Carbon Management of a Coal-to-Liquid Plant and Its Implication for China

Hui Su, Ph.D.Candidate
Natural Resource Economics Ph.D. Program, West Virginia University
Phone +1 304 216 1628, E-mail: Hui.Su@mail.wvu.edu

Haixiao Huang, Research Associate
Energy Biosciences Institute, University of Illinois at Urbana-Champaign
Phone +1 217 333 7239, E-mail: hxhuang@uiuc.edu

Jerald J. Fletcher, Professor and Director
US-China Energy Center, West Virginia University
Phone +1 304 293 4832 x 4452, E-mail: jfletch@wvu.edu

Abstract

In a carbon-constrained world, carbon management options for climate change mitigation are becoming increasingly important, especially in China, one of the biggest energy consuming and GHG emitting nations in the world. As a case study of a carbon capture and storage (CCS) option for a specific coal-to-liquid (CTL) plant, this paper develops a profit-maximizing non-linear programming model of CO$_2$ point sources and associated geological storage reservoirs. The simulation is based on technical-economic modeling for a chain of CCS processes including compression, transportation and storage derived from previous research. The process of capture is not included considering the CTL plant will produce sufficient pure CO$_2$ emissions to store without significant capture cost. The modeling results identify site-specific opportunities for economic feasibility decisions related to the deployment of CCS technologies and provide the information to derive the CO$_2$ sequestration supply curve for the firm. Accordingly, the implications for the firm’s and China’s carbon management are discussed. It is worth noting that though this economic analysis is based on a particular CTL project, the modeling approach can be applied to a broad array of sequestration opportunities.

1 Introduction

Carbon management options for climate change mitigation are becoming increasingly important as the level of atmospheric CO$_2$ increases. Carbon capture and storage (CCS) has been cited as a “potentially important climate change mitigation measures in the coming decades” (Philibert, Ellis and Podkanski, IEA, 2007). The IEA (2006) suggests that by 2050 the importance of CCS as an emission reduction technology could be second only to energy efficiency improvements. It is worth noting the differences in the incentives to implement CCS technologies between developed countries and developing countries that may follow from international climate change programs. CCS technologies
may also provide the latter an additional and attractive incentive to offset the cost of CO₂ mitigation by carbon transactions. Carbon sequestered by CCS technology from verified projects in developing countries may be eligible for an emission reduction credits (CERs) and traded under the Clean Development Mechanism (CDM). In recent years emerging carbon markets, particularly for projected-based carbon emission trading between developed and developing countries under the CDM (World Bank, 2005, 2006, 2007) facilitates carbon management implementation in developing countries.

In this context, research on the CCS potential for a coal-to-liquid (CTL) project in China, seeking to promote for developing more efficient technologies in one of the biggest energy consuming nations in the world, provides a good case study and reference for future developing countries’ carbon management. Overtaking the US as the world’s top CO₂ emitter in 2007 (Reuters News Service, 2007), China is expected to take more responsibility for mitigating greenhouse gas (GHG) emissions given its consistent growth for the past 30 years. Currently China has set a goal for reducing GHG emissions by stricter environmental regulations and energy efficiency improvements. The fact that China has been the largest carbon seller under the CDM since 2005 (World Bank, 2005, 2006, 2007) has shown that China has begun to participate actively in global GHG mitigation. The CCS project tied to the world’s first direct CTL plant in the post-war era now under development in Inner Mongolia, China represents a significant step in China’s carbon management efforts. However, as policy makers seek strategies for GHG reductions, corporations also need to evaluate whether mitigation technologies could be technologically and economically feasible and competitive. The trend also reflects the facts that as concerns over climate change collide with ever increasing energy demands, the cost of mitigating technologies of GHG from carbon intensive energy sources becomes an increasingly important issue. The CCS project is particularly well suited to the CTL plant in that approximately 2.6 mmt of an estimated 3.2 mmt of CO₂ emissions produced by the CTL plant each year are sufficiently pure to store without capture costs. Since the cost of capturing CO₂ is the main contributor to total cost of CCS, the CCS project without significant capture costs owns a comparative advantage over other CCS projects. Therefore, the primary objectives of this study are to estimate CCS potential for the CTL plants in China and to discuss its implications for carbon management. The proposed research will contribute to finding practical and cost-efficient solutions for emitters to participate voluntarily in greenhouse gas mitigation. In addition, the results demonstrate the potential for CO₂ sequestration related to coal liquefaction and gasification, and the economic and environmental feasibility of coal used as a source of liquid fuels for coal-rich countries. Sequestrating CO₂ provides an important step towards carbon management in China.

