ABSTRACT

The main focus of this paper is on techno-economic modeling and analysis of CO₂ pipelines, as it strives to develop a thorough understanding of the essential fluid-mechanics variables involved in modeling and analysis of such pipelines. The authors investigate and analyze the reasons behind the variations in the techno-economic results generated from seven different techno-economic models which are commonly used for construction and operation of CO₂ pipelines. Such variations often translate into tens or, at times, hundreds of millions of dollars in terms of initial financial estimates at the Pre-FEED (Front End Engineering Design) or FEED stages for Carbon Capture and Storage (CCS) projects. Variations of this magnitude can easily bring much unwanted uncertainty to the feasibility of a CO₂ pipeline project and they can potentially cause a major over or under estimation of the project’s true costs. The summary of a detailed analysis and assessment for these seven existing techno-economic models for CO₂ pipeline transport has been presented in this paper. The analysis conducted indicates that some of these models are essentially identical and are rooted in similar fluid mechanics theories and assumptions. This type of analysis assists with explaining and narrowing down the variability of the models’ results. Based on these analyses, a refined and more accurate model was established and the development process was explained. The refined model uses the Reynolds number, Colebrook-White equation using the Darcy friction factor, and the Darcy-Weisbach pressure drop equation to establish the most accurate measure for the pipe’s diameter. To assess the CO₂ pipeline’s total capital cost, total annual cost, and the levelized transport cost, a statistical regression analysis approach was suggested and the adjusted-r² measure was proposed to assess the goodness-of-the-fit of the generated cost function. The accuracy of the new techno-economic model was validated with the figures of a proposed CO₂ infrastructure project in the United Kingdom and also through hydraulic modeling.

INTRODUCTION

The global energy consumption is increasing significantly and is expected to grow by 49 percent, or 1.4 percent per year, from 495 quadrillion Btu in 2007 to 739 quadrillion Btu in 2035 (International Energy Outlook, 2010). This rise is, in part, due to increases in the existing level of energy consumption and also due to the energy required to fuel global economic growth, particularly in emerging economies such as Brazil, Russia, India and China. In order to sustainably meet the growing energy demands and challenges of the future, reliance cannot be placed on the methods and technologies of the past.

According to the Intergovernmental Panel on Climate Change (IPCC), “there is new and stronger evidence that most of the warming observed over the last 50 years is due to human activities” (IPCC, 2005). Burning coal, oil and natural gas will continue to increase the CO₂ concentrations in the atmosphere which directly contributes to anthropogenic global warming. The power industry accounts for about a quarter of the global greenhouse gas (GHG) emissions with the majority of emissions attributable to fossil fuel and, especially, coal-fired power stations (IHS, 2011). Currently coal is the most significant fuel source for power generation. It is estimated that coal-fired generation accounts for 40 percent of the 20,000 terawatt-hours (TWh) of electricity generated worldwide but also accounts for three-quarters of all the CO₂ emitted by the global power sector (IHS, 2011). While renewable technologies are under much needed development, currently the largest portion of the global energy demand has to be met through hydrocarbon sources. Therefore, it is essential, from an environmental standpoint, to generate the demanded energy with fewer emissions.

One of the technologies that have been identified to produce a reduction in the levels of anthropogenic emissions from fossil-fueled energy generation is CCS. The CCS chain of technologies involves the capture of CO₂ at a power plant, or
a large stationary industrial source and transport, generally via a pipeline, to a geological storage site where the CO₂ can either be stored securely or utilized for Enhanced Oil Recovery (EOR). At the heart of determining the viability and applicability of CCS lies the analysis of the technical and economic components of the entire CCS chain, part of which is the CO₂ pipeline system. This paper reviews the techno-economic modeling and analysis of CO₂ pipelines for CCS projects and proposes a refined model, derived from the perceived best practice in the existing models that can be used at the feasibility stages of a CCS project to estimate the cost of the pipeline.

