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An engineering-economic model of pipeline transport of CO_2 with application to carbon capture and storage

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ABSTRACT

Carbon dioxide capture and storage (CCS) involves the capture of CO_2 at a large industrial facility, such as a power plant, and its transport to a geological (or other) storage site where CO_2 is sequestered. Previous work has identified pipeline transport of liquid CO_2 as the most economical method of transport for large volumes of CO_2. However, there is little published work on the economics of CO_2 pipeline transport. The objective of this paper is to estimate total cost and the cost per tonne of transporting varying amounts of CO_2 over a range of distances for different regions of the continental United States. An engineering-economic model of pipeline CO_2 transport is developed for this purpose. The model incorporates a probabilistic analysis capability that can be used to quantify the sensitivity of transport cost to variability and uncertainty in the model input parameters. The results of a case study show a pipeline cost of US$ 1.16 per tonne of CO_2 transported for a 100 km pipeline constructed in the Midwest handling 5 million tonnes of CO_2 per year (the approximate output of an 800 MW coal-fired power plant with carbon capture). For the same set of assumptions, the cost of transport is US$ 0.39 per tonne lower in the Central US and US$ 0.20 per tonne higher in the Northeast US. Costs are sensitive to the design capacity of the pipeline and the pipeline length. For example, decreasing the design capacity of the Midwest US pipeline to 2 million tonnes per year increases the cost to US$ 2.23 per tonne of CO_2 for a 100 km pipeline, and US$ 4.06 per tonne CO_2 for a 200 km pipeline. An illustrative probabilistic analysis assigns uncertainty distributions to the pipeline capacity factor, pipeline inlet pressure, capital recovery factor, annual O&M cost, and escalation factors for capital cost components. The result indicates a 90% probability that the cost per tonne of CO_2 is between US$ 1.03 and US$ 2.63 per tonne of CO_2 transported in the Midwest US. In this case, the transport cost is shown to be most sensitive to the pipeline capacity factor and the capital recovery factor. The analytical model elaborated in this paper can be used to estimate pipeline costs for a broad range of potential CCS projects. It can also be used in conjunction with models producing more detailed estimates for specific projects, which requires substantially more information on site-specific factors affecting pipeline routing.

1. Introduction

Large reductions in carbon dioxide (CO_2) emissions from energy production will be required to stabilize atmospheric concentrations of CO_2 (Hoffert et al., 1998, 2002; Morita et al., 2001). One option to reduce CO_2 emissions to the atmosphere is CO_2 capture and storage (CCS); i.e., the capture of CO_2 directly from anthropogenic sources and sequestration of the

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CO_2 geological sinks for significant periods of time (Bachu, 2003). CCS requires CO_2 to be captured from large-scale industrial processes, compressed to high pressures, transported to a storage site, and injected into a suitable geological formation where it is sequestered and kept from the atmosphere. Studies indicate that under appropriate policy regimes, CCS could act as a potential "bridging technology" that would achieve significant CO_2 emission reductions while allowing fossil fuels to be used until alternative energy sources are more widely deployed. Moreover, as part of a portfolio of emissions reducing technologies, CCS could substantially reduce the cost of achieving stabilization goals (Herzog et al., 2005).

CCS will have significant impacts on the cost of electricity production and costs in other potential applications. Thus, methods are required to estimate the costs of CCS to evaluate actions and policies related to the deployment of CCS projects. In the last decade the understanding of CCS technologies has increased greatly, as reflected by the recent IPCC Special Report on Carbon Dioxide Capture and Storage (Metz et al., 2005). However, there are still significant gaps in knowledge of the cost of integrated capture, transport, and storage processes. For example, many studies of carbon capture processes have been undertaken (Thambimuthu et al., 2005) and engineering-economic models linking process cost to key engineering parameters have been developed (Rao and Rubin, 2002), but the majority have not yet been linked with transport and storage models to determine the cost of an integrated CCS process. Most cost studies either exclude transport and storage costs or assume a constant cost per tonne of CO_2 in addition to capture costs (Metz et al., 2005).

There have been few studies that have addressed the cost of CO_2 transport and storage in detail. However, earlier work by Svensson et al. (2004) identified pipeline transport as the most practical method to move large volumes of CO_2 overland and other studies have affirmed this conclusion (Doctor et al., 2005). Therefore, this paper focuses on the cost of CO_2 transport via pipeline. Skovholt (1993) presented rules of thumb for sizing of CO_2 pipelines and estimated the capital cost of pipeline transport. In 2002, the International Energy Agency Greenhouse Gas Programme (IEA GHG) released a report that presented several correlations for the cost of CO_2 pipelines in Europe based on detailed case study designs (Woodhill Engineering Consultants, 2002). More recently, an engineering-economic CO_2 pipeline model was developed at the Massachusetts Institute of Technology (MIT) (Bock et al., 2003). Results from these and similar studies were summarized in the recent IPCC report (Doctor et al., 2005). However, none of these studies considered the unusual physical properties of CO_2 at high pressures (Fesmire, 1983), the realities of available pipeline diameters and costs, or regional differences in the cost of CO_2 transportation.

The objective of this paper is to estimate the cost per tonne of transporting CO_2 for a range of CO_2 flow rates (e.g., reflecting different power plant sizes) over a range of distances, and to also incorporate regional cost differences within the continental US. These cost estimates are embodied in an engineering-economic model that will be presented in this paper. A probabilistic analysis is used to quantify the impact of uncertainty and variability in cost model parameters on CO_2 transport cost. This analysis also shows the range of costs associated with a given project and the probability of a given cost for a specific scenario.

