ (7,092,089)	$ (7,166,583)	$ (7,241,077)	$ (7,318,827)	$ (7,401,549)	$ (7,490,485)	$ (7,580,919)	$ (7,672,643)
	13	$ (1,427,098)	$ (1,501,592)	$ (1,576,086)	$ (1,650,580)	$ (1,725,075)	$ (1,799,569)	$ (1,874,063)	$ (1,954,518)	$ (2,037,240)	$ (2,127,549)	$ (2,217,983)
	14	$ 4,014,411	$ 3,939,917	$ 3,865,422	$ 3,790,928	$ 3,716,434	$ 3,641,940	$ 3,567,445	$ 3,492,513	$ 3,409,791	$ 3,325,822	$ 3,235,388
	15	$ 9,455,919	$ 9,381,425	$ 9,306,931	$ 9,232,437	$ 9,157,942	$ 9,083,448	$ 9,008,954	$ 8,934,460	$ 8,856,822	$ 8,774,100	$ 8,688,758
	16	$ 14,897,428	$ 14,822,934	$ 14,748,439	$ 14,673,945	$ 14,599,451	$ 14,524,957	$ 14,450,462	$ 14,375,968	$ 14,301,474	$ 14,221,131	$ 14,138,409
	17	$ 20,338,936	$ 20,264,442	$ 20,189,948	$ 20,115,454	$ 20,040,959	$ 19,966,465	$ 19,891,971	$ 19,817,477	$ 19,742,982	$ 19,668,162	$ 19,585,440
	18	$ 25,780,445	$ 25,705,951	$ 25,631,456	$ 25,556,962	$ 25,482,468	$ 25,407,974	$ 25,333,479	$ 25,258,985	$ 25,184,491	$ 25,109,996	$ 25,032,471
	19	$ 31,221,953	$ 31,147,459	$ 31,072,965	$ 30,998,471	$ 30,923,976	$ 30,849,482	$ 30,774,988	$ 30,700,493	$ 30,625,999	$ 30,551,505	$ 30,477,011
	20	$ 36,663,462	$ 36,588,968	$ 36,514,473	$ 36,439,979	$ 36,365,485	$ 36,290,990	$ 36,216,496	$ 36,142,002	$ 36,067,508	$ 35,993,013	$ 35,918,519

Figure 19: Percent of the 45Q Tax Credit the Site Operator is Liable for vs. Price of CO_2 Offtake for the 10% open boundary scenario. The break-even price is $14.

4.3 Insurance Considerations

I consider self-insurance mechanisms whereby the operator devotes a portion of cash flow each year to a contingency fund separate from the remedial response financial responsibility. Using the “Goal Seek” functionality in Excel, I dictate the NPV to be $0 and evaluate what additional revenue through self-insurance is needed to cover the liability and cost present in the model. I do this through a separate revenue item that represents only the self-insurance needed. The 10% open boundary scenario that incurs two years of financial liability for failure to inject has a nominal liability is $77,258,822. Total nominal liability for the additional incurred costs of an offset well through the life of the project is $177,858,856. For financial liability only (for failure to inject), the self-insurance amount must be $0.99/ton over the life of the project. However, the present value of the financial liability is $541,734 using a 15% discount rate. The amount needed to yield this present value over the full life of the project is only $0.09 per ton. This assumes the operator incurs the penalty over the two years injection does not occur. This value represents what the operator must collect over the full 40 years of the project to fund this amount of liability when injection must stop in year 33 of the project.

For the full nominal cost of the offset well in addition to the financial liability, the self-insurance price increases to $2.28/ton over the life of the project. In order for the operator to have enough funds set aside for both the cost of the offset well and financial liability when it occurs in year 33 of the project, rather than accounting for the cost of the offset well over the full 40 years, the self insurance must be $1.34/ton.

4.4 Site Parameter Sensitivity Analysis

Project value in carbon sequestration is largely determined by storage capacity (i.e. how much CO_2 can be stored), however, it is important to consider the operational variables that account for project cost as well. Figure 20 below summarizes the net change in project NPV (using a 15% discount rate) when varying each site parameter one at a time. I evaluate the range of NPV values based on best and worst case scenarios for each variable. I evaluate the impact using the 10% open boundary scenario for the CMG simulation base case in Figure 20. Figure 21 reflects the 0% open scenario. The areal extent of the reservoir that dictates area of review (AOR) monitoring requirements has the most effect on a project, with the NPV decreasing by approximately $6.5 million. 250km^2 is approximately the maximum compartment observed in the Gulf Coast prospect used in this study. Stratigraphy wells for site characterization and transport pipelines have

