U.S. DEPARTMENT OF ENERGY
National Energy Technology Laboratory
OFFICE OF FOSSIL ENERGY

FE/NETL CO_2 Saline Storage Cost Model: Model Description and Baseline Results

July 18, 2014

DOE/NETL-2014/1659

Disclaimer

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The authors wish to acknowledge the excellent guidance, contributions, and cooperation of:

The Carbon Storage Working Group

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Exhibits

Acronyms and Abbreviations

2-D	Two dimensional
3-D	Three dimensional
AoR	Area of review
CO_2	Carbon dioxide
cp	Centipoise
DOE	Department of Energy
EIA	Energy Information Administration
EPA	Environmental Protection Agency
ERR	Emergency and remedial response
FE	Fossil Energy
Gtonne	Giga tonne
IEA GHG	International Energy Agency Greenhouse Gas R&D Programme
IRR_{min}	Minimum acceptable internal rate of return on equity
kg	Kilogram
m	Meter
mD	Milli Darcy
mi	Mile
MPa	Mega Pascal
MRV	Monitoring, Reporting, and Verification
NETL	National Energy Technology Laboratory
NATCARB	National Carbon Storage Interactive Atlas
pH	Negative log (base 10) of the hydrogen ion concentration in water
PISC	Post-injection site care
RCSP	Regional Carbon Sequestration Partnerships
R&D	Research and development
UIC	Underground Injection Control
U.S.	United States
USDW	Underground source of drinking water
USGS	United States Geological Survey

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1 Introduction

The Department of Energy's (DOE) Office of Fossil Energy (FE) National Energy Technology Laboratory (NETL) developed a carbon dioxide (CO_2) saline storage cost model. The model is used to estimate the revenues and costs of CO_2 storage in a saline formation. In this report, the FE/NETL CO_2 Saline Storage Cost Model is described; the assumptions utilized in the Baseline Case, which uses currently available technology, are presented; and results for the Baseline Case are provided. The Baseline Case is intended to provide an estimate of storage costs based on currently available technology.

This report and the analyses described within represent the result of a collaborative effort from a number of individuals within NETL comprising the Carbon Storage Working Group. The Carbon Storage Working Group was assembled by Traci Rodosta, the Technology Manager for the Carbon Storage Program. The individuals in this group are employees from different divisions in NETL or site support contractors that work on storage-related projects. The initial purpose of the group was to provide an internal peer review of the FE/NETL CO_2 Saline Storage Cost Model. The technology manager then asked the group to help develop the assumptions used in the FE/NETL CO_2 Saline Storage Cost Model to estimate storage costs for the Baseline Case.

Exhibit 1 lists the individuals in the Carbon Storage Working Group.

Exhibit 1 Composition of the Carbon Storage Working Group

Name	NETL Division or Contractor Company
Traci Rodosta	Technology Manager, Carbon Storage Program
Bruce Brown	RCSP Program Manager
David Morgan	Office of Program Performance and Benefits
Timothy Grant	Office of Program Performance and Benefits
Brian Strazisar	Office of Research and Development
Grant Bromhal	Office of Research and Development
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David Wildman	Leonardo Technologies, Inc.
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Michael Tennyson	KeyLogic Systems, Inc.
Andrea Poe	Booz Allen Hamilton, Inc.
Christa Court	MRIGlobal
Jeffrey Withum	MRIGlobal
Paul Myles	WorleyParsonsGroup, Inc.
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2 Description of the FE/NETL CO_2 Saline Storage Cost Model

The FE/NETL CO_2 Saline Storage Cost Model is a spreadsheet-based tool that estimates the break-even first-year price or cost of storing CO_2 in a deep saline aquifer from the perspective of the owner of a CO_2 storage site. In order to inject CO_2 into the subsurface for the purpose of storing CO_2 in a saline aquifer, the site owner must comply with regulations developed by the United States (U.S.) Environmental Protection Agency (EPA) for Class VI injection wells under EPA's Underground Injection Control (UIC) Program, which is authorized under the Safe Drinking Water Act. The intent of the Class VI injection well regulations is to protect underground sources of drinking water (USDWs). The site owner must also comply with monitoring and reporting requirements under Subpart RR of the Greenhouse Gas Reporting Rule, which is authorized under the Clean Air Act. The intent of the Subpart RR rule is to quantify and report greenhouse gas emissions (principally CO_2) at saline storage sites. The FE/NETL CO_2 Saline Storage Cost Model includes the cost of complying with these regulations.

The FE/NETL CO_2 Saline Storage Cost Model consists of four modules: a geology module, activity module, financial module, and project management module.

2.1 Geology Module

The geology module is comprised of a database of potential storage formations and algorithms for calculating geology-related variables that influence costs. These variables are the areal extent of the CO_2 plume, the areal extent of elevated pressures in the reservoir resulting from injection and the number of injection wells needed to inject a specified mass of CO_2 each year.

The geology database provides geologic properties for "storage" formations and each storage formation is all or part of a geologic formation. A geologic formation is a continuous layer of rock in the subsurface with similar rock type and depositional environment. Across the areal extent of any geologic formation, its thickness, porosity, permeability, and depth of occurrence will vary. Some geologic formations extend over more than one sedimentary basin; a sedimentary basin may be present in several states. Geologic formations were sub-divided into multiple storage formations such that each storage formation was located within a single state. Geologic formations were also sub-divided into multiple storage formations based on their depth or overall thickness. Some geologic formations are over 1,000 feet thick. Based on discussions with George Koperna of Advanced Resources International, Inc., it was felt that a single CO_2 injection project would not inject CO_2 over more than 1,000 feet. Geologic formations extending over 1,000 feet in thickness were divided into multiple storage formations at different depths reducing the thickness of these storage formations to less 1,000 feet or less. With these refinements, the geologic database consists of 226 storage formations across the lower 48 states. The database contains information on the depth, average thickness, surface area, porosity, permeability, lithology, and depositional environment of each storage formation. The geology database was constructed from NETL's National Carbon Storage Interactive Atlas (NATCARB) database (NETL, 2014) and other publicly available sources. The Class VI injection well regulations are for geologic storage of CO_2 in saline formations. These regulations prohibit injection into USDWs, defined as having total dissolved solids (or salinity) less than 10,000 ppm. All storage formations in the database are believed to satisfy this criterion, although some of the storage formations may have sections where the salinity is less than 10,000 ppm; therefore, those sections of the formation could not be used for CO_2 storage.

One geology-related variable that is important for the cost of saline storage is the extent of the CO_2 plume. In the FE/NETL CO_2 Saline Storage Cost Model, the extent of the CO_2 plume is estimated with the following equation:

$$A_{pl} = \frac{q_{m-CO2} \cdot T_{inj}}{\rho_{CO2} \cdot h \cdot \phi \cdot e_{st}} \quad (Eq. 1)$$

where:

A_{pl}	= CO_2 plume area (m^2)
$q_{m\text{-}CO2}$	= annual average mass rate of CO_2 injection (kg/year)
T_{inj}	= duration of the injection (years)
ρ_{CO2}	= density of CO_2 at reservoir temperature and pressure (kg/m^3)
h	= thickness of formation (m)
ϕ	= porosity
e_{st}	= storage coefficient

The mass rate of injection of CO_2 and duration of injection are design choices, while the thickness and porosity are geologic properties of the storage formation. The density of CO_2 in the reservoir depends on the temperature and pressure in the reservoir. The density of CO_2 is calculated in the model using the Peng-Robinson equation of state for CO_2 (NETL, 2014). The storage coefficient is the fraction of the pore space that is occupied by CO_2. The storage coefficient for each storage formation is taken from a table of site-specific values developed by the International Energy Agency (IEA) Greenhouse Gas (GHG) Research and Development (R&D) Programme (IEA GHG, 2009).

IEA GHG (2009) developed storage coefficients by constructing a set of synthetic storage reservoirs using a reservoir simulation model where each synthetic reservoir was based on a particular rock type, depositional environment, and structural setting. IEA GHG (2009) developed synthetic storage reservoirs for four rock types, up to nine depositional histories and for five structural settings. For a specific rock type and depositional environment, the basic geologic properties for the synthetic reservoir, such as porosity and permeability, were stochastically generated to populate the cells in the reservoir simulation model. Injection of CO_2 into the synthetic reservoir was then simulated and the areal extent of the plume was conservatively determined by fitting an irregular polygon that encompassed the entire plume area. The total pore space within the irregular polygon was determined (i.e., the total pore space is found by multiplying the area of the polygon by the thickness and porosity) and the total volume of CO_2 injected at reservoir conditions was calculated. The storage coefficient was then determined as the volume of CO_2 divided by the total pore space. For a specific rock type, depositional environment and structural setting, multiple realizations of porosity and permeability were stochastically generated and the simulations repeated to generate a distribution of storage coefficients. IEA GHG (2009) reported the 10^{th}, 50^{th}, and 90^{th} values from the cumulative distribution.

