Life Cycle Assessment of a Natural Gas Combined-Cycle Power Generation System

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NREL

Life Cycle Assessment

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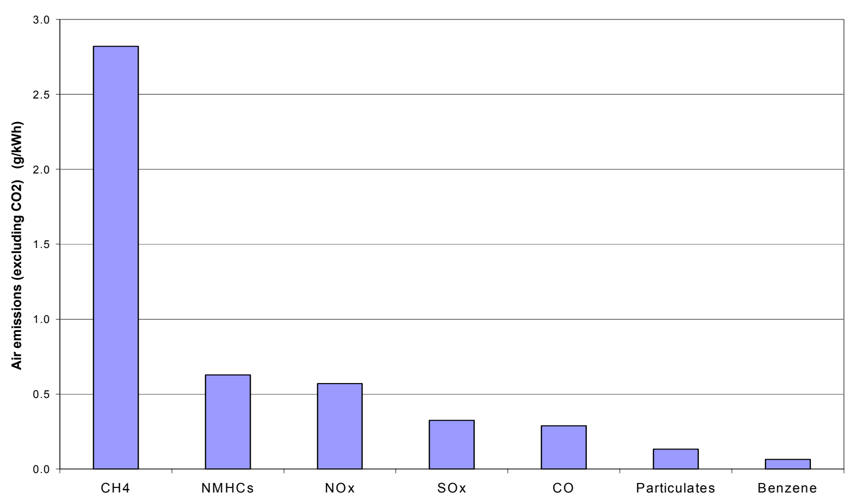
EXECUTIVE SUMMARY

Natural gas accounts for 22% of all of the energy consumed in the United States. It is used for steam and heat production in industrial processes, residential and commercial heating, and electric power generation. Currently, 15% of utility and non-utility power is produced from natural gas, while the U.S. Department of Energy's Energy Information Administration projects that 33% of the electricity generated in 2020 will be from natural gas-fired power plants (U.S. DOE, December 1998, p.5). Because of its importance in the power mix in the United States, a life cycle assessment (LCA) on electricity generation via a natural gas combined-cycle (NGCC) system has been performed. In the near future, this study will be compared with LCAs for other electricity generation systems previously performed by NREL: biomass gasification combined-cycle, coal-fired power production, biomass cofiring in a coal-fired power plant, and direct-fired biomass power generation (Mann and Spath, 1997; Spath and Mann, 1999; Mann and Spath, 2000; and Spath and Mann, 2000). This will give a picture of the environmental benefits and drawbacks of these various power generation technologies.

Since upstream processes can be significantly polluting, the application of LCA methodologies is important for gaining an understanding of the total environmental impact of a process. The system evaluated in this study was divided into the following process steps: construction and decommissioning of the power plant, construction of the natural gas pipeline, natural gas production and distribution, ammonia production and distribution for NO_x removal, and power plant operation.

The size of the NGCC power plant is 505 MW. The plant configuration consists of two gas turbines, a three pressure heat recovery steam generator, and a condensing reheat steam turbine. To minimize the plant's NO_x emissions, the power plant incorporates selective catalytic reduction (SCR) with water injection. Additionally, the base case of this LCA assumes that 1.4% of the gross natural gas that is extracted is lost to the atmosphere as fugitive emissions (Harrison *et al*, 1997).

This study found that CO_2 accounts for 99 wt% of all air emissions. Methane is emitted in the next highest quantity, 74% of which are fugitive emissions from natural gas production and distribution. Following CO_2 and CH_4, the next highest air emissions, in order of decreasing amount, include non-methane hydrocarbons (NMHCs), NO_x, SO_x, CO, particulates, and benzene.



The contributions from three greenhouse gases, CO_2, CH_4, and N_2O, are considered in the assessment of the global warming potential (GWP) of the system. According to the Intergovernmental Panel on Climate Change (IPCC) the cumulative capacities of CH_4 and N_2O to contribute to the warming of the atmosphere are 21 and 310 times higher than CO_2, respectively, for a 100 year time frame (Houghton, *et al*, 1996). The GWP for this system is 499.1 g CO_2-equivalent/kWh. The following table contains the emission rates for the different greenhouse gases and their contribution to the total GWP.

Emissions of Greenhouse Gases and Contribution to GWP

	Emission amount (g/kWh)	Percent of greenhouse gases in this table (%)	GWP relative to CO_2 (100 year IPCC values)	GWP value (g CO_2-equivalent /kWh)	Percent contribution to GWP (%)
CO_2	439.7	99.4	1	439.7	88.1
CH_4	2.8	0.6	21	59.2	11.9
N_2O	0.00073	0.0002	310	0.2	0.04

The GWP of the system can also be divided among the different system operations. The table below shows the contribution of each subsystem to the overall GWP of the system. The power plant CO_2 emissions contribute the most to the GWP at 64%. Because of the natural gas lost to the atmosphere, the natural gas production and distribution subsystem is responsible for nearly all of the remainder of the system's GWP.

GWP Contribution For Each System Component

Process step	GWP value (g CO_2-equivalent /kWh)	Percent contribution to GWP (%)
Power plant operation	372.2	74.6
Natural gas production & distribution	124.5	24.9
Construction & decommissioning	2.0	0.4
Ammonia production & distribution	0.4	0.1
Total	499.1	100.0

Note: The construction and decommissioning subsystem includes power plant construction and decommissioning as well as construction of the natural gas pipeline.

The power plant efficiency for this NGCC system is 48.8% (higher heating value (HHV) basis). This is defined as the energy to the grid divided by the energy in the natural gas feedstock to the power plant. Four other types of efficiencies/energy ratios were defined to study the energy budget of the system.

Energy Efficiency and Energy Ratio Definitions

Life cycle efficiency (%) (a)	External energy efficiency (%) (b)	Net energy ratio (c)	External energy ratio (d)
$=\dfrac{Eg-Eu-En}{En}$	$=\dfrac{Eg-Eu}{En}$	$=\dfrac{Eg}{Eff}$	$=\dfrac{Eg}{Eff-En}$
where: Eg = electric energy delivered to the utility grid Eu = energy consumed by all upstream processes required to operate power plant En = energy contained in the natural gas fed to the power plant Eff = fossil fuel energy consumed within the system (e)			

(a) Includes the energy consumed by all of the processes.
(b) Excludes the heating value of the natural gas feedstock from the life cycle efficiency formula.
(c) Illustrates how much energy is produced for each unit of fossil fuel energy consumed.
(d) Excludes the energy of the natural gas to the power plant.
(e) Includes the natural gas fed to the power plant since this resource is consumed within the boundaries of the system.

The net energy ratio is a more accurate measure of the net energy yield from the system than the external energy ratio because it accounts for all of the fossil energy inputs. The following table contains the resulting efficiencies and energy ratios for the NGCC system. All efficiencies are given on a LHV basis.

Efficiencies and Energy Ratio Results (LHV basis)

System	Life cycle efficiency (%)	External energy efficiency (%)	Net energy ratio	External energy ratio
Natural gas combined-cycle	-70.1%	29.9%	0.4	2.2

Because natural gas is not a renewable resource, the life cycle efficiency is negative, indicating that more energy is consumed by the system than is produced in the form of electricity (i.e., if the feedstock were renewable then the life cycle efficiency and external energy efficiency would be the same). Additionally, the net energy ratio in the table above shows that for every MJ of fossil energy consumed 0.4 MJ of electricity are produced. Excluding the consumption of the natural gas feedstock, the external energy efficiency and the external energy ratio indicate that upstream processes are large consumers of energy. Disregarding the energy in the natural gas feedstock, 98% of the total energy is consumed in the production and distribution of natural gas. This subsystem can be further broken up into natural gas extraction, separation and dehydration, sweetening, and pipeline transport. Of these operations, the natural gas extraction and transport steps consume the most energy. Drilling requires electricity, which is supplied by diesel combustion engines; the pipeline compressors move the natural gas using a combination of grid electricity and natural gas.

In terms of resource consumption, natural gas is used at the highest rate, accounting for nearly 98 wt% of the total resources. This is followed by coal at 1.0 wt%, iron ore plus scrap at 0.7 wt%, oil at 0.4 wt%, and limestone at 0.4 wt%. Practically all of the iron and limestone are used in the construction of the power plant and pipeline, while the production and distribution of the natural gas consumes the vast majority of the coal and oil. Also, the resource requirements associated with pipeline construction are greater than those due to power plant construction.

The total amount of water pollutants was found to be extremely small (0.01 g/kWh) compared to the other emissions. The main water emissions are oils and dissolved matter, making up 80 wt% of the total water emissions. The oils come primarily from natural gas production and distribution, while the dissolved matter is produced from the material manufacturing steps involved in pipeline and power plant construction.

In terms of solid waste, 94 wt% percent of the system's total comes from the natural gas production and distribution block. A large percentage of the waste, 65% of the total, comes from pipeline transport. Although the majority of the pipeline compressors are driven by reciprocating engines and turbines which are fueled by the natural gas, there are some electrical machines and electrical requirements at the compressor stations. Since most of the electricity in the U.S. is generated from coal-fired power plants, the majority of the waste will be in the form of coal ash and flue gas clean-up waste. The second largest waste source is natural gas extraction (29% of the total waste). The only waste stream from the power plant itself will be a small amount of spent catalyst which is generated every one to five years from the SCR unit.

A sensitivity analysis on this system determined that changes in two parameters, power plant efficiency and natural gas losses, have the largest effect on the results. Although NGCC is currently the most efficient technology available for large-scale electricity production, any increases in efficiency will reduce resulting environmental stressors throughout the system. Reducing natural gas losses during production and distribution increases the net energy balance and lowers the GWP.

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Units of Measure

Metric units of measure are used in this report. Therefore, material consumption is reported in units based on the gram (e.g., kilogram or megagram), energy consumption based on the joule (e.g., kilojoule or megajoule), and distance based on the meter (e.g., kilometer). When it can contribute to the understanding of the analysis, the English system equivalent is stated in parenthesis. The metric units used for each parameter are given below, with the corresponding conversion to English units.

