Implications of generator siting for CO_2 pipeline infrastructure

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Abstract

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, we examine where a profit maximizing independent 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, we find that it is always 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.

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 (American Electric Power, 2007a; CNNMoney.com, 2007; Cornwall, 2007; Investor's Business Daily, 2007; NRG Energy Inc., 2007; Southern Company, 2007). 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 hedge against the volatility of other fuel prices such as natural gas price shocks and seasonal variations (O'Brien et al., 2004). Additionally, new coal gasification facilities have environmental advantages over traditional combustion facilities (Klett et al., 2002; Morgan et al., 2005; Ratafia-Brown et al., 2002); one of the largest advantages is the ability to capture carbon dioxide (Rubin et al., 2004). Post-combustion capture of carbon dioxide is also being considered, both for coal (American Electric Power, 2007b) and for natural gas electric generators. Increasing environmental pressures and the likelihood of a price on carbon dioxide emissions in the near future (Ball, 2007; Fialka, 2007; Mufson, 2007) has led project developers to announce that some future plants will be constructed with the ability to capture and sequester carbon dioxide emissions (CCS) (Gasification Technologies Council, 2006). 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 (O'Brien et al., 2004). 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 (O'Brien et al., 2004). 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 (O'Brien et al., 2004), 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 transportation costs for inputs and outputs are minimized and where firm-level profits maximized. For new plants constructed with CCS, in addition to fuel deliver 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 1 illustrates the location of coal mines, major Midwest ISO nodes, and existing CO_2 pipelines and enhances oil recovery fields in the US.

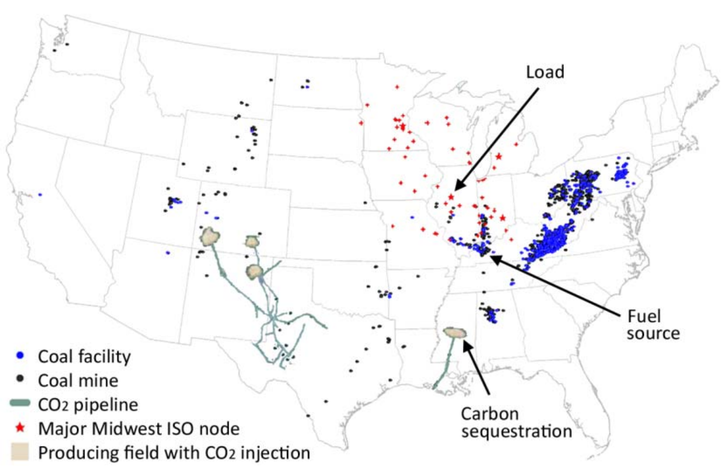


Figure 1. Location of coal mines, major nodes in the Midwest ISO and existing CO_2 pipelines for enhanced oil recovery. Examples of

a potential load, fuel source and CO_2 sequestration site are highlighted. (IPCC, 2005; Midwest ISO, 2007; National Mining Association, 2007)

The facility location problem has important infrastructure implications (in the US, at both state and federal levels) (Parfomak and Folger, 2007). 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 we examine 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.

We develop a model for determining the profit maximizing facility location 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.

2. Method

We consider the location of a coal fueled facility producing electricity with carbon capture and sequestration. We perform a probabilistic analysis 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, we do not consider the economics of the base facility itself, only the sensitivity of the profits to the location. Here we assume that an independent 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. We recognize that 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 we do not constrain the analysis to place the plant on a river. Similarly, we recognize that terrain will influence the construction costs for CO_2 pipelines and electricity transmission lines, and note that the terrain is broadly similar throughout the locus of this study. We note that 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.

We model the engineering and economic details of the baseline IGCC facility from the Integrated Environmental Control Model (IECM) version 5.2.1 (CMU CEES, 2007), 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). 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, we construct a probabilistic engineering and economic model 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. We apply this model to a hypothetical facility located in the US Midwest and use regionally appropriate probabilistic values for parameters (historical and forecasted costs for Illinois #6 coal; actual electricity prices for 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 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.

2.1. Carbon dioxide transport

We model the transport of carbon dioxide to an EOR or CO_2 sequestration site by pipeline. CO_2 is transported in a supercritical fluid state to maximize piping efficiency (McCoy, 2005). 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 (Bock et al., 2002; McCoy, 2005). Variables affecting pipeline pressure include the injection pressure, booster compressors and diameter of the pipeline. We assume 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 (IPCC, 2005).

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, we use a range of 161 to 402 kilometers (100 to 250 miles) between booster stations, reflecting the operation of currently operating CO_2 pipelines (Dakota Gasification Company, 2007; IPCC, 2005). Here, we include 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 we do not optimize the pump size; rather we overestimate and assume a booster of a fixed pump size. The model uses capital cost estimates for booster pumping stations from the International Energy Agency (IEA GHG, 2002b) adjusted to 2005 dollars (BLS, 2007). 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) (IPCC, 2005). 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 (IPCC, 2005).