2. Properties of CO_2 in pipeline transport

Efficient transport of CO_2 via pipeline requires that CO_2 be compressed and cooled to the liquid state (Zhang et al., 2006). Transport at lower densities (i.e., gaseous CO_2) is inefficient because of the low density of the CO_2 and relatively high pressure drop per unit length. Moreover, by operating the pipeline at pressures greater than the CO_2 critical pressure of 7.38 MPa, temperature fluctuations along the pipeline will not result in the formation of gaseous CO_2 and the difficulties encountered with two-phase flow (Recht, 1984).

The properties of CO_2 are considerably different from other fluids commonly transported by pipeline, such as natural gas. Thus, it is necessary to use accurate representations of the phase behavior, density, and viscosity of CO_2 and CO_2-containing mixtures in the design of the pipeline. The results presented here are based on the physical properties (i.e., density and phase behavior) of CO_2 and CO_2-containing mixtures calculated using a cubic equation of state with Peng–Robinson parameters, and mixing rules employing a binary interaction parameter (Reid et al., 1987). The transport properties of CO_2 have been estimated using the Chung et al. (1988) method, extended to high pressures by Reid et al. (1987).

Fig. 1 shows that the compressibility of CO_2 is non-linear in the range of pressures common for pipeline transport and is highly sensitive to any impurities, such as hydrogen sulfide (H_2S). Fig. 1 also shows the significant difference between the compressibility of pure CO_2 and CO_2 with 10 vol. % H_2S. To reduce difficulties in design and operation, it is generally recommended that a CO_2 pipeline operate at pressures greater than 8.6 MPa where the sharp changes in compressibility of CO_2 can be avoided across a range of temperatures that may be encountered in the pipeline system (Farris, 1983). Conversely, line-pipe with ASME-ANSI 900# flanges has a maximum allowable operating pressure of 15.3 MPa at 38 °C (Mohitpour et al., 2003). Operating the pipeline at higher pressures would require flanges with a higher rating. Over the range of typical conditions shown in Fig. 1, the density of CO_2 varies between approximately 800 and 1000 kg/m^3.

Operating temperatures of CO_2 pipelines are generally dictated by the temperature of the surrounding soil. In northern latitudes, the soil temperature varies from a few degrees below zero in the winter to 6–8 °C in summer, while in tropical locations; the soil temperature may reach up to 20 °C (Skovholt, 1993). However, at the discharge of compression stations after-cooling of compressed CO_2 may be required to ensure that the temperature of CO_2 does not exceed the allowable limits for either the pipeline coating or the flange temperature.

3. Pipeline performance model

While there are proven flow equations available for use with high pressure gas pipelines (e.g., AGA fully turbulent equation),

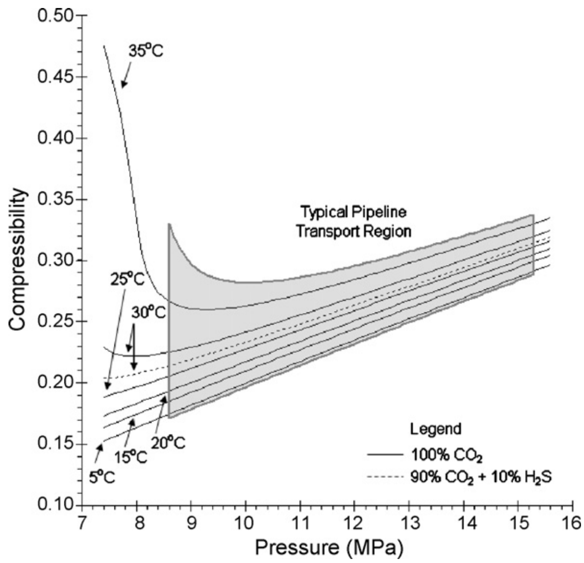

Fig. 1 – The compressibility of CO_2 based on the Peng–Robinson equation of state, showing the nonlinearity in the typical pipeline transport region and the sensitivity to impurities, such as 10% H_2S (by mole fraction).

these equations can introduce error into the estimation of flow rates in liquid CO_2 due to the underlying assumptions made in their development (Farris, 1983). The pipeline performance model used here is based on an energy balance on the flowing CO_2, where the required pipeline diameter for a pipeline segment is calculated while holding the upstream and downstream pressures constant. The mechanical energy balance can be written as (Mohitpour et al., 2003):

$$\frac{c}{v}\mathrm{d}u + \frac{1}{v}\mathrm{d}p + \frac{g}{v^2}\mathrm{d}h + \frac{2 f_F c^2}{D_i}\mathrm{d}L = 0 \tag{1}$$

where c is a constant equal to the product of density, ρ (kg/m^3), and fluid velocity, u (m/s); g is acceleration due to gravity (m/s^2); v is the specific volume of fluid (m^3/kg); p is pressure (Pa); h is height (m); f_F is the fanning friction factor; D_i is the internal pipeline diameter (m); L is the pipeline segment length (m).

The energy balance given in Eq. (1) can be simplified by assuming that changes in kinetic energy of the flowing CO_2 are negligible (constant velocity), and that the compressibility of the CO_2 or CO_2-containing mixture can be averaged over the length of the pipeline. The resulting energy balance, as derived by Mohitpour et al. (2003), and solved for pipe segment diameter:

$$D_i = \left\{ \frac{-64 Z_{ave}^2 R^2 T_{ave}^2 f_F \dot{m}^2 L}{\pi^2 [M Z_{ave} R T_{ave} (p_2^2 - p_1^2) + 2 g P_{ave}^2 M^2 (h_2 - h_1)]} \right\}^{1/5} \tag{2}$$

where Z_{ave} is the average fluid compressibility; R is the universal gas constant (Pa m^3/mol K); T_{ave} is the average fluid temperature (K); $\dot{m}$ is the design mass flow rate (kg/s); M is the molecular weight of the stream (kg/kgmol); p is pressure at points 1 and 2, which are upstream and downstream, respectively; h is the pipeline elevation, where 1 and 2 represent upstream and downstream locations.

