NETL CO₂ Injection and Storage Cost Model
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Abstract
The U.S. Department of Energy’s National Energy Technology Laboratory (NETL) has developed a model to estimate the costs of sequestering captured CO₂. This model includes costs from initial regional geologic evaluation through site characterization, permitting, injection/MVA operations, post-injection site care to final site closure and transfer to long-term stewardship. Differences in storage costs across different geologic formations are driven by two basic factors: injectivity which determines the number of injection wells drilled to accommodate a given rate of CO₂ injection and the volume of CO₂ to be sequestered which determines, per in-situ reservoir parameters, the areal extent of the plume and hence the Area of Review of a Class VI well permit. The AoR defines the areal extent of MVA activities which dominates costs during injection and post-injection operations. The basic framework for this model provides costs for compliance with various sections of EPA’s Class VI regulation and Subpart RR of the GHG Reporting Program. Cost analysis at two levels is provided by this model: site specific where the modeler can enter their own reservoir and cost data and regional in the form of cost supply curves. A geologic and cost database was developed to support this model. Published analyses of storage cost to date have been very general, providing estimates for site characterization or overall costs but few details. While storage costs are a small percentage of overall CCS costs, they represent a significant investment. Getting to the point of injection operations will take tens of millions of dollars. Model results indicate that operation/post-closure MVA costs will represent some 70 percent of overall storage costs. Also, the financial mechanisms used to establishing Financial Responsibility prior to permitting may represent a significant cost. A detailed understanding of overall storage costs is critical for investors and policy planners. This model can be combined with a simple pipeline costing model that is part of NETL’s current Transport, Storage, and Monitoring Cost Model as well as with NETL’s Capture-Transport-Storage pipeline model capable of modeling CO₂ pipeline networks. This model can be combined with NETL’s Power Supply Financial Model for cost analysis across the CCS value chain.

Introduction
The National Energy Technology Laboratory (NETL) has developed a CO₂ Transportation & Storage cost model. This model represents further development of NETL’s existing model, Estimating Carbon Dioxide Transportation and Storage Costs. Recently, NETL developed a Capture-Transport-Storage (CTS) model to model pipeline development for transportation of captured CO₂ from source to sink. NETL also has a Power Supply Financial Model (PSFM) to model the cost of capture for an IGCC or
Super-critical PC plant.

Three modules provide the foundation for the CO₂ Transportation & Storage cost model: geologic, activity cost and financial cost modules. The geologic module has the algorithms for calculating the reservoir values for injection rate and areal extent of the CO₂ plume. Both are the primary cost drivers for the model. The activity cost module contains the technology, service and labor costs for well drilling, MVA, general operations, periodic reporting, and financial responsibility as well as other items for successful operations of a storage field. The financial module posts balance sheet, income statement and state of cash flow information used to determine financing costs, tax liability and cash available to owner(s) along with NPV and IRR values.

The model provides for two basic analyses: an annual cost analysis or a business analysis. The annual cost analysis is activity costs that are incurred to store CO₂ per EPA Class VI regulations and posted in each year they occur by the model over the life of the storage project. These are estimated real costs and can be considered a reference level cost prior to applying a rate of escalation. NETL’s CTS model will require real costs as data input for its interaction with NEMS and modeling CO₂ pipeline routes between sources and sinks. These real costs are tied to a reference year; usually the beginning year of the project or base year of the cost data. Business analysis applies a rate of escalation and costs are considered nominal. A business analysis informs the modeler what price needs to be charged to store a tonne of captured CO₂ to meet investor’s expectations on returns. Business analysis can also provide information regarding financing, return on equity and tax costs. NETL’s Power Supply Financial Model (PSFM) needs the price of CO₂ storage at an IRR value for input, a business analysis result.

Model Description

NETL’s CO₂ Transportation & Storage cost model serves multiple purposes. It has the ability to generate a cost value for a single storage field operation, or single site. It also has the ability to read through a list of geologic formations with associated reservoir data, calculating the cost of storage for each formation, and providing the data to generate a storage cost supply curve. The model has cost data entry capacity for just about all of the technologies envisioned for all of the stages of a CO₂ sequestration operation. This level of detail will provide NETL the ability to assess the numerous research projects funded by the lab.