The model uses pipeline capital costs developed from a regression analysis of IECM data (CMU CEES, 2007) (IECM makes use of industrial analogies to published natural gas pipeline costs (Bock et al., 2002) 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 (McCoy, 2005)). These capital costs include the costs of compressors to inject CO_2 into a pipeline at 13.8 MPa (2000 psia). We note the pipeline capital costs used in our IECM-based model are perhaps a bit higher than those incurred by current pipelines: McCoy (McCoy, 2005) 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) (IEA GHG, 2002b) are about 12% lower than those reported by IECM.

Operating costs for pipelines include annual inspections and maintenance and are those incorporated in IECM. We note that IECM pipeline O&M costs may also be high: McCoy's (McCoy, 2005) review of FERC filings and finds reported O&M costs to be approximately 30%

lower than those used by IECM; and IPCC (IPCC, 2005) 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.

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) averages 23.8 mills for rail and 6.08 mills for barge (from FERC form 580, converted from 1996 dollars (EIA, 2007c)). 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 (EIA, 2007b). The average mine mouth price of coal in Illinois Basin for 2005 was $31.60/tonne (EIA, 2007a). 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.

2.3. Electricity transmission

If the generation facility is not located at the electric load, electricity must be transmitted. Here, we assume that the facility operator must construct the appropriate transmission infrastructure to the nearest electricity node and model 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 (Bielicki and Schrag, 2006)).

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) (Bergerson and Lave, 2005). Because it is unlikely that a single facility serving the Midwest ISO would choose to locate outside a 600 mile radius, here we consider only AC transmission (Figure 2).

Figure 2. Limit of AC transmission 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 (IEA GHG, 2002a). 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 (IEA GHG, 2002a) to determine the necessary transmission line parameters necessary for a given transmission line distances and required power flow (see Appendix). Transmission line losses are modeled as resistive and depend on the power transmitted, conductor resistance, line length and voltage (IEA GHG, 2002a) (see Table 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, but are not considered here).

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 (Hughes and Brown, 1995) (converted to 2005 dollars using (BLS, 2007)) and are generally consistent with transmission cost estimates in the literature (CLRTP, 2004; Denholm and Short, 2006). Right of way and site acquisition costs can "vary enormously" (IEA GHG, 2002a) depending on the geography, terrain and population density; ROW point estimates are 3% of installed costs however, for completeness, we consider 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 (IEA GHG, 2002a) (Table 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 (IEA GHG, 2002a), and are generally consistent with other published estimates (CLRTP, 2004).

2.4. Model

Given the fixed location of a fuel source, CO_2 sequestration site and electric load, we seek 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

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

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

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

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

Table 1. Model parameters

Variable	Description	Values used in analysis	Source
S	facility size index (IECM multiplier)	1–3	(CMU CEES, 2007)
F_{avail}	facility availability (%)	80	
k_f	single train (baseline) coal requirement (tons/hr)	127.6	(CMU CEES, 2007)
k_{elec}	single GE 7FA turbine (baseline) net output (MW/hr)	240	(CMU CEES, 2007)
k_{CO2}	single train CO_2 (baseline) output flowrate (tons/hr)	254.2	(CMU CEES, 2007)
ε	net plant efficiency, HHV (%)	29.21	(CMU CEES, 2007)
A	amortization factor	$i/(1-(1+i)^{-n})$	(Rubin, 2001)
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)	(IPCC, 2005)
$\text{TCC}_{pipeline}$	pipeline capital cost ($M)	$0.6212 \cdot d_{CS} + 0.0059 \cdot Q_{\text{CO2 gen}}$	(CMU CEES, 2007)
$\text{OC}_{pipeline}$	pipeline O&M cost ($M/yr)	$0.005 \cdot d_{CS}$	(CMU CEES, 2007)
$\text{TCC}_{booster}$	booster capital cost ($M)	$9.775 \cdot \dot{W} + 0.575$	(BLS, 2007; IEA GHG, 2002b)
$\text{OC}_{booster}$	booster O&M cost ($M/yr)	$\dot{W} \cdot COE \cdot t$	