Fort the case of a CO_2 pipeline modeled here, the average temperature, T_{ave}, is assumed to be constant at ground temperature so that $T_{ave} = T_{ground}$. Because pressure varies non-linearly along the pipeline, the average pressure, P_{ave}, required in Eq. (2) is calculated (Mohitpour et al., 2003):

$$P_{ave} = \frac{2}{3}\left(p_2 + p_1 - \frac{p_2 p_1}{p_2 + p_1} \right) \tag{3}$$

Thus, Eq. (2) can be used to calculate the pipe diameter required for a given pressure drop. Complicating this, however, is the Fanning friction factor, which is a function of the pipe diameter. The Fanning friction factor cannot be solved for analytically; however, an explicit approximation for Fanning friction factor is given by Eq. (4) (Zigrang and Sylvester, 1982):

$$\frac{1}{2\sqrt{f_F}} = -2.0 \log\left\{ \frac{\varepsilon/D_i}{3.7} - \frac{5.02}{Re}\log\left[\frac{\varepsilon/D_i}{3.7} - \frac{5.02}{Re}\log\left(\frac{\varepsilon/D_i}{3.7} + \frac{13}{Re} \right) \right] \right\} \tag{4}$$

where ε is the roughness of the pipe (m), which is approximately 0.0457 mm for commercial steel pipe (Boyce, 1997), and Re is the Reynolds number, which is defined as (McCabe et al., 1993):

$$Re = \frac{4\dot{m}}{\mu \pi D_i} \tag{5}$$

where μ is the viscosity of the fluid (Pa s). As a result, Eqs. (2), (4), and (5) must be solved iteratively to determine the pipe diameter required for a particular application. In the iteration scheme shown in Fig. 2, the Reynolds number, Eq. (5), is first calculated using an initial estimate of pipe diameter based on a velocity of 1.36 m/s. This initial velocity is representative of CO_2 pipeline flows, and thus minimizes the number of iterations required over a range of model inputs for both design mass flow rate and pipeline length. The calculated Reynolds number is then used in Eq. (4) to estimate the Fanning friction factor, which is then substituted into Eq. (2). This yields an updated diameter, which is compared with the value at the previous iteration. Values for the internal diameter converge to within 10^{-6} m in generally less than five iterations.

Line pipe is not available in continuous diameters. Thus the internal pipe diameter calculated must be adjusted to account for both available pipe diameters and the pipe wall thickness. A discrete size of line pipe is frequently referred to by its Nominal Pipe Size (NPS), which corresponds approximately to the outside pipe diameter measured in inches. In the model presented here, eleven NPS values between 4 and 30 are available. To determine the inside diameter, the pipe wall thickness (also known as the pipe schedule) for each NPS is estimated using the method specified in the US Code of Federal Regulations (CFR), which regulates the design, construction, and operation of CO_2 pipelines in the United

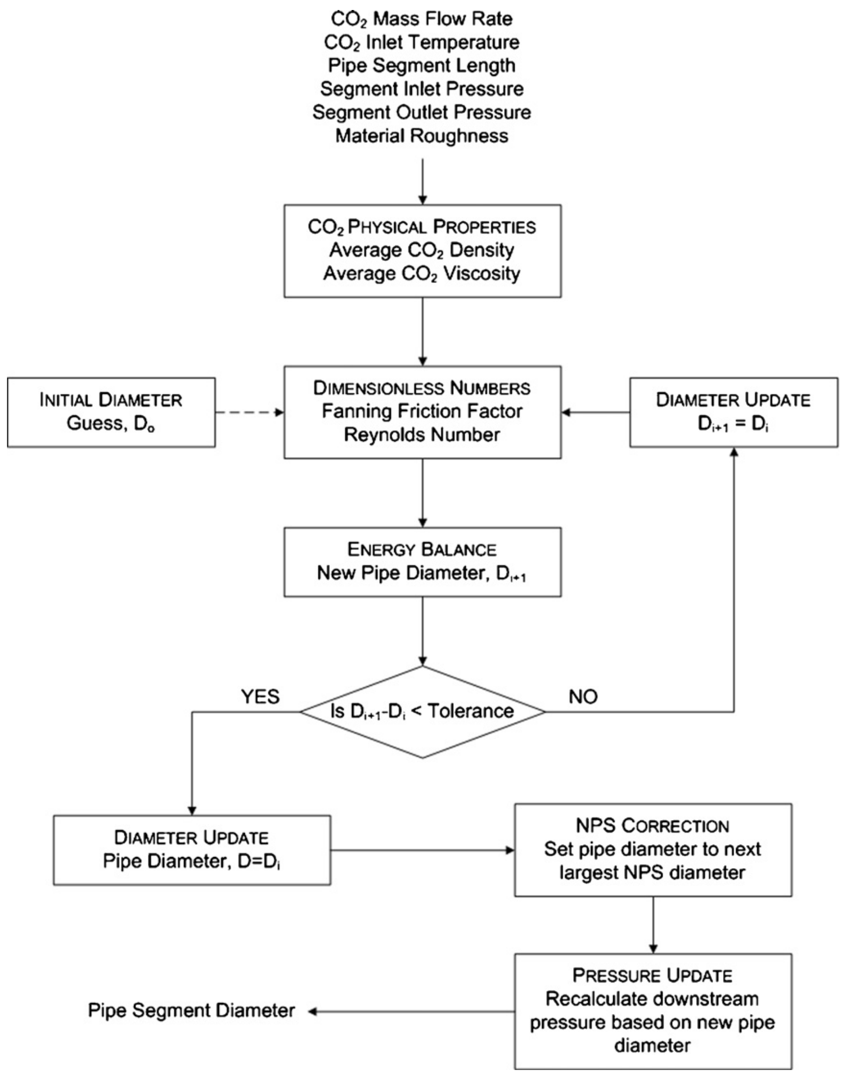

Fig. 2 – Flowchart illustrating the calculation method used to estimate the pipeline diameter.