Mass:	kilogram (kg) = 2.205 pounds
	megagram (Mg) = metric tonne (T) = 1 x 10^6 g = 1.102 ton (t)
Distance:	kilometer (km) = 0.62 mile = 3,281 feet
Area:	hectare (ha) = 10,000 m^2 = 2.47 acres
Volume:	cubic meter (m^3) = 264.17 gallons
Pressure:	kilopascals (kPa) = 0.145 pounds per square inch
Energy:	kilojoule (kJ) = 1,000 Joules (J) = 0.9488 Btu
	gigajoule (GJ) = 0.9488 MMBtu (million Btu)
	kilowatt-hour (kWh) = 3,414.7 Btu
	gigawatt-hour (GWh) = 3.4 x 10^9 Btu
Power:	megawatt (MW) = 1 x 10^6 J/s
Temperature:	°C = (°F - 32)/1.8

Abbreviations and Terms

AGA	American Gas Association
Avoided stressor	an emission, energy use, or resource consumption that does not occur because the system of interest is operating
Avoided operation	a process that normally would have taken place if the system of interest were not operating
Btu	British thermal units
CO_2-equivalence	Expression of the GWP in terms of CO_2 for the following three components CO_2, CH_4, N_2O, based on IPCC weighting factors
CFR	Code of Federal Regulations
DEAM	Data for Environmental Analysis and Management (also referred to as the TEAM® database)
DOE	United States Department of Energy
EIA	Energy Information Administration
GRI	Gas Research Institute
GWP	global warming potential, expressed as grams of CO_2-equivalent
HHV	higher heating value
IPCC	Intergovernmental Panel on Climate Change
kWh	kilowatt-hour (denotes energy)
LAER	lowest achievable emissions rate
LCA	life cycle assessment
MW	megawatt (denotes power)
N_2O	nitrous oxide
NMHCs	non-methane hydrocarbons, including VOCs
NSPS	New Source Performance Standard
NO_x	nitrogen oxides, (NO_2 and NO, expressed as NO_2)
NREL	National Renewable Energy Laboratory
SCR	Selective catalytic reduction
SO_x	sulfur oxides, expressed as SO_2
Stressor	A term that collectively defines emissions, resource consumption, and energy use; a substance or activity that results in a change to the natural environment
Stressor category	A grouping of stressors that defines and delineates impacts
TEAM®	Tools for Environmental Analysis and Management (software by Ecobalance, Inc.)
UDI	Utility Data Institute
U.S. DOE	United States Department of Energy
U.S. EPA	United States Environmental Protection Agency
VOC	volatile organic compound
vol%	percentage by volume
wt%	percentage by weight

1.0 Introduction

Natural gas is an important fuel in the United States. It accounts for 22% of all the energy consumed in the U.S. and is used for steam and heat production in industrial processes, residential and commercial heating, and electric power generation (U.S. DOE, December 1998). Although coal is the feedstock used at the highest rate to produce power in the U.S., because natural gas is one of the cleanest burning fossil fuels, its role in electricity generation is becoming increasingly important. Currently, natural gas accounts for 9.9% of the fuel consumed in power production (U.S. DOE, July 1998), which results in 14.7% of the net electricity generated by the electric power industry. This can be compared to coal, which accounts for 56% of the fuel consumed in making electricity in the U.S. (U.S. DOE, July 1998), but results in 51.7% of the net electricity generated (including non-utility power producers). These numbers show that one advantage of natural gas systems is their higher conversion efficiencies compared to coal-fired power plants. Because electricity restructuring favors less capital-intensive, more efficient generation processes, electricity generated from natural gas is expected to grow from the current 14.7% to 33% by 2020 (U.S. DOE, December 1998).

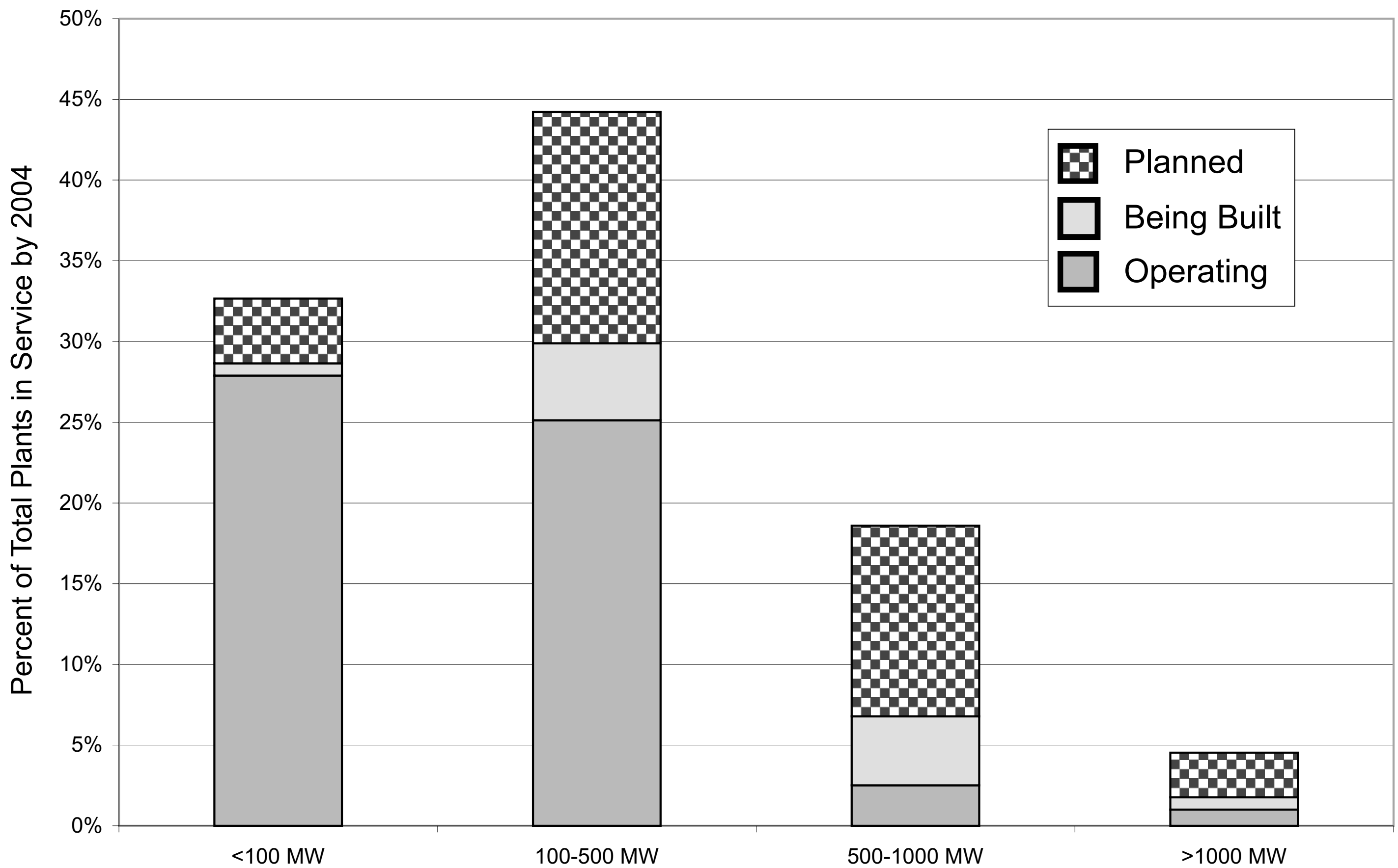
Increasing the use of natural gas for electricity production can benefit the environment in many ways compared to electricity generated from other fossil fuels. Because natural gas has a lower sulfur and nitrogen content than coal, for example, using natural gas will result in fewer SO_x and NO_x emissions per kWh of electricity produced. Additionally, unlike coal-fired power plants, a natural gas combined-cycle (NGCC) system produces no large solid waste streams. The environmental consequences of a power generation facility, though, depend not only on the emissions from the plant, but also those that result from upstream operations such as fuel production and transportation.

This life cycle assessment was performed to quantify and analyze the environmental aspects of producing electricity from a NGCC power generation system, including all necessary upstream operations. The system was divided into the following process steps: construction and decommissioning of the power plant, construction of the natural gas pipeline, natural gas production and distribution, ammonia production and distribution for NO_x removal, and power plant operation. In the near future, this LCA will be compared with previously performed LCAs for other electricity generation systems: biomass gasification combined-cycle, coal-fired power production, biomass cofiring in a coal-fired power plant, and direct-fired biomass power generation (Mann and Spath, 1997; Spath and Mann, 1999; Mann and Spath, 2000; and Spath and Mann, 2000). A report will be issued in late 2000 which examines the environmental benefits and drawbacks of the various electricity generating systems. However, it should be noted that because no operations that are common to the different systems were eliminated, the analysis of the NGCC system is complete, irrespective of the competing technologies.

2.0 System Description and Major Assumptions

The methodology for this LCA is the same as that used in LCAs earlier performed by the National Renewable Energy Laboratory (NREL) (Mann and Spath, 1997 and Spath and Mann, 1999). The NGCC system was modeled in GateCycle™, a software package which performs detailed steady-state and off-design analyses of thermal power systems. This software by Enter Software™ was specifically developed to help design and analyze combined-cycle and fossil boiler power plants. The software was used to obtain an energy balance and some of the material balance data for the power plant itself (see section 7.0 for details about the base case turbine emissions). The plant is assumed to be a baseload plant and the size was chosen to be around 500 MW, which is similar to the size of the plant studied in NREL's coal-fired power plant LCA (Spath and Mann, 1999). A large number of NGCC plants currently operating, being built, or planned are generally in the 100-500 MW size range. Figure 1, which contains data from the Utility Data Institute

Figure 1: Natural Gas Combined-Cycle Plant Size Mix in 2004



database, denotes this fact (UDI, 1999). This figure also shows that the trend is to build larger plants for future electricity generation.

The system in this study contains two Siemens Westinghouse W501F gas turbines, a three pressure heat recovery steam generator, and a condensing reheat steam turbine. In this analysis, the gas turbines are "data driven" and therefore use a set of vendor curves to determine their performance at a given set of operating conditions. Figure 2 shows the system configuration that was modeled in GateCycle™. Data from the UDI database shows Siemens Westinghouse W501 series turbine to be prominent in NGCC plants currently under construction. This series accounts for 34% of the total number of turbines listed in the database (taken from UDI, 1999). However, it is not clear which turbines will be used by future plants since almost all of the planned plants in this database have no designated turbine type or manufacturer. To minimize the power plant's NO_x emissions, the power plant incorporates selective catalytic reduction (SCR) with water injection (see section 6.0). The system parameters for the power plant can be seen in Table 1.

