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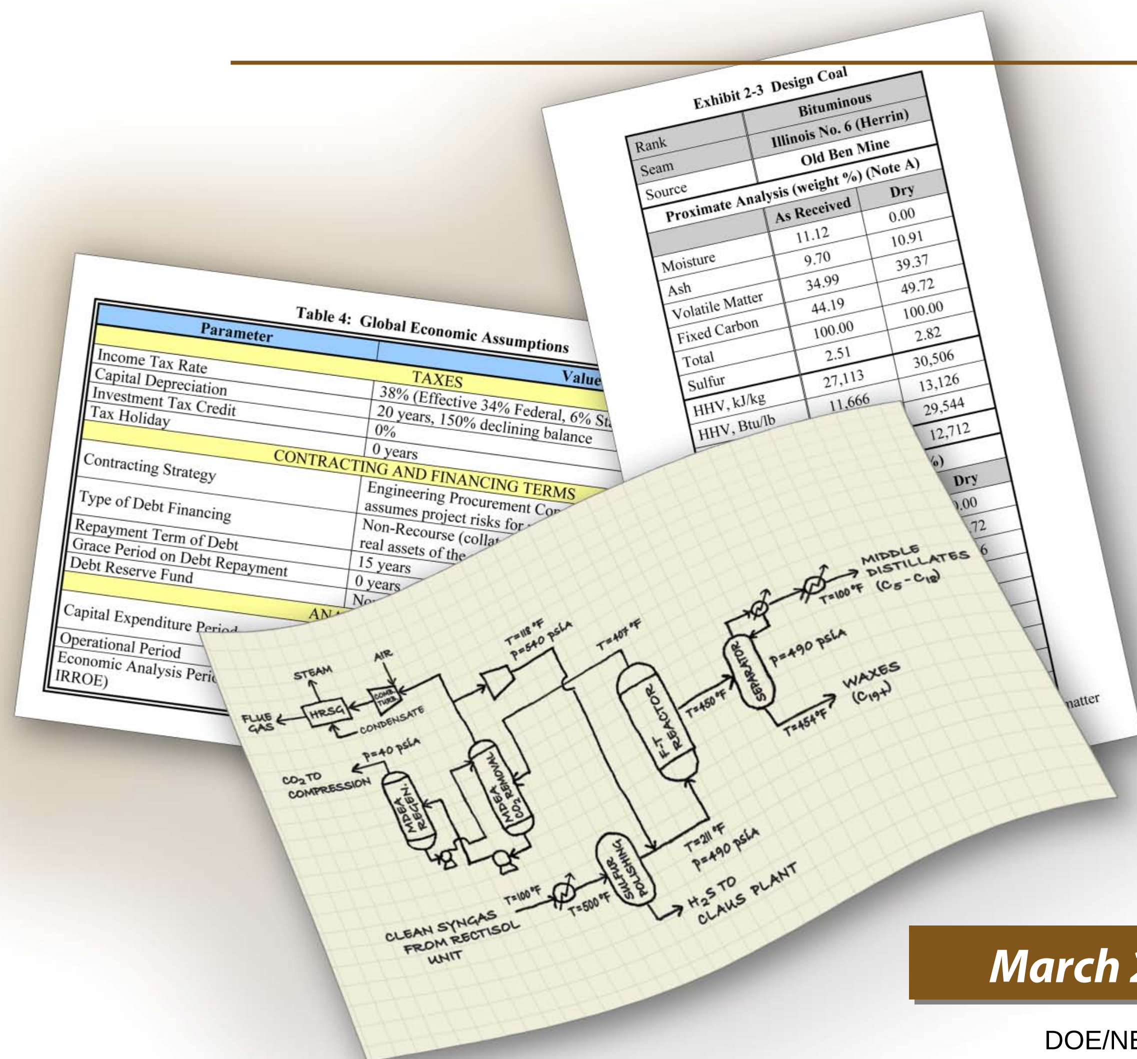
QUALITY GUIDELINES FOR ENERGY SYSTEM STUDIES

Carbon Dioxide Transport and Storage Costs in NETL Studies



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Final Report

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Exhibits

Acronyms and Abbreviations

AoR	Area of Review
BLS	Bureau of Labor Statistics
CEPI	Chemical Engineering Plant cost Index
CO_2	Carbon dioxide
DOE	Department of Energy
EIA	Energy Information Administration
EPA	Environmental Protection Agency
GDP	Gross domestic product
HWI	Handy-Whitman Index
IRROE	Internal rate of return on equity
Mt	Million tonnes
NETL	National Energy Technology Laboratory
O&GJ	Oil and Gas Journal
O&M	Operation and maintenance
PPI	Producer Price Indices
ROW	Right-of-way
T&S	Transport and storage

1 Objective

The purpose of this guideline is to estimate the cost of CO_2 transport and storage (T&S) in a deep saline aquifer for the plant locations used in the energy system studies sponsored by the National Energy Technology Laboratory (NETL).