IEA GHG (2009) developed storage coefficients for three rock types: clastics or sandstone, limestone, and dolomite. For clastic storage formations, IEA GHG (2009) provided storage coefficients for nine different depositional environments. Three depositional environments were evaluated for limestone storage formations but only one depositional environment was evaluated for a dolomite storage formation. Limestone and dolomite are both carbonates. Some of the storage formations in the geology database are characterized as a carbonate depositional environment without specifying limestone or dolomite. For these storage formations, the storage coefficients associated with limestone depositional environments used. Finally, IEA GHG (2009) provided storage coefficients for each rock type across five different structural settings: dome, anticline, 5-degree incline, 10-degree incline, and flat. After it is injected, CO_2 will rise (because it is buoyant relative to brine) until it encounters the seal formation. The CO_2 will then migrate along the interface with the seal unless it is physically constrained by a barrier. The dome and anticline provide barriers. A dome is like an inverted bowl where the surface of the bowl is the lower surface of the seal formation. An anticline is similar to a dome; however, whereas the axes of a dome are similar in length, one axis of an anticline is longer than the other axis so that an anticline is like an inverted platter or a stretched out dome. CO_2 injected under a dome or anticline will rise to the top of the dome or anticline and gradually force brine out of the dome or anticline through buoyancy. The closure formed by the dome or anticline keeps the buoyant CO_2 from migrating laterally (some lateral migration can occur within an anticline along its long axis). Two of the other three structural settings, 5-degree incline and 10-degree incline represent dipping structural settings with a sealing fault at the up dip end. The flat structural setting has no closure, so buoyant CO_2 will continue to slowly migrate along the interface with the seal formation until other trapping mechanisms (primarily residual saturation, but also solubility trapping and precipitation trapping) prevent further migration.

Because the dome and anticline can physically constrain CO_2, these two structural settings have the highest storage coefficients (dome is highest followed by anticline). The other three structural settings have the lowest storage coefficients and their storage coefficients tend to be similar. To reduce the number of storage coefficients considered in this analysis, the 5-degree incline, 10-degree incline, and flat storage coefficients have been averaged to yield a storage coefficient labelled the "regional dip" storage coefficient.

Equation 1 provides an estimate of the area encompassed by the CO_2 plume, which is referred to in this report as the CO_2 Plume Area (see Exhibit 2). However, there is uncertainty in this areal estimate and the precise location of this area relative to the injection wells. To account for this uncertainty, the CO_2 Plume Area is multiplied by a CO_2 plume uncertainty factor to yield the CO_2 Plume Uncertainty Area:

$$A_{pl-un} = A_{pl} \cdot a_{pl-un} \quad (Eq. 2)$$

where:

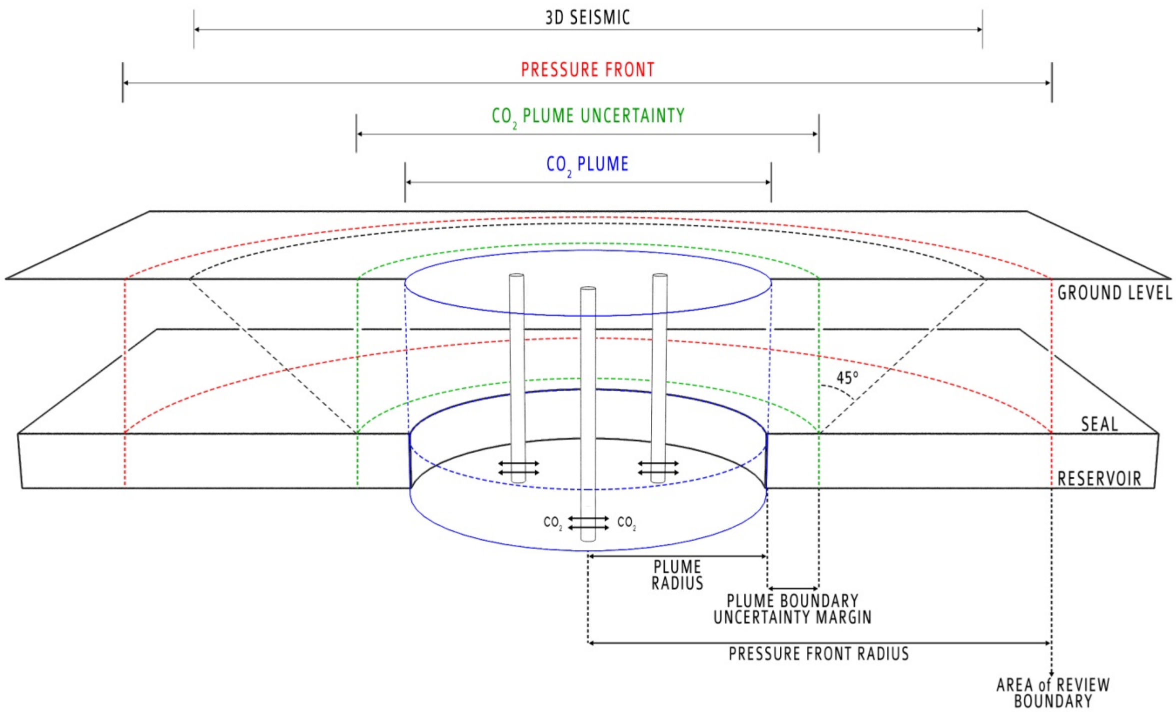
A_{pl-un} = CO_2 Plume Uncertainty Area (m^2)

A_{pl} = CO_2 Plume Area (m^2)

a_{pl-un} = CO_2 Plume Uncertainty factor

The relationship of the CO_2 Plume Area to the CO_2 Plume Uncertainty Area is illustrated in Exhibit 2.

Exhibit 2 CO_2 Plume-related areal quantities



Source: NETL

Another important geology-related quantity is the areal extent of elevated pressures in the storage formation. The Class VI injection well regulations identify two possible reference pressures for determining elevated pressures. One reference pressure is the background or ambient pressure in the storage formation before injection starts. If USDWs above the storage formation have ambient pressures that are higher than the ambient pressures in the storage formation (after the hydrostatic pressure head associated with the distance between the two formations has been taken into account), then the reference pressure is a pressure in the storage formation that will barely enable fluid in an open borehole to flow from the storage formation to the upper formation. It should be noted that if the reference pressure is the ambient pressure, the areal extent of elevated pressures is, in theory, infinite because once injection starts, pressures exceeding ambient pressure should propagate at a fairly rapid rate until, eventually, all locations in the storage formation should have pressures at least slightly higher than the original ambient pressure. In practice, a reference pressure somewhat higher than the ambient pressure will, presumably, have to be determined by the storage site operator and the regulators overseeing the Class VI injection well permitting process during permit negotiations. The areal extent of elevated pressures is very much site specific and investigators have estimated that the area with elevated pressures could be 10 to 100 times greater than the CO_2 Plume Area or more (e.g., Birkholzer et al., 2009). In the model, an areal quantity labelled the Pressure Front Area (see Exhibit 1) is calculated as a multiple of the CO_2 Plume Uncertainty Area:

$$A_{pf} = A_{pl-un} \cdot a_{pf} \quad (Eq. 3)$$

where:

A_{pf}	= Pressure Front Area (m^2)
$A_{pl\text{-}un}$	= CO_2 Plume Uncertainty Area (m^2)
a_{pf}	= Pressure Front multiplier

The Pressure Front Area is used to define the Area of Review (AoR). The AoR is the area of interest in the Class VI injection well permit.

Another geology-related areal quantity determined in the geology module is a quantity relevant to two-dimensional (2-D) and three dimensional (3-D) seismic imaging. It is anticipated that 3-D seismic imaging technologies and, possibly, 2-D seismic imaging technologies will be considered for delineating the CO_2 plume and tracking the plume's evolution over time. When a 3-D seismic monitoring plan is developed, a target area, such as the CO_2 Plume Uncertainty Area, is identified where information is desired. In order for 3-D seismic technology to obtain accurate information for the entire target area, this technology must collect data over a larger area than the target area, an area referred to as the 3-D Seismic Area in Exhibit 1. It is necessary for a 3-D seismic data acquisition program to extend beyond the known or estimated boundary of the subsurface object to be imaged in order to acquire sufficient data to define the subsurface object. Defining the extent of a 3-D survey, it is generally accepted that a line from the edge of the object to be imaged is projected to the surface at an angle of 45 degrees. This angle may be greater or smaller depending on the structural dip of the subsurface strata (Exhibit 1). Two-D seismic data must be collected along a line and, similar to 3-D seismic data, the line must extend beyond the target length such that an imaginary line connecting the end of the line to the outer edge of the target length forms an angle of 45 degrees or more. For this analysis, it was assumed that the length of the 2-D seismic line is the diameter of a circle whose area equals the 3-D Seismic Area.