REVIEW OF EXISTING TECHNO-ECONOMIC MODELS FOR CO₂ PIPELINES

There are existing techno-economic models which provide analytical tools for determining the CO₂ pipeline diameter based on hydraulic calculations, whilst also estimating the costs associated with the construction and maintenance of the pipeline. Predominantly these models provide an estimate of the cost of transporting a unit mass of CO₂ (levelized cost) over a certain distance.

In the current work, seven CO₂ pipelines techno-economic models have been reviewed, including MIT (Heddle and Herzog, 2003), Ecofys (Hendriks et al. 2003), McCoy & Rubin (McCoy and Rubin, 2007), Ogden (Ogden et al., 2004), IEA GHG PH4/6 (IEA, 2002), IEA GHG 2005/2 (IEA, 2005a) and IEA GHG 2005/3 (IEA, 2005b) models. These models have different underlying assumptions and various methods of assessment. The different approaches are discussed in the following sections and summarized in ANNEX A. It is highlighted that most of these models were developed for onshore CO₂ pipelines and there is less published analytical work for offshore CO₂ pipelines.

For pipeline diameter calculations, ANNEX A illustrates that these models, based on their hydraulic analysis approach, fall into three main categories: those that use the Darcy-Weisbach method (colored green), those based on a mechanical energy balance calculation (colored orange) and those based on a mass flow rate calculation or a rule of thumb calculation (colored red).

DARCY-FEISBACH BASED MODELS

The MIT, Ecofys, and the IEA GHG PH4/6 models all apply the Darcy-Weisbach (Menon, 2004) fluid-mechanics principle. Consequently, the pipeline diameters calculated by these models are similar. The Darcy-Weisbach equation expresses the pressure drop, h[m], as a function of the friction factor, f. This relationship is further discussed in the following sections. The calculation approach for these models allows the pipeline diameter to be determined based on robust fluid-mechanics relationships, thereby reducing the number of set-value assumptions required. Consequently, it is reasonable to expect that the calculated diameter values would be more accurate using this approach than those of other methods in which more general assumptions are made.

The strength of the MIT model lies in its simple iterative fluid-mechanics approach, however, the model assumes that the absolute pipeline roughness (ε) of the pipe is a constant figure (0.00015 feet). This is considered to be one of this model’s simplifying assumptions, because, in reality, this value varies for different line pipes. The model also assumes that the annual operation and maintenance cost of the pipeline is only a function of the length and not the diameter of the pipeline. This is not an accurate assumption either for the cost of operation or for the cost of maintenance. For example, assuming similar pressure levels, a larger diameter pipeline often requires a more powerful booster station than a smaller diameter pipeline. This will automatically require more power to operate the larger diameter pipeline, which will increase the operation cost. In addition, for maintenance and integrity management of pipelines often inline inspection and cleaning tools, e.g. pigs, are used. The pipeline diameter determines the size of the inspection or cleaning tool. Assuming similar pig technologies, the larger the tool, the heavier it is to transport and more costly to operate it.

The Ecofys model accounts for various types of terrains through the incorporation of a terrain factor, Fₜ, in its capital cost equation. This is an advantageous consideration as it allows the equation to be adapted to pipeline construction for different terrains. The IEA GHG PH4/6 model also distinguishes between various terrains using terrain factors but, in addition, it acknowledges the importance of accounting for various economic locations by incorporating location factors, Fₗ, in the calculations. However, it is considered that proposed values for location factors in this model could be improved to account for different international and regional economic drivers.

MECHANICAL ENERGY BALANCE BASED MODELS

For the calculation of the pipeline diameter, the McCoy & Rubin and Ogden models apply equations that are based on the mechanical energy balance. The mechanical energy balance essentially assumes that the change in the mechanical energy of an isothermal fluid flow is caused by friction. It is applicable to systems with a single input and a single output. The models assume that an accurate average compressibility value, an accurate average temperature, and an accurate average pressure can be found for any given CO₂ pipeline system. This may or may not be the case and it can potentially introduce inaccuracy in the calculated diameter size of the pipeline.

