NATIONAL ENERGY TECHNOLOGY LABORATORY

# Life Cycle Analysis: Existing Pulverized Coal (EXPC) Power Plant

September 30, 2010

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U.S. DEPARTMENT OF ENERGY

# Disclaimer

# LIFE CYCLE ANALYSIS: EXISTING PULVERIZED COAL (EXPC) POWER PLANT

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**FINAL REPORT**

**September 30, 2010**

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**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 |
| 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 |
| eGRID | Emissions and Generation Resource Integrated Database |
| EIA | Energy Information Administration |
| EIS | Environment Impact Statement |
| EPA | Environmental Protection Agency |
| EPC | Engineer/Procure/Construct |
| ESP | Electrostatic Precipitator |
| EXPC | Existing Pulverized Coal |
| FG | Flue Gas |
| FGD | Flue Gas Desulfurization |
| G&A | General and Administrative |
| GE | General Electric |
| GHG | Greenhouse Gases |
| GtC | Gigatonnes of Carbon |
| $GtCO_2$ | Gigatonnes of Carbon Dioxide |

| | |
|---|---|
| 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 |
| L | Liter |
| 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 |
| 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 |

| | |
|---|---|
| NERC | North American Electric Reliability Corporation |
| NETL | National Energy Technology Laboratory |
| NG | Natural Gas |
| NGCC | Natural Gas Combined Cycle |
| $NH_3$ | Ammonia |
| $NO_X$ | Oxides of Nitrogen |
| O&M | Operations and Maintenance |
| $O_3$ | Ozone |
| 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) |
| ppm | Parts per Million |
| 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 | Subcritical Pulverized Coal |
| SCR | Selective Catalytic Reduction |
| SERC | Southeast Electric Reliability Council |
| $SF_6$ | Sulfur Hexafluoride |
| $SO_2$ | Sulfur Dioxide |
| $SO_X$ | Sulfur Oxides |
| TS&M | Transportation, Storage, and Monitoring |
| U.S. | United States |
| ULSD | Ultra-Low Sulfur Diesel |
| VOC | Volatile Organic Chemical |

# 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: Existing Pulverized Coal (EXPC) Power Plant' 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 EXPC energy conversion cases. One case assumes that the IGCC facility will emit the full amount of carbon dioxide ($CO_2$) resulting from the combustion of the fuel, which is assumed to be mid-western bituminous coal. The second case builds upon the first case by adding $CO_2$ removal capacity to remove 90% of the $CO_2$ from the facility flue gas. The case that captures 90% 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 existing pulverized coal (EXPC) power generation facilities over a 30-year period, based on case studies presented in the NETL 2007 report, *Carbon Dioxide Capture form Existing Coal-Fired Power Plants* (NETL, 2007). It is assumed that both plants are existing. The NETL report provides detailed information on the facility characteristics, operating procedures, and costs. In addition to the power generation facility, the economic and environmental performances of processes upstream and downstream of the power facility are considered.

Two IGCC cases are considered for evaluation:

- Case 1: (EXPC w/o CCS) An EXPC power plant that fires coal at full load without capturing carbon dioxide ($CO_2$) from the flue gas. This case is based on a 434-megawatt electric (MWe) plant with a subcritical boiler that fires mid-western bituminous coal, has been in commercial operation for more than 30 years, and is located in southern Illinois. This case is referred to as the "unmodified EXPC" throughout this document.
- Case 2: (EXPC w/ CCS) An EXPC power plant that is retrofitted with a carbon capture and sequestration (CCS) system. This case is based on a 434-MWe plant with a subcritical boiler that fires mid-western bituminous coal, has been in commercial operation for more than 30 years, and is located in southern Illinois. After being routed through heat recovery equipment (including an economizer and regenerative air heater), the flue gas is sent to air emissions control equipment that includes an electrostatic

precipitator (ESP) and a lime-based flue gas desulfurization (FGD) system. After accounting for the auxiliary power for the EXPC and the energy requirements of the CCS system, the net power of the plant is 303 MWe. To establish a uniform basis of comparison for this study, the difference between the net power of the unmodified EXPC and this case is modeled by assuming that the replacement power is generated within the Southeast Electric Reliability Council (SERC) electric grid. The fuel mix of the SERC grid is based on 2007 operating data for U.S. power plants (EPA 2008b). This case is referred to as the "retrofitted EXPC" throughout this document.

## Scope of the Study

The upstream LC stages (coal mining and coal transport) are modeled for both EXPC cases. The downstream LC stages (electricity distribution) are also included. Cost considerations provide the constant dollar levelized cost of delivered energy (LCOE) and the total plant cost (TPC) over the study period. Environmental inventories include GHGs, criteria air pollutants, mercury (Hg) and ammonia ($NH_3$) emissions to air, water use 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) (IPCC, 2007).

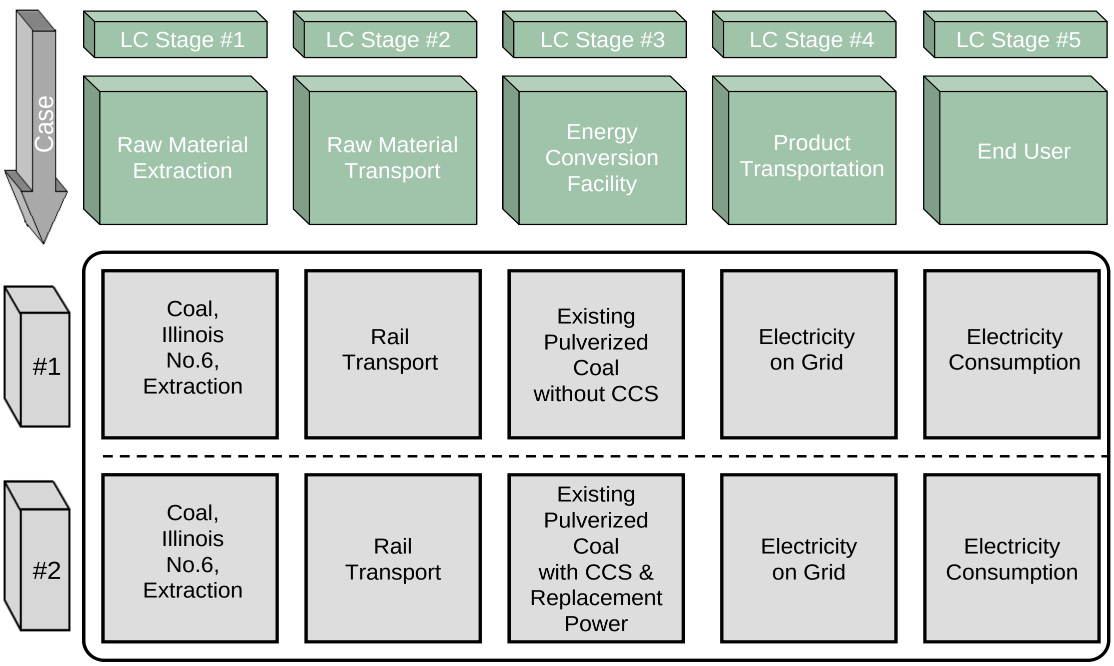


**Figure ES-1: Case Comparison by Life Cycle Stage**

## Modeling Boundaries

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 decommissioning of the coal mine site 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 fuel for unit train operations and emissions from the unit train. The main rail line between the coal mine and the power plant rail spur, including the spur is not included in the modeling boundary, as it is assumed to previously exist. Additional spur trackage is considered. Coal cost data is a “delivered” price, so costs are not included from this stage.
- **LC Stage #3** includes the fuels used in the decommissioning of the power plant site, fuel used in the power plant, costs incurred during the study period, water, and electrical output and emissions from the power plant. In the case for carbon capture and sequestration; costs, equipment and infrastructure to capture, compress, transport, inject, and monitor $CO_2$ are included. The model includes replacement power for the retrofitted EXPC scenario. When a CCS system is retrofitted to an existing power plant, the net power output of the facility is decreased. In the scenarios of this study, the CCS system reduces the net power from 433 MW to 300 MW. For every 0.699 MWh of electricity delivered by the retrofitted EXPC plant, 0.301 MWh of electricity is assumed to be “replaced” by the SERC electricity grid.
- **LC Stage #4** includes the delivery of the electricity to the customer, transmission line losses, and emissions of $SF_6$ 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.

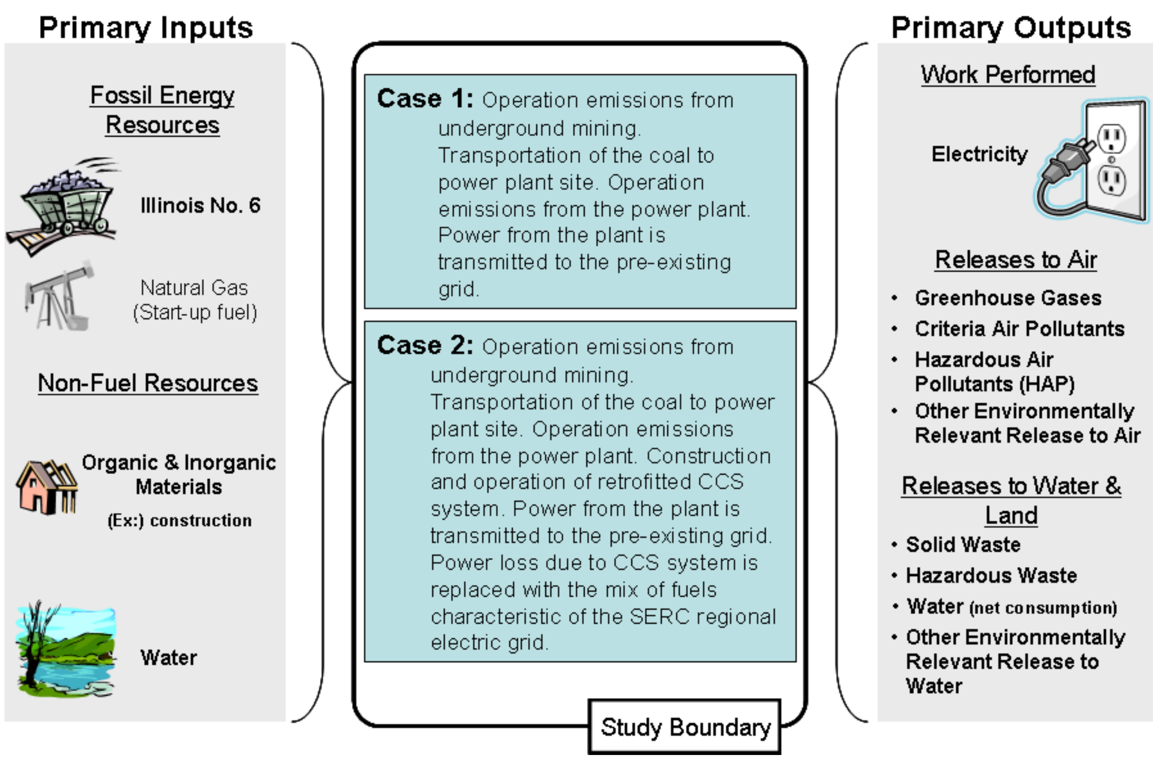


**Figure ES-2: Study Boundary**

## 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 EXPC 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." Additionally, comments originating in the NETL *Carbon Dioxide Capture from Existing Coal-Fired Power Plants* Report is labled as "NETL Carbon Capture Report."

## Summary Results

As shown by **Figure ES-3** the addition of a CCS system to an EXPC facility increases the LCOE from 27.6 mills/kilowatt-hour (kWh) to 125.2 mills/kWh. The LCOE of the CCS-retrofitted EXPC plant is 4.5 times greater than the unmodified case and is mostly due to the capital costs of the CCS equipment, increased variable O&M costs, and the cost of the replacement power.

**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 | Existing Midwestern | Present Study |
| Coal Feedstock | Midwestern Bituminous | NETL Carbon Capture 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 Round One Way Distance | 200 miles | Present Study |
| Rail Spur Constructed Length | Pre-existing with consideration for additional | 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 | Southern Illinois | Present Study |
| EXPC Net Electrical Output (without CCS) | 434 MW | NETL Carbon Capture Report |
| EXPC Net Electrical Output (with CCS) | 303 MW | NETL Carbon Capture Report |
| Trunk Line Constructed Length | Pre-existing | 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 Carbon Capture Report |
| **LC Stage #4: Product Transport** | | |
| Transmission Line Loss | 7% | Present Study |
| Transmission Grid Construction | Pre-existing | Present Study |

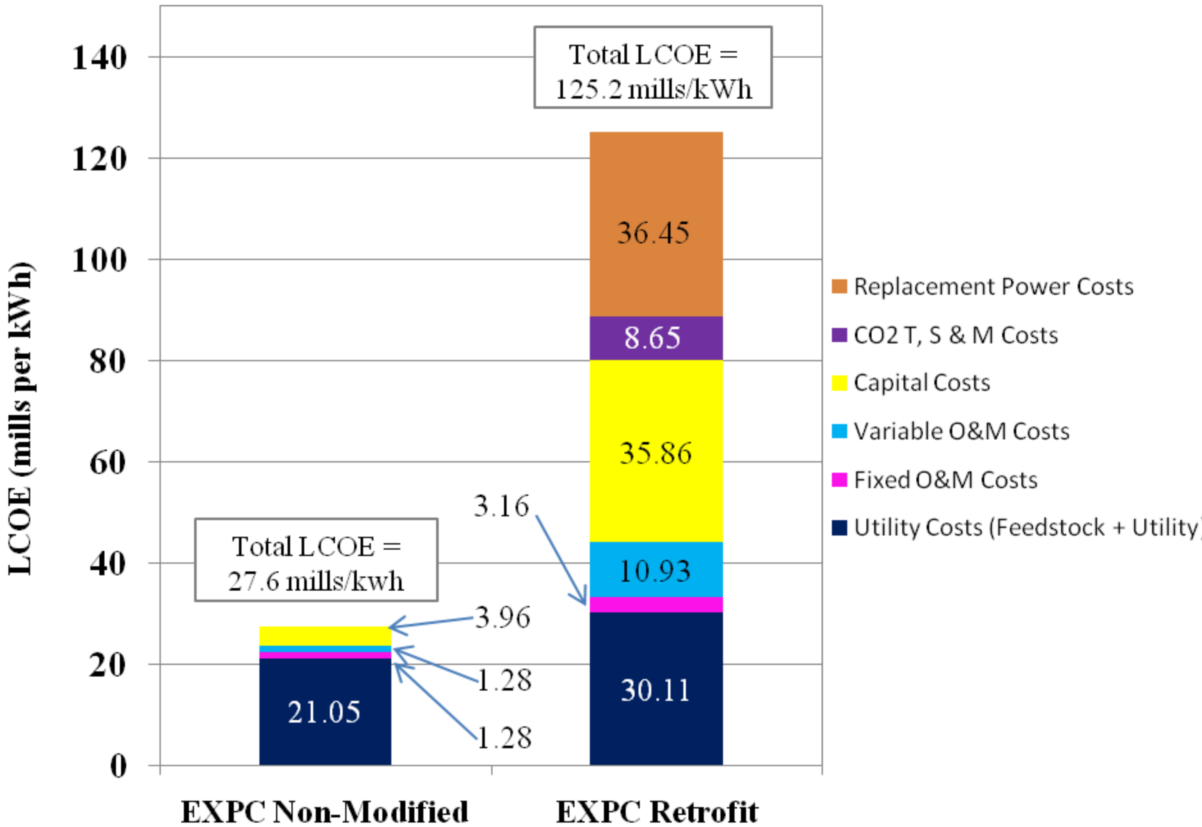


**Figure ES-3: Comparative GHG Emissions (kg $CO_2e[CO_2e]$/MWh Delivered) for EXPC with and without CCS**

LC GHG emissions are summarized in **Table ES-2.** On an LC stage basis, the energy conversion facility (Stage #3) for EXPC without CCS dominates all the other stages for GHG emissions. When CCS is included, Stage #3 still emits the most $CO_2$, but methane ($CH_4$) emissions from coal mining play a more significant role (on a percentage basis) in the total GHG emissions. Sulfur hexafluoride ($SF_6$) emissions are not seen as a large contributor to the total GWP for either case, with a less than one percent impact to Case 1 and Case 2.

Overall, the addition of CCS to an IGCC facility reduces LC GHG emissions by approximately 60 percent. Disadvantages due to the addition of CCS to the EXPC facility include more water and land use. Approximately 62 percent more water is needed for cooling applications during the carbon capture process. This result suggests that CCS may not be feasible in locations with limited water supply. Additional land use is needed to install the $CO_2$ pipeline, which is assumed to impact agricultural land. Finally, to achieve the same amount of delivered electricity in the same amount of time, replacement power is necessary for the retrofitted EXPC case. The generation of replacement power introduces environmental burdens to the LC of retrofitted EXPC scenario.

**Table ES-2: Comparative GHG Emissions ($CO_2e$/MWh Delivered) for Case 1 (EXPC without CCS) and Case 2 (EXPC with 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-EXPC Without CCS** | | | | | |
| $CO_2$ | 3.2 | 5.2 | 1.0E+03 | 0 | 1020 |
| $N_2O$ | 1.4E-02 | 3.7E-02 | 5.1 | 0 | 5.1 |
| $CH_4$ | 80 | 1.9E-01 | 2.8E-01 | 0 | 80 |
| $SF_6$ | 4.3E-07 | 6.0E-08 | 6.3E-03 | 3.3 | 3.3 |
| Total GWP | 83 | 5.4 | 1017 | 3.3 | 1109 |
| **Case 2-EXPC With CCS** | | | | | |
| $CO_2$ | 3.2 | 5.2 | 340 | 0 | 348 |
| $N_2O$ | 1.4E-02 | 3.7E-02 | 6.0 | 0 | 6.0 |
| $CH_4$ | 8.0E+01 | 1.9E-01 | 6.6 | 0 | 87 |
| $SF_6$ | 4.3E-07 | 6.0E-08 | 4.5E-03 | 3.3 | 3.3 |
| Total GWP | 83 | 5.4 | 353 | 3.3 | 444 |

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. Key conclusions of the LCI sensitivity are as follows:

- There were minor changes in the LC results with respect to changes in the quantity of construction materials, which indicates that low data quality for material inputs does not contribute to large uncertainty in total LC results. Key conclusions of the environmental sensitivity analysis are as follows:
- 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 the unmodified EXPC and the retrofitted EXPC by 2.9 percent and 8.7 percent, respectively. 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.
- By omitting rail transport (by cutting the distance between the mine and the EXPC facility from 200 to zero miles), GWP decreased by 0.5 and 2.8 percent for the cases without and with CCS, respectively.

Sensitivity analyses were also performed on several cost parameters. Key conclusions of the LCC sensitivity analysis are as follows:

- The LCC sensitivity analysis demonstrates that the EXPC case without CCS has a strong relationship between LCOE and capacity factor. Varying the capacity factor by ±5 percentage points (from the base case value of 85 percent) causes total LCOE to increase and decrease by six percent. This translates into a range of $0.0259/kWh for an increase to 90 percent to $0.0291/kWh for a decrease in the capacity factor to 80 percent.

- The sensitivity analysis of the CCS-retrofitted EXPC case concluded that a fluctuation in replacement power costs causes the LCOE to change by the greatest amount. When the replacement power costs are varied from 7.59 to 10.45 cents/kWh, the LCOE ranges between 12.52 and 13.89 cent/kWh; on a percentage basis, a 37 percent increase in replacement power cost results in an 11 percent increase in LCOE.
- For both cases (with and without CCS) the LCC sensitivity analysis concluded that the LCC results do not change significantly with changes in capital costs, total tax rate, and feedstock and utility prices. 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

## Key Results

- Adding 90 percent $CO_2$ capture and storage to an EXPC platform will increase the full life cycle cost of power from 2.8¢ to 12.5¢ – roughly a 350 percent increase.
- GHG emissions for coal extraction and transport show no increase in Case 2 (EXPC with CCS). However, the 90 percent $CO_2$ capture at the power plant results in a 60 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 $146.74/tonne.

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# 1.0 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 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 existing pulverized coal (EXPC) electricity generation pathways, with and without carbon capture and sequestration (CCS) capability. By identifying the LC economic and environmental attributes of two scenarios for EXPC power production, the advantages and disadvantages of retrofitting an EXPC plant with a CCS system can be determined.

[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.

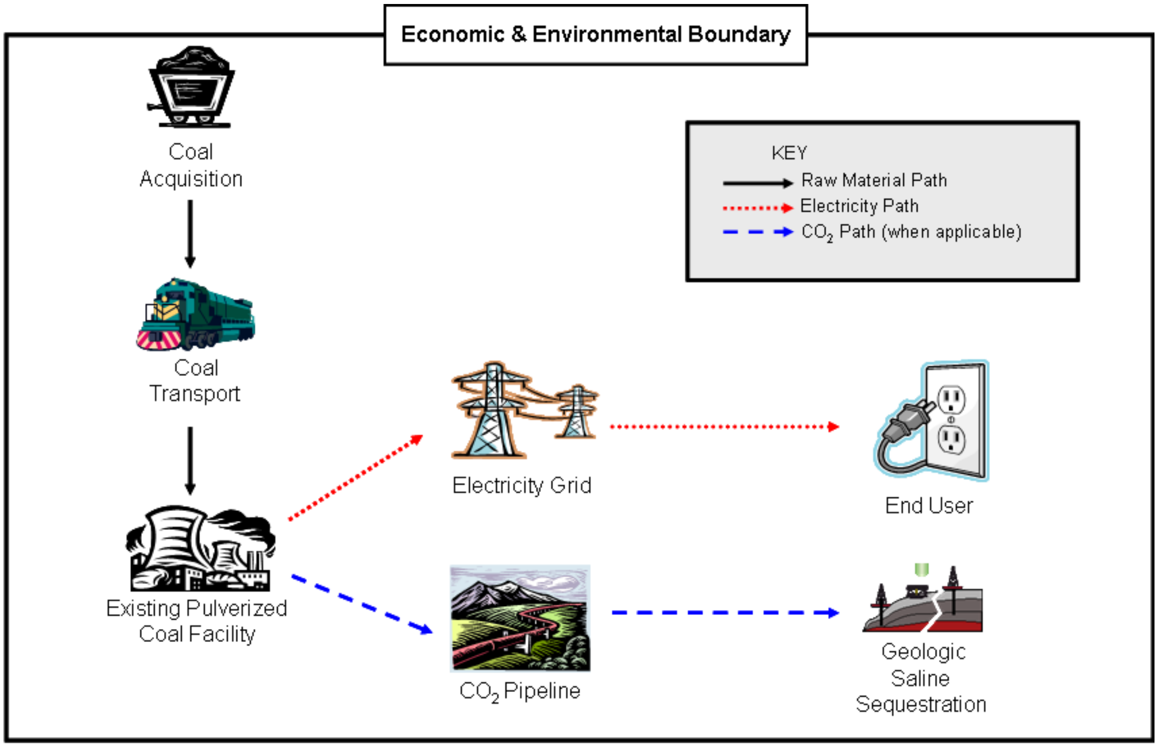



**Figure 1-1: Conceptual Study Boundary**

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 EXPC power generation facilities based on case studies presented in the NETL report Carbon Dioxide Capture from Existing Coal-Fired Power Plants (NETL, 2007b). The NETL report provides detailed information on the facility characteristics, operating procedures, and costs for two EXPC facilities. Throughout the remainder of this document the NETL report, Carbon Dioxide Capture from Existing Coal-Fired Power Plants, will be referred to as the "EXPC Baseline Report."

There are two case scenarios under consideration in this study:

- Case 1: An EXPC power plant that fires coal at full load without capturing carbon dioxide ($CO_2$) from the flue gas. This case is based on a 430-megawatt electric (MWe) plant with a subcritical boiler that fires mid-western bituminous coal, has been in commercial operation for more than 30 years, and is located in southern

Illinois. After being routed through heat recovery equipment (including an economizer and regenerative air heater), the flue gas is sent to air emissions control equipment that includes an electrostatic precipitator (ESP) and a lime-based flue gas desulfurization (FGD) system. The ESP uses a high-voltage electrostatic charge to ionize particles in the gas stream so they can be removed from the stream by a set of charged collection plates, and the FGD initiates a series of chemical reactions in the flue gas that result in the removal of 94.9 percent of the sulfur found in the gas (NETL 2007b). Water that is discharged from the EXPC plant is discharged into a municipal sewer system. After accounting for a seven percent electricity transmission loss, the net power delivered by the plant is 400 MWe. This case is referred to as the "unmodified EXPC" throughout this document.

