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TITLE: Limiting the financial risks of electricity generation capital investments under carbon constraints: applications and opportunities for public policies and private investments

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Limiting the Financial Risks of Electricity Generation Capital Investments under Carbon Constraints: Applications and Opportunities for Public Policies and Private Investments

A Dissertation
submitted in Partial Fulfillment of the Requirements for the Degree of
Doctor of Philosophy

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Abstract

Increasing demand for electricity and an aging fleet of generators are the principal drivers behind an increasing need for a large amount of capital investments in the US electric power sector in the near term. The decisions (or lack thereof) by firms, regulators and policy makers in response to this challenge have long lasting consequences, incur large economic and environmental risks, and must be made despite large uncertainties about the future operating and business environment.

Capital investment decisions are complex: rates of return are not guaranteed; significant uncertainties about future environmental legislation and regulations exist at both the state and national levels – particularly about carbon dioxide emissions; there is an increasing number of shareholder mandates requiring public utilities to reduce their exposure to potentially large losses from stricter environmental regulations; and there are significant concerns about electricity and fuel price levels, supplies, and security.

Large scale, low carbon electricity generation facilities using coal, such as integrated gasification combined cycle (IGCC) facilities coupled with carbon capture and sequestration (CCS) technologies, have been technically proven but are unprofitable in the current regulatory and business environment where there is no explicit or implicit price on carbon dioxide emissions.

The paper examines two separate scenarios that are actively discussed by policy and decision makers at corporate, state and national levels: a future US electricity system where coal plays a role; and one where the role of coal is limited or nonexistent. The thesis intends to provide guidance for firms and policy makers and outline applications and opportunities for public policies and for private investment decisions to limit financial risks of electricity generation capital investments under carbon constraints.

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Chapter 1: Overview and motivation

The US electricity sector is facing an operating environment with an unprecedented number of opportunities and challenges. Increasing demand for electricity, an aging fleet of generators and stricter multi-pollutant emission regulations, principally, are driving a need for large capital investments in the US electric power sector in the near term. The decisions (or lack thereof) by firms, regulators and policy makers in response to this challenge have long lasting consequences, incur large economic and environmental risks, and must be made despite large uncertainties about the future operating and business environment.

Current capital investment decisions are substantially more complex than those of the past for a number of reasons: a restructured business environment in many states where rates of return are not guaranteed; significant uncertainties about future environmental legislation and regulations at both the state and national levels – particularly about carbon dioxide emissions; the increase in shareholder mandates requiring public utilities to reduce their exposure to potentially large losses from stricter environmental regulations; widely varying public perceptions about generation alternatives such as nuclear and renewables; significant concerns about electricity and fuel price levels, supplies, and security; as well as the larger economic competiveness and geopolitical concerns associated with energy.

At the firm level, businesses must decide how to allocate their capital to provide electricity to meet growing customer demand, profitably. New electricity generation facilities are immensely expensive, and the economic performance is sensitive to the relative costs of fuel, the overall demand for electricity and the environmental performance. In a restructured and competitive business environment, where there is no guaranteed rate of return, choosing to build the 'wrong' technology can lead to large losses.

From a public policy perspective, decision makers must respond in a timely and adequate way to address environmental concerns. Concurrently, care must be taken when crafting a policy response to avoid causing rapid and large electricity price increases, which would undoubtedly hurt consumers, industry and the economy. If policy makers enact legislation that effectively chooses a particular electricity generation technology or fuel, by prohibiting coal, for instance, it could lock the US into an electric power sector pathway that could be difficult and expensive from which to recover.

Capital investment concerning coal generation is particularly uncertain. Producing electricity from coal is advantageous because it is an abundant, inexpensive domestic energy source, making it generally free of supply and geopolitical concerns. The current process of generating electricity from coal combustion, however, produces criteria pollutants such as sulfur dioxide (SO_2), nitrogen oxides (NOx), as well as mercury and a large amount of carbon dioxide (CO_2). Stricter multi-pollutant regulations such as the Clean Air Interstate Rule (CAIR) and Clean Air Mercury Rule (CAMR), as well as increasing policy signals that carbon dioxide emissions may soon incur a cost, have made the current coal combustion process less favorable. Because of these potentially large financial and/or environmental risks, some have argued for the disuse of coal to produce electricity, unless the carbon dioxide emissions are physically limited or appropriately monetized and incorporated into the project economics; others have called for a ban on new coal uses altogether.

Large scale, low carbon electricity generation facilities using coal, such as integrated gasification combined cycle (IGCC) facilities coupled with carbon capture and sequestration (CCS) technologies, have technically proven components but are unprofitable in the current regulatory and business environment where there is no explicit or implicit price on carbon dioxide emissions.

The thesis examines two separate scenarios that are actively discussed by policy and decision makers at corporate, state and national levels: a future US electricity system where coal plays a role; and one where the role of coal is limited or nonexistent. The thesis intends to provide guidance for firms and policy makers and outline applications and opportunities for public policies and for private investment decisions to limit financial risks of electricity generation capital investments under carbon constraints.

Chapter two proposes and examines a method for increasing the profitability of low carbon coal energy, to encourage its development. The chapter develops a model to show how adding syngas storage can increase the profitability of an IGCC facility. Although IGCC is generally preferred on an environmental basis, in the absence of carbon pricing mechanisms pulverized coal (PC) facilities are capable of producing electricity at a significantly lower cost than IGCC facilities. A high carbon price is required in order for IGCC facilities to be economically competitive with PC facilities. A developer has to take the risk of building technologies that may pay off in the long run (if there is a price on carbon) but may be less competitive and unprofitable in the short term.

Chapter three discusses how the location of a new electric power generation system with carbon capture and sequestration (CCS) affects the profitability of the facility and determines the amount of infrastructure required to connect the plant to the larger world. The chapter develops a probabilistic analysis to examine where a profit maximizing power producer would locate a new generator with carbon capture in relation to a fuel source, electric load, and CO_2 sequestration site. Based on models of costs for transmission lines, CO_2 pipelines, and fuel transportation, I show that it is preferable to locate a CCS power facility nearest the electric load, reducing the losses and costs of bulk electricity transmission. This result suggests that a power system with significant amounts of CCS requires a very large CO_2 pipeline infrastructure.

Chapter four examines the effects of instantaneously implementing a price on carbon dioxide emissions from US electric generators. The price of delivered electricity would rise if generators have to pay for carbon dioxide emissions through an implicit or explicit mechanism. There are two main effects that a substantial price on CO_2 emissions would have in the short run (before the generation fleet changes significantly). First, consumers would react to increased price by buying less, described by their price elasticity of demand. Second, a price on CO_2 emissions would change the order in which existing generators are economically dispatched, depending on their carbon dioxide emissions and marginal fuel prices. Both the price increase and dispatch changes depend on the mix of generation technologies and fuels in the region available for dispatch, although the consumer response to higher prices is the dominant effect. It is estimated that the instantaneous imposition of a price of $35 per metric ton on CO_2 emissions would lead to a 10% reduction in CO_2 emissions in the PJM and MISO RTO territories at a price elasticity of –0.1. Reductions in ERCOT would be about one-third as large. Thus, a price on CO_2 emissions that has been shown in earlier work to stimulate investment in new generation technology also provides significant CO_2 reductions before new technology is deployed at large scale.

Chapter five examines the implications of a future where the construction of new generators using coal for electricity generation is prohibited and electricity demand must be met though other alternatives. Here, a model is developed to quantify the effects on the US electric power system of banning the construction of coal-fired electricity generators, as has been recently proposed as a means to reduce US emissions. Load growth, resource planning and economic dispatch in the Midwest ISO, ERCOT and PJM is simulated under a ban on new coal generation. I use an economic dispatch model to calculate the resulting changes in dispatch order, CO_2 emissions and fuel use under three near term (until 2030) future electric power sector scenarios. The analysis shows that such a policy is likely to lead to much greater reliance on natural gas to fuel electricity generation in the near term, even with the introduction of wind generation at large scale or aggressive demand reductions. A national ban on new coal-fired power plants substantially increases demand for natural gas and increases the fraction of time that natural gas generators set the market price of electricity; with the potential to place large pressures on natural infrastructure and supplies, lead to significant exposures to natural gas markets, risking significantly higher electricity prices and increased dependence on natural gas imports.

Chapter 2: Storing syngas lowers the carbon price for profitable coal gasification[1]

Although IGCC generation facilities are generally preferred on an environmental basis, in the absence of carbon pricing mechanisms pulverized coal (PC) facilities are capable of producing electricity at significantly lower cost. A high carbon price is required in order for IGCC facilities to be economically competitive with PC facilities. Proposed federal legislation, such as the Lieberman-Warner Climate Security Act, has provisions to monetize CO_2 emissions, however price levels at which low carbon investment are competitive ($30-$35/t CO_2) will not be realized until 2025-2030 [1]. Without other means of increasing the profitability of an IGCC facility, a developer must risk building a facility that may be competitive and profitable in the long run, if there is a price on carbon, but may be less competitive and unprofitable in the short term while CO_2 emissions have no price.

2.1 Introduction

Producing electricity from coal-derived synthesis gas (syngas) in an integrated gasification combined cycle (IGCC) facility can improve criteria pollutant performance over other coal-fueled technologies such as pulverized coal (PC) facilities [2-6] and can be implemented with carbon capture and sequestration.

Previous studies have shown that IGCC with carbon capture and sequestration (CCS) has the potential for CO_2 control at costs comparable to those of other low-carbon generation technologies [5-7]. Using a water gas shift and Selexol process [8], IGCC facilities can achieve 85-90% CO_2 reductions with emission rates near 95 kg CO_2/MWh [6].

[1] Significant portions of this chapter appear in Newcomer, A.; Apt, J., Storing Syngas Lowers the Carbon Price for Profitable Coal Gasification. *Environ. Sci. Technol.* **2007,** *41*, (23), 7974–7979.

Adding CO_2 capture and storage incurs an energy penalty, estimated by previous work as 14% for an IGCC and 24% for a PC plant [6]. CCS has been calculated to increase the cost of delivered electricity by 44% for IGCC facilities and by 78% for PC [6].

In addition to lowering CO_2 emissions, IGCC facilities with CCS have increased environmental advantages over traditional coal combustion technologies because of lower levels of criteria pollutant emissions, reduced water usage and lower amounts of solid waste. Criteria emissions control with IGCC+CCS is cost effective because most clean-up occurs in the syngas, that has higher pressure, lower mass flow and higher pollution concentration than stack exhaust gases [4, 9, 10].

Particulate emissions from existing IGCC units are below 0.001 lb/million Btu versus about 0.015 lb/million Btu from modern PC units [9]. Current NOx emissions at IGCC facilities are 0.06-0.09 lb/million Btu versus 0.09-0.13 lb/million Btu for PC facilities. Further reductions of NOx emissions can be achieved at IGCC facilities with SCR: 0.01 lb NOx/million Btu has been demonstrated commercially in an IGCC unit in Japan [9]. Mercury removal from syngas at IGCC facilities is in the range of 95-99%, versus 85-95% mercury removal for PC facilities using advanced control [3]. IGCC facilities have SO_2 emissions of 0.015-0.08 lb/million Btu while typical PC facilities have emissions ranging from 0.08-0.23 lb SO_2/million Btu, depending on the age of the facility and type of coal [9]. Additionally, IGCC facilities have lower emissions of other byproducts such as chloride, fluoride, cyanide than PC facilities [2], and IGCC uses 20-35% less water than PC [9]. For the same coal feed, an IGCC produces 40-50% less solid waste than a PC and the fused slag can be more easily disposed of than can fly ash [9].

Although IGCC is generally preferred on an environmental basis, in the absence of carbon pricing mechanisms PC facilities are capable of producing electricity at a significantly lower cost than IGCC facilities. A high carbon price is required in order for IGCC facilities to be economically competitive with PC facilities.

There are currently eight gasification facilities operating worldwide producing about 1.7 GW of electricity from coal or petcoke feedstock [11], and in all of these facilities the syngas is used immediately after it is produced. Without storage capabilities, the gasifier must be sized to fit the syngas end-use (such as a gas turbine or chemicals process) and the operation of the two systems must be coupled. For IGCC designs where the air separation unit is not fully integrated with the turbine, adding the capability to store syngas decouples the gasifier from the turbine, allowing the gasifier and turbine to be sized and operated independently, thereby providing valuable flexibility in the way the facility is configured and operated [12, 13]. One example is using syngas storage to generate peak electricity. Syngas storage provides a means to continuously operate the gasifier at the most efficient sustained production rate, but to sell electricity only when daily electricity prices are high, thereby maximizing profits and enhancing plant-level economics over a non-storage IGCC facility while operating the gasifier at the same capacity factor. When used in this manner, diurnal syngas storage at an IGCC facility can increase profits and return on investment and lower the carbon price at which IGCC enters the US generation mix. Here, the value of implementing diurnal storage to produce peak power from an IGCC facility is examined.

2.2 Engineering-economic model

A non-storage (baseline) IGCC facility producing 270 net MW from one gasifier is modeled. Although facilities such as the Wabash River IGCC plant in Indiana operate with a spare gasifier (termed here 1+1), Wabash River was built as a government demonstration project, and new commercial plants are likely to be constructed with no spare (1+0). This baseline facility represents the lowest capital cost IGCC facility that would reasonably be built and operated [14] and has a capital cost of $415 million or $1,540/kW (Table 1). Also examined are facilities with configurations of 1+1, 3+1 and 3+0 and reached similar conclusions as for the 1+0 analysis; due to economies of scale, syngas storage adds greater value to larger sized facilities including those constructed with spare gasifiers despite increased capital costs (see Appendix A).

Syngas storage systems were analyzed using the same gasifier size and configuration as the baseline scenario with the addition of a syngas storage process block and additional peaking turbine (Figure 2.1).

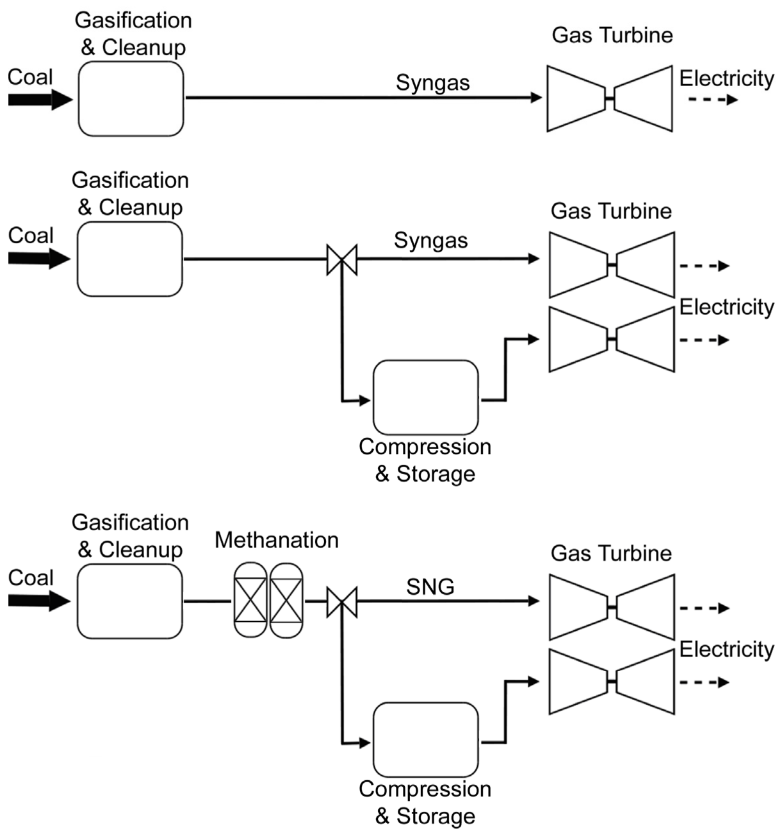

Figure 2.1 Baseline facility (top), syngas storage scenario (middle), SNG storage scenario (bottom)

The return on investment (ROI) and net present value (NPV) are calculated for the baseline, syngas storage and methanation scenarios using both historical and forecast prices for coal and electricity for a hypothetical IGCC facility located in the US Midwest.

The sensitivity of the ROI in each scenario to uncertainty and variability in design parameters, costs and prices was examined probabilistically. The value of adding diurnal syngas storage to produce peak electricity was quantified by comparing the ROI to that of a baseline IGCC facility producing electricity from syngas with no storage capabilities. The ROI for an IGCC facility with carbon capture and sequestration and syngas storage capabilities was calculated under a range of possible future carbon prices and compared to that of a baseline facility with no storage to quantify how storage affects the carbon price at which IGCC enters the US generation mix.

Capital and operating cost distributions for the gasification, cleanup and power block sections in the baseline facility are based on the Integrated Environmental Control Model (IECM) version cs 5.21 [15], a standard tool that provides the flexibility to analyze a wide range of IGCC facility sizes and configurations. The baseline facility includes the process blocks shown in Table 2.1 (a more complete list of the processes and parameters is included in Appendix A).

Table 2.1 Baseline 270 MWe net Facility Configuration and Parameters [15]

Process Block (mean capital cost $2005)	Components	Size / Description
Gasifier	1 train GE/Texaco gasifier	260 tons/hr syngas output
($138.5M)	0 spare train gasifier	
	Coal handling	
	Low temperature gas cooling	
	Process condensate treatment	
Air Separation Unit	1 train	max output: 11,350 lb-mol/hr
($93.5M)		
Cold-gas Cleanup	Hydrolyzer	98.5% efficiency
($32.5M)	Selexol	98% H2S efficiency
	Claus plant	95% efficiency
	Beavon-Stretford tail gas plant	99% efficiency
Power Block	Gas combustion turbine	GE 7FA CCGT
($150.8M)	Heat recovery steam generator	510 MW (gross) combined
	Steam turbine	cycle/turbine
	HRSG feedwater system	9000 Btu/kWh
Fuel	Illinois #6 coal	HHV: 10,900 Btu/lb

Point estimates from IECM were converted into triangular distributions using assumptions of ±5%, following capital cost estimates reported in the literature [16-18]. The distributions, rather than point estimates, were used as inputs into the engineering-economic models. Cost data from IECM are in 2005 constant dollars.

The syngas produced by the gasification process is composed primarily of carbon monoxide and hydrogen and is characterized by a low energy density, typically ranging from 150-280 Btu/scf. Because of the lower energy density, larger volumes of syngas than of natural gas are required to produce electricity in a gas turbine. Syngas storage vessels thus need to be large, have high working pressures, or have these in combination. Although hydrogen is known to embrittle metals, the concentrations and partial pressures of hydrogen typically found in syngas do not appear to require any special preventative measures [19-23] for syngas storage options used in this analysis. An additional potential problem resulting from the hydrogen content of syngas is that atomic hydrogen is a small molecule and can diffuse through most metals [24]. However industrial experience with syngas and analogies with other industrial practices suggests that excessive diffusion and leakage of syngas through a storage chamber wall is not an issue for diurnal and relatively short-term storage [25].

Only compressed gas storage options are considered since it is the most relevant large-scale stationary storage method for syngas production facilities and is less expensive than alternatives such as liquefaction. Compressed gas storage is the simplest storage solution, as the only required equipment is a compressor and a pressure vessel [26]. Operating parameters, capital and operating costs were examined for compressors and different storage vessels including high pressure spheres and cylindrical ‘bullets’ common for liquefied propane and compressed natural gas storage, low pressure gasometers, underground salt caverns and excavated rock caverns.

The design of the syngas storage scenario is conceptual, and is provided to outline the potential benefits of such a system and to open a line of enquiry as to whether syngas storage should be fully considered in the design of an IGCC facility.

There is a wide range of gas compression, storage and relief processes used in industry and the optimal engineering design for a syngas or SNG compression and storage operation is site specific. The purpose of the compression and storage component is to compress the syngas coming out of the gasifier to increase its density and reduce its storage volume. An example, non-optimized compression and storage process block is modeled and illustrated in Figure 2.2.

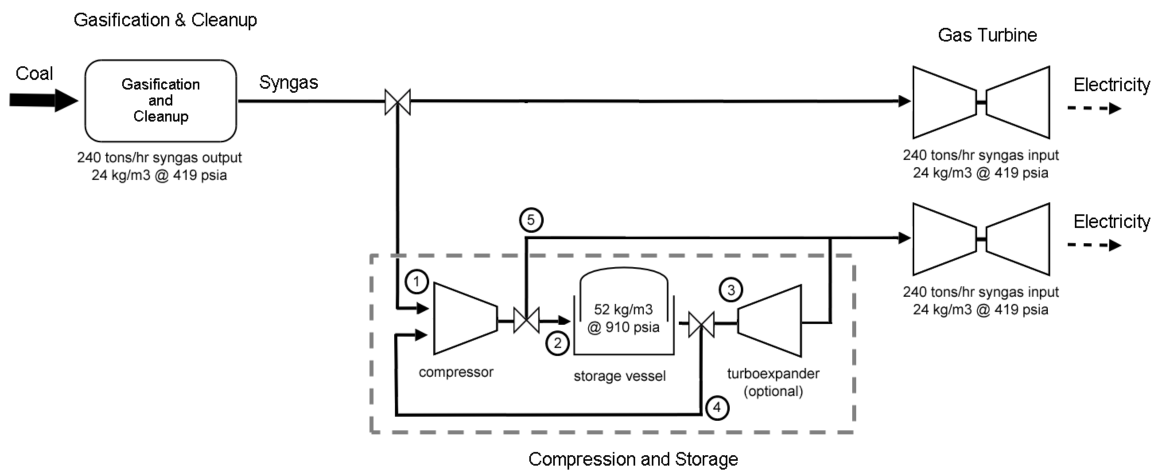

Figure 2.2 Conceptual design of syngas storage process block used in the analysis

The syngas storage process for this analysis is: 1) Syngas from the gasification and cleanup block is pressurized to 910 psia; 2) The high pressure syngas is stored in a vessel; 3) High pressure syngas is released out of the storage vessel at a controlled rate (although not considered here, energy may be recovered through a turboexpander) and used in the peaking turbine; 4) As the pressure in the storage vessel is reduced, the syngas is routed through the compressor to maintain an input pressure required by the peaking turbine; 5) Syngas at the required inlet pressure for the GE 7FA is routed to the peaking turbine. A qualitative example of the storage and draw down pressures and the recompression requirements used in this process are illustrated in Figure 2.3.

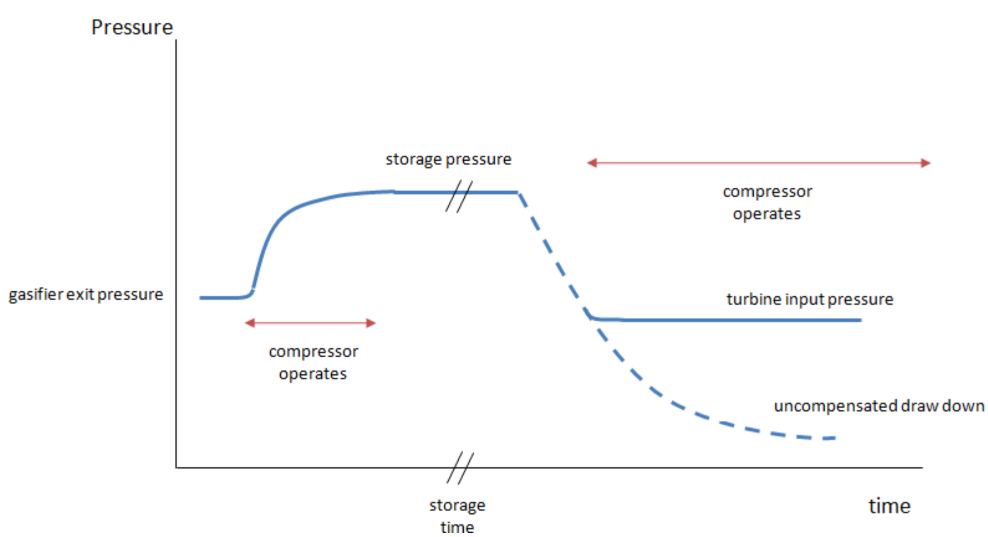

Figure 2.3 Conceptual illustration of storage pressures, draw down rates and recompression requirements for syngas storage process block used in the analysis

Recompression after the storage process allows the entire volume of the storage vessel to be utilized as well as providing a means to control the pressure and mass flow rate of syngas into the additional turbine. The particular arrangement and operating parameters will depend on site specific details such as the type of coal, gasifier and gas turbine, and it is possible that there will be areas where energy losses can be reduced and efficiencies increased through smart engineering design.

Capital costs for compressors, which are required for all storage options, were obtained from the literature [24, 26, 27] and cost distributions were constructed from these data. Compressor capital costs were found to scale linearly with the size of the compressor. The distribution of the capital cost for a given size compressor, reflecting the range of cost uncertainty, was used as an input to the engineering economic models when compression was required.

Capital costs for storage vessels were compiled from studies in the literature and from industry professionals (Appendix A contains physical details, capital costs and cost distribution calculations for storage vessels). From a regression analysis and prediction interval derived from these data, cost distributions were constructed and used as inputs in the model. The capital cost distributions suggest a salt cavern is preferred if it is available because it is the lowest cost. However, because salt and rock caverns are geographically sparse [28], this analysis considers the general case where neither is available.

An IGCC plant located in the US Midwest is modeled using prices for Illinois number 6 coal (HHV 11,350 Btu/lb, sulfur content of 3.2% by weight [29]). The model uses both historic coal data and price forecasts from the Energy Information Administration (EIA) to account for the variability in coal prices (Appendix A discusses the price distributions considered in the analysis). The EIA Annual Energy Outlook (AEO) coal price forecasts for year 2007 are modified with a factor to account for EIA's historical error in forecasting price data [30-32] (see Appendix A for additional details). The 2005-2006 coal prices have a mean of $1.51/MMBtu and standard deviation of $0.1. The 2007 EIA forecast including the historical accuracy factor has a mean value of $1.73/MMBtu, 15% higher than the mean historical 2005-06 prices.

To estimate revenue, the historical locational marginal price (LMP) data for electricity from September 1, 2005 to September 1, 2006 for nodes in the Midwest ISO region [33] are used.

Syngas storage scenarios are examined with 4, 8 and 12 hours storage. Storage size (measured in hours) and compressor size were selected to accommodate 100% of the output of the gasifier for the number of hours indicated (that is also the period the peaking turbine can generate electricity from stored syngas). The model fixed syngas storage pressure at 63 bar for all storage scenarios, requiring a 5,600 kW compressor for both charging and discharging the storage vessel. This storage pressure results in a required storage vessel volume of 17,000 m^3, 34,000 m^3 and 51,000 m^3 for 4, 8 and 12 hours of syngas storage, respectively. In the present model, the directly-fed and storage-fed gas turbines are the same size. Other arrangements may be more profitable (for example, choosing a different size peaking turbine or optimizing the storage pressures and volumes), but the analysis seeks to determine only whether storing syngas for sale at peak times has the potential to significantly increase profitability.

For each of the storage options (0, 4, 8, and 12 hours), the gasifier operates at maximum output at every hour (260 tons/hr), up to its availability. At every hour, the facility operator must decide how much electricity to produce from the IGCC turbine and from the peaking turbine. A profit maximizing operator stores syngas during hours with the lowest LMP and operates both turbines at hours with the highest LMPs. This storage scheme is illustrated for the case of 8 hours of storage, shown over two days in Figure 2.4. In the Midwest ISO over the year examined, the day-ahead and real-time hourly markets exhibited a correlation of 0.81, 0.77, and 0.74 for the 4, 8, and 12 hours of lowest LMPs respectively. It is thus a reasonable approximation for this analysis that the operator could use the day ahead LMPs to operate the storage scheme in real time.

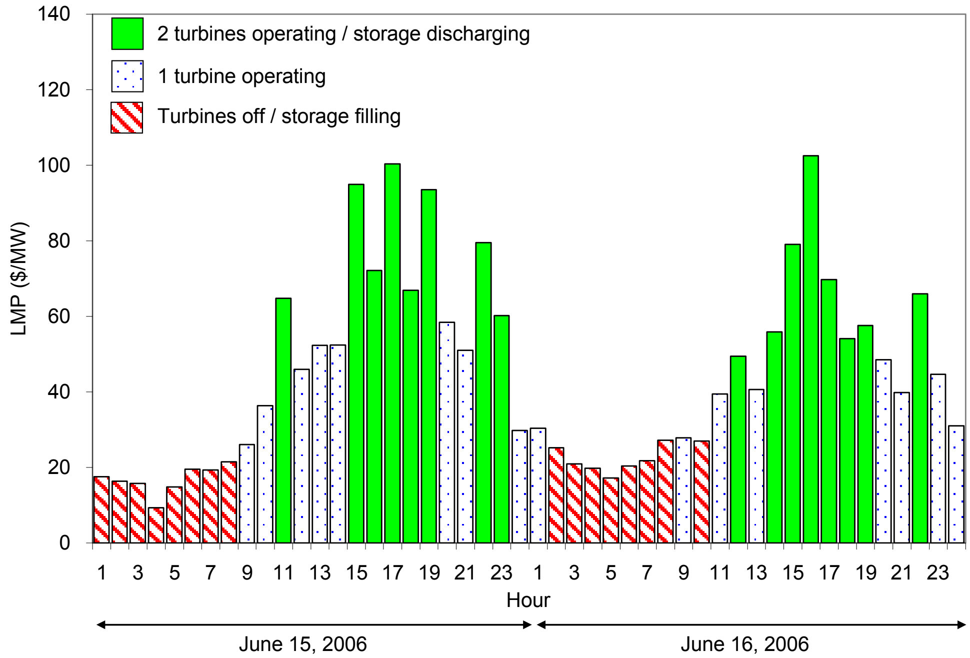

Figure 2.4 Storage scheme for 8 hours of syngas storage to produce peak electricity. At times of low price, the gasifier output fills storage. During high price periods, both the gasifier and stored syngas supply turbines. At intermediate prices, the gasifier output is fed to one turbine and the storage volume is unchanged.

The annual return on investment for the baseline and storage scenario is calculated as:

$$\mathrm{ROI} = \frac{\text{annual revenue}}{\text{total levelized annual expenses}} \tag{1}$$

where the annual revenue is the sum over every hour i of each day j in the year of the hourly amount of electricity produced by the IGCC turbine (MW_1) and the peaking turbine (MW_2) times the selling price of electricity at the hour (LMP) and the facility availability:

$$\text{annual revenue} = \sum_{j=1}^{365} \sum_{i=i}^{24} \left[\mathrm{LMP}_i \cdot \left(\mathrm{MW}_{1i} + \mathrm{MW}_{2i} \right) \cdot \text{availability} \right]_j \tag{2}$$

and where the levelized annual expenses are the sum of the annual operating and maintenance costs and the annualized principal and debt service on the capital cost [34]:

$$\text{total levelized annual expenses} = \sum_{\substack{\text{gasifier}\\ \text{cleanup}\\ \text{air separation}\\ \text{turbine}\\ \text{compressor}\\ \text{storage}}} \begin{pmatrix} \text{annualized capital expenses} + \\ \text{annualized O \& M expenses} \end{pmatrix} \qquad (3)$$

where annualized capital expenses = capital costs × (amortization factor × debt percentage)
and where annualized O&M expenses = fixed annual costs ($/yr) + (variable O&M ($/hr) × 8760 (hr/yr) × availability)

Because the levelized annual expenses are distributions, the resulting probabilistic ROI is also a distribution.

2.3 Profitability results with no carbon price

2.3.1 Syngas storage profitability compared to baseline

The ROI and NPV were calculated for the baseline IGCC facility and for the IGCC facility with diurnal storage; the value of adding storage to an IGCC facility was calculated by calculating the difference in economic performance.

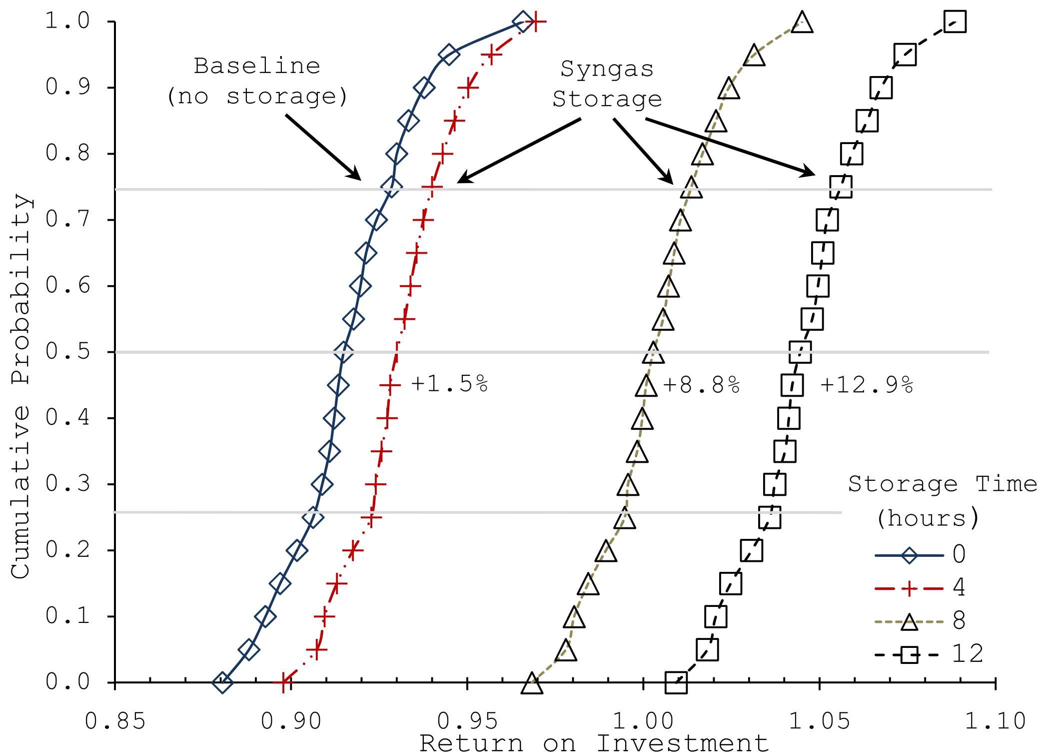

Figure 2.5 ROI for syngas storage scenario using a 1+0 IGCC facility with 80% availability, Cinergy node, 100% debt financing at 8% interest rate, economic and plant life of 30 years (amortization factor 0.0888), 2007 EIA AEO coal price forecast with accuracy factor, 63 bar storage pressure.

The mean ROI for the baseline 1+0 facility with no storage is 0.91 (Figure 2.5), suggesting that this IGCC facility would not be constructed under the assumed operating and financial parameters. The addition of 4, 8 and 12 hours of syngas storage increases the mean ROI by 1.5, 8.8 and 12.9 percentage points, respectively.

The NPV shows similar increases with storage; with 12 hours of syngas storage, the facility realizes increased revenue from producing and selling peak power and the NPV is \$90 million (\$180 million more than the baseline IGCC facility with no syngas storage). Since the magnitude of the NPV increase depends on the nodal LMPs, the model locates the facility at a number of nodes in the Midwest ISO. Storage increases the NPV for all nodes examined (Figure 2.6).

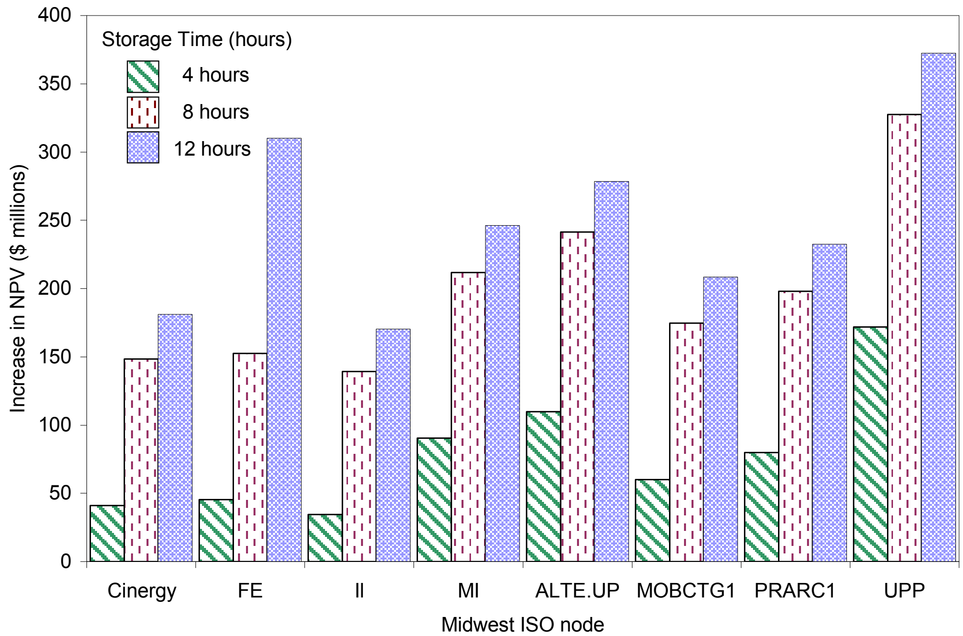

Figure 2.6 Increase in NPV from adding a diurnal syngas storage scheme. Parameters as in Figure 2.5.

The sensitivity of the analysis to variations in the parameters was analyzed. The ROI for the 12 hour storage scenario is sensitive to the gasifier availability, structure of the financing, price of coal, and capital costs of the turbines, gasifier, air separation unit, and cleanup processes. The gasifier availability and the financing are the most important parameters over which the facility developer or operator has control. In addition to a plot of the sensitivity analysis, a closed-form solution of the increase in ROI using mean prices for peak and off peak LMP prices is included in Appendix A. Note, that the mean prices necessary for the closed form solution do not capture the 'peakiness' of the price duration curves, as the gains from using syngas storage depend on the differences in electricity prices at peak and off peak hours for every hour the facility is operated.