$Q_{CO2\ gen}$	total CO_2 generated (tons/hr)	$F_{avail} \cdot k_{CO2i} \cdot S$	
$\dot{W}$	booster pump power (MW)	range (0.5 – 3)	(Babcock Eagleton Inc., 2007)
COE	cost of electricity for pump ($/MW)	normal ($\mu=40$, $\sigma^2=5$)	
t	pump runtime (hr/yr)	$8760 \cdot F_{avail}$	
$Loss_{CO2}$	CO_2 losses during transport (%)	triangle (1.0, 1.5, 2.0)	(Apt et al., 2007)
$revenue_{CO2i}$	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 ($/ton)	triangle (15, 18, 20)	(CMU CEES, 2007)
Fuel delivery			
d_{fuel}	distance to fuel purchase site (miles)	range (0 – 600)	
TCC_f	coal transport capital cost ($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	(EIA, 2007a)
$T_{f\ rail}$	coal rail transport cost (mill/ton-mile)	23.81	(EIA, 2007c)
$T_{f\ barge}$	coal barge transport cost (mill/ton-mile)	6.08	(EIA, 2007c)
$Loss_f$	coal losses during transport (%)	0	
annual $\mathrm{expenses}_{\mathrm{fuel}}$	annual fuel expenses	$8760 \cdot Q_f\left(1 + Loss_f\right) \times \left(P_f + d_f\left(T_{f\ rail} + T_{f\ barge}\right)\right)$	
Electricity transmission			
d_{load}	distance to electric load or ISO hub (miles)	range (0 – 600)	
$Loss_{elec}$	electricity transmission losses (%)	$(Q_{elec\ gen} \cdot \sigma \cdot d_{load})/V^2$	(IEA GHG, 2002b)
$\mathrm{TCC}_{\mathrm{line}}$	total transmission line capital cost ($M)	$\mathrm{TCC}_{\mathrm{line\ only}}$ + ROW	
$\mathrm{TCC}_{\mathrm{line\ only}}$	transmission line capital cost ($000/mile)	219 – 1,446	(IEA GHG, 2002a)
ROW	right of way costs (% $\mathrm{TCC}_{\mathrm{line\ only}}$)	triangle(30, 40, 50)	

OC_{line}	transmission line operating cost (% TCC_{line}/yr)	1.00	(IEA GHG, 2002a)
$TCC_{substation}$	substation capital cost ($M)	TCC_{switch}+TCC_{shunth}+ TCC_{series}	
TCC_{switch}	switchgear and transformer cost ($M)	1.01 – 5.32	(IEA GHG, 2002a)
TCC_{shunt}	shunt capacitor cost ($000/Mvar)	$4E\text{-}05 \cdot Mvar^2 - 0.05 Mvar + 34.77$	(IEA GHG, 2002a)
TCC_{series}	series capacitor cost ($000/Mvar)	$7E\text{-}07 \cdot Mvar^3 - 0.09 \cdot Mvar + 90$	(IEA GHG, 2002a)
Mvar	transmission reactive power requirement (Mvar)	0 - 1,111	(IEA GHG, 2002a)
$OC_{substation}$	substation line operating cost (% $TCC_{substation}$/yr)	0.25	(IEA GHG, 2002a)
σ	conductor resistance (ohms/ph)	0.014 – 0.192	(IEA GHG, 2002a)
V	nominal transmission line voltage (kV)	115 – 750	(IEA GHG, 2002a)
$Q_{elec\ gen}$	total electricity generated (MW/hr)	$F_{avail} \cdot k_{elec} \cdot S$	
$P_{elec\ i}$	hourly electricity price ($/MWh)	MISO historical data	(Midwest ISO, 2006)
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. Results

To estimate the effects of facility location on profit, we consider 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).

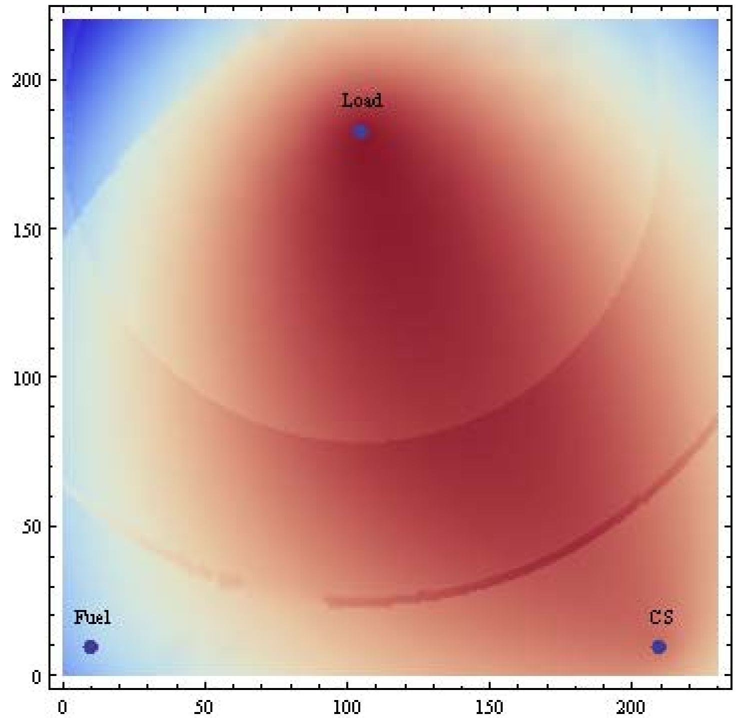


Figure 3. Example facility siting results. Profit as a function of location (in miles). Red indicates higher profits. 240 MW facility selling electricity into MISO AEBN node; Rail transport; Favail=0.8; i=0.08; n=30; D=1; P_{CO2}=18; $Loss_{CO2}$=0.015; $Loss_{fuel}$=0; T_{frail}=23.81; ROW=0.4; d_{boost}=250; Wdot=1; COE=40

Figure 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 cannot 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 4 shows the cross section of the profit along the load–carbon sequestration line.