Table 1: Natural Gas Combine Cycle Power Plant Data

Design parameter	Data
Plant size	505 MW
Net power from gas turbines (@100% capacity)	337 MW
Net power from steam cycle (@100% capacity)	168 MW
Natural gas feed rate @ 100% operating capacity	1,673 Mg/day
Power plant efficiency (HHV basis)	48.8%
Net heat rate (HHV basis)	7,378 kJ/kWh
Water injection ratio	0.8 kg/kg of natural gas
NO_x removal efficiency	78%
Ammonia injection ratio	0.89 mol of NH_3/mol of NO_x removed
Average operating capacity factor	80%

3.0 System Boundaries

The software package used to track the material and energy flows between the process blocks within the system was Tools for Environmental Analysis and Management (TEAM®), by Ecobalance, Inc. Figure 3 shows the boundaries for the system. The solid lines in the figure represent actual material and energy flows; the dotted lines indicate logical connections between process blocks. The stressors associated with natural gas production and distribution, as well as those for ammonia production, were taken from the TEAM® database, known as Data for Environmental Analysis and Management (DEAM). The steps associated with obtaining the natural gas feedstock are drilling/extraction, processing, and pipeline transport. Processing includes glycol dehydration and gas sweetening using the amine process in which sulfur is recovered as elemental sulfur. The emissions associated with each process step in the natural gas production block were obtained through a joint study by Ecobalance and the Gas Research Institute (GRI). The ammonia production process assumes no CO_2 recovery. In addition to being the feedstock, a significant amount of natural gas is required as fuel in the ammonia production block. This results in 60 wt% of the total natural gas into this process block being utilized for the feedstock while 40 wt% is consumed as fuel for the ammonia production.

Figure 2: Natural Gas Combined-Cycle Power Plant Configuration

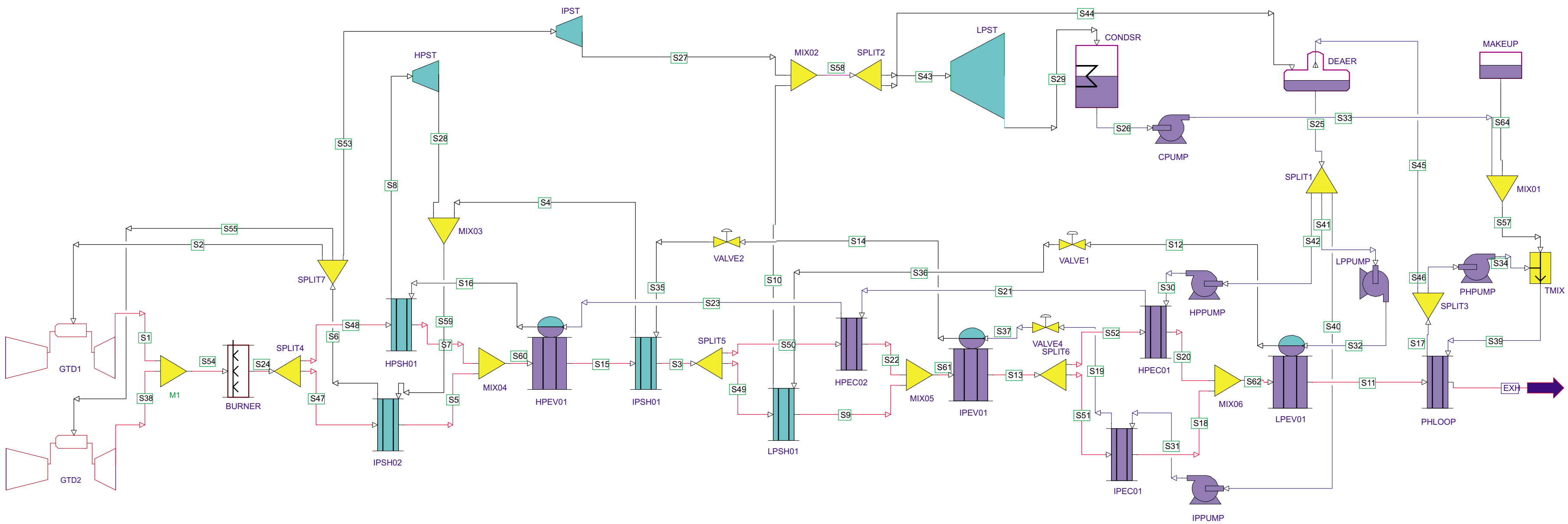
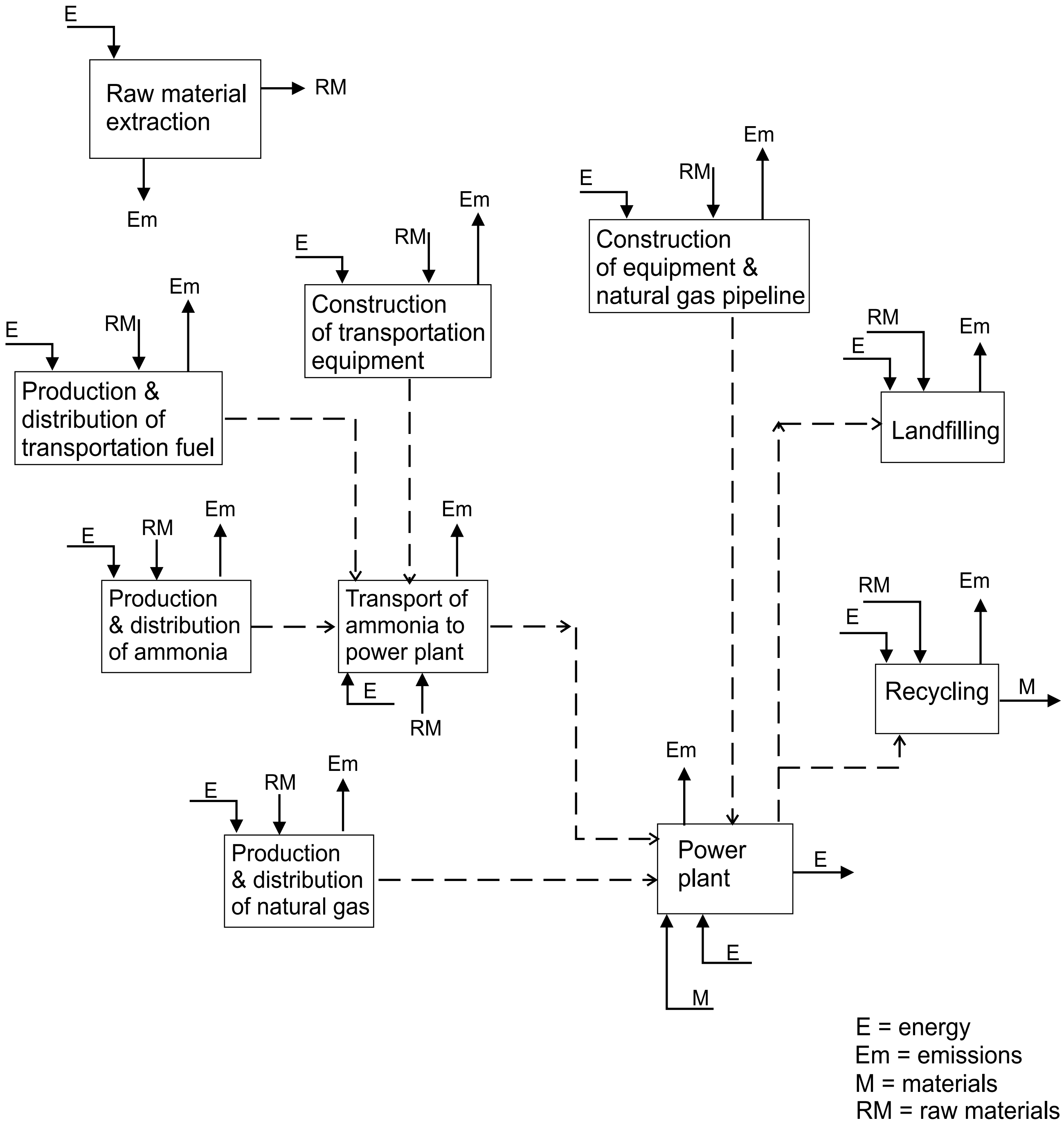


Figure 3: System Boundaries for Electricity Production via a Natural Gas Combined-Cycle Process



The ammonia must be transported from its production point to the power plant. The transportation requirements were assumed to be 60% by rail and 40% by truck over an average distance of 640 km (based on details gathered for NREL's biomass power LCA study) (Mann and Spath, 1997). Light fuel oil and diesel are used in the trains and trucks, respectively. The resources, energy, and emissions related to extracting crude oil, distilling it, producing a usable transportation fuel, and distributing it to refueling stations, plus the emissions produced during combustion of the fuel, were included in the total inventory. These data were taken from the DEAM database, of which some details are shown in Appendix B of NREL's biomass power LCA report (Mann and Spath, 1997). The material requirements for each of the various modes of transportation were used in determining the environmental stressors associated with vehicle production and decommissioning (for more details about these requirements refer to Mann and Spath, 1997).

For this study, the plant life was set at 30 years with 2 years of construction. In year one the power plant begins to operate; plant construction takes place in the two years prior to this (years negative two and negative one). In year one, the power plant is assumed to operate 40% of the time due to start-up activities (50% of the year at a capacity factor of 80%). In years one through 29, normal plant operation occurs with the plant operating at a capacity factor of 80%. In year 30, the power plant is decommissioned during the last quarter of that year. Therefore, the power plant will be in operation 60% of the last year (75% of the year at a capacity factor of 80%).

Methods for determining plant construction and decommissioning are the same as those used in NREL's past LCAs (see Mann and Spath, 1997 and Spath and Mann, 1999). Table 2 lists the power plant construction material requirements used in this study. These values were based on a study by DynCorp (1995) which examined power generation via a number of technologies, including a 200 MW NGCC system.