States. The pipe wall thickness, t, in meters is given as (CFR, 2005):

$$t = \frac{p_{mop} D_o}{2SEF} \tag{6}$$

where p_{mop} is the maximum operating pressure of the pipeline (Pa), D_o is the outside pipe diameter (m), S is the specified minimum yield stress for the pipe material (Pa), E is the longitudinal joint factor (reflecting different types of longitudinal pipe welds), and F is the design factor (introduced to add a margin of safety to the wall thickness calculation). For the purposes of estimating the pipe wall thickness, the maximum operating pressure is assumed to be 15.3 MPa, the longitudinal joint factor is 1.0, and the design factor is 0.72 (as required in the CFR). The minimum yield stress is dependent on the specification and grade of line pipe selected for the pipeline. For CO_2 service, pipelines are generally constructed with materials meeting American Petroleum Institute (API) specification 5L (American Petroleum Institute, 2004). In this case, the minimum yield stress has been specified as 483 MPa, which corresponds to API 5L X-70 line pipe.

The value of D_i calculated from Eq. (2) is adjusted to the next larges value of D_i for an available NPS. Based on the adjusted D_i, the adjusted downstream pressure for the pipeline segment is calculated. This pressure will always be greater than the downstream pressure specified by the user since the adjusted diameter will always be greater than the optimum value calculated by Eq. (2).

Fig. 3 shows the NPS of a pipeline carrying pure CO_2 as a function of the design CO_2 mass flow rate, as calculated by the iteration scheme shown in Fig. 2. For fixed inlet pressure and minimum outlet pressure, the required pipe diameter increases with increasing design CO_2 flow rate and pipeline distance. Steps in pipeline diameter occur because of the discrete NPS available in the model. For example, the model estimates an internal diameter of 0.38 m for a pipeline spanning a distance of 100 km designed to carry 5 million tonnes per year of CO_2 at a pressure drop of 35 kPa/km. However, this is not a common line pipe size; thus, the next largest NPS is selected

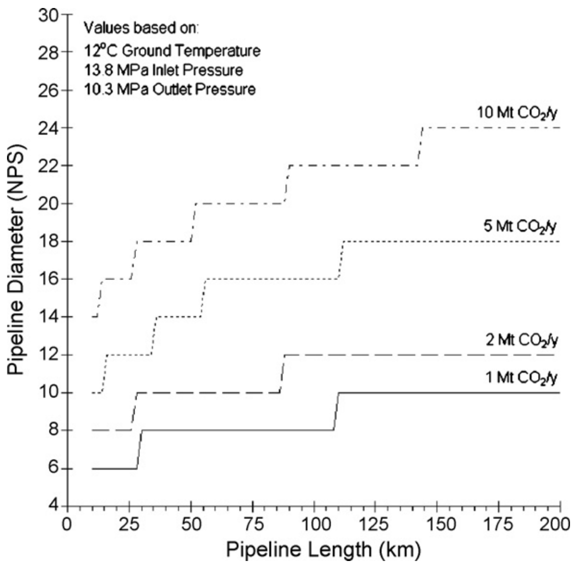

Fig. 3 – Required pipe diameter for the specified inlet and outlet pressures, for different pipeline lengths and four different design mass flow rates, as predicted by the performance model.

by the model, which has an internal diameter of about 0.39 m.

4. Pipeline cost model

Detailed construction cost data for actual CO_2 pipelines (i.e., as-built-cost including the length and diameter) are not readily available; nor have many such projects been constructed in the last decade (Doctor et al., 2005). For these reasons, the data set used to develop the pipeline capital cost models is based on natural gas pipelines. However, there are many similarities between transport of natural gas and CO_2. Both are transported at similar pressures, approximately 10 MPa and greater. Assuming the CO_2 is dry, which is a common requirement for CCS, both pipelines will require similar materials. Thus, a model based on natural gas pipelines offers a reasonable approximation for a preliminary design model used in the absence of more detailed project-specific costs.

The CO_2 pipeline capital cost model is based on regression analyses of natural gas pipeline project costs published between 1995 and 2005 (True, 1995, 1996, 1997, 1999, 2000a,b, 2001, 2002, 2003a,b; True and Stell, 2004; Smith et al., 2005). These project costs are based on Federal Energy Regulatory Commission (FERC) filings from interstate gas transmission companies. The entire data set contains the "as-built" costs for 263 on-shore pipeline projects in the contiguous 48-states and excludes costs for pipelines with river or stream crossings as well as lateral pipeline projects (i.e., a pipeline of secondary significance to the mainline system, such as a tie-in between the mainline and a power plant). Costs from each year's projects have been adjusted to 2004 dollars using the Marshall and Swift equipment cost index (Chemical Engineering, 2006).

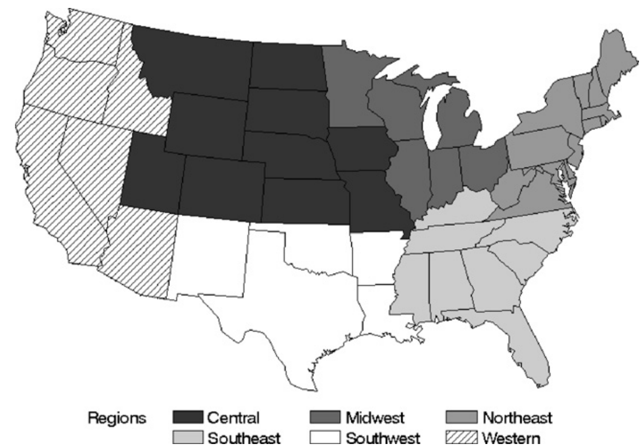

Fig. 4 – The six US regions used in the pipeline transport cost model.