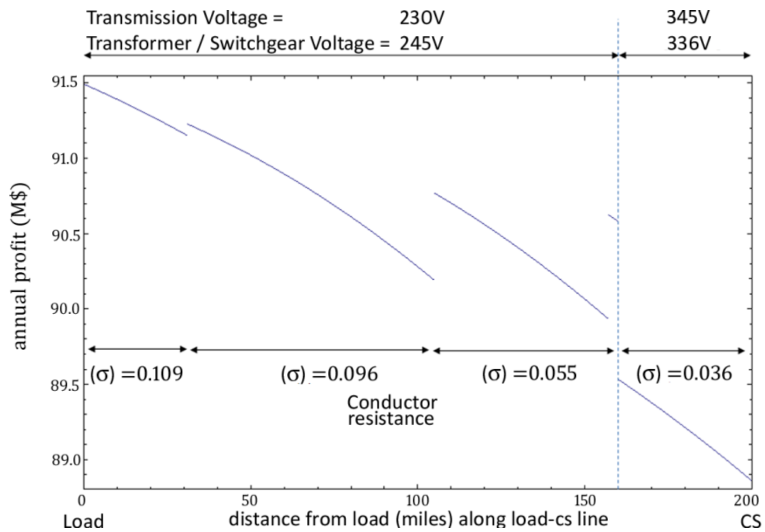
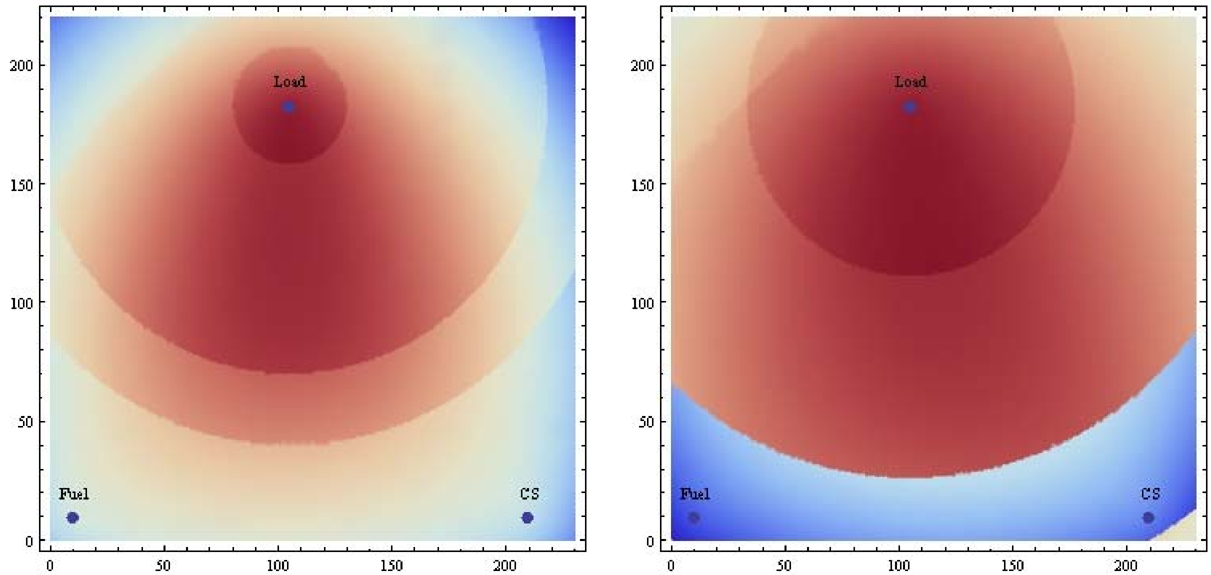


Figure 4. Cross section of profit along the load-carbon sequestration line. The load is at the left side and the CO_2 sequestration site is at the right. Profit jumps occur primarily as a result of changes in transmission line conductor size and line voltages.

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.

We examined 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 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 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.

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 6 illustrates the optimal location as a function of the distance between the load and CO_2 sequestration site.