Table 2: Power Plant Material Requirements (Base Case)

Material	Amount required (kg/MW of plant capacity)
Concrete	97,749
Steel	31,030
Iron	408
Aluminum	204

It was also assumed that with the significant amount of natural gas being consumed, additional pipelines would be required to move the natural gas from the oil or gas wells to the power plant. *Ullmann's Encyclopedia of Industrial Chemistry* (1986) states that typical pipe diameters in the natural gas industry are 60-110 centimeters (23.6-43.3 inches) and *Kirk-Othmer's Encyclopedia of Chemical Technology* (1993) lists a range of 36-142 centimeters (14.2-55.9 inches). For this analysis, the total length of pipeline transport is assumed to be 4,000 km (2,486 mi). The main pipeline diameter was set at 76.2 centimeters (30 inches) and this main pipeline is assumed to extend 80% of the total distance or 3,200 km (1,988 mi). Because the main pipeline is shared by many users, only a portion (19.3%) of the material requirement was allocated for the NGCC plant. To determine this percentage, the total flow through the 76.2 cm diameter pipe at a pressure drop of 0.05 psi/100 feet (0.00035 MPa/30 meters) was calculated then the required natural gas flow rate for this NGCC plant was divided by the total flow, which resulted in a value of 15.4%. The remaining length of the total pipeline, 800 km (498 mi), was also sized so that the pressure drop through the pipe would not exceed 0.05 psi/100 feet (0.00035 MPa/30 meters). This resulted in a pipe diameter of 46 centimeters (18 inches). Thus, the total pipeline steel requirement for the power plant was 94,336 Mg (103,988 tons), assuming a standard wall thickness. The process steps associated with producing the steel were included in the analysis. Due to a lack of data, no additional emissions for digging and laying the pipe were included in the analysis. Nevertheless, a sensitivity analysis was performed with different pipe diameters to determine the material requirement effect on the overall results (see section 9.1).

4.0 Natural Gas Composition

In general, natural gas is produced from gas or oil wells. Methane is the main component in natural gas, usually making up greater than 80 vol% of the constituents. The remaining constituents are ethane, propane, butane, hydrogen sulfide, and inerts (nitrogen, carbon dioxide, and helium). The amount of these compounds can vary greatly depending on the location of the wellhead. The gas almost always undergoes treatment prior to its use, which primarily means drying and sweetening. Most often, the gas is saturated with water vapor and glycol units can dehydrate the natural gas to a moisture content of 8 mg/m^3 (*Ullmann's Encyclopedia of Industrial Chemistry*, 1986). Natural gas containing H_2S is sweetened, most commonly with the amine process, to reduce the H_2S concentration to less than 4 ppmv *(Ullmann's Encyclopedia of Industrial Chemistry*, 1986). To lower the amount of energy expended in transporting the natural gas stream, it is cost effective to minimize the levels of CO_2 and N_2. Additionally, CO_2 is reduced to 1-2 vol% to curtail the amount of corrosion in the transmission systems (*Ullmann's Encyclopedia of Industrial Chemistry*, 1986). There are no universally accepted specifications for marketed natural gas; however, the U.S. standards are listed in Table 3 (taken from *Ullmann's Encyclopedia of Industrial Chemistry*, 1986).

Table 3: U.S. Natural Gas Pipeline Specifications

Characteristic	Specification
Water content	64-112 mg/m^3
Hydrogen sulfide	5.7 mg/m^3 (4 ppmv)
Gross heating value	35.4 MJ/m^3
Hydrocarbon dew point at 5.6 MPa	264.9 K
Mercaptan content	4.6 mg/m^3
Total sulfur	23-114 mg/m^3
Carbon dioxide	1-3 mol%
Oxygen	0-0.4 mol%

The base case of this LCA used the typical natural gas pipeline composition listed in the *Chemical Economics Handbook* (Lacson, 1999), which was adjusted to include H_2S (4 ppmv; based on the specifications above). The composition of the natural gas transported to the power plant is shown in Table 4. To show the diversification of natural gas compositions found throughout the world, the range of wellhead component values is also listed in Table 4.

Table 4: Natural Gas Composition

Component	Pipeline composition used in analysis (a)	Typical range of wellhead components (mol%) (b)	
	Mol % (dry)	Low value	High value
Carbon dioxide (CO_2)	0.5	0	10
Nitrogen (N_2)	1.1	0	15
Methane (CH_4)	94.4	75	99
Ethane (C_2H_6)	3.1	1	15
Propane (C_3H_8)	0.5	1	10
Iso-butane (C_4H_{10})	0.1	0	1
N-butane (C_4H_{10})	0.1	0	2
Pentanes + (C_5^+)	0.2	0	1
Hydrogen sulfide (H_2S)	0.0004	0	30
Helium (He)	0.0	0	5
Heat of combustion, LHV	48,252 J/g (20,745 Btu/lb)	——	——
Heat of combustion, HHV	53,463 J/g (22,985 Btu/lb)		

(a) Taken from *Chemical Economics Handbook* (Lacson, 1999) and adjusted to included H_2S.
(b) Taken from *Ullmann's Encyclopedia of Industrial Chemistry*, 1986.

Changing the composition of the wellhead gas, other than the split of hydrocarbons, primarily affects the processing requirements prior to pipeline distribution. Individual energy and material balances could not be obtained for the glycol dehydration and amine gas sweetening steps; therefore, a sensitivity analysis, which varies the wellhead gas composition was not performed. Furthermore, from the DEAM database a breakdown of the stressors show that the majority come from extraction and pipeline transport and only a small fraction are the result of separation, dehydration, and sweetening. Changing the split of higher hydrocarbons versus CH_4 will slightly change the energy and carbon balance of the power plant, but since natural gas is primarily made up of CH_4 the changes will not be large enough to affect the overall results. To test this, a natural gas composition containing 80 vol% methane and roughly 20 vol% higher hydrocarbons (primarily ethane and propane) was put into the GateCycle™ model. The plant capacity decreased from 504.95 MW to 504.25 MW, the natural gas requirement increased 1% from 1,673 Mg/day to 1,692 Mg/day, and the CO_2 emissions increased by about 4%. Therefore, it was not considered beneficial to perform a sensitivity analysis with different ratios of CH_4 to higher hydrocarbons.

5.0 Natural Gas Losses

Over the past two decades, the natural gas industry and others have tried to better quantify the amount of CH_4 emissions lost to the atmosphere during the extraction, processing, transmission, storage, and distribution of natural gas. There is a general consensus that fugitive emissions constitute the largest source, accounting for about 38% of the total, and that nearly 90% of the fugitive emissions are a result of leaking compressor components (Resch, 1995 and Harrison *et al*, 1997). The second largest source of CH_4 emissions comes from pneumatic control devices, accounting for approximately 20% of the total (Resch, 1995). Pneumatic devices are a major emissions source in the extraction step. Engine exhaust is the third largest source of CH_4

emissions due to incomplete combustion in reciprocating engines and turbines. Thus, these three sources make up nearly 75% of the overall estimated CH_4 emissions (Resch, 1995; Harrison *et al*, 1997).

According to the United States Environmental Protection Agency (U.S. EPA), transmission and storage account for the largest portion of the total methane emissions at 37% followed by extraction at 27%, distribution at 24%, and processing contributing the least at 12% (Harrison *et al*, 1997). In the late 1980s EPA, GRI, and the American Gas Association (AGA) initiated a study which estimated the methane emitted to the atmosphere from U.S. natural gas operations to be 1.4% +/- 0.5% of the gross natural gas produced (Harrison *et al*, 1997). Another publication (Kirchgessner *et al*, 1997) which includes several authors of the EPA/GRI/AGA study, states that numerous estimates of methane emissions are available and that the most commonly cited leakage rates range from 1-4%. Following the U.S. EPA/GRI/AGA study, the Natural Gas STAR Program was launched in 1993. It is a voluntary program with the natural gas industry that is designed to reduce CH_4 emissions through cost-effective measures. The program currently has more than 80 partners. Because this program is designed to keep the methane emissions to a minimum, the overall amount of methane lost to the atmosphere is actually expected to decrease as the natural gas industry grows. The base case of this LCA assumed that 1.4% of the natural gas that is produced is lost to the atmosphere due to fugitive emissions. To determine the effect that natural gas losses have on the results and specifically on the systems global warming potential (GWP), a sensitivity analysis was performed on this variable (see section 9.2). The natural gas production module in DEAM was altered so that it could accommodate different natural gas loss rates.

6.0 NO_x Control: Water Injection and Selective Catalytic Reduction

To minimize NO_x emissions, the power plant incorporates SCR with water injection. The water injection rate is 0.8 kg/kg of natural gas. GateCycle™ has the capability to model water injection but not SCR, so external calculations were performed to estimate flue gas NO_x levels. In the SCR unit, the NO_x removal efficiency was assumed to be 78% (an industry average) and the molar ratio of ammonia injected to NO_x removed is 0.89 based on data from three sources: Environmental Catalyst Consultants, Inc., 1992; SRI International,1989 and U.S. EPA, 1992.

SCR is frequently used to reduce flue gas NO_x emissions from power plants. In this process, ammonia (NH_3) is injected into the gas stream before the gas enters the catalyst bed. The ammonia reacts with the NO_x in the presence of a catalyst to form water vapor and nitrogen. The chemistry can be represented by two reactions: $4NO + 4NH_3 + O_2 \Rightarrow 4N_2 + 6H_2O$ and $2NO_2 + 4NH_3 + O_2 \Rightarrow 3N_2 + 6H_2O$. The base metal of the most common SCR catalysts is either vanadium, platinum, or titanium (Environmental Catalyst Consultants, 1992). Zeolites have also been demonstrated as effective catalysts. The SCR catalyst requires replacement every one to five years depending on the degree of sintering that occurs at the high reaction temperatures, plugging of pores due to solid deposits, and poisoning by alkali compounds or SO_3 (Makansi 1988). Utilities have several options for handling spent catalyst. They can send it to a metals recovery facility for recycling, dispose of it in a landfill, or return it to the original catalyst supplier. It may be possible to regenerate the zeolite catalysts; however, the process is not yet commercial. Because a system design giving the amount of catalyst required could not be obtained for this LCA, the manufacture and disposal of the catalyst were not included. Although the amount of spent catalyst will be small and not produced continuously, this is the only solid waste stream from the power plant.

In general, the SCR catalyst promotes the conversion SO_2 to SO_3 in the presence of O_2. The SO_3 can then react with any residual NH_3 to form ammonium sulfate and ammonium bisulfate which will deposit in downstream heat exchangers causing plugging problems (Makansi 1988). Therefore, it is important to control the amount of excess unreacted NH_3. As the SCR catalyst deactivates, the NH_3 slip (i.e., the NH_3 that exits the SCR unit) increases. The catalyst is usually maintained or replaced periodically to keep the slip below 5 ppm to minimize plugging problems and to maintain emissions below a regulated level (Environmental Catalyst Consultants, Inc., 1992). For this analysis, the ammonia slip was taken from EPA's emission data for stationary gas turbines (U.S. EPA 1995, section 3.1, Stationary Gas Turbines for Electricity Generation, "Emission Factors for Large Gas-Fired Controlled Gas Turbines"), which is 5.5 ppm for this system. Several sensitivity analyses were performed to examine different amounts of NO_x from the power plant with and without NO_x control (see section 9.5).

