NATIONAL ENERGY TECHNOLOGY LABORATORY

Life Cycle Analysis: Natural Gas Combined Cycle (NGCC) Power Plant

September 30, 2010

DOE/NETL-403-110509

U.S. DEPARTMENT OF ENERGY

Disclaimer

Life Cycle Analysis: Natural Gas Combined Cycle (NGCC) Power Plant

DOE/NETL-403/110509

September 30, 2010

NETL Contact:

Timothy Skone
Lead General Engineer

Robert James
General Engineer
Office of Systems, Analyses, and Planning

National Energy Technology Laboratory

www.netl.doe.gov

This page intentionally left blank.

Table of Contents

List of Tables

List of Figures

Preparation

Laura Draucker

Raj Bhander

Barbara Bennett

Tom Davis

Robert Eckard

William Ellis

John Kauffman

James Littlefield

Amanda Malone

Ron Munson

Maura Nippert

Massood Ramezan

Roxanne Bromiley

Research and Development Solutions, LLC

Science Applications International Corporation

DOE Contract #DE-AC26-04NT41817

Acknowledgments

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

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

Robert James, NETL Technical Monitor

Timothy Skone, NETL Situational Analysis Team Lead

List of Acronyms and Abbreviations

°C	Degree Celsius
°F	Degree Fahrenheit
ACSR/AW	Aluminum Conductors, Aluminum-Clad Steel Reinforced
AEO	Annual Energy Outlook
ALNG	Atlantic LNG Company of Trinidad and Tobago
ARRA	American Recovery and Reinvestment Act
ASTM	American Society for Testing and Material Standards
AVB	Aluminum Vertical Break
Btu	British thermal unit
CAP	Criteria Air Pollutant
CCF	Capital Charge Factor
CCS	Carbon Capture and Sequestration
CH_4	Methane
cm	Centimeter
CTG	Combustion Turbine Generator
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
COE	Cost of Electricity
DOE	Department of Energy
EERE	Energy Efficiency and Renewable Energy
EIA	Energy Information Administration
EIS	Environmental Impact Statements
EPA	Environmental Protection Agency
EPC	Engineer/Procure/Construct
F_i	Consumption of Fuel per Unit of Product
g	Gram
G&A	General and Administrative
GHG	Greenhouse Gases
GWP	Global Warming Potential
H_2S	Hydrogen Sulfide
HC	Hydrocarbons
Hg	Mercury
hrs	Hours
HRSG	Heat Recovery Steam Generator
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
kWh	Kilowatt-Hour
lb	Pound

LC	Life Cycle
LCA	Life Cycle Analysis
LCC	Life Cycle Cost
LCI	Life Cycle Inventory
LCI&C	Life Cycle Inventory and Cost
LCIA	Life Cycle Impact Assessment
LCOE	Levelized Cost of Electricity
LNB	Low-Nitrogen Oxides Burner
LNG	Liquefied Natural Gas
MACRS	Modified Accelerated Cost Recovery System
MJ	Mega-Joule
mm	Millimeter
MMV	Measurement, Monitoring, and Verification
MTPA	Metric Tonnes per Annum
MW	Megawatt
MWe	Megawatts (electric)
MWh	Megawatt Hour
N_2O	Nitrous Oxide
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
Pb	Lead
PM	Particulate Matter
PM_{10}	Particulate Matter (diameter 10 micrometer)
$PM_{2.5}$	Particulate Matter (diameter 2.5 micrometer)
ppmv	Parts per Million Volume
psia	Pounds per Square Inch Absolute
PV	Present Value
R&D	Research and Development
RDS	Research and Development Solutions
scf	Standard Cubic Feet
SCR	Selective Catalytic Reduction
SF_6	Sulfur Hexafluoride
SO_2	Sulfur Dioxide
SO_X	Sulfur Oxide
TBD	To Be Determined
TS&M	CO_2 Transportation, Sequestration, and Monitoring
U.S.	United States
VOC	Volatile Organic Chemical

This page intentionally left blank.

Executive Summary

This analysis evaluates the emissions footprint of NGCC technology, including production and delivery stages upstream and downstream of the NGCC facility. 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 NGCC energy conversion cases with two natural gas supply scenarios. One case assumes that the NGCC facility emits the full amount of carbon dioxide (CO_2) resulting from the combustion of the fuel, the second case builds upon the first case by adding CO_2 removal capability 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. The two natural gas supply scenarios include imported and domestic scenarios. As modeled in this analysis, imported natural gas is transported as liquefied natural gas (LNG) from Trindad and Tobago to the U.S., and domestic natural gas is a mix of five extraction technologies currently employed in the U.S.

Purpose of the Study

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

Two NGCC cases are considered for evaluation:

- Case 1: (NGCC without CCS) A 555-megawatt electric (MWe) (net power output) NGCC thermoelectric generation facility, in southern Mississippi, utilizing two parallel, advanced F-Class natural gas-fired combustion turbines/generators (CTGs). Each CTG is followed by a heat recovery steam generator (HRSG). All net steam produced in the two HRSGs flows to a single steam turbine. This case is configured without CCS.

- Case 2: (NGCC with CCS) A 474-MWe (net power output) NGCC thermoelectric generation facility, in southern Mississippi, utilizing the same configuration used in Case 1, and consisting of two parallel, advanced F-Class natural gas-fired CTGs. Each CTG is followed by a HRSG, and all of the net steam produced in the HRSGs flows to a single steam turbine. This case is configured with CCS, and steam is extracted from the steam turbine to provide heat needed for the Fluor Econamine carbon dioxide (CO_2) capture system for solvent regeneration.

In addition to the energy generation facility, the environmental performance of processes upstream and downstream of the NGCC facility are considered. The upstream LC stages (natural gas extraction and transport) include two supply scenarios for natural gas. The first supply case is foreign offshore natural gas extraction, followed by liquefaction, ocean transport, regasification, and pipeline transport to the NGCC facility. The second supply case is a mix of domestic extraction technologies with pipeline transport to the NGCC facility.

The two energy generation cases and the two natural gas supply cases result in a total of four scenarios for this analysis:

- NGCC with imported LNG without CCS
- NGCC with domestic NG without CCS
- NGCC with imported LNG with CCS
- NGCC with domestic NG with CCS

The cost of natural gas as received by the NGCC facility is the same for imported natural gas (via the LNG route) and domestic natural gas. Natural gas is a commodity, and thus the market price of natural gas does not differentiate between two types of extraction and delivery systems. Thus the economic boundaries of the LCC do not differentiate among the different natural gas sources.

Scope of the Study

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

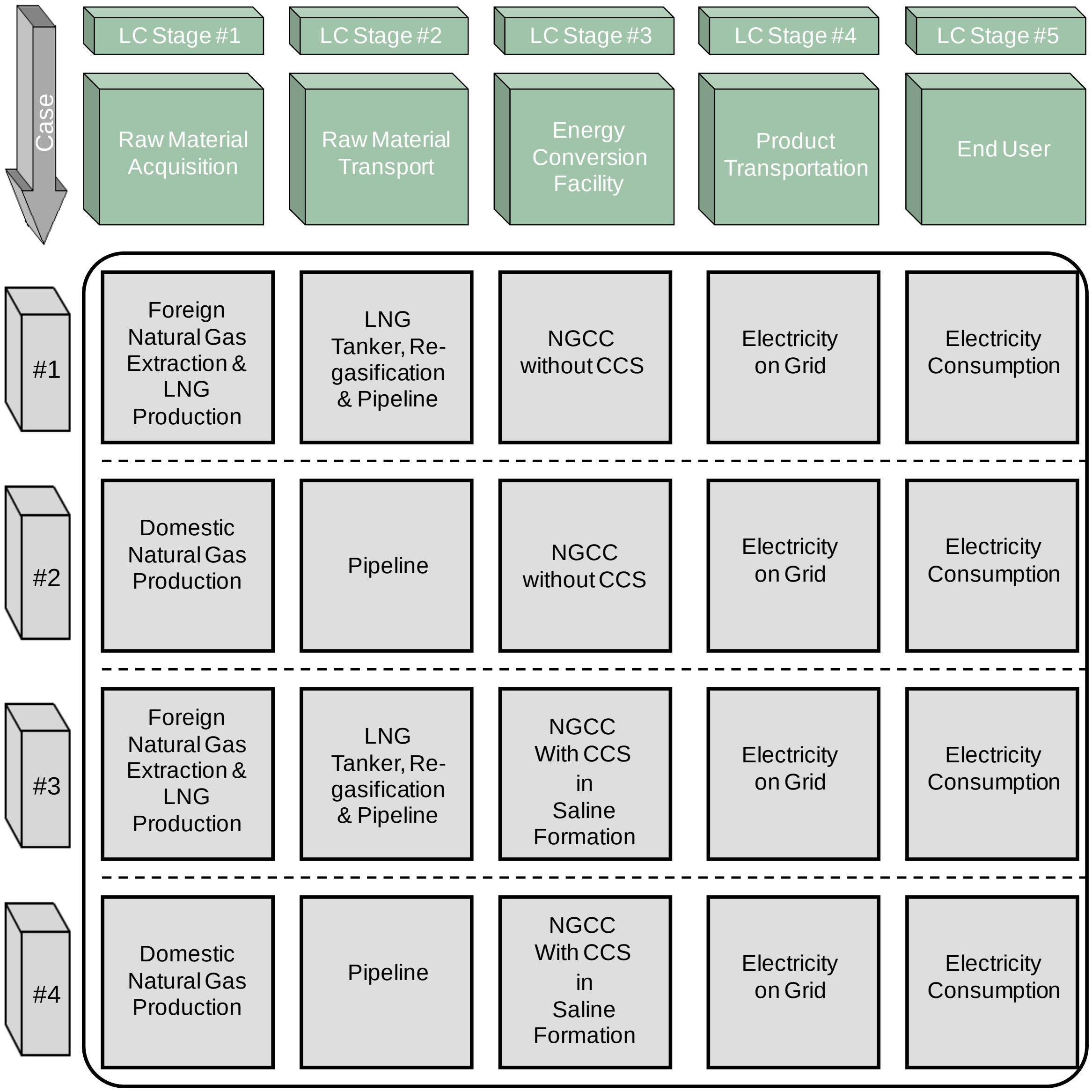

Figure ES-1: Case Comparison by Life Cycle Stage

Modeling 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: raw material extraction, raw material transport, energy conversion, transmission and distribution, and end use. 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 model are listed below:

- **Life Cycle Stage #1** includes the fuels and materials used in the construction, installation/deinstallation, and operation of natural gas wells and, in the case of imported natural gas, the pipelines and liquefaction facilities necessary for LNG.
- **Life Cycle Stage #2** includes the materials and fuels for pipeline transport of natural gas to NGCC plant and, in the case of imported natural gas, the construction and operation of

an LNG tanker, the operation of the tanker escort and jetty terminal, and the construction and operation of a regasification facility.

- **Life Cycle Stage #3** includes the fuels and emissions for the commissioning and decommissioning of the NGCC plant; construction materials for major plant equipment; fuels, emissions, capital and O&M costs for the operation of the NGCC plant; construction materials for the switchyard and trunkline system; and, for the CCS case, the construction, operation, and costs for the equipment and infrastructure to capture, compress, transport, inject, and monitor $CO_{2.}$.
- **Life Cycle 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.
- **Life Cycle Stage #5** assumes all delivered electricity is used by a non-specific, 100% efficient process and is not included in the model.

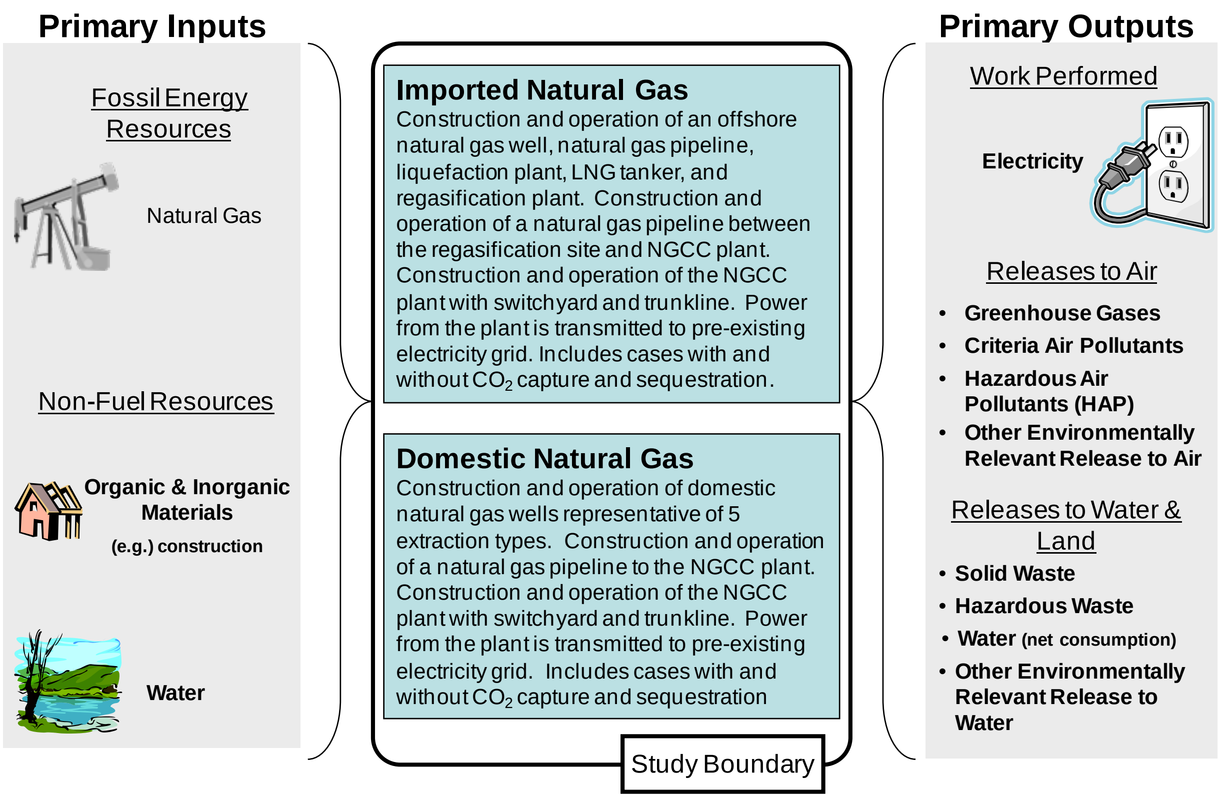

Figure ES-2: Study Boundary

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 NGCC cases. As an example, the study boundary assumptions indicate that the study period is 30 years, interest costs are not considered, and the model does not include effects due to human interaction. The sources for these assumptions are listed in the table as well. Assumptions originating in this report are labeled as "Present Study," while other comments originating in the NETL Cost and Performance Baseline for Fossil Energy Power Plants study, Volume 1: Bituminous Coal and Natural Gas to Electricity Report are labeled as "NETL Baseline Report."

Summary Results

Figure ES-3 shows the comparison of LCOE components in $/kWh delivered energy. Overall, utility costs (feedstock and utilities) used to levelize has the largest impact on the results. The total LCOE results for the NGCC case with CCS exceed the LCOE results for the NGCC case without CCS by 42 percent. Although each cost parameter (operation and maintenance [O&M], labor, utilities, and feed stocks) increases with the addition of CCS, the largest increase is for the capital cost component at 107 percent. The addition of CO_2 transmission, storage, and monitoring (TS&M) costs associated with CCS added 4.1 percent to the total resulting in a net increase in the overall LCOE for Case 2 to $0.132 per kilowatt hour (kWh)

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	Trinidad and Tobago	Present Study
Fuel Feedstock	Natural Gas	NETL Baseline Report
Gas Extraction Construction and Operation Costs	Included in Gas Delivery Price	Present Study
LC Stage #2: Raw Material Transport		
LNG Tanker Distance Traveled (one way)	2260 nautical miles	Present Study
U.S. LNG Terminal Location	Lake Charles, Louisiana	Present Study
Pipeline Distance from LNG Terminal to Power Plant	208 miles	Present Study
LNG Infrastructure Construction and Operation Costs	Included in Gas Delivery Price	Present Study
LC Stage #3: Power Plant		
Power Plant Location	Southern Mississippi	Present Study
NGCC Net Electrical Output (without CCS)	555 MW	NETL Baseline Report
NGCC Net Electrical Output (with CCS)	474 MW	NETL Baseline Report
Auxiliary Boiler Fuel	Natural Gas	Present Study
Trunk Line Constructed Length	50 miles	Present Study
CO_2 Compression Pressure for CCS Case	2,215 psi	NETL Baseline Report
CO_2 Pipeline Length for CCS Case	100 miles	Present Study
Sequestered CO_2 Loss Rate for CCS Case	1% in 100 years	Present Study
Capital and Operation Cost		NETL Bituminous Baseline
LC Stage #4: Product Transport		
Transmission Line Loss	7%	Present Study
Transmission Grid Construction	Pre-existing	Present Study

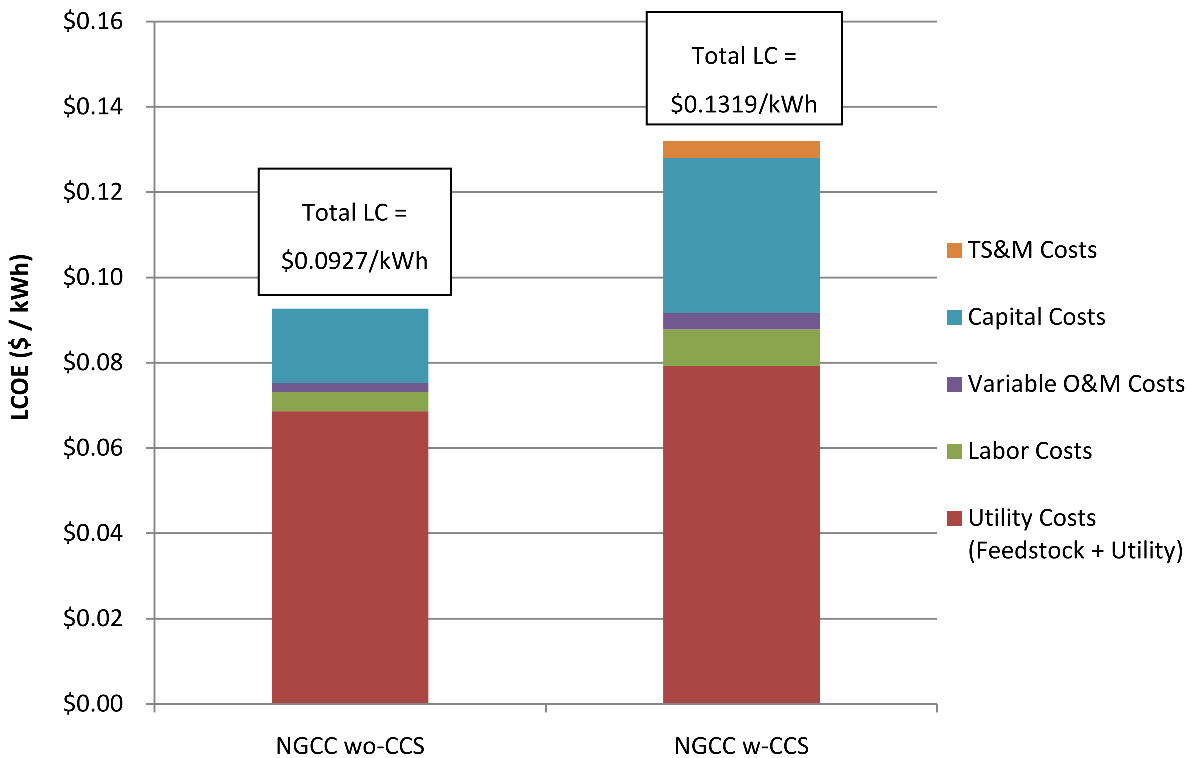

Figure ES-3: Comparative Levelized Cost of Delivered Energy ($/kWh) for NGCC with and without CCS

Table ES-2 compares the GHG emissions (kilogram [kg] CO_2e/MWh (CO_2e /unit of delivered energy) for four cases (NGCC *without* CCS for imported and domestic natural gas, and NGCC *with* CCS for imported and domestic natural gas). On an LC stage basis, the energy conversion facility (Stage #3) for NGCC without CCS dominates all the other stages for GHG emissions. However, when CCS is included, the GWP burdens for the extraction and delivery of natural gas (Stage #1 and #2) produce more GWP burdens than the energy conversion facility (Stage #3). This indicates that when considering NGCC, particularly with imported LNG feed, not only the energy conversion facility should be considered to reduce GHG emissions. Sulfur hexafluoride (SF_6) emissions are not seen as a large contributor to the total GWP, ranging from 0.62 to 2.4 percent of total GWP (depending on the scenario).

Table ES-2: Comparative GHG Emissions (CO_2e/MWh Delivered) for Cases 1-4

Emissions (kg CO_2e /MWh)	Stage #1: Raw Material Acquisition	Stage #2: Raw Material Transport	Stage #3: NGCC Plant	Stage #4: Transmission & Distribution	Total
NGCC with Imported NG without CCS					
CO_2	81.7	20.3	393	0	495
N_2O	1.45E-01	4.89E-02	4.47E-03	0	1.98E-01
CH_4	6.18	19.0	9.20E-03	0	25.2
SF_6	4.18E-08	7.43E-07	7.43E-03	3.27	3.28
Total GWP	88.0	39.4	393.0	3.27	524
NGCC with Domestic NG without CCS					
CO_2	16.4	18.7	393	0	428

N_2O	1.28E-02	9.74E-02	4.47E-03	0	1.15E-01
CH_4	6.39	28.7	9.20E-03	0	35.1
SF_6	1.32E-08	5.68E-07	7.43E-03	3.27	3.28
Total GWP	22.8	47.5	393	3.27	467
NGCC with Imported NG with CCS					
CO_2	95.7	23.8	51.3	0	171
N_2O	1.70E-01	5.74E-02	6.98E-03	0	2.34E-01
CH_4	7.24	22.3	1.39E-02	0	29.5
SF_6	4.90E-08	8.71E-07	8.70E-03	3.27	3.28
Total GWP	103	46.1	51.3	3.27	204
NGCC with Domestic NG with CCS					
CO_2	19.2	21.9	51.3	0	92.4
N_2O	1.50E-02	1.14E-01	6.98E-03	0	1.36E-01
CH_4	7.49	33.7	1.39E-02	0	41.2
SF_6	1.55E-08	6.66E-07	8.70E-03	3.27	3.28
Total GWP	26.7	55.7	51.3	3.27	137

In summary, CCS added to an NGCC facility can greatly reduce the LC GWP of the energy conversion process. However, although CCS removes 90 percent of the CO_2 emissions from the NGCC facility, the energy consumption and emissions of Stage #1 and Stage #2 bring the total GWP reduction to 61 percent for the imported natural gas scenarios and 71 percent for the domestic natural gas scenarios. Additional NGCC LCI&C assessments will need to be completed to determine the GWP of domestic and pipeline-imported (from Mexico and Canada) natural gas.

Adding CCS increases the LCOE by 42 percent, from approximately $0.09/MWh to $0.13/MWh of delivered electricity. This indicates that advancements in CCS technologies that reduce the capital investment and operating costs would most significantly reduce the overall cost differences between the two cases. Other tradeoffs from the addition of CCS included more water and land use. Approximately 44 percent more water is needed for cooling applications during the carbon capture process. This result suggests that depending on the location of the NGCC 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 grass and forest land. Investors and decision makers can use the results presented in this report to weigh the benefits of carbon mitigation to the additional cost of investing in CCS technology. Additionally, these results suggest that investment in research and development (R&D) to advance CCS technologies and lower capital investment costs will have a positive effect on reducing the difference in LCOE between the cases.

Sensitivity analysis was performed on several cost and environmental inventory parameters. Capital costs and high price case feedstock/utility costs have the largest impact on LCOE. This indicates that investors will need to take care when analyzing capital cost parameters for a given NGCC plant. Additionally, these results highlight the uncertainty of natural gas feed prices and the impact they can have on the overall economics of an NGCC plant.

A sensitivity analysis was performed on the quantity of construction materials used throughout the entire life cycle as well as the transportation distances for LNG tankers and natural gas pipelines. Minor impacts were observed when the mass of construction material inputs was increased three times the base case values, indicating that high uncertainty for material inputs does not contribute to high uncertainty in total LC results. In particular, GHG emissions are not significantly affected by a three-fold increase in construction material inputs, demonstrating a 0.4 to 0.6 increase in total CO_2e for scenarios without CCS and a 1.7 to 2.0 percent increase in total CO_2e for scenarios with CCS. Increases in heavy metal (Hg and Pb), carbon monoxide (CO), and sulfur oxide (SO_x) emissions were observed due to their dominance in the upstream profiles for construction materials; the affect of these non-GHG emissions cannot be evaluated further without conducted an impact analysis.

The sensitivity analysis of tanker transport distance showed a large impact on Stage #2 GWP and non-GHG air emissions when distance is increased from delivery from Trinidad versus Egypt. Overall, increasing transport distance from 2,260 to 10,000 miles increases the total GWP for both cases (with and without CCS) by 23.5 and eight percent, respectively. Additionally, reducing the pipeline distance between regasification facility and the NGCC plant reduces the CH_4, NO_X, and CO emissions in Stage #2.

Key Results

- Adding 90 percent CO_2 capture and storage to an NGCC platform will increase the full life cycle cost of power from 9.3¢ to 13.2¢ – a 42 percent increase.

- GHG emissions for natural gas extraction and transport increase slightly when adding a CCS system. This is due to the parasitic power required for CCS. The 90 percent CO_2 capture at the power plant results in a 61 percent reduction in total Life Cycle GHG emissions when using imported natural gas, and a 71 percent reduction in total Life Cycle GHG emissions when using domestic natural gas.

- The difference in LCOE, and GHG emissions between NGCC without CCS and NGCC with CCS result in a GHG avoided cost of $121/tonne.

- There is little difference in the GWP of the upstream extraction sources of natural gas, whether it is extracted domestically or in a foreign gas field. However, the processing and transport of natural gas using liquefaction and regasification significantly increases the upstream emissions of imported natural gas.

1.0 Introduction

In 2008 the United States consumed approximately 41 quadrillion (10^{14}) British thermal units (Btu) of electricity, which is equivalent to 1.2 billion megawatt hours (MWh) per year of electricity generation (EIA, 2009a). 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 coal is the dominant feedstock for electricity generation in the United States, concerns about greenhouse gases (GHGs) and other emissions associated with coal-fired power generation have increased the projected use of alternative energy sources such as renewables, nuclear power, and natural gas. In AEO 2009, natural gas is projected to account for 16.4 ±1 percent of electricity generation between 2006 and 2030 (EIA, 2009a), a different trend than was seen in AEO 2008, which projected a decrease in natural gas electricity generation between 2005 and 2030[2]. Determining what, if any, environmental benefits and economic burdens are associated with natural gas-fired power generation over its life cycle (LC) could provide valuable insight for predicting future investments in energy conversion technology.

The U.S. Department of Energy's (DOE) National Energy Technology Laboratory (NETL) has endeavored to quantify the environmental burdens 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 LC performance of natural gas combined cycle (NGCC) electricity generation pathways, with and without carbon capture and sequestration (CCS) capability. During NGCC, natural gas is combusted in a turbine, and the energy of the exiting flue gas is captured using a heat recovery steam generator (HRSG). NGCC is said to have a higher efficiency than coal combustion and gasification (NETL, 2010). However, to fully quantify the differences (whether benefits or disadvantages) between NGCC and other generation technologies, the full environmental and economic performance needs to be evaluated over the LC of the system; the results of this LC evaluation provide a comparison point for competing

[1] These data were retrieved from AEO 2009 without consideration of the American Recovery and Reinvestment Act (ARRA); 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.

[2] AEO 2008 projected an overall decrease from approximately 14 to 10 percent for natural gas used in electricity generation, with an average value over the study period (2005-2030) of 14 ±2 percent. Additionally, AEO 2009 with ARRA projects approximately 16 percent use of natural gas for electricity generation in 2006 and 2030, with a dip during the middle of the study period (approximately 2010-2025), resulting in the same average value over the entire study period (2006-2030) of 14 ±2 percent. This difference in 2009 cases is due to projected stimulation of renewable energy use through ARRA.

electricity generating pathways assessed within NETL's LCI&C Program. **Figure 1-1** shows the economic and environmental boundaries of this LCI&C.

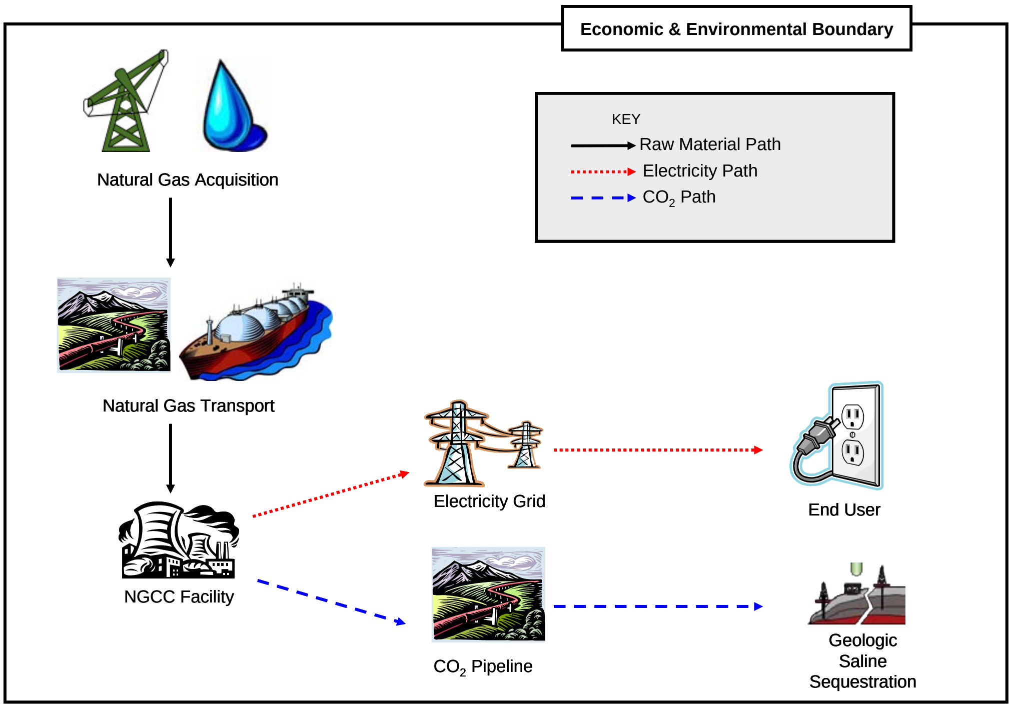

Figure 1-1: Conceptual Life Cycle Boundary

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 NGCC power generation facilities based on case studies presented in the NETL 2010 report, Cost and Performance Baseline for Fossil Energy Plants: Volume 1 (NETL, 2010). The NETL report provides detailed information on the operating procedures and costs for two NGCC facilities (Case 13 and Case 14); the data were used significantly during this study. Throughout the remainder of this document, the NETL Cost and Performance Baseline for Fossil Energy Plants: Volume 1 will be referred to as the "Baseline Report."

There are two power plant scenarios under consideration in this study:

- Case 1: (NGCC without CCS) A 555-megawatt electric (MWe) (net power output) NGCC thermoelectric generation facility, in southern Mississippi, utilizing two parallel, advanced F-Class natural gas-fired combustion turbines/generators (CTGs). Each CTG is followed by a HRSG. All net steam produced in the two HRSGs flows to a single steam turbine. This case is configured without CCS.
- Case 2: (NGCC with CCS) A 474-MWe (net power output) NGCC thermoelectric generation facility, in southern Mississippi, utilizing the same configuration used in Case 1, and consisting of two parallel, advanced F-Class natural gas-fired CTGs. Each CTG is followed by a HRSG, and all of the net steam produced in the HRSGs flows to a single steam turbine. This case is configured with post-combustion CCS, and steam is extracted from the steam turbine to provide heat needed for the Fluor Econamine carbon dioxide (CO_2) capture system for solvent regeneration.

The same NGCC technologies will be used in both cases; the difference in technologies between the two cases is whether or not a CCS system is employed. The cases with CCS include the additional transport and storage of the captured carbon.

In addition to the energy generation facility, the environmental performance of processes upstream and downstream of the facility are considered. The upstream LC stages (natural gas extraction and transport) include two supply scenarios for natural gas. The first supply case is foreign offshore natural gas extraction, followed by liquefaction, ocean transport, regasification, and pipeline transport to the NGCC facility; the second supply case is a mix of domestic extraction technologies with pipeline transport to the NGCC facility.

The two energy generation cases and the two natural gas supply cases result in a total of four scenarios for this analysis:

- NGCC with imported LNG without CCS
- NGCC with domestic NG without CCS
- NGCC with imported LNG with CCS
- NGCC with domestic NG with CCS

The study time period (30 years) allows for the determination of long-term cost and environmental impacts associated with the production and delivery of electricity generated by NGCC. 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 establish 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 natural gas extraction and transport are presented on a kilogram (kg) of natural gas basis, and results from energy conversion and electricity transmission are presented on a MWh basis.

- All primary processes (defined as the flow of energy and materials needed to support generation of electricity from natural gas) from extraction of natural gas, natural gas transport, electricity generation, electricity transport, and end use are accounted for.
- The following phases are considered for primary processes:
    - **Construction**: Emissions associated with the production of materials used during the construction of a process (e.g., steel used to build a power plant). Energy use and associated emissions due to the operation of a process.
    - **Installation/Deinstallation or Commissioning/Decommissioning**: Installation/commissioning is the energy and emissions associated with the site preparation and erection of a facility. Deinstallation/decommissioning includes the energy use and emissions associated with removing a facility and, if necessary, returning the land to its original state.
    - **Operations**: Energy and emissions due to the operation of a process.
- Secondary operations (defined as inputs not immediately needed for the flow of energy and materials, such as the material input for construction) that contribute significantly to mass and energy of the system or environmental or cost profiles are also included within the study boundary. Significance is defined in **Section 1.2.5.** Examples of secondary operations include, but are not limited to:
    - Construction of equipment and infrastructure to support each pathway (e.g., natural gas extraction site, power plant, transport equipment, etc.), with the exception of the power grid for electricity transport and end use being considered "pre-existing."
    - Provision of secondary energy carriers and materials (e.g., electrical power from the U.S. power grid, diesel fuel, heavy fuel oil, concrete production, steel production, etc.).
    - Carbon dioxide transport and injection into the sequestration site.
- Construction of infrastructure (pipelines, transmissions lines) is omitted from the study boundary if it is determined that they would exist without the construction of the studied facility or fuel extraction operation. For example, it is assumed that the transmission lines of the electrical grid would exist with or without the new energy conversion facility, and are thus not included in the model. However, the switchyard and trunkline, which connect the new energy conversion facility to the

transmission lines/grid, would not exist without the new facility and are thus included in the LCI&C.

- Cost parameters were collected for primary operations in order to perform the LCC analysis. These cost parameters 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.
- The cost of natural gas as received by the NGCC facility is the same for imported natural gas (via the LNG route) and domestic natural gas. Natural gas is a commodity, and thus the market price of natural gas does not differentiate between two types of extraction and delivery systems.
- The LCI includes the following magnitude evaluations from each primary and significant secondary operation: anthropogenic GHG emissions, criteria air pollutant (CAP) 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 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 an NGCC plant in a rural area (primary effect is removal of agriculture or native vegetation and installation of uses associated with an NGCC plant) may cause plant 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.

  However, no allocation was needed for this study.

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

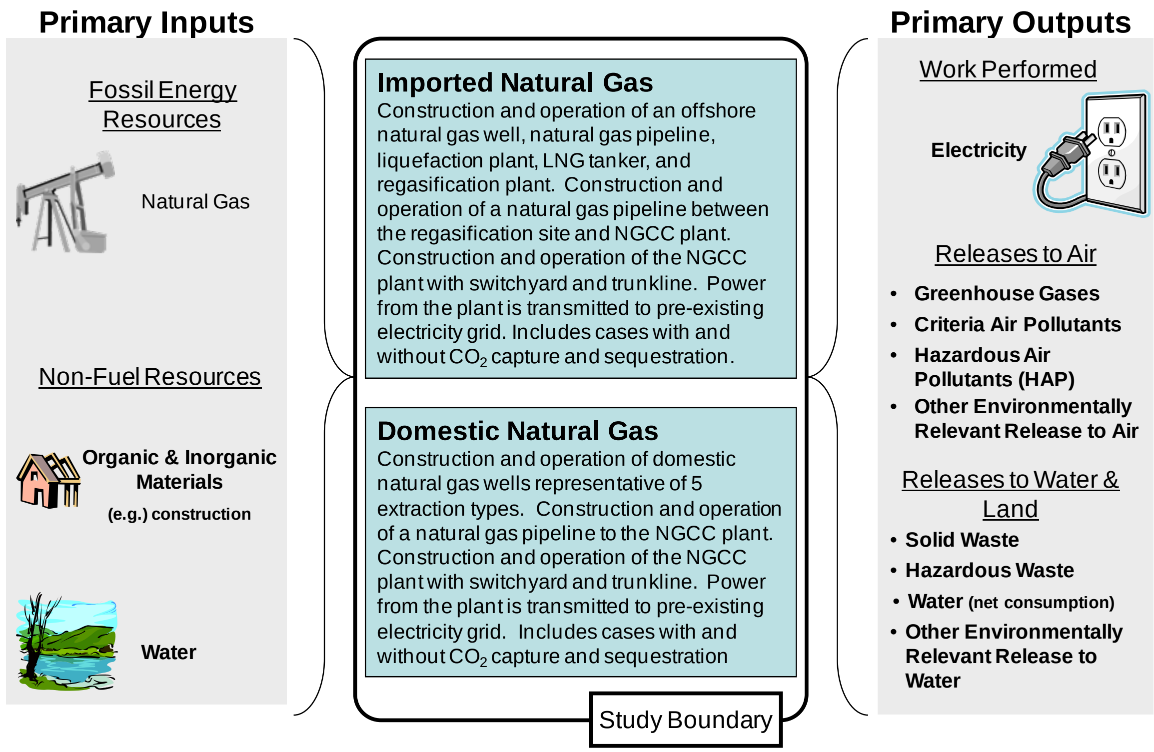

Figure 1-2: Study Boundary

1.2.1 Life Cycle Stages

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

- **Life Cycle Stage #1 (for Imported NG)**: Raw Material Acquisition
  - Boundary begins with the onshore construction of the natural gas drilling platform and transportation of the platform by tow boats to the offshore site near Trinidad and Tobago (for discussion on the location decision, please see **Section 2.1**).
  - Boundary includes construction materials for all known well components and operation of the well and drilling platform.
  - Boundary includes construction materials and operation of the liquefaction facility, storage tank complex, and jetty loading terminal in Trinidad and Tobago. The construction of a natural gas pipeline from the offshore well to the liquefaction and storage facility is also included.
  - Boundary ends with operation of loading natural gas onto the LNG tanker.
- **Life Cycle Stage #1 (for Domestic NG)**: Raw Material Acquisition

- Boundary includes construction materials and installation requirements for natural gas wells.
- Boundary includes the operation of natural gas wells, including extraction, oil/gas separation (where applicable), dehydration, acid gas removal (sweetening), and compression.
- Boundary ends with natural gas ready for pipeline transport.

- **Life Cycle Stage #2 (for Imported NG)**: Raw Material Transport: LNG Tanker and Pipeline, LNG Vaporization
    - Boundary begins after the natural gas is loaded on the LNG tanker in Trinidad and Tobago.
    - The construction and operation (including docking and berthing/deberthing) of the LNG tanker are included in this stage. This boundary also includes operation of the tanker escort, which involves two tug boats for each tanker trip.
    - The boundary includes the construction materials and operation of the jetty terminal, regasification facility, and storage tank complex in Lake Charles, Louisiana.
    - The boundary includes the construction of a pipeline from the storage facility in Lake Charles to the NGCC plant in southeastern Mississippi. Natural gas losses during the operation of the pipeline are also included.
    - Boundary ends when the natural gas in the pipeline reaches the fence line of the NGCC plant, located in southeastern Mississippi.
- **Life Cycle Stage #2 (for Domestic NG)** Raw Material Transport: Natural Gas Pipeline
    - The boundary includes the construction and operation of pipelines from domestic natural gas extraction sites to the NGCC plant in southeastern Mississippi. Natural gas losses during the operation of the pipeline are included.
    - Boundary ends when the natural gas in the pipeline reaches the fence line of the NGCC plant, located in southeastern Mississippi.
- **Life Cycle Stage #3**: Energy Conversion Facility: NGCC Plant, with or without CCS
    - Boundary starts with natural gas entering the NGCC plant, with or without CCS.
    - Construction and decommissioning of the plant structure and major plant equipment are included.
    - Operation of the NGCC plant is included for both cases.
    - Capital and O&M costs are calculated for the operation of the plant for both cases.

