REDUCED ORDER COSTS FOR CO_2 SALINE STORAGE FOR USE IN ENERGY MARKET MODELS

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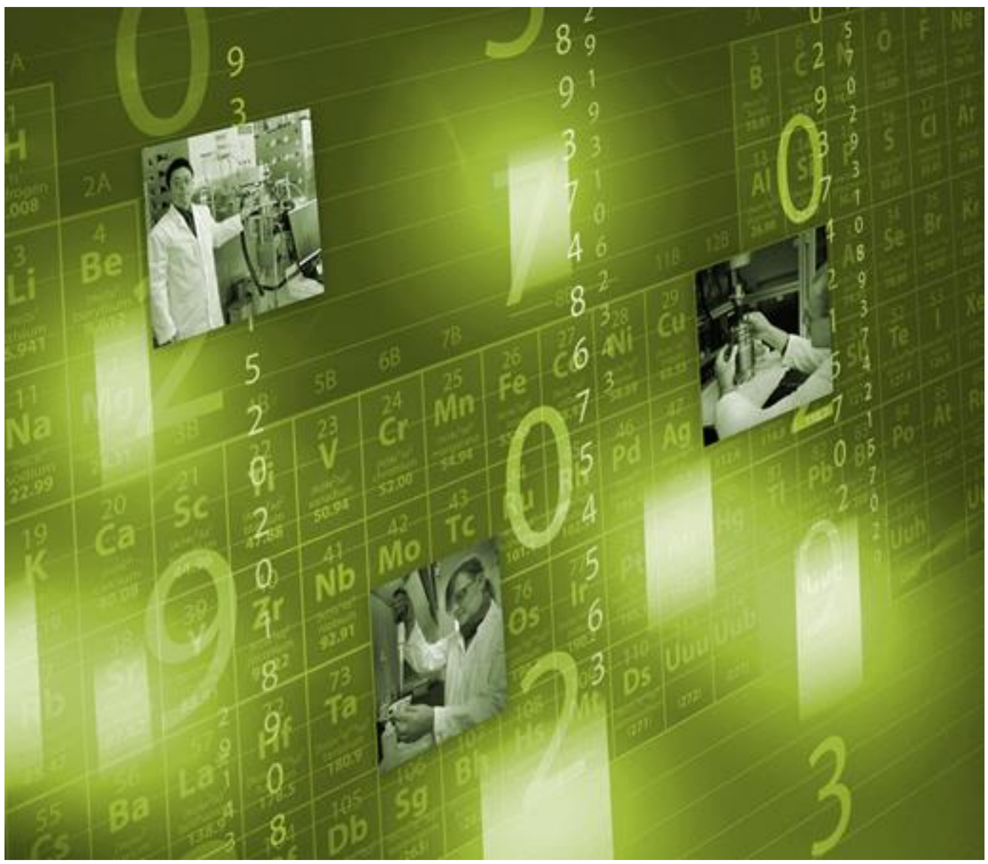

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Disclaimer

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1 Introduction

This report presents reduced order costs for storage of carbon dioxide (CO_2) in saline aquifers. These reduced order costs are intended to be used in models, such as energy system models for assessing and evaluating the deployment of carbon capture and storage (CCS), where detailed costs for CO_2 saline storage are not required. This work was performed at the request of the Department of Energy's (DOE) Office of Fossil Energy and Carbon Management (FECM) by the National Energy Technology Laboratory (NETL) and the Los Alamos National Laboratory (LANL).

NETL has developed the FECM/NETL CO_2 Saline Storage Cost Model (CO2_S_COM) and LANL has developed the Sequestration of CO_2 Tool (SCO_2T). CO2_S_COM and SCO_2T are both techno-economic models that include geologic data, reservoir engineering algorithms to calculate important technical aspects of CO_2 saline storage, revenues from storing CO_2, capital and operating and maintenance (O&M) costs, and financing. As part of this effort, NETL and LANL personnel have worked together to compare the inputs and outputs from their models and have also compared critical technical aspects of a CO_2 saline storage project, such as the CO_2 plume size and the maximum rate of CO_2 injection into a storage formation. Both models have been modified so both incorporate the same technical and cost elements although the two models may use different approaches to addressing the same technical or cost element. When given the same input assumptions, the two models provide results that are very close to each other, although they are not the same.

Since the two models provide similar results, only the results from CO2_S_COM will be discussed in this report.

The publicly available version of SCO_2T is available at this link:

https://github.com/simccs/SCO2T

This version is an Excel file. A new version with a few modified technical and cost elements is being developed in Python and will be publicly released in the future. This new version of SCO_2T is the version used in this analysis.

The publicly available version of CO2_S_COM is available at this link:

https://netl.doe.gov/energy-analysis/search?search=CO2SalineCostModel

This version is also an Excel file and has a User's Manual. This version is from 2017. Like SCO_2T, a new version of CO2_S_COM is being developed and will be released to the public in the future. This new version of CO2_S_COM is the version used in this analysis.

This report provides reduced order costs for CO_2 saline storage. Section 2 provides an overview of CO2_S_COM and the assumptions used in this analysis. Similar assumptions were used by LANL personnel in their analyses using SCO_2T.

Section 3 provides the reduced order costs. Section 3.1 provides the rationale for the reduced order costs. Section 3.2 discusses the reduced order costs which are provided in an Excel spreadsheet that accompanies this report. Section 3.3 discusses how the reduced order costs can be used to estimate the cost of CO_2 storage cost in a saline formation receiving captured CO_2.

Section 4 provides references cited in this report.

2 Overview of CO2_S_COM

CO2_S_COM is a techno-economic model for evaluating the feasibility of a CO_2 saline storage project. From a technical perspective, CO2_S_COM uses geologic data for a potential storage formation and reservoir engineering equations to calculate quantities needed for determining costs, such as injectivity and the area of the CO_2 plume over time. From an engineering economic perspective, CO2_S_COM provides costs for discrete activities associated with CO_2 saline storage. CO2_S_COM also provides revenues, costs and financial performance for a CO_2 storage project from the viewpoint of a CO_2 storage operator who is independent of the CO_2 capture facility and CO_2 pipeline operation. It is assumed that the operator of the CO_2 storage project is being paid to store CO_2, which is the source of the revenue for the project. CO2_S_COM includes capital costs, O&M costs, the cost of complying with the requirements of a Class VI injection well permit, depreciation, taxes, and financing costs (interest and principal on debt and the minimum desired internal rate of return on equity).

