NATIONAL ENERGY TECHNOLOGY LABORATORY

Life Cycle Analysis: Supercritical Pulverized Coal (SCPC) Power Plant

September 30, 2010

DOE/NETL-403-110609

U.S. DEPARTMENT OF ENERGY

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LIFE CYCLE ANALYSIS: SUPERCRITICAL PULVERIZED COAL (SCPC) POWER PLANT

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FINAL REPORT

September 30, 2010

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DOE Contract #DE-AC26-04NT41817

Acknowledgments

This report was prepared by **Research and Development Solutions, LLC (RDS)** for the United States Department of Energy's National Energy Technology Laboratory. This work was completed under DOE NETL Contract Number DE-AC26-04NT41817. This work was performed under RDS Subtask 41817-403.01.11.

The authors wish to acknowledge the excellent guidance, contributions, and cooperation of the NETL staff, particularly:

Robert James, NETL Technical Monitor
Timothy Skone, NETL Situational Analysis Team Lead

Acronyms and Abbreviations

°C	Degree Celsius
°F	Degree Fahrenheit
AEO	Annual Energy Outlook
ASTM	American Society for Testing and Material Standards
AVB	Aluminum Vertical Break
Btu	British Thermal Unit
$CaSO_4$	Calcium Sulfate
CBM	Coalbed Methane
CCF	Capital Charge Factor
CCS	Carbon Capture and Sequestration
C/D	Commissioning/Decommissioning
CH_4	Methane
cm	Centimeter
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
COE	Cost of Electricity
DOE	Department of Energy
DNR	Department of Natural Resources
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EPC	Engineer/Procure/Construct
FG	Flue Gas
FGD	Flue Gas Desulfurization
G&A	General and Administrative
GE	General Electric
GHG	Greenhouse Gases
GWP	Global Warming Potential
Hg	Mercury
HHV	Higher Heating Value

hrs	Hours
I-6	Illinois No. 6
IKP	University of Stuttgart
IPCC	Intergovernmental Panel on Climate Change
ISO	International Organization of Standardization
kg	Kilogram
kg/MWh	Kilogram per Megawatt Hour
km	Kilometer
kV	Kilovolt
kW	Killowatt
kWe	Kilowatt of Electricity
kWh	Kilowatt-Hour
lb	Pound
LC	Life Cycle
LCA	Life Cycle Analysis
LCC	Life Cycle Cost
LCI	Life Cycle Inventory
LCI&C	Life Cycle Inventory and Cost Analysis
LCIA	Life Cycle Impact Assessment
LCOE	Levelized Cost of Electricity
LNB	Low-Nitrogen Oxides Burner
MACRS	Modified Accelerated Cost Recovery System
MEA	Monoethanolamine
mm	Millimeter
MMV	Measurement, Monitoring, and Verification
MPa	Megapascals
MW	Megawatt
MWe	Megawatts (electric)
MWh	Megawatt Hours
N_2O	Nitrous Oxide
NETL	National Energy Technology Laboratory
NH_3	Ammonia

NO_X	Oxides of Nitrogen
O&M	Operations and Maintenance
O_3	Ozone
OFA	Ovenfire Air
OSAP	Office of Systems Analysis and Planning
Pb	Lead
PM	Particulate Matter
PM_{10}	Particulate Matter (diameter 10 micrometer)
$PM_{2.5}$	Particulate Matter (diameter 2.5 micrometer)
ppmv	Parts per Million Volume
psia	Pounds per Square Inch Absolute
PV	Present Value
R&D	Research and Development
RDS	Research and Development Solutions
ROM	Run-of-Mine
scf	Standard Cubic Feet
SCPC	Supercritical Pulverized Coal
SCR	Selective Catalytic Reduction
SF_6	Sulfur Hexafluoride
SO_2	Sulfur Dioxide
SO_X	Sulfur Oxides
ST	Steam Turbine
STG	Steam Turbine Generator
TS&M	Transportation, Storage, and Monitoring
U.S.	United States
VOC	Volatile Organic Chemical

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Executive Summary

Life Cycle Analysis (LCA) is a holistic methodology used to evaluate the environmental and economic consequences resulting from a process, product, or a particular activity over its entire life cycle. The Life Cycle, also known as cradle-to-grave, is studied within a boundary extending from the acquisition of raw materials, through productive use, and finally to either recycling or disposal. An LCA study can yield an environmental true-cost-of-ownership which can be compared with results for other alternatives, enabling a better informed analysis.

'Life Cycle Analysis: Supercritical Pulverized Coal (SCPC) Power Plant' case study evaluates the emissions footprint of the technology, including those from all stages of the Life Cycle. The stages include: fuel acquisition and transportation, the conversion of the fuel to energy, and finally the delivery of the energy to the customer. Also included in the study are the raw material and energy requirements. Additionally the energy cost contributions from each of these stages has been evaluated. The analysis examines two SCPC energy conversion cases. One case assumes that the SCPC facility will emit the full amount of carbon dioxide (CO_2) resulting from the utilization of the fuel (coal), which is assumed to be Illinois #6. The second case builds upon the first case by adding CO_2 removal capacity to remove 90 percent of the CO_2 from the power generation facility. The case that captures 90 percent of the CO_2 includes the additional capture equipment, compression equipment, pipeline and injection well materials and energy requirements

Purpose of the Study

The purpose of this study is to model the economic and environmental life cycle (LC) performance of two supercritical pulverized coal (SCPC) power generation facilities over a 30-year period based on case studies presented in the NETL 2010 report, *Cost and Performance Baseline for Fossil Energy Plants: Volume 1* (NETL, 2010). It is assumed that both plants are built as new greenfield construction projects. The NETL report provides detailed information on the facility characteristics, operating procedures, and costs for two SCPC facilities, one with and one without carbon capture and sequestration (CCS). In addition to the energy generation facility, the economic and environmental performance of processes upstream and downstream of the power facility will be considered.

Two SCPC cases will be considered for evaluation:

- Case 1: (SCPC without CCS) A 550-megawatt electric (MWe) (net power output) SCPC thermoelectric generation facility located in southeastern Illinois and utilizing Illinois No. 6 (I-6) coal as a feedstock. This facility is equipped with control technologies to reduce emissions of nitrogen oxides (NO_X), sulfur compounds, particulate matter (PM), and mercury (Hg). This case is configured without CCS.
- Case 2: (SCPC with CCS) A 550-MWe (net power output) SCPC thermoelectric generation facility located in southeastern Illinois and utilizing I-6 coal as a feedstock.

This facility is also equipped with control technologies to reduce emissions of NO_X, sulfur compounds, PM, and Hg. In addition, an Econamine FG Plus process is included to capture carbon dioxide (CO_2) emissions. The captured CO_2 is compressed and transported 100 miles to an undefined geographical storage formation for permanent sequestration, in a saline formation.

Scope of the Study

For this cradle-to-grave analysis, all stages of power generation are considered. The upstream LC stages (coal mining and coal transport) are modeled for both SCPC cases. The downstream LC stage (electricity distribution) is also included. Cost considerations provide the constant dollar levelized cost of delivered electricity (LCOE) and the total plant cost (TPC) over the study period. Environmental inventories include Greenhouse Gas emissions (GHG), criteria air pollutants, mercury (Hg), and ammonia (NH_3) emissions to air, water withdrawal and consumption, and land use (acres transformed). The GHG inventories were further analyzed using global warming potential (GWP) values from the Intergovernmental Panel on Climate Change (IPCC).

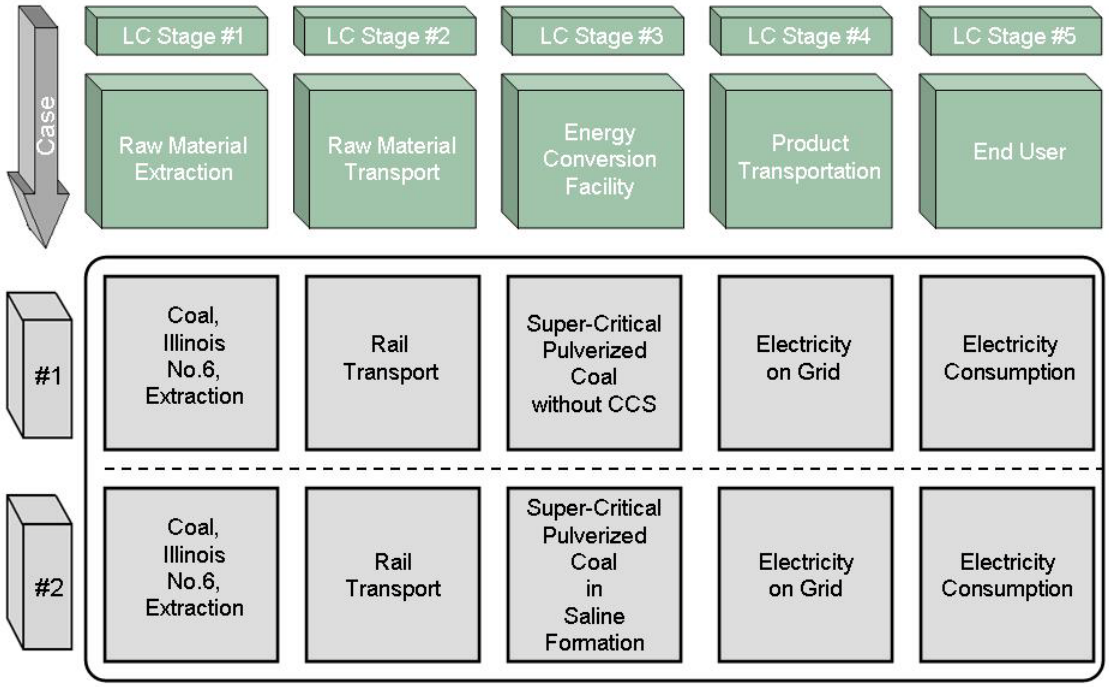

Figure ES–1 Case Comparison by Life Cycle Stage

Modeling Approach

Critical to the modeling effort is the determination of the extent of the boundaries in each Life Cycle (LC) stage. The individual LC stages for both cases are identified in **Figure ES–1**. The LC stages cover the following: the extraction of the coal at the coal mine, the transportation of the coal to the power plant, the burning of the coal and generation of electricity, the transmitting of electricity to the transmission and distribution (T&D) network, and the delivery of the

electricity to the customer. The primary inputs and outputs along with the study boundaries are illustrated in **Figure ES–2** for the two cases. The specific assumptions made in the modeling are listed below

- **LC Stage #1** includes the fuels used in the preparation and the decommissioning of the coal mine site, paving materials, materials for the buildings and the actual coal mining and handling equipment, energy and water for mining operations, land use considerations, and emissions. Capital and O&M costs of the coal mine are included in the minemouth cost of coal and are not explicitly defined.
- **LC Stage #2** includes the materials for the construction of coal unit trains, fuel for unit train operations, materials for the construction of the 25 miles of rail spur to the power plant, and emissions from the unit train. The main rail line between the coal mine and the power plant rail spur is not included in the modeling boundary, as it is assumed to previously exist. Coal cost data is a "delivered" price, so costs are not included from this stage.
- **LC Stage #3** includes the fuels used in the preparation and the decommissioning of the power plant site, materials for the buildings, power plant equipment, switchyards and transmission trunkline, fuel used in the power plant, Capital and O&M costs, electrical output and emissions from the power plant, and in the case for carbon capture and sequestration; equipment and infrastructure to capture, compress, transport, inject, and monitor CO_2.
- **LC Stage #4** includes the delivery of the electricity to the customer, transmission line losses, and emissions of SF6 from power circuit breakers associated with the transmission line. The main transmission grid is not included in the modeling boundary as it is assumed to previously exist.
- **LC Stage #5** assumes all delivered electricity is used by a non-specific, 100% efficient process and is not included in the modeling.

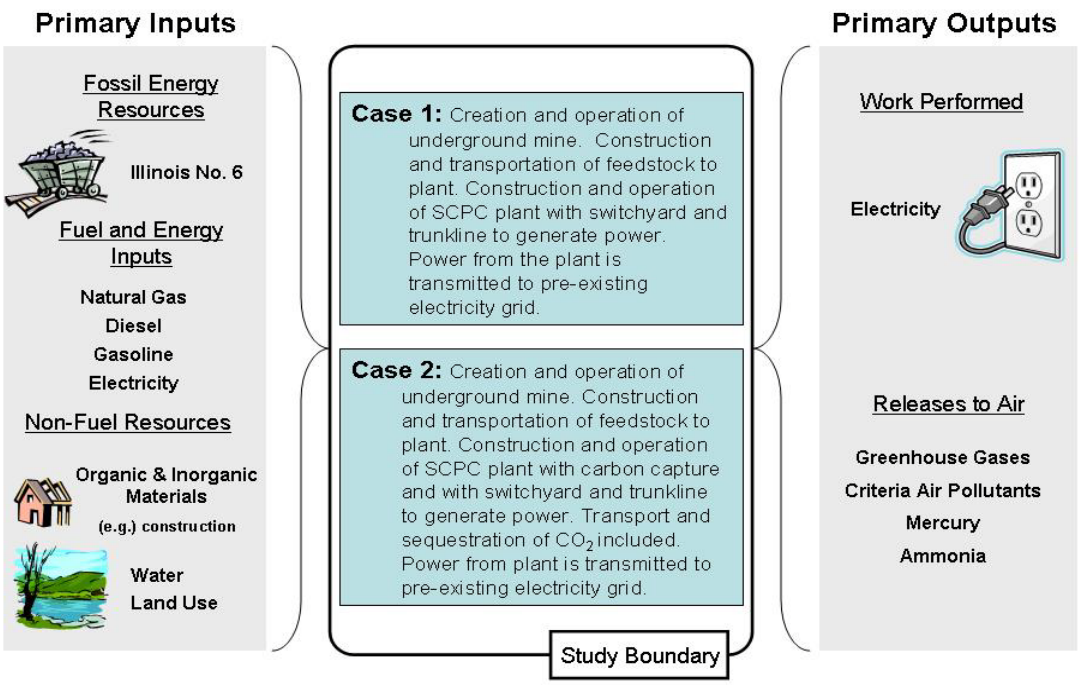

Figure ES–2 Study Boundary

Key Modeling Assumptions

Central to the modeling effort are the assumptions upon which the entire model is based. **Table ES -1** lists the key modeling assumptions for the SCPC with and without CCS cases. As an example, the study boundary assumptions indicate that the study period is 30 years, interest costs are not considered, and the model does not include effects due to human interaction. The sources for these assumptions are listed in the table as well. Assumptions originating in this report are labeled as "Present Study", while other comments originating in the NETL Cost and Performance Baseline for Fossil Energy Power Plants study, Volume 1: Bituminous Coal and Natural Gas to Electricity Report are labeled as "NETL Baseline Report."

Summary Results

Figure ES–3 shows the comparison of LCOE components in $/kWh delivered energy. The addition of an amine-based post combustion carbon capture system (designed for a maximum 90% capture) to an SCPC facility increases LCOE by 73 percent, from $0.0943/kWh to $0.1630/kWh of delivered electricity. It should be noted that the Life Cycle Costing model replicated the Stage #3 Energy Conversion Facility non-LC LCOE values of $0.0855/kWh without- and $0.1441/kWh with-CCS cases from the NETL Baseline Report when distribution loss was set to 0%. CO_2 T, S & M values do differ slightly with the NETL Baseline Report, as a different model approach was used in the Power LCA reports. Capital costs had the most sensitivity to the addition of CCS (increase from $0.052/kWh to $0.094/kWh), due in part to the additional energy intensity of the CCS process. This indicates that advancements in CCS

technologies that reduce capital investment and improve energy efficiency would most significantly reduce the overall cost differences between the two cases. The increase in feedstock costs between the two cases is due to the additional coal input needed for the with CCS plant to achieve a similar net output as the plant without CCS.

Table ES -1 Key Modeling Assumptions

Primary Subject	Assumption	Source
Study Boundary Assumptions		
Temporal Boundary	30 years	NETL Baseline Report
Cost Boundary	"Overnight"	NETL Baseline Report
LC Stage #1: Raw Material Acquisition		
Extraction Location	Southern Illinois	Present Study
Coal Feedstock	Illinois No. 6	NETL Baseline Report
Mining Method	Underground	Present Study
Mine Construction and Operation Costs	Included in Coal Delivery Price	Present Study
LC Stage #2: Raw Material Transport		
Coal Transport Rail Distance	205 miles	Present Study
Rail Spur Constructed Length	25 miles	Present Study
Main Rail Line Construction	Pre-existing	Present Study
Unit Train Construction and Operation Costs	Included in Coal Delivery Price	Present Study
LC Stage #3: Power Plant		
Power Plant Location	Southwestern Illinois	Present Study
IGCC Net Electrical Output (without CCS)	550 MW	NETL Baseline Report
IGCC Net Electrical Output (with CCS)	550 MW	NETL Baseline Report
Auxiliary Boiler Fuel	Natural Gas	Present Study
Trunk Line Constructed Length	50 miles	Present Study
CO_2 Compression Pressure for CCS Case	2,215 psi	NETL Baseline Report
CO_2 Pipeline Length for CCS Case	100 miles	Present Study
Sequestered CO_2 Loss Rate for CCS Case	1% in 100 years	Present Study
Capital and Operation Cost		NETL Bituminous Baseline
LC Stage #4: Product Transport		
Transmission Line Loss	7%	Present Study
Transmission Grid Construction	Pre-existing	Present Study

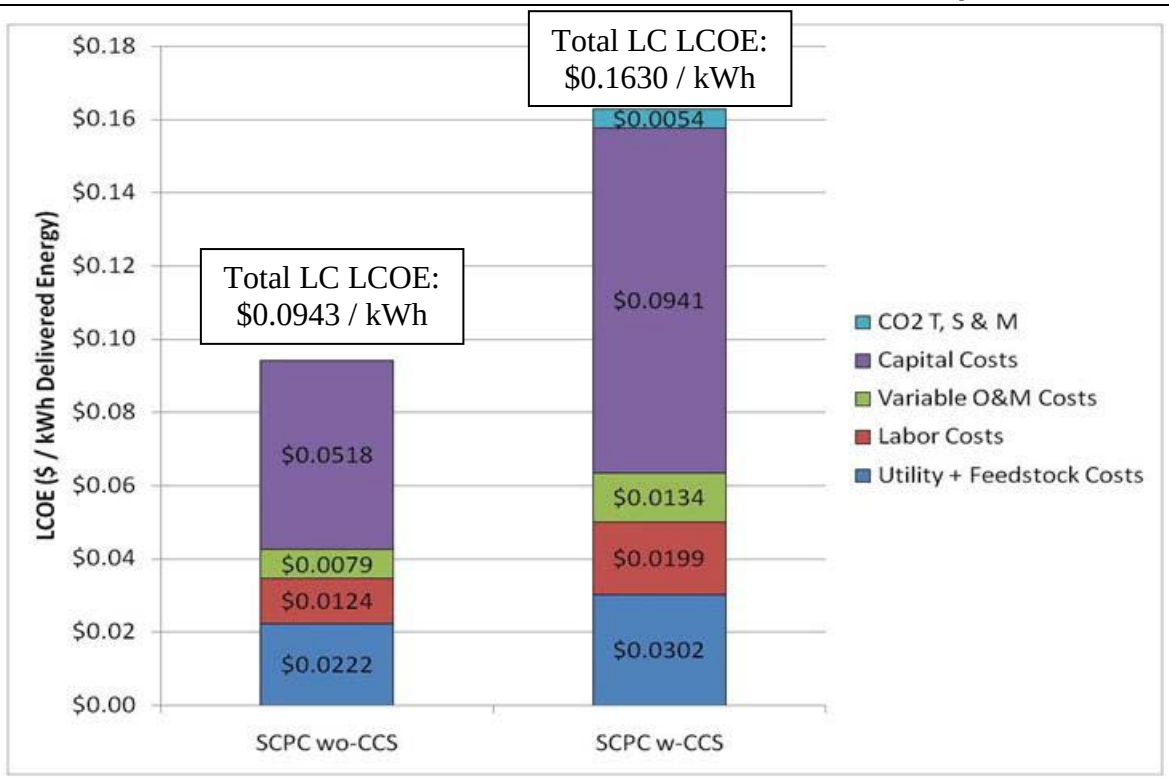

Figure ES–3 Comparative Levelized Cost of Delivered Energy ($/kWh) for SCPC with and without CCS

Table ES -2 compares the GHG emissions (kilogram [kg] CO_2e/MWh (CO_2e /unit of delivered energy) for Case 1 (without CCS) and Case 2 (with CCS) for each stage and the overall LC. The addition of an amine-based post combustion carbon capture system (designed for a maximum 90% capture) to an SCPC facility reduces LC GWP emissions by 74 percent. Approximately 92 percent of the SCPC without CCS GWP is attributable to activities in Stage #3 of which 92.4 percent is due to CO_2 emissions. A total of 59 percent of the SCPC with CCS GWP is attributable to CO_2 emissions, while 39.6 percent is due to CH_4 emissions released during raw material extraction (Stage #1). Although SF_6 has the largest GWP potential, the small mass emittance translates to only a 1.4 percent impact on the overall GHG emissions for the "with CCS" case and 0.3 percent for the "without CCS" case.

Table ES -2 GHG Emissions (CO2e/MWh Delivered) for Case 1 (SCPC without CCS)

Emissions (kg CO_2e /MWh)	Stage #1: Raw Material Acquisition	Stage #2: Raw Material Transport	Stage #3: Power Plant	Stage #4: Transmission & Distribution	Total
Case 1-SCPC Without CCS					
CO_2	2.8	4.7	863.8	0	871.2
N_2O	1.3E-02	3.9E-03	9.4E-03	0	2.6E-02
CH_4	68.7	0.1	0.0	0	68.9
SF_6	1.5E-06	4.7E-07	7.5E-03	3.3	3.3
Total GWP	71.6	4.8	863.8	3.3	943.5
Case 2-SCPC With CCS					
CO_2	3.9	6.4	131.9	0	142.2
N_2O	1.8E-02	5.4E-03	1.4E-02	0	3.8E-02
CH_4	95.0	0.2	0.0	0	95.2
SF_6	2.0E-06	6.6E-07	7.5E-03	3.3	3.3
Total GWP	98.9	6.7	131.9	3.3	240.7

Approximately 65 percent more water is needed for cooling applications during the carbon capture process. This result suggests that depending on the location of the SCPC plant, including (or retrofitting with) CCS may not be practical due to limited water supply. Additional land use is needed to install the CO_2 pipeline, which is assumed to impact agricultural land. Finally, to achieve similar output between cases, the case with CCS required 38 percent more coal. Investors and decision makers can use the results presented in this report to weigh the benefits of carbon mitigation to the additional cost of investing in CCS technology. Additionally, these results suggest that investment in research and development (R&D) to advance CCS technologies and lower capital investment costs will have a positive effect on reducing the difference in LCOE between the cases.

Sensitivity analyses were performed on several cost and environmental inventory parameters. For LCC, variation in capital costs had the largest impact on LCOE, indicating that investors will need to take care when analyzing capital cost parameters for a given SCPC plant. Changing the capacity factor ± five percent had approximately a five percent impact on LCOE, while variations in O&M and taxes had a less than three percent impact. Feedstock and utility costs had a very small impact on LCOE; varying from the AEO reference case to the high price case results in only a 0.02 percent change (EIA, 2008). Therefore, although these results are based on AEO 2008, one can assume that the differences between 2008 and future AEO values will have a small impact on the overall results unless extremely large changes in feedstock and utilities prices are projected.

Sensitivity on environmental parameters was performed on CH_4 emissions from coal mining, train transport distance, and construction material inputs into Stage #1 and Stage #3. Minor impacts were felt when construction material was increased three times the base case values, indicating that low data quality for material inputs does not contribute to large uncertainty in total LC results. In particular, GHG emissions are affected little by material input, experiencing a 1.2 and 0.2 percent increase in total GWP for SCPC with and without CCS, respectively.

Sensitivity analysis of CH_4 emissions showed that the addition of a 40 percent mine CH_4 recovery process could reduce the LC GWP of SCPC with CCS by 16 percent. However, this analysis does not consider other LC benefits or disadvantages associated with the recovery process, so additional modeling would need to be done before a conclusion can be drawn about its overall effectiveness. For SCPC without CCS, recovering CH_4 emissions at the coal mine only has a three percent impact on total GWP due to the large amount of CO_2 emitted during coal combustions. Omitting rail transport (by cutting the distance between the mine and the SCPC facility from 205 to 0 miles) decreased GWP by 0.3 and 1.4 percent for the cases without and with CCS, respectively. More substantial decreases in non-GHG emissions were seen, but overall a small impact was felt over the sensitivity range for raw material transport.

Key Results

- Adding 90 percent CO_2 capture and storage to an SCPC platform will increase the full life cycle cost of power from 9.43¢ to 16.30¢ – a 73 percent increase.

- GHG emissions for coal extraction and transport increase slightly in Case 2 (SCPC with CCS), due to the increase in coal flow. However, the 90 percent CO_2 capture at the power plant results in a 74 percent reduction in total Life Cycle GHG emissions.

- The difference in LCOE, and GHG emissions between Case 1 and Case 2 result in a GHG avoided cost of $97.75/tonne.

1. Introduction

In 2008 the United States consumed approximately 41 quadrillion (10^{14}) British thermal units (Btu) of electricity per year, which is equivalent to 1.2 billion megawatt hours (MWh) per year of electricity generation (EIA, 2009). The 2009 Energy Information Administration's (EIA) Annual Energy Outlook (AEO) reference case projects a growth to 47.9 quadrillion Btu per year by 2030[1]. Although AEO 2009 predicts a 2.7 percent predicted annual increase in renewable energy electricity generation, it is still expected that 66 percent of U.S. electricity will come from fossil fuels in 2030 (EIA, 2009). However, future greenhouse gas (GHG) legislation might require all carbon-intensive energy generation technologies to reduce emissions. Uncertainty about impending legislation has already prompted some investments in emerging energy generation technologies or retrofits will provide both environmental and economic benefits over existing technologies. Investors and decision makers need a concise way to compare the environmental and economic performance of current and existing generation technologies.

The U.S. Department of Energy's (DOE) National Energy Technology Laboratory (NETL) has endeavored to quantify the environmental impacts and resource demands associated with building, operating, and retiring various thermoelectric generation technologies; both conventional and advanced technologies using fossil, nuclear, and renewable fuels. This quantification will be accomplished, in part through a series of life cycle inventory and cost analysis (LCI&C) studies. While NETL has performed similar studies on selected electricity generation technologies in the past, an effort is underway to further expand this capability.

This report compares the economic and environmental life cycle (LC) performance of super critical pulverized coal (SCPC) electricity generation pathways, with and without carbon capture and sequestration (CCS) capability. In a SCPC system, pulverized coal is combusted with air in a wall-fired boiler to create supercritical steam. SCPC has a higher potential efficiency than traditional subcritical pulverized coal processes (NETL, 2010). However, to fully quantify the difference (whether benefits or disadvantages) between SCPC and other generation technologies, the full environmental and economic performance needs to be evaluated over the LC of the system; the results of this LC evaluation provide a comparison point for competing electricity generating pathways assessed within NETL's LCI&C Program. **Figure 1–1** shows the economic and environmental boundaries of this LCI&C.

[1] These data were retrieved from the AEO 2009 early release; all cost data used in the report was taken from AEO 2008, as the full version of AEO 2009 was not released at the time that the cost modeling was completed.

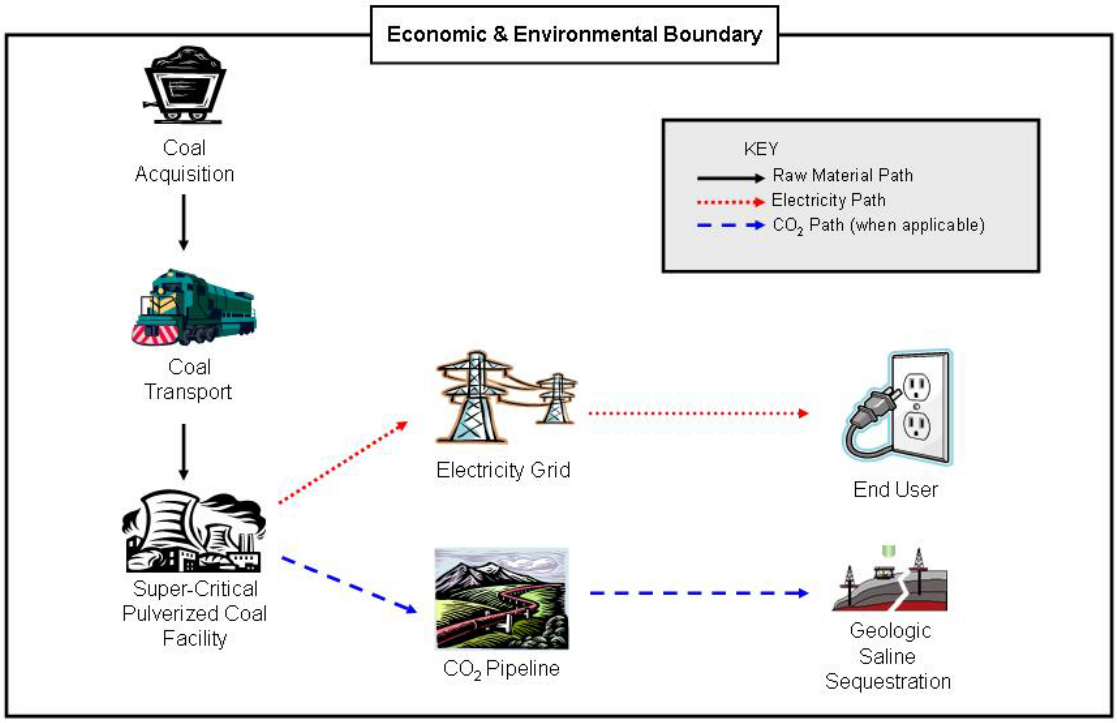

Figure 1–1 Conceptual Study Boundary

The following terms relating to LCI&C are used as defined throughout this document:

- Life Cycle (LC): Consecutive and interlinked stages of a product system, from raw material acquisition to the use stage.
- Life Cycle Inventory (LCI): The specific phase of the LCI&C which includes data collection, review, and verification; modeling of a product system to estimate emissions.
- Life Cycle Costing (LCC): The determination of cost parameters (levelized cost of electricity [LCOE] and net present value [NPV]) for the LCI&C throughout the study period.

1.1 Purpose

This study models the LC of two SCPC power generation facilities based on case studies presented in the NETL 2010 report, *Cost and Performance Baseline for Fossil Energy Plants: Volume 1* (NETL, 2010). The NETL report provides detailed information on the facility characteristics, operating procedures, and costs for two SCPC facilities; data from NETL report Case 11 (SCPC without CCS) and Case 12 (SCPC with CCS) were used significantly during this study. Throughout the remainder of this document, the NETL *Cost and Performance Baseline for Fossil Energy Plants: Volume 1* will be referred to as the "Baseline Report."

There are two case scenarios under consideration in this study:

- Case 1: A 550-megawatt electric (MWe) (net power output) SCPC thermoelectric generation facility located at a greenfield site in southeast Illinois (near Springfield, Illinois), utilizing a single-train supercritical steam generator (Benson-boiler). Illinois No. 6 (I-6) pulverized coal is conveyed to the steam generator by air from the primary air fans. The steam generator supplies steam to a conventional steam turbine generator (STG). Air emission control systems for the plant include a wet limestone scrubber that removes sulfur dioxide (SO_2), a combination of low-nitrogen oxides burners (LNBs) and overfire air (OFA), and a selective catalytic reduction (SCR) unit that removes nitrogen oxide (NO_X), a pulse jet fabric filter (baghouse) that removes particulates, and mercury (Hg) reductions via co-benefit capture. This case is configured without CCS.
- Case 2: A 550-MWe (net power output) SCPC thermoelectric generation facility located at a greenfield site in southeast Illinois (near Springfield, Illinois), utilizing a single-train supercritical steam generator (Benson-boiler). I-6 pulverized coal is conveyed to the steam generator by air from the primary air fans. The steam generator supplies steam to a conventional STG. Air emission control systems are the same as in Case 1, except that this case is configured with CCS utilizing an additional sulfur polishing step to reduce sulfur content below 10ppmv and a Fluor Econamine FG Plus process.