The number of injection wells needed to inject a specified mass of CO_2 each year is the last geology-related quantity calculated in the geology module. To determine the number of injection wells needed, the mass rate that CO_2 can be injected with one well must be determined. The maximum mass rate of CO_2 injection is the maximum mass rate of CO_2 that the storage formation can sustain from a single injection well or the maximum mass rate that the well tubing can sustain, whichever is smaller. The maximum mass rate of CO_2 that the storage formation can sustain from a single injection well was determined using the Law and Bachu (1996) equation.

$$q_{mwmaxf} = a_{LB} \cdot k \cdot h \cdot (p_{max} - p_{amb}) / \mu_{CO2} \quad (Eq. 4)$$

where:

q_{mwmaxf}	= maximum mass rate of CO_2 flow that formation can sustain from a single injection well (kg/sec)
a_{LB}	= Law and Bachu coefficient, 0.0208 (tonne/day-m-MPa)/(mD/cp)

k	= permeability (mD)
h	= thickness of formation (m)
p_{max}	= maximum bottom hole injection pressure (MPa)
p_{amb}	= ambient pressure in the storage formation (MPa)
μ_{CO2}	= viscosity of CO_2 at reservoir temperature and pressure (cp)

The maximum pressure is set at 90 percent of the fracture pressure, as specified by the regulations for Class VI injection wells. Based on discussions with George Koperna of Advanced Resources International, Inc. in 2011, it was estimated that the maximum flow rate in a typical injection well is about 3,660 tonnes/day or about 1.1 million tonnes per year if the well operates, on average, at about 80 percent of its maximum flow rate.

For a storage formation with good permeability and thickness, such as the Mount Simon 3 in Illinois ($k = 125$ mD, $h = 300$ m), q_{mwmaxf} is 15,600 tonnes/day of CO_2. For this formation, the maximum mass flow rate in the well is limited by the well constraint of 3,660 tonnes/day. For the Rose Run 3 storage formation in Pennsylvania, which has less favorable permeability and thickness ($k = 3.0$ mD, $h = 98$ m), q_{mwmaxf} is 360 tonnes/day of CO_2. For this formation, the maximum mass flow rate in the well is limited by the flow the formation can sustain of 360 tonnes/day.

The number of active injection wells needed for an injection project is the maximum design mass rate of CO_2 injection divided by the maximum mass rate of injection by a single well rounded up to the nearest integer. Because the site operator will need to take injection wells offline periodically for testing and maintenance, this number was multiplied by 1.1 and rounded up to the nearest integer to give the total number of injection wells needed for the project.

2.2 Activity Module

The activity module provides equations for calculating the cost of executing a variety of activities at the storage site at various times during the life of the CO_2 storage project. At the simplest level, the equations are unit costs multiplied by the number of units. The activities cover all aspects of CO_2 storage, including the major categories of regional evaluation and initial site selection, site characterization, permitting, operation of the site during injection of CO_2, and post-injection site care (PISC) and site closure.

It should be noted that once the site is given a finding of “non-endangerment” by the applicable regulatory authority (U.S. EPA or state, if they have primacy), PISC ends and the site undergoes closure. The period after site closure is referred to as “long term stewardship” in the FE/NETL CO_2 Saline Storage Cost Model. Long-term stewardship is outside the scope of Class VI regulations. In the model, it is assumed that there are no additional costs incurred by the storage site operator once the site is closed. The model assumes that the state sets up a trust fund to cover the costs of long term stewardship and provides for payment into this trust fund by the storage site operator during storage operations. Some states have enacted legislation regarding long-term stewardship and in the model it is assumed that any costs incurred during long term stewardship are borne by the trust fund managed by the state.

The activity module has over 500 discrete activities. The types of activities included in the module are described below.

- During regional evaluation and initial site selection, the owner obtains available data for candidate storage sites and picks one for site characterization.
- During site characterization, the owner hopes to fully characterize the first site selected and submit it for permitting. However, a number of potential storage sites may be characterized to some level of detail before it is realized that a particular site will not meet storage expectations. The successfully characterized site will have one or more stratigraphic wells drilled and sampled (wireline logs, cores, fluid samples, VSP) to provide data on the reservoir, seal(s), and overlying stratigraphic section. Additional seismic data is acquired, 3-D or 2-D. Detailed reservoir modeling is done to assess the reservoir's ability to receive and retain the injected CO_2. This modeling will also be used to determine the areal extent of the CO_2 plume and associated pressure front which in turn establishes the AoR. Within the AoR, all older wellbores penetrating the seal and reservoir need to be identified and assessed as to whether or not they were properly plugged and abandoned. The AoR also determines the extent for monitoring the storage operations. Based on this work, surface facilities as well as the number of injection and monitoring wells are selected and designed. All of this data and modeling are presented upon permit application in five plans: AoR and Corrective Action Plan, Testing and Monitoring Plan, Injection Well Plugging Plan, Post-Injection Site Care and Site Closure Plan, and Emergency and Remedial Response Plan (ERR). Financial instruments that will fulfill financial responsibility requirements are secured during this time because a demonstration of financial responsibility is required upon application for a Class VI permit. Class VI regulations are tied to the injection well and injected CO_2 but none of this will occur unless the owner has secured, most likely by leasing, the land-use rights and pore-space rights from property owners over the entire areal extent of the modeled CO_2 plume plus extra area to account for uncertainty. This information is also used to develop the Monitoring, Reporting, and Verification (MRV) Plan that needs to be submitted as part of the requirements for Subpart RR.
- Permitting is a two-step process. The owner submits to the applicable regulatory agency a permit application (with the appropriate plans) for installing and operating a well to inject CO_2. Each CO_2 injection well requires its own permit although several Class VI wells can have a common Area of Review. Once the permit is approved, the owner drills and completes the injection well. Wireline logging, core, fluid sample, and wellbore seismic data are acquired from this new well and incorporated in the five submitted plans to confirm the work submitted for the permit. If no major revisions in the plans are indicated by the new data, then injection of CO_2 is authorized. Major revisions will require re-opening the permitting process. Once injection begins, the owner has 180 days to develop and submit the MRV Plan for Subpart RR compliance. It is assumed that injection does not begin until all CO_2 injection wells have obtained their Class VI permits.
- During the operational stage, CO_2 is injected, the injection wells are periodically tested to ensure they are not leaking, the progress of the CO_2 plume and pressure front is measured and modeled, and formations overlying the seal formation are monitored to ensure that there are no leaks. Monitoring is assumed to occur in the storage formation, in formations overlying the seal formation, in the groundwater above the plume that is used as a source of drinking water, in the vadose zone, and in the air above the plume. As the CO_2 plume

and pressure front advance, abandoned wells that need corrective action are addressed and additional monitoring wells are drilled and completed per the monitoring and testing plan. At the conclusion of operations, the injection wells are plugged.

- During PISC, the CO_2 plume continues to be monitored until pressures in the storage formation return to the reference pressure, the CO_2 plume stops moving and non-endangerment can be established. Throughout PISC, monitoring is assumed to occur in the storage formation, in formations overlying the seal formation, in the groundwater above the plume that is used as a source of drinking water, in the vadose zone, and in the air above the plume. At the conclusion of PISC, monitoring wells are plugged and all other monitoring equipment removed.

The costs of each activity are placed in the years when the costs are expected to occur so that cash flows of costs for each activity can be determined. The cost of each activity is also classified as an operational cost (expense) or capital cost. All activity costs are calculated in real or constant 2008 dollars. The capital costs are divided into three categories for the purpose of depreciation: 1) site characterization and development, 2) seismic costs, and 3) well installation and development costs. These categories were developed to be consistent with guidelines from the Internal Revenue Service (IRS) for depreciation (IRS, 2014). Cash flows for total expenses, total capital costs in each of the three categories and total capital costs for all categories are calculated in the activity module, all in constant 2008 dollars.

2.3 Financial Module

The financial module calculates a variety of cash flows with the objective of calculating the present value of cash that investors in the storage project will earn or lose.