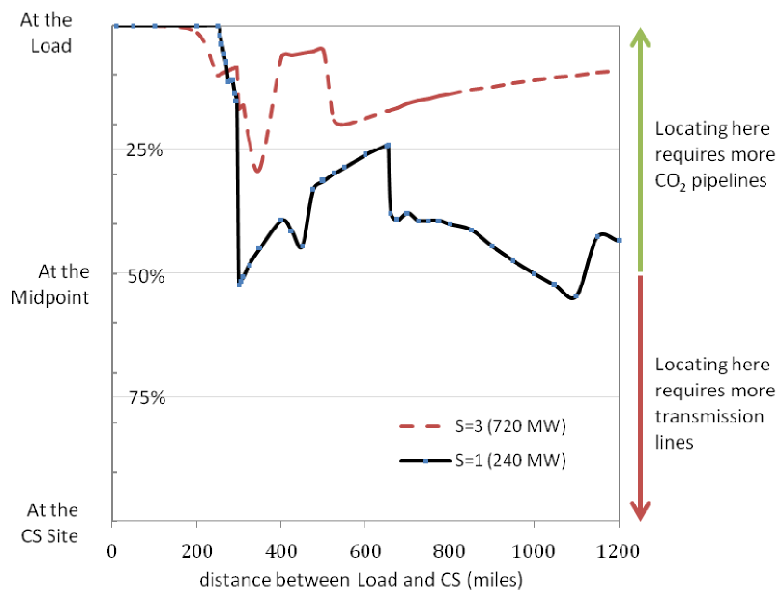


Figure 6. Profit maximizing facility location (% distance from the load) as a function of the distance between the load and CO_2 sequestration site. In nearly all cases, the facility should be located nearest the load. Distance to the fuel source is not considered. Parameter values as in Figure 3.

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.

We apply the model 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 1. The results of the analysis using the indicated values of the parameters are shown in Figure 7.

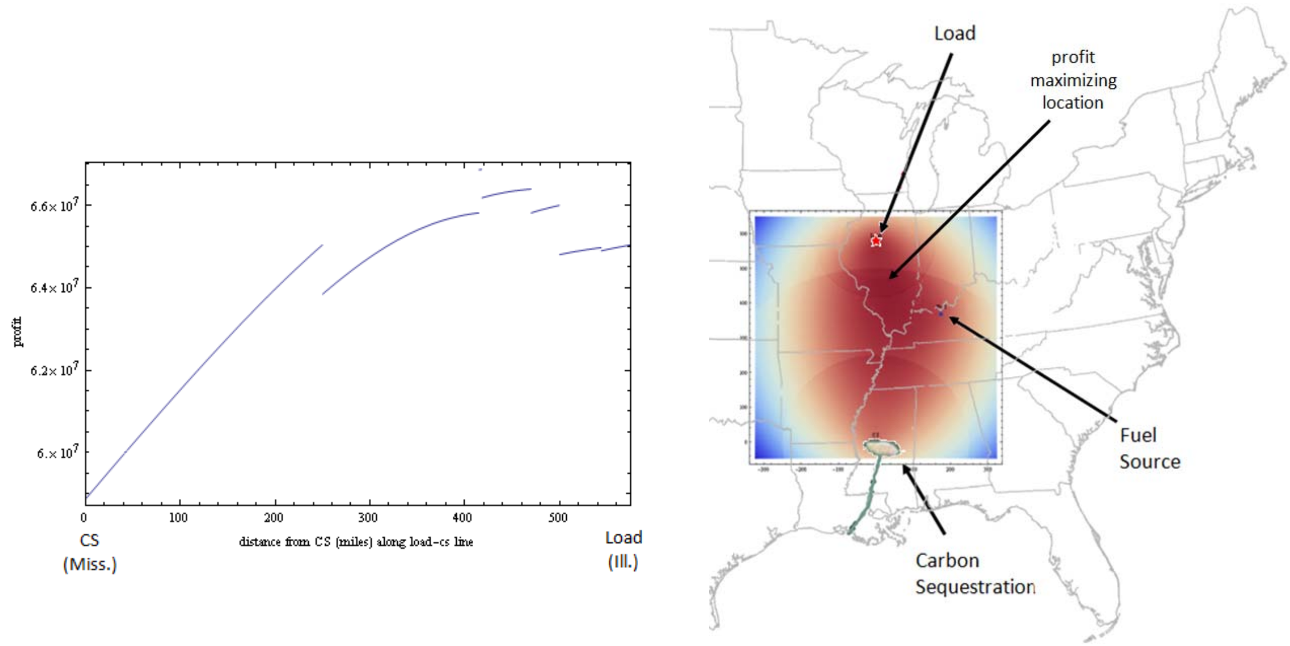


Figure 7. US Midwest location example. Parameters as in Figure 3. The profit maximizing location is about 100 miles south of the load (470 miles from CO_2 sequestration site, along the CS-load line), requiring approximately 100 miles AC transmission, 475 miles of CO_2 pipeline and 200 miles of coal transport 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.

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 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, we show 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 (Dahowski et al., 2001; Gupta et al., 2004), 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 (Blumsack, 2006), making the case for locating near the load stronger.

The present analysis suggests that 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.*

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* While the total mass of CO_2 is 4 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 4 times larger, since at operational conditions, a CO_2 pipeline caries about 3 times more mass per unit length of pipeline than does a natural gas pipeline.