7.0 Base Case - Power Plant Emissions

As mentioned in section 2.0, GateCycle™ was used to obtain material balance data for the gas turbine. This software program does not account for NO_x, SO_x, or incomplete combustion, therefore, additional emission data were obtained from the references given in Table 5. To balance the carbon atoms, the carbon emissions emitted from incomplete combustion (CO, and CH_4) were subtracted from GateCycle's™ CO_2 emissions. Additionally, the non-methane hydrocarbons (NMHCs) and formaldehyde, which are results of the SCR process step, were also subtracted from GateCycle's™ CO_2 emissions. The ammonia and the NO_x is the amount that slips through the SCR unit. All of the sulfur in the feed was converted to SO_2.

Table 5: Power Plant Operating Emissions (Base Case)

Compound	Emission amount (kg/GWh)	Reference
Ammonia (NH_3)	21	U.S. EPA 1995 (a)
Carbon dioxide (CO_2)	371,247	GateCycle - after adjustment
Carbon monoxide (CO)	27	U.S. EPA 1995 (a)
Formaldehyde (CH_2O)	9	U.S. EPA 1995 (a)
Methane (CH_4)	44	U.S. EPA 1995 (a)
Nitrogen oxides (NO_x as NO_2)	95	U.S. EPA 1995 (a)
Non-methane hydrocarbons (NMHCs)	10	U.S. EPA 1995 (a)
Particulates	62	U.S. EPA 1995 (b)
Sulfur oxides (SO_x as SO_2)	2	U.S. EPA 1995 (a)

(a) Section 3.1 - Stationary Gas Turbines for Electricity Generation, "Emission Factors for Large Gas-Fired Controlled Gas Turbines," SCR with water injection
(b) Section 3.1 - Stationary Gas Turbines for Electricity Generation, "Emission Factors for Large Gas-Fired Uncontrolled Gas Turbines," PM-10, solids

Because no data could be found regarding particulate emissions from NGCC power plants with NO_x control, the non-condensable particulate emissions for uncontrolled turbines were used in this study. The SCR catalyst bed will act as a filter for some of the particulates. However, catalyst fines will result in some particulate emissions, possibly canceling particulate reduction in the bed.

For this study, the NGCC power plant emissions are lower than those required by the New Source Performance Standards (NSPS) under the Code of Federal Regulations (CFR) for gas-fired power plants. Table 6 indicates the standards of performance for new electric utility steam generating units using gaseous fossil fuels (other than coal-derived gases) (40 CFR 60.42a, 60.43a, and 60.44a; Office of the Federal Register National Archives and Records Administration, 1996). New plants built after 1978 are required to meet these standards. The base case plant emissions are also shown in Table 6 for comparison. The emission rates listed in the CFR were converted to kg/GWh for comparison to the base case values used in this LCA. Again, several sensitivity analyses were performed to examine different amounts of NO_x from the power plant with and without NO_x control (see section 9.5).

Table 6: New Source Performance Standards for Gas-Fired Power Plants

	NSPS		Base case power plant emissions
	g/GJ heat input, HHV (lb/MMBtu)	For this plant the NSPS would result in an emission amount of (kg/GWh)	(kg/GWh)
NO_x	86 (0.2)	634	95
SO_x	86 (0.2)	634	2
Particulates	13 (0.03)	95	62

Note: These standards do not apply to coal-derived gases.

8.0 Results

The following sections contain the results for the base case analysis, including air emissions, energy requirements, resource consumption, water emissions, and solid wastes. Most values are given in terms of the functional unit (kWh of net electricity produced by the power plant), as averages over the life of the system so that the relative percent of emissions from each subsystem could be examined.

8.1 Greenhouse Gases and Global Warming Potential

The GWP of the system is defined as a combination of the following greenhouse gases: CO_2, CH_4, and N_2O. The capacities of CH_4 and N_2O to contribute to the warming of the atmosphere, are 21 and 310 times higher than CO_2, respectively, for a 100 year time frame according to the IPCC (Houghton *et al*, 1996). Thus, the GWP of the system can be normalized to CO_2-equivalence to describe its overall effect on global climate change. Table 7 contains the GWP as well as the net amount of greenhouse gases for this NGCC power generation system. CO_2, which is emitted in the largest quantity (99 wt% of the greenhouse gases listed in Table 7 as well as 99 wt% of the overall air emissions - see section 8.2), is responsible for 88.1% of the system GWP. Although the CH_4 emitted from this system makes up only 0.6% of all greenhouse gases by weight, its higher radiative forcing factor causes it to be responsible for 11.6% of the total GWP. Nearly all of this methane is a result of natural gas losses during extraction and distribution (see section 8.2).

Table 7: Greenhouse Gas Emissions and Global Warming Potential

	Emission amount (g/kWh)	Percent of greenhouse gases in this table (%)	GWP relative to CO_2 (100 year IPCC values)	GWP value (g CO_2-equivalent /kWh)	Percent contribution to GWP (%)
Total CO_2 emissions	439.7	99.4	1	439.7	88.1
Total CH_4 emissions	2.8	0.6	21	59.2	11.9
Total N_2O emissions	0.00073	0.0002	310	0.2	0.04
Total system GWP	N/A	N/A	N/A	585.2	N/A

In addition to showing the GWP in terms of individual greenhouse gases, the GWP of the system can also be divided among the different process steps. For this study, the overall system was broken out into construction and decommissioning, natural gas production and distribution, ammonia production and distribution, and power plant operation. Figure 4 shows these different process steps and their contribution to the overall GWP of the system. The power plant operating emissions, principally CO_2, contribute the most to the GWP at 75%. Because of the natural gas lost to the atmosphere (which is 1.4% of the gross natural gas production for the base case), the natural gas production and distribution block is responsible for 25% of the system's GWP. Changing the amount of natural gas lost has a significant effect on the GWP, as shown in section 9.2.

8.2 Air Emissions

As previously mentioned, CO_2 is the air emission emitted in the largest quantity. Methane is emitted in the next highest quantity, and 74 wt% of the total methane emissions are fugitive emissions from natural gas production and distribution. Table 8 is a breakdown of the major air emissions and the percentage that comes from construction and decommissioning, natural gas production and distribution, ammonia production and distribution, and electricity generation. Excluding CO_2, CH_4 accounts for 58 wt% of the emissions, followed by NMHCs at 13 wt%, NO_x at 12 wt%, SO_x at 7 wt%, and CO at 6 wt%.

Figure 4: Life Cycle Global Warming Potential

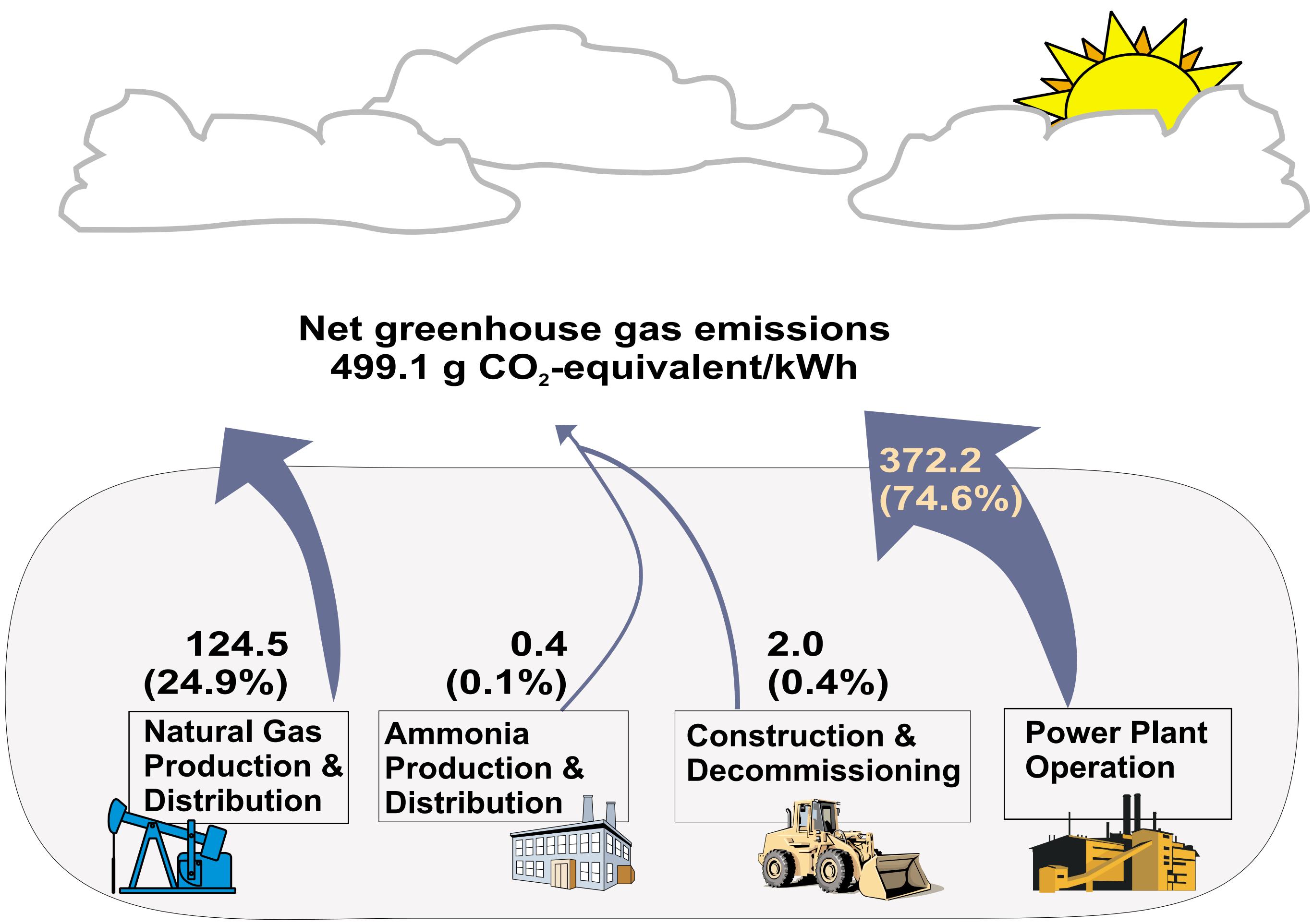


Table 8: Average Air Emissions

Air emission (a)	System total (g/kWh)	% of total in this table	% of total in this table except CO_2	% of total from construction & decommissioning (b)	% of total from natural gas production & distribution	% of total from ammonia production & distribution	% of total from electricity generation
Ammonia (NH_3)	2.10E-02	< 0.0%	0.4%	0.2%	0.0%	1.6%	98.2%
Benzene (C_6H_6)	6.32E-02	< 0.0%	1.3%	0.0%	99.9%	0.1%	0.0%
Carbon dioxide (CO_2)	4.40E+02	98.9%		0.5%	15.0%	0.1%	84.4%
Carbon monoxide (CO)	2.87E-01	0.1%	5.9%	1.6%	88.6%	0.5%	9.3%
Hydrogen sulfide (H_2S)	1.41E-08	< 0.0%	< 0.0%	100.0%	0.0%	< 0.0%	< 0.0%
Formaldehyde (CH_2O)	8.57E-03	< 0.0%	0.2%	0.0%	0.0%	0.0%	100.0%
Methane (CH_4)	2.82E+00	0.6%	58.1%	< 0.0%	98.4%	< 0.0%	1.6%
Nitrogen oxides (NO_x as NO_2)	5.70E-01	0.1%	11.7%	1.6%	81.5%	0.1%	16.7%
Nitrous oxide (N_2O)	7.19E-04	< 0.0%	< 0.0%	19.4%	80.2%	0.5%	0.0%
Non-methane hydrocarbons (NMHCs)	6.28E-01	0.1%	12.9%	2.3%	95.8%	0.2%	1.6%
Particulates	1.33E-01	< 0.0%	2.7%	38.0%	15.6%	< 0.0%	46.4%
Sulfur oxides (SO_x as SO_2)	3.24E-01	0.1%	6.7%	15.4%	83.8%	0.2%	0.6%