2.3.2 SNG storage scenario profitability compared to baseline

The ROI was calculated for a baseline gasification plus methanation facility and for the same facility with diurnal storage; the value of adding storage was calculated by calculating the difference in economic performance. The cumulative probability of the ROI for the baseline 1+0 SNG facility with no storage is shown in Figure 2.7.

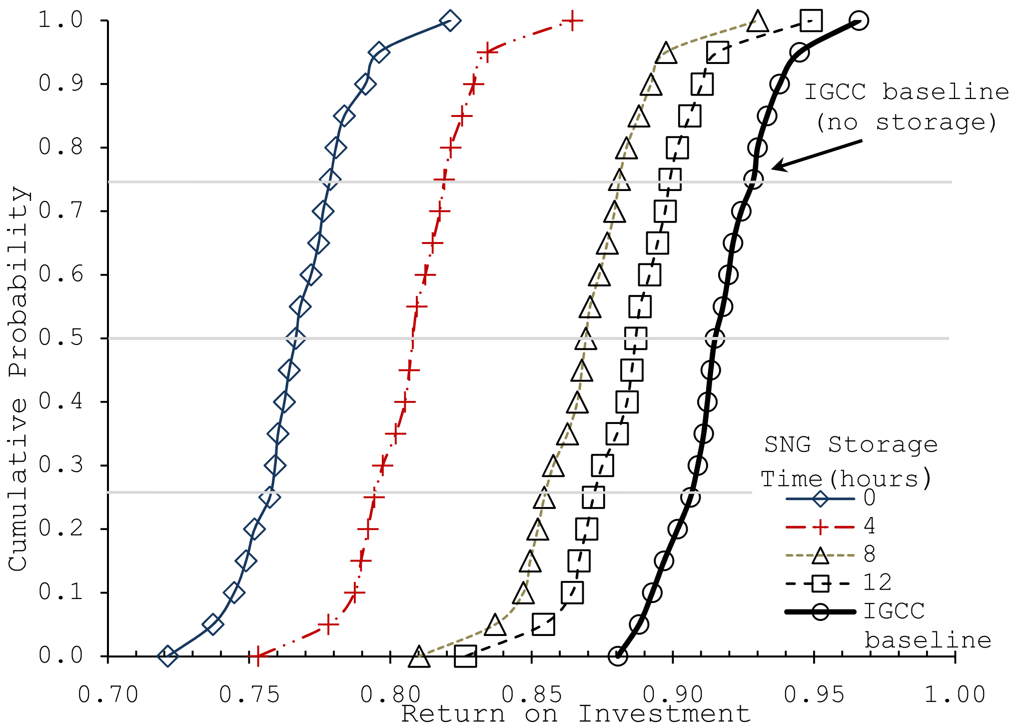

Figure 2.7 ROI for SNG storage scenario using a 1+0 gasification plus methanation facility with 80% availability, Cinergy node, 100% debt financing at 8% interest rate, economic and plant life of 30 years (amortization factor 0.0888), 2007 EIA AEO coal price forecast with accuracy factor, 63 bar storage pressure.

Although adding storage to the SNG scenario increases the ROI, the overall ROI is less than the ROI for non-methanated syngas in all cases. This result would suggest that a SNG storage site would never be economically preferable to a standard IGCC facility.

2.4 Syngas storage profitability with a carbon price

The implications of using diurnal syngas storage scheme at an IGCC facility in a regulatory environment with a carbon tax or carbon allowance price are examined. A carbon price will increase the price of electricity and the revenue received by the IGCC plant. Because storage adds value and increases the ROI for an IGCC facility, the carbon price at which IGCC enters the generation mix may be lowered. The method for examining the hypothesis was to 1) re-examine the baseline (no storage) scenario with the addition of carbon capture, transport and storage process and costs; 2) increase the Midwest ISO LMP prices by redispatching the existing generation with the addition of a carbon price using heat rates and CO_2 emission factors from the US EPA's eGRID database [35]; and 3) plot the facility ROI versus the carbon tax and examine the hurdle rate crossover.

The 1+0 baseline IGCC facility was modified to include a carbon capture, transport and storage process from IECM, consisting of a water gas shift process, Selexol CO_2 capture and transport process. Appropriate adjustments to the performance and the capital and operating costs were made to the engineering economic model (Appendix A provides comprehensive details for the 1+0+CCS scenario).

Adding CCS increases capital costs, and incurs an energy penalty, increasing coal consumption and decreasing net electricity produced. The 1+0+CCS facility has a net output of 238 MW and a capital cost of \$2,380/kW (compared to \$1,540/kW for the 1+0 scenario). Implementing diurnal syngas storage with the 1+0+CCS scenario significantly improves the plant level ROI and NPV of the IGCC facility (Figure 2.8).

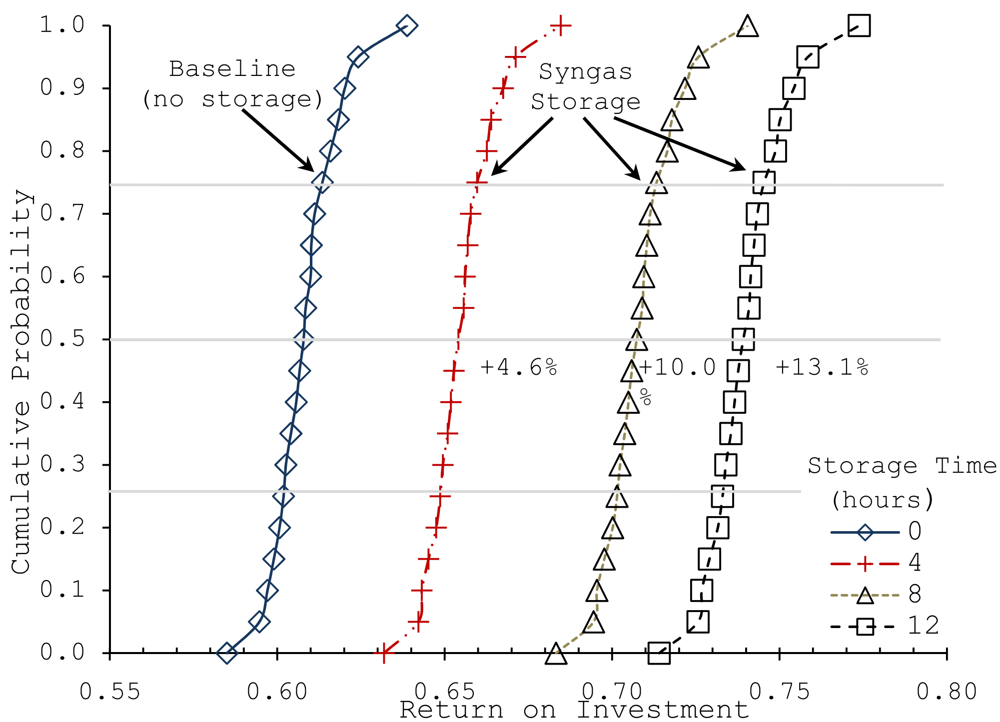

Figure 2.8 ROI for a 1+0 facility with carbon capture, transport and storage: 1+0 gasifier train, 80% availability, Cinergy node, 100% debt financing at 8% interest rate, economic and plant life of 30 years, 2007 EIA AEO coal price forecast with accuracy factor.

The mean ROI for the baseline 1+0+CCS facility with no storage under the assumed operating and financial parameters is 0.61. This ROI is about 30 percentage points lower than the case without CCS due to the increased capital costs and energy penalty associated with carbon capture and storage process. The addition of 4, 8 and 12 hours of syngas storage increases the mean ROI by 5, 10 and 13 percentage points, respectively (although the facility is not profitable, in the absence of special circumstances such as selling the CO_2 for enhanced oil recovery).

A carbon price will increase the price of electricity by an amount dependent on the types of generation units used. Using eGRID data [35], a dispatch curve is constructed for the Midwest ISO, using the rate of carbon emission per kWh for each generator in the ISO reported in eGRID (Figure 2.9, where values are shown for three carbon prices). Using these updated dispatch curves, estimates of electricity prices incorporating the price of carbon were calculated. These prices and the hourly Midwest ISO load in each hour of the year examined were used to estimate the revenue received by the IGCC plant with storage for each hour.

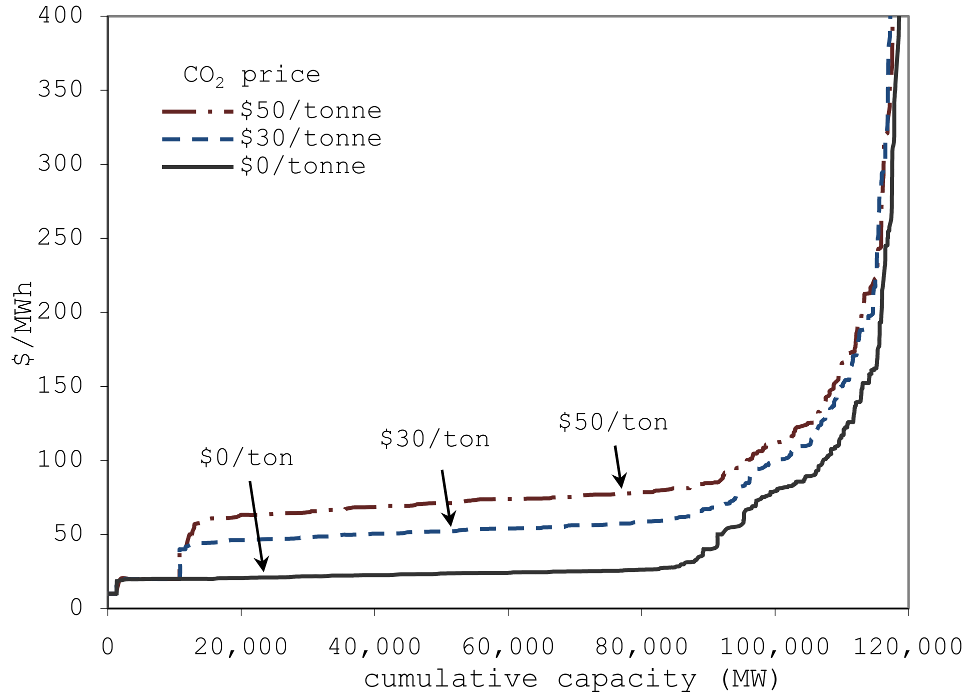

Figure 2.9 Midwest ISO price curves at a range of carbon prices. Redispatch analysis using eGRID data for each generator.

Using LMP data incorporating a carbon price, the analysis was repeated to examine the implications of a carbon price on the ROI of an IGCC facility with syngas storage and 90% carbon capture (paying the carbon price for the remainder). Figure 2.10 plots the mean values of the ROI for the syngas storage scenario versus carbon price and shows that storage lowers the carbon price at which a given investment hurdle rate is achieved.

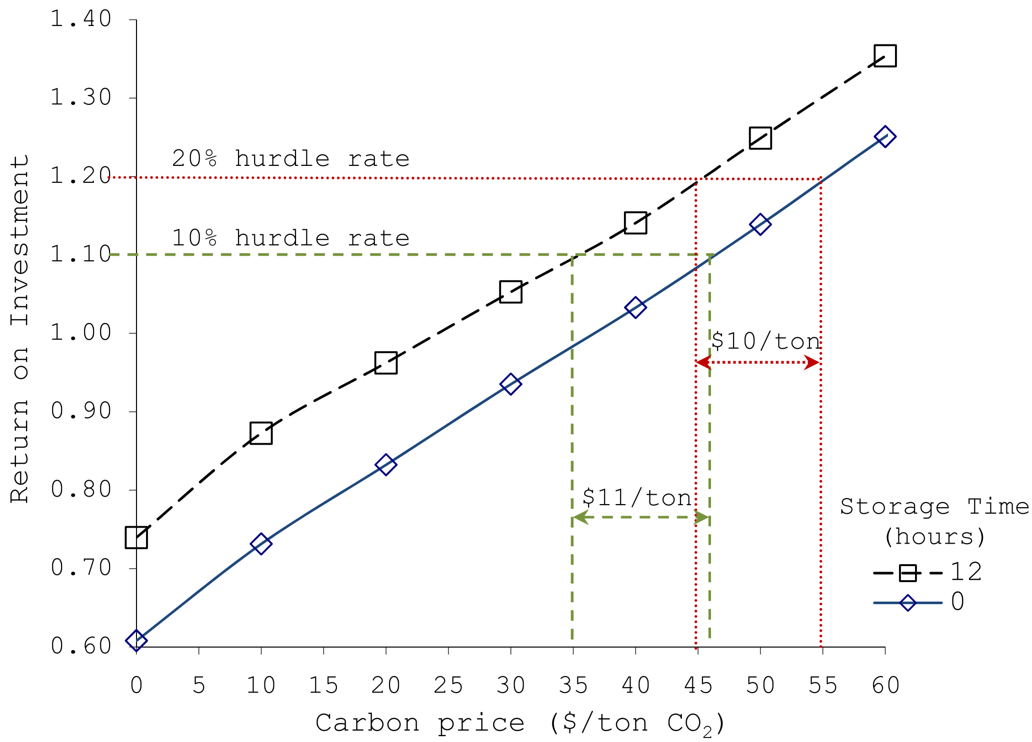

Figure 2.10 Effects of carbon price on return on investment for syngas storage facilities.

A 20% ROI is attained at approximately \$45/ton CO_2 with 12 hours of high pressure above ground storage, versus \$55/ton for a facility with no syngas storage. Because 12 hours of syngas storage increases the ROI for the IGCC facility, the carbon tax at which a 20% hurdle rate is achieved is lowered by about \$10/ton CO_2. The reduction in price depends on the required hurdle rate. Although private firms may require higher hurdle rates in order to undertake projects, for comparison the return on equity that state regulators currently guarantee varies from 9.45 to 12.0% [36]. Using this range as the hurdle rate, storage lowers the carbon price from ~\$45/ton to ~\$35/ton CO_2. At a lower hurdle rate of 10%, 12 hours of syngas storage lowers the required carbon price by \$14/ton CO_2, from \$47 to \$36/ton.

2.5 Additional considerations for application in a real world scenario

Implementing syngas storage efficiently and cost-effectively in an operating real-world IGCC facility requires detailed engineering analysis that is beyond the scope of this paper.

Additional engineering issues that a facility developed should address for successful syngas storage operation include:

1) Humidification and reheating of stored syngas and the implications on thermal plant efficiency.
2) Integration and optimization of potential future hot/warm syngas cleaning technologies where the syngas is maintained at a high enough temperature to keep it humid (greater than 500°F).
3) Stability of syngas for long term storage (longer than diurnal) and investigation of potential deposits on the storage vessel.
4) Potential effects of short term operating periods for the gas turbine. In the analysis the IGCC plant gasifier operates continuously, but the gas are both operated with potentially several short operating periods each day – as short as 1 hour in the report example. Although gas turbines are commonly used for peaking applications, (the size-weighted average capacity factor for the 884 operating gas turbines in eGRID 2004 was 0.29) such transient gas turbine operation may lead to increased plant maintenance. Data on thermal cycling limits for turbines was not available. The design of a facility using syngas storage should consider the specific turbine manufacturer's cycling limits during the design process. For syngas storage times that the analysis shows is most economically favorable (8 and 12 hours) short cycling is less of a concern. For 12 hours of storage, peak hours are generally during the day, and the turbine is operated continuously over this period.
5) The degree of integration between the air separation unit and the gas turbines and the implications for NOx control in the peaking turbine. In a fully integrated IGCC facility, nitrogen from the plant air separation unit is used as a dilutant to control NOx emissions. In the configuration used in the present analysis this method of NOx control would not be feasible. A site specific engineering solution would be needed for a real world application.

To estimate the range of costs for NOx control for the peaking turbine three options are considered: 1) a second air separation unit is constructed and operated solely for the purpose of supplying nitrogen as a dilutant to the peaking turbine; 2) NOx emissions are uncontrolled from the peaking turbine and emission allowances are purchased; and 3) steam is injected to lower the flame temperature in the second turbine and reduce NOx emissions.

For the additional ASU scenario, a second air separation train is added to the facility and operated to provide nitrogen to the second peaking turbine. The produced oxygen is not used or sold, rather it is vented to the atmosphere. This approach is considered to be an extreme worst case design scenario; it is likely that a fully engineering design analysis would lead to a more efficient and less wasteful design. Adding another train of equal size to the ASU to accommodate the second turbine adds $96.5 million in capital costs, $2.1 million per year in fixed operating costs and consumes, or reduces the net output of the facility by, 30.59 MW [15].The return on investment is shown in Figure 2.11.

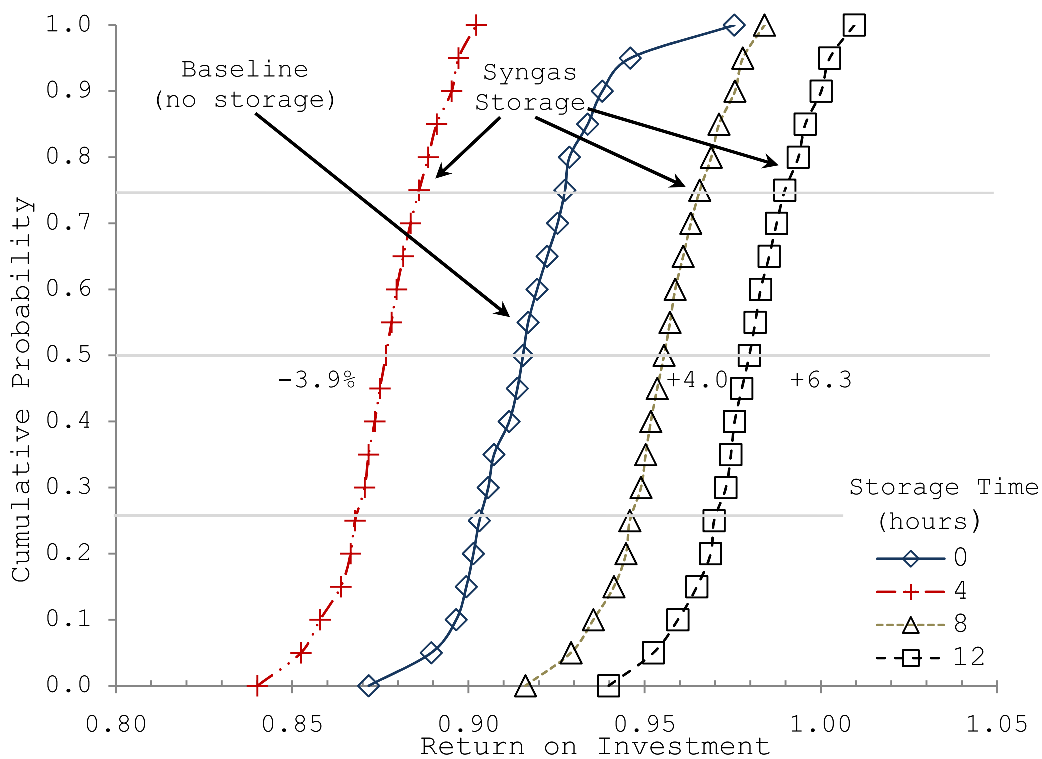

Figure 2.11 Syngas storage scenario (1+0) with 2 trains of air separation unit for NOx control

The additional gains in ROI from adding syngas storage are reduced by the addition of a second ASU train for NOx control. However, despite the additional cost, adding 8 and 12 hours of syngas storage increases the median ROI over the no storage scenario by 4.1% and 6.5%, respectively.

A second way to bound the costs of NOx control is to simply leave the peaking turbine uncontrolled and pay for NOx emission allowances. Uncontrolled NOx emissions from a GE 7FA turbine are 8 lbs/MWh [36]. The US EPA reports the cost of (vintage 2008) NOx permits at about $2,500 per ton [37]. The purchase of NOx emissions for the peaking turbine would cost about $2,600 per hour of peaking turbine run time. The resulting ROI is shown in Figure 2.12.

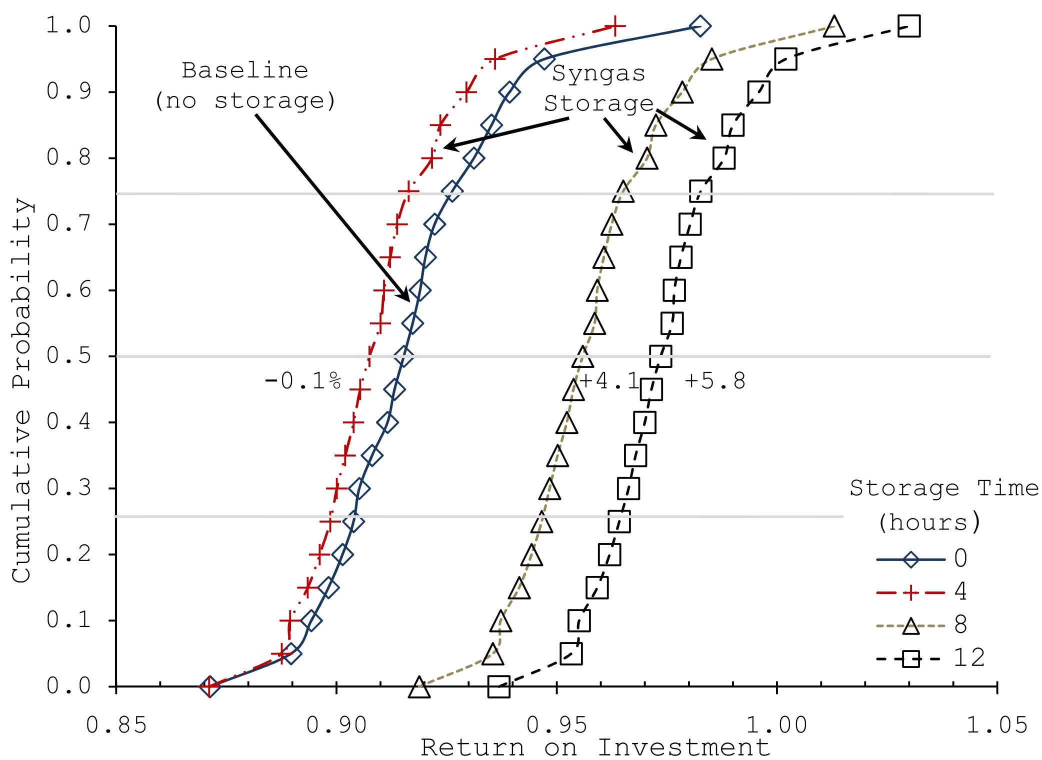

Figure 2.12 Syngas storage scenario (1+0) with the purchase of NOx allowances for the peaking turbine

The additional gains in ROI from adding syngas storage are reduced when NOx emissions allowances are purchased. However, despite the additional cost, adding 8 and 12 hours of syngas storage increases the median ROI over the no storage scenario by 8.8% and 12.9%, respectively.

A third method of bounding the costs of NOx control was to consider the losses associated with steam injection into the gas turbine. Directing a portion of the steam into the gas turbine results in a lower thermal efficiency; values in the literature suggest that this reduction will be approximately 5% [38, 39] when the second turbine is run. The affect of these thermal losses is to lower the output of the facility. The ROI for 4, 8 and 12 hours with the steam injection energy penalty was 0.93, 0.99 and 1.03, respectively. Despite the reduced output, adding 8 and 12 hours of syngas storage increases the median ROI over the no storage scenario by 8% and 11%, respectively.

With any of these high cost and non elegant NOx control options, the overall result of the analysis is unchanged: adding syngas storage increases the ROI substantially over IGCC without storage.

2.6 Discussion

Producing peak electricity from diurnally stored syngas in gas turbines, while operating the gasifier at a constant output, increases firm-level profits for an IGCC facility despite the additional capital cost. Storage decouples the operation of the gasifier from the turbine and allows the facility to produce electricity when it is most valuable. Storing syngas in gas spheres at a pressure of 60 bar would add 25% to the land area of the IGCC plant modeled. Other configurations, optimized storage parameters, lower fuel costs through long term contracts or more sophisticated financing arrangements may further increase profitability. Syngas storage can lower the CO_2 price at which IGCC enters the generation mix by approximately \$10/ton, speeding deployment. As noted in Appendix A, detailed engineering integration of aspects of the system such as NOx control can change the amount that ROI is increased and the decrease in carbon price at which IGCC becomes profitable, but storage adds significant value even at worst-case values for such aspects. Note that, as for construction of any peaking plant, each additional plant using this method would lower peak electricity prices, lowering the incentive for building additional plants. However, the ability of even a small fraction of generators to employ syngas storage to increase profitability is likely to lead to earlier deployment of commercial IGCC at significant scale.

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Chapter 3: Implications of generator siting for CO_2 pipeline infrastructure[2]

The location of a new electric power generation system with carbon capture and sequestration (CCS) affects the profitability of the facility and determines the amount of infrastructure required to connect the plant to the larger world. Using a probabilistic analysis, this chapter examines where a profit maximizing power producer would locate a new generator with carbon capture in relation to a fuel source, electric load, and CO_2 sequestration site. Based on models of costs for transmission lines, CO_2 pipelines, and fuel transportation, the analysis finds that it is preferable to locate a CCS power facility nearest the electric load, reducing the losses and costs of bulk electricity transmission. This result suggests that a power system with significant amounts of CCS will require a large CO_2 pipeline infrastructure.

3.1 Introduction

There is increasing interest in building new coal to energy facilities, such as integrated gasification combined cycle (IGCC) electric power plants, in the United States [1-6]. Many facility developers prefer coal fueled power plants since coal is an abundant domestic source of energy which can provide a level of energy independence and security, and the use of coal provides a partial hedge against the volatility of other fuel prices such as natural gas price shocks and seasonal variations [7]. Additionally, new coal gasification facilities have environmental advantages over traditional combustion facilities [8-10]; one of the largest advantages is the ability to capture carbon dioxide [11]. Post-combustion capture of carbon dioxide is also being considered, both for coal [12] and for natural gas electric generators. Increasing environmental pressures and the likelihood of a price on carbon dioxide emissions in the near future [13-15] has led project developers to announce that some future plants will be constructed with the ability to

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[2] Significant portions of this chapter appear in Newcomer, A.; Apt, J., Implications of generator siting for CO_2 pipeline infrastructure. *Energy Policy* **2008**, *36*, (5), 1776-1787.

capture and sequester carbon dioxide emissions (CCS) [16]. The captured CO_2 from these facilities can be piped either to an oil field where it is sold for enhanced oil recovery (EOR) or to a sequestration (sometimes called storage) site.

As with other high cost and long lived investments, project economics and financing considerations play a large role in the development of a power plant [7]. Several of these proposed new coal based energy facilities are being developed by private firms and will operate in states with restructured electricity markets where there is no guarantee of cost recovery and profitability is a key concern [7]. Site selection is a factor that can play a large role in firm-level profitability, as there are losses and costs associated with transporting the necessary fuel to the power plant and with delivering the produced electricity to the load. Considerable effort is spent in the facility siting process [7], and it is necessary to find a location where the costs of supplying fuel and delivering the output product are minimized, in an effort to increase profitability. *Ceteris paribus,* new power facilities are located where the sum of transportation costs for inputs and outputs are minimized and where firm-level profits maximized. For new plants constructed with CCS, in addition to fuel delivery and electricity transmission costs, the costs of carbon disposal, transporting the CO_2 to the sequestration site, will factor in to the overall profitability and must be considered in the siting process. When siting a coal based energy project, the project facility developer must determine the profit maximizing location in relation to the customer, fuel source and CO_2 sequestration site. Figure 3.1 illustrates the location of coal mines, major Midwest ISO nodes, and existing CO_2 pipelines and enhances oil recovery fields in the US.

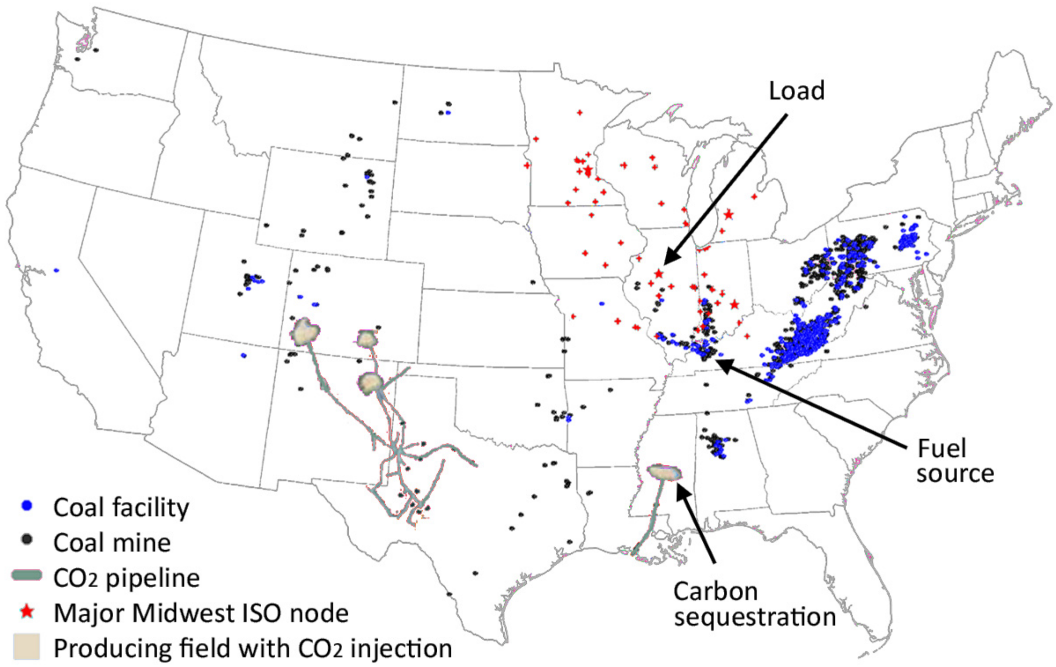


Figure 3.1 Location of coal mines, major nodes in the Midwest ISO and existing CO_2 pipelines for enhanced oil recovery. Examples of a potential load, fuel source and CO_2 sequestration site are highlighted. [21, 37, 41]

The facility location problem has important infrastructure implications (in the US, at both state and federal levels) [17]. If new clean coal generation technologies are widely deployed, capacity additions to or new investment in railways, electric transmission lines and carbon dioxide pipelines will be required. The type and magnitude of the infrastructure requirements depend largely on the firm-level economics and location decisions. For instance, if transmission of electricity is a dominant cost, then new power plants will be located near the load to minimize delivery costs, requiring additional investments in both transport for fuel delivery and in longer CO_2 pipelines. However, if transporting CO_2 is a dominant cost, then new plants will locate near the sequestration site, requiring more transmission investments.

Here, the analysis examines the location problem for a coal based energy facility from a firm-level perspective to provide guidance for increasing profitability and thereby reducing investment risks, as well as to inform state and national policies for subsequent infrastructure requirements, should CCS be widely adopted by industry.

A model for determining the profit maximizing facility location is developed for a coal based electric generator. The model allows the determination of the most important factors when siting a coal fueled facility, given cost distributions for delivering fuel, transmitting the produced electricity to the load, and piping the CO_2 to the EOR or sequestration site.

3.2 Method

The location of a coal fueled facility producing electricity with carbon capture and sequestration is considered. A probabilistic analysis is performed to determine how the facility's annual profit is affected by the distances to the coal source, to the load where energy is delivered and to the carbon disposal site. In this technical and economic analysis of optimal facility location, the economics of the base facility itself are not considered, only the sensitivity of the profits to the location. Here it is assumed that a power producer has made a decision to construct a facility in a general location, such as the US Midwest, based on such factors as their own financing arrangements, internal hurdle rates, and expectations of profitability, and that they wish to site the facility in a location that will minimize transportation costs and maximize profits. There may be other factors that play roles in the siting process – such as availability of suitable land, state permitting requirements, and the availability of labor – but because these are very dependent on the specific project, they are not considered here. The availability of cooling water and barge transport will likely influence most projects to site on rivers, but because rivers abound in the US Midwest, the analysis is not constrained to place the plant on a river. Similarly, the terrain will likely influence the construction costs for CO_2 pipelines and electricity transmission lines, however, the terrain considered here is broadly similar throughout the locus of this study. The vast majority of US coal-fired generation is located in the area between the Appalachian and Rocky Mountains where these two factors do not present serious limitations to the validity of the conclusions.

The engineering and economic details are modeled on the baseline IGCC facility from the Integrated Environmental Control Model (IECM) version 5.2.1 [18], a standard tool that provides the flexibility to analyze a wide range of IGCC facility sizes and configurations. The IECM model used for the baseline IGCC facility examined here uses the GE gasification process, Illinois #6 coal with a HHV of 25.35 MJ/kg (10,900 Btu/lb), GE 7FA combined cycle gas turbines, sour shift plus Selexol CO_2 capture process, and can scale in size from 240 to 1,200 net MW (additional details are in the Appendix B). For any given facility size, IECM provides the hourly fuel requirement, hourly net electricity production, and hourly CO_2 output of the IGCC facility.

Here, a probabilistic engineering and economic model is constructed for delivering the coal to the baseline facility, transmitting the produced electricity to the load, and piping the captured CO_2 either to the sequestration site for storage or to an oil field for EOR. This model is applied to a hypothetical facility located in the US Midwest and uses regionally appropriate probabilistic values for parameters (historical and forecasted costs for Illinois #6 coal; actual 2006 electricity prices for various nodes in the Midwest ISO; and a range of historical prices for CO_2, representing sale for EOR, as well as costs for CO_2, representing disposal and sequestration costs) to determine the profit maximizing location for the facility relative to load, fuel source and CO_2 sequestration sites (see Table 3.1).

Given the locations of the fuel source, load and CO_2 sequestration site relative to the facility, as well as the appropriate costs for plant inputs and prices for outputs, the model calculates the most profitable location for siting the IGCC facility, and the subsequent infrastructure requirements are determined.

3.2.1 Carbon dioxide transport

The transport of carbon dioxide to an EOR or CO_2 sequestration site by pipeline is modeled. CO_2 is transported in a supercritical fluid state to maximize piping efficiency [19]. Operating pressures at the end of the pipe remain above 10.3 MPa to ensure that the CO_2 does not fall below the supercritical state, potentially damaging equipment [19, 20]. Variables affecting pipeline pressure include the injection pressure, booster compressors and diameter of the pipeline. The model assumes fixed-sized injection and booster compressors. The CO_2 pipeline diameters are sized according to the operating parameters of the facility such as the pressure drop, density, mass flow rate, frictional losses, etc., such that the CO_2 remains supercritical throughout the transport step [21].

Additional pumping stations may be required to boost the pressure along the pipeline to compensate for pressure losses depending on the pipeline length. Although the need for a booster station is site specific, a range of 161 to 402 kilometers (100 to 250 miles) is used between booster stations, reflecting the operation of currently operating CO_2 pipelines [21, 22]. The model includes booster stations when the length of the pipeline exceeds the distance at which a booster station is needed. In practice, a booster station's pump would be sized to accommodate the exact mass flow and length of the pipeline segment, however here the pump size is not optimized; rather it is overestimated and a booster of a fixed pump size is assumed. The model uses capital cost estimates for booster pumping stations from the International Energy Agency [23] adjusted to 2005 dollars [24]. Operating costs for booster stations include the electricity needed to run the booster.

Capital costs for pipelines include costs for materials (such as pipe, pipe coating, cathodic protection, and booster stations as necessary), right of way, labor and miscellaneous design costs (such as, project management, regulatory filings, and contingencies allowances) [21]. Pipeline costs generally vary based on the length and diameter of the pipeline as well as the quantity of CO_2 to be transported. The required pipeline diameter is a function of the mass flow rate of the CO_2 flowing through the pipeline, therefore, pipeline costs generally vary with length and with the CO_2 flow rate. Specific pipeline costs may vary depending on the pipeline route and terrain; costs generally increase with population density, in mountainous regions, nature reserves or routes with river crossings [21].

The model uses pipeline capital costs developed from a regression analysis of IECM data [18] (IECM makes use of industrial analogies to published natural gas pipeline costs [20] and data are based on an analysis which incorporates models developed for the United States Department of Energy (DOE) by the Massachusetts Institute of Technology [19]). These capital costs include the costs of compressors to inject CO_2 into a pipeline at 13.8 MPa (2000 psia). Note the pipeline capital costs used in the IECM-based model are perhaps a bit higher than those incurred by current pipelines: McCoy [19] looks at FERC filings and finds reported pipeline capital costs to be approximately 33% lower than those used by IECM; and the most conservative IEA cost estimates (ANSI class 1500# pipe) [23] are about 12% lower than those reported by IECM.

Operating costs for pipelines include annual inspections and maintenance and are those incorporated in IECM. Note that IECM pipeline O&M costs may also be high: McCoy's [19] review of FERC filings and finds reported O&M costs to be approximately 30% lower than those used by IECM; and IPCC [21] O&M estimates are about 20% higher for a pipeline 161 kilometers (100 miles) long and roughly equal for a pipeline 322 kilometers (200 miles) long.

3.2.2 Fuel delivery

If the coal-fired generator is not located at the mine mouth, the required coal must be transported from the mine (or other purchase point, such as a mile marker on a river, as is common for some NYMEX contracts) to the facility. Primary methods of large scale and bulk coal transport are by rail and barge. The analysis assumes that there is existing capacity for additional coal shipments and no new rail or barge terminals are constructed by the plant developer.

