Midwest Geological Sequestration Consortium

Assess Carbon Dioxide Capture Options for Illinois Basin Carbon Dioxide Sources

Topical Report

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Optimization of Geological Sequestration of Carbon Dioxide in the Illinois Basin

Shiaoguo Chen, Yongqi Lu, and Massoud Rostam-Abadi

Abstract

The Midwest Geological Sequestration Consortium (MGSC) is one of seven regional partnerships funded by the United States Department of Energy (DOE). The MGSC partnership is investigating the geological sequestration options for carbon dioxide (CO_2) in the 60,000-mi^2 Illinois Basin. The Basin covers most of Illinois, western Indiana, and western Kentucky.

Stationary sources in the Illinois Basin emitted 283 million metric tonnes of CO_2 in 2002. About 261 millions tonnes of this amount were emitted by 122 power plants (emission sources), each emitting more than 10,000 tonnes annually. The potential geological structures (sinks) for CO_2 storage in the Basin include mature oil reservoirs, deep, unminable coal beds, and deep saline reservoirs. It has been estimated that the storage capacity of the 24 largest sinks within oil fields identified to date in the Basin is about 4,671 million tonnes. The power plants and storage fields are scattered throughout the Illinois Basin.

An integrated sequestration process includes capture, transportation, and injection of CO_2 into the geological fields. The links between different emission sources, sinks, and different transportation routes will impact the economic performance of the sequestration process. The objective of this study was to optimize the integrated CO_2 sequestration process by determining the most economical distribution of captured CO_2 among all of the identified storage fields in the Illinois Basin at CO_2 emission control levels of 10, 25, and 50%.

A commercial optimization software package, LINGO, was used to perform the optimization study. The costs of CO_2 capture from existing coal-fired power plants and pipeline transportation were obtained from an earlier techno-economic study completed by the MGSC in October 2004. The CO_2 capture costs ($53 to 59/tonne CO_2 avoided) were derived from a monoethanolamine (MEA)-based process. The loss of electricity capacity in the Basin due to the installation of MEA plants was not included in the optimization study. Sequestration costs were evaluated with and without by-product credits from enhanced oil recovery (EOR) and coalbed methane recovery (ECBM).

The results from this optimization study revealed that the average cost of the sequestration process with by-products recovery ranged from about $44 to $56/tonne of CO_2 sequestered, depending on the control

level. These costs included the cost of electricity loss due to the installation of MEA plants. The increase in the cost of electricity, shared by all utilities in the Basin, is about 3.72, 10.50, and 22.50 mills/kWh at 10, 25, and 50% of CO_2 emission reductions, respectively. Without by-product recovery, it costs about \$60/tonne of CO_2 sequestered, and electricity cost increases by 5.25, 11.74, and 23.77 mills/kWh for the respective control levels. The cost of capturing CO_2 from power plants contributed to >90% of the total sequestration costs. The average transportation and injection costs were <2% and 8%, respectively, of the total sequestration cost, depending on level of control. One of the reasons for the low cost of transportation is the location of the ubiquitous geological storage structures in the Illinois Basin. A sensitivity study was also performed to evaluate the impact of CO_2 capture cost on sequestration cost.

Executive Summary

The Midwest Geological Sequestration Consortium (MGSC) is one of seven regional partnerships funded by the United States Department of Energy (DOE). The MGSC partnership is investigating the geological sequestration options for carbon dioxide (CO_2) in the 60,000-mi^2 Illinois Basin. The Basin covers most of Illinois, western Indiana, and western Kentucky.

Stationary sources in the Illinois Basin emitted 283 million metric tonnes of CO_2 in 2002. About 261 million tonnes of this amount were emitted by 122 power plants (emission sources). The potential geological structures (sinks) for CO_2 storage in the Basin include mature oil reservoirs, the deepest (unminable) coal beds, and deep saline reservoirs. It has been estimated that the storage capacity of the 24 largest sinks identified to date in the Basin is about 4,671 million tonnes. The power plants and the storage fields are scattered in all areas of the Basin.

An integrated sequestration process includes capture, transportation, and injection of CO_2 into the geological fields. The links between different emission sources and sinks as well as different transportation routes impact the economic performance of the sequestration process. The objective of this study was to optimize the integrated CO_2 sequestration process in the Illinois Basin by determining the most economical distribution of captured CO_2, at control levels ranging from 10 to 50%, among all of the identified storage fields.

A commercial software package, LINGO, was used to optimize the integrated CO_2 sequestration system. The coal-fired power plants with emissions larger than 100,000 tonnes annually (about 98% of total power plant emissions) and the 24 largest storage fields within existing oil fields in the Basin were considered. The costs of CO_2 capture (90% reduction) from coal-fired power plants and pipeline transportation were obtained from an earlier techno-economic study completed by the MGSC in October 2004. The CO_2 capture costs ($53 to $59/tonne of CO_2 avoided) were derived from a monoethanolamine (MEA)-based process. The loss of electricity capacity in the Basin due to the installation of MEA plants was not included in the optimization study. Sequestration costs were evaluated with and without by-product credits from enhanced oil recovery (EOR) and coalbed methane (ECBM) recovery. A 30-year life span was considered for the pipeline and MEA process.

The initial results from the optimization study revealed that capturing CO_2 from the 20 largest coal power plants, which emit about 68% of the total CO_2 emissions in the Basin, is the most economical. Therefore, only these 20 power plants were included in the optimization study. Electricity losses due to installing an MEA plant were about 1,634, 3,873, and 7,746 MW at the 10%, 25%, and 50% control level, respectively. The average cost of the sequestration process with by-product recovery (assuming $20/tonne CO_2 credit for EOR and $15/tonne CO_2 credit for ECBM) ranged from $44 to $56/tonne CO_2

sequestered, depending on the control level. These costs included the cost of electricity loss due to the installation of MEA plants. The increase in the cost of electricity, shared by all utilities in the Basin, is about 3.72, 10.50, and 22.50 mills/kWh at 10, 25, and 50% of CO_2 reduction, respectively. Without by-product recovery, it costs almost $60/tonne of sequestered CO_2. Electricity losses are comparable to those when by-product credits are included, and the increase in electricity cost is about 5.25, 11.74, and 23.77 mills/kWh at 10, 25, and 50% of CO_2 reduction, respectively. The cost of capturing CO_2 from power plants contributes to >90% of the total sequestration costs. The average pipeline and injection costs were <2 and 8%, respectively, of the total sequestration cost. One of the reasons for the low cost of transportation is the location and abundance of geological storage structures in the Illinois Basin. Due to the low cost of the pipeline, the locations of power plants (with respect to sink locations) were found to be less important than the scale of the plants.

The results from a sensitivity analysis revealed that the CO_2 capture cost has the most impact on the overall cost of the of the sequestration process. Data show that sequestration cost is linearly related to capture cost at all levels. The impact of CO_2 capture cost is more pronounced as levels of CO_2 emission control increase, which indicates that future efforts to reduce sequestration cost should focus on developing more cost-effective capture technologies. For example, at the 50% emission control level with a 50% reduction in the current capture costs, the costs for sequestering 1 tonne of CO_2 decreases from $56.35 to $29.61, and the increase in electricity cost decreases from 22.50 to 11.82 mills/kWh.

Introduction

The Midwest Geological Sequestration Consortium (MGSC) is one of the seven regional partnerships funded by the United States Department of Energy (DOE). The MGSC partnership is investigating the geological sequestration options for carbon dioxide (CO_2) in the 60,000-mi^2 Illinois Basin. The Basin covers most of Illinois, western Indiana, and western Kentucky.

In 2002, stationary sources in the Illinois Basin emitted about 283 million tonnes of CO_2 (Chen et al., 2004). Electric generation facilities, which emit more than 10,000 tonnes annually, contribute about 261 million tonnes of the Basin's total emissions. The Basin is rich in different geological structures such as relatively deep coal beds, mature oil reservoirs, and deep saline reservoirs that are potentially suitable for CO_2 storage. The power plants (emission sources) and the storage fields (sinks) are scattered all over the Illinois Basin, but they are mostly concentrated in certain areas. In an integrated sequestration process, the optimal links between these emission sources and geological sinks have to be identified.

An integrated sequestration process includes capture, transportation, and injection of CO_2 into the geological field. The links between different emission sources, sinks, and transportation routes will impact the economic performance of the sequestration process. In this report, the results from an optimization study of the integrated CO_2 sequestration process in the Illinois Basin are presented. The study determined the most economical distribution of captured CO_2 from coal-fired power plants among the 24 largest storage fields at 10, 25, and 50% CO_2 emission control levels.

Profiles of Emission Sources in the Illinois Basin

The Illinois Basin covers most of Illinois, western Indiana, and western Kentucky (Figure 1). Table 1 lists data for CO_2 emissions from the stationary sources for the United States and the Illinois Basin (Chen et al., 2004). In 2002, the total CO_2 emission from stationary sources in the Illinois Basin was 283 million tonnes, or about 11.7% of total U.S. emissions. The emissions from the manufacturing industry sector, which includes oil refineries, the steel industry, the cement industry, and other industries, were responsible for about 22 million tonnes, or 7.8% of the Illinois Basin emissions.

Table 1. Annual CO_2 emissions in the United States and the Illinois Basin.

Sources	U.S. total (tonnes)	Illinois Basin (tonnes)	Basin to U.S. (%)	Source (% of Basin)
Power generation	2,239,700,000[1]	261,310,000[2]	11.7	92.2
Coal	1,868,400,000[1]	256,256,000[2]	13.7	90.5
Natural gas	299,100,000[1]	5,006,000[2]	1.7	1.8
Oil	72,200,000[1]	48,000[2]	0.1	0.02
Industries	324,789,000	21,960,000	6.8	7.7
Refinery	184,918,000[3]	9,703,000[4]	5.2	3.4
Iron and steel	54,411,000[5]	3,857,000[6]	7.1	1.4
Cement	42,898,000[5]	3,245,000[6]	7.6	1.1
Ammonia	17,652,000[5]	214,000[6]	1.2	0.1
Aluminum	4,223,000[5]	820,000[6]	19.4	0.3
Lime	12,304,000[5]	273,000[6]	2.2	0.1
Ethanol	8,383,000[5]	3,848,000[7]	45.9	1.4
Total	2,564,489,000	283,270,000	11.0	100

[1] U.S. Environmental Protection Agency (2004) greenhouse gas inventory sector analysis.
[2] U.S. Environmental Protection Agency acid rain and EGRID data (classified by primary fuel type).
[3] Estimate from 2002 barrels per day totals (U.S. Department of Energy, 2004).
[4] Projected estimates from representative facilities.
[5] U.S. Environmental Protection Agency (2004) greenhouse gas inventory industrial process analysis.
[6] Source data from U.S. Geological Survey (2002).
[7] Source data from Iowa Department of Agriculture and Land Stewardship (2004): www.distillersgrains.com.

Table 2 lists the total CO_2 mass emitted and the number of emission sources (including both utility and manufacturing industries) in Illinois, Indiana, and Kentucky that are within the geological boundary of the Basin, including shaded areas in Figure 1 (Chen et al., 2004). Coal-fired electric power plants are the predominant stationary sources of emissions. In 2002, about 261 million tonnes of CO_2 were emitted in the Illinois Basin from 122 fossil fuel-fired power plants (only the power plants that emitted >10,000 tonnes of CO_2 annually were included). The geographical distribution of these power plants is shown in Figure 1.

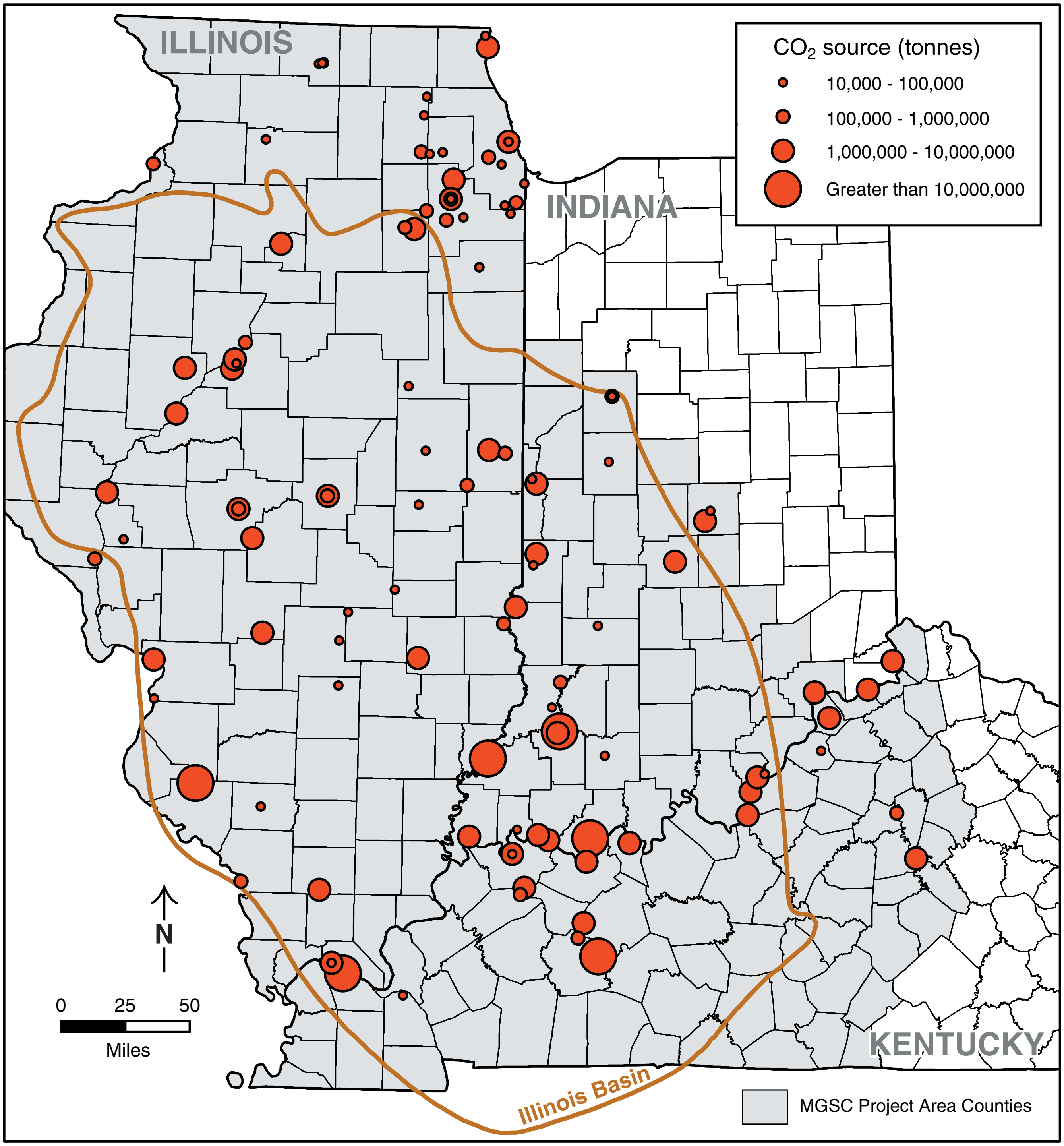


***Figure 1** Geographical distribution of power plants in the Illinois Basin (outline).*

Table 2. CO_2 emissions and emission sources in the Illinois Basin.

Sources	Illinois		Indiana		Kentucky		Total CO_2 emissions in basin (tonnes)	Total in basin (no.)
	CO_2 (tonnes)	Plants (no.)	CO_2 (tonnes)	Plants (no.)	CO_2 (tonnes)	Plants (no.)		
Power generation	94,088,000	75	92,176,000	26	75,045,000	21	261,309,000	122[1]
Coal	89,555,000		91,855,000		74,845,000		256,255,000	
Natural gas	4,485,000		321,000		200,000		5,006,000	
Oil	48,000		0		0		48,000	
Industries	18,593,000	33	2,322,000	11	1,046,000	5	21,961,000	49
Refinery	9,455,000	4	248,000	1	0	0	9,703,000	5
Iron and steel	3,685,000	17	142,000	5	30,000	1	3,857,000	23
Cement	1,301,000	4	1,353,000	3	591,000	1	3,245,000	8
Ammonia	214,000	1	0	0	0	0	214,000	1
Aluminum	0	0	464,000	1	356,000	1	820,000	2
Lime	273,000	1	0	0	0	0	273,000	1
Ethanol	3,665,000	6	115,000	1	69,000	2	3,849,000	9
Total	112,681,000	108	94,498,000	37	72,923,000	26	283,270,000	171

[1] Power plants emitting <10,000 tonnes of CO_2 currently are not included.