The McCoy & Rubin model was developed in the United States and divides the country into six geographical regions of Midwest, North East, South East, Central, South West and West. This is due to the fact that the cost of material, labor and business operation are different in each of these regions and the model’s structure accounts for these regional cost differences. Ogden’s model suggests various ranges for average compressibility, average pressure and average temperature of the CO₂ stream to be used with its proposed equation. Finding the exact value for these variables can be challenging.
MASstoff flow rate calculation based models

The IEA GHG 2005/2 model is based on a mass flow rate calculation in which the diameter is calculated using the following equation:

\[ m = \rho AV = \frac{\pi}{4} D^2 V \]

\[ \Rightarrow V D^2 \rho \pi = AV \rho = m_i \]

(1)

Where \( m \) [kg/s] is the mass flow rate, \( V \) [m/s] is the average velocity of the fluid, \( A \) [m\(^2\)] is the internal cross-sectional area of the pipe, \( D \) [m] is the internal diameter of the pipe and \( \rho \) [kg/m\(^3\)] is the fluid density. A major simplification in the IEA GHG 2005/2 model is that neither the friction factor nor the pipe roughness is taken into account for the diameter calculation process. The impact of this assumption is that the accuracy of the model will decrease as the length of the pipeline increases.

Rule of thumb based models

The IEA GHG 2005/3 model utilizes a rule of thumb approach to determine the pipeline diameter as proposed by Brown et al. (1993). The assumption is that the volumetric flow rate of CO\(_2\) should be equal to a fixed value of 0.65*10\(^6\) scf/day/in\(^2\) of the internal area of the pipe. In addition, as with the IEA GHG 2005/2 model, the model does not take into account either the friction factor or the pipe’s roughness.

Consideration of CO\(_2\) physical properties

Two of the inputs into the pipeline diameter calculations process, in some of the reviewed models, are values of the CO\(_2\) density and viscosity, measured at specific temperature and pressure levels. It is important, therefore, to understand how these properties can vary with temperature and pressure.

CONSIDERATION OF IMPURITIES

CO\(_2\) that is captured from a power plant is not pure and the amount and type of impurities in the CO\(_2\) stream are dependent on the capture technology. There are three main process routes for capturing CO\(_2\) from power plants: post-combustion capture, pre-combustion capture and oxyfuel.
relation to the phase behavior, the impact of impurities is to raise the critical point of the fluid and to lower the density and viscosity. This has important implications on the hydraulic behavior of the CO₂ (Seeyam et al., 2008). Although it is recognized that impurities will impact the hydraulic component of any model, all of the models reviewed, and indeed the current proposed model, do not explicitly account for the effect of impurities.

**CAPITAL COST COMPARISON OF THE REVIEWED MODELS**

It is important to consider that the accuracy of a techno-economic model for calculating a pipeline’s capital cost is directly impacted by the accuracy of the model’s methodology for calculating the pipeline’s diameter. In other words, if the calculated pipeline diameter is only roughly estimated (e.g. calculated by a rule of thumb or an over-simplified calculation) then the calculated costs can be significantly over or under estimated. ANNEX B illustrates the pipeline capital costs values as a function of the mass flow rate, for a 100 km pipeline, for six of the analyzed models.

ANNEX B illustrates that the level of variation in the calculated costs can be as large as 200%. Such variations are often equivalent to tens or, at times, hundreds of millions of dollars in terms of economic uncertainty for the financial feasibility estimates of a CO₂ pipeline or a CCS project. Variations of this magnitude bring much unwanted uncertainty to the feasibility of the project and can potentially cause a major over or under estimation of the project’s true costs. For example, ANNEX B shows that the IEA GHG 2005/3 (which calculates the pipeline diameter based on a rule of thumb) generates the highest estimate of costs compared to IEA GHG PH4/6, which adopts a more sophisticated approach for calculating the pipeline diameter.

**PROPOSED TECHNO-ECONOMIC MODEL FOR CO₂ PIPELINE TRANSPORTATION**

The aim of this current work was to develop a techno-economic model that could be used with confidence, particularly for CCS projects in the UK and North America. Such a model requires two components; a fluid-mechanics model for the calculation of the pipeline diameter and a robust cost model for the calculation of construction, material, operation and maintenance costs. The review of the existing models, as outlined in the previous sections, has highlighted the different approaches that have been adopted for the diameter and cost components of the models and the strengths and weaknesses of these models. As a result, this work proposes an alternative techno-economic model based on the observed best practice in the current models.