Due to the variances in the geologic formations that make up saline aquifers across the United States (U.S.), the cost to store CO_2 can vary greatly depending on location. To account for these variances, region-specific results from NETL's CO_2 Saline Storage Cost Model are utilized to represent costs for the following plant locations used in NETL studies:

- Midwest
- Texas
- North Dakota
- Montana

Transport costs are calculated based on a generic 100 km (62 mi) dedicated pipeline for all regions. Storage and monitoring costs represent significant storage potential (up to 25 billion tonnes of CO_2) in local sedimentary basins.

2 Approach

T&S costs are reported as first-year costs in \$/tonne of CO_2, increasing at a nominal rate of 3 percent per year, which is consistent with the assumed general inflation rate. From the perspective of the CO_2 source (e.g., a power plant or other energy conversion facility), these costs are treated as a disposal cost for each tonne of CO_2 captured during the assumed 30-year operational period. From the pipeline and storage site's perspective, the costs of T&S represent the minimum price that these operators must charge so that they receive the revenue needed across the 30-year operational period to cover all their costs and provide their required internal rate of return on equity (IRROE). All costs are reported in 2011 dollars.

Exhibit 1 Timelines for construction and operations of plant, transport, and storage

Source: NETL

T&S costs are based on the CO_2 flow rate of one example plant: 10,900 tonne/day (12,000 ton/day) or 3.2 million tonnes per year assuming an 80 percent capacity factor. Variability of storage costs based on flow rate and capacity factor can be determined using the CO_2 Saline Storage Cost Model, but is not considered here for use in the NETL system studies.

2.1 Transport Costs

High-pressure (2,200 psig) CO_2 is provided by the power plant or energy conversion facility, and the cost and energy requirements of compression are assumed by that entity. CO_2 is in a dense phase liquid state at this pressure, which is desirable for transportation and storage purposes.

CO_2 exits the pipeline terminus at a pressure of 1,200 psig, and the pipeline diameter was sized for this to be achieved without the need for recompression stages along the pipeline length of 100 km (62 mi). This exit pressure specification: (1) ensures that CO_2 remains in a dense phase liquid state throughout the length of the pipeline regardless of potential pressure drops due to pipeline elevation change; and (2) minimizes the pipeline diameter required and, in turn, transport capital cost. Costs for additional compression that may be required for injection in a particular formation are included as part of storage costs.

The required pipeline diameter was calculated iteratively by determining the diameter required to achieve a 1,000 psig pressure drop (2,200 psig inlet, 1,200 psig outlet) over the specified pipeline distance of 100 km (62 mi) and rounding up to the nearest even-sized pipe diameter. The pipeline was sized based on the CO_2 output produced by the power plant when it is operating at full capacity (100 percent utilization factor) rather than at average capacity.

CO_2 transport costs are broken down into three categories: pipeline capital costs, related capital expenditures, and operation and maintenance (O&M) costs.

Pipeline costs are derived from data published in the *Oil and Gas Journal's* (O&GJ) annual *Pipeline Economics Report* for existing natural gas, oil, and petroleum pipeline project costs from 1991 to 2003. These costs are expected to be analogous to the cost of building a CO_2 pipeline, as noted in various studies. [1, 2, 3] The University of California performed a regression analysis to generate the following cost curves from the O&GJ data: (1) Pipeline Materials, (2) Direct Labor, (3) Miscellaneous Costs,[1] and (4) Right-of-way acquisition, with each represented as a function of pipeline length and diameter. [3] These cost categories are reported individually as a function of pipeline diameter (in inches) and length (in miles) in Exhibit 2.

Related capital expenditures were based on the findings of a previous study funded by the Department of Energy (DOE)/NETL, *Carbon Dioxide Sequestration in Saline Formations – Engineering and Economic Assessment*. [2] This study utilized a similar basis for pipeline costs (*Oil and Gas Journal's* pipeline cost data up to the year 2000) but added a CO_2 surge tank and pipeline control system to the project. These costs are shown in Exhibit 2 as Other Capital Costs.