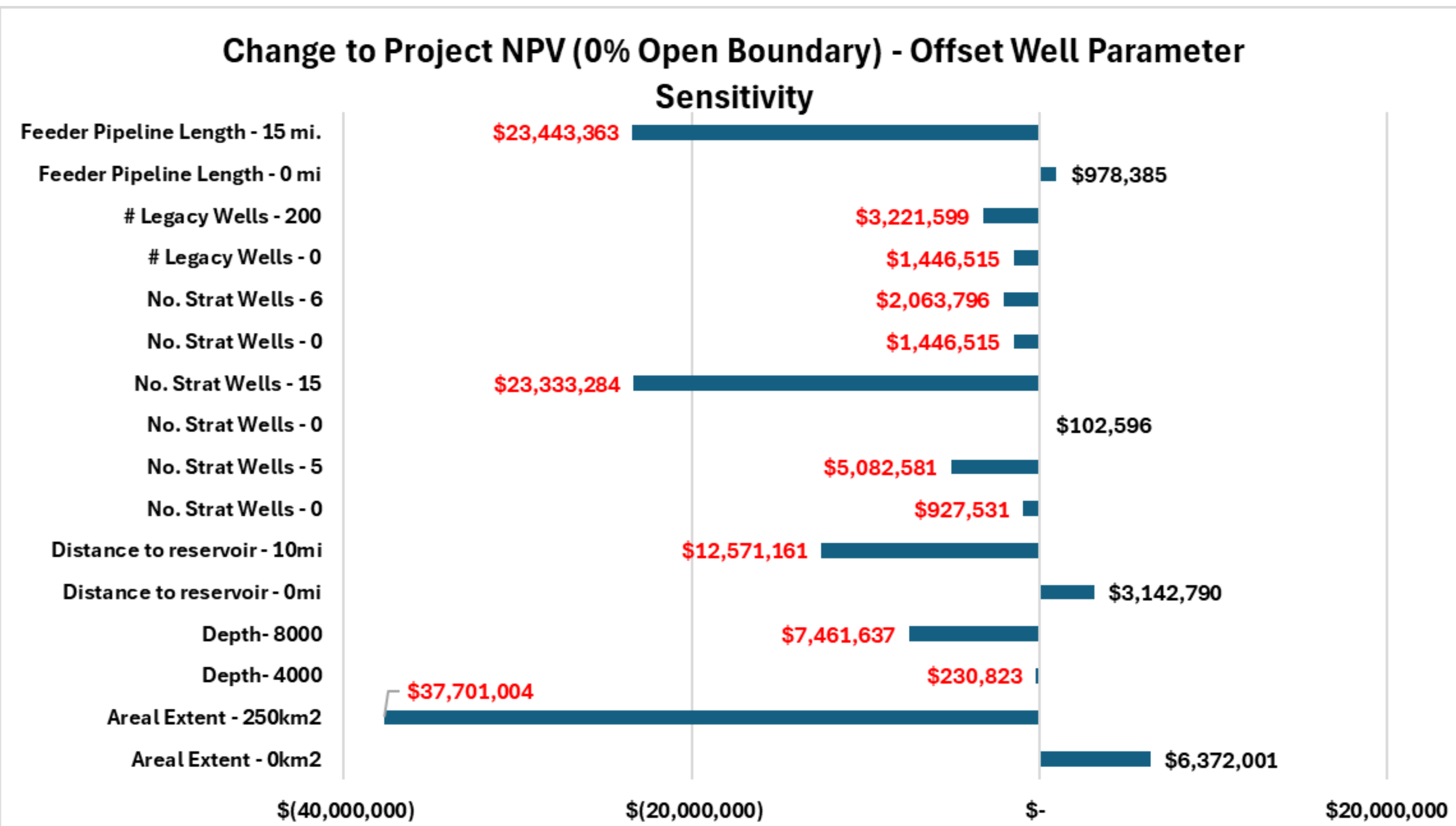

Figure 20: Sensitivity of new well site parameters to NPV. 10% open boundary scenario

the next highest influence on project value. The scenarios where the relocation site has limited transport infrastructure, additional legacy wells to plug or monitoring wells have negligible effects on the base case NPV of $6,772,461. The operator needs to consider these downside risks in their contingency planning based on increase in operational costs given a change to offset well site parameters. The results are similar in the 0% open boundary scenario where compartmentalization occurs in year 1 of injection operations, except each variable has an order of magnitude more impact on the net present value compared to the 10% open boundary scenario where injection occurs in the latter half of the project life.

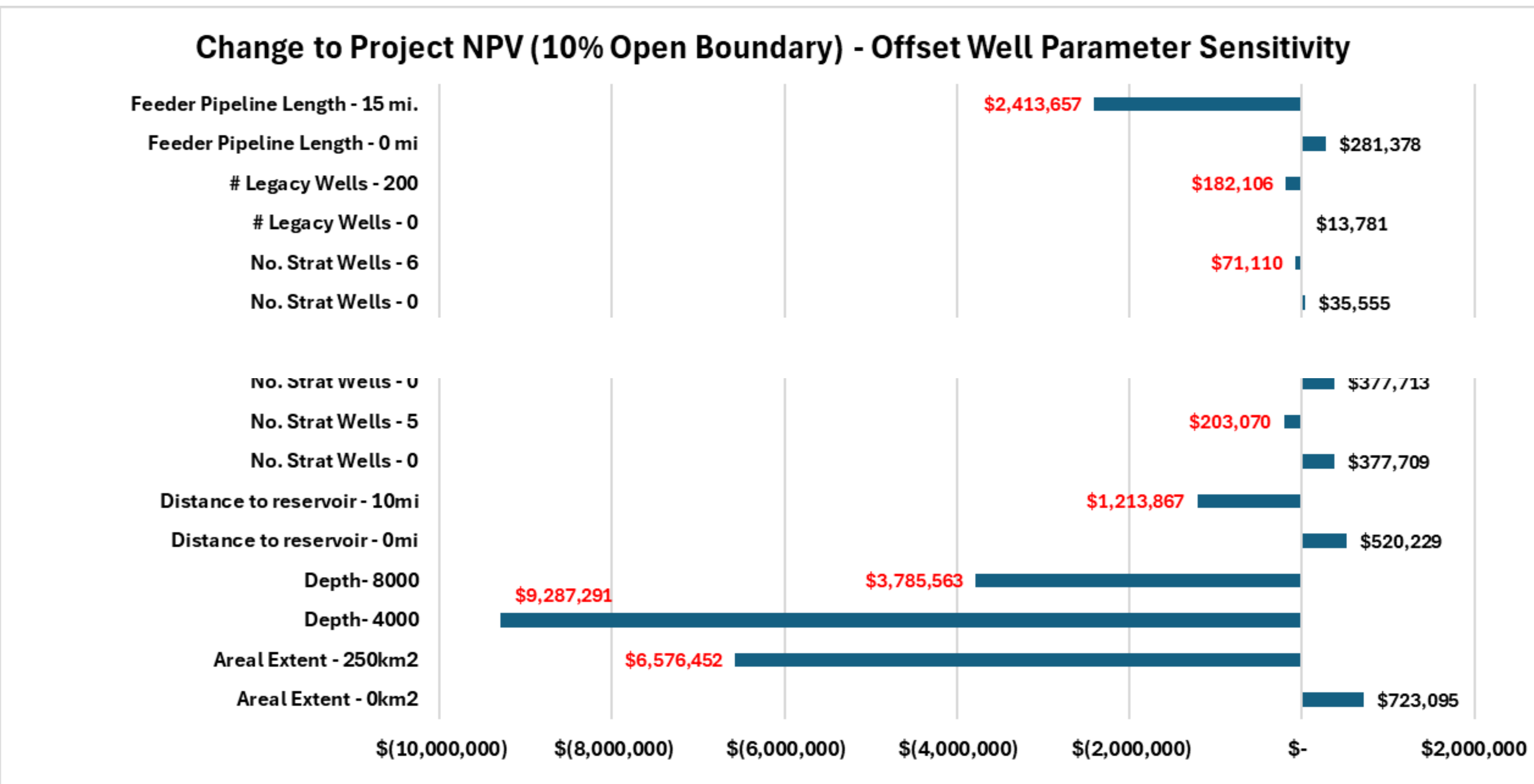

Figure 21: Sensitivity of new well site parameters to NPV. 10% open boundary scenario

4.5 45Q Policy Retirement Results

When considering a policy scenario where the 45Q tax credit expires after 12 years of injection, as currently structured since the passage of the Inflation Reduction Act, any unexpected compartmentalization is going to cause the sequestration project to be unviable due to the limited time the operator can collect tax credit revenue. In the scenario where no injection issue occurs in 12 years of operation, the project remains viable with an NPV of $10,597,263 with a 15% discount rate. The base price of $15/ton for storage leave $70/ton for the capture and transport component. In a closed boundary scenario, where the injection issue occurs in the first year of injection, the NPV is -$45,602,487, assuming 1 year of site characterization and 1 year of permitting and construction and a 10% tax credit financial liability. Eliminating the 1 year of site characterization for an offset well decrases this amount to -$31,131,422 and assuming, hypothetically, no time between the injection issue and operations commencing injection at a new offsite well, the NPV increases to $-20,759,517. The consideration of carbon credits from other sources willing to pay for CO_2 storage notwithstanding, the uncertainty of the 45Q tax credit extension beyond 2033 is something site operators should consider, as the tax credit expiratoin makes or breaks project economics in all scenarios that face injectivity issues in this study.

Under these three conditions, where there is 2 years, 1 year and no years of permitting and construction, the price for CO_2 offtake must be $29.87/ton, $23.82/ton, and $20.88/ton, respectively, for the project to break when an injection issue occurs with only 12 years of 45Q tax credit revenue. At this price, capture and transport costs must break even with $55.13-$64.12/ton. For projects that might experience injectivity issues due to compartmentalization, accounting for this premium due to policy uncertainty needs to be expected.