This paper is organized as follows: After the introduction, section II gives a brief overview of relevant research and modeling approaches of CCS technologies. In Section III, a general profit-maximizing mathematical programming model of a CO₂ point source and associated geological storage reservoirs is developed to examine the cost of CCS. The simulation is based on technical-economic modeling for a chain of CCS processes including compressor, transportation and storage from previous research. Section IV presents estimated results for the optimal carbon sequestration level for a given carbon
price and sensitivity analysis. Meantime, the optimal carbon sequestration level related to carbon price can be interpreted as the marginal abatement cost curve for CO$_2$ emissions or the CO$_2$ storage supply curve. Finally, the policy implications on carbon management are discussed in section V.

2 Literature Review
2.1 Modeling Carbon Capture and Storage


A comprehensive overview by Anderson and Newell (2003), covering research on CCS technology in MIT, CMU and PNNL, illustrated the key results including the date and carbon price at which CCS technologies begin to penetrate and the dynamics of competing CCS technologies over time. Though no single modeling tool completely handles all the modeling and assessment requirements, these analyses indicate a tremendous potential for CCS to mitigate US power sector CO$_2$ emissions conditional on a sufficiently high price on such emissions. More recently, the Intergovernmental Panel on Climate Change (IPCC) Special Report (2005), written by more than 100 authors from different countries and reviewed by more than 200 experts, provides comprehensive information on the costs of capture, transport and storage of CO$_2$, the economic potential, and the social and regulatory issues. The report showed that including CCS as an option reduces the costs of mitigating climate change. The report also points out that the future importance of capture and storage of CO$_2$ for mitigating climate change depends on a variety of factors including financial incentives and whether the risks of storage can be successfully managed.

The recent interest in CCS as a mitigation option for CO$_2$ reduction has resulted in consideration for more and more CCS demonstration projects and a limited number of studies on the technical-economic models for CCS (Bock et al., 2003; Allinson et al., 2003; Anderson and Newell, 2004; McCollum and Ogdem, 2006; McCoy, 2008; Gale and Davison, 2004; Zhan, et al, 2006). This research will be a foundation for further integrated assessments of full CCS systems.
However, these studies are macro-level analyses of CCS for large-scale assessments and policy analyses in a regional, national or global setting. They focus on comparison of CCS with conventional CO$_2$ mitigation technologies such as energy efficiency measures. Specific case studies of the economic potential of CCS projects in practice are not yet available. This paper provides a specific plant-level model of CCS for CTL plants in China. Since many CTL projects are planned or under construction, the model developed in this study can be a reference to assess the feasibility of similar geologic CCS projects. In addition, the research relates CCS to carbon price and addresses the policy implications for carbon management in the context of CCS mitigations, a matter of importance for China, the world’s top CO$_2$ emitter.

2.2 Carbon Capture and Storage and CDM

As a new abatement technology, CCS clearly needs a significant market incentive, which potentially can be provided by carbon markets under the CDM. CCS projects in developing countries eligible for CDM can potentially earn emission credits saleable through the emission markets. A large volume of emission credits could be generated by geosequestration. Philibert, Ellis and Podkanski (2007) analyzed the potential impact of CCS on the CDM portfolio. They considered that widespread uptake of just the short-term CCS opportunities could more than double the current CDM portfolio. This could lead to CCS crowding out other project types from the CDM (Miguez, 2006). However, in practice, the effect of CCS crowding out may be overstated for at least two reasons: the importance of CCS CDM projects is likely to be significantly lower than the technical potential and implementation of CCS projects is more difficult than that of other CDM projects. As Beck and Gray (2006) note, the potential strength of geosequestration in the global market is likely to be realized through access to a broad emissions market. In the medium term, some other abatement options are likely to be cheaper but few are likely to be able to deliver abatement on a scale comparable to geosequestration.