- The cash flow for revenue is the price of storing CO_2 in dollars per tonne multiplied by the mass of CO_2 stored each year. The price for storing CO_2 and the associated revenues are first calculated in real or constant 2008 dollars and then escalated to nominal dollars in future years.
- Cash flows for total expenses, total capital costs for the three categories discussed previously and total capital costs for the three categories are retrieved from the activity module in real dollars. These cash flows are escalated to generate cash flows in nominal dollars.
- Depreciation schedules are generated for each of the three categories of capital costs consistent with IRS guidance (IRS, 2014). For site characterization and development capital costs, the 150% declining balance method is used with a 15 year depreciation recovery period. For seismic capital costs, the straight line method is used with a 5 year depreciation recovery period. For well installation and development capital costs, the 200% declining balance method is used with a 5 year depreciation recovery period. The depreciation schedules are in nominal dollars.
- The costs of complying with the financial responsibility requirements of the Class VI injection well regulations are determined. There are four aspects to financial responsibility: corrective action, injection well plugging, PISC and site closure, and ERR. Long term stewardship, which begins when the site is closed, is outside the scope of Class VI regulations and is not one of the aspects covered by financial responsibility. The

costs of the first three aspects of financial responsibility (corrective action, injection well plugging, and PISC and site closure) will be incurred at every CO_2 storage site and are calculated explicitly in the activity module. Costs for ERR are very uncertain as these costs are incurred only if leaks of CO_2 or brine are detected and a CO_2 storage site will, hopefully, not have any leaks that need to be addressed. ERR can involve repairing undiscovered leaking abandoned wells, repairing leaks observed in the seal formation (if possible) and addressing impacted groundwater, if detected. Because ERR costs are difficult to estimate, they are not calculated explicitly in the model. Instead the storage site operator is assumed to purchase an insurance policy and the insurance covers ERR costs if a leak occurs. This is described in more detail later in the report. In the Class VI injection well regulations, the storage site operator must demonstrate to the regulatory authority that they have financial instruments in place to cover the costs of these four aspects if the owner fails to fulfill their regulatory requirements. The regulations allow a variety of financial instruments to be used to demonstrate compliance with the financial responsibility requirements. The FE/NETL CO_2 Saline Storage Cost Model includes the following financial instruments identified in the Class VI injection well regulations: self-insurance, trust fund, letter of credit, surety bond, escrow account, and insurance. The Class VI injection well regulations also allow the permit applicant to propose other financial instruments that the regulatory authority can consider. The FE/NETL CO_2 Saline Storage Cost Model currently includes two financial instruments in this "other" category: a modified trust fund or a modified escrow account. The financial instruments selected for the Baseline Case are discussed in more detail in a later section. The cash flows of costs associated with implementing the selected financial responsibility instruments are calculated in the financial module in nominal dollars.

- The amount of money that is to be raised using debt to fund the CO_2 storage project is then determined. First, the user specifies the fraction of financing that they desire using debt or, more realistically, the fraction of financing they believe can be raised using debt. Second, the cash flows for expenses, capital, and the costs associated with financial responsibility instruments (such as trust funds) are summed and subtracted from the revenue from storing CO_2 to yield a net cash flow in nominal dollars. The net cash value in each year, if negative, indicates the need for financing. In each year with negative cash values, the absolute value of the cash value is multiplied by the fraction of financing coming from debt to determine the funds from debt that are needed each year. Third, the interest that must be paid each year on the debt is determined. Finally, payments each year on the debt principal are calculated. In the FE/NETL CO_2 Saline Storage Cost Model, the debt principal is assumed to be paid off as quickly as possible using any funds remaining after expenses, capital costs, the costs associated with financial responsibility instruments, interest on the debt and taxes are paid. All these calculations are done using nominal dollars.

- The taxes paid on earnings are then calculated. The tax-based earnings in each year are revenues minus expenses, depreciation, interest on debt, and any carryover losses from previous years. Taxes are only paid in years when tax-based earnings are positive. These calculations are done using nominal dollars.

- The cash flow to or from the owners of the carbon storage project are determined. This is accomplished by summing all sources of cash in a given year and subtracting uses of cash. Sources of cash include revenue from storing CO_2, debt principal received, and cash withdrawals from the applicable financial responsibility instruments[1] (such as trust funds) to pay for relevant costs for corrective action, injection well plugging, or PISC and site closure. Uses of cash include expenses, capital costs, costs associated with financial responsibility instruments, interest on the debt, payments on the debt principal, and taxes. When sources of cash exceed uses of cash, the owners receive cash from the project. When sources of cash are less than uses of cash, the owners must invest money into the project. These calculations are done using nominal dollars.

- The cash flow to owners is then discounted to generate a cash flow in discounted dollars. The discount rate is the lowest internal rate of return on their investment or equity that the owners are willing to accept for investing in the storage project. This is referred to as the cost of equity or the minimum internal rate of return on equity (IRR_{min}) in the financial module. The values in the discounted cash flow are summed to yield the net present value of the project for the owners. If the net present value is positive, the returns to the owners exceed the IRR_{min} and the storage project is, presumably, a good investment. If the net present value is negative, the returns to the owners are below the IRR_{min} and the storage project is not a good investment. As discussed in the next section, a macro is provided that will iterate on the first-year price of CO_2 to determine a price where the net present value of the returns on equity are zero. This price is referred to as the break-even first-year price of CO_2.

2.4 Project Management Module

The project management module is a sheet within the Excel spreadsheet file that provides the main interface with the user. The key inputs are specified here and key outputs are summarized for the user. After all inputs have been specified, the FE/NETL CO_2 Saline Storage Cost Model can be executed in three different modes. In the first mode, the user can specify a first-year price for storing CO_2 (in 2008 dollars per tonne of CO_2), and the model will then calculate the net present value of cash to owners and an internal rate of return. If the net present value is positive, the internal rate of return should exceed the IRR_{min} specified in the inputs, and the project is presumably a good investment for the owners. If the net present value is negative, the internal rate of return should be less than the IRR_{min} and the project is presumably not a good investment. When the net present value is zero, the project just meets the IRR_{min}. The first-year price of CO_2 that yields a net present value of zero is referred to as the break-even first-year price for storing CO_2. Since this price represents the cost to a generator of CO_2, it is also referred to as the break-even first-year cost for storing CO_2.

The break-even first-year price or cost for storing CO_2 is an important financial benchmark for a storage formation. As such, the FE/NETL CO_2 Saline Storage Cost Model has an Excel macro procedure that will find the break-even first-year price or cost for storing CO_2 in a storage formation. Executing the macro to determine the break-even first-year price for storing CO_2 represents the second mode for operating the model.

[1] When a covered task requiring financial responsibility is completed, the financial instrument covering that particular task is released and no longer needed. If the financial instrument is a trust fund or escrow account, these funds are returned to the owner/operator which essentially reimburses the owner/operator for their expense (EPA 2011). In the cost model, these funds directly pay for the covered task.

The FE/NETL CO_2 Saline Storage Cost Model has an Excel macro that executes the model for all storage formations in the geologic database and all three structural settings for each formation to generate a break-even first-year price of CO_2 for each storage formation-structural setting combination. The model also computes the maximum mass of CO_2 that can theoretically be stored in each storage formation-structural setting combination. The break-even first-year price for storing CO_2 for all storage formation-structural settings can then be ranked from lowest to highest price and this data can be used to generate a cost-supply curve, where cost is the break-even first-year price for storing CO_2. Executing the macro that determine the break-even first-year price for storing CO_2 for all storage formations in the geologic database and all three structural settings for each formation represents the third mode for operating the model.

3 Inputs to the FE/NETL CO_2 Saline Storage Cost Model for the Baseline Case

This section presents the inputs for the Baseline Case, which is intended to provide an estimate of storage costs based on currently available technology.

3.1 Basic Design Choices

The following are important design choices.

- It was assumed that 3.2 million tonnes of CO_2 is injected each year for 30 years. This is equivalent to 8,770 tonnes of CO_2 being injected each day on average, with a maximum of 10,960 tonnes injected on any given day assuming a capacity factor of 80 percent. These values were developed to be consistent with the power plant designs developed by NETL in their baseline power plant cost studies (NETL, 2013). More specifically, a subcritical, pulverized coal power plant with a net capacity of 420 MW that operates at an 80 percent capacity factor and captures 90 percent of the CO_2 generated would capture about 3.2 million tonnes of CO_2 each year.
- The start year for the injection project is 2011 to be consistent with costs in NETL's power plant baseline studies (NETL, 2012). This is the year when the injection project begins (i.e., the year when the project operator begins the first phase of the project, regional evaluation and initial site selection), not the year when injection begins.

3.2 CO_2 Plume Parameters

The following are parameters associated with the CO_2 plume and pressure front.