4.6 Injection Management Results

Based on the injection management results in which both the scenario of injection rate reduction and regular well shut ins were tested, injection could occur for the full 40 years of the project in scenarios that previously faced an injection. The total reduced annual amount of CO_2 contributed to financial penalties each year for failure to inject the full 1.9MT CO_2, however, each scenario still had a positive NPV, using a 10% tax credit liability and 15% discount rate. Table 6 summarizes the results below. The same strategies used at Paradox Valley works for a CCS reservoir constrained by compartmentalization. The NPV was smaller than the base case that had no injection issue of $36,910,986, however, it was positive, indicating that lost revenue and financial liabilty due to the CO_2 not injected due to a well shut-in or inejction rate reduction was not enough to make the project unprofitable. In all scenarios where an offset well was built if the bottom-hole pressure exceeded the mitigation threshold, the NPV was negative. Like Paradox Valley, the operator could continue to adjust the injection rate until pressure cessated rather than build an offset well, but this was not tested in this study. Full financial liability for the lost 45Q tax credits would also make theses injection rate management strategies unprofitable.

Boundary % Open	Injection Strategy	Yearly Injection Rate (tons/yr)	NPV15	IRR	# Tons Forsaken Over 40 Years
10%	Shut off 1 well every 6 months for one month	1,741,666	$27,292,907	22%	6,333,333
10%	Shut off 2 wells every 6 months	1,583,333	$16,821,478	19%	12,666,667
10%	Reduce Injection Rate 30% in 2026 (once BHP is 80% frac. Pressure)	1,330,000	$16,183,476	20%	19,380,000

Table 6: Financial Results of Injection management strategies that allow for a full 40 years of injection when injection was previously an issue due to pressure increases. The base 10% financial liability for failure to inject the full 1.9 MT/yr is used. Injection management strategies are successful with a positive NPV, using a discount rate of 15%.

Chapter 5: Discussions and Conclusions

5.1 Discussion of the Injection and Financial Results

5.1.1 Mitigation threshold considerations

In CCS operations, the reservoir pressure is going to indicate the degree to which CO_2 can be injected into a reservoir. This study shows that when the operator decides to halt injection based on an increase in bottom-hole pressure, the viability of a project is significantly impacted with the need to drill an offset well and incur a financial penalty. Coupled with this, the variables influencing the operational parameters of the offset well and timeline for permitting is uncertain. Knowing these factors ahead of time give an optimal time for an operator to stop injecting based on the reservoir pressure, in order to have enough time to permit a new well. From a policy perspective, compartmentalization, or even the general commoditization of pressure space within a reservoir, requires upfront, detailed analysis to understand the risks before building a site. Even then, the operator will not always know about compartmentalization until injection commences. Liability frameworks and levers that control contingency planning need to be coordinated with the DOE and state governments, as well as insurance companies. Factors such as the permitting and the re-evaluation of the Area of Review, and its impact on project success are important considerations for the EPA, as it seeks to coordinate with the DOE to make the first large CCS investment a success. It is too early to tell how current permits' monitoring plans and AOR reevaluation triggers (based on pressure increase) will perform, but the strong bonding requirements covers most of the operational costs with closing a well that's experienced compartmentalization. Like Paradox Valley and the variety of pressure management strategies used, the industry may need to experiment with what works and what doesn't to CCS for a change in injection rate. Secondary to this is the financial liability, through 45Q, which the industry still has not addressed directly. Based on the liabilities incurred over the life of the project, that may amount to hundreds of millions of dollars in forgone 45Q tax credit revenue due to injectivity issues, insurance companies will need to fill the gap between current bond requirements and an operator's financial liability to fulfill an obligation that would otherwise be too costly for the operator to bear alone. The coordination between the CO_2 capture source and the CO_2 injection site operator in this "pay at the gate" tolling fee model for CO_2 offtake requires its own separate study.

5.2 Insurance and Financial Tools

Current Class VI financial assurance requirements are sufficient for well remediation and post-site care that's incurred by the operator in the event of compartmentalization. It has also been proven that based on the total bond value of $30-$40 million that are in real Class VI permits for financial assurance, a site operator can cover their total mitigation costs using this existing tool without the need to buy more insurance. However, in the case where the site operator is liable for the lost 45Q tax credit revenue, substantial insurance is needed as total present-day costs can be upwards of $100 million.

Self-insurance is shown to be a reasonable tool for operators under scenarios where the operator is not liable for the majority of the 45Q tax credit. Accounting for this contingency as the contract between the site operator and CO_2 capture source is agreed upon will ensure the operator can deal with any compartmentalization that may arise.

5.3 Other Considerations in De-risking CCS Operations

The nature of this study is to understand the financial implications for a single CCS site. However, the aim of the Department of Energy through its billions of dollars devoted to CCS is to create regional hubs that de-risk the nascent industry through transportation and sequestration redundancies. Such redundancies reduce the overall risk of a single carbon capture plant or sequestration site, and enable economies of scale. If developers work together to collaborate under a single framework for CCS offtake, then injectivity risk at one site may not pose as large of a risk. However, as previously discussed, permitting obstructions, pipeline cancellations, and regulatory uncertainties create an environment, especially for first movers, where the vision for CCS hubs will not become a reality in the short-term. Given this consideration, injectivity risk remains the single greatest uncertainty during the operations phase of a CCS project.

Other policy uncertainties also require injectivity risk due to compartmentalization to be taken seriously. If the 45Q tax credit is not extended beyond 12 years, then as proven in this study, projects that may face compartmentalization are not economically viable. Insurance companies are now just looking at CCS projects, so understanding what those companies are comfortable with in terms of risk-taking is not clear. Getting an entire industry, especially those familiar with the geological aspect of CCS, comfortable with the science, technology, and risk in CCS is also an obstacle to broad deployment.

5.4 Future Work

While this study characterized the boundary conditions for a range of scenarios pertinent to the Gulf Coast that faces injectivity risk due to unexpected compartmentalization, more work can be done to validate these results by incorporating more detailed geophysical and geochemical variables in the simulations such as capillary pressure, residual trapping, CO_2 dissolution in brine and complex heterogeneities to simulate a real CCS reservoir. This study uses CMG-GEM which is computationally expensive. Analytical tools have the potential to evolve to help to expediate the sensitivity analysis of all the pertinent variables.

For broader risk assessment, the geophysical factors affecting fault stressors that determines the sealing capacity of a fault and the possible induced seismicity will give a better sense of how compartmentalization affects a reservoir given a site-specific fault environment. Additionally, this study used deterministic simulations, in which boundary condition and reservoir input variables are static for each individual simulation in CMG-GEM, to measure a range of injectivity through scenario analysis. Incorporating further geophysical analysis in faults can help give a statistical representation of the degree and severity of compartmentalization. Such work would allow probabilistic inquiry and decision analysis that can yield an expected value of compartmentalization and financial liability.

From an insurance perspective, policymakers and industry should collaborate to understand how such operational risks should be addressed within a project, as well as between projects where pressure interference in a place like the Gulf Coast is omnipresent. The coordination between the capture source and site operator should also be studied more, as aspects like tax credit revenue sharing, liability and other contractual considerations significantly affect how CCS will be deployed. The insurance industry should become more adept in the intricacies of CCS risk management to provide appropriate coverage to projects. Doing so will enable projects to become bankable and thus deployed at a faster rate.