- Construction and operation are included for the switchyard and trunkline system that delivers the generated power to the grid.
- For the NGCC plant with CCS, the boundary includes the following:
    - Carbon dioxide is compressed to 2,215 pounds per square inch absolute (psia) at the NGCC 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 Mississippi 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 (environmental impacts of MMV are not considered within the study boundary).
- Boundary ends when the power created at the NGCC plant is placed onto the grid and CO_2 is verified and sequestered.

- **Life Cycle Stage #4**: Product Transportation: Electrical Grid
    - Boundary starts when the power is placed on the grid.
    - Electricity losses due to transmission and distribution are included.
    - Boundary ends when the power is pulled from the grid.
- **Life Cycle Stage #5**: End User: Electricity Consumption
    - Boundary starts and concludes when the power is pulled from the grid. All NETL power generation LCI&C studies assume electricity is used by a non-specific, 100 percent-efficient process.

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

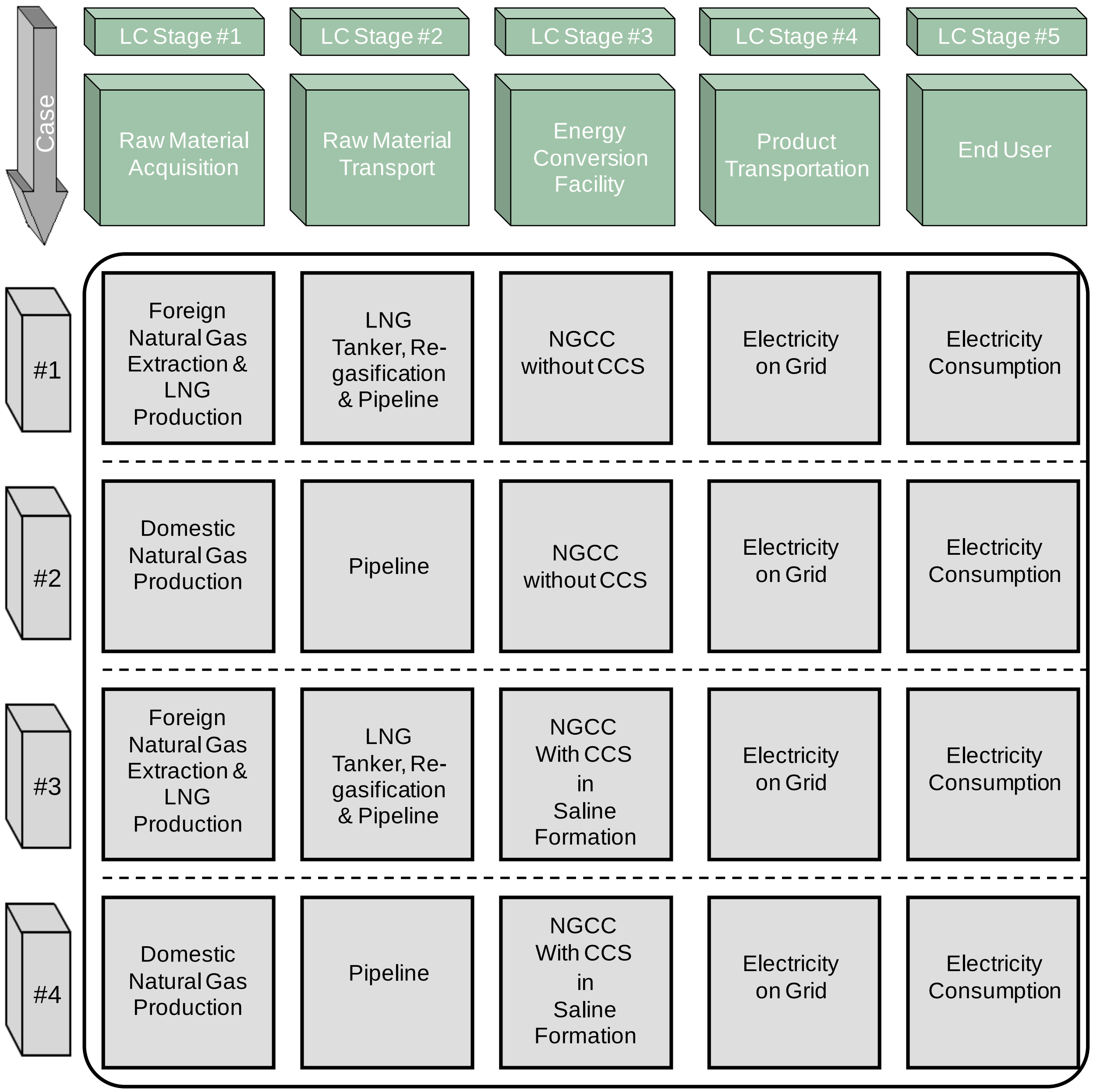

Figure 1-3: Comparison of Cases by Life Cycle Stage

Assessing the environmental LC perspective of each scenario requires that all significant material and energy resources be tracked back to the point of extraction from the earth (commonly referred to as the “cradle” in LCI&C terminology). While the primary material flow in this study is natural gas 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 from this study include concrete, steel, and fuels such as diesel and heavy fuel oil. Cradle-to-grave (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 NGCC plant without CCS is a mature technology and is well represented in full-scale power plant applications. The cost estimates for this case represent the "nth" plant, as done in the Baseline Report (NETL, 2010).

Carbon capture technology for the NGCC capture cases is not well developed as it has not been proven in full-scale power plant applications. The cost estimates for this case represents proven technology for CCS and "n^{th}" plant (when the technology is considered to be fully developed) for the NGCC plant.

1.2.3 Timeframe Represented

The economic and environmental profiles are compared on a 30-year operating time period, referred to as the "Study Period." The base year for the study was 2010 (e.g., Year 1) because the time required for plant and equipment construction would realistically happen before the following Year 1 assumptions were made. All capital investments were considered as "overnight costs" (assumed to be constructed overnight and hence no interest charges) and applied to Year 1 along with the corresponding O&M costs. Similarly, all environmental consequences of construction were assumed to occur on an overnight basis. All processes were thereby considered to be fully operational on day one of the 30-year study period. It was assumed that the life of all facilities and connected infrastructure is equal to that of the power plant.

1.2.4 Data Quality and Inclusion within the Study Boundary

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

- When publically available data were not available, purchasable, non-transparent data were used. 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 3.7**), and specific assumptions for each data input are listed by stages in Appendix A.

1.2.4.1 *Exclusion of Data from the Life Cycle Boundary*

Data were collected for each primary and significant secondary input and output to each LC stage (as defined by the system boundary) except the following, which for the reasons discussed were considered outside the boundary and scope of NETL power generation LCI&Cs.

Humans functioning within the system boundary have associated materials and energy demand as a burden on the environment. For humans working within the boundaries of this study, activities such as commuting to and from work and producing food are part of the overall LC. However, to consider such human activities would tremendously complicate the LC. First, quantifying the human-related environmental inflows and outflows would require a formidable data collection and analysis effort; second, the method 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 1% 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 NGCC 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.

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

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

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

Table 1-1: Global LCC Analysis Parameters

Property	Value	Units
Reference Year Dollars	December 2006/January 2007	Year
Assumed Start-Up Year	2010	Year
Real After-Tax Discount Rate	10.0	Percent
After-Tax Nominal Discount Rate	12.09	Percent
Assumed Study Period	30	Years
MACRS Depreciation Schedule Length	Variable	Years
Inflation Rate	1.87	Percent
State Taxes	6.0	Percent
Federal Taxes	34.0	Percent
Total Tax Rate	38.0	Percent
Fixed Charge Rate Calculation Factors		
Capital Charge Factor – wo-CCS	0.1502	--
Capital Charge Factor – w-CCS	0.1567	--
Levelization Factor – wo-CCS	1.432773	--
Levelization Factor – w-CCS	1.410939	--
Start Up Year (2010) Feedstock & Utility Prices	**$2006 Dollars**	
Natural Gas[1]	6.76	$/MMBtu
Process Water[2]	0.00049 (0.0019)	$/L ($/gal)

1. AEO 2008 Table 3 Energy Prices by Sector and Source: Electric Power-Natural Gas (EIA, 2008).
2. Rafelis Financial Consulting, PA. Rafelis Financial Consulting 2002 Water and Wastewater Rate Survey, Charlotte, NC.

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

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

where

$LCOE_P$ =	levelized cost of electricity over P years, $/MWh
P =	levelization period (e.g., 10, 20 or 30 years)
CCF_P =	capital charge factor for a levelization period of P years (0.1502 for w/o-CCS, 0.1567 for w-CCS)
TOC =	total overnight cost, $

LF = levelization factor (a single levelization factor is used in each case because a single escalation rate is used for all costs) (1.432773 for w/o-CCS, 1.410939 for w-CCS)

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

CF = plant capacity factor

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

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

1.2.7 Environmental LCI & GWP 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.
- CAPs 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 CAPs are currently monitored by the Environmental Protection Agency (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 inventoried, 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 in support of a 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 withdrawal minus water discharged from a process or facility. For instance, water consumption for an energy conversion facility would be calculated by subtracting the amount of liquid water discharged by the facility from the facility's water withdrawal, as previously defined.

- 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 method and results for this inventory are discussed in **Section 3.5**.

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

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

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

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

1.3 Software Analysis Tools

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

1.3.1 Life Cycle Cost Analysis

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

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

1.3.2 Environmental Life Cycle Analysis

GaBi 4, developed by the University of Stuttgart (IKP) and PE INTERNATIONAL of Germany, was used to conduct the environmental LCI. GaBi 4 is an ISO 14040-compliant modular software system used for managing large data volumes. In addition to adding data for a specific study into the GaBi framework, one can make use of the large database of LCI profiles included in GaBi for various energy and material productions, assembly, transportation, and other production and construction materials that can be used to assist in modeling the LC of each pathway. The GaBi 4 software has the ability to analyze the contribution from an individual process or groups of processes (referred to as “Plans”) to the total LC emissions. Plans, processes, and flows form modular units that can be grouped to model sophisticated processes, or assessed individually to isolate effects. The GaBi system follows a process-based modeling approach and works by performing comprehensive balancing (mass and energy) around the various processes within a model. GaBi 4 is a database-driven tool designed to assist practitioners in documenting, managing, and organizing LCI data. Data pulled from the GaBi 4 database and used within this study was considered non-transparent and was subject to sensitivity analysis. For this study, only secondary (or higher order) operations are characterized using GaBi profiles; all primary data were characterized by an additional reference source (peer reviewed journal, government report, manufacturer specifications, etc.) and entered into the GaBi framework.

1.4 Summary of Study Assumptions

Central to the modeling effort are the assumptions upon which the entire model is based. **Table 1-4** lists the key modeling assumptions for the 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 (imported NG)	Trinidad and Tobago	Present Study
Extraction Location (domestic NG)	Onshore/Offshore mix	Present Study
Fuel Feedstock	Natural Gas	NETL Baseline Report
Gas Extraction Construction and Operation Costs	Included in Gas Delivery Price	Present Study
LC Stage #2: Raw Material Transport		
LNG Tanker Distance Traveled (one way)	2260 nautical miles	Present Study
U.S. LNG Terminal Location	Lake Charles, Louisiana	Present Study
Pipeline Distance from LNG Terminal to Power Plant	208 miles	Present Study
Pipeline Distance from domestic extraction site to Power Plant	900 miles	Present Study
LNG Infrastructure Construction and Operation Costs	Included in Gas Delivery Price	Present Study
LC Stage #3: Power Plant		
Power Plant Location	Southern Mississippi	Present Study
NGCC Net Electrical Output (without CCS)	555 MW	NETL Baseline Report
NGCC Net Electrical Output (with CCS)	474 MW	NETL Baseline Report
Auxiliary Boiler Fuel	Natural Gas	Present Study
Trunk Line Constructed Length	50 miles	Present Study
CO_2 Compression Pressure for CCS Case	2,215 psi	NETL Baseline Report
CO_2 Pipeline Length for CCS Case	100 miles	Present Study
Sequestered CO_2 Loss Rate for CCS Case	1% in 100 years	Present Study
Capital and Operation Cost		NETL Bituminous Baseline
LC Stage #4: Product Transport		
Transmission Line Loss	7%	Present Study
Transmission Grid Construction	Pre-existing	Present Study

1.5 Report Organization

This study includes two comprehensive LCI and cost parameter studies for electricity production via NGCC with and without CCS. The method, 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 NGCC electricity generation with and without CCS. Analysis includes comparison of metrics (CAPs, 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 – Upstream Emissions Profiles: Environmental results on the basis of delivered natural gas (upstream profiles) broken out by source are displayed here.

Section 6.0 – 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 7.0 – 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 natural gas, convert natural gas to electricity, capture and sequester CO_2 (when applicable), and transmit electricity are discussed. Additionally, the environmental metrics (GHG emissions, CAP emissions, Hg and NH_3 emissions, water withdrawal/consumption, and land use) are quantified for each stage. The LCC results are given for Stage #3 only; LCC 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 are discussed separately for each case. The discussion of Stage #4 and Stage #5 are combined.

2.1 Life Cycle Stage 1: Raw Material Extraction

This analysis models two pathways for the supply of natural gas to an NGCC facility: imported natural gas and domestic natural gas.

The Stage #1 boundaries for imported natural gas begin with the extraction and processing of natural gas at a foreign offshore platform, include a mix of offshore and onshore pipeline transport to a liquefaction facility, and end with liquefied natural gas (LNG) ready for loading onto an LNG ocean tanker.

The Stage #1 boundaries for domestic natural gas begin with the extraction and processing of natural gas using a five-technology mix of extraction sites, and end with natural gas ready for pipeline transport.

Details on the Stage #1 pathways for imported and domestic natural gas are provided below.

2.1.1 Imported Natural Gas

In 2007, the United States imported approximately 4.6×10^6 million cubic feet (ft^3) of natural gas (EIA, 2009b). Although the majority was through pipelines from Canada (82 percent), approximately 17 percent of natural gas imports were LNG. LNG is transported via LNG tanker from locations all over the world, as represented in **Figure 2-1** (EIA, 2009b). Although LNG imports in 2007 (according to AEO 2009) were high compared to 2006 and 2008, overall imports are predicted to increase with increasing natural gas demand (EIA, 2009a); therefore, determining the LCI&C of an NGCC facility powered with LNG will offer environmental and economic insight into the growth of LNG use in the United States. Trinidad and Tobago was chosen because the majority of LNG (58 percent in 2007) is imported from that region (**Figure 2-1**).

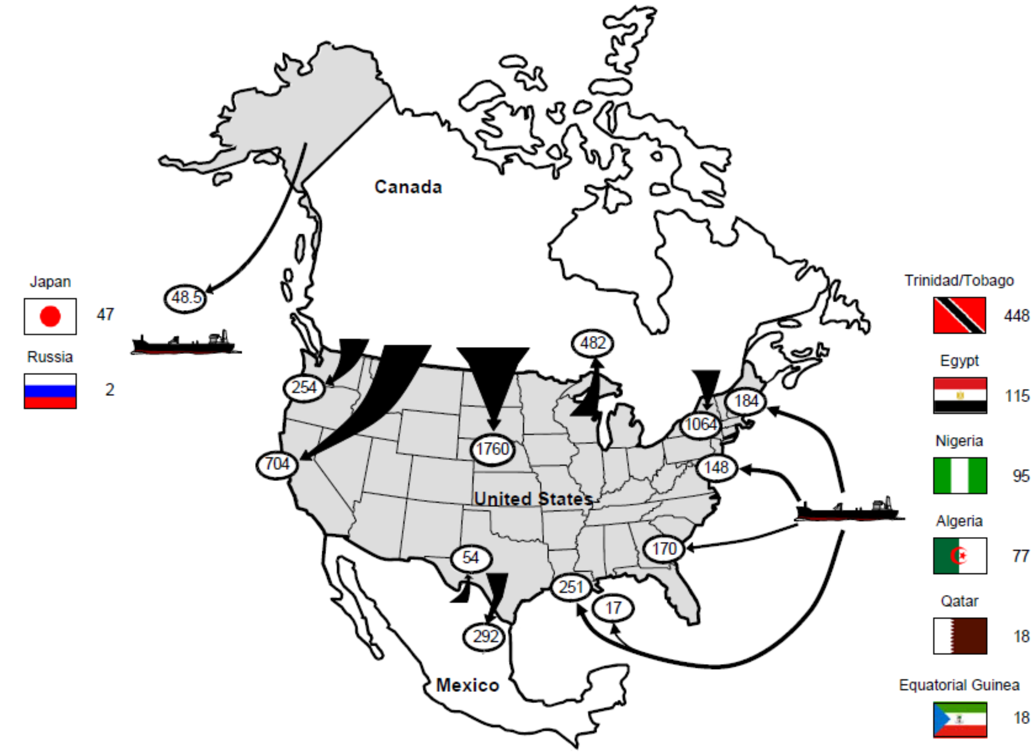

Figure 2-1: Flow of Natural Gas Imports and Exports, 2007 (EIA, 2009b)

The raw material acquisition stage operations begin with the extraction of natural gas from the deepwater gas fields located off the east coast of Trinidad. The extraction activities of offshore natural gas wells include the construction and installation of the extraction platform and extraction and processing operations. For the energy and material flows directly associated with offshore natural gas extraction, this analysis uses the same offshore extraction data for the imported and domestic natural gas scenarios. Details on the activities for offshore natural gas extraction are provided in **Section 2.1.4**.

Once the gas is extracted and cleaned, it is piped underwater from the deepwater field location to the eastern shore of Trinidad. Once there, the gas is further piped onshore, across Trinidad to the ALNG facility, where it is liquefied, stored, and loaded onto a LNG tanker for transport. The total pipeline distance traveled is approximately 50 miles offshore and 63 miles onshore. **Figure 2-2** is included to help visualize the transport activities required during Stage #1 (map adapted from *maps.google.com*).

Figure 2-2: Map of Trinidad and Tobago Including Locations of Interest

2.1.2 Domestic Natural Gas

This analysis includes unit processes for domestic natural gas extracted from five sources: (1) conventional onshore gas, (2) conventional offshore gas, (3) conventional onshore associated gas, (4) Barnett Shale gas, and (5) coal bed methane. The characteristics of these extraction sources are summarized below.

Conventional onshore natural gas is recovered by vertical drilling techniques. Once a conventional onshore gas well has been discovered, the natural gas reservoir does not require significant preparation or stimulation for natural gas recovery. Approximately 63 percent of U.S. natural gas production is from conventional onshore gas wells (EIA, 2009b). The conventional onshore gas wells of this analysis are assumed to have a daily production rate between 400 and 1,550 thousand cubic feet, which is characteristic of approximately 40 percent of gas wells in the U.S. (EIA, 2009c).

Conventional offshore natural gas is recovered by vertical drilling techniques. Once a conventional offshore gas well has been discovered, the natural gas reservoir does not require significant preparation or stimulation for natural gas recovery. A natural gas reservoir must be large in order to justify the capital outlay for the completion of the well and construction of an offshore drilling platform. Approximately 1.2 percent of the U.S. natural gas supply is from the conventional extraction from offshore natural gas wells (EIA, 2009b). The majority of U.S. offshore wells are in the Gulf of Mexico. This analysis assumes that an offshore well produces 25 million cubic feet of natural gas per day.

Associated natural gas is co-extracted with crude oil. The extraction of onshore associated gas is similar to the extraction methods for conventional onshore gas (discussed above). The use of oil/gas separators is necessary to recover natural gas from the mixed product stream. Approximately 21.5 percent of U.S. natural gas production is from conventional onshore oil wells (EIA, 2009b). The majority of these wells are assumed to be in Texas and Louisiana (EIA, 2009). The production rates of onshore associated gas wells is highly variable, but an average associated gas well in the U.S. produces 59 barrels of oil and 61 thousand cubic feet of natural gas per day (EIA, 2009c).

Natural gas is dispersed throughout the Barnett Shale formation in northern Texas. Shale gas cannot be recovered using conventional extraction technologies, but is recovered through the use of horizontal drilling and hydraulic fracturing (hydrofracing). Horizontal drilling creates a wellbore that runs the length of a shale formation, and hydrofracing uses high pressure fluid (a mixture of water, surfactants, and proppants) for breaking apart the shale reservoir and facilitating the flow of natural gas. Natural gas from Barnett Shale accounts for approximately 6.6 percent of the U.S. natural gas production. This production share is based on the new natural gas pipeline capacity that was added solely for natural gas production from Barnett Shale; approximately 11 percent of new pipeline capacity in 2008 (4.8 billion cubic feet per day) was installed for natural gas from Barnett Shale (EIA, 2009d). The average daily output of a natural gas well in the Barnett Shale is 1,000 cubic feet (Hayden and Pursell, 2006).

Natural gas can be recovered from coal seams through the use of horizontal drilling. The development of a well for coal bed methane requires horizontal drilling followed be a depressurization period during which naturally-occurring water is discharged from the coal seam. The production of natural gas from CBM wells accounts for approximately 7.5 percent of the U.S. natural gas production (EIA, 2009b). There are viable coal bed methane deposits nationwide, but the majority of CBM production occurs in the Rocky Mountain region (ALL Consulting, 2004). The average daily output of the CBM wells of this analysis is 800 thousand cubic feet, which is representative of CBM wells in New Mexico and Colorado (ALL Consulting, 2004).

Table 2-1: Domestic Natural Gas Well Profiles

Natural Gas Source	Geography	Drilling Method	Production (1,000 cubic feet/day)	U.S. Supply Share (%)
Conventional Onshore	Southern U.S. (Texas and Louisiana)	vertical	400 – 1,550	63.0%
Conventional Offshore	Gulf of Mexico	vertical	25,000	1.2%
Conventional Onshore Associated	Southern U.S. (Texas and Louisiana)	vertical	61	21.0%
Barnett Shale	Northern Texas	horizontal	1,000	6.6%
Coal Bed Methane	Rocky Mountain Region	horizontal	800	7.5%

2.1.3 LCC Data Assumption

The following text defines assumptions made to determine the cost of producing and transporting natural gas to the energy conversion facility in Stage 1 and Stage 2. Because the natural gas is not used until the plant site, no cost modeling results are necessary for this stage. All cost model results are report in **Section 2.3.2: Stage 3 LCC Data Assumptions and Results**. 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 lifetime were extended beyond 2030 using regression of feedstock and other utility prices. All AEO values are in 2006 dollars. 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 projection 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 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 a simplification.

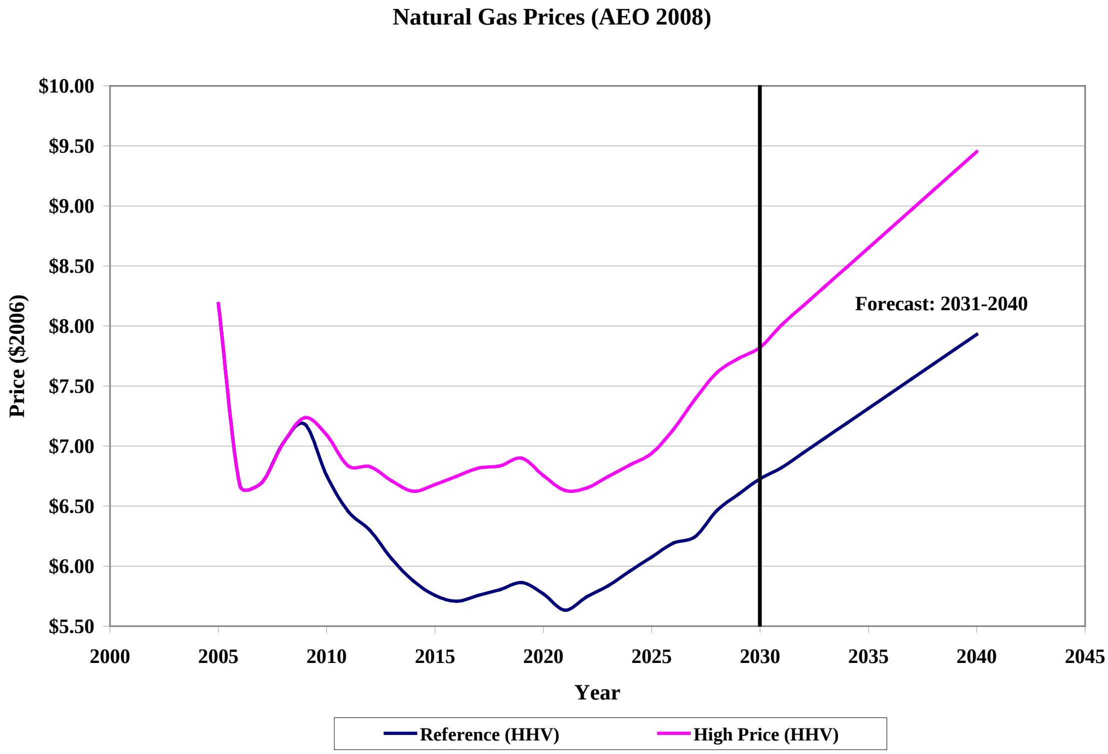

Figure 2-3: Natural Gas Prices for the Lifetime of the Plant

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.

2.1.4 Stage #1 – Natural Gas Well

The construction, installation and deinstallation, and operation of natural gas wells are included in this analysis.

2.1.4.1 *Natural Gas Well Construction and Installation*

The construction and installation of natural gas wells includes the drilling of the well, followed by the installation of a well casing that provides strength to the well bore and prevents contamination of the geological formations that surround the gas reservoir. Vertical drilling is used for conventional wells, which recover natural gas from reservoirs with large pockets of oil or natural gas. Horizontal drilling is used for unconventional natural gas reserves where the distribution of hydrocarbon is dispersed throughout a matrix of shale or coal. Horizontal drilling is often accompanied by hydrofracing operations.

A typical well casing is made from carbon steel, has an inner diameter of 8.6 inches, and weighs 24 pounds per foot (Natural Gas.org, 2004). The weight of concrete used by the well walls is assumed to be equal to the weight of the steel casing. The total weight of materials for the construction of a well bore is estimated by factoring the total well length by the linear weight of carbon steel and concrete.

Offshore extraction operations require a drilling platform that provides a stable surface for the wellhead and associated equipment. Offshore drilling platforms can be secured to the ocean floor using flexible cables or rigid beams. The material requirements for the construction of an offshore platform as modeled in this analysis are based on the materials reported for an offshore platform in the Gulf of Mexico (Offshore-technology.com, 2010).

2.1.4.2 *Natural Gas Well Operation*

The key operation processes for natural gas extraction include compression, dehydration, sweetening, flaring, oil/gas separation, water use, and water quality. These operations are summarized below.

Compressors are used at the natural gas wellhead to increase the gas pressure for pipeline distribution. The operating parameters of a compressor depend on the natural pressure at the wellhead, which varies from reservoir to reservoir and decreases with increasing well life. Centrifugal compressors are preferred for large-scale extraction operations because they are more efficient than reciprocating compressors. Additionally, the smooth operations of centrifugal compressors, in contrast to the vibrations of reciprocating compressors, make centrifugal compressors preferable for offshore extraction operations because it is important to minimize vibrations on offshore platforms. Reciprocating compressors used for industrial applications are driven by a crankshaft that can be powered by 2- or 4-stroke diesel engines. Reciprocating compressors are not as efficient as centrifugal compressors and are typically used for small scale extraction operations that do not justify the increased capital requirements of centrifugal compressors.

Dehydration is necessary to remove water from raw natural gas, which makes it suitable for pipeline transport and increases its heating value. The configuration of a typical dehydration process includes an absorber vessel in which a glycol solution comes into contact with a raw natural gas stream, followed by a stripping column in which the rich glycol solution is heated in order to drive off the water and regenerate the solution. The regenerated glycol solution (the lean solvent) is recirculated to the absorber vessel.

Raw natural gas contains varying levels of hydrogen sulfide (H_2S), a toxic gas that reduces the heat content of natural gas and causes fouling in when combusted in equipment. The removal of H_2S from natural gas is known as “sweetening”. Amine-based processes are the predominant technologies for the sweetening of natural gas. The H_2S content of raw natural gas is highly variable, with typical concentrations ranging from 5.7E-05 kg of H_2S per kg of natural gas to 0.16 kg of H_2S per kg of natural gas. This analysis assumes an H_2S concentration of 2.3E-05 kg of H_2S per kg of natural gas (which is equivalent to 1 mole of H_2S per kg of natural gas).

Flaring is an intermittent operation, necessary in situations where a natural gas (or other hydrocarbon) stream cannot be safely or economically recovered. Flaring may occur when a well is being prepared for operations and the wellhead has not yet been fitted with a valve manifold, when it is not financially preferable to recover the associated natural gas from an oil well, or during emergency operations when the usual systems for gas recovery are not available. The flaring rate of a natural gas well ranges from 0.21 to 0.48 percent of extracted natural gas (U.S. Government Accountability Office, 2004).

Oil and gas separation is necessary when natural gas is co-extracted with crude oil and other liquids. It is accomplished with a series of separation vessels that reduce the pressure of the oil/gas mixture, causing the gas to come out of solution. No data are available for the emissions from oil and gas separation, and the ratio of oil to gas in such operations is highly variable, which leads to issues of co-product allocation. To simplify these data limitation, this analysis assumes that the energy requirements for maintaining the pressure within each oil/gas separation stage are insignificant in comparison to the other compression operations required for oil and natural gas extraction. This analysis also assumes that methane is released at a rate of 0.1 percent and other hydrocarbons (VOCs) are released at a rate of 0.01 percent (these percentages are in terms of the mass of emission per mass of oil or natural gas produced). These percentages are based on professional judgment and are parameterized in the model to allow uncertainty analysis.

Table 2-1 summarizes the air emissions from foreign offshore wells. The majority of greenhouse gas (GHG), carbon monoxide (CO), nitrogen oxide (NO_x), volatile organic compounds (VOCs), and particulate matter (PM) emissions are due to the combustion of natural gas required for natural gas extraction processing operations. The majority of sulfur oxide (SO_x) emissions occur during well construction and are attributable to the combustion of diesel and upstream electricity required for the production and delivery of construction materials. The offshore extraction and processing of natural gas does not produce significant levels of heavy metal or ammonia emissions.

Table 2-1: Air Emissions from Offshore Well Installation/Deinstallation, Construction, and Operation, kg/kg Natural Gas

Pollutants	Well Installation/ Deinstallation	Well Construction	Well Operation	Total
GHG Emissions (kg/kg NG)				
CO_2	9.82E-07	2.90E-03	9.50E-02	9.79E-02
N_2O	2.40E-11	1.50E-07	2.33E-06	2.48E-06
CH_4	1.05E-09	2.23E-06	4.93E-04	4.95E-04
SF_6	2.74E-19	1.89E-17	4.23E-17	6.15E-17
Non-GHG Air Emissions (kg/kg NG)				
Pb	4.81E-15	5.74E-09	7.81E-13	5.74E-09
Hg	3.40E-16	3.55E-10	6.42E-14	3.55E-10
NH_3	3.81E-11	1.20E-10	3.07E-10	4.65E-10
CO	1.18E-09	2.42E-05	5.82E-05	8.24E-05
NO_X	1.31E-08	4.96E-06	2.27E-04	2.32E-04

SO_X	2.82E-09	6.63E-06	2.50E-06	9.14E-06
VOC	3.74E-10	1.45E-08	1.54E-06	1.55E-06
PM	1.09E-10	9.30E-07	4.68E-06	5.61E-06

Table 2-2 summarizes the air emissions from domestic wells, which include a mix of five extraction technologies used in the U.S. As is the case with the data for offshore wells, the majority of greenhouse gas (GHG), carbon monoxide (CO), nitrogen oxide (NO_X), and volatile organic compounds (VOCs) emissions are due to the combustion of natural gas required for natural gas extraction processing operations. The GHG and NO_x emissions are higher for the mix of domestic wells than for the offshore well due to the relatively low efficiencies and high NO_x rates of the reciprocating compressors used by onshore wells. Additionally, in contrast to the data for offshore extraction, the majority of sulfur oxide (SO_x) emissions are associated with well operations and are attributable to the upstream electricity consumed by gas extraction from Barnett Shale. Wells in the Barnett Shale region are close to metropolitan areas and use electrically-powered compressors instead of gas-powered compressors, which results in lower operating costs and reduces the noise associated with extraction operations. The domestic extraction and processing of natural gas does not produce significant levels of heavy metal or ammonia emissions.

Table 2-2: Air Emissions from Domestic Well Installation/Deinstallation, Construction, and Operation, kg/kg Natural Gas

Pollutants	Well Installation/ Deinstallation	Well Construction	Well Operation	Total
GHG Emissions (kg/kg NG)				
CO_2	8.54E-07	2.00E-03	1.05E-01	1.07E-01
N_2O	2.09E-11	6.25E-08	2.19E-07	2.81E-07
CH_4	9.10E-10	3.66E-06	1.67E-03	1.67E-03
SF_6	2.38E-19	8.82E-16	2.90E-15	3.78E-15
Non-GHG Air Emissions (kg/kg NG)				
Pb	4.19E-15	2.96E-09	9.77E-11	3.06E-09
Hg	2.96E-16	8.18E-11	1.46E-11	9.64E-11
NH_3	3.32E-11	7.92E-09	9.27E-09	1.72E-08
CO	1.03E-09	9.99E-06	4.50E-04	4.60E-04

NO_X	1.14E-08	1.23E-05	6.88E-04	7.00E-04
SO_X	2.46E-09	5.49E-06	9.32E-06	1.48E-05
VOC	3.25E-10	1.17E-06	9.50E-05	9.62E-05
PM	9.52E-11	5.20E-06	8.50E-06	1.37E-05

2.1.5 Stage #1 – On and Offshore Pipeline

Table 2-3 and **Table 2-4** summarize the air emissions from offshore and onshore pipeline processes, respectively. The only differences modeled between onshore and offshore pipelines were the energy and emissions associated with undersea versus underground installation. Undersea installation emissions are caused by ship fuel use, while underground is dominated by construction equipment emissions. Underground pipeline operations all included deinstallation while offshore pipeline is assumed to be left in place after use. Construction materials and operation emissions were considered the same for both locations, where emissions associated with operation are due to natural gas-fired reciprocating compressors.

Table 2-3: Air Emissions from Offshore Pipeline Construction, Installation/Deinstallation, and Operation, kg/kg Natural Gas

Pollutants	Offshore Pipeline Installation	Offshore Pipeline Construction	Offshore Pipeline Operations	Total
GHG Emissions (kg/kg NG)				
CO_2	4.19E-04	4.23E-04	8.68E-03	9.52E-03
N_2O	1.02E-08	2.36E-08	0.00E+00	3.38E-08
CH_4	4.46E-07	4.47E-07	6.46E-04	6.47E-04
SF_6	1.17E-16	0.00E+00	0.00E+00	1.17E-16
Non-GHG Emissions (kg/kg NG)				
Pb	2.05E-12	1.29E-09	0.00E+00	1.29E-09
Hg	1.45E-13	3.41E-11	0.00E+00	3.42E-11
NH_3	1.63E-08	0.00E+00	0.00E+00	1.63E-08
CO	2.65E-06	3.13E-06	2.77E-04	2.83E-04
NO_X	5.67E-06	6.89E-07	1.79E-04	1.85E-04

SO_X	1.20E-06	1.20E-06	4.64E-08	2.45E-06
VOC	1.60E-07	-1.64E-15	0.00E+00	1.60E-07
PM	9.28E-07	4.96E-07	7.49E-07	2.17E-06

Table 2-4: Air Emissions from Onshore Pipeline Construction, Installation/Deinstallation, and Operation, kg/kg Natural Gas

Pollutants	Onshore Pipeline Installation	Onshore Pipeline Construction	Onshore Pipeline Operations	Total
GHG Emissions (kg/kg NG)				
CO_2	3.54E-06	4.52E-04	7.96E-03	8.42E-03
N_2O	7.13E-11	2.41E-08	1.38E-07	1.62E-07
CH_4	3.49E-09	5.31E-07	4.94E-04	4.94E-04
SF_6	9.33E-19	2.33E-17	1.07E-14	1.07E-14
Non-GHG Emissions (kg/kg NG)				
Pb	1.64E-14	1.28E-09	3.56E-11	1.32E-09
Hg	1.14E-15	3.40E-11	6.86E-12	4.09E-11
NH_3	1.11E-10	8.82E-10	3.84E-09	4.84E-09
CO	1.17E-08	3.21E-06	8.77E-06	1.20E-05
NO_X	3.36E-08	9.29E-07	9.93E-05	1.00E-04
SO_X	3.39E-09	1.26E-06	4.31E-06	5.58E-06
VOC	1.27E-09	3.19E-08	2.85E-06	2.88E-06
PM	6.42E-09	5.37E-07	5.90E-07	1.13E-06

2.1.6 Stage #1 – Liquefaction Facility

Table 2-5 summarizes the emissions associated with the liquefaction facility installation/de-installation, construction, and operation. For this process, most emissions are dominated by operations. The liquefaction facility using approximately 13 percent of the natural gas input as an energy source during operations, and the majority of combustion and CO_2 emissions are due to natural gas combustion.

Table 2-5: Air Emissions from Natural Gas Liquefaction Installation/Deinstallation, Construction, and Operations, kg/kg Natural Gas

Pollutants	Liquefaction Installation/ De-installation	Liquefaction Construction	Liquefaction Operation	Total
GHG Emissions (kg/kg NG)				
CO_2	6.12E-04	7.31E-04	4.24E-01	4.26E-01
N_2O	1.55E-08	2.35E-08	5.08E-07	5.47E-07
CH_4	3.48E-08	1.20E-06	0.00E+00	1.23E-06
SF_6	0.00E+00	1.25E-15	0.00E+00	1.25E-15
Non-GHG Emissions (kg/kg NG)				
Pb	0.00E+00	8.95E-10	0.00E+00	8.95E-10
Hg	3.03E-14	4.19E-11	0.00E+00	4.20E-11
NH_3	2.61E-08	2.88E-09	6.41E-04	6.41E-04
CO	3.84E-06	3.33E-06	6.80E-05	7.51E-05
NO_X	6.04E-06	1.63E-06	4.75E-04	4.82E-04
SO_X	1.21E-07	2.56E-06	1.35E-05	1.62E-05
VOC	0.00E+00	2.82E-07	0.00E+00	2.82E-07
PM	4.18E-07	3.97E-06	1.37E-05	1.81E-05

2.1.7 Stage #1 – Total Emissions and Water Withdrawal/Consumption

2.1.7.1 *Greenhouse Gas Emissions*

Figure 2-4 compares the GHG emissions for Stage #1 on a per kg LNG produced basis (ready for transport). GHG emissions are calculated on both a mass (kg) and kg CO_2 equivalent (CO_2e) basis to highlight the differences in impact when considering the warming potential of a pollutant versus only the mass emitted. The GWP values used to calculate CO_2e are listed in **Table 1-3**.