- The 50th or median values of the IEA GHG (2009) site-specific storage coefficients were used.
- The CO_2 plume uncertainty factor was assumed to be 1.75 to account for uncertainty in both the areal extent of the CO_2 plume and the location of the CO_2 plume relative to the injection wells. As an indication of the uncertainty in the areal extent of the CO_2 plume, the CO_2 plume area calculated using the 10th percentile storage coefficient is typically 10 to 30 percent higher than the CO_2 plume area calculated using the 50th percentile storage coefficient. Using these percentages alone, the CO_2 plume uncertainty factor would be 1.1 to 1.3. To also account for uncertainty in the location of the CO_2 plume relative to the injection wells, the CO_2 plume uncertainty factor was increased to 1.75.

- The pressure front multiplier was assumed to be 10.
- There is little information on the relative prevalence of various structural settings, such as dome, anticline, and regional dip. A paper for the United States Geological Survey (USGS) examined one geologic formation and they estimated that approximately 2.5 percent of the formation had structural closure, such as that provided by a dome or anticline (Brennan, et al., 2010). For this evaluation, it was assumed that for each storage formation, 1.25 percent of the formation surface is dome, 1.25 percent of the formation surface is anticline, and the remainder (97.5 percent) is regional dip.
- From a physical standpoint, an injection project could encompass an entire storage formation. On a practical level, anthropogenic factors will limit the size of a project. The owner of an injection project will have to obtain pore space rights and surface access leases to a continuous, connected property. Depending on the attitude of property owners and state laws about unitization, there will be limits on how much continuous property an injection project owner can acquire rights over. Unitization is the process of getting property owners to agree on allowing a subsurface project to go forward. In many states, it is not necessary for all property owners to concur for a project to go forward, although the number that must concur varies by state. In addition, densely populated municipalities may not allow injection operations under parts or all of their land. Also, Federal and/or state laws may prohibit injection under large lakes (for example, oil and gas operations are banned in and under the U.S. waters of the Great Lakes), large rivers, parks, forests, and wilderness areas. At this time, the anthropogenic limits on the size of an injection project are not known. To account for this eventuality, the CO_2 Plume Uncertainty Area was constrained to be no larger than 100 mi^2. It was also assumed that the dome and anticline storage coefficients can be applied to areas that generate a CO_2 Plume Uncertainty Area as large as 100 mi^2.
- It is unlikely that the entire areal extent of a storage formation will be utilized for storage. As discussed above, states and municipalities are likely to prohibit injection under portions of a storage formation. In addition, for most formations, a single injection project will cause pressures to be elevated over an area greater than the CO_2 Plume Uncertainty Area (i.e., the Pressure Front Area). Multiple injection projects that are simultaneously injecting CO_2 into the same storage formation will have to be spaced far enough apart that their pressure fronts do not interfere with each other. After an injection project stops injection, time will be needed for the pressures outside the CO_2 Plume Uncertainty Area to subside so that a new injection project can begin injection. These factors will require regional or basin scale management of the storage formation and limit the area of a storage formation that can be used for CO_2 storage. The areal restrictions or limitations are not known at this time. To account for these limitations, it was assumed that 80 percent of the areal extent of dome and anticline structural settings will be available for storage and 40 percent of the areal extent of regional dip will be available for storage. Because dome and anticline structural settings have the highest storage coefficients, it is assumed that injection project operators will search for such structures and will utilize these structures first. After the dome and anticline structures have been used, injection project operators will site projects with regional dip structural settings. Since these projects will begin after the others, the projects with regional dip will be more

restricted by pressure interferences and, consequently, a smaller fraction of the total area with regional dip will be available for storage.

- As a check on the prevalence values for dome, anticline and regional dip (1.25 percent, 1.25 percent and 97.5 percent) and area available for injection (80 percent for dome and anticline, 40 percent for regional dip), a comparison was made to formation-wide general storage coefficients developed by IEA GHG (2009). These formation-wide general storage coefficients were for a formation as a whole and presumably factored in the likely prevalence of structural settings and area available for storage. Using the prevalence values and the fraction of area available for storage to calculate a weighted storage coefficient from the site-specific storage coefficient, the weighted coefficients compare well to IEA GHG's formation-wide general storage coefficients (IEA GHG, 2009).

3.3 Parameters Associated with Stages of CO_2 Storage

The storage of CO_2 is assumed to occur in six stages which are consistent with the Class VI injection well regulations: 1) regional evaluation and initial site selection, 2) site characterization, 3) permitting, 4) operations, 5) post-injection site care and site closure, and 6) long term stewardship.

Regional evaluation and initial site selection—Stage duration: This stage is assumed to take one year to complete.

Site characterization—Stage duration and critical activities: This stage is assumed to take three years to complete and involves the following critical activities.

- Four sites are assumed to undergo initial characterization or pre-characterization, which involves installation of one stratigraphic test well and collection of two lines of 2-D seismic data at each site.
- One of the four initial sites is selected as the injection site and undergoes full characterization, which involves installation of an additional stratigraphic test well and collection of 3-D seismic across the entire CO_2 Plume Uncertainty Area.
- Pore-space rights and property access are leased for the site during this stage.
- The design of the injection system is performed in this stage and the plans needed for the Class VI injection well permits (AoR and Corrective Action Plan, Testing and Monitoring Plan, Injection Well Plugging Plan, Post-Injection Site Care and Site Closure Plan, and Emergency and Remedial Response Plan) are prepared in this stage.

Permitting—Stage duration and critical activities: This stage is assumed to take two years to complete and involves the following critical activities.

- This stage includes submittal of required plans prepared during Site Characterization (AoR and Corrective Action Plan, Testing and Monitoring Plan, Injection Well Plugging Plan, Post-Injection Site Care and Site Closure Plan, and Emergency and Remedial Response Plan) for each Class VI injection well permit to the regulatory authority.
- Once the regulatory authority gives conditional approval of the permits, the injection wells are drilled and completed.

- Data from the new injection wells are incorporated into the plans, as needed, and the permits and associated plans are resubmitted to the regulatory authority.
- After final approval of the Class VI injection well permits are granted, CO_2 injection can begin. The operator now has 180 days to develop and submit the MRV Plan required under Subpart RR to the applicable regulatory authority, with the intent of gaining approval of this plan in the first year of operations.

Operations—Stage duration and critical activities: The injection site is assumed to operate for 30 years, which is a design choice. There are a large number of critical activities that occur during operations.

- The storage site operator takes control of the CO_2 at the property boundary, and pays for a pipeline that transports the CO_2 to a central location where CO_2 is distributed to injection wells. The storage site operator is assumed to not pay for any of the pipelines beyond the property boundary.
- Buildings, roads, surface equipment, initial monitoring wells, and most other monitoring equipment are assumed to be installed instantaneously at the beginning of operations. Additional monitoring wells are assumed to be installed as the CO_2 plume expands, as discussed below.
- The storage site operator operates and maintains the injection wells. These wells undergo two types of mechanical integrity testing: continuous monitoring at the wellhead and annual external tests (e.g., noise logs, temperature log). The well materials also undergo quarterly corrosion testing. The pressure at the bottom of the injection well is assumed to be monitored more or less continuously.
- Corrective action occurs as the CO_2 plume expands toward abandoned wells.
- There are three types of deep monitoring wells, ones that monitor the storage formation (in reservoir monitoring wells), ones that monitor formations above the storage formation and above the cap rock (above seal monitoring wells), and ones that monitor both the storage formation and formations above the cap rock (dual completed monitoring wells). The total number of monitoring wells depends on the CO_2 Plume Uncertainty Area and the Pressure Front Area. The storage coefficient, CO_2 plume uncertainty factor and pressure front multiplier are used to estimate the maximum extent of the CO_2 Plume Uncertainty Area and Pressure Front Area. For the purpose of deploying monitoring wells over time, the CO_2 Plume Uncertainty Area and Pressure Front Area are assumed to expand from a fraction of their maximum areas at the start of injection to their maximum areas in proportion to the mass of CO_2 injected.
- Deep in reservoir monitoring wells and dual completed monitoring wells are constructed to the standards of Class VI injection wells. For the Baseline Case, it was assumed that dual completed monitoring wells were used to monitor the storage formation and formations above the cap rock with additional above seal monitoring wells used to further monitor formations above the cap rock. The dual completed monitoring wells have the following characteristics.
    - Within the CO_2 Plume Uncertainty Area, there is one well every 4 mi^2 with a minimum of two wells initially and a minimum of five total wells at the end of

injection. The well density was inferred from data provided in EPA (2010a, 2010b).