Appendix A: Injectivity Sensitivities of Boundary Conditions on Pressure-Limited Capacity

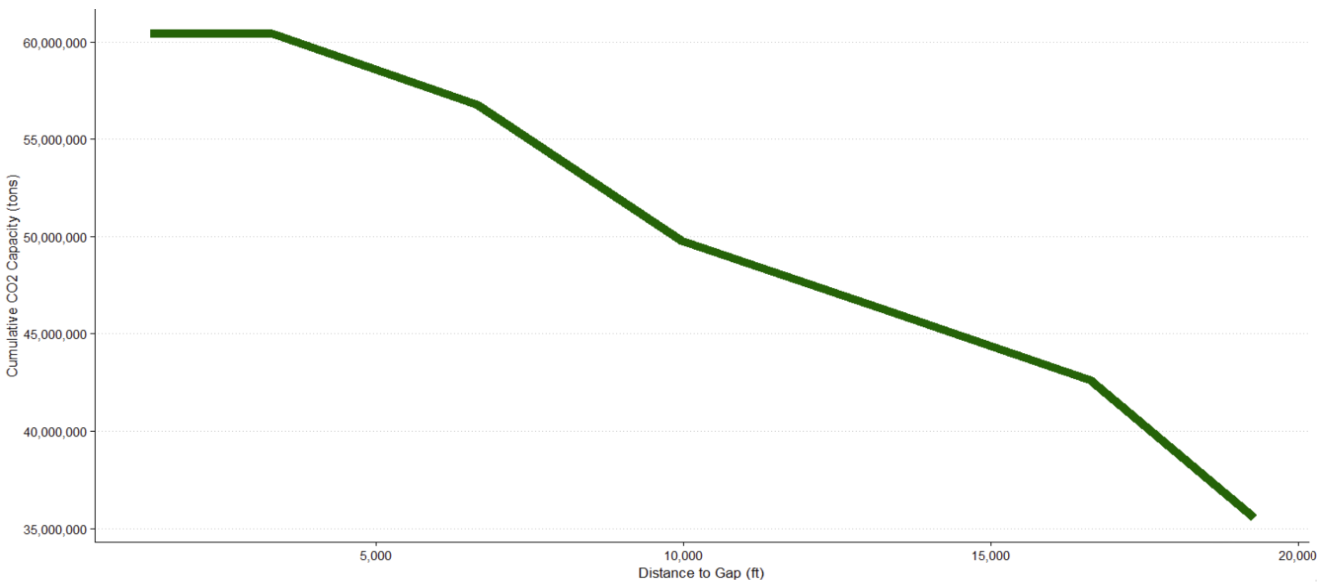

Figure 22: Pressure Limited CO_2 Capacity vs Distance to the Open Gap, 10% open boundary scenarios, as defined by the well location.

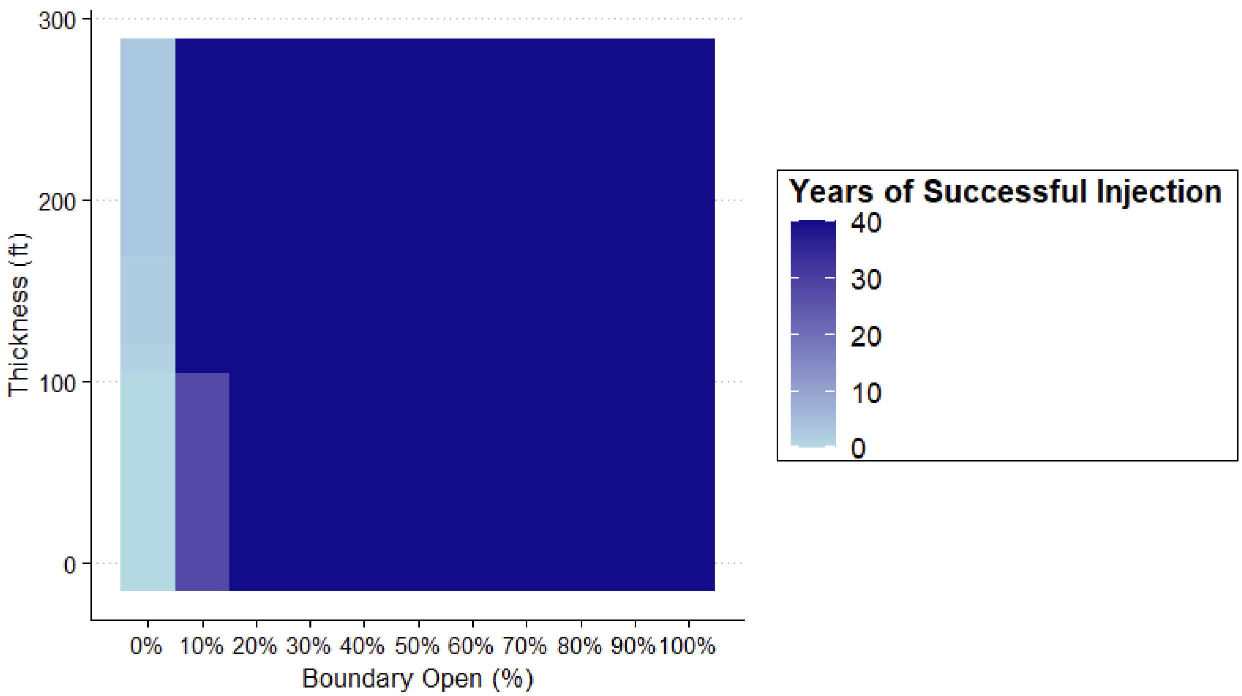

Figure 23: Pressure Limited Injection Period for Thickness Sensitivities vs Boundary Openness for the Base Case Scenario