Figure 2 illustrates the mass of CO_2 emissions from individual plants in the Illinois Basin. The four largest power plants emitted about 23% of the total CO_2 emissions, the 12 largest power plants emitted more than 50% of total CO_2 emissions, and the 29 largest power plants emitted over 80% of total CO_2 emissions in the Illinois Basin (not shown). Considering their economies of scale, the larger power plants in the Basin are the most suitable sources for any CO_2 capture and sequestration retrofits.

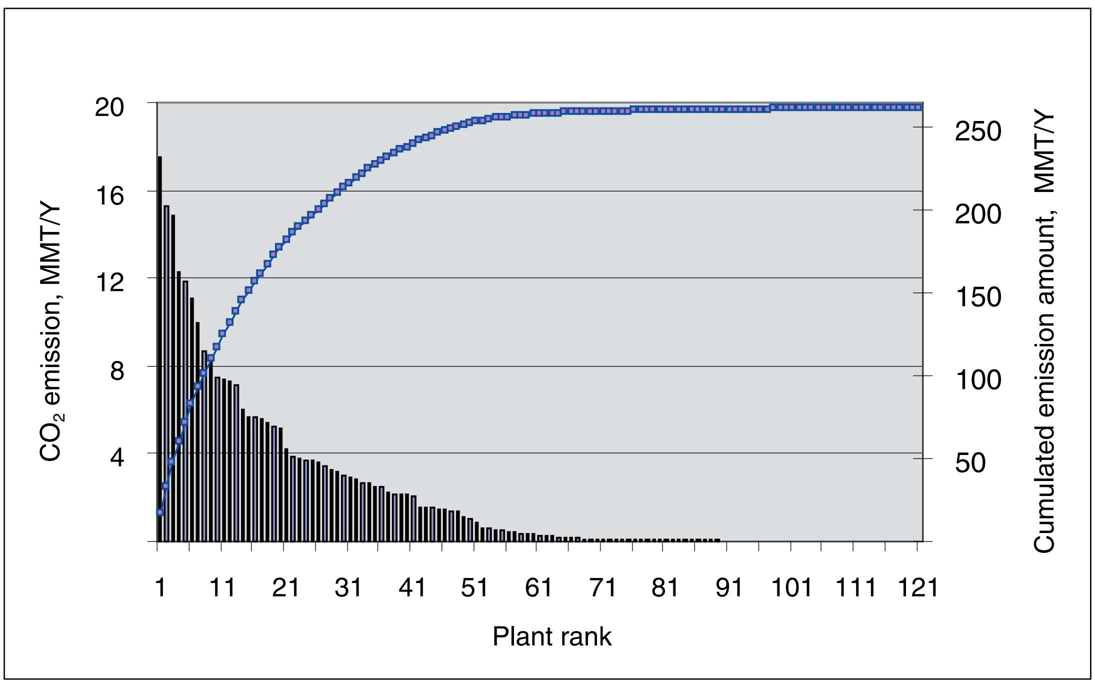


Figure 2 *CO_2 emission profile of the power plants in the Illinois Basin, ranked from largest to smallest.*

Most of the power plants in the Illinois Basin are equipped with pulverized coal boilers and use a simple steam cycle. The flue gas from these power plants contains about 14% CO_2. Other contaminants in the flue gas, such as nitrogen (NOx) and sulfur (SOx), may have to be removed before the gas enters a CO_2 capturing system. Power plants that burn high-sulfur bituminous coals are usually equipped with wet flue gas desulfurization (FGD) processes that are capable of removing >95% of SO_2 from combustion flue gas. As a result of the pre-existing FGD process, these plants may have an advantage over the power plants without the FGD process, which mostly burn western Powder River Basin (PRB) coal, because, if a chemical absorption process is used, SO_2 concentration has to be controlled to <30 ppm in order to reduce the loss of solvent due to reaction with SO_2.

The power plants that burn natural gas tend to be small and are mostly peak power plants. Total CO_2 emissions from these power plants are about 5 million tonnes annually, which is <2% of total emissions in the Illinois Basin. In addition, CO_2 concentration in flue gas from natural gas burning power plants (3 to 4 vol%) will be much lower than that from coal burning power plants (~14 vol%), which, in turn, increases the capture cost. In this optimization study, these small power plants were not considered.

Forty-nine non-utility industrial emission sources contributed about 22 million tonnes of CO_2 in 2002, which accounted for 7.8% of total emissions in the Basin. These energy-intensive manufacturing industries include petroleum refining, iron and steel manufacturing, and cement and lime production. However, these industrial emission sources are relatively small compared with those from typical power plants. The geographic distribution of these industrial sources in Illinois Basin is shown in Figure 3. Because of the economies of scale and lack of infrastructure required for CO_2 capture, these CO_2 emission sources were not considered in this optimization study.

In this optimization study, only 62 coal-fired power plants, each emitting >100,000 tonnes of CO_2 annually, were selected. There are several reasons for this decision. First, a preliminary assessment of the 24 largest sinks that have been identified to date in the Basin showed that their geological sequestration capacities are not sufficient for storage of CO_2 emissions from all of the power plants in the Basin. Second, the remaining power plants account only for about 2% of the total power plant emissions in the Basin, and the economy of scale favors CO_2 capture from larger power plants. Third, if all power plants are included in the optimization process, the number of variables tested exceeds the limits of the LINGO software package. Preliminary results from the optimization study confirmed that the inclusion of the 60 smaller plants did not impact the selection of power plants or storage fields at the control levels selected in this study.

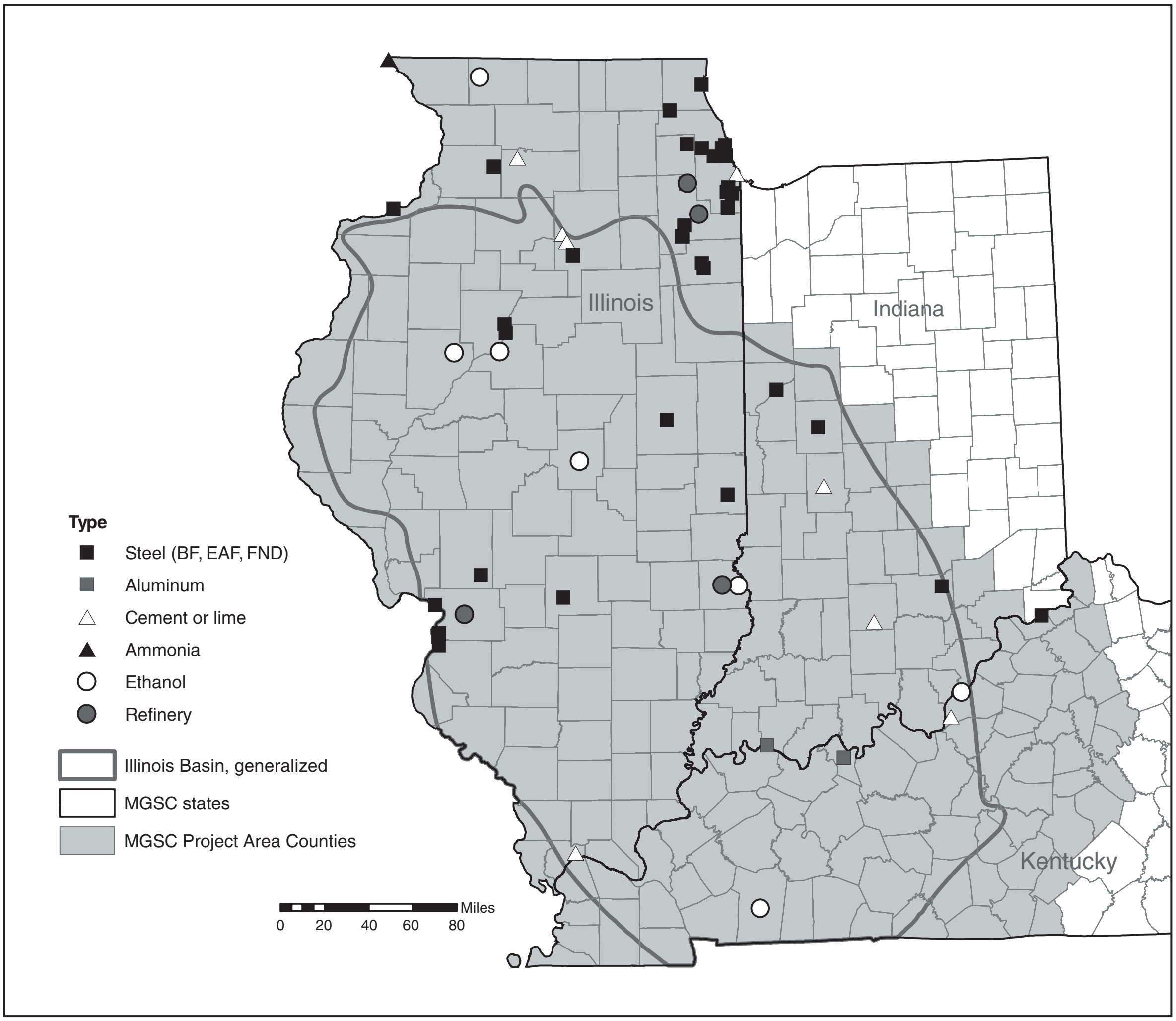


Figure 3 *Geographical distribution of industrial emission sources in the Basin (BF, blast furnace; EAF, electric arc furnace; FND, foundry).*

Profiles of Potential Storage Sinks in the Illinois Basin

The Illinois Basin is rich in geological structures that are potentially suitable for CO_2 sequestration. In this study, three types of storage structures were considered: mature oil field, the deepest coal bed, and deep saline reservoir. Figure 4 shows the geographic distribution of the 24 largest potential storage fields that have been identified to date by the MGSC partnership. Because of the geographical extent of the Clay City Consolidated oil field, the MGSC divided the CO_2 storage of this field into three subfields: Clay City SW (Clay and Wayne Counties), Clay City N (Clay County), and Clay City NE (Jasper County). It should be pointed out that the storage fields are scattered in large areas (some cover hundreds of square miles) across the Basin. In Figure 4, circles represent the centroids of storage fields (based on the total capacity of the field). Each storage field may include all three types of storage structures in a

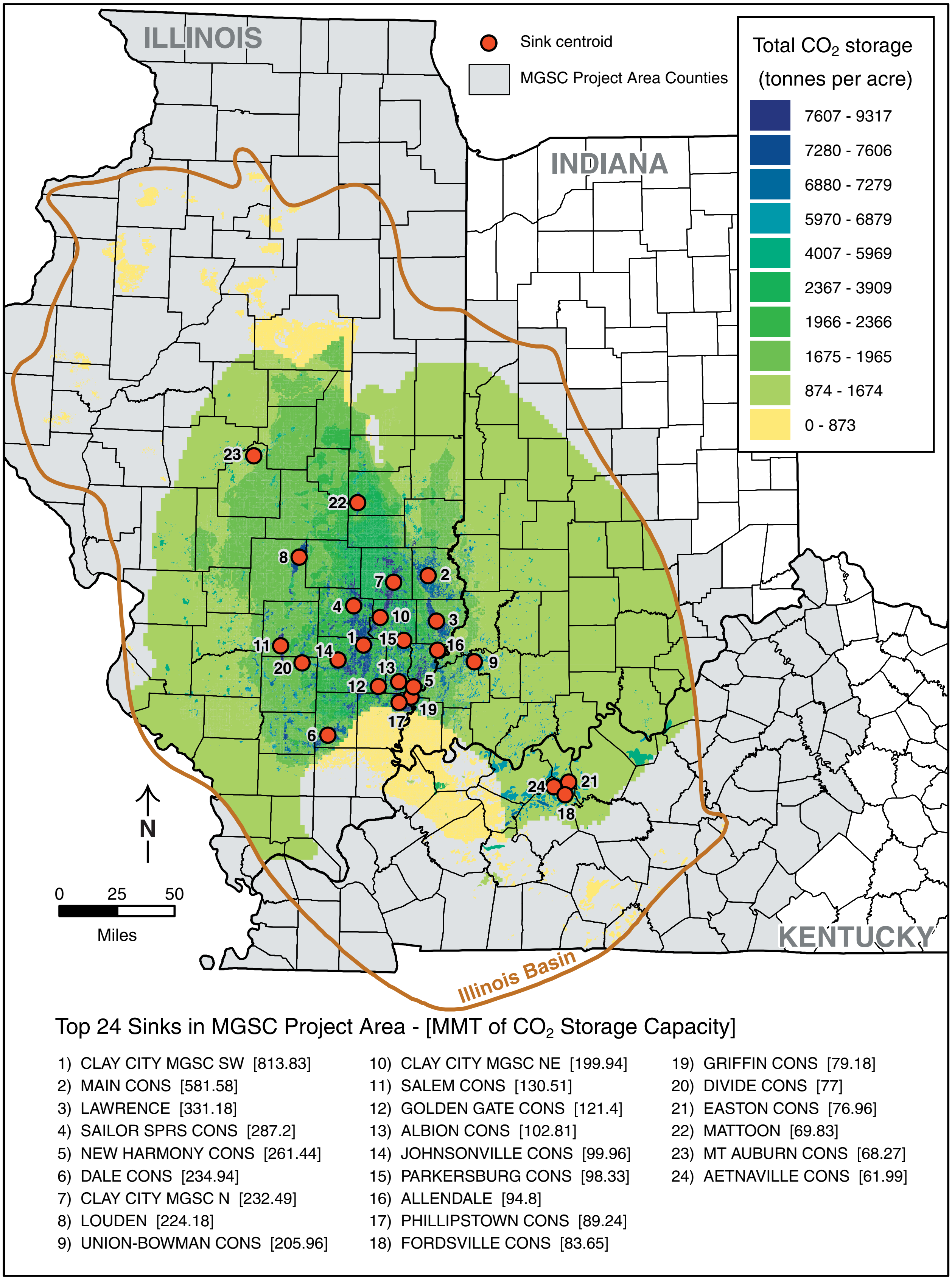


Figure 4 *Geographical distributions of the 24 largest storage sinks in the Illinois Basin.*

vertically stacked arrangem ent. Table 3 lists the CO_2 storage capacity of the 24 storage fields. The total capacity of each storage field consists of the three components.

The best current estimate of the total CO_2 storage capacity for the three types of structures in the Basin is about 4.7 billion tonnes. Oil fields, coal bed seams, and saline reservoirs account for 6%, 6%, and 88%

Table 3. Capacities and locations of the top 24 potential sinks in the Illinois Basin.