  - Within the Pressure Front Area beyond the maximum extent of the CO_2 Plume Uncertainty Area, there is one well every 50 mi^2 with a minimum of one well initially, and two total wells at the end of injection.
  - All wells have pressure monitored more or less continuously from four depth intervals in the storage formation and four depth intervals above the seal. For the wells within the CO_2 Plume Uncertainty Area, one fluid sample is collected annually from each of eight depth intervals, four depth intervals in the storage formation and four depth intervals above the cap rock, for a total of eight fluid samples collected from each well. Each fluid sample is tested for CO_2, pH, and a variety of other constituents. Each sampling interval requires perforations in the casing when the well is constructed and packers to isolate the intervals.
  - Fluid samples are not collected from the monitoring wells in the Pressure Front Area beyond the maximum extent of the CO_2 Plume Uncertainty Area. Only pressure measurements are made in these wells.
- Deep above seal monitoring wells are standard deep wells and have the following characteristics.
  - Within the CO_2 Plume Uncertainty Area, there is one well every 4 mi^2 with a minimum of one well initially and a minimum of two total wells at the end of injection. The well density was inferred from data provided in EPA (2010a, 2010b).
  - There are no deep above seal monitoring wells in the Pressure Front Area beyond the maximum extent of the CO_2 Plume Uncertainty Area. Dual completed monitoring wells are used to monitor conditions in the storage formation and formations above the cap rock in this portion of the Pressure Front Area as discussed above.
  - The deep above seal monitoring wells have pressure monitored more or less continuously and have one fluid sample collected annually from each of four different depths above the cap rock, for a total of four fluid samples collected from each well. Each fluid sample is tested for CO_2, pH, and a variety of other constituents. Each sampling interval requires perforations in the casing when the well is constructed and packers to isolate the intervals.
- Groundwater wells are installed to collect water samples from potential USDWs.
  - There is one groundwater well installed for each injection well.
  - These wells have fluid samples collected quarterly from four different depths with each sample tested for CO_2, pH, and a variety of other constituents.
- Atmospheric and near surface CO_2 concentrations are measured with three technologies: vadose zone wells, soil gas flux chambers, and Eddy covariance towers.
- Vadose zone wells are installed to collect soil gas samples.

- There is one vadose zone well installed for each injection well.
- These wells have soil gas samples collected quarterly from a single depth with each sample tested for CO_2 and other constituents.

- Soil gas flux chambers are devices placed on the soil surface that passively absorb soil gas.
    - There are 20 soil gas flux chambers used for each injection well.
    - These soil gas flux chambers are collected and analyzed for CO_2. Soil gas flux chambers are deployed, collected, and analyzed quarterly.
- Eddy covariance towers are used to monitor CO_2 concentrations in the ambient air.
    - There are five Eddy covariance towers deployed at an inject site.
    - These devices are assumed to monitor CO_2 concentrations more or less continuously.
- Surface equipment on the site, such as pipe flanges, headers, meters, pumps, and tanks, is monitored periodically for CO_2 leaks.
- AoR review occurs every five years.
- 3-D seismic is performed every five years as part of the AoR review. 3-D seismic is performed over an area that is initially about one-half of the full 3-D Seismic Area and increases in proportion to the cumulative mass of CO_2 injected until the area is the full 3-D Seismic Area.
- Injection wells are plugged at the conclusion of injection operations.

PISC and site closure—Stage duration and critical activities: PISC begins when injection stops and is assumed to last until the operator of the storage site obtains a ruling of non-endangerment from the regulatory authority. For the Baseline Case, PISC is assumed to last for 50 years, which is the default duration for PISC in the Class VI injection well regulations. This stage involves the following critical activities.

- Monitoring is assumed to continue for all deep monitoring wells, groundwater wells, and vadose zone wells for the entire PISC period using the sampling schedule employed during injection operations.
- Air monitoring with soil gas flux chambers is assumed to continue throughout the PISC period using the sampling schedule employed during injection operations.
- Air monitoring with Eddy covariance monitors is assumed to continue throughout the PISC period with more or less continuous monitoring of CO_2 concentrations in the air.
- AoR review occurs every five years.
- 3-D seismic is performed every five years as part of the AoR review with the 3-D seismic covering the entire 3-D Seismic Area.
- Monitoring wells are plugged and other monitoring equipment removed at the conclusion of PISC.

Long term stewardship—Stage duration and critical activities: This final stage lasts into the indefinite future.

- This stage is outside the scope of Class VI regulations and is not explicitly included in the model.
- The possible financial implications of long-term stewardship for the storage site operator are included in the model through a state sponsored trust fund that the storage operator pays into during operations.
- Based on legislative activity in some states, when non-endangerment is established and EPA authorizes closure, the state will issue a certificate of closure releasing the operator of further operational obligations. The state assumes oversight and will continue to look after the site with the use of the money in the long-term stewardship trust fund.

3.4 Cost of Activities

There are a large number of activities in the Activity Module. The cost of some activities is fixed lump sum costs. The costs of most activities depend on the scale of the storage project. These costs are typically determined as a unit cost times a number of units, where the units may be the number of injection wells, the number of monitoring wells, the CO_2 Plume Uncertainty Area or some other project scale-related quantity. Many of the lump sum costs and unit costs were taken from EPA's cost analysis for the Class VI injection well regulations (EPA, 2010a; EPA, 2010b).

3.5 Financial Responsibility Costs

In the Baseline Case, financial responsibility is addressed through a "modified" trust fund that covers the cost of corrective action, injection well plugging, and PISC and site closure. Insurance is used to address ERR.

- The Class VI injection well regulations provide for a trust fund as a financial instrument to address financial responsibility. The trust fund, utilizing a three-year pay-in period, is supposed to be entirely funded by the end of the first or second year of operations. The modified trust fund is a trust or reserve account that is set up and funded over the entire operational period. Money in the fund is withdrawn to pay for corrective action, injection well plugging, and PISC and site closure. The fund is set up so that it can earn interest. In the financial module, the costs over time for corrective action, injection well plugging and PISC and site closure are retrieved from the activity module and escalated into nominal dollars. The amount of money that must be deposited into the trust fund each year to cover the withdrawals (including interest earned on the funds in the reserve account) is then determined. The interest rate used for these calculations is the net interest rate after taxes and fees, assuming the trust fund will have to pay taxes on the money the fund earns. The net interest rate used in these calculations is 5 percent. It was felt that reasonably "safe" investments could be identified that would allow the deposits to grow at 5 percent after taxes and administrative fees. The amount of money that must be deposited into the reserve account each year over the duration of injection operations is a constant value in nominal terms (i.e., it declines in real dollars over time).
- The cost of ERR is difficult to estimate. For this effort, it was assumed that ERR would be addressed by an insurance policy, with the premiums paid through a fee of $0.75 in

real (2008) dollars imposed on each tonne of CO_2 injected. The value of $0.75 per tonne was developed based on an analysis of ERR costs for the FutureGen2 project (FutureGen2, 2013) and a study done by the state of Wyoming (Corra et al., 2009). The fee is assumed to increase at the escalation rate in order to generate cash flows in nominal dollars.

3.6 Parameters Related to Financing and Fees

Financial parameters. The following values were used for important financial parameters. These are the values for projects performed by a high risk investor owned utility that were utilized in NETL power plant studies (NETL, 2011).

- Debt 45% and equity 55%
- Interest rate on debt: 5.5%/year
- Cost of equity or minimum internal rate of return on equity: 12%/year
- Escalation rate: 3%/year

Lease and fees. The following values were used for miscellaneous lease or fee costs.

- Lease bonus: $50/acre over the 3-D Seismic Area to secure rights to pore space and surface access.
- Pore space fee: $0.25/tonne of CO_2 injected, analogous to a royalty payment with oil and gas production.
- Long term stewardship trust fund: $0.07/tonne of CO_2 injected

4 Results from the FE/NETL CO_2 Saline Storage Cost Model for the Baseline Case

The output from the FE/NETL CO_2 Saline Storage Cost Model includes the break-even first-year price or cost of storing a tonne of CO_2 in the first year of the project (2011) for each formation and structural setting. The model also calculates the maximum mass of CO_2 that can be stored in each formation for each structural setting.