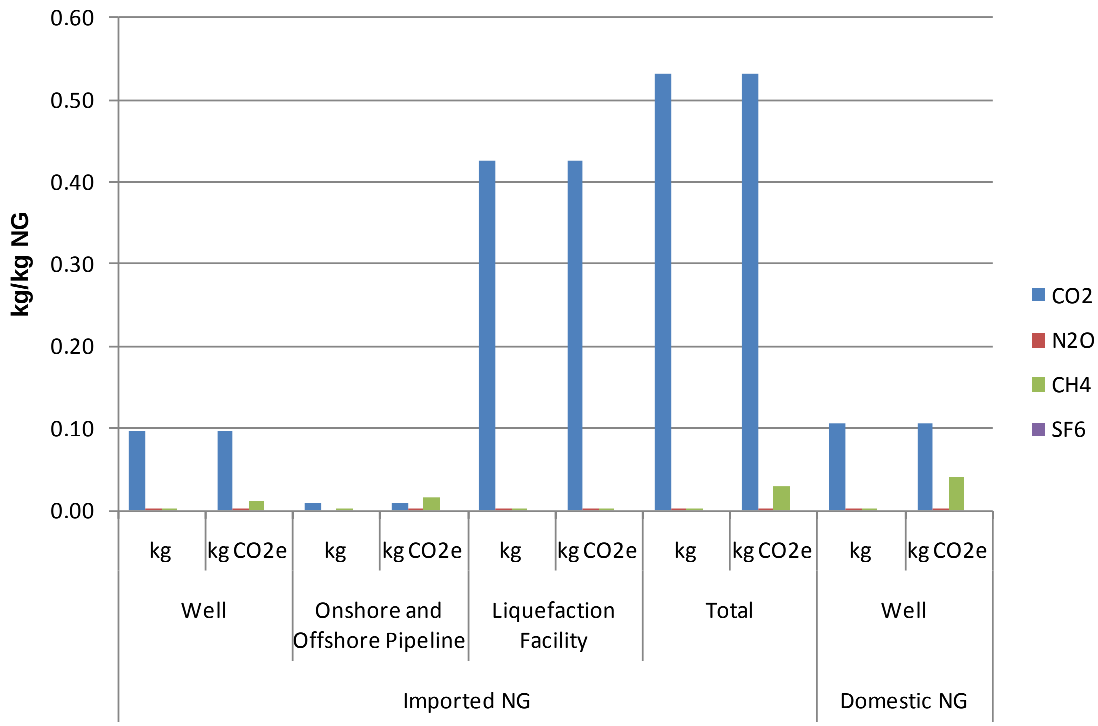

Figure 2-4: NGCC Stage # 1 GHG Emissions per kg of Imported and Domestic NG Ready-for-Transport on a Mass (kg) and kg CO_2e Basis

The CO_2 emissions from well operations represent a significant contribution to Stage #1 activities for imported and domestic natural gas; however, the GHG emissions for Stage #1 for imported natural gas are dominated by the CO_2 emissions during liquefaction.

Table 2-6 summarizes the emissions graphed above. The total GWP for Stage #1 for imported natural gas is 0.56 kg CO_2e per kg LNG and the total GWP for Stage #1 for domestic natural gas is 0.15 kg CO_2e per kg natural gas. It is important to note the differences between the results in **Tables 2-5** and **2-6** when compared to **Tables 2-1** through **2-4**. For each individual unit process, results are reported on the reference flow of that process, i.e. 1 kg of natural gas exiting the well site, offshore/onshore pipeline, or liquefaction facility. However, the results shown in **Tables 2-5** and **2-6** are an aggregation of all Stage #1 unit processes and are on the basis of total natural gas exiting Stage #1. Therefore, due to material losses throughout the chain of unit processes, the values presented in **Tables 2-5** and **2-6** are higher than values in **Tables 2-1** through **2-4**.

Table 2-6: NGCC Stage #1 GHG Emissions (on a Mass [kg] and kg CO2e Basis)/kg NG ready for Transport

GHG Emissions	Foreign Natural Gas								Domestic Natural Gas	
	Well		Onshore and Offshore Pipeline		Liquefaction Facility		Total		Well	
	kg/kg LNG	kg CO_2e /kg LNG	kg/kg LNG	kg/kg LNG	kg/kg LNG	kg CO_2e /kg LNG	kg/kg LNG	kg CO_2e /kg LNG	kg/kg NG	kg CO_2e /kg NG
CO_2	9.79E-02	9.79E-02	9.52E-03	9.52E-03	4.26E-01	4.26E-01	5.33E-01	5.33E-01	1.07E-01	1.07E-01
N_2O	2.48E-06	7.38E-04	3.38E-08	1.01E-05	5.47E-07	1.63E-04	3.06E-06	9.12E-04	2.81E-07	8.38E-05
CH_4	4.95E-04	1.24E-02	6.47E-04	1.62E-02	1.23E-06	3.08E-05	1.14E-03	2.86E-02	1.67E-03	4.17E-02
SF_6	6.15E-17	1.40E-12	1.17E-16	2.66E-12	1.25E-15	2.84E-11	1.42E-15	3.25E-11	3.78E-15	8.61E-11
Total GWP		1.11E-01		2.57E-02		4.26E-01		5.62E-01		1.49E-01

2.1.7.2 *Air Pollutant Emissions*

Table 2-7 and **Figure 2-5** summarize the air emissions (excluding GHGs) that are released during Stage #1. These emissions are shown on the basis of one kg of natural gas ready for transport.

Table 2-7: Air Pollutant Emissions from NGCC Stage #1, kg/kg NG Ready for Transport

Emissions (kg/kg NG)	Imported NG				Domestic NG
	Well	Onshore and Offshore Pipeline	Liquefaction Facility	Total	Well
Pb	5.74E-09	1.29E-09	8.95E-10	7.93E-09	3.06E-09
Hg	3.55E-10	3.42E-11	4.20E-11	4.31E-10	9.64E-11
NH_3	4.65E-10	1.63E-08	6.41E-04	6.41E-04	1.72E-08
CO	8.24E-05	2.83E-04	7.51E-05	4.40E-04	4.60E-04
NO_X	2.32E-04	1.85E-04	4.82E-04	9.00E-04	7.00E-04
SO_X	9.14E-06	2.45E-06	1.62E-05	2.78E-05	1.48E-05
VOC	1.55E-06	1.60E-07	2.82E-07	2.00E-06	9.62E-05
PM	5.61E-06	2.17E-06	1.81E-05	2.59E-05	1.37E-05

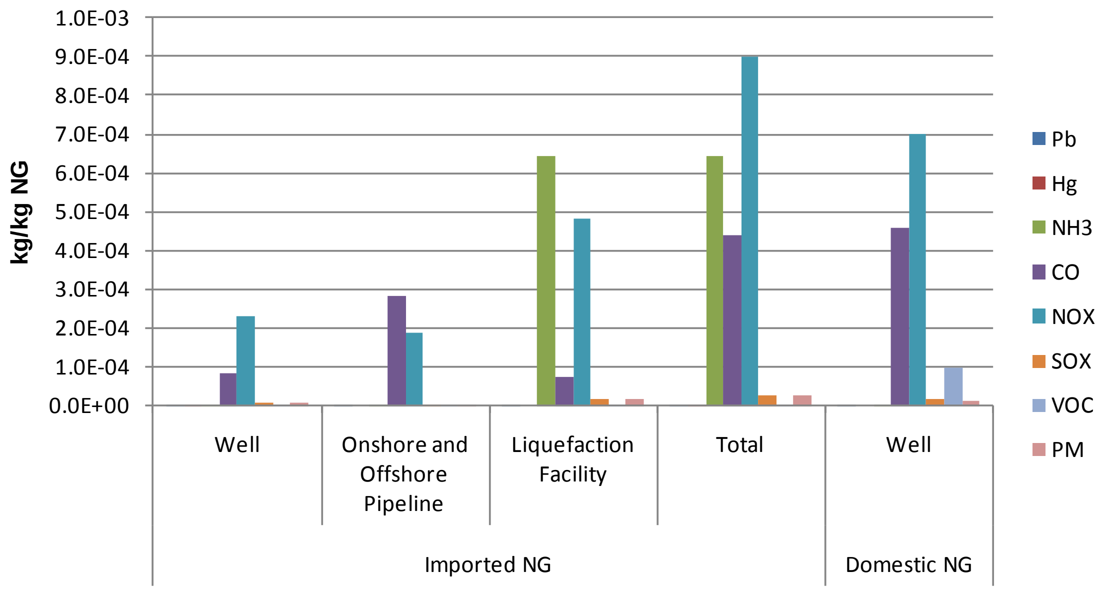

Figure 2-5: Air Pollutant Emissions from NGCC Stage #1 for Imported and Domestic NG, kg/kg NG Ready-for-Transport

The non-GHG air emissions during Stage #1 are due mostly to fuel combustion used to power pipeline installation, and the installation and operation of the drill platform and liquefaction facility. Natural gas is the primary fuel for the wells, pipelines, and liquefaction facility, and thus low levels of SO_x emissions are produced by Stage #1 processes. Ammonia emissions occur during liquefaction are a result of the use of an amine system to remove CO_2 and hydrogen sulfide (H_2S) (acid gas) from the natural gas (ConocoPhillips, 2005). Lead, Hg, and PM emissions are all small for this stage.

2.1.7.3 *Water Withdrawal and Consumption*

Table 2-8 shows water withdrawal, outfall, and consumption in Stage #1 on the basis of 1 kg of natural gas ready for transport. The domestic natural gas scenario has a high share of onshore wells, which, according to the data of this analysis, consume more water than offshore wells. Offshore wells may have lower water requirements than onshore wells, but the Stage #1 results for imported natural gas also include the water requirements incurred during liquefaction. The water consumed by liquefaction is necessary for meeting the cooling demands of gas compression (URS, 2005). The total Stage #1 water consumption for imported natural gas is 0.16 kg, and the Stage #1 water consumption for domestic natural gas is 0.66 kg.

Table 2-8: Water Withdrawal and Consumption during NGCC Stage #1 for Imported and Domestic NG, kg/kg NG Ready-for-Transport

Water (kg/kg LNG)	Imported NG				Domestic NG
	Well	Onshore and Offshore Pipeline	Liquefaction Facility	Total	Well

Water Withdrawal	1.57E-02	1.66E-02	1.76E-01	2.08E-01	6.65E-01
Wastewater Outfall	4.79E-05	5.10E-03	4.12E-02	4.63E-02	1.14E-03
Water Consumption	1.56E-02	1.15E-02	1.35E-01	1.62E-01	6.63E-01

2.2 Life Cycle Stage #2: Raw Material Transport

The activities required for the transport of imported and domestic natural gas are significantly different. This analysis models the transport of imported natural gas via a liquefaction/regasification process in which the natural gas received from Stage #1 is in the form of liquefied natural gas (LNG) and is transported in a specially-designed marine vessel to a U.S. port where it is regasified and then placed in a natural gas pipeline for delivery to the NGCC facility. The transport of domestic natural gas requires only the transport of natural gas in a natural gas pipeline.

For the imported natural gas pathway, the boundary for Stage #2 begins once the LNG has been loaded into an LNG tanker. The LNG is shipped from Port Fortin, Trinidad, to the Trunkline LNG terminal in Lake Charles, Louisiana, where it is unloaded into a storage tank. The LNG is stored at the terminal as a liquid until it is warmed (regasified) for shipment as a gas via pipeline to an NGCC power plant at the southern Mississippi location – a distance of 334.58 kilometers (207.9 miles) from the LNG regasifier. The boundary ends when the natural gas in the pipeline enters the NGCC facility. The LCI data in this stage includes the construction and operation of the tanker (including docking or berthing), and the installation, construction, and operation of the regasification facility and onshore pipeline. The pipeline distance from the regasification facility to the NGCC plant was estimated at 208 miles. (The processes for the construction and operation of natural gas pipelines are summarized in **Section 2.1.5** and are thus not repeated here.)

For the domestic natural gas pathway, the boundary for Stage #2 begins with the receipt of natural gas from a natural gas extraction and processing site, includes 900 miles of pipeline transport, and ends with the delivery of natural gas to the NGCC facility. The pipeline transport distance for domestic natural gas was estimated from the geographic distribution of domestic wells and the location of the NGCC facility. (The processes for the construction and operation of natural gas pipelines are provided **Section 2.1.5** and are thus not repeated here.)

2.2.1 LCC Data Assumption

The AEO 2008 values assume a delivered price of natural gas to the energy conversion facility for use in producing electricity. Prices are discussed in Stage #1 assumptions (S**ection 2.1.3**) and therefore are not repeated here.

2.2.2 Stage #2 – LNG Tanker

Table 2-9 summarizes the air emissions from LNG tanker construction and operation, including berthing. LNG tanker commissioning/decommissioning is not included separately due to lack of data. Berthing operations are important to consider because the security issues of an LNG tanker require escorts to be present when a tanker is brought close to shore. When the LNG tanker has reached the dock it uses residual fuel oil to power the tanker during LNG offloading. LNG tanker construction emissions are due to the LC emission of aluminum, steel plate, and stainless steel manufacturing.

Table 2-9: Air Emissions due to LNG Tanker Construction, Operation, and Berthing, kg/kg LNG Transported

Pollutants	LNG Tanker Construction	LNG Tanker Operation	LNG Tanker Berthing Operation	Total
GHG Emissions kg/kg LNG				
CO_2	1.13E-03	4.23E-02	9.27E-03	5.27E-02
N_2O	3.45E-08	1.03E-08	2.32E-07	2.77E-07
CH_4	1.37E-06	1.73E-04	9.61E-06	1.84E-04
SF_6	6.36E-14	1.16E-15	1.89E-15	6.67E-14
Non-GHG Emissions kg/kg LNG				
Pb	1.00E-09	2.04E-11	3.88E-11	1.06E-09
Hg	6.47E-11	1.44E-12	2.45E-12	6.86E-11
NH_3	2.34E-09	1.62E-07	2.97E-07	4.60E-07
CO	9.33E-06	4.06E-04	4.54E-06	4.20E-04
NO_X	1.97E-06	2.44E-04	3.94E-05	2.85E-04
SO_X	4.71E-06	3.16E-06	2.90E-05	3.69E-05
VOC	1.27E-07	7.17E-05	4.59E-06	7.65E-05
PM	1.25E-06	2.71E-06	6.73E-06	1.07E-05

2.2.3 Stage #2 – Regasification Facility

Table 2-10 summarizes the air emissions from the installation/deinstallation, construction, and operation of the regasification facility. Emissions are dominated by operations, which consumes approximately 1.6 percent of LNG input for onsite power. Additionally, diesel is used for pumps and back-up generators. Diesel is combusted during installation/deinstallation to power construction equipment, and concrete and steel plant manufacturing LC emissions make up the construction profile.

Table 2-10: Air Emissions from Regasification Facility Installation/Deinstallation, Construction, and Operation, kg/kg Natural Gas Output

Pollutants	Regasification Installation/ De-installation	Regasification Construction	Regasification Operation	Total
GHG Emissions kg/kg NG				
CO_2	1.27E-05	4.93E-04	5.53E-02	5.58E-02
N_2O	3.13E-10	1.45E-08	2.97E-07	3.12E-07
CH_4	1.35E-08	3.88E-07	3.18E-03	3.18E-03
SF_6	3.57E-18	6.96E-16	1.15E-13	1.16E-13
Non-GHG Emissions kg/kg NG				
Pb	6.28E-14	3.89E-10	8.42E-10	1.23E-09
Hg	4.44E-15	2.55E-11	2.37E-10	2.63E-10
NH_3	5.13E-10	5.59E-09	8.13E-08	8.74E-08
CO	5.66E-08	2.34E-06	1.64E-05	1.88E-05
NO_X	1.30E-07	2.04E-06	4.99E-05	5.20E-05
SO_X	1.12E-08	1.28E-06	9.61E-05	9.74E-05
VOC	4.88E-09	5.75E-08	1.54E-06	1.60E-06
PM	7.24E-09	2.46E-06	5.09E-06	7.56E-06

2.2.4 Stage #2 – Total Emissions and Water Withdrawal/Consumption

2.2.4.1 *Greenhouse Gas Emissions*

Table 2-11 and **Figure 2-6** show the GHG emissions for Stage #2 on a mass (kg) and kg CO_2e basis per kg of natural gas delivered to the plant gate. As with Stage #1, these values are on a different basis than the values presented in **Tables 2-8** and **2-9**. Due to losses throughout the stage these values appear slightly higher on a per kg of natural gas delivered to the plant gate basis then based on the reference flow of the process.

Table 2-11: NGCC Stage #2 GHG Emissions (Mass [kg] and kg CO_2e)/kg of Natural Gas Delivered

GHG Emissions (kg/kg NG)	LNG Tanker		LNG Tanker Berthing		Regasification		Pipeline Transport		Total	
	kg	kg CO_2e	kg	kg CO_2e	kg	kg CO_2e	kg	kg CO_2e	kg	kg CO_2e
Imported NG										
CO_2	4.35E-02	4.35E-02	9.27E-03	9.27E-03	5.58E-02	5.58E-02	2.96E-02	2.96E-02	1.38E-01	1.38E-01
N_2O	4.48E-08	1.33E-05	2.32E-07	6.91E-05	3.12E-07	9.31E-05	5.28E-07	1.57E-04	1.12E-06	3.33E-04
CH_4	1.75E-04	4.37E-03	9.61E-06	2.40E-04	3.18E-03	7.96E-02	1.81E-03	4.52E-02	5.17E-03	1.29E-01
SF_6	6.48E-14	1.48E-09	1.89E-15	4.30E-11	1.16E-13	2.64E-09	3.92E-14	8.93E-10	2.22E-13	5.06E-09
Total GWP		4.79E-02		9.58E-03		1.35E-01		7.49E-02		2.68E-01
Domestic NG										
CO_2	not applicable						1.27E-01	1.27E-01	1.27E-01	1.27E-01
N_2O							2.22E-06	6.62E-04	2.22E-06	6.62E-04
CH_4							7.82E-03	1.95E-01	7.82E-03	1.95E-01
SF_6							1.69E-13	3.86E-09	1.69E-13	3.86E-09
Total GWP								3.23E-01		3.23E-01

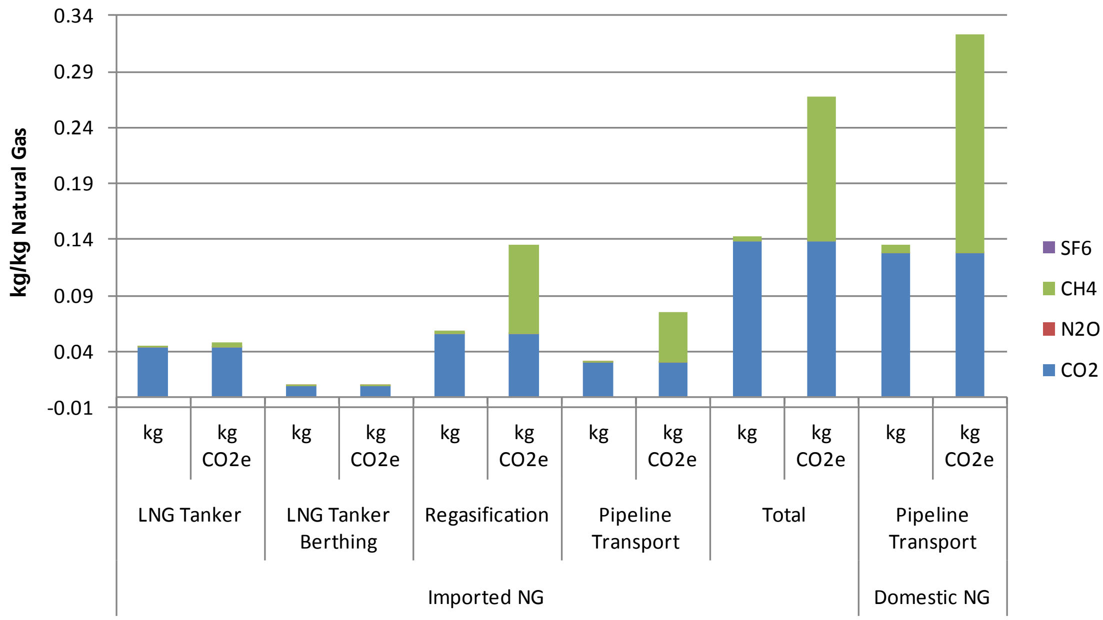

Figure 2-6: NGCC Stage #2 GHG Emissions (Mass [kg] and kg CO_2e)/kg of Natural Gas Delivered

Although GHG emissions are still dominated by CO_2, CH_4 from fugitive natural gas emissions during regasification (applicable to the imported pathway only) and pipeline transport (applicable to imported and domestic pathways) contribute considerably to the total GWP when calculated on a kg CO_2e basis. The total GWP for Stage #2 is 0.268 kg CO_2e per kg of imported natural gas, and 0.323 kg CO_2e per kg of domestic natural gas.

2.2.4.2 *Air Pollutant Emissions*

Table 2-12 and **Figure 2-7** show the non-GHG air emissions associated with Stage #2 on a per kg natural gas transported basis. For imported natural gas, this includes LNG tanker, regasification, and pipeline activities. For domestic natural gas it includes only pipeline activities. Due to the additional processes for the transport of imported natural gas, most Stage #2 non-GHG emissions are higher for the imported pathway than for the domestic pathway. In particular, the imported pathway has significantly higher SO_x emissions than the domestic pathway due to the combustion of diesel and heavy fuel oil by the LNG tanker and LNG regasification facility. However, due to the longer pipeline transport distance for the delivery of domestic natural gas, the domestic pathway has higher NO_x emissions than the imported pathway. Insignificant levels of heavy metals (Pb and Hg) are emitted during this stage.

Table 2-12: NGCC Stage #2 Air Emissions, kg/kg Natural Gas Delivered

Emissions (kg/kg NG)	Imported NG					Domestic NG
	LNG Tanker	LNG Tanker Berthing	Re-gasification	Pipeline Transport	Total	Pipeline Transport
Pb	1.02E-09	3.88E-11	1.23E-09	1.25E-09	3.54E-09	1.69E-09
Hg	6.61E-11	2.45E-12	2.63E-10	5.48E-11	3.86E-10	1.38E-10
NH_3	1.64E-07	2.97E-07	8.74E-08	1.70E-08	5.65E-07	8.11E-08
CO	4.16E-04	4.54E-06	1.88E-05	3.51E-05	4.74E-04	1.44E-04
NO_X	2.45E-04	3.94E-05	5.20E-05	3.65E-04	7.02E-04	1.58E-03
SO_X	7.87E-06	2.90E-05	9.74E-05	1.69E-05	1.51E-04	6.96E-05
VOC	7.19E-05	4.59E-06	1.60E-06	1.05E-05	8.85E-05	4.52E-05
PM	3.95E-06	6.73E-06	7.56E-06	2.76E-06	2.10E-05	1.10E-05

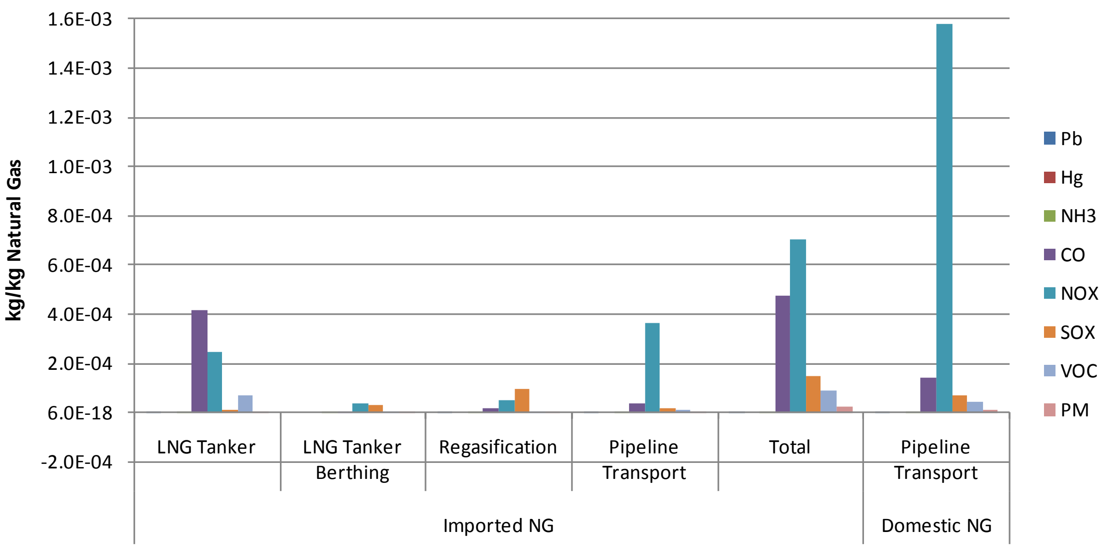

Figure 2-7: NGCC Stage #2 Air Emissions, kg/kg Natural Gas Delivered

2.2.4.3 *Water Withdrawal and Consumption*

Water withdrawal and consumption for Stage #2 are shown in **Table 2-13**. During the regasification process, a cooled exhaust stream results in condensed water discharge, therefore causing a net gain in water (negative water consumed). The water withdrawal and consumption shown in **Table 2-13** for all other operations is due to the LC profiles of material and fuel inputs.

Table 2-13: NGCC Stage #2 Water Withdrawal and Consumption, kg/kg Natural Gas Delivered

Water (kg/kg NG)	Imported NG					Domestic NG
	LNG Tanker	LNG Tanker Berthing	Re-gasification	Pipeline Transport	Total	Pipeline Transport
Water Withdrawal	9.60E-03	4.53E-03	1.63E-01	2.90E-02	2.06E-01	1.11E-01
Wastewater Outfall	3.74E-03	7.24E-04	1.53E-01	1.85E-02	1.76E-01	7.99E-02
Water Consumption	5.86E-03	3.80E-03	9.63E-03	1.05E-02	2.98E-02	3.16E-02

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

Development of the LCI and assessments for the NGCC case without CCS are based on the process description detailed in Case 13 of the Baseline Report (NETL, 2010). The Baseline Report provides detailed stream flow data for major unit processes and describes assumptions made for supporting unit processes with respect to material and energy requirements. The block flow diagram shown in **Figure 2-2** was taken from the Baseline Report and provides a simplified illustration of the interaction between major unit processes of the NGCC case without CCS. This figure shows a single CTG, a single HRSG, and one steam turbine – not representative of the two CTGs, two HRSGs, and single steam turbine sparing philosophy, but meant to give a simplified representation of the NGCC process. Ambient air (stream 1) and natural gas (stream 2) are combined in the dry low NO_X burner (LNB) of the two gas turbines (only one shown), which is operated to control the rotor inlet temperature at approximately 1,399°C (2,550°F). Combustion flue gas (stream 3) exits the gas turbines at 631°C (1,167°F) and passes into the HRSG. An HRSG (one associated with each gasifier) generates both the main steam and reheat steam for the single steam turbine. Flue gas exits the HRSG at 104°C (220°F) and passes to the plant stack.

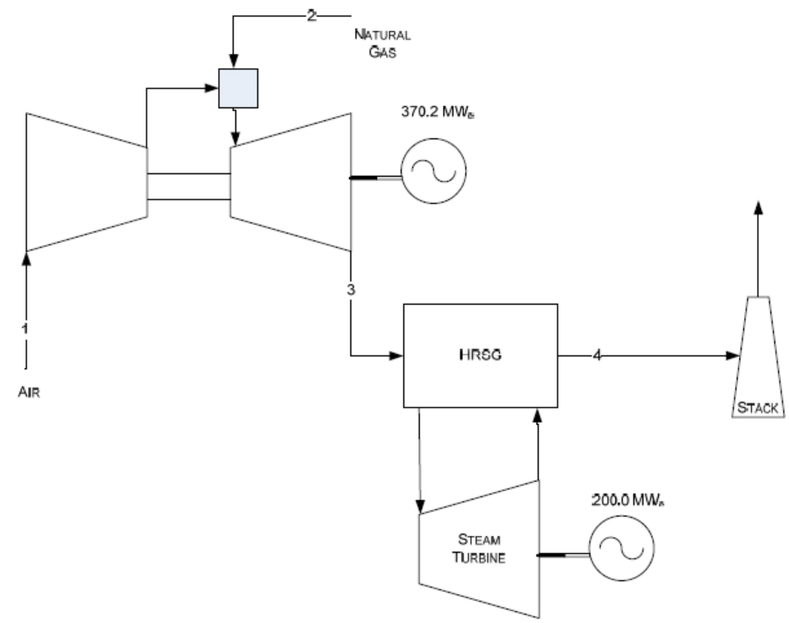

Figure 2-8: Process Flow Diagram, NGCC without CO_2 Capture (NETL, 2010)

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

2.3.1 LCC Data Assumption

Capital, material, and operating costs for both an NGCC power plant without CCS was needed to calculate the total plant cost in PV and LCOE. **Table 2-14** lists the cost data and input parameters used to model the LCC for the NGCC plant without CCS. All values were reported in 2006 dollars and taken directly from the Baseline Report (NETL, 2010). It is assumed that replacement costs for the plant are included in the variable O&M costs taken from the Baseline Report. Fixed labor costs were not amended to account for the change in location of the NGCC plants; therefore, the labor costs listed in **Table 2-14** still account for labor rates from the Midwest rather than Mississippi. Although this is recognized as a data limitation, the difference in rates was not assumed to make enough difference in results to warrant the complex recalculations necessary to account for the location change. Initial start-up costs are considered to be two percent of the total plant costs (capital investment) minus the costs for contingencies. This is included in the analysis as part of the capital investment costs.

Table 2-14: Cost Data from the NETL Baseline Report and Necessary LCC Input Parameters for NGCC without CCS

Parameters	NGCC
Electricity Net (MWe)	555
Capacity Factor	85%
Initial Start-up Costs ($)[1]	$0
Capital Investment	$398,290,000
Fixed O&M Costs, Labor Cost ($/yr)[2]	$12,247,740
Variable O&M Cost ($/yr)[3]	$5,441,560

1. Initial start-up costs are wrapped into the capital investment.
2. Labor rates were not amended from the Baseline Report labor rates, despite re-location of the NGCC facilities from the Midwest to Mississippi.
3. Variable O&M costs exclude process water costs, and include replacement costs.

Natural gas prices were calculated separately from the total O&M costs in the Baseline Report. These prices were defined previously (**Section 2.1.1**). The process water needed was included in the O&M costs of the Baseline Report, but for the purposes of this analysis were not included in the O&M costs used, as annual process water costs were calculated based on another source and the quantity of water withdrawal, stated in the Baseline Report. Process water costs were estimated based on a Water and Wastewater Rate Survey Report (Rafaelis Financial Consulting, 2002). On a per liter basis, process water costs $0.00044. The total quantity of process water withdrawal and consumption was taken from the Baseline Report. Because 50 percent of the water is purchased from the municipal supply, only 50 percent of the listed quantity was used to determine the cost of process water for these cases (NETL, 2010).

Table 2-15 defines the feedrate of each input. Annual feedrates for natural gas and process water were assumed from the Baseline Report.

Table 2-15: Annual Feedrates for Feed/Fuel and Utilities for NGCC Case without CCS

Input	Annual Feedrate
Natural Gas (MMBtu/day)	90,562
Water Needed (gallons/day)[1]	850,320

1. Quantity listed accounts for the portion of water included in the costs of the plant. It is assumed that only half of the process water used in the plant is considered in the costs for the plant.

2.3.1.1 *Switchyard and Trunkline System*

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

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

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

The cost for the total switchyard and trunkline system, including all four components in previously specified quantities, equals $46.6 million. All costs for the switchyard/ trunkline system include only the cost of purchasing the component. Installation, labor, and additional material costs that may be necessary to install the system components are not included in the cost estimate. O&M costs are considered to be negligible and will not be included in the analysis. It is assumed that switchyard/trunkline life is the same as the plant life (30 years); therefore, no capital replacement costs are considered in the analysis. A seven percent transmission loss from the switchyard/trunkline system will be considered when calculating the LCOE for each case. **Table 2-16** gives a summary of the costs for the trunkline, switchyard, and total system.

Table 2-16: Switchyard/ Trunkline Component Costs (Values in $2006)

Component	Total Cost
Trunkline	$45,589,656.96
Switchyard	$1,040,100.70

Total System	$46,629,757.65

2.3.2 LCC Results

Figure 2-9 presents the LCOE for the NGCC case without CCS. As the results indicate, the utilities including the natural gas feed and process water account for the largest portion of the total LCC. The LCOE for the utilities is equal to $0.0686/kWh. This is only at the NGCC energy conversion facility. The remaining cost components including labor, variable O&M costs, and capital costs for the Natural Gas combined cycle (NGCC) facility are equal to $0.0046/kWh, $0.0020/kWh, and $0.0156/kWh, respectively. Switchyard/trunkline system and decommissioning are considered only as capital costs. These are equal to $0.0018/kWh and $0.0001/kWh. The total LCOE value for the NGCC case without CCS is equal to $0.0927/kWh.

Note that this calculation is valid for all “types” of natural gas extracted. As natural gas is commodity, the price at which it is sold on the open market does not distinguish by origin. If the price of gas is too low, operators of high cost extraction operations would not operate their facilities.

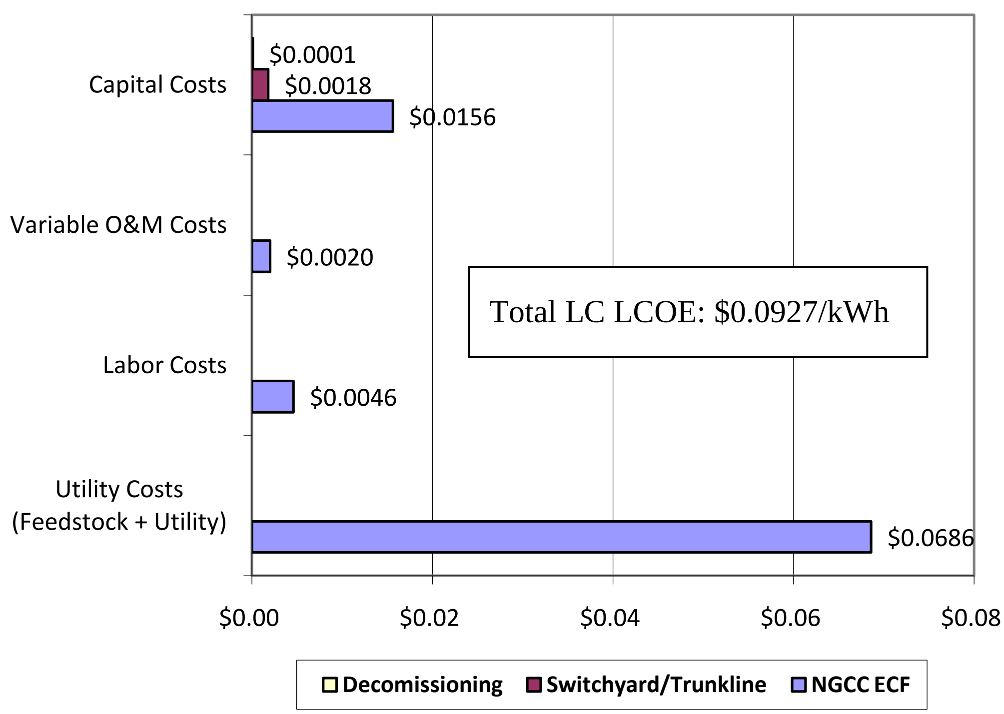

Figure 2-9: LCOE Results for NGCC Case without CCS

2.3.3 Greenhouse Gas Emissions

Table 2-17 and **Figure 2-10** shows the GHG emissions associated with the NGCC without CCS plant, on an MWh plant output basis. Carbon dioxide is the dominant pollutant, with the largest emissions associated with the combustion of natural gas. The total GWP of this stage is 366 kg CO_2e per MWh plant output, with greater than 99 percent due to NGCC plant operations.

Table 2-17: NGCC without CCS Stage #3 GHG Emissions in kg and kg CO_2e/MWh Plant Output

GHG Emissions	Plant Construction		Plant Commissioning/ Decommissioning		Plant Operation w/o CCS		Total	
	kg/MWh	kg CO_2e /MWh	kg/MWh	kg CO_2e /MWh	kg/MWh	kg CO_2e /MWh	kg/MWh	kg CO_2e /MWh
CO_2	3.70E-01	3.70E-01	1.50E-02	1.50E-02	365	365	365	365
N_2O	1.15E-05	3.43E-03	3.75E-07	1.12E-04	2.06E-06	6.14E-04	1.40E-05	4.16E-03
CH_4	3.19E-04	7.97E-03	1.60E-05	4.00E-04	7.47E-06	1.87E-04	3.42E-04	8.56E-03
SF_6	5.62E-12	1.28E-07	4.24E-15	9.67E-11	3.03E-07	6.91E-03	3.03E-07	6.91E-03
Total GWP	na	3.81E-01	na	1.55E-02	na	365	na	366

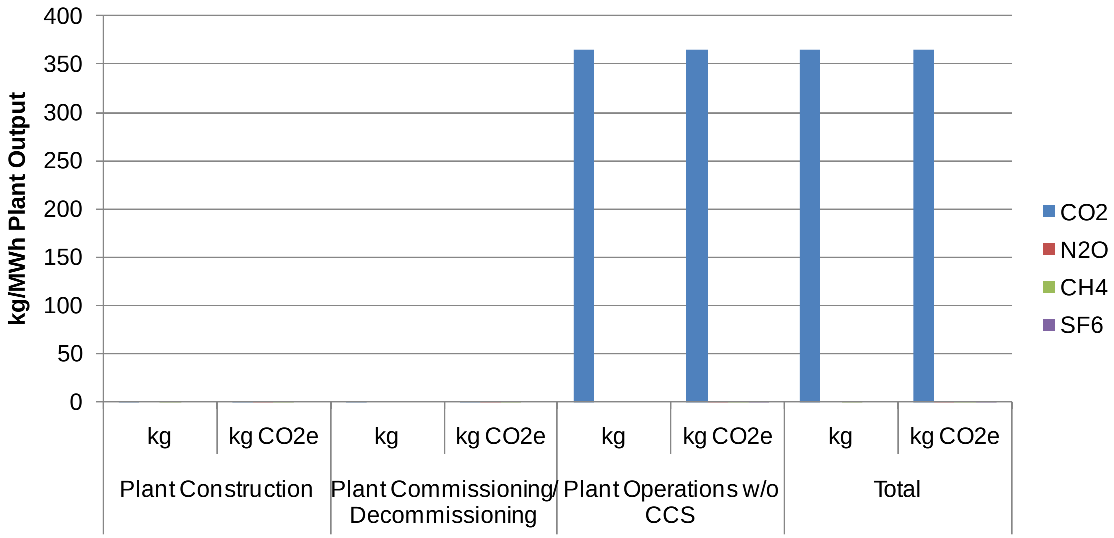

Figure 2-10: NGCC without CCS Stage #3 GHG Emissions in kg and kg CO_2e /MWh Plant Output

2.3.4 Air Pollutant Emissions

Table 2-18 and **Figure 2-11** show the air pollutants released during NGCC plant operations on a per MWh output basis. The two dominate emissions during plant operations are NO_X and NH_3. Nitrogen oxide is a combustion emission which is controlled by LNB and selective catalyst reduction (SCR) to 2.5 parts per million volume (ppmv) stack gas at 15 percent oxygen. 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 2-18** and **Figure 2-11** for NGCC plant operations are a result of this slip, which is reported as 10 ppmv NH_3 at the end of catalyst life (NETL, 2010). The Baseline Report assumes zero SO_X, PM, and Hg emissions associated with natural gas combustion (NETL, 2010). Carbon monoxide and SO_X emissions during construction are due to the LC emissions of material inputs and are dominated by steel plate manufacturing.