2.1 Geologic Model

The foundation for the costs for a CO_2 saline storage project is the geology of the storage formation. CO2_S_COM has a database of 314 potential geologic storage formations in the lower 48 states within the United States (US). Most storage formations in CO2_S_COM are part of a larger geologic formation although a few storage formations are the entire geologic formation. The storage formations have been defined by geologists and then, for purposes of techno-economic modeling, partitioned into units with relatively consistent geologic properties (recognizing heterogeneity and variability inherent in characteristics of subsurface geology) that lie within a single state. Commensurate with the related geology, the storage formations were defined to have relatively large areal extents so that, ideally, the storage formation can contain many commercial-scale CO_2 storage projects (such as the CarbonSAFE projects). Almost all storage formations have areal extents exceeding 1000 mi^2. The geologic properties for each storage formation include the areal extent, depth to the top of the storage formation, thickness, porosity, permeability and salinity. The geologic data used to define the storage formations comes primarily from NATCARB although many other sources were also used. [1]

The temperature and hydrostatic pressure are provided for each storage formation if known. Otherwise, these properties are calculated based on gradient data and the distance from the surface to the middle of the storage formation. The lithostatic pressure is calculated based on gradient data and the distance from the surface to the middle of the storage formation. The fracture pressure is calculated as a percentage of the lithostatic pressure with typical values ranging from 60% to 80%. A value of 70% was used in this analysis. The lithology and depositional environment of the storage formation are also provided for each storage formation. The geologic properties are intended to be generally representative of any location within the storage formation.

The latitude and longitude of the centroid of all catalogued storage formations are provided in the database as well as the state where each storage formation is located and the assigned name of the storage formation. The assigned storage formation name is the name of the geologic formation followed by a number or a number and a letter (such as Mount Simon1 for a storage formation in the Mount Simon geologic formation or Frio3a and Frio3b for two storage formations in the Frio geologic formation). A storage formation is defined to be no greater than 1000 feet thick. Geologic formations such as the Frio that are greater than 1000 feet thick have been partitioned into separate storage formations at different depths with thicknesses that do not exceed 1000 feet.

2.2 STAGES OF A CO_2 STORAGE PROJECT

CO2_S_COM assumes a CO_2 storage project is executed in six stages.

- Site screening: Each storage project includes 1 year of site screening where one or more sites are identified for more investigation.
- Site selection, characterization and design: In this analysis it is assumed that one site is preliminarily characterized with two lines of 2-D seismic and drilling one stratigraphic well. A full 3-D seismic characterization is done to image the expected full extent of the CO_2 Plume Uncertainty Area or across the 3-D Seismic Area. The 3-D seismic image is conducted to characterize the subsurface geology and establish a baseline for 3-D seismic images collected during CO_2 injection and follow on stages. The CO_2 Plume Uncertainty Area and 3-D Seismic Area are discussed below. During this stage surface access and pore space rights are assumed to be purchased for the project. The design of the project is executed, and the Class VI permit documents are prepared. The Class VI permit documents are submitted to the governing regulatory authority at the end of this stage which is assumed to last 2 years in this analysis.
- Permitting and construction: In this stage, the operator works with the regulatory authority to get the Class VI permits conditionally approved. The injection wells are installed, the permit documents are revised as necessary and submitted again to the regulatory authority. Additional construction, such as the installation of access roads, office buildings, pipelines, meters and the like, is performed. Monitoring equipment that needs to be installed before CO_2 injection begins is also installed, especially monitoring equipment that needs background or baseline data before CO_2 injection begins. This may include deep monitoring wells, groundwater wells that monitor underground sources of drinking water (USDWs) and equipment that monitors ambient concentrations of CO_2 in the air. In this analysis, this stage is assumed to last 2 years.
- Operations: This stage covers the entire CO_2 injection operation. Monitoring is performed to estimate the location of the CO_2 plume and to detect leaks of CO_2 and/or brine from the storage formation into USDWs. Monitoring for induced seismicity is also performed. This analysis assumes that no leakage is detected during or after operations and there are no induced seismicity incidents that exceed any thresholds that would require the CO_2 injection to cease or the rate of injection to be reduced. At the end of this stage CO_2 injection ceases and the injection wells are plugged and abandoned. This stage is assumed to last 30 years.

- Post-injection site care (PISC) and site closure: In this stage, monitoring continues. The location of the CO_2 plume is tracked, and the site is monitored for leakage and induced seismicity incidents. During this stage the CO_2 plume is expected to stabilize, expanding very slowly and pressures in the storage formation are expected to decline. The pressures should decline below pressures where the threat of leakage of fluid out of the storage formation is extremely low. At the end of this stage, the regulatory authority issues a finding of non-endangerment. All monitoring equipment and unwanted surface structures are removed, and the site is closed. This stage is assumed to last 10, 20, 30 or 50 years as discussed below.
- Long-term stewardship: After closure, the CO_2 storage site enters the long-term stewardship stage. A finding of non-endangerment implies that the risk of adverse events, such as leakage of fluids out of the storage formation or induced seismic incidents, should be very low at this time. There is always the possibility that a leak that occurred in the past is discovered during this stage. The entity responsible for addressing any adverse events associated with the CO_2 storage operation depends on the laws and regulations in the state where the storage formation is located. Some states are accepting liability for addressing adverse events that might occur during this stage. In CO2_S_COM, it is assumed that the CO_2 storage project operator pays money into a trust fund operated by the state during injection. After the site is closed, the state accepts liability and uses money in the trust fund to address liability issues that might arise during the long-term stewardship stage. Apart from the long-term stewardship trust fund, which is paid for during injection operations, CO2_S_COM does not calculate any costs associated with this stage, which lasts for an indeterminate time.

2.3 CO_2 MASS FLOW RATES FOR PROJECT

Two key inputs to CO2_S_COM are the average annual mass rate of CO_2 injection for the storage project and maximum hourly mass rate of CO_2 injection. The ratio of the average annual mass rate of CO_2 injection and the maximum mass rate of CO_2 injection (expressed in the same units such as tonnes injected per year) is referred to as the capacity factor in CO2_S_COM. The annual average mass rate of CO_2 injection depends on the rate at which sources of CO_2 can supply the storage project, but there is a limit to the annual average mass flow the storage project can sustain. A CO_2 storage project must periodically take injection wells and other equipment offline for testing and maintenance. Some testing of injection wells is mandated by the Class VI injection well regulations. The Class VI permit document for Project Tundra in North Dakota indicated that the injection wells would be operational except for roughly 5 to 7 days each year. [2] Assuming the storage project cannot inject CO_2 seven days or one week out of the year, this suggests the storage project can be operated at its maximum CO_2 injection rate 51 days out of 52 or roughly 98% of the year. This represents the maximum capacity factor for this storage project.