In additional to the energy generation facility, the economic and environmental performance of processes upstream and downstream of the facility will be considered. The upstream LC stages (coal mining and coal transport) will be the same for both SCPC cases; the case with CCS includes the additional transport and storage of the captured carbon. The study time period (30 years) will allow for the determination of long-term cost and environmental impacts associated with the production and delivery of electricity generated by SCPC. Although not within the scope of this report, the overarching purpose of this study is to compare these results to other competing electricity generating pathways assessed within NETL's LCI&C Program.

1.2 Study Boundary and Modeling Approach

The following directives were used to initially frame the boundary of this study and outline the modeling approach:

- The basis (i.e., functional unit) of NETL electricity generation studies is defined generally as the net work (output from the process minus losses during the delivery and use of the product) in MWh over the 30-year study period. Therefore, for this study, the functional unit is the range of MWh output from both energy generation facilities (with and without CCS). To calculate results, the environmental and economic data from each stage was totaled, and then normalized to a 1 MWh basis for comparison. Additionally, results from each stage are reported on a unit process reference flow basis. For example, results from coal mining and coal transport are presented on a kilogram (kg) of coal basis, and results from energy conversion and electricity transmission are presented on an MWh basis.
- All primary operations (defined as the flow of energy and materials needed to support generation of electricity from coal) from extraction of the coal, material transport, electricity generation, electricity transport, and end use were accounted for.
- Secondary operations (defined as inputs not immediately needed for the flow of energy and materials, such as the material input for construction) that contribute significantly to mass and energy of the system or environmental or cost profiles are also included within the study boundary. Significance is defined in **Section 1.2.5.** Examples of secondary operations include, but are not limited to:
    - Construction of equipment and infrastructure to support each pathway (e.g., coal mine, power plant, transport equipment, etc.), with the exception of the power grid for electricity transport and end use being considered "pre-existing."
    - Provision of secondary energy carriers and materials (e.g., electrical power from the U.S. power grid, diesel fuel, heavy fuel oil, concrete production, steel production, etc.).
    - Carbon dioxide (CO_2) transport and injection into the sequestration site.
- Construction of infrastructure (pipelines, railways, transmissions lines) is omitted from the study boundary if it is determined that they would exist without the construction of the studied facility or fuel extraction operation. For example, it is assumed that the transmission lines of the electrical grid would exist with or without the new energy conversion facility, and are thus not included in the model. However, the switchyard and trunkline, which connect the new energy conversion facility to the transmission lines/grid, would not exist without the new facility and are thus included in the LCI&C.
- Cost parameters will be collected for primary operations to perform the LCC analysis and will account for all significant capital and operating and maintenance (O&M) contributions.
- Detailed upstream cost profiles for secondary material and energy production are not required for the LCC analysis. Material purchase costs (for the secondary materials) are considered inclusive of upstream production costs in the final product cost.

- LCI will include the following magnitude evaluations from each primary and significant secondary operation: anthropogenic GHG emissions, criteria air pollutant emissions, Hg and ammonia (NH_3) emissions to air, water withdrawal and consumption, and land use. All emission results are reported in terms of mass (kg) released per functional unit and unit process reference flow, when applicable; water withdrawals and consumption are reported (by volume) on the same basis. Land use is reported as transformed land (type and amount [square meters] of land transformed).
- Indirect land use (or secondary land use effects) is not considered within the boundary of this study. Secondary land use effects are indirect changes in land use that occur as a result of the primary land use effects. For instance, installation of a coal mine in a rural area (primary effect is removal of agriculture or native vegetation and installation of uses associated with a coal mine) may cause coal mine employees to move nearby, causing increased urbanization in the affected area (secondary effect).
- If a process produces a co-product that, due to the purpose of the study, cannot be included within the study boundary, the allocation procedure will be determined using the following steps (in decreasing order of preference) as defined in International Organization of Standardization (ISO) 14044 (ISO, 2006):
    - Avoid allocation by either dividing the process into sub-processes or expanding the boundaries.
    - When allocation cannot be avoided, inputs and outputs should be divided among the products, reflecting the physical relationships between them.
    - When physical relationships do not establish basis for allocation, other relationships should be considered.

The following sections expand on the specific system boundary definition and modeling used for this study. Inputs and outputs from primary operations are shown in **Figure 1–2**. This simplified diagram illustrates how primary input materials move through the system, resulting in primary outputs.

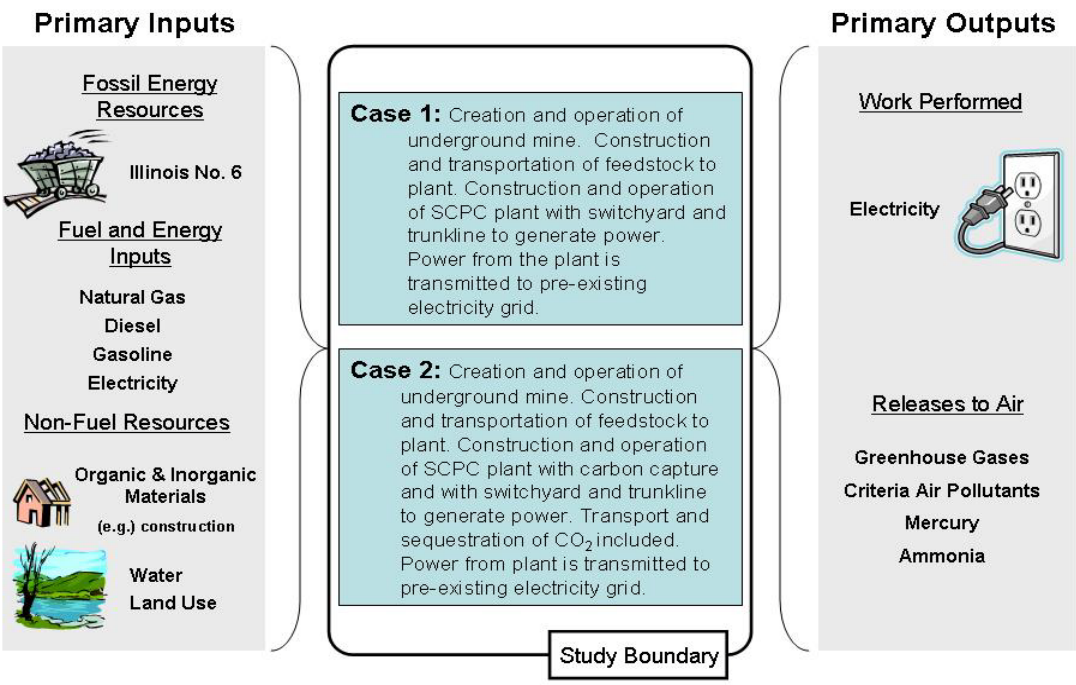

Figure 1–2 Study Boundary

1.2.1 Life Cycle Stages

The following text defines the LC stages considered in this study and outlines specifications for the primary operations for each stage. Secondary operations are included based on data availability; if data is available the operation is included for completeness, if data is not available surrogate data is assumed or the operation is considered insignificance due to cut-off criteria specifications.

- Life Cycle Stage #1: Raw Material Acquisition: Coal Mining and Processing
    - Boundary begins with the opening of the coal mine and the extraction of the coal. All mining was assumed to be large-scale subterranean longwall mining of I-6 bituminous coal.
    - All major energy and materials inputs to the mining process (e.g., electricity use, fuel use, water withdrawals, chemical use, etc.) are considered for inclusion.
    - Capital and O&M costs of the coal mine are included in the minemouth cost of coal and are not explicitly defined (EIA, 2008).
    - Energy use and emissions associated with the commissioning and decommissioning of the mine are considered.
    - Boundary ends when the processed coal is loaded onto a railcar for transport to the SCPC facility.
- Life Cycle Stage #2: Raw Material Transport: Coal Transport
    - Boundary starts when the railcar has been loaded.

- The diesel powered locomotive transports the coal to the SCPC facility, a distance of approximately 205 miles.
- Railroad right-of-way and tracks are considered pre-existing. Installation of railcar unloading facilities and additional tracks connecting the facility to existing railroad lines is considered.
- Boundary ends when the coal is delivered to the SCPC plant.

- Life Cycle Stage #3: Energy Conversion Facility: SCPC Plant
  - Boundary starts with coal entering the SCPC plant, with or without CCS.
  - Construction and decommissioning of the plant structure and major plant equipment are included.
  - Operation of the SCPC plant is included for both cases.
  - Capital and O&M costs are calculated for the operation of the plant for both cases.
  - Construction and operation are included for the switchyard and trunkline system that delivers the generated power to the grid.
  - For the SCPC plant with CCS, the boundary includes the following:
    - CO_2 is compressed to 2,215 pounds per square inch absolute (psia) at the SCPC plant. No additional compression is required at the injection site.
    - Construction and operations of plant equipment required for CCS.
    - Construction and operation of a CO_2 pipeline from the plant site in southwestern Illinois to a non-specific saline formation sequestration site 100 miles away. Losses of CO_2 from the pipeline during transport and injection are also included.
    - Construction of the pipeline and casing for CO_2 injection at the sequestration site.
    - Costs associated with the operation of measurement, monitoring, and verification (MMV) of CO_2 sequestration at the sequestration site.
  - Boundary ends when the power created at the SCPC plant is placed onto the grid and CO_2 is verified and sequestered.
- Life Cycle Stage #4: Product Transportation: Electrical Grid
  - Boundary starts when the power is placed on the grid.
  - Electricity losses due to transmission and distribution are included.
  - Boundary ends when the power is pulled from the grid.

- Life Cycle Stage #5: End User: Electricity Consumption
    - Boundary starts and concludes when the power is pulled from the grid. All NETL power generation LCI&C studies assume electricity is used by a non-specific, 100 percent-efficient process.

The system boundary is consistently applied for all of the pathways included in the study. A comparison of the pathways by LC stage is depicted in **Figure 1–3.**

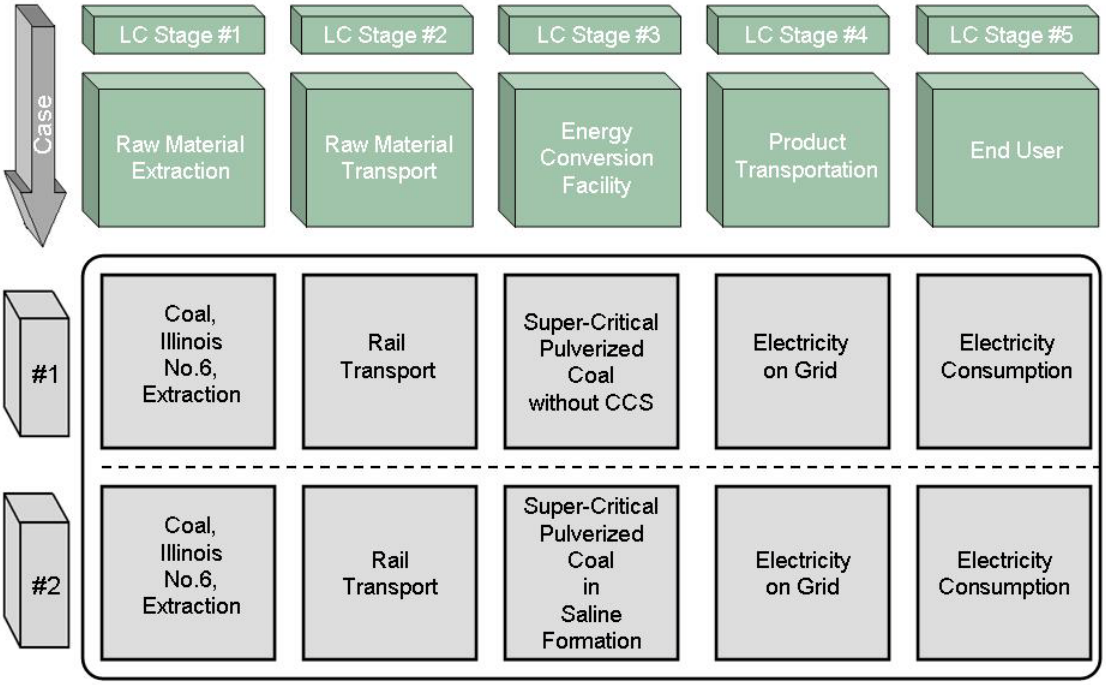

Figure 1–3 Comparison of Cases by Life Cycle Stage

Assessing the environmental LC perspective of each scenario requires that all significant material and energy resources be tracked back to the point of extraction from the earth (commonly referred to as the "cradle" in LCI&C terminology). While the primary material flow in this study is coal into electricity, many other material and energy inputs are considered significant and must be accounted for to accurately depict the LCI&C. These are considered secondary materials, and examples include concrete, steel, and combustion fuels such as diesel and heavy fuel oil. Cradle-to-gate (e.g., raw material acquisition through delivery of a finished product to the end user) environmental profiles for secondary materials are considered for all significant secondary material inputs.

1.2.2 Technology Representation

SCPC plants with CCS have not been commercially built, but for the purposes of this study the CCS process as applied to an SCPC plant will be assumed to be commercially available. The cost estimates for this case were taken directly from the Baseline Report and represent proven technology for CCS and for the SCPC Plant.

1.2.3 Timeframe Represented

The economic and environmental profiles are compared on a 30-year operating time period, referred to as the "Study Period." The base year for the study was 2010 (e.g.,

Year 1) because the time required for plant and equipment construction would realistically happen before the following Year 1 assumptions were made. All capital investments were considered to be "overnight costs" (assumed to be constructed overnight and hence no interest charges) and applied to Year 1 along with the corresponding O&M costs. Similarly, all environmental consequences of construction were assumed to occur on an overnight basis. All processes were thereby considered to be fully operational on day one of the 30-year study period. It was assumed that the life of all facilities and connected infrastructure is equal to that of the power plant.

1.2.4 Data Quality and Inclusion within the Study Boundary

High quality, transparent data were used for all inputs and outputs into each LC stage when available. To the greatest possible extent, transparent publicly available data sources were used to model each pathway. When available, data which was geographically, temporally, and technologically accurate was used for the LCI and LCC. However, that quality of data could not realistically be collected for each primary and secondary input and output into an LC stage. Therefore, the following additional data sources were used within this study:

- When publically available data were not available, purchasable, non-transparent data were use. For this study, purchasable data included secondary material LC profiles available from the GaBi modeling software database (GaBi data can be purchased publicly).
- In the event that neither public nor non-public data were available, surrogate data or engineered calculations were used.

When primary data (collected directly from operation of the technology being studied) was not available, uncertainty in data quality associated with geographic, temporal, or technological considerations was minimized using the following criteria:

- Data from the United States for similar processes were always preferred and used when available.
- Data for a process (or similar process) based on averages or best available technologies had to be dated from 1990 to present.
- European data were considered only for similar technologies or processes (consistent in scope and magnitude) when U.S. data were not available.
- If no data were available for the technology (or a reasonably similar technology), surrogate data were used.

Any data collected using an additional data source or different geographical, temporal, or technological specification was subject to uncertainty and sensitivity analysis depending on the significance of said data on the LC stage results. Sensitivity analysis results are discussed during interpretation of results (**Section 0**), and specific assumptions for each data input are listed by stages in Appendix A.

1.2.4.1 Exclusion of Data from the Life Cycle Boundary

Data were collected for each primary and significant secondary input and output to each LC stage (as defined by the system boundary) except the following, which for the reasons

discussed were considered outside the boundary and scope of NETL power generation LCI&Cs.

Humans functioning within the system boundary have associated materials and energy demand as a burden on the environment. For humans working within the boundaries of this study, activities such as commuting to and from work and producing food are part of the overall LC. However, to consider such human activities would tremendously complicate the LC. First, quantifying the human-related environmental inflows and outflows would require a formidable data collection and analysis effort; second, the methodology for allocating human-related environmental flows to fuel production would require major assumptions. For example, if human activities are considered from a consequential perspective, it would be necessary to know what the humans would be doing if the energy conversion facility of this study did not exist; it is likely that these humans would be employed by another industry and would still be commuting and eating, which would result in no difference in environmental burdens from human activities with or without the energy conversion facility. For the LCC, labor costs associated with the number of employees at each energy conversion facility was included.

Low-frequency, high-magnitude, non-predictable environmental events (e.g., non-routine/fugitive/accidental releases) were not included in the system boundaries because such circumstances are difficult to associate with a particular product. However, more frequent or predictable events, such as material loss during transport or scheduled maintenance shut downs, were included when applicable.

1.2.5 Cut-Off Criteria for the Life Cycle Boundary

"Cut-off criteria" defines the significance of materials and processes included in the system boundary and in general is represented as a percent of significance related to the mass, cost, or environmental burden of a system (ISO, 2006). If the input or output of a process is less than the given percentage of all inputs and outputs into the LC stage, then that process can be excluded. Whenever possible, surrogate or purchasable data assumptions were used as they are preferred over using a cut-off limit. However, when the cut-off criteria was used, a significant material input was defined as a material or environmental burden that has a greater than one percent per unit mass of the principal product of a unit process (e.g., 0.01 gram [g] per unit g). A significant energy input is defined as one that contributes more than one percent of the total energy used by the unit process. Although cost is not recommended as a basis to determine cut-off for LCI data, cost-based cut-off considerations were applicable to LCC data.

1.2.6 Life Cycle Cost Analysis Approach

The LCC analysis captures the significant capital and O&M expenses incurred by the SCPC cases with and without CCS for their assumed 30-year life. The LCC provides the constant dollar levelized cost of electricity (LCOE) of the production and delivery of energy over the study period (in years).

Cash flow is affected by several factors, including cost (capital, O&M, replacement, and decommissioning or salvage), book life of equipment, Federal and state income taxes, tax and equipment depreciation, interest rates, and discount rates. For NETL LCC assessments, Modified Accelerated Cost Recovery System (MACRS) deflation rates are

used. O&M cost are assumed to be consistent over the study period except for the cost of energy and feedstock materials determined by EIA.

Capital investment costs are defined in the Baseline Report as including "equipment (complete with initial chemical and catalyst loadings), materials, labor (direct and indirect), engineering and construction management, and contingencies (process and project)." The following costs are excluded from the Baseline Report definition:

- Escalation to period-of-performance.
- All taxes, with the exception of payroll taxes.
- Site-specific considerations (including, but not limited to seismic zone, accessibility, local regulatory requirements, excessive rock, piles, laydown space, etc.).
- Labor incentives in excess of a five-day/10-hour work week.
- Additional premiums associated with an Engineer/Procure/Construct (EPC) contracting approach.

The capital costs were assumed to be "overnight costs" (not incurring interest charges) and are expressed in 2007 dollars. Accordingly, all cost data from previous reports and forthcoming studies are normalized to 2007 dollars. In accordance with the Baseline Report, all values are reported in January 2007 dollars; it is the assumption of this study that there is no difference between December 2006 dollars and January 2007 dollars. **Table 1-1** summarizes the LCC economic parameters that were applied to both pathways.

Table 1-1 Global LCC Analysis Parameters

Property	Value	Units
Reference Year Dollars	December 2006/January 2007	Year
Assumed Start-Up Year	2010	Year
Real After-Tax Discount Rate	10.0	Percent
After-Tax Nominal Discount Rate	12.09	Percent
Assumed Study Period	30	Years
MACRS Depreciation Schedule Length	Variable	Years
Inflation Rate	1.87	Percent
State Taxes	6.0	Percent
Federal Taxes	34.0	Percent
Total Tax Rate	38.0	Percent
Fixed Charge Rate Calculation Factors		
Capital Charge Factor (wo-CCS / w-CCS)	0.1691 / 0.1773	--
Levelization Factor (wo-CCS / w-CCS)	1.451213 / 1.426885	--
Start Up Year (2010) Feedstock & Utility Prices	*$2006*	
Natural Gas[1]	6.76	$/MMBtu
Coal[2]	1.51	$/MMBtu
Process Water[3]	0.00049 (0.0019)	$/L ($/gal)

1. AEO 2008 Table 3 Energy Prices by Sector and Source: Electric Power-Natural Gas (EIA, 2008).
2. AEO 2008 Table 112 Coal Prices by Region and Type: Eastern Interior, High Sulfur (Bituminous). To account for delivery of the coal, 25% was added to the minemouth price.
3. Rafelis Financial Consulting, PA. Rafelis Financial Consulting 2002 Water and Wastewater Rate Survey, Charlotte, NC.

The LCC analysis uses a revenue requirement approach, which is commonly used for financial analysis of power plants. This approach uses the cost of delivered electricity (COE) for a comparison basis, which works well when trying to evaluate different plant configurations. COE is levelized over a 20-year period, although the plant is modeled for a 30-year lifetime. The method for the 20-year LCOE is based on the NETL Power Systems Financial Model (NETL, 2008). The LCOE is calculated using the PV costs. All PV were levelized using a capital charge factor (CCF) for capital costs and a levelization factor for O&M costs. The LCOE is determined using the following equation from the Baseline Report (NETL, 2010).

$$LCOE_P = \frac{(CCF_P)(TOC) + (LF)[(OC_{F1}) + (OC_{F2}) + \ldots] + (CF)(LF)[(OC_{V1}) + (OC_{V2}) + \ldots]}{(CF)(MWh)}$$

where

$LCOE_P$ = levelized cost of electricity over P years, $/MWh

P = levelization period (e.g., 10, 20 or 30 years)

CCF_P = capital charge factor for a levelization period of P years

TOC = total overnight cost, $

LF = levelization factor (a single levelization factor is used in each case because a single escalation rate is used for all costs)

OC_{Fn} = category n fixed operating cost for the initial year of operation (but expressed in "first-year-of-construction" year dollars)

CF = plant capacity factor

OC_{Vn} = category n variable operating cost at 100 percent CF for the initial year of operation (but expressed in "first-year-of-construction" year dollars)

MWh = annual net megawatt-hours of power generated at 100 percent CF

1.2.7 Environmental Life Cycle Inventory and Global Warming Impact Assessment Approach

The following pollutant emissions and land and water resource consumptions were considered as inventory metrics within the study boundary:

- GHG Emissions: CO_2, methane (CH_4), nitrous oxide (N_2O), and sulfur hexafluoride (SF_6) are included in the study boundary.
- Criteria air pollutants are designated as such because permissible levels are regulated on the basis of human health and/or environmental criteria as set forth in the Clean Air Act (EPA, 1990). Six criteria air pollutants are currently monitored by the EPA and are therefore included in the LCI of current NETL LCI&C studies, as shown in **Table 1-2**.

Table 1-2 Criteria Air Pollutants Included in Study Boundary

Emissions to Air	Abbreviation	Description
Carbon Monoxide	CO	--
Nitrogen Oxides	NO_X	Includes all forms of nitrogen oxides.
Sulfur Dioxide	SO_2	Includes SO_2 and other forms of sulfur oxides.
Volatile Organic Compounds	VOCs	VOCs combined with NO_X and sunlight form ozone in the atmosphere. Releases of VOCs are reported as a precursor to ozone formation. VOCs are also reported as non-methane VOCs to avoid double counting with reported methane emissions.
Particulate Matter	PM	Includes all forms of PM: PM_{10}, $PM_{2.5}$, and unspecified mean aerodynamic diameter.
Lead	Pb	--

- Air emissions of Hg and NH_3 are included within the study boundaries due to their potential impact when assessing current and future electricity generation technologies.
- Water withdrawal and consumption is included within the Study Boundary, including that extracted directly from a body of water (above or below ground) and water obtained from municipal or industrial water source. The amount of water required to support a procedure or process can be discussed in terms of withdrawal or consumption. Within NETL LCI&C studies, water withdrawal is defined as the total amount of water that is drawn from an outside source into a particular process or facility, in support of that process/facility. For instance, water use for an energy conversion facility would include all water that is supplied to the facility, via municipal supply, pumped groundwater, surface water uptake, or from another source. Water consumption is defined as water withdrawal minus water discharged from a process or facility. For instance, water consumption for an energy conversion facility would be calculated by subtracting the amount of liquid water discharged by the facility from the facility's water withdrawal.
- Transformed land area (e.g., square meters of land transformed) is considered in NETL life cycle analysis (LCA) studies for primary land use change. The transformed land area metric estimates the area of land that is altered from a reference state. Land use effects are not discussed for each stage in **Section 2.0**; the methodology and results for this inventory are discussed in **Section 3.0**.

Global warming potential (GWP) is also evaluated in NETL LCI&C studies. The final quantities of GHG emissions for each gas included in the study boundary were converted to a common basis of comparison using their respective GWP for a 100-year time horizon. These factors quantify the radiative forcing potential of each gas as compared to CO_2. The most recent 100-year GWP values reported by the Intergovernmental Panel on Climate Change (IPCC) are listed in **Table 1-3** (IPCC, 2007).

Table 1-3 Global Warming Potential for Various Greenhouse Gases for 100-Yr Time Horizon (IPCC, 2007)

GHG	2007 IPCC GWP (CO_2e)
CO_2	1
CH_4	25
N_2O	298
SF_6	22,800

The purpose of this study and all other NETL electricity generation studies is to perform and publish transparent LCI&Cs. Assuming this goal is achieved, any additional impact category related to the studied LCI data metrics can be applied to the LCI&C results. Thus, while it was not within the scope of this work to apply all available impact assessment methods, others can use this work to apply impact assessment methods of their own choosing. As methods are updated and developed, and when the LCI&C community reaches a consensus on their accuracy, other impact methods may be considered in future NETL LCI&Cs.

1.3 Software Analysis Tools

The following software analysis tools were used to model each of the study pathways. Any additional modeling conducted outside of these tools is considered a "data source" used to inform the analysis process.

1.3.1 Life Cycle Cost Analysis

An LCC model was developed as part of this study to calculate the LCOE ($/MWh) for each of the scenarios. The LCC model was developed in Microsoft® Excel to document the sources of economic information, while ensuring that all pathways utilize the same economic factors. The model calculates all costs on an LC stage basis, and then sums the values to determine the total LCC. This process enables the differentiation of significant cost contributions identified within the LCC model.

The LCC model was developed in-house by Research and Development Solutions, LLC (RDS) as part of the project effort. The LCC model leverages the experience gained in developing a similar cost model in the previous LCI&C studies conducted by NETL.

1.3.2 Environmental Life Cycle Analysis

GaBi 4, developed by the University of Stuttgart (IKP) and PE INTERNATIONAL of Germany, was used to conduct the environmental LCI. GaBi 4 is an ISO 14040-compliant modular software system used for managing large data volumes. In addition to adding data for a specific study into the GaBi framework, one can make use of the large database of LCI profiles included in GaBi for various energy and material productions, assembly, transportation, and other production and construction materials that can be used to assist in modeling the LC of each pathway. The GaBi 4 software has the ability to analyze the contribution from an individual process or groups of processes (referred to as "Plans") to the total LC emissions. Plans, processes, and flows form modular units that can be grouped to model sophisticated processes, or assessed individually to isolate effects. The GaBi system follows a process-based modeling approach and works by performing comprehensive balancing (mass and energy) around the various processes

within a model. GaBi 4 is a database-driven tool designed to assist practitioners in documenting, managing, and organizing LCI data. Data pulled from the GaBi 4 database and used within this study was considered non-transparent and was subject to sensitivity analysis. For this study, only secondary (or higher order) operations are characterized using GaBi profiles; all primary data were characterized by an additional reference source (peer reviewed journal, government report, manufacturer specifications, etc.) and entered into the GaBi framework.

1.4 Summary of Study Assumptions

Central to the modeling effort are the assumptions upon which the entire model is based. **Table 1-4** lists the key modeling assumptions for the SCPC with and without CCS cases. As an example, the study boundary assumptions indicate that the study period is 30 years, interest costs are not considered, and the model does not include effects due to human interaction. The sources for these assumptions are listed in the table as well. Assumptions originating in this report are labeled as "Present Study", while other comments originating in the NETL Cost and Performance Baseline for Fossil Energy Power Plants study, Volume 1: Bituminous Coal and Natural Gas to Electricity Report are labeled as "NETL Baseline Report."

Table 1-4 Study Assumptions by LC Stage

Primary Subject	Assumption	Source
Study Boundary Assumptions		
Temporal Boundary	30 years	NETL Baseline Report
Cost Boundary	"Overnight"	NETL Baseline Report
LC Stage #1: Raw Material Acquisition		
Extraction Location	Southern Illinois	Present Study
Coal Feedstock	Illinois No. 6	NETL Baseline Report
Mining Method	Underground	Present Study
Mine Construction and Operation Costs	Included in Coal Delivery Price	Present Study
LC Stage #2: Raw Material Transport		
Coal Transport Rail Distance	205 miles	Present Study
Rail Spur Constructed Length	25 miles	Present Study
Main Rail Line Construction	Pre-existing	Present Study
Unit Train Construction and Operation Costs	Included in Coal Delivery Price	Present Study
LC Stage #3: Power Plant		
Power Plant Location	Southwestern Illinois	Present Study
IGCC Net Electrical Output (without CCS)	550 MW	NETL Baseline Report
IGCC Net Electrical Output (with CCS)	550 MW	NETL Baseline Report
Auxiliary Boiler Fuel	Natural Gas	Present Study
Trunk Line Constructed Length	50 miles	Present Study
CO_2 Compression Pressure for CCS Case	2,215 psi	NETL Baseline Report
CO_2 Pipeline Length for CCS Case	100 miles	Present Study
Sequestered CO_2 Loss Rate for CCS Case	1% in 100 years	Present Study
Capital and Operation Cost		NETL Bituminous Baseline
LC Stage #4: Product Transport		
Transmission Line Loss	7%	Present Study
Transmission Grid Construction	Pre-existing	Present Study

1.5 Report Organization

This study includes two comprehensive LCI and cost parameter studies for electricity production via SCPC with and without CCS. The methodology, results, and conclusions are documented in the following report sections:

Section 1.0 – Introduction: Discusses the purpose and scope of the study. The system boundaries for each pathway and LC stages are described, as well as the study modeling approach.

Section 2.0 – Life Cycle Stages LCI and Cost Parameters: Provides an overview of each LC stage and documents the economic and environmental LC results. For both cases, all stages are the same except for Stage #3; a description and results for Stage #3 of both cases will be included in this section.

Section 3.0 – Interpretation of Results: Detailed analysis of the advantages and disadvantages of SCPC electricity generation with and without CCS. Analysis includes comparison of metrics (criteria air pollutants, Hg and NH_3 emissions to air, water and land use), GWP impact assessment, and sensitivity analysis results.

Section 4.0 – Summary: Discusses the overall study results and conclusions.

Section 5.0 – Recommendations: Provides suggestions for future improvements to the evaluation of LCC and environmental emissions related to complex energy systems as well as recommendations on areas for further study.

Section 6.0 – References: Provides citation of sources (government reports, conference proceedings, journal articles, websites, etc.) that were used as data sources or references throughout this study.

Appendix A – Process Modeling Data Assumptions and GaBi Modeling Inputs: Detailed description of the modeling properties, assumptions, and reference sources used to construct each process and LC stage. All modeling assumptions are clearly documented in a concise and transparent manner.

2. Life Cycle Stages: LCI Results and Cost Parameters

For each of the following LC stages, key details on LCI and LCC data assumptions for all major processes used to extract and transport coal, convert coal to electricity, capture and sequester CO_2 (when applicable), and transmit electricity are discussed. Additionally, the environmental metrics (GHG emissions, criteria air pollutant emissions, Hg and NH_3 emissions, and water withdrawal/consumption and land use) will be quantified for each stage. The LCC results will be given for Stage #3 only and include transmission loss; assumptions for Stage #1 and Stage #2 are not quantified until Stage #3, and the COE at the end of Stage #5 can be assumed equal to the cost calculated at the gate of the conversion facility. All stages are applicable to both cases except Stage #3, where the description and results will be discussed for Case 1 and Case 2 separately. Discussion of Stage #4 and Stage #5 will be combined.

2.1 Life Cycle Stage 1: Raw Material Extraction

The following assumptions were made when modeling Stage #1:

- All mining was assumed to be large-scale underground longwall mining of I-6 bituminous coal.
- The mining took place in southern Illinois.
- Information from the Galatia Mine was used as representative data for the mine characterized in this study.