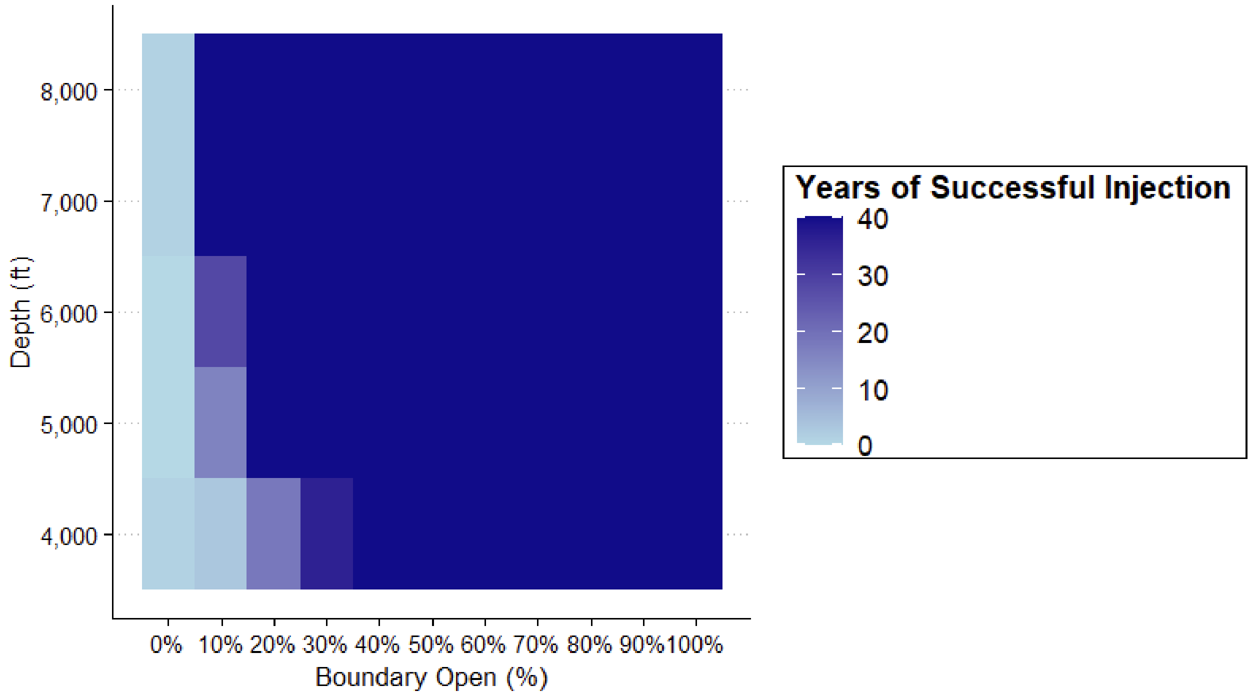

Figure 24: Pressure Limited Injection Period for Injection Depth vs Boundary Openness for the Base Case Scenario

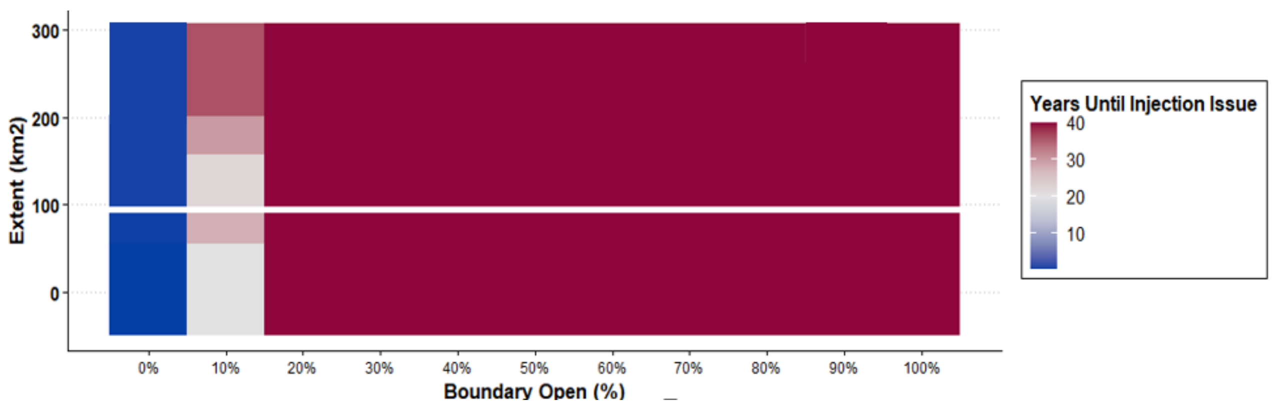

Figure 25: Pressure Limited Injection Period for Injection Depth vs Boundary Openness for the Base Case Scenario

Appendix B: Geological Sensitivities of Boundary Conditions on Saturation Limited Capacity

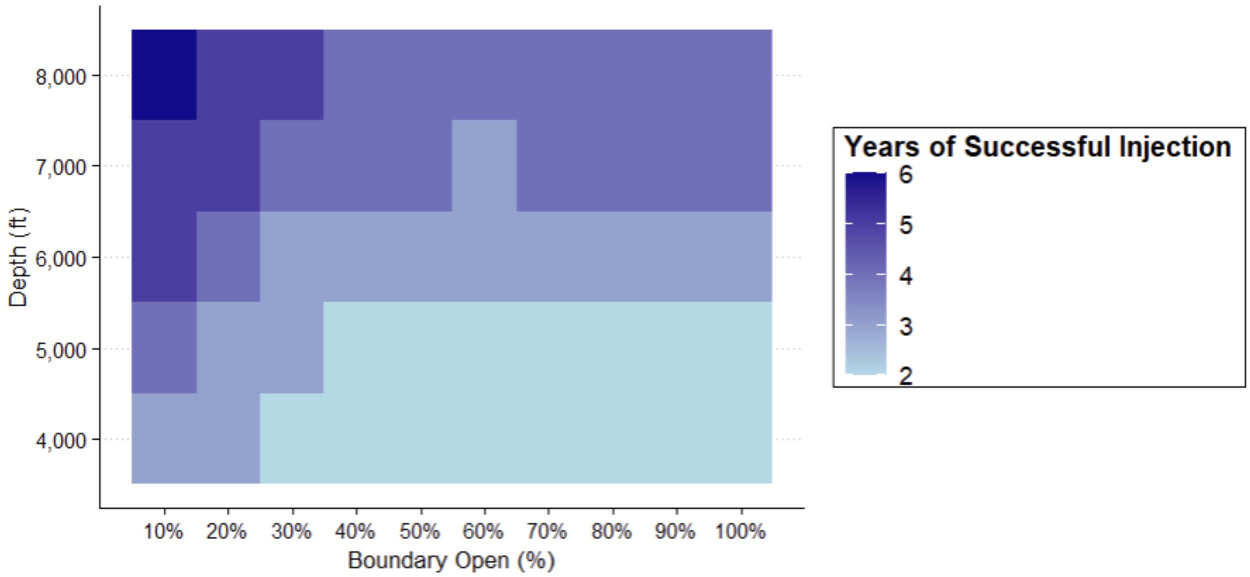

Figure 26: Saturation Limited Injection Period for Depth vs Boundary Openness for the Base Case Scenario

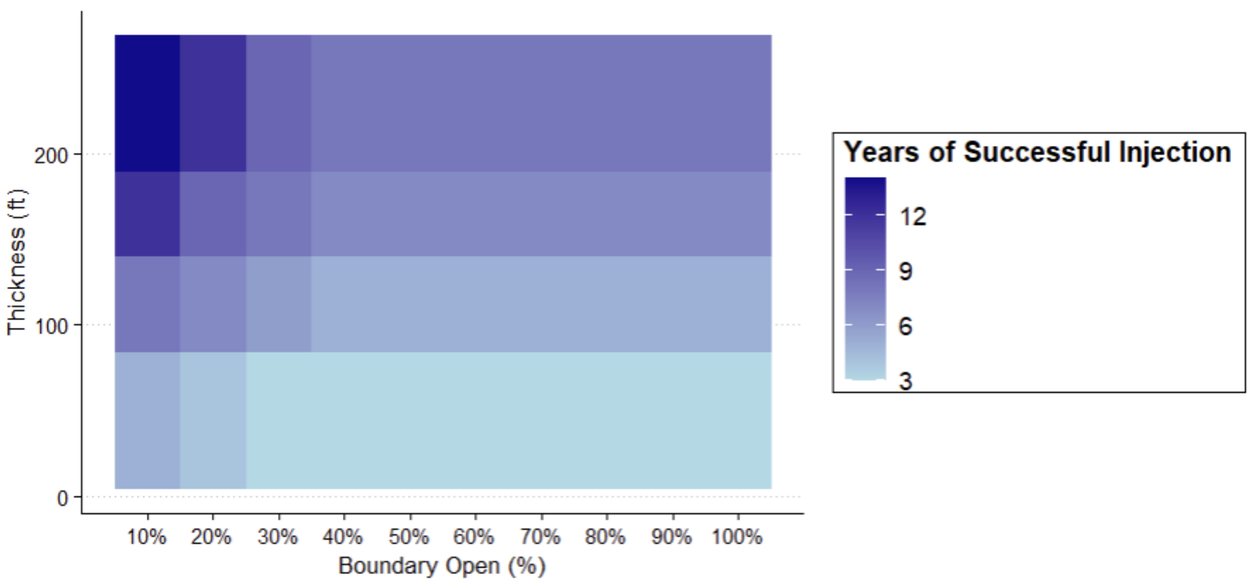

Figure 27: Saturation Limited Injection Period for Formation Thickness vs Boundary Openness for the Base Case Scenario