Some researchers suggested that rather than receiving a competitive market price for emission reductions, developing countries may simply be paid the actual cost of abatement, perhaps with some markup (Chander, 2003). Babu and others (2003) posit that the total gains from CDM will depend on the relative bargaining power with developed countries. Bertram describes technical progress effects on the CDM.

3 Methodology

3.1 Income and Costs of a Full CCS System

CCS project income, with the exception of income from the value-added activities such as Enhanced Oil Recovery (EOR) and Enhanced Coal Bed Methane (ECBM), is generated by the emission reduction credits for CO$_2$ storage.

3.2 Costs of a Full CCS System

According to the previous research on the CCS techno-economic modeling, the estimated capital costs, O&M costs and any on-going costs associated with each components of
compression, transportation and injection, were shown in one form of geological parameters of the pressure, pipeline and reservoirs etc. Based on their outputs, the paper develops a profit-maximizing mathematical programming model characterizing the integrated chain of CCS process. An overview of the modeling framework is given in Figure 1. Methodologies and models developed in related research to estimate the costs have been formulated and reflected in the objective function of the following programming model.

![Model Overview Diagram](image)

**Figure 1: Model Overview Diagram**

### 3.2.1 Estimation of Compressor Costs

By IPCC report, the capture cost generally includes capture cost, the cost of compressing the CO\(_2\) to a pressure suitable for transport, additional capital requirement(s), and added operating and maintenance costs. For most large sources of CO\(_2\), the cost of capturing is the largest contributor to overall CCS costs and thus is a focus of cost reduction efforts. However, CTL plants produce sufficiently pure CO\(_2\) for storage. The particular characteristic of CTL industry makes the cost of CO\(_2\) capture will not be a project focus. Thus, the capture costs considered here include mainly the capital costs, O&M costs and the total electric power costs of the compressor and pump. The capital costs includes the capital costs of the compressors and pumps because compressors are required for compression when CO\(_2\) is in the gas phrase and pump can be used to boost the pressure when CO\(_2\) is in the liquid/dense phrase.

By the model from McCollum & Ogden (2006),

\[
\text{Total annual costs ($/yr)} = C_{\text{annual}} + O&M_{\text{annual}} + E_{\text{annual}}
\]

\[
= C_{\text{total}} \times \text{CRF} + C_{\text{total}} \times O&M_{\text{factor}} + (E_{\text{comp}} + E_{\text{pump}})
\]

\[
= C_{\text{total}} \times (\text{CRF} + O&M_{\text{factor}}) + (E_{\text{comp}} + E_{\text{pump}})
\]

\[
= (C_{\text{comp}} + C_{\text{pump}}) \times (\text{CRF} + O&M_{\text{factor}}) + (E_{\text{comp}} + E_{\text{pump}})
\]

(C\(_{\text{annual}}\), total annual capital cost; O&M\(_{\text{annual}}\), annual operation and maintenance costs; E\(_{\text{annual}}\), total electric power costs; C\(_{\text{total}}\), the sum of capital costs of compressors and pump; CRF, capital recovery factor)

\[
C_{\text{comp}} = f(N_{\text{train}}, P_{\text{cut-off}}, P_{\text{initial}}) = f(W_{\text{comp}}, P_{\text{cut-off}}, P_{\text{initial}}) = f(m, P_{\text{cut-off}}, P_{\text{initial}}, \text{etc.})
\]

(N\(_{\text{train}}\), number of parallel compressor trains; W\(_{\text{comp}}\), total compression power requirement; m, CO\(_2\) mass flow rate; P\(_{\text{cut-off}}\) the pressure at which compression switches
to pumping, is assumed as 7.38MPa, \( P_{\text{initial}} \) initial pressure of CO\(_2\) from CTL system and assumed as 0.1MPa

\[
C_{\text{pump}} = g(W_{\text{pump}}) = g(m, P_{\text{final}}, P_{\text{cut-off}})
\]