The Galatia Mine was chosen based on its similarities with the studied mine, as well as the wealth of information available in the literature and through phone interviews with mine staff (DNR, 2006; EPA, 2008a). The Galatia Mine is an underground mine with longwall operation located in Galatia, Illinois. The Galatia Mine uses heavy media separation in its preparation plant.

Longwall mining and room-and-pillar mining are the two most commonly employed methods of underground coal mining in the United States. In contrast to the room-and-pillar mining method, in which “rooms” are excavated from the mine seam and “pillars” are left in place between rooms to support the mine roof, longwall mining results in extraction of long rectangular blocks or “panels” of coal, allowing the roof to collapse following coal extraction (EIA, 1995). The large-scale, continuous, and semi-automated nature of longwall mining makes average longwall mining operations more productive than traditional room-and-pillar operations. Longwall mining has also been proven safer than room-and-pillar mining; however, longwall mining does have higher capital costs and large amounts of dust and CH_4 are generated during the mining process (EIA, 1995). Even with the disadvantages, longwall continues to grow as a common mining technology in the United States, recently accounting for 49.2 percent of coal mined (EIA, 2007a). For this study, longwall mining was considered the primary mining technology. However, before longwall mining can begin, the mine workings must be prepared; the panel is “blocking out” by excavating passageways and staging areas around the perimeter of the panel to be mined (see **Figure 2–1**). Blocking out is a room-and-pillar type operation that can be accomplished using a coal cutting machine referred to as a continuous miner.

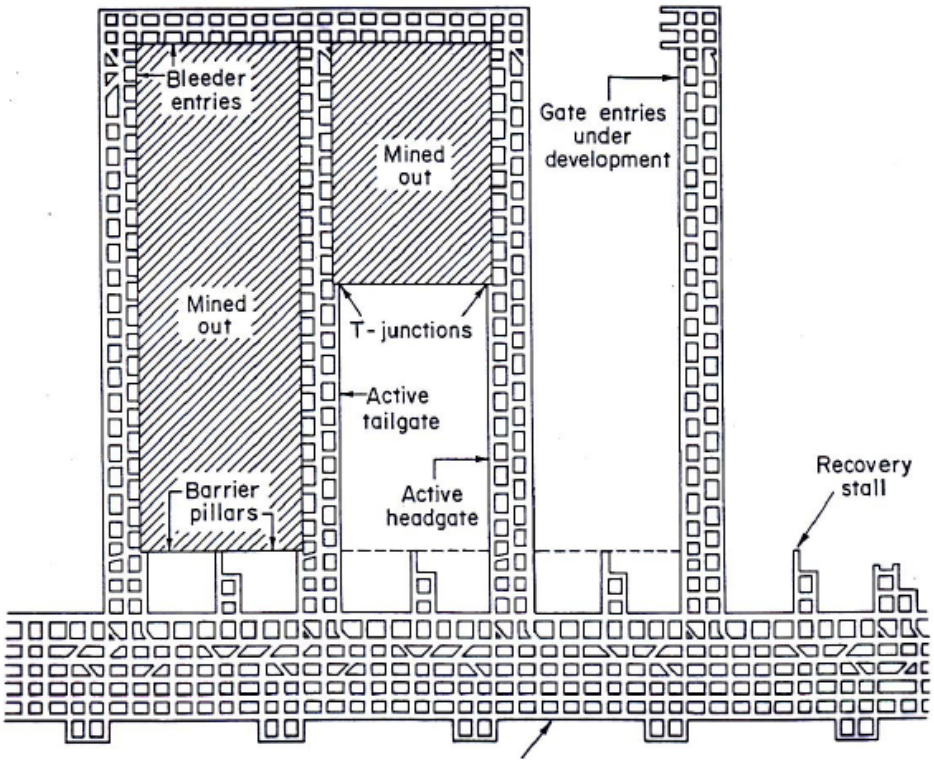

Figure 2–1 Setup, Operation, and Maintenance of the Longwall Unit Requires Preliminary Preparation of Access Entries and Staging Rooms that are Excavated Using Continuous Mining Machines-Overhead View (Mark 1990)

Following mining, coal from both types of equipment is conveyed from the mine using an electrically-driven slope conveyance system. At the surface, coal is transferred from the slope conveyor to large, electrically-driven stacking machinery that stockpiles the run-of-mine (ROM) coal adjacent to the coal cleaning facility. Stockpiled ROM coal is then fed into the coal comminution (size reduction) and cleaning facility. Cleaned and dewatered coal is transferred to a storage silo located near the cleaning facility where the cleaned coal is then transferred from the storage silo to the railcar for transport. Reject material is partially dewatered and transferred to an onsite impoundment for storage. A simplified process schematic is shown in **Figure 2–2.**

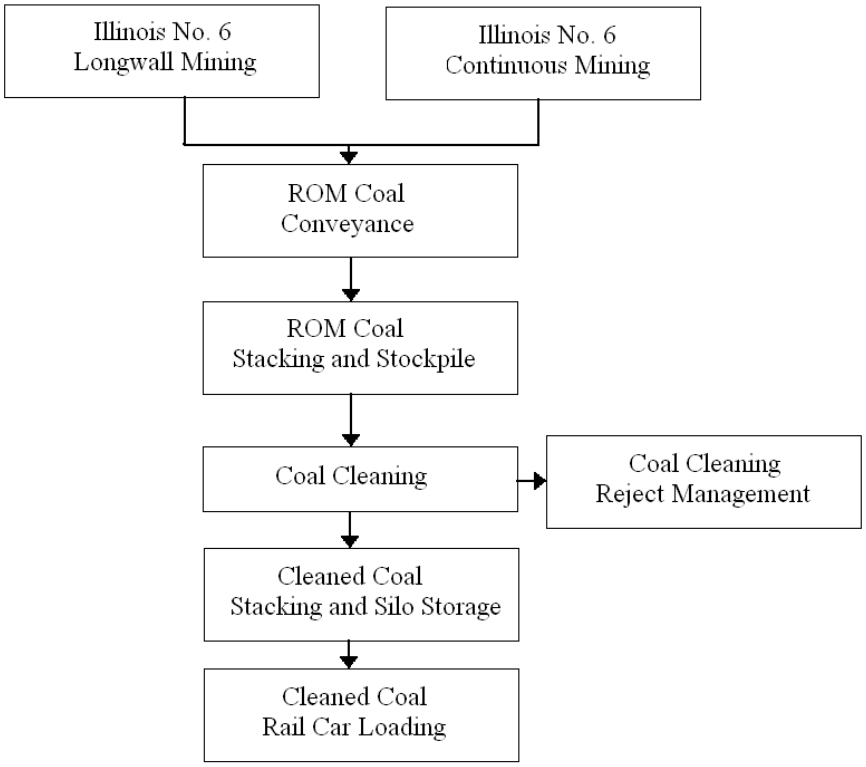

Figure 2–2 Simplified Schematic of Illinois No. 6 Bituminous Coal Mining, Processing, and Management

Major operations during Stage #1 include the mining equipment (longwall and continuous), material moving, and coal preparation (size reduction and cleaning). Most of the energy consumed during mining was due to the operation of electrically-driven machinery; however, some diesel fuel use was assumed to be used during installation of the mine and for moving materials around the mine site. Besides combustion emissions, particulate matter (PM), CH_4, and Hg are also environmental outputs from a coal mine. Of the coal mined, a reject rate was assumed from Galatia Mine data to be 45 percent, which is lost during coal preparation and loading. Land use change was due to the creation of the underground mine and appurtenant surface facilities on greenfield land in southern Illinois. Water withdrawal and consumption during mining activities was dominated by the coal cleaning operation.

2.1.1 LCC Data Assumption

The following text defines assumptions made to determine the cost of producing coal in Stage #1. Because the coal is not used until the plant site, no cost modeling results are necessary for this stage. All cost model results are reported in the Stage #3 LCC data results sections. AEO values were used for feed/fuel costs (i.e., fuel used as inputs to a unit process or LC stage) over the lifetime of the plant, beginning in 2010 and ending in 2040 (EIA, 2008). The AEO forecasts to 2030, so the final 10 years of the plant's lifetime were extended beyond 2030 using regression of feedstock and other utility prices. All AEO values are in 2006 dollars. AEO 2008 Reference Case Coal Prices by Region and Type Table (Table 112) was used to account for the coal prices for the first

20 years of the plant (EIA, 2008). These are minemouth costs for coal. The AEO 2008 reference case predicts a growth of 2.4 percent/year for the U.S. economy between the study period of 2006 to 2030 (EIA, 2008). In order to reflect the uncertainty associated with projected economic growth, AEO 2008 also includes high and low economic growth cases. The high case assumes higher growth in population, labor force, and productivity. This in turn lowers inflation and interest rates, increasing investment, disposable income, and industrial production. This all results in a three percent/year increase in economic output compared to 2.4 percent for the reference case. Conversely, the low case assumes the opposite; with less growth in population, labor, and productivity resulting in an economic growth of only 1.8 percent per year. **Figure 2–3** shows the AEO reference and high case prices for coal (higher heating value [HHV] basis) until 2030 and forecasted prices from 2031 to 2040. The initial decline in the extended data is due to the slope of the linear regression, which on average is less than the slope over the last years of AEO predictions; this is recognized as a simplification. This study assumed AEO reference case prices as the primary LCC modeling data set and used the high case prices to analyze the sensitivity of the LCC to variation in feed/fuel costs; low growth case values were not readily available in the LCC model and therefore are not included in this report.

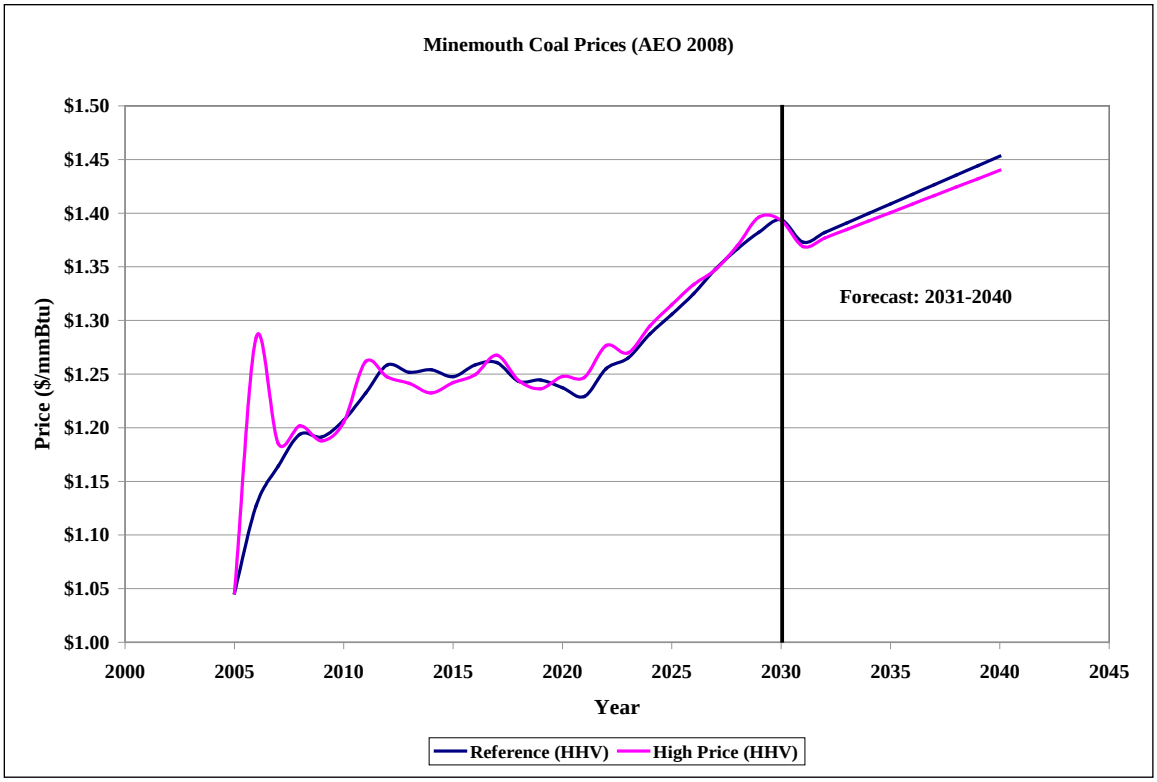

Figure 2–3 Coal Prices for the Lifetime of the Plant, 2006-2040 (EIA 2008)

2.1.2 Greenhouse Gas Emissions

Figure 2–4 compares the GHG emissions for Stage #1 on a per kg coal produced basis (ready for transport). In this study, the following definitions are used to describe the processes that occur during a stage:

- **Construction**: Emissions associated with the production of materials used during the construction of a process (i.e., steel used to build a power plant).

- **Commissioning/Decommissioning (C/D)**: Commissioning is the energy used and emissions created while preparing the land to install a coal mine. This is also when land use change occurs. Decommissioning is energy use and emissions associated with removing the processing facility and returning the land to grassland.
- **Operations**: Energy use and subsequent emissions due to the operation of a process (electricity and diesel during coal mining, natural gas for the auxiliary boiler during power plant operations).

GHG emissions are calculated on both a mass (kg) and kg CO_2 equivalent (CO_2e) basis to highlight the differences in impact when considering the warming potential of a pollutant versus only the mass emitted. The GWP values used to calculate CO_2e are listed in **Table 1-3**.

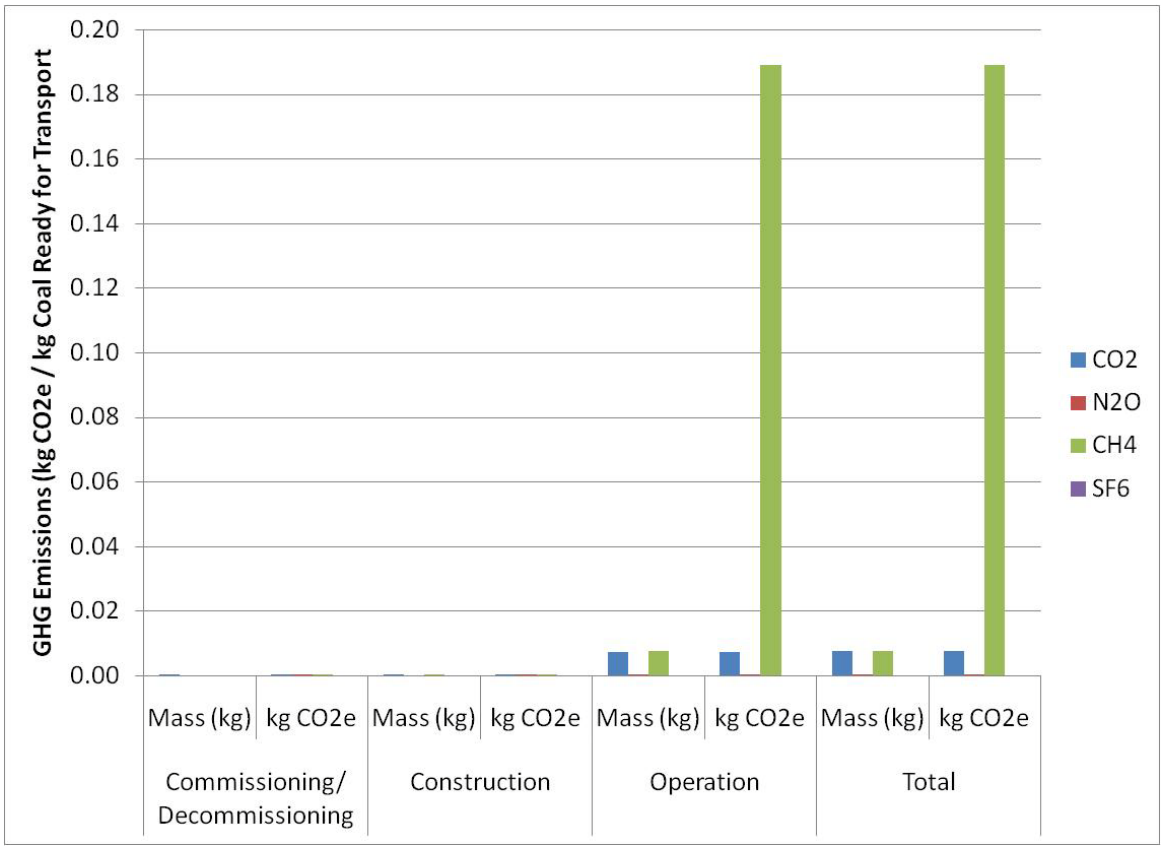

Figure 2–4 SCPC Stage # 1 GHG Emissions/kg Coal Mine Output

GHG emissions in this stage are dominated by CH_4 emitted during coal mining operation; CH_4 gases are trapped in the coal bed and released when the coal is mined. On a mass basis, CH_4 and CO_2 have similar outputs, but because CH_4 has 25 times the GWP, the impact is larger. Emissions during C/D and construction are small in comparison**. Table 2-1** summaries the emissions graphed above. The total GWP for Stage #1 is 0.2 kg CO_2e per kg coal ready for transport.

Table 2-1 SCPC Stage #1 GHG Emissions (on a Mass [kg] and kg CO2e Basis) /kg Coal Ready for Transport

Coal Mine Processes	Commissioning/ Decommissioning		Construction		Operation		Total	
Emissions (per kg coal)	Mass (kg)	kg CO_2e	Mass (kg)	kg CO_2e	Mass (kg)	kg CO_2e	Mass (kg)	kg CO_2e
CO_2	1.4E-05	1.4E-05	2.8E-04	2.8E-04	7.4E-03	7.4E-03	7.7E-03	7.7E-03
N_2O	2.5E-10	7.5E-08	1.2E-08	3.5E-06	1.1E-07	3.3E-05	1.2E-07	3.6E-05
CH_4	1.1E-08	2.7E-07	3.9E-07	9.8E-06	7.6E-03	1.9E-01	7.6E-03	1.9E-01
SF_6	3.8E-18	8.7E-14	1.3E-13	3.1E-09	4.5E-14	1.0E-09	1.8E-13	4.1E-09
Total GWP		1.4E-05		2.9E-04		2.0E-01		2.0E-01

2.1.3 Air Pollutant Emissions

Table 2-2 and **Figure 2–5** summarize the air emissions (excluding GHGs) that are released during Stage #1 on a per kg of coal output (ready for transport) basis.

Table 2-2 Air Pollutant Emissions from SCPC Stage #1, kg/kg Coal Ready for Transport

Emissions kg/kg coal	Commissioning/ Decommissioning	Construction	Operation	Total
Pb	4.51E-14	4.77E-10	3.29E-10	8.06E-10
Hg	4.21E-15	2.70E-11	9.18E-11	1.19E-10
NH_3	6.68E-12	7.36E-10	6.60E-08	6.68E-08
CO	3.45E-08	2.10E-06	7.29E-06	9.43E-06
NO_X	1.04E-07	5.22E-07	1.35E-05	1.41E-05
SO_X	4.09E-09	6.92E-07	3.74E-05	3.81E-05
VOC	4.56E-09	3.25E-08	2.39E-07	2.76E-07
PM	3.41E-07	9.84E-08	1.97E-06	2.41E-06

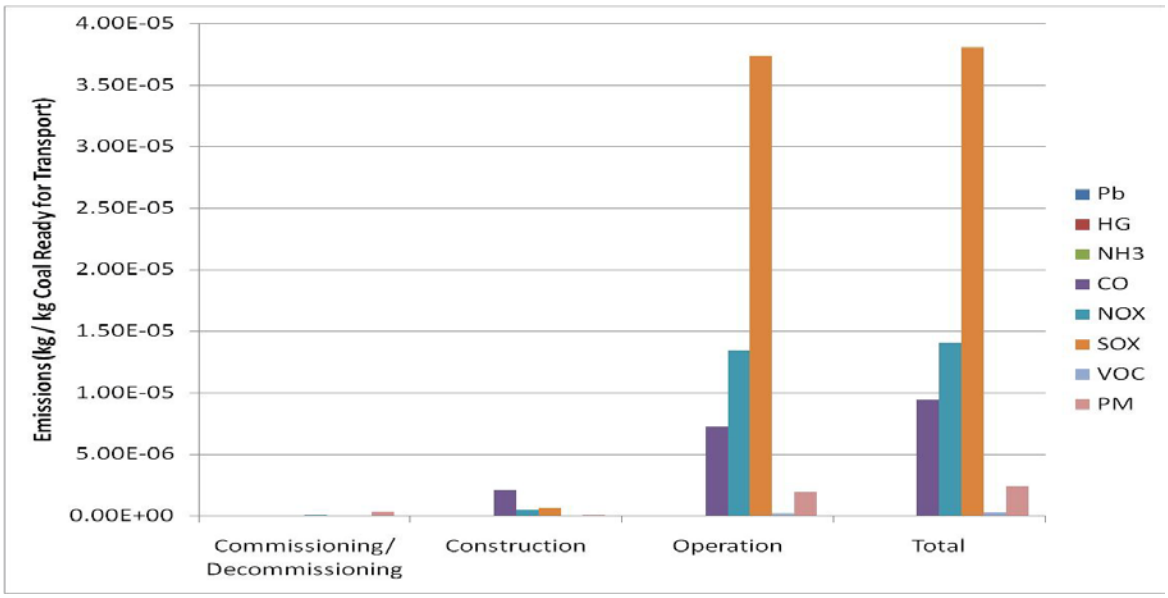

Figure 2–5 Air Pollutant Emissions from SCPC Stage #1, kg/kg Coal Ready for Transport

Sulfur oxide (SO_X) is the dominant emission during Stage #1, due mostly to LC emissions associated with electricity use. The carbon monoxide (CO) and NO_X emissions are due to combustion, and the PM emissions are due to fugitive dust during installation. However, all emissions at this stage are reported in very small quantities.

2.1.4 Water Withdrawal and Consumption

Table 2-3 shows water withdrawal and consumption, as well as wastewater outfall in Stage #1 on the basis of 1 kg coal ready for transport.

Table 2-3 Water Withdrawal and Consumption during SCPC Stage #1, kg/kg Coal Ready for Transport

Water (kg/kg Coal Output)	Commissioning/ Decommissioning	Construction	Operation	Total
Water Withdrawal	3.1E-06	1.4E-03	4.1E-01	4.1E-01
Wastewater Outfall	2.2E-06	1.8E-04	2.0E+00	2.0E+00
Water Consumption	9.5E-07	1.2E-03	-1.6E+00	-1.6E+00

All water withdrawal and consumption during C/D and coal mine construction is attributed to secondary LC such as diesel production and material manufacturing. The only primary data for water withdrawal and consumption during Stage #1 is for the coal mine operation, where water is used during coal prep, cleaning, and for dust suppression. Water output from the mine operations includes storm water and sanitary waste water as reported to the U.S. Environmental Protection Agency (EPA) by the Galatia Mine (EPA, 2008a). It is important to consider storm water from a coal mine in an LCI because it must be treated for sediment and other contaminants, and also requires energy during stormwater handling. However, no specific data were located on the water consumed during mine operations (such as water loss due to evaporation during coal cleaning), so a

value could not be separated from the storm water output. Therefore, a negative water consumed value (more output than input, or, water produced) is calculated for Stage #1.

2.2 Life Cycle Stage #2: Raw Material Transport

In Stage #2 it was assumed that the mined coal was transported by rail from the coal mine in southern Illinois to the energy conversion facility located in southwestern Illinois, a distance of 205 miles. For this study, a unit train is defined as one locomotive pulling 100 railcars loaded with coal. The locomotive is powered by a 4,400-horsepower diesel engine (General Electric, 2008) and each car has a 91-tonne (100-ton) coal capacity (NETL, 2010).

The major operation included in this stage is the combustion of diesel by the locomotive engine. Loss of coal during transport is assumed to be equal to the fugitive dust emissions; loss during loading at the mine is assumed to be included in the coal reject rate and no loss is assumed during unloading. Emissions are due to diesel combustion and fugitive dust. It was assumed that the majority of the railway connecting the coal mine and the SCPC facility was existing infrastructure which, assuming this particular mine and facility did not exist, would still be operational. Therefore, only a rail spur from the coal mine and the facility to the main rail line was considered for land use change. No water withdrawal or consumption was assumed during Stage #2 operations.

2.2.1 LCC Data Assumption

The Baseline Report assumed an additional cost equal to 25 percent of the minemouth coal price (NETL, 2010) to account for transportation of the coal from the mine to the plant facility. Lacking other specific data on transportation costs, 25 percent was also assumed for this study. The result is the delivered coal price shown in **Figure 2–6.** Because the coal is not used until the plant site, no cost modeling results are necessary for this stage. All cost model results are reported in the Stage #3 LCC results section.

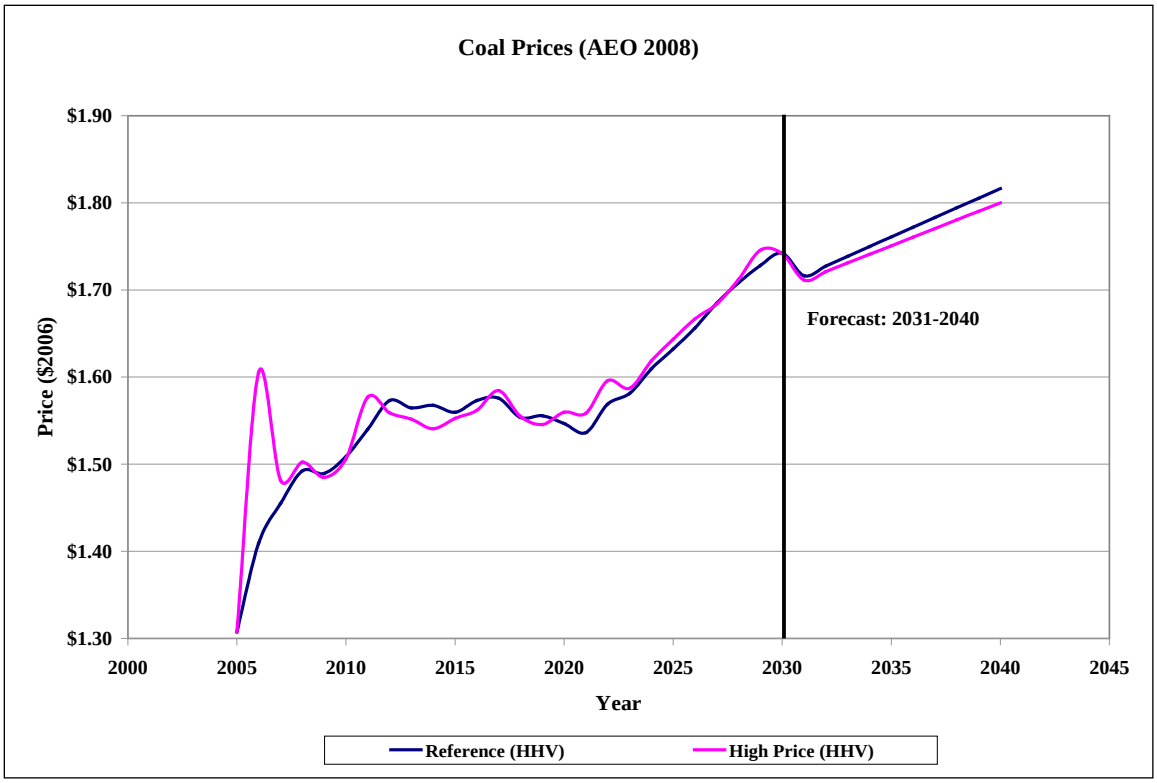

Figure 2–6 Delivered Coal Prices for Lifetime of the Plant

2.2.2 Greenhouse Gas Emissions

Table 2-4 and **Figure 2–7** show the GHG emissions for Stage #2 on a mass (kg) and kg CO_2e basis per kg of coal transported. CO_2 is the dominant pollutant due to the combustion of diesel fuel during train operation. The total GWP of Stage #2 is 0.013 kg CO_2e per kg coal transported.

Table 2-4 SCPC Stage #2 GHG Emissions (Mass [kg] and kg CO2e)/kg of Coal Transported

Processes	Train Construction		Train Operation		Total	
Emissions (/kg coal)	Mass (kg)	kg CO_2e	Mass (kg)	kg CO_2e	Mass (kg)	kg CO_2e
CO_2	5.9E-04	5.9E-04	1.2E-02	1.2E-02	1.3E-02	1.3E-02
N_2O	1.2E-08	3.5E-06	2.4E-08	7.2E-06	3.6E-08	1.1E-05
CH_4	8.8E-07	2.2E-05	1.6E-05	3.9E-04	1.6E-05	4.1E-04
SF_6	5.2E-14	1.2E-09	5.4E-15	1.2E-10	5.7E-14	1.3E-09
Total GWP		6.1E-04		1.3E-02		1.3E-02

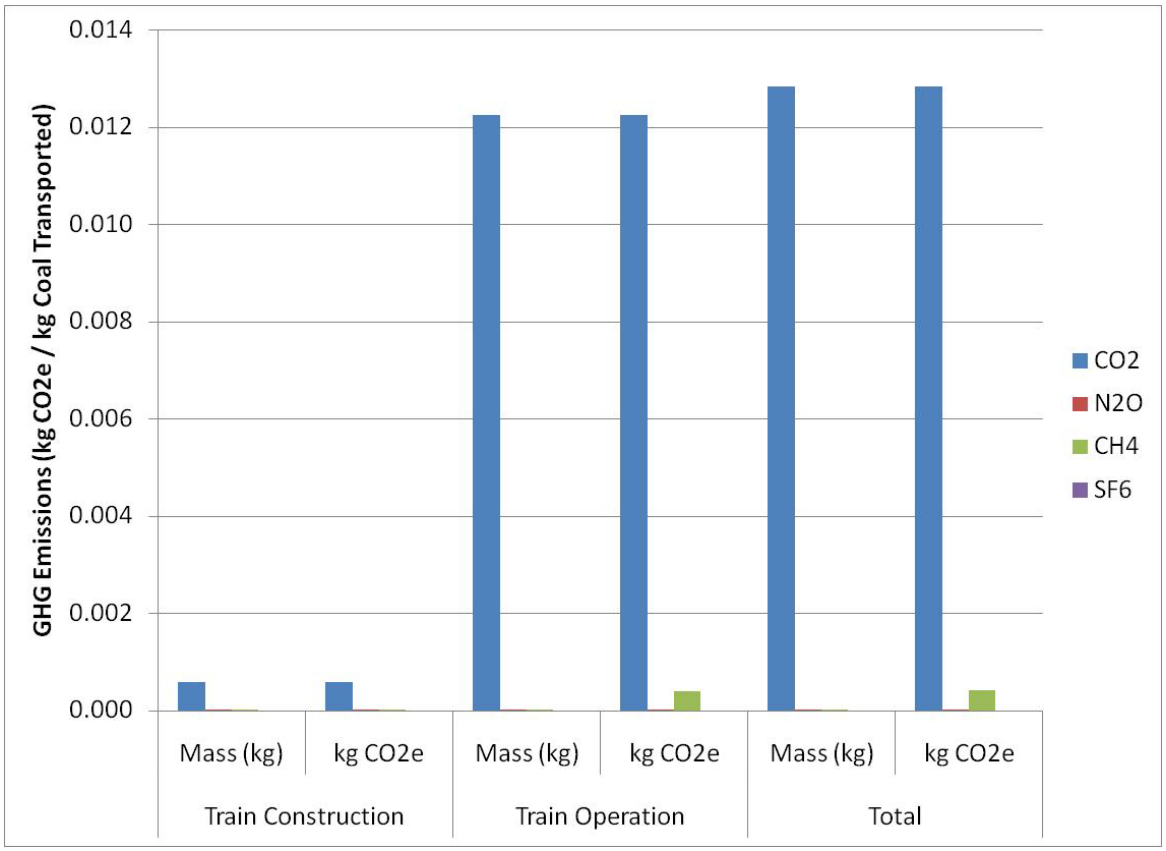

Figure 2–7 SCPC Stage #2 GHG Emissions (Mass [kg] and kg CO2e) /kg of Coal Transported

2.2.3 Air Pollutant Emissions

Table 2-5 and **Figure 2–8** show the non-GHG air emissions associated with Stage #2 on a per kg coal transported basis. Emissions are dominated by the train operations, where diesel fuel is combusted to power the unit train and coal dust loss contributes to PM.