(a) Because of significant figures some of the percentages in this table are not actually zero and therefore are denoted as less than zero percent.
(b) The construction and decommissioning subsystem includes power plant construction and decommissioning as well as construction of the natural gas pipeline.

8.3 Energy Consumption and System Energy Balance

Table 9 shows the energy balance for the NGCC system (LHV basis). The majority, 80%, of the total energy consumed is that contained in the natural gas feedstock. The upstream fossil energy, which accounts for 21% of the total energy consumption, includes the energy of the natural gas that is lost to the atmosphere. Although not listed separately in Table 9, this energy loss is equal to 0.11 MJ/kWh or 1.4% of the total energy consumed by the system.

Table 9: Average Energy Requirements per kWh of Net Electricity Produced (LHV basis)

	System total (MJ/kWh)	% of total in this table	% of total from construction & decommissioning (a)	% of total from natural gas production, distribution, and use	% of total from ammonia production & distribution
Energy in the natural gas to power plant	6.7	79.5%	N/A	100.0%	N/A
Non-feedstock energy consumed by system (b)	1.7	20.5%	1.4%	97.9%	0.5%
Total energy consumed by system	8.4	N/A	N/A	N/A	N/A

(a) The construction and decommissioning subsystem includes power plant construction and decommissioning as well as construction of the natural gas pipeline.
(b) Excludes the energy in the natural gas feedstock energy but includes the energy in the natural gas lost to the atmosphere during natural gas production.

The energy use within the system was tracked so the net energy production could be assessed. Several types of efficiencies can be defined to study the energy budget. As stated earlier, the power plant efficiency for this NGCC system is 48.8% (HHV basis). This is defined as the energy to the grid divided by the energy in the natural gas feedstock to the power plant. Four other types of efficiencies/energy ratios can be defined as follows:

Table 10: Energy Efficiency and Energy Ratio Definitions

Life cycle efficiency (%) (a)	External energy efficiency (%) (b)	Net energy ratio (c)	External energy ratio (d)
$= \frac{Eg - Eu - En}{En}$	$= \frac{Eg - Eu}{En}$	$= \frac{Eg}{Eff}$	$= \frac{Eg}{Eff - En}$
where: Eg = electric energy delivered to the utility grid Eu = energy consumed by all upstream processes required to operate power plant En = energy contained in the natural gas fed to the power plant Eff = fossil fuel energy consumed within the system (e)			

(a) Includes the energy consumed by all of the processes.
(b) Excludes the heating value of the natural gas feedstock from the life cycle efficiency formula.
(c) Illustrates how much energy is produced for each unit of fossil fuel energy consumed.
(d) Excludes the energy of the natural gas to the power plant.
(e) Includes the natural gas fed to the power plant since this resource is consumed within the boundaries of the system.

The net energy ratio is a more accurate and rigorous measure of the net energy yield from the system than the external energy ratio because it accounts for all of the fossil energy inputs. However, the external definitions give a better understanding of upstream energy consumption. It is important to have these four definitions because the fossil fuel fed to the power plant overshadows the energy consumption from other process steps. Table 11 contains the resulting efficiencies and energy ratios for the system; given on a LHV basis.

Table 11: Efficiencies and Energy Ratio Results (LHV basis)

System	Life cycle efficiency (%)	External energy efficiency (%)	Net energy ratio	External energy ratio
Natural gas combined-cycle	-70.1%	29.9%	0.4	2.2

Because the natural gas is not a renewable source, the life cycle efficiency (which gives the total energy balance for the system) is negative, indicating that more energy is consumed by the system than is produced in the form of electricity. Excluding the consumption of the natural gas feedstock, the low values of the external energy efficiency and the external energy ratio indicate that upstream processes are large consumers of energy. Although not derived from the information in Table 11, disregarding the energy in the natural gas feedstock, 98% of the total energy consumption comes from natural gas production and distribution (see Table 9). This process block can be further broken up into natural gas extraction, processing, transmission, storage, and distribution. Of these, the largest consumers of energy are the natural gas extraction and pipeline transport steps. Diesel oil is combusted to meet the energy requirements of the drilling equipment, while pipeline transport uses a combination of grid electricity and natural gas to move the natural gas from its point of origin to its destination. Additionally, the net energy ratio in the table above shows that for every MJ of fossil energy consumed 0.4 MJ of electricity are produced.

8.4 Resource Consumption

As one would expect, natural gas is consumed at the highest rate, accounting for nearly 98 wt% of the total resources. This is followed by coal, iron ore plus scrap, oil, and limestone. Table 12 shows the amount of resources consumed per kWh and the percentage from the different process steps. Practically all of the iron and limestone are used in the construction of the power plant and pipeline, while the vast majority of the coal and oil are consumed during the production and distribution of the natural gas.

Table 12: Average Non-Renewable Resource Consumption per kWh of Net Electricity Produced

Resource (a)	System Total (g/kWh)	% of total in this table	% of total from construction & decommissioning (b)	% of total from natural gas production & distribution	% of total from ammonia production & distribution
Natural gas (in ground)	169.2	97.6%	0.0%	99.9%	0.1%
Coal (in ground)	1.8	1.0%	33.8%	65.5%	0.7%
Oil (in ground)	0.6	0.4%	32.2%	67.7%	0.2%
Iron scrap	0.6	0.4%	100.0%	0.0%	< 0.0%
Iron (Fe, ore)	0.6	0.3%	100.0%	0.0%	< 0.0%
Limestone ($CaCO_3$, in ground)	0.6	0.4%	100.0%	0.0%	< 0.0%

(a) Because of significant figures some of the percentages in this table are not actually zero and therefore are denoted as less than zero percent.
(b) The construction and decommissioning subsystem includes power plant construction and decommissioning as well as construction of the natural gas pipeline.

The resources consumed during construction and decommissioning can be further broken into those required for constructing and decommissioning the power plant and those required for construction of the pipeline. The results of this breakdown are shown in Table 13. Other than limestone and oil, the majority of the resources are consumed during pipeline construction. This is due to the large steel requirement for the pipeline network (94,336 Mg) versus the steel and even total material requirement (concrete, steel, iron, and aluminum) for the power plant (15,639 Mg of steel and 65,213 Mg of total materials). A large amount of limestone is consumed for cement manufacture for plant construction.

Table 13: Breakdown of Resource Consumption for Power Plant and Pipeline

Resource	% of total from power plant construction & decommissioning	% of total from pipeline construction
Natural gas (in ground)	< 0.0%	< 0.0%
Coal (in ground)	6.0%	27.7%
Oil (in ground)	25.1%	7.1%
Iron scrap	5.5%	94.5%
Iron (Fe, ore)	5.7%	94.3%
Limestone ($CaCO_3$, in ground)	91.1%	8.9%

Note: Because of significant figures some of the percentages in this table are not actually zero and therefore are denoted as less than zero percent.

8.5 Water Emissions

Similar to the findings of previously performed LCAs at NREL, the total amount of water pollutants was found to be small compared to other emissions. The total amount of water pollutants for this study is 0.01 g/kWh. The two main pollutants are oils and dissolved matter, accounting for 57 wt% and 23 wt%, respectively, of the total water pollutants. The oils come primarily from natural gas production and distribution while the dissolved matter is produced from the material manufacturing steps involved in pipeline and power plant construction.

8.6 Solid Waste

About 94 wt% percent of the total waste for this system comes from the natural gas production and distribution block. Upon further examination, it is evident that most of the waste (65% of the total waste) comes from pipeline transport and that the second largest waste source is natural gas extraction (29% of the total waste). Even though the majority of the pipeline compressors are driven by reciprocating engines and turbines which are fueled by the natural gas, there are some electrical machines and electrical requirements at the compressor stations. The waste due to pipeline transport is a result of this electricity requirement. Since most of the electricity in the U.S. is generated from coal-fired power plants (51.7%) (U.S. DOE, July 1998), the majority of the waste will be in the form of coal ash and flue gas clean-up waste. Although this study did not account for any solid wastes from the natural gas power plant itself, it should be noted that the only waste stream from the plant will be a small amount of spent catalyst generated every one to five years from the SCR unit.

9.0 Sensitivity Analysis

A sensitivity analysis was conducted to examine the effect of varying the base case assumptions for several parameters. Table 14 shows the cases that were studied. Previous LCAs conducted by NREL examined more variables, including the amount of materials used or recycled in plant construction/decommissioning and the production and decommissioning of transportation vehicles and other equipment. Because the impact of these variables on the results of those studies was not found to be significant, they were not restudied here.