Table 2-18: NGCC without CCS Stage #3 Air Pollution Emissions, kg/MWh Plant Output

Emissions kg/MWh	Plant Construction	Plant Commissioning/ Decommissioning	Plant Operations w/o CCS	Total
Pb	4.16E-07	7.46E-11	2.11E-06	2.53E-06
Hg	2.25E-08	5.28E-12	0.00E+00	2.25E-08
NH_3	5.61E-07	5.86E-07	1.75E-02	1.75E-02
CO	2.03E-03	6.15E-04	2.73E-04	2.92E-03

NO_X	7.20E-04	2.28E-04	2.75E-02	2.84E-02
SO_X	1.29E-03	1.61E-05	1.95E-06	1.31E-03
VOC	1.77E-05	5.80E-06	0.00E+00	2.35E-05
PM	2.01E-03	3.02E-05	2.47E-05	2.07E-03

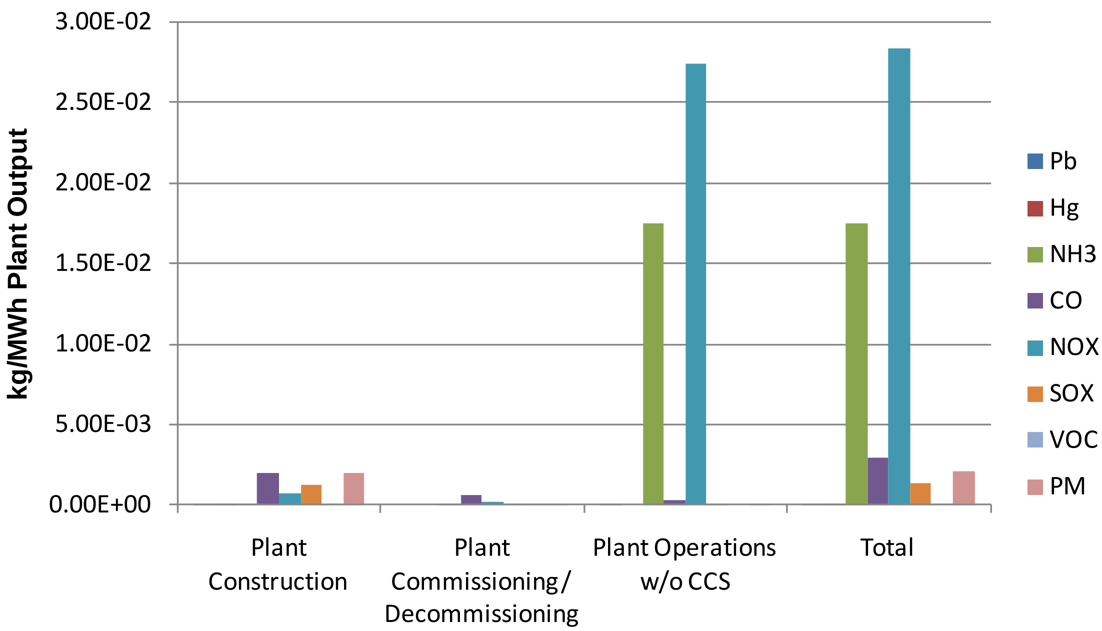

Figure 2-11: NGCC without CCS Stage #3 Air Pollution Emissions, kg /MWh Plant Output

2.3.5 Water Withdrawal and Consumption

Table 2-19 shows water withdrawal and consumption for the NGCC plant without CCS. The most water is consumed during plant operation due to cooling water evaporation. Water withdrawal and consumption during decommissioning is due to the LC impacts of diesel fuel.

Table 2-19: NGCC without CCS Stage #3 Water Withdrawal and Consumption, kg/MWh Plant Output

Water kg/MWh	Plant Construction	Plant Commissioning/ Decommissioning	Plant Operations w/o CCS	Total
Water Withdrawal	2.31	4.60E-02	962	964

Wastewater Outfall	8.18E-01	1.71E-03	216	217
Water Consumption	1.49	4.42E-02	746	747

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

The block flow diagram shown in Figure 2-12 was taken from the Baseline Report and provides a simplified illustration of the interaction between major unit processes of the NGCC case with CCS (NETL, 2010). This figure shows a single CTG, a single HRSG, and one steam turbine – not representative of the two CTGs, two HRSGs, single steam turbine, and two carbon separation units sparing philosophy, but meant to give a simplified representation of the NGCC process. Ambient air (stream 1) and natural gas (stream 2) are combined in the dry LNB of the two gas turbines (only one shown), which is operated to control the rotor inlet temperature at approximately 1,399°C (2,550°F). Combustion flue gas (stream 3) exits the gas turbines at 631°C (1167°F) and passes into the HRSG. An HRSG (one associated with each gasifier) generates both the main steam and reheat steam for the single steam turbine. Flue gas exits the HRSG at 139°C (283°F) and passes to the two amine units (stream 4). Carbon dioxide-lean flue gas is released to the air via flue stack (stream 5) and separated CO_2 travels to the six-stage compression unit process (stream 6). Equivalent masses of reboiler steam and condensate return enter and leave the amine unit at temperatures of 288°C (550°F) and 149°C (300°F), respectively. The plant has a significantly lower net power output, 474 megawatts (MW), than the NGCC Case 1 without CCS because of extraction of steam from the steam turbine and the significantly higher auxiliary power load required for operation of the amine unit for CO_2 capture and for CO_2 compression. The NGCC's carbon capture facility comprises two major elements: separation of CO_2 using an amine-based absorption/stripping process and subsequent conditioning and compression of separated CO_2.

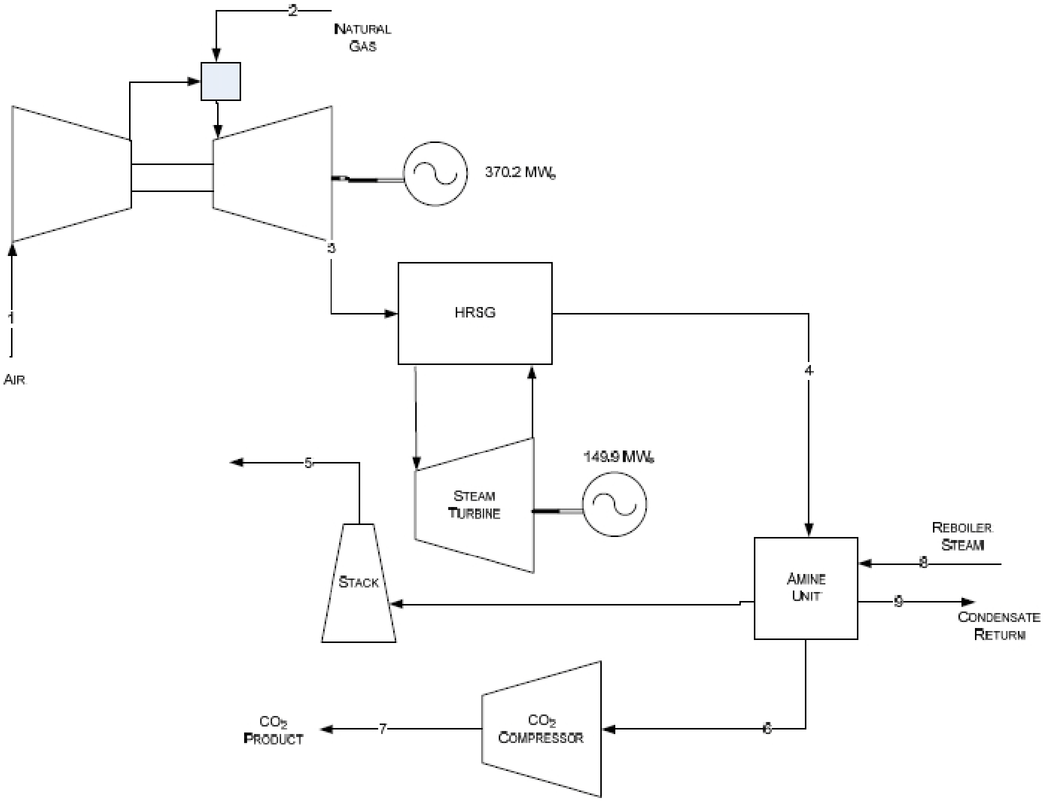

Figure 2-12: Block Flow Diagram Summarizing the Major Streams of the NGCC Process with Integrated Carbon Capture (NETL, 2010)

2.4.1 LCC Data Assumption

Assumptions for NGCC case Sage #1 and Stage #2, as well as the assumptions for costs for Stage #3, are described within the previous sections relating to Stage #1 and Stage #2 and the NGCC facility without CCS. Listed below in **Table 2-20** are the assumptions and parameters used to determine the NGCC with CCS cost analysis results.

Table 2-20: NGCC Facility with CCS Cost Parameters and Assumption Summary

Parameter	NGCC w/ CCS
Electricity Net (MWe)	474
Capacity Factor	85%
Initial Costs ($)[1]	$0
Capital Investment	$709,039,000
Fixed O&M Costs, Labor Cost ($/yr)[2]	$19,939,120
Variable O&M Cost ($/yr)[3]	$9,024,121

1. Initial start-up costs are wrapped into the Capital Investment costs.
2. Labor rates were not amended from the Baseline Report labor rates, despite re-location of the NGCC facilities from the Midwest to Mississippi.
3. Variable O&M costs exclude process water costs and include replacement costs.

The assumptions applied to the NGCC case with CCS are the same as those applied to the feed/fuel and utilities used for the NGCC case without CCS, as shown in **Table 2-21**.

Table 2-21: Annual Feedrate for Feed/Fuel and Utilities for NGCC Case with CCS

Inputs	Feedrate
Natural Gas (MMBtu/day)	90,562
Water Needed (gallons/day)[1]	1,432,800

1. Quantity listed accounts for the portion of water included in the costs of the plant. It is assumed that only half of the process water used in the plant is considered in the costs for the plant.

2.4.1.1 *CO_2 Transportation, Sequestration, and Monitoring*

For the NGCC 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.

2.4.1.2 *CO_2 Pipeline*

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

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

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 kilometers (100 miles) of CO_2 pipeline equal to $51,907,790. The fixed O&M costs were determined using the following assumptions:

1. There is one full-time laborer per 160.9 kilometers (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 kilometers [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 $2,091,964. Labor is considered a stand-alone fixed cost and equals $31,304. **Table 2-22** summarizes the CO_2 pipeline capital and O&M costs.

Table 2-22: Summary of CO_2 Pipeline Capital and Fixed Costs

CO_2 Pipeline	NGCC w/ CCS
Material Cost ($/mile)	$91,075.60
Labor Cost ($/mile)	$268,722.30
Misc Costs ($/mile)	$119,160.80
Land Costs ($/mile)	$40,119.20
Total CO_2 Pipeline Capital Costs ($/100 Miles)	$51,907,790
Labor (Annual)	$31,304.00
G&A Labor (Annual)	$15,652.00
Other O&M Costs (Annual)	$2,076,312
Total O&M Costs (Annual)	$2,091,964
Total length of pipeline (Miles)	100

2.4.1.3 *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 NGCC 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. Fixed operating costs, including normal daily expenses and maintenance on the surface and subsurface, have a total cost of $135,097 per year. The variable operating costs equal $14,238.

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.

2.4.2 LCC Results

The primary contributor to the total LC LCOE for the NGCC case with CCS is the utility costs at the NGCC energy conversion facility. The total LC LCOE of the plant is equal to $0.1319/kWh. Of the total LC LCOE, the NGCC energy conversion facility cost components account for the majority of the costs. **Figure 2-13** presents the LC LCOE costs broken up by cost component. Utility LCOE, including natural gas feed and process water, is equal to $0.0792/kWh, whereas labor, variable O&M, and capital LCOE at the NGCC energy conversion facility are equal to $0.0086/kWh, $0.0039/kWh, and $0.0339/kWh, respectively. Included in the costs of the NGCC energy conversion facility with CCS is the CO_2 removal and compression system. The switchyard/trunkline system and decommissioning contribute $0.0022/kWh and $0.0002/kWh. In addition to the inclusion of CO_2 removal and compression system costs at the plant, costs related to the CO_2 TS&M system were also included in the total LC LCOE for the NGCC case with CCS. The CO_2 TS&M system contributes $0.0029/kWh in capital costs, $0.0009/kWh in variable O&M costs, and $0.0001/kWh in labor costs.

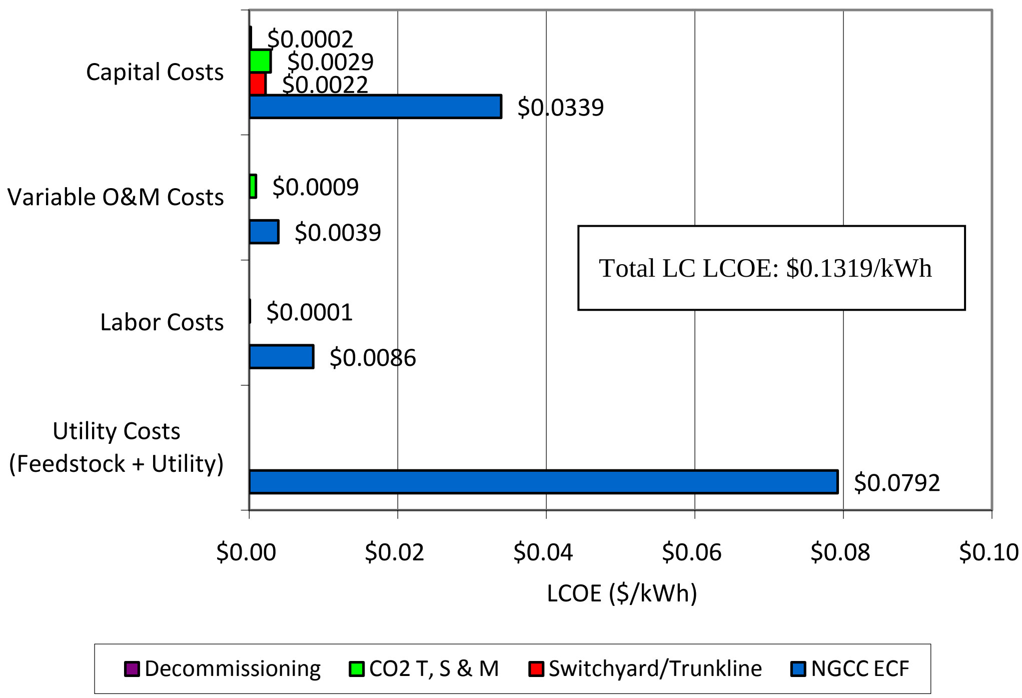

Figure 2-13: LCOE for NGCC Case with CCS

1. NGCC EC facility represents the energy conversion facility alone.
2. CO_2 TS&M represents the transportation, sequestration, and monitoring of the CO_2.
3. The labor cost for CO_2 TS&M are small and therefore are not represented on the chart with a bar, only the value of $0.00001/kWh appears on the chart.

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 NGCC facilities are normalized to the basis of net power output, which is 555 MW for the

NGCC facility and 474 MW for the NGCC 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 NGCC facility is $882/kW; 81 percent of this TPC is related to the energy conversion facility, and the balance is related to the switchyard and trunkline and decommissioning activities. The TPC of the NGCC facility with CCS is $1,898/kW, which is 115 percent higher than the base NGCC facility. For the NGCC facility with CCS, 79 percent of the TPC is related to the energy conversion facility, 6.8 percent is related to the CO_2 pipeline and injection well, and the balance is related to the switchyard and trunkline and decommissioning activities. The TPC of the NGCC facilities are presented in **Figure 2-14**.

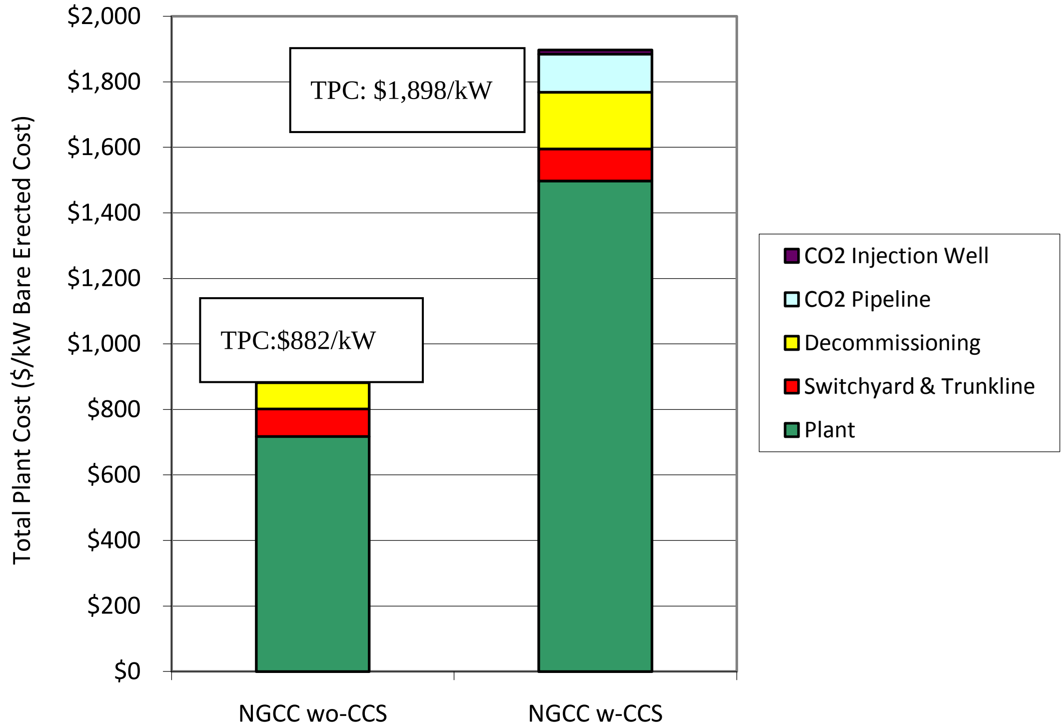

Figure 2-14: TPC ($/kW) for NGCC Case with and without CCS

2.4.3 Greenhouse Gas Emissions

Table 2-23 and **Figure 2-15** show the GHG emissions associated with the NGCC 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 natural gas. However, the addition of CCS reduces the magnitude of those emissions by a nominal 90 percent (NETL, 2010). Emissions associated with the CO_2 pipeline is also included and a small amount (less than one percent of the total on both a mass [kg] and kg CO_2e basis) of additional GHG emissions are associated with that process. The total GWP of Stage #3 with CCS is 47.7 kg CO_2e per MWh plant output.

Table 2-23: NGCC with CCS Stage #3, GHG Emissions (kg and kg CO_2e) /MWh Plant Output

GHG Emissions	Plant Construction		CO_2 Pipeline		Plant Commissioning/ Decommissioning		Plant Operation with CCS		Total	
	kg/MWh	kg CO_2e /MWh	kg/MWh	kg CO_2e /MWh	kg/MWh	kg CO_2e /MWh	kg/MWh	kg CO_2e /MWh	kg/MWh	kg CO_2e /MWh
CO_2	5.10E-01	5.10E-01	3.62E-02	3.62E-02	1.94E-02	1.94E-02	47.1	47.1	47.7	47.7
N_2O	1.82E-05	5.41E-03	7.30E-07	2.18E-04	4.83E-07	1.44E-04	2.39E-06	7.14E-04	2.18E-05	6.49E-03
CH_4	4.57E-04	1.14E-02	3.11E-05	7.79E-04	2.06E-05	5.16E-04	8.76E-06	2.19E-04	5.18E-04	1.29E-02
SF_6	6.35E-12	1.45E-07	8.26E-15	1.88E-10	5.47E-15	1.25E-10	3.55E-07	8.09E-03	3.55E-07	8.09E-03
Total GWP		5.27E-01		3.72E-02		2.00E-02		47.1		47.7

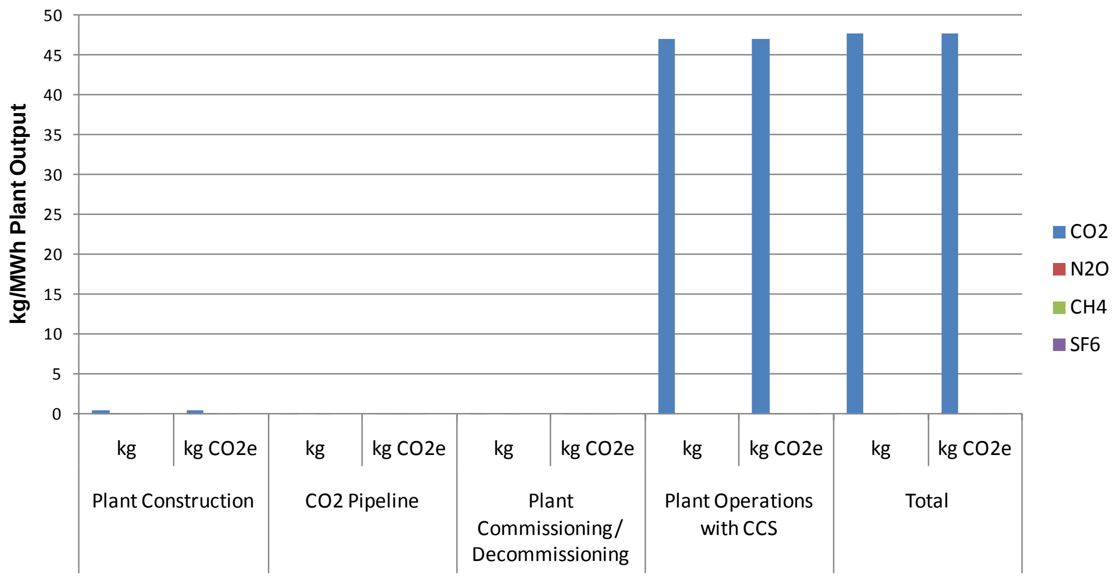

Figure 2-15: NGCC with CCS Stage #3, GHG Emissions (kg and kg CO_2e) /MWh Plant

2.4.4 Air Pollutant Emissions

Table 2-24 and **Figure 2-16** show the air pollutants released during NGCC plant operations on a per MWh output basis. Nitrogen oxide and NH_3 dominate, as was seen in the case without CCS due to natural gas combustion and SCR end of catalyst life NH_3 slip. Less than one percent of air emissions are associated with the addition of the CO_2 pipeline.

Table 2-24: NGCC with CCS Stage #3 Air Emissions, kg /MWh Plant Output

Emissions (kg/MWh)	Plant Construction	CO_2 Pipeline	Plant Commissioning/ Decommissioning	Plant Operations with CCS	Total
Pb	7.66E-07	1.45E-10	9.62E-11	2.11E-06	2.88E-06
Hg	3.22E-08	1.03E-11	6.80E-12	0.00E+00	3.23E-08
NH_3	6.12E-07	1.14E-06	7.56E-07	1.89E-02	1.89E-02
CO	2.98E-03	1.21E-04	7.92E-04	3.20E-04	4.21E-03
NO_X	9.63E-04	3.47E-04	2.94E-04	3.02E-02	3.18E-02
SO_X	1.73E-03	3.17E-05	2.07E-05	2.28E-06	1.78E-03
VOC	1.96E-05	1.13E-05	7.47E-06	0.00E+00	3.83E-05
PM	2.29E-03	6.67E-05	3.89E-05	2.89E-05	2.43E-03

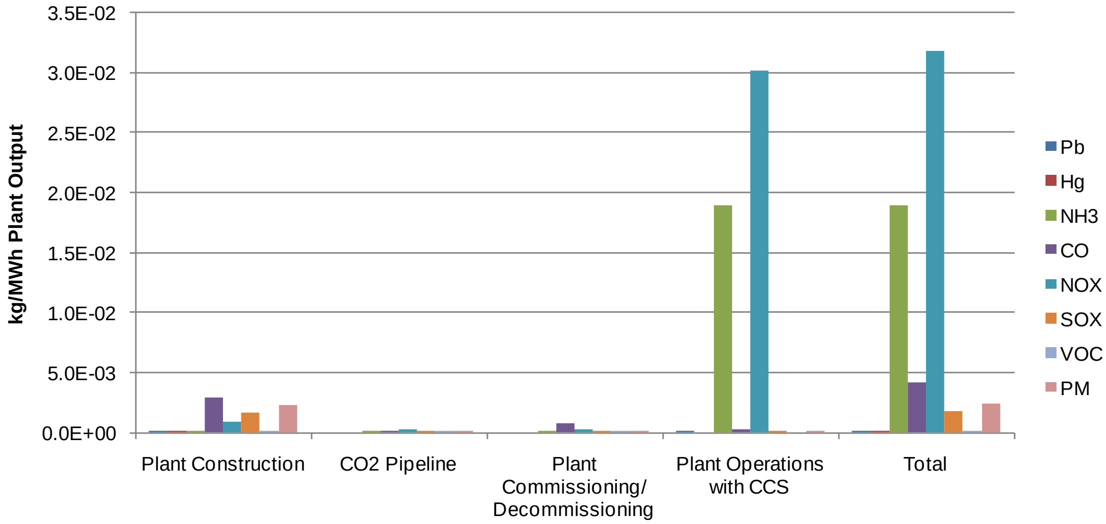

Figure 2-16: NGCC with CCS Stage #3 Air Emissions, kg/MWh Plant Output

2.4.5 Water Withdrawal and Consumption

Table 2-25 shows water withdrawal and consumption for the NGCC plant with CCS. As with the case without CCS, the most water is consumed during plant operation due to cooling water evaporation. Water withdrawal for the CO_2 pipeline and plant decommissioning is due to the LC impacts of diesel fuel.

Table 2-25: NGCC with CCS Stage #3 Water Withdrawal and Consumption, kg /MWh Plant Output

Water kg/MWh	Plant Construction	CO_2 Pipeline	Plant Commissioning/ Decommissioning	Plant Operations with CCS	Total
Water Withdrawal	3.75	1.90E-02	5.92E-02	1913	1917
Wastewater Outfall	0.89	3.34E-03	2.21E-03	483	483
Water Consumption	2.86	1.57E-02	5.70E-02	1431	1433

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, 2007). This loss only impacts the cost parameters as no environmental inventories are associated with transmission loss. The transmission line was considered existing infrastructure, therefore, the construction of the line, along with the associated costs, emissions, and land use changes, was not included within the system boundaries for this study.

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

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

Finally, in 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: NGCC With Imported NG Without CCS

Table 3-1 summarizes all water withdrawals, consumption, and emissions from the NGCC case without CCS, in kg/MWh delivered to the end user, 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 is not discussed further, and Stage #4 is discussed only in the context of GHG emissions.

It is important to note the differences between the values in **Table 3-1** and the previous values reported for each individual stage, as the values here are normalized to the functional unit of MWh delivered energy. Therefore the Stage #3 values presented in Tables 2-16 to 2-18 will be slightly larger as the basis of MWh plant output does not included transmission loss during Stage #4. Additionally, normalizing Stage #1 and Stage #2 to a MWh delivered energy basis resulted in approximate normalization factors of 149 kg NG/MWh and 144 kg NG/MWh, respectively.

Table 3-1: Water and Emissions Summary for NGCC without CCS using Imported NG, kg/MWh Delivered Energy

Pollutants	Stage #1: Raw Material Acquisition	Stage #2: Material Transport	Stage #3: Energy Conversion Facility (w/o CCS)	Stage #4: Transmission & Distribution	Total
GHG Emissions (kg/MWh)					
CO_2	81.7	20.3	393	0	495
N_2O	4.86E-04	1.64E-04	1.50E-05	0	6.65E-04
CH_4	2.47E-01	7.60E-01	3.68E-04	0	1.01
SF_6	1.83E-12	3.26E-11	3.26E-07	1.43E-04	1.44E-04
Non-GHG Air Emissions (kg/MWh)					
Pb	1.40E-06	5.21E-07	2.72E-06	0	4.63E-06
Hg	7.13E-08	5.68E-08	2.42E-08	0	1.52E-07
NH_3	9.67E-02	8.30E-05	1.88E-02	0	1.16E-01
CO	6.82E-02	6.97E-02	3.14E-03	0	1.41E-01

Pollutants	Stage #1: Raw Material Acquisition	Stage #2: Material Transport	Stage #3: Energy Conversion Facility (w/o CCS)	Stage #4: Transmission & Distribution	Total
NO_X	1.51E-01	1.03E-01	3.05E-02	0	2.85E-01
SO_X	5.03E-03	2.22E-02	1.41E-03	0	2.87E-02
VOC	7.36E-04	1.30E-02	2.53E-05	0	1.38E-02
PM	4.08E-03	3.09E-03	2.22E-03	0	9.39E-03
Water Withdrawal and Consumption (kg/MWh)					
Water Withdrawal	149	30.2	1037	0	1216
Wastewater Outfall	125	25.8	234	0	384
Water Consumption	24.4	4.38	803	0	832

3.1.1 Greenhouse Gas Emissions

Table 3-2 and **Figure 3-1** show the GHG emissions associated with the NGCC plant operations without CCS in kg CO_2e per MWh delivered to the end user.

Table 3-2: GHG Emissions for NGCC without CCS using Imported NG, kg CO_2e /MWh Delivered Energy

GHG Emissions (kg CO_2e/ MWh)	Stage #1: Raw Material Acquisition	Stage #2: Material Transport	Stage #3: Energy Conversion Facility (w/o CCS)	Stage #4: Transmission & Distribution	Total
CO_2	81.7	20.3	393	0	495
N_2O	1.45E-01	4.89E-02	4.47E-03	0	1.98E-01
CH_4	6.18	19.0	9.20E-03	0	25.2
SF_6	4.18E-08	7.43E-07	7.43E-03	3.27	3.28
Total GWP	88.0	39.4	393	3.27	524

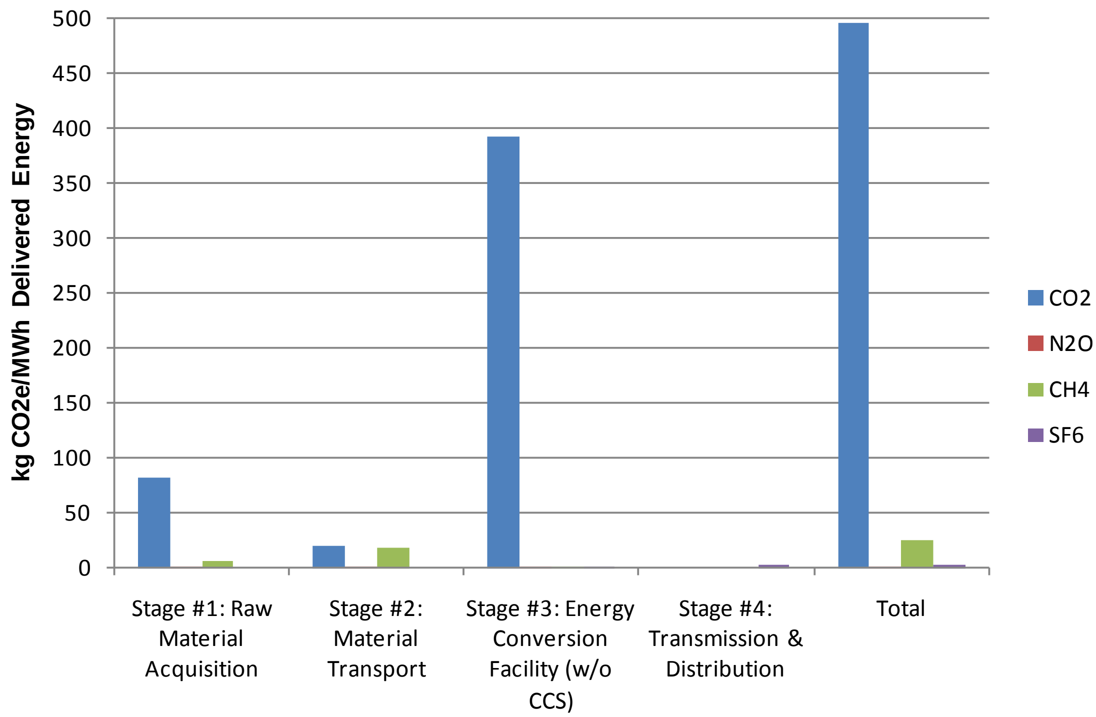

Figure 3-1: GHG Emissions for NGCC without CCS using Imported NG, kg CO_2e /MWh Delivered Energy

The total GWP of NGCC without CCS is 524 kg CO_2e per MWh delivered energy. Of those 524 kg CO_2e, 93 percent is due to CO_2 emissions. Methane accounts for 4.5 percent, N_2O for 1.6 percent, and SF_6 accounts for the remaining 0.9 percent. Approximately 74 percent of the total GWP is attributable to activities in Stage #3, which is dominated by natural gas combustion. Stage #1 attributes 17 percent due mainly to liquefaction facility operation.

3.1.2 Air Emissions

When compared to GHG emissions, particularly CO_2, all other air emissions are emitted on a much smaller scale. 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 NGCC case without CCS.

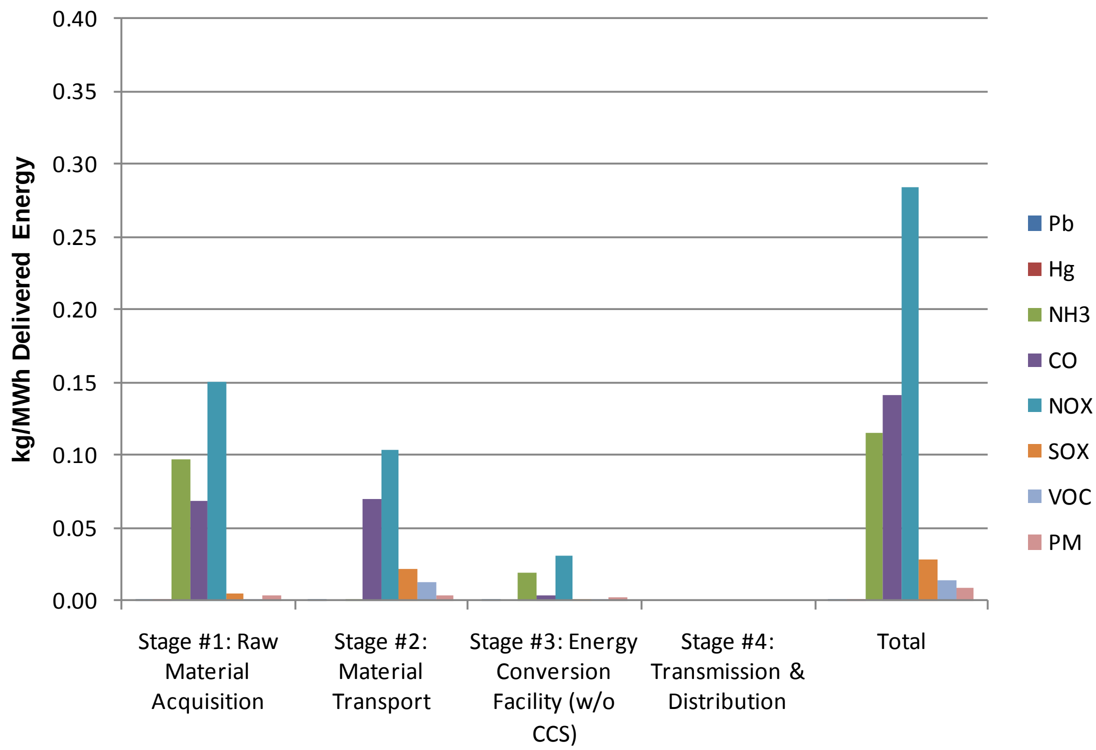

Figure 3-2: Air Emissions for NGCC without CCS using Imported NG, kg /MWh Delivered Energy

Nitrogen oxide, CO, and VOC emissions dominate this case, due mostly to fuel combustion. Sulfur oxide is emitted at slightly lower levels due to the use of natural gas as a fuel in many stages, which has negligible sulfur content. Sulfur dioxide (SO_2) emissions are dominated by Stage #1 where diesel and jet fuel are used during drill rig operations. Ammonia emissions are dominated by liquefaction facility operations in Stage #1.

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. Water withdrawal and consumption is dominated by energy conversion (Stage #3) due to cooling water requirements in the power plant.

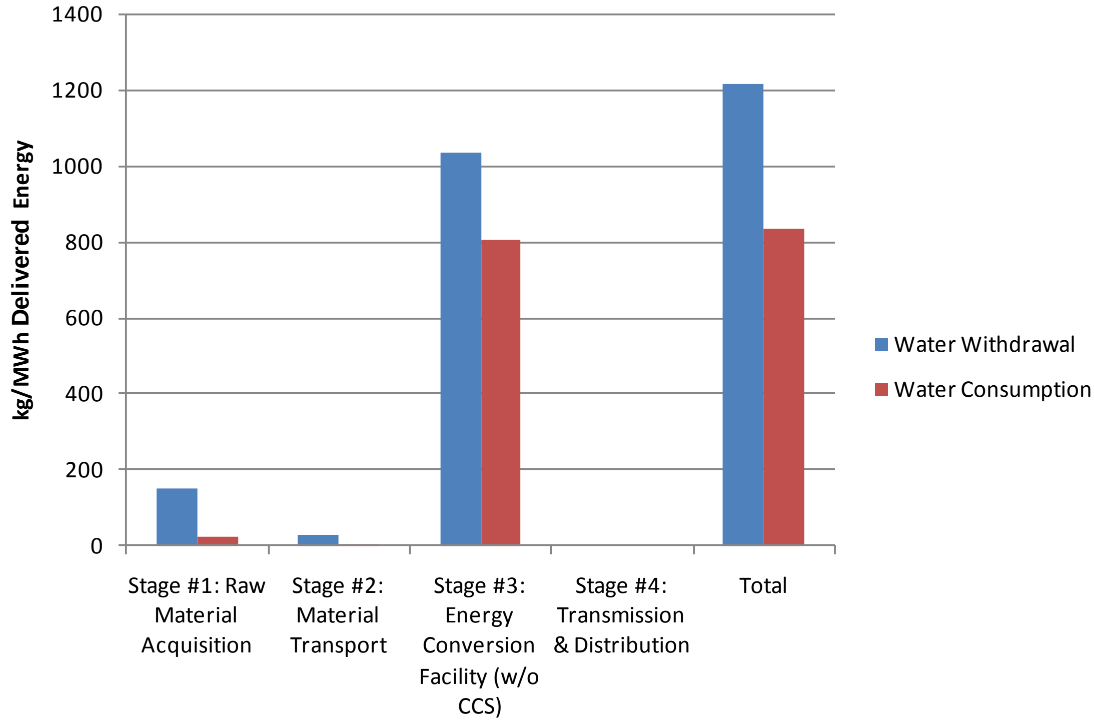

Figure 3-3: Water Withdrawal and Consumption for NGCC without CCS using Imported NG, kg/MWh Delivered Energy

3.2 LCI results: NGCC With Domestic NG Without CCS

Table 3-1 summarizes all water withdrawals, consumption, and emissions from the NGCC case without CCS, in kg/MWh delivered to the end user, 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 is not discussed further, and Stage #4 is discussed only in the context of GHG emissions.

It is important to note the differences between the values in **Table 3-1** and the previous values reported for each individual stage, as the values here are normalized to the functional unit of MWh delivered energy. Therefore the Stage #3 values presented in Tables 2-16 to 2-18 will be slightly larger as the basis of MWh plant output does not included transmission loss during Stage #4. Additionally, normalizing Stage #1 and Stage #2 to a MWh delivered energy basis resulted in approximate normalization factors of 149 kg NG/MWh and 144 kg NG/MWh, respectively.

Table 3-3: Water and Emissions Summary for NGCC without CCS using Domestic NG, kg/MWh Delivered Energy

Pollutants	Stage #1: Raw Material Acquisition	Stage #2: Material Transport	Stage #3: Energy Conversion Facility (w/o CCS)	Stage #4: Transmission & Distribution	Total
GHG Emissions (kg/MWh)					
CO_2	16.4	18.7	393	0	428
N_2O	4.31E-05	3.27E-04	1.50E-05	0	3.85E-04
CH_4	2.56E-01	1.15E+00	3.68E-04	0	1.41
SF_6	5.79E-13	2.49E-11	3.26E-07	1.43E-04	1.44E-04
Non-GHG Air Emissions (kg/MWh)					
Pb	4.68E-07	2.48E-07	2.72E-06	0	3.43E-06
Hg	1.48E-08	2.03E-08	2.42E-08	0	5.94E-08
NH_3	2.64E-06	1.19E-05	1.88E-02	0	1.88E-02
CO	7.04E-02	2.11E-02	3.14E-03	0	9.47E-02
NO_X	1.07E-01	2.32E-01	3.05E-02	0	3.70E-01
SO_X	2.27E-03	1.02E-02	1.41E-03	0	1.39E-02
VOC	1.47E-02	6.64E-03	2.53E-05	0	2.14E-02
PM	2.10E-03	1.62E-03	2.22E-03	0	5.94E-03
Water Withdrawal and Consumption (kg/MWh)					
Water Withdrawal	324	16.4	1037	0	1377
Wastewater Outfall	228	11.7	234	0	473
Water Consumption	96.4	4.64	803	0	904

3.2.1 Greenhouse Gas Emissions

Table 3-2 and **Figure 3-1** show the GHG emissions associated with the NGCC plant operations without CCS in kg CO_2e per MWh delivered to the end user.