- Case 2: An EXPC power plant that is retrofitted with a CCS system. This case is based on a 430-MWe plant with a subcritical boiler that fires mid-western bituminous coal, has been in commercial operation for more than 30 years, and is located in southern Illinois. After being routed through heat recovery equipment (including an economizer and regenerative air heater), the flue gas is sent to air emissions control equipment that includes an ESP and a lime-based FGD system. The ESP uses a high-voltage electrostatic charge to ionize particles in the gas stream so they can be removed from the stream by a set of charged collection plates, and the FGD initiates a series of chemical reactions in the flue gas that result in the removal of 94.9 percent of the sulfur found in the gas (NETL 2007b). Water that is discharged from the EXPC plant is discharged into a municipal sewer system. The EXPC plant of this case is retrofitted with a CCS system, which includes unit processes for the absorption, compression, pipeline transport, and final sequestration of $CO_2$. This CCS system includes a state-of-the art advanced amine process that recovers 90 percent of $CO_2$ from the flue gas. After accounting for the auxiliary power for the EXPC, the energy requirements of the CCS system, and a seven percent electricity transmission loss, the net power delivered by the plant is 336 MWe. To establish a uniform basis of comparison for this study, the difference between the net power of the unmodified EXPC and this case is modeled by assuming that the replacement power is generated within the Southeast Electric Reliability Council (SERC) electric grid. The fuel mix of the SERC grid is based on 2007 operating data for U.S. power plants (EPA 2008b). This case is referred to as the "retrofitted EXPC" throughout this document.

In addition 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 EXPC 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 EXPC. 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:
    - 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.).
    - $CO_2$ 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.
- 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, mercury (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.

### 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 operating requirements of an existing coal mine. All mining was assumed to be large-scale subterranean longwall mining of Illinois 6 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).

- Boundary ends when the processed coal is loaded onto a railcar for transport to the EXPC 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 EXPC facility, a distance of approximately 200 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 EXPC facility.
- Life Cycle Stage #3: Energy Conversion Facility: EXPC Plant
  - Boundary starts with coal entering the EXPC plant, with or without CCS.
  - Construction and decommissioning of new plant equipment (applicable only to the retrofitted case) and decommissioning of the plant (applicable to both cases) are included.
  - Operation of the EXPC plant is included for both cases.
  - Capital and O&M costs are calculated for the operation of the plant for both cases.
  - Operation of the switchyard and trunkline system that delivers the generated power to the grid is included.
  - For the EXPC plant with CCS, the boundary includes the following:
    - $CO_2$ is compressed to 2,215 pounds per square inch absolute (psia) at the EXPC 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 southern 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 EXPC 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 1-2.**

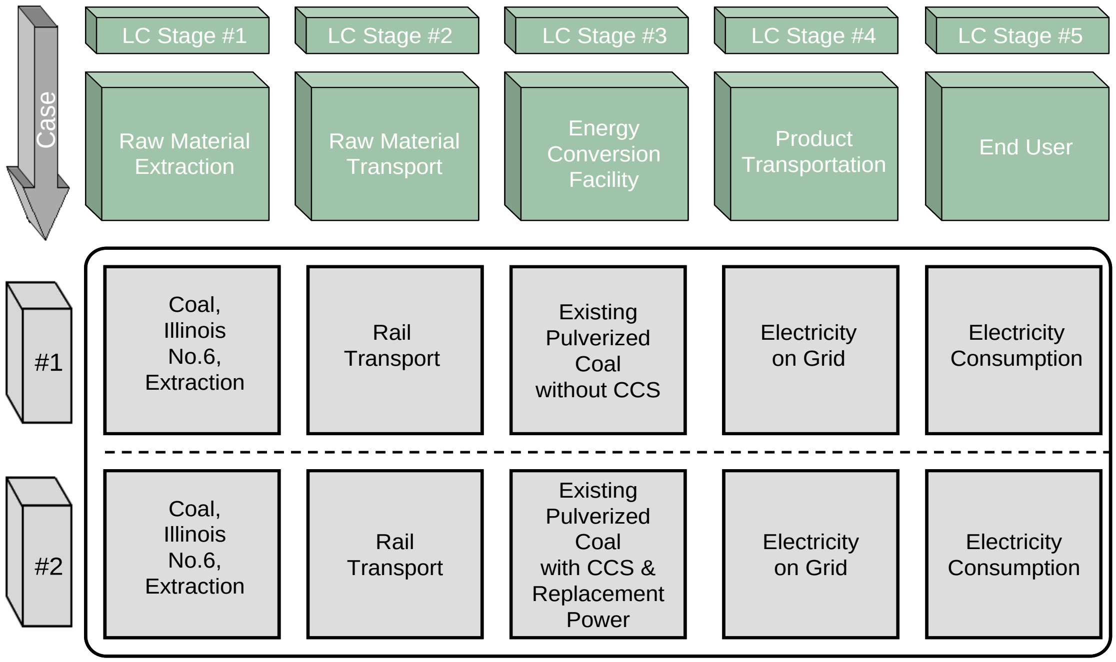



**Figure 1-2: Comparison of Cases by Life Cycle Stage**

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

The EXPC plant of this analysis is representative of subcritical pulverized coal (SCPC) technology, which is a mature technology that accounts for the majority of existing U.S. coal-fired power plant capacity. EXPC plants with CCS have not been commercially implemented, but for the purposes of this study the CCS process as applied to an EXPC plant will be assumed to be commercially available.

### 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

The quality of LC model results depends on the quality of input data. 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 3.5**), and specific assumptions for each data input are listed by stages in Appendix A.

No data are available for the energy and emissions associated with the decommissioning of a power plant (or other type of facility). It was assumed that decommissioning activities are 10 percent of commissioning activities. Thus, data for the decommissioning of the EXPC power plants were based on an application for a power plant in California, which included equipment specifications and fuel use for commissioning activities. Operations data for these scenarios came from a several sources.

The emission of sulfur oxide ($SO_x$) and other non-GHG emissions were derived from the U.S. Environmental Protection Agency (EPA) emissions inventory data (EPA 2009) for the Conesville power plant, a facility that has been retrofitted with a CCS system. The EPA inventory data (EPA 2009) did not provide adequate details for estimating the affect that a CCS system has on non-GHG emissions. The lack emission inventory data for $SO_X$ emissions before and after a CCS installation is a data limitation of this study.

#### 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 EXPC cases with and without CCS for their assumed 30-year life. The LCC provides the constant dollar LCOE and the PV of the production and delivery of energy over the study period (in years). PV (also called net present value) is the sum of all years' discounted after-tax cash flows, and represents the viability of investment in a particular technology (DOE, 1997).

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.

The capital costs associated with the construction of the existing equipment are not included in this analysis because they are a sunk cost represented by a prior decision-making process that is outside the scope of this study. However, the capital costs are applicable to the retrofitted EXPC case because it represents the construction of new equipment.

Capital investment costs are defined in the EXPC Baseline Report as including "equipment (complete with initial chemical and catalyst loadings), materials, labor (direct and indirect), engineering (e.g., labor associated with engineering of the EXPC plant) and construction management, and contingencies (process and project)." The EXPC Baseline Report excludes the following costs from capital investment costs:

- Escalation to period-of-performance.
- Owner's costs (including, but not limited to, land acquisition and right-of-way, permits and licensing, royalty allowances, economic development, project development costs, allowance for funds used during construction, legal fees, owner's engineering, preproduction costs, furnishings, owner's contingency, etc.).
- 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 the Baseline Report, all values are reported in December 2006 dollars and 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** | | |
| After-Tax Real Capital Recovery Factor | 0.106 | -- |
| Real Present Value of Depreciation | 0.487 | -- |
| Real Fixed Charge Rate | 0.139 | -- |
| Sum of PV Factors (Used in Calculating O&M Levelized Values) | 9.427 | -- |
| **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 30-year period (with the exception of depreciation rates, which are based on a 20-year period). The method for the LCOE is based on the NETL Power Systems Financial Model (NETL, 2008). The LCOE is calculated using the PV costs. All PV costs were levelized using a capital charge factor (CCF) for capital costs and a levelization factor for O&M costs. The LCOE is determined using Equation 1:

$$LCOE = \frac{CC_L + O\&M_L}{kWh \times CF \times T_{loss}} \tag{1}$$

Where: $CC_L$ is the levelized capital costs, $O\&M_L$ is the levelized O&M costs, kWh is net-kilowatt output of the plant, CF is the capacity factor of the plant, and $T_{loss}$ is the transmission loss factor, which is essentially 100 percent minus the transmission loss.

The $CC_L$ is calculated using Equation 2:

$$CC_L = CCF \times PV \tag{2}$$

Where: CCF is the capital charge factor, which is calculated using Equation 3:

$$CCF = \frac{\left(CRF \times \left(1 - tax\_rate \times PVD\right)\right)}{1 - tax\_rate} \tag{3}$$

Where: CRF is the capital recovery factor and PVD is the present value of depreciation. Equations 4 and 5 for these two factors are provided below:

$$CRF = \frac{\left(real\_dis\_rate \times \left(1 + real\_dis\_rate\right)^{anaP}\right)}{\left(1 + real\_dis\_rate\right)^{anaP} - 1} \tag{4}$$

$$PVD = MACRS\_DEP \times \left(1 + real\_dis\_rate\right) \tag{5}$$

Where: real_dis_rate is the real after tax discount rate, anaP is the analysis period, and MACRS_DEP is the deflation rate (described above), which is dependent upon the depreciation schedule.

The $O\&M_L$ was calculated using Equation 6:

$$O\&M_L = \frac{PV}{LF} \tag{6}$$

Where: LF is the levelization factor, determined using Equation 7:

$$LF = \frac{\left(\left(1 + real\_dis\_rate\right)^{anaP-1}\right)}{\left(real\_dis\_rate \times \left(1 + real\_dis\_rate\right)^{anaP}\right)} \tag{7}$$

### 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 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. For instance, water withdrawal 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 use 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 ($CO_2$e) |
|---|---|
| $CO_2$ | 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 NGCC 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 | Existing Midwestern | Present Study |
| Coal Feedstock | Midwestern Bituminous | NETL Carbon Capture 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 Round One Way Distance | 200 miles | Present Study |
| Rail Spur Constructed Length | Pre-existing with consideration for additional | 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 | Southern Illinois | Present Study |
| EXPC Net Electrical Output (without CCS) | 434 MW | NETL Carbon Capture Report |
| EXPC Net Electrical Output (with CCS) | 303 MW | NETL Carbon Capture Report |
| Trunk Line Constructed Length | Pre-existing | 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 Carbon Capture Report |
| **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 EXPC 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 EXPC 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.

# 2.0 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.

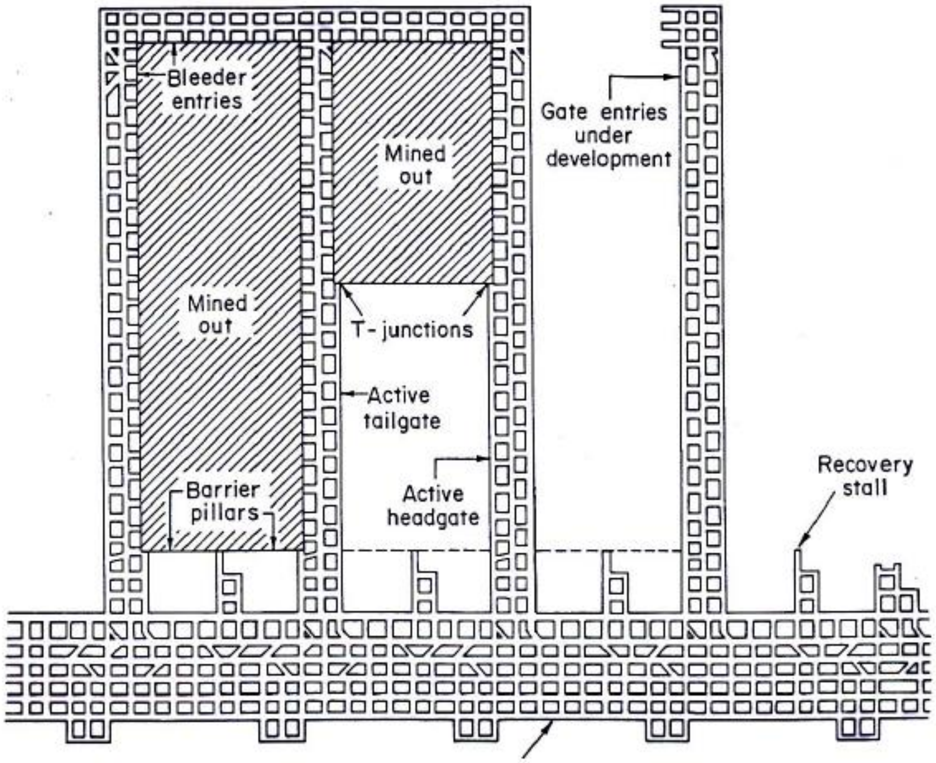



**Figure 2-1: Setup, Operation, and Maintenance of the Longwall Unit Requires Preliminary Preparation of Access Entries and Staging Rooms that are Excavated Using Continuous Mining Machines-Overhead View (Mark 1990)**

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**.

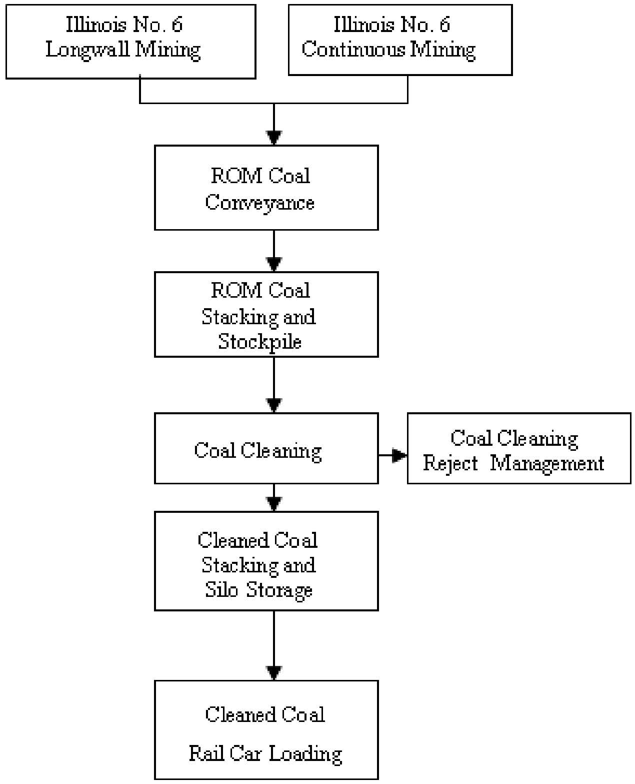



**Figure 2-2: Simplified Schematic of Illinois No. 6 Bituminous Coal Mining, Processing, and Management**

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.

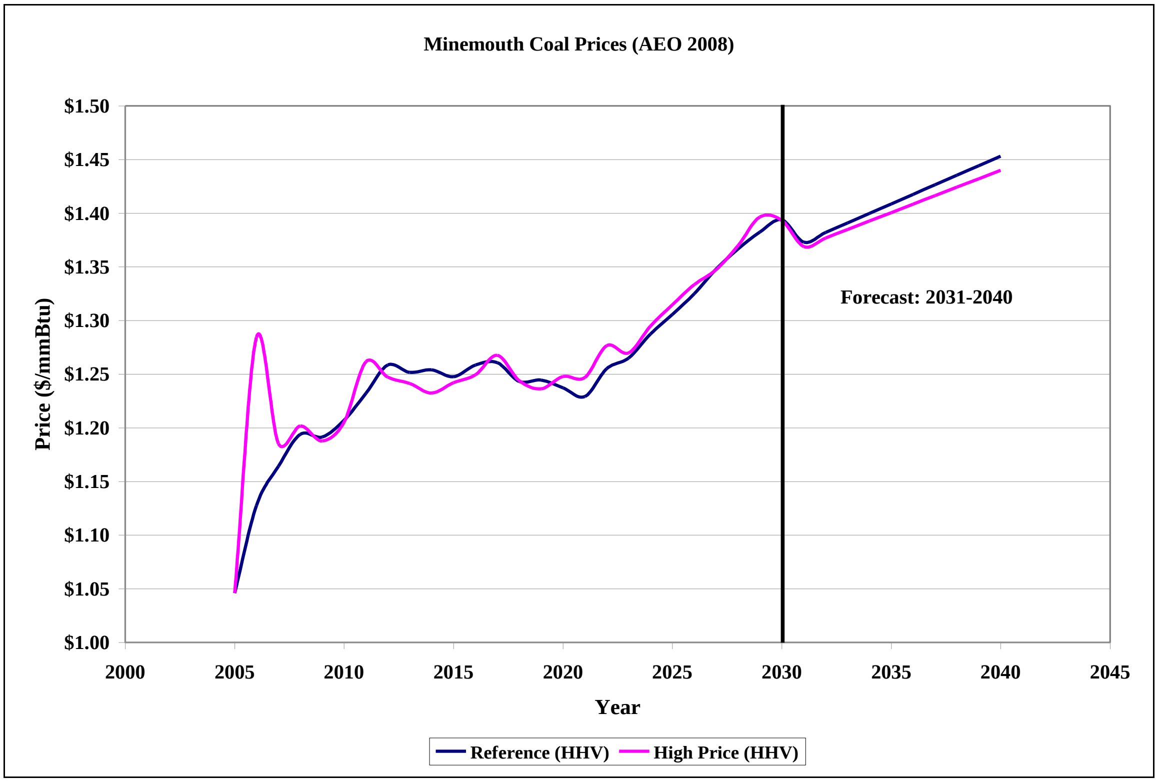



**Figure 2-3: Minemouth Coal Prices for the Lifetime of the Plant, 2006-2040 (EIA 2008)**

## 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:

- **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 represents energy use and emissions associated with removing the processing facility and returning the land to grassland. For this analysis, commissioning is excluded from system boundaries because the coal mine is existing. Decommissioning, however, is included within the system boundaries and is estimated as 10 percent of commissioning requirements.

- **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 $CO_2$e 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 $CO_2$e are listed in **Table 1-3**.

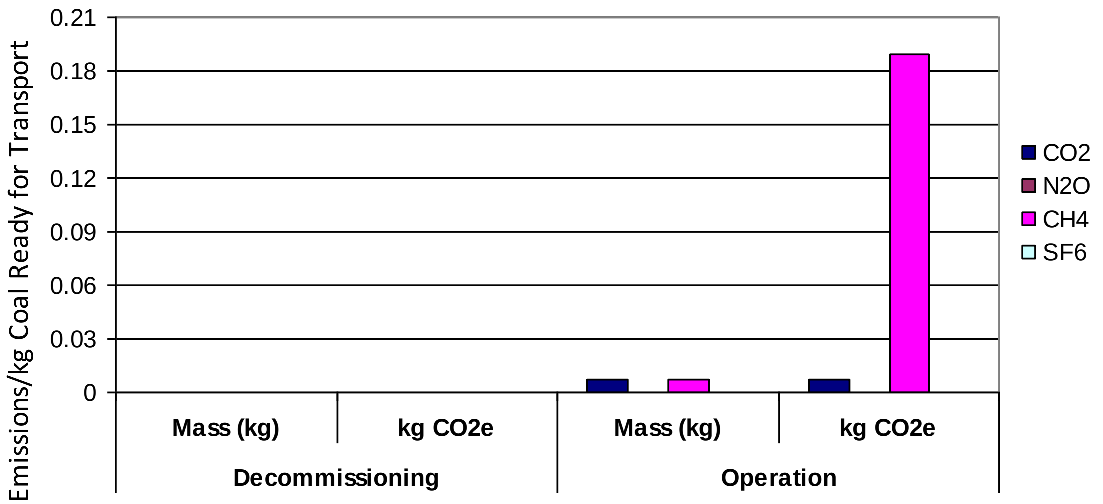



**Figure 2-4: EXPC Stage # 1 GHG Emissions/kg Coal Mine Output on a Mass (kg) and kg $CO_2$e Basis**

GHG emissions in this stage are dominated by $CH_4$ emitted during coal mining operation; $CH_4$ gases are trapped in the coalbed 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** summarizes the emissions graphed above. The total GWP for Stage #1 is 0.2 kg $CO_2$e per kg coal ready for transport.

**Table 2-1: EXPC Stage #1 GHG Emissions (on a Mass [kg] and kg $CO_2$e Basis) /kg Coal Ready for Transport**

| Coal Mine Processes | Decommissioning | | Operation | | Total | |
|---|---|---|---|---|---|---|
| Emissions (/kg coal) | Mass (kg) | kg $CO_2$e | Mass (kg) | kg $CO_2$e | Mass (kg) | kg $CO_2$e |
| $CO_2$ | 1.0E-07 | 1.0E-07 | 7.5E-03 | 7.5E-03 | 7.5E-03 | 7.5E-03 |
| $N_2O$ | 1.9E-12 | 5.7E-10 | 1.1E-07 | 3.2E-05 | 1.1E-07 | 3.2E-05 |
| $CH_4$ | 3.2E-12 | 8.1E-11 | 7.6E-03 | 1.9E-01 | 7.6E-03 | 1.9E-01 |
| $SF_6$ | 4.4E-23 | 1.0E-18 | 4.5E-14 | 1.0E-09 | 4.5E-14 | 1.0E-09 |
| Total GWP | | 1.1E-07 | | 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 EXPC Stage #1, kg/kg Coal Ready for Transport**

| Emissions kg/kg coal | Decommissioning | Operation | Total |
|---|---|---|---|
| Pb | 5.9E-19 | 3.3E-10 | 3.3E-10 |
| Hg | 3.3E-18 | 9.2E-11 | 9.2E-11 |
| $NH_3$ | 2.6E-12 | 6.6E-08 | 6.6E-08 |
| CO | 2.7E-10 | 7.3E-06 | 7.3E-06 |
| $NO_X$ | 8.3E-10 | 1.4E-05 | 1.4E-05 |
| $SO_X$ | 7.3E-13 | 3.7E-05 | 3.7E-05 |
| VOC | 3.8E-11 | 2.4E-07 | 2.4E-07 |
| PM | 2.8E-09 | 1.3E-06 | 1.3E-06 |

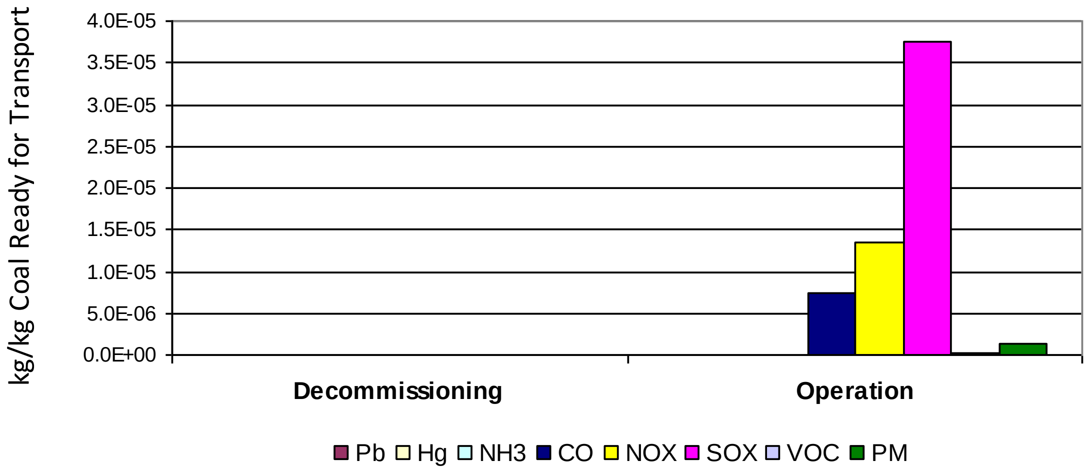



**Figure 2-5: Air Pollutant Emissions from EXPC Stage #1, kg/kg Coal Ready for Transport**

The emissions for decommissioning of a coal mine are negligible in comparison to the emissions for coal mining operations. Thus, decommissioning emissions are too low to appear within the scale of **Figure 2-5**.

Sulfur oxide is the dominant emission during Stage #1, due mostly to LC emissions associated with electricity use. The carbon monoxide (CO) and nitrogen oxide ($NO_X$) 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 EXPC Stage #1, kg/kg Coal Ready for Transport**

| Water (kg/kg Coal Output) | Decommissioning | Construction | Operation | Total |
|---|---|---|---|---|
| Water Withdrawal | 4.00E-10 | 1.4E-03 | 0.41 | 0.41 |
| Wastewater Outfall | 3.55E-10 | 1.8E-04 | 1.0 | 1.0 |
| Water Consumption | 4.50 E-11 | 1.2E-03 | -0.59 | -0.59 |

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 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 storm water 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 conversions facility located in southwestern Illinois, a distance of 200 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, 2007).

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 all railway infrastructure connecting the coal mine and the EXPC facility was existing; if the EXPC facilities did not exist, the railway infrastructure would still exist. 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 2007a) 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.