Table 2-5 SCPC Stage #2 Air Emissions, kg/kg Coal Transported

Emissions (kg/kg coal)	Train Construction	Train Operation	Total
Pb	1.88E-10	6.39E-11	2.52E-10
Hg	1.33E-11	5.95E-12	1.93E-11
NH_3	1.91E-09	4.54E-07	4.56E-07
CO	4.91E-06	3.54E-05	4.03E-05
NO_X	1.04E-06	3.33E-05	3.43E-05
SO_X	3.06E-06	5.77E-06	8.83E-06
VOC	2.82E-08	3.12E-06	3.15E-06
PM	9.11E-07	4.13E-05	4.22E-05

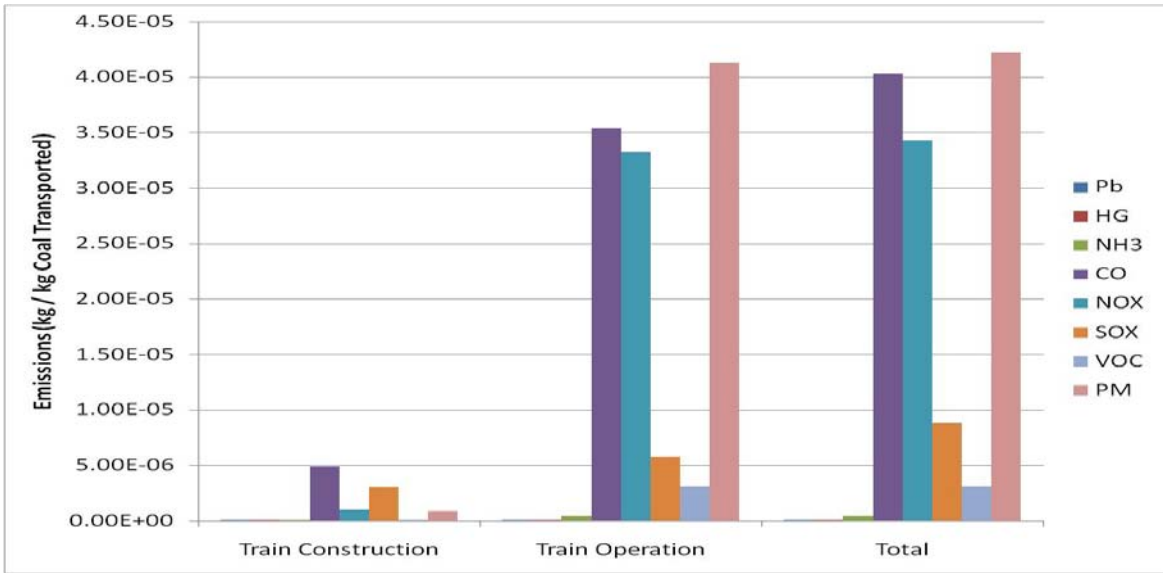

Figure 2–8 SCPC Stage #2 Air Emissions, kg/kg Coal Transported

2.2.4 Water Withdrawal and Consumption

Water withdrawal and consumption for Stage #2 are shown in **Table 2-6.** No water withdrawal or consumption was associated with the primary processes of constructing and operating the train; however, water associated with secondary processes (the LC of diesel fuel and steel materials used during construction) does result in some water withdrawal/consumption. Therefore, the water withdrawal and consumption for this stage are small and based solely on secondary data sources, such as GaBi profiles.

Table 2-6 SCPC Stage #2 Water Withdrawal and Consumption, kg/kg Coal Transported

Water (kg/kg coal)	Train Construction	Train Operation	Total
Water Withdrawal	3.99E-03	4.39E-03	8.39E-03
Wastewater Outfall	2.67E-03	3.05E-03	5.72E-03
Water Consumption	1.33E-03	1.35E-03	2.67E-03

2.3 Life Cycle Stage #3: Energy Conversion Facility for SCPC without CCS

The following briefly describes the operation of a 550-MWe net output SCPC plant without CCS; most data for this stage were taken from the Baseline Report (NETL, 2010). From the sparing philosophy employed in the Baseline Report, the plant design consists of the following major subsystems:

- One dry-bottom, wall-fired SCPC steam generator (1 × 100 percent)
- Two SCR reactors (2 × 50 percent)
- Two single-stage, in-line, multi-compartment fabric filters (2 × 50 percent)

- One wet limestone forced oxidation positive pressure absorber (1 × 100 percent)
- One steam turbine (ST) (1 × 100 percent)

The 2 × 50 percent rating is to be interpreted as the number of units and its capacity as a percentage of the total plant requirement.

The block flow diagram shown in **Figure 2–9** provides a simplified illustration of the interaction between major unit processes of the SCPC case without CCS (NETL, 2010). This figure shows only a single train for all SCPC subsystems and, as such, is not representative of the two SCR and fabric filter units described in the sparing philosophy.

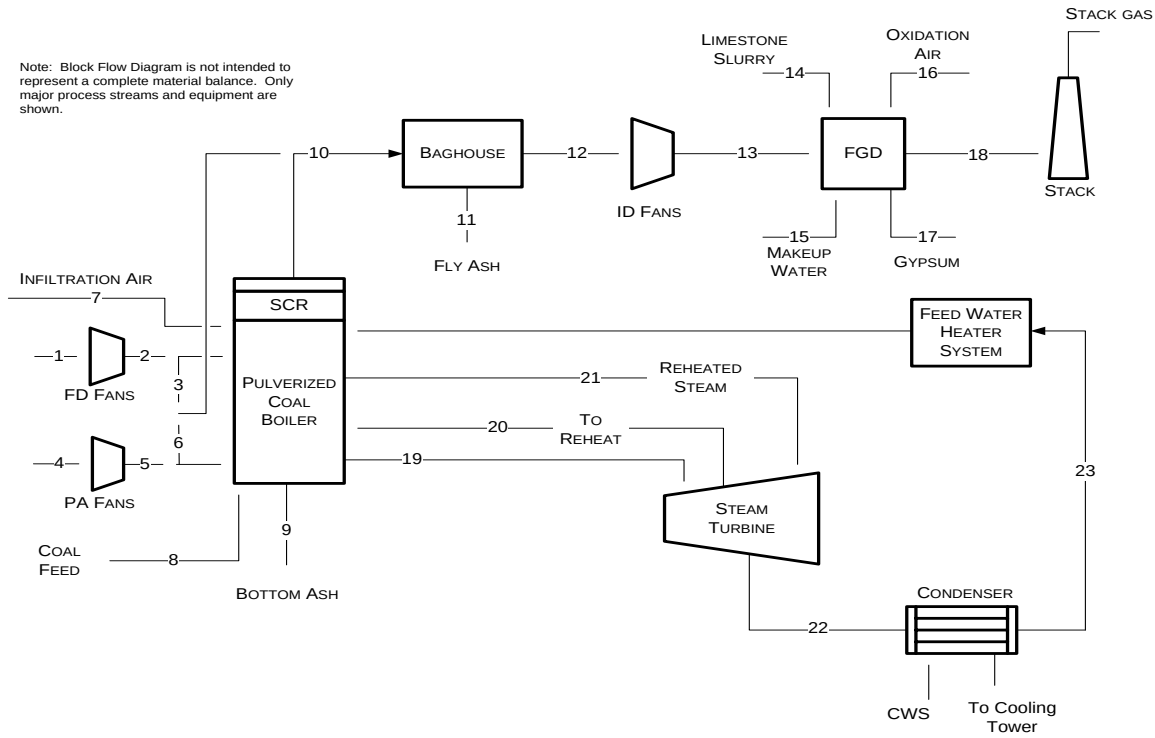

Figure 2–9 Process Flow Diagram, SCPC without CO2 Capture

Supercritical steam is generated by an air blown pulverized coal boiler which utilizes LNB with OFA to reduce NO_X emissions. The hot flue gas exiting the steam generator passes through the economizer and air preheater heat exchangers and is cooled through an SCR unit for additional removal of NO_X. PM is removed from the flue gas as it passes through a baghouse with fabric filters. With the high chloride content of I-6 coal, the removal of SO_2 from the flue gas occurs in the flue gas desulfurization (FGD) process and is accomplished by sending the flue gas through a wet limestone forced oxidation scrubber. The combination of the SCR, fabric filters, and the FGD result in significant co-benefit capture of Hg to the degree that activated carbon injection is not required. The flue gas is then discharged through the plant stack (NETL, 2010). Waste products, including fly ash, bottom ash, calcium sulfate ($CaSO_4$) from the scrubber, and other process wastes, would be sold as product streams or properly disposed of in an acceptable landfill, as applicable; however, the fate of these products once leaving the plant gate is not included within the boundaries of this study. Associated wastewater is treated in the plant's wastewater treatment plant and either recycled as process water or discharged to the cooling unit. Water discharged from the SCPC plant, including treated process water

and cooling tower blowdown, is assumed to be discharged into a municipal sewer system. The reader is referred to the Baseline Report for more details on other streams shown in **Figure 2-9** (NETL, 2010).

Primary inputs associated with operation of the SCPC without CCS are coal, natural gas for auxiliary boiler power, and process water. Construction materials for the plant, plant equipment, and trunkline/switchyard system are also included in Stage #3. Because this stage contains the main operating process, the economic and environmental burdens of this stage are large compared to the preceding and subsequent LC stages.

2.3.1 LCC Data Assumption

Capital, material inputs, and operating costs for both an SCPC power plant without CCS and an SCPC power plant with CCS were needed to calculate the total plant cost in both PV and LCOE for each case. **Table 2-7** lists the cost data and input parameters used to model the LCC for the SCPC plant without CCS. All values were reported in 2006 dollars and taken directly from the Baseline Report (NETL, 2010). It is assumed that replacement costs for the plant are included in the variable O&M costs taken from the Baseline Report. Initial start-up costs are considered to be two percent of the total plant costs (capital investment) minus the costs for contingencies. This is included in the analysis as part of the capital investment costs.

Table 2-7 Cost Data from the NETL Baseline Report and Necessary LCC Input Parameters for SCPC without CCS

Parameters	SCPC
Electricity Net (MWe)	550
Capacity Factor	85%
Initial Start-Up Costs ($)[1]	$0
Capital Investment	$1,113,445,000
Fixed O&M Costs, Labor Cost ($/yr)	$32,634,546
Variable O&M Cost ($/yr)[2]	$20,633,239

1. Initial start-up costs are wrapped into the capital investment.
2. Variable O&M costs exclude process water costs, and include replacement costs.

Coal, natural gas for the auxiliary boiler, and water were major inputs into the SCPC plant not considered in the capital or O&M costs assumed from the Baseline Report; all other inputs (catalysts, solvents, etc.) were assumed to be included. Coal prices were assumed from AEO 2008 as defined in Stage #1 Cost Assumptions (**Section 2.1.1**). Natural gas costs for the auxiliary boiler were also determined using AEO 2008 values and were extended to 2040 based on AEO 2008 reference case values (Table 3, Energy Prices by Sector and Source: Electric Power – Natural Gas). Due to the abrupt changes in the values from 2005 to 2030, the forecasted values for 2031 to 2040 assume the same trend as the values for 2022 through 2030, rather than assuming the trend of the entire set of AEO values. A standard line equation was used, however, only the final eight years of the AEO forecasts were used. This is recognized as a simplification but deemed appropriated since the volatility of natural gas prices makes any forecast a simplification.

Figure 2–10 presents the AEO 2008 reference and high-price case for natural gas based on HHV.

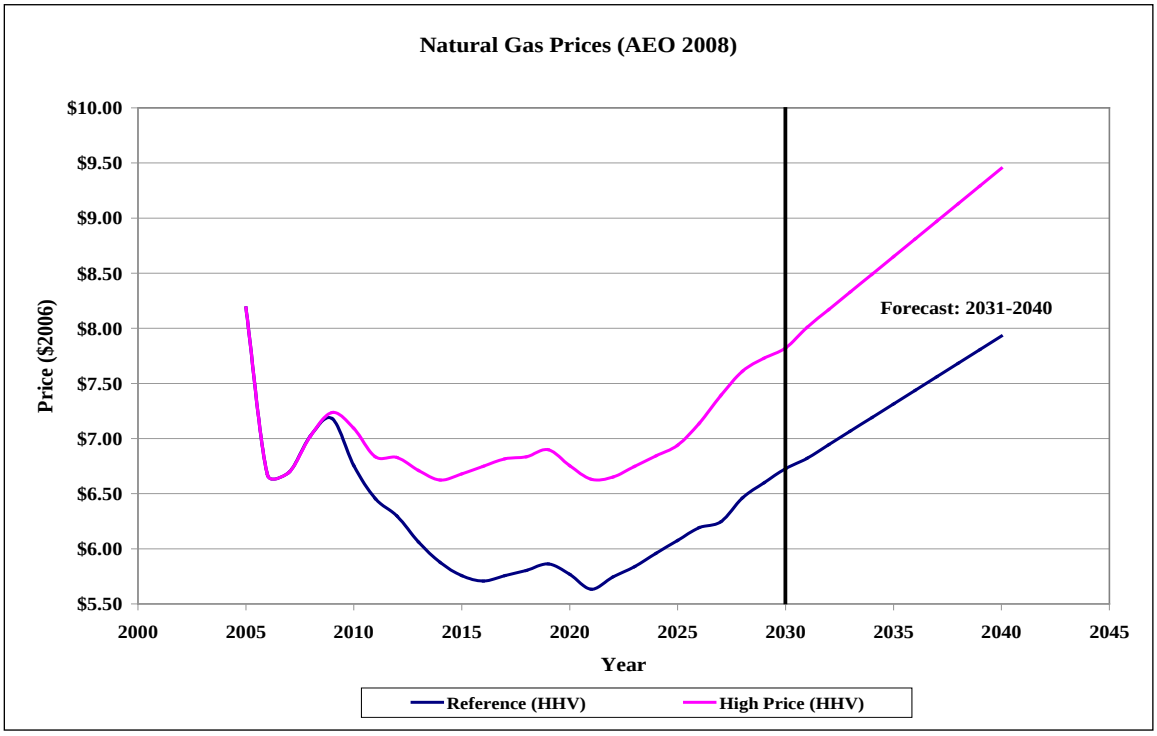

Figure 2–10 Natural Gas Prices for the Lifetime of the Plant

1. Prices ($/MMBtu) prior to 2030 calculated using AEO values (Reference Case/High Price Case Table 3 ($2006/MMBtu). Values post-2030 were extended using a regression based on the calculated values for price ($/MMBtu) 2005 through 2030.

Process water costs were estimated based on a Water and Wastewater Rate Survey Report (Rafaelis Financial Consulting, 2002). On a per liter basis, process water costs $0.00044. The total quantity of process water needed was taken from the Baseline Report. Because 50 percent of the water is purchased from the municipal supply, only 50 percent of the listed quantity was used to determine the cost of process water for these cases (NETL, 2010).

Table 2-8 defines the annual feedrate of each input. Annual feedrates for coal and process water were assumed from the Baseline Report. Natural gas was calculated based on an hourly feedrate of 53,000 ft^3/hr (Wabash Power Equipment Company, 2009).

Table 2-8 Annual Feedrates for Feed/Fuel and Utilities for SCPC Case without CCS

Input	Annual Feedrate
Coal (Tons/day)	4,914
Natural Gas (mmBtu/day)[1]	98
Water Needed (gallons/day)[2]	1,942,000

1. Natural gas consumed in the auxiliary boiler for start-up was calculated using a natural gas feed rate of 53,000 ft^3/hr and the assumption that the auxiliary boiler would be operating for 50 percent of the annual downtime (20 percent of the year).
2. Quantity listed accounts for the portion of water included in the costs of the plant. It is assumed that only half of the process water used in the plant is considered in the costs for the plant.

2.3.1.1 Switchyard and Trunkline System

Included in the costs for Stage #3 are the capital costs for the switchyard and trunkline. Costs for the switchyard/trunkline system are not included in the Baseline Report, so additional sources of information were used. The switchyard system is composed of two components – circuit breakers and disconnect switches. Components in the trunkline are conductors and transmission towers.

There are four SF_6 gas circuit breakers and eight aluminum vertical break (AVB) disconnect switches used in the switchyard. Because no cost information could be found for a 345-kilovolt (kV) circuit breaker, the cost is for a breaker rated at 362 kV. The AVB disconnect switches are rated at 345 kV. Cost for the switchyard components are based on disclosed and non-disclosed manufacturer estimates. In total, the switchyard capital costs are approximately $1,040,101 (Zecchino, 2008).

The trunkline system is made up of 294 towers and three aluminum-clad steel reinforced conductors spanning 80 km (50 miles). The entire trunkline system equals $45,589,656 (ICF Consulting Ltd, 2002).

The cost for the total switchyard and trunkline system, including all four components in previously specified quantities, equals $46.1 million. All costs for the switchyard/ trunkline system include only the cost of purchasing the component. Installation, labor, and additional material costs that may be necessary to install the system components are not included in the cost estimate. O&M costs are considered to be negligible and will not be included in the analysis. It is assumed that switchyard/trunkline life is the same as the 30-year plant life, therefore, no capital replacement costs are considered in the analysis. A seven percent transmission loss from the switchyard/trunkline system will be considered when calculating the LCOE for each case. **Table 2-9** gives a summary of the costs for the trunkline, switchyard, and total system.

Table 2-9 Switchyard/Trunkline Component Costs (Values in $2006)

Component	Total Cost
Trunkline	$45,589,656.96
Switchyard	$520,050.35
Total System	$46,109,707.31

2.3.2 LCC Results

The LCOE on a delivered energy basis for the SCPC without CCS is shown in **Figure 2–11**. The SCPC facility portion of the LCOE totaled $0.15498/kWh, which equals the NETL Baseline result of $0.1441/kWh when the 7% distribution loss is not applied. The results indicate that capital costs account for the largest portion of the total LCC. Of the capital costs, the SCPC energy conversion facility contributes the majority of the cost at $0.0494 per kilowatt-hour (kWh), whereas the switchyard/trunkline system and decommissioning account for $0.0020/kWh and $0.0003/kWh, respectively. Decommissioning costs were not included in the Baseline Report, but 10 percent of the capital cost was attributed to decommissioning, a common assumption in the literature (Hill, O"Keefe *et al.*, 1995; Odeh and Cockerill, 2008; Gorokhov, Manfredo *et al.*, 2002).

The decommissioning cost determination included the switchyard/trunkline and was only applied to capital costs; no data were available to make additional assumptions. Next to capital costs, the utility costs including coal feedstock, natural gas fuel, and process water contribute the second largest amount to the total LCC, or $0.0222/kWh. Variable O&M and labor costs contribute $0.0079/kWh and $0.0124/kWh. The total LC LCOE for the SCPC case without CCS is equal to $0.0943/kWh.

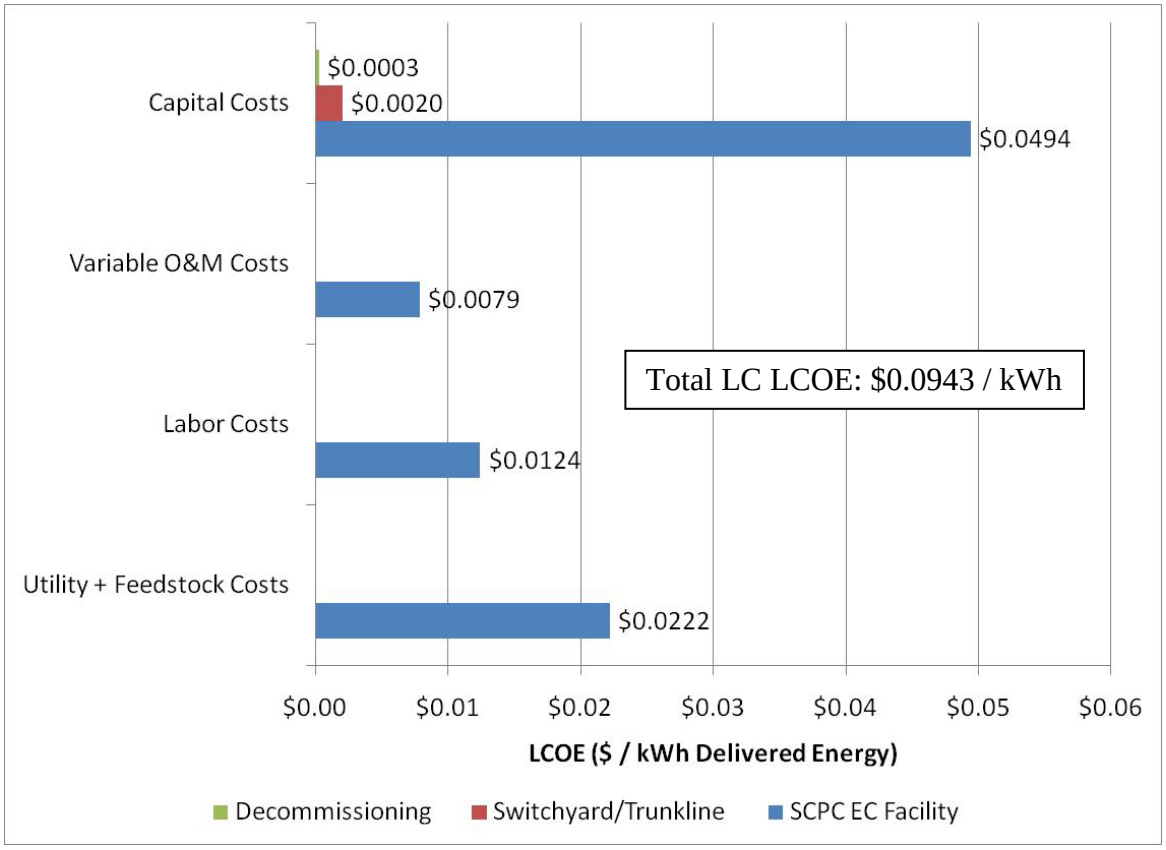

Figure 2–11 LCOE Results for SCPC Case without CCS

1. All calculations are based on an 85 percent capacity factor and include a seven percent electricity loss during transmission.

2.3.3 Greenhouse Gas Emissions

Table 2-10 and **Figure 2–12** shows the GHG emissions associated with the SCPC without CCS plant, on an MWh plant output basis. CO_2 is the dominant pollutant, with the largest emissions associated with the combustion of coal. The total GWP of this stage is 928.85 kg CO_2e per MWh plant output, 99 percent of which is due to the SCPC plant operations.

Table 2-10 SCPC without CCS Stage #3 GHG Emissions in kg and kg CO2e/MWh Plant Output

SCPC Processes	Plant Construction		Commissioning/ Decommissioning		Operation		Total	
Emissions (/MWh)	Mass (kg)	kg CO2e	Mass (kg)	kg CO_2e	Mass (kg)	kg CO_2e	Mass (kg)	kg CO_2e
CO_2	0.98	0.98	0.05	0.05	927.76	927.76	928.79	928.79
N_2O	2.9E-05	8.7E-03	1.3E-06	3.8E-04	3.7E-06	1.1E-03	3.4E-05	1.0E-02
CH_4	7.5E-04	1.9E-02	6.5E-05	1.6E-03	7.6E-04	1.9E-02	1.6E-03	3.9E-02
SF_6	9.2E-12	2.1E-07	2.3E-14	5.2E-10	3.5E-07	8.1E-03	3.5E-07	8.1E-03
Total GWP		1.01		0.05		927.79		928.85

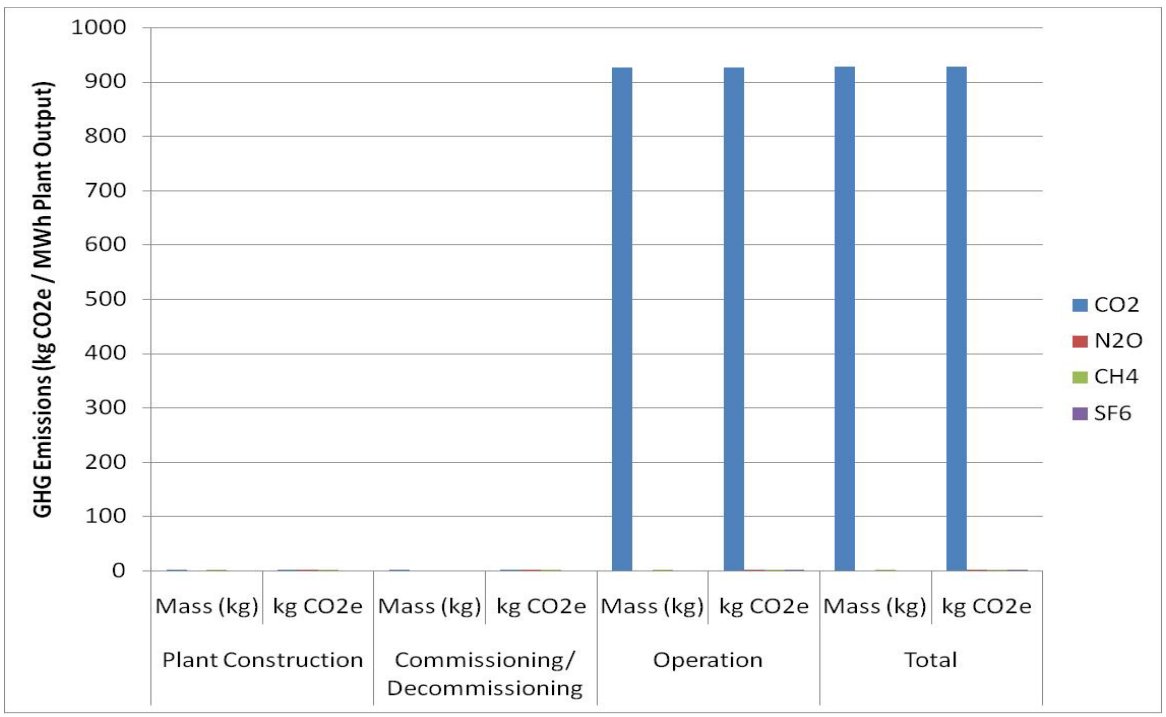

Figure 2–12 SCPC without CCS Stage #3 GHG Emissions in kg and kg CO2e/MWh Plant Output

2.3.4 Air Pollutant Emissions

Table 2-11 and **Figure 2–13** show the air pollutants released during SCPC plant operations on a per MWh output basis. As with GHGs, emissions are dominated by the combustion of coal during plant operation. These emissions reflect the use of best practice emissions control technologies for SO_X, NO_X, PM, and Hg as outlined in the Baseline Report (NETL, 2010). During SCR, NH_3 and a catalyst are used to control NO_X, and as the catalyst degrades, NH_3 is released to the stack (Mack and Patchett, 1997). The NH_3 emissions shown in **Table 2-11** and **Figure 2–13** for SCPC plant operations are a result of this slip, which is reported as two parts per million volume (ppmv) NH_3 at the end of catalyst life (NETL, 2010).

Table 2-11 SCPC without CCS Stage #3 Air Pollution Emissions, kg/MWh Plant Output

Emissions (kg/MWh)	Plant Construction	Plant Commissioning/ Decommissioning	Plant Operation	Total
Pb	9.74E-07	2.72E-10	4.79E-05	4.89E-05
Hg	6.24E-08	2.54E-11	4.77E-06	4.83E-06
NH_3	1.45E-06	1.93E-06	2.56E-03	2.57E-03
CO	4.94E-03	2.15E-03	4.06E-04	7.50E-03
NO_X	1.96E-03	7.88E-04	3.19E-01	3.22E-01
SO_X	3.31E-03	4.36E-05	3.91E-01	3.95E-01
VOC	9.39E-05	2.04E-04	2.13E-05	3.19E-04
PM	8.42E-04	1.04E-04	5.92E-02	6.01E-02

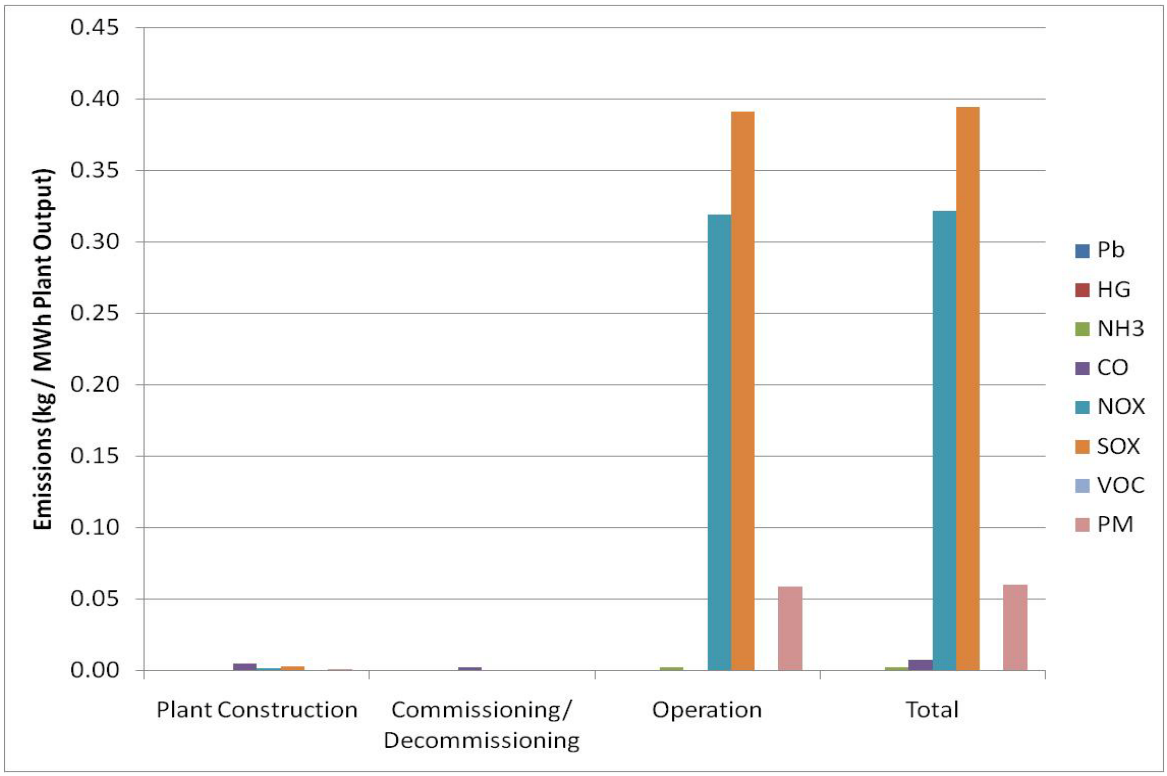

Figure 2–13 SCPC without CCS Stage #3 Air Pollution Emissions, kg/MWh Plant Output

2.3.5 Water Withdrawal and Consumption

Table 2-12 shows water withdrawal and consumption for the SCPC plant without CCS. The most water is consumed during plant operation due to cooling water evaporation. Water withdrawal and consumption during decommissioning is due to the LC impacts of diesel fuel.

Table 2-12 SCPC without CCS Stage #3 Water Withdrawal and Consumption, kg/MWh Plant Output

Water(kg/MWh)	Plant Construction	Commissioning/ Decommissioning	Plant Operation	Total
Water Withdrawal	5.50	0.15	2535.69	2541.33
Wastewater Outfall	2.15	0.01	517.39	519.55
Water Consumption	3.35	0.13	2018.29	2021.77

2.4 Life Cycle Stage #3: Energy Conversion Facility for SCPC with CCS (Case 2)

The following briefly describes the operation of a 550-MWe net output SCPC plant with CCS; as with the operation of the SCPC plant without CCS (**Section 0**) most data were taken directly from the Baseline Report. From the sparing philosophy employed in the Baseline Report, the plant design consists of the following major subsystems (NETL, 2010):

- One dry-bottom, wall-fired SCPC steam generator (1 × 100 percent)
- Two SCR reactors (2 × 50 percent)
- Two single-stage, in-line, multi-compartment fabric filters (2 × 50 percent)
- One wet limestone forced oxidation positive pressure absorber (1 × 100 percent)
- One ST (1 × 100 percent)

Figure 2–14 contains many of the same operation steps and processes that were shown previously in **Figure 2–9**. The major difference for SCPC with CCS is the inclusion of the Econamine FG plus block, a monoethanolamine (MEA)-based solvent process which removes approximately 90 percent of CO_2 from the flue gas (NETL, 2010). In the CO_2 compression stage, CO_2 is dehydrated and compressed to a pressure of 15.3 megapascals (MPa) (2,215 psia) – appropriate for pipeline transport and direct injection/saline sequestration.