Table 3-4: GHG Emissions for NGCC without CCS using Domestic NG, kg CO_2e /MWh Delivered Energy

GHG Emissions (kg CO_2e/ MWh)	Stage #1: Raw Material Acquisition	Stage #2: Material Transport	Stage #3: Energy Conversion Facility (w/o CCS)	Stage #4: Transmission & Distribution	Total
CO_2	16.4	18.7	393	0	428
N_2O	1.28E-02	9.74E-02	4.47E-03	0	1.15E-01
CH_4	6.39	28.7	9.20E-03	0	35.1
SF_6	1.32E-08	5.68E-07	7.43E-03	3.27	3.28
Total GWP	22.8	47.5	393	3.27	467

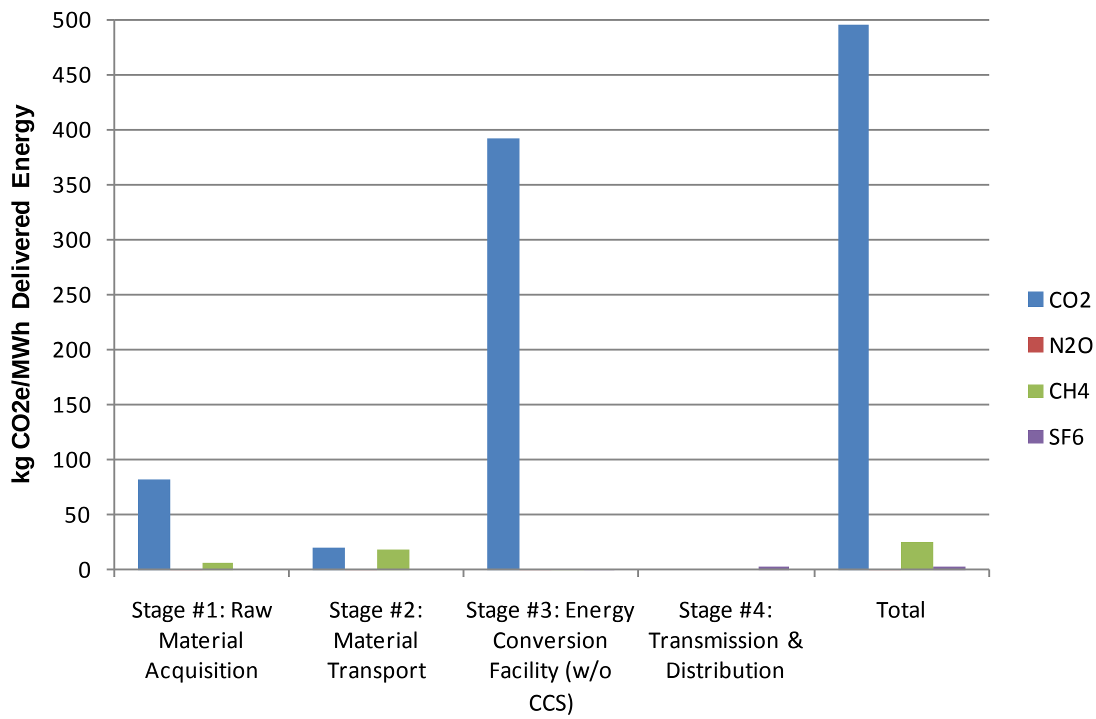

Figure 3-4: GHG Emissions for NGCC without CCS using Domestic NG, kg CO_2e /MWh Delivered Energy

The total GWP of NGCC without CCS is 524 kg CO_2e per MWh delivered energy. Of those 524 kg CO_2e, 93 percent is due to CO_2 emissions. Methane accounts for 4.5 percent, N_2O for 1.6 percent, and SF_6 accounts for the remaining 0.9 percent. Approximately 74 percent of the total GWP is attributable to activities in Stage #3, which is dominated by natural gas combustion. Stage #1 attributes 17 percent due mainly to liquefaction facility operation.

3.2.2 Air Emissions

When compared to GHG emissions, particularly CO_2, all other air emissions are emitted on a much smaller scale. 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 3-5** shows the air pollutant emissions (kg/MWh delivered) for the NGCC case without CCS.

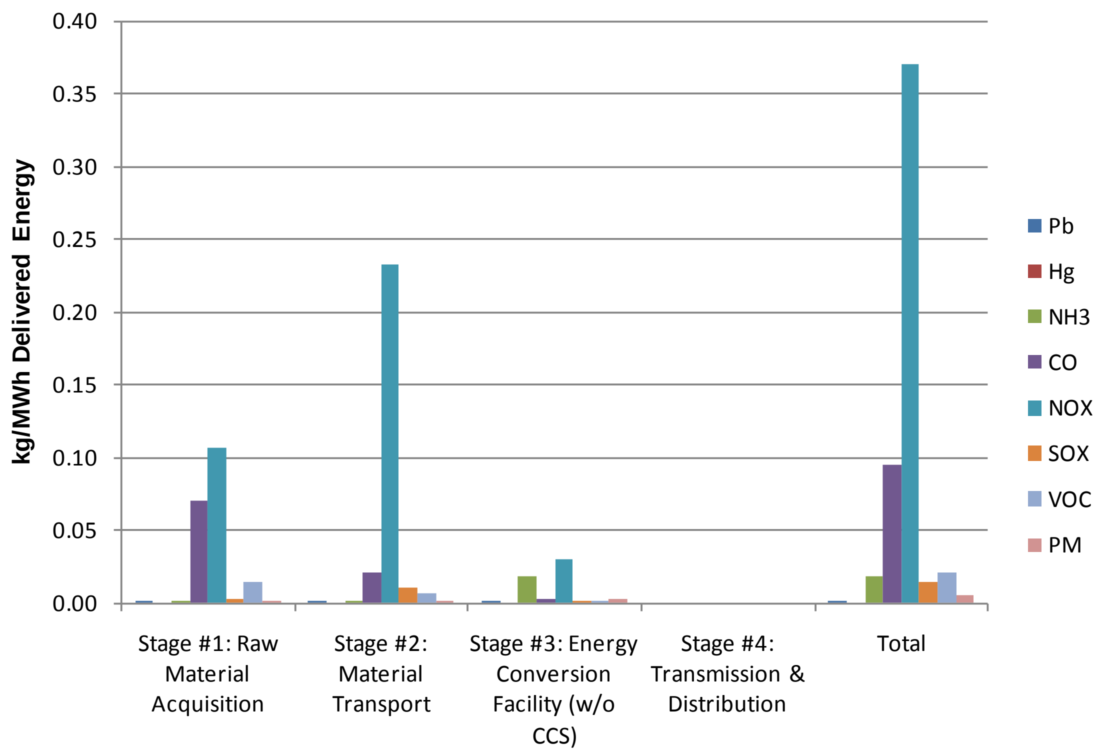

Figure 3-5: Air Emissions for NGCC without CCS using Domestic NG, kg /MWh Delivered Energy

Nitrogen oxide, CO, and VOC emissions dominate this case, due mostly to fuel combustion. Sulfur oxide is emitted at slightly lower levels due to the use of natural gas as a fuel in many stages, which has negligible sulfur content. Sulfur dioxide (SO_2) emissions are dominated by Stage #1 where diesel and jet fuel are used during drill rig operations. Ammonia emissions are dominated by liquefaction facility operations in Stage #1.

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. Water withdrawal and consumption is dominated by energy conversion (Stage #3) due to cooling water requirements in the power plant.

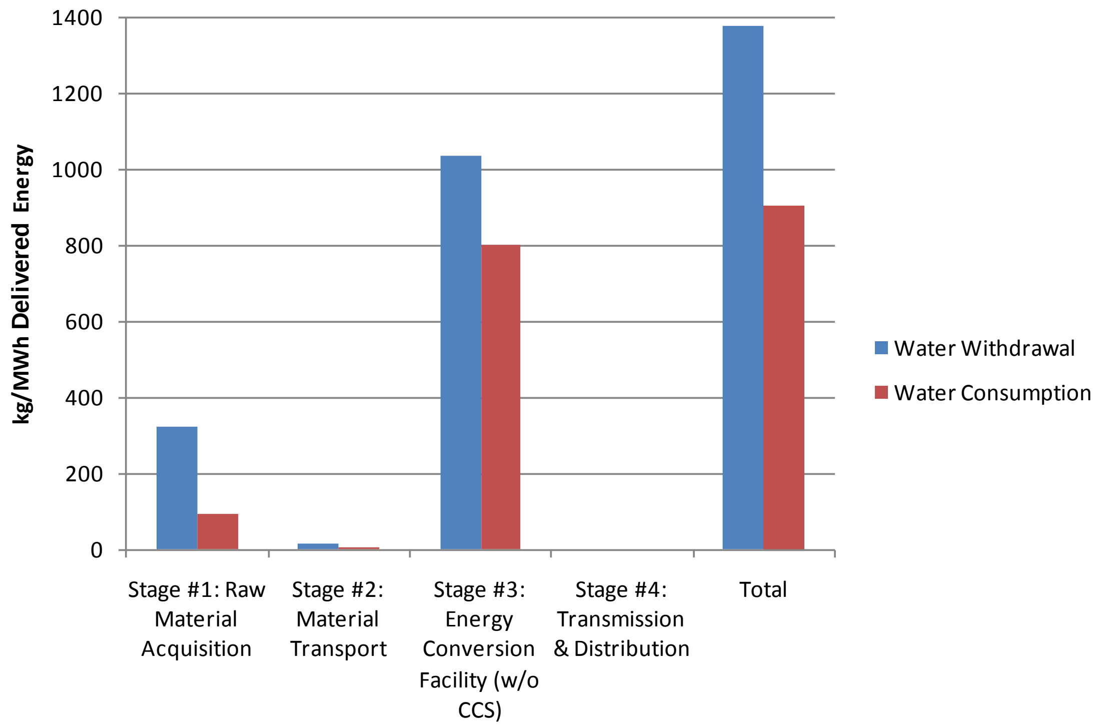

Figure 3-6: Water Withdrawal and Consumption for NGCC without CCS using Domestic NG, kg/MWh Delivered Energy

3.3 LCI results: NGCC With Imported NG with CCS

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

It is important to note the differences between the values in **Table 3-5** and the previous values reported for each individual stage, as the values here are normalized to the functional unit of MWh delivered energy. Therefore the Stage #3 values presented in Tables 2-22 to 2-24 will be slightly larger as the basis of MWh plant output does not include transmission loss during Stage #4. Additionally, normalizing Stage #1 and Stage #2 to a MWh delivered energy basis resulted in approximate normalization factors of 173 kg NG/MWh and 167 kg NG/MWh, respectively.

Table 3-5: Water and Emissions Summary for NGCC with CCS using Imported NG, kg /MWh Delivered Energy

Pollutants	Stage #1: Raw Material Acquisition	Stage #2: Material Transport	Stage #3: Energy Conversion Facility (with CCS)	Stage #4: Transmission & Distribution	Total
GHG Emissions (kg/MWh)					
CO_2	95.7	23.8	51.3	0	171
N_2O	5.70E-04	1.92E-04	2.34E-05	0	7.86E-04
CH_4	2.90E-01	8.91E-01	5.57E-04	0	1.18
SF_6	2.15E-12	3.82E-11	3.82E-07	1.43E-04	1.44E-04
Non-GHG Air Emissions (kg/MWh)					
Pb	1.64E-06	6.11E-07	3.09E-06	0	5.34E-06
Hg	8.35E-08	6.66E-08	3.47E-08	0	1.85E-07
NH_3	1.13E-01	9.73E-05	2.03E-02	0	1.34E-01
CO	8.00E-02	8.17E-02	4.53E-03	0	1.66E-01
NO_X	1.77E-01	1.21E-01	3.42E-02	0	3.32E-01
SO_X	5.90E-03	2.60E-02	1.92E-03	0	3.39E-02
VOC	8.62E-04	1.53E-02	4.12E-05	0	1.62E-02
PM	4.78E-03	3.62E-03	2.61E-03	0	1.10E-02
Water Withdrawal and Consumption (kg/MWh)					
Water Withdrawal	175	35.4	2061	0	2271
Wastewater Outfall	146	30.3	520	0	696
Water Consumption	28.7	5.14	1541	0	1575

3.3.1 Greenhouse Gas Emissions

Table 3-6 shows the GHG emissions from **Table 3-5** based on kg CO_2e.

Table 3-6: GHG Emissions for NGCC with CCS using Imported NG, kg CO_2e /MWh Delivered Energy

GHG Emissions (kg CO_2e/MWh)	Stage #1: Raw Material Acquisition	Stage #2: Material Transport	Stage #3: Energy Conversion Facility (with CCS)	Stage #4: Transmission & Distribution	Total
CO_2	95.7	23.8	51.3	0	171
N_2O	1.70E-01	5.74E-02	6.98E-03	0	2.34E-01
CH_4	7.24	22.3	1.39E-02	0	29.5
SF_6	4.90E-08	8.71E-07	8.70E-03	3.27	3.28
Total GWP	103.1	46.1	51.3	3.27	204

The total GWP for NGCC with CCS is 206 kg CO_2e per MWh delivered energy. **Figure 3-7** compares the GHG emissions for each stage. When CCS is included, Stage #1 becomes the dominate stage for GHG emissions. Of these emissions, 69 percent are due to CO_2 emissions during liquefaction operations. Carbon dioxide emissions for liquefaction were taken from data for the Darwin LNG facility run by Conoco Phillips in Australia (ConocoPhillips, 2005). They report 0.42 kg CO_2/kg LNG output, which is within the range reported by Jaramillo (Adapted from Tamura et al.) of 11-31 lb CO_2/MMBtu (0.24 to 0.67 kg CO_2/kg LNG) (Jaramillo, 2007; Tamura, Tanaka et al., 2001). However, reducing GHG emissions for Stage #1 to the lowest value in the range above only reduces GWP of Stage #1 by approximately 30 kg CO_2e per MWh delivered energy; therefore, Stage #1 would still be the dominant GHG emitter for this case. Of the GHG emissions on a kg CO_2e basis, 51 percent are from Stage #1, 23 percent are from Stage #2, and 24 percent are from Stage #3.

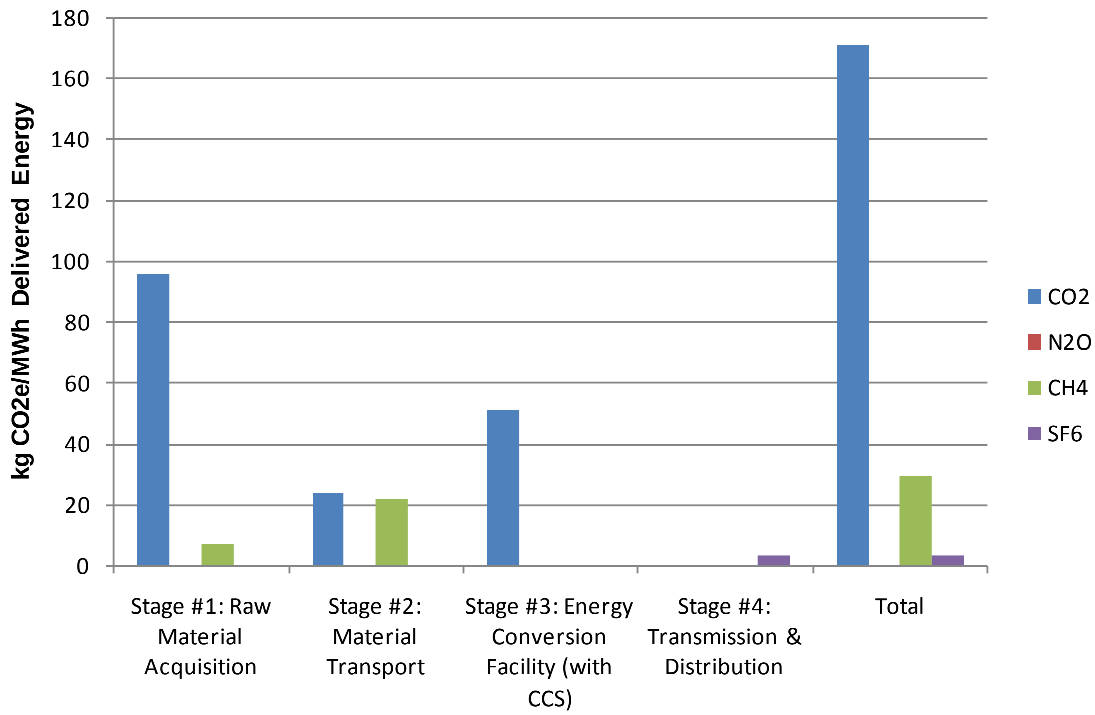

Figure 3-7: GHG Emissions for NGCC with CCS using Imported NG, kg CO_2e /MWh Delivered Energy

3.3.2 Air Emissions

Figure 3-8 compares the air emissions for each stage and the total LC. Like the case without CCS, combustion emissions CO, NO_X, and VOC are dominate, with SO_X and NH_3 from Stage #1 also attributing significantly to the non-GHG emissions.

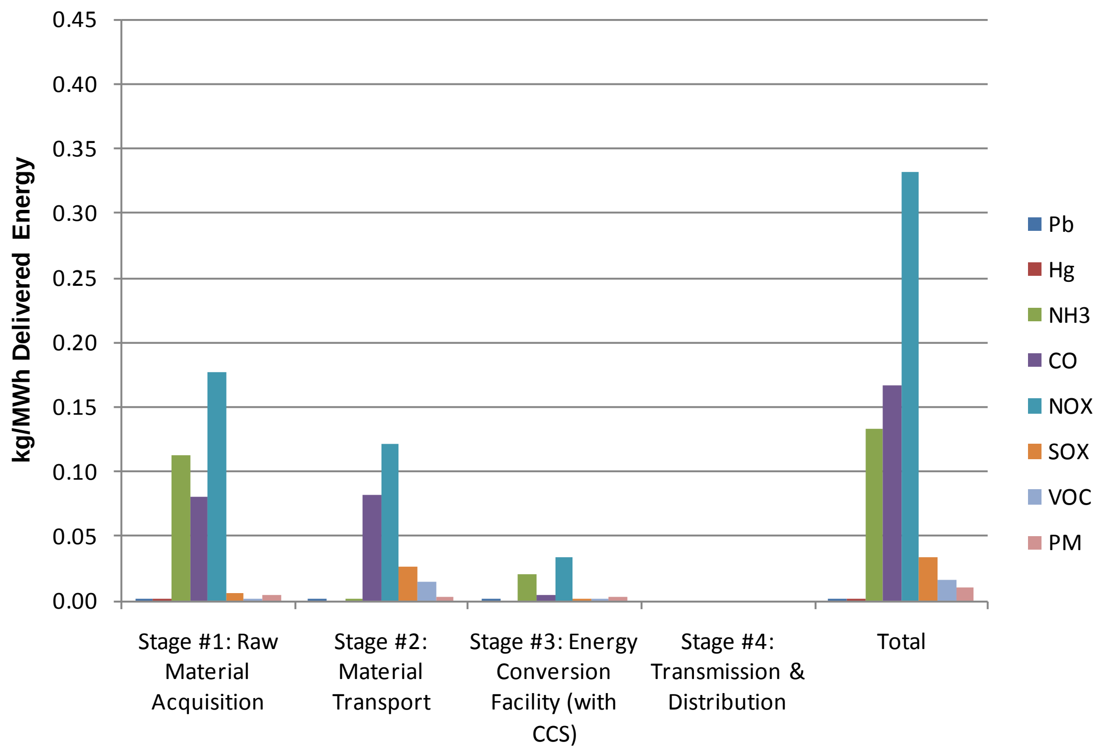

Figure 3-8: Air Emissions for NGCC with CCS using Imported NG, kg/MWh Delivered Energy

3.3.3 Water Withdrawal and Consumption

Figure 3-9 shows the total water withdrawal and water consumption for each stage and the total LC. As with the case without CCS, water withdrawal and consumption is dominated by energy conversion (Stage #3) due to cooling water requirements in the power plant.

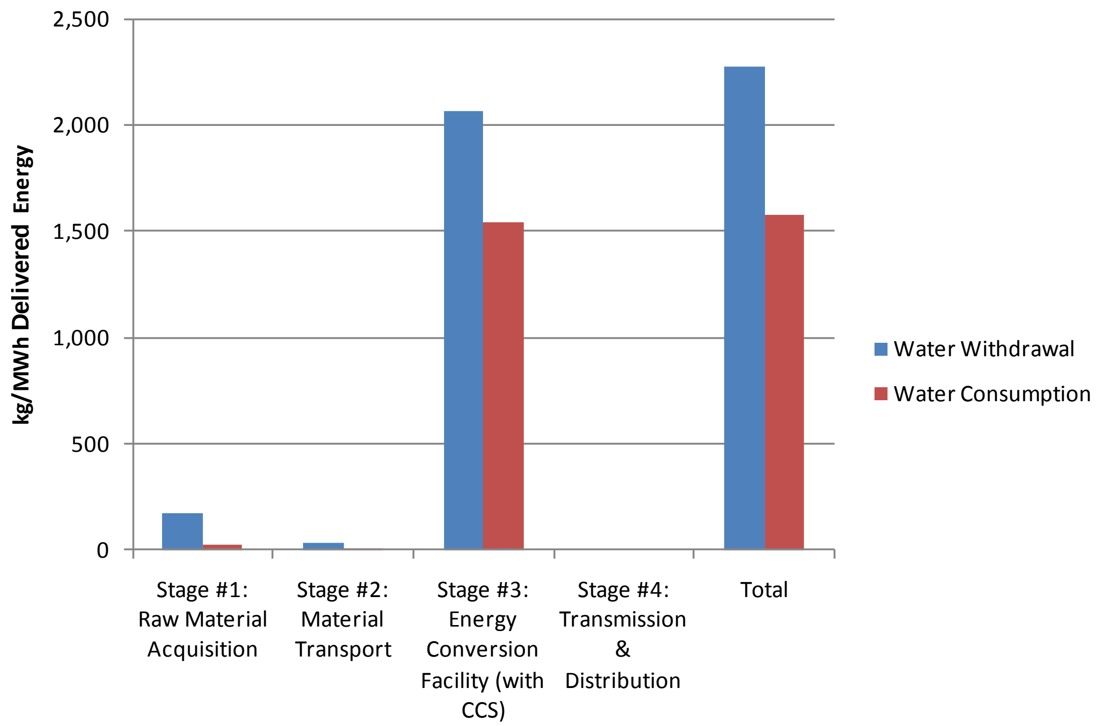

Figure 3-9: Water Withdrawal and Consumption for NGCC with CCS using Imported NG, kg/MWh Delivered Energy

3.4 LCI results: NGCC With Domestic NG with CCS

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

It is important to note the differences between the values in **Table 3-5** and the previous values reported for each individual stage, as the values here are normalized to the functional unit of MWh delivered energy. Therefore the Stage #3 values presented in Tables 2-22 to 2-24 will be slightly larger as the basis of MWh plant output does not include transmission loss during Stage #4. Additionally, normalizing Stage #1 and Stage #2 to a MWh delivered energy basis resulted in approximate normalization factors of 173 kg NG/MWh and 167 kg NG/MWh, respectively.

Table 3-7: Water and Emissions Summary for NGCC with CCS using Domestic NG, kg /MWh Delivered Energy

Pollutants	Stage #1: Raw Material Acquisition	Stage #2: Material Transport	Stage #3: Energy Conversion Facility (with CCS)	Stage #4: Transmission & Distribution	Total
GHG Emissions (kg/MWh)					
CO_2	19.2	21.9	51.3	0	92
N_2O	5.05E-05	3.83E-04	2.34E-05	0	4.57E-04
CH_4	3.00E-01	1.35	5.57E-04	0	1.65
SF_6	6.78E-13	2.92E-11	3.82E-07	1.43E-04	1.44E-04
Non-GHG Air Emissions (kg/MWh)					
Pb	5.49E-07	2.91E-07	3.09E-06	0	3.93E-06
Hg	1.73E-08	2.38E-08	3.47E-08	0	7.58E-08
NH_3	3.09E-06	1.40E-05	2.03E-02	0	2.03E-02
CO	8.25E-02	2.48E-02	4.53E-03	0	1.12E-01
NO_X	1.26E-01	2.72E-01	3.42E-02	0	4.32E-01
SO_X	2.66E-03	1.20E-02	1.92E-03	0	1.66E-02
VOC	1.73E-02	7.78E-03	4.12E-05	0	2.51E-02
PM	2.46E-03	1.90E-03	2.61E-03	0	6.97E-03
Water Withdrawal and Consumption (kg/MWh)					
Water Withdrawal	380	19.2	2061	0	2460
Wastewater Outfall	267	13.8	520	0	801
Water Consumption	113.0	5.44	1541	0	1660

3.4.1 Greenhouse Gas Emissions

Table 3-6 shows the GHG emissions from **Table 3-5** based on kg CO_2e.

Table 3-8: GHG Emissions for NGCC with CCS using Domestic NG, kg CO_2e /MWh Delivered Energy

GHG Emissions (kg CO_2e/MWh)	Stage #1: Raw Material Acquisition	Stage #2: Material Transport	Stage #3: Energy Conversion Facility (with CCS)	Stage #4: Transmission & Distribution	Total
CO_2	19.2	21.9	51.3	0	92.4
N_2O	1.50E-02	1.14E-01	6.98E-03	0	1.36E-01
CH_4	7.49	33.7	1.39E-02	0	41.2
SF_6	1.55E-08	6.66E-07	8.70E-03	3.27	3.28
Total GWP	26.7	55.7	51.3	3.27	137

The total GWP for NGCC with CCS is 206 kg CO_2e per MWh delivered energy. **Figure 3-10** compares the GHG emissions for each stage. When CCS is included, Stage #1 becomes the dominate stage for GHG emissions. Of these emissions, 69 percent are due to CO_2 emissions during liquefaction operations. Carbon dioxide emissions for liquefaction were taken from data for the Darwin LNG facility run by Conoco Phillips in Australia (ConocoPhillips, 2005). They report 0.42 kg CO_2/kg LNG output, which is within the range reported by Jaramillo (Adapted from Tamura et al.) of 11-31 lb CO_2/MMBtu (0.24 to 0.67 kg CO_2/kg LNG) (Jaramillo, 2007; Tamura, Tanaka et al., 2001). However, reducing GHG emissions for Stage #1 to the lowest value in the range above only reduces GWP of Stage #1 by approximately 30 kg CO_2e per MWh delivered energy; therefore, Stage #1 would still be the dominant GHG emitter for this case. Of the GHG emissions on a kg CO_2e basis, 51 percent are from Stage #1, 23 percent are from Stage #2, and 24 percent are from Stage #3.

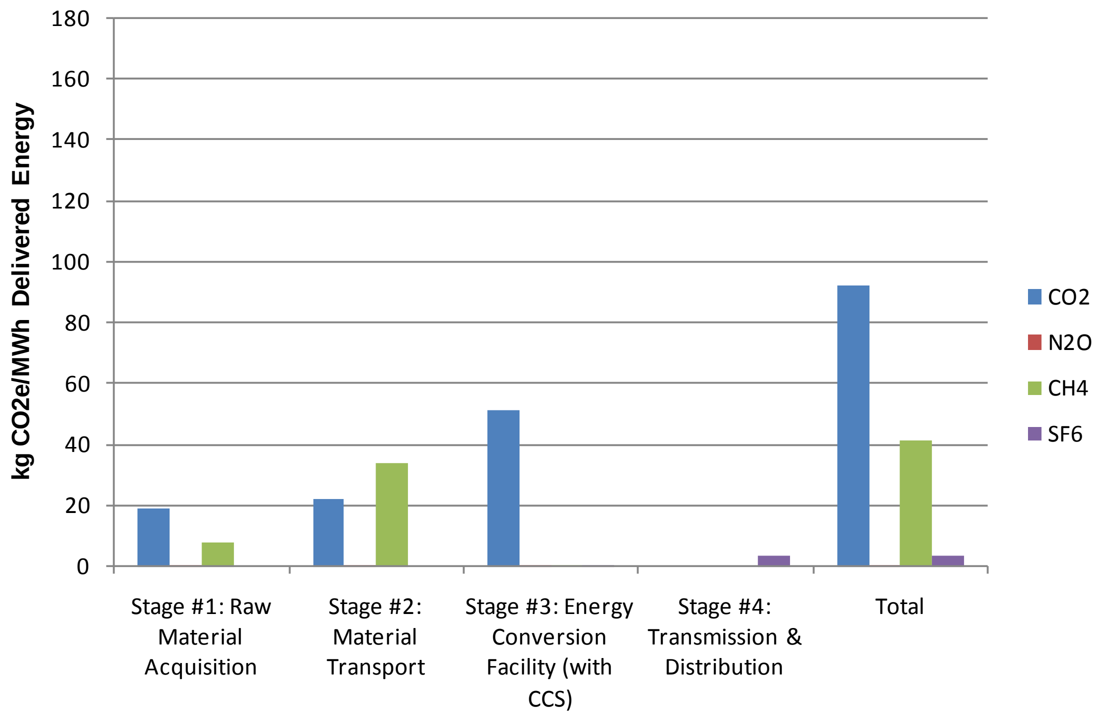

Figure 3-10: Air Emissions for NGCC with CCS using Domestic NG, kg CO_2e /MWh Delivered Energy

3.4.2 Air Emissions

Figure 3-11 compares the air emissions for each stage and the total LC. Like the case without CCS, combustion emissions CO, NO_X, and VOC are dominate, with SO_X and NH_3 from Stage #1 also attributing significantly to the non-GHG emissions.

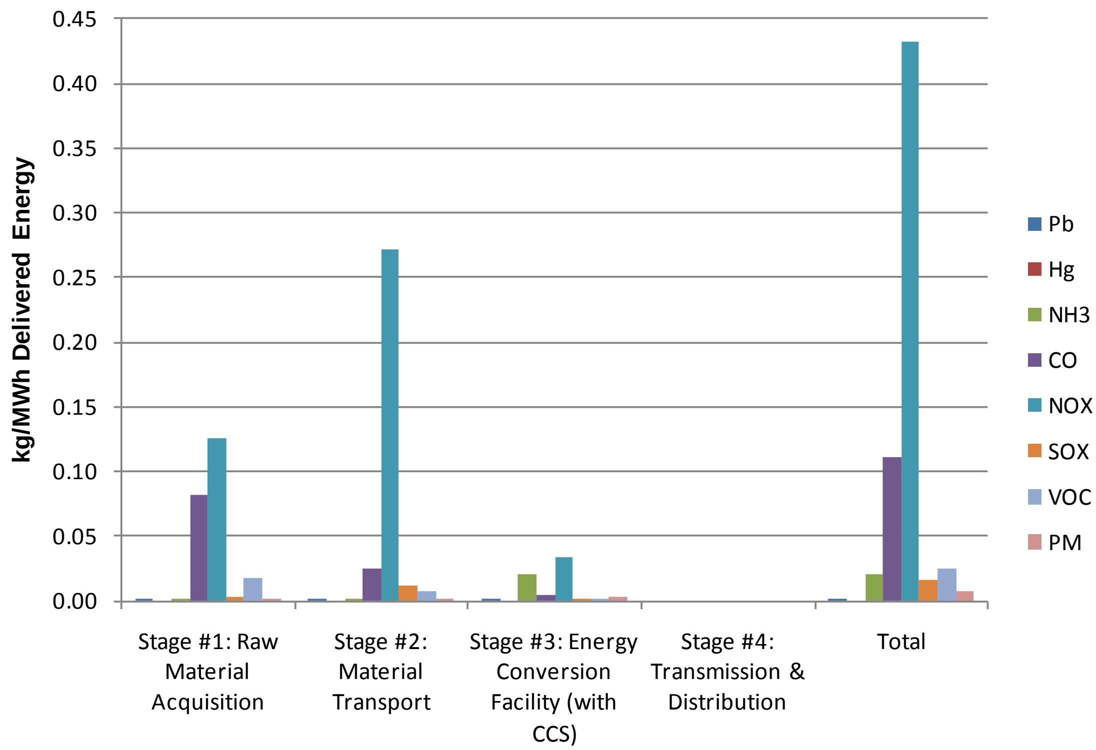

Figure 3-11: Air Emissions for NGCC with CCS using Domestic NG, kg/MWh Delivered Energy

3.4.3 Water Withdrawal and Consumption

Figure 3-12 shows the total water withdrawal and water consumption for each stage and the total LC. As with the case without CCS, water withdrawal and consumption is dominated by energy conversion (Stage #3) due to cooling water requirements in the power plant.

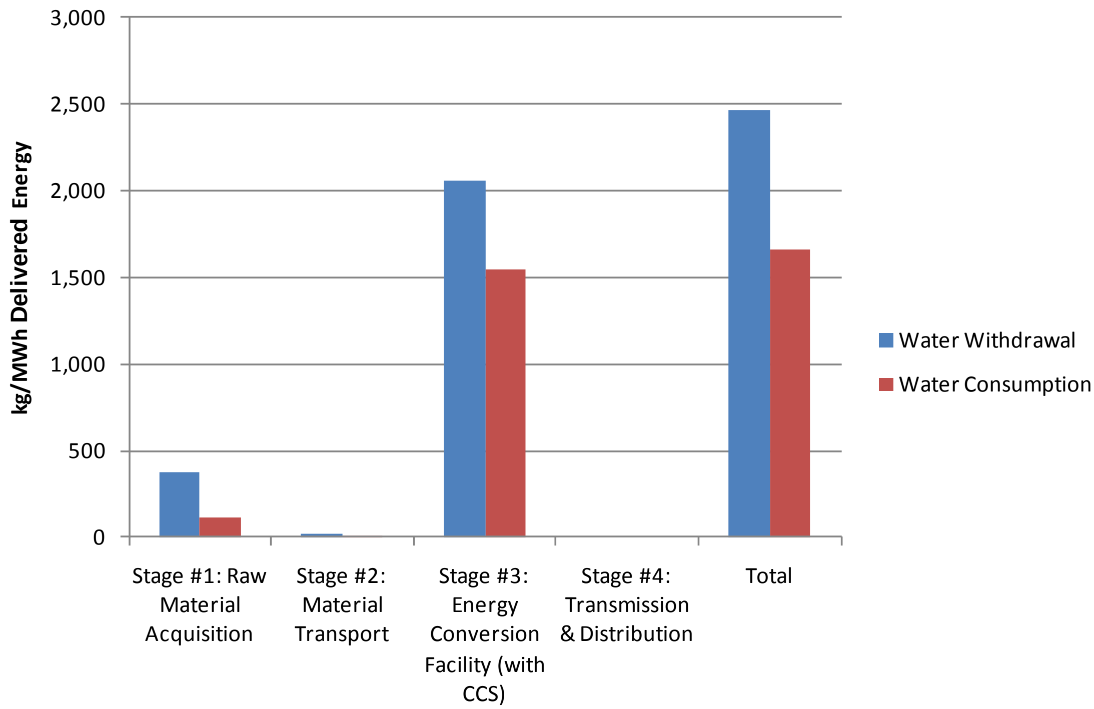

Figure 3-12: Water Withdrawal and Consumption for NGCC with CCS using Domestic NG, kg/MWh Delivered Energy

3.5 Land Use

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 ASTM procedural standards. Additionally, the U.S. Environmental Protection Agency (EPA) released a final version of the Renewable Fuel Standard Program (RFS2; EPA, 2010). Included in RFS2 is a method for assessing land use change and associated GHG emissions that is relevant to this LCA. The land use analysis presented in this study is consistent with the proposed methodology presented in RFS2, and quantifies both the area of land changed, as well as the GHG emissions associated with that change.

3.5.1 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 and deliver the alternative fuels. Primary land use change is determined by tracking the change from an existing land use type (native vegetation, agricultural lands, barren areas) to a new land use that supports production. Examples of facilities that result in land use change include coal mines, biomass feedstock cropping, and refining facilities.

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). Another common example of secondary land use is the large scale displacement of agriculture as a result of biomass crop production: existing farmland is transformed into use for bioenergy production, and the lost farmland is displaced elsewhere, resulting in indirect impacts. Although some farmland would be affected under the present study, the magnitude of these effects would be limited in extent or in time. For instance, pipeline installation may affect a substantial area of agriculture, however, we assume that pipelines would be buried, and after a brief construction period, no farmland would be displaced. The permanent land area conversion required for other facilities is not large enough to warrant analysis of displaced agriculture. Therefore, only primary land use effects are considered within this study, while secondary land use effects are outside the scope of this study.

3.5.2 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 (e.g., area of land transformed from a pre-existing state) and GHG emissions (kg CO_2E). The transformed land area metric estimates the area of land that is altered from a reference state, while the GHG metric quantifies the flux of carbon associated with that change (Fthenakis and Kim 2008), including the loss of carbon due to vegetation removal, the loss of soil carbon, and changes in the sequestration rate for carbon under the transformed land use, as compared to the existing land use. **Table 3-9** summarizes the land use metrics included in this study.

Table 3-9: 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 facilities.	square meters (acres)	Primary
Greenhouse Gas Emissions	Emissions of greenhouse gases due to land transformation, as defined above.	kg CO_2 equivalent (lbs CO_2 equivalent)	Primary

For this study, the assessment of GHG emissions includes those emissions that would result from the following, for each LC Stage as relevant:

- Quantity of GHGs emitted due to biomass clearing during construction of each facility.
- Quantity of GHGs emitted from soil carbon following land transformation, for each facility.

- Comparison of existing state GHG sequestration to transformed state GHG sequestration, including biomass and soil carbon, for each facility.

GHG emissions from diesel fuel combustion during the construction of facilities, for each LC stage, are included in the overall results for this study, and are not accounted for in the land use assessment.

Additional land use 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, 2007), or otherwise outside the scope of this study. Therefore, only transformed land area and GHG emissions are quantified for this study.

3.5.3 Method

As discussed previously, the land use metrics that will be used for this analysis quantify the land area that is transformed from its original state due to production of electricity, including supporting facilities. Calculations are based on a 30-year study period, or as relevant for each facility as discussed in the following text.

3.5.3.1 *Transformed Land Area*

The transformed land area metric was evaluated using assumptions regarding facility size taken from the Baseline Report, as well as satellite imagery and total statewide land use patterns available from the USDA (2005), to assess and quantify original state land use. This was completed for each relevant facility including natural gas extraction areas, pipelines and other natural gas and liquefied natural gas transport facilities, the NGCC plant, CCS pipeline, and other installed facilities, for all LC Stages. The facility sizes and locations used elsewhere in the study were incorporated into the land transformed metric for consistency. Only LC Stages #1-4 include installation of facilities; LC Stage 5 was not considered (**Table 3-10**).

Table 3-10: Facility Locations

LC Stage No.	Facility	Location
Stage #1	Domestic NG Wells and Associated Infrastructure	Continental U.S.
	Cross-Trinidad and Tobago Pipeline	Southern Trinidad and Tobago
	LNG Facility	Southwestern Trinidad and Tobago
Stage #2	Pipelines for Domestic Onshore NG Transport	Continental U.S.

	Regasification Facility	Lake Charles, LA
	NG Pipeline for Domestic and Foreign Offshore	Lake Charles, LA
Stage #3	NGCC	Southern MS
	Trunkline	Southern MS
	CCS Pipeline	Southern MS
Stage #4-5	Not Considered	Not Considered

Removal of on-site, existing land use was assumed to be complete (100 percent removal) for all facilities. **Table 3-11** summarizes the facility sizes that were assumed for this analysis.

Table 3-11: Key Facility Assumptions

Pathway	Facility	Total Area	Units	Key Assumptions
Coal Bed Methane Extraction	**Extraction; Normalized per Well**	1,012 (0.25)	m^2/well (acres/well)	Average among several CBM basins
Barnett Shale NG Extraction	**Extraction; Normalized per Well**	20,234 (5)	m^2/well (acres/well)	Includes hydrofracking land area requirements
Conventional Onshore NG Extraction	**Extraction; Normalized per Well**	10,177 (2.5)	m^2/well (acres/well)	Based on Canadian NG wells
Conventional Onshore Associated Gas	**Extraction; Normalized per Well**	10,177 (2.5)	m^2/well (acres/well)	Based on Canadian NG wells
All Domestic Onshore NG Pathways	**Well Field to NGCC Pipelines**	22,073,762 (5,456)	m^2 (acres)	50 foot construction width, 900 mile length
Foreign NG	**Cross-Trinidad and Tobago Pipeline**	1,471,584 (363)	m^2 (acres)	50 foot construction width, 60 mile length
Foreign NG	**LNG Facility**	1,578,274 (390)	m^2 (acres)	390 acre site, based on Yukon liquefaction site
Foreign NG	**Regasification Facility**	134,760 (33)	m^2 (acres)	33 acre site, based on surrogate data from the Gulf of Mexico

Foreign NG, Domestic Offshore	**Pipeline to NGCC Facility, Landside Only**	613,160 (151)	m^2 (acres)	50 foot construction width, 25 mile length
All	**NGCC**	40,469 (10)	m^2 (acres)	10 acres assumed based on Baseline Report
All	**Trunkline**	14,716 (3.6)	m^2 (acres)	30 foot width, 1 mile length
All	**CCS Pipeline**	2,452,640 (364)	m^2 (acres)	50 foot construction width, 100 mile length

Due to its proximity to the NGCC, original state land use for the CCS pipeline and trunkline were assumed to consist of the same proportion of original state land use as the NGCC. This assumption is reasonable given generally similar original state land use types in the proximity of the site, and assuming that these additional facilities would not be routed through a city or large water feature.