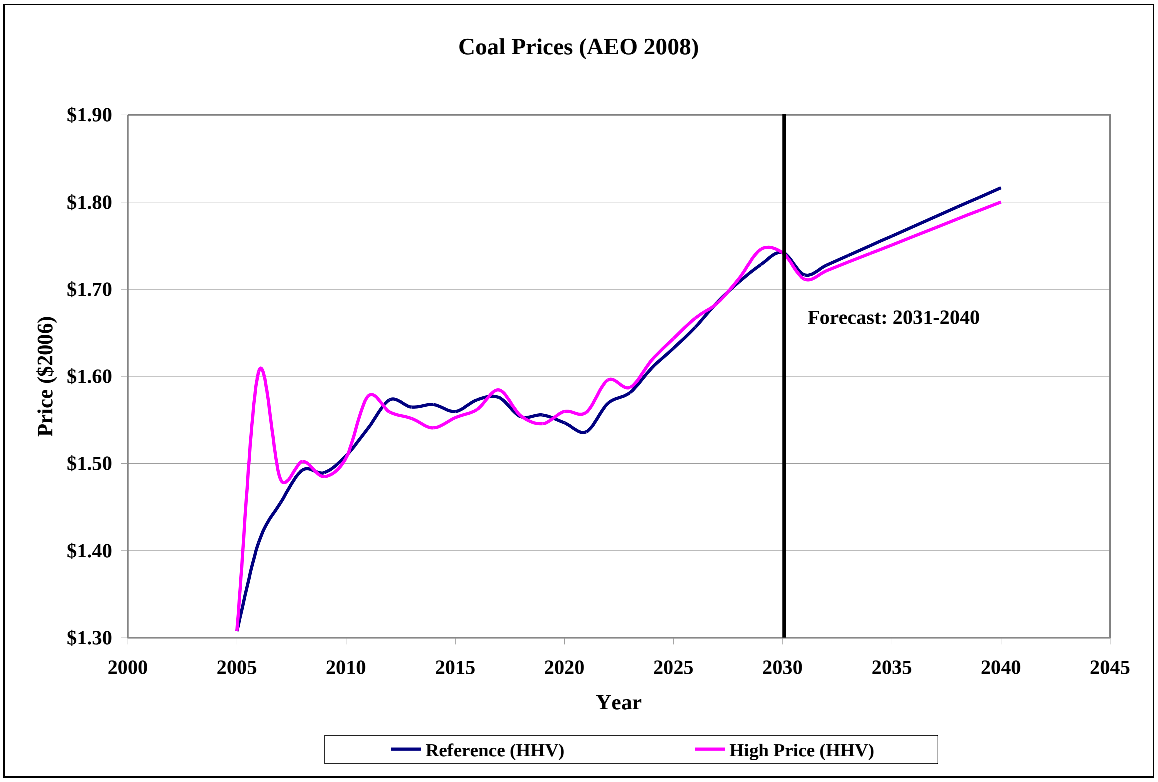



**Figure 2-6: Delivered Coal Prices for Lifetime of the Plant**

### 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 $CO_2$e basis per kg of coal transported. Carbon dioxide is the dominant pollutant due to the combustion of diesel fuel during train operation. The total GWP of Stage #2 is 0.0037 kg $CO_2$e per kg coal transported.

**Table 2-4: EXPC Stage #2 GHG Emissions (Mass [kg] and kg $CO_2$e) /kg of Coal Transported**

| Processes | Train Operation | |
|---|---|---|
| Emissions (/kg coal) | Mass (kg) | kg $CO_2$e |
| $CO_2$ | 3.6E-02 | 3.6E-02 |
| $N_2O$ | 8.7E-07 | 2.6E-04 |
| $CH_4$ | 5.2E-05 | 1.3E-03 |
| $SF_6$ | 1.8E-14 | 4.1E-10 |
| Total GWP | | 3.7E-02 |

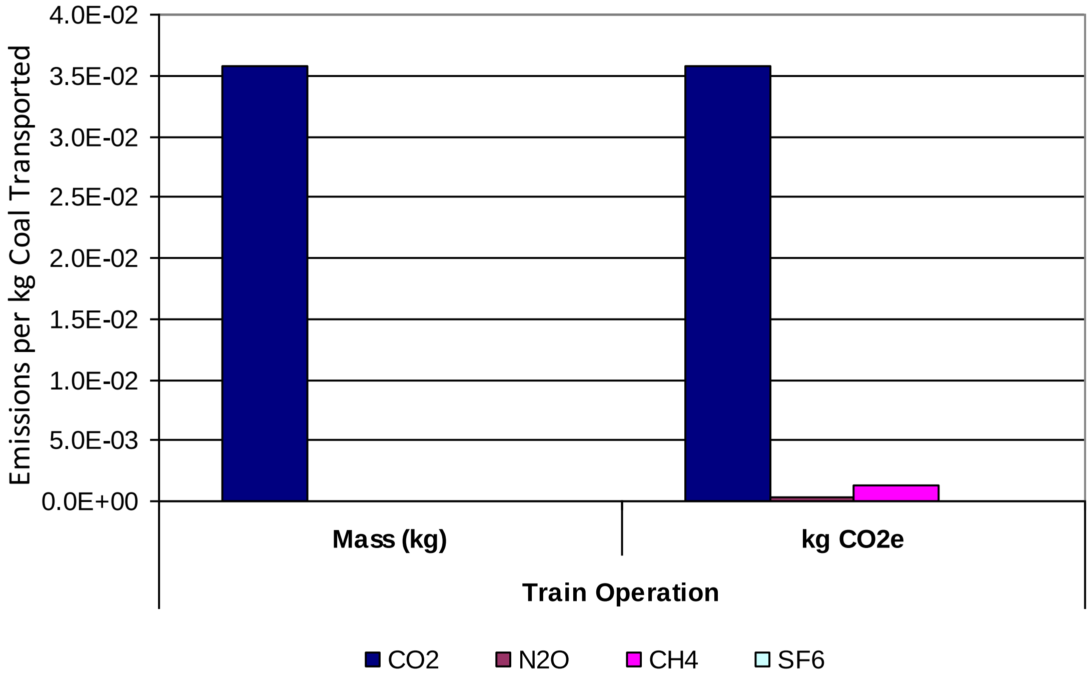



**Figure 2-7: EXPC Stage #2 GHG Emissions (Mass [kg] and kg $CO_2$e) /kg of Coal Transported**

### 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: EXPC Stage #2 Air Emissions, kg/kg Coal Transported**

| Emissions (kg/kg coal) | Train Operation |
|---|---|
| Pb | 2.1E-10 |
| Hg | 2.0E-11 |
| $NH_3$ | 1.3E-06 |
| CO | 1.0E-04 |
| $NO_X$ | 9.7E-05 |
| $SO_X$ | 1.9E-05 |
| VOC | 8.9E-06 |
| PM | 1.2E-04 |

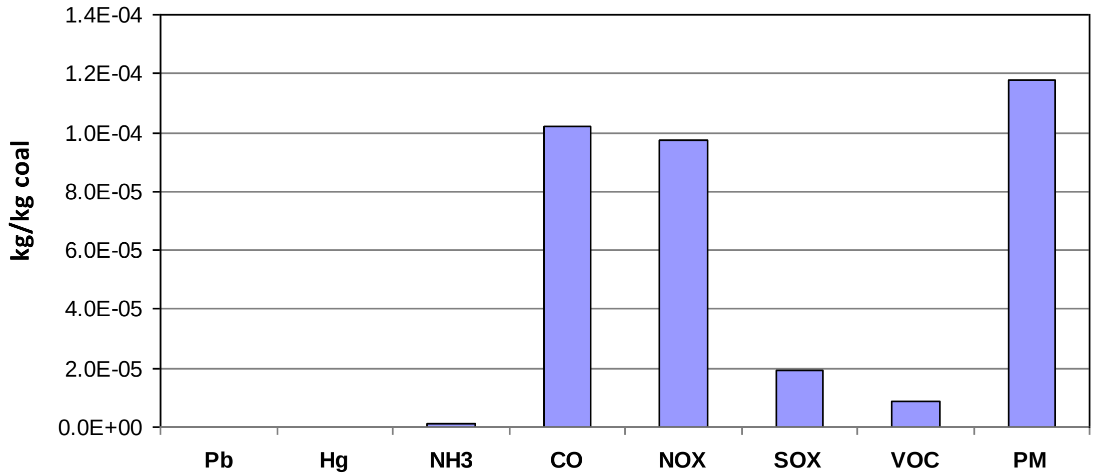



**Figure 2-8: EXPC Stage #2 Air Emissions, kg/kg Coal Transported**

### 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, water withdrawal and consumption for this stage are small and based solely on secondary data sources, such as GaBi profiles.

**Table 2-6: EXPC Stage #2 Water Withdrawal and Consumption, kg/kg Coal Transported**

| Water (kg/kg coal) | Train Operation |
|---|---|
| Water Withdrawal | 2.49E-03 |
| Wastewater Outfall | 1.80E-03 |
| Water Consumption | 6.88E-04 |

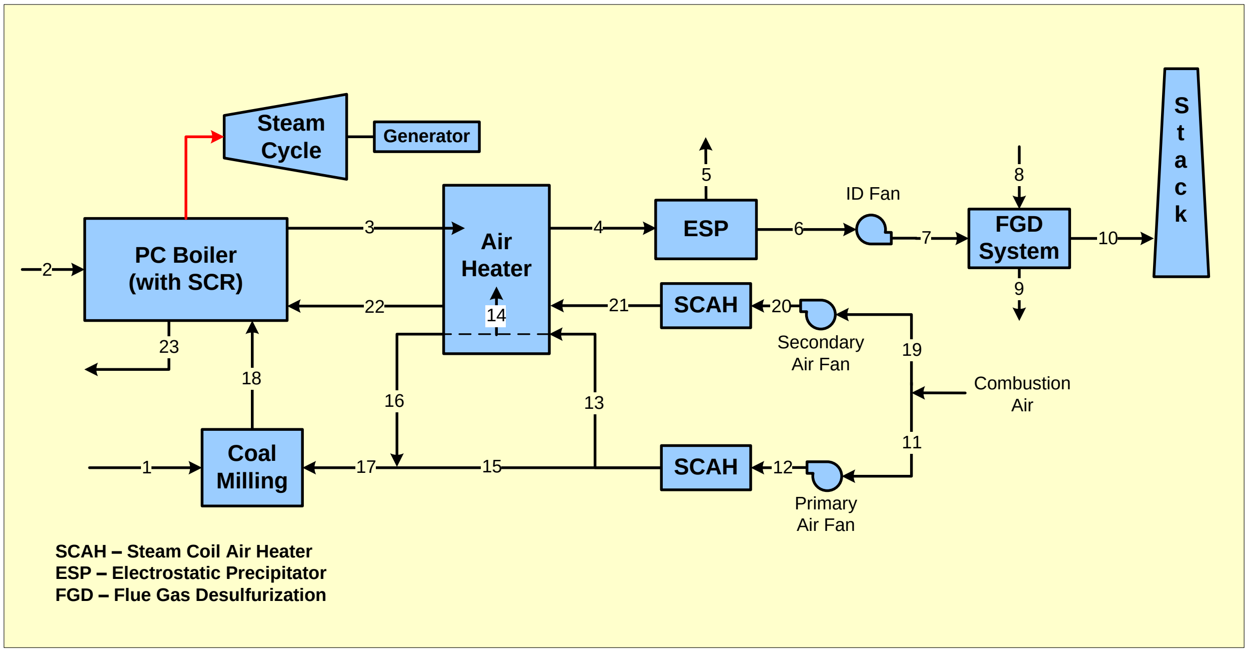
## 2.3 Life Cycle Stage #3: Energy Conversion Facility for EXPC without CCS

The following briefly describes the operation of a 433-MWe net output EXPC plant without CCS; most data for this stage were taken from the Baseline Report (NETL, 2007).

The unmodified EXPC plant will be modeled using current NETL study results for an EXPC plant without CCS (NETL 2007b) as well as from NETL case studies for fossil energy plants (NETL 2007a). The EXPC plant is a 433-MWe unit with a subcritical boiler that fires mid-western bituminous coal and has been in commercial operation for more than 30 years. The furnace is a single-cell design that employs corner firing with five elevations of tilting tangential coal burners. Five RP-903 coal pulverizers supply coal to the burner elevations. The steam generation process is facilitated by the superheater, reheater, and accompanying elements. A steam-driven boiler feed pump directs recycled water into a series of six feedwater heaters (three low-pressure heaters, a deaerator, and two high-pressure heaters) where the feedwater is preheated to 256°C (493°F) (NETL 2007b). The preheated water is directed to the economizer where it is heated further by hot exhaust from the combustion process. The water is converted to steam at a temperature of 538°C (1,000°F) and pressure of 175 bara (2,535 psia) by the superheater, which then sends it through the high-pressure steam turbine (NETL 2007b). The used steam is then directed to a two-stage reheater, where it is prepared for the intermediate-pressure steam turbine. At this point, the steam expands through the intermediate- and low-pressure turbine sections where it is exhausted to the condenser at the appropriate pressure. From here, the water eventually finds its way back to the boiler feed pump and the process repeats.

The hot flue gas from the coal combustion is used to heat water entering the economizer. The gas then enters the Ljungström® trisector regenerative air heater, which is used to heat both the primary and secondary air streams prior to combustion in the lower furnace. In addition to selective catalytic reduction (SCR) used by the boiler, an ESP and lime-based FGD system are used to clean the cooled flue gas before it is discharged to the atmosphere. The ESP uses a high-voltage electrostatic charge to ionize particles in the gas stream so they can be removed from the stream by a set of charged collection plates. The FGD initiates a series of chemical reactions in the flue gas that result in the removal of 94.9 percent of the sulfur found in the gas (NETL 2007b). Additional and detailed description of these environmental control systems are provided in the EXPC Baseline Report.

The relationships among the unit processes of the EXPC (without a CCS system) are illustrated in **Figure 2-9**, which is based on information provided in the EXPC Baseline Report (NETL, 2007b). The figure represents the relationships between subsystems and related flows.




Material Flow Stream Identification:

| | | | | | |
|---|---|---|---|---|---|
| 1 | Raw Coal to Pulverizers | 9 | FGD System Solids to Disposal | 17 | Mixed Primary Air to Pulverizers |
| 2 | Air Infiltration Stream | 10 | Flue Gas to Stack | 18 | Pulverized Coal and Air to Furnace |
| 3 | Flue Gas from Economizer to Air Heater | 11 | Air to Primary Air Fan | 19 | Secondary Air to Forced Draft Fan |
| 4 | Flue Gas Leaving Air Heater to ESP | 12 | Primary Air to Steam Coil Air Heater | 20 | Secondary Air to Steam Coil Air Heater |
| 5 | Fly Ash Leaving ESP | 13 | Primary Air to Air Heater | 21 | Secondary Air to Air Heater |
| 6 | Flue Gas Leaving ESP to Induced Draft Fan | 14 | Air Heater Leakage Air Stream | 22 | Heated Secondary Air to Furnace |
| 7 | Flue Gas to Flue Gas Desulfurization System | 15 | Tempering Air to Pulverizers | 23 | Bottom Ash from Furnace |
| 8 | Lime Feed to FGD System | 16 | Hot Primary Air to Pulverizers | | |

**Figure 2-9: Process Flow Diagram, EXPC without $CO_2$ Capture**

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 EXPC plant, including treated process water and cooling tower blowdown, is assumed to be discharged into a municipal sewer system.

Primary inputs associated with operation of the EXPC without CCS are coal, natural gas for auxiliary boiler power, and process water. 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

For the EXPC facility without CCS, only O&M costs are considered in the analysis. **Table 2-7** lists the cost data and input parameters used to model the LCC for the EXPC plant without CCS. All values were reported in 2006 dollars and taken directly from the EXPC Baseline Report (NETL, 2007b). It is assumed that replacement costs for the plant are included in the variable O&M costs taken from the EXPC Baseline Report.

**Table 2-7: Cost Data from the NETL Baseline Report and Necessary LCC Input Parameters for EXPC without CCS and EXPC with CCS**

| Parameter | EXPC |
|---|---|
| Electricity Net ($MW_e$) | 434 |
| Capacity Factor | 85% |
| Fixed O&M Costs, Labor Cost ($/yr) | $3,446,125 |
| Variable O&M Cost ($/yr)[1] | $2,906,920 |
| Decommissioning ($)[2] | $85,261,200 |

1. Variable O&M costs include replacement costs.
2. Decommissioning costs for the energy conversion facility are considered to be equal to 10 percent of the capital cost of the SCPC facility. Because no capital costs are considered for the EXPC unmodified case, decommissioning costs were estimated based on SCPC facility capital costs (NETL, 2007).

It should be noted that the environmental LC analysis did not calculate the energy and environmental flows specific to the auxiliary boiler. The reason for this omission was to avoid the possibility of double counting emissions data. However, the costs of the auxiliary boiler activities are specified in the LCC model because, unlike the environmental data, we know that the cost data does not double count the activities of the auxiliary boiler.

Coal and natural gas for the auxiliary boiler were major inputs into the EXPC plant not considered in the O&M costs assumed from the Baseline Report (NETL, 2007b); 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 (0). 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 to 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. **Figure 2-10** presents the AEO 2008 reference and high-case prices for natural gas based on HHV.

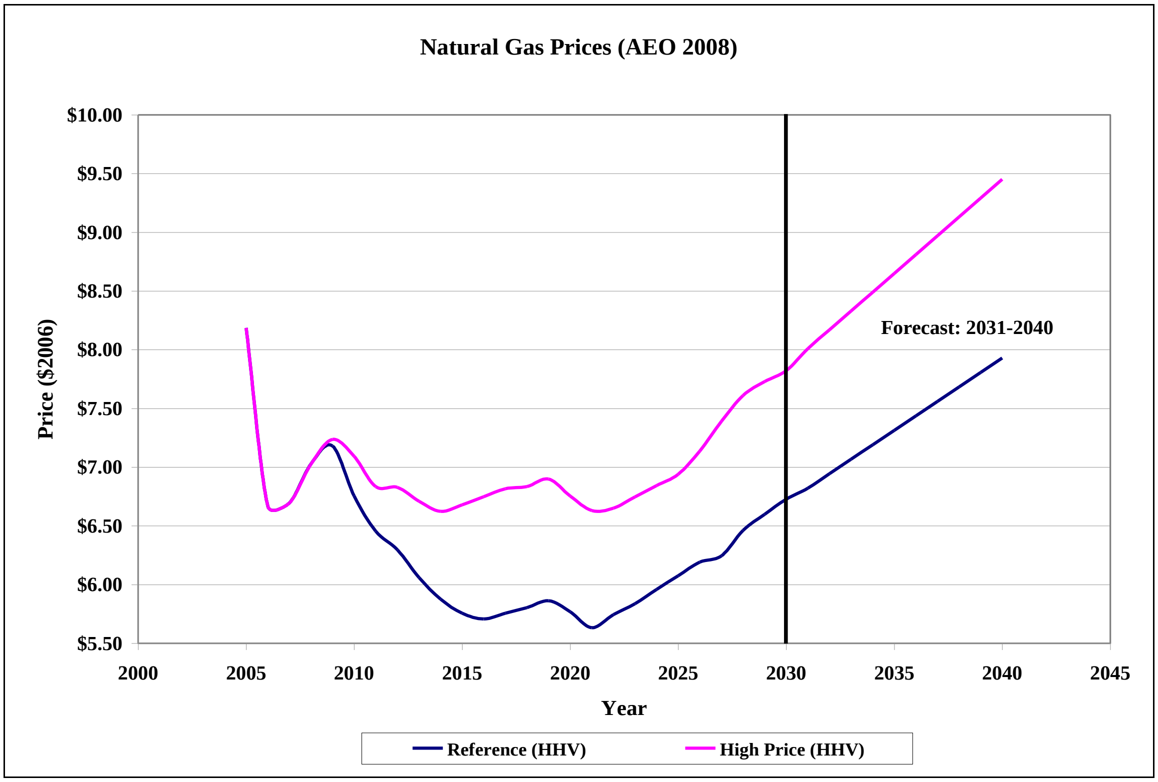



**Figure 2-10: Natural Gas Prices for the Lifetime of the Plant**

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.

**Table 2-8** shows the feedrate of each input. The feedrate for coal was assumed from the EXPC Baseline Report (NETL, 2007b). The natural gas feedrate was calculated based on an hourly feedrate of 53,000ft$^3$/hr and the operating time of the auxiliary boiler, which is assumed to be 50 percent of the total plant downtime (15 percent in this case) (Wabash Power Equipment, 2008).

**Table 2-8: Feedrates for Feed/Fuel and Utilities for EXPCCase without CCS**

| Input | Feedrate |
|---|---|
| Coal (Tons/day) | 3,823 |
| Natural Gas (MMBtu/day)[1] | 98 |

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).

## Decommissioning

Decommissioning was assumed to be equal to 10 percent of the total LC capital costs for the case. Because no capital costs are considered for the energy conversion facility for this case, decommissioning costs were determined based on the capital costs for an SCPC facility (NETL, 2007a). The decommissioning costs for the EXPC case without CCS are equal to $85,261,200.

### 2.3.2 LCC Results

The levelized costs for the EXPC plant without CCS are shown in **Figure 2-11**. Results indicate that utility costs contribute the largest amount to the total LC LCOE costs. The utility costs account for $0.0211/kWh of the total LCC. Following this, capital costs from the decommissioning of the facility account for $0.0040/kWh; fixed plant O&M costs and variable O&M cost contribute $0.0013/kWh, each. Capital costs for the energy conversion facility are not included in this study.

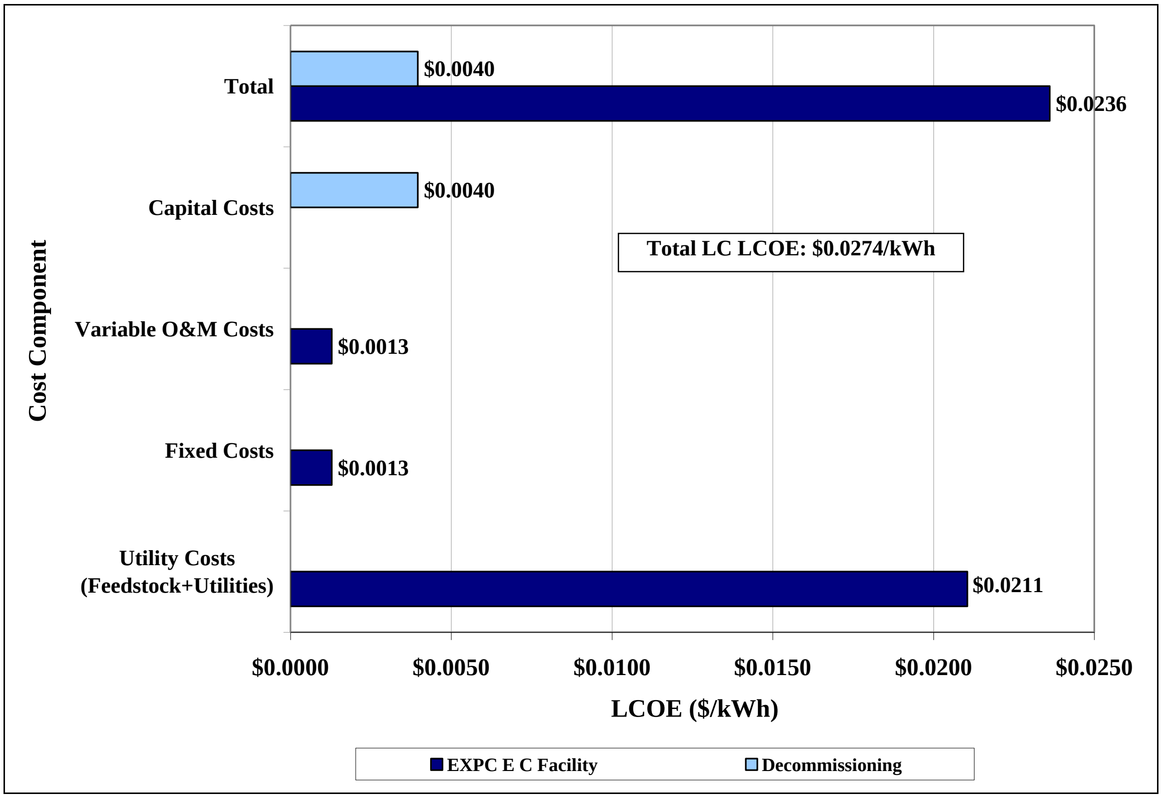



**Figure 2-11: LCOE for the EXPC without CCS, $/kWh**

1. LCOE calculated using 85% capacity factor and a 7% transmission loss.
2. EXPC EC facility represents the energy conversion facililty alone.
3. Decommissioning is equal to 10% of SCPC capital costs (NETL, 2007).

**Figure 2-12** presents the total LC costs, measured in $/kW, for the EXPC case without CCS. As with the LCOE, the results indicate that the majority of the total LC costs are contributed by the utility costs. The EXPC energy conversion facility is the primary source of the costs for the LC. At the EXPC energy conversion facility, the utility cost equals $1,739/kW, the fixed O&M costs equal $106/kW, and the variable O&M costs equal $89/kW. Decommissioning costs equal $249/kW and are considered to be capital costs. The total LC costs are equal to $2,182/kW.