In CO2_S_COM, the user specifies the average annual mass rate of CO_2 injection and the capacity factor. The capacity factor is used to calculate the maximum mass rate of CO_2 injection. For this analysis, the average annual CO_2 mass flow rate for the CO_2 storage project was

1,960,000 tonnes/yr and the capacity factor was set to a maximum value of 98 percent based on the data for Project Tundra. The maximum mass rate of CO_2 injection on an annualized basis is 2,000,000 tonnes/yr.

2.4 RESERVOIR ENGINEERING QUANTITIES

CO2_S_COM has algorithms for calculating technical or reservoir engineering quantities needed to determine costs.

- The number of injection wells needed for a project is calculated by CO2_S_COM as follows.
    - First, the maximum CO_2 mass injection rate that the storage formation can sustain for a single injection well is determined. This maximum injection rate depends on the thickness, porosity and permeability of the storage formation. CO2_S_COM has several algorithms for calculating the maximum CO_2 mass injection rate that the storage formation can sustain for a single injection well. The algorithm by Valluri et al. (2021) was used in this analysis. [3] The maximum injection rate is given by the following equation:

      $$q_{m-max-form-CO2} = a_{inj-val} * k_h * h * (P_{max} - P_{amb})$$

      Where:

      $q_{m\text{-}max\text{-}form\text{-}CO2}$ = maximum mass rate of CO_2 injection that formation can sustain (tonne/year)

      $a_{inj\text{-}val}$ = coefficient = 0.104 tonne/(day-MPa-mD-m)

      k_h = horizontal or lateral permeability (mD)

      h = thickness of formation (m)

      P_{max} = maximum allowed pressure (MPa)

      P_{amb} = ambient hydrostatic pressure in storage formation (MPa)

      This equation relates the maximum injection rate to the permeability, storage formation thickness and maximum allowed pressure increase in the formation over the ambient hydrostatic pressure. The maximum allowed pressure, Pmax, is assumed to be 90% of the fracture pressure, consistent with the Class VI injection well regulations.
    - Second, the user inputs a maximum CO_2 mass injection rate for a well that the well mechanics can sustain, $q_{m\text{-}max\text{-}mech\text{-}CO2}$. In this analysis, a value of 2,740 tonnes per day was used for $q_{m\text{-}max\text{-}mech\text{-}CO2}$, which is equivalent to 1 Mtonne per year on an annualized basis.
    - The maximum CO_2 injection rate for an injection well is $q_{m\text{-}max\text{-}CO2}$, which is the lower of these two numbers (i.e., $q_{m\text{-}max\text{-}form\text{-}CO2}$ and $q_{m\text{-}max\text{-}mech\text{-}CO2}$).
    - The minimum number of injection wells needed is the maximum CO_2 mass flow rate for the project divided by $q_{m\text{-}max\text{-}CO2}$ with this value rounded up to the

nearest integer. CO2_S_COM allows the user to specify that one or more backup injection wells can be installed. However, for this analysis, it was assumed that there are no backup injection wells.

- CO2_S_COM estimates the size of the CO_2 plume each year as CO_2 is injected. The best estimate of the plume area, referred to as the CO_2 Plume Area in CO2_S_COM, is calculated with the following equation:

$$A_{pl}(t) = \frac{q_{m-av-CO2} * t}{p_{CO2} * h * \phi * e_{st}}$$

Where:

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

$q_{m\text{-}av\text{-}CO2}$ = annual average mass rate of CO_2 injection (kg/year)

t = duration of injection (years)

ρ_{CO2} = density of CO_2 at reservoir temperature and pressure (kg/m3)

ϕ = porosity

e_{st} = storage coefficient

The storage coefficient is the fraction of the pore space that can be occupied by CO_2 and is discussed below.

- Since the size of the CO_2 plume is uncertain as well as the orientation of the plume, an uncertainty factor is utilized to calculate a larger area that is called the CO_2 Plume Uncertainty Area using the following equation:

$$A_{pl-un} = A_{pl} * a_{pl-un}$$

Where:

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

$a_{pl\text{-}un}$ = CO_2 plume uncertainty factor

The CO_2 plume uncertainty factor used in this analysis is 1.25.

- CO2_S_COM estimates a quantity called the Pressure Front Area which is the area where pressures are elevated above a threshold. Fluid within the Pressure Front Area can migrate upward through fractures or fissures or improperly plugged legacy wells toward USDWs. The Pressure Front Area is the CO_2 Plume Uncertainty Area multiplied by a pressure front factor.

$$A_{pl-pf} = A_{pl-un} * a_{pf}$$

Where:

$A_{pl\text{-}pf}$ = Pressure Front Area (m^2)

$a_{pl\text{-}un}$ = pressure front multiplier

The pressure front multiplier used in this analysis is 10.

- The size of the CO_2 Plume Area, the CO_2 Plume Uncertainty Area and Pressure Front Area depend on the storage coefficient. The storage coefficients used in this analysis were developed by IEA Greenhouse Gas R&D Programme and depend on the lithology and depositional environment of the storage formation. [4] The storage coefficient also depends on whether there is a structure that can trap free phase CO_2. CO2_S_COM has storage coefficients for three structures: dome, anticline and regional dip (essentially flat). The dome structure has the highest storage coefficient (approximately 15%), followed by the anticline (approximately 10%) and regional dip (roughly 4 to 7%). While the dome and anticline structures provide the best trapping properties and result in smaller CO_2 plume areas, it is not known how common these structures are. It is also not known how large these structures are when they do occur in nature. The United States Geological Survey (USGS) estimated that 2.5% of the area of one basin had dome or anticline structures. [5] Unfortunately, the report did not quantify the number of discrete occurrences of these structures within the basin or the areal extent of a typical occurrence of a dome or anticline structure. For this analysis, only the regional dip structure was considered since it is believed to be the most common structure by far.
- CO2_S_COM has two methods for calculating the CO_2 Plume Area. Both methods use the equation provided previously to calculate the CO_2 Plume Area, but the methods use different mass rates of CO_2 injected. The first method uses the cumulative mass of CO_2 injected at any time for the project to calculate the CO_2 Plume Area for the project at that time. The second method uses the cumulative mass of CO_2 injected into a single injection well at any time to calculate the CO_2 Plume Area for the injection well. This area is multiplied by the number of injection wells to give the CO_2 Plume Area for the project. For both methods, the CO_2 Plume Area is used in the equations provided previously to calculate the CO_2 Plume Uncertainty Area and Pressure Front Area. The two methods give the same CO_2 Plume Area, the CO_2 Plume Uncertainty Area and Pressure Front Area for the project but give different 3D Seismic Areas and 2D Seismic Line Lengths. The second method was used in this analysis.
- In this analysis, 3D seismic and 2D seismic imaging are used. 2D seismic imaging is utilized for the initial or preliminary characterization of the site. Once the site is selected for the CO_2 storage project, the site is subjected to 3D seismic imaging for characterization. Repeat 3D seismic imaging (or 4-D seismic) is also used during operations and PISC to track the evolution of the CO_2 plume. During characterization, 3D seismic and 2D seismic are used to image the anticipated extent of the CO_2 Plume Uncertainty Area at the end of injection. During operations and PISC, repeat 3D seismic is used to track the evolution of the CO_2 Plume Uncertainty Area.
    - To image a target area in the subsurface, 3D seismic must be deployed over a larger area than the target area and the area needed for 3D seismic is a nonlinear function of the target area. When the first method is used to calculate the CO_2 Plume Uncertainty Area, the 3D seismic area at any time is a function of the CO_2