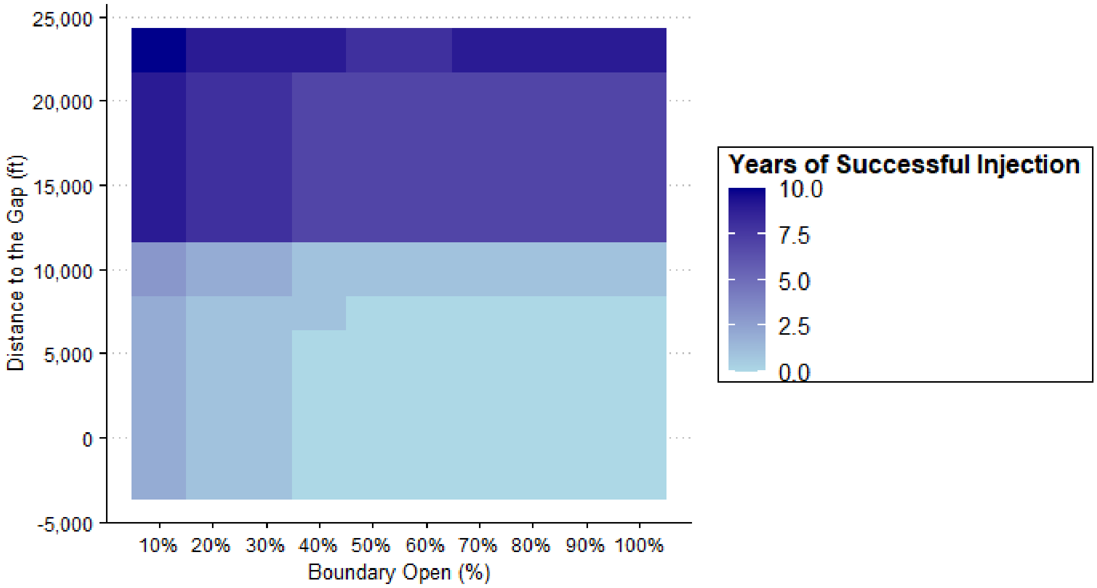

Figure 28: Saturation Limited Injection Period for Distance to the Gap vs Boundary Openness for the Base Case Scenario

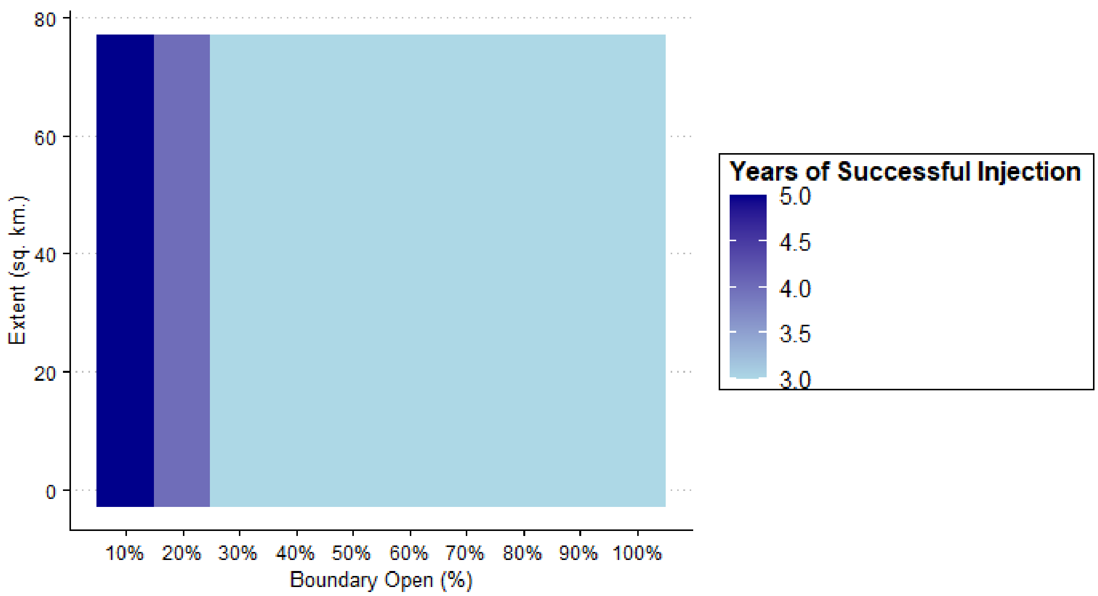

Figure 29: Saturation Limited Injection Period for Areal Extent vs Boundary Openness for the Base Case Scenario

Appendix C: Cost Items

Input			
category	measure	input	
Compartment	Compartment	37extent_100thick_6000depth_15loc_92000000injrate_0percopen	
Mitigation	Mitigation method	Percent BHP	
	Mitigation threshold	100%	
	Max Pressure Override (leave blank if none)		
	Mitigation Scenario	Offset well	
Curtail?		No	
		Start	Backup Well
Compartment	Areal Extent	37	37
	Permeability		
	Depth	6000	6000
	Distance to compartment	3	
	No. Strat Wells	2	2
	Monitoring Wells - In Reservoir	2	2
	Monitoring Wells - Above Seal		
	Monitoring wells - dual completion		
	monitoring wells - groundwater	1	1
	monitroing wells - vadose zone	1	1
	Injection Wells	2	2
	# Legacy Wells	15	15
	Total Injection Rate	1.9	1.9
	Acres	50	40
	Pressure at Injection	2,300	2,300
	Pressure rate start	2200	2200
	Feeder Pipeline Length	2	2
	AOR	46.25	46.25

Figure 30: User Inputs for CMG Scenario to Evaluate, Offset Well Parameters, and Mitigation Threshold. Inputs for the original site and the augmented site with the backup well drive the costs for the project and mitigation efforts.