Rank	Field name	Field ID	State	Summary, oil CO_2 (MMT)	Summary, coal CO_2 (MMT)	Summary, saline CO_2 (MMT)	Total_CO_2 (MMT)	Longitude (DD_N83_X)	Latitude (DD_N83_Y)
1	CLAY CITY (MGSC SW)	171119	IL	39.38	70.39	709.95	819.72	–88.33	38.56
2	MAIN CONS.	171361	IL	39.01	17.32	533.12	589.46	–87.81	39.00
3	LAWRENCE	171336	IL	29.21	14.06	289.80	333.07	–87.74	38.71
4	SAILOR SPRS. CONS.	171530	IL	9.25	29.44	251.20	289.89	–88.41	38.80
5	NEW HARMONY CONS.	171415	IL	21.73	20.54	222.25	264.52	–87.92	38.30
6	DALE CONS.	171151	IL	15.70	9.86	211.09	236.65	–88.60	37.98
7	CLAY CITY (MGSC N)	171119	IL	10.89	27.06	196.55	234.49	–88.09	38.95
8	LOUDEN	171354	IL	21.93	8.44	195.33	225.71	–88.86	39.10
9	UNION-BOWMAN CONS.	181996	IN	8.99	1.32	199.42	209.73	–87.44	38.46
10	CLAY CITY (MGSC NE)	171119	IL	9.55	19.74	172.36	201.65	–88.20	38.73
11	SALEM CONS.	171533	IL	17.38	4.17	109.55	131.09	–88.99	38.54
12	GOLDEN GATE CONS.	171230	IL	4.24	8.80	109.90	122.94	–88.20	38.30
13	ALBION CONS.	171010	IL	4.86	7.72	91.76	104.33	–88.04	38.33
14	JOHNSONVILLE CONS.	171299	IL	3.78	7.57	89.47	100.83	–88.53	38.46
15	PARKERSBURG CONS.	171462	IL	2.72	7.83	88.91	99.47	–88.00	38.59
16	ALLENDALE	171015	IL	4.46	4.78	87.79	97.02	–87.73	38.53
17	PHILLIPSTOWN CONS.	171474	IL	3.99	7.86	77.87	89.72	–88.04	38.20
18	FORDSVILLE CONS	2112962	KY	1.88	0.00	82.08	83.97	–86.72	37.62
19	GRIFFIN CONSOL.	181787	IN	12.08	5.60	62.26	79.95	–87.94	38.23
20	DIVIDE CONS.	171160	IL	1.82	3.41	72.40	77.63	–88.82	38.44
21	EASTON CONS	21212261	KY	0.47	0.00	76.85	77.32	–86.69	37.70
22	MATTOON	171377	IL	2.08	5.35	62.82	70.24	–88.39	39.45
23	MT. AUBURN CONS.	171399	IL	1.69	0.93	66.63	69.25	–89.25	39.73
24	AETNAVILLE CONS.	214643	KY	0.87	0.00	61.54	62.41	–86.80	37.67
	Total			**267.96**	**282.21**	**4,120.91**	**4,671.08**		

of the total storage capacity, respectively. This capacity would be filled in about 18 years if 90% of the CO_2 emission mass at the 2002 level (283 million tonnes) is sequestered each year.

CO_2 Capture Options and Cost

Several options are available for the capture of CO_2 from electric power plants. Depending on the stage that CO_2 is removed from the power generation system, CO_2 capture can be classified as pre-combustion, post-combustion, or oxyfuel combustion.

In the post-combustion configuration, CO_2 is captured from the flue gas after the fuel is combusted. In the pre-combustion configuration, the original carbon-containing fuel is transformed into a non-carbon-containing fuel (usually hydrogen) prior to combustion. Carbon in the fuel is converted to CO_2 and separated. Hydrogen is then used to produce power in a gas turbine, fuel cell, or other power generation system. In oxyfuel combustion, pure oxygen instead of air is used for combustion in either a boiler or gas turbine. However, if fuel is combusted in very pure oxygen, the flame temperature will be excessively high; therefore, a CO_2-rich flue gas is usually recycled to the boiler to reduce the flame temperature. The advantages and disadvantages of each configuration were discussed in the 2004 MGSC topical report prepared for the DOE (Chen et al., 2004).

In each configuration, different capture technologies may be selected, depending on the power generation technology and the characteristics of the flue gases. The most important parameters are the CO_2 concentration and the total pressure in the flue gas stream. Other parameters include contaminants in the gas stream, transportation, and disposal methods. In the topical report, Chen et al. (2004) presented the results from a detailed engineering analysis of many separation technologies such as absorption (physical or chemical), adsorption (temperature swing adsorption and pressure swing adsorption), membrane, and cryogenic processes. Absorption-based processes were identified as having the best opportunities for post-combustion configuration, and membrane processes were identified as best for pre-combustion configuration for high temperature H_2 separation. Oxy-combustion may be an alternative to post-combustion configuration, but this technology is still in pilot-scale development. Table 4 lists the characteristics of different CO_2 emission sources and recommended capture technologies. Currently, most of the existing power plants in the Illinois Basin use conventional pulverized coal (PC) combustion technologies. For these existing power plants, a post-combustion configuration is the most suitable, and absorption-based processes are the best options.

Solvent is the key to the performance of an absorption-based process. Currently, commercially available solvents for absorption-based processes are amines. Among them, the monoethanolamine amine (MEA) process is the most widely used. In this study, the MEA absorption process was considered as the technology of choice for capturing CO_2 from the existing power plants in the Illinois Basin.

A techno-economic analysis of the PC plant retrofitted with the MEA system (PC+MEA) was performed using the CHEMCAD software package. A summary of the cost analysis results for retrofitting Illinois

Table 4. Capture technologies for power plants and industrial facilities.

Emission source	Pressure (bar)	CO_2 (%)	Impurities	Capture technology[1]
Power plants				
PC	1.2	14	SO_x, NO_x	CA
IGCC post-combustion	1.2	8	NO_x	CA
IGCC shifted syngas	30	40	H_2S	PA or H_2 membrane
NGCC post-combustion	1.2	4	NO_x	CA
NGCC shifted syngas				PA or H_2 membrane
PC + O_2/CO_2	1.2	>90	SO_x, NO_x, H_2O	Cryogenic
Industrial processes				
Iron and steel	1.2	20–27		CA or shift + PA
Refineries		8–15	SO_x, NO_x	CA
Cement	1.2	13–33		CA
Lime		13–33		CA
Ammonia	30	>95		Pure
Ethanol	1.0	85	VOCs, H_2O	Cryogenic

[1] CA, chemical absorption; PA, physical absorption; PC, pulverized coal; VOCs, volatile organic compounds.

Table 5. Cost analysis of the power plant retrofit with the MEA unit (Chen et al., 2004).

Net power plant output, MW	250	500	1,000
Net output (with MEA), MW	179	358	708
Capital cost, $1,000			
Total plant cost	89,252	147,331	240,095
Total plant investment	97,298	160,614	261,742
Total capital requirement	102,416	170,008	278,741
Annual carrying charge, $1,000/year	18,619	30,908	50,675
O & M[1] costs, $1,000/year			
Fixed O & M	3,410	5036	7,634
Variable O & M	7,673	15796	31,202
Electricity loss	39,083	78,339	154,940
Increase of electricity cost, mills/kWh	62.77	59.24	56.30
CO_2 avoided, 1,000 tonnes/year	1,157	2,320	4,572
Cost of CO_2 avoidance, $/tonnes of CO_2	59.47	56.07	53.47

[1]O & M, operating and maintenance.

coal-fired power plants is provided in Table 5. The power plant was assumed to be fully depreciated with a 30-year life remaining. A retrofit factor of 20% was assumed to account for the extra cost needed to retrofit older plants compared with that needed for new plants. The financial criteria were the same as in the previous techno-economic study presented in the 2004 MSGS topical report (Chen et al., 2004).

The scale of a power plant can strongly influence its economics, especially when the plant size is small. In order to examine the economy of scale, the economic analysis was conducted for three plant capacities with net outputs of 250, 500, and 1,000 MW, respectively (Table 5 and Figure 5).

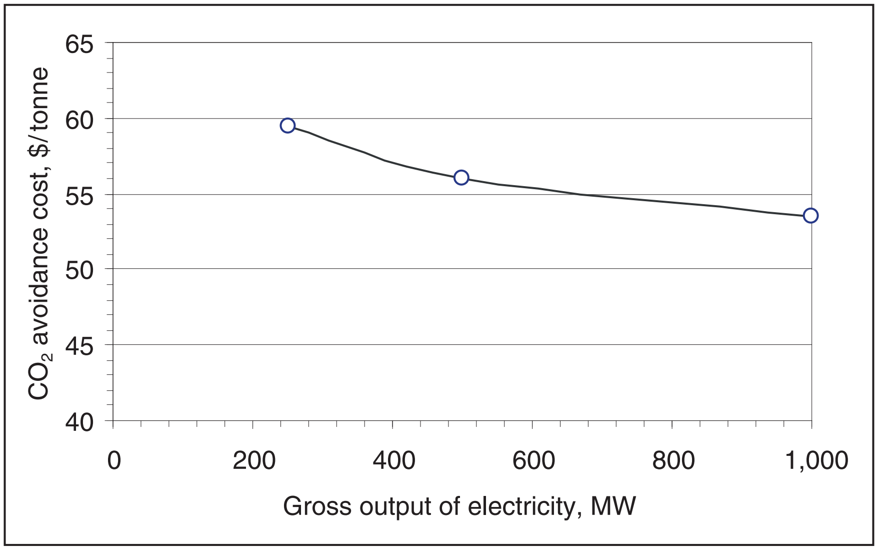


Figure 5 *Effect of plant size on CO_2 avoidance costs of the pulverized coal plus monoethylamine-based process.*

The economy of scale diminishes above a certain plant size, because more parallel trains are needed, and cost will be roughly proportional to the capacity. In this study, a 1,000-MW capacity was selected as the cut-off size. Above this capacity, CO_2 avoidance cost was assumed to remain constant.

Based on the results from the techno-economic analyses (Table 5), the correlation between the annual emission reduction of a power plant and the total CO2 avoidance cost was determined. The equation is

$$\textit{Avoidance cost}\ (\$MM/Y) = 60.05 \times Q^{0.9226}$$

where Q is the amount of CO_2 captured, in million tonnes per year. This equation is suitable for plant capacities less than 1,000 MW. For power plants >1,000 MW, CO_2 avoidance cost was assumed to be constant ($53.47/tonne), and the total annual cost was proportional to CO_2 reductions. These avoidance costs include the cost of electricity loss due to the installation of MEA plants.

Pipeline Transportation and Cost

CO_2 can be transported by truck/motor carriers, railways, ships, and pipeline. Pipeline transportation of CO_2 captured from a power plant is the most economical transportation method because the sequestration process involves transportation of a large volume of CO_2 over long periods. In this study, only pipeline transportation was considered.

Pipeline diameter was calculated based on the flow rate of CO_2 (Table 6) (Chen et al., 2004). Table 6 also includes cases where long pipelines and, thus, a midpoint pressure boost, is required. In this study, no midpoint boosting was considered because all of the pipelines were <125 miles long.

Table 6. Flow capacity as a function of pipe diameter and pressure drop.

Pipe diameter (inches) (1)	Flow capacity with inlet pressure only, 1,000 psi pressure drop over 200 miles (MMSCFD)[1] (2)	Flow capacity with 100% boosting at mid-point, 1,000-psi pressure drop over 100 miles		
		Flow capacity (MMSCFD) (3)	Required BHP[2] for 100% boosting at 100-mile mid-point	
			BHP/mile (4)	BHP/ 100 miles (5)
12	125	190	24	2,400
16	250	350	36	3,600
18	340	490	55	5,500
20	450	650	68	6,800
22	560	840	86	8,600
24	700	1,050	110	11,000

[1]MMSCFD, million standard cubic feet per day.

[2]BHP, brake horsepower.

The pipeline transportation cost analysis was conducted by D.J. Nyman and Associates and was described in the 2004 topical report (Chen et al., 2004). The cost includes right-of-way, materials, construction and services, and annual operating cost. Tables 7 and 8 summarize the pipeline costs for different pipeline sizes.

The pipeline cost (excluding the operating cost) on a per mile basis was depreciated over 30 years. The depreciation was based on 45% bonds at 9% nominal interest rate per year and 55% equity at a return rate of 12% per year. The income tax and inflation rate were assumed to be 38% and 0%, respectively. A correlation (Figure 6) between annual transportation cost (million dollars/mile) and million tonnes of CO_2 transported annually *(Q)* was developed:

$$Cost\ (\$MM/mile/Y) = 0.0494 \times Q^{0.4413}.$$

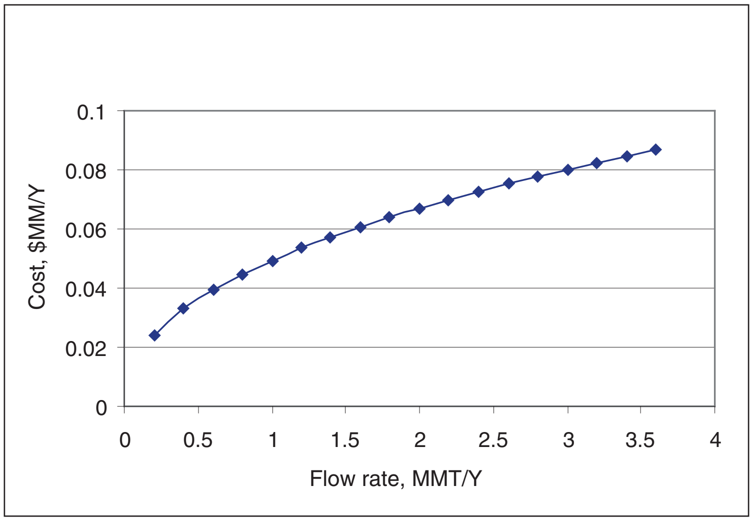


Figure 6 *Correlation between transportation cost and flow rate.*

Table 7. Summary of pipeline transportation cost.

Diameter (inches)	Right-of-way ($/mile)	Materials ($/mile)	Construction ($/mile)	Services ($/mile)	Total cost($/mile)[1]
4	36,713	24,303	85,071	29,217	175,304
6	36,713	47,630	115,915	38,049	238,307
8	44,500	79,370	141,753	47,812	313,435
10	44,500	115,424	173,476	56,678	390,078
12	51,731	159,084	210,730	67,447	488,992
16	66,750	247,199	275,533	88,422	677,905
18	66,750	310,766	306,206	95,721	779,444
20	66,750	381,893	336,354	102,050	887,047
22	66,750	460,465	365,978	107,183	1,000,375
24	66,750	546,136	395,601	121,018	1,129,505

[1]Some numbers have been rounded.

Table 8. Annual pipeline operating costs.

Diameter (inches)	($/mile)	($/200 miles)
4	2,667	533,333
6	4,000	800,000
8	5,333	1,066,667
10	6,667	1,333,333
12	8,000	1,600,000
16	10,667	2,133,333
18	12,000	2,400,000
20	13,333	2,666,667
22	14,667	2,933,333
24	16,000	3,200,000

Cost of CO_2 Injection into Storage Fields and By-product Credit

The permeability and depth of the geological structures impact the economics of CO_2 injection into storage fields. Injection of CO_2 into oil fields most likely will be least expensive (compared with coalbed and saline reservoirs) because mature oil fields have numerous existing wells and surface infrastructure. In addition, injection of CO_2 into oil fields and coal seams generates revenues from sales of oil and coalbed methane, respectively.

In this study, the variability in permeability, depth, and other characteristics of sinks was not considered, which is, of course, not realistic because permeability and depth impact the injectability of an injection well. However, these detailed data are not currently available for all of the selected injection sites. In this study, all of the selected sinks were assumed to have comparable permeability, depth, and other injectability characteristics.

An injection cost of $5/tonne CO_2 was assumed for storage in saline reservoirs. For mature oil fields, the sequestration process was considered as an EOR process. According to several research reports (Bergman et al., 1997; Holtz et al., 1999, 2001; Stevens, 1998), EOR is a break-even business if CO_2 can be purchased at about $20/tonne and the recovered oil can be sold at $25/barrel. Therefore, in this study, a $20/tonne CO_2 credit was allocated to the EOR sequestration process. Obviously, at the current price of $50 to 60 per barrel of oil, a higher CO_2 credit is possible. Only a few studies related to CBM recovery from CO_2 injection are available. Based on the review of several research reports (Gale and Fruend, 2001; Stevens et al., 2001; Reeves and Schoeling, 2001), a credit of $15/tonne of CO_2 was assigned to sequestering CO_2 into coal bed seams.

These cost data are preliminary estimates. For a more detailed economic analysis, updated cost data related to the specific fields should be used.