3.5.4 Transformed Land Area Results

3.5.4.1 *Domestic Onshore Natural Gas Extraction Areas: Conventional Onshore, Onshore Associated, Barnett Shale, and Coal Bed Methane*

Precise locations for conventional onshore, onshore associated, Barnett Shale, and coal bed methane natural gas extraction facilities are not identified within this study. Generally speaking, these facilities may occur in various areas within the U.S., based on the availability and distribution of natural gas resources. For instance, conventional onshore and onshore associated natural gas production occurs in all states (EIA, 2010), while Barnett Shale natural gas production is limited to the Permian Basin of Texas. Coal bed methane production potential also exists in specific states, with most existing and potential future available resources located in Montana, Wyoming, New Mexico, Colorado, Oklahoma, and Illinois.

To evaluate the types of land area that would be transformed for natural gas extraction, existing land use was assessed based on state land use data available through the USDA (2005). USDA (2005) includes land use breakdowns for each state in the U.S., into four categories: Cropland, Grassland/Pasture/Rangeland, Forest, and Urban/Special Use/Other. For the purposes of this analysis, we assumed that all facilities would be installed outside of urban and special use areas (special use/other areas, as defined in USDA (2005), include primarily natural preserve and parks areas), and that the Grassland/Pasture/Rangeland category is equivalent to grassland. For each NG pathway, **Table 3-12** shows a breakdown of the proportions of transformed land area that would be converted from cropland, grassland, or forest.

Table 3-12: Existing Land Use Categories for Natural Gas Extraction Areas

Pathway	States	Cropland	Grassland	Forest
Conventional Onshore NG Extraction	National Average (lower 48 states)	27.8%	36.9%	35.3%
Conventional Onshore Associated Gas	National Average (lower 48 states)	27.8%	36.9%	35.3%
Coal Bed Methane Extraction	MT, WY, NM, CO, OK, IL	22.6%	56.8%	20.7%
Barnett Shale NG Extraction	Texas	26.9%	65.3%	7.8%
Domestic and Foreign Offshore	Not Considered (see below)	n/a	n/a	n/a

3.5.4.2 *Domestic and Foreign Offshore Natural Gas Extraction Areas*

Domestic and foreign offshore natural gas extraction would occur at wells located offshore in the ocean. Therefore, offshore natural gas extraction areas would not result in disturbance or alteration to land areas, and no land use change would occur. These areas are not considered further.

3.5.4.3 *Domestic Onshore Natural Gas Transport: Conventional Onshore, Onshore Associated, Barnett Shale, and Coal Bed Methane*

The analysis of existing land use for domestic onshore natural gas pipeline transport areas is similar to the analysis for domestic onshore natural gas extraction areas. Existing land use types were evaluated based on the likely location of a pipeline that would connect each category of natural gas resource type to the NGCC facility, which is assumed to be located in southern Mississippi. The states most likely to be intersected by such a pipeline were evaluated, based on USDA (2005) data, as discussed previously. Table 3-13 shows the proportions of each existing land use category that is expected to occur for each natural gas pathway.

Table 3-13: Existing Land Use Categories for Natural Gas Pipeline Transport

Pathway	States	Cropland	Grassland	Forest
Conventional Onshore NG, Pipeline Transport	National Average (lower 48 states)	27.8%	36.9%	35.3%
Conventional Onshore Associated Gas, Pipeline Transport	National Average (lower 48 states)	27.8%	36.9%	35.3%

Coal Bed Methane, Pipeline Transport	WY, NE, KS, OK, AK, MS	36.0%	42.8%	21.2%
Barnett Shale NG, Pipeline Transport	TX, LA, MS	26.2%	51.6%	22.2%
Domestic and Foreign Offshore, Pipeline Transport	Assessed Separately (see below)	n/a	n/a	n/a

3.5.4.4 *Foreign Offshore Natural Gas Extraction: LNG Facility, Cross Trinidad and Tobago Pipeline*

Results from the analysis of land use at the LNG facility site indicated 2 primary land use categories: tropical forest and tropical grassland. As shown in **Figure 3-13**, tropical forest accounts for most of the total area (76% of total area), followed by tropical grassland (24% of total area). Minor areas containing other land uses, such as roads or minor drainages, were allocated to one of these two categories. Due to its proximity to the LNG facility site, the proportion of each existing land use category (e.g. proportion of tropical forest:tropical grassland) for the LNG facility site was also applied to the landside portion of the pipeline connecting the NG rig to the LNG facility.

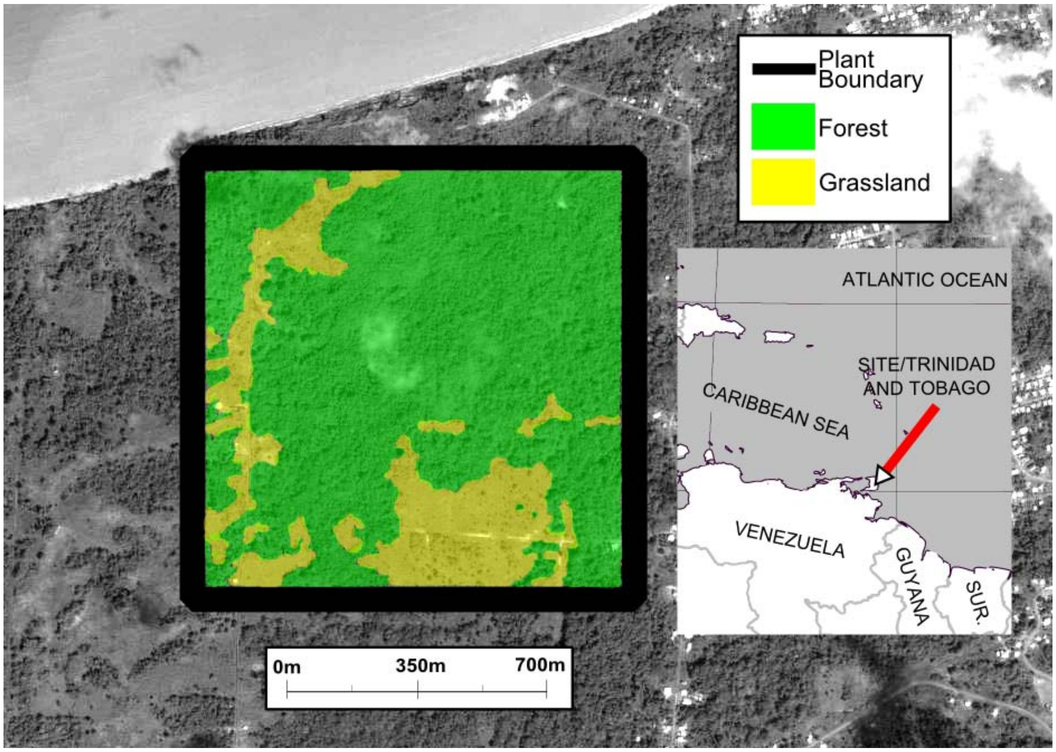

Figure 3-13: Existing Condition Land Use Assessment: LNG Facility Site

3.5.4.5 *Regasification Facility*

Results from the analysis of land use at the regasification facility site indicated only one land use category, agriculture, which accounted for 100% of the area of the regasification facility, as shown in **Figure 3-14**. Small areas containing other land uses, such as roads and minor drainages, were allocated to this category, as relevant.

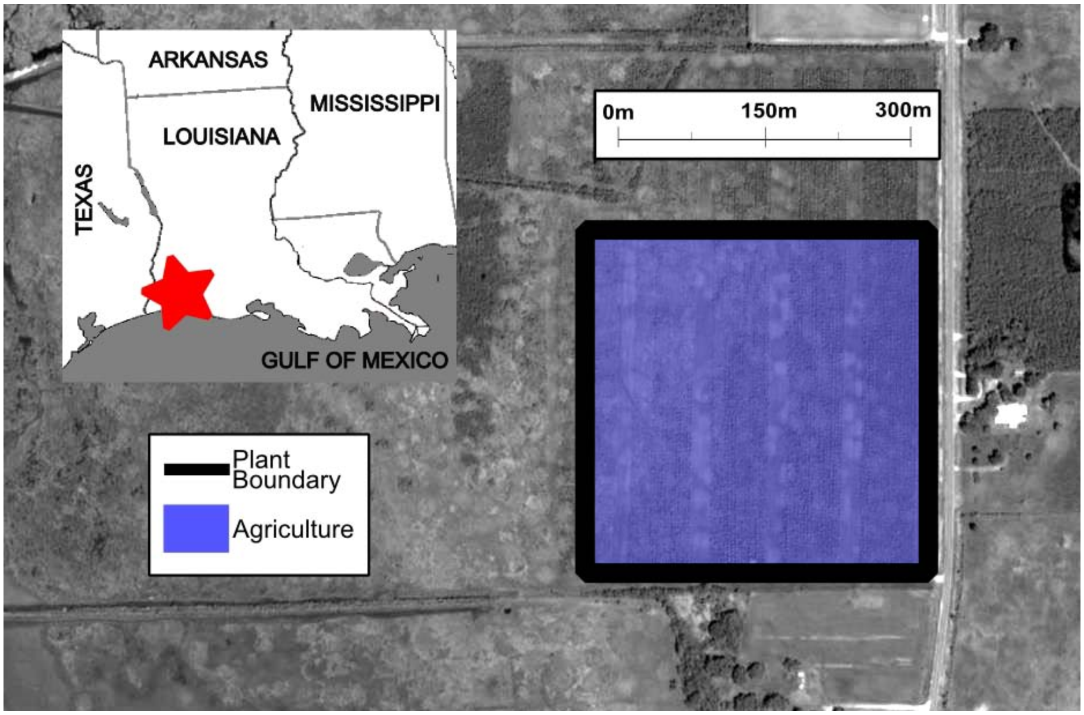

Figure 3-14: Existing Condition Land Use Assessment: Regasification Facility Site

3.5.4.6 *NGCC, Short Pipeline to NGCC (Offshore Profiles Only), CCS Pipeline, Trunkline*

Results from the analysis of land use at the NGCC site indicated 2 primary land use categories: forest and grassland. As shown in **Figure 3-15**, forest accounts for most of the total area (61% of total area), followed by grassland (39% of total area). Small areas containing other land uses, such as roads or small drainages, were allocated to one of these two categories, as relevant. Due to proximity to the NGCC site, the proportion of each existing land use category (e.g. proportion of forest:grassland) for the NGCC site was also applied to the short pipeline to the NGCC (offshore profiles only), the trunkline and CCS pipeline.

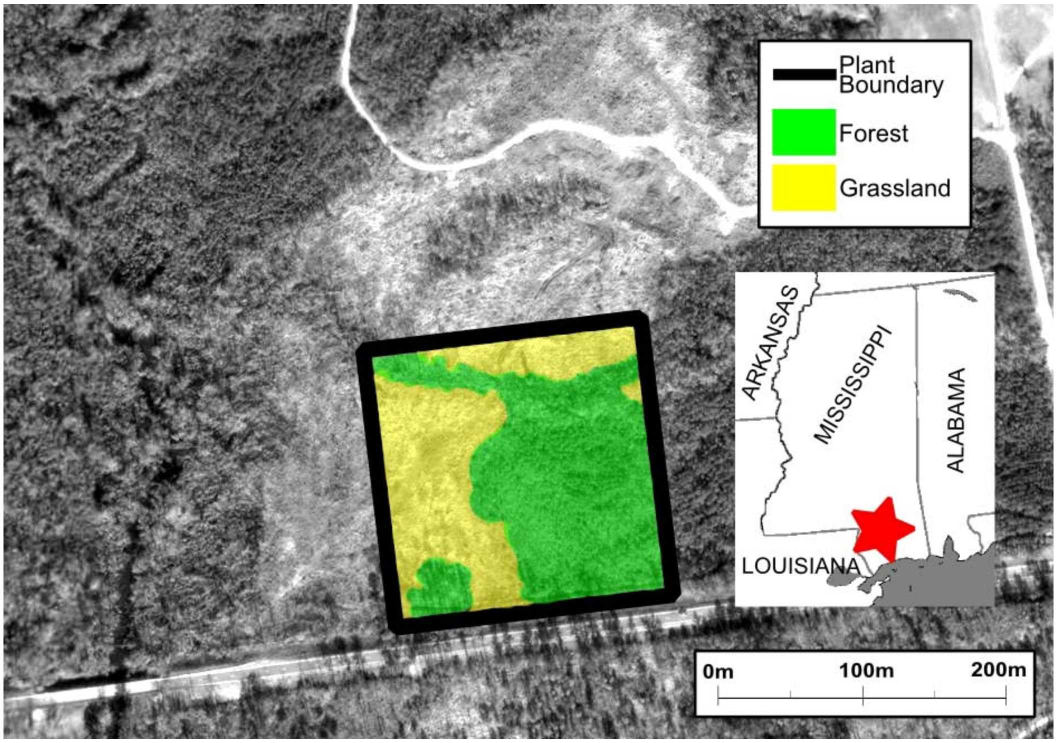

Figure 3-15: Existing Condition Land Use Assessment: NGCC Site

The total transformed land area for all LC Stages combined, on a square meters per MWh delivered basis, is shown in **Figure 3-16**. As shown, total transformed land area for domestic natural gas extraction is approximately double that for foreign extraction. This occurs because the domestic natural gas extraction profile includes primarily onshore extraction and onshore pipeline transport, while the foreign natural gas profile includes only offshore extraction and primarily tanker transport. For domestic extraction, most of the land use change (a total of and 0.198 m^2/MWh without CCS and 0.22 m^2/MWh with CCS) occurs as a result of the transport pipelines, which are 900 miles long. For the foreign profile, total transformed land area is distributed more evenly among facilities. A total of 0.048 m^2/MWh results from the regasification facility, 0.014 m^2/MWh from the LNG facility in Trinidad and Tobago, 0.013 m^2/MWh from the onshore portion of the pipeline across Trinidad and Tobago, while the remaining facilities total 0.0058 m^2/MWh of land use change.

Land use change for the with-CCS cases is also substantially higher than the without-CCS cases. Both the with and without-CCS cases are assumed to require the same amount of natural gas, over the course of the study period. However, the with-CCS cases have reduced generation capacity, as compared to the without-CCS cases, and it is this disparity that is responsible for the difference between the with and without-CCS cases, on a per MWh delivered basis.

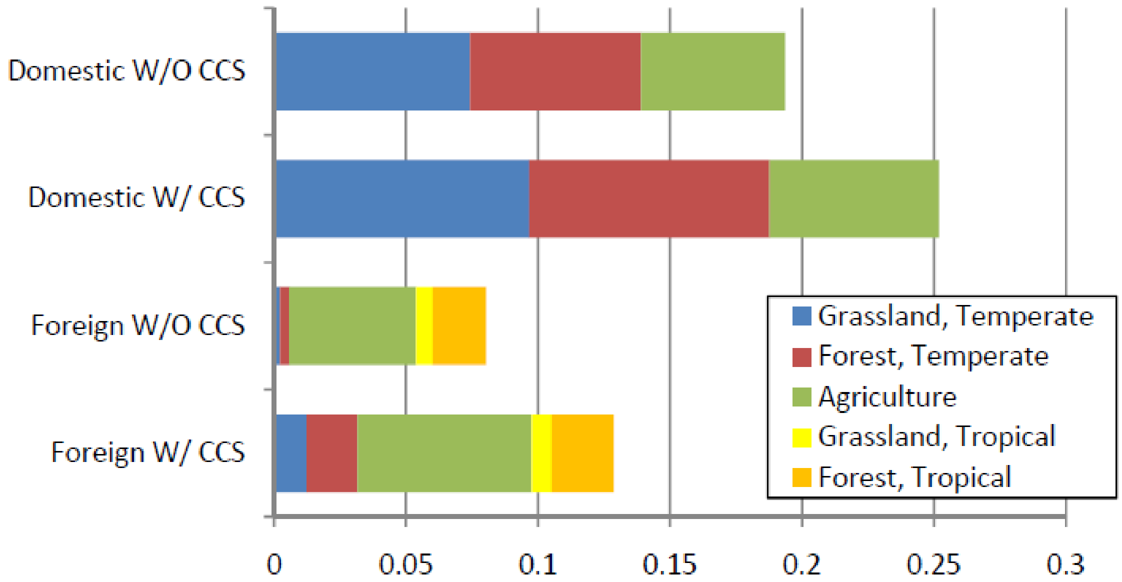

Figure 3-16: Total Transformed Land Area (m^2/MWh)

Table 3-14 through **Table 3-17** provide additional detail regarding how each of the facilities would cause land transformation, for domestic and foreign natural gas profiles, with and without CCS. These tables show transformed land area on the basis of the reference flow for each LC stage. LC Stages #4 and #5 are not shown, because no new facilities would be installed under these two stages, therefore, these two LC stages do not cause land transformation.

The tables below allow comparison among domestic and foreign natural gas supply pathways, with and without CCS. The NGCC plant would use the same amount of natural gas for the with-CCS cases as for the without-CCS cases. As a result, comparing **Table 3-14** and **Table 3-15**, the transformed land area per reference flow for all facilities in LC Stages #1 and 2 would be the same between the without and with CCS cases. Transformed land area Stage #3 facilities, which have reference flows that depend on power output from the NGCC, are consequently higher for the with CCS case, relative to the without CCS case. Similar trends are shown for the foreign natural gas profiles.

Table 3-14: Total Transformed Land Area: Domestic Natural Gas Supply Without CCS Case

Category		LC Stage #1: Well Extraction	LC Stage #2: Pipeline Transport	LC Stage #3: NGCC	LC Stage #3: Trunkline
Units per Reference Flow		m^2/kg NG extracted	m^2/kg NG transported	m^2/MWh	m^2/MWh
Land Use Category	Grassland, Tropical	n/a	n/a	n/a	n/a
	Forest,	n/a	n/a	n/a	n/a

	Tropical				
	Grassland, Temperate	1.13×10^{-5}	4.92×10^{-4}	1.27×10^{-4}	4.98×10^{-5}
	Forest, Temperate	8.73×10^{-6}	4.28×10^{-4}	1.99×10^{-4}	7.79×10^{-5}
	Agriculture	7.68×10^{-6}	3.64×10^{-4}	n/a	n/a
Total Transformed Land Area		**2.77×10^{-5}**	**1.28×10^{-3}**	**3.27×10^{-4}**	**1.28×10^{-4}**

Table 3-15: Total Transformed Land Area: Domestic Natural Gas Supply With CCS Case

Category		LC Stage #1: Well Extraction	LC Stage #2: Pipeline Transport	LC Stage #3: NGCC	LC Stage #3: CCS Pipeline	LC Stage #3: Trunkline
Units per Reference Flow		$m^{2/}$kg NG extracted	m^2/kg NG transported	m^2/MWh	m^2/MWh	m^2/MWh
Land Use Category	Grassland, Tropical	n/a	n/a	n/a	n/a	n/a
	Forest, Tropical	n/a	n/a	n/a	n/a	n/a
	Grassland, Temperate	1.13×10^{-5}	4.92×10^{-4}	1.49×10^{-4}	9.05×10^{-3}	5.84×10^{-5}
	Forest, Temperate	8.73×10^{-6}	4.28×10^{-4}	2.34×10^{-4}	1.42×10^{-2}	9.13×10^{-5}
	Agriculture	7.68×10^{-6}	3.64×10^{-4}	n/a	n/a	n/a
Total Transformed Land Area		**2.77×10^{-5}**	**1.28×10^{-3}**	**3.83×10^{-4}**	**2.32×10^{-2}**	**1.50×10^{-4}**

Table 3-16: Total Transformed Land Area: Foreign Natural Gas Supply Without CCS Case

Category		LC Stage #1: Pipeline	LC Stage #1: LNG Facility	LC Stage #2: Regasificatio n Facility	LC Stage #2: NG Spur Pipeline	LC Stage #3: NGCC	LC Stage #3: Trunkline
Units per Reference Flow		$m^{2/}$kg NG extracted	$m^{2/}$kg NG extracted	$m^{2/}$kg NG transported	m^2/kg NG transported	m^2/MWh	m^2/MWh
Land Use Category	Grassland, Tropical	2.08×10^{-5}	2.23×10^{-5}	n/a	n/a	n/a	n/a
	Forest,	6.58×10^{-5}	7.05×10^{-5}	n/a	n/a	n/a	n/a

	Tropical						
	Grassland, Temperate	n/a	n/a	n/a	n/a	n/a	n/a
	Forest, Temperate	n/a	n/a	n/a	1.41×10^{-5}	1.27×10^{-4}	4.98×10^{-5}
	Agriculture	n/a	n/a	3.26×10^{-4}	2.20×10^{-5}	1.99×10^{-4}	7.78×10^{-5}
Total Transformed Land Area		**8.65×10^{-5}**	**9.28×10^{-5}**	**3.26×10^{-4}**	**3.60×10^{-5}**	**3.26×10^{-4}**	**1.28×10^{-4}**

Table 3-17: Total Transformed Land Area: Foreign Natural Gas Supply With CCS Case

Category		**LC Stage #1: Pipeline**	**LC Stage #1: LNG Facility**	**LC Stage #2: Regasification Facility**	**LC Stage #2: NG Spur Pipeline**	**LC Stage #3: NGCC**	**LC Stage #3: CCS Pipeline**	**LC Stage #3: Trunkline**
Units per Reference Flow		m^2/kg NG extracted	m^2/kg NG extracted	m^2/kg NG transported	m^2/kg NG transported	m^2/MWh	m^2/MWh	m^2/MWh
Land Use Category	**Grassland, Tropical**	2.08×10^{-5}	2.23×10^{-5}	n/a	n/a	n/a	n/a	n/a
	Forest, Tropical	6.58×10^{-5}	7.05×10^{-5}	n/a	n/a	n/a	n/a	n/a
	Grassland, Temperate	n/a	n/a	n/a	n/a	n/a	n/a	n/a
	Forest, Temperate	n/a	n/a	n/a	1.27×10^{-5}	1.49×10^{-4}	9.04×10^{-3}	5.88×10^{-5}
	Agriculture	n/a	n/a	3.26×10^{-4}	1.99×10^{-5}	2.33×10^{-4}	1.41×10^{-2}	9.12×10^{-5}
Total Transformed Land Area		**8.65×10^{-5}**	**9.28×10^{-5}**	**3.26×10^{-4}**	**3.26×10^{-5}**	**3.83×10^{-4}**	**2.32×10^{-2}**	**1.50×10^{-4}**

3.5.5 Land Use GHG Emissions Results

The total land use GHG emissions for all LC Stages combined, on a kg per MWh delivered basis, are shown in **Figure 3-17**. As shown, GHG emissions for the domestic natural gas extraction pathway are approximately the same as for foreign extraction. Note that the gross land required for the domestic extraction pathway is approximately double that of the foreign case (see previous discussion). The surprisingly similar results are caused primarily by differences in the vegetation types that would be disturbed under the domestic versus foreign pathways. Although the domestic pathway would disturb significantly more land area, the domestic pathway would also result in substantially more carbon uptake, as compared to the foreign pathway. Sequestration occurs because the analysis assumes that pipeline installation would not result in permanent land use change. To the contrary, it is assumed that pipelines would be installed underground, resulting in removal of surface vegetation and initial upset of soils. However, after two years, it is assumed that the initial land use would return to the disturbed area, and would resume carbon sequestration into biomass and soil organic matter. These areas would continue to sequester carbon for the remainder of the study period (28 years), according to country, state, and vegetation-specific carbon sequestration rates as documented for RFS2.

Similar to transformed land area, land use GHG emissions for the with-CCS cases are substantially higher than the without-CCS cases. Both the with- and without-CCS cases are assumed to require the same amount of natural gas, over the course of the study period. However, the with-CCS cases have reduced generation capacity, as compared to the without-CCS cases, and it is this disparity that is responsible for the difference between the with and without-CCS cases, on a per MWh delivered basis. Installation of the CO_2 pipeline under the with-CCS case also contributes substantially to land use GHG emissions for the with-CCS cases. More precisely, destruction of a substantial amount of existing forest during CCS pipeline installation would not be fully offset by carbon uptake during the remainder of the study period. Therefore, GHG emissions associated with temperate forest loss under the domestic and foreign with-CCS cases contribute substantially to total land use GHG emissions.

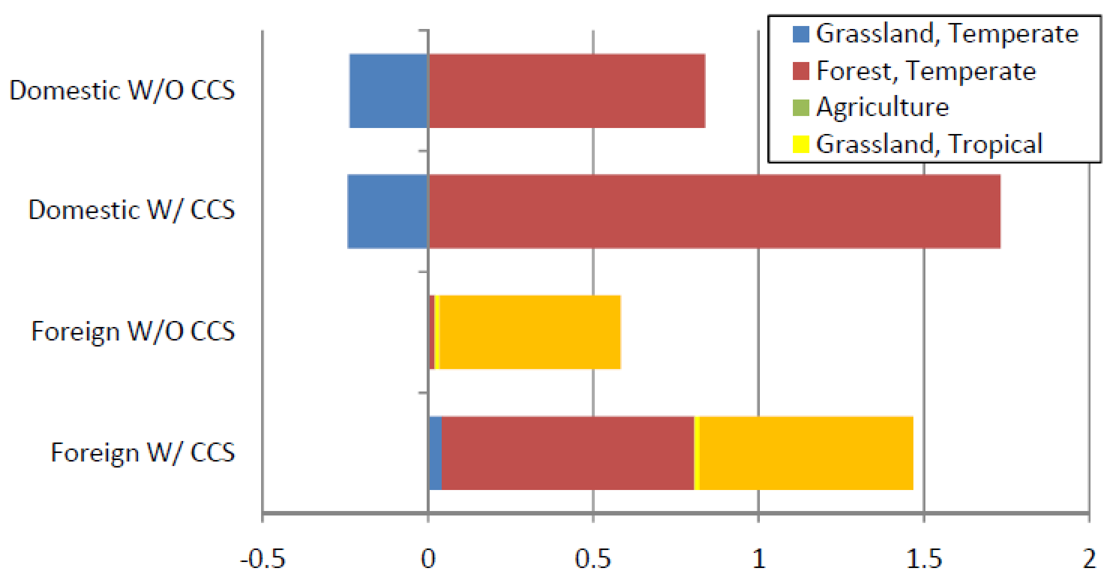

Figure 3-17: Total Land Use GHG Emissions (kg CO_2E/MWh)

Table 3-22 through **Table 3-21** provide additional detail regarding how each of the facilities would cause land use related GHG emissions, for domestic and foreign natural gas profiles, with and without CCS. These tables show land use GHG emissions on the basis of the reference flow for each LC stage. LC Stages #4 and #5 are not shown, because no new facilities would be installed under these two stages, therefore, these two LC stages do not cause land use related GHG emissions.

The tables below allow comparison among domestic and foreign natural gas supply pathways, with and without CCS. The NGCC plant would use the same amount of natural gas for the with-CCS cases as for the without-CCS cases. As a result, comparing **Table 3-18** and **Table 3-19**, the land use GHG emissions per reference flow for all facilities in LC Stages #1 and 2 would be the same between the without and with CCS cases. GHG emissions for Stage #3 facilities, which have reference flows that depend on power output from the NGCC, are consequently higher for the with CCS case, relative to the without CCS case. Similar trends are shown for the foreign natural gas profiles.

Table 3-18: Total Land Use GHG Emissions: Domestic Natural Gas Supply Without CCS Case

Category		LC Stage #1: Well Extraction	LC Stage #2: Pipeline Transport	LC Stage #3: NGCC	LC Stage #3: Trunkline
Units per Reference Flow		kg CO_2E/kg NG extracted	kg CO_2E /kg NG transported	kg CO_2E /MWh	kg CO_2E /MWh
Land Use Category	Grassland, Tropical	n/a	n/a	n/a	n/a
	Forest, Tropical	n/a	n/a	n/a	n/a
	Grassland, Temperate	4.21×10^{-5}	-1.66×10^{-3}	4.54×10^{-4}	1.78×10^{-4}
	Forest, Temperate	3.93×10^{-4}	5.18×10^{-3}	9.80×10^{-3}	3.83×10^{-3}
	Agriculture	0.00	0.00	n/a	n/a
Total Transformed Land Area		**4.35×10^{-4}**	**3.52×10^{-3}**	**1.03×10^{-2}**	**4.01×10^{-3}**

Table 3-19: Total Land Use GHG Emissions: Domestic Natural Gas Supply With CCS Case

Category	LC Stage #1: Well Extraction	LC Stage #2: Pipeline Transport	LC Stage #3: NGCC	LC Stage #3: CCS Pipeline	LC Stage #3: Trunkline
Units per Reference Flow	kg CO_2E /kg NG extracted	kg CO_2E /kg NG transported	kg CO_2E /MWh	kg CO_2E /MWh	kg CO_2E /MWh

Land Use Category	**Grassland, Tropical**	n/a	n/a	n/a	n/a	n/a
	Forest, Tropical	n/a	n/a	n/a	n/a	n/a
	Grassland, Temperate	4.21×10^{-5}	-1.66×10^{-3}	5.32×10^{-4}	3.23×10^{-2}	2.08×10^{-4}
	Forest, Temperate	3.93×10^{-4}	3.52×10^{-3}	1.15×10^{-2}	$6. \times 10^{-1}$	4.49×10^{-3}
	Agriculture	0.00	0.00	n/a	n/a	n/a
Total Transformed Land Area		**4.35×10^{-4}**	**3.52×10^{-3}**	**1.20×10^{-2}**	**7.28×10^{-1}**	**4.70×10^{-3}**

Table 3-20: Total Land Use GHG Emissions: Foreign Natural Gas Supply Without CCS Case

Category		LC Stage #1: Pipeline	LC Stage #1: LNG Facility	LC Stage #2: Regasification Facility	LC Stage #2: NG Spur Pipeline	LC Stage #3: NGCC	LC Stage #3: Trunkline
Units per Reference Flow		kg CO_2E/kg NG extracted	kg CO_2E/kg NG extracted	kg CO_2E/kg NG transported	kg CO_2E /kg NG transported	kg CO_2E /MWh	kg CO_2E /MWh
Land Use Category	**Grassland, Tropical**	-2.10×10^{-4}	2.98×10^{-4}	n/a	n/a	n/a	n/a
	Forest, Tropical	-6.04×10^{-4}	4.34×10^{-3}	n/a	n/a	n/a	n/a
	Grassland, Temperate	n/a	n/a	n/a	3.62×10^{-5}	4.54×10^{-4}	1.77×10^{-4}
	Forest, Temperate	n/a	n/a	n/a	9.53×10^{-7}	9.79×10^{-3}	3.83×10^{-3}
	Agriculture	n/a	n/a	0.00	n/a	n/a	n/a
Total Transformed Land Area		**-8.15×10^{-4}**	**4.64×10^{-3}**	**0.00**	**3.72×10^{-5}**	**1.02×10^{-2}**	**4.01×10^{-3}**

Table 3-21: Total Transformed Land Area: Foreign Natural Gas Supply With CCS Case

Category	LC Stage #1: Pipeline	LC Stage #1: LNG Facility	LC Stage #2: Regasification Facility	LC Stage #2: NG Spur Pipeline	LC Stage #3: NGCC	LC Stage #3: CCS Pipeline	LC Stage #3: Trunkline
Units per	kg CO_2E/kg NG	kg CO_2E/kg NG	kg CO_2E/kg NG	kg CO_2E /kg NG	kg CO_2E	kg CO_2E	kg CO_2E

	Reference Flow	extracted	extracted	transported	transported	/MWh	/MWh	/MWh
Land Use Category	Grassland, Tropical	-2.10×10^{-4}	2.98×10^{-4}	n/a	n/a	n/a	n/a	n/a
	Forest, Tropical	-6.04×10^{-4}	4.34×10^{-3}	n/a	n/a	n/a	n/a	n/a
	Grassland, Temperate	n/a	n/a	n/a	3.62×10^{-5}	5.32×10^{-4}	3.22×10^{-2}	2.08×10^{-4}
	Forest, Temperate	n/a	n/a	n/a	9.53×10^{-7}	1.15×10^{-2}	6.95×10^{-1}	4.49×10^{-3}
	Agriculture	n/a	n/a	0.00	n/a	n/a	n/a	n/a
Total Transformed Land Area		**8.15×10^{-4}**	**4.64×10^{-3}**	**0.00**	**3.72×10^{-5}**	**1.20×10^{-2}**	**7.28×10^{-1}**	**4.69×10^{-3}**

3.6 Comparative Results

This section compares the cost and environmental results for four scenarios (two NGCC cases combined with two natural gas supply cases).

3.6.1 Comparative LCC Results

Comparatively, the two NGCC cases are similar in that more than half of the total LCC is contributed by the utility costs. When the LCOE results of the two NGCC cases are compared, the case with CCS is approximately 42 percent more than the case without CCS. A summary of the LCOE by cost component for each case is given in **Table 3-22**, and represented graphically in **Figure 3-18.**

Table 3-22: Comparison of the LCOE Results for the NGCC Cases without and with CCS

LCOE ($/kWh)	NGCC wo-CCS	NGCC w-CCS	Change
Utility Costs (Feedstock + Utilities)	$0.0686	$0.0792	15%
Labor Costs	$0.0046	$0.0086	88%
Variable O&M Costs	$0.0020	$0.0039	91%
Capital Costs	$0.0175	$0.0363	108%
CO_2 TS&M Costs		$0.0039	
Total LCOE	**$0.0927**	**$0.1319**	**42%**

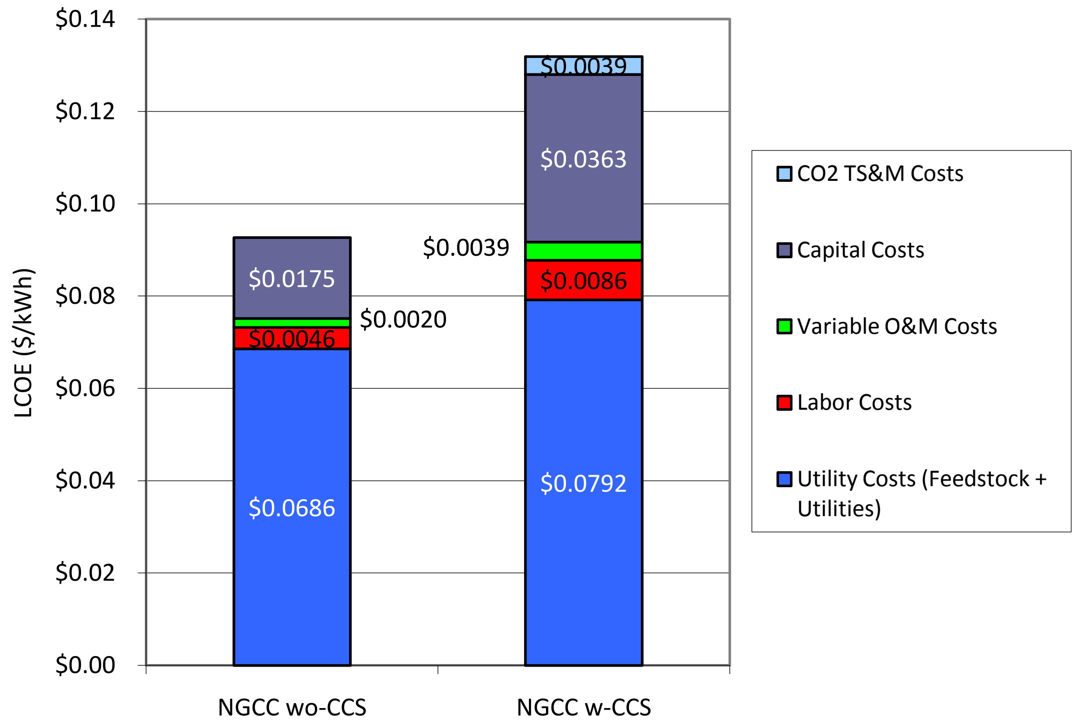

Figure 3-18: Comparative LCOE ($/kWh) for NGCC with and without CCS

3.6.1.1 *Comparative GHG Results*

Figure 3-19 compares the GHG emissions (kg CO_2e/MWh delivered) for the four cases of this analysis, which are based on two natural gas supply scenarios (imported natural gas via the LNG route and domestic natural gas) and two NGCC scenarios (with and without CCS).

For the imported and domestic cases *without* CCS, the total LC GHG emissions are 524 and 467 kg CO_2e/MWh, respectively. For the imported and domestic cases *with* CCS, the total LC GHG emissions are 204 and 137 kg CO_2e/MWh, respectively. The use of CCS at the NGCC plant results in a 61 percent reduction in total LC GHG emissions for the imported natural gas pathway and a 71 percent reduction for the domestic natural gas pathway. CCS results in significant GHG reductions at the NGCC plant, but it also reduces the overall efficiency of the NGCC plant. Based on equal amounts of natural gas combustion, an NGCC plant with CCS produces only 86 percent of the electricity produced by an NGCC plant without CCS. Since this analysis uses a functional unit of the delivery of one MWh of electricity, the efficiency loss caused by the CCS system in Stage #3 translates to higher burdens for upstream processes (Stage #1 and Stage #2).

The capture of CO_2 at the NGCC plant (Stage #3) accounts for the majority of LC GHG reductions. However, there are other LC activities that contribute significantly to total LC GHG emissions. In particular, the combustion of natural gas during the liquefaction of natural gas accounts for 76% of the GHG emissions within Stage #1 of imported natural gas. Since liquefaction is not required for the domestic natural gas scenarios, based on a the functional unit of 1 MWh of delivered electricity, the Stage #1 GHG emissions for imported natural gas are 3.9 times higher than the Stage #1 GHG emissions for domestic natural gas.

Pipeline methane emissions are another significant source of GHG emissions. For the scenarios without CCS, methane emissions from pipeline transport (Stage #2) account for 3.6 to 6.2 percent of total life cycle CO_2e emissions. For the scenarios with CCS, methane emissions from pipeline transport (Stage #2) account for 11 to 25 percent of total life cycle CO_2e emissions. The domestic natural gas pathways represent the high boundary of these ranges because they have a longer pipeline transportation distance than the imported natural gas pathways. More details on the sensitivity between pipeline distance and methane emissions are provided in **Section 3.7.2**.

Based on the scope and boundaries of this analysis, sulfur hexafluoride emissions are not a large contributor to total GHG emissions. SF_6 emissions account for less than one percent of LC GHG emissions for cases without CCS and less than 1.6 percent of LC GHG emissions for cases with CCS. Therefore, even when multiplied by its relatively large GWP (22,800 CO_2e) (IPCC, 2007), SF_6 emissions are overshadowed by other LC GHG emissions. The insignificant contribution of SF6 emissions to the total LC GHG emissions is illustrated by the short bars shown in Stage #4 (electricity transmission and distribution) **Figure 3-19**.