The model has three basic modules: Geologic, Activity Cost and Financial. The overall framework of the model follows a sequence of six operational stages over the life span of a CO₂ sequestration operation (Table 1): Regional Geologic Evaluation, Site Characterization, Permitting, Operations/MVA, Post-Injection Site Care (PISC) and Site Closure and Long-term Stewardship. Long-term Stewardship is not modeled since responsibility for this segment in the life of a storage site will, most likely, be assumed by an entity other than the operator. The model does have provisions to collect fees for a Long-term Stewardship trust fund as well as other funds that may be required by state law or other regulation. A key aspect of the model is the ability of the user to define the time frame for each segment modeled. Current assumptions are that regional geologic evaluation will take a year, site characterization three years, permitting one year, operations 30 years and post-injection site care and site closure 50 years, a span of 85 years. The user can modify the time span for any segment creating a new modeling scenario.
Table 1: Sequence of events for CO₂ storage operations and framework for CO₂ Transportation & Storage cost model.

Geologic Module

The Geologic module provides for calculation of rate of CO₂ injection and areal extent of the CO₂ plume. The model user can enter the geologic data needed or use values from a default geologic database, based on the NATCARB database, provided. Alternatively, a new geologic database can be created by the model user and incorporated in the model. Injection rate is calculated by a methodology developed by Law and Bachu.iii,iv It is assumed that the reservoir is an open reservoir and that injection of CO₂ is steady state over the operational period of the storage project. Based on the annual volume of CO₂ to be sequestered, the model will determine the number of injection wells required by the project. A user-defined factor is used to increase the number of injection wells to provide for spare injectivity to provide for continuation of operations when injection wells are shut-in for repairs. If the annual injection rate can be accommodated by one injection well, the model will assign a minimum of two injection wells for a storage project. Well costs are based on the API-Joint Association Surveyv on drilling costs and algorithms to calculate wells costs by state are included in the model. Injection wells
will be plugged at the end of operations and an Injection Well Plugging Plan is one of five plans required for permit application.

Plume size is also calculated within the Geologic module and is a critical cost driver. Modeled plume size determines, in this model, the areal extent of the Area of Review (AoR), a key parameter for any CO₂ storage field operation. The AoR is also based on the position of the pressure front where pressure is great enough to lift fluid to a USDW. However, calculation of this pressure front is beyond the scope of this model. Within the AoR, the operator identifies the number of old wellbores that they determine will require corrective action and prepares the Area of Review and Corrective Action Plan, one of five plans to be submitted for a Class VI permit. The AoR and underlying geology provide the foundation to design the monitoring, verification and accounting (MVA) program which is described in the Testing and Monitoring Plan submitted for a Class VI permit. Key cost items here are the number of monitoring wells to be drilled and the extent of the 3-D seismic program. These two cost items are also included in the Post-Injection Site Care (PISC) & Site Closure Plan. The fifth of five plans prepared based on the AoR is the Emergency and Remedial Response Plan.

Plume size is determined by the volume of captured CO₂ sequestered, reservoir porosity, reservoir storage efficiency, height of the reservoir and the density of the CO₂ in the reservoir. Model user selects the annual volume of CO₂ to be injected and the life of the storage project, the model will calculate the total volume of CO₂ sequestered. Reservoir porosity can be listed in the geologic database and read by the model or the user can enter this information. While porosity for any particular formation can be found in the literature, storage efficiency of CO₂ in saline reservoirs is a more elusive and critical parameter, often best estimated by reservoir modeling, which is beyond the scope of the CO₂ Transportation & Storage cost model. A lookup table is included in the model with storage efficiencies posted by general lithology and depositional environments. Data in the table is from a study done by the IEA Greenhouse Gas R&D Programme. The Peng-Robinson equation of state is embedded in the model, calculating the density of the CO₂ under reservoir conditions. Height of the reservoir can be user defined or read from the geologic database.