Plume Uncertainty Area for the entire project at that time. When the second method is used to estimate the CO_2 Plume Uncertainty Area, the 3D seismic area at any time is a function of the CO_2 Plume Uncertainty Area for a single injection well at that time. The 3D seismic area for a single injection well is multiplied by the number of injection wells to give the 3D Seismic Area for the entire site. Since the 3D seismic area is a nonlinear function of the target area, the 3D Seismic Area for the project is larger using method 2 than the 3D Seismic Area for the project using method 1. As noted above, method 2 was used in this analysis.

  - When using 2D seismic to image a target area in the subsurface, 2D seismic must similarly be deployed over a larger length than the length of the target area. In CO2_S_COM, the length of a line for 2D seismic is a function of the diameter of the CO_2 Plume Uncertainty Area, assuming the CO_2 Plume Uncertainty Area is a circle. When the first method is used, the length of a 2D Seismic Line Length at any time is a function of the diameter of the CO_2 Plume Uncertainty Area for the project at that time. When the second method is used, the 2D seismic line length at any time is a function of the diameter of the CO_2 Plume Uncertainty Area for a single injection well at that time and this length is multiplied by the number of injection wells to give the 2D Seismic Line Length at that time for the entire site.

CO2_S_COM calculates the prospective storage resource for the storage formation. This is the total mass of CO_2 that could potentially be stored in the storage formation. The prospective storage resource is subject to three constraints.

- First, the user must specify the fraction of the surface area of the storage formation that is available for storage projects. It is assumed that some areas of the storage formation, such as areas that have high population density, cannot be used for CO_2 storage projects. In this analysis, it was assumed that 80 percent of the surface area of a storage formation can be used for saline storage.
- Second, CO2_S_COM assumes that pore space rights are purchased for the entire CO_2 Plume Uncertainty Area, and it is assumed that only one project can use this pore space. This limits the number of projects that can be implemented in a single storage formation.
- Third, if multiple storage projects are implemented at the same time in a storage formation, pressure interference can arise between the projects which can limit the number of projects that can be implemented simultaneously. A paper by Teletzke et al. (2018), includes the results of simulating multiple injection wells being installed and operated at the same time. [6] Teletzke et al. (2018) vary the permeability and demonstrate that lowering the permeability lowers the maximum injection rate that each well can sustain without exceeding pressure limits of the Class VI regulations. Alternatively, fewer projects can be implemented simultaneously. The paper provides a factor to lower the prospective storage resource of a storage formation based on the permeability of the formation. CO2_S_COM calculates the prospective storage resource two ways. The first prospective storage resource is calculated using the first two

constraints. The second prospective storage resource is calculated using all three constraints. In this analysis, the second prospective resource is used.

2.5 MONITORING PROGRAM

CO2_S_COM has many monitoring technologies that can be employed to track the evolution of the CO_2 plume, to monitor for leaks of CO_2 or brine out of the storage formation into or toward USDWs, and to monitor induced seismicity. For this analysis the following monitoring technologies were assumed to be utilized.

- 3D seismic imaging is performed every 5 years during operations and PISC to track the evolution of the CO_2 plume. The cost of 3D seismic depends on the size of the CO_2 Plume Uncertainty Area and this cost increases as the CO_2 plume expands.
- In this analysis, it was assumed that deep dual completed monitoring wells are used. These monitoring wells are completed in the storage formation and in a permeable formation above the caprock. It is assumed that pressures and temperatures are monitored on an almost continuous basis in the storage formation and the overlying permeable formation. Once a year, fluid samples are collected from four depths in the storage formation and four depths in the overlying permeable formation and analyzed for CO_2 and other constituents. It was assumed that one deep dual completed monitoring well is installed for each injection well and that all deep dual completed monitoring wells are installed the year before CO_2 injection begins so that background conditions in the storage formation and overlying permeable formation waters can be established.
- In this analysis, groundwater monitoring wells are also implemented. These wells are used to monitor conditions in groundwater within 400 feet of the surface. Fluid samples are collected from 4 depths in each groundwater monitoring well four times each year and analyzed for CO_2 and other constituents. It was assumed that one groundwater well is installed for each injection well and that all groundwater monitoring wells are installed the year before CO_2 injection begins so that background conditions in the groundwater can be established.
- It was assumed that portable instruments to monitor for CO_2 in the atmosphere are used to periodically check for leaks of CO_2 from surface equipment at the CO_2 storage project.

2.6 COSTS

CO2_S_COM includes costs for the equipment and monitoring devices discussed above. These include stratigraphic test wells, injection wells, monitoring wells, 3D seismic and 2D seismic surveys, and portable air monitoring devices. CO2_S_COM also includes costs for purchasing geologic data from third parties, costs for aerial surveys, costs for cataloging and locating active and plugged and abandoned wells, costs for constructing geologic models of the storage formation, costs for developing and running reservoir simulation models of the storage project design, costs for the design of the project, and costs for preparing the Class VI injection well permit documents. CO2_S_COM includes costs for surface equipment. Costs are provided for a high-quality custody transfer gauge that measures the mass flow rate of CO_2 coming onto the site, a pump for increasing the pressure of CO_2 so the CO_2 can flow through distribution pipes to injection wells, a header that diverts the incoming CO_2 flow from the pump to distribution pipelines, and distribution pipelines. Additional surface equipment or structures include an onsite office building, control system and access roads. CO2_S_COM includes costs for collecting, assimilating, and analyzing monitoring data, costs for modeling the evolution of the CO_2 plume and pressure front, and costs for preparing reports for submittal to the governing regulatory authority.