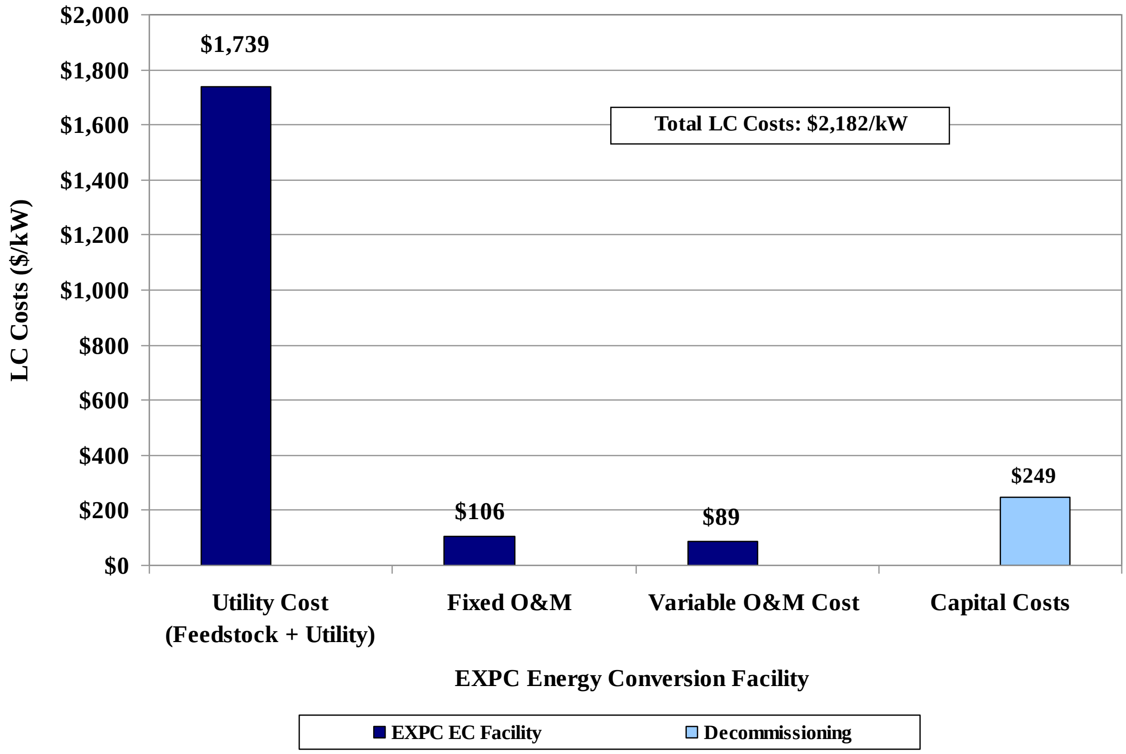



**Figure 2-12: Total LC Costs ($/kW) for EXPC Case without CCS**

1. LC costs calculated using 85% capacity factor and a 7% transmission loss.
2. EXPC EC facility represents the energy conversion facililty alone.
3. Decommissioning is equal to 10% of SCPC capital costs (NETL,2007).

### 2.3.3 Greenhouse Gas Emissions

**Table 2-9** and **Figure 2-13** shows the GHG emissions associated with the EXPC plant without CCS, on an MWh plant output basis. Carbon dioxide is the dominant pollutant, with the largest emissions associated with the combustion of coal. The total GWP of this stage is 946 kg $CO_2$e per MWh plant output, 99 percent of which is due to the EXPC plant operations.

Table 2-9: EXPC without CCS Stage #3 GHG Emissions in kg and kg $CO_2$e/MWh Plant Output

| EXPC Processes | Decommissioning | | Operation | | Total | |
|---|---|---|---|---|---|---|
| Emissions (/MWh) | Mass (kg) | kg $CO_2$e | Mass (kg) | kg $CO_2$e | Mass (kg) | kg $CO_2$e |
| $CO_2$ | 6.3E-05 | 6.3E-05 | 941 | 941 | 941 | 941 |
| $N_2O$ | 1.6E-09 | 4.6E-07 | 1.6E-02 | 4.7 | 1.6E-02 | 4.7 |
| $CH_4$ | 7.9E-08 | 2.0E-06 | 1.1E-02 | 2.7E-01 | 1.1E-02 | 2.7E-01 |
| $SF_6$ | 2.8E-17 | 6.3E-13 | 2.6E-07 | 5.9E-03 | 2.6E-07 | 5.9E-03 |
| Total GWP | | 6.5E-05 | | 946 | | 946 |

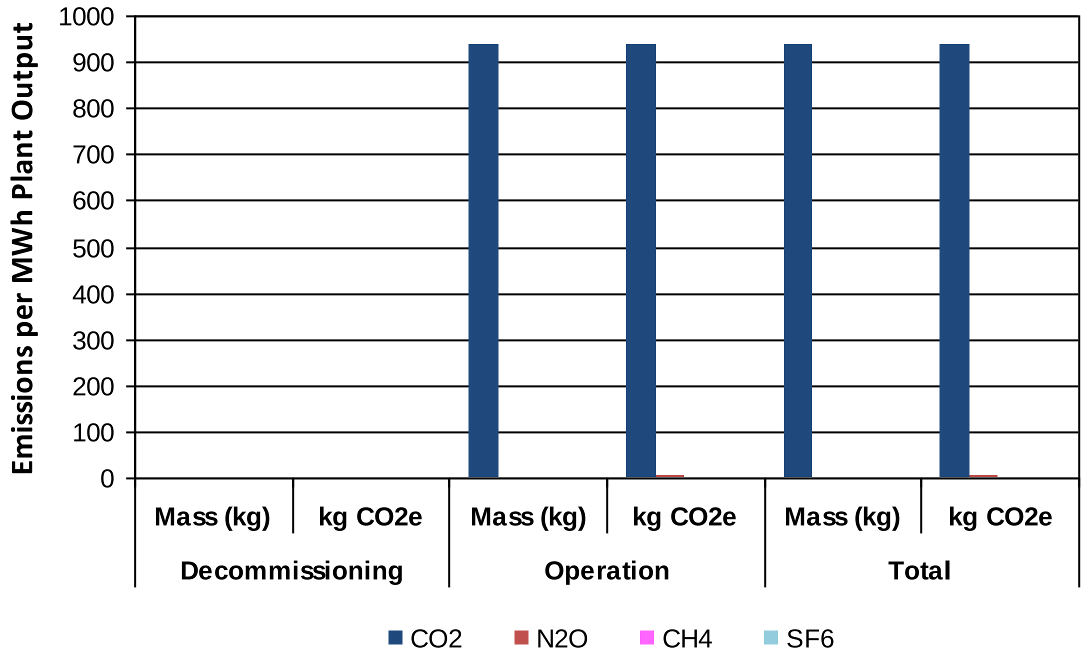



Figure 2-13: EXPC without CCS Stage #3 GHG Emissions in kg and kg $CO_2$e/MWh Plant Output

### 2.3.4 Air Pollutant Emissions

**Table 2-10** and **Figure 2-14** show the air pollutants released during EXPC plant operations on a per MWh output basis. As with GHGs, emissions are dominated by the combustion of coal during plant operation. 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 2-10** and **Figure 2-14** for EXPC 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, 2007).

**Table 2-10: EXPC without CCS Stage #3 Air Pollution Emissions, kg/MWh Plant Output**

| Emissions (kg/MWh) | Decommissioning | Plant Operation | Total |
|---|---|---|---|
| Pb | 3.3E-13 | 5.9E-06 | 5.9E-06 |
| Hg | 3.1E-14 | 4.8E-05 | 4.8E-05 |
| $NH_3$ | 2.3E-09 | 2.0E-04 | 2.0E-04 |
| CO | 2.6E-06 | 1.0E-01 | 1.0E-01 |
| $NO_X$ | 9.5E-07 | 1.9 | 1.9 |
| $SO_X$ | 5.3E-08 | 2.2 | 2.2 |
| VOC | 2.5E-07 | 1.2E-02 | 1.2E-02 |
| PM | 1.3E-07 | 6.3E-01 | 6.3E-01 |

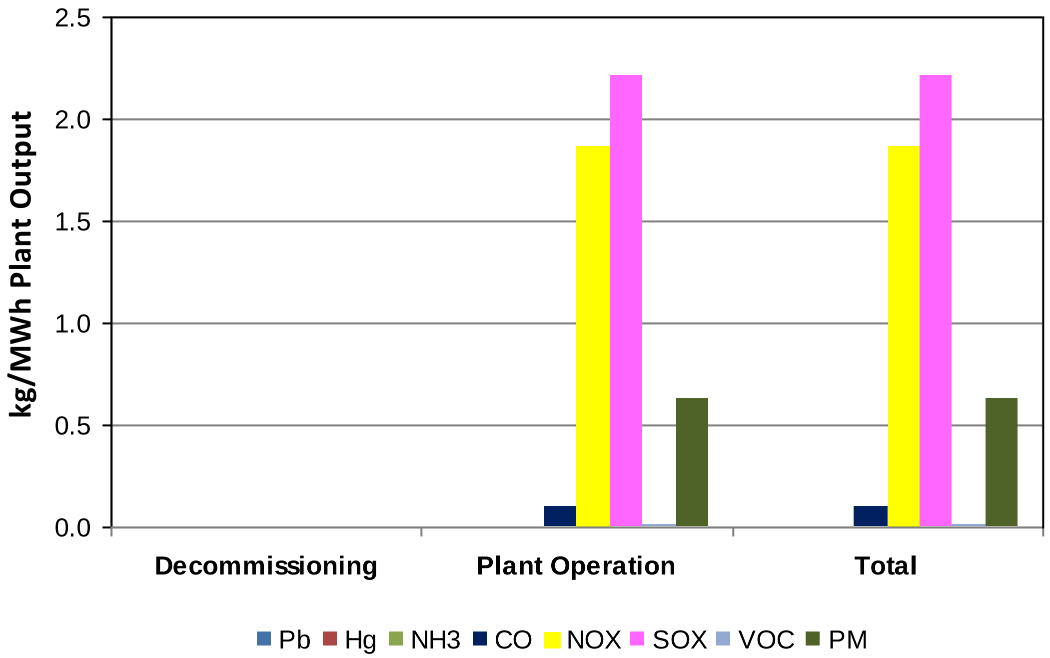



**Figure 2-14: EXPC without CCS Stage #3 Air Pollution Emissions, kg/MWh Plant Output**

### 2.3.5 Water Withdrawal and Consumption

**Table 2-11** shows water withdrawal and consumption for the unmodified EXPC plant. 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 2-11: EXPC without CCS Stage #3 Water Withdrawal and Consumption, kg/MWh Plant Output**

| Water (kg/MWh) | Decommissioning | Plant Operation | Total |
|---|---|---|---|
| Water Withdrawal | 1.18E-02 | 2702 | 2702 |
| Wastewater Outfall | 9.09E-04 | 609 | 609 |
| Water Consumption | 1.09E-02 | 2093 | 2093 |

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

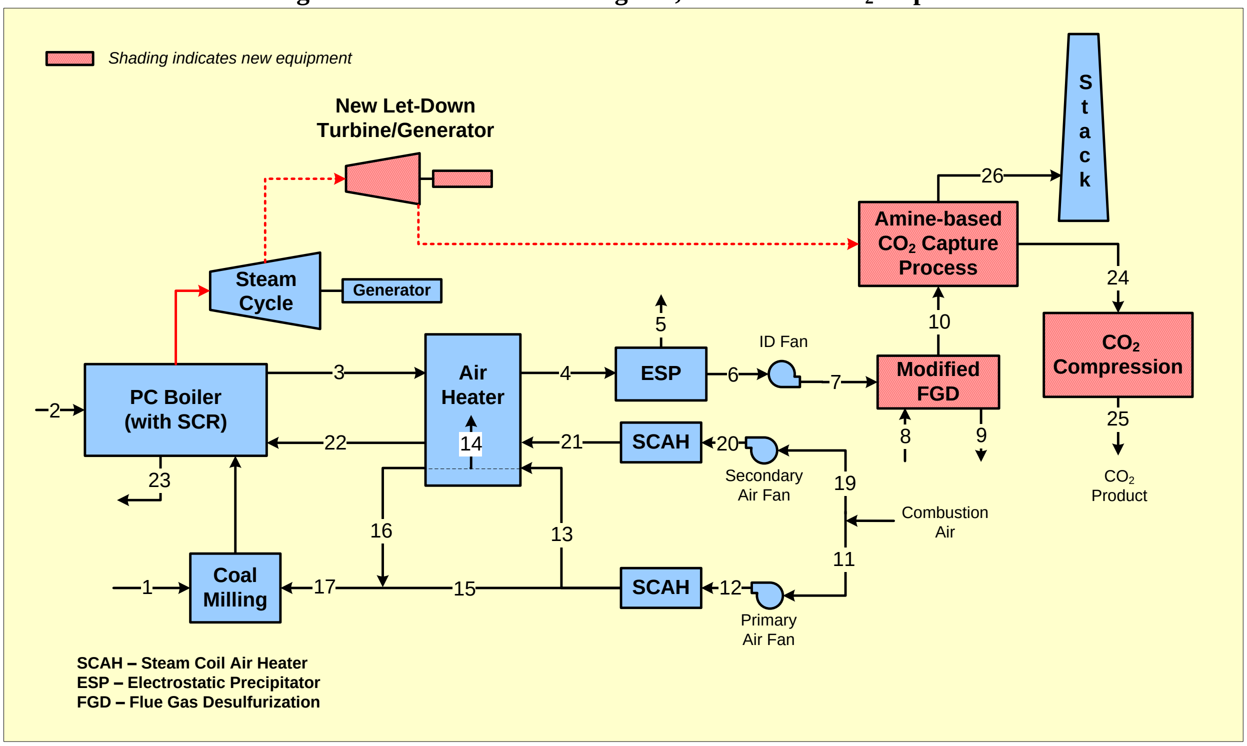
The following briefly describes the operation of a 303-MWe net output EXPC plant that has been retrofitted with CCS (the installation of the CCS system reduced net power output of the plant from 433 to 303 MWe). As with the operation of the unmodified EXPC plant (**Section 2.3**), data were from the EXPC Baseline Report (NETL, 2007b) as well as from NETL case studies for fossil energy plants (NETL 2007a). In contrast to the case of EXPC without CCS, the flue gas is further scrubbed for additional sulfur dioxide ($SO_2$) removal and also cooled in a polishing scrubber as a prerequisite for $CO_2$ removal. The monoethanolamine (MEA)-based solvent process is used to remove approximately 90 percent of the $CO_2$ from the flue gas. The concentrated $CO_2$ stream is then directed to the $CO_2$ compression stage. 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 for saline sequestration. The addition of CCS to the EXPC technology decreases net energy conversion facility power output, increases water and reagent requirements, and increases byproduct production rates.

Carbon dioxide captured at the EXPC power plant is transported a distance of approximately 161 km (100 miles) via pipeline to a sequestration site. The $CO_2$ is sequestered in a geologic saline formation at a depth of 1,236 meters (4,055 feet) (NETL 2007a). The pressure of the $CO_2$ when it leaves the EXPC plant is such that no recompression is needed along the length of the pipeline (NETL 2007a). According to NETL's Cost and Performance Baseline for Fossil Energy Plants, one well is able to inject 9,979 metric tonnes (10,320 short tons) of $CO_2$ per day (2007a).

Estimates of storage capacity for captured $CO_2$ vary, but most estimates agree that the potential for a significant amount of storage does exist. Benson et al. (2000) estimate that there exists enough storage for anywhere from 100 to 3,000 gigatonnes (110,231,131,090 to 3,306,933,932,800 short tons) of carbon (GtC) around the world, and one to 300 GtC (1,102,311,311 to 330,693,393,280 short tons) for brine formations in the United States alone. Geologic formations could hold as much as 11,000 gigatonnes of $CO_2$ ($GtCO_2$) worldwide, according to a Global Energy Technology Strategy Program Report (Dooley et al 2006).

**Figure 2-15** shows many of the same operation steps and processes that were shown previously in **Figure 2-9**. The major difference for EXPC with CCS is the inclusion of the Econamine FG plus block, an MEA-based solvent process which removes approximately 90 percent of $CO_2$ from the flue gas (NETL, 2007b). In the $CO_2$ compression stage, $CO_2$ is dehydrated and compressed to a pressure of 15.3 MPa (2,215 psia) – appropriate for pipeline transport and direct injection/saline sequestration.

**Figure 2-15: Process Flow Diagram, EXPC with $CO_2$ Capture**




Material Flow Stream Identification:

| | | | | | |
|---|---|---|---|---|---|
| 1 | Raw Coal to Pulverizers | 10 | Flue Gas $CO_2$ capture process | 20 | Secondary Air to Steam Coil Air Heater |
| 2 | Air Infiltration Stream | 11 | Air to Primary Air Fan | 21 | Secondary Air to Air Heater |
| 3 | Flue Gas from Economizer to Air Heater | 12 | Primary Air to Steam Coil Air Heater | 22 | Heated Secondary Air to Furnace |
| 4 | Flue Gas Leaving Air Heater to ESP | 13 | Primary Air to Air Heater | 23 | Bottom Ash from Furnace |
| 5 | Fly Ash Leaving ESP | 14 | Air Heater Leakage Air Stream | 24 | Recovered $CO_2$ to compression |
| 6 | Flue Gas Leaving ESP to Induced Draft Fan | 15 | Tempering Air to Pulverizers | 25 | $CO_2$ ready for sequestration |
| 7 | Flue Gas to Flue Gas Desulfurization System | 16 | Hot Primary Air to Pulverizers | 26 | Flue gas to stack (post treatment) |
| 8 | Lime Feed to FGD System | 17 | Mixed Primary Air to Pulverizers | | |
| 9 | FGD System Solids to Disposal | 19 | Secondary Air to Forced Draft Fan | | |

Adding CCS to the EXPC plant decreases the net power output while increasing water and coal input requirements. 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

Listed below in **Table 2-12** are the assumptions and parameters used to determine the EXPC with CCS cost analysis results. The EXPC plant with CCS has a net electricity output of 303 MWe (NETL, 2007b).

**Table 2-12: EXPC Facility with CCS Cost Parameters and Assumption Summary**

| Parameter | EXPC w/CCS |
|---|---|
| Electricity Net (MWe) | 303 |
| Capacity Factor | 85% |
| Capital Investment | $400,094,000 |
| Fixed O&M Costs ($/yr) | $5,939,958 |
| Variable O&M Cost ($/yr)[1] | $20,552,335 |

1. Variable O&M costs include replacement costs.

The assumptions applied to the EXPC case with CCS are the same as those applied to the feed/fuel and utilities used for the EXPC case without CCS (**Section 1.3.1**).

**Table 2-13: Feedrates for Feed/Fuel and Utilities for EXPC Case with CCS**

| Parameter | Feedrate |
|---|---|
| Coal (Tons/day) | 3,823 |
| Natural Gas (MMBtu/day)[1] | 98 |

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).

### $CO_2$ Transportation, Sequestration, and Monitoring

For the EXPC 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, 40.64 cm (16 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:

$$
\begin{aligned}
Material(\$/mile) &= 1.1\left(330.5d^2 + 687d + 26{,}960\right) \\
Land(\$/mile) &= 1.1\left(577d + 29{,}788\right) \\
Labor(\$/mile) &= 1.1\left(343d^2 + 2074d + 170{,}013\right) \\
Misc(\$/mile) &= 1.1\left(8417d + 7324\right)
\end{aligned}
\tag{8}
$$

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 $65,403,910. 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 $31,304.00. **Table 2-14** summarizes the $CO_2$ pipeline capital and O&M costs.

**Table 2-14: Summary of $CO_2$ Pipeline Capital and Fixed Costs**

| $CO_2$ Pipeline | EXPC w/CCS |
|---|---|
| Material Cost ($/mile) | $134,816 |
| Labor Cost ($/mile) | $320,106 |
| Misc Costs ($/mile) | $156,196 |
| Land Costs ($/mile) | $42,922 |
| Total $CO_2$ Pipeline Capital Costs ($/100 miles) | $65,403,910 |
| 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) | $2,630,400.40 |
| 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 EXPC case with CCS, it is assumed that two, 1,239-meter (4,065-feet) 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

$6.2 million. Capital costs include the siting, well construction, installation of equipment, and other miscellaneous costs, including project and process contingency costs. The O&M costs for the $CO_2$ injection well are equal to $161,958.

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). There are no capital costs included in the monitoring costs, only O&M costs.

### Replacement Power Cost

With the addition of the CCS components at the power plant, there is a decrease in net-output; due to this replacement power, costs were added to make-up for the loss in output. To determine replacement power costs, the average SERC region retail electricity price was used. The average retail electricity price was determined by taking the average of the retail electricity prices for each state within the SERC region. It was assumed that the average price for each state is representative of the electricity make-up of the SERC region as a whole. It is recognized that some states belong to more than one North American Electric Reliability Corporation (NERC) region, however, the percentage of each state that belongs to each region was unavailable. For this reason, the calculated SERC region's average retail price being used for replacement power in this case was calculated from whole state average retail price. This is a simplification. The average replacement power cost being used in the base case is 7.59 cents/kWh.

### Decommissioning

Decommissioning costs are considered to be 10 percent of the capital costs. Because the capital costs in this study only represent the cost of additional and modified equipment necessary for $CO_2$ removal and compression for the EXPC energy conversion facility as well as the costs of $CO_2$ pipeline and injection wells, the capital costs of an SCPC plant with CCS were used to account for the energy conversion facility decommissioning costs (NETL, 2007). The estimated decommissioning costs of the CO2 removal and compression equipment is $47,290,097 and the estimated decommissioning costs of the existing equipment is $92,935,300, for a total decommissioning of the EXPC with CCS case equal $140,225,397.

## 2.4.2 LCC Data Results

### Results

The levelized costs for the EXPC plant without CCS are shown in **Figure 2-16**. Results indicate that utility costs contribute the largest amount to the total LC LCOE costs. The utility costs account for $0.0211/kWh of the total LCC. Following this, capital costs from the decommissioning of the facility account for $0.0040/kWh; fixed plant O&M costs and variable O&M cost contribute $0.0013/kWh each. Capital costs for the energy conversion facility are not included in this study.

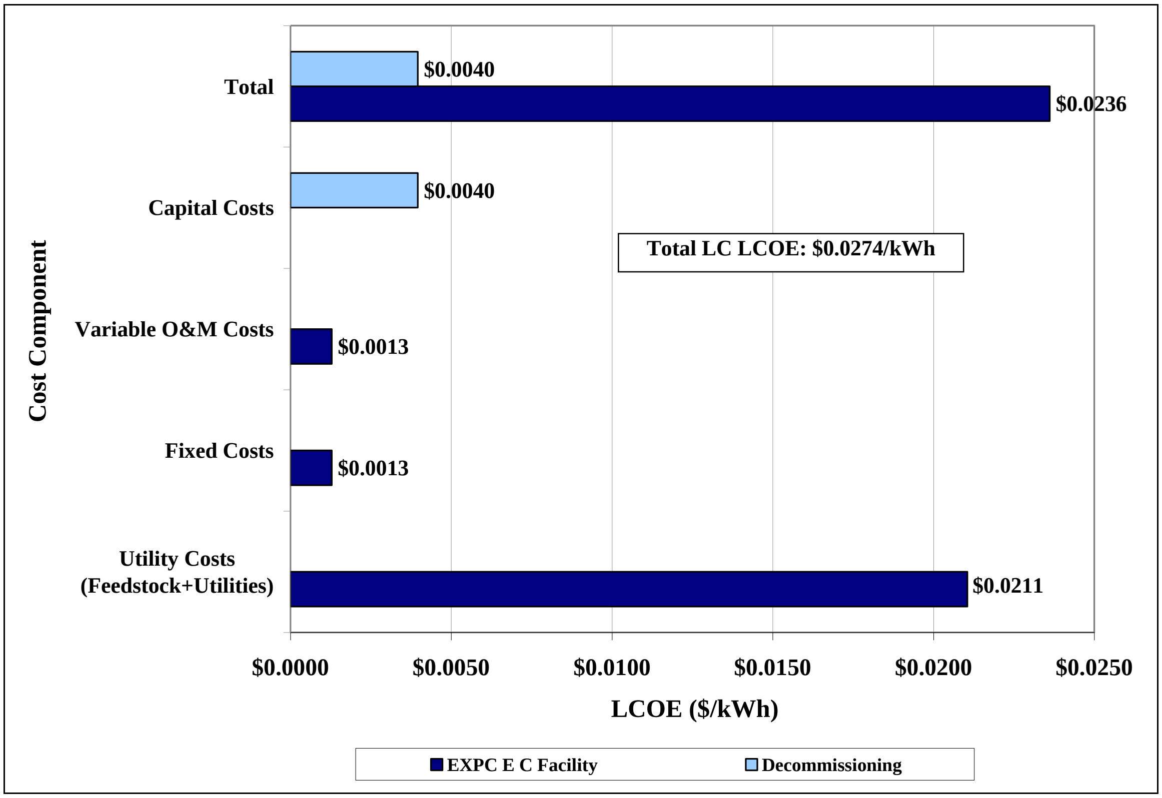



**Figure 2-16: LCOE Results for EXPC Case without CCS**

Figure Notes:
1. LCOE calculated using 85% capacity factor and a 7% transmission loss.
2. EXPC EC facility represents the energy conversion facililty alone.
3. Decommissioning is equal to 10% of SCPC capital costs (NETL, 2007).