Cost Module

The cost module has three sections: Well Drilling-Technology Costs, MVA Technology costs and General Field Operation & Labor Costs. Each of these modules will calculate the annual cost for each technology, labor or reporting/compliance function selected. Costs for items selected in each of the cost worksheets are then scheduled out across the project life in the years in which they are incurred. As posted they represent real costs. If an escalation rate is selected for the model run, the escalation rate is applied to the individual costs items posted in these worksheets.

The well drilling-technology cost worksheet provides for the calculation of well costs for strat-wells, injection wells, monitoring wells to the storage reservoir and above the seal, groundwater monitoring wells and vadose zone monitoring wells. Water production and water disposal (injection) wells are in the model but not included in the model run discussed in this paper. The number of injection wells is determined in the Geologic module. The total depth drilled (TD) for injection wells can be determined by the model or input by the user. TD for the other well types will require an input from the user. For each well type, the user can select the technology used in each well during drilling, testing, completion, operations and plugging. Technologies and materials listed here include wireline logging, coring, VSP, DST, casing, tubing, wellhead, MIT and items to plug and abandon (P&A) the well. Each well type and the number needed will be drilled in the sequestration stage selected by the user: strat-wells are drilled during site characterization, CO₂ injection wells are drilled during permitting and all other wells are drilled during operations in the year they need to be drilled.
The MVA Technology Costs worksheet provides for selection of technology to be used for site characterization, permitting if necessary and to monitor the plume during operations and post-injection site care and site closure. Technologies listed here included surface and wellbore seismic and other geophysical methods, fluid sampling, gas sampling, atmospheric sampling, aerial/satellite surveys, and corrosion testing. Space is provided to add new technology not already listed. Cost parameters include unit, acquisition or sampling costs, costs per unit area and processing or lab costs.

The General Field Operation & Labor Costs worksheet provides for input of cost and labor data to perform tasks during the stages of a sequestration operation. Costs incurred during regional geologic evaluation and site characterization are more labor intensive with selective use of technology. During these two stages a considerable amount of data is gathered, modeled, interpreted and incorporated in reports and plans required for permitting. These costs are posted in this worksheet; any technology or wells utilized in either of these two stages is selected in the MVA Technology Costs or Well Drilling-Technology Costs worksheets. Costs to secure pore space rights (leasing of land, annual payment for injection) are posted in this worksheet. Cost for preparation of the Area of Review and corrective action plan, testing and monitoring plan, injection well plugging plan, PISC & site closure plan and emergency and remedial response plan are in this module. Valuation of Financial Responsibility for corrective action, injection well plugging, PISC & site closure and emergency and remedial response and selection of financial instruments is also posted in this worksheet. Labor to prepare the MRV plan for compliance with Subpart RR, to prepare annual reports during operation and post-injection and site care (PISC) and site closure, and to prepare annual evaluation of financial responsibility are also included here.

Financial Module

The financial module posts balance sheet, income statement and statement of cash flow information used to determine financing costs, tax liability and cash available to owner(s). This module sources its operating and capital cost information from the Activity Cost module.

This module provides a business analysis that informs the modeler of the starting price that needs to be charged to store a tonne of captured CO2 to meet an equity investor’s required return. This price output will be utilized by NETL’s Power Supply Financial Model (PSFM) for analysis of a power plant’s business scenario. The CO2 Transportation & Storage cost model can also provide information regarding financing, return on equity and tax costs across breakeven and NPV positive scenarios.