The pipeline data set contains information on the year and location of the project and the length and diameter of the pipeline. Locations are listed by state in the data set; however, to develop the regression models presented here, the states have been grouped into six geographical regions. The project regions used here are the same as those used by the Energy Information Administration (2006) for natural gas pipeline regions, and are shown in Fig. 4.

The total construction cost for each project is broken down into four categories: materials, labor, right-of-way (ROW), and miscellaneous charges. The materials category includes the cost of line pipe, pipe coatings, and cathodic protection. Labor is the cost of pipeline construction labor. ROW covers the cost of obtaining right-of-way for the pipeline and allowance for damages to landowners' property during construction. Miscellaneous includes the costs of surveying, engineering, supervision, contingencies, telecommunications equipment, freight, taxes, allowances for funds used during construction (AFUDC), administration and overheads, and regulatory filing fees.

Separate cost models have been developed for each of the cost categories. The capital cost models take this general form:

$$\log(C) = a_0 + a_1\mathrm{NE} + a_2\mathrm{SE} + a_3\mathrm{CL} + a_4\mathrm{SW} + a_5\mathrm{W} + a_6\log(L) + a_7\log(D_{\mathrm{nps}}) \quad (7)$$

where NE, SE, CL, SW, and W are binary variables reflecting the five geographic regions besides Midwest (i.e., Northeast, Southeast, Central, Southwest, and West, respectively) that take a value of 1 or 0 depending on the region and increase or decrease the estimated cost relative to the Midwest value. C is the pipeline capital cost in 2004 US dollars. The variable L is the total pipeline length in kilometers, and the D is the pipeline NPS. Regional variables exist in the cost model only if they are statistically significant predictors of the cost; thus different cost-component models include different sets of regional variables.

Table 1 – Regression coefficients for the pipeline cost model, Eq. (7); with standard errors indicated in parentheses

Coefficient estimate	Cost component			
	Materials	Labor	ROW	Miscellaneous
a_0	3.112** (0.067)	4.487** (0.109)	3.950** (0.244)	4.390** (0.132)
a_1	–	0.075* (0.032)	–	0.145** (0.045)
a_2	0.074** (0.021)	–	–	0.132* (0.054)
a_3	–	−0.187** (0.048)	−0.382** (0.093)	−0.369** (0.061)
a_4	–	−0.216** (0.059)	–	–
a_5	–	–	–	−0.377** (0.066)
a_6	0.901** (0.012)	0.820** (0.023)	1.049** (0.048)	0.783** (0.027)
a_7	1.590** (0.045)	0.940** (0.077)	0.403* (0.167)	0.791** (0.091)

* Significant at the 5% level.
** Significant at the 1% level.

If the intercept and regional variables in Eq. (7) are collected into a single term and rearranged, the cost model can be rewritten in Cobb-Douglas form[1]:

$$C = bL^{a_6}D_{\text{nps}}^{a_7}, \quad \text{where } \log(b) = a_0 + a_1\text{NE} + a_2\text{SE} + a_3\text{CL} + a_4\text{SW} + a_5\text{W} \tag{8}$$

There are several properties of Cobb-Douglas functions that are of interest in the context of the cost models. If the sum of a_6 and a_7 is equal to one, the capital cost exhibits constant returns to scale (i.e., cost is linear with L and D). If the sum is less than one, there are decreasing returns to scale, and if the sum is greater than one, increasing returns to scale. Moreover, the values of a_6 and a_7 represent the elasticity of cost with respect to length and diameter, respectively.

Parameter estimates for the materials, labor, miscellaneous charges, and ROW cost components are given in Table 1. The generalized regression model given in Eq. (7) accounts for a large proportion of the variation in the data set for each of the cost categories, as reflected by all of the cost component models having an adjusted-r^2 value greater than 0.81, with the exception of ROW, which has an adjusted-r^2 value of 0.67.

Based on the regression results shown in Table 1, several general observations can be made. The cost of all four components exhibit increasing returns to scale, which means that multiplying both the length and diameter by a constant n multiplies the materials cost by a factor greater than n. For example, doubling both pipeline length and diameter results in a nearly 6-fold (rather than 4-fold) increase in materials cost. For the materials, labor and miscellaneous costs, the elasticity of substitution for length is less than one; thus, a doubling in pipeline length results in less than a doubling of the cost for these components (often referred to as economies of scale). However, the elasticity of substitution for length in the ROW cost is approximately one, so that doubling the length results in a doubling of ROW cost (which is reasonable, as the ROW cost per unit of land should be approximately constant regardless of the pipeline length). The elasticity of substitution for pipeline diameter is less than one for labor, miscellaneous, and ROW costs, again indicating economies of scale; however, for materials cost it is approximately 1.6, so that doubling the pipeline diameter results in a 3-fold materials cost increase. Note that this still reflects an economy of scale in the total cost of materials since doubling the diameter would quadruple the total mass of steel needed.

At least one regional variable was found to be statistically significant in all of the regression model cost categories, implying that for some regions, the cost of constructing a pipeline is higher or lower than the average for the Midwest region. For example, the labor cost regression results (Table 1) show that the cost multiplier is approximately US$ 6000 greater in the Northeast than the Midwest and approximately US$ 10,000 lower in the Central and Southwest regions. There is no statistical difference (at the 5% level) between the Midwest and West or Southeast cost intercepts.