Coal transportation rates per ton-mile in the Illinois basin (2005) average 23.8 mills for rail and 6.08 mills for barge (from FERC form 580, converted from 1996 dollars [25]). For context, in 2001 the average domestic coal shipping distance from the Illinois Basin coal field was 375 kilometers (233 miles) by rail and 1,900 kilometers (1,180 miles) by barge [26]. The average mine mouth price of coal in Illinois Basin for 2005 was $31.60/tonne [27]. Total fuel transport costs increase with distance from the fuel source; rail transport is always more expensive than barge transport, however rail transport is widely available while barge transport is available to facilities located on a suitable waterway.

3.2.3 Electricity transmission

If the generation facility is not located at the electric load, electricity must be transmitted. Here, the model assumes that the facility operator must construct the appropriate transmission infrastructure to the nearest electricity node and models the appropriate costs for a given electrical output and transmission distance (others have focused on the "brownfield" case where existing electricity infrastructure may be available for use [28]).

Long distance and bulk electricity transmission is achieved though high voltage AC or DC transmission lines to minimize resistive and other losses. Previous studies show high voltage DC (HVDC) transmission is cost effective only when transporting large quantities of power over long distances, greater than approximately 965 kilometers (600 miles) [29]. Because it is unlikely that a single facility serving the Midwest ISO would choose to locate outside a 600 mile radius, here, the model considers only AC transmission (Figure 3.2).

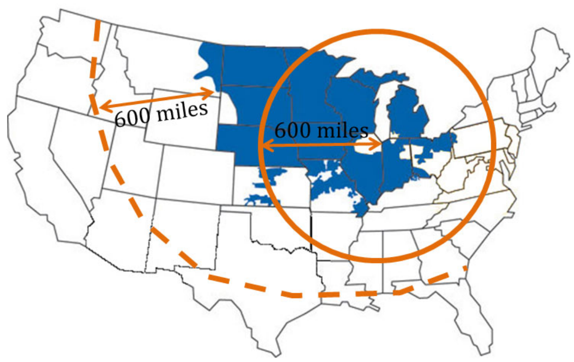


Figure 3.2 Limit of AC transmission distance considered in the analysis to any Midwest ISO node (dashed line) and to a major load center (solid line)

The cost and parameters of the transmission line such as operating voltage, line diameter and number of conductors, depend on the transmission distance and power flow across the line. Smaller amounts of power transmitted over shorter distances can use less costly transmission lines that operate at lower voltages (115-230 kV), have smaller cross sectional areas and require smaller support structures; while larger amounts of power flowing over long distances require large operating voltages (345-765 kV), wires with large cross sections and large support structures [30]. Hence, longer transportation distances require more transmission investment, incur more transmission losses, and require larger operating expenses to move the generated electricity to the load.

The model incorporates a detailed International Energy Agency engineering model of electric transmission systems [30] to determine the transmission line parameters necessary for a given transmission line distances and required power flow (see Appendix B). Transmission line losses are modeled as resistive and depend on the power transmitted, conductor resistance, line length and voltage [30] (see Table 3.1). For typical transmission parameters, the transmission losses are between 2-7%. Transmission lines are assumed to be one circuit, sized to 100% of the desired capacity (other arrangements are common to provide additional security against faults or outages; these generally more expensive arrangements are not considered here, but do not affect the conclusions of the analysis).

Electricity transmission costs include the transmission line, tower, right of way (ROW) or easement costs, substations with switchgear and transformers to step up/down voltages and labor. Transmission line installed costs (exclusive of right of way costs), as a function of the specified power flow, nominal line voltage, conductor size and line length, are from [31] (converted to 2005 dollars using [24]) and are generally consistent with transmission cost estimates in the literature [32, 33]. Right of way and site acquisition costs can "vary enormously" [30] depending on the geography, terrain and population density; ROW point estimates are 3% of installed costs however, for completeness, the model considers ROW costs up to 50% of installed costs. Operating and maintenance costs for transmission lines and substations include line inspection, vegetation clearing and ROW maintenance and are estimated as a percentage of capital costs [30] (Table 3.1).

Total substation costs include the costs of the transformers, switchgear, circuit breakers, and compensation equipment such as shunt and series capacitors, as required. Substation and compensation equipment are assumed to be in open terminals (as opposed to smaller, enclosed gas insulated substations) with one circuit breaker on each end of the line, and six circuit breakers and transformers per substation, each rated slightly higher than nominal line voltage. When transmission distances exceed 500 kilometers (310 miles), series and shunt capacitors are included to control for losses and voltage drops. The required sizes and costs of the switchgear and capacitors are from the IEA study [30], and are generally consistent with other published estimates [32].

3.2.4 Model

Given the fixed location of a fuel source, CO_2 sequestration site and electric load, the analysis seeks to find the location (that is, find the fuel transport distance, d_{fuel}, CO_2 transport distance, d_{cs}, and electricity transmission distance, d_{load}) that maximizes annual facility profits. The annual profit function for an IGCC facility (excluding capital expenses for the base facility which do not depend on the location) as a function of distance from the fuel purchase site, load and EOR site can be expressed as:

$$\text{annual profit}\,(d_{fuel}, d_{cs}, d_{load}) = \text{annual revenue} - \text{annual expenses} \qquad (1)$$

where annual revenue is the quantity of output sold in each hour at the hourly market price

$$\text{annual revenue} = \sum_{j} \sum_{i=1}^{8760} Q_{ij} \cdot P_{ij} \qquad ; j = \text{electricity, } CO_2 \qquad (2)$$

and where annual expenses are the annualized capital costs and sum of hourly operating costs for the coal, electricity and CO_2 transport infrastructures

$$\begin{aligned} \text{annual expenses} &= \sum_{j} \text{annual expenses}_j \qquad ; j = \text{fuel, electricity, } CO_2 \\ &= \sum_{j} \left((\text{TCC}_j \cdot A \cdot D) + \sum_{i=1}^{8760} OC_{ij} \right) \end{aligned} \qquad (3)$$

Details of the engineering and economic variables in equations 1-3 including descriptions and values considered in the analysis are listed in Table 3.1 (additional details are included in Appendix B).

Table 3.1 Facility location model parameters

Variable	Description	Values used in analysis	Source
S	facility size index (IECM multiplier)	1–3	[18]
F_{avail}	facility availability (%)	80	
k_f	single train (baseline) coal requirement (tons/hr)	127.6	[18]
k_{elec}	single GE 7FA turbine (baseline) net output (MW/hr)	240	[18]
k_{CO2}	single train CO_2 (baseline) output flowrate (tons/hr)	254.2	[18]
ε	net plant efficiency, HHV (%)	29.21	[18]
A	amortization factor	$i/(1-(1+i)^{-n})$	[34]
D	debt fraction	1	
i	interest rate (%)	8	
n	debt term (years)	30	
CO_2 transport			
d_{cs}	distance to the CO_2 sequestration site (miles)	range (0-600)	
d_{boost}	distance at which booster station is needed (miles)	range (100-200)	[21]
$\mathrm{TCC}_{\mathrm{pipeline}}$	pipeline capital cost ($M)	$0.6212 \cdot d_{CS} + 0.0059 \cdot Q_{\mathrm{CO2\ gen}}$	[18]
$\mathrm{OC}_{\mathrm{pipeline}}$	pipeline O&M cost ($M/yr)	$0.005 \cdot d_{CS}$	[18]
$\mathrm{TCC}_{\mathrm{booster}}$	booster capital cost ($M)	$9.775 \cdot \dot{W} + 0.575$	[23, 24]
$\mathrm{OC}_{\mathrm{booster}}$	booster O&M cost ($M/yr)	$\dot{W} \cdot COE \cdot t$	
$Q_{\mathrm{CO2\ gen}}$	total CO_2 generated (tons/hr)	$F_{avail} \cdot k_{CO2i} \cdot S$	
$\dot{W}$	booster pump power (MW)	range (0.5 – 3)	[35]
COE	cost of electricity for pump ($/MW)	normal (μ=40, σ^2=5)	
t	pump runtime (hr/yr)	$8760 \cdot F_{avail}$	
$Loss_{CO2}$	CO_2 losses during transport (%)	triangle (1.0, 1.5, 2.0)	[36]
annual revenue$_{CO2i}$	CO_2 revenue	$\sum_{i=1}^{8760} Q_{CO2\,gen} \cdot (1 - Loss_{CO2}) \cdot P_{CO2i}$	
annual expenses$_{CO2}$	annual expenses for CO_2 transport	$(\mathrm{TCC}_{CO2} \cdot A \cdot D) + \sum_{i=1}^{8760} \mathrm{OC}_{CO2i}$	
TCC_{CO2}	CO_2 transport total capital cost	$\mathrm{TCC}_{\mathrm{pipeline}} + (n_{boost} \cdot \mathrm{TCC}_{\mathrm{booster}})$	
n_{boost}	number of required CO_2 booster stations	$\left\lfloor \frac{d_{cs}}{d_{boost}} \right\rfloor$	
$\mathrm{OC}_{\mathrm{CO2}i}$	hourly CO_2 transport cost	$\mathrm{OC}_{\mathrm{pipeline}i} + (n_{boost} \cdot \mathrm{OC}_{\mathrm{booster}i})$	

P_{CO2}	price of CO_2 sold for EOR (\$/ton)	triangle (15, 18, 20)	[18]
Fuel delivery			
d_{fuel}	distance to fuel purchase site (miles)	range (0 – 600)	
TCC_f	coal transport capital cost (\$M)	0	
Q_f	total coal required (tons/hr)	$F_{avail} \cdot k_f \cdot S$	
P_f	coal purchase price at mine mouth	29.67	[27]
$T_{f\,rail}$	coal rail transport cost (mill/ton-mile)	23.81	[25]
$T_{f\,barge}$	coal barge transport cost (mill/ton-mile)	6.08	[25]
$Loss_f$	coal losses during transport (%)	0	
annual $expenses_{fuel}$	annual fuel expenses	$8760 \cdot Q_f(1 + Loss_f) \times \left(P_f + d_f\left(T_{f\,rail} + T_{f\,barge}\right)\right)$	
Electricity transmission			
d_{load}	distance to electric load or ISO hub (miles)	range (0 – 600)	
$Loss_{elec}$	electricity transmission losses (%)	$(Q_{elec\,gen} \cdot \sigma \cdot d_{load})/V^2$	[23]
TCC_{line}	total transmission line capital cost (\$M)	$TCC_{line\ only}$ + ROW	
$TCC_{line\ only}$	transmission line capital cost (\$000/mile)	219 – 1,446	[30]
ROW	right of way costs (% $TCC_{line\ only}$)	triangle(30, 40, 50)	
OC_{line}	transmission line operating cost (% TCC_{line}/yr)	1.00	[30]
$TCC_{substation}$	substation capital cost (\$M)	TCC_{switch}+TCC_{shunth}+ TCC_{series}	
TCC_{switch}	switchgear, transformer cost (\$M)	1.01 – 5.32	[30]
TCC_{shunt}	shunt capacitor cost (\$000/Mvar)	$4E\text{-}05 \cdot Mvar^2 - 0.05 Mvar + 34.77$	[30]
TCC_{series}	series capacitor cost (\$000/Mvar)	$7E\text{-}07 \cdot Mvar^3 - 0.09 \cdot Mvar + 90$	[30]
Mvar	transmission reactive power requirement (Mvar)	0 - 1,111	[30]
$OC_{substation}$	substation line operating cost (% $TCC_{substation}$/yr)	0.25	[30]
σ	conductor resistance (ohms/ph)	0.014 – 0.192	[30]
V	nominal transmission line voltage (kV)	115 – 750	[30]
$Q_{elec\ gen}$	total electricity generated (MW/hr)	$F_{avail} \cdot k_{elec} \cdot S$	
$P_{elec\ i}$	hourly electricity price (\$/MWh)	2006 MISO historical data	[37]
annual $expenses_{elec}$	annual electricity transmission expenses	$A \cdot D \cdot (TCC_{line} + TCC_{substation}) + OC_{line} + OC_{substation}$	
annual $revenue_{elec}$	annual electricity transmission revenue	$Q_{elec\,gen} \cdot (1 - Loss_{elec}) \sum_{i=1}^{8760} P_{elec\,i}$	

Using the model, the profit maximizing location for facility location are determined, given the locations of a fuel source, electric load or ISO hub, and CO_2 sequestration site.

3.3 Results

To estimate the effects of facility location on profit, the analysis considers an example where the fuel source, load, and CO_2 sequestration site are situated on an equilateral triangle with a length of 322 kilometers (200 miles) (Figure 3.3).

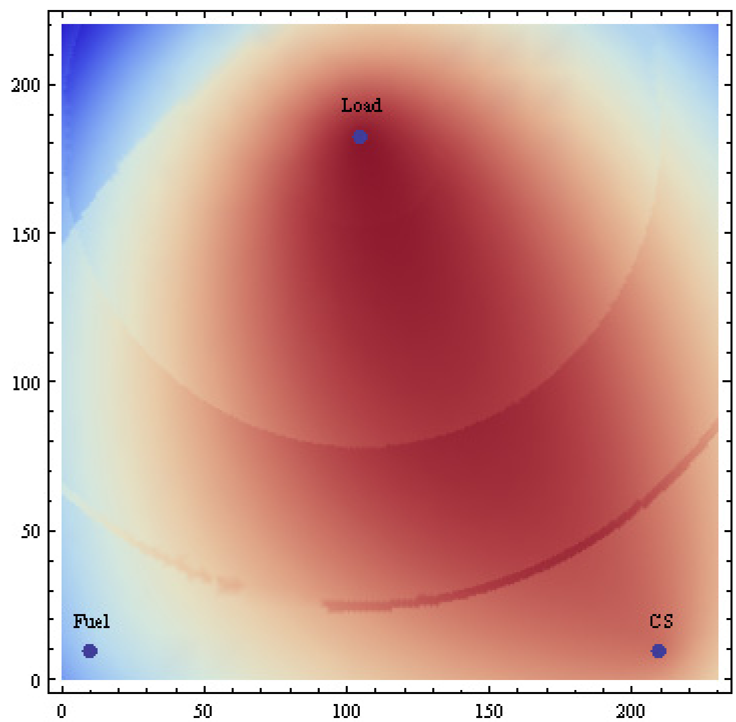


Figure 3.3 Example facility siting results. Profit as a function of location (in miles). Higher profits indicated by red in color reproductions or darker in black and white reproductions. 240 MW facility selling electricity into MISO AEBN node; Rail transport; Favail=0.8; i=0.08; n=30; D=1; PCO2=18; LossCO2=0.015; Lossfuel=0; Tfrail=23.81; ROW=0.4; dboost=250; Wdot=1; COE=40

Figure 3.3 is a density plot showing the profit that would be realized by locating the facility at every location in the map (higher profits are indicated by darker red). For the assumed facility parameters, the profit maximizing location for the facility is at the load. In this example, if the facility can not be located at the load, the profit maximizing locations are along the line from the load to the CO_2 sequestration site. This is reasonable since building transmission lines and CO_2 pipelines are more expensive than moving fuel by rail. Figure 3.4 shows the cross section of the profit along the load–carbon sequestration line.

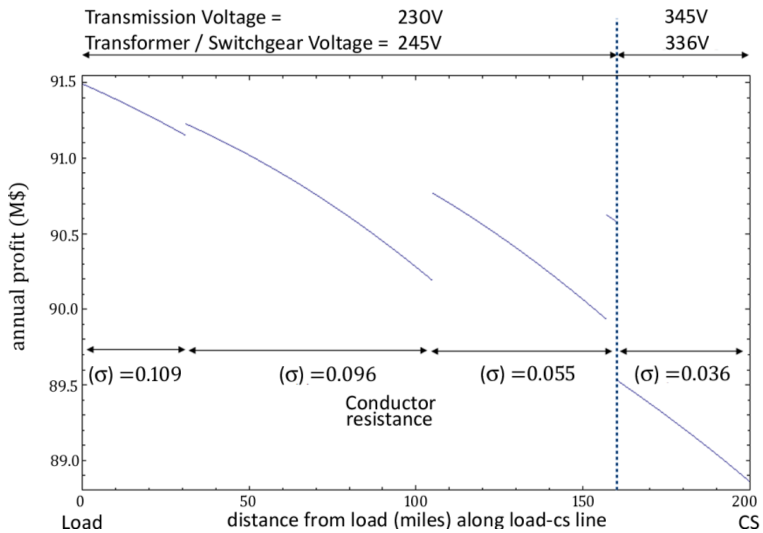
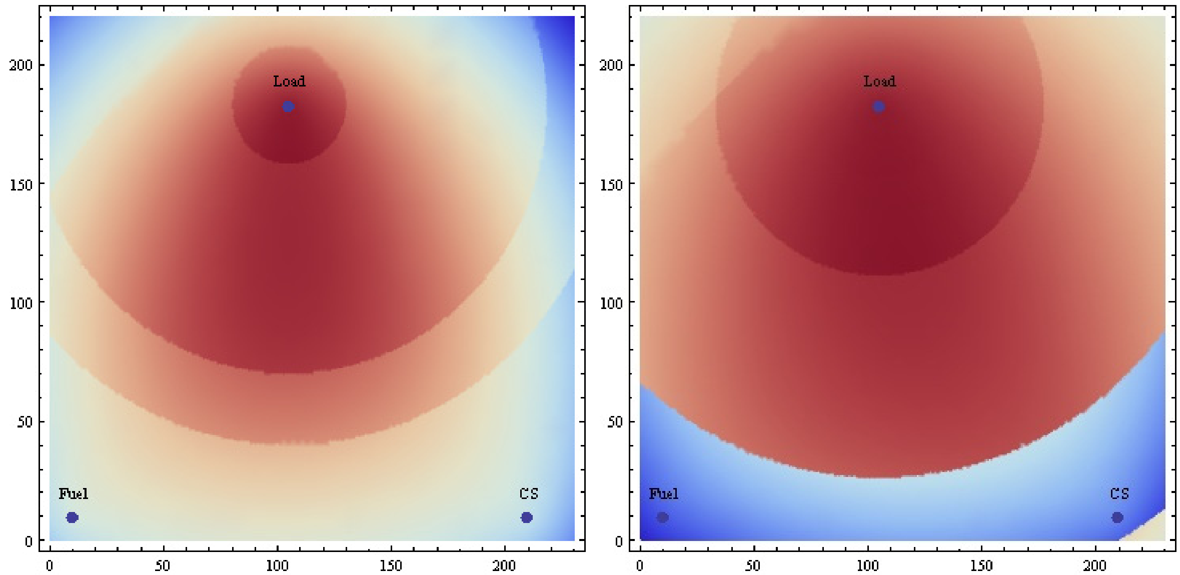


Figure 3.4 Cross section of profit along the load-carbon sequestration line. The load is at the left side and the CO_2 sequestration site is at the right. Profit jumps occur primarily as a result of changes in transmission line conductor size and line voltages.

In general, as the transmission line distance increases, the profits decrease because of the high cost of electrical transmission. There are jumps in the profitability as larger lines with smaller resistances can be used. At a distance of about 260 kilometers (160 miles), the transmission voltage (and subsequently, the transformer and switchgear voltages) must be stepped up to transmit electricity effectively, and profits decrease significantly.

The analysis examines the sensitivity of the results to the distance between the sites as well as to the size of the facility. At larger distances between the fuel, CO_2 sequestration site and load, similar results are achieved. Figure 3.5 shows the sensitivity of the facility location as a function of the size of the facility



(a) S = 2; (480 MW) (b) S = 3; (720 MW)

Figure 3.5 Facility location (in miles) as a function of facility size (net electrical output is shown in parentheses). Red indicates higher profit. Other parameter values as in Figure 3.3.

As the electrical output of the facility increases, the profit maximizing location moves closer to the load due to the large expenses of building large capacity, high voltage transmission lines.

In general, the fuel delivery costs are the least important when considering facility location, and the optimal location of the IGCC facility depends on the distance between the fuel source and CO_2 sequestration site. Figure 3.6 illustrates the optimal location as a function of the distance between the load and CO_2 sequestration site.

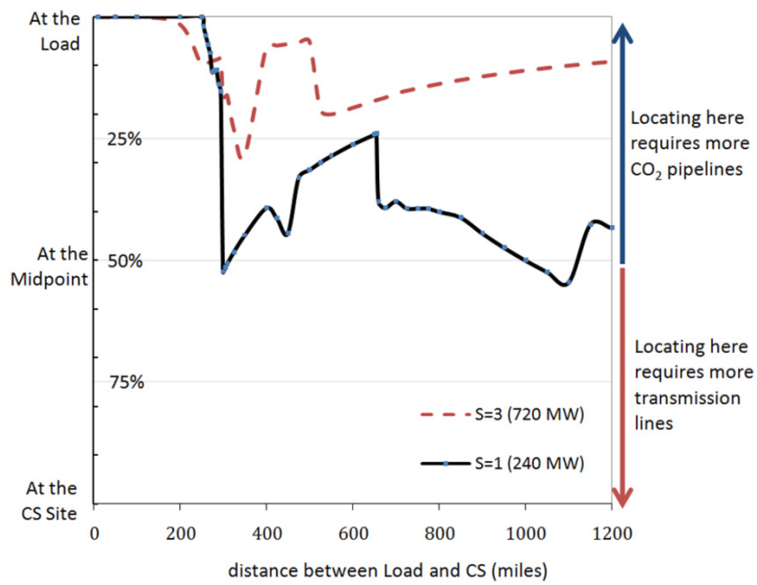


Figure 3.6 Profit maximizing facility location (% distance from the load) as a function of the distance between the load and CO_2 sequestration site. In nearly all cases, the facility should be located nearest the load. Distance to the fuel source is not considered. Parameter values as in Figure 3.3.

As the figure illustrates, in nearly all cases the generator should be located nearest the load, requiring more CO_2 pipelines than electric transmission lines. Locating near the load is even more important for larger facilities. At small distances, the generator should be located exactly at the load. At larger distances between the load and CS site, the optimal location moves away from the load, requiring both CO_2 pipelines and transmission lines.

The model is applied to a hypothetical IGCC facility located in the US Midwest. The locations of the specific fuel sources, load, and CO_2 sequestration site are indicated by the arrows in Figure 3.1. The results of the analysis using the indicated values of the parameters are shown in Figure 3.7.

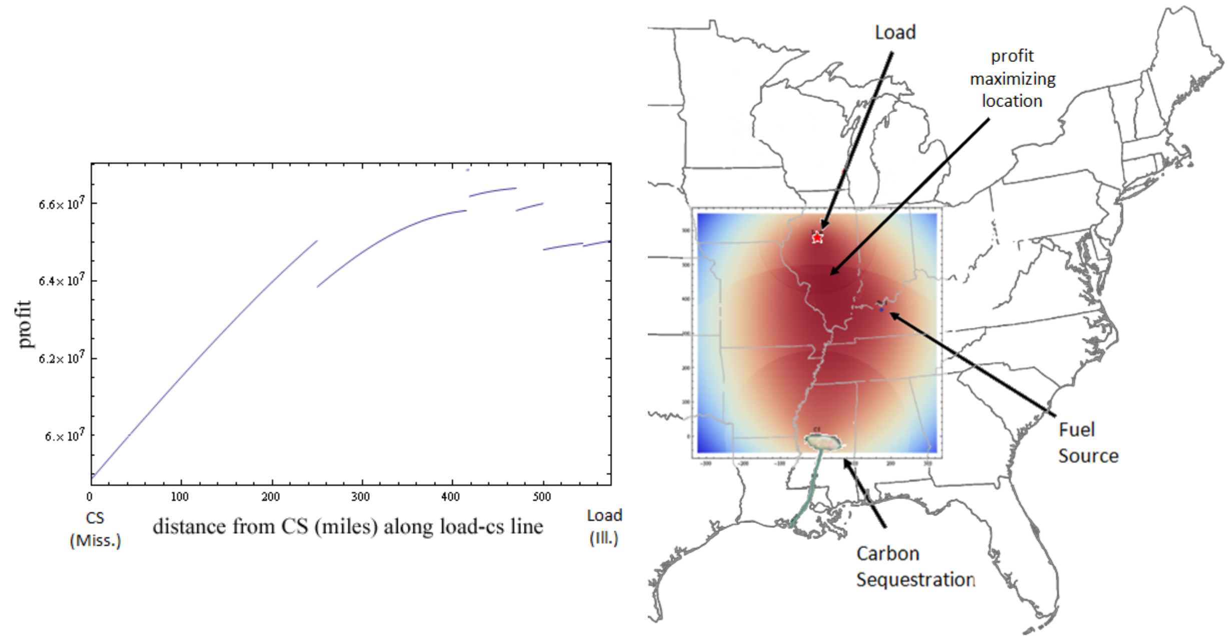


Figure 3.7 US Midwest location example. Parameters as in Figure 3.3. The profit maximizing location is about 100 miles south of the load (470 miles from CO2 sequestration site, along the CS-load line), requiring approximately 100 miles AC transmission, 475 miles of CO_2 pipeline and 200 miles of coal transport by rail.

As the figure illustrates, the profit maximizing location in this example is approximately 100 miles south of the load, along the load to CO_2 sequestration site line. This facility location requires approximately 100 miles of AC transmission, 475 miles of CO_2 pipelines and 200 miles of coal transport by rail.

3.4 Discussion

The optimal location for a generator with carbon capture is dominated primarily by the costs of electricity transmission. The cost of piping CO_2 is not negligible, but is much less than the transmission cost. The distance to the fuel source for a coal-fired plant has almost no effect on the facility location (even under the most expensive assumptions) as rail transport is extremely efficient and low cost relative to electricity and CO_2 transport.

For all but the smallest sized facilities, it is always more cost effective to locate the generator near the load. This is because losses from transmission are greater than for CO_2 and because transmission lines are more expensive to construct. These results are relatively insensitive to the prices assumed for coal, CO_2 and electricity. Even with a negative price for CO_2 (the facility must pay to dispose of the CO_2, rather than sell it for EOR as an additional revenue stream), the most cost effective location for generator with carbon capture is near the load.

This result has important implications for future infrastructure requirements if carbon capture and sequestration is widely adopted. Here, the analysis shows that new facilities (especially those proposed by private developers in deregulated markets) may not be located near CO_2 sequestration sites, as has been suggested [38, 39], because it is not cost effective. Building a new generator with carbon capture near the load is cost effective as transmission losses and costs are minimized; additionally, other studies have shown that adding new transmission lines can have unintended consequences and lead to additional congestion [40], making the case for locating near the load stronger.

The present analysis suggests that, given no serious siting constraints on any of the facilities, a profit maximizing entity will elect to site an electric generation plant with carbon capture much closer to load than to geologic sequestration sites. Plausible capture rates (~80%) of the carbon dioxide from fossil fuels used for electric power production in the U.S. today would produce a CO_2 stream of approximately 1,800 million tonnes (Mt) per year injected into a variety of geological formations. Today there is a modest network of pipelines in the US that carry 45 Mt of CO_2 per year for use in secondary oil recovery. The CO_2 pipeline infrastructure required for effective control of carbon dioxide emissions is likely to be at least an order of magnitude larger than the existing network of CO_2 pipelines, and could be of the same scale as the existing natural gas pipeline infrastructure.[3]

[3] While the total mass of CO_2 is four times larger than the mass of current natural gas transport (455 Mt in the US), that does not mean that the pipeline infrastructure will be four times larger, since at operational conditions, a CO_2 pipeline caries about three times more mass per unit length of pipeline than does a natural gas pipeline.

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Chapter 4: Short Run Effects of a Price on Carbon Dioxide Emissions from U.S. Electric Generators[4]

The price of delivered electricity will rise if generators have to pay for carbon dioxide emissions through an implicit or explicit mechanism. There are two main effects that a substantial price on CO_2 emissions would have in the short run (before the generation fleet changes significantly). First, consumers would react to increased price by buying less, described by their price elasticity of demand. Second, a price on CO_2 emissions would change the order in which existing generators are economically dispatched, depending on their carbon dioxide emissions and marginal fuel prices. Both the price increase and dispatch changes depend on the mix of generation technologies and fuels in the region available for dispatch, although the consumer response to higher prices is the dominant effect. The analysis estimates that the instantaneous imposition of a price of \$35 per metric ton on CO_2 emissions would lead to a 10% reduction in CO_2 emissions in PJM and MISO at a price elasticity of -0.1. Reductions in ERCOT would be about one-third as large. Thus, a price on CO_2 emissions that has been shown in earlier work to stimulate investment in new generation technology also provides significant CO_2 reductions before new technology is deployed at large scale.

4.1 Introduction

Recent judicial [1, 2], political [3-5] and industrial [6-11] actions suggest that there may soon be either an explicit or implicit price on carbon dioxide (CO_2) emissions in the United States. Because 72% of the electricity generated in the U.S. comes from carbon intensive fossil fuels (50% from coal) [12] a price on carbon emissions will increase the cost of generating electricity. Previous studies [13-20] have examined the effects of the price of emitted CO_2 on firm-level decisions about what type of generation to build, and on whether to retrofit or replace an existing plant. These studies have generally found

[4] Significant portions of this chapter appear in Newcomer, A.; Blumsack, S. A.; Apt, J.; Lave, L. B.; Morgan, M. G., Short Run Effects of a Price on Carbon Dioxide Emissions from U.S. Electric Generators. *Environ. Sci. Technol.* **2008,** *42*, (9), 3139-3144.

that costs of between $35 and $50 per metric ton of CO_2 will be required to induce private firms to invest in low carbon technologies such as coal with carbon capture and sequestration.

Here, the analysis considers the short run effects of imposing such prices on the CO_2 emissions of the existing fleet of generation plants. That is, the analysis considers the effects on electricity price and demand before any new or replacement capacity can be built. The replacement time for U.S. generation plants has been very long (the median size-weighted age of the in-service coal generation units is 35 years; 75% of the capacity is at least 27 years old and 25% is at least 42 years old [21]). While replacement rates would likely increase with carbon controls, clearly short run marginal carbon emission reductions are an important policy metric.

With a carbon price, electric generation units powered by fossil fuels will have increased marginal costs. In the short run (before changes in the mix of available generation could be brought online), demand for electricity could be met at the lowest cost by redispatching existing generation assets according to their marginal costs, including the costs of their carbon emissions, taking into account transmission constraints. The resulting change in electricity price due to a price on carbon depends on the portfolio of generation facilities available for dispatch and on the demand for electricity. Regions with significant amounts of low carbon generation, such as nuclear, hydroelectricity, or natural gas, would see smaller increases in generation costs, while areas that are predominantly supplied by coal generation facilities would see larger increases in short run electricity prices.

The analysis examines the effects of a carbon price on electricity demand in three U.S. Independent System Operator (ISO) or Regional Transmission Organization (RTO) regions. The imposition of a carbon price in the Midwest ISO, ERCOT (Texas) and PJM is simulated, and the resulting change in carbon dioxide emissions in each area is calculated. Appendix C includes a discussion of the generation portfolio for each ISO included in the analysis. The analysis quantifies the effect of a carbon price on load by first redispatching existing generators in these control areas under a range of carbon prices to determine the electricity price increase due to a carbon price, and then by analyzing a range of consumers' price elasticity of demand in response to the increase in electricity price.

A price for carbon emissions can change the demand for each fuel, since it can affect the order of dispatch of the generators. The analysis finds that a carbon dioxide price of $50 per tonne or less has a small effect on the dispatch order between coal and natural gas generators (heat rate, rather than fuel, has the largest dispatch order effect). Some low-carbon plants (for example, biomass) are dispatched before fossil plants at high carbon prices, but they do not account for much capacity. The main short run effect of the price increase is to lower the demand for electricity. In the long run, consumers may respond to higher electricity prices by adjusting their stock of goods that are powered by electricity (for example, they may purchase more energy-efficient appliances); in the short run they can only curtail use. Spees and Lave [22] report a "typical" short-run price elasticity of demand approximately equal to -0.1, while the long-run elasticity is thought to be around -1. Note that this analysis is confined to the short run, where the capital stock held by consumers is assumed not to change as a result of electricity price increases, and the reader is referred to the extensive literature on long-run capital investment e.g. [13-18, 22-26]. The analysis is a partial equilibrium analysis in that the prices for various generation fuels are held constant, however the effects of fuel prices on the results is examined.

4.2 Method

Because marginal costs for generators are not public information, the model uses estimates of marginal costs [27-29] as well as heat rates and fuel types from the U.S. EPA eGRID database [21] and regionally appropriate assumptions for fuel prices [30] to calculate the short run marginal cost for each existing generator in each region (Appendix C contains details on the costs used for each ISO).

Demand for electric energy in each control area is met by economic dispatch within transmission constraints, with the lowest cost generation used to meet the demand. The analysis focuses only on the demand for electric energy; the model does not consider the variety of ancillary services (e.g. reactive power, voltage/frequency regulation) that generators provide. Figure 2.1 is an estimate of the short run marginal cost curve used for economic dispatch for the Midwest ISO in the absence of transmission constraints.

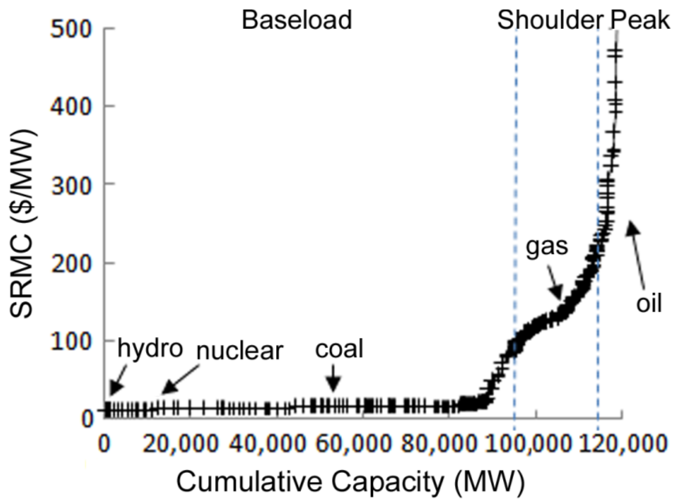


Figure 4.1 Midwest ISO short run marginal cost curve. Each tick mark represents an additional plant being brought on line to meet growing load as one moves to the right in the curve. The fuel types are indicative, but some high heat rate coal plants may have higher costs than some efficient gas plants, for example.

Because there are transmission, distribution, and other costs, consumers see electricity prices that are higher than the economic dispatch-based wholesale price. The model assumes that consumers see prices that reflect the increased cost of generating the electricity. The price varies by customer class due to different markups. The average electricity price by customer class for each region in the analysis, as reported by the EIA [31], and the average markup from the short run marginal cost, or wholesale price (the difference in average retail price from the wholesale price) are shown in Table 4.1. Using these and the total electricity sales to each customer class, a weighted average markup for each control area is calculated, allowing the average retail price and short run marginal price curve to be estimated from the economic dispatch.

Table 4.1 Average electricity price and markup by customer class (2005) [31]

	PJM	ERCOT	MISO
Average price by customer class (cents/kWh)			
Wholesale	5.4	5.5	4.0
Residential	12.5	10.9	8.4
Commercial	11.8	8.9	7.7
Industrial	7.3	7.1	4.9
Markup from wholesale (cents/kWh)			
Residential	7.1	5.4	4.4
Commercial	6.4	3.3	3.6
Industrial	1.9	1.6	0.9
Electricity sales by customer class (percent)			
Residential	36	38	33
Commercial	43	33	31
Industrial	21	29	36
Weighted average markup from wholesale (cents/kWh)	5.7	3.6	2.9

ISO data estimated from EIA data reported by NERC region and state

With a price on emitted CO_2, the marginal costs of a generator will increase based on the generator's CO_2 emissions; the model assumes this cost increase is passed directly to the consumer, resulting in increased electricity prices. As before, the electricity price at any hour is set by the generator at the margin, but with a price on emitted CO_2, marginal costs depend on fuel prices and carbon prices, hence the increase in electricity price paid by consumers depends on the mix of generation technologies and fuels in the region available for dispatch to meet the load (in real time or over a year). The model uses generator heat rates and CO_2 emission factors from eGRID [21] to construct dispatch curves under a range of carbon dioxide prices. As with the short run marginal cost curve (Figure 2.1), this analysis assumes that the transmission grid has sufficient capacity that economic dispatch (incorporating CO_2 costs) does not create any bottlenecks. The dispatch curves constructed are essentially short run marginal cost curves, reflecting the price of fuel, variable operating costs and price of carbon dioxide emissions for generation in each RTO/ISO.

A significant carbon dioxide price makes minor changes to the dispatch order at moderate load (a few low heat rate gas units displace a few inefficient coal generators). Combining this effect with the demand reduction due to the price increase, the analysis finds that for PJM at a price of \$35/tonne CO_2 and an elasticity of -0.1, coal and natural gas use are reduced by 10% and 12% respectively. Details of the calculation are in Appendix C. Not included in the present partial equilibrium analysis are the effects of fuel use changes, such as fuel switching, on the price; a large differential change in prices among fuels will alter the dispatch order. The effects of natural gas price changes are estimated in the next section.

With a price on CO_2 emissions, the price of electricity will increase and consumers will respond to this price increase by lowering their purchases. The literature reports a range of price elasticities [22, 32-34], that are likely to vary among RTO/ISOs. The elasticity calculations are based on the demand model estimated in [34-36]. Specifically, the model assumes a constant elasticity aggregate demand function with the following form:

$$P(L) = \beta L^{1/\varepsilon} \tag{1}$$

$$\beta = \frac{P_0}{L_0^{1/\varepsilon}} \tag{2}$$

In equations (1) and (2), *P(L)* is the demand function, *L* is the quantity demanded in the system, and ε is the price elasticity of demand. P_0 and L_0 represent price and quantity under zero elasticity (where demand is completely unresponsive to price).