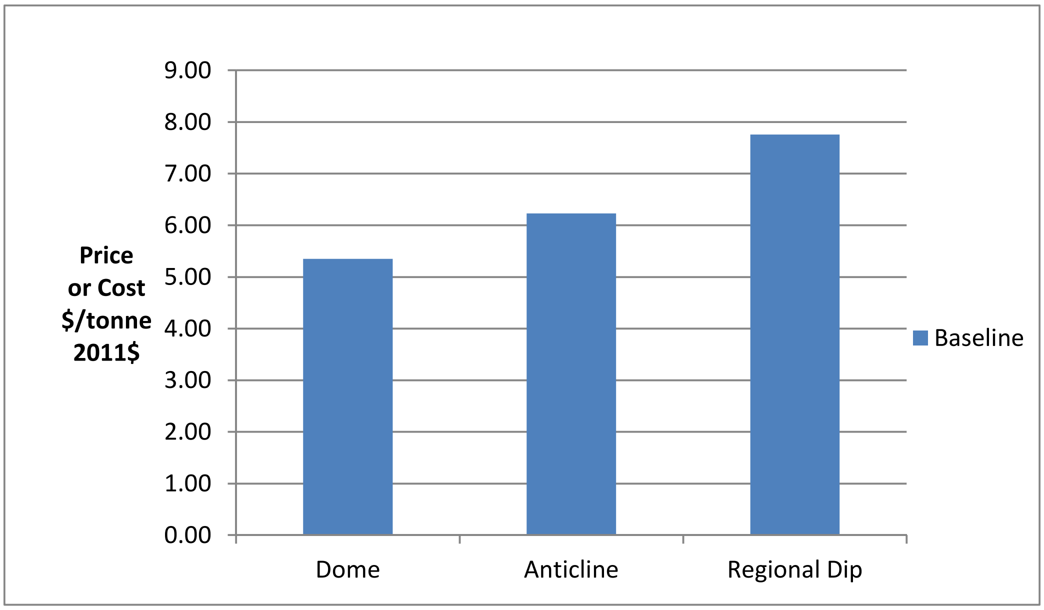
4.1 Formation Specific Results

The structural setting of a formation (dome, anticline, or regional dip) is an important determinant of cost and will therefore be considered when presenting results for specific formations. Recall that the axes of a dome are about equal in length, analogous to an inverted bowl while the one axis of an anticline is longer than the other, analogous to an inverted platter or a stretched out dome. These two types of structural settings form a closure beneath which buoyant CO_2 is trapped, preventing lateral migration. The other structural setting, regional dip, provides no closure, which means that buoyant CO_2 will continue to slowly migrate along the interface with the seal formation until other trapping mechanisms (primarily capillary trapping or residual saturation, but also solubility trapping and precipitation trapping) prevent further migration.

Because the dome and anticline can physically constrain CO_2, these two structural settings have the highest storage coefficients (dome is highest followed by anticline). Regional dips have the lowest storage coefficients for a specific storage formation. These differences in storage coefficients are responsible for different break-even first-year prices or costs of CO_2 storage within for a specific storage formation in the geology database. Therefore, results presented below for specific storage formations will be presented as break-even first-year prices or costs of CO_2 storage for each type of structural setting.

The Mount Simon 3 storage formation is located in Illinois. The depth to the top of this storage formation is approximately 4,300 feet and it is about 1,000 feet thick. The storage formation has a porosity of 12 percent and a permeability of 125 mD. The Mount Simon 3 storage formation is an excellent candidate for CO_2 storage. Exhibit 3 shows the break-even first-year price or cost of CO_2 storage for the three structural settings within the Mount Simon 3 storage formation. This storage formation has Baseline Case prices or costs ranging from around \$5.40 per tonne of CO_2 in the dome structural setting to about \$7.80 per tonne of CO_2 in the regional dip structural setting. The prices or costs are in 2011 dollars.

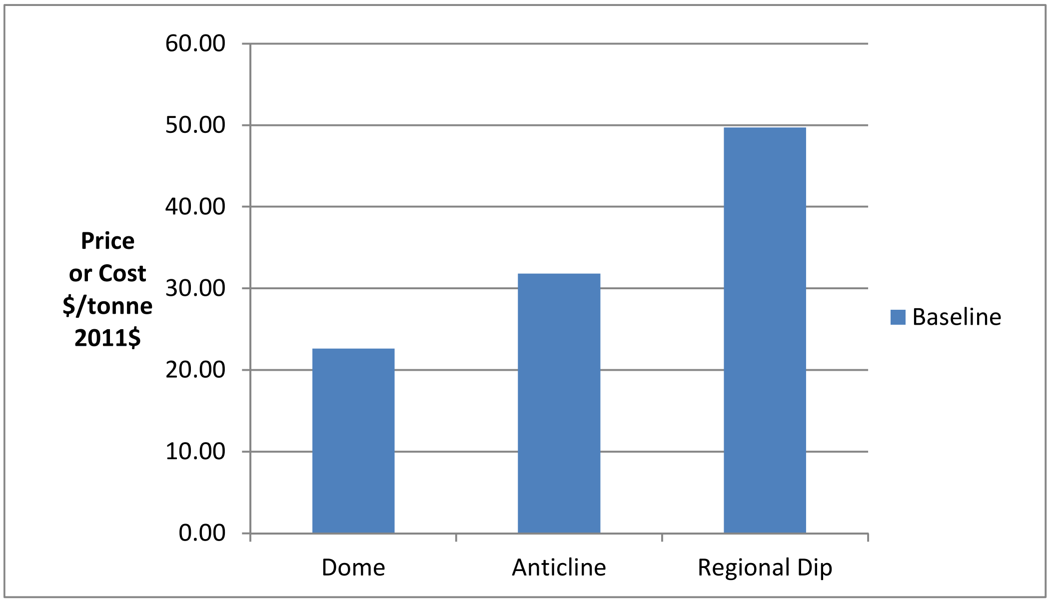
Exhibit 3 Break-even first-year price/cost of CO_2 - Mount Simon 3



Source: NETL/DOE

Exhibit 4 displays the same information for a second storage formation, the Rose Run 3. The Rose Run 3 formation is located in central Pennsylvania. It is approximately 14,000 feet to the top of this formation, which is about 320 feet thick. The porosity of this formation is 8 percent and the permeability is 3 mD. The Rose Run 3 storage formation is a less attractive candidate for CO_2 storage than the Mount Simon 3 formation. The Baseline Case break-even first-year prices or costs of CO_2 storage for the three structural settings within the Rose Run 3 storage formation are shown in Exhibit 4. These break-even first-year prices or costs of CO_2 storage range from \$22.60 per tonne of CO_2 in the dome structural setting to \$49.80 per tonne of CO_2 in the regional dip structural setting. The prices or costs are in 2011 dollars.

Exhibit 4 Break-even first-year price/cost of CO_2 - Rose Run 3



Source: NETL/DOE

4.2 Results for All Formations

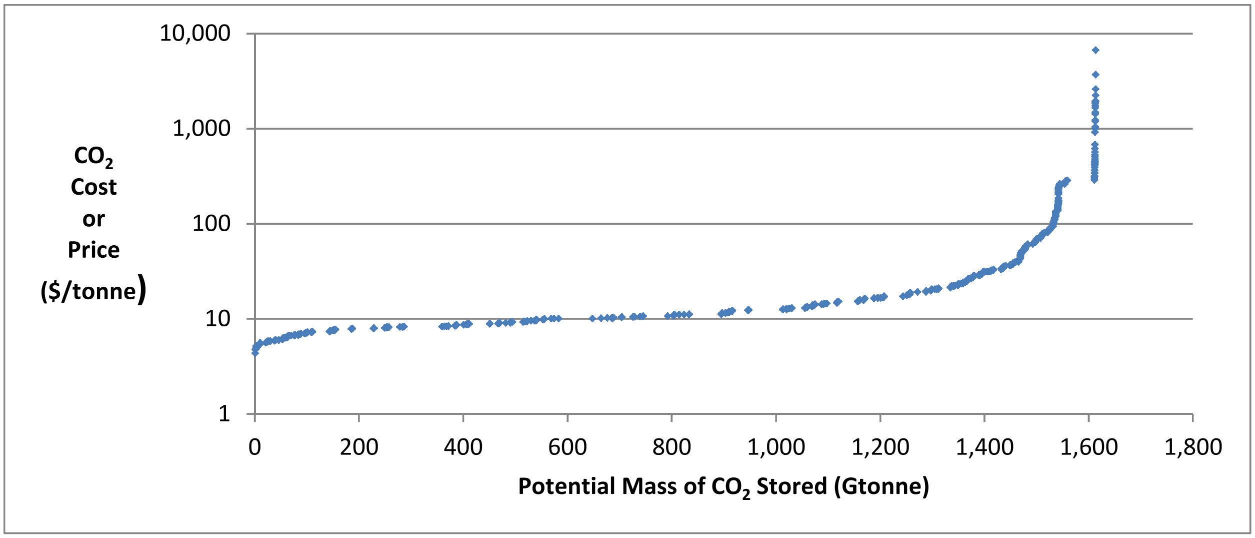
Exhibit 5 presents a cost-supply curve for the Baseline Case. The following process is used to generate the cost supply curve.