Cost differences between regions could be caused by a combination of two types of factors: differences between regions in the average cost of materials, labor, miscellaneous costs, and land (affecting ROW cost); and, differences in other geographic factors, such as population density and terrain. Regional variation in labor and materials cost for power plant construction have been documented by the Electric Power Research Institute (EPRI) (Electric Power Research Institute, 1993). However, because the routings of pipeline projects are not reported in the data set, it is not possible to identify how these individual factors contributed to overall cost of the projects. Thus, there are plausible circumstances where similar pipeline projects in different regions could have costs much closer to one another than to comparable projects within their respective regions (e.g., pipelines of similar length and design CO_2 mass flow in heavily populated versus unpopulated areas within the same state). Zhang et al. (2007) have developed more data intensive tools to study least-cost routing of specific CO_2 pipelines which are complimentary to the use of the current screening level model.

While operating and maintenance (O&M) costs are not large in comparison to the annualized capital cost of pipeline transport, they are nonetheless significant. Bock et al. (2003) report that the O&M cost of operating a 480 km CO_2 pipeline is between US$ 40,000 and US$ 60,000 per month. On an annual basis, this amounts to approximately US$ 3250 per kilometer of pipeline in 2004 dollars.

[1] In economic theory, a Cobb-Douglas production function has the form $f(K,L) = AK^aL^b$, where K and L traditionally refer to capital and labor.

Table 2 – Illustrative case study values for the model parameters

Model parameter	Deterministic value	Uncertainty distribution
Pipeline parameters		
Design mass flow (Mt/year)	5	Variable[a]
Pipeline length (km)	100	Variable[a]
Pipeline capacity factor (%)	100	Uniform (50, 100)
Ground temperature (°C)	12	
Inlet pressure (MPa)	13.79	Uniform (12, 15)
Minimum outlet pressure (MPa)	10.3	
Pipe roughness (mm)	0.0457	
Economic and financial parameters		
Project region	Midwest	
Capital recovery factor (%)	15[b]	Uniform (10, 20)
Annual O&M cost (US$/km/year)	3250	Uniform (2150, 4350)
Escalation factor for materials cost	1	Uniform (0.75, 1.25)
Escalation factor for labor cost	1	Uniform (0.75, 1.25)
Escalation factor for ROW cost	1	Uniform (0.75, 1.25)
Escalation factor for miscellaneous cost	1	Uniform (0.75, 1.25)

[a] This parameter is modeled as a series of discrete values.
[b] Corresponds to a 30-year plant lifetime with a 14.8% real interest rate (or, a 20-year life with 13.9% interest rate).

5. Combining performance and cost

To facilitate calculations, the linked pipeline performance and cost models have been programmed as a stand-alone spreadsheet model using Visual Basic in Microsoft Excel. Implementation of all equations has been validated by comparing spreadsheet results to manually calculated results using the same input parameters. The pipeline model has also been implemented in the Integrated Environmental Control Model (IECM), a power plant simulation model developed by Carnegie Mellon University for the U.S. Department of Energy (USDOE) to estimate the performance, emissions, and cost of alternative power generation technologies and emissions control options (Rao and Rubin, 2002; Berkenpas et al., 2004). The new CO_2 pipeline transport module allows the IECM to analyze in greater detail the performance and cost of alternative CO_2 capture and sequestration technologies in complex plant designs involving multipollutant emission controls.

The key results reported by the newly developed pipeline model include the total capital cost, annual O&M cost, total levelized cost, and the levelized cost per metric tonnes of CO_2 transported (all in constant 2004 US dollars). The capital cost can be subject to capital cost escalation factors applied to individual categories of the capital cost (i.e., materials, labor, miscellaneous, and ROW). These escalation factors can be used to account for anticipated changes in capital cost components (e.g., in the cost of steel) or other project-specific factors that might affect capital costs relative to the regional averages discussed earlier (e.g., river crossings). Capital costs are annualized using a levelized fixed charge factor calculated for a user-specified discount rate and project life (Berkenpas et al., 2004). The cost per tonne CO_2 transported reflects the amount of CO_2 transported, which is the product of the design mass flow rate and the pipeline capacity factor.

6. Case study results

Illustrative results from the pipeline model were developed using parameters representative of a typical coal-fired power plant in the Midwest region of the United States (Table 2). Several parameter values (e.g., capital recovery factor) are default values from the IECM software. Table 2 includes a nominal CO_2 mass flow rate and pipeline length, but these two parameters are varied parametrically in the case study results presented here.

Table 3 – The levelized cost of pipeline transport in the Midwest and regional differences relative to the Midwest, based on assumptions in Table 2

Transport cost (US$/tonne CO_2)	Midwest	Difference from midwest cost				
		Northeast	Southeast	Southwest	West	Central
Materials	0.20	0	0.04	0	0	0
Labor	0.54	0.10	0	(0.21)	0	(0.19)
ROW	0.10	0	0	0	0	(0.06)
Miscellaneous	0.24	0.10	0.09	0	(0.14)	(0.14)
O&M	0.07	0	0	0	0	0
Total	1.16	0.20	0.12	(0.21)	(0.14)	(0.39)

Bracketed values are negative (all costs in constant 2004 US dollars).

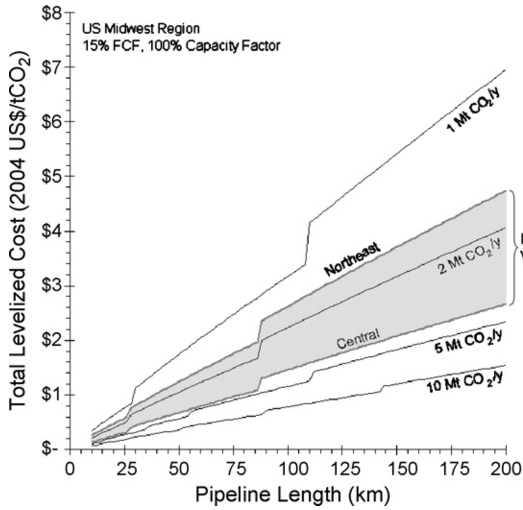

Fig. 5 – Illustrative results from the transport model showing the total transport cost over a range of pipeline design capacities and pipeline lengths. All costs in 2004 US dollars.