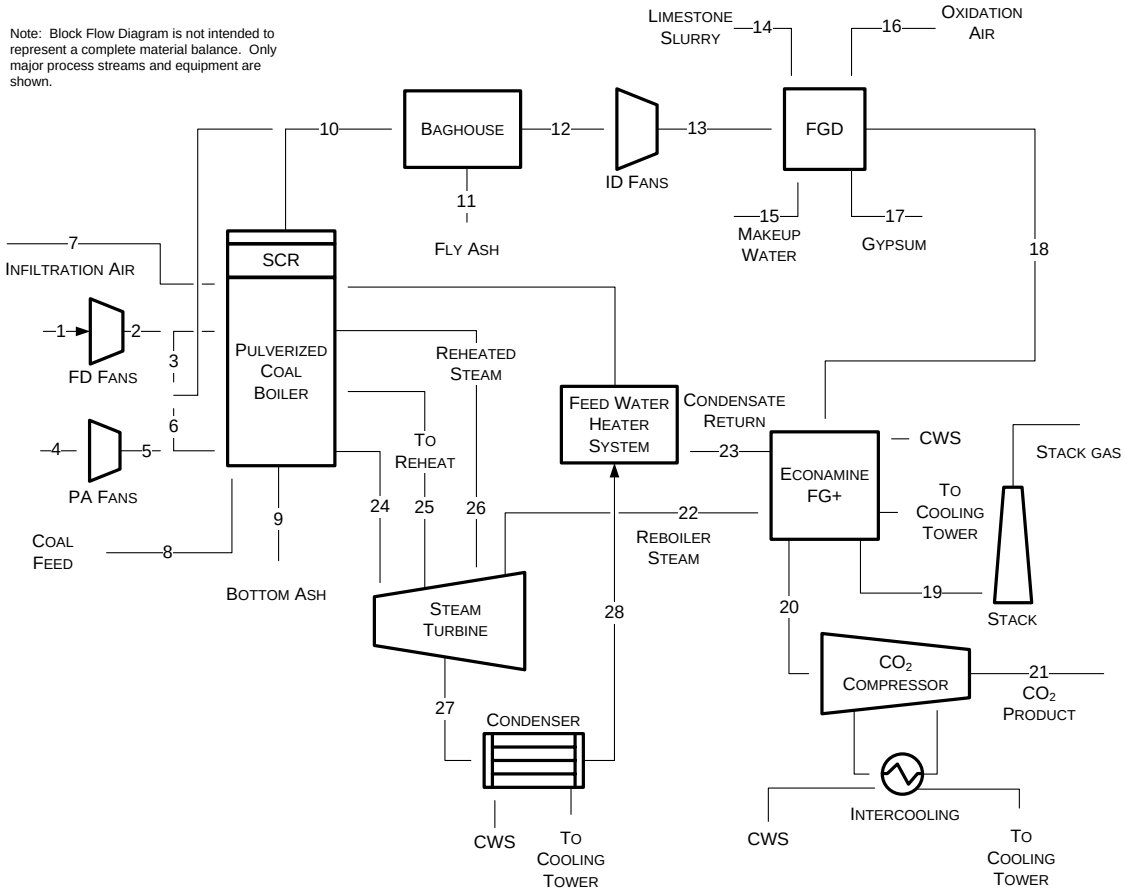

Figure 2–14 Process Flow Diagram, SCPC with CO2 Capture

Adding CCS to the SCPC plant decreases the net power output while increasing water and coal input requirements. Stage #3 for the SCPC case with CCS includes consideration of the natural gas used in the auxiliary boiler and the switchyard and trunkline operations. Also included in this stage is the operation of the CO_2 pipeline between the plant and the sequestration site and any losses associated with that operation.

2.4.1 LCC Data Assumption

Assumptions for the SCPC case Stage #1 and Stage #2, as well as the assumptions for costs for LC Stage #3, are described within the previous sections relating to Stage #1 and Stage #2 and the SCPC facility without CCS. **Table 2-13** lists the assumptions and parameters used to determine the SCPC with CCS cost analysis results. The SCPC plant with CCS has a net electricity output of 550 megawatts (MW) at a capacity of 85 percent (NETL, 2010).

Table 2-13 SCPC Facility with CCS Cost Parameters and Assumption Summary

Parameter	SCPC w/ CCS
Electricity Net (MW_e)	550
Capacity Factor	85%
Initial Costs ($)[1]	$0
Capital Investment	$1,963,644,000
Fixed O&M Costs, Labor Cost ($/yr)	$53,197,981
Variable O&M Cost ($/yr)[2]	$35,729,917

1. Initial start-up costs are considered to equal two percent of the total plant costs minus the contingencies costs (NETL, 2010).
2. Variable O&M costs exclude process water costs, and include replacement costs.

The same assumptions apply to the SCPC case with CCS as applied to the feed/fuel and utilities used for the SCPC case without CCS (**Section 2.3.1**); the feed quantities are listed again in **Table 2-14** for completeness. For SCPC with CCS, an additional 1,876 tons/day of coal is needed to account for the additional auxiliary needs associated with CO_2 capture (NETL, 2010).

Table 2-14 Annual Feedrate for Feed/Fuel and Utilities for SCPC Case with CCS

Input	Annual Feedrate
Coal (Tons/day)	6,790
Natural Gas (mmBtu/day)[1]	98
Water Needed (gallons/day)[2]	3,662,000

1. Natural gas consumed in the auxiliary boiler for start-up was calculated using a natural gas feed rate of 53,000 ft^3/hr and the assumption that the auxiliary boiler would be operating for 50 percent of the annual downtime (20 percent of the year).
2. Quantity listed accounts for the portion of water included in the costs of the plant. It is assumed that only half of the process water used in the plant is considered in the costs for the plant.

CO_2 Transportation, Sequestration, and Monitoring

For the SCPC case with CCS, CO_2 transportation, sequestration, and monitoring (TS&M) costs are included in the Stage #3 costs. Contributing to the TS&M costs are the capital and O&M costs for the CO_2 pipeline, injection wells, and O&M costs for the monitoring of the sequestration site.

CO_2 Pipeline

Based on the diameter, 43.17 centimeters (cm) (17 inches) and length, 160 km (100 miles) of the CO_2 pipeline, the capital costs and fixed O&M costs were calculated. The following equations were used to calculate the material, land, labor, and miscellaneous costs in dollars per mile ($/mile) included in the capital investment costs (Argonne National Laboratory, 2008):

$$Material(\$/mile) = 1.1(330.5d^2 + 687d + 26{,}960)$$
$$Land(\$/mile) = 1.1(577d + 29{,}788)$$
$$Labor(\$/mile) = 1.1(343d^2 + 2074d + 170{,}013)$$
$$Misc(\$/mile) = 1.1(8417d + 7324)$$

Where: "d" equals the diameter of the pipeline, measured in inches. The costs ($/mile) calculated using the equations listed above were added together to give the capital cost per mile and then multiplied by the number of pipelines, one in this case, and the length of the pipeline (miles). This translates to a capital investment cost for the 160.9 km (100 miles) of CO_2 pipeline equal to $77,020,185. The fixed O&M costs were determined using the following assumptions:

1. There is one full-time laborer per 160.9 km (100 miles) of pipeline being paid $15.05 per hour for 2,080 hours per year.
2. General and administrative (G&A) labor is considered to be equal to 50 percent of the labor costs (one full-time laborer per 160.9 km [100 miles]).
3. Other O&M costs are equal to four percent of the total annual capital investment.

Total fixed O&M costs were calculated by adding G&A labor and other O&M costs together. These costs totaled $3,096,459. Labor is considered a stand-alone fixed cost and equals $31,304. **Table 2-15** summarizes the CO_2 pipeline capital and O&M costs.

Table 2-15 Summary of CO2 Pipeline Capital and Fixed Costs

CO_2 Pipeline	SCPC w/ CCS
Material Cost ($/mile)	$175,255.85
Labor Cost ($/mile)	$366,566.20
Misc Costs ($/mile)	$183,971.70
Land Costs ($/mile)	$44,408.10
Total CO_2 Pipeline Capital Costs ($/100 miles)	$77,020,185
Labor (Annual)	$31,304.00
G&A Labor (Annual)	$15,652.00
Other O&M Costs (Annual)	$3,080,807
Total O&M Costs (Annual)	$3,096,459
Total Length of Pipeline (miles)	100

CO_2 Sequestration

Both construction and operation economic costs will be modeled for CO_2 injection and sequestration into a geologic saline formation. Costs related to the CO_2 injection well were determined based on the LCOE calculation spreadsheet model used for the Baseline. For the SCPC case with CCS, it is assumed that two, 1,239-meter (4,065-ft) wells will be used to store CO_2. This well will be injected daily with 9,063 tonnes (10,318 tons) of CO_2. According to this model, total capital costs for the project equals $7.7 million. Capital costs include the siting, well construction, installation of

equipment, and other miscellaneous costs including project and process contingency. Fixed operating costs, including normal daily expenses and maintenance on the surface and subsurface, have a total cost of $202,476 per year. The variable operating costs equal $44,383.

Monitoring costs are not included in the injection well costs; rather, these costs will be determined based on the amount of CO_2 sequestered per year and the monitoring costs found within the Baseline Report, $0.176/kWh. There is no capital costs included in the monitoring costs, only O&M costs.

2.4.2 LCC Data Results

Figure 2–15 presents the LCOE on a delivered energy basis for the SCPC with CCS. The SCPC facility portion of the LCOE totaled $0.0919/kWh, which equals the NETL Baseline result of $0.0855/kWh when the 7% distribution loss is not applied. As with the case without CCS, the SCPC energy conversion facility accounts for the majority of the costs for the case LC. The capital costs contribute the majority of the costs when analyzed by cost component. The SCPC energy conversion facility is equal to $0.0914/kWh, whereas the switchyard/trunkline and decommissioning of the system contribute $0.0021/kWh and $0.0006/kWh to the LC levelized capital costs. Decommissioning costs were not included in the Baseline Report, but 10 percent of the capital cost was attributed to decommissioning, a common assumption in the literature (Hill, O"Keefe *et al.*, 1995; Odeh and Cockerill, 2008; Gorokhov, Manfredo *et al.*, 2002). The decommissioning cost determination included the switchyard/trunkline and carbon capture system, and was only applied to capital costs; no data were available to make additional assumptions. Utility costs including coal feedstock, natural gas fuel for the auxiliary boiler and process water accounts for $0.0302/kWh, followed by contributions of $0.0134/kWh and $0.0199/kWh from variable O&M and labor costs.

The CO_2 TS&M costs include capital and O&M costs for the CO_2 pipeline and injection wells as well as the O&M costs for monitoring. Capital costs for the CO_2 TS&M are equal to $0.0042/kWh, whereas labor and variable O&M are equal to $0.0001/kWh and $0.0012/kWh. The capital costs for the CO_2 capture equipment are included in the SCPC energy conversion facility cost, as calculated in the Baseline Report. The total LC LCOE for the SCPC case with CCS is equal to $0.1630/kWh.

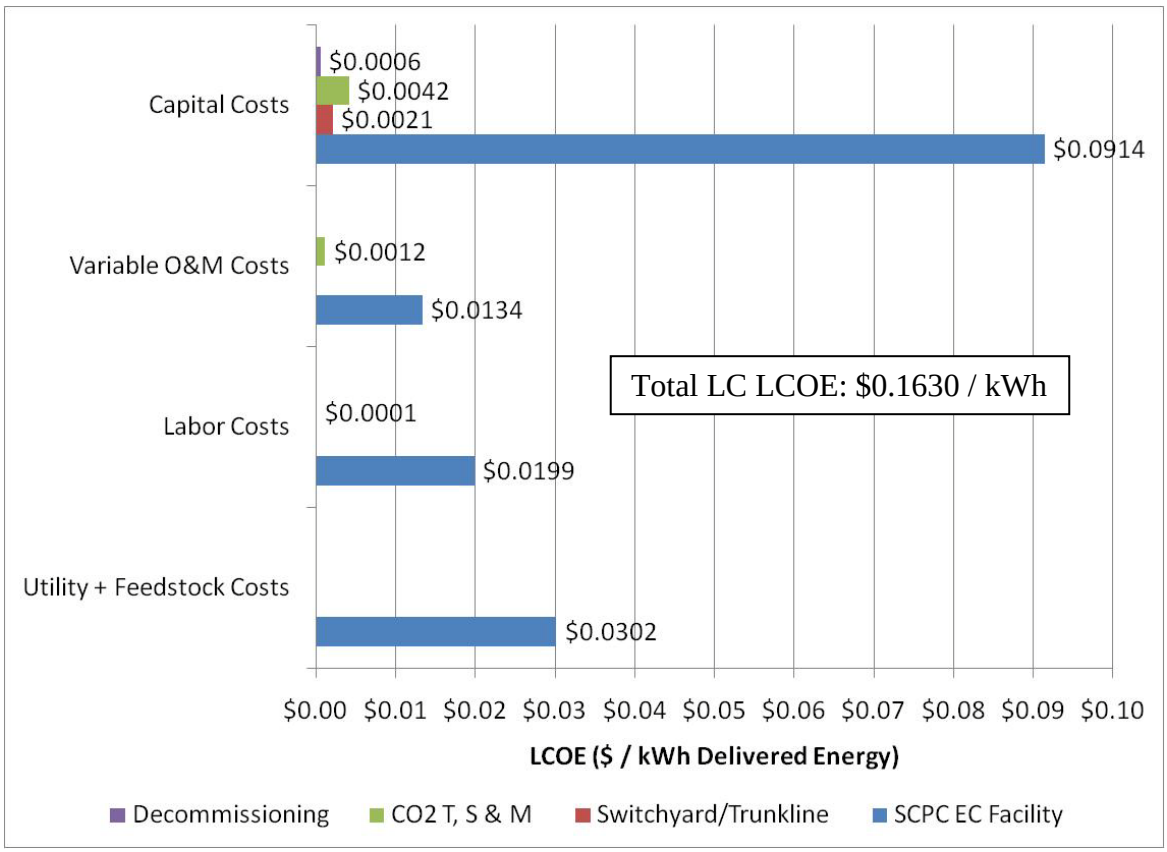

Figure 2–15 LCOE for SCPC Case with CCS

1. SCPC EC facility represents the energy conversion facility alone.
1. CO_2 TS&M represents the transportation, sequestration, and monitoring of the CO_2.
2. The labor cost for CO_2 TS&M are small and therefore are not represented on the chart with a bar, only the value of $0.00001/kWh appears on the chart.
3. All calculations are based on an 85 percent capacity factor and include a seven percent electricity loss during transmission.

TPC (total plant cost) includes the cost of equipment, materials, labor, engineering and construction management, and contingencies related to the construction of a facility. It does not include owner's costs, such as the acquisition of land, licenses, or administrative costs. In this study the capital costs include those of the energy conversion facility, switchyard and trunkline, and decommissioning activities. In the cases for CCS, the capital costs also include the CO_2 pipeline and injection well. The TPC for the SCPC facilities are normalized to the basis of net power output, which is 550 MW for the SCPC facility and 550 MW for the SCPC facility with CCS. (Net power output does not account for the capacity factor of the energy conversion facility or the transmission loss of electricity.) The TPC of the base SCPC facility is $2,319/kW; 87 percent of this TPC is related to the energy conversion facility, and the balance is related to the switchyard and trunkline and decommissioning activities. The TPC of the SCPC facility with CCS is $4,199/kW, which is 81 percent higher than the base SCPC facility. For the SCPC facility with CCS, 85 percent of the TPC is related to the energy conversion facility, 3.8 percent is related to the CO_2 pipeline and injection well, and the balance is related to the switchyard and trunkline and decommissioning activities. The TPC of the SCPC facilities are presented in **Figure 2–16**.

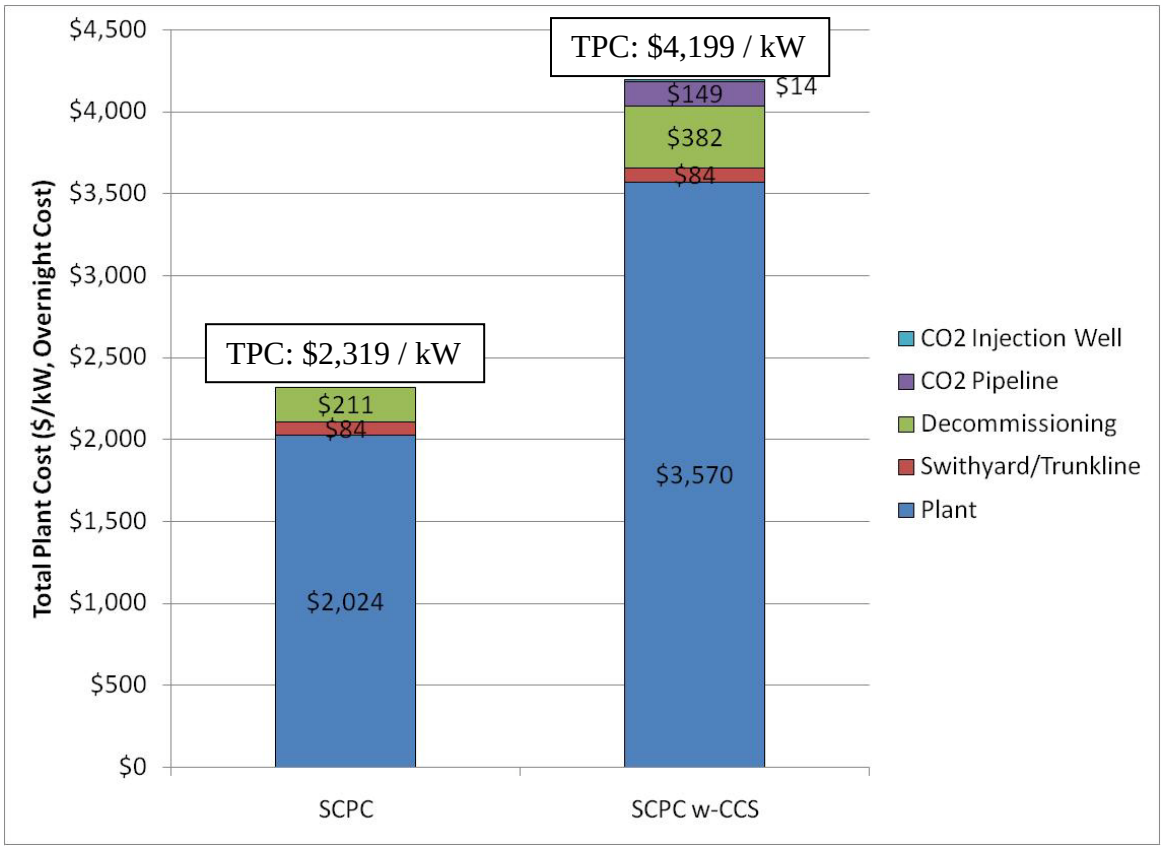

Figure 2–16 TPC ($/kW) for SCPC Case without CCS

2.4.3 Greenhouse Gas Emissions

Table 2-16 and **Figure 2–17** show the GHG emissions associated with the SCPC with CCS plant, on an MWh plant output basis. CO_2 is still the dominant GHG pollutant, with the largest emissions associated with the combustion of coal. However, the addition of CCS reduces the magnitude of those emissions by a nominal 90 percent (NETL, 2010). An additional phase, pipeline C/D is included; a very small amount (less than one percent of the total on both a mass [kg] and kg CO_2e basis) of additional GHG emissions are associated with that process. The total GWP of Stage #3 with CCS is 141.9 kg CO_2 equivalents per MWh plant output.

Table 2-16 SCPC with CCS Stage #3, GHG Emissions (kg and kg CO2e) /MWh Plant Output

Emissions (per MWh)	Plant Construction		Pipeline C/D		Plant C/D		Plant Operations with CCS		Total	
	Mass (kg)	kg CO_2e	Mass (kg)	kg CO_2e	Mass (kg)	kg CO_2e	Mass (kg)	kg CO_2e	Mass (kg)	kg CO_2e
CO_2	1.33	1.33	3.6E-02	3.6E-02	5.4E-02	5.4E-02	140.36	140.36	141.78	141.78
N_2O	4.6E-05	1.4E-02	7.1E-07	2.1E-04	1.3E-06	4.0E-04	3.7E-06	1.1E-03	5.2E-05	1.5E-02
CH_4	1.1E-03	2.7E-02	3.6E-05	9.0E-04	6.7E-05	1.7E-03	7.6E-04	1.9E-02	1.9E-03	4.9E-02
SF_6	9.7E-12	2.2E-07	1.3E-14	2.9E-10	2.4E-14	5.4E-10	3.5E-07	8.1E-03	3.5E-07	8.1E-03
Total GWP		1.37		0.04		0.06		140.39		141.85

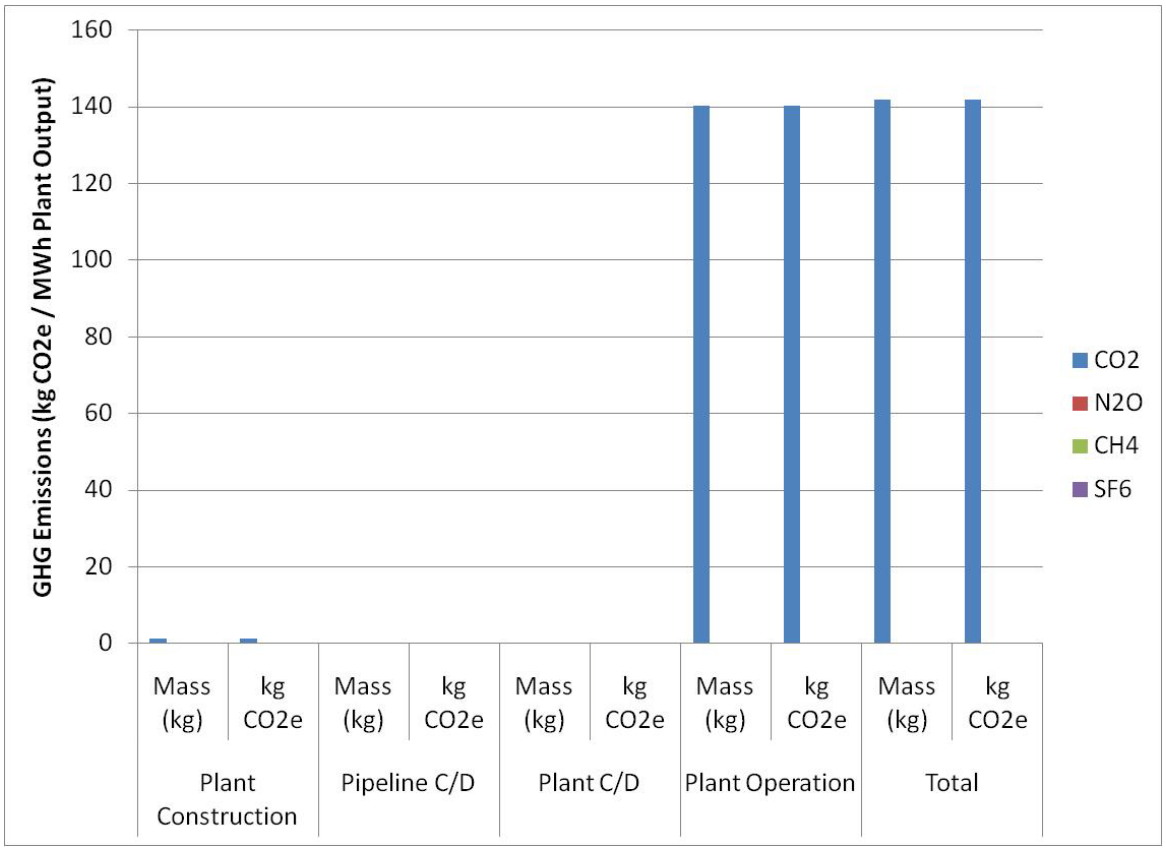

Figure 2–17 SCPC with CCS Stage #3, GHG Emissions (kg and kg CO2e) /MWh Plant

2.4.4 Air Pollutant Emissions

Table 2-17 and **Figure 2–18** show the air pollutants released during SCPC plant operations on a per MWh output basis. As with GHGs, emissions are dominated by the combustion of coal during plant operation. These emission values reflect the use of best practice emissions control technologies for SO_X, NO_X, PM, and Hg as outlined in the Baseline Report (NETL, 2010). An interesting co-benefit to the addition of the CO_2 capture system is that most of the remaining SO_X is also absorbed by the Econamine solvent (NETL, 2010).

SCR, NH_3, and a catalyst are used to control NO_X, and as the catalyst degrades, NH_3 is released to the stack (Mack and Patchett, 1997). The NH_3 emissions shown in **Table 2-17** for SCPC plant operations are a result of this slip, which is reported as 2 ppmv NH_3 at the end of catalyst life (NETL, 2010). Less than one percent of air emissions are associated with pipeline commissioning/decommissioning (C/D).

Table 2-17 SCPC with CCS Stage #3 Air Emissions, kg per MWh Plant Output

Emissions (kg/MWh)	Plant Construction	Pipeline C/D	Plant C/D	Plant Operations with CCS	Total
Pb	1.89E-06	1.51E-10	2.81E-10	4.79E-05	4.98E-05
Hg	8.75E-08	1.40E-11	2.62E-11	7.63E-06	7.72E-06
NH_3	1.51E-06	1.07E-06	2.00E-06	2.95E-03	2.95E-03
CO	7.30E-03	1.19E-04	2.22E-03	4.06E-04	1.00E-02
NO_X	2.56E-03	3.41E-04	8.15E-04	4.41E-01	4.45E-01
SO_X	4.36E-03	1.34E-05	4.51E-05	1.08E-02	1.52E-02
VOC	1.36E-04	2.43E-05	2.11E-04	2.13E-05	3.92E-04
PM	1.25E-03	6.56E-05	1.08E-04	8.20E-02	8.35E-02

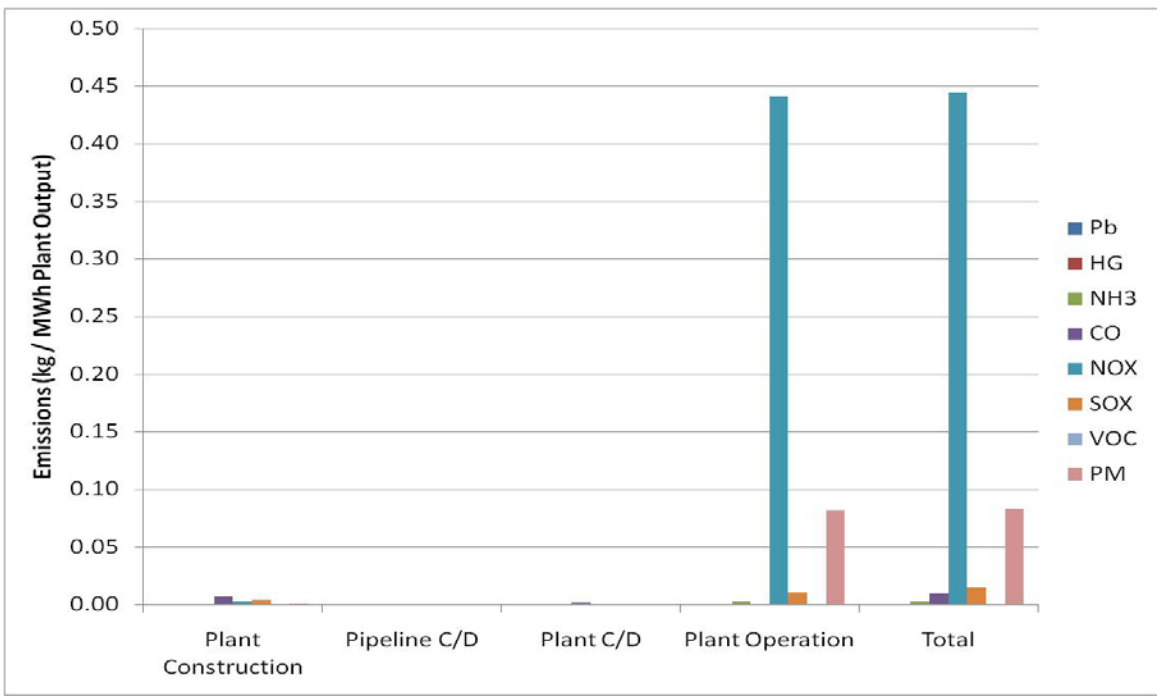

Figure 2–18 SCPC with CCS Stage #3 Air Emissions, kg/MWh Plant Output

1. C/D is an acronym for commissioning/decommissioning.

2.4.5 Water Withdrawal and Consumption

Table 2-18 shows water withdrawal and consumption for the SCPC plant with CCS. As with the case without CCS, the most water is consumed during plant operation due to

cooling water evaporation. Water withdrawal and consumption during decommissioning is due to the LC impacts of diesel fuel.

Table 2-18 SCPC with CCS Stage #3 Water Withdrawal and Consumption, kg/MWh Plant Output

Water(kg/MWh)	Plant Construction	Pipeline C/D	Plant C/D	Plant Operation	Total
Water Withdrawal	7.92	0.01	0.13	4341	4349.06
Wastewater Outfall	1.93	0.006	0.01	909.11	911.06
Water Consumption	5.99	0.004	0.12	3431.89	3438.00

2.5 Life Cycle Stages #4 & #5: Product Transport and End Use

Once the electricity is produced and sent through the switchyard and trunkline system it is ready for transmission, via the grid, to the user. A seven percent loss in electricity during transmissions was assumed for all the NETL power LCA studies (Bergerson, 2005; EIA, 2007b). This loss only impacts the cost parameters as no environmental inventories are associated with transmission loss. The transmission line was considered existing infrastructure, therefore, the construction of the line, along with the associated costs, emissions, and land use changes, was not included within the system boundaries for this study.

However, SF_6 leakage does occur due to circuit breakers used through the U.S. transmission line system and was therefore included in the Stage #4 inventory. An average leakage rate of 1.4×10^{-4} kg SF_6/MWh was calculated based on 2007 leakage rates reported by the EPA SF_6 Emission Reduction Partnership (EPA, 2007); additional consideration was given to leakage by companies outside the partnership to calculate the assumed leakage rate. SF_6 leakage during Stage #4 was calculated at 1.4×10^{-4} kg/MWh (plant output minus transmission loss).

As with Stage #1 and Stage #2, costs associated with transmission losses are included with the LC Stage #3 results. Costs are based on an electricity output that considers both the 85 percent capacity factor of both SCPC plants and the seven percent loss during transmission.

Finally, in LC Stage #5, the electricity is delivered to the end user. All NETL power generation LCA studies assume electricity is used by a non-specific, 100 percent efficient process. This assumption avoids the need to define a unique user profile and allows all power generation studies to be compared on equal footing. Therefore, no environmental inventories or cost parameters were collected for Stage #5.

3. Interpretation of Results

The following sections report comparative assessment results over the complete LC for both cases considering GWP impact, LCC results, and quantification of total outputs for all other LCI metrics. In addition, this section will report the results of sensitivity analysis.

3.1 LCI results: SCPC without CCS

Table 3-1 summarizes all water withdrawals, consumption, and emissions from the SCPC case without CCS, in kg/MWh, for each stage and the total LC. No environmental impacts are associated with Stage #5. Similarly, only GHG emissions associated with SF_6 leakage are included in Stage #4. Therefore, Stage #5 will not be discussed further, and Stage #4 will only be included when discussing GHG emissions.