Table 14: Variables Changed in Sensitivity Analysis

Variable	Base case	Sensitivity analysis cases	Case reference name
Materials requirement for natural gas pipeline	94,336 Mg of steel	decrease by 20%	pipeline_low
		increase by 20%	pipeline_high
Natural gas losses	1.4% of the gas removed from the ground	0.5%	ng_loss_low
		4%	ng_loss_high
Operating capacity factor	0.80	0.75	cap_factor_75
		0.90	cap_factor_90
		0.95	cap_factor_95
Power plant efficiency	48.8% (HHV basis)	decrease by 5 points to 43.8% (HHV basis)	efficiency_low
		increase by 5 points to 53.8% (HHV basis)	efficiency_high
Power plant NO_x emissions	9.4 ppm out of stack	43 ppm (SCR not used)	NO_x_Case1
		2 ppm (LAER limit, new catalytic technology)	NO_x_Case2
		63 ppm (NSPS limit, no SCR)	NO_x_Case3
		16 ppm (Average turbine emissions, 72 ppm) (SRI International, 1989)	NO_x_Case4
		35 ppm (High turbine emissions, 160 ppm (SRI International, 1989), SCR)	NO_x_Case5
		20 ppm (Low turbine emissions, no SCR)	NO_x_Case6

Figures 5 and 6 show the results for total GWP and system energy balance, respectively. As expected, because the natural gas used by the power plant represents the largest source of greenhouse gases (see Figure 4) and the largest consumer of energy (see Table 9), the efficiency sensitivity cases result in significant changes to GWP and energy balance. Varying the natural gas loss also has a large effect on system GWP because of the higher radiative forcing potential of CH_4 compared to CO_2. Changes in other stressors (e.g., total air emissions, resource consumption, etc.) are generally less dramatic because system operation is so heavily dominated by natural gas production and consumption. The tabulated results from all sensitivity cases can be found in the Tables in the Appendix. For those instances where there was meaningful variance from the base case results, more detail is given in the following sections.

Figure 5: Sensitivity Analysis Results: GWP

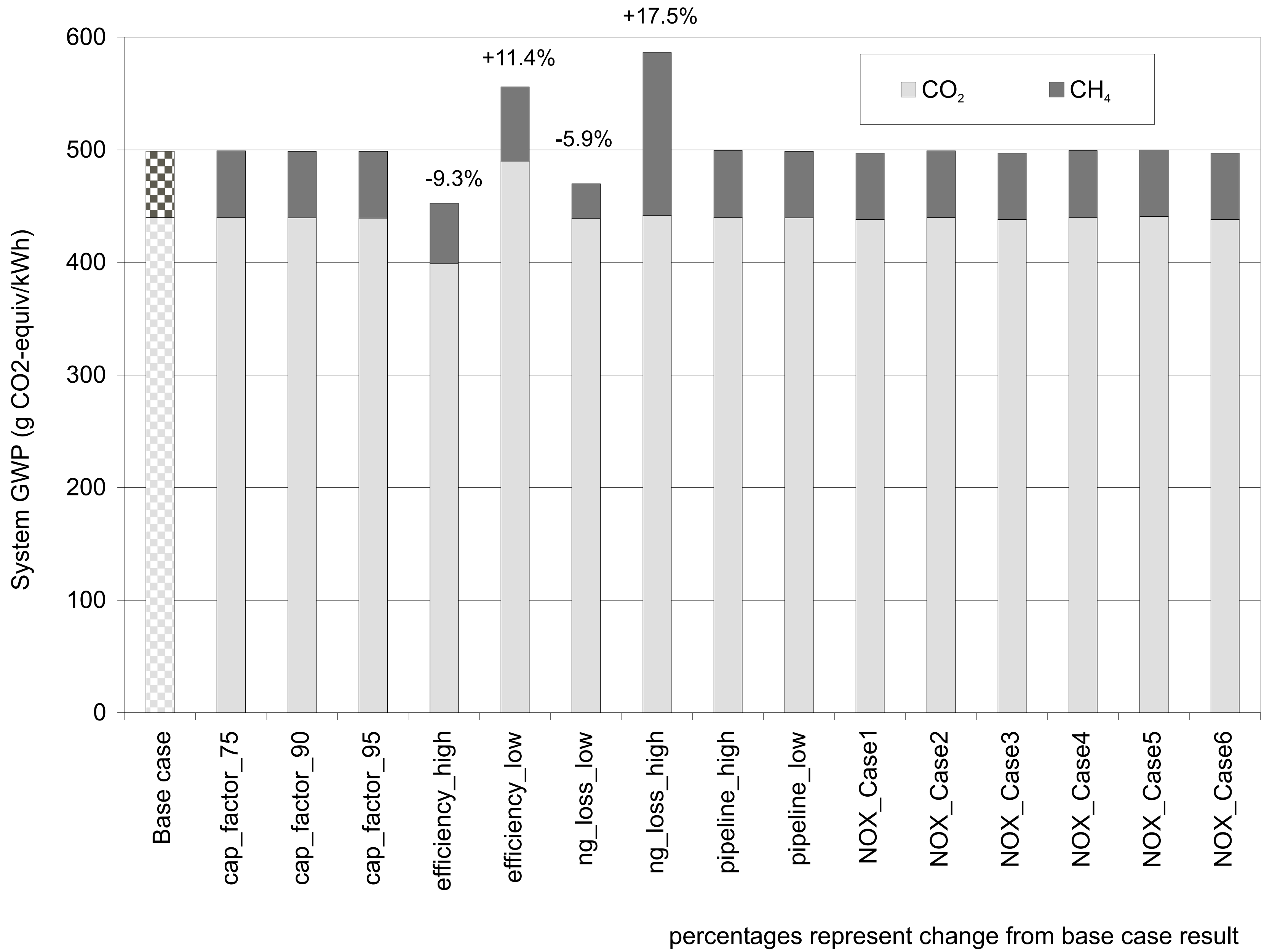
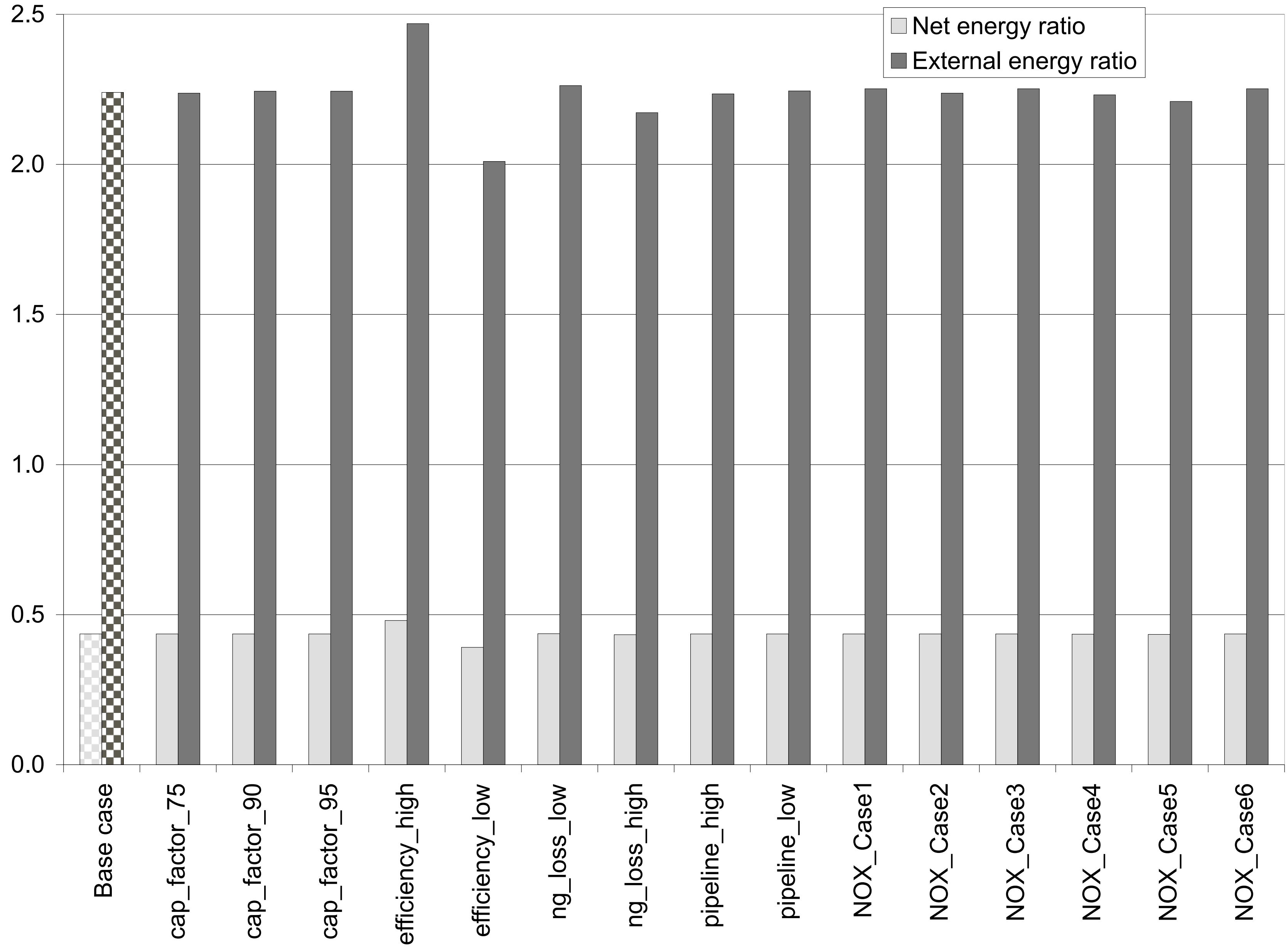


Figure 6: Sensitivity Analysis Results: Energy Balance



9.1 Sensitivity - Material Requirement for Natural Gas Pipeline

Because the amount of steel required to construct a new natural gas pipeline is significantly more than that required for building the power plant, the pipeline construction was deemed to be important enough to vary in a sensitivity analysis. Changing the amount of steel required by +/- 20% resulted in very small changes to the total stressors from the system. Although N_2O emissions changed by +/- 3%, the GWP of the system varied by less than 1/10th of a percent. The energy results also changed only slightly with this parameter, due to the fact that most of the energy consumed by the system is contained in the natural gas used at the power plant. Most air emissions change very slightly, although H_2S emissions change by +/- 15% from the base case because of the sulfur emitted during steel manufacturing. However, H_2S makes up a negligible amount of the total air emissions, even when CO_2 is excluded (see Table 8). Iron and iron scrap requirements change by +/-19%, which is not insignificant given that this is the construction material used in the greatest amount. Changing the pipeline also changes the coal requirements somewhat (+/-6%) because of the coke used to manufacture steel. The amount of waste generated changes only slightly.