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Appendix

Profit for the facility is its revenue minus expenses

$$\Pi_{\text{facility}} = \text{revenue}_{\text{facility}} - \text{expenses}_{\text{facility}} \qquad \text{(A1)}$$

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

$$\text{revenue}_{\text{facility}} = \text{electricity revenue} + CO_2 \text{ for EOR revenue} \qquad \text{(A2)}$$

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}

$$\text{annual revenue}_{\text{ij}} = \sum_{j} \sum_{i=1}^{8760} Q_{ij} \cdot P_{ij} \quad ; j = \text{ electricity, CO}_2 \qquad \text{(A3)}$$

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

$$Q_j = Q_{j\ gen} \cdot (1 - Loss_j) \quad ; j = \text{ electricity, CO}_2 \qquad \text{(A4)}$$

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}

$$Q_{j\ gen} = F_{avail} \cdot F_{size\,j} \quad ; j = \text{ electricity, CO}_2 \qquad \text{(A5)}$$

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

$$F_{size\,j} = S \cdot k_j \quad ; j = \text{ electricity, CO}_2 \qquad \text{(A6)}$$

The annual revenue for the facility can be expressed as

$$\text{annual revenue}_{\text{ij}} = \sum_{j} \sum_{i=1}^{8760} \left[F_{avail} \cdot S \cdot k_j \cdot (1 - Loss_j)\right]_i \cdot P_{ij} \qquad ; \, j = \text{ electricity, } \mathrm{CO_2} \qquad \text{(A7)}$$

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.

$$\begin{aligned}\text{locational expenses}_{\text{facility}} &= \text{fuel expenses + energy transmission expenses + } \mathrm{CO_2} \text{ transmission} \\ &= \sum_{j} \text{locational expenses}_j \qquad ; \, j = \text{fuel, energy, } \mathrm{CO_2}\end{aligned} \qquad \text{(A8)}$$

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.

$$\text{expenses}_j = \text{TCC}_j + \text{OC}_j \quad ; \, j = \text{fuel, energy, } \mathrm{CO_2} \qquad \text{(A9)}$$

Profit from the CO_2 transmission component of the facility decreases with the distance from the CO_2 sequestration site (Figure A1).

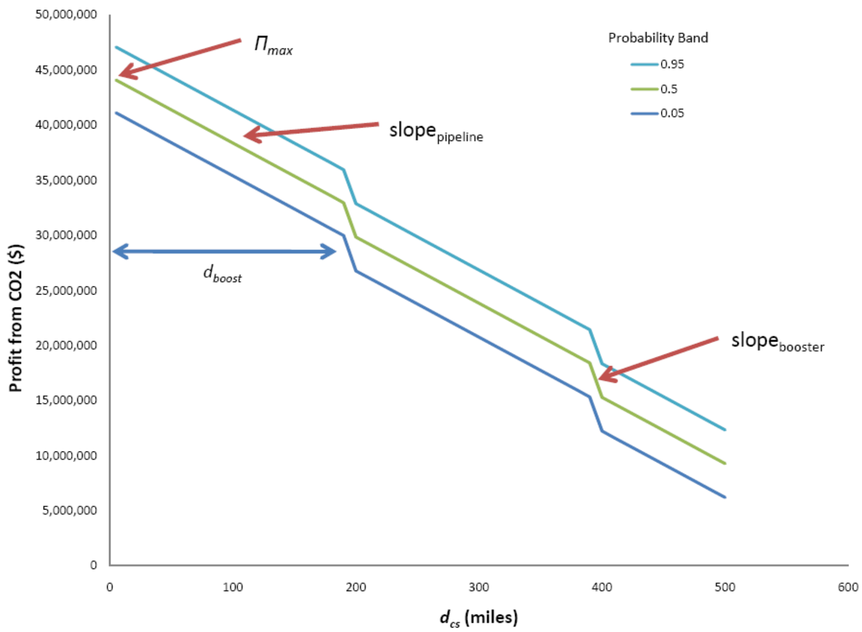


Figure A1. Profit from CO_2 transmission as a function of distance from CO_2 sequestration site. S=1, d_{boost}=200, A=0.088827,W=2, F_{avail}=1, P_{CO2} = Tri (18,20,22), $Loss_{CO2}$=0, D=1, COE=Normal(40,5), k_{CO2}=254.2

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 (IEA GHG, 2002a). For a given power requirement and distance, the appropriate values of the conductor resistance and nominal line voltage were selected (Table A1)

Table A1. AC Transmission line capacity (MW) lookup table (IEA GHG 2002a)

	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 (CRU International, 2007)

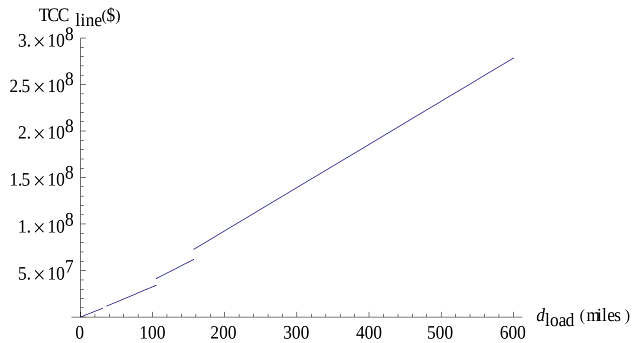
The sizes and costs of the switchgear and capacitors are chosen from an EIA lookup table developed through a detailed engineering analysis (Table A2) (IEA GHG, 2002).