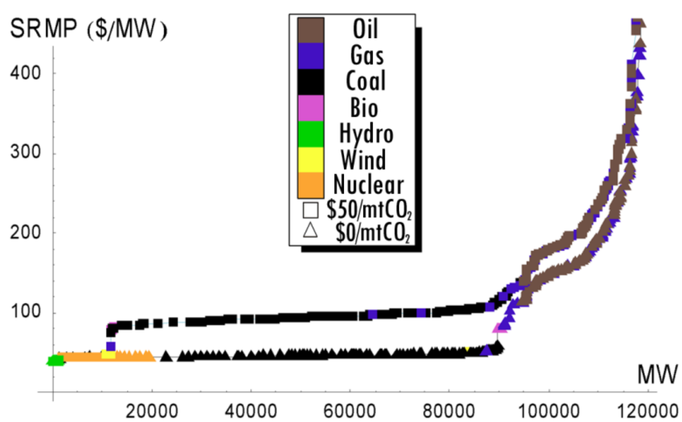
For a given CO_2 price, the percent increase in retail electricity price is calculated, for each hour of historical load and then a range of short run elasticities is used to calculate the reduced load (Appendix C discusses this methodology in detail).

The analysis examines the effects of changes in load due to a carbon price on the total annual carbon dioxide emissions from each area. Because the actual price elasticity of demand is uncertain, the analysis examines the short run change in carbon dioxide emissions in the Midwest ISO, ERCOT and PJM as a function of both the price on CO_2

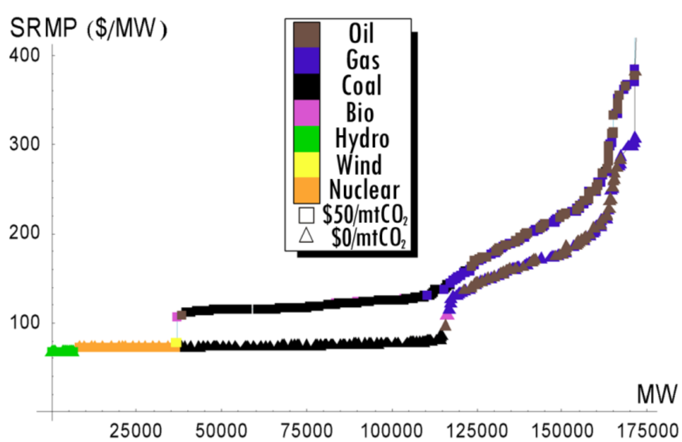
emissions and the price elasticity of demand. The model uses historical hourly load data for 2006 in each of the three areas [37-39] and dispatch existing generation to meet the hourly load using economic dispatch under a range of carbon dioxide prices. Hourly carbon dioxide emissions from each dispatched generator are summed over the year and compared to annual CO_2 emissions from generators in the absence of a carbon price. The resulting percentage change in carbon dioxide emissions is calculated for a range of CO_2 prices and elasticities of demand.

4.3 Results

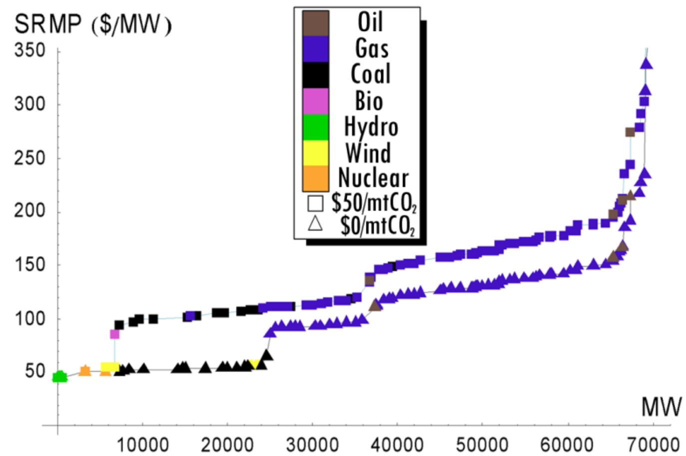
The short run retail marginal price with no price on carbon dioxide emissions and with a price of \$50 per tonne CO_2 is shown for the Midwest ISO, PJM and ERCOT in Figure 4.2.



(a) Midwest ISO



(b) PJM



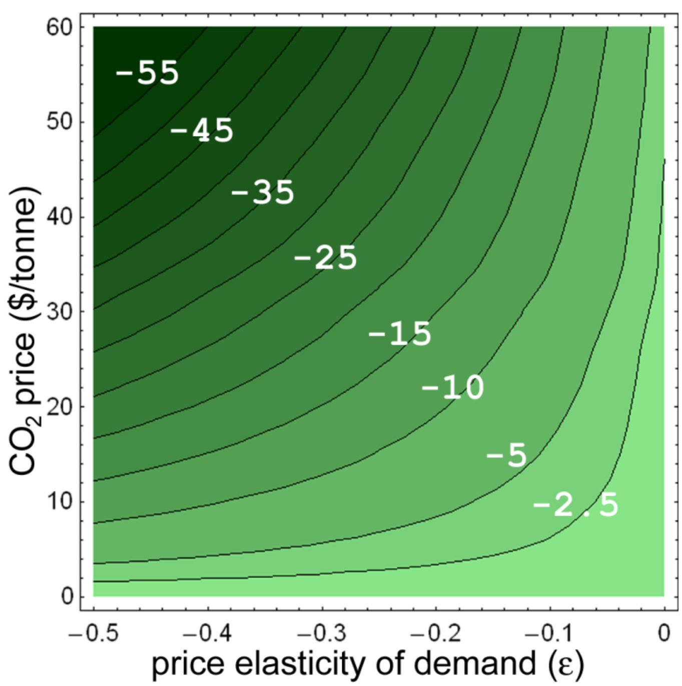
(c) ERCOT

Figure 4.2 Short run retail marginal prices versus cumulative capacity for (a) Midwest ISO (b) PJM and (c) ERCOT. All figures: $50/tonne CO_2 (top, square) and no price on carbon emissions (bottom, triangle); generator fuel type shown by color.

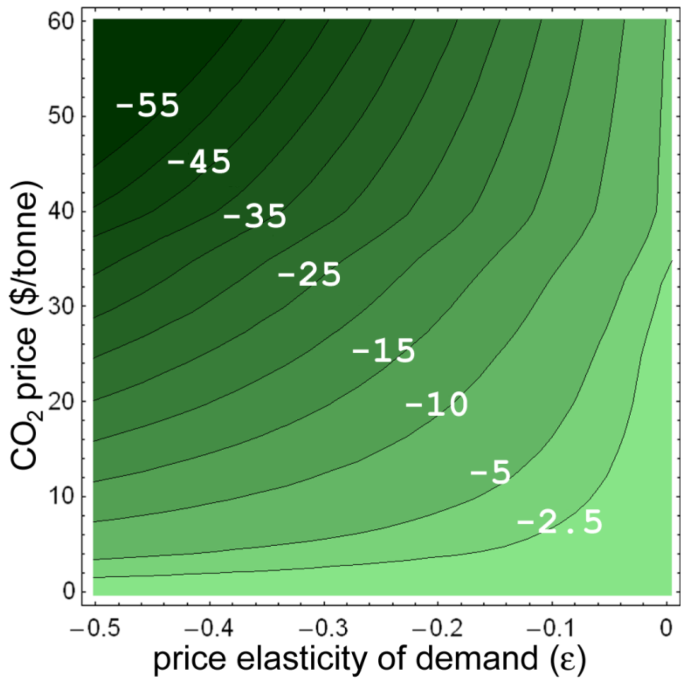
Low cost, low carbon generators (nuclear and hydro) are generally dispatched first in all regions (although for a carbon price of zero in the Midwest ISO, some coal is dispatched before nuclear (Figure 4.2a)) while generators with high heat rates and high carbon emissions (oil) are generally dispatched last. The variation in generator marginal costs within the same fuel type (most pronounced for natural gas and oil-fired units) is due to a large variation in generator efficiencies. The increase in electricity price due to a price on carbon depends on the load (Figure 4.2). At very small loads, there is no change in price since low cost, low carbon generation is dispatched first. In all regions, the largest percentage increases in price are at baseload, because there are large amounts of coal generation. At higher levels of demand (shoulder and peak) the percentage increase in price is less, since generators with lower carbon emissions (natural gas) are dispatched.

In the Midwest ISO, at an emission price for carbon dioxide of $50 per metric ton, the price of baseload electricity doubles, while the price increase at peak demand is approximately 30% (Figure 4.2). Using an elasticity of -0.1, the baseload demand decreases by about 10% and the peak load decreases by approximately 4%. In the Midwest ISO, $100/MWh is reached at a level of demand less than 20,000 MW (17% of 2006 maximum load) with a CO_2 price of $50/tonne. The generation mix in PJM contains a large fraction of coal, similar to the Midwest ISO. However PJM has a larger nuclear and natural gas base than the Midwest ISO, resulting in lower baseload generation costs when carbon emissions are priced. The price of electricity remains below \$100/MWh in the PJM system, even with a \$50/tonne price on carbon dioxide, until dispatch reaches 35,000 MW, or 24% of maximum load (Figure 4.2b). The generation mix in ERCOT is composed primarily of natural gas and inefficient coal plants with large CO_2 emissions, as reflected in Figure 2c. Prices in ERCOT are generally higher than in either PJM or the Midwest ISO. In ERCOT, \$100/MWh is reached at a level of demand less than 10,000 MW (16% of maximum load) with a CO_2 price of \$50/tonne.

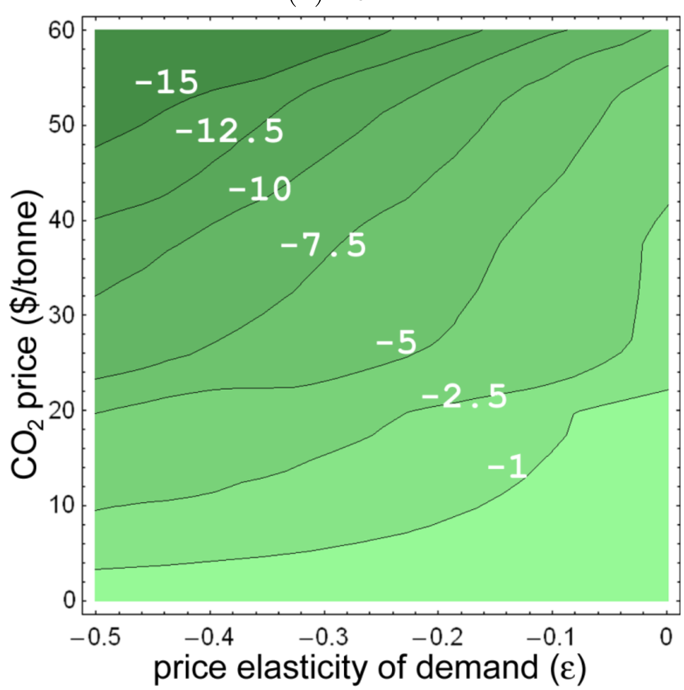
The percentage reduction in annual carbon dioxide emissions at a range of carbon prices and elasticities is shown in Figure 4.3 for the Midwest ISO, PJM and ERCOT. These are short run marginal carbon dioxide reductions, reflecting demand reduction in response to higher prices and redispatch of existing generation plants.



(a) Midwest ISO



(b) PJM

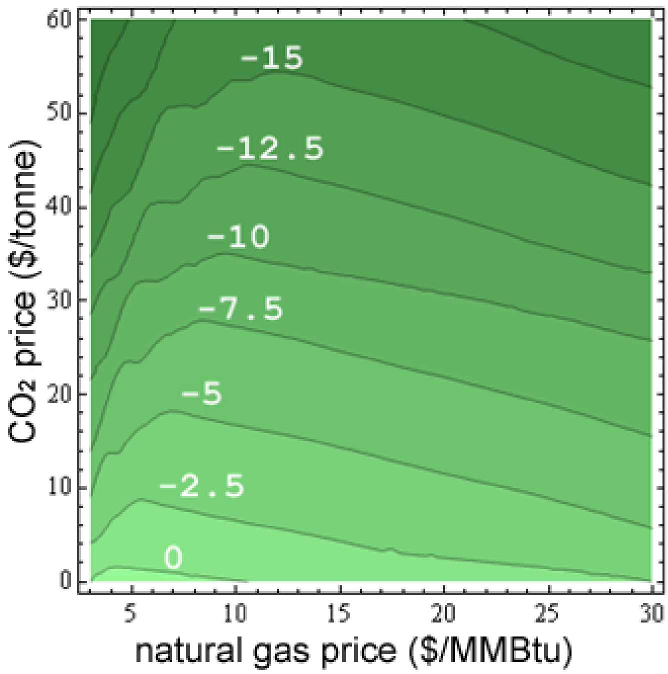


(c) ERCOT

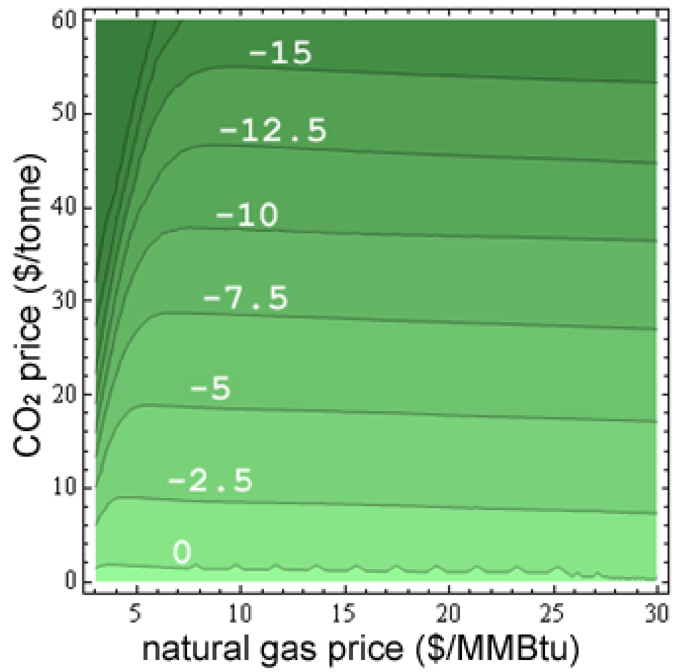
Figure 4.3 Percentage reduction in carbon dioxide emissions for ranges of CO_2 prices and elasticities in (a) Midwest ISO (b) PJM and (c) ERCOT. The contour lines are isoquants corresponding to specific percentage reductions in CO_2 emissions.

Carbon dioxide emissions reductions are almost entirely due to reduced demand rather than a change in dispatch order in the short run, although small changes in the dispatch order are reflected in the reductions seen at zero elasticity in Figure 2.3. Since the Midwest ISO (Figure 4.3a) and PJM (Figure 4.3b) have large amounts of coal generation, the reductions will be larger than in ERCOT (Figure 4.3c) which relies more heavily on natural gas generation.

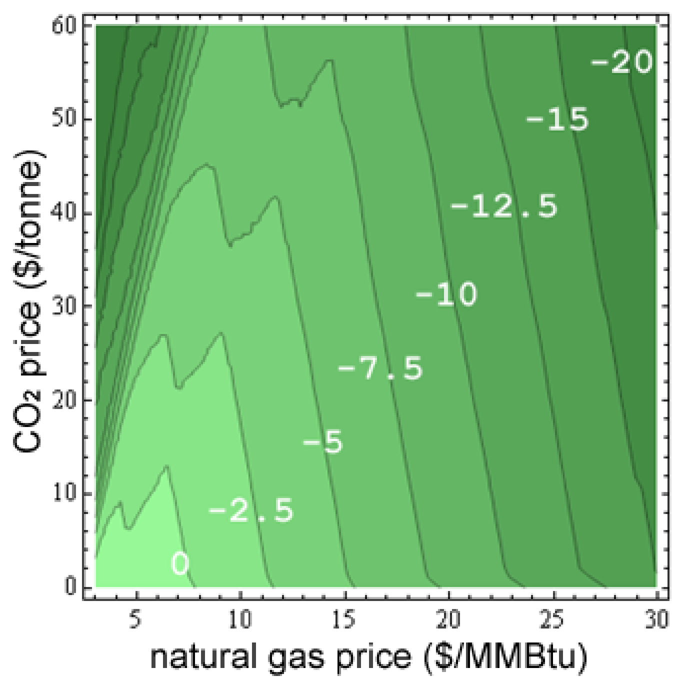
The sensitivity of the percentage of carbon dioxide emissions to the price of natural gas is shown in Figure 4.4.



(a) Midwest ISO



(b) PJM



(c) ERCOT

Figure 4.4 Percentage reduction in carbon dioxide emissions for ranges of CO_2 prices and elasticities in (a) Midwest ISO (b) PJM and (c) ERCOT. The contour lines are isoquants corresponding to specific percentage reductions in CO_2 emissions.

As Figure 4.4 illustrates, at very low natural gas prices, carbon dioxide emission reductions are large, since it is economical to dispatch low carbon natural gas units ahead of coal fired units. For any given CO_2 price, as the price of natural gas increases, the CO_2 emission reductions are smaller as it become more costly to dispatch natural gas generation (that is, the contour lines slope up). Because there are natural gas generators in each control area with very high heat rates, at some natural gas price point (~$3-5/MMBtu in MISO and PJM and ~$7-10/MMBtu in ERCOT), these units are underbid by other resources. Although the magnitude of CO_2 emissions reductions may change, the overall results of the analysis are not affected by the price of natural gas, and holding natural gas prices constant does not change the conclusions of the analysis.

4.4 Discussion

The short run change in demand that would result from instantaneously imposing a price on CO_2 emissions with no change in the mix of available generation technology, as well as the overall amount of carbon dioxide reduction, varies among ISOs, as shown in Table 4.2. Control areas with large amounts of carbon intensive generation, such as the Midwest ISO and PJM, are likely to see large CO_2 reductions even with a modest CO_2 price, since demand is reduced at high CO_2 prices.

Table 4.2 Average Carbon dioxide reductions at representative values of elasticity (ε) and CO_2 price

parameters		percent CO_2 reduction		
ε	CO_2 price ($/tonne)	MISO	ERCOT	PJM
0	20	1.1	0.2	0.9
0	35	2.0	2.1	2.5
0	50	2.7	3.4	3.9
-0.1	20	5.8	1.2	5.7
-0.1	35	10.1	3.9	10.6
-0.1	50	14.0	6.0	15.6
-0.2	20	10.4	2.3	10.5
-0.2	35	17.9	5.6	18.4
-0.2	50	24.9	8.5	27.2
-0.4	20	19.4	4.1	19.9
-0.4	35	33.0	9.0	34.2
-0.4	50	46.3	13.7	49.9

Regions with a large percentage of natural gas or other low carbon generation such as ERCOT will see relatively small short run decreases in carbon dioxide emissions even at high CO_2 prices and large elasticity. One reason is that there is generally no other lower carbon generator to dispatch ahead of the natural gas that is currently being dispatched. A second reason is that price increases are relatively modest, even with a $50/tonne CO_2 price.

The analysis has estimated the short run carbon-reduction impacts of a policy where carbon emissions from electric power plants are priced via cap-and-trade or directly taxed, and where all consumers see and respond to prices that reflect the cost of generation. As noted above, the actual imposition of a CO_2 price will likely be gradual, hopefully with a clear time-table that allows utilities and customers to make informed investment decisions. With the proper policy instruments, it may be possible to retrofit old plants as well as accelerate the introduction of new ones; here it is assumed that neither has occurred.

This analysis covers three regional transmission organizations in the US: PJM, ERCOT and the Midwest ISO. In PJM and the Midwest ISO, short-term carbon reductions of approximately 10% would occur at a $35/tonne CO_2 and a demand elasticity of -0.1. In ERCOT, only 4% CO_2 reductions would occur under the same conditions.

Thus, if it were imposed instantaneously(which, of course, it will not be), a carbon price that has been shown in other work [13-20] to stimulate investment in new generation technology (~$35/tonne CO_2) would also lead to significant CO_2 reductions via demand response and, to a lesser extent, dispatch order before any new technology was deployed.

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Chapter 5: Near term implications of a ban on new coal-fired power plants in the US

A model is developed to examine the effects on the US electric power system of banning the construction of coal-fired electricity generators, as has been recently proposed as a means to reduce US emissions. The model simulates load growth, resource planning and economic dispatch in the Midwest ISO, ERCOT and PJM under a ban on new coal generation, and use an economic dispatch model to calculate the resulting changes in dispatch order, CO_2 emissions and fuel use under three near term (until 2030) future electric power sector scenarios. Implementing such a policy is likely to lead to much greater reliance on natural gas to fuel electricity generation in the near term. A national ban on new coal-fired power plants substantially increases the fraction of time that natural gas generators set the market price of electricity, and increases demand for natural gas but does not lead to CO_2 reductions of the scale required under proposed federal legislation such as Lieberman-Warner. A ban on new coal has the potential to lead to a future electricity system where, increasingly, natural gas generators are the marginal unit of generation, placing large pressures on natural infrastructure and supplies, leading to significant exposures to natural gas markets and the risks of significantly higher electricity prices with limited CO_2 emissions reductions.

5.1 Introduction

There is growing resistance to the construction of new coal fueled electric power plants in the United States because of concerns of emissions, including CO_2 [1-9]. Recently, some new coal facilities in the US have been blocked [10, 11], and some policymakers have called for a complete moratorium on new coal facilities without the ability to safely trap and store carbon dioxide [12, 13].

The environmental objectives of these actions are meritorious, but because of the unique physical and market characteristics of the electric power sector, care must be taken to ensure that such decisions do not incur untended consequences. Because new electric generators are expensive, require long lead times to construct, and have very long operating lifetimes, capital investment decisions about new generation can have effects on the electric power sector for decades, effectively locking the US into pathways that may be difficult and expensive to move away from.

Prohibiting new coal generation would mean that new demand for electricity is met by demand reductions, increased use of existing spare generation capacity and by new non-coal generation. Currently, about 50% of electricity generated in the US is from coal-fired units with the bulk of the remainder from nuclear, natural gas and hydroelectric sources (Table 1); and, with the exception of natural gas, there is not a great deal of excess unused capacity in the portfolio of generators.

Table 5.1 US electricity generation and capacity (2004) [14].

Notes: eGRID plant file data have been used throughout this analysis. The capacity factor is calculated by dividing the generated energy by the capacity.

	billion kWh		MW		implied capacity factor
Coal	2,051.98	52.15%	380,131	36.10%	62%
Nuclear	732.02	18.60%	97,777	9.29%	85%
Gas	649.54	16.51%	384,505	36.52%	19%
Hydro	257.98	6.56%	96,004	9.12%	31%
Oil	147.31	3.74%	71,328	6.77%	24%
Bio	48.9	1.24%	9,400	0.89%	59%
Geothermal	13.63	0.35%	2,772	0.26%	56%
Wind	13.48	0.34%	5,984	0.57%	26%
Other	20.23	0.51%	5,095	0.48%	45%
Total	3,935.07		1,052,996		

Before the recent discussion of banning coal, the US Energy Information Administration anticipated that coal would play a large and increasing role in the future to generate electricity and to meet growing demand, with coal fuelling over 3,000 billion kWh, or 56%, of electricity generation in 2030 (Figure 5.1) [15].

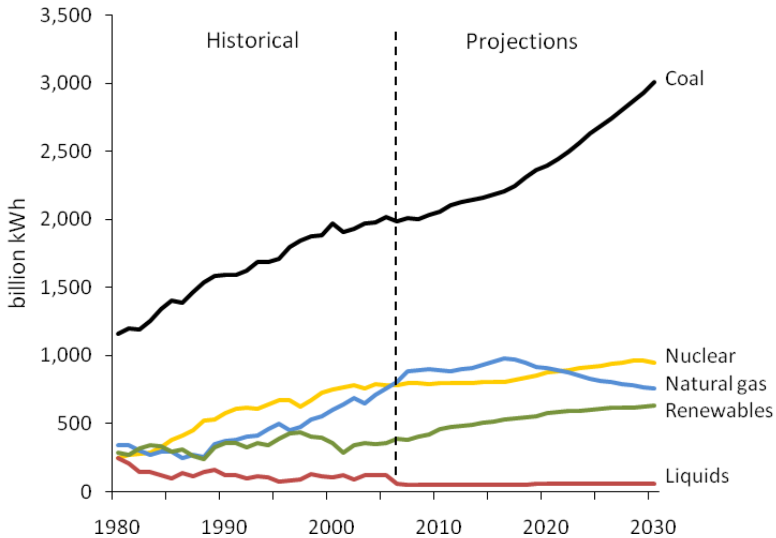


Figure 5.1. US electricity generation by fuel, 1980-2006 and EIA future scenario, 2007-2030 [15]

The effects of restricting the construction of new coal-fired generation in three US regions are examined. Load growth, resource planning and economic dispatch are simulated in the Midwest ISO, ERCOT and PJM under a ban on new coal generation, and the resulting changes in dispatch order, CO_2 emissions and fuel use are calculated under three near term (until 2030) future electric power sector scenarios. The outcomes of the models can provide broad guidance about the potential CO_2 and natural gas implications of a ban on new coal-fired electricity generation.

5.2 Future Electric Power Sector Scenarios

The future electric power scenarios examined in the analysis reflect possible alternatives to new coal generation that could be implemented in the near term to meet demand for electricity (Table 5.2) (Appendix D contains details on all scenarios).

Table 5.2. Future electric power sector scenarios investigated in the analysis

Scenario	**Description**
Business as usual (BAU)	Future coal and natural gas generation capacity is constructed to approximately match current generation percentages in each ISO/RTO
No coal. Big natural gas push (NG)	New generation is exclusively natural gas combined cycle plants (NGCC)
No coal. Big wind push (wind)	New generation is wind paired with natural gas for firm power at a ratio of 1:0.75; (*e.g.,*100 MW of new wind requires 75 MW of NG for fill in)
No coal. Aggressive demand reductions exceeding those achieved by California (DR)	Aggressive demand reductions with 0% per capita demand growth rate. New generation is wind (the model allows up to 20% penetration, but the limit is not reached in the short timeframe to 2030) and natural gas

In the business as usual (BAU) scenario, annual demand for electricity grows at historical per capita rates, and new generation capacity is added to match the current fuel mix of generators. The natural gas scenario reflects a future where there is a large push towards installing natural gas combined cycle (NGCC) generators. Note that natural gas makes up a large fraction of the permitted and progressing new generation in most regions of the US [16]. In this scenario, annual demand for electricity grows at historical per capita rates, and new generation is exclusively NGCC units. The wind scenario reflects a future where there is a large push towards renewables and wind turbines. Because of the well-known wind output power variability [17, 18] and low capacity factors (25-45% [19]), the wind scenario pairs wind with natural gas generators to create firm, dispatchable power. The model installs 3 MW of NGCC for every 4 MW of wind, even though lulls in the wind in regions such as ERCOT may require 1:1 [20]. The model dispatches wind resources with an overnight capacity factor of 0.41 and a daytime (4am-4pm) capacity factor of 0.276, reflecting that the wind blows more often at night [21]; gas is dispatched appropriately to maintain firm power.

The demand reduction scenario reflects a future where aggressive demand reductions are implemented and annual load grows at a reduced rate. This scenario uses the per capita demand reductions achieved in California as a model for potential future reductions in other US regions. California has implemented policies that have aggressively reduced per capita electricity demand growth in the state (growth of 3.4% from 1995 to 2005), as compared to the rest of the United States (growth of 7.5% from 1995-2005) [22-25]. In the demand reduction scenario, the case is examine where demand reductions are even larger than seen in California, at 0% per capita growth, using an exponential population growth of 1.55%/y in ERCOT [26]; and linear population growth rates of 4.6% and 3.4% over the period 2010-2030 in the Midwest ISO [27] and in PJM [27], respectively. New generation in this scenario is wind and natural gas (see Appendix D).

The scenarios in the analysis do not reflect predictions of the future US electric power sector, nor do they encompass all combinations of possible futures. Rather, they are meant to highlight certain issues and tradeoffs - they serve to examine the decision space and represent reasonable near term (to 2030) responses to a significant shift in policy: the prohibition of new coal generation. New nuclear generation is not included in any future scenarios up to 2030 because of the significant associated unknowns, such as the lead times required for permitting and construction, unknown capital costs and other financial risks. Other generation and load management technologies, such as solar thermal, smart grids, distributed generation, load shaping from electrical storage, and plug in hybrid vehicles, may appear on the grid before 2030, but because of the uncertainties in size and timeframes, they are not modeled here. Rather, the goal is to examine the implications of a policy in which no new coal plants of any kind are constructed, in which large increases in NGCC, wind and demand response play significant roles.

The model outputs from each scenario are compared to the business as usual scenario to quantify the implications of a ban on new coal generation: the increase in exposure to natural gas prices, as determined by the increase in hours that natural gas generation set electricity prices; the increase in the quantity of natural gas needed for electric generation; and the increase in CO_2 emissions. Rather, the analysis examines the implications of a policy in which no new coal plants of any sort are built, and the electric power grid relies on natural gas, wind + natural gas, or large behavior changes that affect demand.

5.3 Model

An economic dispatch model is constructed, consistent with previous work [28] for generators in the Midwest ISO, ERCOT and PJM. Because marginal costs for generators are not public information, the model uses estimates of marginal costs [29-31] as well as heat rates, emission rates, rated capacity and fuel types from the US EPA eGRID2006 database [14] and regionally appropriate assumptions for fuel prices [32] to calculate the short run marginal cost for each existing generator in each region (Appendix D contains details on the costs used for each ISO).

Demand for electric energy in each control area is met by economic dispatch within transmission constraints, with the lowest cost generation used to meet the demand. Our analysis focuses only on electric energy; the model does not consider the variety of ancillary services (*e.g.* reactive power, voltage/frequency regulation) that generators provide. Figure 5.2 is an estimate of the short run marginal cost curve used for economic dispatch for the ERCOT region in the absence of transmission constraints.

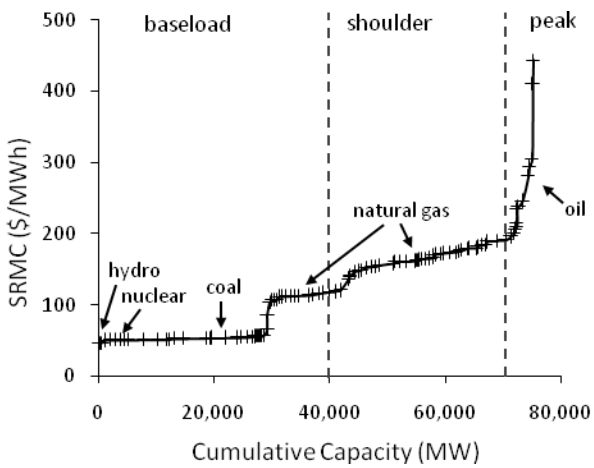


Figure 5.2 ERCOT short run marginal cost curve [14, 32]. Each tick mark represents an additional plant being brought on line to meet growing load as one moves to the right in the curve. The fuel types are indicative (some high heat rate coal plants may have higher costs than some efficient gas plants, for example).

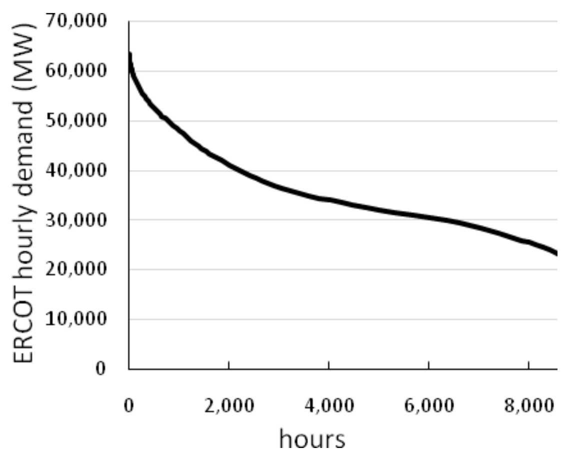


Figure 5.3 ERCOT 2006 load duration curve [33]. Actual hourly data are used in the analysis. With Fig 5.2, natural gas is generally on the margin and sets electricity prices.

Similar to other short-run dispatch models [34], the model calculates a weighted average price markup from the short run marginal cost, incorporating estimates of transmission, distribution, and other costs, which allows the average retail price and short run marginal price curve to be estimated from the economic dispatch of generators over the annual hourly load from each ISO (Figure 5.3) (additional details on the retail price calculation are included in Appendix D).

The model incorporates generator heat rates and CO_2 emission factors from eGRID [14] to construct dispatch curves for each region. The dispatch curves constructed are essentially short run marginal cost curves, reflecting the price of fuel, variable operating costs and price of carbon dioxide emissions for generation in each RTO/ISO. As with the short run marginal cost curve (Figure 5.2), it is assumed for this analysis that the transmission grid has sufficient capacity so that economic dispatch does not create any bottlenecks.

For a given level of electric demand, the economic dispatch model can be used to calculate the type and number of generators required to generate enough electricity to meet demand, and the resulting fuel use and CO_2 emissions.

The model uses historical hourly load data for 2006 in each of the three ISOs [33, 35, 36] and uses economic dispatch of existing generation to meet the hourly load. Hourly fuel usage and carbon dioxide emissions from each dispatched generator are summed over the year to determine the total annual fuel use by fuel type, total annual CO_2 emissions, and reserve margin.

Annual load growth for each region is incorporated into the model. Except for the demand response scenario where per capital demand growth is held flat, growth rates are estimated from analyses of historical load data in each region as well as from published estimates by regional planners and the ISOs [37-39]. ERCOT load growth is modeled as 2.1%/year, PJM load growth is modeled as linear growth of 12 million MWh/y (~1.5%/y), and the Midwest ISO load is modeled as linear growth of 9.9 million MWh/y (~1.4%/y) (Appendix D). The load growth rate is applied uniformly to all hours. The model calculates the annual load in each ISO for the years 2008 to 2030 using the scenario-appropriate load growth rate.

To help ensure that electricity is available under contingencies, each ISO has a reserve margin requirement mandating the excess amount of installed generation capacity that must be available given forecast peak load (12.5% in ERCOT [40], 12% in the Midwest ISO [41], and 15% in PJM [42]). If projected demand exceeds the reserve margin limit, then new generation units must be constructed to maintain the reserve margin requirement. Because the time required for constructing new generation varies, the model uses EIA estimates of construction times for new electricity generation technologies [43] and looks ahead to see if the reserve margin limit is reached in the future and if the construction of new generation should start in the current year.

If new generation within an ISO is required to meet projected future demand, units with the properties shown in Table 5.3 are constructed until the reserve margin is met; the type of generation is determined by the scenario.

Table 5.3 Cost and performance characteristics of new electricity generating technologies used in the model [43, 44]

Technology	Size (MW)	Lead time (years)	Heatrate (Btu/kWh)	CO_2 emissions (lb/MWh)
Coal	600	4	8,844	1,886
NGCC	400	3	6,717	797
Wind	50	3	-	-

There are a number of existing planned generator additions for the years 2008-2013 in the three ISOs. The model includes these queued generators into the model in the appropriate year if they currently have a signed Interconnection Agreement and hold the required air permits [45-48]. Note that some of these queued projects include new coal-fired generation, but the model assumes that these would be allowed and grandfathered under new legislation since a significant amount of money has already been spent and current ISO/RTO planning margins depend on these units.

The model does not consider any unit retirements, as history and previous studies have shown that without a significant price on CO_2 emissions, existing power plants will likely stretch out their operating lifetimes through extensive retrofits [49]. Many coal units operating in the US have been significantly upgraded and retrofitted over their lifetime increasing their operational life. Most operating coal fired generation in the US is 20-50 years old (Figure 5.4) [14].