CO2_S_COM calculates the costs of complying with the following components of financial responsibility required by the Class VI injection well regulations: corrective action, injection well plugging, PISC and site closure, and the cost of developing and implementing the Emergency and Remedial Response (ERR) Plan. CO2_S_COM also includes the cost of implementing financial instruments to satisfy that aspect of financial responsibility (e.g., trust fund, escrow account, self-insurance, insurance, surety bonds, letter of credit). In this analysis, CO2_S_COM explicitly calculates the costs of corrective action, injection well plugging, PISC and site closure. These costs are used to calculate the cost of a trust fund used to cover the cost of these three components. CO2_S_COM does not calculate the costs of implementing an ERR Plan, but CO2_S_COM includes the cost of purchasing an insurance policy that can be used to cover the cost of implementing the ERR Plan if an adverse event occurs and the CO_2 storage operator cannot pay to implement the ERR Plan.

Most of the unit costs used in the model come from reports EPA generated to estimate the cost associated with the Class VI injection well regulations. [7] [8] These reports provide costs in 2008 dollars. Consequently, the base year for costs in CO2_S_COM is 2008.

CO2_S_COM assumes the CO_2 storage operator must pay landowners for surface access and the right to use their pore space. The operators are assumed to pay a lease bonus for the maximum extent of the CO_2 Plume Uncertainty Area. In this analysis, the lease bonus is assumed to be $50 per acre in 2008 dollars.

CO2_S_COM assumes there can be several fees associated with operating a CO_2 storage facility. These fees are all expressed as costs per tonne of CO_2 injected where the costs are in 2008 dollars.

- Cost of the insurance policy for implementing the ERR Plan (part of financial responsibility): $0.75/tonne.
- Royalty paid to pore space owners: $0.25/tonne.
- Money paid into a long-term stewardship trust fund operated by the state: $0.07/tonne.
- Operational oversight fund utilized by the regulatory authority: $0.01/tonne.

2.7 FINANCIAL MODEL

The objective of the storage operator is to manage the CO_2 storage project so that it is profitable. CO2_S_COM has a financial model to determine if a project is profitable or, alternatively, to determine the lowest CO_2 price the operator must charge to have a viable CO_2 storage project. The financial model has the following elements.

- All costs and revenues are provided in the base year of 2008. CO2_S_COM provides two escalation rates. The first escalation rate is used to escalate prices, fees, unit costs and, consequently, revenues and costs to the first year of the project (not the first year of CO_2 injection). In this analysis, the first year of the project was assumed to be 2023, the default in the model. The second escalation rate escalates revenues and costs beyond the first year of the project. If the user wishes to perform an analysis where future revenues and costs are in the expected dollar values in future years (often called nominal or current dollars), the user must choose a value for the second escalation rate that reflects the anticipated inflation rate across the duration of the project. This is referred to as a nominal dollar analysis in CO2_S_COM. Alternatively, the user may not wish to anticipate the influence of inflation on future prices, fees and unit costs. In this case the user will set the inflation rate to zero and all prices, fees and unit costs will remain in their dollar value at the beginning of the CO_2 storage project. This is referred to as a real or constant dollar analysis in CO2_S_COM. When the user selects the second escalation rate, they must also select the interest rate on debt and the minimum desired internal rate of return on equity to be consistent with this rate as these two values depend on the selected escalation rate (i.e., whether inflation is included in the analysis). For this study, the second escalation rate was set to zero, so a real or constant dollar analysis was performed. The interest rate on debt and the minimum desired internal rate of return on equity were selected to be consistent with this escalation rate.
- In CO2_S_COM, the user selects a price for CO_2 in the first year of the project. CO2_S_COM multiplies the mass of CO_2 injected each year by the CO_2 price to generate revenues in each year. Revenues are generated in real dollars in the base year, real dollars in the first year of the project, and nominal dollars using the second escalation rate.
- CO2_S_COM calculates capital and O&M costs, and these are posted in the appropriate years in real base year dollars. These costs are summed to give cash flows of capital costs and O&M costs in real base year dollars. CO2_S_COM also provides cash flows in real dollars for the first year of the project and nominal dollars using the second escalation rate. The capital cost cash flows are totaled by different categories for tax purposes. For each category, the appropriate depreciation schedule is applied to depreciate the capital expenses. Depreciation is done with nominal cash flow dollars. Because the second escalation rate was set to zero in this analysis (i.e., a real dollar analysis was performed), all the costs calculated in nominal dollars are the same as the costs in real dollars for the first year of the project.
- In this analysis, a trust fund is used as the financial instrument to cover the costs of corrective action, injection well plugging and PISC and site closure to comply with the financial responsibility requirements of the Class VI injection regulations. CO2_S_COM calculates the payments needed into the trust fund which begin in the year before injection begins and last three years. CO2_S_COM assumes the money in the trust fund

is conservatively invented, so the funds in the trust fund grow each year. The trust fund is available to the regulatory authority not the CO_2 storage operator, but the regulatory authority can release money from the trust fund as the various items covered by the trust fund are paid by the operator. In this analysis, it is assumed that funds are released from the trust fund in the year that items covered by the trust fund are paid.

- CO2_S_COM calculates the amount of debt needed in each year along with the interest payments and principal payments on debt. CO2_S_COM uses debt (if needed) to cover a portion of costs in all years through the end of operations but not during PISC and site closure. It is assumed that expenses incurred during PISC and site closure are paid by equity. CO2_S_COM uses a cash sweep to pay off the principal and interest on debt.
- CO2_S_COM calculates tax-based earnings as revenues plus withdrawals from the trust fund minus depreciated capital costs, O&M costs, interest on debt, and payments into the trust fund. Carry-over losses from previous years are also considered. The tax-basis earnings are used to calculate federal corporate income taxes as well as state and local taxes.
- CO2_S_COM then calculates the net cash flow to owners (i.e., equity investors) in each year as revenues, withdrawals from the trust fund, and debt proceeds minus capital costs, O&M costs, interest payments on debt, principal payments on debt, payments into the trust fund, and taxes. The net cash flow to owners is calculated in nominal dollars.
- The net cash flow to owners is discounted by the minimum desired internal rate of return on equity to give present value cash flow to owners. This present value cash flow is summed to give the net present value (NPV) for the project. If NPV is greater than zero, then the price set for CO_2 in the first year of the project is high enough to cover all costs, including financing costs, and the CO_2 storage project is economically viable. If NPV is less than zero, then the first-year CO_2 price is too low and will not generate sufficient revenues to cover all costs. In this instance, the CO_2 storage project is not economically viable. If NPV equals zero, then the first-year CO_2 price is sufficient to cover all costs, including capital costs, O&M costs, taxes, and the principal and interest on debt, and equity investors will receive their minimum desired internal rate of return on their investment. Thus, the saline storage project is economically viable at this first-year CO_2 price.
- The first-year CO_2 price that gives an NPV of zero is an extremely useful benchmark and is called the first-year break-even CO_2 price since this is the CO_2 price where the CO_2 storage project is breakeven. The first-year break-even CO_2 price is the lowest price the storage project operator can charge and still have an economically viable project. CO2_S_COM has the capability to calculate the first-year break-even CO_2 price. The first-year break-even CO_2 price is also called the levelized price of CO_2.