Table A2. Substation switchgear, shunt and series compensation lookup table (IEA GHG, 2002a)

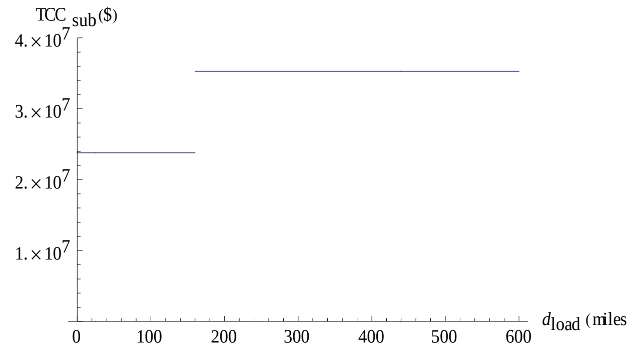
	Line voltage (kV)	115	115	230	230	230	230	345	345	500	500	750	750
	Conductors	1	2	1	2	2	3	3	4	4	4	4	4
	Transformer/ Switchgear voltage (kV)	145	145	245	245	245	245	363	363	525	525	765	765
	Transformer/ Switchgear cost[a] ($M)	1.01	1.01	1.70	1.70	1.70	1.70	2.52	2.52	3.66	3.66	5.32	5.32
Line length (km)	shunt <500	0	0	0	0	0	0	0	0	0	0	0	0
	500	0	0	31	39	41	52	114	126	253	256	549	0
	800	0	0	62	78	93	104	229	251	506	512	1099	556
	series <500	0	0	0	0	0	0	0	0	0	0	0	1111
	500	0	0	0	0	19	26	58	84	151	187	325	0
	800	0	0	0	0	30	42	93	134	241	300	604	359
	Shunt cost[a] ($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 (CRU International, 2007)

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 * 1.70 = $56.4 million.



(a)



(b)

Figure A2. 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 electricity transmission is shown in Figure A3.

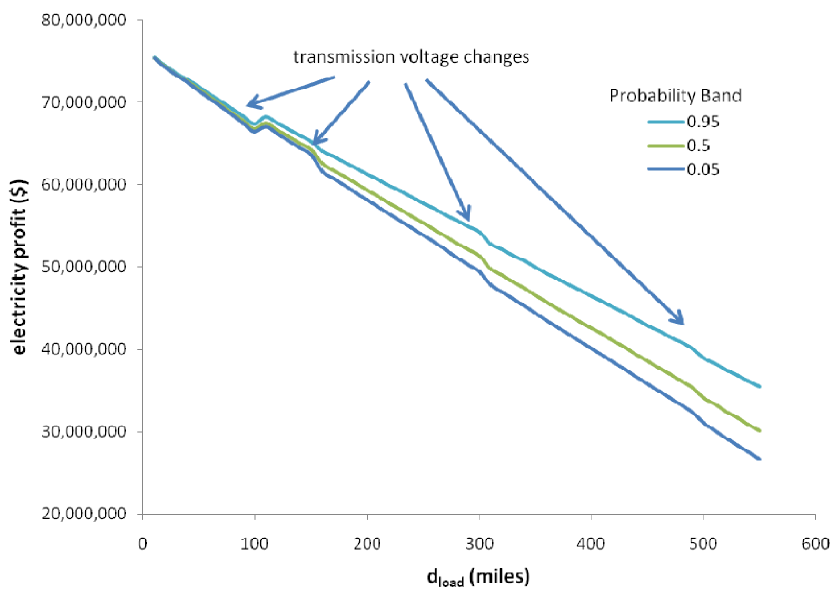


Figure A3. Profit from electricity transmission as a function of distance from load. S=1, k_{elec}=240, A=0.088827, D=1, F_{avail}=1, P_{elec} = MISO AEBN interface (9/05-9/06), ROW =Tri (1.03, 1.4, 1.5)

Additional information on the baseline facility used in the model, derived from the Integrated Environmental Control Model, is shown in Table A3.