\( E_{\text{comp}} + E_{\text{pump}} = j(W_{\text{comp}}, W_{\text{pump}}) \) (\( W_{\text{pump}} \), pumping power requirement; number of parallel compressor trains; \( P_{\text{final}} \) the pressure of CO\(_2\) for pipeline transport, is assumed as 15 MPa)

### 3.2.2 Estimation of Transport Costs

IPCC report also shows that the costs of pipelines transportation can be categorized into three major elements: Construction costs (material/equipment costs such as pipe, possible booster stations, installation costs such as labor); Operation costs (monitoring costs, maintenance costs); other costs (design, project management, regulatory filing fees, insurances costs, right-of-way costs, contingencies allowances). The pipeline capital cost and O&M costs are the focus of this component since they account for the major transport costs.

Considering its simplicity and reliability, McCollum & Ogden’s model (2006), which provides transportation costs as a function of CO\(_2\) mass flow rate in the pipeline and pipeline length, is used in this study. The advantage of its dealing with this is to omit “the need to calculate the pipeline diameter in advance of calculating costs”. The model takes the average of the output from seven other studies (Ogden, MIT, Ecofys, IEA GHG PH4/6, IEA GHG 2005/2, IEA GHG 2005/3, and Parker) at different CO\(_2\) mass flow rates and pipeline lengths after they have been put on common bases.

\[
\text{Total annual cost} ($/\text{yr}) = C_{\text{annual}} + C_{\text{O&M annual}}
\]

\[
= C_{\text{total}} \times CRF + C_{\text{total}} \times O&M \text{ factor}
\]

\[
= C_{\text{total}} \times (CRF + O&M \text{ factor})
\]

\[
= F_L \times F_T \times L \times C_{\text{cap}} \times (0.15/\text{yr} + 0.025),
\]

where, \( C_{\text{total}} \) is total capital cost, it is the sum of pipeline capital cost and booster station capital cost; CRF is capital recovery factor and is assumed to be 0.15/year; O&M \text{ factor} is calculated approximately as 2.5% of the total capital cost, that is the average O&M factor from a handful of studies on CO\(_2\) pipeline transport; \( F_L \) a location factor. By IEA research, USA/Canada=1.0, Europe=1.0, UK=1.2, Japan=1.0, Australia=1.0, \( F_T \), a terrain factor. By IEA research, cultivated land =1.10, grassland=1.00, wooded=1.05, jungle=1.10, stony deser =1.10, <20% mountainous=1.30, >50% mountainous =1.50; \( L \) pipeline lengths: km. Then

\[
\text{Total annual cost} = F_L \times F_T \times L \times C_{\text{cap}} \times 9970 \times (m^{0.35}) \times (L^{0.13}) \times (0.15/\text{yr} + 0.025)
\]

That is, pipeline capital cost =9970\( \times (m^{0.35}) \times (L^{0.13}) \), \( m \) mass flow rate: tonnes/day. The upper and lower bounds for the pipeline capital cost \( C_{\text{cap}} \) are 8500\( \times (m^{0.35}) \times (L^{0.06}) \) and 4100\( \times (m^{0.50}) \times (L^{0.13}) \), respectively.

### 3.2.3 Estimation of Storage Costs

Compared with the first two processes, carbon injection and storage is probably more complex and more difficult to model since it is tough to apply one common model mode
into different types of reservoirs. IPCC report shows that the elements for geological storage costs include capital cost such as drilling wells, infrastructure (for EOR and ECBM options, additional facilities needs to handle produced oil and gas); operation costs (manpower, maintenance and fuel; license cost and engineering feasibility study for site selection; monitoring cost). The paper aims to estimate the injection and storage costs on ECBM, EOR/EGR, depleted oil and gas reservoirs and deep saline aquifers. The first two kinds of reservoirs can be referenced from Bock paper. Research on Bock & Goldberg (2002) and McCollum & Ogden (2006) provide a same reference modeling for three types of reservoirs in the depleted oil and gas reservoirs and deep saline aquifers “though typical value of the three types of reservoirs parameters such as pressure, thickness, depth, and permeability differ substantially from one another”. The reason for the same cost method applied to these CO\(_2\) storage options is “the process that govern the rate which CO\(_2\) can be injected at a well, and thus the number of wells required, are however essentially identical for them” (Bock & Goldberg, 2002). These geological properties of actual reservoirs needed by model include different ranges of reservoir pressure (P), thickness (h), depth (d), and horizontal permeability (kh).