Mathematical Model for Optimization of Integrated Capture-transportation-storage

The large number of emission sources and sinks selected for this study (Figure 7) provides many different sequestration scenarios and different economic performances at a required CO_2 emission control level. The objective of the optimization study was to find the most economical integrated sequestration scenarios for the three emission control levels. A simple example is shown schematically in Figure 8. The most general mathematical model that can be used to describe the optimization of the integrated sequestration process is a distribution network that includes multiple emission sources,

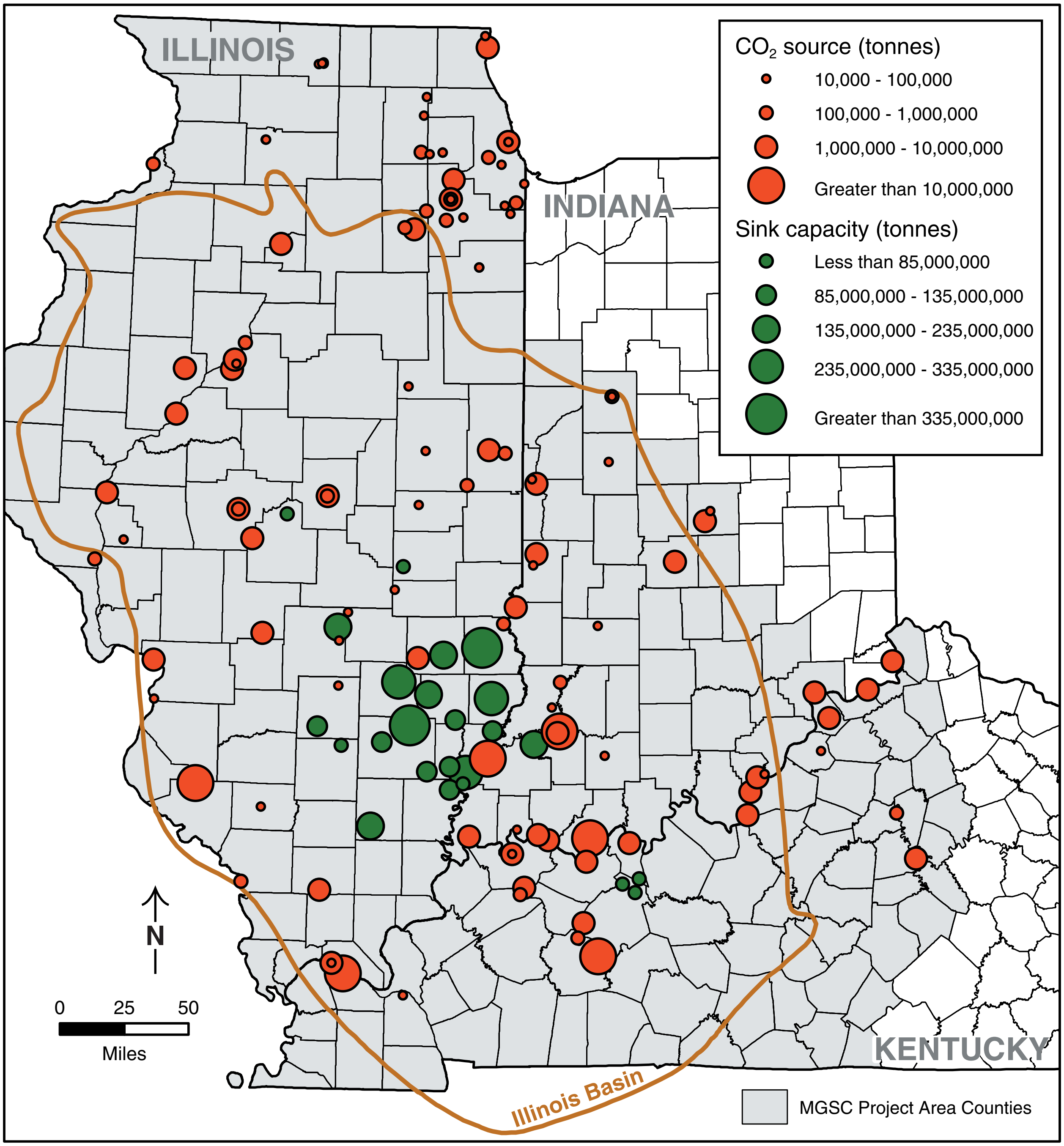


Figure 7 *The geographical distribution of selected CO_2 sources and sinks in the study area.*

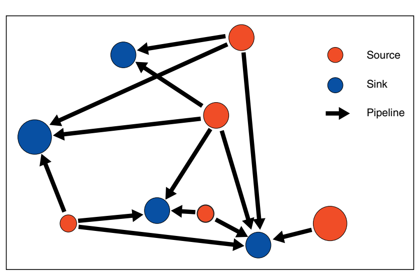
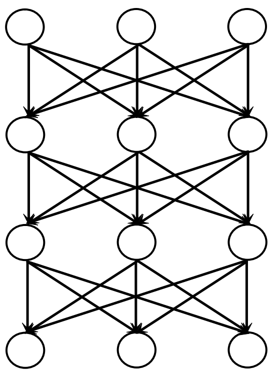


Figure 8 *Schematic diagram of the optimization problem.*

different transportation routes, multiple storage sinks, and different technologies or options available at each level.

The CO_2 sequestration cost is related to each node of the network and is a function of specific conditions such as the locations of the CO_2 sources, scales of the sources, separation technologies, transportation methods, and the sinks (type, location, and scale). For a specific CO_2 sequestration pathway, a minimum sequestration cost exists.



… level i = 1,2,3… CO_2 emission (e.g., power plants)

… level j = 1,2,3… separation (chemical adsorption technology option)

… level k = 1,2,3… transportation methods (pipeline route)

… level l = 1,2,3… geologic storage fields

The arrows in the diagram represent various contributions of options considered. Mathematically, this nonlinear optimization problem can be expressed as follows:

$$\min \sum_i \sum_j \sum_k \sum_l R_i X_i (S_{ij} C_{ij} + F_{il} T_{ikl} D_{il} C_{ikl} + F_{il} C_l)$$

$$\textit{subject to} \quad \begin{cases} \sum_i R_i X_i = R_{\text{target}} \\ X_i = \{0,1\}, \qquad \forall i \\ \sum_j S_{ij} = 1, \qquad \forall i \\ \sum_k T_{ikl} = 1, \qquad \forall i,l \\ \sum_l F_{il} = 1, \qquad \forall i \\ \sum_i R_i X_i F_{il} \le Cap_l, \qquad \forall l \\ S_{ij},\ T_{ik},\ F_{il} \ge 0, \qquad \forall i, j, k, l \end{cases}$$

where i is the source; j is the separation technology; k is the transportation option; l is the type of sink; R_i is the recoverable CO_2 emissions from ith source, million tonnes/year; X_i is the integer constant 0 or 1; R_{target} is the total CO_2 sequestration target in the region, million tonnes/year; S_{ij} is the share of jth separation technology to the ith source; T_{ikl} is the share of kth transportation option for the ith source to transport to the lth sink; F_{il} is the share of lth sink to the ith source; D_{il} is the distance from ith source to the lth sink, miles; Cap_l is the total capacity of the lth sink, million tonnes/year; C_{ij} is the unit cost of the jth capture technology for the ith source, \$/tonne; C_{ikl} is the unit cost of the kth transportation option for the ith source to the lth sink, \$/tonne/mile, C_l is the CO_2 injection unit cost in the lth sink, \$/tonne, and $\forall$ is for all. It should be pointed out that Cap is the annual available capacity of the geological sinks (data in Table 3 divided by 30 years).

In this study, the general model just described was simplified by considering several assumptions. First, only the PC power plants in the Basin were considered as emission sources. An MEA-based absorption process was selected for capturing CO_2 from the PC plants.
Second, whenever an emission source was selected, all of its flue gas volume was treated to capture 90% of its CO_2. This assumption makes the optimization an integer planning problem, which is more complicated mathematically.

Third, once a power plant has been selected, the CO_2 emissions can be transported to more than one sink. This assumption is based on the fact that splitting CO_2 emissions from one source into several sinks could be economically favorable when the transportation cost is only a small fraction of the total sequestration cost.

Fourth, to simplify the optimization further, a straight pipeline connected a source to a sink was assumed; however, this assumption may not be realistic in some cases. Pipeline diameter was selected based on the optimized flow rate between source and sink. For the case shown in Figure 9, the preferred pipeline route to sink 2 is from a side pipeline from the main pipeline connecting source 1 and sink 1, rather than installation of a separate pipeline (dashed line) to connect source 1 to sink 2. For simplicity, the shortest length between a source and a sink (i.e., straight line) was assumed for the estimate of the cost of the pipeline. For a more specific case study, the geological conditions of the area must be considered to determine the pipeline routes accurately.

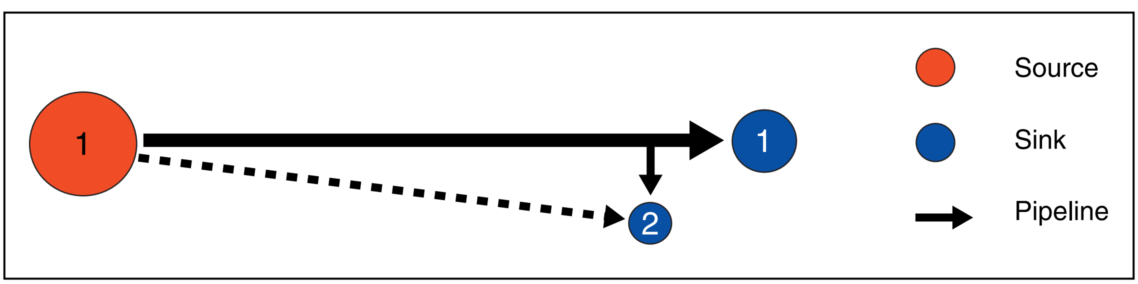


Figure 9 *An extreme example of the optimization problem.*

Fifth, CO_2 emissions from new power generation plants to compensate for the electricity loss due to the installation of the MEA plants were not considered. The power consumed by an MEA plant is typically about 30% of the net electricity output of a power plant.

Based on the above assumptions, the mathematical model is reduced to

$$\min \sum_i \sum_l R_i X_i (C_i + F_{il} D_{il} C_{il} + F_{il} C_l)$$

$$\textit{subject to} \quad \begin{cases} \sum_i R_i X_i = R_{\text{target}} \\ X_i = \{0, 1\}, \quad \forall i \\ \sum_l F_{il} = 1, \quad \forall i \\ \sum_i R_i X_i F_{il} \le Cap_l, \quad \forall l \\ F_{il} \ge 0, \quad \forall i, l \end{cases}$$

where i is the source; l is the type of sink; R_i is the recoverable CO_2 emissions from ith source (assuming 90% of capture efficiency), million tonnes/year; X is the integer 0 or 1; R_{target} is the total CO_2 sequestration target in the region, million tonnes/year; F_{il} is the share of lth sink to the ith source, D_{il} is the distance from ith source to lth sink, mile; Cap_l is the total capacity of the lth sink, million tonnes/year; C_i is the CO_2 capture unit cost, \$/tonne; C_{il} is the CO_2 pipeline transportation unit cost, \$/tonne/mile; C_l is the CO_2 injection unit cost, \$/tonne; and $\forall$ is for all.

In the preceding model, the credits from the EOR and ECBM recovery were added into the CO_2 injection cost, C_l. This was achieved according to the following relationships:

$$\sum_i R_i X_i F_{il} \le Cap_{l1}, \; C_l = -C_{l1}$$

$$Cap_{l1} \le \sum_i R_i X_i F_{il} \le Cap_{l1} + Cap_{l2},$$

$$C_l = \frac{-C_{l1} Cap_{l1} - C_{l2} (\sum_i R_i X_i F_{il} - Cap_{l1})}{\sum_i R_i X_i F_{il}}$$

$$\sum_i R_i X_i F_{il} \ge Cap_{l1} + Cap_{l2},$$

$$C_l = \frac{-C_{l1} Cap_{l1} - C_{l2} Cap_{l2} + C_{l3} (\sum_i R_i X_i F_{il} - Cap_{l1} - Cap_{l2})}{\sum_i R_i X_i F_{il}}$$

where C_{l1} and C_{l2} are the unit benefits of the EOR and ECBM, respectively, and C_{l3} is the unit injection cost of the saline reservoir, \$/tonne. Cap_{l1} and Cap_{l2} are the annual CO_2 storage capacities of the EOR and ECBM (million tonnes/year), respectively.

A commercial optimization software package, LINGO version 9.0, was used in this study (LINDO Systems Inc., 2004). CO_2 capture cost data, Geographic Information Systems (GIS) databases related to the location and scale of each source and sink in the region, and storage costs were the main inputs for the optimization study.

Scenario Analysis of the Integrated System

As described earlier, the preliminary CO_2 storage capacity of the 24 largest sinks identified to date in the Illinois Basin is about 4.7 billion tonnes. This capacity would be filled in about 18 years if 90% of the CO_2 emission mass at the 2002 level (283 million tonnes) is sequestered each year. Because infrastructure will last >30 years, and a 90% control level is unlikely, it was decided to use 50%, 25%, and 10% emission control levels rather than a 90% control level.

The initial optimization efforts focused on evaluating the impacts of the transportation and capture costs on the overall sequestration cost. It was concluded that sequestering CO_2 emissions from the 20 largest power plants in the Basin (about 68% of the total emissions from power plants) provides the most economical scenario. Transportation cost was found to be <\$1.1/tonne CO_2 sequestered for the 50% control level (less for the 25% and 10% levels). The cost of capturing CO_2 from smaller power plants, even those that are located near a sink, increased the overall sequestration cost, mainly due to economies of scale. The 20 selected power plants are listed in Table 9.

Table 9. Power plants selected in optimization studies.

Plant name	ORIS code	Emitted (million tonnes)	Captured (million tonnes)	Plant name	ORIS code	Emitted (million tonnes)	Captured (million tonnes)
GIBSON	006113	17.46	15.71	NEWTON	006017	7.37	6.63
ROCKPORT	006166	15.27	13.75	POWERTON	000879	7.30	6.57
PARADISE	001378	14.83	13.35	MEROM	006213	7.12	6.41
AES	000994	12.23	11.01	KINCAID	000876	6.00	5.40
BALDWIN	000889	11.86	10.67	WARRICK	006705	5.67	5.10
GHENT	001356	11.09	9.98	WILL_COUNTY	000884	5.66	5.09
SHAWNEE	001379	9.95	8.96	JOLIET_29	000384	5.57	5.01
MILL_CREEK	001364	8.67	7.81	WABASH_RIVER	001010	5.38	4.85
JOPPA_STEAM	000887	8.35	7.52	COFFEEN	000861	5.22	4.70
CLIFTY_CREEK	000983	7.48	6.73	CAYUGA	001001	5.19	4.67

50% Basin Emission Control Level

At a 50% Basin emission control level, 128.4 million tonnes of CO_2 emissions/year from 15 power plants are sequestered. The selected power plants are listed in Table 10. The CO_2 emissions from these power plants range from 5.2 to 17.5 million tonnes/year with a total of 142.7 million tonnes/year. The efficiency of CO_2 capture at each selected power plant was assumed as 90%.

Table 10. Power plants selected at the 50% emission control level.

Plant name	ORIS code	Emitted (million tonnes)	Captured (million tonnes)	Capture cost ($ million)
GIBSON	006113	17.46	15.71	840.01
ROCKPORT	006166	15.27	13.75	735.21
PARADISE	001378	14.83	13.35	713.82
AES	000994	12.23	11.01	588.70
BALDWIN	000889	11.86	10.67	570.52
SHAWNEE	001379	9.95	8.96	479.09
MILL_CREEK	001364	8.67	7.81	417.60
JOPPA_STEAM	000887	8.35	7.52	402.09
NEWTON	006017	7.37	6.63	354.51
POWERTON	000879	7.30	6.57	351.30
MEROM	006213	7.12	6.41	342.74
KINCAID	000876	6.00	5.40	288.74
WARRICK	006705	5.67	5.10	272.70
WABASH_RIVER	001010	5.38	4.85	259.33
COFFEEN	000861	5.22	4.70	251.31
Total		**142.71**	**128.44**	**6,867.69**

The capacity usages of the 24 sinks are listed in Table 11. All of the capacity of mature oil fields and coal beds is utilized. This result is expected because CO_2 sequestration in these sinks produces revenue from selling valuable by-products and thus reduces the cost of the sequestration process. Overall, about 82% of the total geological storage capacity is projected to be filled in 30 years.

The geographical connections between the 15 emission sources and 24 sinks and the CO_2 flow rates in pipelines are listed in Table 12. The distances between various sources and sinks range from 9.9 to 122 miles. The flow-weighted average distance is 57.4 miles (Figure 10). This result is consistent with the assumption that no pressure boost is required in the middle point of a pipeline because pipeline distances were <200 miles.