---

1. The McCoy & Rubin model generates various graphs for different regional areas of the United States and these graphs are not depicted in ANNEX B.

**DIAMETER CALCULATION PROCESS**

The recommendation for the calculation of the diameter of the pipeline is based on the premise that application of the model should require as few set-value assumptions as possible. In addition, the model has to be based on robust fluid-mechanics principles. These premises are to improve the model’s results accuracy. Consequently the diameter calculation methods using the Darcy-Weisbach fluid-mechanics principles are recommended as this approach requires fewer initial assumptions to be made (i.e. those coloured green in ANNEX A).

The Darcy-Weisbach equation expresses the loss of pressure head caused by friction, h[μm], as a function of the friction factor. The Darcy-Weisbach equation is given by Menon (2004) as:

$$h = f(L/D_i)(V^2 / 2g)$$  

(2)

Where L[μm] is the pipeline length, f is the Darcy friction factor and g [μm/s²] is the acceleration due to gravity (all other terms having being defined previously). From basic hydraulics it is known that:

$$\Delta P = \rho g h = \Delta P = \frac{f(L/D_i)}{2} \rho \frac{V^2}{g}$$  

(3)

And the average velocity can be obtained from Equation 1 as:

$$V = \frac{4m}{\rho \pi D_i^2}$$  

(4)

Therefore, substitution of Equations 2 and 4 into Equation 3 enables the pressure drop to be represented as:

$$\Delta P = \frac{f(L/D_i)}{2} \rho \left( \frac{m}{\rho A} \right)^2 = \frac{f(L/D_i)}{2} \rho \frac{m^2}{\rho g^2} = \frac{8fLm^2}{\rho \pi D_i^2}$$  

(5)

Which, rearranged, enables an expression for internal diameter to be developed:

$$D_i = \left( \frac{8fLm^2}{\rho \pi \Delta P} \right) \frac{\rho g^2}{L} = 0.81 \frac{fLm^2}{\rho \Delta P} = 0.81 \frac{fLPQ^2}{\rho \Delta P}$$  

(6)

Where Q is the volumetric flow rate [μm³/s].

The Darcy friction factor (f), can be calculated from the Colebrook-White equation (Equation 7). In order to do this, the pipe’s relative roughness, ε/D, is required. ε[μm] is the pipe’s
absolute roughness. If absolute roughness is not specified for a pipe then \( \varepsilon = 4.57 \times 10^{-3} \) m is a reasonable approximation (McCoy-Rubin, 2007).

\[
1/\sqrt{f} = 2\log_{10}\left(\frac{\varepsilon}{3.7D_i} + \frac{2.51}{Re \sqrt{f}}\right)
\]

(7)

As Equation 7 contains the friction factor \( (f) \) on both sides of the equation, an easier way to calculate the Darcy friction factor is via calculation of the Fanning friction factor \( (f_F) \) and utilizing the relationship:

\[
f = 4f_F
\]

(8)

The Fanning friction factor can be expressed as (Zigrang and Sylvester, 1982):

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

(9)

Where \( Re \) is the Reynolds number and is given by the equation:

\[
Re = \frac{VD_i}{\mu} = \frac{4m}{\mu D_i}
\]

(10)

Where \( \mu [\text{Pa.s}] \) is the absolute dynamic viscosity of dense phase \( CO_2 \) which can be assumed to be roughly \( 6.06 \times 10^{-5} \) [Pa.s] (Heddle et al., 2003).

It is observed from Equation 10 that the internal diameter is required as an input into the calculation of \( Re \). Therefore, the pipeline diameter has to be calculated by an iterative process, in which an initial estimate of the diameter is required. As a rule of thumb, the values of internal diameter tend to converge within a \( 10^{-6} \) range in less than five iterations (McCoy and Rubin, 2007).