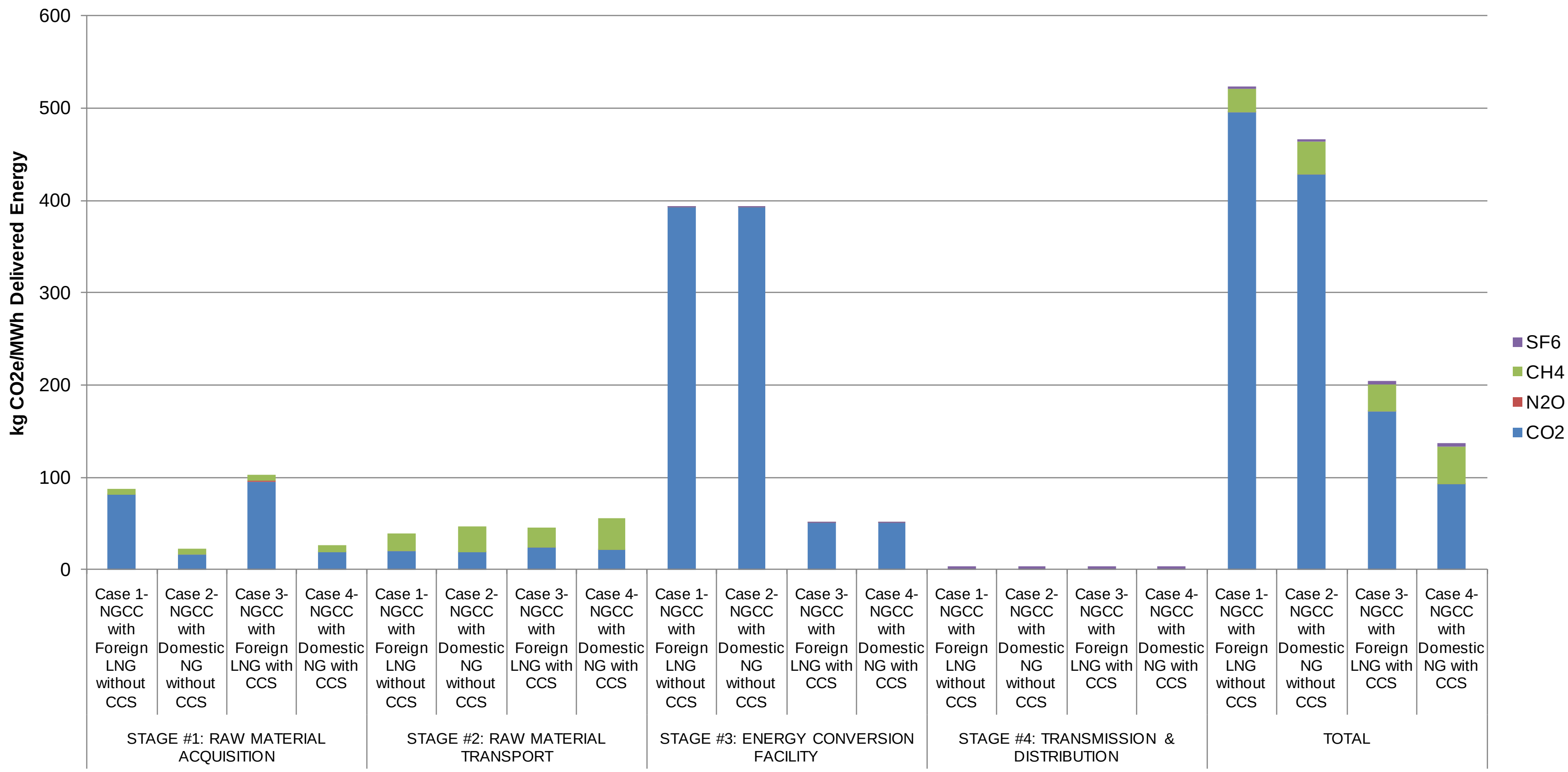

Figure 3-19: Comparative GHG Emissions (kg CO_2e/MWh Delivered) for NGCC with and without CCS

3.6.1.2 *Comparative Air Pollutant Emissions*

Figure 3-20 and **Figure 3-21** compare the non-GHG air pollutants on a kg/MWh delivered energy basis. These figures allow a comparison of imported vs. domestic natural gas as well as a comparison of cases without CCS and cases with CCS.

Non-GHG emissions are dominated by CO and NO_x, which arise from the combustion of fuels (natural gas, diesel, and heavy fuel oil) by the primary activities throughout LC Stages #1, #2, and #3 as well as by secondary fuel and material production activities. SO_x emissions arise from the combustion of diesel and heavy fuel oil in LC Stages #1 and #2, as well as from the secondary production of electricity used by the pipeline operations of Stage #2. NH_3 emissions result from liquefaction (Stage #1 for imported natural gas) and NGCC plant operations. Lead and Hg emissions do not represent a significant contribution to the LC emissions of any of the scenarios of this analysis and are highly concentrated in construction activities.

A comparison of **Figure 3-20** and **Figure 3-21** demonstrates that the addition of CCS does not result in a significant change to the non-GHG emissions. The slightly higher non-GHG emissions from the CCS cases are due to the normalization of the LC results to the functional unit of one MWh of delivered electricity (due to the decreased NGCC efficiency caused by the CCS system, more natural gas is combusted by the CCS cases than the cases that do not have CCS).

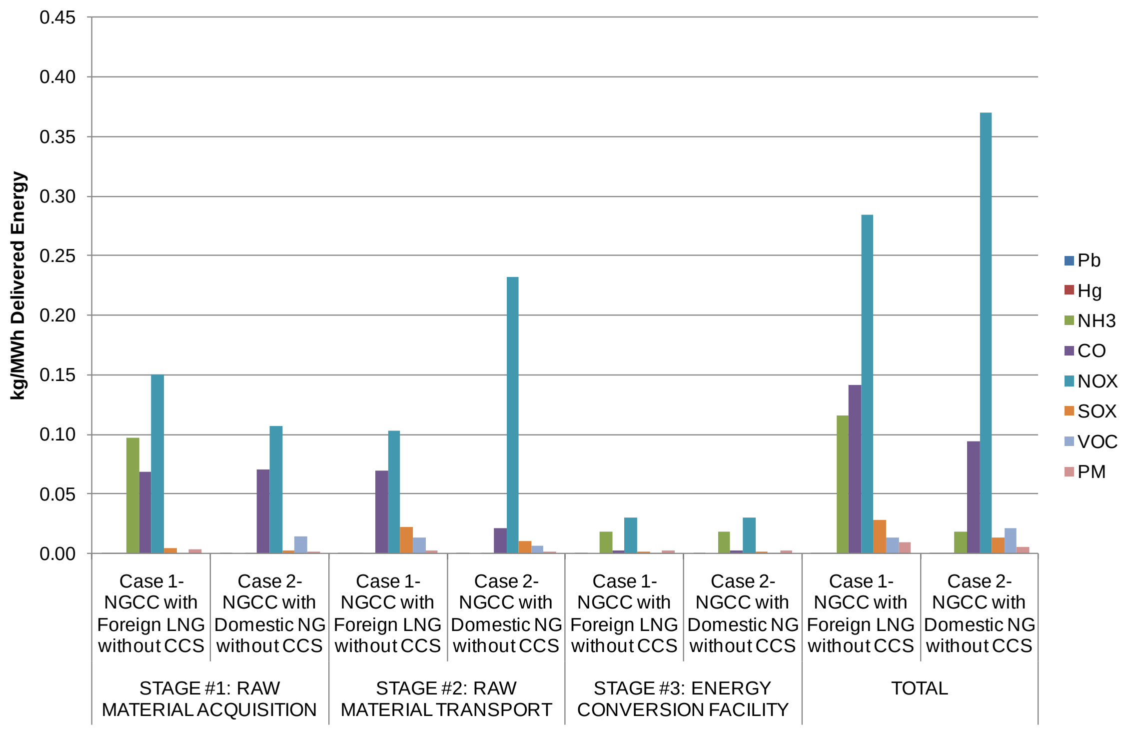

Figure 3-20: Comparison of Air Emissions (kg/MWh Delivered Energy) for NGCC without CCS

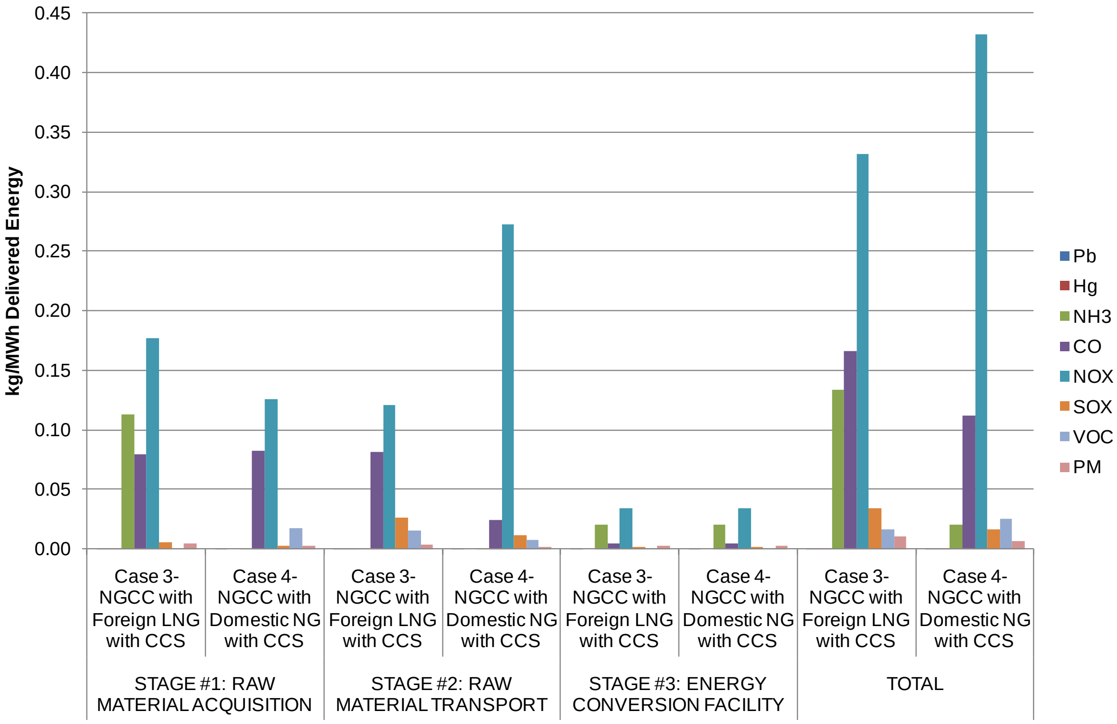

Figure 3-21: Comparison of Air Emissions (kg/MWh Delivered Energy) for NGCC with CCS

3.6.1.3 *Comparative Water Withdrawal and Consumption*

The LC results for water withdrawal and consumption are shown in **Figure 3-22**. The LC water consumed by the cases with CCS are approximately 1.8 times higher than the LC water consumed by the cases without CCS. This difference is due to the water requirements of the CCS system. The Econamine FG Plus process requires cooling water to reduce the flue gas temperature from 57°C to 32°C, cool the solvent (the reaction between CO_2 and the amine solvent is exothermic), remove the heat input from the additional auxiliary loads, and remove the heat in the CO_2 compressor intercoolers (NETL, 2010; Reddy, Johnson et al., 2008). The NGCC case without CCS consumed 80 percent of water input while the case with CCS consumed 79 percent.

The extraction of natural gas (Stage #1) also results in significant water withdrawal and consumption. On the basis of one MWh of delivered electricity, the water consumed during the extraction of natural gas is approximately four times higher for domestic natural gas than for imported natural gas. This analysis assumes that imported natural gas is extracted solely from offshore extraction operations, while domestic natural gas is a mix of extraction sites with offshore extraction representing only 1.2 percent of domestic natural gas extraction. The data used by this analysis indicate that offshore extraction processes consume less water than onshore extraction processes, which partly due to the ability of offshore platforms to extract water from the natural gas reservoir and re-inject used water back into the reservoir.

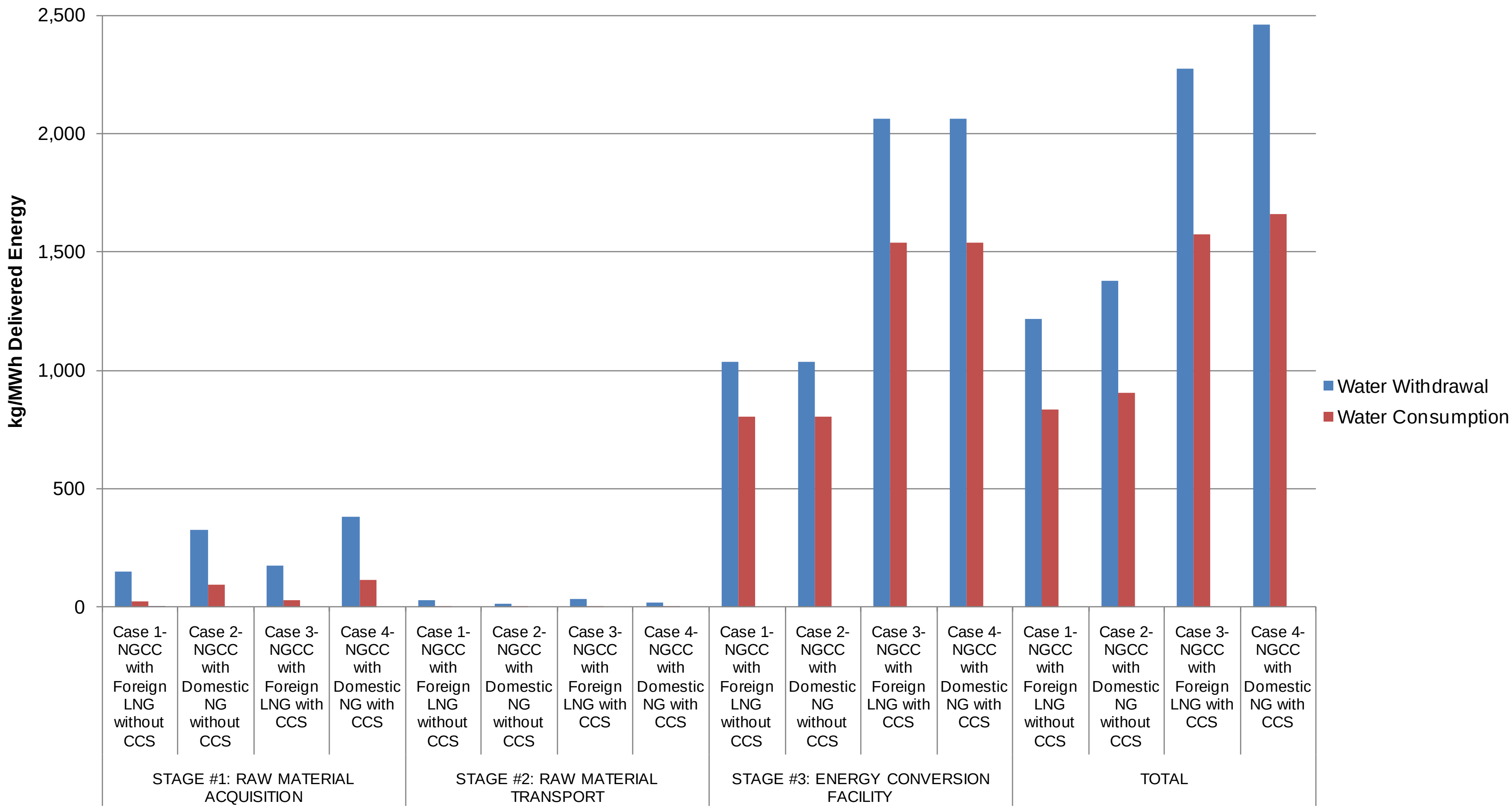

Figure 3-22: Comparative Water Withdrawal and Consumption for NGCC with and without CCS

3.6.1.4 *Comparative Land Use Transformation*

The total transformed land area for all LC stages combined is shown in **Figure 3-23,** on a per MWh delivered basis. Land use change for the case with CCS is nearly twice that of the case without CCS. This is due to the additional land area required for the CCS pipeline, as well as the parasitic load of the CCS, which results in reduced power plant output. The majority of additional land use change is from grassland and forest.

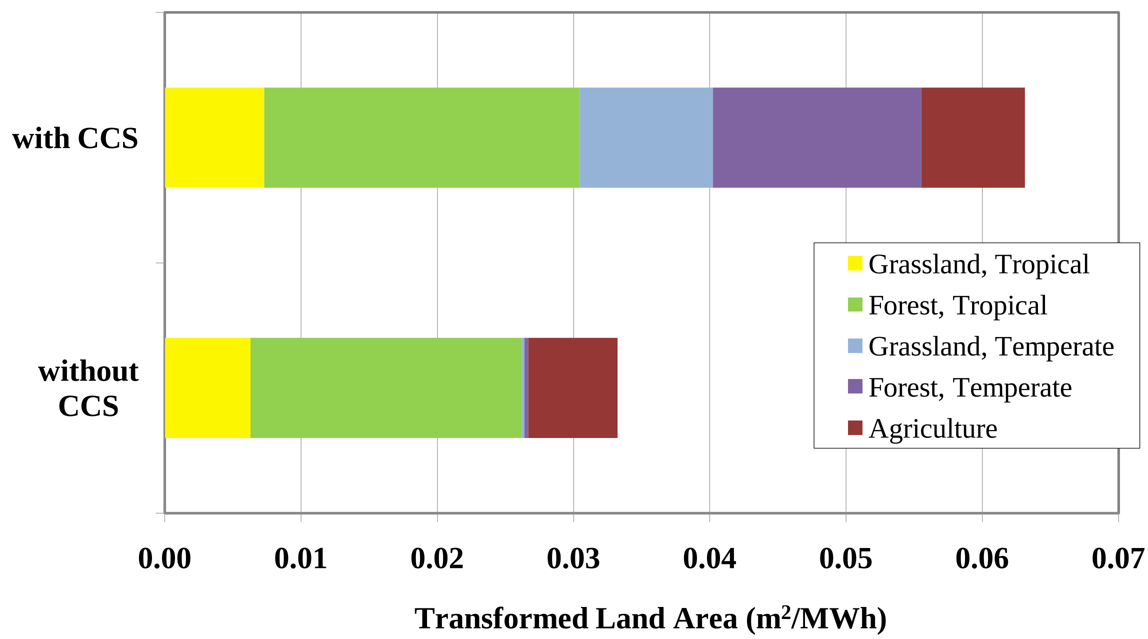

Figure 3-23: Total Transformed Land Area for NGCC with and without CCS

3.7 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.

3.7.1 Sensitivity Analysis of Cost Assumptions

To test the sensitivity of LCC for the NGCC cases with and without CCS, capital and variable O&M costs for all components, as well as fuel/feed costs from AEO 2008, were varied (**Table 3-23**).

Table 3-23: LCC Uncertainty Analysis Parameters

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

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

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

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

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

3.7.1.1 *Sensitivity Analysis Results for Case 1: NGCC without CCS*

The results for the NGCC case without CCS uncertainty analysis indicate that the LCOE is most responsive to the change in capital costs. An increase and decrease in capital costs of 30 percent for all major components included in the analysis increased and decreased the total LC LCOE by +/- 6 percent. This translates into a range from $0.0874/kWh to $0.0979/kWh.

When the base case feed prices, which are from the AEO 2008 reference case natural gas prices, are replaced with the AEO 2008 high price case for natural gas, LCOE costs increase by 4 percent as compared to the base case LCOE of $0.0927/kWh. The replacement of the AEO reference case values with the high price case values increase the LCOE of the NGCC case without CCS to $0.0960/kWh, as shown in **Figure 3-24** and **Figure 3-25**.

Varying the capacity factor by +/-5 percent from the base case 85 percent causes total LCOE to increase and decrease by one to two percent. This translates into a range of $0.0913/kWh to $0.0942/kWh.

Increasing the total tax rate (Federal plus state) by +/-10 percent resulted in a percent change of less than one percent. The range for this is $0.0920/kWh to $0.0934/kWh.

Similarly, variable O&M costs increased and decreased by 30 percent, causing a change in the total LCOE for the case by less than one percent in both directions. LCOE costs when O&M costs are increased and decreased had a range from $0.0921/kWh to $0.0933/kWh.

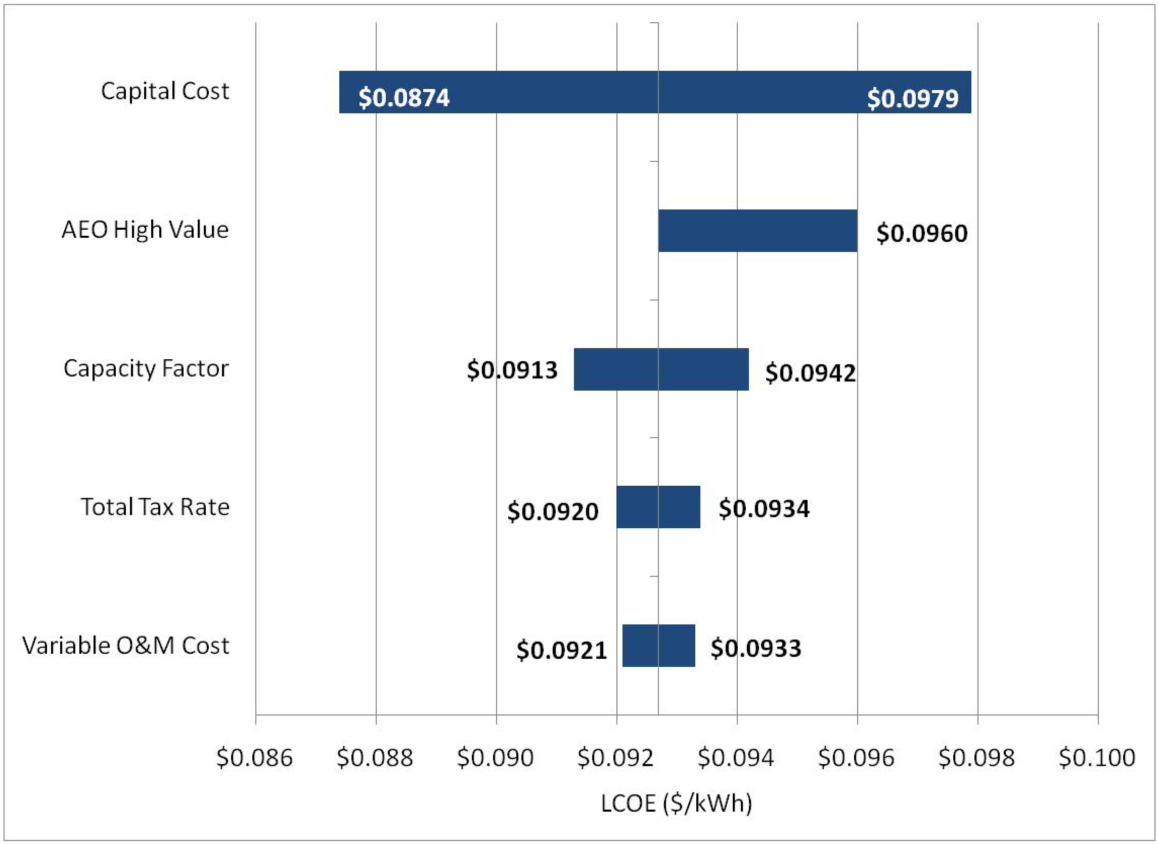

Figure 3-24: Uncertainty Analysis LCOE Ranges for the NGCC Case without CCS

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 natural gas values rather than the AEO 2008 reference case values used in the base case.

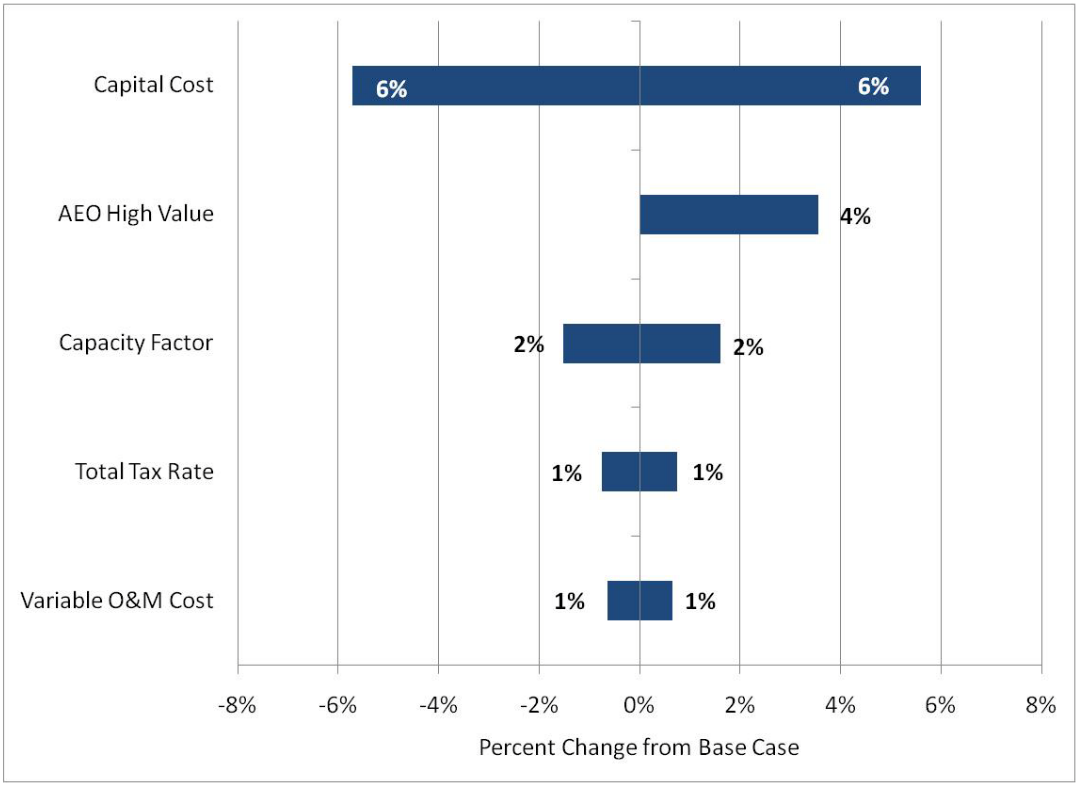

Figure 3-25: Percent Change due to Uncertainty Analysis from Base Case LCOE for the NGCC Case without CCS

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 natural gas values rather than the AEO 2008 reference case values used in the base case.

3.7.1.2 *Uncertainty Analysis Results for Case 2: NGCC with CCS*

The results indicate that the NGCC case with CCS LCOE is most responsive to a change in fluctuations in capital costs. When the capital costs input into the model are increased and decreased by 30 percent, the LCOE increases and decreases by 9 percent from the Base Case LCOE value of $0.1319/kWh. This is equal to a range from $0.1201/kWh to $0.1437/kWh. LCOE ranges for each uncertainty case and the percent change for each case as compared to the base case LCOE value are presented in **Figure 3-26** and **Figure 3-27**.

When AEO reference case values are replaced with the high price case values for natural gas, the total LC LCOE for the NGCC case with CCS increases by three percent. This translates into an LCOE of $0.1357/kWh.

With a capacity factor range from 80 to 90 percent, the LCOE ranged from $0.1290/kWh to $0.1352/kWh. This is equal to a change of two to three percent.

A variation of the total tax rate by 10 percent in both directions causes the LCOE to change by one percent. This translates into a range of $0.1303/kWh to $0.1334/kWh. Similarly, variation in the variable O&M costs by +/-30 percent resulted in an LCOE range from $0.1304/kWh to $0.1333/kWh. This is represented by a percent change of less than one.

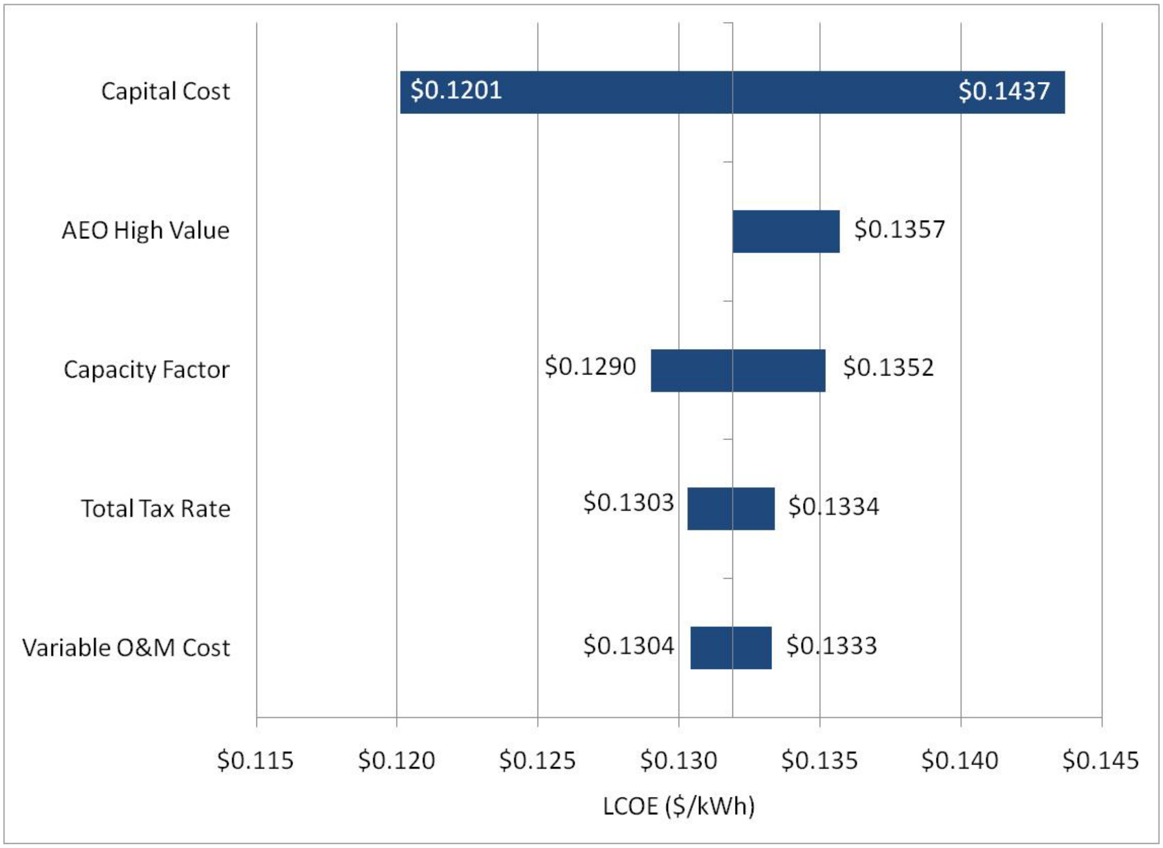

Figure 3-26: Uncertainty Analysis LCOE Results for the NGCC Case with CCS

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 natural gas values rather than the AEO 2008 reference case values used in the base case.

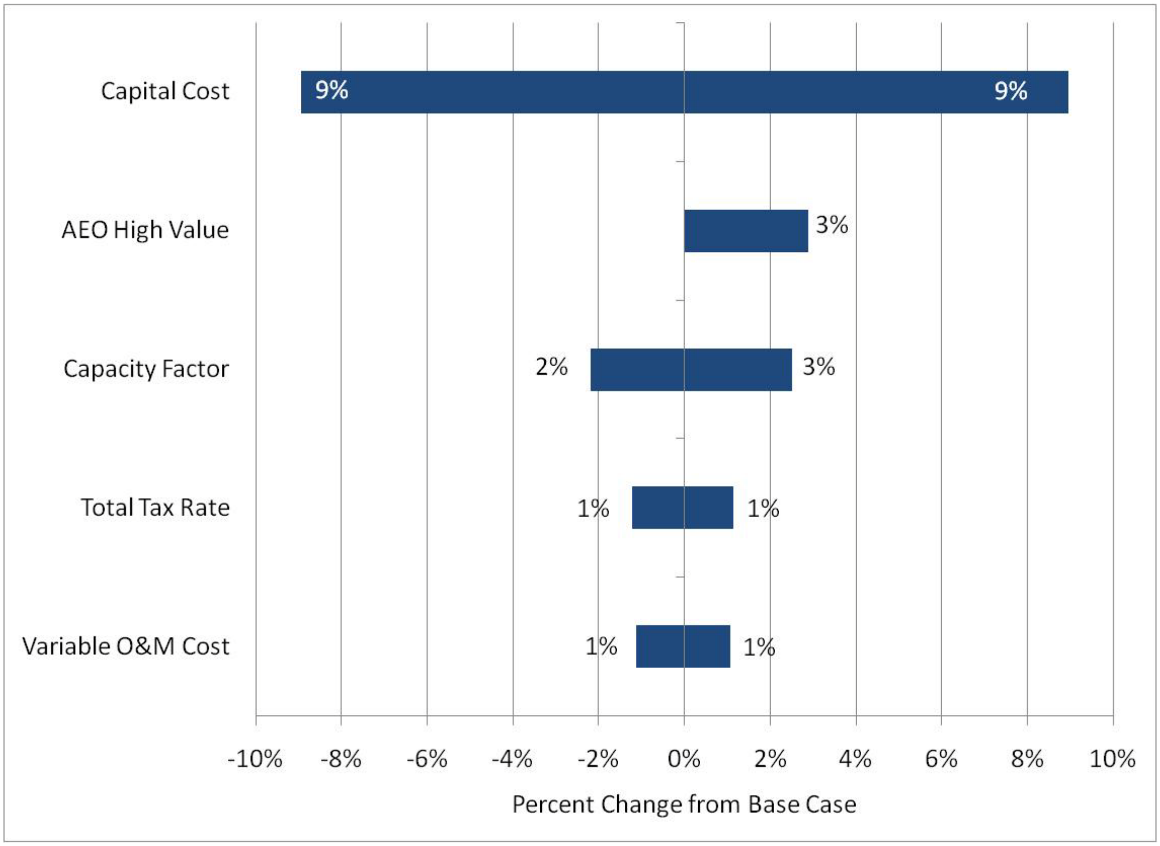

Figure 3-27: Percent Change from Base Case LCOE for the NGCC Case with CCS

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 natural gas values rather than the AEO 2008 reference case values used in the base case.

3.7.2 Sensitivity Analysis of LCI Assumptions

For this study, sensitivity analysis is performed on a few key parameters listed in **Table 3-24**. These parameters were chosen based on perceived impact and data quality.

Table 3-24: Sensitivity Analysis Parameters

Parameter	Stages Effected	Value in Model	Sensitivity Range/Value	Source/Reasoning
Materials	1, 2, 3	Totals for steel, concrete, etc.	3 times increase material amount (200 percent)	Arbitrary range to account for replacement parts, missed data.
Tanker Transport Distance	2	2260 miles	10,000 miles	Miles to transport LNG from Egypt instead of Trinidad.
NG Pipeline Distance	2	900 miles	450 miles	Decrease pipeline transport of domestic pathway by 50%, making it comparable to the Stage #2 pipeline distance for imported NG.

3.7.2.1 *Construction Material Contributions*

The effect of an additional three times the material input on GHG emissions for both NGCC cases are shown in **Table 3-25**. Stage #1, Stage #2, Stage #3, and total (all stages) emissions are shown; the GHG emissions for the remaining stages were not varied from the base case values.

Table 3-25: GHG Emissions (kg CO_2e/MWh) for Cases Without CCS and Sensitivity of Increase in Construction Requirements

Emissions (kg CO_2e /MWh)	Stage #1: Raw Material Acquisition			Stage #2: Material Transport			Stage #3: Energy Conversion Facility (w/o CCS)			Total		
	Base	3 × Base	% Increase	Base	3 × Base	% Increase	Base	3 × Base	% Increase	Base	3 × Base	% Increase
NGCC with Imported NG without CCS												
CO_2	81.7	83.3	2.0%	20.3	20.9	3.0%	393.0	393.8	0.2%	495	498	0.6%
N_2O	1.45E-01	1.67E-01	15.3%	4.89E-02	5.52E-02	12.8%	4.47E-03	1.21E-02	170.5%	1.98E-01	2.34E-01	18.2%
CH_4	6.18	6.21	0.6%	19.0	19.0	0.1%	9.20E-03	2.72E-02	195.6%	25.2	25.3	0.3%
SF_6	4.18E-08	5.15E-08	23.2%	7.43E-07	1.17E-06	58.0%	7.43E-03	7.43E-03	0.0%	7.57E-03	7.57E-03	0.0%
Total GWP	88.0	89.7	2.0%	39.4	40.0	1.6%	393.0	393.9	0.2%	520.4	523.6	0.6%
NGCC with Domestic NG without CCS												
CO_2	16.4	17.0	3.7%	18.7	19.0	1.6%	393.0	393.8	0.2%	428	430	0.4%
N_2O	1.28E-02	1.85E-02	44.5%	9.74E-02	1.00E-01	3.0%	4.47E-03	1.21E-02	170.5%	1.15E-01	1.31E-01	14.2%
CH_4	6.39	6.42	0.4%	28.7	28.7	0.0%	9.20E-03	2.72E-02	195.6%	35.1	35.2	0.1%
SF_6	1.32E-08	1.94E-08	46.7%	5.68E-07	5.68E-07	0.1%	7.43E-03	7.43E-03	0.0%	7.57E-03	7.57E-03	0.0%
Total GWP	22.8	23.5	2.8%	47.5	47.8	0.6%	393.0	393.9	0.2%	463.4	465.2	0.4%

Table 3-26: GHG Emissions (kg CO_2e/MWh) for Cases With CCS and Sensitivity of Increase in Construction Requirements

Emissions (kg CO_2e /MWh)	Stage #1: Raw Material Acquisition			Stage #2: Material Transport			Stage #3: Energy Conversion Facility (w/o CCS)			Total		
	Base	3 × Base	% Increase	Base	3 × Base	% Increase	Base	3 × Base	% Increase	Base	3 × Base	% Increase
NGCC with Imported NG with CCS												
CO_2	95.7	97.7	2.0%	23.8	24.5	3.0%	51.3	52.5	2.4%	171	175	2.3%
N_2O	1.70E-01	1.96E-01	15.3%	5.74E-02	6.47E-02	12.8%	6.98E-03	1.94E-02	178.0%	2.34E-01	2.80E-01	19.6%
CH_4	7.24	7.28	0.6%	22.3	22.3	0.1%	1.39E-02	4.13E-02	196.6%	29.5	29.6	0.3%
SF_6	4.90E-08	6.03E-08	23.2%	8.71E-07	1.38E-06	58.0%	8.70E-03	8.70E-03	0.0%	3.28E+00	3.28E+00	0.0%
Total GWP	103.1	105.2	2.0%	46.1	46.9	1.6%	51.3	52.6	2.4%	203.8	207.9	2.0%
NGCC with Domestic NG with CCS												
CO_2	19.2	20.0	3.7%	21.9	22.2	1.6%	51.3	52.5	2.4%	92	95	2.5%
N_2O	1.50E-02	2.17E-02	44.5%	1.14E-01	1.18E-01	3.0%	6.98E-03	1.94E-02	178.0%	1.36E-01	1.59E-01	16.5%
CH_4	7.49	7.53	0.4%	33.7	33.7	0.0%	1.39E-02	4.13E-02	196.6%	41.2	41.2	0.2%
SF_6	1.55E-08	2.27E-08	46.7%	6.66E-07	6.66E-07	0.1%	8.70E-03	8.70E-03	0.0%	3.28E+00	3.28E+00	0.0%
Total GWP	26.7	27.5	2.8%	55.7	56.0	0.6%	51.3	52.6	2.4%	137.0	139.4	1.7%

From the calculation of total GWP, it can be see that, although the percentage increase of individual pollutants can be large, a 200 percent increase in construction materials causes a 0.4 to 0.6 percent increase for the NGCC without CCS scenarios, and a 1.7 to 2.0 percent for the NGCC with CCS scenarios. This is because CO_2 emissions are dominated by the operation unit processes which include the combustion of fuels and are not directly related to construction materials. Therefore, construction material inputs have little impact on the overall GWP of the NGCC scenarios.

Table 3-27 and **Table 3-28** show the sensitivity of non-GHG air pollutants to material inputs for NGCC cases without and with CCS, respectively. Mercury, Pb, and PM (and, to a lesser extent, SO_x, and CO) show significant *percent* increases because they are highly-concentrated in the cradle-to-gate profiles of construction materials such as concrete, steel plate, steel pipe, aluminum sheet, and cast iron.