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 EXPC facilities are normalized to the basis of net power output, which is 434 MW for the EXPC facility and 303 MW for the EXPC 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 EXPC facility is $197/kW; no construction activities are included for the base EXPC facility and thus 100 percent of the TPC is related to decommissioning activities. The TPC of the EXPC facility with CCS is $2,021/kW, which is 928 percent higher than the base EXPC facility. For the EXPC facility with CCS, 65 percent of the TPC is related to the $CO_2$ recovery equipment that is retrofitted to the energy conversion facility, 12 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 EXPC facilities are presented in **Figure 2-17**.

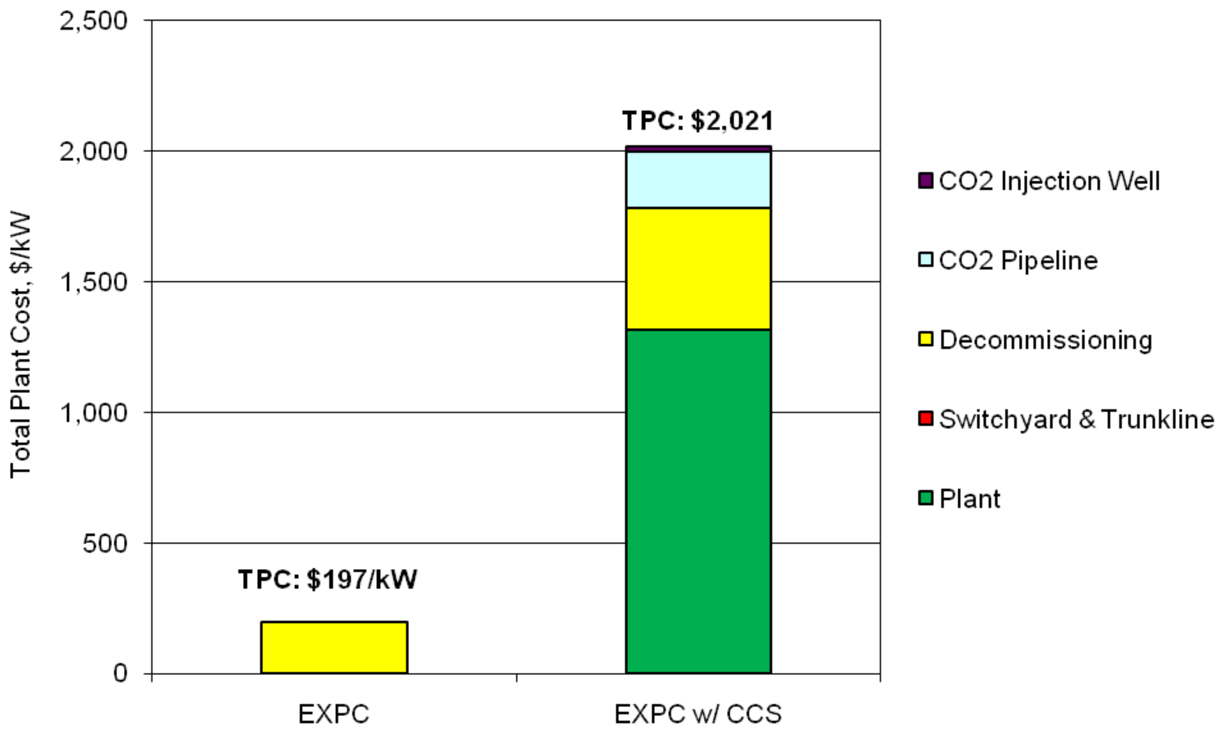



**Figure 2-17: TPC ($/kW) for EXPC Case without CCS**

### Results

**Figure 2-18** presents the LC LCOE results for the EXPC case with CCS. As with the case without CCS, the EXPC energy conversion facility accounts for the majority of the costs for the case LC. The replacement costs contribute the majority of the costs when analyzed by cost component. These account for $0.0365/kWh of the total LC LCOE costs. Of the capital costs, the addition of the $CO_2$ removal and compression system and the modification of the FGD system contribute an extra $0.0266/kWh to the EXPC energy conversion facility. Utility costs including coal feedstock and natural gas fuel for the auxiliary boiler account for $0.0301/kWh, followed by contributions of $0.0109/kWh and $0.0032/kWh from variable and fixed O&M 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 $0.0048/kWh, whereas fixed and variable O&M are equal to $0.00002/kWh and $0.0032/kWh. The total LC LCOE for the EXPC case with CCS is equal to $0.1252/kWh.

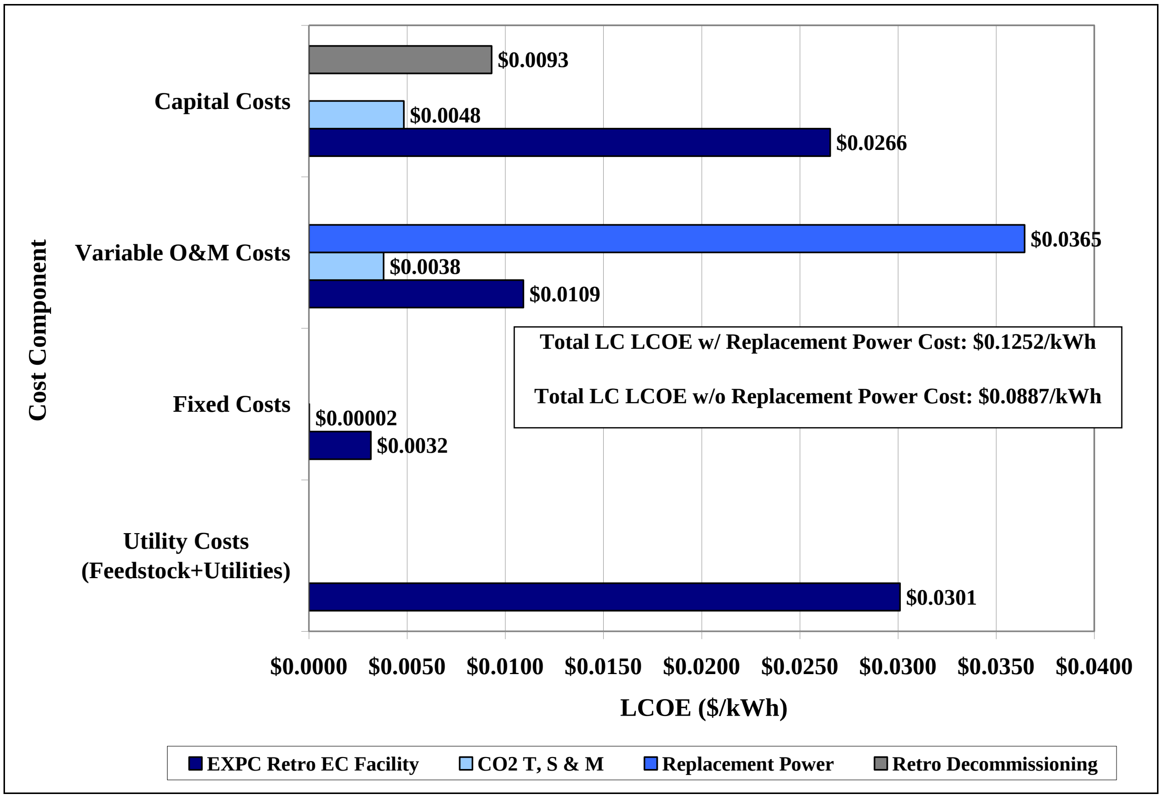



**Figure 2-18: LCOE for EXPC Case with CCS**

Figure Notes:

1. LCOE calculated using 85% capacity factor and a 7% transmission loss.
2. EXPC EC facility represents the energy conversion facililty alone.
3. $CO_2$ TS&M represents the transportation, sequestration, and monitoring of the $CO_2$.
4. Decommissioning equals 10% of capital costs. Capital costs for entire EC facility equal to SCPC plant minus $CO_2$ removal and compression system and FGD modification.

The LC cost results for CCS are similar to the costs results for the case without CCS in that the replacement power costs are the primary component of the total LC costs. This case adds costs for the $CO_2$ compression and removal system in the EXPC energy conversion facility as well as the addition of the $CO_2$ pipeline, injection wells, and monitoring costs. Replacement power costs equal $3,010/kW. The EXPC energy conversion facility capital costs are equal to $1,669/kW, whereas the $CO_2$ TS&M system and decommissioning are equal to $304/kW and $585/kW, respectively. Utility costs at the facility equal $2,486/kW. Fixed and variable O&M costs are considered in the energy conversion facility as well as the $CO_2$ TS&M system costs. For the energy conversion facility, fixed costs account for $261/kW and the variable O&M contribute $902/kW to the total LC costs The $CO_2$ TS&M system has fixed costs equal to $1.00/kW and variable O&M costs equal to $314/kW. Total LC costs are equal to $9,532/kW with replacement power included. When replacement power costs are not included, the total LC costs are equal to $6,522/kW. Costs for the LC are presented in **Figure 2-19**.

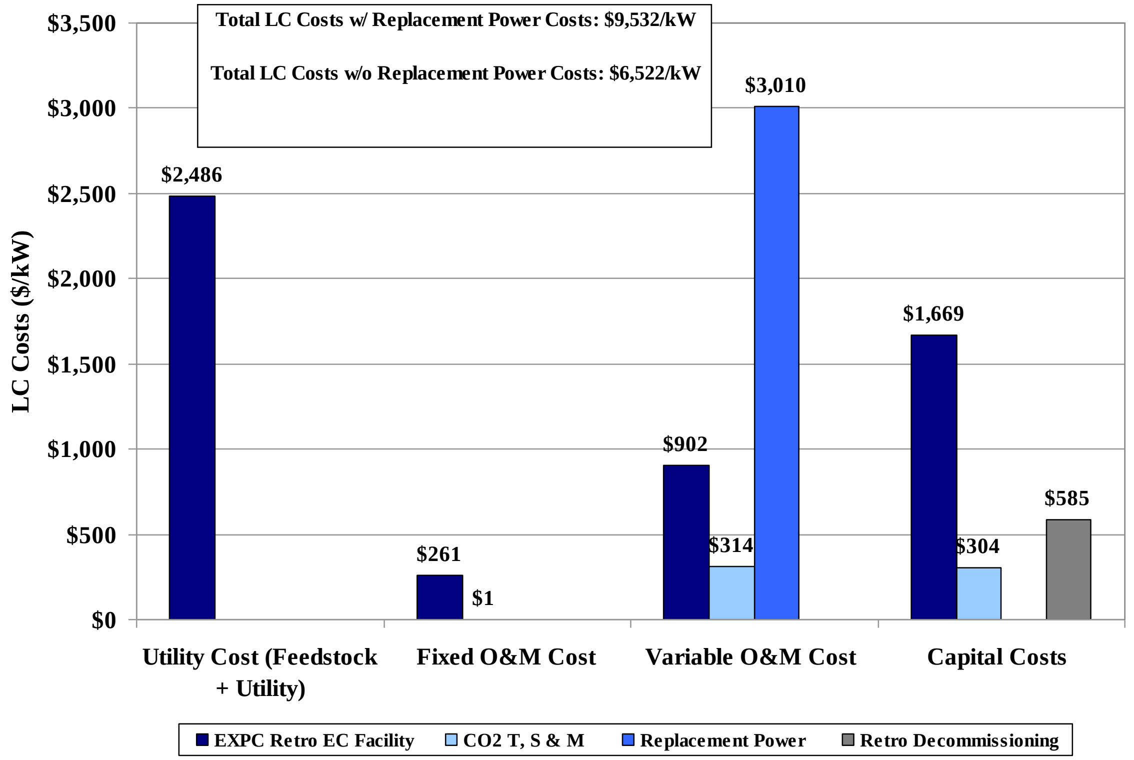



**Figure 2-19: Total LC Costs ($/kW) for EXPC Case with CCS**

Figure Notes:

1. LC costs were calculated using 85% capacity factor and 7% transmission loss.
2. EXPC EC facility represents the energy conversion facility alone.
3. $CO_2$ TS&M represents the transportation, sequestration, and monitoring of the $CO_2$.
4. Decommissioning equals 10% of capital costs. Capital costs for entire EC facility equal to SCPC plant minus $CO_2$ removal and compression system and FGD modification.
5. The fixed O&M cost of $1 represents the fixed costs of the $CO_2$ TS&M system.

### 2.4.3 Greenhouse Gas Emissions

**Table 2-15** and **Figure 2-20** show the GHG emissions associated with the EXPC with CCS plant, on an MWh plant output basis. Carbon dioxide 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, 2007). An additional phase, pipeline C/D, is included; a small amount (less than one percent of the total on both a mass [kg] and kg $CO_2$e basis) of additional GHG emissions are associated with that process. The total GWP of Stage #3 with CCS is 327.5 kg $CO_2$e per MWh plant output.

**Table 2-15: EXPC with CCS Stage #3, GHG Emissions (kg and kg $CO_2$e) /MWh Plant Output**

| EXPC Processes | Plant Construction | | $CO_2$ Pipeline Commissioning and Plant Decommissioning | | Operation | | Replacement power (SERC grid) | | Total | |
|---|---|---|---|---|---|---|---|---|---|---|
| Emissions (/MWh) | Mass (kg) | kg $CO_2$e | Mass (kg) | kg $CO_2$e | Mass (kg) | kg $CO_2$e | Mass (kg) | kg $CO_2$e | Mass (kg) | kg $CO_2$e |
| $CO_2$ | 1.8E-01 | 1.8E-01 | 3.9E-02 | 3.9E-02 | 103 | 103 | 213 | 213 | 316 | 316 |
| $N_2O$ | 9.0E-06 | 2.7E-03 | 7.8E-07 | 2.3E-04 | 1.6E-02 | 4.7 | 2.8E-03 | 0.8 | 1.9E-02 | 5.6 |
| $CH_4$ | 1.7E-04 | 4.3E-03 | 4.0E-05 | 9.9E-04 | 1.1E-02 | 2.7E-01 | 2.3E-01 | 5.8 | 2.4E-01 | 6.1 |
| $SF_6$ | 7.5E-15 | 1.7E-10 | 1.4E-14 | 3.2E-10 | 1.8E-07 | 4.1E-03 | 1.5E-09 | 3.3E-05 | 1.8E-07 | 4.1E-03 |
| Total GWP | | 1.9E-01 | | 4.0E-02 | | 108 | | 220 | | 328 |

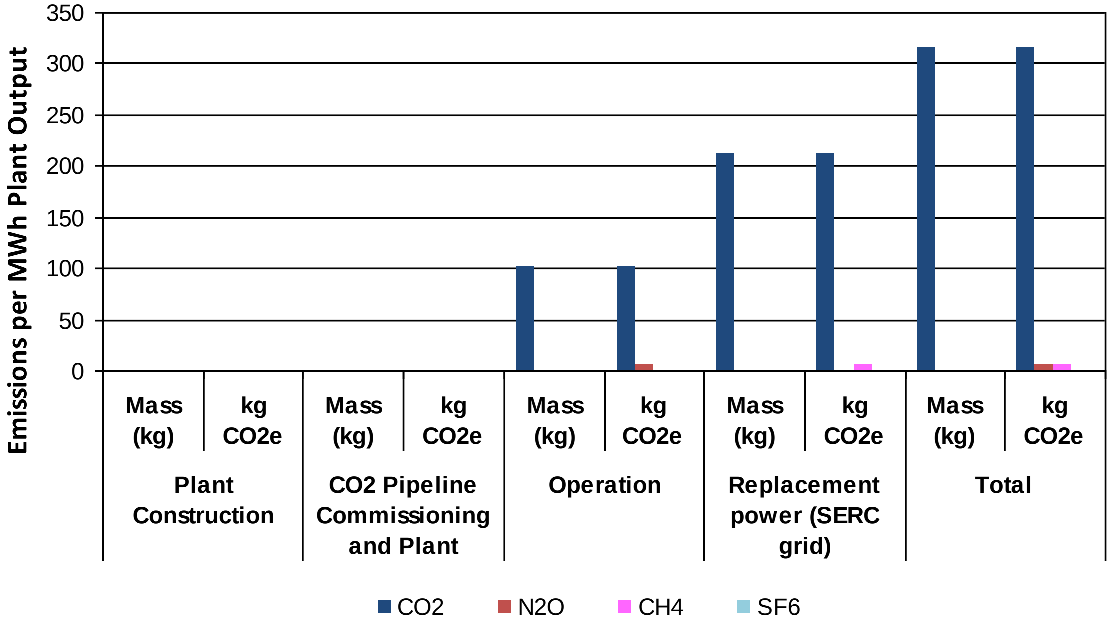



**Figure 2-20: EXPC with CCS Stage #3, GHG Emissions (kg and kg $CO_2$e) /MWh**

### 2.4.4 Air Pollutant Emissions

**Table** 2-16 and **Figure 2-21** show the air pollutants released during EXPC plant operations on a per MWh output basis. As with GHGs, emissions are dominated by the combustion of coal during plant operation. An interesting co-benefit to the addition of the $CO_2$ capture system is that most of the remaining $SO_X$, NOx and PM is also absorbed by the Econamine solvent (NETL, 2007b).

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** 2-16 for EXPC plant operations are a result of this slip, which is reported as two ppmv $NH_3$ at the end of catalyst life (NETL, 2007). Less than one percent of air emissions are associated with pipeline C/D

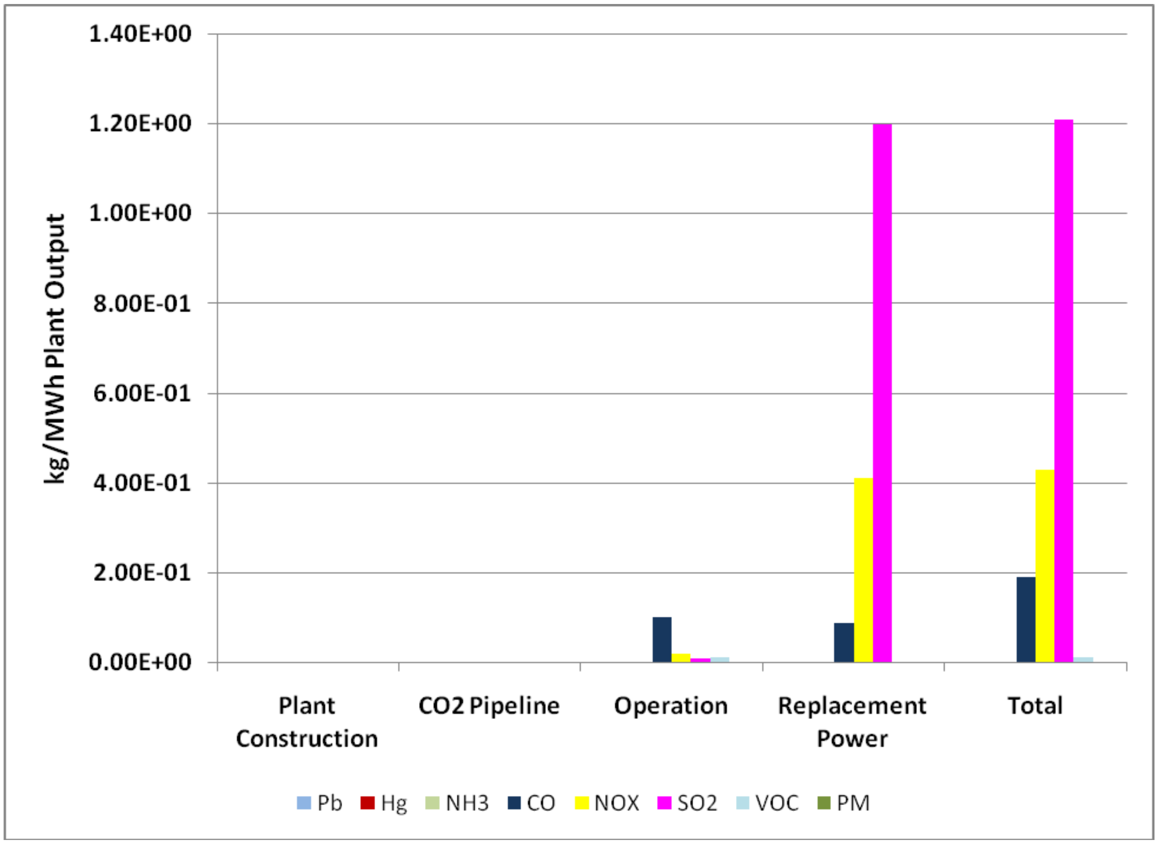



**Figure 2-21 EXPC with CCS Stage #3, GHG Emissions (kg and kg $CO_2$e) /MWh**

**Table 2-16: EXPC with CCS Stage #3 Air Emissions, kg/MWh Plant Output**

| Emissions (kg/MWh) | Plant Construction | $CO_2$ Pipeline Commissioning and Plant Decommissioning | Plant Operation | Replacement Power | Total |
|---|---|---|---|---|---|
| Pb | 4.9E-07 | 1.7E-10 | 5.90E-06 | 1.1E-05 | 1.74E-05 |
| Hg | 1.3E-08 | 1.5E-11 | 4.80E-05 | 3.0E-06 | 5.10E-05 |
| $NH_3$ | 5.3E-09 | 1.2E-06 | 2.00E-04 | 1.0E-03 | 1.20E-03 |
| CO | 1.2E-03 | 1.3E-04 | 1.00E-01 | 8.8E-02 | 1.89E-01 |
| $NO_X$ | 3.0E-04 | 3.7E-04 | 2.00E-02 | 4.1E-01 | 4.31E-01 |
| $SO_X$ | 4.7E-04 | 1.5E-05 | 1.00E-02 | 1.2 | 1.21E+00 |
| VOC | 2.2E-05 | 2.7E-05 | 1.20E-02 | 3.0E-05 | 1.21E-02 |
| PM | 2.0E-05 | 7.2E-05 | 0.00E+00 | 0 | 9.20E-05 |

### 2.4.5 Water Withdrawal and Consumption

**Table 2-17** shows water withdrawal and consumption for the EXPC 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 2-17: EXPC with CCS Stage #3 Water Withdrawal and Consumption, kg/MWh Plant Output**

| Water (kg/MWh) | Plant Construction | Pipeline Commissioning | Plant Commissioning and Decommissioning | Plant Operation | Replacement power | Total |
|---|---|---|---|---|---|---|
| Water Withdrawal | 2.1 | 1.221E-02 | 2.077E-03 | 3306 | 2146 | 5454 |
| Wastewater Outfall | 8.554E-03 | 8.472E-03 | 1.856E-04 | 425 | 1631 | 2057 |
| Water Consumption | 2.1 | 3.741E-03 | 1.892E-03 | 2880 | 515 | 3397 |

## 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 $1.4\times10^{-4}$ 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. Sulfur hexafluoride leakage during Stage #4 was calculated at $1.4\times10^{-4}$ 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 EXPC 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.