Total annual cost ($/yr)
\[= C_{\text{site}} + C_{\text{equip}} + C_{\text{drill}} + O&M_{\text{annual}}\]
where, \(C_{\text{site}}\), the capital cost of site screening and evaluation; \(C_{\text{equip}}\), injection equipment costs; \(C_{\text{drill}}\), drilling cost of injection well. The last three terms has relationship with \(N_{\text{well}}\), the calculated number of wells. \(N_{\text{well}}\) for different kinds of reservoirs can be calculated by their respective geological parameters.

\[N_{\text{well}} = \frac{m}{Q_{\text{CO}_2}} = \frac{m}{\text{CO}_2 \text{ injectivity}*h*(P_{\text{down}}-P_{\text{res}})}\]
\[= \frac{m}{0.0208*\text{CO}_2 \text{ mobility}*h*(P_{\text{down}}-P_{\text{res}})}\]
\[= \frac{m*\mu_{\text{inter}}}{0.0208*K_a*0.3*K_h^{0.5}*h*(P_{\text{down}}-P_{\text{res}})}\]
Due to the \(P_{\text{down}}\) initially is unknown, the difficulty is that the calculating the number of \(\text{CO}_2\) injection well number is iterative. However, one computer programming is enough to deal with the problem.

### 3.3 A General Mathematical Programming Model

Modeling and assessment will be based on developing a programming model framework characterizing the performance of carbon sequestration and revenue and cost of the technologies. One CCS project is assumed to maximize its economic benefit over the planning horizon \(T\) (20 years) from CCS with the following constraints and the full project revenues are discounted over the life of the project:

\[\text{Maximize } \pi = \sum_{i=1}^{T} \sum_{i=1}^{n} \sum_{j=1}^{n} \left( \frac{P_{\text{X}_{ijt}} - c_{ijt}(x_{ijt})}{1+r} \right) = \sum_{i=1}^{T} \frac{1}{(1+r)^i} \sum_{i=1}^{n} \sum_{j=1}^{n} \left[ P_{\text{X}_{ijt}} - c_{ijt}(x_{ijt}) \right] \]
where \(x_{ijt}\) = at time \(t\), the captured amount of \(\text{CO}_2\) from source \(i\) and transported to and sequestrated to storage \(j\) (unit: mt \(\text{CO}_2\)/year \(t\)). Since the total amount of \(\text{CO}_2\) that must be transported every year is found by calculating \(x_{ijt} = m_{ijt} * 365 * \text{CF} = m_{ijt} * 365 * 0.8\) (CF is capacity factor), the objective function is a function of \(m\).

\[C_{\text{ccs}_{ijt}} = C_{\text{capture}_i} + C_{\text{transportation}_{ijt}} + C_{\text{storage}_j} + C_{\text{monitoring}_{ijt}}\]
The full chain of CCS costs from capture and storage has to be considered and consist of. At time \(t\), the total cost of \(\text{CO}_2\) capture, transportation and sequestration from source \(i\) to storage \(j\) (Unit: $/mt \text{CO}_2$).
More specifically,

\[ C_{\text{capture}} = C_{\text{compressor}} = f(m, P_{\text{initial}}, P_{\text{final}}, P_{\text{cut-off}}, \text{etc.}) \]

\[ C_{\text{transportation}} = F \cdot F_{\text{T}} \cdot L_{ij} \cdot 9970 \cdot (m_{ij}^{0.35} \cdot L_{ij}^{0.13}) \cdot (0.15/\text{yr} + 0.025) \]

Regarding to depleted oil and gas reservoirs and deep saline aquifers,

\[ C_{\text{storage}} = f(N_{\text{well}}) = f(m, h, P, d, k_h) \]

Regarding to EOR, EGR, ECBM

\[ C_{\text{storage}} = f(P_{\text{CH}_4}, P_{\text{CO}_2}, N_{\text{well}}) \]