At the 50% control level, the sequestration cost including capture, injection, and transportation is $7.24 billion/year ($56.35/tonne of CO_2). Contributions from capture, transportation, and injection are $6.87 billion/year ($53.47/tonne CO_2), $138.72 million/year ($1.08/tonne CO_2), and $230.75 million/year ($1.80/

tonne of CO_2), respectively, which account for 95%, 2%, and 3% of the total sequestration cost in the Basin. Note that the negative total injection costs in Table 11 indicate that the revenue from selling the by-products (oil and coalbed methane) exceeds the cost of injection. Finally, the loss of electricity due to installing MEA equipment is about 7,746 MW. CO_2 emissions from new power generation plants designed to compensate for the electricity loss were not included in this study.

Table 11. The capacity usage of all the sinks at the 50% emission control level.[1]

Field name	Field ID	Mature oil fields		Coal bed		Saline aquifer		Total	Injection
		Capacity (MMT/Y)	Used (MMT/Y)	Capacity (MMT/Y)	Used (MMT/Y)	Capacity (MMT/Y)	Used (MMT/Y)	Used (MMT/Y)	Cost ($MM/Y)
CLAY_CITY_SW	171119	1.31	1.31	2.35	2.35	23.67	22.14	25.79	49.22
MAIN_CONS	171361	1.30	1.30	0.58	0.58	17.77	17.18	19.06	51.25
LAWRENCE	171336	0.97	0.97	0.47	0.47	9.66	9.57	11.01	21.34
SAILOR_SPRS	171530	0.31	0.31	0.98	0.98	8.37	4.16	5.45	–0.06
NEW_HARMONY	171415	0.72	0.72	0.68	0.68	7.41	7.41	8.82	12.28
DALE_CONS_	171151	0.52	0.52	0.33	0.33	7.04	6.67	7.52	17.93
CLAY_CITY_N	171119	0.36	0.36	0.90	0.90	6.55	4.39	5.66	1.16
LOUDEN	171354	0.73	0.73	0.28	0.28	6.51	5.92	6.93	10.73
UNION	181996	0.30	0.30	0.04	0.04	6.65	6.65	6.99	26.58
CLAY_CITY_NE	171119	0.32	0.32	0.66	0.66	5.75	0.00	0.98	–16.23
SALEM_CONS_	171533	0.58	0.58	0.14	0.14	3.65	3.65	4.37	4.59
GOLDEN_GATE_CONS	171230	0.14	0.14	0.29	0.29	3.66	0.00	0.43	–7.23
ALBION_CONS_	171010	0.16	0.16	0.26	0.26	3.06	3.06	3.48	8.20
JOHNSONVILLE	171299	0.13	0.13	0.25	0.25	2.98	2.98	3.36	8.60
PARKERSBURG	171462	0.09	0.09	0.26	0.26	2.96	0.00	0.35	–5.73
ALLENDALE	171015	0.15	0.15	0.16	0.16	2.93	2.93	3.23	9.27
PHILLIPSTOWN	171474	0.13	0.13	0.26	0.26	2.60	0.00	0.39	–6.59
FORDSVILLE	2112962	0.06	0.06	0.00	0.00	2.74	2.74	2.80	12.42
GRIFFIN	181787	0.40	0.40	0.19	0.19	2.08	2.08	2.66	–0.48
DIVIDE	171160	0.06	0.06	0.11	0.11	2.41	2.41	2.59	9.15
EASTON_CONS	21212261	0.02	0.02	0.00	0.00	2.56	0.00	0.02	–0.31
MATTOON	171377	0.07	0.07	0.18	0.18	2.09	2.09	2.34	6.41
MT__AUBURN_CONS	171399	0.06	0.06	0.03	0.03	2.22	2.22	2.31	9.51
AETNAVILLE	214643	0.03	0.03	0.00	0.00	2.05	1.86	1.89	8.73
Total		**8.93**	**8.93**	**9.41**	**9.41**	**137.36**	**110.10**	**128.44**	**230.75**

[1]Some numbers are rounded.

25% Emission Control Level

At an emission control level of 25%, seven power plants were identified (Table 13). The total CO_2 emissions from the seven power plants is 71.1 million tonnes/year with 64.0 million tonnes/year captured (90% removal).

Table 12. Connections between emission sources and sinks at the 50% control level.

Sources	ID	Sinks	ID	Flow rate (MMT/Y)	Distance (mile)	Transportation cost ($MM/Y)
GIBSON	6113	CLAY_CITY_SW	171119	3.09	32.96	2.68
GIBSON	6113	NEW_HARMONY	171415	2.46	10.01	0.74
GIBSON	6113	GOLDEN_GATE_CONS	171230	0.43	24.26	0.83
GIBSON	6113	ALBION_CONS	171010	3.48	15.20	1.30
GIBSON	6113	PARKERSBURG	171462	0.35	19.67	0.61
GIBSON	6113	ALLENDALE	171015	3.23	11.00	0.91
GIBSON	6113	GRIFFIN	181787	2.66	13.68	1.04
ROCKPORT	6166	CLAY_CITY_SW	171119	13.75	82.72	12.99
PARADISE	1378	NEW_HARMONY	171415	6.36	88.30	9.87
PARADISE	1378	UNION	181996	2.29	86.45	6.15
PARADISE	1378	FORDSVILLE	2112962	2.80	28.78	2.24
PARADISE	1378	EASTON_CONS	21212261	0.02	34.33	0.27
PARADISE	1378	AETNAVILLE	214643	1.89	29.87	1.95
AES	994	LAWRENCE	171336	11.01	29.44	4.19
BALDWIN	889	LOUDEN	171354	0.36	82.19	2.57
BALDWIN	889	SALEM_CONS	171533	4.37	52.29	4.95
BALDWIN	889	JOHNSONVILLE	171299	3.36	74.05	6.25
BALDWIN	889	DIVIDE	171160	2.59	58.54	4.40
SHAWNEE	1379	CLAY_CITY_SW	171119	8.96	100.19	13.02
MILL_CREEK	1364	MAIN_CONS	171361	7.81	121.97	14.92
JOPPA_STEAM	887	DALE_CONS	171151	7.52	55.40	6.67
NEWTON	6017	CLAY_CITY_N	171119	5.66	9.94	1.06
NEWTON	6017	CLAY_CITY_NE	171119	0.98	14.86	0.73
POWERTON	879	LOUDEN	171354	6.57	108.64	12.32
MEROM	6213	MAIN_CONS	171361	6.41	20.51	2.30
KINCAID	876	SAILOR_SPRS	171530	0.75	79.77	3.48
KINCAID	876	MATTOON	171377	2.34	59.70	4.29
KINCAID	876	MT__AUBURN_CONS	171399	2.31	16.58	1.19
WARRICK	6705	UNION	181996	4.71	37.84	3.70
WARRICK	6705	PHILLIPSTOWN	171474	0.39	43.07	1.41
WABASH_RIVER	1010	MAIN_CONS	171361	4.85	42.30	4.19
COFFEEN	861	SAILOR_SPRS	171530	4.70	56.18	5.50
Total				**128.44**	**57.37 (avg.)**	**138.72**

The capacity usages of the 24 sinks are listed in Table 14. Similar to the 50% control level, all of the mature oil fields and coal beds are filled. In addition, 45.7 million tonnes/year of CO_2 are sequestered in saline reservoirs. About 41% of the total geological storage capacity is filled in 30 years.

The geographical connections between the seven power plants, the 24 sinks, and the CO_2 flow rates in pipelines are listed in Table 15. The pipeline distance between various sources and sinks ranged from 9.9 to 77.5 miles with a flow-weighted average distance of 26.7 miles (Figure 11).

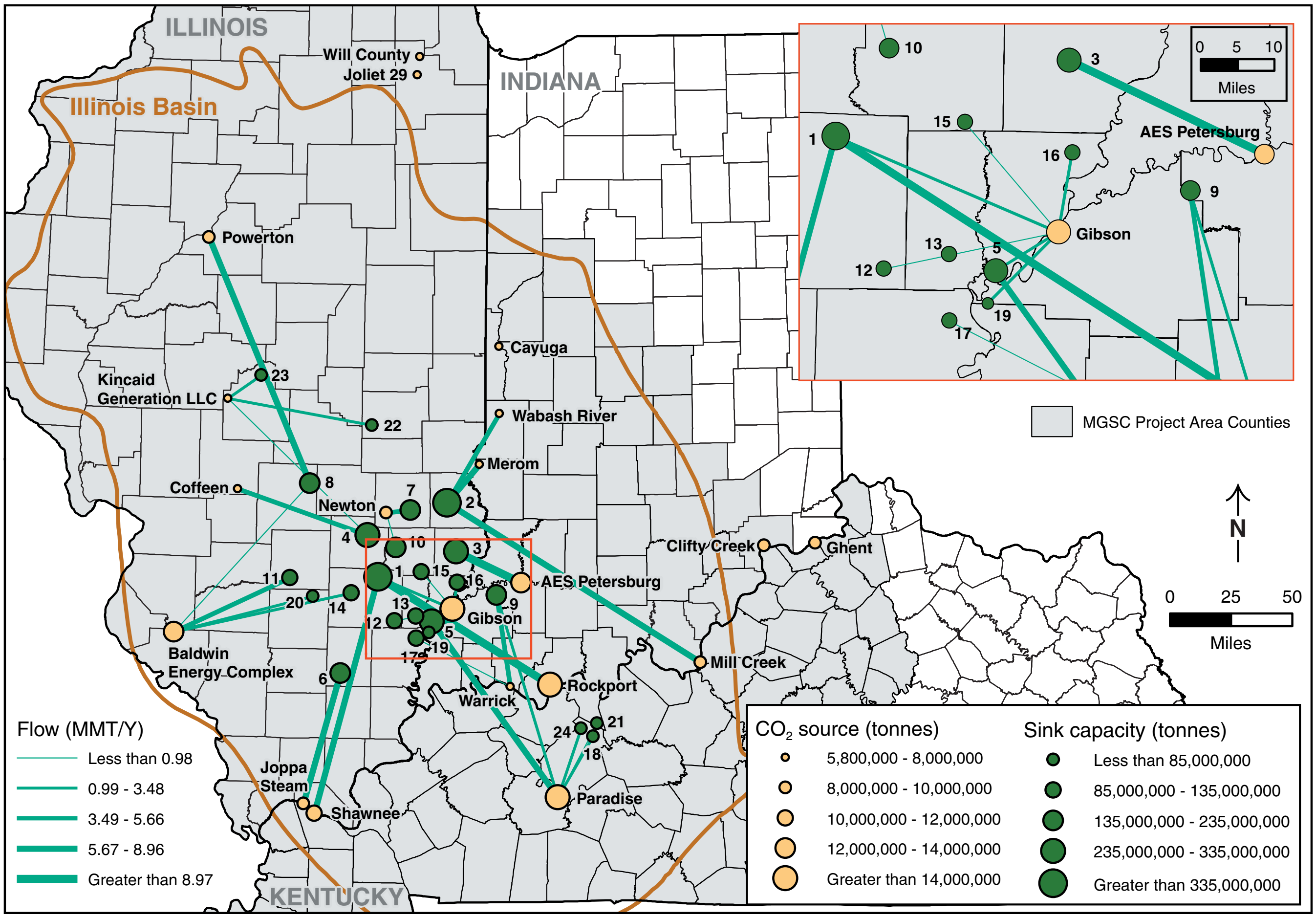


Figure 10 *Distribution of the captured CO_2 among the sinks at 50% emission control level.*

At a 25% control level, the total sequestration cost including capture, injection, and transportation is \$3.38 billion/year (\$52.77/tonne of CO_2). Contributions from capture, transportation, and injection are \$3.42 billion/year (\$53.46/tonne of CO_2), \$47.27 million/year (\$0.74/tonne of CO_2), and –\$91.35 million/year (–\$1.43/tonne of CO_2), respectively. Note that for the 25% control level, total transportation cost is about one third of the 50% control level. The negative injection cost indicates that the revenues from selling the by-products exceed the injection costs. The net benefit of the CO_2 injection to storage sinks is \$91.35 million/year, compared with the injection expense of \$230.75 million/year at the 50% control level. This is an absolute difference of \$322.1 million/year. At the 25% control level, a smaller amount of CO_2 is stored in the higher cost saline reservoirs. The loss of electricity due to CO_2 capture is about 3,873 MW at the 25% control level.

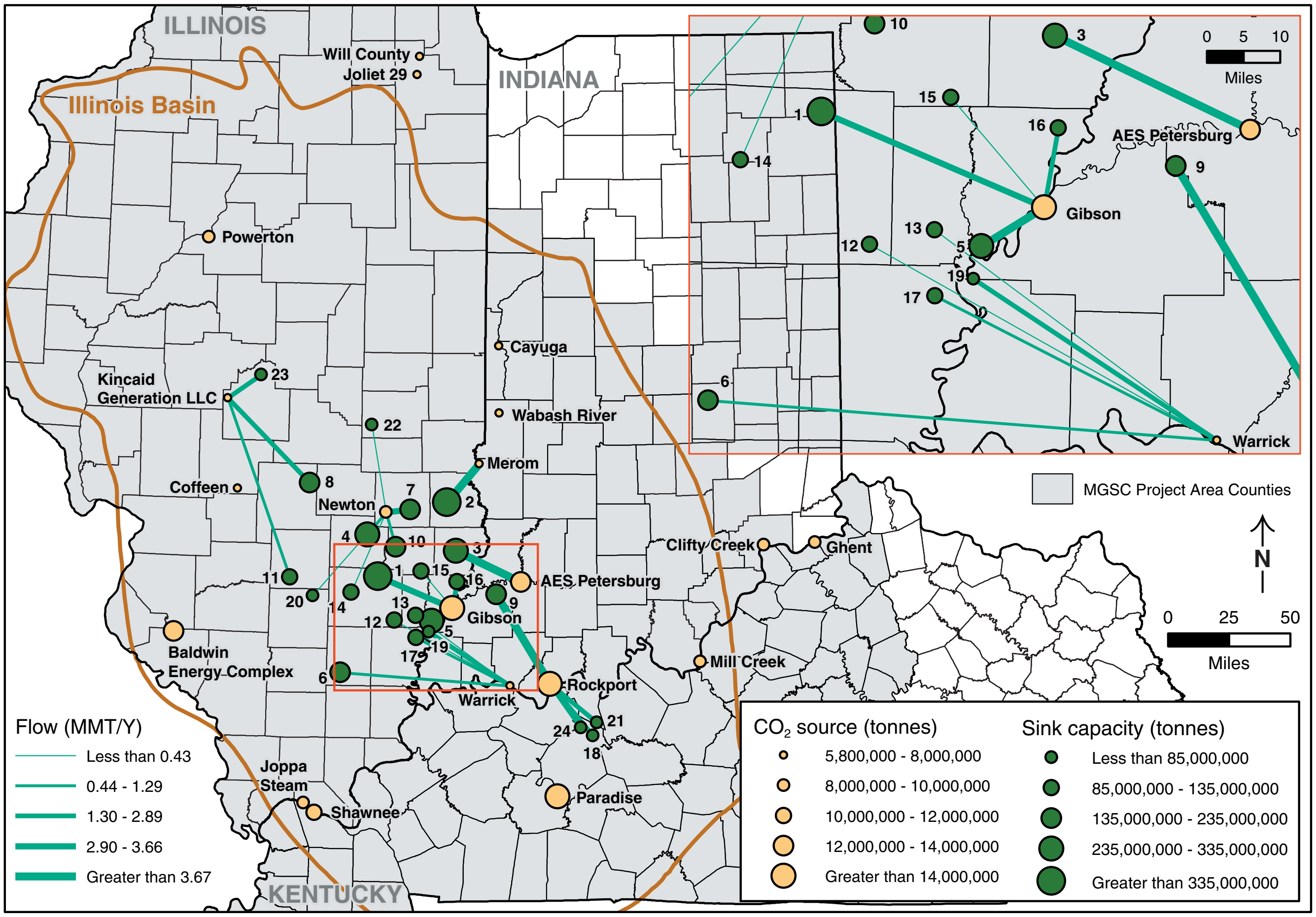


Figure 11 *Distribution of the captured CO_2 among the sinks at the 25% emission control level.*

10% Emission Control Level

At a 10% emission control level, only three power plants were identified (Table 16). The total CO_2 emissions from the three power plants are 30.05 million tonnes/year with 27.04 million tonnes/year captured (90% removal).