Table 3-1 Water and Emissions Summary for SCPC without CCS

Parameters	Stage #1: Raw Material Acquisition	Stage #2: Raw Material Transport	Stage #3: Energy Conversion (without CCS)	Stage#4: Product Transport	Stage #5: End User	Total
GHG Emissions kg/MWh						
CO_2	2.8	4.7	863.8	0	0	871.2
N_2O	4.4E-05	1.3E-05	3.2E-05	0	0	8.9E-05
CH_4	2.7	6.0E-03	1.5E-03	0	0	2.8
SF_6	6.5E-11	2.1E-11	3.3E-07	1.4E-04	0	1.4E-04
Air Pollutants (non GHG) kg/MWh						
Pb	2.9E-07	9.2E-08	4.5E-05	0	0	4.6E-05
Hg	4.3E-08	7.0E-09	4.5E-06	0	0	4.5E-06
NH_3	2.4E-05	1.7E-04	2.4E-03	0	0	2.6E-03
CO	3.4E-03	1.5E-02	7.0E-03	0	0	2.5E-02
NO_X	5.1E-03	1.2E-02	3.0E-01	0	0	3.2E-01
SO_X	1.4E-02	3.2E-03	3.7E-01	0	0	3.8E-01
VOC	1.0E-04	1.1E-03	3.0E-04	0	0	1.5E-03
PM	8.8E-04	1.5E-02	5.6E-02	0	0	7.2E-02
Water Withdrawal and Consumption kg/MWh						
Water Withdrawal	148.5	3.0	2363.4	0	0	2515.0
Wastewater Outfall	738.0	2.1	483.2	0	0	1223.3
Water Consumption[2]	-589.5	1.0	1880.2	0	0	1291.7

[2] For the coal mine operations, water output includes storm water and a small amount of sanitary wastewater (EPA, 2008a), which equals more than the water input and therefore gives a negative value for the overall water consumed. This value does not mean that the mining process creates water, only that storm water is processed during operation.

3.1.1. Greenhouse Gas Emissions

Table 3-2 and **Figure 3–1** show the GHG emissions associated with the SCPC plant operations without CCS in kg CO_2e per MWh delivered to the end user. Although some CH_4 is emitted during Stage #1, the CO_2 emissions during Stage #3 dominant the LC.

Table 3-2 SCPC without CCS GHG Emissions, kg CO2e/MWh Delivered Energy

Emissions (kg CO_2e MWh)	Stage #1: Raw Material Acquisition	Stage #2: Raw Material Transport	Stage #3: Energy Conversion (without CCS)	Stage #4: Product Transport	Total
CO_2	2.8	4.7	863.8	0	871.2
N_2O	1.3E-02	3.9E-03	9.4E-03	0	2.6E-02
CH_4	68.7	0.1	0.0	0	68.9
SF_6	1.5E-06	4.7E-07	7.5E-03	3.3	3.3
Total GWP	71.6	4.8	863.8	3.3	943.5

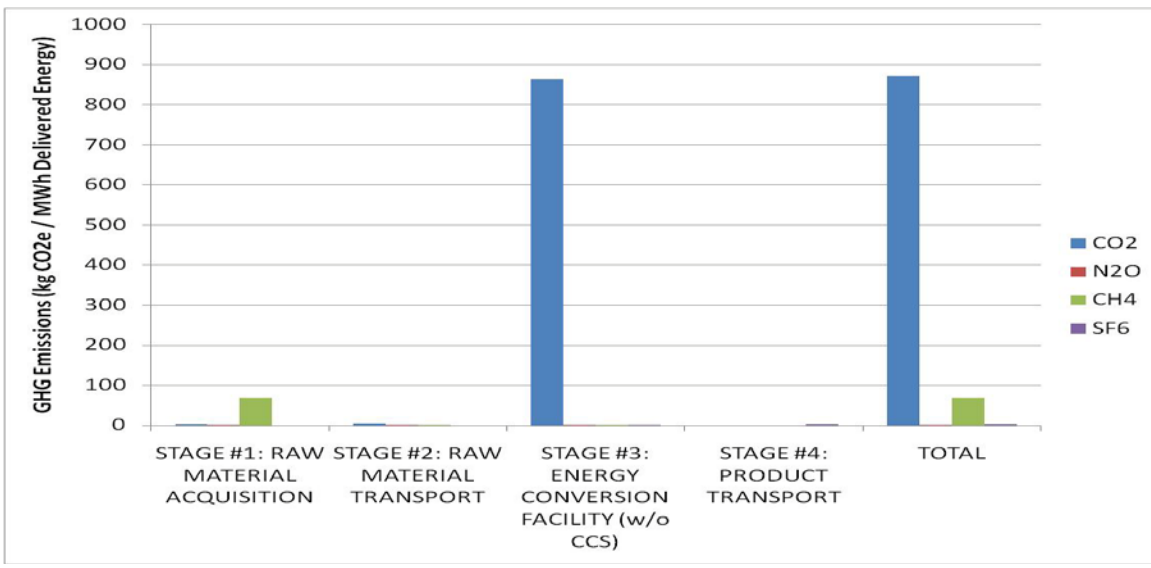

Figure 3–1 SCPC without CCS GHG Emissions, kg CO2e/MWh Delivered Energy

The total GWP of SCPC without CCS is 944 kg CO_2e per MWh delivered energy. Of those 944 kg CO_2e, 92.3 percent is due to CO_2 emissions. CH_4 accounts for 7.3 percent, while SF_6 accounts for the remaining 0.3 percent. N_2O accounts for less than 0.01 percent of the total GWP. Approximately 92 percent of the total GWP is attributable to activities in Stage #3.

3.1.2. Air Emissions

When compared to GHG emissions, particularly CO_2, all other air emissions are emitted on a much smaller scale. This is due mainly to the regulations placed on all criteria and hazardous air emissions; because all operations assume best practice management of emissions, most operations include some control measures. Although the scope of this

study focuses on only the inventory of these emissions and conclusions are drawn only on a mass-emitted basis, further conclusions could be drawn using available impact assessment methodologies (Bare, Norris *et al.*, 2003; SCS, 2008). **Figure 3–2** shows the air pollutant emissions (kg/MWh delivered) for the SCPC case without CCS.

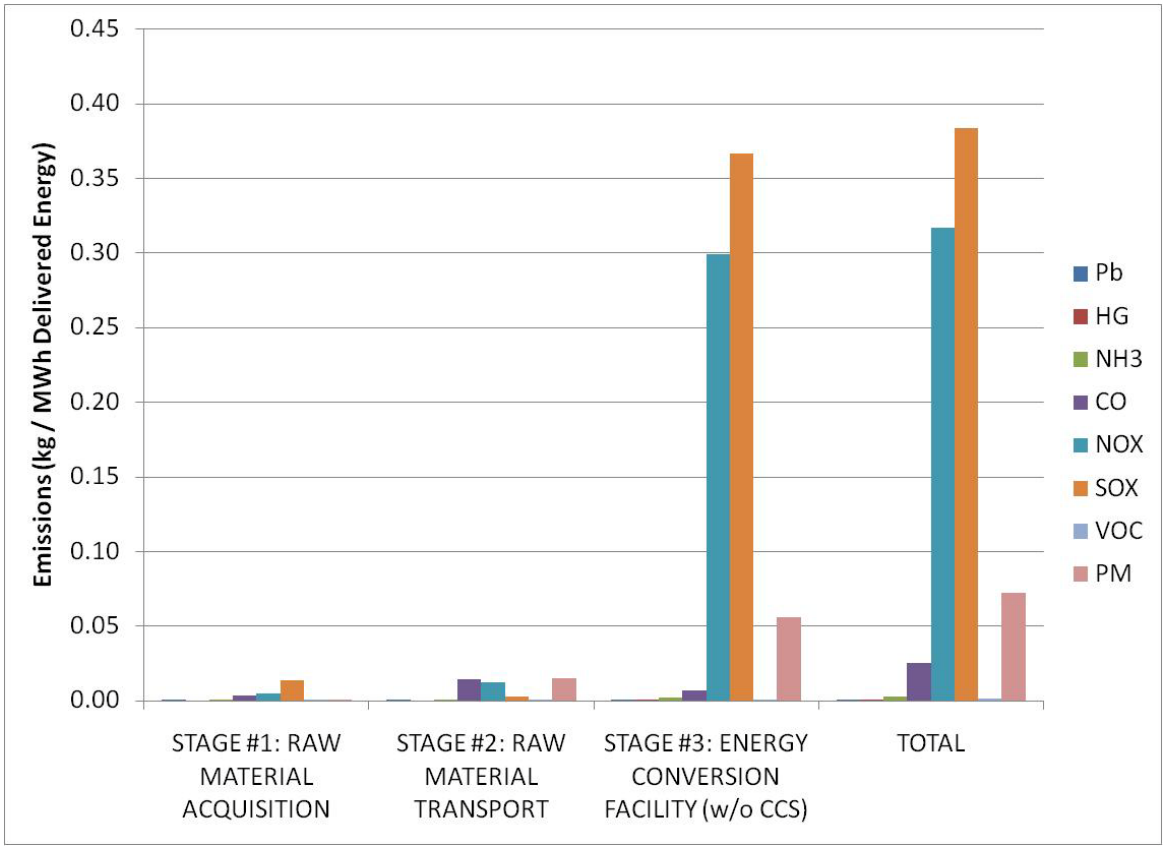

Figure 3–2 SCPC without CCS Air Emissions, kg/MWh Delivered Energy

The dominant air pollutant for SCPC without CCS is SO_X and NO_X released during coal conversion (Stage #3). PM emissions are dominated by energy conversion, with a small contribution from coal dust lost during train transport. NH_3 and volatile organic compounds (VOCs) contribute 0.3 and 0.4 percent to overall (non-GHG) air emissions, respectively; lead (Pb) and Hg both contribute less than 0.01 percent.

3.1.3. Water Withdrawal and Consumption

Figure 3–3 shows the total water input and water consumed for each stage and the total LC.

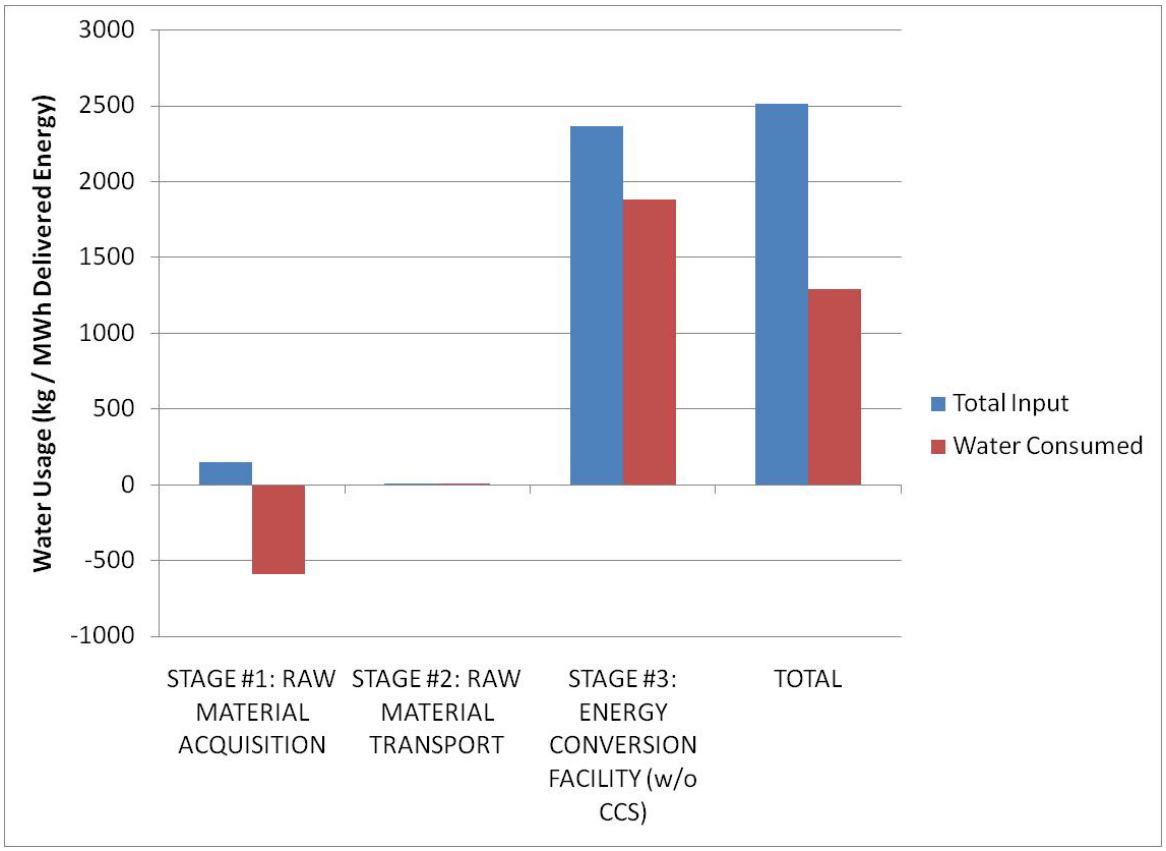

Figure 3–3 SCPC without CCS Water Withdrawal and Consumption, kg/MWh Delivered Energy

Water withdrawal and consumption is dominated by energy conversion (Stage #3) due to cooling water requirements in the power plant. The negative value for water consumed during raw material acquisition (Stage #1) is due to the additional output of storm water and is not due to water production during processes such as mining and coal cleaning. The amount of storm water processed by mine waste water treatment affects the energy use and pollutant emissions during operation and is therefore important to consider.

3.2 LCI results: SCPC with CCS

Table 3-3 summarizes all water withdrawals and emissions from the SCPC case with CCS, in kg/MWh, for each stage and the total LC. As with the case without CCS, no environmental impacts are associated with Stage #5. Similarly, only GHG emissions associated with SF_6 leakage are included in Stage #4. Therefore, Stage #5 will not be discussed further, and Stage #4 will only be included when discussing GHG emissions.

Table 3-3 Water and Emissions Summary for SCPC with CCS

Parameters	Stage #1: Raw Material Acquisition	Stage #2: Raw Material Transport	Stage #3: Energy Conversion (with CCS)	Stage #4: Product Transport	Stage #5: End User	Total
GHG Emissions kg/MWh						
CO_2	3.9	6.4	131.9	0.0	0.0	142.2
N_2O	6.1E-05	1.8E-05	4.8E-05	0	0	1.3E-04
CH_4	3.8	8.2E-03	1.8E-03	0	0	3.8
SF_6	9.0E-11	2.9E-11	3.3E-07	1.4E-04	0	1.4E-04
Air Pollutants (non GHG) kg/MWh						
Pb	4.0E-07	1.3E-07	4.6E-05	0	0	4.7E-05
Hg	6.0E-08	9.7E-09	7.2E-06	0	0	7.2E-06
NH_3	3.3E-05	2.3E-04	2.7E-03	0	0	3.0E-03
CO	4.7E-03	2.0E-02	9.3E-03	0	0	3.4E-02
NO_X	7.1E-03	1.7E-02	4.1E-01	0	0	4.4E-01
SO_X	1.9E-02	4.4E-03	1.4E-02	0	0	3.8E-02
VOC	1.4E-04	1.6E-03	3.6E-04	0	0	2.1E-03
PM	1.2E-03	2.1E-02	7.8E-02	0	0	1.0E-01
Water Withdrawal and Consumption kg/MWh						
Water Withdrawal	205.2	4.2	4478.5	0.0	0.0	4687.9
Wastewater Outfall	1019.7	2.9	1034.6	0.0	0.0	2057.2
Water Consumption	-814.5	1.3	3443.8	0.0	0.0	2630.7

3.2.1 Greenhouse Gas Emissions

Table 3-4 shows the GHG emissions from **Table 3-3** based on kg CO_2e.

Table 3-4 SCPC with CCS GHG Emissions, kg CO2e/MWh Delivered Energy

Emissions (kg CO_2e/MWh)	Stage #1: Raw Material Acquisition	Stage #2: Raw Material Transport	Stage #3: Energy Conversion (with CCS)	Stage #4: Product Transport	Total
CO_2	3.9	6.4	131.9	0	142.2
N_2O	1.8E-02	5.4E-03	1.4E-02	0	3.8E-02
CH_4	95.0	0.2	0.0	0	95.2
SF_6	2.0E-06	6.6E-07	7.5E-03	3.3	3.3
Total GWP	98.9	6.7	131.9	3.3	240.7

The total GWP for SCPC with CCS is 240.7 kg CO_2e per MWh delivered energy. **Figure 3–4** compares the GHG emissions for each stage. A total of 59 percent of the GWP is attributable to CO_2 emissions, while 39.5 percent is due to CH_4 emissions released during raw material extraction (Stage #1). Although SF_6 has the largest GWP potential, the small mass emittance translates to only a 1.4 percent impact on the overall GHG emissions. N_2O attributes less 0.1 percent to the total GWP of this case. On a stage basis, 55 percent of the GWP is from Stage # 3 and 42 percent is from Stage #1.

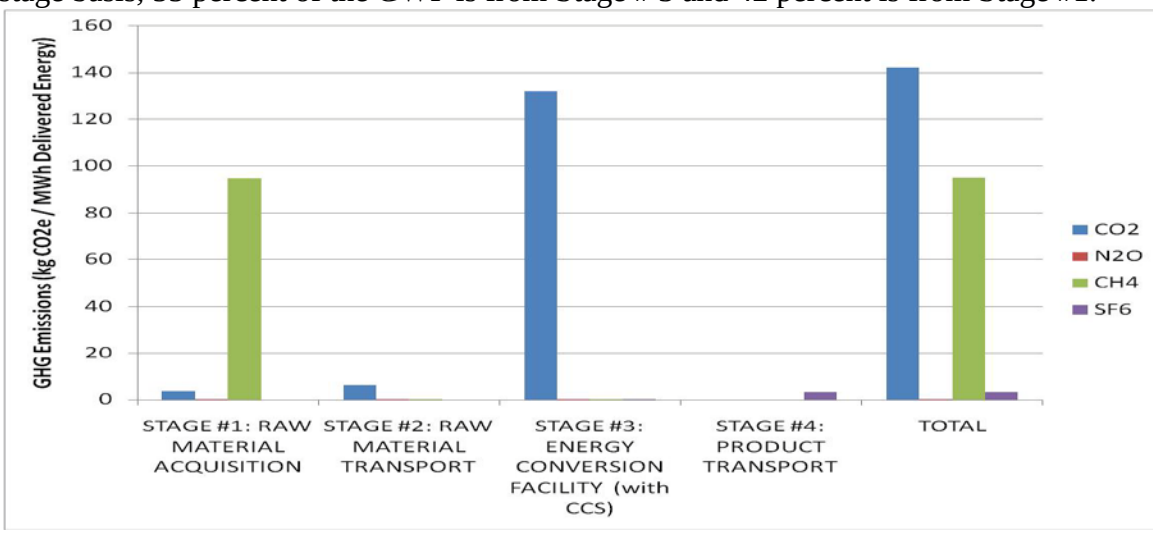

Figure 3–4 SCPC with CCS GHG Emissions, kg CO2e/MWh Delivered Energy

3.2.2 Air Emissions

Figure 3–5 compares the air emissions for each stage and the total LC. The dominant air pollutant for SCPC with CCS is NO_X, which is formed during combustion reactions. CO, NO_X, and SO_X are all emitted during fuel combustion in all stages; however, total SO_X is significantly lower that NO_X for this case due to the additional absorption of SO_X in the Econamine system during energy conversion (Stage #3). PM emissions are dominated by

energy conversion, with a small contribution from coal dust lost during train transport (Stage #2). NH_3 and VOCs contribute 0.5 and 0.7 percent to overall (non-GHG) air emissions, respectively; Pb and Hg both contribute less than 0.02 percent.

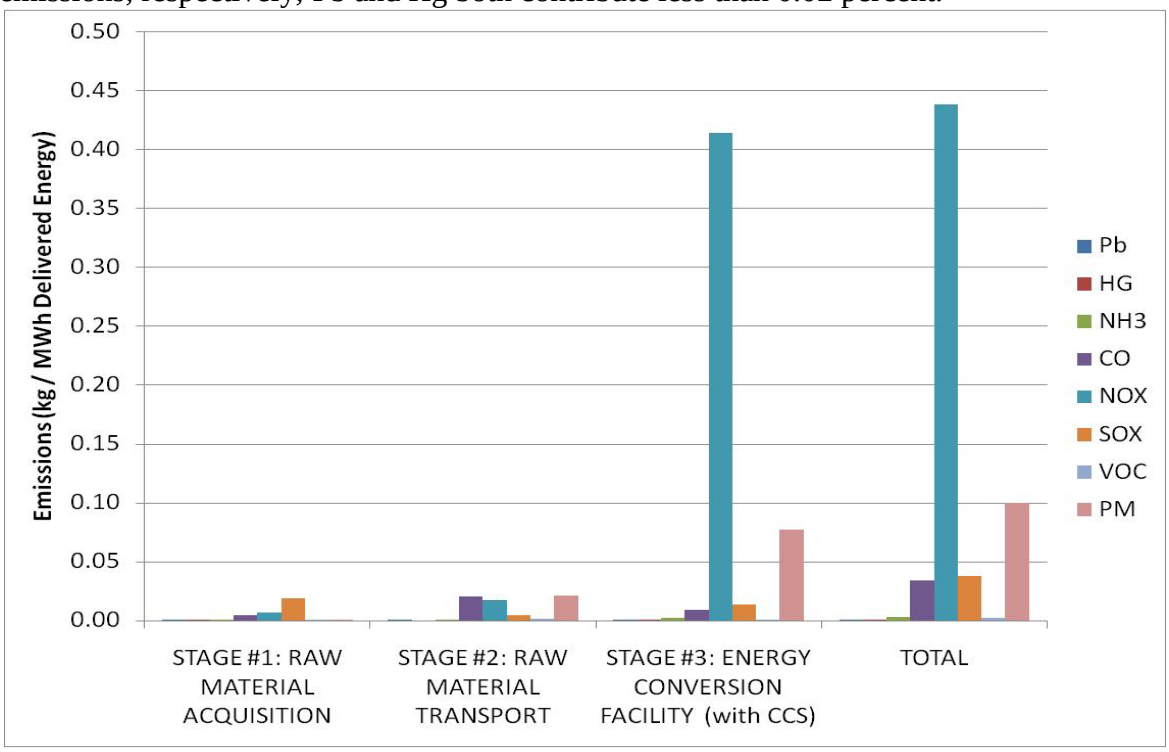

Figure 3–5 with CCS Air Emissions, kg/MWh Delivered Energy

3.2.3. Water Withdrawal and Consumption

Figure 3–6 shows the total water withdrawal and consumption for each stage and the total LC.

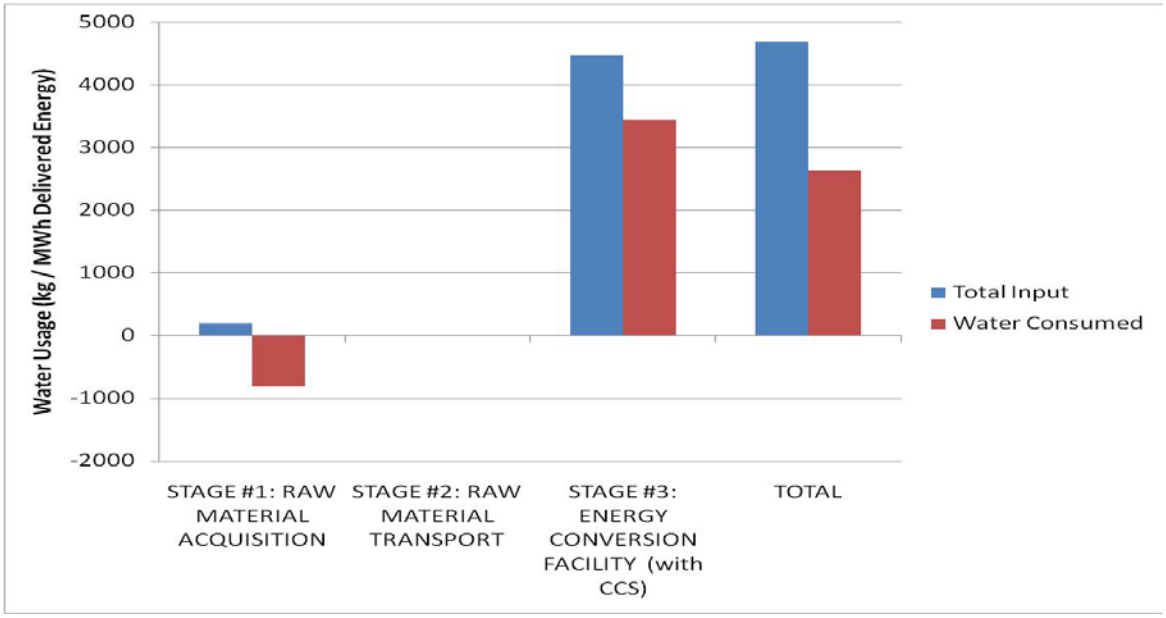

Figure 3–6 SCPC with CCS Water Withdrawal and Consumption, kg/MWh Delivered Energy

Water withdrawal and consumption is dominated by energy conversion (Stage #3) due to cooling water requirements in the power plant. Additional, the CCS operation requires more water because the flue gas must be at a lower temperature to enter the amine capture facility. As with SCPC without CCS, the negative value for water consumed during raw material acquisition (Stage #1) is due to the additional output of storm water and is not due to water production during the mining. The amount of storm water processed by the mines waste water treatment affects the energy use and emissions during operation, and is therefore important to consider.

3.3 Land Use Change

Analysis of land use effects associated with a process or product is considered a central component of an LCA investigation, under both ISO 14044 and American Society for Testing and Material Standards (ASTM) procedure. For the purposes of this study, land use encompasses the changes in the type or nature of activity that occurs in the land area considered within the study boundary.

3.3.1 Definition of Primary and Secondary Impacts

Land use effects can be roughly divided into primary and secondary. In the context of this study, primary land use effects occur as a direct result of the LC processes needed to produce electricity via SCPC. Primary land use change is determined by tracking the change from an existing land use type (native vegetation or agricultural lands) to a new land use that supports production; examples include coal mines, biomass feedstock cropping, and energy conversion facilities.

Secondary land use effects are indirect changes in land use that occur as a result of the primary land use effects. For instance, if the primary effect is the conversion of agriculture land to a coal mine in a rural area, a secondary effect might be the migration of coal mine employees to the mine site causing increased urbanization in surrounding areas. Due to the uncertainty in predicting and quantifying secondary effect, only primary effects are considered within the scope of this study.

3.3.2 Land Use Metrics

A variety of land use metrics, which seek to numerically quantify changes in land use, have been devised in support of LCAs. Two common metrics in support of a process-oriented LCA are transformed land area (square meters of land transformed) and GHG (kg CO_2e). The transformed land area metric estimates the area of land that is altered from a reference state, while the GHG metric quantifies the amount of carbon emitted in association with that change. **Table 3-5** summarizes the land use metrics included in this study.

Table 3-5 Primary Land Use Change Metrics Considered in this Study

Metric Title	Description	Units	Type of Impact
Transformed Land Area	Area of land that is altered from its original state to a transformed state during construction and operation of the advanced energy conversion facilities.	square meters (acres)	Primary
Greenhouse Gas Emissions	Emissions of greenhouse gases associated with land clearing/transformation.	kg CO_2e (lbs CO_2e)	Primary

For this study, the assessment of GHG emissions included those emissions that resulted from the combustion of diesel fuel during the construction of the indicated facilities, for all LC stages. Additional considerations for the GHG emissions metric have been suggested, including quantifying the amount of carbon released from vegetation and soil organic matter as a result of construction activities, or quantification of the amount of carbon that would have been sequestered had no land use change occurred (Fthenakis and Kim 2008; Canals and others 2007; Koellner and Scholz 2007). However, no standardized or widely accepted methodology has been developed to quantify these emissions, and no further consideration of these issues is provided within the framework of this study.

Additional metrics, such as potential damage to ecosystems or species, water quality changes, changes in human population densities, quantification of land quality (e.g. farmland quality), and many other land use metrics may conceivably be included in the land use analysis of an LCA. However, much of the data needed to support accurate analysis of these metrics are severely limited in availability (Canals, Bauer *et al.*, 2007; Koellner and Scholz, 2007), or otherwise outside the scope of this study. Therefore, only transformed land area is quantified for this study.

3.3.3 Methodology

As previously discussed, the land use metrics used for this analysis quantify the land area that is transformed from its original state due to construction and operation of the SCPC plant and supporting facilities. Results from the analysis are presented as per the reference flow for each relevant LC stage, or per MWh when considering the additive results of all stages.

3.3.3.1 Transformed Land Area

The transformed land area metric was assessed using satellite imagery and aerial photographs to assess and quantify the area of original state land use for agriculture, forest, or grassland. Urban, residential, and other land uses were avoided during the siting of each facility. Assumed facility locations and sizes are shown in **Table 3-6** and **Table 3-7**. The facility sizes and locations used elsewhere in this LCA were incorporated into the land transformed metric for consistency. Only LC Stage #1, Stage #2, and Stage #3 include installation of facilities in support of the SCPC pathway. No land use change occurred in LC Stage #4 and Stage #5; the transmission line infrastructure was considered existing and therefore installation (land use) was not included in the system boundary.

Table 3-6 SCPC Facility Locations and Sizes

LC Stage No.	Facility	Location
LC Stage #1	Coal Mine	Southern IL, near Galatia, IL
LC Stage #2	Rail Spur	Southern IL, near Galatia, IL
LC Stage #3	SCPC	Springfield, IL
	Trunkline	Springfield, IL
	CCS Pipeline	Springfield, IL
LC Stage #4-5	Not Considered	Not Considered

Removal of onsite existing land use was assumed to be complete (100 percent removal) for all facilities except the coal mine. Assessment of the existing Galatia Mine (Saline County, Illinois) indicated that coal cleaning facilities, wastewater treatment ponds, storage areas, loading facilities, and other facilities associated with the coal mine were distributed across the coal mine site and that approximately half of the mine site retained pre-existing land use characteristics. Therefore, the land use analysis of the coal mine assumes that half of the total mine site area would be converted from its original state land use. **Table 3-7** summarizes the facility sizes that were assumed for this analysis.

Table 3-7 Key Facility Assumptions

Facility	Total Area	Units	Key Assumptions
Coal Mine	6,916,077 (1,709)	m^2 (acres)	Based on Galatia Mine, IL; 50 percent of land area is used for facilities
Rail Spur	374,028 (92)	m^2 (acres)	126 inch track width plus additional 20 feet gravel/cleared area; 25 mile length
SCPC	121,406 (30)	m^2 (acres)	30 acres assumed based on similar plant footprints and Baseline Report
Trunkline	367,896 (91)	m^2 (acres)	30 foot width, 1 mile length
CCS Pipeline	2,452,640 (364)	m^2 (acres)	50 foot construction width, 100 mile length

Due to its proximity to the coal mine, original state land use for the rail spur was assumed to consist of the same proportion of agricultural, forest, and grassland as the coal mine site. This assumption is reasonable given generally similar original state land use types in the proximity of the coal mine site, and assuming that the rail spur would not be routed through a city or large water feature. Similarly, assessment of the original state land use for the trunkline and CCS sequestration pipeline, as applicable, were assumed to consist of the same proportion of original state land uses as the SCPC site.

Following decommissioning, it was assumed for the purposes of the land use analysis that all transformed land area would be re-seeded or planted as grassland. Results from the transformed land area analysis are reported per the relevant reference flow for each LC stage, and per one MWh electricity delivered to the consumer, assuming a seven percent grid loss.

3.3.4 Results: Transformed Land Area

Results from the analysis of land use at the coal mine site indicated three primary land use categories: forest, grassland, and agriculture. As shown in **Figure 3–7,** agriculture accounts for most of the total area (72 percent), followed by forest (26 percent), and grassland (two percent). Minor areas containing other land uses, such as roads or waterways, were allocated to one of these three categories. As previously discussed, due to its proximity to the coal mine site, the proportion of each existing land use category (e.g., proportion of agriculture/forest/grassland) for the coal mine was also applied to the rail spur.