Table A3. Baseline 238 MW_e net Facility Configuration and Parameters (CMU CEES, 2006)

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	98.5% efficiency
	Selexol	98% H_2S efficiency
	Claus plant	95% efficiency
	Beavon-Stretford tail gas plant	99% efficiency
CO_2 Capture ($42.0M)	Sour Shift + Selexol	2 operating absorbers max CO_2 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

Tables

Table 1. Model parameters

Variable	Description	Values used in analysis	Source
S	facility size index (IECM multiplier)	1–3	(CMU CEES, 2007)
F_{avail}	facility availability (%)	80	
k_f	single train (baseline) coal requirement (tons/hr)	127.6	(CMU CEES, 2007)
k_{elec}	single GE 7FA turbine (baseline) net output (MW/hr)	240	(CMU CEES, 2007)
k_{CO2}	single train CO_2 (baseline) output flowrate (tons/hr)	254.2	(CMU CEES, 2007)
ε	net plant efficiency, HHV (%)	29.21	(CMU CEES, 2007)
A	amortization factor	$i/(1-(1+i)^{-n})$	(Rubin, 2001)
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)	(IPCC, 2005)
$TCC_{pipeline}$	pipeline capital cost ($M)	$0.6212 \cdot d_{CS} + 0.0059 \cdot Q_{CO2\ gen}$	(CMU CEES, 2007)
$OC_{pipeline}$	pipeline O&M cost ($M/yr)	$0.005 \cdot d_{CS}$	(CMU CEES, 2007)
$TCC_{booster}$	booster capital cost ($M)	$9.775 \cdot \dot{W} + 0.575$	(BLS, 2007; IEA GHG, 2002b)
$OC_{booster}$	booster O&M cost ($M/yr)	$\dot{W} \cdot COE \cdot t$	
$Q_{CO2\ gen}$	total CO_2 generated (tons/hr)	$F_{avail} \cdot k_{CO2i} \cdot S$	
$\dot{W}$	booster pump power (MW)	range (0.5 – 3)	(Babcock Eagleton Inc., 2007)
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)	(Apt et al., 2007)

$revenue_{CO2i}$	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)	(CMU CEES, 2007)
Fuel delivery			
d_{fuel}	distance to fuel purchase site (miles)	range (0 – 600)	
$\mathrm{TCC_f}$	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	(EIA, 2007a)
$T_{f\,rail}$	coal rail transport cost (mill/ton-mile)	23.81	(EIA, 2007c)
$T_{f\,barge}$	coal barge transport cost (mill/ton-mile)	6.08	(EIA, 2007c)
$Loss_f$	coal losses during transport (%)	0	
$\mathrm{annual\ expenses_{fuel}}$	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 (%)	$(Q_{elec\,gen} \cdot \sigma \cdot d_{load})/V^2$	(IEA GHG, 2002b)
$\mathrm{TCC_{line}}$	total transmission line capital cost ($M)	$\mathrm{TCC_{line\ only}}$ + ROW	
$\mathrm{TCC_{line\ only}}$	transmission line capital cost ($000/mile)	219 – 1,446	(IEA GHG, 2002a)
ROW	right of way costs (% $\mathrm{TCC_{line\ only}}$)	triangle(30, 40, 50)	
$\mathrm{OC_{line}}$	transmission line operating cost (% $\mathrm{TCC_{line}}$/yr)	1.00	(IEA GHG, 2002a)
$\mathrm{TCC_{substation}}$	substation capital cost ($M)	$\mathrm{TCC_{switch}}$+$\mathrm{TCC_{shunth}}$+ $\mathrm{TCC_{series}}$	
$\mathrm{TCC_{switch}}$	switchgear and transformer cost ($M)	1.01 – 5.32	(IEA GHG, 2002a)
$\mathrm{TCC_{shunt}}$	shunt capacitor cost ($000/Mvar)	4E-05$\cdot$Mvar^2-0.05Mvar + 34.77	(IEA GHG, 2002a)
$\mathrm{TCC_{series}}$	series capacitor cost ($000/Mvar)	7E-07$\cdot$Mvar^3-0.09$\cdot$ Mvar +90	(IEA GHG, 2002a)

Mvar	transmission reactive power requirement (Mvar)	0 - 1,111	(IEA GHG, 2002a)
$OC_{substation}$	substation line operating cost (% $TCC_{substation}$/yr)	0.25	(IEA GHG, 2002a)
σ	conductor resistance (ohms/ph)	0.014 – 0.192	(IEA GHG, 2002a)
V	nominal transmission line voltage (kV)	115 – 750	(IEA GHG, 2002a)
$Q_{elec\ gen}$	total electricity generated (MW/hr)	$F_{avail} \cdot k_{elec} \cdot S$	
$P_{elec\ i}$	hourly electricity price ($/MWh)	MISO historical data	(Midwest ISO, 2006)
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	$Q_{elec\ gen} \cdot (1 - Loss_{elec}) \sum_{i=1}^{8760} P_{elec\ i}$	

Table A1. AC Transmission line capacity (MW) lookup table (IEA GHG 2002a)

	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 (CRU International, 2007)

Table A2. Substation switchgear, shunt and series compensation lookup table (IEA GHG, 2002a)

	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 (CRU International, 2007)

Table A3. Baseline 238 MW_e net Facility Configuration and Parameters (CMU CEES, 2006)

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	98.5% efficiency
	Selexol	98% H_2S efficiency
	Claus plant	95% efficiency
	Beavon-Stretford tail gas plant	99% efficiency
CO_2 Capture ($42.0M)	Sour Shift + Selexol	2 operating absorbers max CO_2 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