[1] Miscellaneous costs are inclusive of surveying, engineering, supervision, contingencies, allowances for funds used during construction, administration and overheads, and regulatory filing fees.

Pipeline O&M costs, shown in Exhibit 2 as a function of pipeline length per year, were assessed using metrics published in a second DOE/NETL sponsored report entitled *Economic Evaluation of CO_2 Storage and Sink Enhancement Options*. [1] This study was chosen due to the reporting of O&M costs in terms of pipeline length, whereas the other studies mentioned above either (1) do not report operating costs, or (2) report them in absolute terms for one pipeline, as opposed to as a length- or diameter-based metric.

Exhibit 2 Pipeline cost breakdown (2011 dollars) [1, 2, 3]

Cost Type	Units	Cost
Pipeline Capital Costs		
Materials	*Diameter (inches), Length (miles)*	$\$70{,}350 + \$2.01 \times L \times (330.5 \times D^2 + 686.7 \times D + 26{,}960)$
Labor	*Diameter (inches), Length (miles)*	$\$371{,}850 + \$2.01 \times L \times (343.2 \times D^2 + 2{,}074 \times D + 170{,}013)$
Miscellaneous	*Diameter (inches), Length (miles)*	$\$147{,}250 + \$1.55 \times L \times (8{,}417 \times D + 7{,}234)$
Right of Way	*Diameter (inches), Length (miles)*	$\$51{,}200 + \$1.28 \times L \times (577 \times D + 29{,}788)$
Other Capital Costs		
CO_2 Surge Tank	$	$1,244,724
Pipeline Control System	$	$111,907
Pipeline O&M Costs		
Fixed O&M	$/mile/year	$8,454

Four different cost escalation indices were utilized to escalate costs from the year-dollars they were originally reported in to June 2011-year dollars. These are the Chemical Engineering Plant Cost Index (CEPI), U.S. Bureau of Labor Statistics (BLS) Producer Price Indices (PPI), Handy-Whitman Index (HWI) of Public Utility Costs, and the Gross Domestic Product (GDP) Chain-type Price Index. [4, 5, 6]

Exhibit 3 details which price index was used to escalate each cost metric, as well as the year-dollars in which the cost was originally reported. Note that this reporting year is likely to be different than the year that the cost estimate is from.

Exhibit 3 Summary of cost escalation methodology

Cost Metric	Year-$	Index Utilized
Transport Costs		
Pipeline Materials	2000	HWI: Steel Distribution Pipe
Direct Labor (Pipeline)	2000	HWI: Steel Distribution Pipe
Miscellaneous Costs (Pipeline)	2000	BLS: Support Activities for Oil & Gas Operations
Right-of-Way (Pipeline)	2000	GDP: Chain-type Price Index
CO_2 Surge Tank	2000	CEPI: Heat Exchangers & Tanks
Pipeline Control System	2000	CEPI: Process Instruments
Pipeline O&M (Fixed)	1999	BLS: Support Activities for Oil & Gas Operations

The minimum price the CO_2 pipeline operator needs to charge to cover all costs and provide the required IRROE was calculated in $/tonne of CO_2 assuming the following, which match the low-risk business scenario for an investor-owned utility [7]:

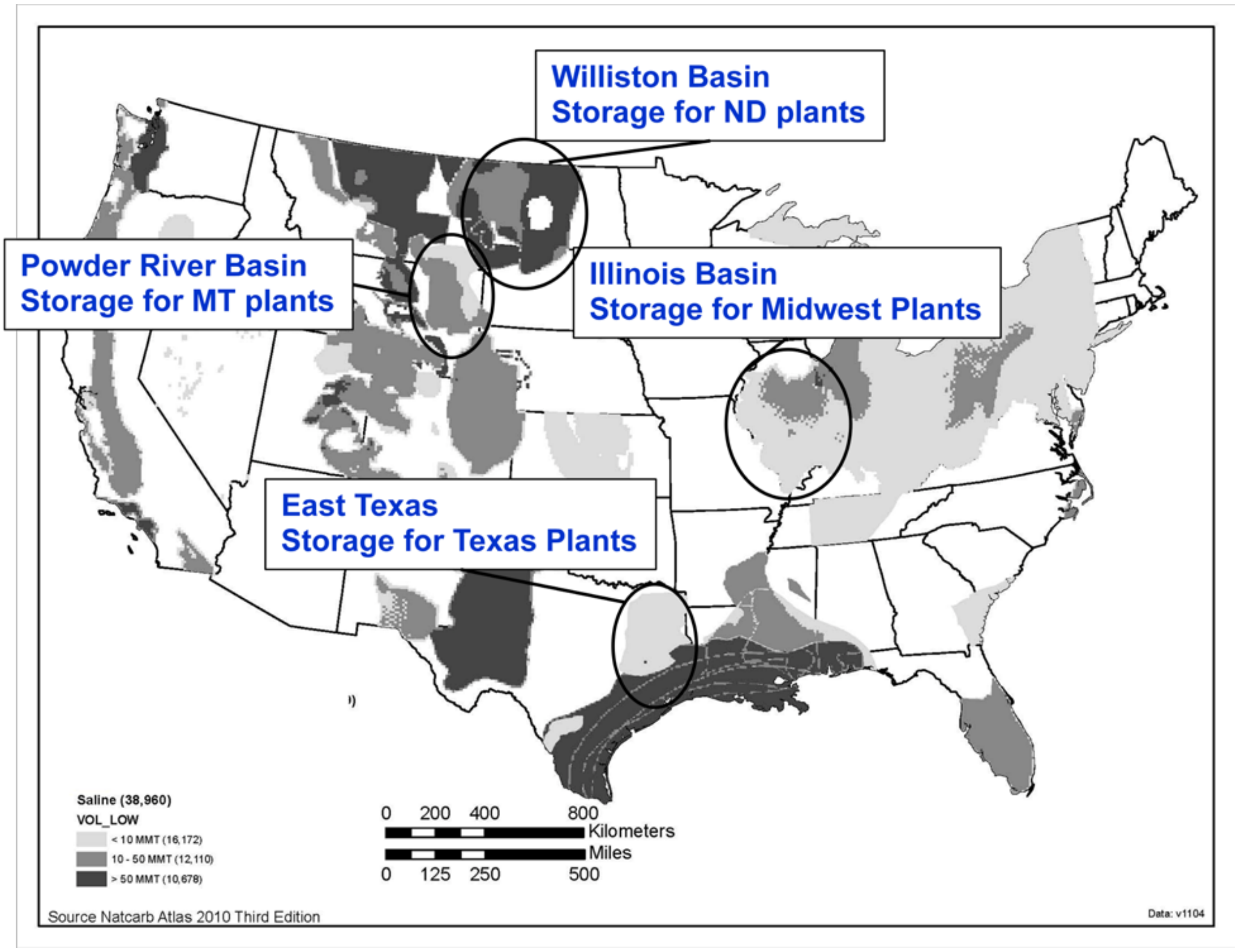
- 3-year capital expenditure period distributed by year as 10%, 60%, 30%
- Escalation of all costs at a rate of 3% per year
- Debt to equity ratio of 50%/50%
- Interest rate of 4.5%/year
- IRROE of 12%
- 30-year operational period

2.2 Storage and Monitoring Costs

Storage and monitoring costs were estimated using NETL's CO_2 Saline Storage Cost Model. This model is a spreadsheet-based tool that estimates the break-even required revenue for storing CO_2 in a deep saline aquifer from the perspective of the owner of a CO_2 storage site. The CO_2 Saline Storage Cost Model includes the cost of complying with key regulations. In order to inject CO_2 into the subsurface for the purpose of storing CO_2 in a saline aquifer, the site owner must comply with the U.S. Environmental Protection Agency (EPA) regulations for Class VI injection wells under EPA's Underground Injection Control Program, which is authorized under the Safe Drinking Water Act. The site owner must also comply with monitoring and reporting requirements under Subpart RR of the Greenhouse Gas Reporting Rule, which is authorized under the Clean Air Act.

Results from the CO_2 Saline Storage Cost Model for storage and monitoring costs were aligned with the NETL system studies by taking the four generic plant locations and overlaying them with possible storage basins from the cost model. This pairs generic system study plant locations of Midwest, Texas, North Dakota, and Montana with the Illinois, East Texas, Williston, and Powder River Basins, respectively, as shown in Exhibit 4.

Exhibit 4 Location of four basins selected for this study



Source: NETL

Inputs to the CO_2 Saline Storage Cost Model that have a significant influence on cost include financial parameters, timelines for the various stages of storage, and important activities in stages.