Geologic and Cost Databases

Two geologic databases were developed for the CO2 Transportation & Sequestration cost model: a saline reservoir database and a depleted oil & gas reservoir database. The necessary reservoir parameters needed by the model are in these geologic databases. Presently, the saline geologic database has 120 potential reservoirs in 21 basins across 23 states ranging in geologic age from Cambrian through Tertiary. Clastic horizons outnumber carbonate horizons 98 to 22. The saline database is based on the NATCARB database with formation data provided by numerous sources. The majority of the data is gleaned from publicly available publications and studies produced by NATCARB Regional Carbon Sequestration Partnerships (RCSPs). Other sources include the USGS, the Gulf Coast Carbon Center of the Bureau of Economic Geology at the University of Texas, State Geologic Surveys, National Laboratories and Universities. Where not immediately available, some reservoir data for deep saline horizons was inferred from wells drilled into the same horizon at shallower depths. Many of the saline formations have a large areal extent stretching across multiple basins and/or states. For example, the Mt. Simon in the Illinois and Michigan basins or the Dakota Sandstone in the Uinta, Piceance and San
Juan basins of Utah, Colorado and New Mexico. To obtain more granularity in the dataset, saline formations were divided spatially in a number of ways, with focus on mimicking the various RCSPs’ formation subdivisions as much as possible. The Big Sky Partnership evaluated formations within the plays and geologic provinces defined by the USGS 1995 National Assessment of United States Oil and Gas Resources. WESTCARB calculated sequestration capacity volumes on a basin-wide scale with...
little published reservoir data on individual formations. SECARB used a mixture of individual horizon studies and an agglomeration of formations sorted by geologic age, for example Miocene, Upper Cretaceous (Figure 1). SWP in Colorado, designated seven “Pilot Study Regions” and investigated potential saline storage horizons within those areas (Figure 2).

In this model’s geologic database, the saline formations were split spatially mainly by state and basin. If sufficient geologic study was available to provide a range of reservoir parameters by area, some formations could be further delineated based on those parameters. For instance, contoured porosity data of the Mount Simon formation in Michigan was available and allowed division of the state by regions based on areas of high, medium and low porosity. The Midwest Regional Carbon Sequestration Program (MRCSP) extensively contoured formation structure and thickness and made these maps available on their web site (Figure 3). The Gulf Coast Carbon Center has similar maps of twenty-one potential storage horizons from all regions of the U.S. (Figure 4). From these various sources, the potential storage capacity for formations listed in the geologic database could be defined based on the gross height of the formation with its area in square miles calculated in ArcGIS.

The oil & gas database contains 1,387 reservoirs in 34 basins across 24 states and consists of a combination of data derived from the GASIS database and Advanced Resources International’s proprietary depleted oilfields database.

Either database, saline or oil and gas, can be used to evaluate a single project by selecting a unique horizon for modeling. The model can also run through one of the geologic databases, calculating a storage cost for each horizon, providing the data needed to build a cost curve. The output from the cost supply curve run is posted to a new worksheet tab. In addition to the cost to sequester a tonne of CO₂, the reservoir information for each horizon is posted along with plume area (for example see Table 2 & 3). The data output discussed in this paper is from a model run of the saline database.

The cost database is not a distinct database posted on a separate worksheet tab in the model, but rather cost values are distributed over the three Activity Cost worksheets. Here, the cost value for each item or technology is posted at their respective location in the model. All costs for technology and labor selected is calculated on an annual basis and posted in the financial framework within operational stage...
Model Runs

The modeler can either select a geologic horizon listed in the geologic database for cost analysis or enter other proprietary reservoir data. This is also true for technologies selected and their respective costs as well as for other operational and labor costs. It is often necessary to gather reservoir and cost data from published papers or surveys; especially since reliable cost data is a more guarded proprietary item. Technologies listed in the model are those found in either the EPA’s cost analysis or NETL’s MVA Best Practices Guidelines.

The CO₂ Transportation & Storage cost model can be run to provide cost analysis of a single site or run to generate data to create a cost supply curve representing multiple potential sites. Output is the same for either and is posted on the Input/Output worksheet. The formation selected for cost analysis along with injection equation used, reservoir and financial parameters are posted. The costs of each sequestration stage are also posted on this worksheet. Presently, stage costs posted are not discounted and reflect the escalation rate selected. Data related to the cost supply curve is posted in a new worksheet created when the cost supply curve macro is run. Generating cost supply curve data, the model also provides as output associated costs and reservoir parameters for all the geologic horizons listed in the data base (for example see data posted in Tables 2 & 3).