# 3.0 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: EXPC without CCS

**Table 3-1** summarizes all water withdrawals, consumption, and emissions from the EXPC 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 EXPC 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** | | | | | | |
| $CO_2$ | 3.2 | 5.2 | 1012 | 0 | 0 | 1020 |
| $N_2O$ | 1.4E-02 | 3.7E-02 | 5.1 | 0 | 0 | 4.0 |
| $CH_4$ | 80.0 | 1.9E-01 | 2.8E-01 | 0 | 0 | 80.5 |
| $SF_6$ | 4.3E-07 | 6.0E-08 | 6.3E-03 | 3.3 | 0 | 3.3 |
| **Air Pollutants (non GHG) kg/MWh** | | | | | | |
| Pb | 1.4E-07 | 3.1E-08 | 6.3E-06 | 0 | 0 | 6.5E-06 |
| Hg | 3.9E-08 | 2.9E-09 | 5.2E-05 | 0 | 0 | 5.2E-05 |
| $NH_3$ | 2.8E-05 | 1.9E-04 | 2.2E-04 | 0 | 0 | 4.4E-04 |
| CO | 3.1E-03 | 1.5E-02 | 1.1E-01 | 0 | 0 | 1.3E-01 |
| $NO_X$ | 5.7E-03 | 1.4E-02 | 2.0 | 0 | 0 | 2.0 |
| $SO_X$ | 1.6E-02 | 2.8E-03 | 2.4 | 0 | 0 | 2.4 |
| VOC | 1.0E-04 | 1.3E-03 | 1.3E-02 | 0 | 0 | 1.4E-02 |
| PM | 5.5E-04 | 1.7E-02 | 6.7E-01 | 0 | 0 | 6.9E-01 |
| **Water Withdrawal and Consumption kg/MWh** | | | | | | |
| Water Withdrawal | 172 | 2.1 | 2702 | 0 | 0 | 2876 |
| Wastewater Outfall | 439 | 1.5 | 609 | 0 | 0 | 1049 |
| Water Consumption[1] | -267 | 6.5E-01 | 2093 | 0 | 0 | 1827 |

### 3.1.1 Greenhouse Gas Emissions

**Table 3-2** and **Figure 3-1** show the GHG emissions associated with the EXPC plant operations without CCS in kg $CO_2$e 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: EXPC without CCS GHG Emissions, kg $CO_2$e/MWh Delivered Energy**

| Emissions (kg $CO_2$e/MWh) | Stage #1: Raw Material Acquisition | Stage #2: Raw Material Transport | Stage #3: Energy Conversion (without CCS) | Stage #4: Product Transport | Total |
|---|---|---|---|---|---|
| $CO_2$ | 3.2 | 5.2 | 1.0E+03 | 0 | 1020 |
| $N_2O$ | 1.4E-02 | 3.7E-02 | 5.1 | 0 | 5.1 |
| $CH_4$ | 80 | 1.9E-01 | 2.8E-01 | 0 | 80 |
| $SF_6$ | 4.3E-07 | 6.0E-08 | 6.3E-03 | 3.3 | 3.3 |
| Total GWP | 83 | 5.4 | 1017 | 3.3 | 1109 |

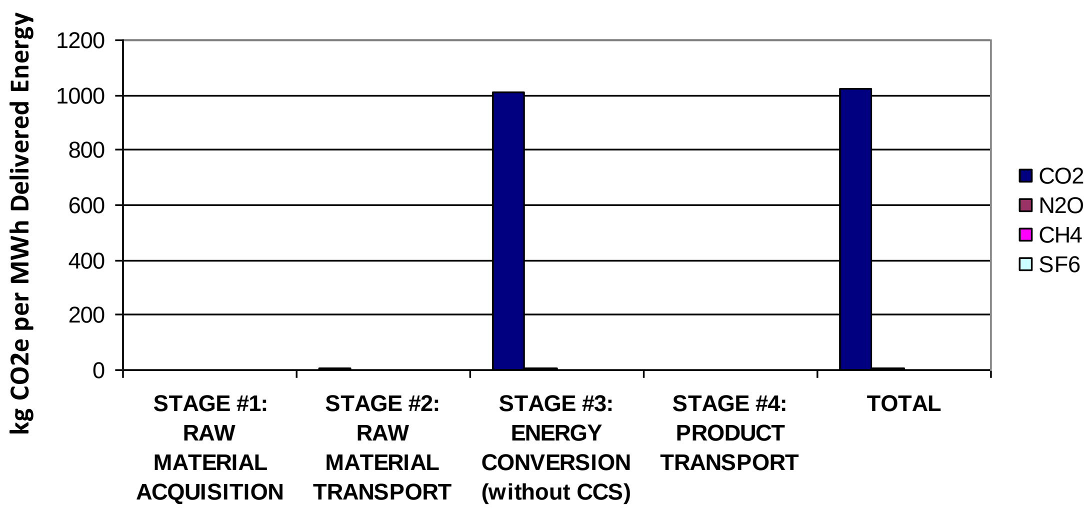



**Figure 3-1: EXPC without CCS GHG Emissions, kg $CO_2$e/MWh Delivered Energy**

The total GWP of the unmodified EXPC is 1,109 kg $CO_2$e per MWh delivered energy. Of those 1,109 kg $CO_2$e, 92.0 percent is due to $CO_2$ emissions. Methane accounts for 7.3 percent, $N_2O$ accounts for 0.5 percent, and $SF_6$ accounts for the remaining 0.3 percent. 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 EXPC case without CCS.

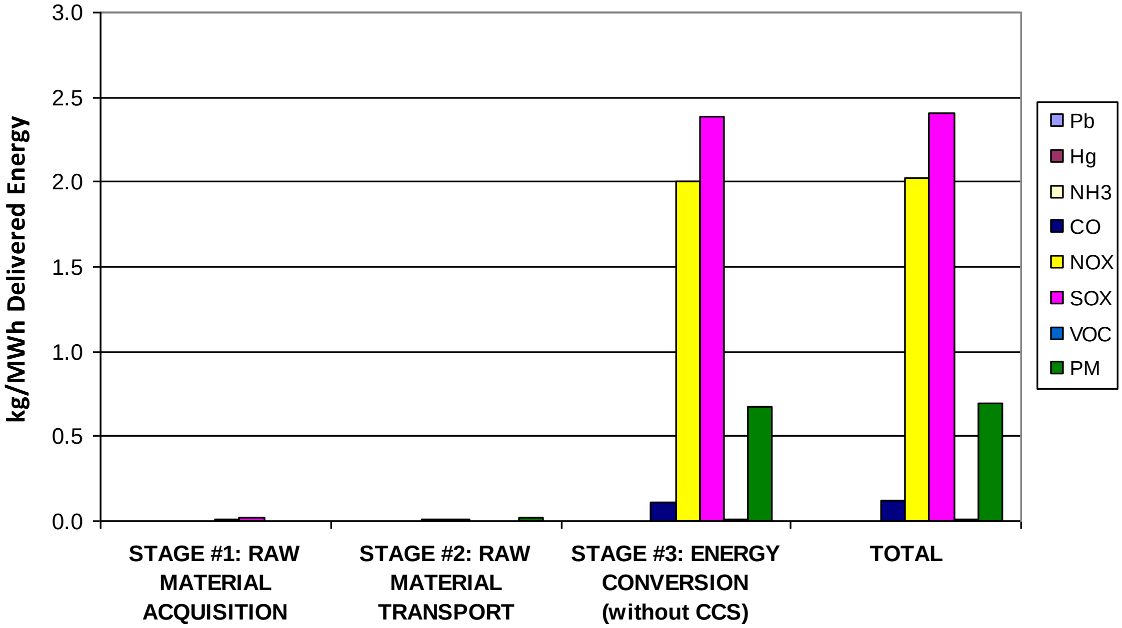



**Figure 3-2: EXPC without CCS Air Emissions, kg/MWh Delivered Energy**

The dominant air pollutant for EXPC without CCS is $SO_X$ and $NO_X$ released during coal combustion at the energy conversion facility (Stage #3). The majority of PM emissions occur during energy conversion (Stage #3), with a small contribution from coal dust lost during train transport (Stage #2). The other non-GHG air pollutants contribute less than one percent by weight to the total LC air emissions. As stated above, further conclusions on the environmental attributes of these emissions cannot be made without using an impact assessment method, which is outside the scope of this analysis.

### 3.1.3 Water Withdrawal and Consumption

**Figure 3-3** shows the total water withdrawal and water consumption for each stage and the total LC.

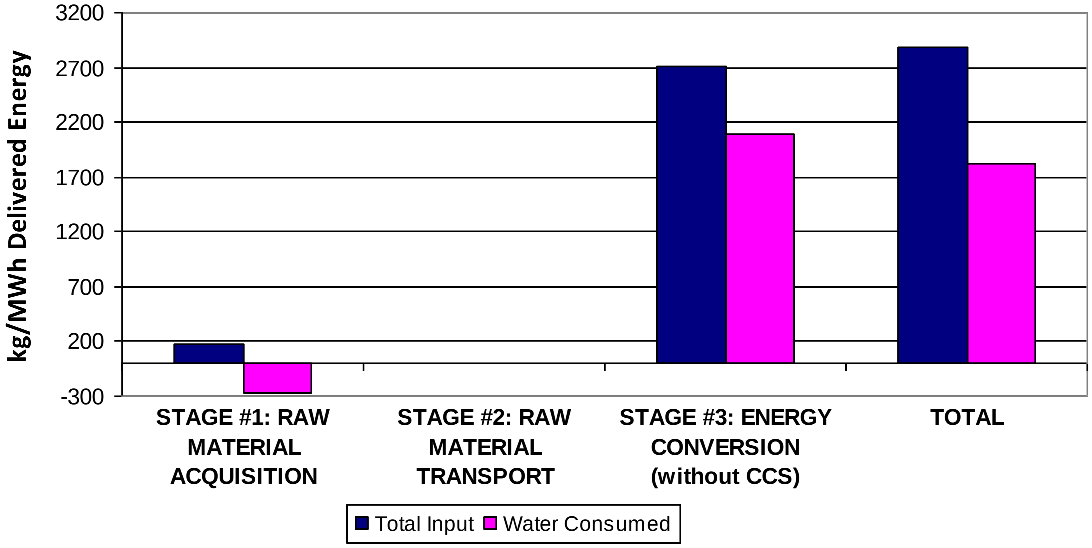



**Figure 3-3: EXPC without CCS Water Withdrawal and Consumption, kg/MWh Delivered Energy**

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: EXPC with CCS

**Table 3-3** summarizes all water withdrawals and emissions from the EXPC case with CCS, in kg/MWh, for each stage and the total LC. As with the case without CCS (the unmodified EXPC scenario), 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 EXPC 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** | | | | | | |
| $CO_2$ | 3.2 | 5.2 | 340 | 0 | 0 | 348 |
| $N_2O$ | 1.4E-02 | 3.7E-02 | 6.0 | 0 | 0 | 6.0 |
| $CH_4$ | 80.0 | 1.9E-01 | 6.6 | 0 | 0 | 86.8 |
| $SF_6$ | 4.3E-07 | 6.0E-08 | 4.5E-03 | 3.3 | 0 | 3.3 |
| **Air Pollutants (non GHG) kg/MWh** | | | | | | |
| Pb | 1.4E-07 | 3.1E-08 | 1.87E-05 | 0 | 0 | 1.9E-05 |
| Hg | 3.9E-08 | 2.9E-09 | 5.49E-05 | 0 | 0 | 5.5E-05 |
| $NH_3$ | 2.8E-05 | 1.9E-04 | 1.29E-03 | 0 | 0 | 1.5E-03 |
| CO | 3.1E-03 | 1.5E-02 | 2.04E-01 | 0 | 0 | 2.2E-01 |
| $NO_X$ | 5.7E-03 | 1.4E-02 | 4.63E-01 | 0 | 0 | 4.8E-01 |
| $SO_X$ | 1.6E-02 | 2.8E-03 | 1.30E+00 | 0 | 0 | 1.3E+00 |
| VOC | 1.0E-04 | 1.3E-03 | 1.30E-02 | 0 | 0 | 1.4E-02 |
| PM | 5.5E-04 | 1.7E-02 | 9.89E-05 | 0 | 0 | 1.8E-02 |
| **Water Withdrawal and Consumption kg/MWh** | | | | | | |
| Water Withdrawal | 172 | 2.1 | 5485 | 0 | 0 | 5659 |
| Wastewater Outfall | 439 | 1.5 | 2080 | 0 | 0 | 2521 |
| Water Consumption[1] | -267 | 6.5E-01 | 3405 | 0 | 0 | 3138 |

### 3.2.1 Greenhouse Gas Emissions

**Table 3-4** shows the GHG emissions from **Table 3-3** based on kg $CO_2$e.

**Table 3-4: EXPC with CCS GHG Emissions, kg $CO_2$e/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 |
|---|---|---|---|---|---|
| $CO_2$ | 3.2 | 5.2 | 340 | 0 | 348 |
| $N_2O$ | 1.4E-02 | 3.7E-02 | 6.0 | 0 | 6.0 |
| $CH_4$ | 8.0E+01 | 1.9E-01 | 6.6 | 0 | 87 |
| $SF_6$ | 4.3E-07 | 6.0E-08 | 4.5E-03 | 3.3 | 3.3 |
| Total GWP | 83 | 5.4 | 353 | 3.3 | 444 |

The total GWP for EXPC with CCS is 437 kg $CO_2$e per MWh delivered energy, which includes the activities related to the retrofitted EXPC facility as well as those associated with the replacement power provided by the SERC electric grid. The $CO_2$ emissions from replacement power account for 53 percent of LC GWP. **Figure 3-4** compares the GHG emissions for each stage. A total of 78 percent of the GWP is attributable to $CO_2$ emissions, while 18 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 less than one percent contribution to overall GHG emissions. Nitrous oxide attributes less 1.4 percent to the total GWP of this case. On a stage basis, 80 percent of the GWP is from Stage # 3 and 19 percent is from Stage #1.

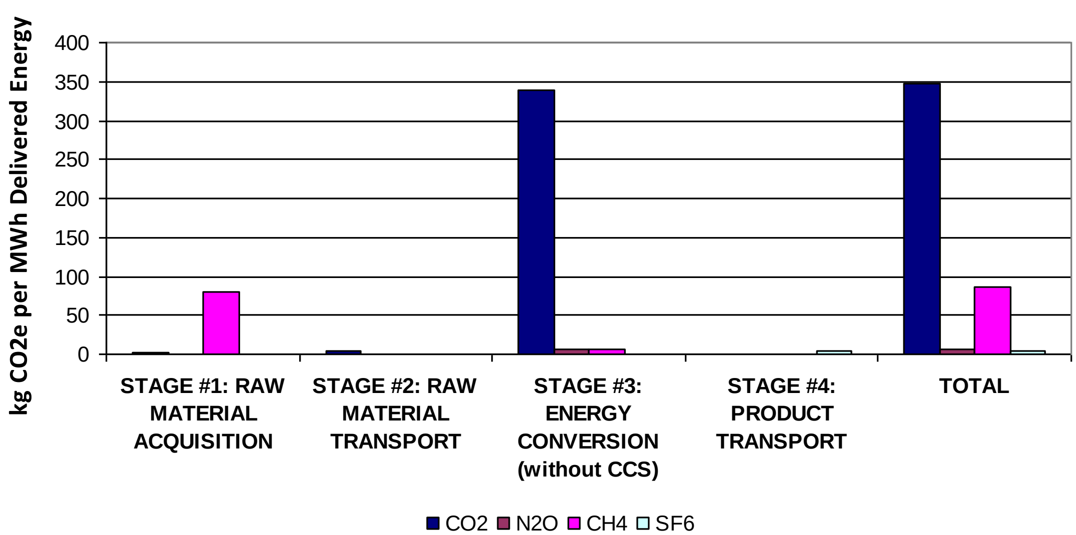



**Figure 3-4: EXPC with CCS GHG Emissions, kg $CO_2$e/MWh Delivered Energy**

### 3.2.2 Air Emissions

**Figure 3-5** compares the air emissions for each stage and the total LC. The dominant air pollutant for the CCS-retrofitted EXPC scenario is $SO_X$, which accounts for 66 percent of LC non-GHG air emissions. The emission of $SO_X$ and other non-GHG emissions were derived from EPA emissions inventory data (EPA 2009) for the Conesville power plant, a facility that has been retrofitted with a CCS system, as well as information from IEA (IEA GHG R&D, November 2004).

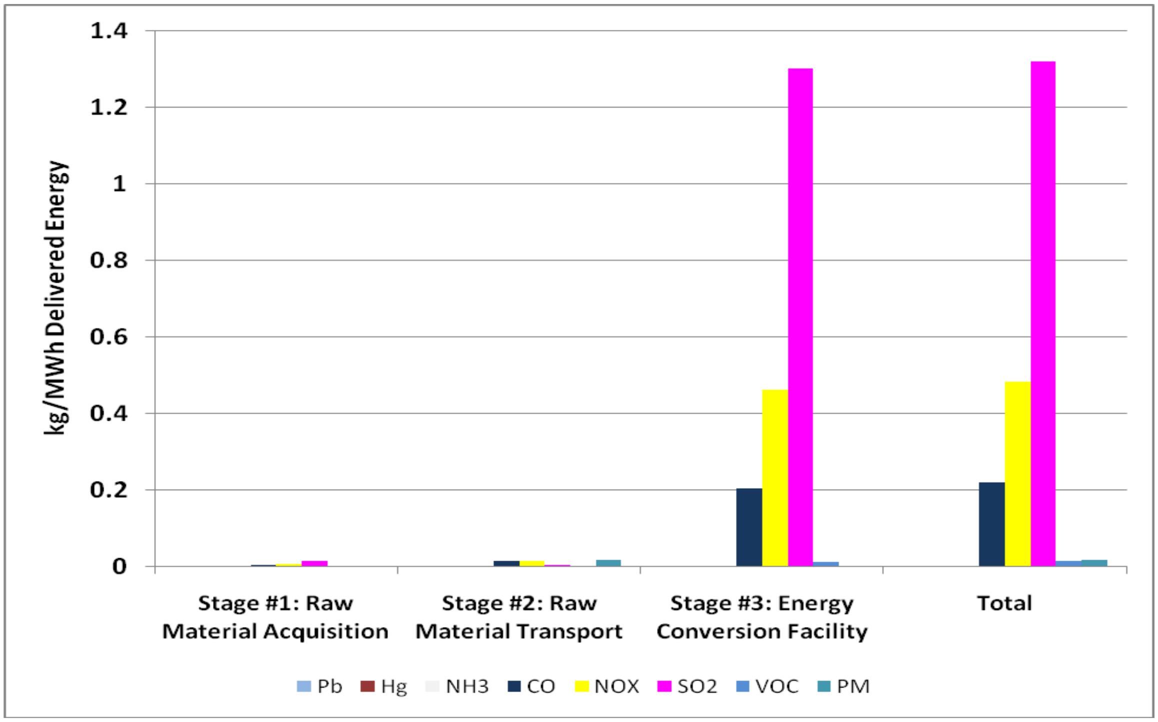



**Figure 3-5: EXPC with CCS Air Emissions, kg/MWh Delivered Energy**

### 3.2.3 Water Withdrawal and Consumption

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

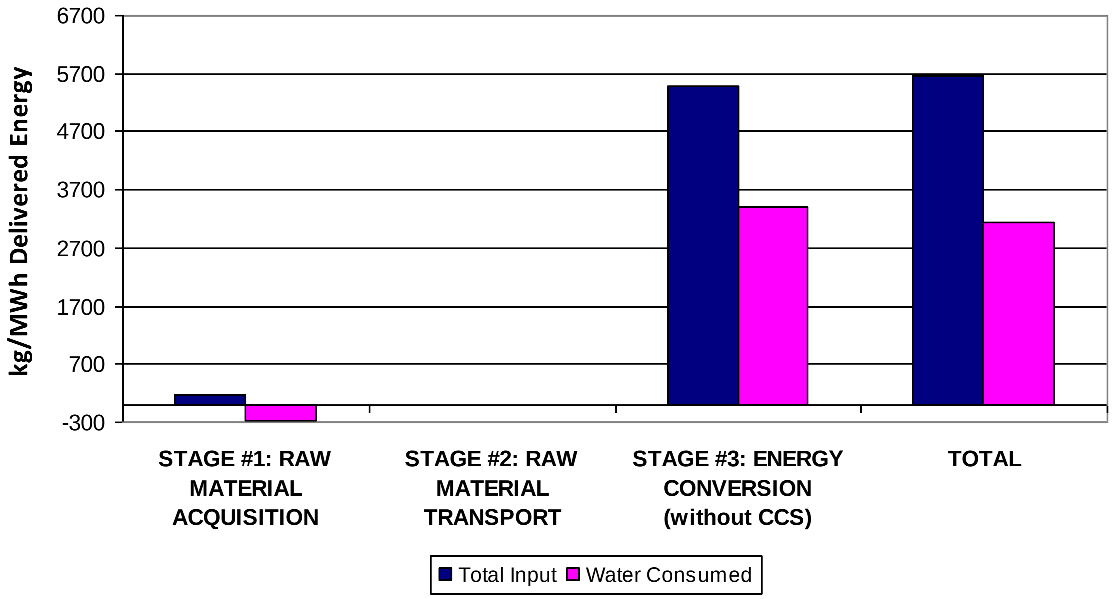



**Figure 3-6: EXPC with CCS Water Withdrawal and Consumption, kg/MWh Delivered Energy**

Water withdrawal and consumption is dominated by energy conversion (Stage #3) due to cooling water requirements in the power plant. Additionally, the CCS operation requires more water because the flue gas must be at a lower temperature to enter the amine capture facility. As with EXPC 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 process. 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 EXPC. 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 $CO_2$e). 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 $CO_2$e (lbs $CO_2$e) | 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 EXPC 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.

#### 1.3.3.1 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 #3 includes installation of facilities in support of the EXPC pathway. No land use change occurred in the other LC stages; the coal mine, rail and locomotive, and electricity transmission infrastructure were considered existing and therefore installation (land use) was not included in the system boundary (**Section 1.2**).

**Table 3-6: EXPC Facility Locations and Sizes**

| LC Stage No. | Facility | Location |
|---|---|---|
| LC Stage #1 | Not Considered | Not Considered |
| LC Stage #2 | Not Considered | Not Considered |
| LC Stage #3 | EXPC Retrofit | Eastern OH |
| | CCS Pipeline | Eastern OH |
| LC Stage #4-5 | Not Considered | Not Considered |

Removal of on-site, existing land use was assumed to be complete (100 percent removal) for the CCS pipeline and the portion of the existing energy conversion facility site that would be affected during the retrofit. **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 |
|---|---|---|---|
| EXPC | 16,187 (4) | $m^2$ (acres) | 4 acres assumed based on Baseline Report and assumptions indicated elsewhere in this report |
| CCS Pipeline | 2,452,640 (364) | $m^2$ (acres) | 50 foot construction width, 100 mile length |

A precise alignment for the CCS pipeline is not specified within the study. Therefore, a representative portion of land in close proximity to the EXPC site was selected and analyzed to approximate the land use located within the CCS pipeline footprint. 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 EXPC plant site indicated two primary land use categories: grassland and existing plant footprint. As shown in **Figure 3-7**, the footprint of the existing EXPC plant accounts for most of the total area (77 percent of total area), followed by grassland (23 percent of total area). Minor areas containing other land uses, such as roads or small waterways, were allocated to one of these two categories.


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

Results from the analysis of land use for the CCS pipeline indicated three primary land use categories: grassland, forest, and agriculture. As shown in **Figure 3-8**, forest accounts for most of the total area (59 percent of total area), followed by grassland (21 percent of total area), and agriculture (20 percent of total area). Similar to the analysis at the coal mine site, small areas containing other land uses, such as roads or minor waterways, were allocated to one of these three categories, as relevant.

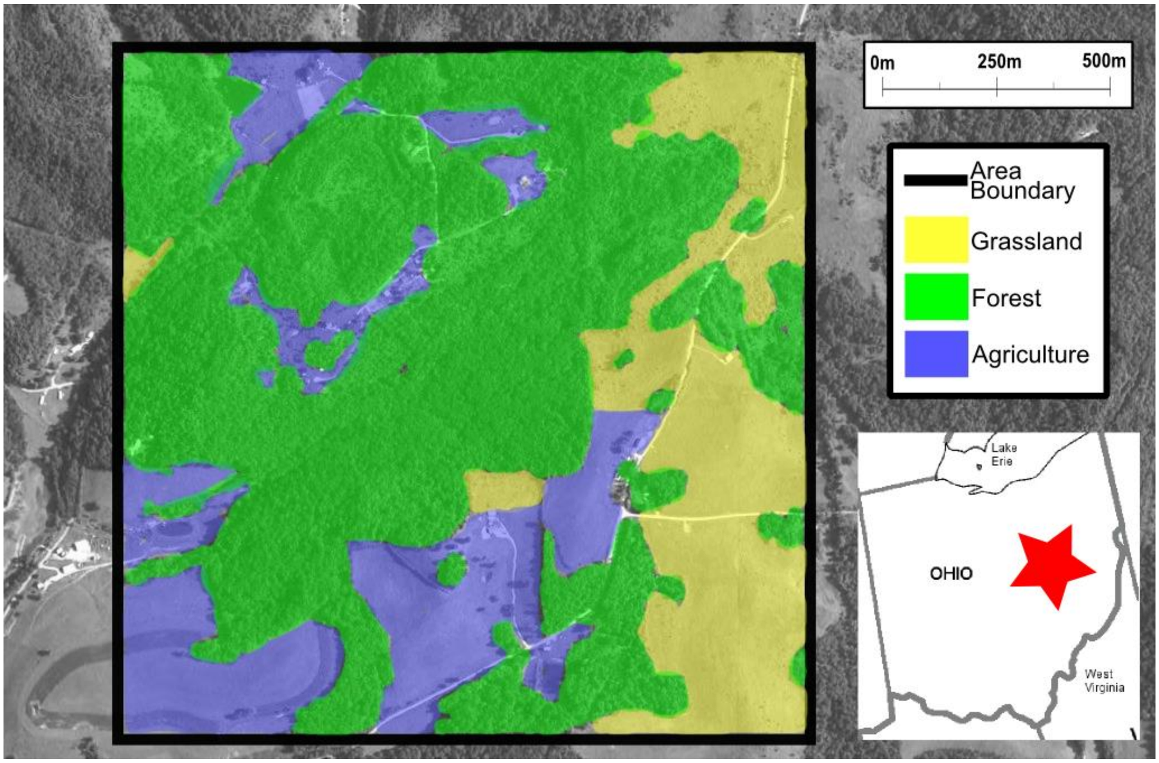



**Figure 3-8: Existing Condition Land Use Assessment: EXPC Site**

The total amounts of transformed land, including land area associated with the EXPC retrofit and the CCS pipeline, are shown in **Table 3-8** below. As shown, the EXPC plant retrofit would affect only grassland and existing power plant land uses, while the CCS pipeline would affect grassland, forest, and agriculture land uses. Also, the total land area affected on a per MWh basis would be approximately two orders of magnitude larger for the CCS pipeline as compared to the EXPC retrofit area. This finding is consistent with the relative sizes of these two facilities. **Figure 3-9** provides a summary of the total land transformed area, per 1 MWh of power delivered, including grid losses. As shown, forested areas account for most of the land use change area, with affected existing power plant area being only a tiny fraction of the total affected land use, shown by a thin line along the far right of the bar chart.