Once the internal diameter has been calculated, to further specify the pipe’s geometry, the wall thickness can be determined using:

\[
t = \frac{P_{MOP} \ast D_o}{2 \ast SMYS \ast E \ast D.F.}
\]

(11)

In this equation, ‘E’ is the longitudinal joint factor and is assumed to be equal to ‘1’ unless otherwise specified. \( D_o \) is the external diameter, SMYS is the Specified Minimum Yield Stress of the pipe material and \( P_{MOP} \) is the maximum operating pressure. Evidently, the outer diameter can be calculated by adding the internal diameter with twice the wall thickness of the pipe. D.F. is the design factor and its value is established based on the governing code and operator specifications for the \( CO_2 \) pipeline. To establish the design factor value, the code will normally take into account the fluid category to which dense phase \( CO_2 \) belongs and the associated population density based on the route and location of the pipeline. Building proximity distances are then established.

COST CALCULATION PROCESS

Although the diameter calculation methodology can be universally applied to various \( CO_2 \) pipeline projects in different locations around the world, finding a single capital cost or maintenance cost equation to accurately and universally evaluate the pipeline costs in all of the various locations and regulatory structures around the world is not practical. This is due to the various location-specific cost elements and also due to the cost implications of different regulations that impact the final cost of each specific pipeline project.

In a simplified approach, the capital costs (CAPEX) for the construction of a pipeline project can be estimated by a function of the pipeline’s external diameter (\( D_e \)) and its length (L). Such estimations can be made through regression modelling analysis of pipeline assets’ capital costs sourced from databases such as the Oil and Gas Journal. A more detailed approach should consider the specific pipeline’s wall-thickness. The same simplified relationship can also be assumed for the operation and maintenance costs, sometimes referred to as OPEX. Indeed, the annual operation and maintenance costs of a pipeline are usually estimated to be a specific fraction of the CAPEX. In some models, the OPEX is even further simplified and is expressed only as a function of the pipeline’s length. This further simplification is not recommended, particularly when considering operation and maintenance costs of pipelines with large diameters. Such a simplification can underestimate the actual operation and maintenance costs involved and could potentially cause operational cash flow shortages. Based on the models analyzed in Section 2, 2%-5% of the CAPEX is considered to be a realistic range for operation and maintenance costs.

Although there is limited cost data available for the construction of \( CO_2 \) pipelines, it is considered that the available capital cost data for natural gas pipelines can be used as the cost of construction should be largely independent of the fluid. It is then recommended that the data would be normalized to one reference year, preferably to the current year. In order to undertake this cost normalization accurately, for each pipeline project, the project’s value for return-on-equity (ROE) rate, project’s value for return-on-debt (ROD) rate, and each corresponding year’s inflation rate have to be specified and accounted for in the calculation. Through application of regression analysis it is then possible to derive an equation that provides a best-fit to the available cost data, i.e. the equation with the highest adjusted-\( r^2 \) value. This methodology has been used to derive the cost formulae used in the IEA GHG PH4/6 and IEA GHG 2005/2 models. It is, therefore, these cost models that have been adopted for the current analysis. The
corresponding capital cost formulae for onshore pipelines, based on the IEA GHG 2005/2, model is:

\[
\text{Pipeline Capital Cost}_{\text{onshore}} (\epsilon) = F_t \cdot 10^6 \cdot \left[ (0.057 \cdot L_{\text{onshore}} + 1.8663) + (0.00129 \cdot L_{\text{onshore}}) \cdot D_o + (0.000486 \cdot L_{\text{onshore}} - 0.000007) \cdot D_o^2 \right]
\]

(12)

The only adjustment made to IEA GHG 2005/2 for generating the above equation is inclusion of the location factor, \( F_t \). The suggested location factor values for Equation 12 are the same as those used for the IEA GHG PH4/6 model. The location factor for USA, Canada, and Europe is assumed to be 1, while it is set at 1.2 for the United Kingdom. Terrain factor, \( F_t \), is assumed to be 1.10 for cultivated land, 1.00 for grassland, 1.05 for wood land, 1.10 for jungle, 1.10 for stony desert, 1.30 for mountainous (<20%) and 1.50 for mountainous (>50%).