Subject to

\[ \sum_{j=1}^{n} x_{ijt} \leq E_{it}, i = 1, 2, ..., m \quad t = 1, 2, ..., T \quad \text{Source constraints (1)} \]

\[ \sum_{i=1}^{M} \sum_{j=1}^{n} x_{ijt} = \sum_{t=1}^{T} Q_{ijt} \leq Q_{j}, j = 1, 2, ..., n \quad \text{Sink constraints (2)} \]

\[ \sum_{j=1}^{n} Q_{ijt} \leq \sum_{i=1}^{m} E_{it}, t = 1, 2, ..., T \quad \text{Per-term constraints (3)} \]

\[ x_{ijt} \geq 0 \quad \text{Non-negativity constraints (4)} \]

\[ x_{ijt} \leq x_{ij}^{\text{max}}, \forall i, j, t \quad \text{Storage rate constraints (5)} \]

\[ \sum_{i=1}^{m} x_{ijt} \leq x_{ij}^{\text{max}}, \forall j, t \quad \text{Injection rate constraints (6)} \]

where \( P(t) \) = the price of carbon on the international market at time \( t \), it is an exogenous variable (unit: $/\text{tonnes CO}_2) ;

\( r \) = the discount rate.

\( Q_{ijt} \) = the mass sequestrated by storage \( j \) at time \( t \) (unit: tonnes CO\(_2\)/year);

\( Q_j \) = the storage capacity of storage \( j \) (unit: tonnes CO\(_2\));

\( E_{it} \) = the mass of CO\(_2\) generated by point source \( i \) at time \( t \) (unit: million tones CO\(_2\)/year);

\( i \) = index, denoting point sources, \( i = 1, 2 \ldots m; \)

\( j \) = index, denoting storage reservoirs, \( j = 1, 2 \ldots n; \)

\( t \) = index, denoting time periods over the lifetime of the CTL plant, \( t = 1, 2 \ldots T \).

Explanations of the constraints:

1. Source constraints: At time \( t \), the total amount of CO\(_2\) at source \( i \) to be transported and sequestrated to all storage sites is not more than mass of CO\(_2\) generated by source \( i \);

2. Sink constraints: During the whole planning horizon, the total amount of captured CO\(_2\) at all sources to be sequestrated into storage \( j \), is equal to the mass sequestrated by storage \( j \) at the same period, and is not more than the storage capacity of storage \( j \);

3. Per-term constraints: During the per-period, the sequestrated CO\(_2\) of all storages is not more than mass of CO\(_2\) generated by all sources;

4. Non-negativity constraints

In addition, some technological requirements will also be shown in technical constraints.
4 Empirical Model Application to Carbon Sequestration Project

4.1 Development of Carbon Storage in China

In 1998, China began its first CO$_2$ storage project CO$_2$-EOR in the Liaohe oil field, one of China’s largest oil fields in the Bohai Basin (IPCC, 2005). More recently, a joint venture was formed between the China United Coal Bed Methane Corporation and the Alberta Research Council of Canada to develop technology for extracting coal-bed methane via CO$_2$ injection (CO$_2$-ECBM) (Meng, 2007). In addition, China in 2003 joined the Carbon Sequestration Leadership Forum (CSLF), a ministerial-level organization initiated by the United States that aims to foster cooperation for CO$_2$ storage projects among the 17 signatory countries (Meng, 2007). Recently, an international team including Battelle, PNNL, and Chinese Academy of Sciences et al. worked on assessing market opportunities for CCS in China (Dahowski, 2005). To assess CO$_2$ storage location and estimates of their own effective storage capacity within the different reservoir types are underway. In all, China is more and more paying attention on CCS technologies and tries to make its contributions on GHG mitigation for the world.

4.2 A Brief Introduction on Carbon Sequestration for Shenhua CTL project

The Shenhua Group Corporation (Shenhua) is currently developing the world’s first commercial direct coal liquefaction (DCL) facility, which is currently undergoing startup operations in the Inner Mongolia Autonomous Region of China and is expected to produce nearly 1 million metric tons of oil products per year by 2010. As a large, stationary source of CO$_2$ emissions, the CTL project has interest in CCS based on two reasons: Firstly, the capture cost of CO$_2$ is a main contributor for total cost of CCS. The CTL project will produce approximately 3.1 million metric tons of CO$_2$ emission per year that is sufficiently pure for sequestration without significant capture costs. Secondly, the carbon sequestered from the CTL plants may be treated as credits (CERs) in a future CDM portfolio, it provides a market incentive for the CCS project. This study tries to explore the sequestration potential and optimal sequestration for the Shenhua’s CTL operations.