The capacity usages at the 10% emission control level are listed in Table 17. Again, as with the previous two cases, all of the capacities available in oil fields and coal beds are filled. In addition, 8.71 million tonnes/year of CO_2 is sequestered in saline reservoirs. About 17% of the total storage capacity would be filled in 30 years.

The geographical connections between the three power plants and the 24 sinks and the CO_2 flow rates in pipelines are listed in Table 18. The pipeline distance range from 10 to 77 miles with a flow-weighted average distance of 22.2 miles (Figure 12). This distance is shorter than the distances for the 50% (57.4 miles) and 25% (26.7 miles) control level cases, respectively.

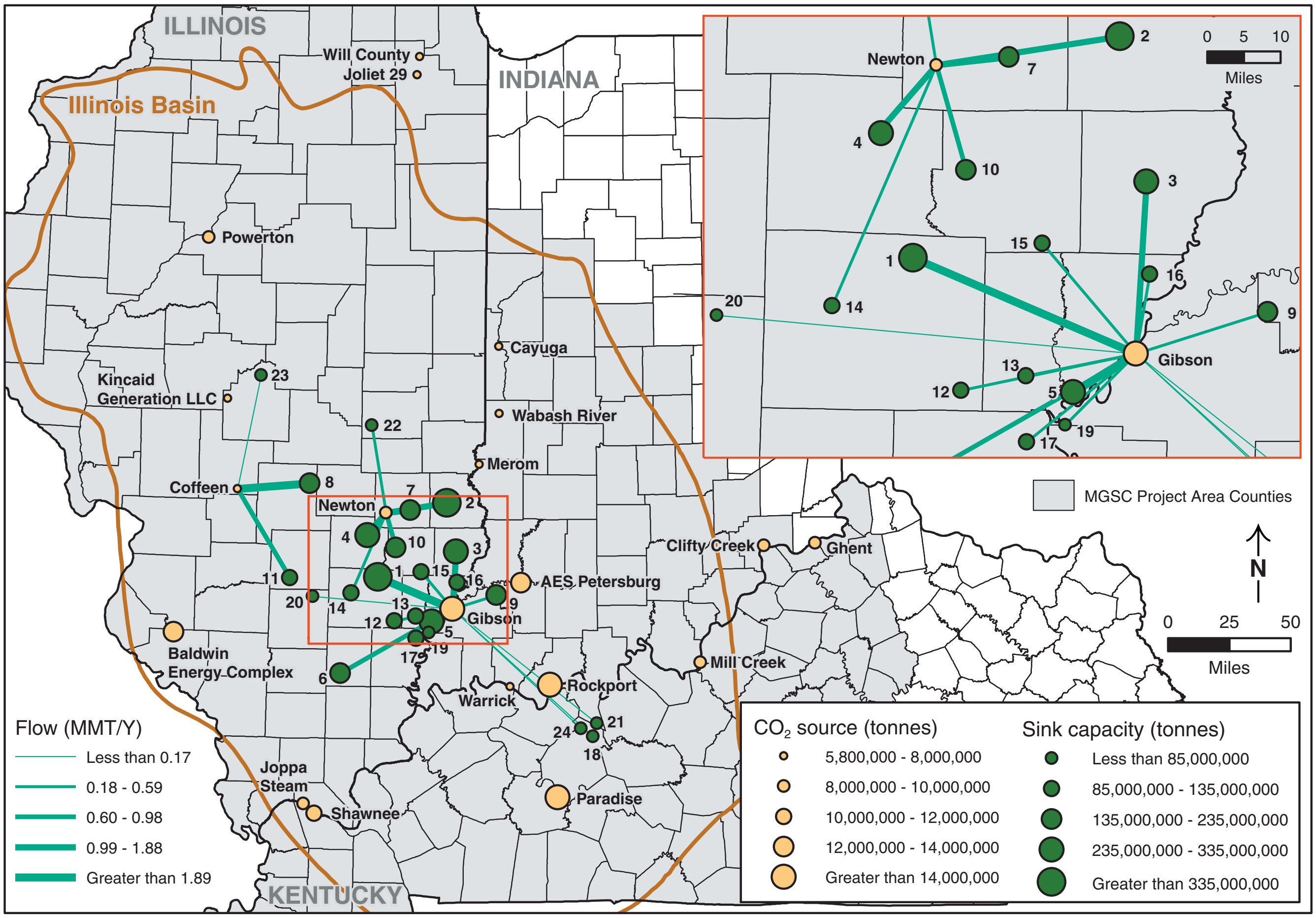


Figure 12 *Distribution of the capture CO_2 among the sinks at the 10% emission control level.*

Table 13. Power plants selected in 25% CO_2 emission control level.

Plant name	ORIS code	Emitted (million tonnes/year)	Captured (million tonnes/year)	Capture cost (million tonnes/year)
GIBSON	6113	17.46	15.71	840.01
ROCKPORT	6166	15.27	13.75	735.21
AES	994	12.23	11.01	588.70
NEWTON	6017	7.37	6.63	354.51
MEROM	6213	7.12	6.41	342.74
KINCAID	876	6.00	5.40	288.74
WARRICK	6705	5.67	5.10	272.70
Total		**71.12**	**64.02**	**3,422.61**

At a 10% emissions control level, the total sequestration cost—including capture, injection, and transportation—is $1.20 billion/year ($44.22/tonne of CO_2). Contributions from capture, transportation, and injection are $1.45 billion/year ($53.45/tonne of CO_2), $26.63 million/year ($0.98/tonne of CO_2), and

–$276.20 million/year (–$10.21/tonne of CO_2), respectively. Again, the negative injection cost indicates that the injection is profitable. The loss of electricity due to CO_2 capture is about 1,634 MW at the 10% control level.

Table 14. Capacity usage of all of the sinks at the 25% emission control level.[1]

Field name	Field ID	Mature oil fields		Coal beds		Saline aquifer		Total used (MMT/Y)	Injection cost ($MM/Y)
		Capacity (MMT/Y)	Used (MMT/Y)	Capacity (MMT/Y)	Used (MMT/Y)	Capacity (MMT/Y)	Used (MMT/Y)		
CLAY CITY (MGSC SW)	171119	1.31	1.31	2.35	2.35	23.67	0.00	3.66	–61.45
MAIN CONS.	171361	1.30	1.30	0.58	0.58	17.77	4.53	6.41	–12.01
LAWRENCE	171336	0.97	0.97	0.47	0.47	9.66	9.57	11.01	21.34
SAILOR SPRS. CONS.	171530	0.31	0.31	0.98	0.98	8.37	0.00	1.29	–20.89
NEW HARMONY CONS.	171415	0.72	0.72	0.68	0.68	7.41	7.41	8.82	12.28
DALE CONS.	171151	0.52	0.52	0.33	0.33	7.04	0.00	0.85	–15.40
CLAY CITY (MGSC N)	171119	0.36	0.36	0.90	0.90	6.55	2.72	3.99?	–7.18
LOUDEN	171354	0.73	0.73	0.28	0.28	6.51	1.36	2.38	–12.02
UNION-BOWMAN CONS.	181996	0.30	0.30	0.04	0.04	6.65	6.65	6.99	26.58
CLAY CITY (MGSC NE)	171119	0.32	0.32	0.66	0.66	5.75	0.00	0.98	–16.23
SALEM CONS.	171533	0.58	0.58	0.14	0.14	3.65	0.00	0.72	–13.67
GOLDEN GATE CONS.	171230	0.14	0.14	0.29	0.29	3.66	0.00	0.43	–.23
ALBION CONS.	171010	0.16	0.16	0.26	0.26	3.06	0.00	0.42	–7.10
JOHNSONVILLE CONS.	171299	0.13	0.13	0.25	0.25	2.98	0.00	0.38	–6.31
PARKERSBURG CONS.	171462	0.09	0.09	0.26	0.26	2.96	0.00	0.35	–.73
ALLENDALE	171015	0.15	0.15	0.16	0.16	2.93	2.16	2.46	5.42
PHILLIPSTOWN CONS.	171474	0.13	0.13	0.26	0.26	2.60	0.00	0.39	–6.59
FORDSVILLE CONS.	2112962	0.06	0.06	0.00	0.00	2.74	2.74	2.80	12.42
GRIFFIN CONS.	181787	0.40	0.40	0.19	0.19	2.08	2.08	2.66	–0.48
DIVIDE CONS.	171160	0.06	0.06	0.11	0.11	2.41	0.00	0.17	–2.92
Easton CONS	21212261	0.02	0.02	0.00	0.00	2.56	2.20	2.21	10.66
MATTOON	171377	0.07	0.07	0.18	0.18	2.09	0.00	0.25	–4.06
MT. AUBURN CONS.	171399	0.06	0.06	0.03	0.03	2.22	2.22	2.31	9.51
AETNAVILLE CONS.	214643	0.03	0.03	0.00	0.00	2.05	2.05	2.08	9.68
Total		**8.93**	**8.93**	**9.41**	**9.41**	**137.36**	**45.68**	**64.02**	**–91.35**

[1]Some numbers are rounded.

Comparison of Emission Control Levels

The total CO_2 sequestration costs for the three selected CO_2 control levels in the Basin are summarized in Table 19. These costs include the electricity loss due to the installation of MEA plants. The increase in the cost of electricity, shared by all utilities in the Basin, is about 3.72, 10.50, and 22.50 mills/kWh at 10, 25, and 50% of CO_2 reduction, respectively.

Table 15. Connections between emission sources and sinks at the 25% emission control level.

Sources	ID	Sinks	ID	Flow rate (MMT/Y)	Distance (miles)	Transportation cost ($MM/Y)
GIBSON	6113	CLAY_CITY_SW	171119	3.66	32.96	2.89
GIBSON	6113	NEW_HARMONY	171415	8.82	10.01	1.29
GIBSON	6113	PARKERSBURG	171462	0.35	19.67	0.61
GIBSON	6113	ALLENDALE	171015	2.89	11.00	0.87
ROCKPORT	6166	UNION	181996	6.66	42.71	4.87
ROCKPORT	6166	FORDSVILLE	2112962	2.80	27.43	2.13
ROCKPORT	6166	EASTON_CONS	21212261	2.21	24.68	1.73
ROCKPORT	6166	AETNAVILLE	214643	2.08	21.83	1.49
AES	994	LAWRENCE	171336	11.01	29.44	4.19
NEWTON	6017	DIVIDE	171160	0.17	45.27	1.03
NEWTON	6017	MATTOON	171377	0.25	36.12	0.96
NEWTON	6017	SAILOR_SPRS	171530	1.29	11.92	0.66
NEWTON	6017	CLAY_CITY_N	171119	3.57	9.94	0.86
NEWTON	6017	CLAY_CITY_NE	171119	0.98	14.86	0.73
NEWTON	6017	JOHNSONVILLE	171299	0.38	35.73	1.15
MEROM	6213	MAIN_CONS	171361	6.41	20.51	2.30
KINCAID	876	LOUDEN	171354	2.38	48.04	3.48
KINCAID	876	SALEM_CONS	171533	0.72	77.46	3.31
KINCAID	876	MT__AUBURN_CONS	171399	2.31	16.58	1.19
WARRICK	6705	DALE_CONS	171151	0.85	69.32	3.19
WARRICK	6705	GOLDEN_GATE_CONS	171230	0.43	54.24	1.86
WARRICK	6705	ALBION_CONS	171010	0.42	47.91	1.61
WARRICK	6705	PHILLIPSTOWN	171474	0.73	43.07	1.85
WARRICK	6705	GRIFFIN	181787	2.66	39.74	3.03
Total				**64.02**	**26.68 avg.**	**47.27**

Table 16. Power plants selected at the 10% CO_2 emission control level.

Plant name	ORIS code	Emissions (MMT/Y)	Captured (MMT/Y)	Capture cost ($MM/Y)
GIBSON	006113	17.46	15.71	840.01
NEWTON	006017	7.37	6.63	354.51
COFFEEN	000861	5.22	4.70	251.31
Total		**30.05**	**27.05**	**1,445.83**

Table 17. Capacity usage of all the sinks at the 10% emission control level.

Field name	Field ID	Mature oil fields		Coal beds		Saline aquifer		Total used (MMT/Y)	Injection cost ($MM/Y)
		Capacity (MMT/Y)	Used (MMT/Y)	Capacity (MMT/Y)	Used (MMT/Y)	Capacity (MMT/Y)	Used (MMT/Y)		
CLAY CITY (MGSC SW)	171119	1.31	1.31	2.35	2.35	23.67	0.00	3.66	–61.45
MAIN CONS.	171361	1.30	1.30	0.58	0.58	17.77	0.00	1.88	–34.67
LAWRENCE	171336	0.97	0.97	0.47	0.47	9.66	0.00	1.44	–26.50
SAILOR SPRS. CONS.	171530	0.31	0.31	0.98	0.98	8.37	0.00	1.29	–20.89
NEW HARMONY CONS.	171415	0.72	0.72	0.68	0.68	7.41	5.23	6.64	–1.09
DALE CONS.	171151	0.52	0.52	0.33	0.33	7.04	0.00	0.85	–15.40
CLAY CITY (MGSC N)	171119	0.36	0.36	0.90	0.90	6.55	0.60	1.86	–15.33
LOUDEN	171354	0.73	0.73	0.28	0.28	6.51	2.88	3.90	–4.43
UNION-BOWMAN CONS.	181996	0.30	0.30	0.04	0.04	6.65	0.00	0.34	–6.65
CLAY CITY (MGSC NE)	171119	0.32	0.32	0.66	0.66	5.75	0.00	0.98	–16.23
SALEM CONS.	171533	0.58	0.58	0.14	0.14	3.65	0.00	0.72	–13.67
GOLDEN GATE CONS.	171230	0.14	0.14	0.29	0.29	3.66	0.00	0.43	–7.23
ALBION CONS.	171010	0.16	0.16	0.26	0.26	3.06	0.00	0.42	–7.10
JOHNSONVILLE CONS.	171299	0.13	0.13	0.25	0.25	2.98	0.00	0.38	–6.31
PARKERSBURG CONS.	171462	0.09	0.09	0.26	0.26	2.96	0.00	0.35	–5.73
ALLENDALE	171015	0.15	0.15	0.16	0.16	2.93	0.00	0.31	–5.36
PHILLIPSTOWN CONS.	171474	0.13	0.13	0.26	0.26	2.60	0.00	0.39	–6.59
FORDSVILLE CONS.	2112962	0.06	0.06	0.00	0.00	2.74	0.00	0.06	–1.26
GRIFFIN CONSOL.	181787	0.40	0.40	0.19	0.19	2.08	0.00	0.59	–10.86
DIVIDE CONS.	171160	0.06	0.06	0.11	0.11	2.41	0.00	0.17	–2.92
Easton CONS.	21212261	0.02	0.02	0.00	0.00	2.56	0.00	0.02	–0.31
MATTOON	171377	0.07	0.07	0.18	0.18	2.09	0.00	0.25	–4.06
MT. AUBURN CONS.	171399	0.06	0.06	0.03	0.03	2.22	0.00	0.09	–1.59
AETNAVILLE CONS.	214643	0.03	0.03	0.00	0.00	2.05	0.00	0.03	–0.58
Total		**8.93**	**8.93**	**9.41**	**9.41**	**137.36**	**8.71**	**27.05**	**–276.20**

Sensitivity Analysis

The capture cost and EOR and ECBM by-product credits could change during the course of a sequestration period. The DOE has set a target cost of $10/tonne for CO_2 sequestration. This might be an ambitious goal; however, with advancement in various technologies employed in the sequestration process and an anticipated increase in the price of oil and natural gas, the net CO_2 sequestration cost will tend to decrease. This section presents the results from a sensitivity study to evaluate the impacts of costs of CO_2 capture and by-products recovered from CO_2 storage on the overall sequestration cost.