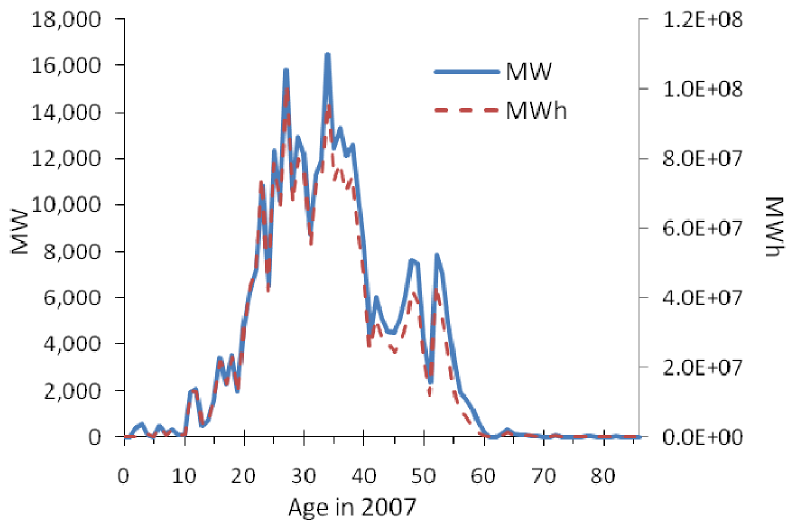


Figure 5.4 Age of US coal fired generating plants [14]

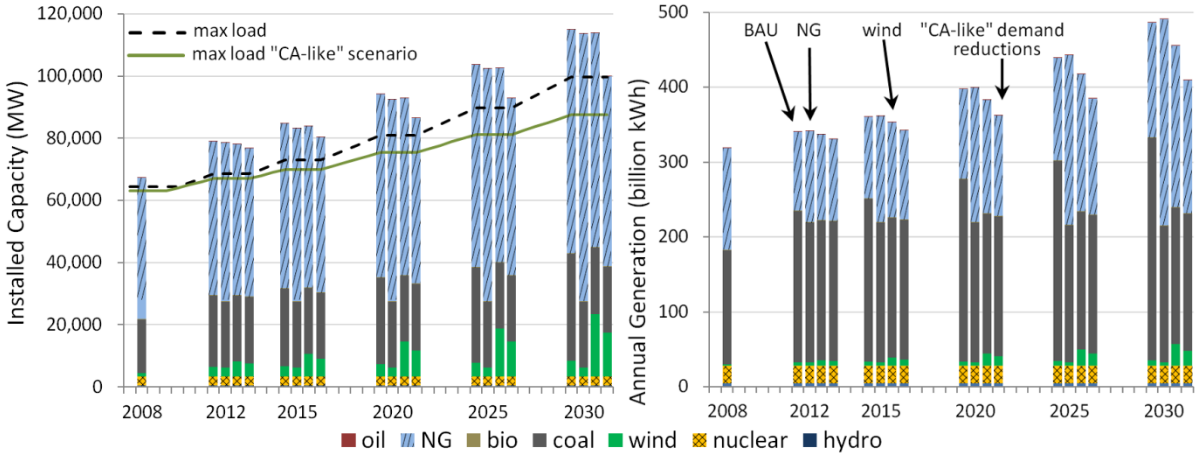
It is anticipated that if the construction of new coal generation is prohibited, this trend will continue and existing coal units will continue to be maintained and operated beyond their initial planned lifetime. Note that not including unit retirements does not change the validity of the results, if unit retirements were included in the model, the results of the conclusions would be strengthened as the existing capacity would have to be replaced by new non-coal units.

A price on carbon dioxide emissions is incorporated into the model as a linear function starting at \$10/t in 2010 and reaching \$50/t (with sensitivity analysis up to \$100/t CO_2) in calendar year 2030. If generators pay for carbon dioxide emissions through an implicit or explicit mechanism, their marginal costs of generation increases depending on their CO_2 emission performance, and the order in which units are dispatched is changed accordingly.

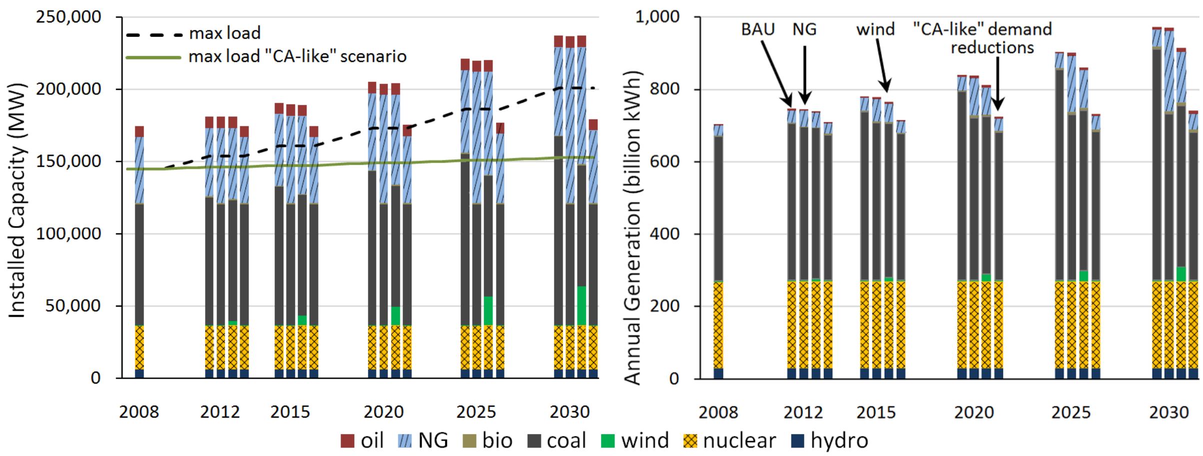
The model outputs outline the essential character of a no coal future and are consistent and comparable to other models used by industry planners when thinking about the future US electric system [50].

5.4 Results

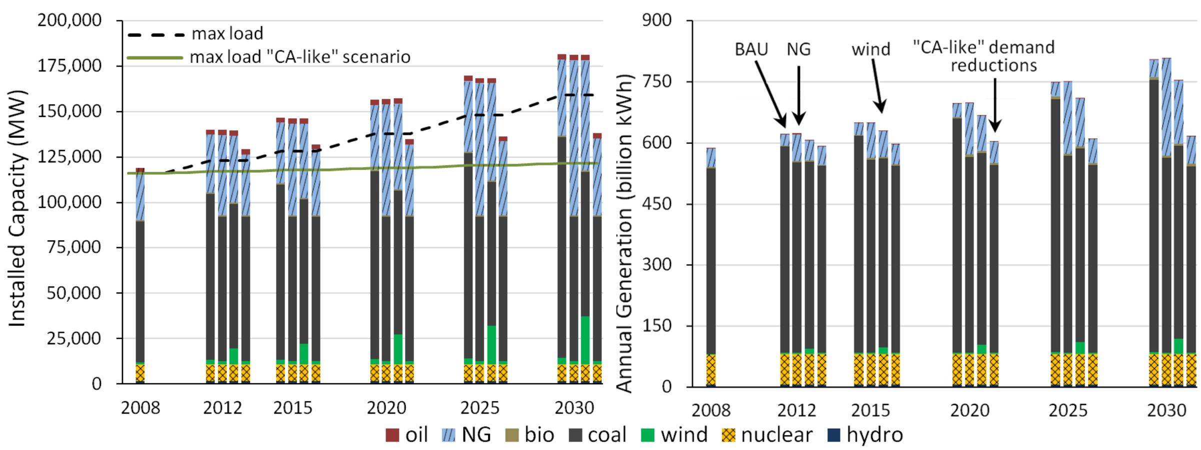
The annual maximum loads, installed capacities and generation for ERCOT under the four scenarios from 2008-2030 are illustrated in Figure 5.5.



(a) ERCOT capacity (b) ERCOT generation



(c) PJM capacity (d) PJM generation



(e) Midwest ISO capacity (f) Midwest ISO generation

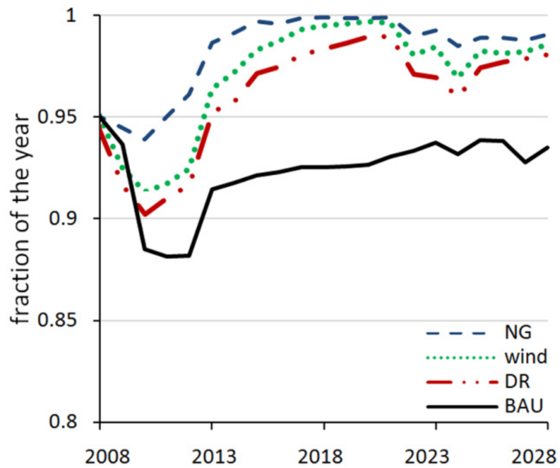
Figure 5.5 Annual installed capacity and energy by fuel type for each of the four scenarios described in the text modeled to 2030. The order of the scenarios displayed is from left to right: Business as usual (left); natural gas; wind; “California like” demand reduction (right). All scenarios in the start year, 2008, are the same as BAU and are not displayed. Coal plant capacity increases in the non-BAU scenarios are due to existing queued generation.

Load growth in each ISO drives the need for new generation to maintain the reserve requirement. Total installed generation capacity increases of approximately 70%, 52% and 36% in ERCOT, Midwest ISO and PJM, respectively, are required to meet increases in demand from 2008 to 2030 (Table 4). In the significant demand reduction scenario, where per capita load growth is flat, generation increases of approximately 48%, 16% and 3% are required to meet demand in high population growth ERCOT, modest population growth in Midwest ISO, and nearly flat population growth in PJM, respectively (Table 5.4). The fraction of coal generation increases from 2008 to 2012 because of the existing queued coal generation units; the fraction of nuclear and hydro generation decreases from 2008 to 2030 as the model constructs no units of this type in these RTOs.

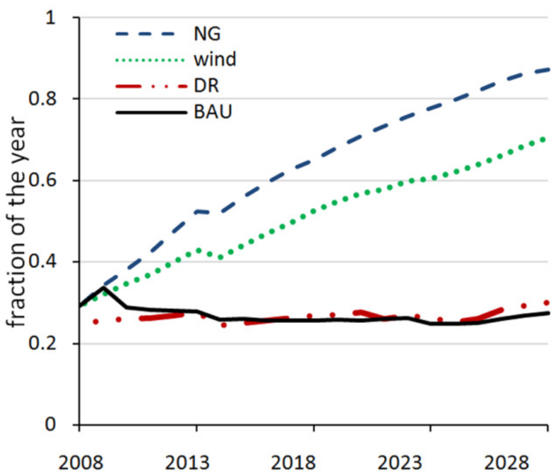
Table 5.4 Installed capacity and generation by fuel type

		ERCOT					Midwest ISO					PJM				
	year	2008	2030				2008	2030				2008	2030			
	scenario		BAU	NG	wind	DR		BAU	NG	wind	DR		BAU	NG	wind	DR
	total annual capacity (GW)	67.5	115.2	113.9	114.1	100.1	119.0	181.5	181.3	181.1	138.1	174.8	237.2	236.8	237.1	179.6
capacity by type (%)	hydro	0.8	0.4	0.5	0.5	0.5	1.1	0.7	0.7	0.7	1.0	3.5	2.6	2.6	2.6	3.5
	nuclear	4.0	2.4	2.4	2.4	2.7	7.9	5.2	5.2	5.2	7.0	17.4	12.8	12.8	12.8	16.9
	coal	25.8	30.0	18.8	18.8	21.4	65.7	67.1	44.0	44.0	58.9	48.0	55.1	35.4	35.4	46.7
	wind	1.6	4.4	2.5	17.8	14.3	0.7	2.0	1.0	14.6	1.4	0.1	0.1	0.1	11.4	0.1
	bio	0.0	0.0	0.0	0.0	0.0	0.6	0.4	0.4	0.4	0.5	0.5	0.3	0.3	0.3	0.4
	natural gas	67.7	62.8	75.8	60.6	61.1	21.5	23.1	47.1	33.5	29.1	26.0	25.8	45.4	34.2	28.0
	oil	0.0	0.0	0.0	0.0	0.0	2.4	1.6	1.6	1.6	2.1	4.5	3.3	3.3	3.3	4.4
	generation (billion kWh)	322.1	498.0	497.7	498.7	439.9	590.2	812.9	812.1	811.3	622.0	703.9	973.0	971.1	971.5	742.2
generation by type (%)	hydro	1.4	0.9	0.9	0.9	1.0	1.1	0.8	0.8	0.8	1.0	4.2	3.0	3.0	3.0	4.0
	nuclear	7.4	4.8	4.8	4.8	5.4	12.7	9.2	9.3	9.3	12.1	34.2	24.7	24.8	24.8	32.4
	coal	47.4	59.8	36.7	36.7	41.7	77.1	82.3	59.1	58.5	73.8	57.0	66.0	47.7	46.1	55.6
	wind	0.5	1.4	0.8	5.7	4.6	0.1	0.6	0.3	4.6	0.4	0.0	0.0	0.0	3.9	0.0
	bio	0.1	0.1	0.1	0.1	0.1	0.6	0.7	0.7	0.7	0.9	0.3	0.5	0.7	0.7	0.8
	natural gas	42.6	30.9	55.6	43.3	40.4	7.8	5.3	29.3	19.2	11.0	3.8	4.7	22.6	14.5	5.8
	oil	0.0	0.0	0.0	0.0	0.0	0.4	0.0	0.0	0.0	0.0	0.5	0.9	1.1	1.1	1.3

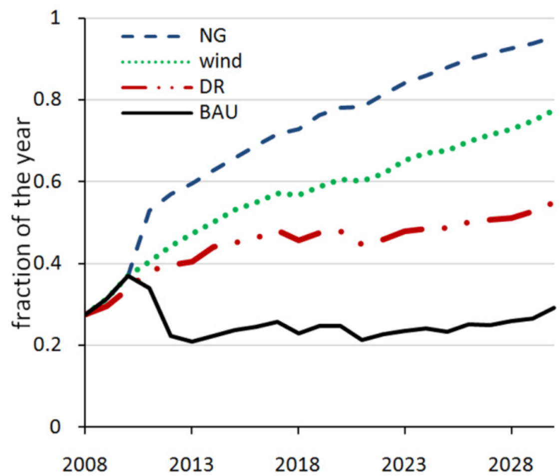
In each year, the actual MWh of electricity generation is calculated by economic dispatch of the installed generators. The model calculates the fraction of the time that natural gas generation is on the margin, setting the market clearing price of electricity in each ISO/RTOs for the scenarios (Figure 5.6)



(a) ERCOT



(b) PJM

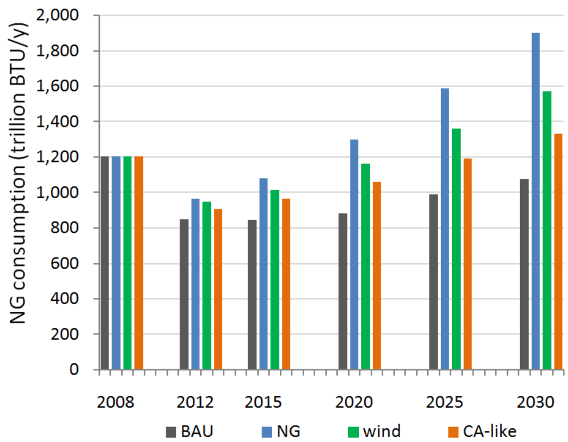


(c) Midwest ISO

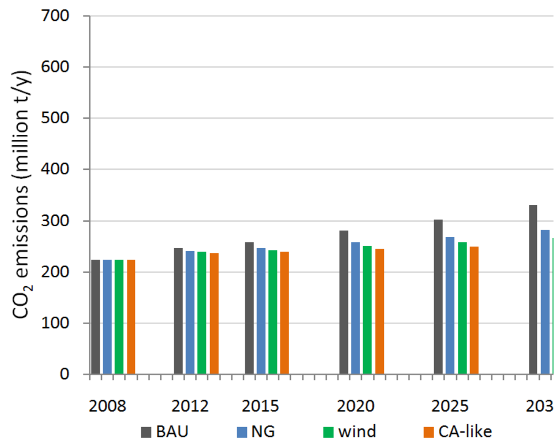
Figure 5.6 Fraction of the year that natural gas is the marginal unit of generation in (a) ERCOT, (b) PJM and (c) the Midwest ISO. In all scenarios except the significant demand reduction, moving away from the business as usual scenario substantially increases the exposure to the price/cost of natural gas. Large decreases in the BAU scenario are due to queued coal generation as well as the immediate construction of new coal generation to meet reserve requirements.

Currently, ERCOT relies on natural gas generation much more than the Midwest ISO and PJM, as illustrated by the high fraction of time that natural gas is on the margin. Under a ban on new coal generation, in all ISO/RTOs the amount of time that natural gas is the marginal unit of generation increases substantially, except the scenario with aggressive per capita demand reductions in low population growth PJM. Without aggressive demand management, banning new coal generation substantially increases the amount of time that electricity prices are set by natural gas generation, increasing the exposure to natural gas markets.

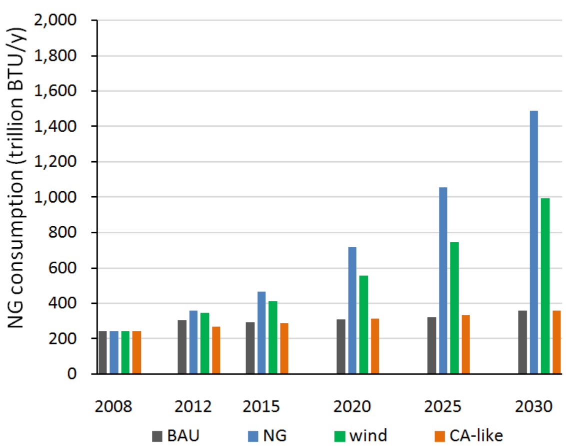
In the wind and natural gas generation scenarios examined in the model, the use of natural gas generation increases substantially over the business as usual scenario and, hence, the overall consumption of natural gas increases significantly (Figure 5.7a,c,e and Table 5.5). Greater use of natural gas has the benefit of lowering the increase of CO_2 emissions over the business as usual scenario (Figure 5.7b,d,f)



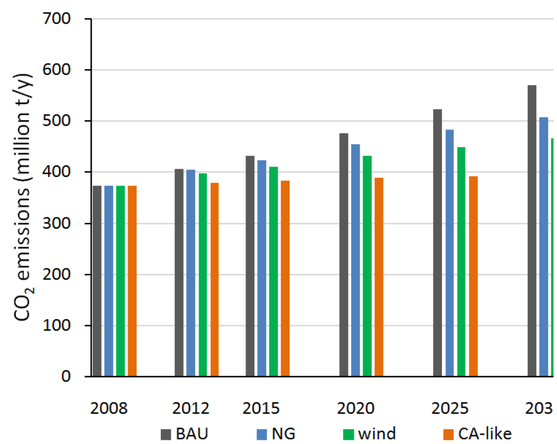
(a) ERCOT natural gas



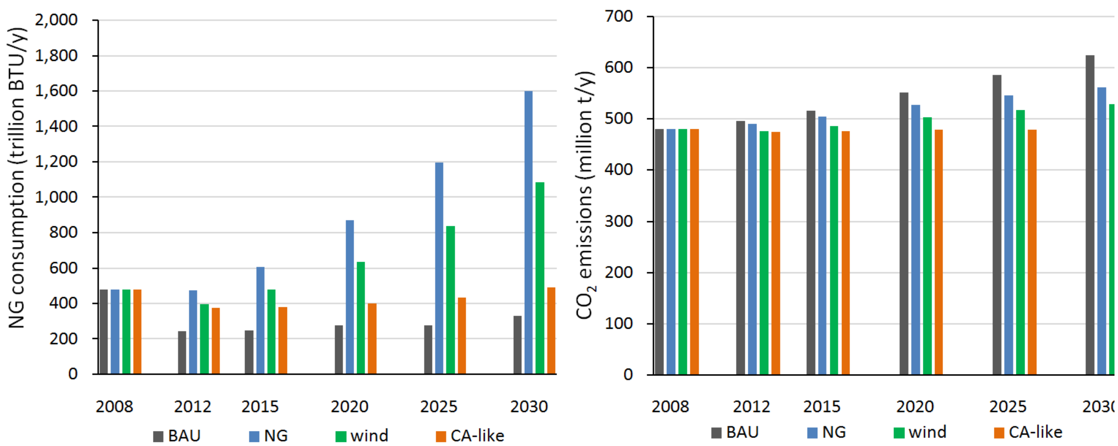
(b) ERCOT CO_2



(c) PJM natural gas



(d) PJM CO_2



(e) Midwest ISO natural gas (f) Midwest ISO CO_2

Figure 5.7 Annual natural gas consumption and CO_2 emissions by scenario. In ERCOT and Midwest ISO, natural gas use falls from 2008 levels as queued coal generation comes online in years 2008-2012, and then increases in subsequent years as NGCC units are built to meet peak loads. CO_2 emission reductions from banning coal generation are significant, but at the cost of much higher natural gas use.

In the natural gas scenario, reflecting a future where natural gas combined cycle generators are used to meet growing demand, both natural gas use and CO_2 emissions increase significantly (Table 5.5).

Table 5.5 Increase (percent) 2008-2030 in natural gas consumption and CO_2 emissions

	ERCOT			PJM			Midwest ISO		
Increase over 2008 levels (%)	load	NG use	CO_2 emissions	load	NG use	CO_2 emissions	load	NG use	CO_2 emissions
BAU scenario	58	-11	48	39	46	53	37	-31	30
NG scenario	58	58	26	39	509	36	37	235	17
wind scenario	58	31	19	39	307	25	37	128	10
demand reductions	39	11	13	6	47	5	5	3	0

A ban on new coal generation without aggressive demand reductions leads to large increases in natural gas use, particularly in PJM and the Midwest ISO, where generation is currently primarily coal based (natural gas use falls in ERCOT and the Midwest ISO under the BAU scenarios because of queued coal generation). In ERCOT, even in the most aggressive scenario (per capita demand reductions exceed those achieved in California, and wind and NGCC units are used to meet growing demand), natural gas consumption increases 11% over 2008 levels by 2030 and CO_2 emissions increase 13%

over the same timeframe. In the scenario that introduces large scale wind with current load growth, gas use in ERCOT increase by 31%, and by factors of 3 and 1.3 in PJM and MISO, respectively; CO_2 emissions are increased over 2008 levels. Actual CO_2 emissions, particularly those attributed to wind power may be even larger than modeled here, if the fill-in turbines are not optimized for partial load [51]. The sensitivity of the results to a supply elasticity for natural gas is investigated in Appendix D.

5.5 Implications and Discussion

A ban on new coal generation significantly increases the exposure of electricity prices to the natural gas markets and, although there are CO_2 emissions reductions from BAU, does not achieve the CO_2 emission reductions necessary to meet requirements in proposed federal legislation.

If new coal generation is prohibited, the amount of time that natural gas generators are the marginal unit of generation, setting the market price of electricity, increases substantially. The price risks of increased exposure to natural gas are large. Increases in natural gas demand, due to a ban on coal, would lead to higher market prices for natural gas, which in turn, would lead to increased electricity prices. The amount of this price increase depends on natural gas markets; if US natural gas supplies and infrastructure are robust enough to accommodate the large increased demand for natural gas in the future power sector, then electricity price increases could be modest. However, electricity price increases could be very large if natural gas supplies are constrained, pipeline transport capacities are limited, or if commodities speculators drive large price increases. Consumers will react to higher electricity prices by purchasing less, as described by their price elasticity of demand, which will lead to lower demand for natural gas, making the absolute increase in natural gas consumption difficult to determine, however it is clear from the analysis that overall demand for natural gas will increase if new coal-fueled generation is prohibited.

The increased use of low-carbon natural gas for electricity generation resulting from a ban on coal will lead to CO_2 reductions from the business as usual scenario, however overall CO_2 emissions increase. Proposed federal legislation call for CO_2 emissions reductions of approximately 10-35% from 2010 levels by 2030 (Figure 5.8) [52].

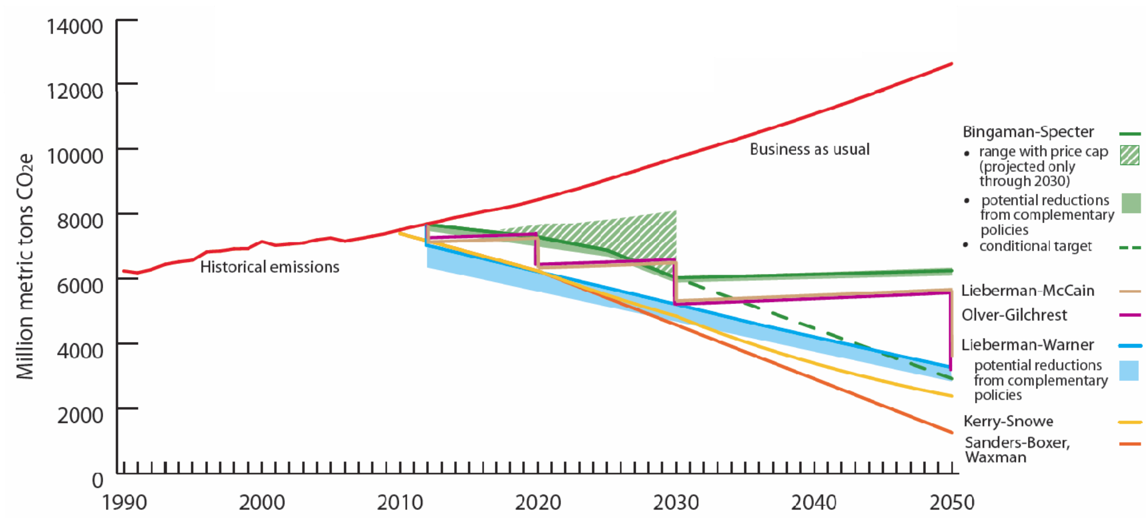


Figure 5.8 Comparison of Legislative Climate Change Targets in the 110th Congress, 1990-2050. Reproduced from World Resources Institute [52].

Even with a complete ban on coal-fired generation, CO_2 emissions from the electricity sector are likely to increase and the electricity sector's share of emissions reductions in proposed legislation could not be met.

Strong actions and smart policies are needed to appropriately and timely address CO_2 emissions from the electric power sector in order to meet proposed reduction targets. However, the outright ban on new coal-fired generation, as proposed by some, is not prudent. Enacting such a policy would significantly increase the dependence on natural gas to produce electricity, and expose utilities, and ultimately consumers, to natural gas markets and the increased risk of substantially higher electricity prices. Banning new coal has the potential to lock the future electric power system into a natural gas path that would be difficult and expensive to deviate from and could cause stress on existing natural gas infrastructure and supplies by the large increases in demand. A full portfolio of policies that result in CO_2 emissions reductions should be encouraged including low-carbon coal generation (gasification and post-combustion technologies with carbon capture and sequestration), aggressive demand reductions, and carbon portfolio standards.

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Appendix A: Notes on Chapter 2, Storing syngas lowers the carbon price for profitable coal gasification

A.1 Syngas and SNG storage

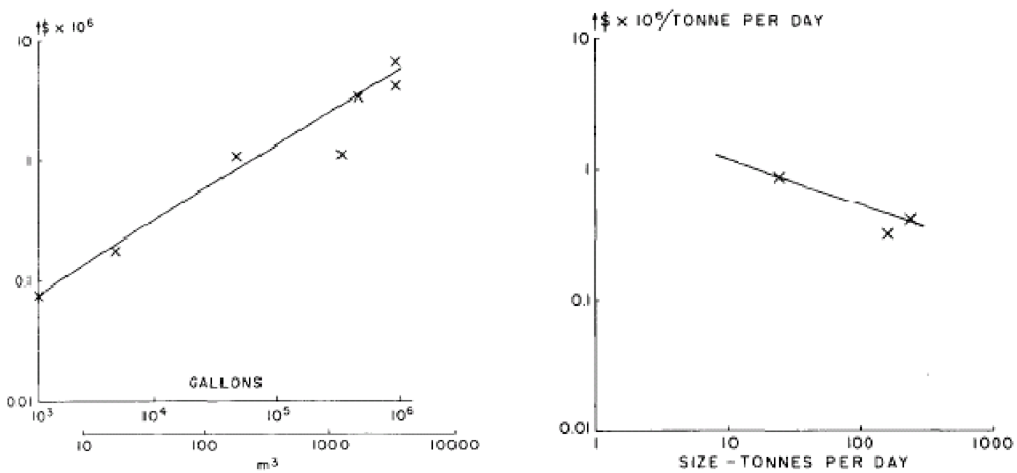
Storage options for syngas and SNG are not well reported in the literature; however, both technical and economic aspects of hydrogen and natural gas storage are addressed. From these related studies, costs for syngas and SNG storage[5] can be reasonably estimated, based on the composition and properties (pressure, temperature, etc) of the gas to be stored. Costs for syngas storage in above ground and underground ground vessels are estimated based on existing estimates for natural gas and hydrogen storage options.

Above ground options include storage in existing piping infrastructure, in gasometers or in cylindrical "bullets" common for LPG, LNG and CNG storage. Underground storage options include salt caverns and excavated rock caverns. The choice of storage vessel depends on both technical and economic considerations including the composition and quantity of the gas to be stored, the charge and discharge rates, as well as capital, operating and maintenance costs.

Options for the large scale, bulk storage of gasses include compressed gas, cryogenic liquid, solids such as metal hydrides and liquid carriers such as methanol and ammonia. Metal hydride storage is an emerging technology used for storing pure gases such as hydrogen. Liquid carriers such as methanol and ammonia are also useful for a pure gas. As syngas and SNG are gas mixtures of varying compositions, depending on the gasification process, solid and liquid carrier storage options are unlikely to be feasible and are not further considered here.

[5] As used here, a storage system includes both the storage reservoir as well as the mechanism for providing mass flow during the charging or discharging, such as a compressor.

Cryogenic liquid storage has been used for large scale hydrogen storage, with the technology largely driven by the needs of space programs. Storing liquid hydrogen presents numerous engineering challenges due to its low heat of vaporization and resultant very high loss index [1]. Because the boil-off would be too high, liquid hydrogen cannot be stored in cylindrical tanks of the type used for LNG [2]. Spherical tanks are used for large-scale applications because this shape has the lowest surface area for heat transfer per unit volume. NASA uses liquid hydrogen tanks up to 3.8×10^3 cubic meters (10^6 US gallons) which are about 22m in diameter [1]. Liquid hydrogen storage is expensive; costs include both the spherical storage tanks as well as the facility required for cooling and liquefaction. Capital costs for liquid hydrogen storage and liquefaction facilities from a 1986 study are illustrated in Figure A.1.



(a) installed liquid H_2 tank cost (b) installed H_2 liquefaction facility costs

Figure A.1 Capital cost of liquid hydrogen facilities [1]

From the above costs, liquid hydrogen storage capital charges, including a 15% ROI, are calculated to be $1,916/tonne ($2004)[6] [1] or approximately[7] $350/Nm^3. Although the above study is 20 years old and steel prices have changed and high strength steel technology has improved, the reported costs are still approximately 6 to 9 times more expensive than other storage options. In addition to high costs, there are technical

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[6] Converted $1986 Canadian to $2004 US, using reported exchange rate of $1C(1986) = $0.83US (1986) and a deflator of $1986 to $2004 = 1.505 http://www1.jsc.nasa.gov/bu2/inflateGDP.html

[7] Calculated using a liquid hydrogen density of 70.99g/l and STP density of 0.08988 g/l

concerns related to liquid syngas storage. Syngas is a gas mixture and not pure gas. The chemical components that make up syngas liquefy and react at different temperatures and pressures. As such, it is unknown what technical difficulties may arise from liquefy and cryogenically storing syngas. Additionally, syngas and SNG is typically used in gaseous form for an end-use process, such as combustion in a turbine. Compressing and liquefying the gas for storage (an energy consuming process), followed by expansion and vaporization for end use, is inefficient. Because of the high capital costs, technical uncertainties, and gas-to-liquid-to-gas conversion inefficiencies, liquid storage does not appear particularly suited to syngas storage, and is not further considered in this paper.

Compressed gas storage is the most relevant large-scale stationary storage systems for syngas production facilities, as it can be readily used for syngas and SNG containing either hydrogen or methane. Compressed gas storage is the simplest storage solution as the only required equipment required is a compressor and a pressure vessel [2]. The main problem with compressed gas storage is the low storage density, which depends on the storage pressure. For pure hydrogen storage, several stages of compression are required because of the low density [3]. Compressed gas can be stored in high and low pressure above ground vessels, existing pipelines, and in underground cavities.

Compressed gas storage requires a compressor to provide the necessary mass flow of gas into the storage vessel. No literature discusses syngas compression or compressor requirements for syngas service, however reasonable estimates can be drawn from literature discussing compressors for natural gas and hydrogen service. The density and molecular weight of the gas to be compressed is an important consideration for compressor choice. Centrifugal compressors, which are widely used for natural gas, are not generally suitable for pure hydrogen compression as the pressure rise per stage is very small due to the low density and low molecular weight [2, 4]. Positive displacement, reciprocating compressors may be the best choice for large-scale hydrogen compression [4], and hydrogen can be compressed using standard axial, radial or reciprocating piston-type compressors with slight modifications of the seals to take into account the higher diffusivity of the hydrogen molecules [2].

The capital costs of compression depend on the properties of the gas to be compressed. Compressing pure hydrogen requires about three times the compressor power as natural gas and specific capital costs for large hydrogen compressors are expected to be 20 to 30% higher than for natural gas [5]. Compressor costs are based on the amount of work done by the compressor, which depends on the inlet pressure, outlet pressure, and flow rate [2]. Capital costs of compressors reported in the literature range from $479-$4,900/hp ($650-$6,600/kW) and are shown in Table A.1.

Table A.1 Small compressor capital costs [1, 2]

Size (hp)	Capital cost ($)	Cost/hp ($/hp)	Source
13	63,700	4,900	Amos
100	180,000	1,800	Amos
100	187,373	1,874	Taylor[8]
335	164,150-246,225	n/a	Amos
3,600	2,330,000	647	Amos
3,600	2,248,470	625	Amos
5,000	2,440,000	488	Amos
6,000	3,160,000	527	Amos
6,000	2,873,045	479	Taylor
38,000	20,000,000	526	Amos

Costs for large-scale, megawatt sized compression facilities for pipeline transport were developed by the International Energy Agency (IEA) [6] and are shown in Table A.2.

[8] Taylor figures converted from $1986 Canadian to $2004 US. Using $1C(1986) = $0.83US(1986) and a deflator of $1986 to $2004 = 1.505 from http://www1.jsc.nasa.gov/bu2/inflateGDP.html

Table A.2 Compressor capital cost estimates for large (MW) pipeline compressors ($MM)

Type	Initial Pressure Facility	Booster Station
Electrical Power Generation Plant CO_2 export pipeline	$5.590 + 0.509P - 0.006 P^2$	$6.388 + 0.581P - 0.008 P^2$
Fuel Synthesis Plant Hydrogen product pipeline	$24.902 + 0.549P - 0.005 P^2$	$28.460 + 0.628P - 0.005 P^2$
CO_2 Storage Facilities	$5.590 + 0.509P - 0.006 P^2$	$6.388 + 0.581P - 0.008 P^2$
Pipeline Branch CO_2	$6.388 + 0.581P - 0.008 P^2$	$6.388 + 0.581P - 0.008 P^2$
Natural Gas and Hydrogen	$28.460 + 0.628P - 0.005 P^2$	$28.460 + 0.628P - 0.005 P^2$

where P is the compressor power in MW

The costs developed by the IEA are significantly higher than the costs reported in Table A.1. For example, the IEA estimate for the 38,000hp (28 MW) compressor listed in Table A.1 is about $36 million, or 1.8 times higher than the cost reported by Amos. Because of this difference, care should be taken to choose the appropriate cost estimated based on the size of the compressor when estimating compressor capital costs.

The largest operating cost for compressors is the energy required to compress the gas [2]. The exact energy requirements for compression depend on the desired final pressure. The theoretical work for isothermal compression of ideal gas from pressure p_1 to p_2 is given by:

$$W_{1,2} = p_1 V_1 \ln\left(\frac{p_2}{p_1}\right) \tag{1}$$

where V_1 is the volume of the gas at pressure p_1. Figure A.1 illustrates the work required to compress a gas from an initial pressure, p_1, to a higher pressure, p_2.

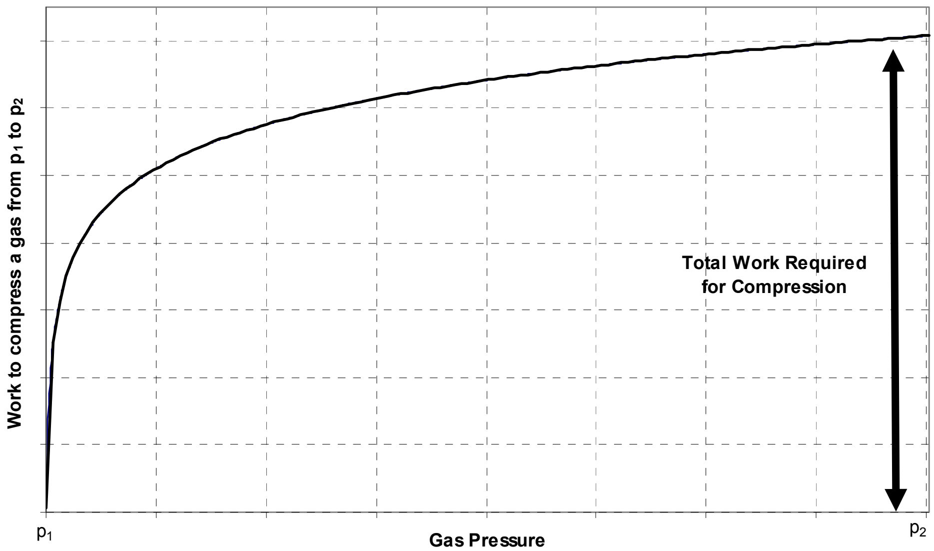

Figure A.2 Work to compress an ideal gas from P_1 to P_2

Because of the logarithmic relationship, the work and electricity consumption of the compressor is highest in the low-pressure range, and a high final storage pressure requires minimal power compared to the initial compression of the gas.

The physical parameters necessary for the model are related to the compression of the gas for storage. Compression increases the pressure and changes the volumetric density of the gas. The volumetric density of a gas mixture varies with the pressure of the gas. The ideal gas law can be used to determine the relationships between compression and pressure of a gas to first order. Some gases may vary significantly from the ideal gas law, particularly at high pressures, and may be more accurately described by cubic equations of state. To determine how the volumetric density varies with pressure, pure methane, syngas[9] and SNG[10] gases were modeled in Aspen using the ideal gas law, as well as the more accurate, Soave-Redlich-Kwong (SRK), and Peng-Robinson equations of state [7]. The results of the models are illustrated in Figure A.3.