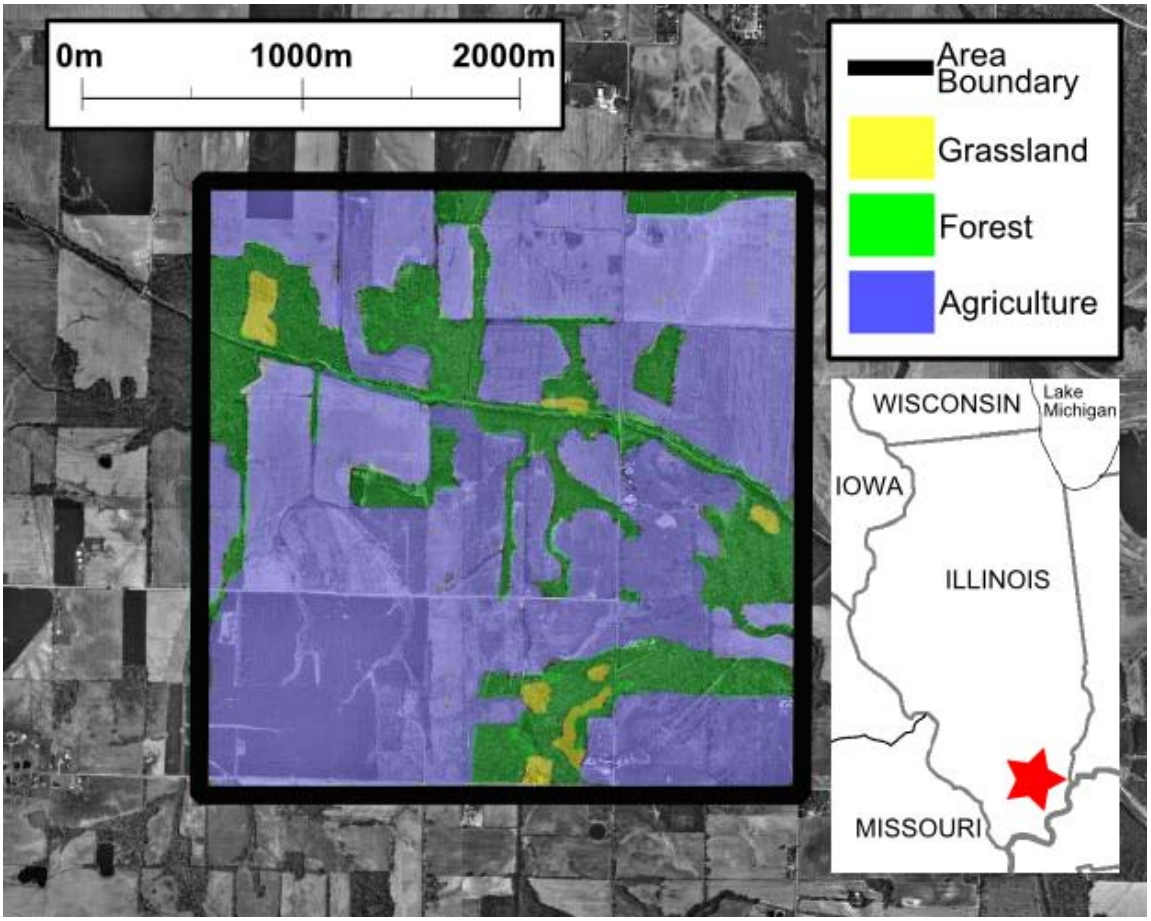

Figure 3–7 Existing Condition Land Use Assessment: Coal Mine Site

Results from the analysis of land use at the SCPC site indicated two primary land use categories: forest and agriculture. As shown in **Figure 3–8**, agriculture accounts for most of the total area (83 percent of total area), followed by forest (17 percent of total area).

Similar to the analysis at the coal mine site, small areas containing other land uses, such as roads or waterways, were allocated to one of these two categories, as relevant. As previously discussed, due to proximity to the SCPC site, the proportion of each existing land use category (e.g. proportion of forest/grassland) for the SCPC site was also applied to the trunkline and CCS pipeline.

Figure 3–8 Existing Condition Land Use Assessment: SCPC Site

The total amounts of transformed land, which includes land area associated with the coal mine, rail spur, SCPC, trunkline, and, as relevant, the CCS pipeline, are shown in **Table 3-8** and **Table 3-9**. Production at the coal mine is assumed to be constant over the lifetime of the facility (5.99 million tonnes/yr production rate), and the SCPC cases would require only a portion of the total coal mined (1.39 million tonnes/yr without CCS; 1.98 million tonnes/yr with CCS) (NETL, 2010). Therefore, transformed land area for the coal mine is calculated based on the total annual production rate of the mine, and not on the amount of coal required specifically to feed the SCPC plant. As a result, coal mine transformed land area per kg of coal produced at the coal mine does not change between the two cases (with and without CCS).

As shown, the total transformed land area per kg of coal transported along the rail spur would be less for the case with CCS than for the case without CCS. This is because more coal would be transported under the case with CCS, yet the rail spur would be the same size under both cases. The SCPC and trunkline would be the same size for the cases with and without CCS, however, the transformed land area per MWh for these two facilities would be greater for the case with CCS, because it has a lower production capacity.

Table 3-8 Total Transformed Land Area: Without CCS Case

Category		Coal Mine	Rail Spur	SCPC	Trunkline
Units per Reference Flow		m^2/kg coal produced	m^2/kg coal transported	m^2/MWh	m^2/MWh
Transformed Land Area	Grassland	3.84×10^{-7}	1.80×10^{-7}	n/a	n/a
	Forest	5.00×10^{-6}	2.33×10^{-6}	1.63×10^{-4}	4.94×10^{-4}
	Agriculture	1.38×10^{-5}	6.46×10^{-6}	8.20×10^{-4}	2.48×10^{-3}
Total Transformed Land Area		1.92×10^{-5}	8.98×10^{-6}	9.83×10^{-4}	2.98×10^{-3}

Table 3-9 Transformed Land Area: With CCS Case

Category		Coal Mine	Rail Spur	SCPC	Trunkline	CCS Pipeline
Units		m^2/kg coal produced	m^2/kg coal transported	m^2/MWh	m^2/MWh	m^2/MWh
Transformed Land Area	Grassland	3.84×10^{-7}	1.26×10^{-7}	n/a	n/a	n/a
	Forest	5.00×10^{-6}	1.64×10^{-6}	1.64×10^{-4}	4.98×10^{-4}	3.32×10^{-3}
	Agriculture	1.38×10^{-5}	4.53×10^{-6}	8.26×10^{-4}	2.50×10^{-3}	1.67×10^{-2}
Total Transformed Land Area		1.92×10^{-5}	6.29×10^{-6}	9.90×10^{-4}	3.00×10^{-3}	

3.4 Comparative Results

3.4.1 Comparative LCC Results

All parameters experience an increase in cost due to the inclusion of CCS, with variable O&M and capital costs experiencing an 70 and 82 percent increase, respectively. Utility/feedstock costs increased by 36 percent, while labor costs increased by 60 percent. Including the costs for CO_2 TS&M, the total LC LCOE for SCPC with CCS is approximately 73 percent higher than the LCOE for SCPC without CCS. A summary of the LCOE by cost component for each case is given in **Table 3-10**, and represented graphically in **Figure 3–9.**

Table 3-10 Comparison of SCPC Cases without and with CCS for LCOE

LCOE ($/kWh)	SCPC w/o CCS	SCPC w/ CCS	Percent Change
Utility Costs (Feedstock + Utilities)	$0.0222	$0.0302	36%
Labor Costs	$0.0124	$0.0199	60%
Variable O&M Costs	$0.0079	$0.0134	70%
Capital Costs	$0.0518	$0.0941	82%
CO_2 TS&M Costs		$0.0054	-
Total LC LCOE	$0.0943	$0.1630	73%

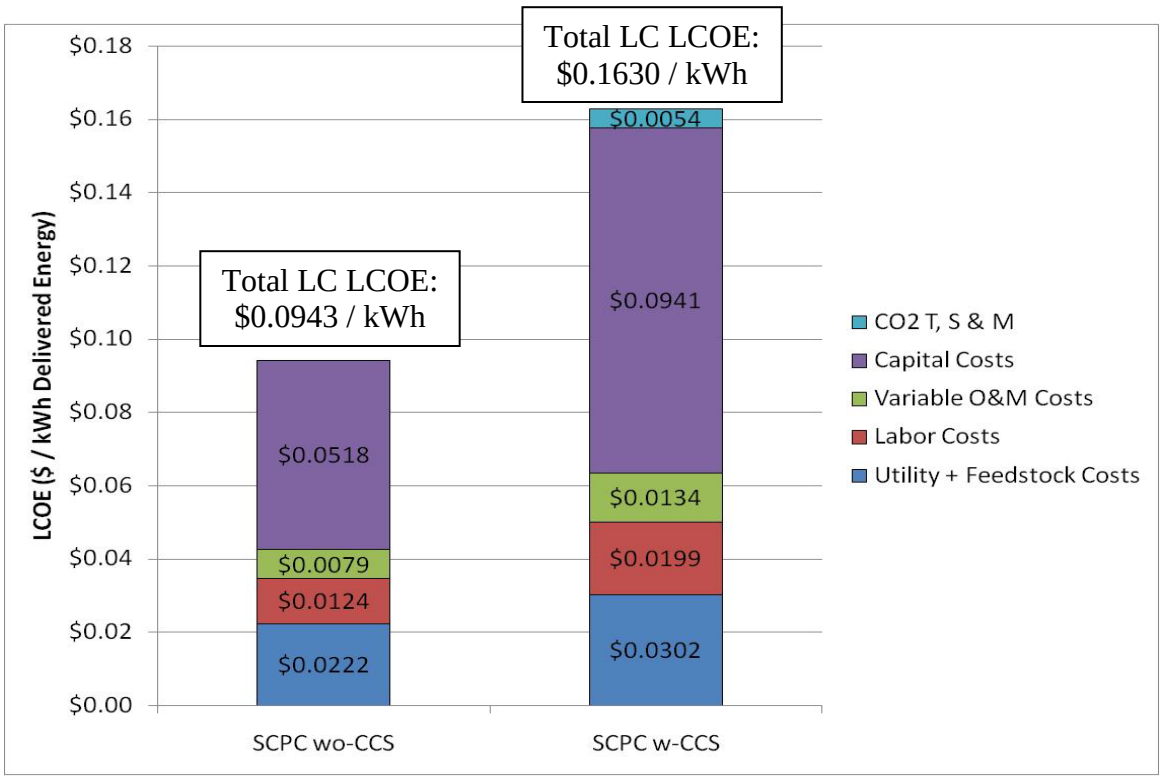

Figure 3–9 Comparative LCOE ($/kWh) for SCPC with and without CCS

3.4.1.1 Global Warming Potential

Figure 3–10 compares the GHG emissions (kg CO_2e/MWh delivered) for SCPC with and without CCS. Total LC GWP potentials are 944 and 241 for the cases without CCS and with CCS, respectively. Overall, the case without CCS has a 74 percent greater GWP than the case that utilizes CCS, even with an increase in coal consumption for the case with CCS[3] (NETL, 2010). CH_4 emissions for the case with CCS are higher due to the increased coal output during raw material acquisition (Stage #1). It is interesting to note that when considering the case with CCS, total CH_4 emissions (on a CO_2e basis) account for 40 percent of the total GHG emissions; this impact would have been ignored in GWP evaluations of only the energy generation facility. SF_6 emissions are not seen as a large

[3] To model two SCPC plants with similar MWh outputs, the Baseline Report assumes a 43 percent increase in coal input for Case 12, SCPC with CCS (NETL, 2010). Even with additional coal resources, Case 12 still outputs slightly less MWh than Case 11 (SCPC without CCS) (NETL, 2010).

contributor to the total GWP for either case, with a 1.3 percent impact with CCS (and less than one percent without CCS). Therefore, one can conclude that although SF_6 has a very large GWP (22,800 CO_2e) (IPCC, 2007), when multiplied by the small mass emitted it does not correlate to a large overall impact.

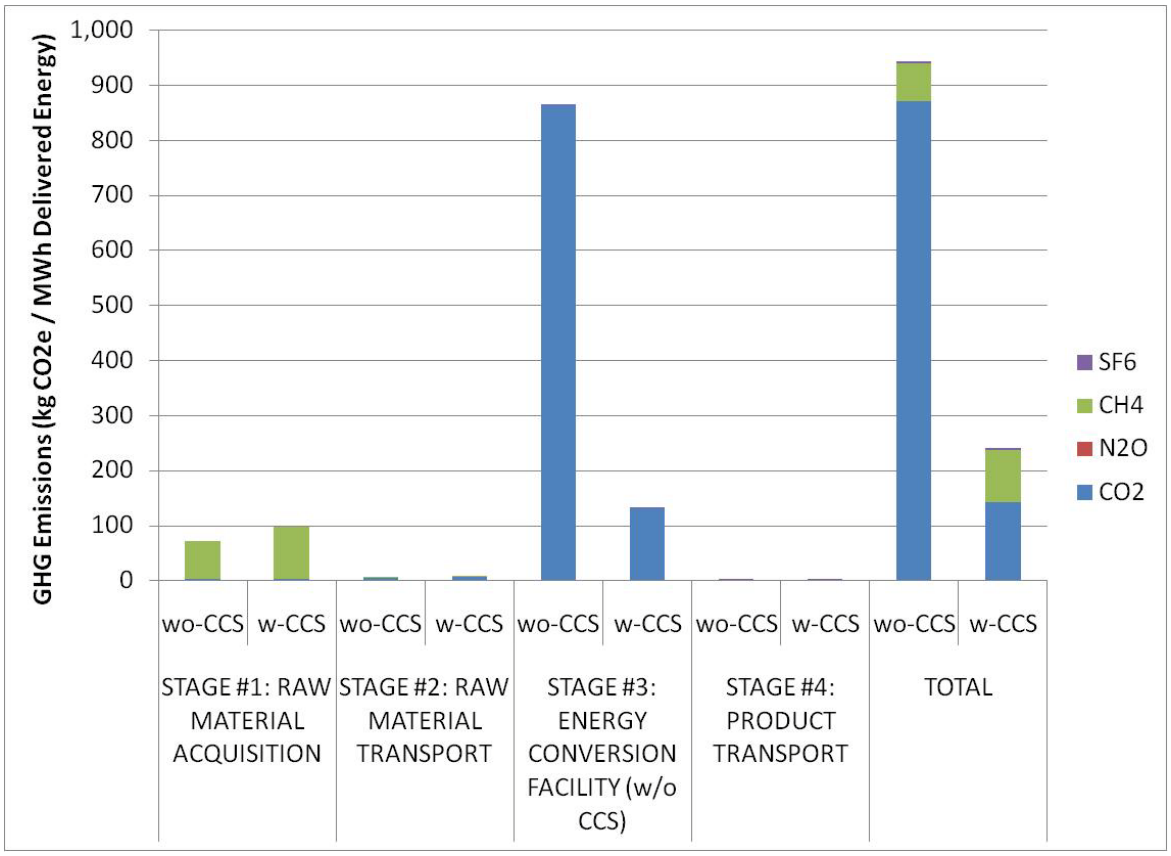

Figure 3–10 Comparative GHG Emissions (kg CO2e/MWh Delivered) for SCPC with and without CCS

3.4.1.2 Comparative Air Pollutant Emissions

Figure 3–11 compares the non-GHG air pollutants between the two cases on a kg/MWh delivered energy basis.

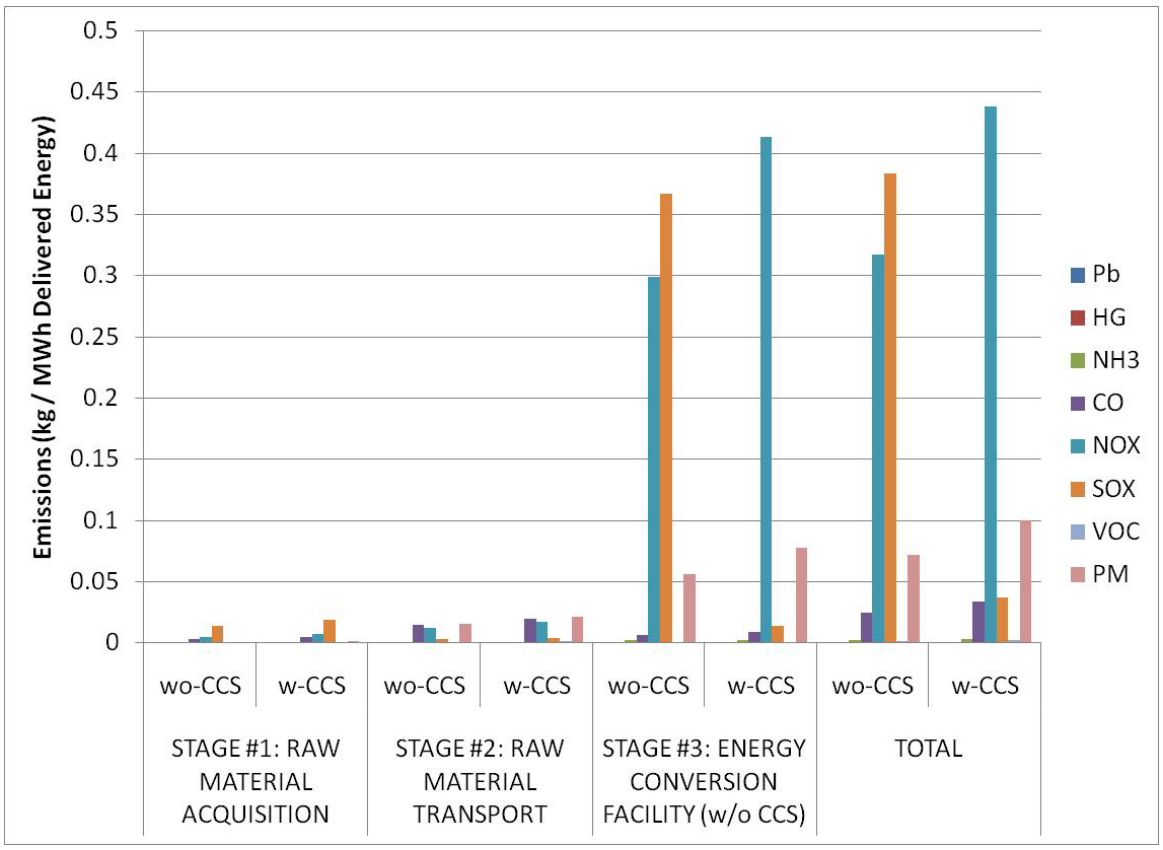

Figure 3–11 Comparison of Air Emissions (kg/MWh Delivered Energy) for SCPC with and without CCS

In addition to less GHG emissions, SCPC with CCS also has 90 percent less SO_X emissions due to an additional SO_X polishing step that is required by the Econamine system for the CO_2 capture case. This is also in spite of the additional 38 percent of coal that is combusted at lower efficiency in the SCPC case with CCS (NETL, 2010). However, the increase in coal feed coupled with the decrease in efficiency does cause an increase in NO_X, CO, and PM emissions. The addition of CO_2 pipeline C/D with CCS showed less than a one percent overall impact on additional air pollutant emissions during energy conversion (Stage #3). All other emissions (Pb, Hg, NH_3, and VOCs) contributed less than 0.8 and 1.2 percent to the total LC (non-GHG) air emissions for the cases without and with CCS, respectively.

3.4.1.3 Comparative Water Withdrawal and Consumption

Figure 3–12 compares water withdrawal and consumption for both cases.

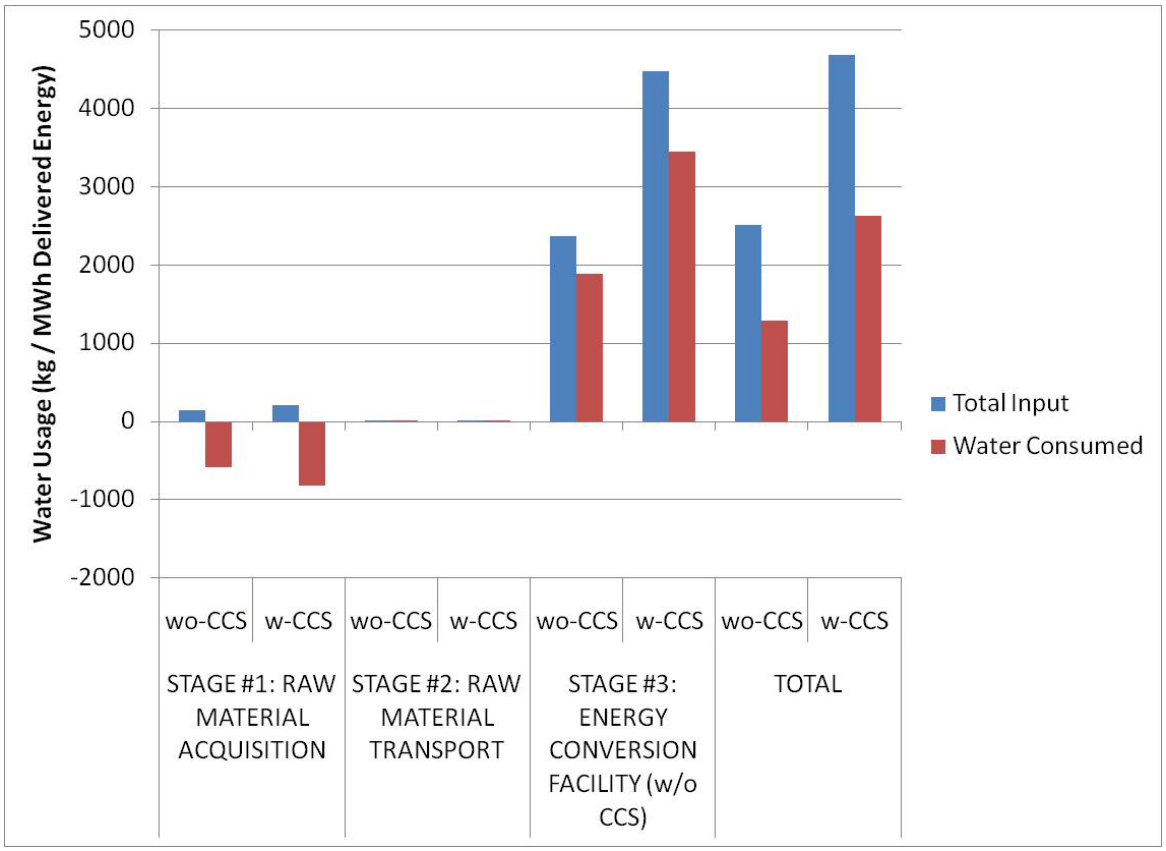

Figure 3–12 Comparative Water Withdrawal and Consumption for SCPC with and without CCS

The increase in water withdrawal (86 percent) for the case with CCS is due to additional water needs during the carbon capture process. The Econamine FG Plus process requires cooling water to reduce the flue gas temperature from 57°C to 32°C, cool the solvent (the reaction between CO_2 and the amine solvent is exothermic), remove the heat input from the additional auxiliary loads, and remove the heat in the CO_2 compressor intercoolers (NETL, 2010; Reddy, Johnson *et al.*, 2008). The SCPC case without CCS consumed 51 percent of water input while the case with CCS consumed 56 percent.

3.4.1.4 Comparative Land Use Transformation

The total transformed land area for all LC stages combined is shown in **Figure 3–13,** on a per MWh delivered basis. Land use change for the case with CCS is more than twice that of the case without CCS. This is due to the additional land area required for the CCS pipeline, as well as the parasitic load of the CCS, which results in reduced power plant output and greater feedstock requirements per MWh output. Agricultural and forest land see the most transformation as they are used for the pipeline and SCPC plant. A small amount of grassland and additional agricultural land were assumed to be used when developing the coal mine.

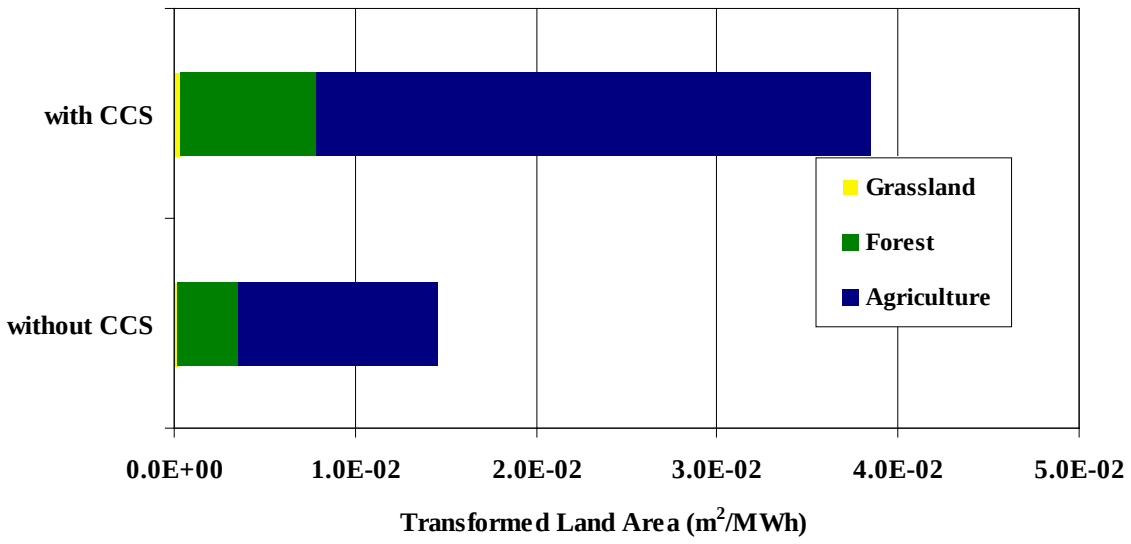

Figure 3–13 Total Transformed Land Area for SCPC with and without CCS

3.5 Sensitivity Analysis

Sensitivity analysis is a "what-if" analysis approach that identifies the impact of system parameters, including assumptions, on the final results. The outcome of a sensitivity analysis is the knowledge of the magnitude of the change of an output for a given variation of a system parameter. A final result is said to be sensitive to a parameter if a small change in the parameter gives the result of a larger change in a final result.

Another application for sensitivity analysis is when uncertainty exists about a parameter. Reasons for the uncertainty could be due to, among others, an absence of data regarding the construction estimates for an energy conversion facility or a questionable emissions profile for a specific piece of equipment. Knowing the effect that a parameter has on final results can therefore reduce the uncertainty about the parameter.

3.5.1. Sensitivity Analysis of Cost Assumptions

To test the sensitivity of LCC for the SCPC cases with and without CCS, capital and variable O&M costs for all components, as well as fuel/feed costs from AEO 2008, were varied (**Table 3-11**).

Table 3-11 LCC Uncertainty Analysis Parameters

Parameter	Uncertainty Range
Capital Costs (CC)	+/-30%
Variable O&M Costs	+/-30%
AEO Values	Reference Case/High Case
Total Tax Rate	+/-10%
Capacity Factor	+/-5%

The sensitivity of the LCC results to the fluctuation of capital and variable O&M costs was analyzed by inflating and deflating each by a factor of 30 percent, based on the Baseline Report's stated accuracy rating (NETL, 2010). This 30-percent range was applied to the capital costs for all major components of the LC, as well as the CO_2 pipeline and injection well for the case with CCS.

The base case used AEO reference case values as the primary data set. Values from the AEO high price case were used to analyze the sensitivity of the LC to variation in feed/fuel and utility prices.

The total tax rate used for the base case is 38.9 percent. This was varied by +/-10 percent. The range is 35 percent on the low side and 42.8 percent on the high side to account for possible fluctuation in taxes at both the Federal and state levels.

For the base case, the capacity factor is set at 85 percent. To test the sensitivity of the LCC to a change in the capacity factor, the capacity factor was varied from 80 percent to 90 percent.

3.5.1.1 Sensitivity Analysis Results: SCPC without CCS

The results for the SCPC case without CCS uncertainty analysis indicate that the LCOE is most responsive to the change in capital costs by +/-30 percent. The change in the LCOE is measured compared to the Base Case LCOE of $0.0943/kWh. When capital costs for all major components of the SCPC without CCS LC are increased and decreased by 30 percent, the total LCOE of the plant increases and decreases by 17 percent, giving the LCOE a range of $0.0787/kWh to $0.1098/kWh, as shown in **Figure 3–14** and **Figure 3–15**.

Varying the capacity factor by +/- five from the base case 85 percent causes total LCOE to increase and decrease by four to five percent. This translates into a range of $0.0903/kWh for an increase to 90 percent to $0.0988/kWh for a decrease in the capacity factor to 80 percent.

Variable O&M costs increased and decreased by 30 percent, causing a slight, three percent, change in the total LCOE for the case. LCOE costs when O&M costs are increased and decreased had a range from $0.0919/kWh to $0.0966/kWh.

Increasing the total tax rate (Federal plus state) by +/-10 percent resulted in a percent change of +/- two percent. The range for this is $0.0922/kWh to $0.0964/kWh.

Little change occurred when feedstock and utility prices were increased by changing from the AEO reference case prices used in the base case to the AEO high price case. Based on AEO values for the high price case, increased feed/fuel and utility prices present a change of 0.42 percent.

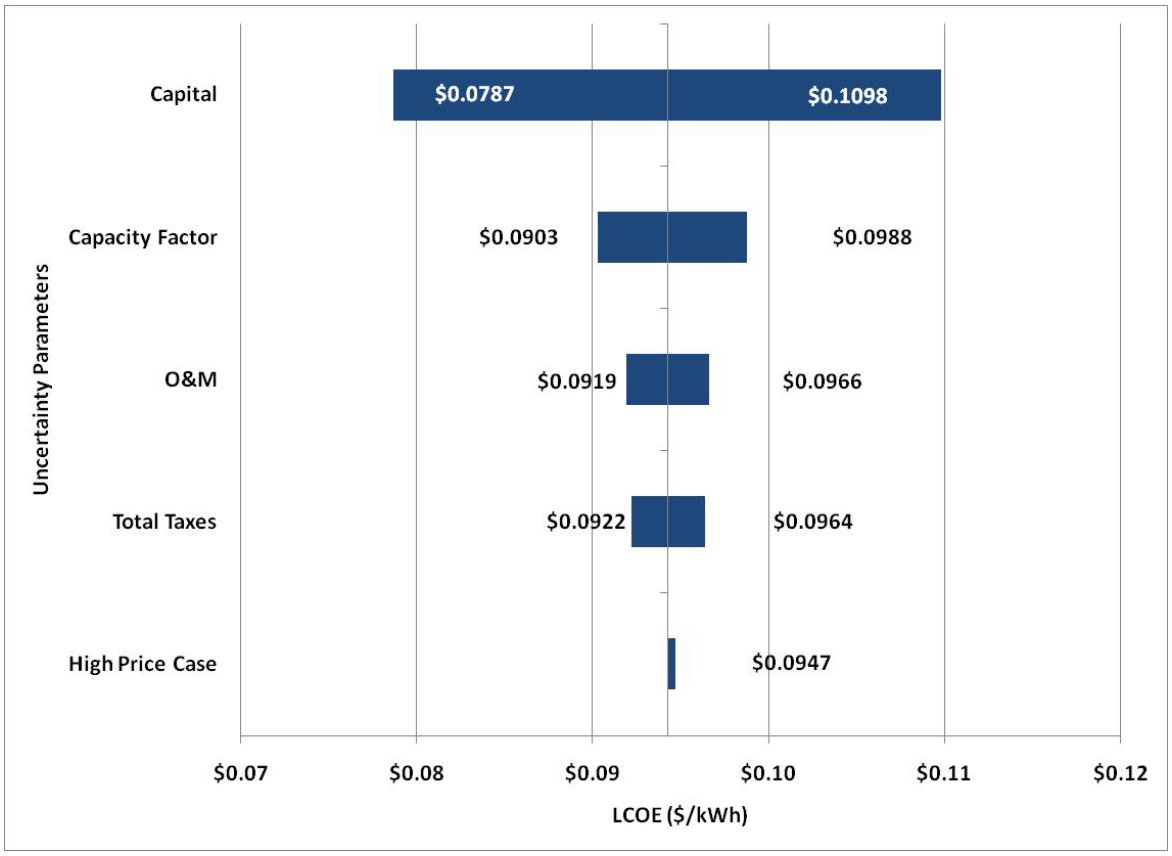

Figure 3–14 Uncertainty Analysis LCOE Ranges for the SCPC Case without CCS

1. Capital costs are a result of varying the base case capital costs by +/-30 percent.
2. Capacity factor represents the analysis of the case varying the capacity factor +/-5 of the base case capacity factor.
3. O&M costs are a result of varying the base case variable O&M costs by +/-30 percent.
4. Total taxes represent a variation in base case taxes of +/-10 percent.
5. High price case represents the use of AEO 2008 high price case coal and natural gas values rather than the AEO 2008 reference case values used in the base case.