CO_2 Capture Cost

The sensitivity study was performed by assuming that the CO_2 capture cost of an MEA-based absorption process will be reduced by 80%, 50%, and 25% from the current estimate of $53.47/tonne for a new

1,000-MW power plant. The change in capture cost will not impact the selection of capture sources or transportation routes. Thus, transportation and injection costs remain the same. The results are shown in Figure 13 and Table 20.

The sequestration cost is linearly related to the capture cost at all levels. The impact of CO_2 capture cost is more pronounced with an increase in CO_2 emission control levels. This observation indicates that future efforts to reduce sequestration costs should focus on developing more cost-effective capture technologies.

Table 20 presents the impact of capture cost on the average costs of CO_2 sequestration per tonne, total sequestration costs, and the average increase in electricity cost at different control levels. For example, at the 50% control level and a 50% reduction in the current capture costs, the costs for sequestering 1 tonne of CO_2 decreases from \$56.35 to \$29.61, and the increase in electricity cost decreases from 22.50 to 11.82 mills/kWh.

Table 18. Connections between emission sources and sinks at the 10% control level.

Plant name	ID	Sink name	ID	Flow rate (MMT/Y)	Distance (miles)	Transportation cost ($MM/Y)
GIBSON	6113	CLAY_CITY_SW	171119	3.66	32.96	2.89
GIBSON	6113	LAWRENCE	171336	1.44	23.48	1.36
GIBSON	6113	NEW_HARMONY	171415	6.64	10.01	1.14
GIBSON	6113	DALE_CONS	171151	0.85	52.68	2.43
GIBSON	6113	UNION	181996	0.34	18.77	0.58
GIBSON	6113	GOLDEN_GATE_CONS	171230	0.43	24.26	0.83
GIBSON	6113	ALBION_CONS	171010	0.42	15.20	0.51
GIBSON	6113	PARKERSBURG	171462	0.35	19.67	0.61
GIBSON	6113	ALLENDALE	171015	0.31	11.00	0.32
GIBSON	6113	PHILLIPSTOWN	171474	0.39	19.12	0.63
GIBSON	6113	FORDSVILLE	2112962	0.06	77.43	1.13
GIBSON	6113	GRIFFIN	181787	0.59	13.68	0.54
GIBSON	6113	DIVIDE	171160	0.17	57.11	1.31
GIBSON	6113	EASTON_CONS	21212261	0.02	75.09	0.59
GIBSON6	6113	AETNAVILLE	214643	0.03	71.61	0.74
NEWTON	6017	MATTOON	171377	0.25	36.12	0.96
NEWTON	6017	MAIN_CONS	171361	1.88	25.25	1.65
NEWTON	6017	SAILOR_SPRS	171530	1.29	11.92	0.66
NEWTON	6017	CLAY_CITY_N	171119	1.86	9.94	0.65
NEWTON	6017	CLAY_CITY_NE	171119	0.98	14.86	0.73
NEWTON	6017	JOHNSONVILLE	171299	0.38	35.73	1.15
COFFEEN	861	LOUDEN	171354	3.90	29.37	2.64
COFFEEN	861	SALEM_CONS	171533	0.72	42.09	1.80
COFFEEN	861	MT__AUBURN_CONS	171399	0.09	47.37	0.80
Total				**27.05**	**22.19 (avg.)**	**26.63**

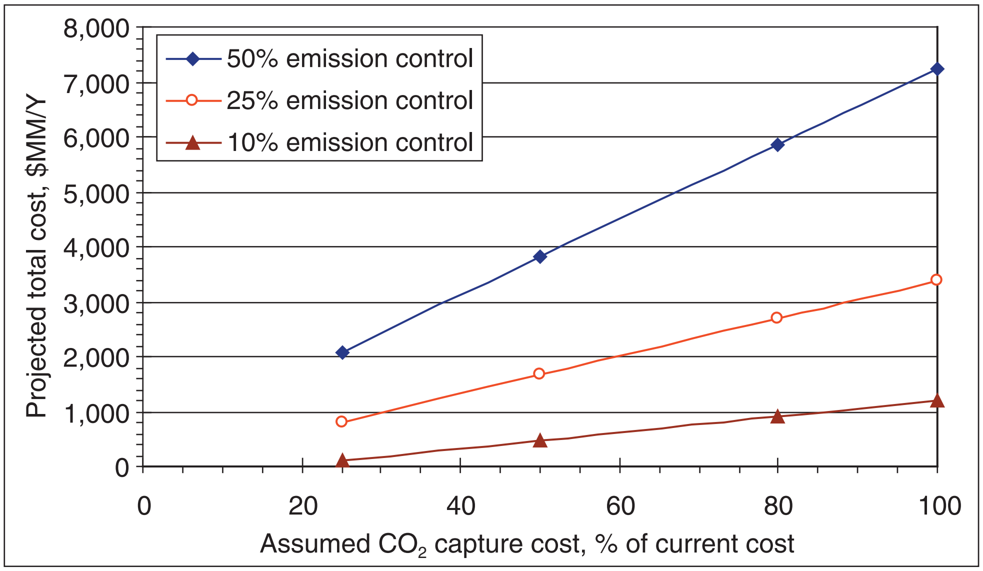


Figure 13 *Sensitivity of total CO_2 sequestration cost to the capture cost.*

Table 19. Summary of CO_2 sequestration costs with by-product credits.

Emission control level	**50% (128.44MMT/Y)**	**25% (64.02MMT/Y)**	**10% (27.05MMT/Y)**
Capture cost, $MM/Y	6,867.69	3,422.61	1,445.83
Transportation cost, $MM/Y	138.72	47.27	26.63
Injection cost, $MM/Y	230.75	–91.35	–276.20
Total cost, $MM/Y	7,237.16	3,378.53	1,196.26
Average cost, $/tonne of CO_2 sequestered	56.35	52.77	44.22
Electricity loss, MW	7,746	3,873	1,634
Average increase electricity cost, mills/kWh	22.50	10.50	3.72

Table 20. Sensitivity of CO_2 sequestration cost to capture cost.

Capture cost reduction, %	25%	50%	80%	100%
	50% emission control			
Total cost, $MM/Y	2,086.39	3,803.32	5,863.62	7,237.16
Average cost, $/tonne of CO_2 sequestered	16.24	29.61	45.65	56.35
Average increase of electricity cost, mills/kWh	6.49	11.82	18.23	22.50
	25% emission control			
Total cost, $MM/Y	811.57	1,667.23	2,694.01	3,378.53
Average cost, $/tonne of CO_2 sequestered	12.68	26.04	42.08	52.77
Average increase of electricity cost, mills/kWh	2.52	5.18	8.37	10.50
	10% emission control			
Total cost, $MM/Y	111.89	473.35	907.09	1,196.26
Average cost, $/tonne of CO_2 sequestered	4.14	17.50	33.53	44.22
Average increase of electricity cost, mills/kWh	0.35	1.47	2.82	3.72

CO_2 Sequestration Cost without EOR and ECBM Benefits

Without EOR and ECBM by-product credits, the distribution of captured CO_2 among the 24 sinks will be different from the scenarios described with by-product benefits. However, excluding the by-product credits in the optimization process has little impact on the selection of emission sources. The results from the optimization study confirmed this prediction. When by-product credits were not considered, the emission sources identified were identical to the cases in which the by-products were included for the 50% and 25% control levels, and only one emission source was different for the 10% control level.

The capacity usages at the three different emission control levels are listed in Table 21. For the 50%, 25%, and 10% control levels, 19, 15, and 5 sinks, respectively, were identified. These results are different from the scenarios when by-product credits were included. The total injection costs were proportional to the amount of CO_2 stored at a unit cost of $5/tonne of CO_2. Differences in the injectability characteristics of sinks are not considered.

The distribution of captured CO_2 among the sinks at different emission control levels is listed in Tables 22 to 24. Figures 14, 15, and 16 present the geographical distribution of the selected power plants and sinks for the 50%, 25%, and 10% emission control levels, respectively. The total transportation cost in this scenario is lower than when by-product credits were included. For example, at 50% emission control level, transportation cost is reduced from $138.7 million/year with by-product recovery to $137.8 million/year without by-product recovery. Trends for the 25% and 10% control levels are similar.

Table 25 provides a summary of the results. The total costs for transportation and injection are small compared with the capture cost with or without by-product credits. One reason for lower transportation cost is the relatively short distance between the emission sources and the available geological structures in the Illinois Basin. Also included in Table 25 are the increases in electricity costs, shared by all utilities in the Basin, for the sequestration process. They range from 5.25 to 23.77 mills/kWh, depending on the level of control.

Summary and Conclusions

Stationary sources in the Illinois Basin emitted 283 million tonnes of CO_2 in 2002, about 261 million tonnes of which were emitted by 122 power plants.

At the time this study was conducted, the 24 largest geological storage sites (outlined by the presence of oil fields) were identified in the Basin. These sites had a total CO_2 geological storage capacity of about 4.7 billion tonnes (6% in oil fields, 6% in coal bed seams, and 88% in saline reservoirs).

Table 21. Capacity usage of all the sinks at different emission control levels.

Field name	Field ID	50%			25%			10%		
		Total capacity (MMT/Y)	Used (MMT/Y)	Injection cost ($MM/Y)	Total capacity (MMT/Y)	Used (MMT/Y)	Injection cost ($MM/Y)	Total capacity (MMT/Y)	Used (MMT/Y)	Injection cost ($MM/Y)
CLAY_CITY_SW	171119	27.32	27.02	135.10	27.32	0	0	27.32	0	0
MAIN_CONS_	171361	19.65	19.06	95.30	19.65	6.41	32.05	19.65	6.41	32.05
LAWRENCE	171336	11.10	11.01	55.05	11.1	11.01	55.05	11.1	0	0
SAILOR_SPRS_	171530	9.66	5.45	27.25	9.66	0	0	9.66	0	0
NEW_HARMONY	171415	8.82	8.82	44.10	8.82	8.82	44.10	8.82	8.82	44.10
DALE_CONS_	171151	7.89	7.52	37.60	7.89	0	0	7.89	0	0
CLAY_CITY_N	171119	7.82	6.63	33.15	7.82	6.63	33.15	7.82	6.63	33.15
LOUDEN	171354	7.52	6.93	34.65	7.52	3.09	15.45	7.52	0	0
UNION	181996	6.99	6.99	34.95	6.99	6.99	34.95	6.99	3.66	18.3
CLAY_CITY_NE	171119	6.72	0	0	6.72	0	0	6.72	0	0
SALEM_CONS_	171533	4.37	4.37	21.85	4.37	0	0	4.37	0	0
GOLDEN_GATE_CONS	171230	4.10	0	0	4.10	0	0	4.1	0	0
ALBION_CONS_	171010	3.48	3.48	17.40	3.48	3.48	17.40	3.48	0	0
JOHNSONVILLE	171299	3.36	3.36	16.80	3.36	0	0	3.36	0	0
PARKERSBURG	171462	3.32	0	0	3.32	0.19	0.95	3.32	0	0
ALLENDALE	171015	3.23	3.23	16.15	3.23	3.23	16.15	3.23	3.23	16.15
PHILLIPSTOWN	171474	2.99	0	0	2.99	2.44	12.20	2.99	0	0
FORDSVILLE	2112962	2.80	0	0	2.80	2.10	10.50	2.8	0	0
GRIFFIN	181787	2.66	2.66	13.30	2.66	2.66	13.30	2.66	0	0
DIVIDE	171160	2.59	2.59	12.95	2.59	0	0	2.59	0	0
EASTON_CONS	21212261	2.58	2.58	12.90	2.58	2.58	12.90	2.58	0	0
MATTOON	171377	2.34	2.34	11.70	2.34	0	0	2.34	0	0
MT__AUBURN_CONS	171399	2.31	2.31	11.55	2.31	2.31	11.55	2.31	0	0
AETNAVILLE	214643	2.08	2.08	10.40	2.08	2.08	10.40	2.08	0	0
Total		**155.70**	**128.44**	**642.15**	**155.7**	**64.02**	**320.10**	**155.70**	**28.75**	**143.75**

Table 22. The connection between emission sources and sinks at 50% control level.

Sources	ID	Sinks	ID	Flow rate (MMT/Y)	Distance (miles)	Transportation cost ($MM/Y)
GIBSON	6113	CLAY_CITY_SW	171119	4.32	32.96	3.11
GIBSON	6113	NEW_HARMONY	171415	2.02	10.01	0.67
GIBSON	6113	ALBION_CONS	171010	3.48	15.20	1.30
GIBSON	6113	ALLENDALE	171015	3.23	11.00	0.91
GIBSON	6113	GRIFFIN	181787	2.66	13.68	1.04
ROCKPORT	006166	CLAY_CITY_SW	171119	13.75	82.72	12.99
PARADISE	1378	NEW_HARMONY	171415	6.80	88.30	10.16
PARADISE	1378	UNION	181996	6.55	86.45	9.79
AES	000994	LAWRENCE	171336	11.01	29.44	4.19
BALDWIN	889	LOUDEN	171354	0.36	82.19	2.57
BALDWIN	889	SALEM_CONS	171533	4.37	52.29	4.95
BALDWIN	889	JOHNSONVILLE	171299	3.36	74.05	6.25
BALDWIN	889	DIVIDE	171160	2.59	58.54	4.40
SHAWNEE	001379	CLAY_CITY_SW	171119	8.96	100.19	13.02
MILL_CREEK	001364	MAIN_CONS	171361	7.81	121.97	14.92
JOPPA_STEAM	000887	DALE_CONS	171151	7.52	55.40	6.67
NEWTON	6017	CLAY_CITY_N	171119	6.63	9.94	1.13
POWERTON	000879	LOUDEN	171354	6.57	108.64	12.32
MEROM	006213	MAIN_CONS	171361	6.41	20.51	2.30
KINCAID	876	SAILOR_SPRS	171530	0.75	79.77	3.48
KINCAID	876	MATTOON	171377	2.34	59.70	4.29
KINCAID	876	MT__AUBURN_CONS	171399	2.31	16.58	1.19
WARRICK	6705	UNION	181996	0.44	37.84	1.30
WARRICK	6705	EASTON_CONS	21212261	2.58	38.37	2.88
WARRICK	6705	AETNAVILLE	214643	2.08	33.59	2.29
WABASH_RIVER	001010	MAIN_CONS	171361	4.85	42.30	4.19
COFFEEN	000861	SAILOR_SPRS	171530	4.70	56.18	5.50
Total				**128.44**	**59.52 (avg.)**	**137.81**

The integrated CO_2 sequestration process in the Illinois Basin was optimized at control levels of 10%, 25%, and 50% using a commercial nonlinear optimization software tool, LINGO, for evaluating the most economical options for the integrated sequestration process.

The costs of CO_2 capture (90% reduction) from coal-fired power plants and pipeline transportation were obtained from a previous techno-economic study completed by the MGSC in October 2004. The CO_2 avoidance costs ($53 to $59/tonne) were based on an MEA process. An injection cost of $5/tonne of CO_2 for saline reservoirs and net revenues of $20/tonne of CO_2 for EOR and $15/tonne CO_2 for ECBM were assumed. The loss of electricity capacity in the Basin due to the installation of MEA plants was not included in the optimization study. Sequestration costs were evaluated with and without by-product credits from EOR and ECBM. A 30-year life span was considered for the pipeline and MEA process.

Table 23. Connections between emission sources and sinks at 25% control level.

Sources	ID	Sinks	ID	Flow rate (MMT/Y)	Distance (miles)	Transportation cost ($MM/Y)
GIBSON	6113	NEW_HARMONY	171415	8.82	10.01	1.29
GIBSON	6113	ALBION_CONS	171010	3.48	15.20	1.30
GIBSON	6113	PARKERSBURG	171462	0.19	19.67	0.46
GIBSON	6113	ALLENDALE	171015	3.23	11.00	0.91
ROCKPORT	006166	UNION	181996	6.99	42.71	4.98
ROCKPORT	006166	FORDSVILLE	2112962	2.10	27.43	1.88
ROCKPORT	006166	EASTON_CONS	21212261	2.58	24.68	1.85
ROCKPORT	006166	AETNAVILLE	214643	2.08	21.83	1.49
AES	000994	LAWRENCE	171336	11.01	29.44	4.19
NEWTON	6017	CLAY_CITY_N	171119	6.63	9.94	1.13
MEROM	006213	MAIN_CONS	171361	6.41	20.51	2.30
KINCAID	876	LOUDEN	171354	3.09	48.04	3.91
KINCAID	876	MT__AUBURN_CONS	171399	2.31	16.58	1.19
WARRICK	6705	PHILLIPSTOWN	171474	2.44	43.07	3.15
WARRICK	6705	GRIFFIN	181787	2.66	39.74	3.03
Total				**64.02**	**24.44 (avg.)**	**33.06**

Table 24. Connections between emission sources and sinks at 10% control level.