The financial parameters match the high-risk business scenario for an Investor Owned Utility [7] and include:

- Debt to equity ratio of 45%/55%
- Interest rate on debt of 5.5%/year
- IRROE of 12%
- Escalation rate of 3%
- Financial responsibility is met by funding a modified trust fund over the period of injection operations
- Project contingency factor of 15%, and process contingency factor of 20%

In the CO_2 Saline Storage Cost Model, the storage process is divided into six stages. The timelines and important activities impacting costs for these stages are:

- Regional evaluation and initial site selection: 1 year
- Site characterization: 3 years
  - Four sites simultaneously undergo characterization, each having a 2-D seismic survey and one strat-well drilled to collect relevant reservoir data.
  - One of these four sites is selected as the eventual storage site and has an additional strat-well drilled plus a 3-D seismic survey covering the Area of Review (AoR); pore-space rights and property access are also purchased.
- Permitting: 2 years
  - Includes submittal of required reports for Class VI injection well permit, permission to drill injection wells, drilling and completion of injection wells, incorporation of new data from injection wells into reports, resubmission of reports, and final permission to inject captured CO_2.
- Operations: 30 years
  - Injection of 3.2 million tonnes of CO_2 per year for 30 years.
  - Installation of buildings, surface equipment, monitoring wells, and other monitoring equipment per submitted testing and monitoring plan.
  - AoR review occurs every five years with 3-D seismic every five years as part of the AoR review.
  - Plugging injection wells at conclusion of injection operations.
  - Fund-modified trust fund to cover financial responsibility requirements for corrective action, injection well plugging and post-injection site care, and site closure. Emergency and Remedial Response covered by insurance.
- Post-injection site care and site closure: 50 years
  - Monitoring continues per submitted testing and monitoring plan.
  - Monitoring wells are plugged and other monitoring equipment removed at the conclusion of post-injection site care.
  - Costs during this period are covered by the storage site operator's trust fund.
- Long-term stewardship: This stage is not explicitly included in the model. The possible financial implication of long-term stewardship is included in the model as a state-sponsored trust fund that the storage operator pays into during operations.

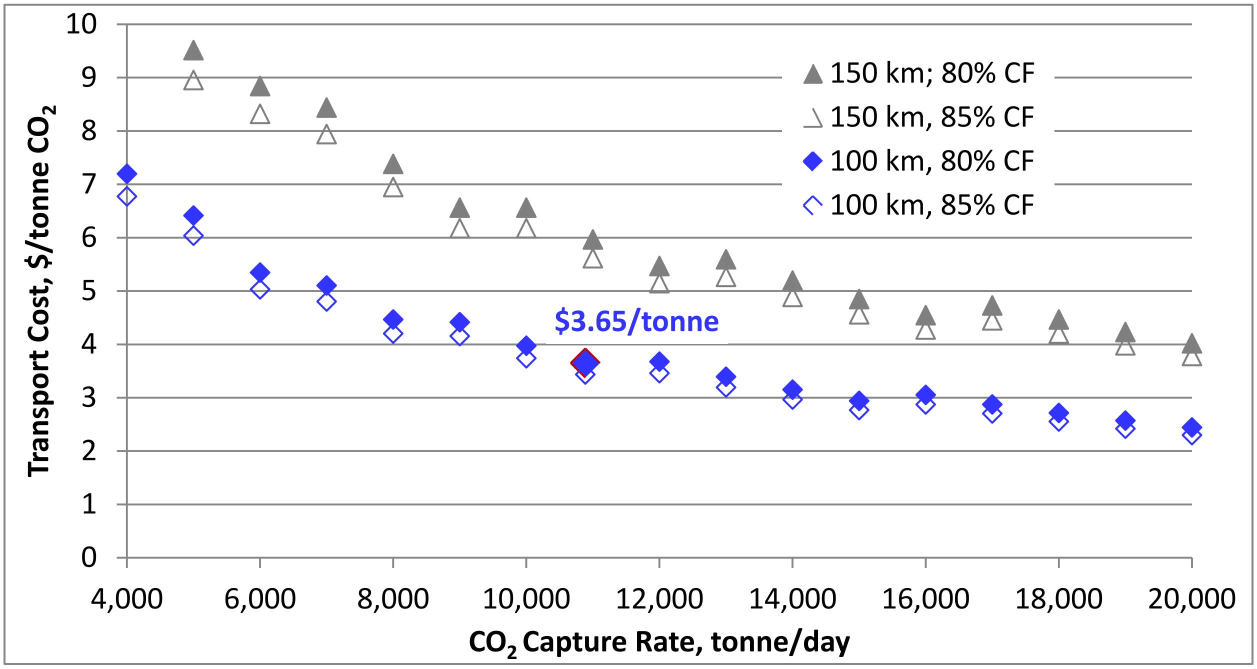
3 Results

3.1 Transport Costs

Transport of 10,900 tonne/day of CO_2 a distance of 100 km (62 mi) with 1,000 psi pressure drop requires a 16-inch pipe diameter and has estimated capital costs of $106 million and O&M costs of $0.53 million per year. Based on the assumptions outlined in Section 2.1 above and a capacity factor of 80 percent, the resulting required first-year cost for transport is $3.65/tonne of CO_2 in 2011 dollars.