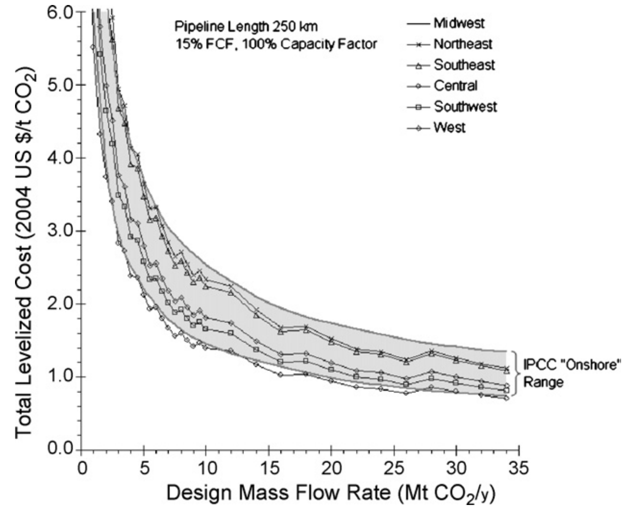

Fig. 6 – A comparison of pipeline cost results from the model developed in this study for the six US regions with the range of costs (represented by the shaded area) presented in the IPCC Special Report on Carbon Capture and Storage (Doctor et al., 2005).

For the case study CO_2 pipeline, the total levelized cost is estimated to be US$ 1.16 per tonne of CO_2 transported. Table 3 shows the regional differences in CO_2 transport cost relative to the Midwest region for a pipeline with the same parameters as in Table 2. In general, the model shows that the cost is greatest in the Northeast, followed by (in descending order) the Southeast, Midwest, West, Southwest, and Central U.S. This trend applies to all pipeline lengths and design mass flows. Overall, the cost category that accounts for the largest regional difference is the labor cost, which is lowest in the Southwest and highest in the Northeast.

Fig. 5 shows results from the model as a function of pipeline distance for a project in the Midwest for four different design mass flow rates. In this example the pipeline capacity factor is assumed to be 100%, so the annual mass transported equals the design capacity of the pipeline. Fig. 5 shows that the levelized transport cost increases with distance and decreases with increasing design capacity for a fixed distance. For a typical 500 MW power plant (emissions of approximately 2–3 million tonnes per year), transport cost could range from US$ 0.15 per tonne for a 10 km pipeline to US$ 4.06 per tonne for a 200 km pipeline based on a 100% capacity factor. For an annual capacity factor of 75% (typical of existing coal-fired power plants), the levelized cost per tonne would increase to between US$ 0.20 per tonne for the 10 km pipeline to US$ 5.41 per tonne for 200 km pipeline. Fig. 5 also illustrates the differences in levelized cost between the same pipeline constructed in the Northeast and Central regions. For all pipeline distances and all pipeline design capacities, the transport cost is lowest in the Central region and highest in the Northeast region.

7. Comparison with other studies

A number of recent studies and reports have estimated the cost of onshore CO_2 pipelines, including studies by IEAGHG (Woodhill Engineering Consultants, 2002), MIT (Bock et al., 2003), and Hendriks et al. (2003). To the best of our knowledge, however, there are no publicly available CO_2 pipeline cost models that have been published in peer-reviewed journals. Results from these and other recent studies were compared in the IPCC Special Report on Carbon Dioxide Capture and Storage (Doctor et al., 2005). Levelized costs generated by the current pipeline model are compared with the range of results presented by the IPCC for onshore pipelines, represented by the shaded area in Fig. 6. Parameter values for our model are listed in Table 2, where a fixed distance of 250 km was used for pipeline length, and mass flow varied, consistent with the IPCC assumptions. Costs estimated by the pipeline model agree well with the IPCC results, although that report does not specify assumptions beyond the pipeline length and mass flow rate. Thus, parameter values different from those listed in Table 2 could generate transport costs lower or higher than the IPCC range.

8. Probabilistic results

To assess the sensitivity of the model to changes in multiple design and financial parameters, uniform distributions were assigned to several parameters of interest and a series of Monte Carlo trials were used to calculate the pipeline transport cost. The uniform distribution was selected to represent uncertainty or variability because there is no prior information that would suggest choosing a more complex distribution (such as a triangular or lognormal distribution). The design parameters of interest are the ground temperature, and pipeline inlet pressure, while financial parameters include pipeline capacity factor, capital recovery factor, and annual pipeline O&M cost. Values of the input parameters for the probabilistic analysis are also shown in Table 2.

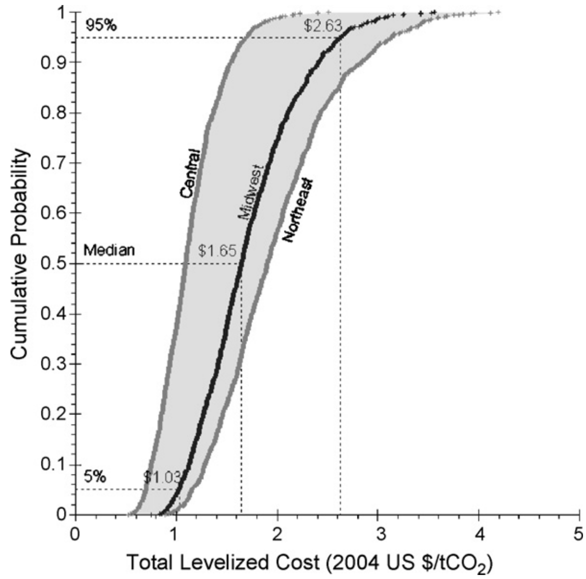

Fig. 7 – Cumulative probability distribution of pipeline transport cost generated from the Monte Carlo analysis for the case study parameters values in Table 2.