The cost data plotted against the cumulative potential storage capacity creates the CO₂ storage cost supply curve shown in Figure 1. It should be noted that the cumulative potential capacity on the x-axis in Figure 1 represents only a portion of the total potential CO₂ storage capacity listed in NETL’s Carbon Sequestration Atlas of the United States and Canada. In the Atlas, the range of potential CO₂ saline storage capacity in the lower 48 state is between 1,123,430 and 13,406,090 million tonnes. The storage
Business scenario includes 3% escalation with 45% equity/55% debt financing. Financial Responsibility not included. Operation parameters are discussed in the text.

The annual rate of injection and costs established by the modeler are applied to each geologic horizon listed in the geologic database worksheet. Each formation receives the same amount of CO₂ and sequesters the same total volume of CO₂. As noted earlier, variation in costs reflects different injection rates, plume size and associated well and MVA costs due to changes in porosity, storage efficiencies, permeability, formation thickness and depth from one formation and basin to another in the database. Each formation has the potential to sequester a fixed amount of CO₂ based on its areal extent, thickness, porosity and storage efficiency; i.e. its resource capacity. The x-axis in Figure 5 represents the cumulative resource capacity for the formations posted to the cost supply curve. Each cost per tonne of CO₂ posted represents the cost to store a tonne of CO₂ in that particular formation, for example the Arbuckle in Oklahoma. There is the potential for several sequestration projects in the Arbuckle, since the 123 million tonnes of CO₂ sequestered only occupied one-half of one percent of the estimated theoretical capacity of this formation. Sequestering 123 million tonnes of CO₂ in other formations consumed more or less space (see % Form. Filled in Table 2). In a few, more than 100 percent of the formation was utilized and these formations are not included in the storage cost supply curve posted in Figure 5.

Some of the reservoir and operation parameters generating the cost supply curves posted in Figure 5 are posted in Table 2 and represent some of the data posted from a cost supply curve run of the model. Formation height is the gross height for each formation posted in the database. A gross value is used here because the storage efficiency factors are modeled on a net/gross basis. Calculating storage mass, \( G_{CO2} \) in equation 1, area (A), height (h) and porosity (Φ) are gross or total values; \( ρ_{CO2} \) is the density of CO₂ at reservoir conditions. Reservoir modeling was done to estimate storage efficiency factors for saline reservoirs (\( E_{saline} \)) in net/gross units. The ‘gross’ or ‘total’ cancel out leaving a net volume available for storage in tonnes. xviii
Plume area in Table 2 is the area of a circle since in this model the mass of sequestered CO\textsubscript{2} is assumed to occupy a cylinder. The radius of the circular surface area of a plume depends on the gross height of the storage formation, porosity, storage efficiency factor, and the density of the CO\textsubscript{2} at reservoir conditions. Also, during injection operations, the model accounts for growth in plume area and adjusts the cost of 3-D seismic surveys needed to image the plume for AoR reviews over the operational period.

\begin{equation}
G_{\text{CO}_2} = A_{\text{total}} \times h_{\text{gross}} \times \Phi_{\text{total}} \times \phi_{\text{CO}_2} \times E_{\text{saline}}
\end{equation}

Other models calculate injection rate on the annual rate of capture at the plant which reflects an annual capacity factor for power generation. However, there will be many time periods when a power plant is running 24/7 and the maximum injection rate reflects this rate of capture. The number of injection wells is those needed to inject the annual volume sequestered in this modeling exercise, 4.1 million tonnes per year, at the maximum injection rate. As noted earlier, spare injection capacity is built into the model to provide for well maintenance. Note in Table 2 that the minimum number of injections wells is two; one can be shut-in for maintenance while the other maintains operations.

Monitoring wells in Table 2 are only those drilled into the storage reservoir and above the seal. Wells drilled into the reservoir are at a density of one per four square miles and those above the seal at one per two square miles. This is the monitoring well density adopted by the EPA in their cost analysis and noted in the preamble to the Class VI regulations. Monitor well density is an input value that can be modified by the modeler. In their guidance, EPA suggested that where possible, monitoring wells can be dually completed in the reservoir and above the seal.\textsuperscript{xix} This is not done for the modeling discussed in this paper.