SCHEDULE								
Year	Input	4	5	6	7	8	9	10
Injection Issue Flag		0	0	0	0	1	1	1
Mitigation Year Start Flag		0	0	0	0	1	1	1
Site Screening	0	0	0	0	0	0	0	0
Site Selection and Characterization	1	0	0	0	0	1	0	0
Permitting and Construction	2	0	0	0	0	0	1	1
Operations	40		0	0	0	0	0	0
PISC	50			0	0	0	0	0

Figure 31: Offset Well Schedule

SITE COSTS		8.00	<<<< mitigation year start (used to move PISC forwards)				0	0	0	0	1
Year	$/unit		Start year	End year	Every X year	Multiplier	4	5	6	7	8
Site Selection and Characterization - CAPEX											
Lease bonus - per land	$	50	2	2	1	9143	-	$ -	$ -	$ -	$ -
2d seismic	$	26,000	2	2	1	10	-	$ -	$ -	$ -	$ -
Aerial Survey	$	11,575	2	4	1	46.25	535,344	$ -	$ -	$ -	$ -
Acquire Existing Data, Modelling and Plann	$	1,522,850	1	6	1		522,850	$ 1,522,850	$ 1,522,850	$ -	$ -
3d Seismic	$	160,000	4	4	1	46.25	400,000	$ -	$ -	$ -	$ -
Acquire /purchase/analyze existing data	$	94,002	1	1	1		-	$ -	$ -	$ -	$ -
Prepare Reports	$	113,064	2	4	1		113,064	$ -	$ -	$ -	$ -
Reservoir Model - Per Site	$	113,022	2	4	1		113,022	$ -	$ -	$ -	$ -
Reservoir Model - Per Well	$	3,664	2	4	1		3,664	$ -	$ -	$ -	$ -
FEED - injection per site	$	207,000	2	4	1		207,000	$ -	$ -	$ -	$ -
FEED - per inj well	$	41,400	2	4	1	2	82,800	$ -	$ -	$ -	$ -
FEED - monitoring per site	$	100,000	2	4	1		100,000	$ -	$ -	$ -	$ -
FEED - surface facilities per site	$	20,700	2	4	1		20,700	$ -	$ -	$ -	$ -
FEED - monitoring wells per well	$	5,200	2	4	1	2	10,400	$ -	$ -	$ -	$ -
Eddy covariance per site plus labor	$	75,160	4	4	1		75,160	$ -	$ -	$ -	$ -
Aerial Survey	$	18,400	2	4	1		18,400	$ -	$ -	$ -	$ -
Strat well	$	2,217,468	2	2	1	2	-	$ -	$ -	$ -	$ -
Preparation of plans for Class VI Permit	$	119,068	2	4	1		119,068	$ -	$ -	$ -	$ -
Site Selection and Characterization - OPEX											
Flux Accumulation Chamber (Gas Samples	$	11,200	2	4	1		11,200	$ -	$ -	$ -	$ -
Total costs for plugging & abandoning wells	$	50,900	4	4	1	2	101,800	$ -	$ -	$ -	$ -
PISC -CAPEX											
Injection well plugging	$	141,839	46	46	1	2	-	$ -	$ -	$ -	$ 283,678
Total costs for VSP monitoring	$	300,000	46	96	5	2	-	$ -	$ -	$ -	$ -
Eddy covariance - per site one time	$	35,000	46	46	1		-	$ -	$ -	$ -	$ 35,000
3d Seismic	$	160,000	46	96	5	46.25	-	$ -	$ -	$ -	$ -

Figure 32: Initial Site Costs (1)

PISC -OPEX							-	$	-	$	-	$	-
MIT Test - in res	$	28,008	46	96	5		-	$	-	$	-	$	-
MIT Test - dual compl	$	28,008	46	96	5	0	-	$	-	$	-	$	-
Eddy covariance - per site	$	10,000	46	96	1		-	$	-	$	-	$	-
Reservoir modelling and analysis - annual	$	25,000	46	96	1		-	$	-	$	-	$	-
Reservoir modelling and analysis - periodic	$	25,000	46	96	5		-	$	-	$	-	$	-
Public Outreach	$	100,000	46	46	1		-	$	-	$	-	$	-
Periodic Reports	$	27,735	46	96	1		-	$	-	$	-	$	-
fluid samples, in res	$	16,000	46	96	1	2	-	$	-	$	-	$	-
fluid samples, dual completion	$	64,000	46	96	1		-	$	-	$	-	$	-
fluid samples, above seal	$	16,000	46	96	1		-	$	-	$	-	$	-
fluid samples, groundwater monitoring	$	7,200	46	96	1	1	-	$	-	$	-	$	-
pressure data, pisc in res	$	600	46	96	1		-	$	-	$	-	$	-
Well Plugging - in res	$	91,600	46	96	1	2	-	$	-	$	-	$	-
well plugging - ab seal	$	71,600	46	96	1	0	-	$	-	$	-	$	-
well plugging - dual comp	$	91,600	46	96	1	0	-	$	-	$	-	$	-
well plugging dual comp	$	2,000	46	96	1	0	-	$	-	$	-	$	-
well plugging-gw	$	700	46	96	1	1	-	$	-	$	-	$	-
well plugging - vad			46	96	1	1	-	$	-	$	-	$	-
O&M in res	$	45,275	46	96	1	2	-	$	-	$	-	$	-
O&M above seal	$	42,485	46	96	1	0	-	$	-	$	-	$	-
O&M dual completion	$	45,275	46	96	1	0	-	$	-	$	-	$	-
O&M groundwater	$	2,000	46	96	1		-	$	-	$	-	$	-
O&M vasadose zsone	$	100	46	96	1		-	$	-	$	-	$	-
Operations - CAPEX													
Drilling Cost - In Res	$	1,427,085	6	7	1	2	-	$	-	$	2,854,170	$	2,854,170
Drilling Cost - Ab Seal	$	1,097,460	6	7	1		-	$	-	$	1,097,460	$	1,097,460
Drilling Cost - Dual completion	$	1,427,085	6	7	1		-	$	-	$	1,427,085	$	1,427,085
Drilling Cost - GW	$	22,912	6	7	1	1	-	$	-	$	22,912	$	22,912
Cost of VSP Characterization - In Res	$	300,000	6	46	1	2	-	$	-	$	600,000	$	600,000
Cost of VSP Characterization - Ab Seal	$	300,000	6	46	1	0	-	$	-	$	-	$	-
Cost of VSP Characterization - Dual comple	$	300,000	6	46	1	0	-	$	-	$	-	$	-
Cost of all coring activities	$	18,100	6	46	1	3	-	$	-	$	54,300	$	54,300
Feeder Pipeline	$	540,000	6	6	1	2	-	$	-	$	1,080,000	$	-
Header	$	200,000	6	6	1		-	$	-	$	200,000	$	-
Distribution Pipes	$	659,340	6	6	1	2	-	$	-	$	1,318,680	$	-
Office/Control systems/Road	$	570,000	6	6	1		-	$	-	$	570,000	$	-
Custody Transfer Guage	$	250,000	6	6	1		-	$	-	$	250,000	$	-
Wireline - revisit (well cnt)	$	46,758	6	46	1		-	$	-	$	46,758	$	46,758
downhole equipment- well cnt	$	10,400	6	46	1	3	-	$	-	$	31,200	$	31,200
3d Seismic	$	160,000	6	46	5	46.25	-	$	-	$	-	$	-

Figure 33: Initial Site Costs (2)