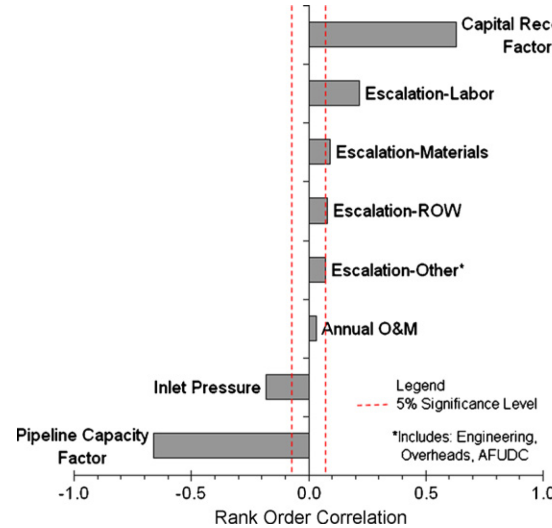

Fig. 8 – Rank order correlation between results of the Monte Carlo analysis and the parameters assigned uniform distributions (see Table 2).

For this analysis, 1000 trials were conducted. From these trials a cumulative distribution function (CDF) for transport cost was generated, shown in Fig. 7. The CDF shows that for a Midwest pipeline project transporting 5 million tonnes of CO_2 annually over 100 km, a 90% probability interval (which reflects the selection of input parameters) yields levelized costs between approximately US$ 1.03 and US$ 2.63 per tonne of CO_2 transported. The minimum and maximum cost predicted by the model are US$ 0.75 and US$ 3.56 per tonne of CO_2 transported; however, these values are very sensitive to the number of Monte Carlo simulations performed. A less sensitive measure is the median cost of transport, which is US$ 1.65 per tonne under these conditions.

Using the cost models for different regions changes the results of the sensitivity analysis, also shown in Fig. 7. Thus, a project in the Central US region will have costs less than a project in the Midwest or Northeast for all combinations of input parameters. The median cost of the case study project in the Central US is US$ 1.09 per tonne CO_2, with a 90% confidence interval between US$ 0.70 and US$ 1.69 per tonne. In the Northeast, the project cost could approach that of the Midwest for some combinations of input parameters. The median cost of this project in the Northeast is US$ 1.90 per tonne CO_2, with a 90% confidence interval between US$ 1.16 and US$ 3.14 per tonne.

Results of the Monte Carlo trials can also be used to assess the sensitivity of transport cost to the uncertain model parameters. The measure used to assess the sensitivity is the Spearman rank-order correlation (r_s) (Morgan et al., 1990). Similar to the commonly used Pearson product–moment correlation (i.e., r-value), which measures strength of a linear relationship between variables, rank-order correlation is a measure of direction and association between the statistical rank of variables. The value of the rank order correlation coefficient between transport cost and each uncertain model parameter is shown in Fig. 8. The dashed vertical lines to the left and right of the axis in Fig. 8 indicate the 5% significance level ($r_s = \pm 0.07$); rank-order correlation coefficients smaller than this value are not statistically significant at the 5% level. Fig. 8 shows the strongest correlation is between transport cost and pipeline capacity factor ($r_s = -0.66$), followed by capital recovery factor ($r_s = 0.63$). Following these, significant rank-order correlation coefficients (by decreasing magnitude) are the labor escalation factor, inlet pressure, materials escalation factor, and ROW escalation factor. This implies that the pipeline capacity factor and capital recovery factor are far stronger determinants of pipeline transport cost than any of the escalation factors. For example, to double the levelized cost of transport for the illustrative CO_2 pipeline (parameters presented in Table 2) the capital cost escalation factor for pipeline materials would have to be increased between 400 and 800%, depending on the project region. By contrast, only a 50% reduction in the pipeline capacity factor is required to double the levelized cost.

9. Conclusions

The model of CO_2 transport developed in this paper builds on past work in this area by linking the design of CO_2 pipelines with the cost of construction and operation to arrive at the total cost of CO_2 transport for six major regions of the United States. For the illustrative example presented here (i.e., 5 million tonnes of CO_2 transported annually over 100 km in the Midwest), the estimated cost of CO_2 transport was US$ 1.16 per tonne of CO_2; however, this cost could vary by over 30% for other US regions of construction. CO_2 transport costs can vary more significantly with pipeline length and design capacity. For example, for a typical 500 MW power plant in the Midwest the model estimates costs that ranged from US$ 0.15 per tonne for a 10 km pipeline to US$ 4.06 per tonne for a 200 km pipeline. Cost of construction is generally greatest in the Northeast and least in the Central region of the US. An illustrative probabilistic analysis showed how the model can yield a range of transport costs for a particular project reflecting the uncertainty or variability of project parameters. The probabilistic analysis further showed that the most important determinants of the pipeline cost for a specific project were likely the pipeline capacity factor and the capital recovery factor.

Using this model in combination with performance and cost models of CO_2 capture and storage technologies can allow the overall cost of an integrated project to be estimated with greater accuracy than afforded by with generic rule-of-thumb estimates for transport costs, as often found in the literature. The Integrated Environmental Control Model (IECM) developed at Carnegie Mellon (Berkenpas et al., 2004) is an example of a tool with that capability. The CO_2 transport model developed here also is suitable for use in addressing larger questions on the optimal policies that might encourage infrastructure development to support carbon capture and storage.

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