[9] Composition by weight: 0% CH_4, 45% CO, 35.4% H_2, 17.1% CO_2, 2.1% N_2, 0.4% H_2O

[10] Composition by weight 81.12% CH_4, 0.78% H_20, 10.67% H_2, 0.07% CO, 4.48% CO_2, 2.88% N_2

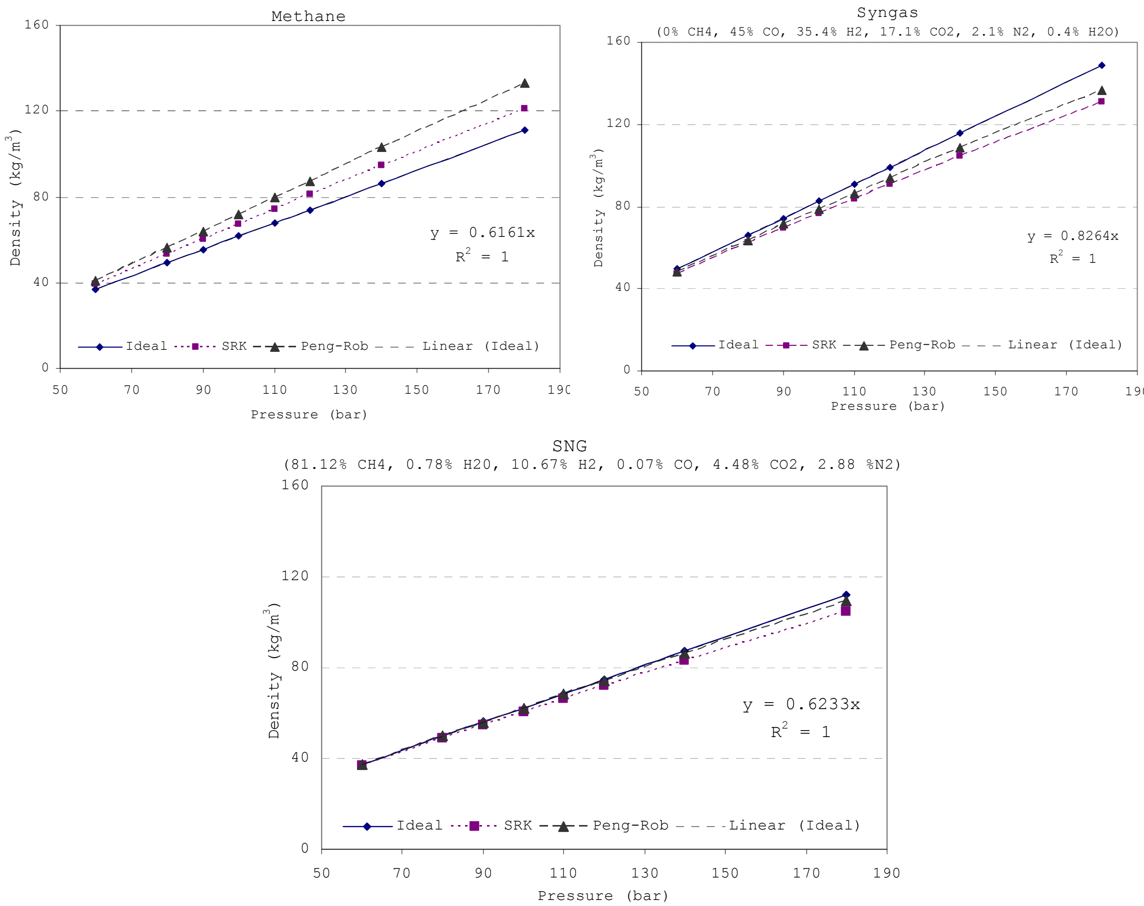

Figure A.3 Volumetric density versus pressure for three different gas mixtures using three different equations of state

For each of the fuels modeled, the volumetric density varies linearly with pressure and none of the gas mixtures varies significantly from the ideal gas law, even at high pressures. The models show that the ideal gas law is a reasonable approximation for estimating volumetric density at varying pressure for methane, SNG and syngas.

Conventional methods of above-ground compressed gas storage range from small high-pressure gas cylinders to large, low-pressure spherical gas containers [3, 8]. Compressed gas pressure vessels are commercially available at pressures of 1200-8000 psi, typically holding 6000-9000 scf per vessel. Low-pressure spherical tanks can hold roughly 13,000 Nm^3 of gas at 1.2-1.6 MPa (1,700-2,300 psig) [2]. High pressure tube storage is available for larger gas volumes, typically around 500,000 scf (14,000 Nm^3) [1]. Because of the relatively small storage capacity, industrial facilities typically use above ground compressed gas storage in pressure tanks for gas storage on the order of a few million scf or less [5]. Pressure vessels are physically configured in rows or in stacks of tanks; such storage is modular, with little economy of scale [2].

Capital costs for above ground pressure vessel storage range from approximately \$22-\$214/Nm^3 (\$0.62-\$6.02/scf), as shown in Table A.3.

Table A.3 Above ground high pressure vessel capital costs [1, 2, 9]

Size (Nm^3)	Capital cost (\$)	Cost/Nm^3 (\$/Nm^3)	Source
2,800	187,373	67	Taylor[11]
14,000	874,405	62	Taylor
12,071	840,000	70	Amos
2,414	180,000	75	Amos
44	3,560	80	Amos
4,433	540,350	122	Amos
n/a	n/a	38.4 - 64	Amos
n/a	n/a	21.76 -115.2	Padró
n/a	n/a	51.2 - 213.76	Newson, Huston, Ledjeff, Carlson, reported in Padró
n/a	n/a	64.6 - 214	Capretis reported in Amos
n/a	n/a	98.1 -144	Oy, reported in Amos

Sizes and other physical parameters for the smallest and largest reported cost per storage volume in the range are not reported, making it difficult to explain why they vary significantly from the average costs.

Gasometers are above ground vessels designed for storing large amounts of gas, typically at low pressure. Gasometers typically have a variable volume, through the use of a weighted movable cap, which provides gas output at a constant pressure. Gasometers operate at low pressure, with typical pressures in the range of 200-300mm water (0.28-0.43psig); maximum operating pressures are 1000mm water (1.4psig) [10]. Typical volumes for large gasometers are about 50,000-70,000m^3, with approximately 60 m diameter structures; although the largest gasholder installed by one manufacturer was 340,000m^3 [10]. Gasometers have long operating lifetimes; the structure itself can operate

[11] Taylor figures converted from \$1986 Canadian to \$2004 US. Using \$1C(1986)=\$0.83US(1986) and a deflator of \$1986 to \$2004=1.505 from http://www1.jsc.nasa.gov/bu2/inflateGDP.html

for over 100 years [10], while the diaphragm that seals the gasometer has a lifetime of 200,000 strokes or approximately 10 years [11].

Table A.4 Above ground low pressure vessel (gasometer) capital costs

Size (Nm^3)	Capital cost ($)	Cost/Nm^3 ($/$Nm^3$)	Source
65,000	22,080,000[12]	340	Clayton Walker

Syngas can also be stored, or packed, in piping systems. Pipelines are usually several miles long, and in some cases may be hundreds of miles long. Because of the large volume of piping systems, a slight change in the operating pressure of a pipeline system can result in a large change in the amount of gas contained within the piping network. By making small changes in operating pressure, the pipeline can effectively used as a storage vessel [2]. Storing gas in an existing pipeline system by increasing the operating pressure requires no additional capital expense as long as the pressure rating of the pipe and the capacity of the compressors are not exceeded [2]. Existing hydrogen pipelines are generally constructed of 0.25-0.30m (10-12in) commercial steel and operate at 1-3 MPa (145-435 psig); natural gas mains for comparison are constructed of pipe as large as 2.5 m (5 ft) in diameter and have working pressures of 7.5 MPa (1,100 psig) [12]. A 30 km, 3 inch diameter hydrogen distribution pipeline could carry a flow of 5 MMscf of hydrogen per day. Assuming that the pipeline operated at 1000 psi, the storage volume available in the pipeline would be 340,000 scf, or about 7% of the total daily flow rate [5].

Underground storage is a special case of compressed gas storage where the vessel is located underground and generally has a lower cost [2]. Because of their large capacities and low cost, underground compressed gas systems are generally most suitable for large quantities and/or long storage times [9]. There are four underground formations in which gas can be stored under pressure: (a) depleted oil or gas field; (b) aquifers; (c) excavated rock caverns; and (d) salt caverns [1].

[12] Converted from reported cost of £12 million (UK 2006) using £1(UK) = $1.84 US. Single lift, Wiggins, dry seal gasometer.

There is significant industrial experience in underground gas storage: natural gas has been stored underground since 1916 [1]; the city of Kiel, Germany has been storing town gas (60-65% hydrogen) in a gas cavern since 1971 [1]; Gaz de France has stored town gas containing 50% hydrogen in a 330 million cubic meter aquifer structure near Beynes, France; Imperial Chemical Industries stores hydrogen at 50 atm ($5x10^6$ Pa) pressure in three brine compensated salt caverns at 1200 ft (366 m) near Teeside, UK; and in Texas, helium is stored in rock strata beneath an aquifer whereby water seals the rock fissures above the helium reservoir, sealing in the helium atoms [4].

Underground storage volumes in depleted oil and gas fields can be extremely large; volumes of gas stored exceed 10^9 m^3 and pressures can be up to 40 atm. Salt caverns, large underground voids that are formed by solution mining of salt as brine, tend to be smaller, typically around 10^6-10^7 m^3. Although smaller, salt caverns offer faster discharge rates and tend to be tighter than other underground formations, reducing leakage. Hydrogen, a small molecule with high leakage rates, has been stored in salt caverns [13]. Rock caverns are usually smaller cavities, typically on the order of 1 million to10 million cubic meters.

Underground gas storage requires the use of a cushion gas that occupies the underground storage volume at the end of the discharge cycle. Cushion gas is non-recoverable base gas necessary to pressurize the storage reservoir. Cushion gas can be as much as 50% of the working volume, or several hundred thousand kilograms of gas [2] and the cost of the cushion gas is a significant part of the capital costs for large storage reservoirs [1].

Capital costs for underground storage are reported in the literature. Underground storage is reported to be the most inexpensive means of storage for large quantities of gas, up to two orders of magnitude less expensive than other methods [2, 8]. The only case where underground storage would not be the least cost option is with small quantities of gas in large caverns where the amount of working capital invested in the cushion gas is large compared to the amount of gas stored [2]. Capital costs vary depending on whether there is a suitable natural cavern or rock formation, or whether a cavern must be mined. An abandoned natural gas well was reported to be the least expensive, however the likelihood of a gasification facility being near such a formation (and choosing to use it to store syngas rather than to sequester CO_2), seems small, so it is not further considered in this paper. Solution mining, excavating a salt formation with a brine solution, capital costs were estimated at \$19-\$23/m^3 (\$0.54\$0.66/ft^3) [8]; hard rock mining costs were estimated at \$34-\$84/m^3 (\$1.00-\$2.50/ft^3) depending on the depth [2]. Additionally, construction times for underground storage facilities can be long and may contribute to their costs. One estimate for solution mining a salt formation to create a 160 million cubic foot cavern was 2.5 years [14]. Table A.5 shows reported ranges of underground storage capital costs for salt and excavated rock caverns.

Table A.5. Underground storage capital cost estimates [1, 2, 8]

Salt caverns	Excavated rock caverns	Source
\$19-\$23/m^3 (\$0.54-\$0.66/ft^3)		Carpetis
	\$34-\$84/m^3 (\$1.00-\$2.50/ft^3)	Amos
\$19.50/m^3 (\$0.55/ft^3)		Taylor

Underground compressed gas storage has been successfully used for compressed air energy storage (CAES) systems. There are currently two operating CAES systems in the world, both of which use salt caverns for air storage. The 290 MW Huntorf project in Germany uses a 62 MW compressor train to charge an 11 million ft^3 cavern to 1015 psi. The 110 MW McIntosh project in the US uses a 53 MW compressor train to charge a 19.8 million ft^3 cavern to 1100 psi [14].

As with all storage technologies, the overall cost of storage depends on throughput and storage time [9]. The longer the gas is to be stored, the more favorable underground storage becomes because of lower capital costs. If gas is stored for a long time, the operating cost can be a small factor compared to the capital costs of storage [2]. Operating costs for underground storage are primarily for compression power and limited to the energy and maintenance costs related to compressing the gas into underground storage and possibly boosting the pressure coming back out [9, 15]. The cost of the electricity requirements to compress the gas is independent of storage volume, which means the cost of underground storage is very insensitive to changes in storage time [2]. If the gasification facility is not geographically located near an area with suitable underground storage, transport costs would also need to be considered in the engineering economic analysis.

A.2 Historical Accuracy of Energy Information Administration Price Forecasts

The economic results of the analysis depend, in part, on the price at which the facility can purchase coal. The analysis examined coal price data from different sources and timeframes in order to analyze the scenarios within an envelope of prices incorporating the recent past as well as future forecasts. The coal prices used include: historical FOB prices for Illinois #6 coal, with a higher heating value of 11,350 Btu/lb and a sulfur content of 3.2% by weight [16]; Energy Information Administration Annual Energy Outlook (AEO) forecasts for year 2007 coal prices[13] [17, 18]; 2007 NYMEX futures for central application coal[19]; and EIA forecasts for year 2007 coal prices with a factor that includes EIA's historical error in forecasting price data [20]. This last price distribution incorporates uncertainty in the price due to error in EIA forecasts.

EIA price forecasts do not include much data on the relative uncertainty in the estimate. The uncertainty in EIA Annual Energy Outlook (AEO) price forecasts is addressed by examining historical deviation of actual prices from EIA forecasted prices following the methods from Rode and Fischbeck [20].

Using recent historical AEO forecast data from 1994 to 2005, EIA forecast error is modeled as a normal distribution with a mean of 2.5% and a standard deviation of 5.0%. The EIA forecast error was applied to the 2007 EIA forecast from the Annual Energy Outlook. Figure A.4 shows the 2007 EIA forecast from the Annual Energy Outlook

[13] The mean estimate is taken from the 2007 Annual Energy Outlook (early release), Table 15, delivered prices for electric power; the standard deviation is derived from data in the December 2006 Short-Term Energy Outlook.

compared to the same forecast with the EIA historical accuracy factor for the error included.

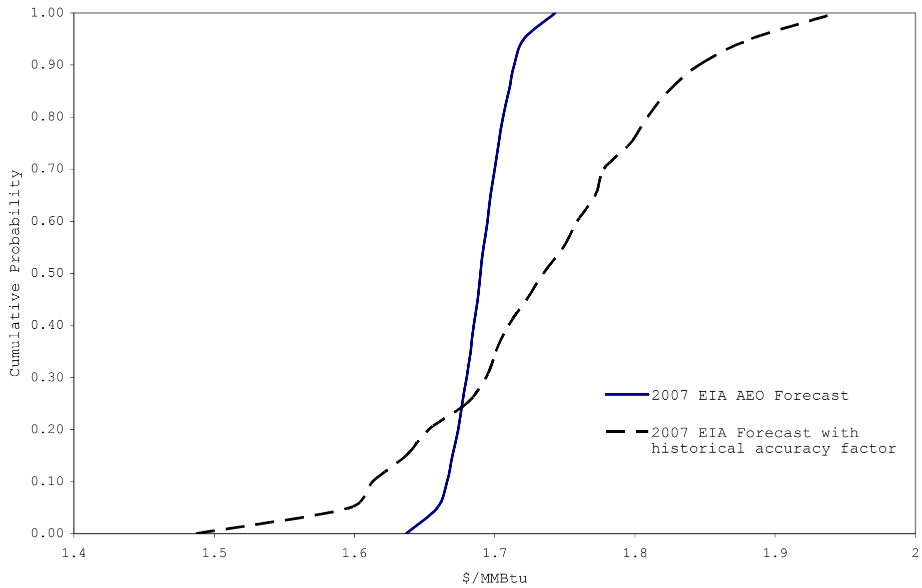

Figure A.4 CDF of 2007 EIA AEO coal price forecasts with and without the historical accuracy factor

As the figure shows, including a factor which incorporates the historical error in EIA forecasts significantly widens the cdf for coal prices. It is this broader price distribution, reflecting greater uncertainty in the future price for coal that is used in the analysis.

Figure A.5 illustrates the cumulative distribution functions of the coal price distributions examined in the analysis including the EIA forecast with the historical accuracy factor.

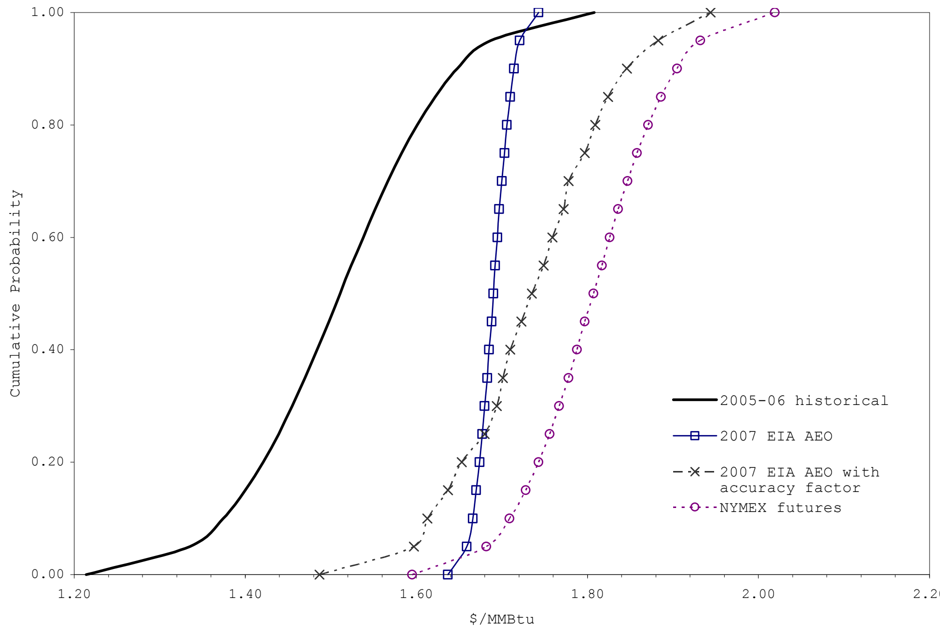

Figure A.5 Coal price distributions. CDF of historical and future FOB coal prices [16-20]

The historical 2005-06 prices have a mean of $1.51/MMBtu and standard deviation of 0.13. The 2007 EIA forecast shown in the figure has a mean value of $1.69/MMBtu and a standard deviation of 0.02. The 2007 EIA forecast that included the historical accuracy factor has a mean value of $1.73/MMBtu and a standard deviation of 0.10. The NYMEX futures price for Central Appalachian coal is higher than the EIA and historical prices for Illinois #6 coal, with a mean value of $1.81/MMBtu and a standard deviation of 0.09. Although futures prices vary as the contract settlement date approaches, and although Appalachian coal has a lower sulfur content than the Illinois coal, the NYMEX futures price serves as a useful upper bound for the Illinois coal price distribution. The forecasted future prices for coal represent an approximate 15% increase over the historical 2005-06 prices.

Distributions of costs were used in the analysis to capture the uncertainty in the cost parameter. Cost distributions were constructed directly from the cost data. The cost data were plotted on the y-axis against the relevant parameter (size, output, etc) on the x-axis and a mean regression line was calculated using an ordinary least squares method shown in equation 2.

$$\text{mean regression line: } \hat{y} = \beta_0 + \beta_1 x_0 \qquad (2)$$

where β_0 and β_1 are calculated using the usual method of ordinary least squares. At any point x_0, the prediction interval for the value of y is given by

$$\text{prediction interval: } \hat{y} \pm t_{1-\alpha/2} \cdot se(\hat{y}_0) \qquad (3)$$

$$= \hat{y} \pm t_{1-\alpha/2} \cdot \sqrt{\sigma^2 \cdot \left(1 + \frac{1}{n} + \frac{(x_0 - \bar{x})^2}{\sum (x_i - \bar{x})^2}\right)} \qquad (4)$$

where $t_{1-\alpha/2}$ is the student's t distribution evaluated at the α significance level, *se* is the standard error, $\bar{x}$ is the average and σ^2 is the mean square error. Figure A.6 illustrates the prediction interval for the value of y at any given x value, in relation to the underlying data.

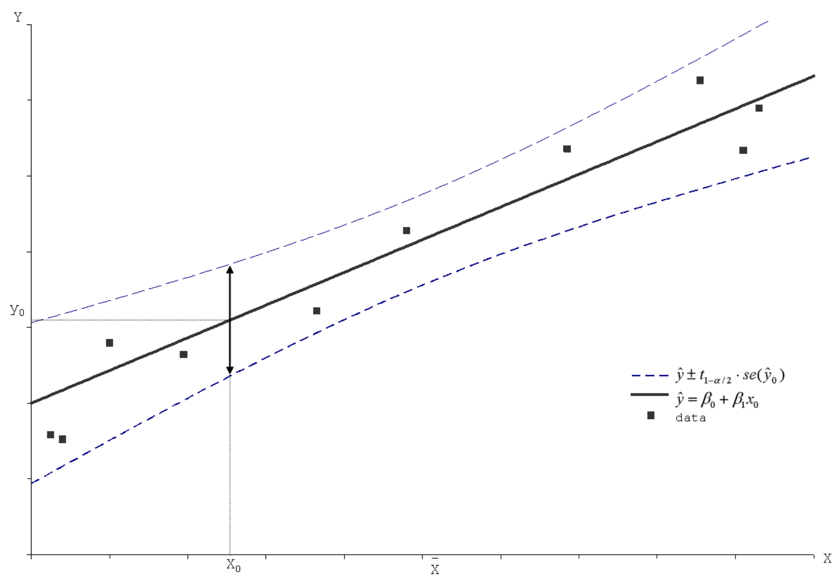

Figure A.6 Regression analysis illustration with underlying data points, mean regression line, and upper and lower prediction intervals plotted. The mean and prediction interval for the value of y at point x_0 is shown.

The figure shows the individual data, the mean regression line and the prediction interval. The mean regression line represents the point estimate for the value of y given a value of x. The prediction interval represents the distribution at the α confidence level for the value of y given a value of x. As the figure illustrates, as x_0 moves away from the mean value of x, the prediction interval spreads out indicating more uncertainty in the value of y at the point x_0. At any point x0, the distribution of y can be plotted using equations 3 and 4. Figure A.7 shows the cumulative distribution function of the value of y at a point x_0.

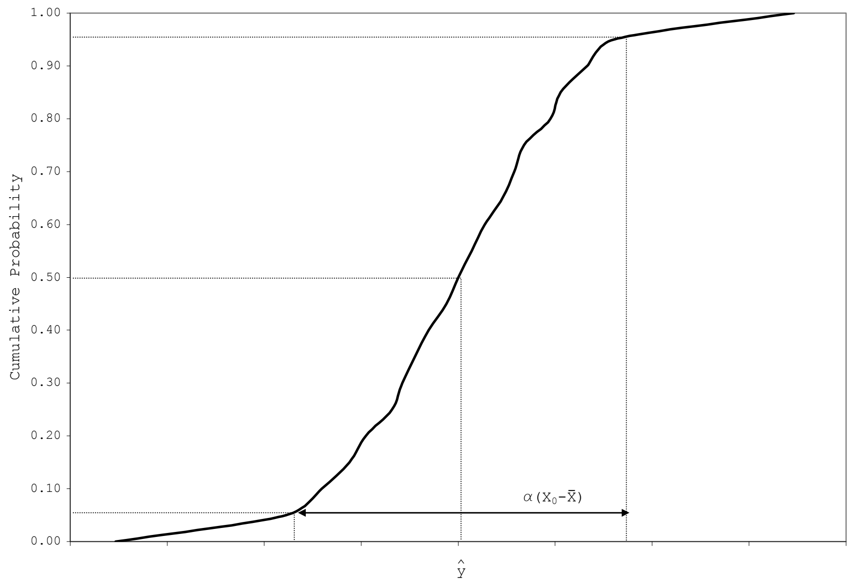

Figure A.7 Cumulative distribution function of the value of Y at point x_0

As the figure shows, the standard error of y increases as x_0 moves away from $\bar{x}$, resulting in a wider cumulative distribution function.

A.3 Hydrogen Embrittlement

There is significant research on embrittlement and other metallurgical issues associated with hydrogen and hydrogen-rich gases. The oil and gas industry has been troubled by internal and external hydrogen attack on steel pipelines, described variously as hydrogen-induced cracking (or corrosion) (HIC), hydrogen corrosion cracking (HCC), stress corrosion cracking (SCC), hydrogen embrittlement (HE), and delayed failure [4]. These issues are serious; corrosion damages cause most of the failures and emergencies of trunk gas pipelines, and stress corrosion defects of pipelines are extremely severe. Corrosion defects, such as general corrosion, pitting corrosion and SCC, make up the major number of detected effects in pipelines [21].

Hydrogen can cause corrosion, hydrogen induced cracking or hydrogen embrittlement if there is a mechanism that produces atomic hydrogen (H^+) [6]. Atomic hydrogen diffuses into a metal and reforms as microscopic pockets of molecular hydrogen gas, causing cracking, embrittlement and corrosion which can ultimately lead to failure. The hardness of a metal correlates to the degree of embrittlement; if a material has a Vickers Hardness Number (VHN) greater than 300, the tendency for the material to fail due to plastic straining when there is significant absorption of atomic hydrogen is greater than with a softer material [21].

Molecular hydrogen (H_2) alone does not cause embrittlement of steel; however problems can arise if there is a mechanism that produces atomic hydrogen. The two primary mechanisms leading to hydrogen induced cracking are HIC due to wet conditions and HIC due to elevated temperatures [21]. Temperatures greater than 220°C can cause dissociation of molecular hydrogen into atomic hydrogen. Studies show that molecular hydrogen should be water dry, or below 60% relative humidity, to provide a sufficient margin for avoidance of moisture and water dropout [6]. Molecular hydrogen, then, may be handled without problems with standard low-alloy carbon steel irrespective of the gas pressure, provided that the conditions are dry (to prevent HIC due to wet conditions) and under 220°C (to prevent HIC due to elevated temperatures) [6].

Because of the metallurgical issues associated with hydrogen, care must be taken when choosing metals for hydrogen pipelines and storage. Surveys of existing hydrogen pipelines show that a variety of steels, but primarily mild steel, is in use [22, 23]. Options for steel pipe for 100% hydrogen service include Al-Fe (aluminum-iron) alloy; and variable-hardness pipe, with the harder material in the interior and softer material toward the exterior, so that any hydrogen which diffuses into the interior steel diffuses rapidly outward and escapes [4].

Existing natural gas pipelines can be used for less than 15 to 20% hydrogen, by volume, without danger of hydrogen attack on the line pipe steel, however further hydrogen enrichment will risk hydrogen embrittlement [4]. Existing pipelines originally designed for sour service can provide additional protection against HIC and hydrogen embrittlement due to their specific metallurgy [6]. If hydrogen embrittlement is found to be a potential problem for an unusual situation, costs for any materials will be relatively low. Steel used for hydrogen transport and storage are low carbon steel and low in alloy content. These steels may have a restriction of some alloy elements (those that attract and stabilize H and a structure called austenite), however the cost should not be affect by these restrictions [24]. For large diameter pipelines and vessels, options include low carbon steel plate, such as type X52, which is easy to make, readily available, easy to weld, and easy to fabricate. Smaller pipes can be constructed from either seamless or welded pipe. The main failure of the material is by hydrogen embrittlement in the zone near the weld. This area is affected by the heating and cooling during welding and has more internal stress. Because of the care required for welding, the most costly component is likely welding by certified welders [24].

A.4 Additional Technical and Engineering Considerations

Implementing syngas storage efficiently and cost-effectively in an IGCC facility requires detailed engineering analysis that is beyond the scope of this paper. Engineering issues that have been identified and that should be addressed for successful operation of an IGCC facility with syngas storage follow.

- Humidification and reheating of stored syngas and the implications on thermal plant efficiency.

- Integration and optimization of potential future hot/warm syngas cleaning technologies where the syngas is maintained at a high enough temperature to keep it humid (greater than 500°F).

- Stability of syngas for long term storage and investigation of potential deposits on the storage vessel.

- Potential effects of short term operating periods for the gas turbine. In the analysis the IGCC plant gasifier operates continuously, but the gas are both operated with potentially several short operating periods each day – as short as 1 hour in the report example. Although gas turbines are commonly used for peaking applications, (the size-weighted average capacity factor for the 884 operating gas turbines in eGRID 2004 was 0.29) such transient gas turbine operation may lead to increases plant maintenance. Data on thermal cycling limits for turbines was not available. The design of a facility using syngas storage should consider the specific turbine manufacturer's cycling limits during the design process. For syngas storage times that the analysis shows is most economically favorable (8 and 12 hours), short cycling is less of a concern. For 12 hours of storage, peak hours are generally during the day, and the turbine is operated continuously over this period.

Table A.6 and Table A.7 detail the operating and financial parameters for the IECM-based [25] IGCC facility used in the model.

Table A.6. IGCC 1+0+ccs scenario operating and financial parameters

IECM cs version 5.21 (February 2, 2007)

Operating parameters			Financial parameters		
Overall Plant					
Base GE Quench			Year Costs Reported	2005	
Cold gas cleanup			Constant Dollars		
CO_2 Capture: Sour Shift + Selexol			Discount Rate (Before Taxes)	8.00E-02	fraction
Slag: landfill			Fixed Charge Factor (FCF)	8.88E-02	fraction
Sulfur: sulfur plant					
			Inflation Rate	0	%/yr
Capacity Factor	80	%	Plant or Project Book Life	30	years
			Real Bond Interest Rate	8	%
Gross Plant Size	297.7	MWg	Real Preferred Stock Return	0	%
Net Plant Size	238.1	MW	Real Common Stock Return	0.1	%
Net Electrical Output (MW)	238.1		Percent Debt	99.99	%
Total Plant Energy Input (MBtu/hr)	2781		Percent Equity (Preferred Stock)	0	%
Gross Plant Heat Rate, HHV (Btu/kWh)	9343		Percent Equity (Common Stock)	1.00E-02	%
Net Plant Heat Rate, HHV (Btu/kWh)	11680				
			Federal Tax Rate	35	%
Net Plant Efficiency, HHV (%)	29.17		State Tax Rate	4	%
Ambient Air Temperature	77	°F	Property Tax Rate	2	%
Ambient Air Pressure	14.7	psia	Investment Tax Credit	0	%
Ambient Air Humidity	1.80E-02	lb H_2O/lb dry air	Construction Time	0.25	years
			Operating Labor Rate	24.82	$/hr
Coal			Water Cost	0.8316	$/1000 gal

Illinois #6		
Heating Value	1.09E+04	btu/lb
Carbon	61.2	wt% as received
Hydrogen	4.2	
Oxygen	6.02	
Chlorine	0.17	
Sulfur	3.25	
Nitrogen	1.16	
Ash	11	
Moisture	13	
Plant Inputs	Flow Rate (tons/hr)	
Coal	127.6	
Oil	0.3479	
Other Fuels	3.04E-02	
Other Chemicals, Solvents & Catalyst	2.39E-03	
Total Chemicals	2.39E-03	
Oxidant	109.3	
Process Water	48.63	
Plant Outputs	Flow Rate (tons/hr)	
Slag	16.38	
Ash Disposed	0	
Other Solids Disposed	0	
Particulate Emissions to Air	1.39E-03	
Captured CO2	254.2	
By-Product Ash Sold	0	
By-Product Gypsum Sold	0	
By-Product Sulfur Sold	4.066	
By-Product Sulfuric Acid Sold	0	
Total Solids & Liquids	274.6	
Plant Energy Requirements	Value	
Total Generator Output (MW)	510.5	
Air Compressor Use (MW)	208.6	
Turbine Shaft Losses (MW)	6.036	
Gross Plant Output (MWg)	297.7	
Misc. Power Block Use (MW)	5.954	
Air Separation Unit Use (MW)	31.77	
Gasifier Use (MW)	4.343	
Sulfur Capture Use (MW)	3.291	
Claus Plant Use (MW)	0.4343	
Beavon-Stretford Use (MW)	1.321	
Water-Gas Shift Reactor Use (MW)	-11.52	

Sulfur Byproduct Credit	68.64	$/ton
Sulfur Disposal Cost	10	$/ton
Selexol Solvent Cost	2.32	$/lb
Claus Plant Catalyst Cost	565.8	$/ton
Beavon-Stretford Catalyst Cost	218.6	$/cu ft
Slag Disposal Cost	13.07	$/ton
Limestone Cost	19.64	$/ton
Lime Cost	72.01	$/ton
Ammonia Cost	248.2	$/ton
Urea Cost	412.4	$/ton
MEA Cost	1293	$/ton
Activated Carbon Cost	1322	$/ton
Caustic (NaOH) Cost	624.7	$/ton
High Temperature Catalyst Cost	60.1	$/cu ft
Low Temperature Catalyst Cost	300.5	$/cu ft
Glycol Cost	2.356	$/lb
Bulk Reagent Storage Time	60	days
The following apply to all process blocks		
General Facilities Capital	15	%PFC
Engineering & Home Office Fees	10	%PFC
Project Contingency Cost	15	%PFC
Booster Pump Operating Cost	1.5	%PFC
Pre-Production Costs		
Months of Fixed O&M	1	months
Months of Variable O&M	1	months
Misc. Capital Cost	2	%TPI
Inventory Capital (gasifier)	1	%TPC
Inventory Capital (other processes)	0.5	%TPC
Maint. Cost Allocated to Labor	40	% total
Administrative & Support Cost	30	% total labor
TCR Recovery Factor	100	%
Number of Operating Jobs	6.67	jobs/shift
Number of Operating Shifts	4.75	shifts/day
Royalty Fees	0.5	%PFC
Process Contingency Cost		
gasifier	11.77	%PFC
turbine	8.006	%PFC
air separation	5	%PFC
sulfur removal	8.348	%PFC
CO2 capture	5	%PFC
Total Maintenance Cost		
gasifier	3.707	%TPC
turbine	1.5	%TPC

Selexol CO2 Capture Use (MW)	24.01
Net Electrical Output (MW)	238.1

air separation	2	%TPC
sulfur removal	2	%TPC
CO2 capture	2	%TPC

Gasifier Area		
Number of Operating Trains	1	
Number of Spare Trains	0	
Gasifier Temperature	2450	°F
Gasifier Pressure	615	psia
Total Water or Steam Input	0.5566	mol H2O/mol C
Oxygen Input from ASU	0.4945	mol O2/mol C
Total Carbon Loss	3	%
Sulfur Loss to Solids	0	%
Coal Ash in Raw Syngas	0	%
Percent Water in Slag Sluice	0	%
Raw Gas Cleanup Area		
Particulate Removal Efficiency	100	%
Power Requirement	1.362	% MWg

Syngas output	vol%	Syngas Out (tons/hr)
Carbon Monoxide (CO)	30.64	109.4
Hydrogen (H2)	32.92	8.478
Methane (CH4)	0.261	0.5338
Ethane (C2H6)	0	0
Propane (C3H8)	0	0
Hydrogen Sulfide (H2S)	0.975	4.237
Carbonyl Sulfide (COS)	4.10E-02	0.314
Ammonia (NH3)	8.00E-03	1.74E-02
Hydrochloric Acid (HCl)	4.80E-02	0.2231
Carbon Dioxide (CO2)	18.52	103.9
Moisture (H2O)	14.86	34.13
Nitrogen (N2)	0.864	3.086
Argon (Ar)	0.872	4.442
Total	100	268.8

GE Gasifier Process Area Costs	Capital Cost (M$)
Coal Handling	23.86
Gasification	38.5
Low Temperature Gas Cooling	19.64
Process Condensate Treatment	9.929
General Facilities Capital	13.79
Eng. & Home Office Fees	9.193
Project Contingency Cost	13.79
Process Contingency Cost	10.93
Interest Charges (AFUDC)	-4.003
Royalty Fees	0.4596
Preproduction (Startup) Cost	5.672
Inventory (Working) Capital	1.396
Total Capital Requirement (TCR)	143.2

Variable Cost Component	O&M Cost (M$/yr)
Oil	0.838
Other Fuels	2.04E-02
Water	0.2836
Slag Disposal	1.501

Fixed Cost Component	O&M Cost (M$/yr)
Operating Labor	2.009
Maintenance Labor	1.966
Maintenance Material	2.949
Admin. & Support Labor	1.193

Cost Component	M$/yr	$/MWh
Annual Fixed Cost	8.117	4.862
Annual Variable Cost (excluding coal)	2.64	1.582
Total Annual O&M Cost	10.76	6.44
Annualized Capital Cost	14.86	8.898
Total Levelized Annual Cost	25.62	15.34

Gas Turbine/Generator	
Gas Turbine Model	GE 7FA
No. of Gas Turbines	1

Power Block Plant Costs	Capital Cost (M$)
Gas Turbine	54.81
Heat Recovery Steam Generator	17.27

Total Gas Turbine Output	202.6	MW
Fuel Gas Moisture Content	33	vol %
Turbine Inlet Temperature	2420	°F
Turbine Back Pressure	2	psia
Adiabatic Turbine Efficiency	95	%
Shaft/Generator Efficiency	98	%
Air Compressor		
Pressure Ratio (outlet/inlet)	15.7	ratio
Adiabatic Compressor Efficiency	70	%
Combustor		
Combustor Inlet Pressure	294	psia
Combustor Pressure Drop	4	psia
Excess Air For Combustor	171.1	% stoich.
Heat Recovery Steam Generator		
HRSG Outlet Temperature	250	°F
Steam Cycle Heat Rate, HHV	9000	Btu/kWh
Steam Turbine		
Total Steam Turbine Outlet	95.13	MW
Power Block Totals		
Power Requirement	2	% MWg