This value will be used in NETL System Studies as a reasonable approximation for CO_2 transport costs for all plants regardless of the capacity factor and CO_2 capture rates. Exhibit 5 shows the sensitivity of this cost to capacity factor and CO_2 capture rate. In addition, costs are shown for 150 km (93 mi).

Exhibit 5 Sensitivity of transport costs to plant and distance assumptions



Source: NETL

Cost Comparisons

The capital cost metrics used in this study result in a pipeline cost (in 2011 dollars) ranging from $70,000 to $84,000/inch-Diameter/mile for pipeline lengths of 250 and 10 miles, and 3 to 4 million metric tonnes of CO_2 sequestered per year, respectively. When project and process contingencies of 30 percent and 20 percent (respectively) are taken into account, this range increases to $104,000 to $126,000/inch-Diameter/mile. These costs were compared to contemporary pipeline costs quoted by industry experts, such as Kinder-Morgan and Denbury Resources for verification purposes. Exhibit 6 details typical rule-of-thumb costs for various terrains and scenarios as quoted by a representative of Kinder-Morgan at the Spring Coal Fleet

Meeting in 2009. [8] As shown, the base NETL cost metric falls midway between the costs quoted for "Flat, Dry" terrain ($50,000/inch-Diameter/mile) and "High Population" or "Marsh, Wetland" terrain ($100,000/inch-Diameter/mile), although the metric is closer to the "High Population" or "Marsh, Wetland" when contingencies are taken into account. [8] These costs were stated to be inclusive of right-of-way (ROW) costs.

Ronald T. Evans, formerly of Denbury Resources, Inc., provided a similar outlook, citing pipeline costs as ranging from $55,000/inch-Diameter/mile for a project completed in 2007, $80,000/inch-Diameter/mile for a recently completed pipeline in the Gulf Region (no wetlands or swamps), and $100,000/inch-Diameter/mile for a currently planned pipeline, with route obstacles and terrain issues cited as the reason for the inflated cost of that pipeline. [9, 10] Mr. Evans qualified these figures as escalated due to spikes in construction and material costs, quoting pipeline project costs of $30,000/inch-Diameter-mile as recently as 2006. [9, 10]

A second pipeline capital cost comparison was made with metrics published within the 2008 IEA report entitled *CO_2 Capture and Storage: A key carbon abatement option*. This report cites pipeline costs ranging from $22,000/inch-Diameter/mile to $49,000/inch-Diameter/mile (once escalated to June-2011 dollars), between 30 percent and 69 percent less than the lowest NETL metric of $70,000/inch-Diameter/mile. [11]