Sources	ID	Sinks	ID	Flow rate (MMT/Y)	Distance (miles)	Transportation cost ($MM/Y)
GIBSON	6113	NEW_HARMONY	171415	8.82	10.01	1.29
GIBSON	6113	UNION	181996	3.66	18.77	1.64
GIBSON	6113	ALLENDALE	171015	3.23	11.00	0.91
NEWTON	6017	CLAY_CITY_N	171119	6.63	9.94	1.13
MEROM	006213	MAIN_CONS	171361	6.41	20.51	2.30
Total				**28.75**	**13.56 (avg.)**	**7.27**

Table 25. Summary of CO_2 sequestration costs without by-product credits.

Sequestration cost	**Emission control level**		
	50% (128.44 MMT/Y)	**25% (64.02 MMT/Y)**	**10% (28.75 MMT/Y)**
Capture cost, $MM/Y	6,867.69	3,422.61	1,537.26
Transportation cost, $MM/Y	137.81	33.06	7.27
Injection cost, $MM/Y	642.20	320.10	143.75
Total cost, $MM/Y	7,647.70	3,775.77	1,688.28
Average cost, $/tonne CO_2 sequestered	59.54	58.98	58.72
Electricity loss, MW	7,746	3,873	1,634
Average increase of electricity cost, mills/kWh	23.77	11.74	5.25

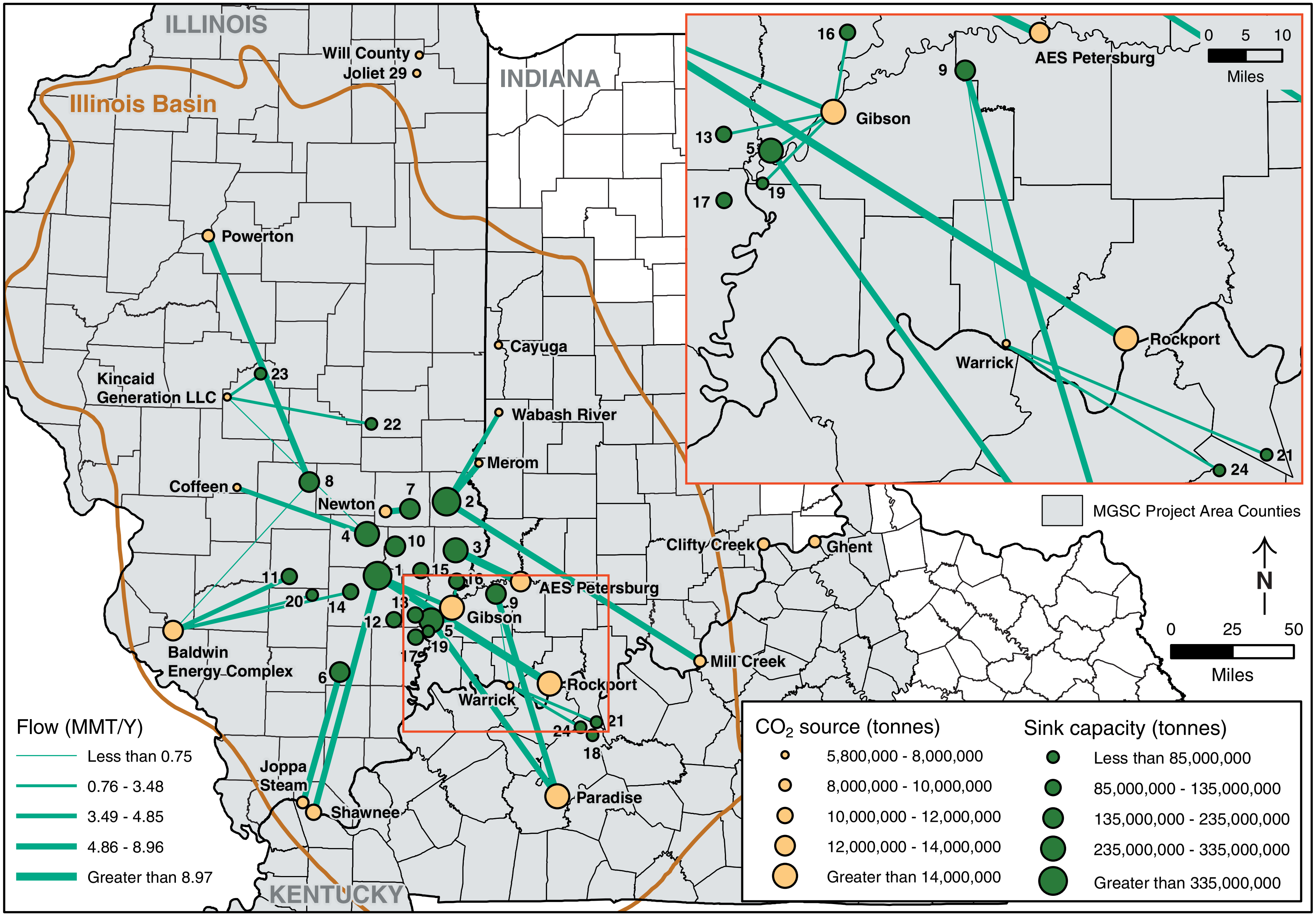


Figure 14 *Distribution of the captured CO_2 among the sinks at 50% emission control level, without EOR or ECBM benefit.*

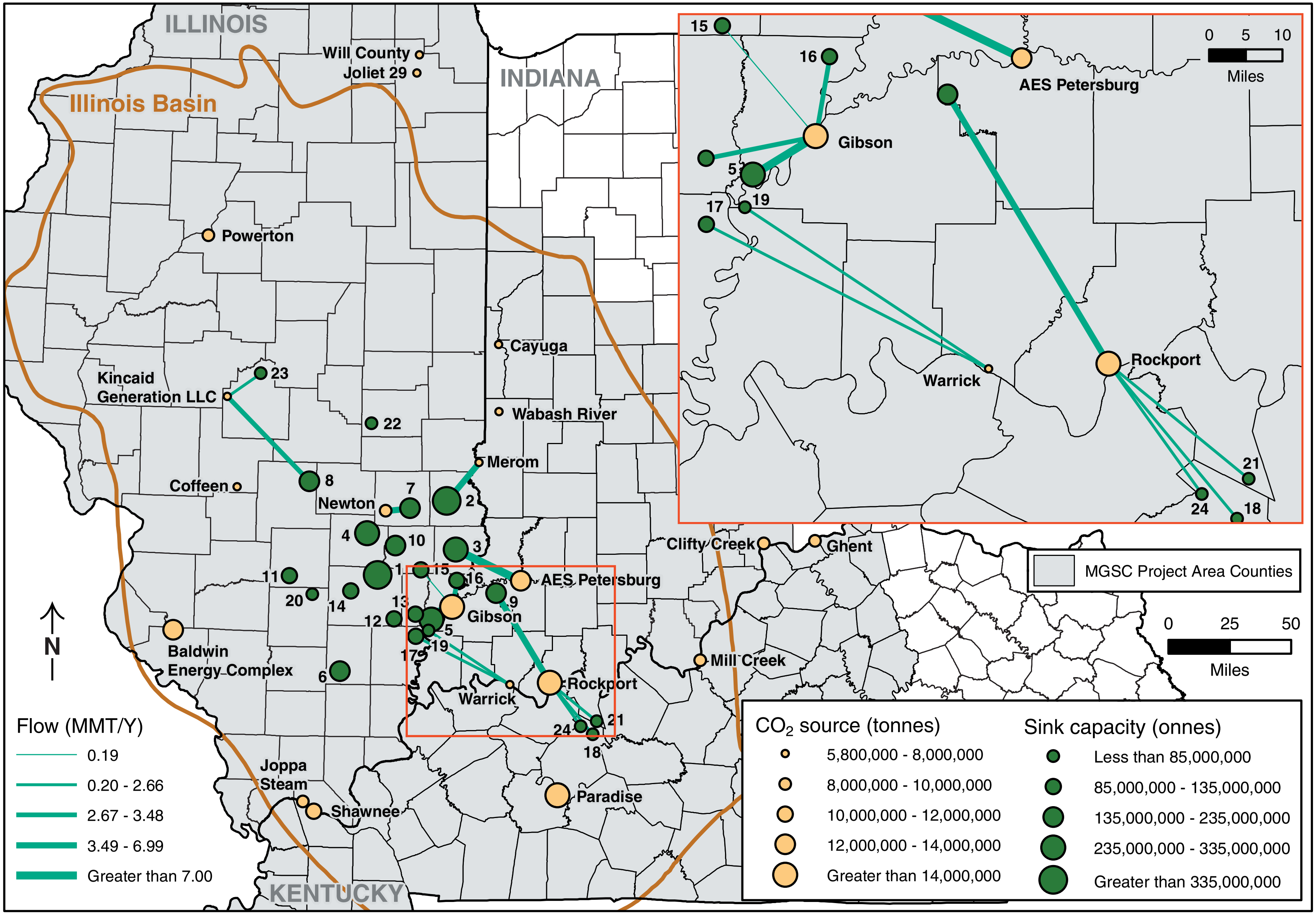


Figure 15 *Distribution of the captured CO_2 among the sinks at 25% emission control level, without EOR or ECBM benefits.*

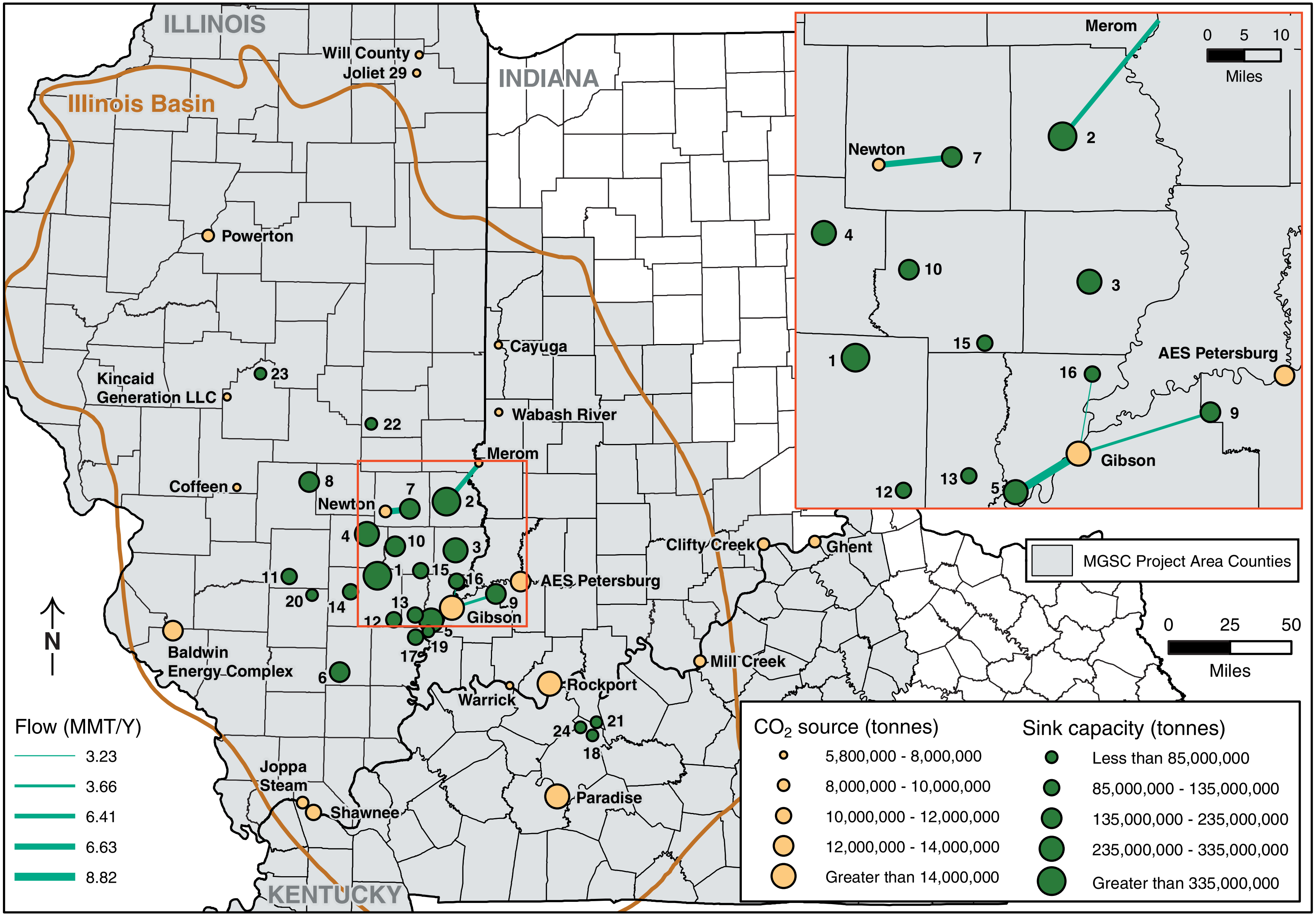


Figure 16 *Distribution of the captured CO_2 among the sinks at 10% emission control level, without EOR or ECBM benefits.*

The scale of a power plant impacted the overall sequestration cost more than its location did. Thus, CO_2 control from large power plants was more economical than that from small power plants. In addition, regardless of the locations of storage sinks, CO_2 storage in EOR and ECBM fields was economically preferable due to the potential income from by-products.

When the revenues from by-products recovery were included, the average cost of the sequestration process ranged from $44 to $56/tonne of CO_2 sequestered, depending on the control level. The cost for capturing CO_2 from power plants contributed to more than 95% of the total sequestration cost when the benefits from EOR and ECBM were included.
Electricity loss due to installing MEA plant was about 7,746, 3,873, and 1,634 MW at the 50%, 25%, and 10% emission control levels, respectively. The costs associated with the electricity loss were incorporated in the CO_2 avoidance costs. The total sequestration cost thus includes the cost of electricity loss.

With by-products recovery, the increase in electricity costs in the Basin were estimated to be 3.72, 10.50, and 22.50 mills/kWh at 10, 25, and 50% emission control levels, respectively. With a 50% reduction in capture cost, the increased electricity costs are 1.47, 5.18, and 11.82 mills/kWh.
Without EOR and ECBM by-product recovery, the cost of CO_2 sequestration was about $60/tonne of CO_2 sequestered. The average costs of CO_2 capture, transportation, and injection were about 90%, 2%, and 8%, respectively, of the total sequestration cost. The cost of sequestering each tonne of CO_2 significantly increased at a lower emission control level when the benefits from EOR and ECBM were not included.

Without by-product recovery, increased costs for electricity in the Basin were estimated to be 5.25, 11.74, and 23.77 mills/kWh at the 10, 25, and 50% emission control levels, respectively.

Sensitivity analysis confirmed that the most attractive approach to reduce the overall cost of the sequestration process was to develop more cost-effective technologies for capturing CO_2 from existing coal-fired power plants.

Recommendations

The following recommendations should be considered in future optimization studies of the integrated sequestration process in the Illinois Basin:

- Incorporate CO_2 emissions from auxiliary power plants that are needed to compensate electricity loss due to CO_2 capture from existing power plants.

- Include a projection of the future CO_2 emissions from new power plants according to the mid-term energy demand and supply analysis.

- Update the integrated sequestration costs, especially as improved and new capture technologies become available.

- Use updated capacities of the geological structures in the Basin including more detailed characterization of data that are specific to individual storage sinks, such as permeability, reservoir thickness, and reservoir depth.

- Perform a dynamic analysis accounting for CO_2 emissions, transportation, and storage over the lifetime of the sequestration process.

- Allow nodes in pipelines for optimizing network transportation.

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