Steam Turbine	25.86
HRSG Feedwater System	3.611
General Facilities Capital	15.23
Eng. & Home Office Fees	10.16
Project Contingency Cost	15.23
Process Contingency Cost	8.111
Interest Charges (AFUDC)	-4.309
Royalty Fees	0.5078
Preproduction (Startup) Cost	3.307
Inventory (Working) Capital	0.7515
Total Capital Requirement (TCR)	150.6

Fixed Cost Component	O&M Cost (M$/yr)
Operating Labor	1.636
Maintenance Labor	0.9018
Maintenance Material	1.353
Admin. & Support Labor	0.7612

Cost Component	M$/yr	$/MWh
Annual Fixed Cost	4.651	2.79
Total Annual O&M Cost	4.651	2.79
Annualized Capital Cost	13.25	7.946
Total Levelized Annual Cost	17.9	10.74

Syngas Input	Syngas In (tons/hr)	Heated Syngas In (tons/hr)
Carbon Monoxide (CO)	5.471	5.471
Hydrogen (H2)	15.97	15.97
Methane (CH4)	0.5338	0.5338
Ethane (C2H6)	0	0
Propane (C3H8)	0	0
Hydrogen Sulfide (H2S)	5.30E-03	5.30E-03
Carbonyl Sulfide (COS)	3.16E-03	3.16E-03
Ammonia (NH3)	1.74E-02	1.74E-02
Hydrochloric Acid (HCl)	2.23E-01	2.23E-01
Carbon Dioxide (CO2)	13.37	13.37
Water Vapor (H2O)	33.37	76.94
Nitrogen (N2)	3.086	3.086
Argon (Ar)	4.442	4.442
Oxygen (O2)	0	0
Total	76.5	120.1

Air Separation

Oxidant Composition

Air Separation Plant Costs	Capital Cost (M$)
Process Facilities Capital	66.33

Oxygen (O2)	95	vol %
Argon (Ar)	4.234	vol %
Nitrogen (N2)	0.7657	vol %
Final Oxidant Pressure	580	psia
Maximum Train Capacity	1.14E+04	lb-moles/hr
Number of Operating Trains	1	integer
Number of Spare Trains	0	integer
Unit ASU Power Requirement	210.4	kWh/ton O2
Total ASU Power Requirement	10.67	% MWg

General Facilities Capital	9.949
Eng. & Home Office Fees	6.633
Project Contingency Cost	9.949
Process Contingency Cost	3.316
Interest Charges (AFUDC)	-2.757
Royalty Fees	0.3316
Preproduction (Startup) Cost	2.266
Inventory (Working) Capital	0.4809
Total Capital Requirement (TCR)	96.5

Fixed Cost Component	O&M Cost (M$/yr)
Operating Labor	2.009
Maintenance Labor	0.7694
Maintenance Material	1.154
Admin. & Support Labor	0.8337

Cost Component	M$/yr	$/MWh
Annual Fixed Cost	4.767	2.859
Total Annual O&M Cost	4.767	2.859
Annualized Capital Cost	8.492	5.093
Total Levelized Annual Cost	13.26	7.952

Sulfur Removal		
Hydrolyzer (or Shift Reactor)		
COS to H2S Conversion Efficiency	98.5	%
Sulfur Removal Unit		
H2S Removal Efficiency	98	%
COS Removal Efficiency	33	%
CO2 Removal Efficiency	0	%
Max Syngas Capacity per Train	2.50E+04	lb-mole/hr
Number of Operating Absorbers	3	
Power Requirement	1.106	% MWg
Claus Plant		
Sulfur Recovery Efficiency	95	%
Max Sulfur Capacity per Train	1.00E+04	lb/hr
Number of Operating Absorbers	3	
Power Requirement	1.46E-01	% MWg
Tailgas Treatment		
Sulfur Recovery Efficiency	99	%
Power Requirement	0.4438	% MWg
Sulfur Sold on Market	90	%

Sulfur Removal Plant Costs	Capital Cost (M$)
Sulfur Removal System - Hydrolyzer	0
Sulfur Removal System - Selexol	13.29
Sulfur Recovery System - Claus	7.057
Tail Gas Clean Up - Beavon-Stretford	4.584
General Facilities Capital	3.739
Eng. & Home Office Fees	2.493
Project Contingency Cost	3.739
Process Contingency Cost	2.14
Interest Charges (AFUDC)	-1.062
Royalty Fees	0.1246
Preproduction (Startup) Cost	0.8692
Inventory (Working) Capital	0.1852
Total Capital Requirement (TCR)	37.16

Variable Cost Component	O&M Cost (M$/yr)
Makeup Selexol Solvent	7.77E-02
Makeup Claus Catalyst	3.36E-03
Makeup Beavon-Stretford Catalyst	4.90E-03
Sulfur Byproduct Credit	1.761
Disposal Cost	2.85E-02

Fixed Cost Component	O&M Cost (M$/yr)
Operating Labor	2.009

Maintenance Labor	0.2963
Maintenance Material	0.4445
Admin. & Support Labor	0.6917

Cost Component	M$/yr	$/MWh
Annual Fixed Cost	3.442	2.064
Annual Variable Cost	-1.647	-0.9878
Total Annual O&M Cost	1.795	1.08E+00
Annualized Capital Cost	3.27	1.961
Total Levelized Annual Cost	5.065	3.038

CO2 Capture
Water-Gas Shift Reactor

CO to CO2 Conversion Efficiency	95	%
COS to H2S Conversion Efficiency	98.5	%
Steam Added	0.99	mol H2O/mol CO
Maximum Train CO2 Capacity	1.50E+04	lb-moles/hr
Number of Operating Absorbers	2	integer
Number of Spare Absorbers	0	integer
Thermal Energy Credit	3.87	% MWg

Water Gas Shift Process Area Costs	Capital Cost (M$)
High Temperature Reactor	1.536
Low Temperature Reactor	1.722
Heat Exchangers	25.87
General Facilities Capital	4.369
Eng. & Home Office Fees	2.913
Project Contingency Cost	4.369
Process Contingency Cost	1.456
Interest Charges (AFUDC)	-1.211
Royalty Fees	0.1456
Preproduction (Startup) Cost	0.9396
Inventory (Working) Capital	0.2112
Total Capital Requirement (TCR)	42.32

Variable Cost Component	O&M Cost (M$/yr)
Water	9.25E-02

Fixed Cost Component	O&M Cost (M$/yr)
Operating Labor	0.3013
Maintenance Labor	0.3379
Maintenance Material	0.5068
Admin. & Support Labor	0.1917

Cost Component	M$/yr	$/MWh
Annual Fixed Cost	1.338	0.8023
Annual Variable Cost	9.25E-02	5.55E-02
Total Annual O&M Cost	1.43E+00	0.8578
Annualized Capital Cost	3.72E+00	2.234
Total Levelized Annual Cost	5.154	3.091

Selexol

CO2 Product Stream		
Number of Compressors	3	
Product Pressure	2000	psig
CO2 Compressor Efficiency	80	%
Transport & Storage		

Selexol (CO2) Process Area Costs	Capital Cost (M$)
Absorbers	7.809
Power Recovery Turbines	1.936
Slump Tanks	0.7871
Recycle Compressors	3.467
Flash Tanks	1.675

Storage Method:	Geologic	
CO2 Removal Efficiency	95	%
H2S Removal Efficiency	94	%
Max Syngas Capacity per Train	3.20E+04	lb-mole/hr
Number of Operating Absorbers	2	
Number of Spare Absorbers	0	
Power Requirement	8.065	% MWg

Selexol Pumps	1.589
Refrigeration	3.073
CO2 Compressors	11.95
Final Product Compressors	1.23
Heat Exchangers	3.702
General Facilities Capital	5.582
Eng. & Home Office Fees	3.722
Project Contingency Cost	5.582
Process Contingency Cost	3.722
Interest Charges (AFUDC)	7.063
Royalty Fees	0.1861
Preproduction (Startup) Cost	2.651
Inventory (Working) Capital	0.2791
Total Capital Requirement (TCR)	66

Variable Cost Component	O&M Cost (M$/yr)
CO2 Transport	3.086
CO2 Storage	9.719

Fixed Cost Component	O&M Cost (M$/yr)
Operating Labor	0.6025
Maintenance Labor	1.116
Maintenance Material	1.675
Admin. & Support Labor	0.5157

Cost Component	M$/yr	$/MWh
Annual Fixed Cost	3.909	2.345
Annual Variable Cost	1.28E+01	7.68E+00
Total Annual O&M Cost	1.67E+01	10.02
Annualized Capital Cost	5.81E+00	3.484
Total Levelized Annual Cost	22.52	13.51

CO2 Transport		
Total Pipeline Length	62.14	miles
Net Pipline Elevation Change (Plant->Injection)	0	feet
Number of Booster Stations	0	integer
Compressor/Pump Driver	Electric	
Booster Pump Efficiency	75	%
Pipeline Region	Midwest US	
Design Pipeline Flow (% plant cap)	100	%
Actual Pipeline Flow	1.78E+06	tons/yr
Inlet Pressure (@ power plant)	2000	psia
Min Outlet Pressure (@ storage site)	1494	psia
Average Ground Temperature	42.08	°F
Pipe Material Roughness	1.80E-03	inches
Pipe Size	10	inches

CO2 Transport Process Area Costs	Capital Cost (M$)
Material Cost	5.195
Labor Costs	16.73
Right-of-way Cost	2.91
Miscellaneous Costs	7.642
Interest Charges (AFUDC)	-0.9311
Total Capital Requirement (TCR)	31.54

Fixed Cost Component	O&M Cost (M$/yr)
Total Fixed Costs	0.31

Cost Component	M$/yr	$/MWh
Annual Fixed Cost	0.31	0.1859
Annual Variable Cost	0.00E+00	0.00E+00
Total Annual O&M Cost	3.10E-01	0.1859

Annualized Capital Cost	2.78E+00	1.665
Total Levelized Annual Cost	3.086	1.851

Table A.7. IGCC 3+1 Scenario operating and financial parameters

IECM cs version 5.21 (February 2, 2007)

Operating parameters			Financial parameters		
Overall Plant					
Base GE Quench			Year Costs Reported	2005	
Cold gas cleanup			Constant Dollars		
Slag: landfill			Discount Rate (Before Taxes)	8.00E-02	fraction
Sulfur: sulfur plant			Fixed Charge Factor (FCF)	8.88E-02	fraction
Capacity Factor	80	%	Inflation Rate	0	%/yr
			Plant or Project Book Life	30	years
Gross Plant Size	945.3	MWg	Real Bond Interest Rate	8	%
Net Plant Size	813.8	MW	Real Preferred Stock Return	0	%
Net Electrical Output (MW)	813.8		Real Common Stock Return	0.1	%
Total Plant Energy Input (MBtu/hr)	8035		Percent Debt	99.99	%
Gross Plant Heat Rate, HHV (Btu/kWh)	8500		Percent Equity (Preferred Stock)	0	%
Net Plant Heat Rate, HHV (Btu/kWh)	9873		Percent Equity (Common Stock)	1.00E-02	%
Net Plant Efficiency, HHV (%)	34.56		Federal Tax Rate	35	%
Ambient Air Temperature	77	°F	State Tax Rate	4	%
Ambient Air Pressure	14.7	psia	Property Tax Rate	2	%
Ambient Air Humidity	1.80E-02	lb H2O/lb dry air	Investment Tax Credit	0	%
			Construction Time	0.25	years
			Operating Labor Rate	24.82	$/hr
Coal					
Illinois #6			Water Cost	0.8316	$/1000 gal
Heating Value	1.09E+04	btu/lb	Sulfur Byproduct Credit	68.64	$/ton
Carbon	61.2	wt% as received	Sulfur Disposal Cost	10	$/ton
Hydrogen	4.2		Selexol Solvent Cost	2.32	$/lb
Oxygen	6.02		Claus Plant Catalyst Cost	565.8	$/ton
Chlorine	0.17		Beavon-Stretford Catalyst Cost	218.6	$/cu ft
Sulfur	3.25		Slag Disposal Cost	13.07	$/ton
Nitrogen	1.16		Limestone Cost	19.64	$/ton
Ash	11		Lime Cost	72.01	$/ton
Moisture	13		Ammonia Cost	248.2	$/ton
			Urea Cost	412.4	$/ton
Plant Inputs	Flow Rate (tons/hr)		MEA Cost	1293	$/ton
Coal	368.6		Activated Carbon Cost	1322	$/ton
Oil	1.191		Caustic (NaOH) Cost	624.7	$/ton
Other Fuels	0.1042		The following apply to all process blocks		

Other Chemicals, Solvents & Catalyst	5.38E-03		General Facilities Capital	15	%PFC
Total Chemicals	5.38E-03		Engineering & Home Office Fees	10	%PFC
Oxidant	315.8		Project Contingency Cost	15	%PFC
Process Water	140.5				
			Pre-Production Costs		
Plant Outputs	Flow Rate (tons/hr)		Months of Fixed O&M	1	months
Slag	47.31		Months of Variable O&M	1	months
Ash Disposed	0		Misc. Capital Cost	2	%TPI
Other Solids Disposed	0		Inventory Capital (gasifier)	1	%TPC
Particulate Emissions to Air	4.02E-03		Inventory Capital (other processes)	0.5	%TPC
Captured CO2	0				
By-Product Ash Sold	0		Maint. Cost Allocated to Labor	40	% total
By-Product Gypsum Sold	0		Administrative & Support Cost	30	% total labor
By-Product Sulfur Sold	11.75		TCR Recovery Factor	100	%
By-Product Sulfuric Acid Sold	0		Number of Operating Jobs	6.67	jobs/shift
Total Solids & Liquids	59.06		Number of Operating Shifts	4.75	shifts/day
			Royalty Fees	0.5	%PFC
Plant Energy Requirements	Value		Process Contingency Cost		
Total Generator Output (MW)	1538		gasifier	11.77	%PFC
Air Compressor Use (MW)	579.2		turbine	8.006	%PFC
Turbine Shaft Losses (MW)	19.17		air separation	5	%PFC
Gross Plant Output (MWg)	945.3		sulfur removal	8.348	%PFC
Misc. Power Block Use (MW)	18.91		Total Maintenance Cost		
Air Separation Unit Use (MW)	91.77		gasifier	3.707	%TPC
Gasifier Use (MW)	12.87		turbine	1.5	%TPC
Sulfur Capture Use (MW)	6.143		air separation	2	%TPC
Claus Plant Use (MW)	0.4343		sulfur removal	2	%TPC
Beavon-Stretford Use (MW)	1.321				

Gasifier Area				
Number of Operating Trains	3		**GE Gasifier Process Area Costs**	Capital Cost (M$)
Number of Spare Trains	1		Coal Handling	68.93
			Gasification	148.6
Gasifier Temperature	2450	°F	Low Temperature Gas Cooling	52.52
Gasifier Pressure	615	psia	Process Condensate Treatment	18.76
Total Water or Steam Input	0.5566	mol H2O/mol C	General Facilities Capital	43.32
Oxygen Input from ASU	0.4945	mol O2/mol C	Eng. & Home Office Fees	28.88
Total Carbon Loss	3	%	Project Contingency Cost	43.32
Sulfur Loss to Solids	0	%	Process Contingency Cost	33.99
Coal Ash in Raw Syngas	0	%	Interest Charges (AFUDC)	-12.57
Percent Water in Slag Sluice	0	%	Royalty Fees	1.444
			Preproduction (Startup) Cost	16.88
Raw Gas Cleanup Area			Inventory (Working) Capital	4.384
Particulate Removal Efficiency	100	%	Total Capital Requirement (TCR)	448.5
Power Requirement	1.362	% MWg		
			Variable Cost Component	O&M Cost (M$/yr)
Syngas output	vol%	Syngas Out	Oil	2.869

		(tons/hr)
Carbon Monoxide (CO)	30.64	316.1
Hydrogen (H2)	32.92	24.49
Methane (CH4)	0.261	1.542
Ethane (C2H6)	0	0
Propane (C3H8)	0	0
Hydrogen Sulfide (H2S)	0.975	12.24
Carbonyl Sulfide (COS)	4.10E-02	0.9072
Ammonia (NH3)	8.00E-03	5.02E-02
Hydrochloric Acid (HCl)	4.80E-02	0.6446
Carbon Dioxide (CO2)	18.52	300.2
Moisture (H2O)	14.86	98.61
Nitrogen (N2)	0.864	8.914
Argon (Ar)	0.872	12.83
Total	100	776.6

Gas Turbine/Generator

Gas Turbine Model	GE 7FA	
No. of Gas Turbines	3	
Total Gas Turbine Output	659.3	MW
Fuel Gas Moisture Content	33	vol %
Turbine Inlet Temperature	2420	°F
Turbine Back Pressure	2	psia
Adiabatic Turbine Efficiency	95	%
Shaft/Generator Efficiency	98	%
Air Compressor		
Pressure Ratio (outlet/inlet)	15.7	ratio
Adiabatic Compressor Efficiency	70	%
Combustor		
Combustor Inlet Pressure	294	psia
Combustor Pressure Drop	4	psia
Excess Air For Combustor	171.1	% stoich.
Heat Recovery Steam Generator		
HRSG Outlet Temperature	250	°F
Steam Cycle Heat Rate, HHV	9000	Btu/kWh
Steam Turbine		
Total Steam Turbine Outlet	286	MW
Power Block Totals		
Power Requirement	2	% MWg

Air Separation

Oxidant Composition		
Oxygen (O2)	95	vol %
Argon (Ar)	4.234	vol %
Nitrogen (N2)	0.7657	vol %

Other Fuels	6.99E-02	
Electricity	3.472	
Water	0.8192	
Slag Disposal	4.335	

Fixed Cost Component	O&M Cost (M$/yr)
Operating Labor	2.009
Maintenance Labor	6.5
Maintenance Material	9.749
Admin. & Support Labor	2.553

Cost Component	M$/yr	$/MWh
Annual Fixed Cost	20.81	3.647
Annual Variable Cost (excluding coal)	11.57	2.026
Total Annual O&M Cost	103.9	18.2
Annualized Capital Cost	39.85	6.983
Total Levelized Annual Cost	143.7	25.19

Power Block Plant Costs	Capital Cost (M$)
Gas Turbine	164.4
Heat Recovery Steam Generator	51.82
Steam Turbine	77.74
HRSG Feedwater System	8.511
General Facilities Capital	45.38
Eng. & Home Office Fees	30.25
Project Contingency Cost	45.38
Process Contingency Cost	24.22
Interest Charges (AFUDC)	-12.84
Royalty Fees	1.513
Preproduction (Startup) Cost	9.502
Inventory (Working) Capital	2.239
Total Capital Requirement (TCR)	448.1

Fixed Cost Component	O&M Cost (M$/yr)
Operating Labor	1.636
Maintenance Labor	2.686
Maintenance Material	4.03
Admin. & Support Labor	1.297

Cost Component	M$/yr	$/MWh
Annual Fixed Cost	9.648	1.691
Total Annual O&M Cost	9.648	1.691
Annualized Capital Cost	46.51	8.15
Total Levelized Annual Cost	56.16	9.84

Air Separation Plant Costs	Capital Cost (M$)
Process Facilities Capital	181.5
General Facilities Capital	27.22
Eng. & Home Office Fees	18.15
Project Contingency Cost	27.22

Final Oxidant Pressure	580	psia
Maximum Train Capacity	1.14E+04	lb-moles/hr
Number of Operating Trains	2	integer
Number of Spare Trains	0	integer
Unit ASU Power Requirement	210.4	kWh/ton O2
Total ASU Power Requirement	9.708	% MWg

Sulfur Removal

Hydrolyzer (or Shift Reactor)		
COS to H2S Conversion Efficiency	98.5	%
Sulfur Removal Unit		
H2S Removal Efficiency	98	%
COS Removal Efficiency	33	%
CO2 Removal Efficiency	15	%
Max Syngas Capacity per Train	2.50E+04	lb-mole/hr
Number of Operating Absorbers	4	
Power Requirement	0.6499	% MWg
Claus Plant		
Sulfur Recovery Efficiency	95	%
Max Sulfur Capacity per Train	1.00E+04	lb/hr
Number of Operating Absorbers	3	
Power Requirement	4.60E-02	% MWg
Tailgas Treatment		
Sulfur Recovery Efficiency	99	%
Power Requirement	0.1398	% MWg
Sulfur Sold on Market	90	%

Process Contingency Cost	9.073
Interest Charges (AFUDC)	-7.544
Royalty Fees	0.9073
Preproduction (Startup) Cost	5.821
Inventory (Working) Capital	1.316
Total Capital Requirement (TCR)	263.6

Fixed Cost Component	O&M Cost (M$/yr)
Operating Labor	2.009
Maintenance Labor	2.105
Maintenance Material	3.158
Admin. & Support Labor	1.234

Cost Component	M$/yr	$/MWh
Annual Fixed Cost	8.506	1.49
Total Annual O&M Cost	8.506	1.49
Annualized Capital Cost	27.36	4.794
Total Levelized Annual Cost	35.87	6.285

Sulfur Removal Plant Costs	Capital Cost (M$)
Sulfur Removal System - Hydrolyzer	1.478
Sulfur Removal System - Selexol	29.56
Sulfur Recovery System - Claus	13.76
Tail Gas Clean Up - Beavon-Stretford	5.789
General Facilities Capital	7.589
Eng. & Home Office Fees	5.059
Project Contingency Cost	7.589
Process Contingency Cost	4.223
Interest Charges (AFUDC)	-2.152
Royalty Fees	0.253
Preproduction (Startup) Cost	1.415
Inventory (Working) Capital	0.3753
Total Capital Requirement (TCR)	74.95

Variable Cost Component	O&M Cost (M$/yr)
Makeup Selexol Solvent	0.175
Makeup Claus Catalyst	9.71E-03
Makeup Beavon-Stretford Catalyst	1.42E-02
Sulfur Byproduct Credit	5.089
Disposal Cost	8.24E-02

Fixed Cost Component	O&M Cost (M$/yr)
Operating Labor	2.009
Maintenance Labor	0.6004
Maintenance Material	0.9007
Admin. & Support Labor	0.783

Cost Component	M$/yr	$/MWh
Annual Fixed Cost	4.294	0.7523
Annual Variable Cost	-4.807	-0.8424
Total Annual O&M Cost	-0.5139	-9.01E-02
Annualized Capital Cost	7.778	1.363
Total Levelized Annual Cost	7.264	1.273

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Appendix B: Notes on Chapter 3, Implications of generator siting for CO_2 pipeline infrastructure

B.1 Firm level profit calculations

Profit for the facility is its revenue minus expenses

$$\Pi_{\text{facility}} = \text{revenue}_{\text{facility}} - \text{expenses}_{\text{facility}} \tag{1}$$

Facility revenue is the sum of revenue received from selling electricity and from selling CO_2 for EOR.

$$\text{revenue}_{\text{facility}} = \text{electricity revenue} + CO_2 \text{ for EOR revenue} \tag{2}$$

Annual revenue is the sum over all product streams of the quantity of product sold at each hour, Q_{ij}, multiplied by the hourly price, P_{ij}

$$\text{annual revenue}_{\text{ij}} = \sum_{j} \sum_{i=1}^{8760} Q_{ij} \cdot P_{ij} \quad ; j = \text{ electricity}, CO_2 \tag{3}$$

The quantity of product sold, Q_j, is the quantity generated by the facility, $Q_{j\,gen}$, minus the transmission losses, $Loss_j$

$$Q_j = Q_{j\,gen} \cdot (1 - Loss_j) \quad ; j = \text{ electricity}, CO_2 \tag{4}$$

Generally the transmission losses are proportional to the distance to the load or CO_2 sequestration site (d_{load}, d_{cs}, respectively) and the quantity of product produced by the facility scale with the facility size, F_{size}, and availability F_{avail}

$$Q_{j\,gen} = F_{avail} \cdot F_{size\,j} \quad ; j = \text{ electricity}, CO_2 \tag{5}$$

A new facility could be designed and engineered at almost any size to produce a given level of output. Here, the model chooses facility sizes, S, that are multiples of those in IECM, and outputs k_j for electricity and CO_2 are determined by IECM.

$$F_{size\,j} = S \cdot k_j \quad ; j = \text{electricity}, \mathrm{CO_2} \tag{6}$$

The annual revenue for the facility can be expressed as

$$\text{annual revenue}_{\mathrm{ij}} = \sum_{j} \sum_{i=1}^{8760} \left[F_{avail} \cdot S \cdot k_j \cdot (1 - Loss_j)\right]_i \cdot P_{ij} \quad ; j = \text{electricity}, \mathrm{CO_2} \tag{7}$$

Similarly, facility expenses can be separated into fixed and locational component pieces. Fixed expenses are those which do not depend on where the facility is sited, such as the base capital costs of the facility (coal handling, gasifier, syngas cleanup, turbine), labor, etc. Non-locational costs are important for setting the scale of profits, but do not add information on locations for optimal siting. Locational expenses vary with the facility location and are important for siting decisions. These include fuel transportation expenses, electric transmission lines, and CO_2 transmission expenses.

$$\begin{aligned} \text{locational expenses}_{\text{facility}} &= \text{fuel expenses} + \text{energy transmission expenses} + \mathrm{CO_2} \\ &\quad\ \text{transmission} \\ &= \sum_j \text{locational expenses}_j \qquad ; j = \text{fuel, energy}, \mathrm{CO_2} \end{aligned} \tag{8}$$

Fuel expenses are the cost of coal needed to operate the facility, energy transmission expenses are the costs for transmitting the electricity to the load, and CO_2 transmission costs are the costs needed to get the produced CO_2 to the EOR facility. Each component piece is composed of the total capital costs, TCC, as well as operating and maintenance costs, OC.

$$\text{expenses}_j = \mathrm{TCC}_j + \mathrm{OC}_j \quad ; j = \text{fuel, energy}, \mathrm{CO_2} \tag{9}$$

Profit from the CO_2 transmission component of the facility decreases with the distance from the CO_2 sequestration site (Figure B.1).

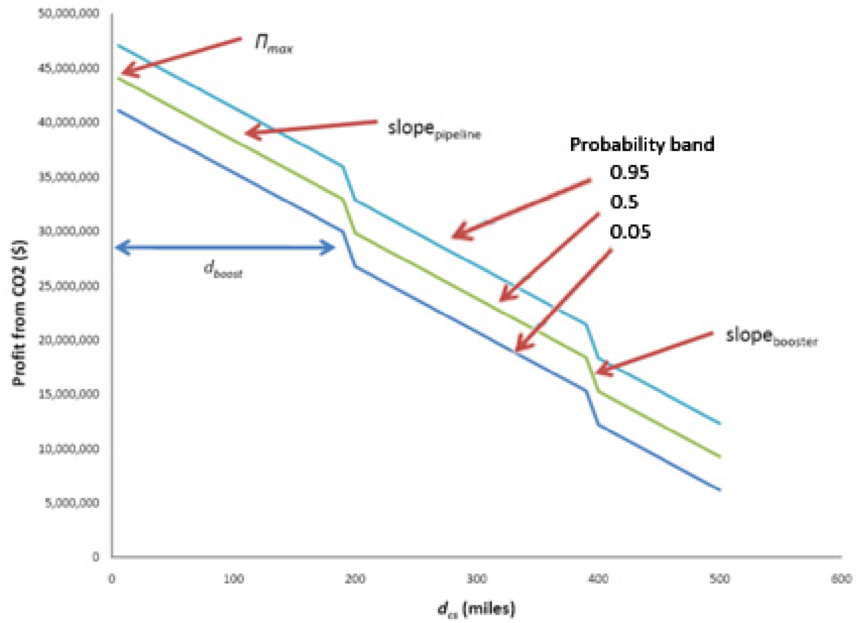


Figure B.1 Profit from CO_2 transmission as a function of distance from CO2 sequestration site. S=1, d_{boost}=200, A=0.088827,W=2, F_{avail}=1, P_{CO2} = Tri (18,20,22), $Loss_{CO2}$=0, D=1, COE=Normal(40,5), k_{CO2}=254.2

As the Figure A1 illustrates, the number and size of the booster station play an important role in determining profit from the CO_2 transmission process block.

The parameters of the transmission line were chosen from a lookup table developed from detailed engineering modeling of electric transmission systems [1]. For a given power requirement and distance, the appropriate values of the conductor resistance and nominal line voltage were selected (Table B.1)

Table B.1 AC Transmission line capacity (MW) lookup table [1]

Voltage (kV)	115	115	230	230	230	230	345	345	500	500	750	750
conductors	1	2	1	2	2	3	3	4	4	4	4	4
Conductor cross section (mm^2)	175	175	300	175	300	300	300	400	300	500	400	625
σ (ohms/ph)	0.192	0.096	0.109	0.096	0.055	0.036	0.036	0.021	0.027	0.017	0.021	0.014
Line length (km) 0	87	174	248	351	497	745	1120	1733	2166	2837	3777	4835
10	87	174	248	351	497	745	1120	1733	2166	2837	3777	4835
20	86	171	247	348	493	739	1114	1723	2159	2826	3770	4825
50	82	161	242	340	480	711	1093	1673	2130	2776	3740	4775
100	53	92	232	321	434	524	1036	1383	2053	2623	3665	4629
200	31	53	160	196	244	294	650	761	1502	1576	3352	3466
500	0	0	78	96	113	130	288	362	689	775	1932	2031
800	0	0	0	0	102	130	288	362	689	775	1614	1754
Installed cost[a] ($000/mile)	219	258	310	326	395	464	564	737	783	1,013	1,140	1,446

(a) converted to $2005; exclusive of right of way and site acquisition costs; materials costs (60% of total) adjusted for steel price increase from [2]

The sizes and costs of the switchgear and capacitors are chosen from an EIA lookup table developed through a detailed engineering analysis (Table B.2) [1].

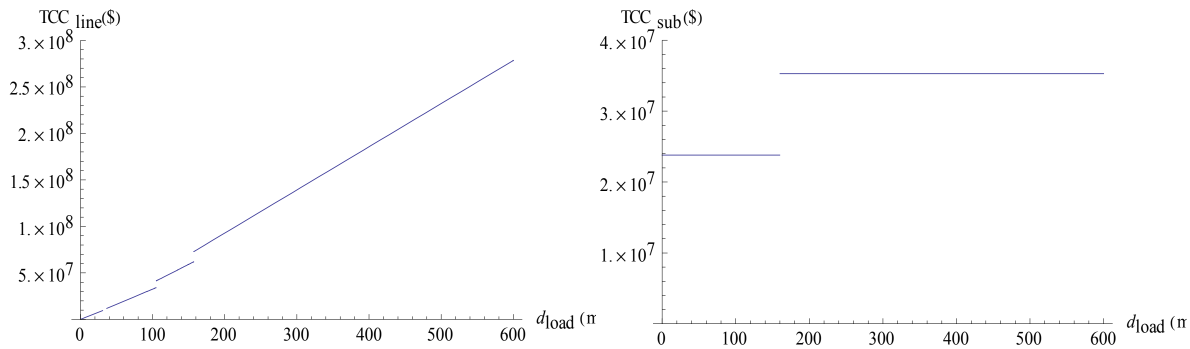
Table B.2 Substation switchgear, shunt and series compensation lookup table [1]

Line voltage (kV)	115	115	230	230	230	230	345	345	500	500	750	750
Conductors	1	2	1	2	2	3	3	4	4	4	4	4
Transformer/ Switchgear voltage (kV)	145	145	245	245	245	245	363	363	525	525	765	765
Transformer/ Switchgear cost[a] ($M)	1.01	1.01	1.70	1.70	1.70	1.70	2.52	2.52	3.66	3.66	5.32	5.32
Line length (km) shunt <500	0	0	0	0	0	0	0	0	0	0	0	0
500	0	0	31	39	41	52	114	126	253	256	549	0
800	0	0	62	78	93	104	229	251	506	512	1099	556
series <500	0	0	0	0	0	0	0	0	0	0	0	1111
500	0	0	0	0	19	26	58	84	151	187	325	0
800	0	0	0	0	30	42	93	134	241	300	604	359
Shunt cost[a] ($k/Mvar)	$4E\text{-}05 \cdot Mvar^2 - 0.05 \cdot Mvar + 34.77$											
Series cost[a] ($k/Mvar)	$7E\text{-}07 \cdot Mvar^3 - 0.09 \cdot Mvar + 90.00$											

(a) converted to $2005; materials costs (75% of total) adjusted for steel price increase from [2]

As an example, a 240 net MW IGCC facility transmitting electricity 100 miles would require a 230 kV line, with 2 conductors each with a 175 mm^2 cross sectional area, a total of 14 (1 line and 6 substation per line end) 245 kV transformers and switchgear and no shunt or series capacitors. Total capital costs, exclusive of right of way, are

(\$326,000/mile ×100 mile) + (14 transformers × \$1.70 million/transformer) = \$56.4 million.



(a) (b)

Figure B.2 Total capital costs verses distance from the load based on tables 3 and 4. (a) transmission line (b) substation and switchgear. Example facility size of 240 net MW

For an IGCC facility, annual profit from sales of electricity is shown in Figure B.3.

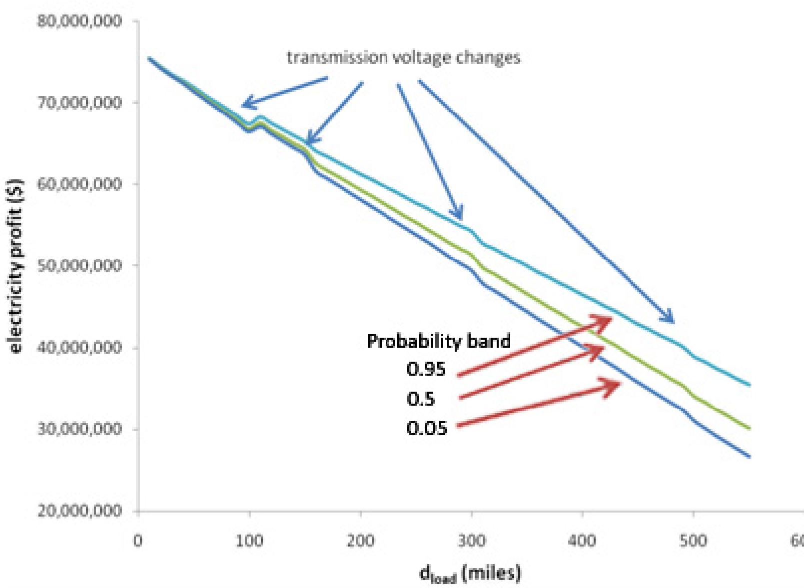


Figure B.3 Profit from sales of electricity as a function of distance from load. S=1, k_{elec}=240, A=0.088827, D=1, F_{avail}=1, P_{elec} = MISO AEBN interface (9/05-9/06), ROW =Tri (1.03, 1.4, 1.5)

Additional information on the baseline facility used in the model, derived from the Integrated Environmental Control Model, is shown in Table B.3.

Table B.3 Baseline 238 MW_e net Facility Configuration and Parameters [3]

Process Block (mean capital cost $2005)	Components	Size / Description
Gasifier ($143.1M)	1 train GE gasifier 0 spare train gasifier Coal handling Low temperature gas cooling Process condensate treatment	269 tons/hr syngas output
Air Separation Unit ($97.4M)	1 train	max output: 23,940 lb-mol/hr
Cold-gas Cleanup ($37.3M)	Hydrolyzer Selexol Claus plant Beavon-Stretford tail gas plant	98.5% efficiency 98% H_2S efficiency 95% efficiency 99% efficiency
CO_2 Capture ($42.0M)	Sour Shift + Selexol	2 operating absorbers max CO2 capacity: 15,000 lb-moles/hr
Power Block ($149.1M)	Gas combustion turbine Heat recovery steam generator Steam turbine HRSG feedwater system	GE 7FA CCGT 510.5 MW (gross) combined cycle/turbine 9000 Btu/kWh
Fuel	Illinois #6 coal	HHV: 10,900 Btu/lb

B.2 References

1. IEA GHG *Electrical Transmission Cost and Energy Loss Spreadsheet Data in Transmission of CO_2 and Energy*; International Energy Agency Greenhouse Gas R&D Programme: Cheltenham, UK, 2002.
2. CRU International Steel Price Index. http://www.cruspi.com/HomePage.aspx (July 16, 2007).
3. CMU CEES Carnegie Mellon University Center for Energy and Environmental Studies, IECM-cs Integrated Environmental Control Model Carbon Sequestration Edition. http://www.iecm-online.com/ (June 26, 2007).

Appendix C: Notes on Chapter 4, Short Run Effects of a Price on Carbon Dioxide Emissions from U.S. Electric Generators

C.1 Generation portfolio of ISOs included in the analysis

The three geographic areas analyzed vary in the annual amount of electricity produced and have significantly different portfolios of generation capacity used to meet demand. The model uses the most recent available data, from 2004. The dispatched generated energy at the present zero carbon dioxide prices is reflected in the MWh column in Table C.1. With carbon dioxide constraints, dispatch will be affected by the capacity in each region, reflected in the MW column. The Midwest ISO generation capacity is two-thirds coal. ERCOT's natural gas generators are two-thirds of its capacity, while PJM's capacity is roughly half coal, 30% natural gas, and 20% nuclear. None of the three has substantial hydroelectric generation. ERCOT has a small fraction of wind.