Similarly, the adjusted capital cost formulae for offshore pipelines model is:

\[
\text{Pipeline Capital Cost}_{\text{offshore}} (\epsilon) = F_t \cdot 10^6 \cdot \left[ (0.4048 \cdot L_{\text{offshore}} + 4.6946) - 0.00153 \cdot L_{\text{offshore}} + 0.0113) \cdot D_o + (0.000511) \cdot L_{\text{offshore}} + 0.00024) \cdot D_o^2 \right]
\]

(13)

\( L_{\text{onshore}} [\text{km}] \) refers to the length portion of the pipeline which is situated onshore while \( L_{\text{offshore}} [\text{km}] \) refers to the length portion of the pipeline that is situated offshore.

The annual pipeline operation and maintenance costs are estimated to be about 3% of the total pipeline capital costs in the IEA GHG 2005/2 and these have also been assumed in the current analysis.

It is highlighted that, for the estimation of the capital construction costs for CO₂ pipelines in the United States, the McCoy and Rubin (2007) models are recommended as the utilized database of cost data is comprehensive and the analysis can be tailored for individual cost regions of the country. In practice, however, determining the capital costs involved with a high level of accuracy, i.e. with less than 5% or even 8% deviation from actual figures, is a much more detailed and project specific process. The models proposed here can only provide a rough estimate of the actual costs. These rough estimates are useful for the feasibility and FEED studies of the projects.

**CASE STUDY AND VALIDATION**

Once the proposed techno-economic model had been assembled, it was important that it was validated against detailed hydraulic analysis and the cost analysis of a potential CCS project. The case study that was chosen for this analysis was the proposed Yorkshire and Humber network of CO₂ pipelines in the UK, for which published data was available (Yorkshire Forward (2009), Rennie (2010)). The proposed CCS scheme in the Yorkshire and Humber region aims to capture 60 million tons of the region’s 90 million ton emissions and transport it via an onshore and offshore pipeline network to a storage site in the Southern North Sea.

The techno-economic model developed in this paper was used to estimate and validate the diameter size of the network’s trunk-line and the associated costs of building the trunk-line with those in the Yorkshire Forward study. Following are the input values for the project’s variables used in this validation process. Where explicit data was not available, estimations were made or values were assumed.

Provided Values:
- Design Life = 40 years, \( P_{\text{in}} = 125 \text{ bar}, P_{\text{out}} = P_{\text{min}} = 100 \text{ bar}, T_{\text{max}} = 30^\circ \text{C}, m = 1616.7 \text{ kg/s} \)

Estimated Values and Assumptions:
- \( L_{\text{onshore}} = 109 \text{ km}, L_{\text{offshore}} = 135 \text{ km}, L_{\text{total}} = 244 \text{ km}, T_{\text{ave}} = 20^\circ \text{C} \)
- Plant Capacity Factor = 0.85, \( \rho = 800 \text{ kg/m}^3 \) [suggested density value in Ecofys, IEA GHG PH4/6 and IEA GHG 2005/2 models], \( \mu = 6.06 \times 10^{-3} \text{ Pa.s} \) [suggested viscosity value for the MIT model], D.F. = 0.72

The onshore and offshore pipeline lengths are estimated values generated from a scaled map published by CO₂Sense Yorkshire (2009). Based on available literature ((Mohitpour, 2007) and (McCullum and Ogden, 2007)) it is considered that 800kg/m², assuming the 20°C average temperature, is a reasonable estimate of the density. For diameter calculations, the onshore and offshore trunk lines will be considered as a single 244 km pipeline. However, for cost calculations, the onshore and offshore capital costs will be calculated separately (using Equations 12 and 13) and combined together to produce the total capital cost.

The only unknown for calculating the diameter is now the friction factor, \( f \), which is a function of the pipe’s relative roughness, \( \varepsilon/D_0 \). Considering the very large mass flow rate of this pipeline project, i.e. 1616.7 kg/s, a large diameter trunk line will most likely be required. Hence, it is expected that the friction factor value for this pipe will fall within the low spectrum of friction factor values, i.e. between 0.0100 – 0.0120, due to the relationship in Equation 9. A value of 0.0104 was selected as an initial estimate of friction factor to reduce the number of iterations.