Potential deep CO$_2$ geologic storage reservoirs in close proximity to the CTL project include depleted and active oil fields and gas basins, unminable coal beds, and saline aquifers. The selection of potential storage locations depends on the costs of the options available in the region. Several suitable CO$_2$ storage sites are available within the projects area and a significant CO$_2$ storage potential exists. The identified storage reservoirs are located in areas within a 100 to 150 km radius from the two plants.

4.3 Model Specification and Sensitivity Analysis

The programming model is being on the way to be more realistic and applicable and basic GAMS program for it is being developed. As the data needed are obtained, the preliminary results for the programming model are planned to be presented at 28th USAEE conference.
The study has shown that there is high uncertainty in calculating the cost of CCS and estimating capacities of different storage sinks. A section of sensitivity analysis will be included. In this section, key parameters such as carbon price, capture and sequestration costs, transportation costs and related maximum distance from point sources to sinks would be examined. In other words, the issues how changes of those parameters will affect the optimal solutions will be discussed.

4.4 Predicted Result

Using the General Algebraic Modeling System (GAMS), we can solve the carbon sequestration profit maximization problem to obtain the carbon sequestration level $x$ where the net present value is at a maximum for each carbon price $p$. Typically, this $(p, x)$ relationship can be interpreted as the firm’s specified marginal abatement cost curve of the CO$_2$ emissions or CO$_2$ storage supply curve, with the amount of storage non-decreasing at higher prices. Figure 1 describes the theoretical relationship between cost and storage for the specified firm, where the X axis represents the total amount of CO$_2$ sequestration ($\sum_{j=1}^{T} \sum_{i=1}^{M} \sum_{j=1}^{N} x_{ijt}$) over the investment horizon. With a given carbon price, there exists a maximum amount of CO$_2$ sequestration. Below the carbon price of $P_0$, firm prefers to not sequester CO$_2$ over its planning horizon. When the price approaches to $P_0$, it has a tendency to sequester CO$_2$ of $Q_0$. If the price continues to rise and lie within a certain range between $P_0$ and $P_1$, the obtained revenues from selling carbon credits by sequestering additional unit of CO$_2$ can not offset increased total sequestration costs, therefore firm keeps the total amount of storage constant until $P_1$. If the price rises to $P_2$, the firm finally realizes its maximum amount of sequestration over the whole horizon at the highest $P_2$ value. Below $P_2$, CCS technology will be competitive for the firm. The shape of the supply curve reflects the fact that as the amount of sequestration increases, the economic-feasible reservoirs is more and more difficult to be applicable and marginal abatement costs for CO$_2$ rise dramatically. The supply curve will be in accord with the basic process of carbon sequestration: initially, the lower the transportation and storage cost and higher grade the reservoirs, the earlier the reservoirs will be utilized. These kinds of sinks probably include value-added formation (EOR and ECBM) considering they can provide credits and particularly offset the costs of CCS. As the sequestrated CO$_2$ increase
and time proceeds, poorer grade reservoirs with higher storage costs and unfavorable locations would trend to come into play.

5 Implications for Policy on Carbon Management

5.1 Firm-level Carbon Management

Once the programming model is solved, the optimal sequestration level to each storage sink for the firm in each term can be obtained.

5.2 Macro-level Carbon Management

Fighting global warming, developed countries are expected to take primary responsibility for emission reductions and developing countries need to be further engages in emission reductions through the CDM. In recent years, international carbon emission trading is growing at a spectacular rate, particularly CDM. China has been the largest carbon seller under the CDM since 2005. As of April 2, 2008, 1150 CDM projects in China, have been approved. These projects are mainly for energy saving and energy efficiency improvement, new energy and renewable energy use and recycling methane. The International Energy Agency (IEA) forecast (2006) that China’s CDM trades would account for 40 percent of an annual market of 250 million metric tons of carbon dioxide traded in 2010. Considering that few abatement projects have a scale to geosequestration, CCS projects could change the structure of CDM projects in China.