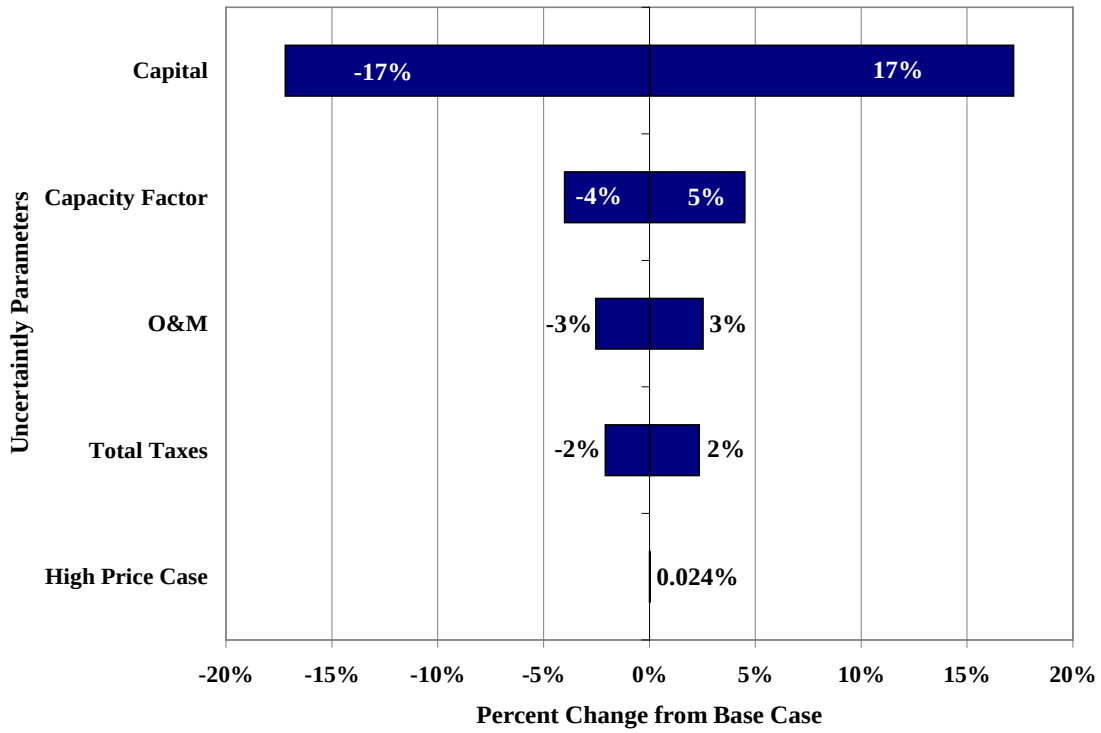

Figure 3–15 Percent Change due to Uncertainty Analysis from Base Case LCOE for the SCPC Case without CCS

1. Capital costs are a result of varying the base case capital costs by +/-30 percent.
2. Capacity factor represents the analysis of the case varying the capacity factor +/-5 of the base case capacity factor.
3. O&M costs are a result of varying the base case variable O&M costs by +/-30 percent.
4. Total taxes represent a variation in base case taxes of +/-10 percent.
5. High price case represents the use of AEO 2008 high price case coal and natural gas values rather than the AEO 2008 reference case values used in the base case.

3.5.1.2 Sensitivity Analysis Results for Case 2: SCPC with CCS

As with the SCPC case without CCS, the results indicate that a fluctuation in capital costs will cause the LCOE to change by the greatest amount. When capital costs are varied by +/-30 percent, the total LC LCOE for the case has a range of $0.1336/kWh to $0.1925/kWh. The Base Case LCOE is equal to $0.1630/kWh. This translates into a percent change of approximately 18 percent in both directions. Results for the LCOE values and percent change can be seen in **Figure 3–16** and **Figure 3–17.**

With a capacity factor range from 80 to 90 percent, the LCOE ranged from $0.1557/kWh with an increase in the capacity factor by five to $0.1713/kWh with a decrease in the capacity factor. This is equal to a percent change of four to five percent.

Variation in the variable O&M costs by +/-30 percent resulted in an LCOE range from $0.1587/kWh to $0.1674/kWh. This is represented by a percent change of +/- three percent. Similarly, a variation of the total tax rate by 10 percent in both directions causes the LCOE to change by +/- two percent. This translates into a range of $0.1591/kWh to $0.1670/kWh.

The AEO 2008 high price case values showed little variation in the LCOE value. As a result of replacing the AEO 2008 reference case values used in the base case with the AEO 2008 high price case, the LCOE increased by less than one percent, 0.36 percent. This means the fluctuation in the coal feed price or the natural gas fuel price, based on the forecasted AEO values, will cause little variation in the total LC LCOE for the SCPC case with CCS.

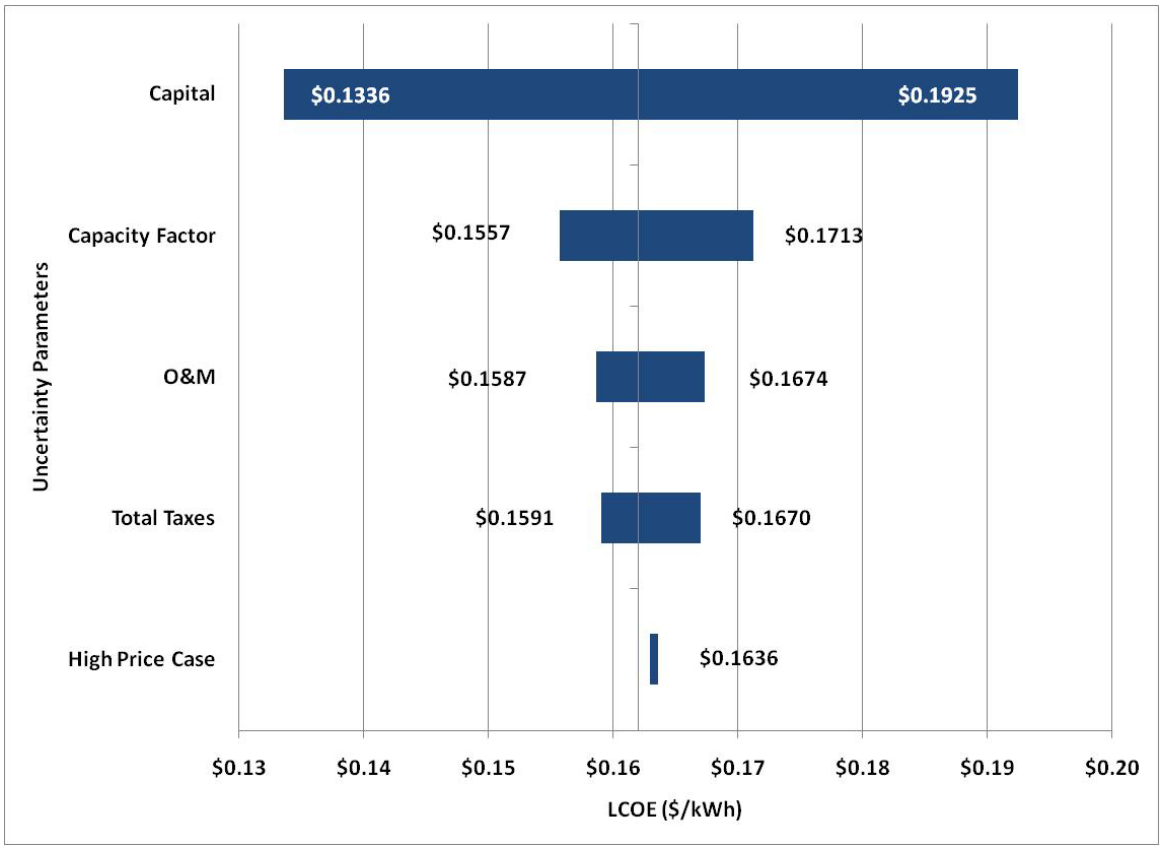

Figure 3–16 Analysis LCOE Results for the SCPC Case with CCS

1. Capital costs are a result of varying the base case capital costs by +/-30 percent.
2. Capacity factor represents the analysis of the case varying the capacity factor +/-5 of the base case capacity factor.
3. O&M costs are a result of varying the base case variable O&M costs by +/-30 percent.
4. Total taxes represent a variation in base case taxes of +/-10 percent.
5. High price case represents the use of AEO 2008 high price case coal and natural gas values rather than the AEO 2008 reference case values used in the base case.

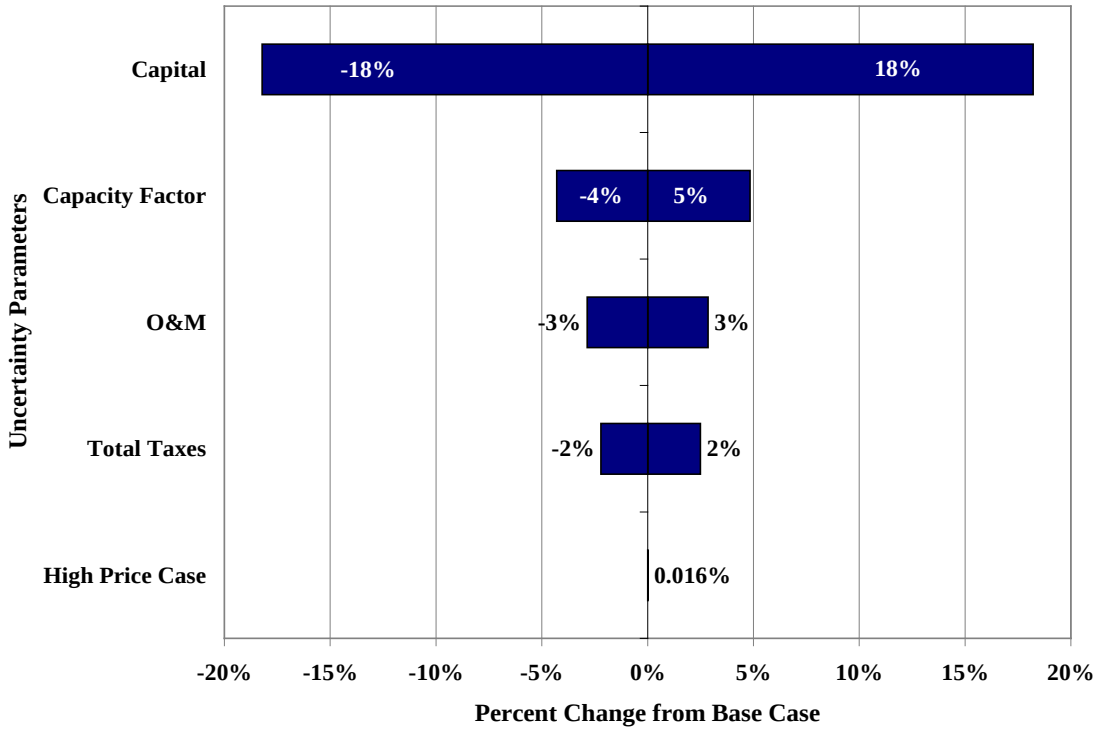

Figure 3–17 Percent Change Due to Uncertainty Analysis from Base Case LCOE for the SCPC Case with CCS

1. Capital costs are a result of varying the base case capital costs by +/-30 percent.
2. Capacity factor represents the analysis of the case varying the capacity factor +/-5 of the base case capacity factor.
3. O&M costs are a result of varying the base case variable O&M costs by +/-30 percent.
4. Total taxes represent a variation in base case taxes of +/-10 percent.
5. High price case represents the use of AEO 2008 high price case coal and natural gas values rather than the AEO 2008 reference case values used in the base case.

3.5.2 Sensitivity Analysis of LCI Assumptions

For this study, sensitivity analysis is performed on a few key parameters listed in **Table 3-12**. These parameters were chosen based on perceived impact and data quality.

Table 3-12 Sensitivity Analysis Parameters

Parameter	Stages Effected	Value in Model	Sensitivity Range/Value	Source/Reasoning
Materials	1, 3	Totals for steel, concrete, etc.	3 times material increase (200 percent)	Arbitrary range to account for replacement parts, missed data.
Methane Emissions	1	360 ft^3 CH_4/ton coal	216 to 450 ft^3 CH_4/ton coal	Based on potential for 40% methane recovery versus maximum methane emissions based on average error from source (EPA, 2008c).
Rail line Distance	2	205 miles	0 miles	Vary to zero to see if any impact is felt from this stage.

3.5.2.1 Construction Material Contributions

The effect of an additional three times the material input on GHG emissions for both SCPC cases are shown in **Table 3-13**. Only Stage #1, Stage #3, and total (all stages) emissions are shown; the GHG emissions for the remaining stages were not varied from the base case values presented in **Table 3-4**.

Table 3-13 GHG Emissions (kg CO2e/MWh) for Base Cases and Sensitivity Impacts of Three Times the Material Inputs

Emissions (kg CO_2e /MWh)	Stage #1: Raw Material Acquisition			Stage #3: Energy Conversion			Total		
	Base	3 × Base	% Increase	Base	3 × Base	% Increase	Base	3 × Base	% Increase
SCPS with CCS									
CO_2	4.1	4.4	7.2%	137.1	139.5	1.8%	144.5	147.2	1.9%
N_2O	1.9E-02	2.3E-02	19.2%	1.4E-02	4.0E-02	177.4%	5.8E-02	8.7E-02	50.7%
CH_4	99.2	99.2	0.0%	0.0	0.1	106.5%	99.4	99.4	0.1%
SF_6	2.1E-06	5.3E-06	149.8%	7.5E-03	7.6E-03	0.0%	3.3	3.3	0.0%
Total GWP	103.3	103.6	0.30%	137.1	139.7	1.86%	247.2	250.0	1.16%
SCPS without CCS									
CO_2	2.8	3.0	7.2%	866.2	868.0	0.2%	871.3	873.3	0.2%
N_2O	1.3E-02	1.6E-02	19.2%	9.4E-03	2.6E-02	171.0%	4.0E-02	5.8E-02	47.2%
CH_4	69.0	69.0	0.0%	0.0369	0.1	96.2%	69.1	69.2	0.1%
SF_6	1.5E-06	3.7E-06	149.8%	7.5E-03	7.5E-03	0.0%	3.3	3.3	0.0%
Total GWP	71.9	72.1	0.30%	866.2	868.1	0.22%	943.8	945.8	0.22%

From the calculation of total GWP, it can be seen that, although the percentage increase of individual pollutants can be large, the overall percent increase is only 1.2 percent for SCPC with CCS and 0.22 percent for SCPC without CCS. This is because CO_2 emissions are dominated by coal combustion and CH_4 emissions by coalbed methane (CBM) release, neither of which is impacted by construction materials. Therefore, construction material inputs have little impact on the overall GWP of either SCPC plant.

Table 3-14 shows the sensitivity of non-GHG air pollutants to material inputs for both SCPC cases. NO_X and PM emissions, measurable pollutants in each cases (**Figure 3–11**), are only slightly sensitive to material inputs with maximum increases (considering both cases) of 1.3 and 2.6 percent, respectively. Pb, VOC, and Hg are more sensitive, but even with the material input increase neither emission contributes more than one percent to the overall non-GHG LC emissions. However, CO emissions are sensitive to material inputs, showing a 66 and 62 percent increase for with and without CCS, respectively, when compared to the base case. Additionally, a large SO_X increase is seen in the SCPC case with CCS. This is because, after CO_2, CO and SO_X are the largest pollutant inventories in the concrete, steel plate, steel pipe, aluminum sheet, and cast iron manufacturing LC profiles. The sensitivity of SO_X is not as large for the case without CCS because SO_X emissions are dominated by coal combustion in Stage #3. Therefore, sensitivity is seen when considering construction material impacts on CO and SO_X emissions, but overall, uncertainty in material quantities does not have a large impact on LCI results.

Table 3-14 Air Pollutant Emissions (kg/MWh) for the Base Cases and Sensitivity Impacts of Three Times the Material Inputs

Emissions (kg /MWh)	Stage #1: Raw Material Acquisition			Stage #3: Energy Conversion			Total		
	Base	3 × Base	% Increase	Base	3 × Base	% Increase	Base	3 × Base	% Increase
SCPS with CCS									
Pb	4.23E-07	9.22E-07	118.2%	4.63E-05	4.98E-05	7.6%	4.68E-05	5.08E-05	8.6%
Hg	6.23E-08	9.05E-08	45.3%	7.05E-06	7.21E-06	2.3%	7.12E-06	7.31E-06	2.7%
NH_3	3.52E-05	3.60E-05	2.2%	2.77E-03	2.77E-03	0.1%	2.92E-03	2.92E-03	0.1%
CO	0.004953	0.007159	44.5%	0.009392	0.023007	145.0%	0.023949	0.039769	66.1%
NO_X	0.007407	0.007954	7.4%	0.432056	0.436824	1.1%	0.448471	0.453786	1.2%
SO_X	0.019984	0.020709	3.6%	0.004406	0.012544	184.7%	0.026305	0.035168	33.7%
VOC	0.000145	0.000179	23.5%	0.000367	0.00062	69.0%	0.001342	0.001629	21.4%
PM	0.001265	0.001368	8.1%	0.080861	0.083185	2.9%	0.09301	0.095437	2.6%
SCPS without CCS									
Pb	2.94E-07	6.42E-07	118.2%	4.55E-05	4.73E-05	4.0%	4.58E-05	4.80E-05	4.7%
Hg	4.33E-08	6.30E-08	45.3%	4.93E-06	5.05E-06	2.4%	4.98E-06	5.12E-06	2.7%
NH_3	2.45E-05	2.50E-05	2.2%	2.39E-03	2.39E-03	0.1%	2.49E-03	2.50E-03	0.1%
CO	0.003447	0.004981	44.5%	0.006974	0.016171	131.9%	0.017103	0.027834	62.7%
NO_X	0.005153	0.005534	7.4%	0.301109	0.304761	1.2%	0.31253	0.316562	1.3%
SO_X	0.013905	0.01441	3.6%	0.364189	0.370345	1.7%	0.379427	0.386087	1.8%
VOC	0.000101	0.000125	23.5%	0.000297	0.000472	58.8%	0.000975	0.001174	20.3%
PM	0.00088	0.000952	8.1%	0.055878	0.057443	2.8%	0.064331	0.065968	2.5%

3.5.2.2 Methane Emissions

The CH_4 emissions from CBM in the base cases were based the average annual CH_4 emitted (between 2002 and 2006) per short ton of coal produced at the Galatia Mine (EPA, 2008b). The average value, 360 standard cubic feet (scf)/ton coal, assumed all CH_4 released from the coalbed was emitted to the atmosphere. However, some coal mines have begun to incorporate a CBM recovery process, which captures CH_4 to either sell as a co-product or create onsite energy generation. EPA estimates that 20 to 60 percent of liberated CH_4 could be recovered using these processes (EPA, 2008b). Therefore, sensitivity analysis was performed assuming a 40 percent CH_4 recovery (216 scf CH_4/ton coal emitted) during Stage #1 of both cases. In addition, the CH_4 emissions reported for the Galatia Mine between 2002 and 2006 range from 238 to 464 scf/ton. Considering the calculated standard deviation of 90 scf/ton, a high-emission case was run at 450 scf/ton to determine the total GWP when emissions were higher than the base case.

Figure 3–18 shows the total GWP for the total LC of both SCPC facilities assuming base, low, and high CH_4 emissions during coal mining (Stage #1). As expected, increasing CH_4 emissions increases the GWP potential for both cases (with and without CCS) by 10 and 1.8 percent, respectively. When considering the total LC emissions, the largest benefit associated with CH_4 recovery is seen for the SCPC with CCS, which has a 16 percent reduction in GWP. When considering SCPC without CCS, the large impact from CO_2 emissions reduces the total impact of CH_4 reduction to three percent.

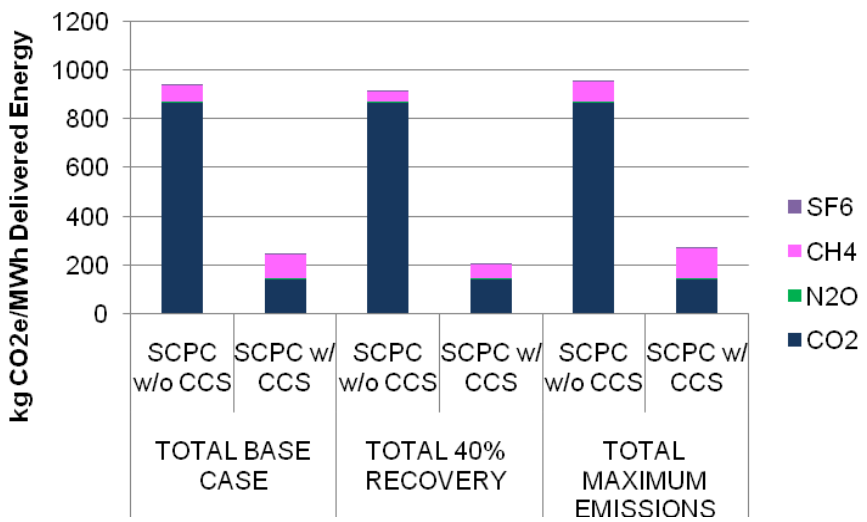

Figure 3–18 Sensitivity Analysis of Methane Recovery on GWP (kg CO2e/MWh Delivered Energy)

3.5.2.3 Rail Transport

In the base cases, coal was transported from the mine to the SCPC facility via rail for a distance of 205 miles. In order to determine the impact of raw material transport (Stage #2) on the overall LC, the rail distance was reduced to zero and total LC emissions were calculated. **Table 3-15** summarizes sensitivity of emissions to rail distance for both SCPC with and without CCS. Overall, rail distance only has a slight impact on total GWP, with a decrease of 0.3 and 1.4 percent for the SCPC cases without and with CCS,

respectively. This is mainly a result of less CO_2 emissions as a result of no diesel fuel use. The sensitivity of rail distance to GWP is similar the increase in construction materials.

Table 3-15 Rail Distance Sensitivity on Total GHG Emissions (kg CO2e) and Air Emissions (kg) /MWh Delivered Energy

Emissions	Total Base Case- 205 Miles		Total - 0 Miles		% Decrease	
	SCPC w/o CCS	SCPC w/ CCS	SCPC w/o CCS	SCPC w/ CCS	SCPC w/o CCS	SCPC w/ CCS
GWP (kg CO_2e/MWh Delivered Energy)						
CO_2	871.3	144.5	869.0	141.2	0.3%	2.3%
N_2O	4.0E-02	5.8E-02	2.3E-02	3.4E-02	42.2%	41.5%
CH_4	69.1	99.4	69.1	99.2	0.1%	0.1%
SF_6	3.3	3.3	3.3	3.3	0.0%	0.0%
Total GWP	943.8	247.2	941.4	243.7	0.3%	1.4%
Non-GHG Air Emissions (kg/MWh Delivered Energy)						
Pb	4.58E-05	4.68E-05	4.58E-05	4.68E-05	0.0%	0.1%
Hg	4.98E-06	7.12E-06	4.98E-06	7.11E-06	0.0%	0.0%
NH_3	2.49E-03	2.92E-03	2.41E-03	2.80E-03	3.3%	4.1%
CO	1.71E-02	2.39E-02	1.06E-02	1.45E-02	38.3%	39.3%
NO_X	3.13E-01	4.48E-01	3.06E-01	4.40E-01	2.0%	2.0%
SO_X	3.79E-01	2.63E-02	3.78E-01	2.45E-02	0.3%	6.9%
VOC	9.75E-04	1.34E-03	4.05E-04	5.22E-04	58.5%	61.1%
PM	6.43E-02	9.30E-02	5.68E-02	8.21E-02	11.8%	11.7%

For non-GHG emissions, the largest decreases are seen graphically in **Figure 3–19** for PM, and CO. Smaller decreases are seen for SO_X and NO_X. Although NH_3 and VOCs show large decreases in **Table 3-15** they contribute a small amount in the base cases when compared to the other emissions.

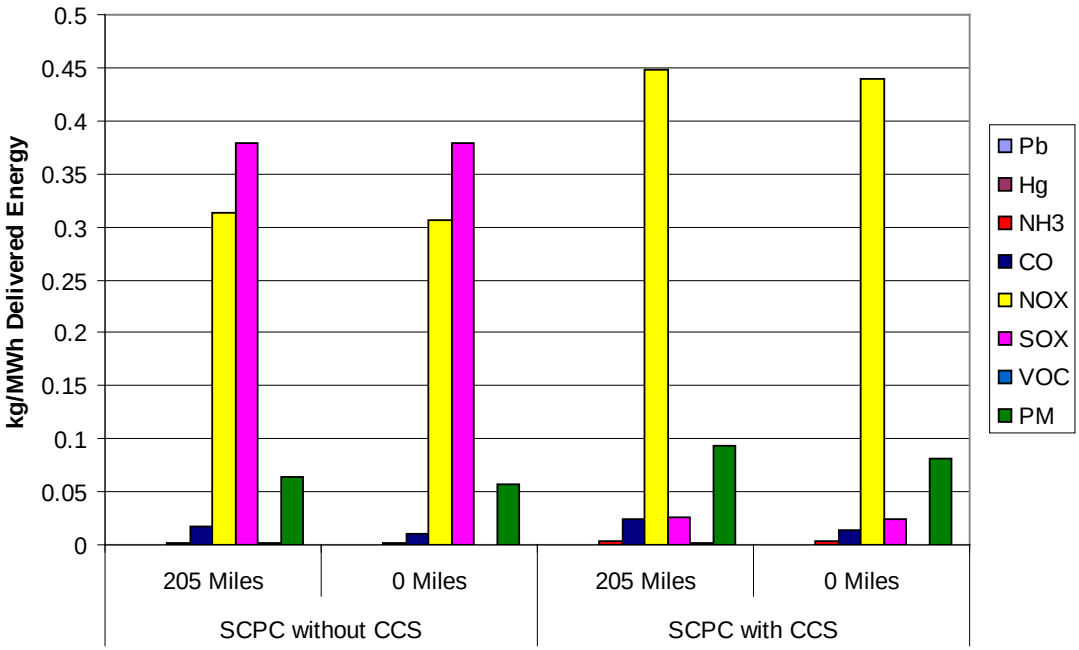

Figure 3–19 Rail Distance Sensitivity on Air Emissions (kg)/MWh Delivered Energy

4. Summary

The addition of an amine-based post combustion carbon capture system (designed for a maximum 90% capture) to an SCPC facility reduces LC GWP and SO_X emissions by 72 and 91 percent, respectively. However, adding CCS increases the LCOE by 77 percent, from approximately $0.07/MWh to $0.12/MWh of delivered electricity. Although the increase occurred for all cost parameters (capital, O&M, labor, etc.), capital and O&M costs had the largest increase at 81 and 79 percent, respectively. This indicates that advancements in CCS technologies that reduce the capital investment and operating costs would most significantly reduce the overall cost differences between the two cases. Other tradeoffs from the addition of CCS included more water and land use. Approximately 47 percent more water is needed for cooling applications during the carbon capture process. This result suggests that depending on the location of the SCPC plant, including (or retrofitting) with CCS may not be practical due to limited water supply. Additional land use is needed to install the CO_2 pipeline, which is assumed to impact agricultural land. Finally, to achieve similar output between cases, the case with CCS required 43 percent more coal, which increases non-GHG combustion emissions like NO_X, CO, and PM. Investors and decision makers can use the results presented in this report to weigh the benefits of carbon mitigation to the additional cost of investing in CCS technology. Additionally, these results suggest that investment in R&D to advance CCS technologies and lower capital investment costs will have a positive effect on reducing the difference in LCOE between the cases.

Sensitivity analyses were performed on several cost and environmental inventory parameters. For LCC, variation in capital costs of ±30 percent had the largest impact on LCOE, indicating that investors will need to take care when analyzing capital cost parameters for a given SCPC plant. Changing the capacity factor ± five percent had approximately a five percent impact on LCOE, while variations in O&M and taxes had a less than three percent impact. Feedstock and utility costs had a very small impact on LCOE; varying from the AEO reference case to the high price case results in only a 0.02 percent change (EIA, 2008). Therefore, although these results are based on AEO 2008, one can assume that the differences between 2008 and future AEO values will have a small impact on the overall results unless extremely large changes in feedstock and utilities prices are projected.

A sensitivity analysis on environmental parameters was performed on CH_4 emissions from coal mining, train transport distance, and construction material inputs into Stage #1 and Stage #3. Minor impacts on environmental emissions were felt when construction material inputs were increased three times the base case values, indicating that low data quality for material inputs does not contribute to large uncertainty in total LC results. In particular, GHG emissions are effected little by material input, experiencing a 1.2 and 0.2 percent increase in total GWP for SCPC with and without CCS, respectively. Increases in CO and SO_X emissions were seen due to their dominance in several material manufacturing LC profiles. Sensitivity analysis of CH_4 emissions showed that the addition of a 40 percent mine CH_4 recovery process could reduce the LC GWP of SCPC with CCS by 16 percent. However, this analysis does not consider other LC benefits or disadvantages associated with the recovery process, so additional modeling would need

to be done before a conclusion can be drawn about its overall effectiveness. For SCPC without CCS, recovering 40 percent of the CH_4 emissions at the coal mine only has a three percent impact on total GWP due to the large amount of CO_2 emitted during coal combustions. Omitting rail transport (by cutting the distance between the mine and the SCPC facility from 205 to 0 miles) decreased GWP by 0.3 and 1.4 percent for the cases without and with CCS, respectively. Decreases were also seen in total emission of NO_X, CO, and PM. Although the overall impacts were small, the assumed travel distance was relatively short for this study, which when varied to zero created a smaller sensitivity range then was performed for construction materials.

5. Recommendations

Based on the results from this study the following recommendations are made for consideration during future LCI&C studies:

- Comparison of the results in the present study to other existing and advanced electricity generation technologies would provide more insight into overall life cycle environmental and economic benefits/tradeoffs between several options.
- Detailed analysis of the quantity and type of water resources available to the energy conversion facility would add insight into the ability to retrofit or build with CCS technology. If water is available at a higher cost, the consideration of this during LCC may add further insight.
- Detailed cost analysis of fuel production (upstream of the energy conversion facility) would add value to the LCC and provide a clear distinction between LCOE for the plant and life cycle LCOE. This type of detail could be used to verify (or disprove) the sensitivity analysis result that fuel/feedstock prices have little impact on the overall LCC.
- Inclusion of specific data for the carbon sequestration (i.e., injection) components would add value to the power generation cases with CCS.
- Little impact was seen from the inclusion of the CO_2 pipeline installation, deinstallation, and operations. The identification of a specific sequestration location, and distance from the power facility, would verify (or disprove) the LC contributions of the pipeline. Additionally, knowing the capacity of the sequestration site may indicate that, in future studies, more than one sequestration location will need to be utilized throughout the study period.
- Extending the present LCI&C to include cases with methane recovery system at the coal mine. Different mines and coal types have different levels of gassiness, and there are different end-use profiles (on-site electricity generation versus being piped to a customer). An LCI with LCC would help to draw a conclusion on its effectiveness.
- Based on sensitivity analyses, uncertainty in data quality for material inputs quantities during construction has a minimal impact on GHG emissions, even with an increase of three times the base case assumptions. For future LCI&C studies, secondary LCI profiles for materials should be checked for accuracy to further verify sensitivity results, particularly for CO and SO_X emissions.
- Further sensitivity analyses on rail distance, varied from zero to a physically possible maximum, would provide more insight on the sensitivity of LCI&C results to raw material transport distances. Additional, if a SCPC facility can, at any given time, purchase coal from a variety of different locations, the range of values over those distances would be informative for future studies, particularly when considering the LCI&C of an existing facility.

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