Table C.1 Electricity generation capacity and production by fuel source in 2004 [1]

	MISO [1845 lb CO_2/MWh average]				ERCOT [1519 lb CO_2/MWh average]				PJM [1256 lb CO_2/MWh average]			
	MW	MWh	% MW	% MWh	MW	MWh	% MW	% MWh	MW	MWh	% MW	% MWh
Nuclear	9,424	67,685,529	8.0%	13.5%	5,139	40,435,372	7.3%	17.2%	30,332	232,047,537	17.4%	35.5%
Wind	880	2,087,996	0.7%	0.4%	1,164	2,869,261	1.7%	1.2%	248	146,782	0.1%	0.0%
Hydro	1,327	5,203,463	1.1%	1.0%	521	878,980	0.7%	0.4%	6,199	7,850,440	3.6%	1.2%
Biomass	138	781,199	0.1%	0.2%	30	171,571	0.0%	0.1%	834	4,483,999	0.5%	0.7%
Coal	78,213	418,047,310	66.0%	83.5%	17,777	116,679,710	25.3%	49.5%	78,599	384,951,505	45.2%	58.9%
Natural Gas	25,639	6,619,249	21.6%	1.3%	45,639	74,528,231	64.9%	31.6%	49,923	21,575,626	28.7%	3.3%
Oil	2,879	77,233	2.4%	0.0%	94	456	0.1%	0.0%	7,807	2,698,905	4.5%	0.4%
Total	118,500	500,501,979	100%	100%	70,364	235,563,581	100%	100%	173,942	653,754,794	100%	100%
Peak Load (2006)	116,030				63,056				144,904			

C.2 Generator marginal costs

Because marginal costs for generators are not public information, the model uses estimates for marginal costs [2-4] as well as heat rates and fuel types from the US EPA eGrid database [1] and regionally appropriate assumptions for fuel prices [5] to calculate the unit dispatch (Table C.2).

Table C.2 Assumed fuel prices and variable costs

		PJM[a]	MISO[b]	ERCOT[c]
Nuclear	($/MWh)	16.5	16.5	16.5
Wind[d]	($/MWh)	20	20	20
Hydro	($/MWh)	10	10	10
Biomass	($/MWh)	50	50	50
Coal	($/MMBTU)	1.73	1.41	1.29
Natural Gas	($/MMBTU)	9.95	10.52	7.79
Oil[e]	($/MMBTU)	8.49	11.63	10.45

[a] estimate from EIA MidAtlantic census division including New Jersey, New York, Pennsylvania
[b] from EIA East North Central census division including Illinois, Indiana, Michigan, Ohio, Wisconsin
[c] from EIA Texas state data
[d] excludes production tax credit
[e] Distillate fuel oil includes all diesel, No. 1, No. 2, and No. 4 fuel oils

C.3 Calculating price increase and load reduction due to a carbon dioxide price

For a given CO_2 price, the model calculates the percent increase in retail electricity price, at each point in the load curve and then use a range of short run elasticities to calculate the reduced load. The steps taken to calculate the price increase, load reduction and overall carbon dioxide emission reductions are illustrated in Figure C.1 and Figure C.2.

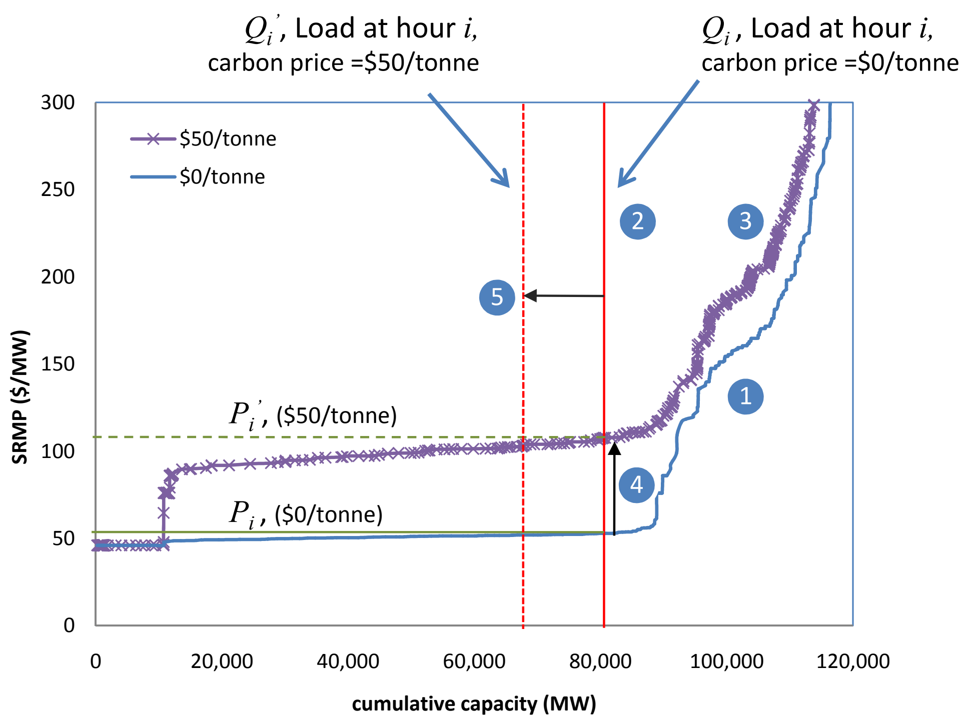


Figure C.1 Illustration of the iterative methodology used in the analysis

(1) For each control area, the appropriate weighted average markup from wholesale is applied to obtain a short run marginal price curve for electricity.

(2) The model assumes that there is a centralized entity (like an ISO) dispatching generation to meet hourly demand, Q_i, and that all customers see a real-time price equal to the marginal cost of the marginal unit (system lambda), P_i. This assumption is equivalent to real-time pricing in a competitive market with a uniform price auction. The model uses actual, historical hourly demand from 2005 for each ISO.

(3) The model use generator heat rates and CO_2 emission factors from eGRID [1] to construct dispatch curves for a given carbon dioxide price. This dispatch curve represents the short run marginal price of generation including the price of carbon dioxide emissions. In some circumstances, it is possible that a sufficiently high carbon price may shift the dispatch order; i.e., a generator positioned higher in the dispatch order (and thus dispatched only at higher levels of demand) may find itself positioned lower in the dispatch order (and thus dispatched more often) following the imposition of a CO_2 price.

(4) With a price on CO_2 emissions, to meet the same load, Qi, the price paid by consumers increases to Pi'. The percentage price increase is given by $(Pi'- Pi)\times 100/\ Pi$

(5) Hourly load is reduced according to the percent increase in electricity price and a given price elasticity. $Qi' = Qi \times (1 + ((Pi'- Pi) \times 100/\ Pi) \times \varepsilon)$

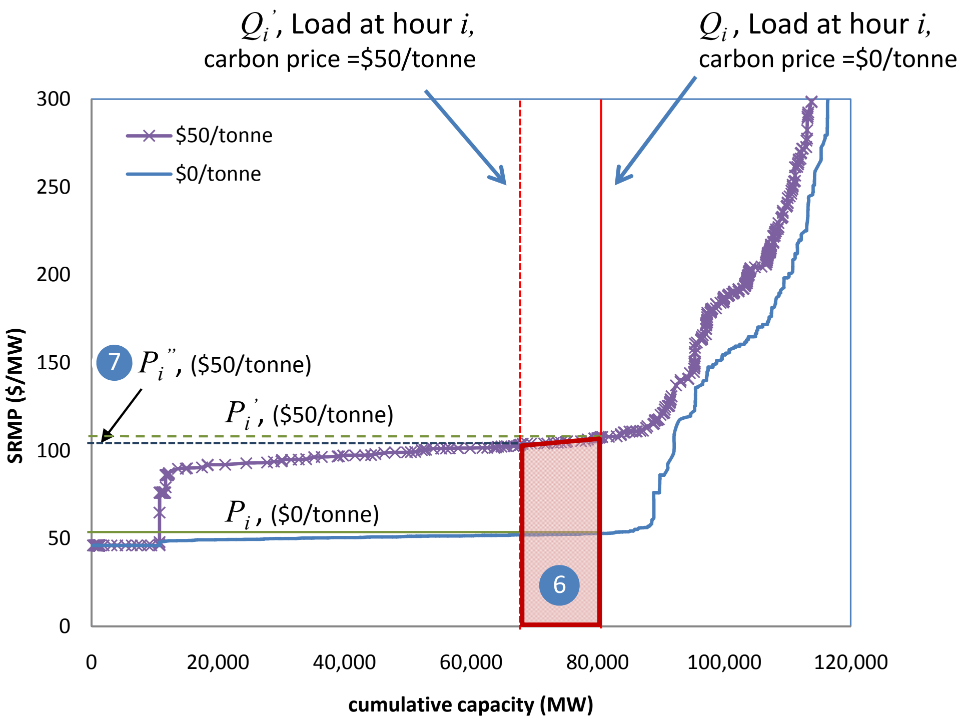


Figure C.2 Illustration of the iterative methodology used in the analysis (continued)

(6) The reduction in hourly carbon dioxide emissions due to decreased demand is the sum of all CO_2 emissions from generators between the original load, Q_i and reduced load, Q_i' . The CO_2 emission reductions per hour is the sum over each generator (j) no longer dispatched due to the reduced load(j=Q_i' to Q_i) of the generator output times the hourly CO_2 emissions rate, $\sum_{j=Qi'}^{j=Qi} MW_j \cdot CO_2 \text{ emission rate(tonne/MWh)}_j$.

(7) At the reduced demand, Q_i', the new price paid by consumers for electricity is P_i''. The model assumes the new price (P_i'') and quantity (Q_i'), after taking elasticity into account, represents a new equilibrium quantity and price for the system.

(8) This process is repeated for all 8760 hours of load data for each ISO to find the total amount of CO_2 reductions for a given CO_2 price and elasticity. This process is repeated for ranges of CO_2 prices and elasticities to create a contour plot of CO_2 reductions versus CO_2 price and elasticity. Figure C.3 illustrates how the percent load reduction depends on the load. The figure shows the percent price increase in the Midwest ISO due to a price on carbon dioxide emissions of $50/tonne versus the cumulative capacity, or load.

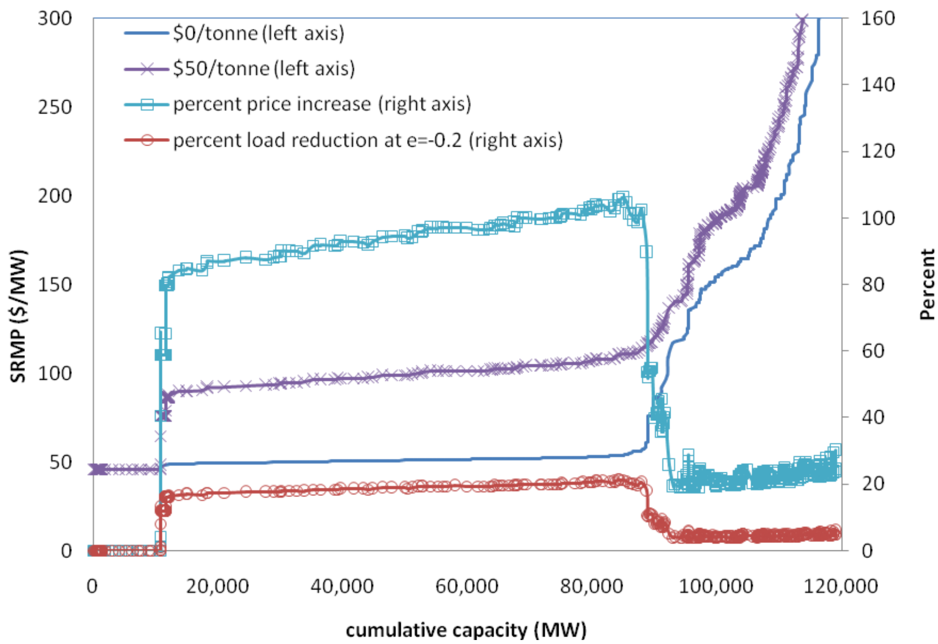
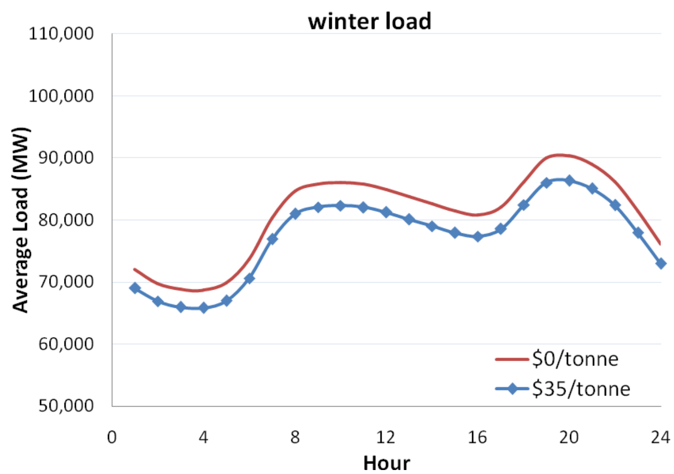


Figure C.3 Price increase and load reduction in Midwest ISO with a CO_2 price of $50/tonne and an elasticity of -0.2. Marginal costs have been converted into retail prices using a customer class weighted average for Midwest ISO.

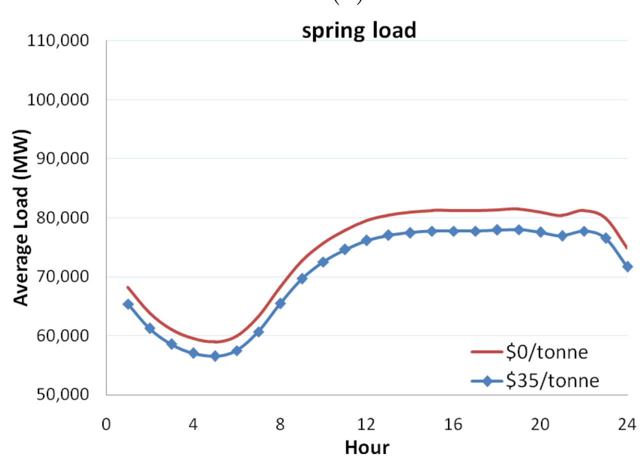
At very small loads, less than about 18,000 MW, there is no increase in the short run marginal price because only carbon dioxide free, hydroelectric, wind and nuclear power is dispatched. At baseload levels of demand, the percent price increase due to carbon dioxide emissions increases as coal fired plants are dispatched to meet the demand. For an assumed elasticity of -0.2, the percent reduction in load due to consumers elasticity is shown in red. For example, if demand is 80 GW at a given hour with no carbon dioxide price, the load would be expected to be reduced by about 18% for that same hour, with a carbon dioxide price of $50/tonne.

C.4 Electricity price increase due to a price on carbon dioxide emissions

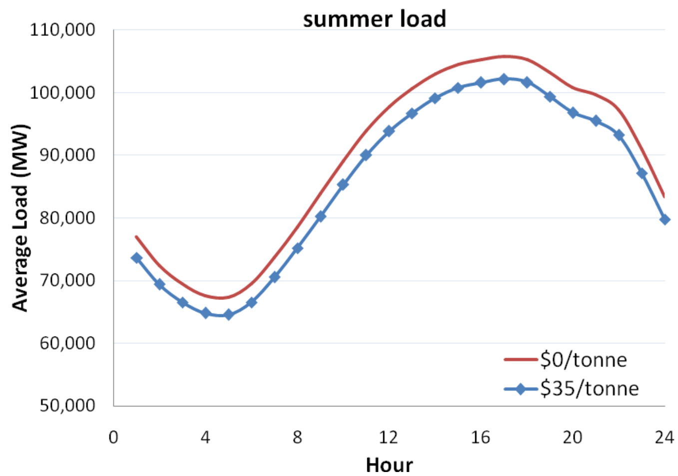
As Figure C.1 and Figure C.2 illustrate, a price on CO_2 emissions will increase the price of delivered electricity. The increase in hourly price ($P_i'' - P_i$, from Figure C.2), depends on the load, price of CO_2 and elasticity: baseloads levels of demand have the highest price increases while peak loads see smaller price increases; higher CO_2 prices lead to larger price increases; and larger elasticities lead to smaller price increases. The model examines the effect of a carbon dioxide price of $35/t on average electricity prices in each ISO. The average load in each ISO/RTO depends on the season, with highest loads generally occurring in the summer months. Figure C.4 shows the seasonal average loads by hour in PJM.



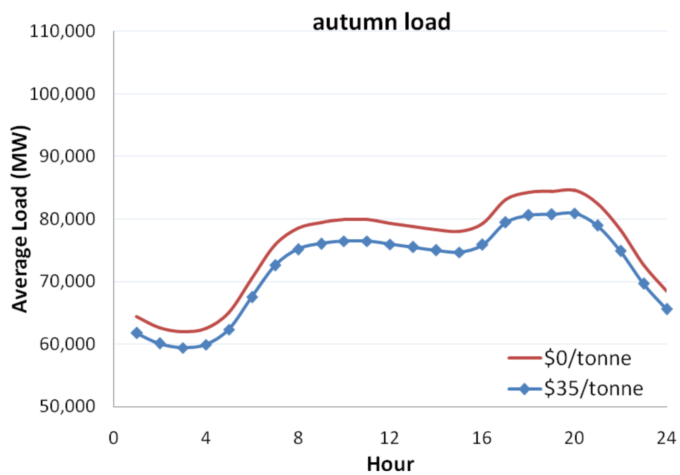
(a)



(b)



(c)



(d)

Figure C.4 PJM seasonal average load by hour; no carbon dioxide price (top) and \$35/tonne CO2 with an elasticity of -0.1 (bottom)

Using the average percent load reduction, the analysis examines the average hourly increase in electricity price (Table C.3).

Table C.3 PJM average electricity price ($/MW) by hour at $35/tonne and ε =-0.1

Hour	average SRMC ($/MW) $0	$35/tonne	% SRMC increase	average SRMP ($/MW) $0	$35/tonne	% SRMP increase	% load reduction (@ ε=-0.1)
1	17.87	48.48	171.3%	74.87	105.48	40.9%	4.09%
2	17.00	47.45	179.1%	74.00	104.45	41.1%	4.11%
3	16.66	46.79	180.9%	73.66	103.79	40.9%	4.09%
4	16.52	46.49	181.5%	73.52	103.49	40.8%	4.08%
5	16.44	46.35	182.0%	73.44	103.35	40.7%	4.07%
6	16.43	46.32	181.9%	73.43	103.32	40.7%	4.07%
7	16.55	46.54	181.3%	73.55	103.54	40.8%	4.08%
8	16.85	47.20	180.1%	73.85	104.20	41.1%	4.11%
9	17.20	47.96	178.8%	74.20	104.96	41.5%	4.15%
10	17.48	48.46	177.3%	74.48	105.46	41.6%	4.16%
11	17.66	48.88	176.7%	74.66	105.88	41.8%	4.18%
12	18.21	49.41	171.3%	75.21	106.41	41.5%	4.15%
13	18.88	49.97	164.6%	75.88	106.97	41.0%	4.10%
14	19.54	50.61	159.1%	76.54	107.61	40.6%	4.06%
15	20.30	51.24	152.4%	77.30	108.24	40.0%	4.00%
16	21.11	51.72	145.0%	78.11	108.72	39.2%	3.92%
17	22.10	52.22	136.3%	79.10	109.22	38.1%	3.81%
18	22.65	52.70	132.7%	79.65	109.70	37.7%	3.77%
19	23.10	53.30	130.8%	80.10	110.30	37.7%	3.77%
20	22.89	53.41	133.4%	79.89	110.41	38.2%	3.82%
21	21.85	52.61	140.8%	78.85	109.61	39.0%	3.90%
22	20.39	51.62	153.1%	77.39	108.62	40.3%	4.03%
23	19.67	50.98	159.2%	76.67	107.98	40.8%	4.08%
24	18.96	50.14	164.4%	75.96	107.14	41.0%	4.10%
Annual average				76.02	106.6	**40.3%**	4.03%

In PJM, imposing an instantaneous price on carbon dioxide emissions of $35/tonne will lead to a price increase of approximately 40 percent at an assumed elasticity of -0.1. The results of repeating the same procedure for the Midwest ISO and ERCOT are shown in Table C.4.

Table C.4 Average annual SRMP ($/MW)

RTO/ISO	$0/tonne	ε=-0.1, $50/tonne	Percent increase	ε=-0.1, $35/tonne	Percent increase
PJM	76.02	119.48	57.17	106.63	40.3
ERCOT	102.23	127.33	24.55	119.70	17.1
Midwest ISO	63.66	107.28	68.52	94.00	47.7

The price increase due to a $35/tonne price on carbon dioxide emissions is largest in the Midwest ISO (48%) and smallest in ERCOT (17%) at an elasticity of -0.1.

C.5 Changes in fuel use

A price on carbon dioxide emissions will change the amount of coal and natural gas generation in each ISO. If fuel mix changes lead to increased demand for certain fuels, there may be significant cost increases. The model examines the changes in annual coal and gas generation in each ISO across the ranges of elasticities and carbon dioxide prices (Table C.5). The model calculates the amount of coal and natural gas generation (MWh) needed to meet the 2005 historical annual load for each ISO at a given elasticity and CO2 price, and make comparisons to the generation needed when there is no CO_2 price.

Table C.5. Percent change in annual coal and gas generation (MWh) at representative values of elasticity (ε) and CO_2 price

parameters		Percent change					
	CO_2 price	MISO		ERCOT		PJM	
ε	($/tonne)	Coal	NG	Coal	NG	Coal	NG
0	20	-1.0	1.5	-0.2	0.1	-0.7	4.9
0	35	-1.8	5.8	-2.1	3.4	-2.6	5.9
0	50	-2.5	31.0	-4.0	6.5	-4.3	11.0
-0.1	20	-5.1	-9.2	-0.6	-2.9	-5.2	-4.9
-0.1	35	-8.9	-13.7	-2.8	-1.9	-10.1	-11.6
-0.1	50	-12.6	-4.7	-5.1	-0.9	-15.4	-14.4
-0.2	20	-9.2	-19.0	-1.0	-5.9	-9.8	-14.7
-0.2	35	-16.0	-30.4	-3.4	-7.3	-17.5	-25.5
-0.2	50	-22.7	-27.6	-6.0	-8.5	-26.7	-33.4
-0.4	20	-17.5	-36.6	-1.7	-11.7	-18.8	-30.8
-0.4	35	-30.4	-55.8	-4.6	-17.5	-32.8	-50.6
-0.4	50	-43.6	-64.3	-8.3	-22.8	-49.3	-64.6

At zero elasticity and a significant carbon price, there are minor changes to the dispatch order at moderate load (a few low heat rate gas units displace a few inefficient coal generators) and the amount of natural gas generation increases while the amount of coal generation decreases. When there is any elasticity of demand, a price on CO_2 emissions leads to an overall decreased demand and reductions in both natural gas and coal generation. Based on this partial equilibrium analysis, at typically cited values for elasticity, a price on CO_2 emissions would not increase prices for coal or natural gas fuels.

C.6 References

1. US Environmental Protection Agency eGRID Emissions & Generation Resource Integrated Database, eGRID2006 Version 2.1 (Year 2004 Data). http://www.epa.gov/cleanenergy/egrid/index.htm (November 1, 2007).
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Appendix D: Notes on Chapter 5, Near term implications of a ban on new coal-fired power plants in the US

D.1 Data

Generation plant data, including heat rates, emission rates, fuel type and rated capacity, are from the US EPA eGRID2006 version 2.1 database [1]. The analysis considers only dispatchable electricity generation and excludes cogeneration units such as hospitals and universities. Generators in the eGRID database with negative or zero heatrates were removed from the analysis (4 oil units totaling 222 MW; 1 coal unit of 150 MW; 24 NG units totaling 7469 MW). Generation from eGRID, reported by NERC region, was re-categorized by ISO. Load data are historical, hourly aggregate load reported by the ISO [2, 3]. The analysis uses all 8760 hourly load data points for each ISO.

D.2 Generation unit additions

To help ensure an adequate supply of electricity is available, ISO maintain reserve margins. The reserve margin target is 12.5% for ERCOT [4], 15% for PJM and 12% for the Midwest ISO. If forecast demand exceeds the reserve margin limit, then new generation units must be constructed. New generation is constructed with sizes, construction times, and heat rates from the EIA annual Energy Outlook [5]; emission performance data for new generation technologies are from a 2007 NETL fossil energy cost and performance report [6]. Note that construction times for new generation from the EIA, appear optimistic and actual construction times for new generation are considerably longer [7, 8], and that construction times for transmission lines are not included (the median time to construct a transmission line longer than 80 km in the US has been 7 years [9]).

D.3 Generator marginal costs and retail price calculation

Because marginal costs for generators are not public information, estimates for marginal costs [10-12] are used as well as heat rates and fuel types from the US EPA eGrid database [1] and regionally appropriate assumptions for fuel prices [13] to calculate the unit dispatch (Table D.1).

Table D.1. Assumed fuel prices and variable costs [10-13]

		PJM[a]	MISO[b]	ERCOT[c]
Nuclear	($/MWh)	16.5	16.5	16.5
Wind[d]	($/MWh)	20	20	20
Hydro	($/MWh)	10	10	10
Biomass	($/MWh)	50	50	50
Coal	($/MMBTU)	1.73	1.41	1.29
Natural Gas	($/MMBTU)	9.95	10.52	7.79
Oil[e]	($/MMBTU)	8.49	11.63	10.45

[a] estimate from EIA MidAtlantic census division including New Jersey, New York, Pennsylvania
[b] from EIA East North Central census division including Illinois, Indiana, Michigan, Ohio, Wisconsin
[c] from EIA Texas state data
[d] excludes production tax credit
[e] Distillate fuel oil includes all diesel, No. 1, No. 2, and No. 4 fuel oils

Applying these variable generation costs to the fleet of generators in ERCOT, as well as the historical load, the price duration curve for the year is shown in Figure D.1.

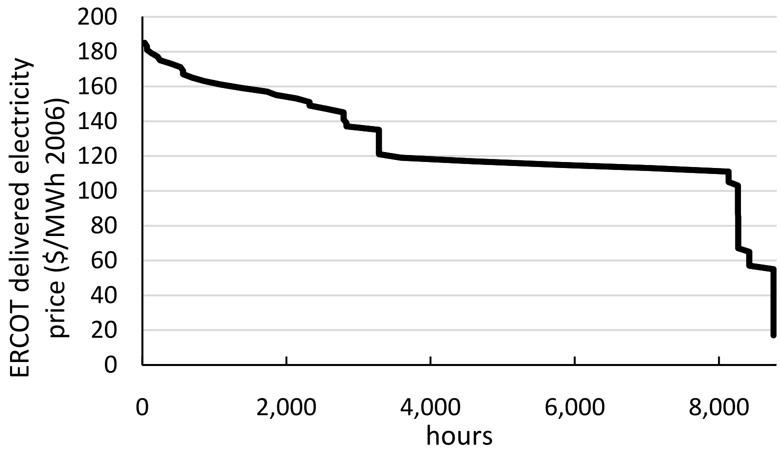

Figure D.1 Calculated ERCOT 2006 delivered electricity price duration curve using economic dispatch and a retail adder of $36/MWh

D.4 Historical and forecast load growth

Assumptions for load growth used in the model come from analysis of historical data in each region and from published estimates from ISOs. Load growth is assumed to be constant across all hours and the load growth rate is applied uniformly to all hourly data.

The model uses ERCOT load growth of 2.1%/year through the year 2030, based on the published reports from ERCOT. A 2006 ERCOT planning report [15] looking 10 years into the future uses three representative load growth scenarios: Base Case, incorporating peak and energy growth of 2%/ year; High Growth Case: incorporating peak and energy growth of 4%/year; and High Energy Case, incorporating peak growth of 2%/year and energy growth of 3%/year. A NERC long term assessment [16] forecasts ERCOT summer load growing by 2.15% per year from 2007-2016 (62,669 to 75,899MW), and winter load growing by 2.21% per year from 2007-2016 (46,038 to 56,053 MW). These numbers incorporate the conservation efforts that are planned for ERCOT. A 2007 report [17] from the Public Utility Commission of Texas reports a standard forecast methodology using an exponential firm load forecast of 2.2%/year from 2007-2016.

Load growth in the Midwest ISO is projected to be at a lower rate than in ERCOT; a 10-year forecast shows peak load growing 14% over the period 2007-2017 [18] (about

1.4%/year), inclusive of planned demand side load management initiatives. This linear forecast is extended to 2030 in the model. Load growth in PJM is linear as well; a 15-year forecast shows peak loads growing 25% over the period 2007-2022 [19] (about 1.5%/year). This linear forecast is extended to 2030 in the model.

D.5 Queued generation

There are a number of announced existing planned additions over the years 2008-2013 in each ISO (Table D.2). The model includes new generation with Signed Interconnection Agreement and Air Permits from ERCOT [20], the Midwest ISO [18] and PJM [21, 22] in the appropriate year. Note that some of these include coal, but assume that these projects would be grandfathered in and allowed to enter operation since money has already been spent.

Table D.2. Queued capacity additions by year and ISO. New units with signed Interconnection Agreement[18, 20-22]

ISO	Year	Type	MW	Total
ERCOT	2009	NGCC	255	2,534
		Coal	581	
		Wind	1,698	
	2010	Coal	2,460	2,520
		Wind	60	
	2012	Coal	925	925
Midwest ISO	2009	NGCC	1,800	3,300
		Coal	500	
		Wind	1,000	
	2010	NGCC	500	750
		Coal	250	
	2011	Coal	250	250
	2012	Coal	500	500
PJM	2009	NGCC	820	1,365
		Wind	545	
	2010	NGCC	545	893
		Coal	196	
		Wind	152	
	2011	NGCC	560	800
		Coal	240	

D.6 Per-capita demand growth

The demand reduction scenario reflects a future where aggressive demand reductions are implemented and annual load grows at a reduced rate. This scenario uses the per capita demand reductions achieved in California as a model for other regions in the US. California has implemented policies that have aggressively reduced per capita electricity demand growth in the state (3.4% from 1995 -2005), as compared to the rest of the United States (7.4% from 1995-2005)

D.7 Scenarios

Scenarios investigated in the analysis are shown in Table D.3.

Table D.3. Future electric power sector scenarios investigated in the analysis

Scenario	**Description**
Business as usual (BAU)	Future coal and natural gas generation capacity is constructed to approximately match current generation percentages in each ISO/RTO
No coal. Big natural gas push (NG)	New generation is exclusively natural gas combined cycle plants (NGCC)
No coal. Big wind push (wind)	New generation is wind (the model allows up to 20% penetration, but the limit is not reached in the short timeframe to 2030) paired with natural gas for firm power at a ratio of 1:0.75; (*e.g.,*100 MW of new wind requires 75 MW of NG for fill in)
No coal. Aggressive demand reductions exceeding those achieved by California (DR)	Aggressive demand reductions with 0% per capita demand growth rate. New generation is wind (the model allows up to 20% penetration, but the limit is not reached in the short timeframe to 2030) and natural gas

In the business as usual scenario, annual demand for electricity in each ISO grows at historical rates and new generation capacity is constructed to match the mix of generators. New generation capacity in the BAU scenario is constructed to match 25%

coal, 63% NG and 4% wind in ERCOT; 66% coal, 22% NG and 1% wind in the Midwest ISO; and, 47% coal, 26% NG and 0% wind in PJM.

The natural gas scenario reflects a future where there is a large push towards natural gas combined cycle (NGCC) generators. In this scenario, annual demand for electricity grows at historical per capita rates, and new generation is exclusively NGCC units.

The wind scenario reflects a future where there is a large push towards renewables and wind turbines. Because of the well know variability issued associated with wind [23], the wind scenario pairs natural gas generators with wind to create firm, dispatchable power. Because there is more wind at night than during the day, more fill in natural gas must operate during the day to maintain firm power. 10s data from 7 operating wind turbines summed over 15 days was used to calculate an average overnight (4pm -4am) capacity factor of 0.401 and an average daytime capacity factor is 0.276. Two curves (day and night) are used when dispatching wind resources using these calculated average capacity factors for wind and the complements for natural gas.

The demand reduction scenario reflects a future where aggressive demand reductions are implemented and annual load grows at a reduced rate. This scenario uses the per capita demand reductions achieved in California as a model for other regions in the US. California has implemented policies that have aggressively reduced per capita electricity demand growth in the state (3.4% from 1995 -2005), as compared to the rest of the United States (7.4% from 1995-2005) (Figure D.2).

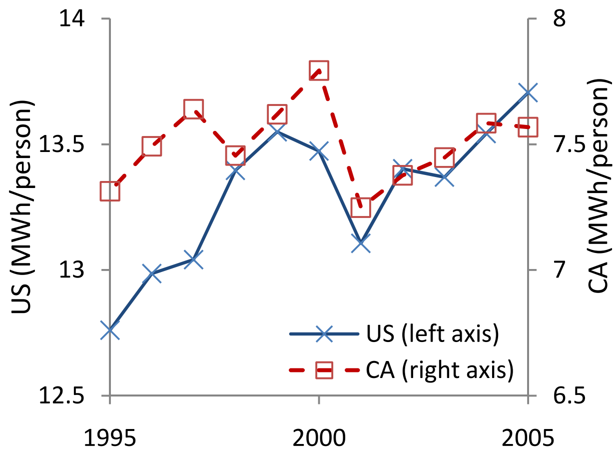

Figure D.2 Per capita electricity consumption and growth rates from 1995 to 2005 in the US (left axis) and in California (right axis). Population data from [24, 25]; electricity data from [26, 27].

The demand reduction scenario examines the case where demand reductions are even larger than seen in California, with 0% per capita growth. In this scenario, new generation is wind and natural gas units.

Because the demand reduction scenario incorporates per capita demand growth of 0%, load grows at the projected population growth rate in each region. Texas/ERCOT population is projected to grow exponentially at a rate of 1.55%/y through 2030 [28]; Midwest/Midwest ISO population is projected to grow more slowly with linear growth of about 4.6% over the period 2010-2030 [29]; PJM population is projected to grow linearly at 3.4% over the period 2010-2030 [29].

D.8 Natural gas supply and demand

The model does not incorporate a supply elasticity for natural gas. However, the price of natural gas is determined by the market and responds to supply and demand (as well as other factors such as speculation, weather, levels of natural gas storage, pipeline capacities, imports, etc).To investigate the sensitivity of the results to the interactions of natural gas supply, demand and price a simplified model of natural gas price and demand is developed using the historical monthly average price of natural gas to electric generators (in adjusted $2006) [30] and natural gas deliveries to electric power consumers

[31, 32]. From fits of these historical data, three forecast models are created representing high, medium and low natural gas price response to demand (Figure D.3).

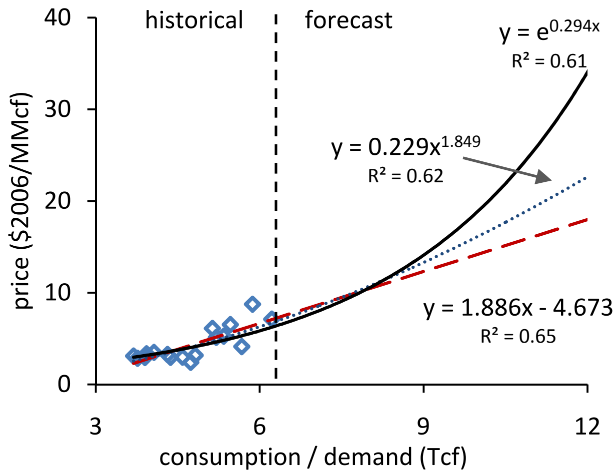

Figure D.3 Average annual natural gas price for electric generators versus demand for electricity production. Historical monthly average price (in adjusted $2006) [30] and consumption [31, 32] data from 1990-2006. Forecasts are from linear, power and exponential regressions.

From these forecast models, models are developed to determine the percent price increase, given the percent increase in demand from 2006 demand levels (Figure D.4).

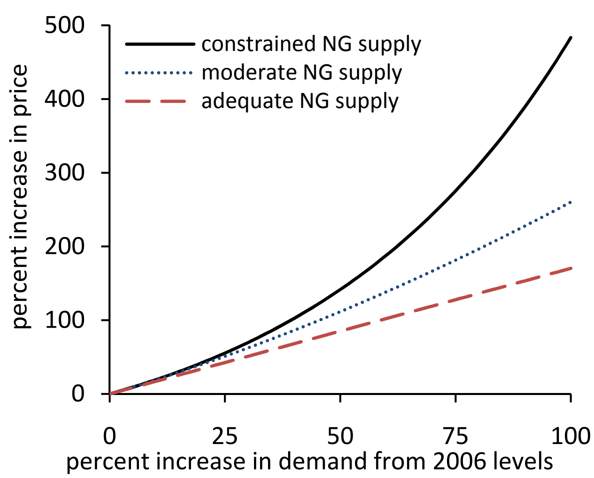

Figure D.4 Natural gas price versus demand models used in the analysis. A doubling of natural gas demand for electric generators leads to a price increase of approximately 175% to 500% depending on the model used.

Using these price versus demand models, a doubling of natural gas demand for electric generators leads to a price increase of approximately 175-500% depending on the particular model (Table D.4).

Table D.4. Natural gas price versus demand models used in the analysis. Percent price increase (y) due to percent demand increase from 2006 levels (x)

NG supply scenario	model
constrained	$y = 0.0397x^2 + 1.0297x$
moderate	$y = 0.0074x^2 + 1.8606x$
adequate	$y = 1.7036x$

The models represent expectations of the future supply of natural gas in the US. If natural gas supply is constrained, then moderate levels of increased demand can lead to large price increases. Whereas, if natural gas is generally available and faces resource constraints, then demand increases will lead to only moderate price increases.

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