The percent of the formation filled represents the volume of the reservoir formation filled by the amount of CO\textsubscript{2} injected as estimated by the model and reported in this paper. The surface area for each formation posted in the geologic database saline was calculated by GIS. This surface area does not encompass the entire potential area for any of the formations posted in the geologic database. Using the formation height, porosity, and storage efficiency factor also posted in the database along with the density of CO\textsubscript{2}, a total storage resource capacity was calculated for each formation. The project modeled here sequestered a total of 123 million tonnes which occupies various volumes in each formation depending on reservoir characteristics. Of the 120 formations listed in the database, 111 are in the cost supply curve. As noted above, those formations filled to 40 percent or more by the project modeled in this paper were removed from the data comprising the cost supply curve.

A breakdown of sequestration costs by operation stage is presented in Table 3. Costs for regional geologic evaluation are identical for all horizons in this model run at $140,000. Three strat-wells are drilled for site characterization for all horizons. The costs variation here is due to areal extent of the plume (see Table 2) and the need to image this entire area with 3-D seismic. Calibrating the 3-D seismic data with the data gathered by the strat-wells provides critical data for the reservoir models. Other
Critical expenses incurred during site characterization are land leasing, securing pore space rights and an aerial magnetic survey to locate old well bores that might require corrective action. Another critical expense here is establishment of financial responsibility. There are six mechanisms recognized by the EPA for financial responsibility and these costs are not included in this model run. Preparation of all documentation for permit application is done during site characterization.

<table>
<thead>
<tr>
<th></th>
<th>Sequestration Stage Costs – million $ (escalated at 3%, not discounted)</th>
<th>Regional Geologic Evaluation Costs not posted</th>
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</thead>
<tbody>
<tr>
<td></td>
<td>$/tonne</td>
<td>Site Charact.</td>
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<tr>
<td>Mean</td>
<td>71.59</td>
<td>91.38</td>
</tr>
<tr>
<td>Mean costs % of Total</td>
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<tr>
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</table>

**Table 3: Cost to store 1 tonne of CO2, Stage costs, Total project costs.**

For the model run reported in this paper, the costs for four of the five stages of sequestration operation are posted in Table 3. It should be noted the cost values posted in Table 3 are escalated at 3% but are not discounted back to a present value. Post-injection site care (PISC) and site closure represents the largest cost as a percentage of total costs, a reasonable expectation since PISC is done over a 50 year period, 20 years longer than injection operations. PISC begins when injection ceases and the injection wells are plugged and abandoned, 35 years after the project begins initial regional geologic evaluation for prospects. Granted, this period of time may be reduced but this will not be known with certainty until the PISC and site closure plan is reviewed when injection operations cease. For planning and modeling purposes, it is reasonable to expect PISC to last 50 years since this is the default time period in Class VI regulations.

Costs during operations and PISC are driven by the number of wells and the amount of 3-D seismic acquired. For the model run reported in this paper, 3-D seismic data is acquired every five years during operations and PISC and the number of monitoring wells drilled that will require maintenance during and plugging at the end of PISC are considerably more than the number of injection wells drill through the P50 value (Table 2). The groundwater monitoring and vadose zone monitoring wells drilled will be less expensive to maintain and plug than the deeper monitoring well above the seal or into the reservoir. Even at the P90 level operation costs are less than those incurred for PISC. What is important here is that the positive cash flow during operations covers the cost of regional geologic evaluation, site characterization, permitting, and operations as well as PISC and site closure. During operations, the model will have to be set aside funds to provide for PISC and site closure expenses.
Output from running the model for storage cost supply curves can be sorted to facilitate interpretation of the data. The cost supply curve illustrated in Figure 5 is disaggregated by basin and posted in Figure 6. Rocky Mountain basins are those located in Wyoming, Colorado, Utah and New. This particular cost curve can be broken out further into individual basins.
The rate of injection depends, among other factors, on the height of the injection interval and the permeability of the reservoir. Looking at the product of permeability (k) and height (h) is a common method in evaluating the sweat spots in a reservoir. In this model, the injection interval is synonymous with formation height. The kh data plotted in Figure 7 shows a negative relationship between kh and storage costs and confirms the position of the CO2 storage cost supply curves in Figure 6. The Gulf Coast Tertiary reservoirs have the highest kh values and lowest storage costs while the Appalachian and Rocky Mountain basins post the lowest kh values and highest storage costs.