Assumptions used for key financial variables in this analysis are as follows.

- 20% General and Administrative (G&A) factor assessed on all labor costs.
- 20% process contingency assessed on all monitoring technologies.

- 15% project contingency assessed on all capital costs.
- Percent equity: 45% (debt is 55%).
- Escalation rate from base year for costs to first year of project: 3.5%/yr.
- Escalation rate after project starts: 0%/yr (real dollar analysis).
- 10.77%/yr minimum desired internal rate of return on equity (adjusted for real dollar analysis).
- 3.91%/yr interest rate on debt (adjusted for real dollar analysis).
- 25.74%/yr effective tax rate accounting for 21%/yr federal corporate income tax rate and 4.74%/yr for state and local taxes.

The basis for these values is described in Appendix A of the forthcoming User's Manual for CO2_S_COM.

3 Reduced Order Costs

3.1 Basis for Reduced Order Costs

The objective for defining reduced order costs is to aggregate costs that are in the same categories, such as capital costs that are all subject to the same depreciation schedule, and aggregate costs that depend on some characteristic of the CO_2 saline storage project that is easy to track. Many costs, whether capital or O&M, depend on the maximum mass injection rate for the CO_2 saline storage project. The number of injection wells also depends on the maximum CO_2 mass injection rate for the project, so many costs are essentially dependent on the number of injection wells. Other costs depend on the annual average or the cumulative mass rate of CO_2 injection. Finally, some costs are fixed and depend on neither the number of injection wells nor the annual average mass rate of CO_2 injection, although these costs are not a large percentage of the total costs.

CO2_S_COM has three depreciation schedules for capital costs.

- The drilling and completion of stratigraphic test wells, injection wells, deep dual completed monitoring wells and groundwater wells are subject to the same depreciation schedule which is the 200% declining balance method with a 5-year recovery period. The capital costs associated with these wells include drilling and completion of the wells, logging, core recovery, and fluid recovery during drilling.
- The 2D and 3D seismic surveys are capital costs and are subject to the same depreciation schedule which is the straight-line method with a 5-year recovery period.
- All other capital costs are subject to a general depreciation schedule which is the 150% declining balance method with a 15-year recovery period. These capital costs include purchase of data from third parties during site screening and site selection, aerial surveys, obtaining leases for property access and pore space rights, costs associated with the design of the CO_2 saline storage system, and costs associated with preparing permitting documents. These capital costs also include the costs of installing surface equipment (meters, headers, distribution pipelines), access roads, and an office building.

With one exception, all capital costs occur before CO_2 injection begins. These costs include capital costs for drilling and completing stratigraphic test wells, injection wells, deep dual completed monitoring wells, and groundwater wells. The capital costs of much of the surface equipment, such as pipelines and the size of the CO_2 pump, also depend, at least partially, on the number of injection wells. In developing reduced order costs, all capital costs for a specific depreciation schedule that were incurred before injection begins were summed for a particular stage and then divided by the number of injection wells. This results in a capital cost per injection well for a specific depreciation schedule and a specific stage.

The capital costs that do not occur before injection begins are the costs of 3D seismic surveys performed to track the evolution of the CO_2 plume and check for leakage of CO_2 which are performed during operations and PISC. The capital costs for 3D seismic surveys performed during operations in any given year depend on the 3D Seismic Area which depends on the cumulative mass of CO_2 injected in that year. The 3D Seismic Area is a nonlinear function of the cumulative mass of CO_2 injected. In addition, 3D seismic surveys occur once every 5 years. Consequently, there is not an easy method to relate costs to the mass of CO_2 injected in a specific year. For this study, the total costs of performing 3D seismic in a particular stage were summed and divided by the total CO_2 injected for the project. This gives a cost for performing 3D seismic surveys in that stage per tonne of CO_2 injected.

Most O&M costs in CO2_S_COM are fixed costs that depend on the equipment operating at that time. The equipment in place at any time depends to a large extent on the maximum mass rate of CO_2 injection and the number of injection wells depends on the maximum mass rate of CO_2 injection. Thus, the fixed O&M costs for a particular stage were summed and then divided by the number of years in that stage and the number of injection wells to give an average annual O&M cost per injection well.

The variable O&M costs are the cost of electricity used and the fees discussed previously. These costs depend on the mass of CO_2 injected each year during the operations stage. In this analysis, the fees were summed for the stage and divided by the number of years in the stage and the mass of CO_2 injected for the project to give an average annual cost per tonne of CO_2 injected.

The electricity costs were not explicitly calculated. Many energy market models calculate the cost of electricity, so the quantity of electricity used per tonne of CO_2 injected is needed. Therefore, the electricity used in a year was calculated and divided by the CO_2 injected that year to give an annual average quantity of electricity used per tonne of CO_2 injected.

The last cost considered is the trust fund. In this analysis, it is assumed that the trust fund is financed by three payments beginning in year 5 and ending in year 7 of the project. These payments were summed and divided by the number of injection wells to give a cost for financing the trust fund per injection well.

Since releases of money from the trust fund are assumed to cover the costs of corrective action, injection well plugging, and PISC and site closure, these costs should not be included in cost modeling if the trust fund is used to cover financial responsibility costs. In the spirit of completeness, the costs of corrective action, injection well plugging, and PISC and site closure are included. These costs would need to be included if self-insurance is used as the financial instrument for addressing financial responsibility costs rather than the trust fund. The following additional costs are provided.

- Corrective action costs are assumed to be proportional to the maximum extent of the Pressure Front Area and are assumed to be incurred during the first half of the operational stage. These costs were summed for the entire operational stage. Because these costs are proportional to the total mass of CO_2 injected the costs total costs were divided by the total mass of CO_2 injected to give corrective action costs per tonne of CO_2 injected.
- Injection well plugging costs are assumed to occur at the end of the operational stage when injection stops. These costs depend on the number of injection wells. These costs were summed and divided by the number of injection wells to give an injection well plugging cost per injection well.
- During PISC and site closure, two categories of costs are incurred.
  - One category is fixed O&M costs. These were summed and divided by the number of injection wells to give fixed O&M costs per injection well during the PISC and site closure stage.
  - The second category is 3D seismic survey costs. These costs were incurred every five years and are the same each time since the 3D Seismic Area is at its maximum extent and assumed to be constant during PISC. These costs were divided by the duration of PISC to give an average annual cost for performing a 3D seismic survey during PISC.