Based on the available data, and using the iterative approach described for calculating the diameter, the internal diameter for the pipeline, \( D_i \), is calculated to be 1.2139 m or 47.79 inches. As the final diameter iterations were within 0.18 inches, a diameter of 48 inches (1.219m) is the closest available API diameter specification. Assuming that X60 pipe (i.e. SMYS= 413.8MPa), manufactured as per API 5L specifications, is a suitable line pipe option, the wall thickness can be calculated using Equation 11 to be 25.57mm.

The diameter size calculated by this method was also cross-checked and re-validated using fluid-mechanics
simulation of the pipeline with the ASPEN HYSYS software (HYSYS 2004.2). The pipeline was simulated for pure CO\textsubscript{2} using the Beggs and Brill flow equation (Beggs and Brill, 1973) and the Peng Robinson equation of state (Peng and Robinson, 1976). The diameter calculated using this method was 1.2140m or 47.80 inches.

Knowing the diameter and the length values of the pipeline, onshore and offshore capital costs were calculated using Equations 12 and 13:

\[
\text{Pipeline Capital Cost}_{\text{onshore}} (\text{€}) = 181,210,642.6 \\
\text{Pipeline Capital Cost}_{\text{offshore}} (\text{€}) = 249,630,827.1
\]

Adding the onshore and offshore costs will result in a total cost of €430,841,469.7. It is important to notice that this value is calculated based on 2005 cost figures and considers a 10\% annual discount rate. Therefore, the equivalent euro value for 2010 would be €693,874,495.4 (€580,716,147).

Based on the project’s estimated 40 year design life, the annual capital cost (equivalent annuity value) would be £59,383,693. The annual operation and maintenance cost is calculated based on 3\% of this value, which will be £1,781,511. Therefore, the total annual cost to build and operate this pipeline will be £61,165,204. Therefore, the levelized CO\textsubscript{2} transport cost is:

\[
\frac{£61,165,204}{(60*10^6 \times 0.85)\text{ton/ year}} = £1.20/\text{ton}
\]

The Yorkshire Forward report (Yorkshire Forward, 2009) estimates a levelized transport cost for a number of different transport scenarios depending on the amount of CO\textsubscript{2} captured, the availability of CO\textsubscript{2} sources and the year in which CCS is adopted. In this respect the analysis is more sophisticated than the simple model outlined here, particularly with respect to economic drivers affecting the adoption and deployment of CCS. It is therefore highlighted that the intention of the calculation in this paper was validation for the methodology of the current model and not to provide any comment on the accuracy of the approach adopted by Yorkshire Forward.

However, it is deemed that the estimated costs of £1.20/ton are within the range of the costs calculated in the Yorkshire Forward study and consequently it is considered that the model presented in this paper could be used to provide feasibility study cost analyses for CCS transport projects.

**CONCLUSION**

It is considered that CCS is one of the primary modern technologies that can significantly contribute to reducing anthropogenic CO\textsubscript{2} emissions produced by a range of industrial facilities and enable global emissions targets for CO\textsubscript{2} to be met. Pipelines are currently the most common and economical means of transporting large volumes of CO\textsubscript{2} over long distances and they allow for safe and reliable transportation of CO\textsubscript{2} from a capture facility to a sequestration or an enhanced oil recovery site.

A great effort is therefore underway to analyze and support the viability of CCS projects, part of which is the calculation of the cost of the pipeline transportation of CO\textsubscript{2}. However, it was observed, through detailed analyses, that the current pipeline techno-economic models could produce differences in calculated costs for transportation of up to 200\%.