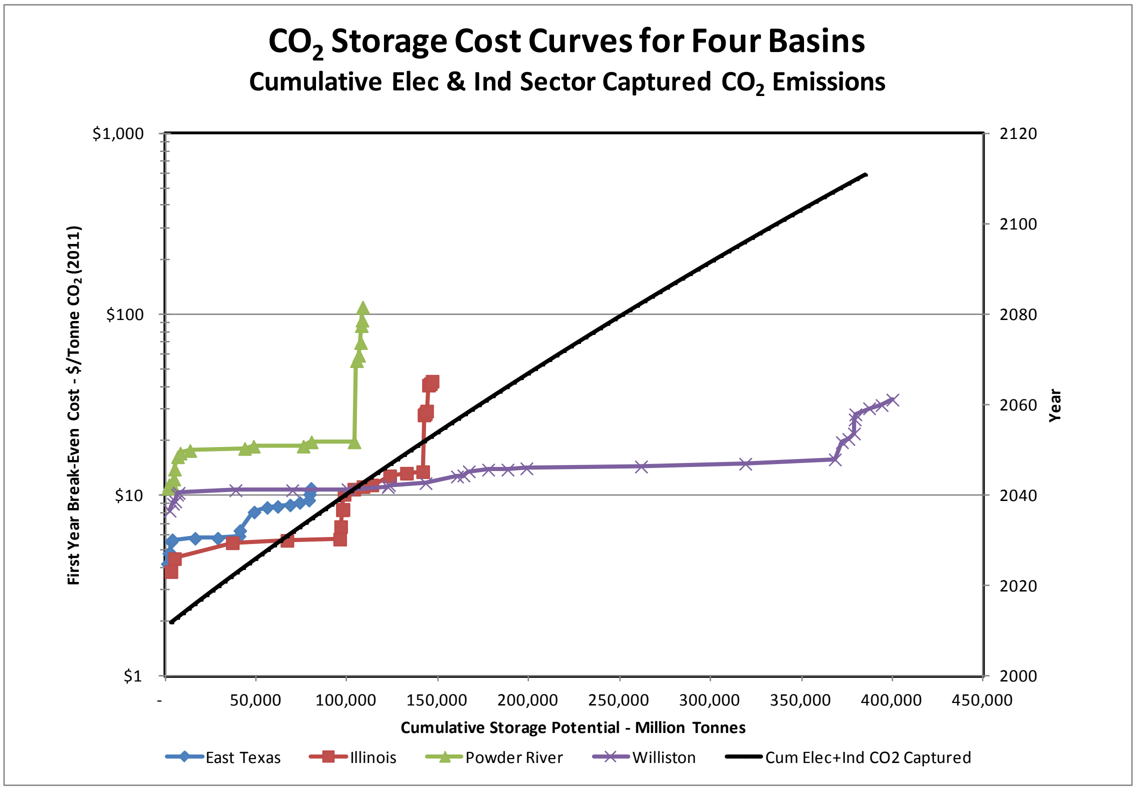
Exhibit 6 Kinder-Morgan pipeline cost metrics [8]

Terrain	Capital Cost ($/inch-Diameter/mile)
Flat, Dry	$50,000
Mountainous	$85,000
Marsh, Wetland	$100,000
River	$300,000
High Population	$100,000
Offshore (150’-200’ depth)	$700,000

3.2 Storage and Monitoring Costs

Cost supply curves are plotted in Exhibit 7 for the East Texas, Illinois, Powder River and Williston basins. This figure presents the mass of CO_2 that can be stored theoretically in each basin at a given price of CO_2. The price is the break-even price of CO_2 for a storage project in each basin (i.e., the price of CO_2 where the net present value for the project is zero). Each basin includes two or more storage formations. The curves in Exhibit 7 represent the storage resource potential for the Paluxy and Woodbine formations in the East Texas Basin; the Mt. Simon, and St. Peter formations in the Illinois Basin; the Red River and Mission Canyon formations in the Williston Basin; and the Minnelusa, Muddy, and Madison formations in the Powder River Basin. Also plotted in Exhibit 7 is a projection, based on data from the Energy Information Administration (EIA) (14), of the cumulative mass of CO_2 emissions from the electric power and industrial sectors that can be captured over the next century, assuming 90 percent of all CO_2 emissions are captured.

Exhibit 7 CO_2 storage cost supply curves



Source: NETL

The storage potential for each formation depends upon the storage coefficient, which is the percentage of the formation's brine-filled pore volume that may be occupied by CO_2. The storage coefficient depends on the depositional environment and the structural setting. (15) The storage resource potential for each formation in the basins shown previously in Exhibit 4 is partitioned into five structural settings: dome, anticline, ten-degree regional dip, five-degree regional dip, and flat structural setting. The depositional environments for the various formations are eolian (Minnelusa), shallow shelf (Muddy, Madison, Mission Canyon), peritidal (St. Peter), strand plain (Mt. Simon), fluvial (Woodbine), and delta (Paluxy).

The storage resource potential for any particular formation reflects the areal extent of the formation as well as its thickness, porosity, and storage coefficient. In the CO_2 Saline Storage Cost Model, over the total area of any formation, only 2.5 percent of the area is assigned to structural closure or 1.25 percent each for dome and anticline structures. (16) The remaining area is split evenly between the ten- and five-degree regional dip and flat structural settings (32.5 percent each). Dome and anticline structures have higher storage coefficients, but ten- and five-degree regional dip and flat structural settings have much higher storage potential due to their larger areal extent. CO_2 storage potential modeled here is a resource that has yet to be proven. This process begins with site characterization for a specific storage project.