- The break-even first year price or cost of storing CO_2 in each storage formation-structural setting combination is calculated. The break-even first year price or cost is for storing 3.2 million tonnes of CO_2 each year unless storing this much CO_2 over 30 years exceeds the 100 mi^2 limit on the CO_2 Plume Uncertainty Area. If that is the case, the annual mass rate of CO_2 injection is reduced so that the CO_2 Plume Uncertainty Area equals 100 mi^2 at the end of 30 years of injection. For each storage formation, the area available for each structural setting is also considered. For example, if the area of a storage formation is 5,000 mi^2, then the area with a dome structural setting that is available for storage is 5,000 mi^2 x 0.0125 x 0.8 or 50 mi^2. The value 0.0125 is the fraction of the storage formation that is assumed to have a dome structure and the value 0.8 is the fraction of the dome area that can be used for storage based on institutional constraints. For this storage formation and dome combination, 50 mi^2 would be used in the above calculation instead of 100 mi^2. The number of injection projects that can be implemented in each storage formation-structural setting combination is calculated and rounded down to the nearest integer. This integer value is multiplied by the total mass of CO_2 stored by each injection project to yield the total mass of CO_2 that can be stored in each storage formation-structural setting combination.
- The results for all storage formation-structural setting combinations were sorted by their break-even first-year price/cost of CO_2, from lowest to highest price or cost.

- The cumulative mass of CO_2 that can be stored at each break-even first-year CO_2 price point was determined (i.e., this is the total mass of CO_2 that can be stored at a profit at a particular price for CO_2).

In Exhibit 5, the vertical axis is the break-even first-year price or cost of CO_2 ($/tonne) in 2011 dollars, and the horizontal axis is the cumulative mass of CO_2 that can be profitably stored at a particular price (Gtonne). The lowest break-even first-year price is about $4.30/tonne and the highest is over $1,000/tonne.

Exhibit 5 Cost-supply curve for Baseline Case

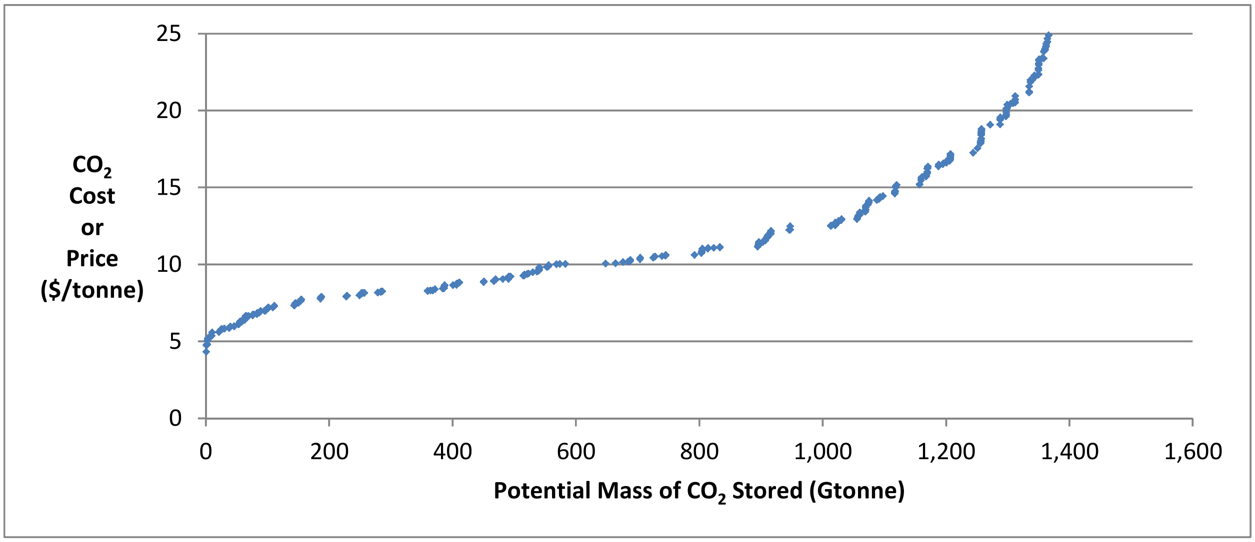


Source: NETL/DOE

As discussed previously, a subcritical, pulverized coal power plant with a net capacity of 420 MW that operates at an 80 percent capacity factor and captures 90 percent of the CO_2 generated would capture about 3.2 million tonnes of CO_2 each year (NETL, 2013) or 96 million tonnes of CO_2 over 30 years of operation. Approximately 10 power plants with these specifications operating for 30 years would be needed to generate 1 Gtonne of CO_2 for storage.

Using data from the Energy Information Administration (EIA, 2013), it is estimated that if 90 percent of all the CO_2 emitted from power plants and stationary industrial sources over the next 100 years were captured, the mass of captured CO_2 would be about 315 Gtonnes. Exhibit 6 shows only the portion of the cost-supply curve for the Baseline Case that is below $25/tonne, which represents a cumulative storage capacity of about 1,350 Gtonnes. Figure 6 suggests that there is a little over 550 Gtonnes of storage capacity available for under $10/tonne. Both storage capacity numbers exceed the value of 315 Gtonnes of CO_2 that could potentially be captured over the next 100 years for storage.

Exhibit 6 Cost-supply curve for Baseline Case, costs below $25/tonne



Source: NETL/DOE

5 Summary

In this report, the FE/NETL CO_2 Saline Storage Cost Model was described, the assumptions utilized in the Baseline Case were provided, and results for the Baseline Case were presented. The FE/NETL CO_2 Saline Storage Cost Model is a relatively high level cost model that is designed to mimic CO_2 storage operations in order to calculate the revenues and all the costs for such a project from the perspective of the owner/operator of the storage site. The costs include the costs associated with injecting CO_2 into the subsurface, the costs associated with complying with the Class VI injection well and Subpart RR regulations (such as monitoring, modeling and reporting costs, and financial responsibility costs), taxes, and financing costs. The model utilizes basic geo-engineering equations to calculate a number of cost inputs for a CO_2 storage project, such as the area of the CO_2 plume and the number of CO_2 injection wells to be drilled and completed. The FE/NETL CO_2 Saline Storage Cost Model does not include sophisticated multiphase flow equations as would be found in a numerical reservoir simulation model.

The FE/NETL CO_2 Saline Storage Cost Model can be used in three modes. In the first mode, the user can set a price for CO_2 and the model will calculate the net present value of returns to the owner. If the net present value is greater than zero, then the returns exceed the minimum internal rate of return on equity and, presumably, the project is a good investment for the owners. In the second mode, an Excel macro can be executed that will calculate the price of CO_2 where the net present value of returns to the owner is zero when discounted at the owner's minimum internal rate of return. This is the break-even first-year price of CO_2. The owner must be able to price the storage of CO_2 at this value or higher for the storage project to meet or exceed the minimum internal rate of return on equity. The break-even first-year price of CO_2 is also the likely minimum cost that a CO_2 generator, such as a power plant, is likely to be charged for storing the CO_2 captured by the generator. This break-even first-year price or cost of CO_2 does not include the cost of transporting the CO_2 from the source (e.g., a power plant) to the storage site. In the third mode, a different Excel macro can be executed that calculates the break-even first-year price of CO_2 for all the storage formations in the geology database in the model. The results generated from this macro can be used to develop cost supply curves for potential CO_2 storage.

The assumptions used in the Baseline Case were also presented. The Baseline Case is intended to provide an estimate of storage costs based on currently available technology applied by a storage project operator in a manner that will comply with Class VI injection well and Subpart RR regulations. The assumptions incorporated in the Baseline Case were developed from discussions with individuals within NETL, discussions with people outside NETL engaged in storage projects, EPA reports, and the open literature. Proprietary data was not used in the FE/NETL CO_2 Saline Storage Cost Model or the assumptions utilized in the Baseline Case.

With the baseline assumptions, the FE/NETL CO_2 Saline Storage Cost Model was used to estimate the break-even first-year price or cost of storing CO_2 in each of the 226 storage formations in the geology database for each of three possible structural settings (dome, anticline, and regional dip). The lowest break-even first-year baseline prices/costs were about $4.30 per tonne of CO_2 in 2011 dollars. Over 550 Gtonnes of potential storage capacity is estimated to be available for under $10 per tonne in 2011 dollars. To provide context for the 550 Gtonne storage resource value, if 90 percent of all the CO_2 emitted from power plants and stationary industrial sources over the next 100 years were captured, the mass of captured CO_2 would be about 315 Gtonnes (estimated from EIA, 2013).

6 References

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