Operations - OPEX									
General O&M	$ 1,113,739	6	46	1		-	$ -	$ 1,113,739	$ 1,113,739
mit testing - well dependent, inj	$ 56,015	6	46	1	2	-	$ -	$ 112,030	$ 112,030
mit testing - well dependent, in res	$ 28,008	6	46	5	2	-	$ -	$ 56,016	$ 56,016
mit testing - well dependent, above seal	$ -	6	46	5		-	$ -	$ -	$ -
mit testing - well dependent, dual completic	$ 28,008	6	46			-	$ -	$ 28,008	$ 28,008
inj o&m	$ 96,875	6	46	1	2	-	$ -	$ 193,750	$ 193,750
in res O&M	$ 45,275	6	46	1	2	-	$ -	$ 90,550	$ 90,550
above seal O&M	$ 42,485	6	46	1	0	-	$ -	$ 42,485	$ 42,485
dual completion O&M	$ 45,275	6	46	1	0	-	$ -	$ 45,275	$ 45,275
groundwater O&M	$ 2,000	6	46	1	1	-	$ -	$ 2,000	$ 2,000
vasadose zone O&M	$ 100	6	46	1	1	-	$ -	$ 100	$ 100
reservoir modeling and analysis	$ 50,000	6	46	1		-	$ -	$ 50,000	$ 50,000
periodic reserovir modeling and analysis	$ 50,000	6	46	5		-	$ -	$ 50,000	$ 50,000
Fall off and corrosion test	$ 25,866	6	46	1		-	$ -	$ 25,866	$ 25,866
Fluid Samples - Per monitroing well in reser	$ 20,800	6	46	1	2	-	$ -	$ 41,600	$ 41,600
Fluid Samples - Per monitroing well dual co	$ 41,600	6	46	1	0	-	$ -	$ -	$ -
Fluid Samples - Per monitroing well ab seal	$ 20,800	6	46	1	0	-	$ -	$ -	$ -
Fluid Samples - Per monitroing well gw well	$ 7,200	6	46	1	1	-	$ -	$ 7,200	$ 7,200
Well Completion - Injection Well	$ 145,313	6	46	1	2	-	$ -	$ 290,626	$ 290,626
Well Completion - In Reservoir	$ 145,313	6	46	1	2	-	$ -	$ 290,626	$ 290,626
Well Completino - Ab Seal	$ -	6	46	1		-	$ -	$ -	$ -
Pressure Boosting O&M	$ 0.1036	6	46	1	485,187	-	$ -	$ 50,265	$ 50,265
Well Completino - Dual Completion	$ 145,313	6	46	1		-	$ -	$ 145,313	$ 145,313
Eddy covariance per site & surface equipm	$ 10,000	6	46	1		-	$ -	$ 10,000	$ 10,000
Transport Pipeline O&M	$ 720,509	6	46	1		-	$ -	$ 720,509	$ 720,509
Corrective Action - Remediating Deep Well	$ 31,200	6	46	5		-	$ -	$ 31,200	$ 31,200
gas sampling	$ 3,200	6	46	1		-	$ -	$ 3,200	$ 3,200
Permitting and Construction - O&M									
Public Outreach	$ 100,000	5	5	1		-	$ 100,000	$ -	$ -
Total Misc. Well Equipment and Completion	$ 189,063	6	6	1		-	$ -	$ 189,063	$ -

Figure 34: Initial Site Costs (3)

Permitting and Construction - CAPEX								
Permits	$ 10,400	5	5	1		-	$ 10,400	$ -
Permits	$ 6,000	5	5	1		-	$ 6,000	$ -
Eddy covariance equipment	$ 35,000	5	5	1		-	$ 35,000	$ -
Pressure Boosting Pump	$ 1,400	6	6	1	69	-	$ -	$ 96,927
Reporting Labor	$ 121,285	5	6	1		-	$ 121,285	$ 121,285
Feeder Pipeline	$ 3,080,000	6	6	1	2	-	$ -	$ 6,160,000
Transport Pipeline	$ 4,413,812	4	6	1	3	,241,436	$ 13,241,436	$ 13,241,436
Pipes to Injection Wells	$ 2,289,600	6	6	1	2	-	$ -	$ 4,579,200
Legacy Well Plugging	$ 25,055	5	6	1	15	-	$ 375,825	$ 375,825
Injection well drilling plans	$ 24,114	5	6	1	2	-	$ 48,228	$ 48,228
MVR plan	$ 97,141	5	6	1		-	$ 97,141	$ 97,141
Wirline logging	$ 46,758	6	6	1	4	-	$ -	$ 187,032
VSP Characterization	$ 300,000	6	6	1	2	-	$ -	$ 600,000
Coring activities	$ 18,100	6	6	1	4	-	$ -	$ 72,400
Well Construction - CAPEX								
Injection Well Drilling, Equipment and Comp	$ 1,616,648	6	6	1	2	-	$ -	$ 3,233,296
Strat Well	$ 1,631,749	6	6	1	2	-	$ -	$ 3,263,498

Figure 35: Initial Site Costs (4)

DISCOUNTED CASH FLOW												
Year	Input Value	Start year	End year	Every X year	Multiplier	4	5	6	7	8	9	10
Cost Escalation	3%					1.092727	1.12550881	1.159274074	1.194052297	1.229873865	1.266770081	1.304773184
CO2 Price Escalation	3%							1	1.03	1.0609	1.092727	1.12550881
Ton/Year	15							1,900,000	1,900,000	1,900,000	1,900,000	1,900,000
Curtail Injection Rate								1,900,000	1,638,637	53,978	17,573	9,328
CO2 Price	15							15	15.45	15.9135	16.390905	16.88263215
Injection Issue Flag						0	0	0	0	1	1	1
Injection Flag - Mitigation Scenario Operations						0	0	0	0	0	0	0
Revenue						-	$ -	$ 28,500,000	$ 29,355,000	$ -	$ -	$ -
Penalty for Failure to Inject (Full 45Q Credit	20%					-	$ -	$ -	$ -	$ 34,267,070	$ 35,295,082	$ 36,353,935
Pore Space Fee	0.25								$ 475,000	$ 475,000	$ 475,000	$ 475,000
General O&M												
OPEX						123,478	$ 112,551	$ 4,161,123	$ 4,060,206	$ 76,375	$ 366,176	$ -
EBITDA						(123,478)	$ (112,551)	$ 24,338,877	$ 24,819,794	$ (34,818,445)	$ (36,136,258)	$ (36,828,935)
Depreciation						851,961	$ 2,568,483	$ 3,728,369	$ 7,078,978	$ 7,567,257	$ 9,463,137	$ 10,525,543
Taxes	0.3					-	$ -	$ 6,183,152	$ 5,322,245	$ -	$ -	$ -
NOPAT						975,439)	$ (2,681,034)	$ 14,427,355	$ 12,418,572	$ (42,385,702)	$ (45,599,395)	$ (47,354,478)
Depreciation						851,961	$ 2,568,483	$ 3,728,369	$ 7,078,978	$ 7,567,257	$ 9,463,137	$ 10,525,543
CAPEX						747,825	$ 17,398,301	$ 50,259,127	$ 7,324,180	$ 28,438,206	$ 15,936,097	$ 1,474,991
FCF						,871,304)	$ (17,510,852)	$ (32,103,403)	$ 12,173,369	$ (63,256,651)	$ (52,072,355)	$ (38,303,926)
WACC	10%											
RESULTS												
NPV	($12,420,532.49)											
IRR	9%											

Figure 36: Final Discounted Cash Flow Model that accounts for financial liability fo failure to inject.

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