Conclusions

The CO2 Transportation & Storage cost model developed by the National Energy Technology Laboratory provides a significant level of detail for analysis of CO2 storage operations. These details include well and well technology costs, available MVA technology and associated costs, financial responsibility and selection of suitable instruments, pore space costs, labor costs, as well as operational and compliance costs. The model incorporates several simple assumptions: an open reservoir, steady state injection over the operational period, and a simple cylindrical configuration of the reservoir. Since these assumptions are applied to all reservoirs modeled, the model illustrates the relative cost differences between the various geologic and/or business scenarios modeled. A distinct advantage of this model is its ability to place costs in the year they occur and the modeler’s ability to modify the time frame for each sequestration stage over which these costs occur.

Another assumption of the model is that all of the CO2 supplied to the saline storage field over its project life is sequestered; the saline reservoir always has sufficient capacity. This assumption is check against the areal extent of the formation as posted in the geologic database. Each formation listed in the database for a state/basin area has an estimate potential total capacity and as noted in the text, the 123 million tonnes of CO2 sequestered filled eleven of the 120 formations listed to 40 percent or more of their potential capacity. Storage capacity value for sequestration of captured CO2 is a resource value that has yet to be proven, i.e. a proved or economic reserve. This will be done by site characterization and, subsequently, by operations. A formation that is filled to almost half of its potential capacity under modeling is probably not suitable for sequestration operations. For the moment, 40 percent is an arbitrary, though logical, cutoff point.

Risk has yet to be incorporated in the model. The model reported on in this paper has enjoyed success; all wells were drilled and completed has planned and there were no unexpected leaks from the reservoir. Risk is especially important during site characterization where the first prospect selected may prove to be inadequate and a second or even a third site may undergo site characterization. Consideration of risk will also be important for the strat-wells drilled during site characterization. Risks in drilling injection wells may be low but the monitoring wells are drilled over the period of operations and risks of a successful well may be higher due to the importance of hitting the reservoir at increasing distance from the injection wells. Risk for saline reservoir will be difference from utilization of depleted oil & gas reservoirs. Development of saline reservoirs will be similar to exploration since there has been no economic reason to develop water saturated formations with high dissolved solids. The United States is the most drilled country in the world with good to very good knowledge of the subsurface in many areas or basins. Early movers in developing saline reservoirs will have the advantage of being able to select the best structural features to develop. There is also the possibility of regulatory risk associated with Long-term Stewardship and developing a trust fund for this purpose. Contribution levels have been established by some states but whether or not these contributions prove adequate has yet to be determined.
The model as only been recently completed in its present state. Further work is underway to simplify the model’s operation and proof the geologic and cost database. We are in process of separating the schedule of costs from the data entry portions in order to make the model more transparent and user friendly. Presently, cost values used are those utilized by the EPA in their cost analysis for the Class VI rules. Many of these costs need to be updated. Some technologies listed in NETL’s MVA Best Practices guide are new and the value of these technologies and method of costs need to be established.

The purpose of the CO₂ Transportation & Storage cost model is to understand the composition of costs involved in and the impact upon a CO₂ sequestration operation. The overall effort here is to understand how costs can be reduced. Towards this effort, the model needs to be evaluated as a standalone analytical tool and in conjunction with NETL’s other models assessing costs across the CCS value chain. A test matrix of different scenarios is under development that will provide a framework for evaluating the CO₂ Transportation & Storage cost model.


Gulf Coast Carbon Center, 2003. Inventory of Brine Formations Suitable for Geologic Sequestration, Online Data Matrix. Bureau of Economic Geology, University of Texas at Austin. Found at: http://www.beg.utexas.edu/environqlty/co2seq/co2data.htm