Table 3-27: Air Pollutants (kg/MWh) for Cases Without CCS and Sensitivity of Increase in Construction Requirements

Emissions (kg/MWh)	Stage #1: Raw Material Acquisition			Stage #2: Material Transport			Stage #3: Energy Conversion Facility (w/o CCS)			Total		
	Base	3 × Base	% Increase	Base	3 × Base	% Increase	Base	3 × Base	% Increase	Base	3 × Base	% Increase
NGCC with Imported NG without CCS												
Pb	1.40E-06	4.17E-06	199.2%	5.21E-07	1.26E-06	141.8%	2.72E-06	3.61E-06	32.9%	4.63E-06	9.05E-06	95.2%
Hg	7.13E-08	2.12E-07	197.1%	5.68E-08	9.20E-08	62.1%	2.42E-08	7.27E-08	200.0%	1.52E-07	3.76E-07	147.2%
NH_3	9.67E-02	9.67E-02	0.0%	8.30E-05	8.64E-05	4.0%	1.88E-02	1.88E-02	0.0%	1.16E-01	1.16E-01	0.0%
CO	6.82E-02	8.04E-02	17.9%	6.97E-02	7.40E-02	6.2%	3.14E-03	8.84E-03	181.3%	1.41E-01	1.63E-01	15.8%
NO_X	1.51E-01	1.57E-01	4.0%	1.03E-01	1.05E-01	1.6%	3.05E-02	3.26E-02	6.7%	2.85E-01	2.94E-01	3.4%
SO_X	5.03E-03	8.95E-03	77.8%	2.22E-02	2.43E-02	9.4%	1.41E-03	4.21E-03	199.7%	2.87E-02	3.75E-02	30.8%
VOC	7.36E-04	8.84E-04	20.1%	1.30E-02	1.31E-02	0.5%	2.53E-05	7.58E-05	200.0%	1.38E-02	1.40E-02	1.9%
PM	4.08E-03	6.28E-03	54.0%	3.09E-03	4.36E-03	41.1%	2.22E-03	6.62E-03	197.6%	9.39E-03	1.73E-02	83.8%
NGCC with Domestic NG without CCS												
Pb	4.68E-07	1.38E-06	193.6%	2.48E-07	5.78E-07	133.1%	2.72E-06	3.61E-06	32.9%	3.43E-06	5.56E-06	62.1%
Hg	1.48E-08	3.98E-08	169.7%	2.03E-08	2.91E-08	43.0%	2.42E-08	7.27E-08	200.0%	5.94E-08	1.42E-07	138.7%
NH_3	2.64E-06	5.07E-06	92.4%	1.19E-05	1.79E-05	49.9%	1.88E-02	1.88E-02	0.0%	1.88E-02	1.88E-02	0.1%
CO	7.04E-02	7.35E-02	4.3%	2.11E-02	2.26E-02	6.8%	3.14E-03	8.84E-03	181.3%	9.47E-02	1.05E-01	10.8%
NO_X	1.07E-01	1.11E-01	3.5%	2.32E-01	2.34E-01	0.9%	3.05E-02	3.26E-02	6.7%	3.70E-01	3.78E-01	2.1%
SO_X	2.27E-03	3.95E-03	74.2%	1.02E-02	1.06E-02	3.9%	1.41E-03	4.21E-03	199.7%	1.39E-02	1.88E-02	35.2%
VOC	1.47E-02	1.51E-02	2.4%	6.64E-03	6.66E-03	0.3%	2.53E-05	7.58E-05	200.0%	2.14E-02	2.18E-02	2.0%
PM	2.10E-03	3.69E-03	75.9%	1.62E-03	2.11E-03	30.3%	2.22E-03	6.62E-03	197.6%	5.94E-03	1.24E-02	109.1%

Table 3-28: Air Pollutants (kg/MWh) for Cases With CCS and Sensitivity of Increase in Construction Requirements

Emissions (kg/MWh)	Stage #1: Raw Material Acquisition			Stage #2: Material Transport			Stage #3: Energy Conversion Facility (w/o CCS)			Total		
	Base	3 × Base	% Increase	Base	3 × Base	% Increase	Base	3 × Base	% Increase	Base	3 × Base	% Increase
NGCC with Imported NG with CCS												
Pb	1.64E-06	4.89E-06	199.2%	6.11E-07	1.48E-06	141.8%	3.09E-06	4.74E-06	53.3%	5.34E-06	1.11E-05	108.1%
Hg	8.35E-08	2.48E-07	197.1%	6.66E-08	1.08E-07	62.1%	3.47E-08	1.04E-07	200.0%	1.85E-07	4.60E-07	149.0%
NH_3	1.13E-01	1.13E-01	0.0%	9.73E-05	1.01E-04	4.0%	2.03E-02	2.03E-02	0.0%	1.34E-01	1.34E-01	0.0%
CO	8.00E-02	9.42E-02	17.9%	8.17E-02	8.68E-02	6.2%	4.53E-03	1.29E-02	184.8%	1.66E-01	1.94E-01	16.7%
NO_X	1.77E-01	1.84E-01	4.0%	1.21E-01	1.23E-01	1.6%	3.42E-02	3.77E-02	10.1%	3.32E-01	3.44E-01	3.7%
SO_X	5.90E-03	1.05E-02	77.8%	2.60E-02	2.85E-02	9.4%	1.92E-03	5.75E-03	199.7%	3.39E-02	4.47E-02	32.1%
VOC	8.62E-04	1.04E-03	20.1%	1.53E-02	1.53E-02	0.5%	4.12E-05	1.24E-04	200.0%	1.62E-02	1.65E-02	2.1%
PM	4.78E-03	7.36E-03	54.0%	3.62E-03	5.11E-03	41.1%	2.61E-03	7.77E-03	197.6%	1.10E-02	2.02E-02	83.8%
NGCC with Domestic NG with CCS												
Pb	5.49E-07	1.61E-06	193.6%	2.91E-07	6.78E-07	133.1%	3.09E-06	4.74E-06	53.3%	3.93E-06	7.03E-06	78.8%
Hg	1.73E-08	4.67E-08	169.7%	2.38E-08	3.41E-08	43.0%	3.47E-08	1.04E-07	200.0%	7.58E-08	1.85E-07	143.7%
NH_3	3.09E-06	5.95E-06	92.4%	1.40E-05	2.09E-05	49.9%	2.03E-02	2.03E-02	0.0%	2.03E-02	2.04E-02	0.1%
CO	8.25E-02	8.61E-02	4.3%	2.48E-02	2.65E-02	6.8%	4.53E-03	1.29E-02	184.8%	1.12E-01	1.25E-01	12.2%
NO_X	1.26E-01	1.30E-01	3.5%	2.72E-01	2.75E-01	0.9%	3.42E-02	3.77E-02	10.1%	4.32E-01	4.42E-01	2.4%
SO_X	2.66E-03	4.63E-03	74.2%	1.20E-02	1.25E-02	3.9%	1.92E-03	5.75E-03	199.7%	1.66E-02	2.29E-02	37.9%
VOC	1.73E-02	1.77E-02	2.4%	7.78E-03	7.80E-03	0.3%	4.12E-05	1.24E-04	200.0%	2.51E-02	2.56E-02	2.1%
PM	2.46E-03	4.33E-03	75.9%	1.90E-03	2.47E-03	30.3%	2.61E-03	7.77E-03	197.6%	6.97E-03	1.46E-02	109.1%

3.7.2.2 *LNG Tanker Distance*

This analysis assumes that imported natural gas is transported from Trinidad & Tobago a distance of approximately 2,260 miles to the coast of Louisiana. This assumption was made because the majority of LNG imports into the United States come from Trinidad & Tobago; however, these imports could come from other areas of the world. The second largest overseas supplier of natural gas to the U.S. is Egypt, at an approximate distance of 10,000 miles from from the United States. Therefore, sensitivity was run to determine the impact LNG tanker distance has on the overall results.

The increase in tanker transport distance has a large impact on the results for the transport of imported natural gas (Stage #2). Increasing the one-way tanker distance from 2,260 to 10,000 miles increases the GWP of Stage #2 from 0.27 to 0.43 kg CO2e/kg of delivered natural gas (a 60 percent increase). As illustrated in **Figure 3-28**, a tanker with a one-way distance of 10,000 miles would produce more GHG emissions than the berthing, regasification, and pipeline processes combined.

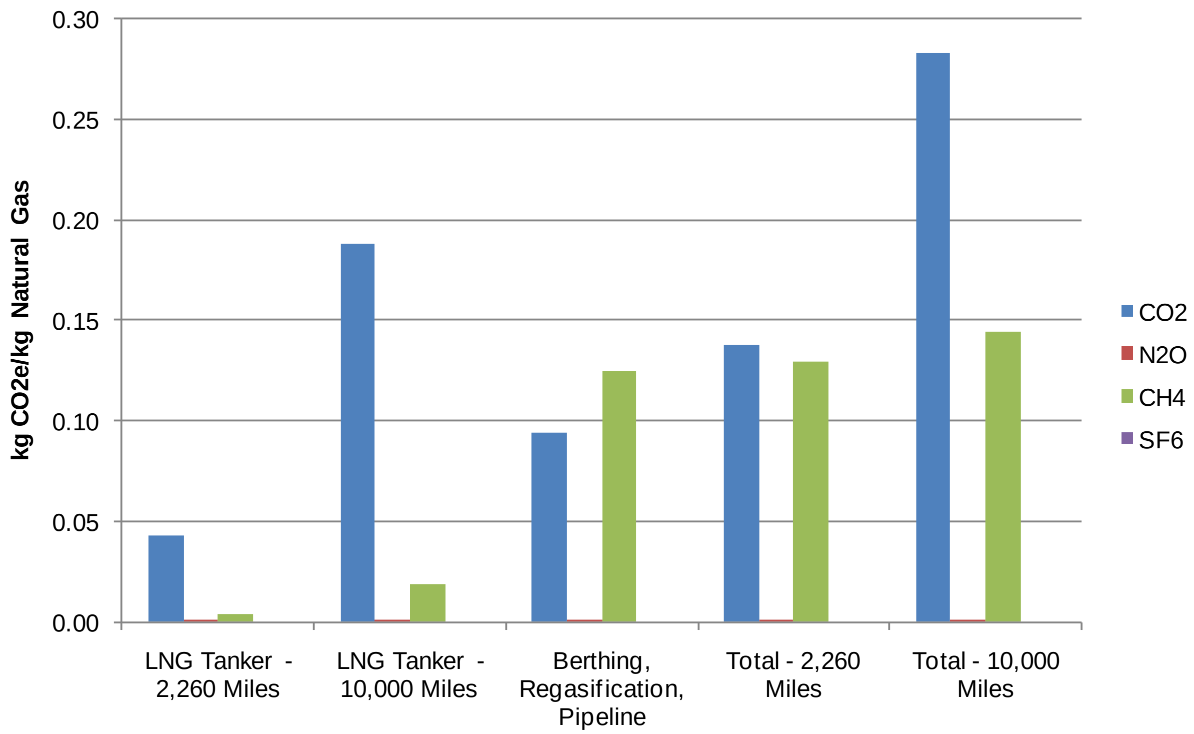

Figure 3-28: Stage #2 GWP Including 10,000 Mile LNG Tanker Transport, kg/kg LNG Transported

It should be noted that while the GHG emissions of LNG tanker operations for a 10,000 mile transport scenario are high in comparison to the other activities within Stage #2, they are lower than key upstream and downstream activities. For example, the liquefaction of natural gas (which occurs in Stage #1) produces 0.43 kg of CO_2e/kg of natural gas ready for delivery. And the combustion of natural gas (which occurs in Stage #3), produces approximately 2.7 kg of CO2e/kg of combusted natural gas for cases where CCS is not used.

Figure 3-29 shows a similar increase in non-GHG emissions. When LNG tanker transport is increased to 10,000 miles, LNG tanker activities dominate the Stage #2 emissions with large increases in CO and NO_X. When considering the total emissions from both cases (2,260 miles vs. 10,000 miles), the 340 percent increase in tanker transport distance increases CO and NO_X emissions from Stage #2 transport of imported natural gas by 300 and 120 percent, respectively. These results further prove the influence that LNG production and transport has on the overall environmental burdens of NGCC electricity production.

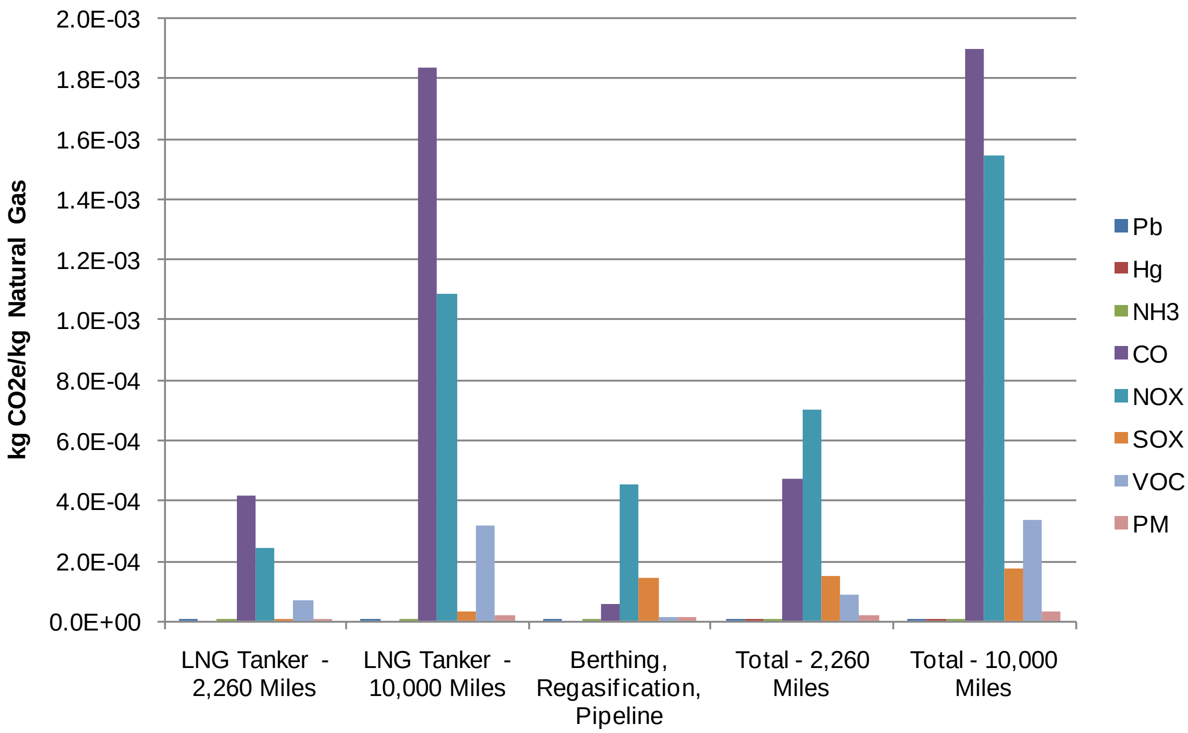

Figure 3-29: Stage #2 Non-GHG Emission Increases Due to Increased LNG Tanker Travel, kg/kg LNG

3.7.2.3 *Pipeline Distance*

Pipeline distance was decreased in Stage #2 for the domestic pathways, where pipelines are used to carry natural gas from natural gas extraction and processing sites to the NGCC plant. This sensitivity was analyzed because the default pipeline transportation distance for Stage #2 is significantly higher for the domestic pathway than for the imported pathway (900 miles vs. 335 miles). Thus, a sensitivity analysis of this parameter allows an evaluation of the extent to which a longer pipeline transportation distance adversely affects the LC results for the domestic pathways.

Although Stage #2 is not the dominate stage within this LC, changes to pipeline transportation distances affect the overall LC environmental burdens significantly. When the pipeline distance for domestic natural gas is reduced by 50 (from 900 miles to 450 miles), all life cycle metrics for Stage #2 decrease by 50 percent. This direct 1:1 correlation is due to the fact that pipeline activities are the only activities included in Stage #2 of the domestic natural gas scenarios. From a broader perspective, the overall LC burdens per 1 MWh of delivered electricity, the 50 percent decrease in pipeline distance results in a 21 percent reduction in GHG emissions. This relatively large decrease in GHG emissions is attributable to the reduced pipeline methane losses realized by a shorter pipeline distance. The sensitivity between pipeline distance and life cycle GHG emissions is illustrated in **Figure 3-30.**

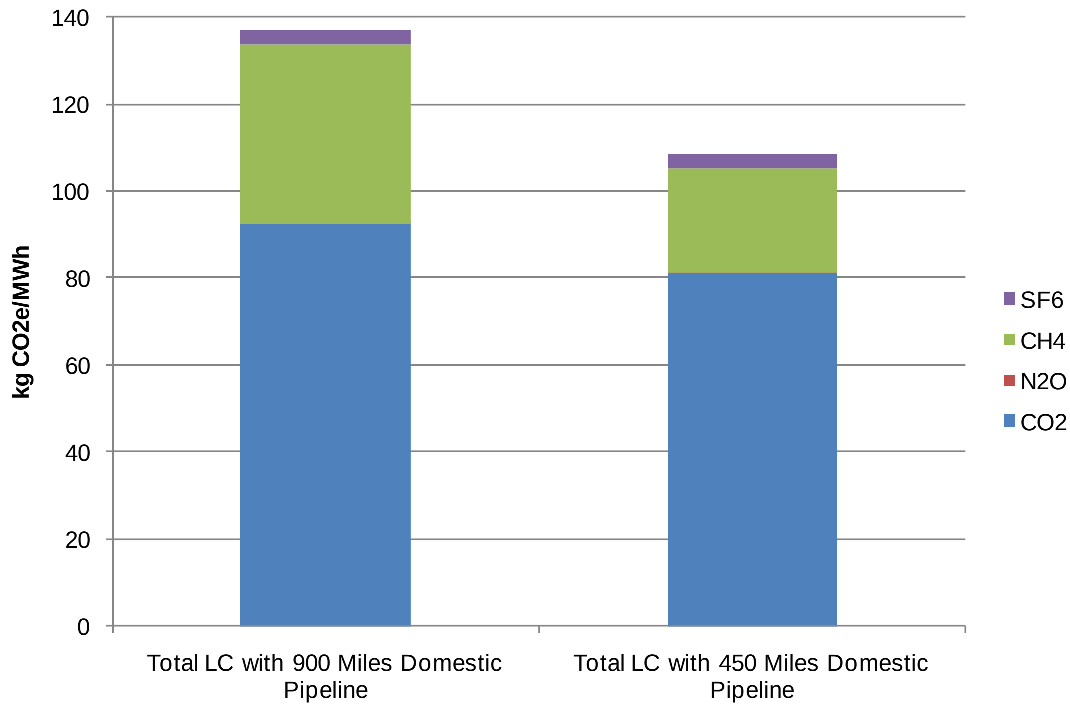

Figure 3-30: Stage #2 GHG Emission Descreases Due to Decreased Pipeline Distance for Domestic NG, kg CO_2e/MWh

A reduction in pipeline distance also has a significant effect on non-GHG emissions. A 50 percent decrease in pipeline distance results in overall LC emission reductions of 36 percent for SO_x, 32 percent for NO_x, 13 percent for Hg, and 12 percent for CO. These emissions are characteristic of fossil fuel-derived electricity. Approximately 6 percent of the power consumed by domestic natural gas pipelines is provided by electricity. The only other primary process in the domestic natural gas life cycle that uses purchased electricity is the extraction of natural gas from Barnett Shale. Thus, a decrease in the natural gas pipeline transport distance results in a significant decrease in the amount of electricity consumed by the domestic natural gas scenario, which, in turn, significantly reduces the SO_x, NO_x, Hg, CO and other non-GHG emissions for the life cycle of domestic natural gas. The differences between non-GHG emissions for the two pipeline scenarios are illustrated in and **Figure 3-31**.

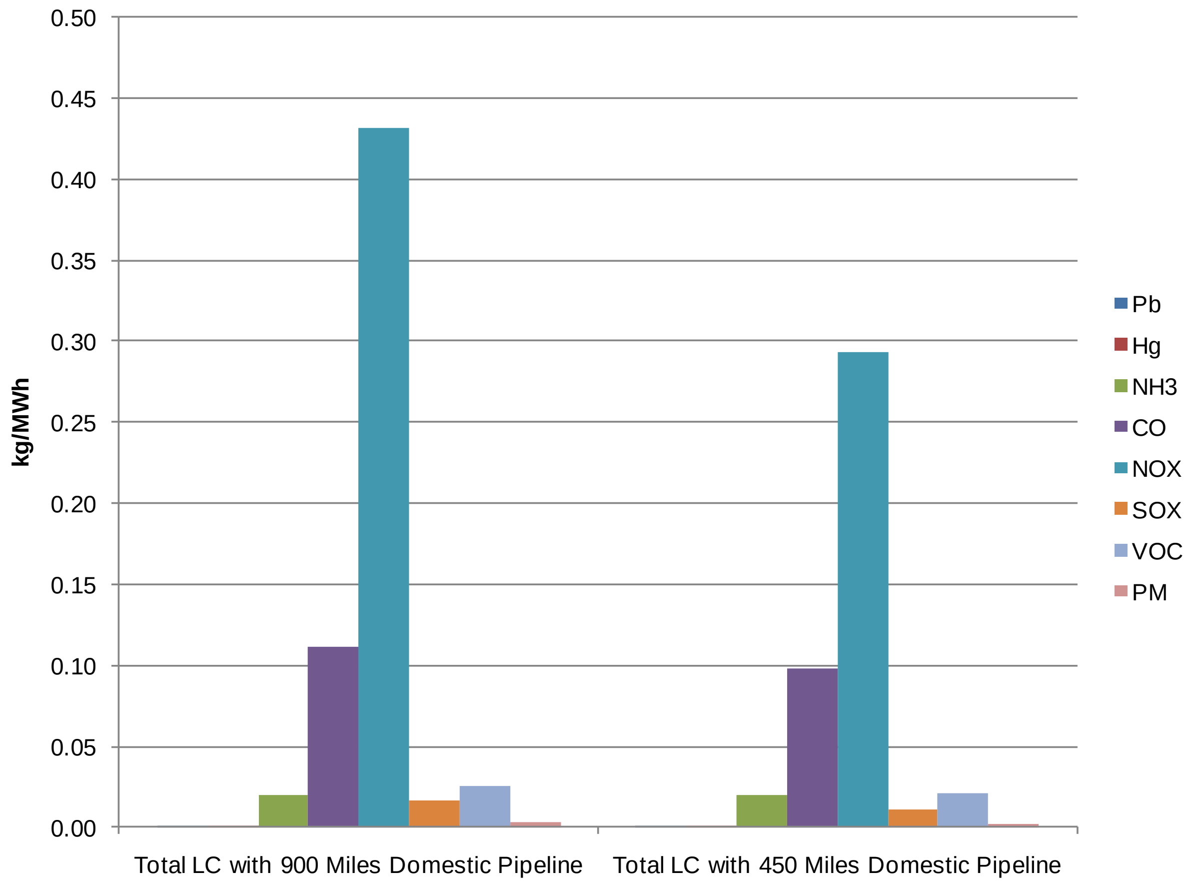

Figure 3-31: Stage #2 Non-GHG Emission Descreases Due to Decreased Pipeline Distance for Domestic NG, kg/MWh

The above results represent the sensitivity of the domestic natural gas pipeline for an NGCC plant that does not use CCS. However, the results for the NGCC plant with CCS lead to similar results for all metrics except for CO_2. Since Stage #3 of the NGCC scenario with CCS captures 90 percent of CO_2 from NGCC combustion, the sensitivity between pipeline distance and pipeline-related CO_2 emissions is more pronounced for the CCS cases than for the non-CCS cases.

4.0 Summary

This study compares the LCI&C of two NGCC plants, with and without CCS. It was shown that CCS can be added to an NGCC facility to reduce the LC GWP. However, although CCS removes 90 percent of the CO_2 emissions from the NGCC facility, for this particular case the GWP impacts of Stage #1 and Stage #2 bring the total GWP reduction to only 61 to 71 percent. This is due to the environmental burdens of natural gas extraction, the CO_2 emissions during natural gas liquefaction (applicable only to imported natural gas pathways), and material losses during pipeline transport of natural gas. These results suggest that to further reduce the total LC GWP of NGCC life cycles, one would need to focus on carbon mitigation technologies during Stage #1 and Stage #2.

Additionally, adding CCS increases the LCOE by 42 percent, from approximately $0.09/MWh to $0.13/MWh of delivered electricity. This indicates that advancements in CCS technologies that reduce the capital investment and operating costs would most significantly reduce the overall cost differences between the two cases.

Other tradeoffs from the addition of CCS included more water and land use. Approximately 44 percent more water is needed for cooling applications during the carbon capture process. This result suggests that depending on the location of the NGCC 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 grass and forest land. 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. Non-GHG emissions do not vary much between the cases indicating that no additional air pollutant benefits are achieved due to the inclusion of CCS.

Sensitivity analysis was performed on several cost and environmental inventory parameters. Capital costs and high price case feedstock/utility costs have the largest impact on LCOE. This indicates that investors will need to take care when analyzing capital cost parameters for a given NGCC plant. Additionally, these results highlight the uncertainty of natural gas feed prices and the impact they can have on the overall economics of an NGCC plant.

Sensitivity on environmental parameters was performed on construction material inputs, LNG tanker travel distance, and natural gas pipeline distance. Minor changes to the LC results were observed when the amount of construction materials were increased by a factor of three, indicating that a high degree of uncertainty for construction material inputs does not contribute to high uncertainty in total LC results. In particular, GHG emissions are not significantly affected by a three-fold increase in construction material inputs, demonstrating a 0.4 to 0.6 increase in total CO_2e for scenarios without CCS and a 1.7 to 2.0 percent increase in total CO_2e for scenarios with CCS. Increases in heavy metal, CO, and SO_x emissions were observed due to their dominance in the upstream profiles for construction materials; the affect of these non-GHG emissions cannot be evaluated further without conducted an impact analysis. Sensitivity analysis of tanker transport distance showed a large impact on Stage #2 GWP and non-GHG air emissions when distance is increased from delivery from Trinidad versus Egypt. Overall, increasing transport distance from 2,260 to 10,000 miles increases the total GWP for both cases (with and without CCS) by 23.5 and eight percent, respectively. Additionally, reducing the pipeline distance between regasification facility and the NGCC plant reduces the CH_4, NO_X, and CO emissions in Stage #2. These results give further proof that Stage #1 and Stage #2 processes have large impacts on the overall GWP and environmental burden of the NGCC cases.

5.0 Air Emissions and Water for Delivered Natural Gas

The above results are on the basis of one MWh of delivered electricity and aggregate the five extraction sources for domestic natural gas. The air emissions and water flows per delivery of one kilogram of natural gas for each of the five domestic sources as well as imported natural gas are shown in **Table 5-1**. These results represent the first two life cycle stages: raw material extraction and raw material transport.

Table 5-1: Environmental Burdens for Acquisition and Transport of NG from Six Sources

	Domestic NG					Imported NG
kg/kg delivered NG	Coal Bed Methane	Barnett Shale	Offshore	Associated Gas	Onshore	Offshore
GHG Emissions						
CO_2	0.245	0.263	0.216	0.220	0.243	0.685
N_2O	2.62E-06	3.07E-06	4.47E-06	2.45E-06	2.43E-06	4.26E-06
CH_4	9.39E-03	9.22E-03	8.28E-03	1.02E-02	9.41E-03	6.34E-03
SF_6	1.73E-13	2.21E-13	1.69E-13	1.70E-13	1.70E-13	2.23E-13
CO_2e	0.481	0.495	0.424	0.475	0.479	0.845
Non-GHG Air Emissions						
Pb	1.52E-08	1.39E-08	6.90E-09	3.90E-09	3.00E-09	1.17E-08
Hg	5.03E-10	6.76E-10	4.60E-10	1.97E-10	1.73E-10	8.29E-10
NH_3	1.18E-07	2.67E-07	8.14E-08	8.70E-08	8.46E-08	6.59E-04
CO	6.95E-04	6.03E-04	2.21E-04	5.40E-04	6.54E-04	9.25E-04
NO_X	2.40E-03	2.31E-03	1.79E-03	2.18E-03	2.35E-03	1.62E-03
SO_X	9.47E-05	2.39E-04	7.78E-05	7.39E-05	7.24E-05	1.79E-04
VOC	1.57E-04	1.41E-04	4.67E-05	1.28E-04	1.52E-04	9.05E-05
PM	4.31E-05	3.95E-05	1.51E-05	2.09E-05	2.14E-05	4.55E-05
Water						
Water Withdrawal	6.15	2.24	0.83	2.02	2.03	1.22
Wastewater Outfall	6.06	0.64	0.79	1.32	1.33	1.02
Water Consumption	0.09	1.60	0.05	0.70	0.70	0.20

Figure 5-1 shows the upstream (extraction and transportation to plant gate) global warming potential of each natural gas source expressed in terms of kg CO_2e per unit energy in MMBTU. The domestic pathways show a significantly lower GWP than imported LNG.

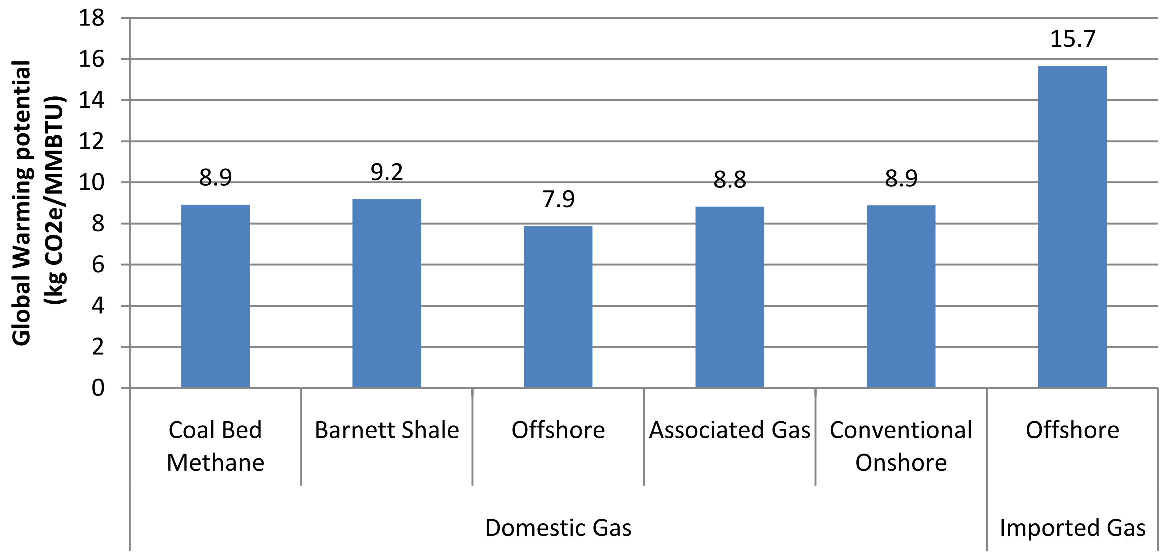

Figure 5-1: Comparative Upstream Global Warming Potential by Natural Gas Source

6.0 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.
- Future analysis on carbon mitigation strategies that could be applied to the liquefaction facility and whether those technologies could be used to reduce the overall GWP of an NGCC process.
- 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 distinguish between LCOE for the plant and LC LCOE.
- 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.

7.0 References

ALL Consulting (2004). Coal Bed Methane Primer: New Source of Natural Gas -- Environmental Implications. February, 2004.

ALNG (2006). Atlantic LNG: Company of Trindad and Tobago [cited May 13 2009] Available from: http://www.atlanticlng.com/.

Argonne National Laboratory (2008). Transportation Technology R&D Center, DOE H2A Delivery Analysis [cited November 11th, 2008] Available from: http://www.transportation.anl.gov/modeling_simulation/h2a_delivery_analysis/.

Arnold (1999). Surface Production Operations: Design of gas-handling systems and facilities. Gulf Professional Publishing. Houston, Texas. 1999.

API (2009). Compendium of Greenhouse Gas Emissions for the Oil and Natural Gas Industry. API. Washington, DC. 2009. http://www.api.org/ehs/climate/new/upload/2009_GHG_COMPENDIUM.pdf (Accessed May 18, 2010)EPA AP-42

Bare, Jane C., Norris, Gregory A., Pennington, David W., et al. (2003). "TRACI: The Tool for the Reduction and Assessment of Chemical and Other Environmental Impacts". Journal of Industrial Ecology **6** (3-4):49-78. http://www.epa.gov/ORD/NRMRL/std/sab/traci/index.html

Bergerson, Joule Andrea. (2005). Future Electricity Generation: An Economic and Environmental Perspective on Near-, Mid- and Long-Term Technology Options and Policy Implementations, Carnegie Mellon University, Pittsburgh, Pennsylvania.

Canals, L. M., Bauer, C., Depestele, J., et al. (2007). "Key Elements in a Framework for Land Use Impact Assessment within LCA". International Journal of Life Cycle Assessment **12**:5-15.

ConocoPhillips,(2005). Dawmin LNG Operations Environmental Management Plan [cited May 1 2009] Available from: http://www.conocophillips.com.au/NR/rdonlyres/79B19009-8E3F-44A1-81A0-7E78F7227888/0/DLNGHSEPLN001_s05_r1.pdf.

Dennis (2005). Improved Estimates of Ton Miles. Journal of Transportation Statistics. Vol. 8, Issue 1. Bureau of Transportation Statistics, Washington, D.C. 2005.

DOE (1996). Buying an Energy-Efficient Electric Motor. Department of Energy, Industrial Technologies Program. 1996. http://www1.eere.energy.gov/industry/bestpractices/pdfs/mc-0382.pdf (Accessed May 18, 2010)\ EIA, 2007. Natural Gas Compressor Stations on the Interstate Pipeline Network: Developments Since 1996.

DOE (1997). Renewable Energy Technology Characterization. Department of Energy, Office of Utility Technologies, Energy Efficiency and Renewable Energy, Washington DC. Report Number TR-109496.

DOI (2001). Proposed Use of Floating Production, Storage, and Offloading Systems On the Gulf of Mexico Outer Continental Shelf. Department of the Interior, Minerals Management Services, New Orleans, Louisiana. Report Number OCS EIS/EA MMS 2000-090.

EIA (2007). Annual Energy Outlook 2007 with Projections to 2030. Energy Information Administration. http://www.eia.doe.gov/oiaf/archive/aeo07/index.html. Report Number DOE/EIA-0383(2007).

EIA (2007b). http://tonto.eia.doe.gov/FTPROOT/features/ngcompressor.pdf. (Accessed May 18, 2010)

EIA (2008). Annual Energy Outlook 2008. Department of Energy, Energy Information Administration, Washington, D.C. Report Number DOE/EIA-0383.

EIA (2009a). Annual Energy Outlook 2009. Department of Energy, Energy Information Administration. http://www.eia.doe.gov/oiaf/aeo/index.html. DOE/EIA-0383(2009).

EIA (2009b). Natural Gas Annual 2007. Energy Information Administration, Office of Oil and Gas, Washington, DC. http://www.eia.doe.gov/pub/oil_gas/natural_gas/data_publications/natural_gas_annual/current/pdf/nga07.pdf. DOE/EIA-0131(07).

EIA (2009c). United States Total 2008: Distribution of Wells by Production Rate Bracket. Energy Information Administration. 2009.

EIA (2009d). *Natural Gas Year-In-Review*. http://www.eia.doe.gov/pub/oil_gas/natural_gas/feature_articles/2009/ngyir2008/ngyir2008.html (Accessed July 16, 2010).

EIA (2010). Personal communication with Damian Gaul, Natural Gas Division, Office of Oil and Gas, EIA. May 10, 2010.

EPA (1990). Clean Air Act. In Title 42, Chapter 85, Subchapter I, Part A, edited by U.S Environmental Protection Agency.

EPA (1995). Compilation of Air Pollutant Emission Factors, Volume I: Stationary Point and Area Sources, AP-42. US EPA Office of Air Quality Planniing and Standards. Research Triangle Park, North Carolina. 1995. http://www.epa.gov/ttnchie1/ap42 (Accessed May 18, 2010)

EPA (2006). Replacing Glycol Dehydrators with Desiccant Dehydrators, EPA, October 2006, Washington DC. http://www.epa.gov/gasstar/documents/ll_desde.pdf (Accessed June 1, 2010)

EPA (2007). SF6 Emission Reduction Partnership for Electric Power Systems : 2006 Annual Report. http://www.epa.gov/electricpower-sf6/documents/sf6_2006_ann_report.pdf.

EPA (2010). Inventory of Greenhouse Gas Emissions and Sinks: 1990-2008. U.S. EPA, Washington, D.C. April 15, 2010.

FERC (1995). Yukon Pacific LNG Project: Final Environmental Impact Statement. Office of Pipeline Regulation, Washington, DC. Report Number: FERC/EIS-0071.

GE Oil and Gas (2005). Reciprocating Compressors. General Electric Company. Florence, Italy. 2005.

Hayden, J., D. Pursell (2005). The Barnett Shale: Visitors Guide to the Hottest Gas Play in the US. Pickering Energy Partners. October 2005.

Houston Advanced Research Center (2006). Natural Gas Compressor Engine Survey for Gas Production and Processing Facilities, H68 Final Report. Houston Advanced Research Center. Houston, Texas. 2006. http://www.utexas.edu/research/ceer/GHG/files/ConfCallSupp/H068FinalReport.pdf (Accessed May 18, 2010)

ICF Consulting Ltd (2002). Unit Costs of Constructing New Transmission Assets at 380kV within the European Union, Norway, and Switzerland. DG TREN/European Commission. http://ec.europa.eu/energy/electricity/publications/doc/comp_cost_380kV_en.pdf. Study Contract NoTREN/CC/03-2002.

IPCC (2007). Climate Change 2007 Fourth Assessment Report. Edited by Intergovernmental Panel on Climate ChangeNew York: Cambridge University Press.

ISO (2006). Environmental management - Life Cycle assessment - Requirements and guidelines. International Standards Organization. ISO - 14044:2006.

Jaramillo, Paulina. (2007). A Life Cycle Comparison of Coal and Natural Gas for Electricity Generation and the Production of Transportation Fuels, Civil and Environmental Engineering, Carnegie Mellon University, Pittsburgh, Pennsylvania.

Koellner, T. and Scholz, R.W. (2007). "Assessment of Land Use Impacts on the Natural Environment. Part 1: An Analytical Framework for Pure Land Occupation and Land Use Change". International Journal of Life Cycle Assessment **12**:16-23.

Lunsford, K. (2006). Optimization of Amine Sweetening Units. Bryan Research and Engineering. 2006.

Mack, Stanley and Patchett, Joseph. (1997). SCR Catalyst Management Strategies to Reduce Operating Expenses. Paper presented at Conference on Selective Catalytic and Non-Catalytic Reduction for NOx Control.

Natural Gas.org (2004). Well Completion. http://naturalgas.org/naturalgas/well_completion.asp#liftingwell (Accessed July 1, 2010)

NETL (2010). Cost and Performance Baseline for Fossil Energy Plants: Volume 1. Department of Energy, National Energy Technology Laboratory, Pittsburgh, Pennsylvania. Report Number DOE/NETL-2010/1397.

NETL (2008). DOE/NETL's Power Systems Financial Model (PSFM) [cited August 28, 2008] Available from: http://www.netl.doe.gov/technologies/coalpower/gasification/sys-analysis/.

Offshore-technology.com (2010). Mars, Gulf of Mexico, USA. Net Resources International. http://www.offshore-technology.com/projects/mars/(Accessed June 11, 2010)

Polasek (2006). Selecting Amines for Sweetening Units. Bryan Research and Engineering. 2006.

Reddy, Satish, Johnson, Dennis and Gilmartin, John,(2008). Fluor's Econamine FG Plus^{SM} Technology for CO_2 Capture at Coal-fired Power Plants. Fluors.

SCS (2008). LCSEA FRAMEWORK: Protocols for Conducting LCIA in Accordance with Draft ASTM E06.71.10. Scientific Certification Systems. http://www.scscertified.com/events/DOCS/AnnexA_LCSEA_0108F.pdf.

Stewart, E.J. (1994). Reduce Amine Plant Solvent Losses. Hydrocarbon Processing. Gulf Publishing. Houston, Texas. May 1994.

Tamura, I., Tanaka, T., Kagajo, T., et al. (2001). "Life Cycle CO_2 Analysis of LNG and City Gas". Applied Energy **68**:301-319.

URS (2005). Darwin LNG Plant Environmental Management Programme, Volume 1 - EMP Overview and Compliance Audit Register. URS Australia Pty Ltd.

U.S. Government Accountability Office (2010). Natural Gas Flaring and Venting: Opportunities to Improve Data and Reduce Emissions. Washington, D.C. July 2004. http://www.gao.gov/new.items/d04809.pdf (Accessed June 18, 2010)

Zecchino, Paul. (2008). Phone Conversation with HVB AE Power Systems, Ltd. Representative, October 24, 2008.