This supply curve offers insights into the prospects for carbon sequestration whether or not a carbon sequestration activity is economically feasible based on estimated future carbon prices in the CDM carbon market. Such a supply curve can also be used to assess the potential cost of possible climate policies that mandate emission reductions. The model developed in this analysis is also useful for feasibility assessment of future geologic carbon sequestration projects. The results help demonstrate the potential for successful CO$_2$ sequestration related to coal liquefaction and gasification production and the economic and environmental feasibility of coal as a source of liquid fuels in a carbon constrained environment for all countries with significant coal resources.

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**Nomenclature**

### CO₂ compression

\[ C \text{annual} \quad \text{total annual capital cost,} \]
\[ O&M \text{annual} \quad \text{annual operation and maintenance costs} \]
\[ E\text{annual} \quad \text{total electric power costs. It is the sum of electric power cost of compressor and pump} \]
\[ E_{\text{comp}} + E_{\text{pump}} \]
\[ C\text{total} \quad \text{the sum of } C_{\text{comp}} \text{ and } C_{\text{pump}} \]
\[ C_{\text{comp}} \quad \text{capital costs of compressors} \]
\[ C_{\text{pump}} \quad \text{capital costs of pump} \]
\[ \text{CRF} \quad \text{Capital recovery factor} \]
\[ \text{O&M factor} \quad \text{O&M cost factor} \]
\[ N_{\text{train}} \quad \text{number of parallel compressor trains} \]
\[ P_{\text{cut-off}} \quad \text{the pressure at which compression switches to pumping, 7.38MPa} \]
\[ P_{\text{initial}} \quad \text{initial pressure of CO₂ from CTL system, 0.1MPa} \]
\[ P_{\text{final}} \quad \text{the pressure of CO₂ for pipeline transport, 15 MPa} \]
\[ W_{\text{comp}} \quad \text{total compression power requirement} \]
\[ m_{\text{CO₂}} \quad \text{mass flow rate} \]
\[ W_{\text{pump}} \quad \text{pumping power requirement; number of parallel compressor trains} \]

### CO₂ transport

\[ C\text{annual} \quad \text{annualized pipeline capital cost ($/yr)} \]
\[ O&M\text{ annual} \quad \text{annualized O&M costs($/yr)} \]
\[ C\text{total} \quad \text{Total pipeline capital cost($)} \]
\[ \text{CRF} \quad \text{Capital recovery factor} \]
\[ \text{O&M factor} \quad \text{O&M cot factor} \]
\[ F_l \quad \text{location factor} \]
\[ F_T \quad \text{terrain factor} \]
\[ C_{\text{cap}} \quad \text{pipeline capital costs ($/km)} \]
\[ m_{\text{CO₂}} \quad \text{mass flow rate in pipeline (tones/day)} \]
L  pipeline length (km)

**CO₂ injection and storage**

- $C_{\text{site}}$: the capital cost of site screening and evaluation
- $C_{\text{equip}}$: injection equipment costs
- $C_{\text{drill}}$: drilling cost of injection well
- $O&M_{\text{annual}}$: annualized O&M costs ($/yr)
- $N_{\text{well}}$: the calculated number of wells
- $Q_{\text{CO₂well}}$: CO₂ injection rate per well (tones/day/well)
- CO₂ injectivity: mass flow rate of CO₂ that can be injected per unit of reservoir thickness (h) and per unit of downhole pressure difference (P_{\text{down}}-P_{\text{res}}) (tones/day/m/MPa)
- h: reservoir depth (m)
- P_{\text{down}}: downhole injection pressure (MPa)
- P_{\text{res}}: pressure in the reservoir (MPa)
- m: CO₂ mass flow rate delivered to injection site per day (tones/day)
- CO₂ mobility: absolute permeability $K_a$ divided by CO₂ viscosity $\mu_{\text{inter}}$
- $K_a$: absolute permeability of reservoir
- $\mu_{\text{inter}}$: CO₂ viscosity at intermediate pressure
- Kh: horizontal permeability of reservoir