**Table 3-8: Total Amounts of Transformed Land Area**

| Category | | EXPC | CCS Pipeline |
|---|---|---|---|
| Units | | $m^2$/MWh | $m^2$/MWh |
| Transformed Land Area | Grassland | $5.50 \times 10^{-5}$ | $7.61 \times 10^{-3}$ |
| | Forest | n/a | $2.14 \times 10^{-2}$ |
| | Agriculture | n/a | $7.25 \times 10^{-3}$ |
| | Existing Power Plant | $1.84 \times 10^{-4}$ | n/a |
| Total Transformed Land Area | | $2.39 \times 10^{-4}$ | $3.62 \times 10^{-2}$ |

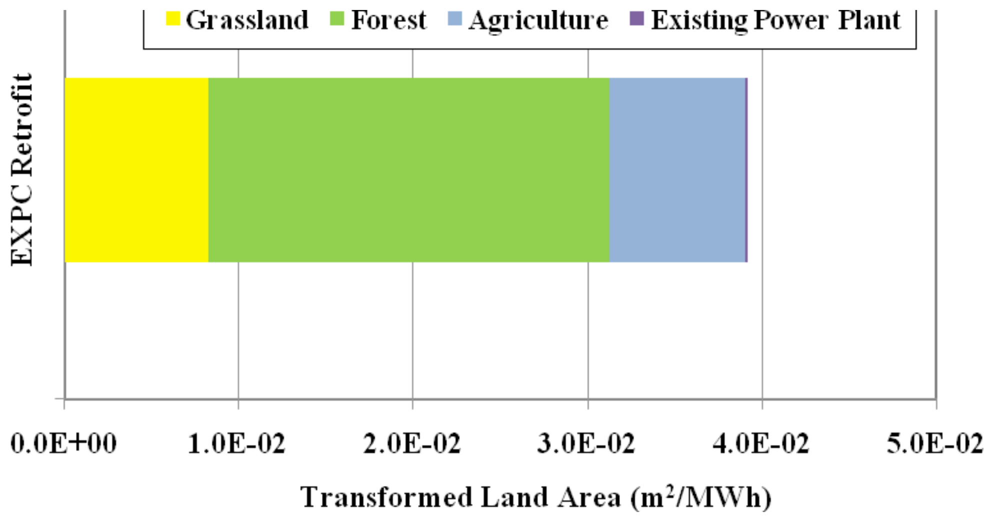



**Figure 3-9: Total Transformed Land Area: EXPC Site**

As shown, forested areas account for most of the land use change area, with affected existing power plant area being only a tiny fraction of the total affected land use, shown by a thin line along the far right of the bar chart.

## 3.4 Comparative Results

The above section presents the results for the two cases. The following section continues with the presentation of LCC and environmental results, but compares and contrasts the two cases.

### 3.4.1 Comparative LCC Results

Comparatively, the two EXPC cases are similar in that nearly half of the total LCC are contributed by the capital costs. **Figure 3-10** present the results for both EXPC cases in PV measured in $/kW. **Figure 3-11** presents the contributions of each cost component to the total LCC. The LCC for the case with CCS exceeds the LCC for the case without CCS due to the additions of the $CO_2$ compression and removal system at the plant and the $CO_2$ TS&M system. Also contributing to the higher costs at the EXPC plant with CCS is the reduction in net-output of the plant, meaning that on a kW basis, costs will be higher. On a per kW basis, the EXPC facility with CCS has a total LCC approximately $7,350/kW more than the case without CCS (**Table 3-9**). Of the total LCC, the capital costs equal approximately 11 and 24 percent of the total LCC, or $249/kW and $2,253/kW for the EXPC case without CCS and EXPC case with CCS, respectively. Utility costs, fixed costs, and variable O&M costs account for approximately 80, five, and four percent of the total LCC for the case without CCS. For the case with CCS, utility, fixed, and variable O&M costs contribute 26, three, and nine percent of the total LCC. The addition of the $CO_2$ TS&M system increases the costs for the EXPC case with

CCS by $619/kW, contributing approximately six percent to the total LC. Because the net-output of the plant is reduced, replacement power costs were also considered in the total LCC. An additional $3,010/kW, or 32 percent, is added to the LCC for the case with CCS for replacement power.

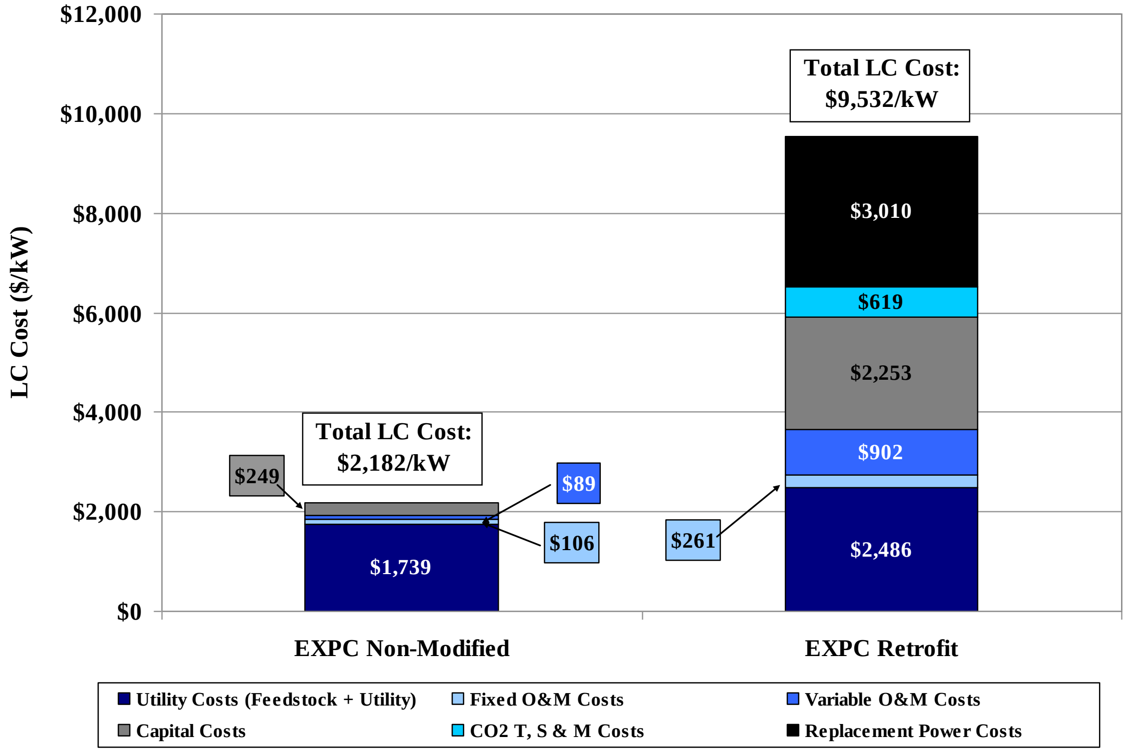



**Figure 3-10: Comparison of EXPC Cases without and with CCS**

1. Utility costs include feedstock (coal/natural gas) needed as well as process water.
2. Labor costs are from the Baseline Report. This was not amended for the re-location of the EXPC facility from the Midwest to the South.
3. Variable O&M costs include maintenance costs (excluding labor), daily chemical consumption costs, and daily waste disposal costs. Process water costs were excluded as they are included in the utility costs.
4. Capital costs included costs for the EXPC facility, switchyard/trunkline, and decommissioning. The EXPC facility includes capital investment plus initial costs equaling two percent of the plant capital costs without contingencies. Switchyard/trunkline costs equal the purchasing costs for the components. Decommissioning is equal to 10 percent of the total capital costs for the plant, switchyard/trunkline, and other components including the $CO_2$ TS&M.
5. $CO_2$ TS&M costs include capital and O&M costs for the $CO_2$ pipeline, injection wells, and monitoring. This excludes decommissioning of the $CO_2$ TS&M components as it is included in the capital cost category.

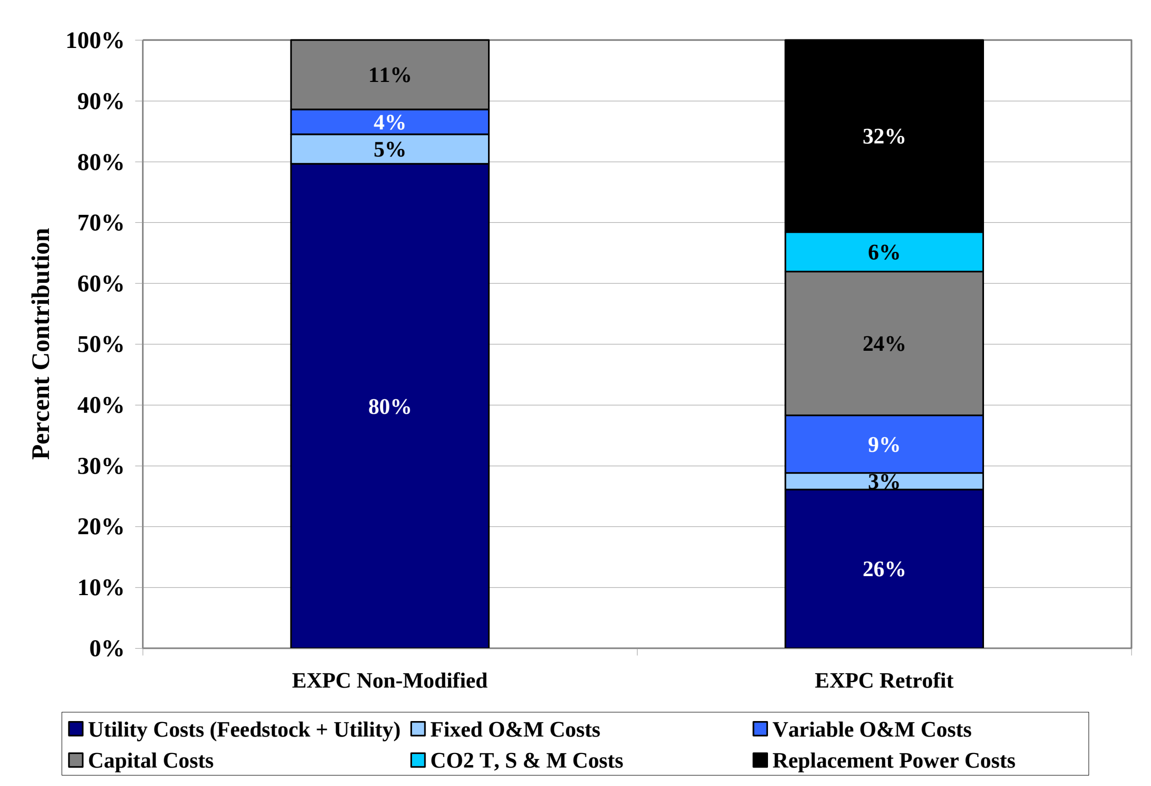



**Figure 3-11: Contribution Comparison of EXPC Case without and with CCS**

**Table 3-9: Comparison of EXPC Cases without and with CCS for LC costs**

| LC Cost($/kW) | EXPC Non-Modified | EXPC Retrofit | Change |
|---|---|---|---|
| Utility Costs (Feedstock + Utility) | $1,738.60 | $2,486.39 | $747.78 |
| Fixed O&M Costs | $105.79 | $260.79 | $154.99 |
| Variable O&M Costs | $89.24 | $902.33 | $813.09 |
| Capital Costs | $248.65 | $2,253.47 | $2,004.82 |
| $CO_2$ TS&M Costs | $0.00 | $619.25 | $619.25 |
| Replacement Power Costs | $0.00 | $3,010.06 | $3,010.06 |
| Total LC Costs | $2,182.29 | $9,532.28 | $7,349.99 |

The LCOE results for the EXPC cases follow the same trend in that the LCOE for the case with CCS exceeds that of the case without CCS. Results indicate that the LCOE for the case with CCS is approximately $0.0976/kWh higher than the LCOE for the case without CCS. This can be seen in **Table 3-10**.

**Table 3-10: Comparison of LCOE Results for the EXPC Cases without and with CCS**

| LCOE ($/kWh) | EXPC Non-Modified | EXPC Retrofit | Change |
|---|---|---|---|
| Utility Costs (Feedstock + Utility) | $0.0211 | $0.0301 | $0.0091 |
| Fixed O&M Costs | $0.0013 | $0.0032 | $0.0019 |
| Variable O&M Costs | $0.0013 | $0.0109 | $0.0096 |
| Capital Costs | $0.0040 | $0.0359 | $0.0319 |
| $CO_2$ TS&M Costs | $0.0000 | $0.0087 | $0.0087 |
| Replacement Power Costs | $0.0000 | $0.0365 | $0.0365 |
| Total LCOE | $0.0276 | $0.1252 | $0.0976 |

#### 3.4.1.1 Global Warming Potential

**Figure 3-12** compares the GHG emissions (kg $CO_2$e/MWh delivered) for EXPC with and without CCS. Total LC GWP potentials are 1109 and 444 for the cases without CCS and with CCS, respectively. When compared on the same basis (a functional unit of 1 MWh of delivered electricity), the retrofit of a CCS system to an EXPC plant reduces life cycle GWP by 60 percent. Methane 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 $CO_2$e basis) account for 20 percent of the total GHG emissions; this impact would have been ignored in GWP evaluations of only the energy generation facility. Sulfur hexafluoride emissions are not seen as a large contributor to the total GWP for either case, representing less than one percent of life cycle GWP for both caes. Therefore, one can conclude that although $SF_6$ has a very large GWP (22,800 $CO_2$e)(IPCC, 2007), when multiplied by the small mass emitted it does not correlate to a large overall impact.

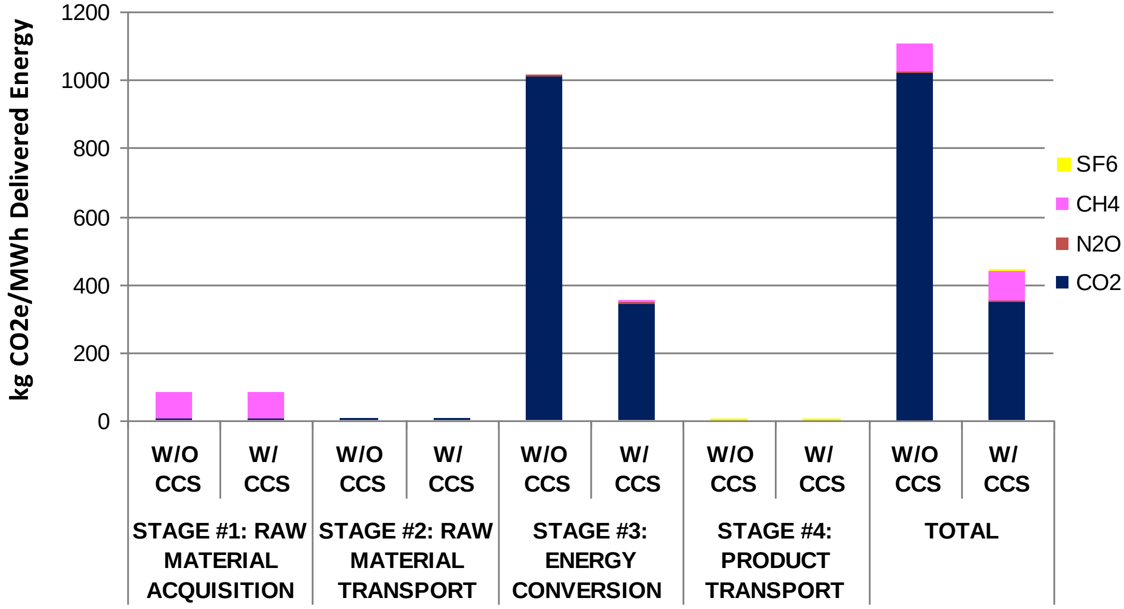



**Figure 3-12: Comparative GHG Emissions (kg $CO_2$e/MWh Delivered) for EXPC with and without CCS**

### 3.4.1.2 Comparative Air Pollutant Emissions

**Figure 3-13** compares the non-GHG air pollutants between the two cases on a kg/MWh delivered energy basis.

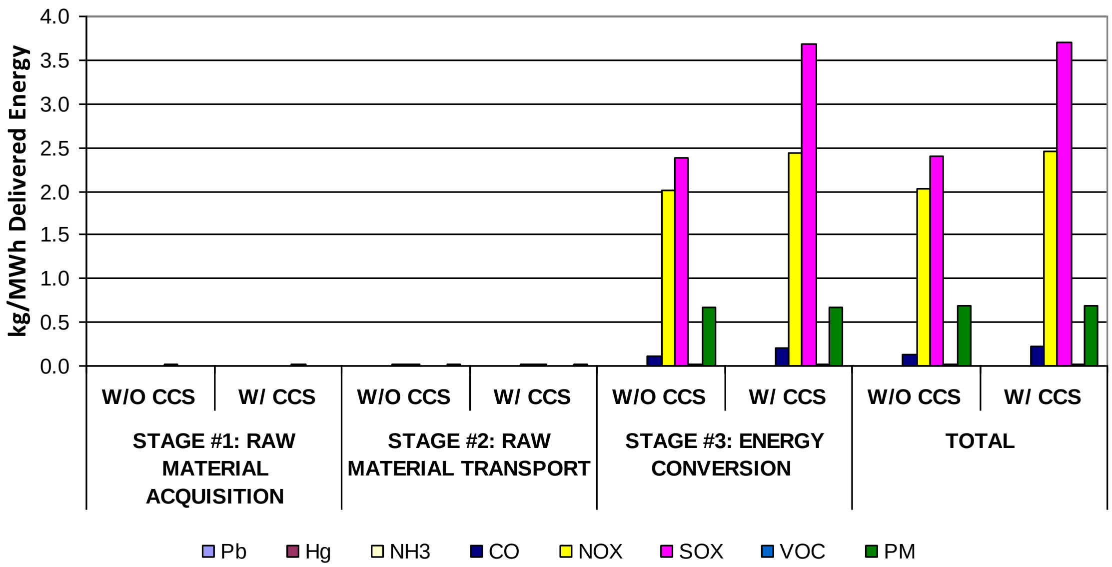



**Figure 3-13: Comparison of Air Emissions (kg/MWh Delivered Energy) for EXPC with and without CCS**

Both EXPC cases use the same emissions inventory for non-GHG air pollutants. There are only two differences between the two cases: (1) the emissions are scaled according to the net power output of the scenario, and thus the unmodified EXPC case has lower non-GHG air emissions on a per MWh basis than the EXPC plant that is retrofitted with a CCS system; (2) Stage #3 of the retrofitted EXPC case includes emissions from the SERC grid due to the use of replacement power. Due to the co-benefit of reduced $SO_X$ emission from the installation of a CCS system, it is likely that the $SO_X$ emissions of the retrofitted EXPC case are lower than shown in **Figure 3-14**. However, a data limitation of this analysis is the lack of detailed non-GHG emissions for pre- and post-CCS installation for EXPC facilities.

#### 3.4.1.3 Comparative Water Withdrawal and Consumption

**Figure 3-14** compares water withdrawal and consumption for both cases.

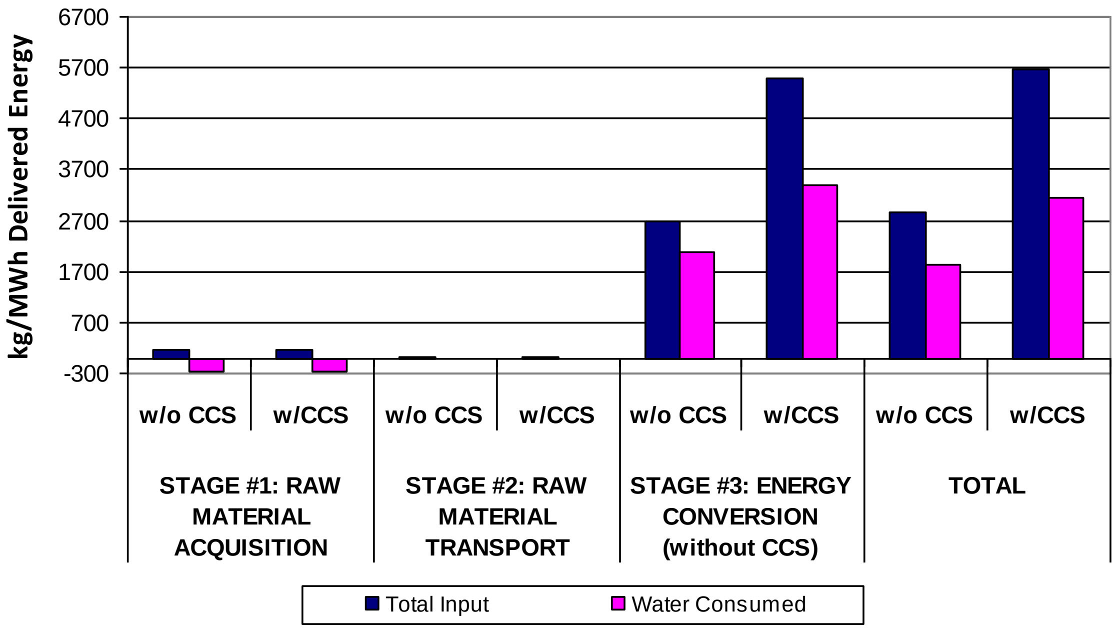



**Figure 3-14: Comparative Water Withdrawal and Consumption for EXPC with and without CCS**

The increase in water withdrawal 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, 2007; Reddy, Johnson et al., 2008).

#### 3.4.1.4 Comparative Land Use Transformation

Land use changes are applicable only to the EXPC scenario with a CCS retrofit, which requires a small increase to the footprint of the EXPC plant as well as the land used by the $CO_2$ pipeline. There are no land use changes for the unmodified EXPC scenario.

## 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 the LCC for the EXPC 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 in **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% |
| Replacement Power (cents/kWh) | 5.43 – 10.45 |

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, 2007). 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 35.0 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.

Replacement costs were varied from 5.43 to 10.45 cents/kWh. The base case represents the average retail cost of electricity for the states included in the SERC region, where the power plant is located. The base case replacement cost is 7.59 cents/kWh. The range for the replacement cost represents the highest and lowest costs listed for the States included in the SERC region. Florida has the highest average retail cost of electricity while Kentucky represents the lowest average retail COE.

## Results for EXPC without CCS

The results for the EXPC case without CCS uncertainty analysis indicate that the LCOE is most responsive to the change in capacity factor (CC) by ±5. The change in the LCOE is measured compared to the base case LCOE of $0.0274/kWh. Varying the capacity factor by ±5 from the base case 85 percent causes total LCOE to increase and decrease by six percent. This translates into a range of $0.0259/kWh for an increase to 90 percent to $0.0291/kWh for a decrease in the capacity factor to 80 percent. This is shown in **Figure 3-15** and **Figure 3-17.**

When capital costs which include only the decommissioning for all major components of the EXPC without CCS LC are increased and decreased by 30 percent, the total LCOE of the plant increases and decreases by four percent, giving the LCOE a range of $0.0262/kWh to $0.0286/kWh.

Variable O&M costs increased and decreased by 30 percent, caused a slight, one percent, change in the total LCOE for the case. LCOE costs when O&M costs are increased and decreased had a range from $0.0270/kWh to $0.0277/kWh.

Increasing the total tax rate (state plus federal) by ±10 percent resulted in a percent change of less than one percent. The range for this is $0.0272/kWh to $0.0275/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 0.069 percent.