In this paper seven techno-economic models for CO\textsubscript{2} pipeline transport have been reviewed and the main similarities and differences of these models have been highlighted. This analysis allowed a refined techno-economic model to be developed based on the best-practices of the seven models studied. All of the techno-economic models involve a hydraulic calculation, to determine the pipe diameter, and a cost calculation, to determine CAPEX and OPEX. It is therefore important that as few assumptions as possible are made in these calculations in order to increase the accuracy and relevance of the costs calculated. To establish a more accurate measure for the pipe’s diameter, the proposed model applies the Reynolds–Peng–Robinson equation of state (Peng and Robinson, 1976). The pipeline was simulated for pure CO\textsubscript{2} using Equations 12 and 13:

\[
\text{Pipeline Capital Cost}_{\text{onshore}} = 181,210,642.6 \\
\text{Pipeline Capital Cost}_{\text{offshore}} = 249,630,827.1
\]

\[
\frac{£61,165,204}{(60*10^6 \times 0.85)\text{ton/ year}} = £1.20/\text{ton}
\]

\[
\text{The Yorkshire Forward report (Yorkshire Forward, 2009) estimates a levelized transport cost for a number of different transport scenarios depending on the amount of CO}_2\text{ captured, the availability of CO}_2\text{ sources and the year in which CCS is adopted. In this respect the analysis is more sophisticated than the simple model outlined here, particularly with respect to economic drivers affecting the adoption and deployment of CCS. It is therefore highlighted that the intention of the calculation in this paper was validation for the methodology of the current model and not to provide any comment on the accuracy of the approach adopted by Yorkshire Forward.}

However, it is deemed that the estimated costs of £1.20/ton are within the range of the costs calculated in the Yorkshire Forward study and consequently it is considered that the model presented in this paper could be used to provide feasibility study cost analyses for CCS transport projects.

**REFERENCES**

Bachu, S. (2011), Private e-mail communication with N. Ghazi, May 6, 2011


CO\textsubscript{2}Sense Yorkshire (2009), ‘CCS Network to the Future Report’, *CO\textsubscript{2}Sense Yorkshire*. Available at:
HYSYS (2004), ASPEN HYSYS 2004.2 – aspenONE, AspenTech, Available at: www.aspentech.com
IPCC, 2005 - Bert Metz, Ogunlade Davidson, Heleen de Coninck, Manuela Loos and Leo Meyer (Eds.) Cambridge University Press, UK. pp 431
# ANNEX A

## TECHNO-ECONOMIC MODELS COMPARISON

<table>
<thead>
<tr>
<th>Model Components and Assumptions</th>
<th>Techno-Economic Models</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>MIT</td>
</tr>
<tr>
<td><strong>Hydraulic Basis for Diameter Calculations</strong></td>
<td>Darcy-Weisbach</td>
</tr>
<tr>
<td>O&amp;M Factor</td>
<td>$3,100/km/yr</td>
</tr>
<tr>
<td>Booster Station Calculation</td>
<td>No</td>
</tr>
<tr>
<td>Plant Capacity Factor (%)</td>
<td>80</td>
</tr>
<tr>
<td>Friction Factor or Absolute Roughness - ε [mm]</td>
<td>-0.0035 (Moody Chart)</td>
</tr>
<tr>
<td>Terrain Factor</td>
<td>-</td>
</tr>
<tr>
<td>Location Factor</td>
<td>-</td>
</tr>
<tr>
<td>Currency</td>
<td>USD</td>
</tr>
<tr>
<td>Capital Recovery Factor</td>
<td>15</td>
</tr>
<tr>
<td>Discount Rate, i</td>
<td>-</td>
</tr>
<tr>
<td>Operational Life Time (yrs)</td>
<td>-</td>
</tr>
<tr>
<td>Cost of Electricity [$/kWh]</td>
<td>-</td>
</tr>
<tr>
<td>CO₂ Temperature [°C]</td>
<td>25</td>
</tr>
<tr>
<td>CO₂ Density [kg/m³]</td>
<td>$84</td>
</tr>
<tr>
<td>CO₂ Viscosity [N-s/m²]</td>
<td>6.05x10⁻⁵</td>
</tr>
</tbody>
</table>
ANNEX B

COMPARISON OF CAPITAL COST ESTIMATES FOR THE MODELS REVIEWED

[Graph showing a comparison of capital cost estimates for different models with varying CO₂ mass flow rates. The models include MIT, Ecofys, Ogden, IEA GHG PH4/6, IEA GHG 2005/2, and IEA GHG 2005/3.]