Each formation in each basin has a maximum theoretical capacity to store CO_2, and this capacity significantly exceeds the mass of CO_2 being stored by a single storage project. In constructing the cost supply curves, it is assumed that multiple storage projects can be implemented in each formation until the total mass of CO_2 injected from all the projects approaches 40 percent of the maximum theoretical storage capacity for each formation. It is assumed that institutional issues (such as obtaining property rights to store CO_2, restrictions on storage in urban areas) and pressure interferences from multiple storage sites will prevent more than 40 percent of the theoretical storage capacity from being used.

For each basin plotted in Exhibit 7, the cost to store at least 25,000 million tonnes (Mt) is shown in Exhibit 8. For the East Texas Basin, 25,000 Mt of cumulative storage resource potential is provided by a combination of sedimentary depositional and structural settings in the Woodbine and Paluxy formations, each represented by a point on the cost supply curve. In the East Texas Basin, the low cost point is \$4.58 per tonne of CO_2 stored for a dome structure in the Woodbine. A reservoir with a five-degree structural setting in the Woodbine provides the storage resource potential at the 25,000 Mt mark at a cost of \$6.34 per tonne of CO_2. At this price within this potential reservoir of the Woodbine formation is the potential to store up to 28,860 Mt of captured CO_2. This storage resource potential represents 7.57 percent of the volume of CO_2 emissions that can be captured from the electric power and industrial sectors over the next century. Similar information for the Illinois, Powder River, and Williston Basins are also posted in Exhibit 8.

Exhibit 8 Storage resource potential for four basins

BASIN	25,000 Mt Storage Resource Potential				50,000 Mt Storage Resource Potential			75,000 Mt Storage Resource Potential		
	$/tonne to 25,000 Mt (2011$)	Storage Resource Potential at this $/t	% of next 100 yrs captured emissions	GW Storage Resource Potential	$/tonne to 50,000 Mt (2011$)	Storage Resource Potential at this $/t	% of next 100 yrs captured emissions	$/tonne to 75,000 Mt (2011$)	Storage Resource Potential at this $/t	% of next 100 yrs captured emissions
Illinois	$5.98	36,931 Mt	9.68%	185 GW	$6.16	66,961 Mt	17.56%	$6.26	95,968 Mt	25.16%
East Texas	$6.34	28,860 Mt	7.57%	144 GW	$9.36	56,021 Mt	14.69%	$10.28	78,991 Mt	20.71%
Williston	$11.67	38,649 Mt	10.13%	194 GW	$11.67	69,879 Mt	18.32%	$11.81	100,308 Mt	26.30%
Powder River	$19.84	43,667 Mt	11.45%	214 GW	$20.44	75,910 Mt	19.90%	$20.44	75,910 Mt	19.90%
Total		148,107 Mt	38.83%	743 GW		268,771 Mt	70.47%		351,177 Mt	92.08%

Source: NETL

For these four basins, the storage resource potential at the CO_2 price associated with cumulative storage of 25,000 Mt totals 148,107 Mt. This represents 38.83 percent of the volume of CO_2 emissions that can be captured from the electric power and industrial sectors over the next century. Assuming 6.64 million tonnes of CO_2 captured from a 1 GW power plant (30 years of operation, 30 percent plant efficiency, 80 percent capacity factor, and 90 percent capture efficiency), this storage resource potential is equivalent to 743 GW of power generation.

Storage resource potential with respect to electric power generation ranges from 144 GW in the East Texas Basin to 214 GW in the Powder River Basin. Total storage resource potential for these four basins, through the CO_2 price associated with cumulative storage of 75,000 Mt, represents 92 percent of the volume of CO_2 emissions that can be captured from the electric power and industrial sectors over the next century. The Illinois Basin, with the Mt. Simon Formation, is the low-cost provider. The Williston Basin, as illustrated in Exhibit 7, has the largest storage resource potential.

3.3 Combining Transport and Storage

Exhibit 9 reports the storage cost results from the CO_2 Saline Storage Cost Model for the 25,000 Mt of cumulative storage resource potential and transport cost for the example plant parameters. The resulting CO_2 T&S values (rounded up to the nearest whole dollar) to be used in NETL systems studies are shown in the far right column.

Exhibit 9 Total transport and storage costs for use in NETL system studies

Plant Location	Basin	Transport (2011$ per tonne)	Storage (2011$ per tonne)	Total T&S (2011$ per tonne)	T&S Value for System Studies (2011$ per tonne)
Midwest	Illinois	3.65	5.75	9.40	10
Texas	East Texas		6.06	9.71	10
North Dakota	Williston		10.96	14.61	15
Montana	Powder River		17.86	21.51	22

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