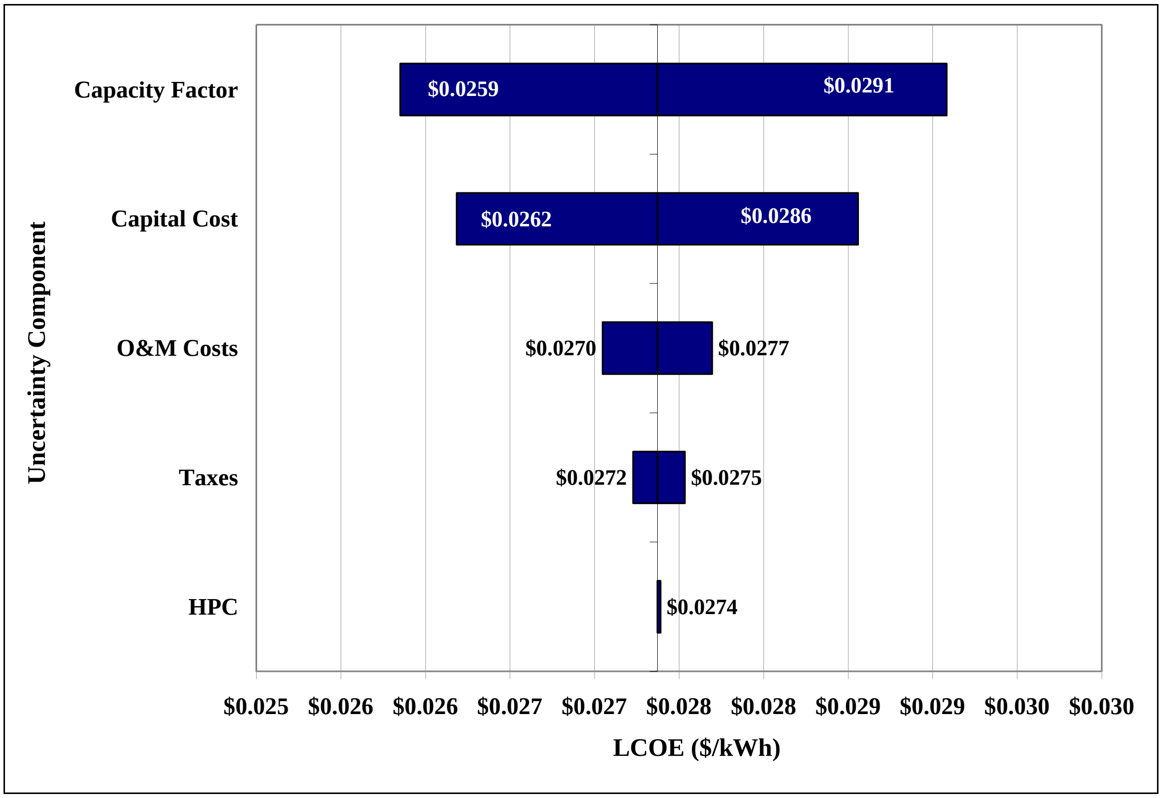



**Figure 3-15: Uncertainty Analysis LCOE Ranges for the EXPC Case without CCS**

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.

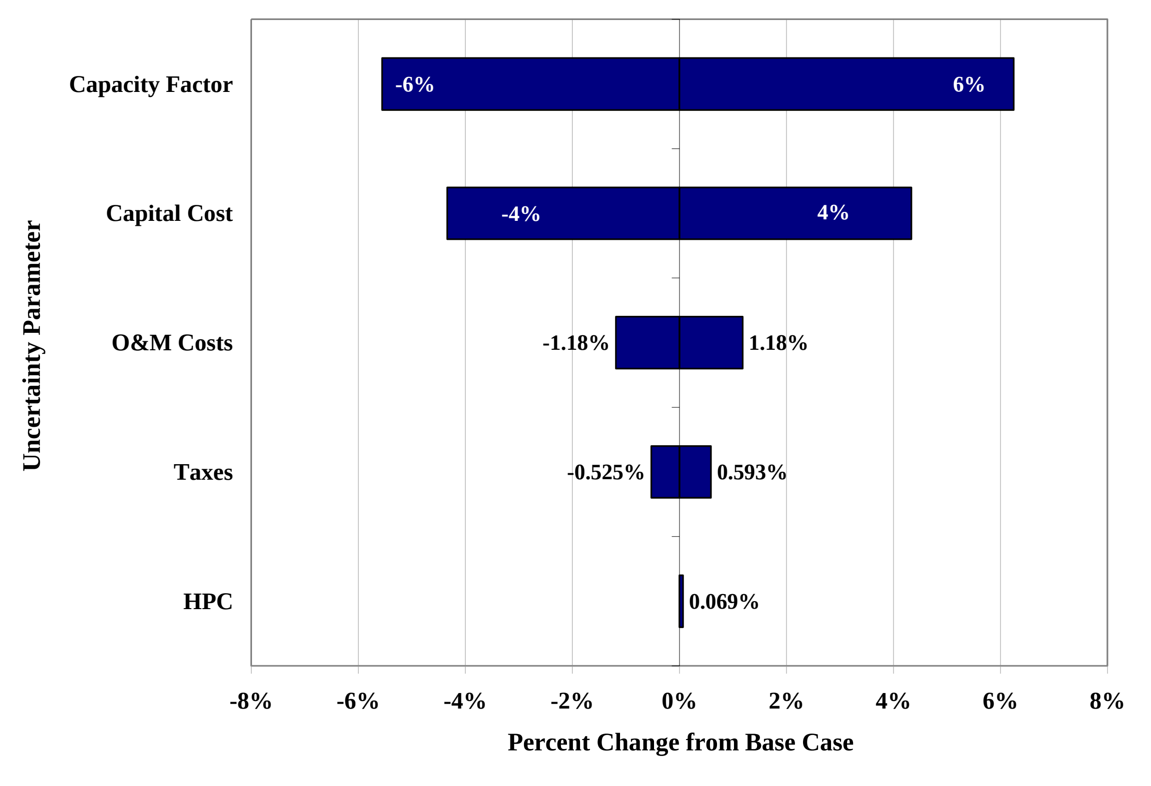



**Figure 3-16: Percent Change from Base Case LCOE for the EXPC Case without CCS**

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.

## Results for EXPC with CCS

The sensitivity analysis of the EXPC case retrofitted with CCS concluded that a fluctuation in replacement power costs causes the LCOE to change by the greatest amount. An increase in the replacement power cost from 7.59 cents/kWh to 10.45 cents/kWh causes the LCOE to increase from $0.1252/kWh to $0.1389/kWh. This translates into a change of 11 percent. A decrease in replacement power from the base case value to 5.43 cents/kWh causes the LCOE to decrease by eight percent to an LCOE of $0.1148/kWh.

Variation in capital costs by ±30 percent will cause the LCOE to change by ±10 percent. The total LC LCOE for the case has a range of $0.01129/kWh to $0.1374/kWh. The base case LCOE is equal to $0.1252/kWh.

With a capacity factor range from 80 to 90 percent, the LCOE ranged from $0.1202/kWh with an increase in the capacity factor by five to $0.1307/kWh with a decrease in the capacity factor. This is equal to a percent change of approximately four percent.

Variation in the variable O&M costs by ±30 percent resulted in an LCOE range from \$0.1207/kWh to \$0.1296/kWh. This is represented by a percent change of ±3.5 percent.

A variation of the total tax rate by 10 percent in both directions causes the LCOE to change by approximately ±1 percent. This translates into a range of \$0.1237/kWh to \$0.1268/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, 0.022 percent. In other words 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 EXPC case with CCS.

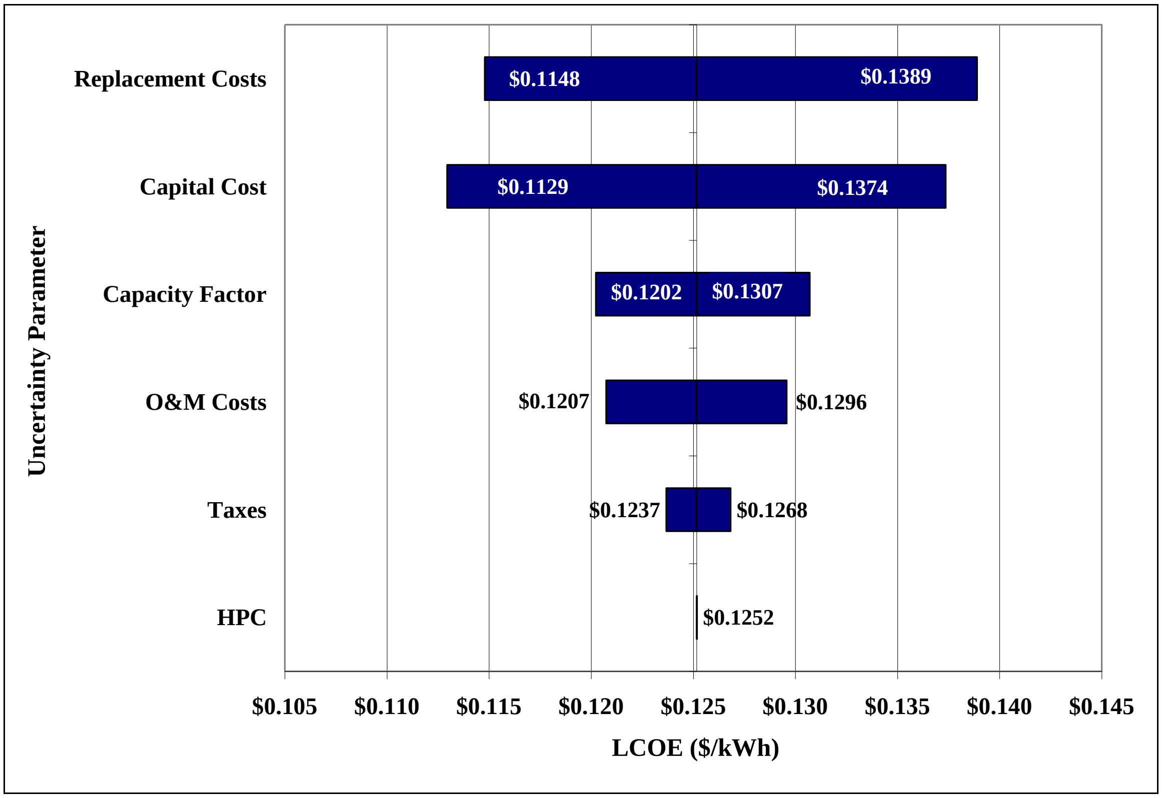



**Figure 3-17: Uncertainty Analysis LCOE Results for the EXPC Case with CCS**

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.

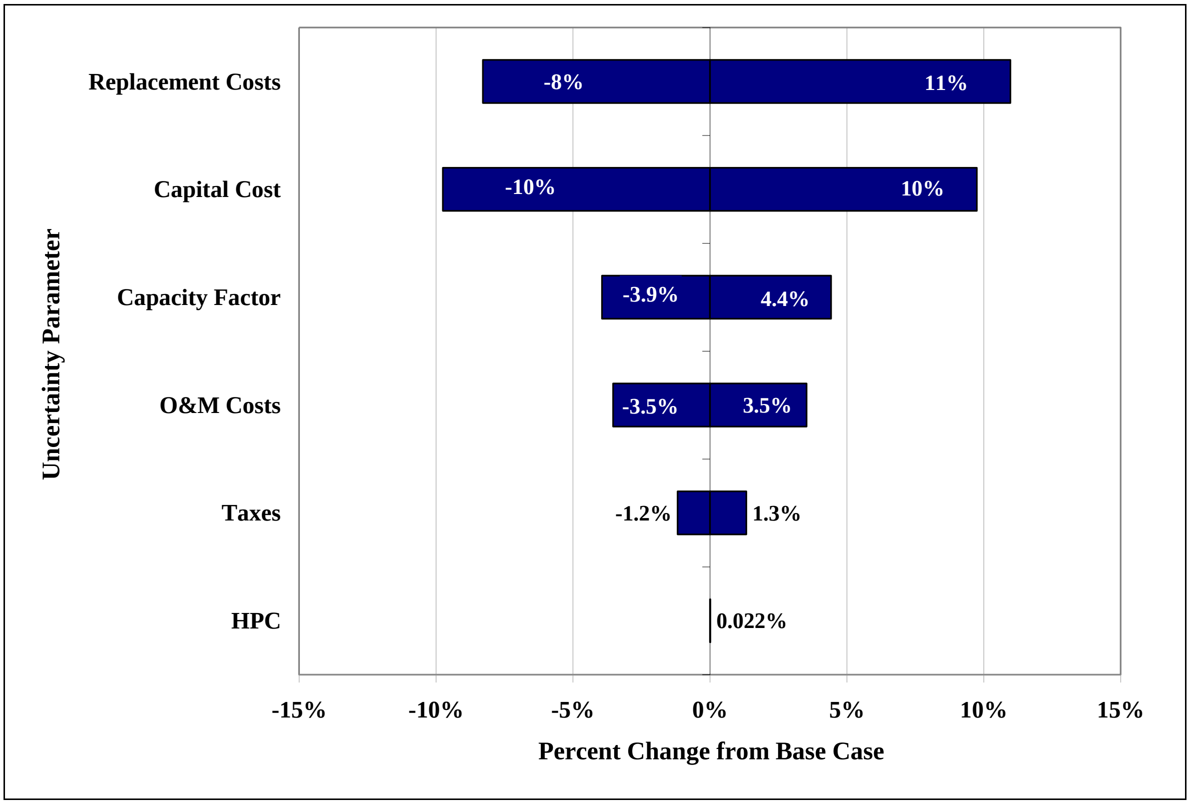



**Figure 3-18: Percent Change from Base Case LCOE for the EXPC Case with CCS**

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 | 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 the EXPC plant retrofitted with a CCS system is shown in **Table 3-13**. New construction is not necessary for the unmodified EXPC plant, so construction materials are not modeled for the unmodified plant. 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 $CO_2$e/MWh) for Base Cases and Sensitivity Impacts of Three Times the Material Inputs**

| Emissions (kg $CO_2$e/MWh) | Stage #3 Energy Conversion | | |
|---|---|---|---|
| | Base | 3 x Base | % Increase |
| **EXPC Retrofitted (with CCS)** | | | |
| $CO_2$ | 339.8 | 340.9 | 0.11% |
| $N_2O$ | 5.97 | 5.98 | 0.10% |
| $CH_4$ | 6.56 | 6.56 | 0.14% |
| $SF_6$ | 4.41E-03 | 4.41E-03 | 0% |
| Total GWP | 352.58 | 352.9 | 0.11% |

From the calculation of total GWP, it can be see that the overall percent increase is only 0.11 percent for the EXPC plant retrofitted with 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 the EXPC scenarios. **Table 3-14** demonstrates the same conclusion for non-GHG emissions.

**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 #3 Energy Conversions | | |
|---|---|---|---|
| | Base | 3 x Base | % Increase |
| EXPC Retrofitted (with CCS) | | | |
| Pb | 1.7E-05 | 1.8E-05 | 5.79% |
| Hg | 5.14E-05 | 5.14E-05 | 0.05% |
| $NH_3$ | 1.2E-03 | 1.2E-03 | 0% |
| CO | 1.9E-01 | 1.9E-01 | 1.29% |
| $NO_X$ | 2.274 | 2.275 | 0.03% |
| $SO_X$ | 3.427 | 3.428 | 0.03% |
| VOC | 1.2E-02 | 1.2E-02 | 0.36% |
| PM | 6.262E-01 | 6.263E-01 | 0.01% |

### 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 3-19** shows the total GWP for the total LC of both EXPC 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 the unmodified EXPC and CCS-retrofitted EXPC by 1.8 and 2.9 percent, respectively. When considering the total LC emissions, the largest benefit associated with $CH_4$ recovery is seen for the EXPC with CCS, which has an 8.7 percent reduction in GWP.

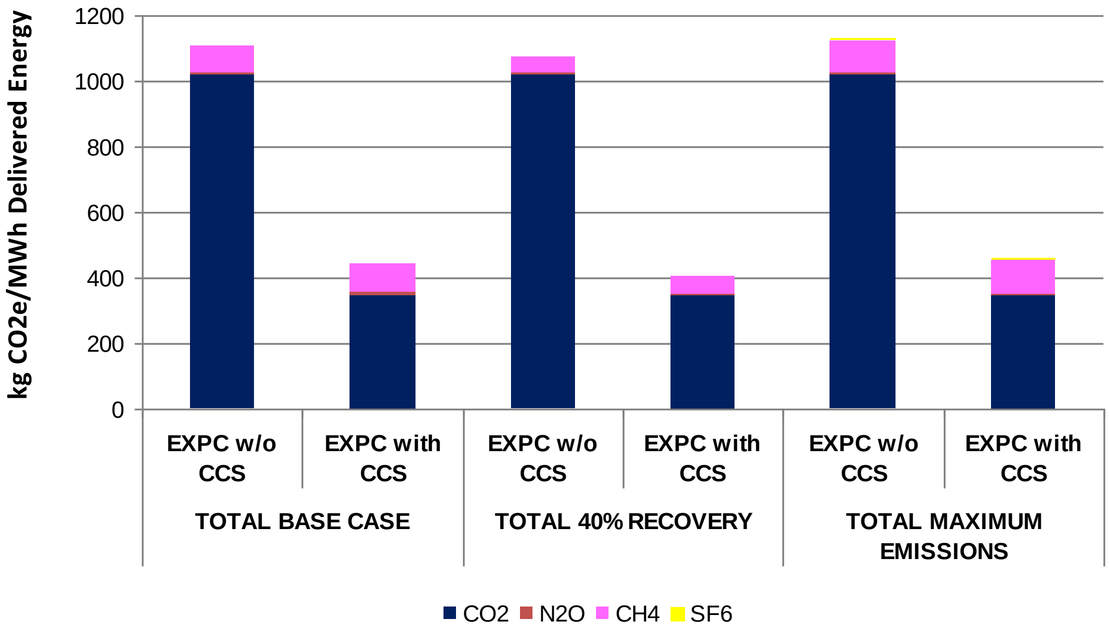



**Figure 3-19: Sensitivity Analysis of Methane Recovery on GWP (kg $CO_2$e/MWh Delivered Energy)**

### 3.5.2.3 Rail Transport

In the base cases, coal was transported from the mine to the EXPC facility via rail for a distance of 200 miles, with a roundtrip distance of 400 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 the EXPC with and without CCS. Overall, rail distance only has a slight impact on total GWP, with a decrease of 0.5 and 2.8 percent for the EXPC cases without and with CCS, respectively. This is mainly a result of less $CO_2$ emissions as a result of no diesel fuel use.

**Table 3-15: Rail Distance Sensitivity on Total GHG Emissions (kg $CO_2$e) and Air Emissions (kg)/MWh Delivered Energy**

| Emissions | Total Base Case | | Total - 0 Miles | | % Decrease | |
|---|---|---|---|---|---|---|
| | EXPC w/o CCS | EXPC with CCS | EXPC w/o CCS | EXPC with CCS | EXPC w/o CCS | EXPC with CCS |
| **GWP (kg $CO_2$e/MWh Delivered Energy)** | | | | | | |
| $CO_2$ | 1020 | 348 | 1015 | 338 | -0.5% | -2.8% |
| $N_2O$ | 5 | 6 | 5.07 | 5.90 | -0.7% | -1.9% |
| $CH_4$ | 80 | 87 | 80 | 85 | -0.2% | -1.5% |
| $SF_6$ | 3 | 3 | 3.27 | 2.26 | 0.0% | -31.0% |
| total GWP | 1109 | 444 | 1104 | 432 | -0.5% | -2.8% |
| **Non-GHG Air Emissions (kg/MWh Delivered Energy)** | | | | | | |
| Pb | 6.49E-06 | 1.84E-05 | 6.46E-06 | 1.82E-05 | -0.5% | -1.5% |
| Hg | 5.21E-05 | 5.53E-05 | 5.21E-05 | 5.46E-05 | 0.0% | -1.3% |
| $NH_3$ | 4.35E-04 | 1.54E-03 | 2.47E-04 | 1.33E-03 | -43.2% | -13.4% |
| CO | 1.25E-01 | 2.22E-01 | 1.11E-01 | 2.05E-01 | -11.8% | -7.9% |
| $NO_X$ | 2.02E+00 | 2.46E+00 | 2.01 | 2.42E+00 | -0.7% | -1.9% |
| $SO_X$ | 2.40E+00 | 3.70E+00 | 2.40 | 3.65E+00 | -0.1% | -1.4% |
| VOC | 1.44E-02 | 1.45E-02 | 1.31E-02 | 1.31E-02 | -8.9% | -10.0% |
| PM | 6.91E-01 | 6.91E-01 | 6.74E-01 | 6.65E-01 | -2.5% | -3.7% |

For non-GHG emissions, a variation in rail distance has a negligible affect on the LC results. This is shown graphically in **Figure 3-20**.

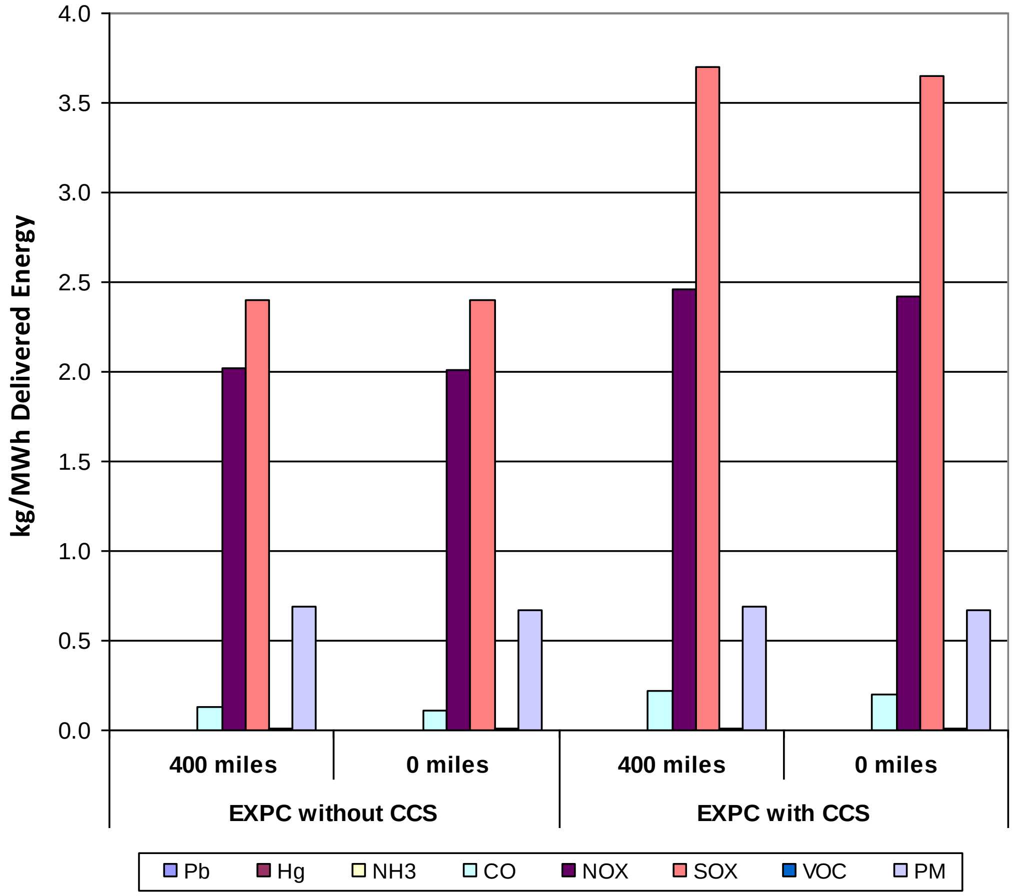



**Figure 3-20: Rail Distance Sensitivity on Air Emissions (kg) /MWh Delivered Energy**

# 4.0 Summary

The addition of an amine-based post-combustion carbon capture system (designed for a maximum 90 percent capture) to an EXPC facility reduces LC GWP by 61 percent. However, adding CCS increases the LCOE by a factor of 4.5, from approximately \$0.027/kWh to \$0.125/kWh of delivered electricity. Although the increase occurred for all cost parameters (capital, O&M, labor, etc.), capital and O&M costs exhibited the largest cost increases, indicating 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. From a GWP perspective, the replacement power for the retrofitted EXPC case accounts for approximately 53 percent of LC GWP; this demonstrates that when a CCS system reduces the output of an EXPC plant, a significant share of GHG emissions result from the generation of replacement power.

Other tradeoffs from the addition of CCS included more water and land use. Approximately 72 percent more water is consumed by the EXPC case with CCS due to the increase cooling requirements for the carbon capture process. This result suggests that depending on the location of the EXPC 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 replacement power from the regional electricity grid, which emits additional GHG and non-GHG emissions. 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.

Due to data limitations, strong conclusions cannot be made for non-GHG emissions. The non-GHG emissions for both cases are derived from the same emission inventory and do not account for the changes in emissions due to the installation of a CCS system. However, the LC results demonstrate that the emission of non-GHG emissions occur on a much smaller scale than $CO_2$ and $CH_4$. Even if higher quality data was available for non-GHG emissions, the interpretation of the results would be limited because impact assessment is not used in this analysis.

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 EXPC plant. Changing the capacity factor ±5 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 observed 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. 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 EXPC with CCS by 8.7 percent. However, this analysis does not consider other LC benefits or disadvantages associated with the CBM recovery process, so additional modeling would need to be done before a conclusion can be drawn about its overall effectiveness. For EXPC without CCS, recovering 40 percent of the $CH_4$ emissions at the coal mine has only a 2.9 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 EXPC facility from 200 to zero miles) decreased GWP by 0.5 and 2.8 percent for the cases without and with CCS, respectively.

# 5.0 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 LC 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 LC 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 $CH_4$ recovery system at the coal mine would provide more insight into the benefits of coal bed $CH_4$ capture. Different mines and coal types have different levels of gassiness, and there are different end-use profiles (onsite 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. Additionally, if an EXPC 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.

- Further analysis on $SO_X$ emissions from unmodified EXPC facilities and CCS-retrofitted facilities is necessary in order to quantify the $SO_X$ capture realized by the addition of a CCS system.
- Additional scenarios for replacement power should be evaluated. This will allow the implications of CCS retrofits to EXPC plants for specific regions in the United States because regional electricity grids have unique emissions profiles.

# 6.0 References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