3.2 REDUCED ORDER COSTS

The attached file named “Red_ord_stor_costs_CO2_S_COM_2024_01_15.xlsx” contains the results of this analysis. Results are presented for 4 different durations of PISC: 50, 25, 15 and 10 years because the duration of PISC has a significant influence on the money that needs to be invested in the trust fund. The money invested in the trust fund has a significant influence on the first-year break-even price for CO_2 which is one of the best overall financial metrics for storing CO_2 in a storage formation. The duration of PISC does not influence any of the other reduced order costs.

The results are in sheets named “Red_ord_costs_mm” where mm is 50, 25, 15 or 10 corresponding to the duration of PISC in years. Each sheet contains the results for the 314 storage formations in CO2_S_COM. A row provides results for one of the storage formations and the columns provide values for a single output variable. The output variables for each column are described below. The column number referred to in the discussion below is in row 4.

- Columns 1 to 5: These columns provide the number of the storage formation, name of the storage formation, state where the storage formation is located and the latitude and longitude of the centroid of the storage formation.
- Columns 6 and 7: These columns provide the surface area of the storage formation and the surface area of the storage formation that can be used for storage.

- Columns 8 to 11: The duration in years of four stages: site screening; site selection, characterization and design; permitting and construction; and operations (injection). Injection is assumed to start at the beginning of the 6th year of the project and last 30 years.
- Column 12: Number of injection wells for the project.
- Column 13: Maximum number of injection wells that can be operating in the storage formation simultaneously without exceeding pressure interference and plume spacing constraints.
- Columns 14-17: Average annual injection rate for each injection well, maximum rate of injection on an annualized basis for each injection well, percentage of time the maximum rate is available, and the total mass of CO_2 injected by each injection well. The average annual injection rate for an injection well is less than the maximum annualized injection rate multiplied by the availability of the well. The number of injection wells is the maximum annualized injection rate for the project divided by the maximum annualized flow rate in an injection well. If this number is not an integer, it is rounded up to the nearest integer. Thus, each injection well will often have an average annual flow rate less than the annualized mass flow rate in the well at maximum availability.
- Column 18: Prospective storage resource for the storage formation including pressure interference and plume spacing constraints. These constraints lower the prospective storage resource that can be utilized when multiple CO_2 storage projects are operating (injecting) at the same time.
- Note: The analysis was done using real 2023 dollars. The Handy Whitman cost indices for Cost Trends of Gas Utility Construction for Storage Plants were used to escalate costs from 2008 to 2023. [9] Most of the base costs in CO2_S_COM are in 2008 dollars. The first year of the project is 2023 and all revenues and costs beyond 2023 were held constant. The interest rate on debt and the minimum desired internal rate of return on equity were selected to be consistent with a zero escalation rate.
- Columns 19-21: Total fixed general capital costs per new injection well incurred in site screening stage (year 1 of project), site selection, characterization and design stage (years 2 and 3 of the project) and permitting and construction stage (years 4 and 5 of the project). These capital costs are depreciated using the 150% declining balance method over 15 years.
    - Column 19: The value in this column is the total money spent per new injection well in the site screening stage (project year 1). This value should be applied in year 1 of the project. This is a one-time cost for each new injection well.
    - Column 20: The value in this column is the total money spent per new injection well in the site selection, characterization and design stage (project years 2 and 3). This value should be applied in year 2 or 3 of the project for each new injection well but not both years. This is a one-time cost for each new injection well.

    - Column 21: The value in this column is the total money spent per new injection well in the permitting and construction stage (project years 4 and 5). This value should be applied in year 4 or 5 of the project for each new injection well but not both years. This is a one-time cost for each new injection well.

- Columns 22 and 23: Total fixed well capital costs per new injection well incurred in site selection, characterization and design stage (years 2 and 3 of the project) and permitting and construction stage (years 4 and 5 of the project). These capital costs are depreciated using the 200% declining balance method over 5 years.
    - Column 22: The value in this column is the total money spent per new injection well in site selection, characterization and design stage (project years 2 and 3). This value should be applied in year 2 or 3 for each new injection well but not both years. This is a one-time cost for each new injection well.
    - Column 23: The value in this column is the total money spent per new injection well the permitting and construction stage (project years 4 and 5). This value should be applied in year 4 or 5 for each new injection well but not both years. This is a one-time cost for each new injection well.
- Columns 24 and 25: Total fixed seismic capital costs per new injection well incurred in site screening stage (year 1 of project) and site selection, characterization and design stage (years 2 and 3 of the project). These capital costs are depreciated using the straight-line method over 5 years.
    - Column 24: The value in this column is the total money spent per new injection well in the site screening stage (project year 1). This value should be applied in year 1 of the project. This is a one-time cost for each new injection well.
    - Column 25: The value in this column is the total money spent per new injection well in the site selection, characterization and design stage (project years 2 and 3). This value should be applied in year 2 or 3 of the project for each new injection well but not both years. This is a one-time cost for each new injection well.
- Column 26: Variable seismic capital costs per tonne of CO_2 injected during operations stage (years 6 through 35 of the project). This is an annual cost that should be applied to all the CO_2 injected in each year of operations. Since this is a seismic cost, it is a capital cost that should be depreciated using the straight-line method over 5 years.
- Column 27: Average annual fixed expenses per injection well incurred during operations stage (years 6 through 35 of the project). This is an annual cost that should be applied to each active injection well during operations.
- Column 28: Variable expenses (excluding electricity costs) per tonne of CO_2 injected during operations stage (years 6 through 35 of the project). This is an annual cost that should be applied to the CO_2 injected in each year of operations.

- Column 29: Electricity usage per tonne of CO_2 injected during operations stage (years 6 through 35 of the project). This is the annual electricity used that should be applied to all the CO_2 injected in each year of operations.

The remaining columns present results for the duration of the PISC and site closure stage used to generate the results in the sheet. For each value of PISC, 7 results are presented.

- Column 30: The duration of the PISC and site closure stage. This stage begins in year 36 of the project.
- Column 31: Money deposited in a trust fund in years 5 through 7 of the project per new injection well.
    - Note: The value in this column is the total amount of money deposited into the trust fund and should be applied in year 5, 6 or 7 for each new injection well but not all three years. This is a one-time cost.
    - The trust fund is set up by the operator of the CO_2 storage project for use by the regulatory authority. The trust fund is designed to cover the costs of the following components of financial responsibility: corrective action, injection well plugging, and PISC and site closure. The trust fund is intended for use by the regulatory authority in the event the operator of the CO_2 storage project cannot pay for any element of financial responsibility. However, the regulatory authority can release money from the trust fund to the CO_2 storage project operator as elements of financial responsibility are completed. In this analysis, it is assumed the regulatory authority releases money from the trust fund shortly after elements of financial responsibility are completed. Consequently, the costs of corrective action, injection well plugging and PISC and site closure are covered by releases of money from the trust fund.
- Column 32: First-year break-even price of CO_2 in 2023 dollars per tonne. This is the lowest price the operator of the CO_2 storage project can charge and receive enough revenue to cover all costs including financing costs. The first-year break-even CO_2 price is also called the levelized price of CO2.

The last set of columns present costs for corrective action, injection well plugging and PISC and site closure. These costs are presented for completeness but should not be included in an energy market model since these costs are assumed to be covered by releases of money from the trust fund as discussed above.

- Column 33: Corrective action expenses per tonne of CO_2 injected each year during the operations stage. This is an annual cost that should be applied to the CO_2 injected in each year of operations.
- Column 34: Total injection well plugging expenses per plugged injection well incurred at the end of the operations stage or start of PISC (year 35 or 36 of the project). This is a one-time cost that should be applied to each plugged injection well.

- Column 35: Average annual fixed expenses per closed injection well incurred during the PISC and site closure stage (years 36 of the project through the duration of PISC). This is an annual cost that should be applied to each closed injection well during PISC.
- Column 36: Average annual seismic capital costs per closed injection well incurred during the PISC and site closure stage (years 36 of the project through the duration of PISC). This is an annual cost that should be applied to each closed injection well during PISC. This is technically a seismic cost, so these costs should be depreciated using the straight-line method over 5 years. If accounting is done on a project basis and there is no project income from injection during PISC, it may be acceptable to treat these costs as expenses rather than capital costs.

3.3 APPLICATION OF REDUCED ORDER COSTS

This section describes how the reduced order costs can be applied. The discussion is for a single storage formation and needs to be replicated for all storage formations that are used for storage. The discussion assumes the user knows how many capture facilities will come online each year. The discussion actually assumes the user can project the number of capture facilities that will come online at least five years in the future so that storage projects can be initiated five years before the capture facilities begin shipping CO_2 to the storage facility. The user also needs to know how many capture facilities will stop capturing CO_2 in each year. This analysis assumes that if there is excess capacity in the storage formation (i.e., some capture facilities have stopped capturing CO_2), capture facilities that are coming online can use any spare capacity that is available in existing injection wells.

- The user needs to know the number of new capture facilities that will come online in a given year, the number of capture facilities that will go offline in that same year. The user needs to know the maximum mass flow rate from the new and currently active capture facilities. The user also needs to know the total mass of CO_2 that will be captured that year as well as the cumulative CO_2 that will be captured by the end of that year.
- In a given year, the total maximum mass flow rate of CO_2 coming from capture facilities will be used to determine the number of injection wells needed. First the user needs to determine the number of currently active injection wells which is the number of active injection wells in the previous year minus any injection wells that stopped injecting at the end of the previous year. Second, the total maximum mass flow rate of CO_2 coming from capture facilities is used to calculate the total number of injection wells needed using the maximum injection rate the well can accommodate (see Column 15 in the results spreadsheet. Third, if the total number of injection wells needed exceeds the maximum number of injection wells that the storage formation can sustain (see Column 13 in the results spreadsheet). If the total number of injection wells needed exceeds the maximum allowed, then the user will need to send some captured CO_2 to a different storage formation so that the number of injection wells needed is less than or equal to the maximum number of injection wells allowed. Fourth, if the total number of injection wells needed exceeds the number of currently active injection wells, then new injection

wells will need to be added in that year. The user needs to keep track of the number of new wells added each year, the number of injection wells that go offline at the end of each year and the total number of injection wells that are active during each year.

- Before adding new injection wells, the user should check that the storage formation has the necessary storage capacity. The user should keep track of the cumulative mass of CO_2 injected into the storage formation. Since the user has kept track of the number of injection wells that have come online each year, the user can determine how many more years of injection for each injection well assuming each injection well operates for 30 years. The number of years remaining for all the injection wells are summed and multiplied by the average mass of CO_2 injected each year (see Column 14 of the results spreadsheet). This total mass of CO_2 that will be injected is added to the cumulative mass of CO_2 injected already. If this sum exceeds the prospective storage resource for the formation (see Column 18 of the results spreadsheet), then no new injection wells can be added.
- Once the number of new injection wells is known for each year, the one-time capital costs need to be applied to the appropriate years before the year when the new injection wells come online. Since these are capital costs, they need to be depreciated appropriately (see Columns 19 through 26 of the results spreadsheet).
- For each new injection well, the one-time cost of financing the trust fund (see Column 31 of the results spreadsheet) needs to be applied in the appropriate year.
- In each year, the annual costs of operating the CO_2 storage project need to be determined.
    - The number of active injection wells in a given year needs to be multiplied by the average annual fixed expenses per injection well (see Column 27 of the results spreadsheet) to give the total fixed expenses incurred in that year.
    - The total mass of CO_2 injected in a given year needs to be multiplied by the variable seismic capital costs per tonne of CO_2 injected (see Column 26 of the results spreadsheet) to give the 3D seismic capital costs in that year. Since these are capital costs they need to be depreciated appropriately.
    - The total mass of CO_2 injected in a given year needs to be multiplied by the variable expenses per tonne of CO_2 injected (see Column 28 of the results spreadsheet) to give the total variable expenses incurred in that year.
    - The cost of electricity used in a given year is determined by first calculating the total electricity used. The total mass of CO_2 injected in a given year is multiplied by the electricity used by each tonne of CO_2 injected (see Column 29 of the results spreadsheet) to give the total electricity used in that year. The electricity used is then multiplied by the cost of electricity to give the cost of electricity use in that year.

The process described in this section may seem involved. However, this process can be implemented as a computer program as long as the mass of CO_2 that needs to be captured in a given year can be represented by the model early enough (i.e., at least 5 years before capture begins), so that there is enough time to get the needed storage projects characterized, designed, permitted and infrastructure implemented (e.g., injection wells) before capture commences.

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