9.2 Sensitivity - Natural Gas Losses

The natural gas losses were decreased from 1.4% of the total amount of gas pulled from the ground to 0.5% based on data from a study by U.S. EPA/GRI/AGA (Harrison *et al*, 1997; section 5.0). They were also increased to 4% to account for higher numbers that have been reported (Kirchgessner *et al*, 1997). It is unlikely that natural gas losses will be higher than 4% because of the implementation of the STAR program (see section 5.0).

Because of the higher global warming potential of CH_4, the system GWP was significantly affected by changes in the natural gas loss. A 0.5% loss results in a 6% decrease in the GWP from the base case result. Increasing the natural gas losses to 4% increases the system GWP by 18%. Table 15 shows the total GWP and sources of greenhouse gases for the base case and natural gas loss sensitivity cases.

Table 15: Sources of Greenhouse Gases for Natural Gas Loss Sensitivity Cases

	System GWP (g CO_2-equivalent/kWh)	% from construction (power plant and pipeline)	% from natural gas production and distribution	% from ammonia production	% from power plant
Base Case (1.4% loss)	499.1	0.4	24.9	0.1	74.6
ng_loss_low (0.5% loss)	469.9	0.4	20.2	0.1	79.2
ng_loss_high (4% loss)	586.6	0.4	36.1	0.1	63.5

Total energy results for these sensitivity cases varied only slightly, as did most air emissions. However, emissions of CH_4 and NMHCs changed in proportion to the amount of natural gas lost, as natural gas is primarily comprised of methane, ethane, plus some propane and other hydrocarbons (see Table 4). Changes in resources consumed reflect the need for more or less natural gas extraction to meet the demand at the power plant. Total waste generated changed by only a small amount.

9.3 Sensitivity - Operating Capacity Factor

The capacity factor at which the plant operates was varied to 75%, 90%, and 95%, from the base case assumption of 80%. Since the electricity generated from this plant will likely be among the cheapest available in many regions, and since this is a base load plant (i.e., not a peaking plant) it's likely that the actual operating capacity factor will be high. Thus, a case lower than 75% was not deemed to be probable. Additionally, a capacity factor higher than 95% is unlikely given the need for routine maintenance and mechanical failure, although these will be minimal for such a system.

The GWP and energy balance results for these sensitivity cases do not vary much from the base case results. Although H_2S varies by the greatest amount, as pointed out in section 9.1, above, this gas contributes such a small quantity to the total air emissions of the system that the importance of such a variance is small. Other air emissions that vary are NO_x, SO_x, and particulates.

9.4 Sensitivity - Power Plant Efficiency

Varying the power plant efficiency has the largest overall effect on the results of the study. All air emissions vary by +11.4% and -9.3% for +5 and -5 percentage points, respectively. Resource consumption and waste generation also changed by these amounts.

Life cycle efficiency and net energy ratio vary by +/-7.9% and +/-10.2%, respectively for the efficiency cases studied. The external energy efficiency changed by +/-19.0%, further demonstrating that upstream energy consumption is high for this system. The fact that power plant efficiency has the largest effect on the results, shows that developing technologies designed to increase efficiency is the most effective strategy for reducing the impact on the environment from power production.

9.5 Sensitivity - Power Plant NO_x Emissions

Thermal NO_x is typically formed at high temperatures, in the neighborhood of 1,204 ˚C (2,200 ˚F) (Schultz and Kitto, 1992). The higher the gas turbine combustion temperature, the more thermal NO_x produced. Because models to predict generation of thermal NO_x by the gas turbine are often inaccurate, several sensitivity cases were run. Cases were designed to compare systems with and without NO_x control, low NO_x formation, control by water/steam injection, and control with SCR. Statistics from the UDI database show that currently 55% of today's operating NGCC plants have some type of NO_x control, while 23% of today's plants have steam injection only, and 22% have SCR by itself or combined with a low NO_x burner or water injection (Utility Data Institute, 1999). Of the plants that are currently being constructed, 33% are incorporating some combination of low NO_x burners and SCR. Most of the plants being built are in Texas (26% of the total plants under construction) and Massachusetts (10% of the total plants under construction). Of the total number of planned plants, 12% will be in California, 11% in Texas, 8% in Florida, followed by 6% in Massachusetts and 6% in Arizona. Almost all of the planned plants have nothing listed for NO_x control; however, with the strict NO_x regulations implemented by many states, these plants are expected to at least use low NO_x burners and/or SCR.

The base case assumes that the gas turbine exhaust contains 43 ppm NO_x, and that an SCR unit with a removal efficiency of 78% is used to reduce this level to 9.4 ppm prior to releasing it from the plant. The ammonia required to operate the SCR unit is equal to 0.89 moles NH_3 per mole of NO_x, or 9.1 moles/hour that the system operates. Water injection in the gas turbine combustor is assumed to be used in the base case and in all sensitivity cases to reduce NO_x formation. However, the lower flame temperature that results from the presence of increased water will cause higher CO, CH_4, and NMHC emissions compared to a turbine without water injection. The use of SCR, though, will reduce the concentration of these compounds in the flue gas, although data could only be found for CO. For the three NO_x sensitivity cases that do not use SCR (cases 1, 3, and 6), the CO emissions were taken from AP-42 (U.S. EPA, 1995; section 3.1, Stationary Gas Turbines for Electricity Generation, "Emission Factors for Large Gas-Fired Controlled Gas Turbines") for water injection only (888 kg/GWh versus 27 kg/GWh for the base case). Not using SCR causes CO emissions to nearly triple for the overall system from 0.29 g/kWh to 1.15 g/kWh. This is due to a 33-fold increase in the power plant CO emissions.

For all NO_x cases, the GWP and energy value results vary only slightly, as do the resources consumed and the waste generated. Stressors that changed are the air emissions that are directly associated with NO_x formation and gas clean-up (NH_3, CO, formaldehyde, and NO_X). Depending on whether or not SCR is used, and how much ammonia is required, ammonia emissions in the flue gas vary from case to case. Emissions of CO also change according to the use of the SCR technology.

NO_x_Case1:

NO_x_Case1 assumes that the SCR unit is not used, making the NO_x emissions from the plant equal to those coming from the gas turbine (43 ppm). This case was derived from the fact that this level of turbine NO_x is lower than NSPS regulations (63 ppm). It's important to note, however, that individual state regulations may require emissions substantially lower than this level. This case, as well as NO_x_Case3, merely test the levels that might be emitted were NSPS to be followed. Without the SCR, production, use, and fugitive emissions of ammonia are eliminated.

NO_x_Case2:

NO_x_Case2 represents the current lowest achievable emissions rate (LAER), 2 ppm, which is possible using a precious metal-based catalytic system developed by ABB Group. Because of its proprietary nature, data on this technology were not available. Therefore, SCR with higher ammonia requirements, was used to bring NO_x emissions down to this level. System NO_x emissions for this case are reduced by 13% from the base case.

NO_x_Case3:

NO_x_Case3 assumes that NO_x levels from the gas turbine are equal to those required under NSPS requirements (63 ppm) and that SCR was not used. Power plant ammonia usage is then eliminated and total CO emissions are higher because of lost reductions in the SCR unit.

NO_x_Case4:

NO_x_Case4 takes the average turbine emissions reported in SRI (1989), which are 72 ppm NO_x, and reduces them to 16 ppm using an SCR unit with a removal efficiency of 78%. Because more NO_x is being removed by this unit, the ammonia requirements are increased over the base case.

NO_x_Case5:

NO_x_Case5 assumes that an SCR unit, with a 78% removal efficiency, is used to reduce NO_x from the high turbine emissions reported in SRI (1989). As with NO_x_Case4, an increased rate of ammonia use is required to treat more NO_x coming from the turbine.

NO_x_Case6:

NO_x_Case6 was chosen based on the low end of the range of turbine emissions reported in SRI (1989). Beyond water injection, no NO_x control was assumed.

10.0 Impact Assessment

Life cycle impact assessment is a means of examining and interpreting the inventory data from an environmental perspective. There are several options for analyzing the system's impact on the environment and human health. To meet the needs of this study, categorization and less-is-better approaches have been taken. See SETAC (1997, 1998) for additional details about the different methods available for conducting impact assessments. Table 16 summarizes the stressor categories and main stressors from the NGCC system. A discussion of these stressor categories as well as information about the known effects of these stressors can be found in Spath and Mann (1999).

Table 16: Impacts Associated with Stressor Categories

Stressor categories		Stressors	Major impact category H = human health E = ecological health	Area impacted L= local (county) R = regional (state) G = global
Major	Minor			
Ozone depletion compounds		NO	H, E	R, G
Climate change	Greenhouse gases	CO_2, CH_4, N_2O, CO and NO_x (indirectly - see note), water vapor, sulfates	H, E	R, G
		Particulates	H, E	L, R
Contributors to smog	Photochemical	NO_x, VOCs	H, E	L, R
Acidification precursors		SO_2, NO_x, CO_2	H, E	L, R
Contributors to corrosion		NH_3, NH_4^+ salts, SO_2, H_2S, H_2O, HCl	E	L
Other stressors with toxic effects		NMHCs, benzene	H, E	L
Resource depletion		Fossil fuels, water, minerals, and ores	E	R, G
Solid waste		Catalysts, coal ash, flue gas clean up waste	H, E	L, R

Note: CO and NO_x, although not typically referred to as greenhouse gases, are also included as climate change gases in this table. This is because they directly influence the atmospheric concentrations of actual greenhouse gases (IEA/OECD, 1991). For example, a molecule of carbon monoxide may react with a hydroxyl radical to form carbon dioxide. Also, both carbon monoxide and nitrogen oxides are involved in the production of tropospheric ozone.

11.0 Improvement Opportunities

Another component of LCA, known as improvement, is used to identify opportunities for reducing the environmental impact of the system. The sensitivity analysis indicates that the largest environmental gains would be achieved by an increase in the power plant efficiency. Per kWh of net electricity produced, increasing the efficiency reduces all system stressors (resources, emissions, waste, and energy use). This, in turn, results in a lower GWP and higher energy ratios (meaning that more electricity is produced per unit of fossil fuel consumed). Some advances in gas turbine efficiency are expected in the future, however, it should be noted that NGCC is the most efficient, cost-effective large-scale generation technology today.

Another improvement that would change the GWP of the system is a reduction in the natural gas losses. The base case analysis shows that 12% of the GWP is a result of methane emissions and 74 wt% of the total system methane comes from natural gas lost during production and distribution. If the losses were reduced from 1.4% to 0.5%, methane would account for about 7% of the GWP instead of 12%. Reducing the natural gas losses will also improve the energy balance of the system. Depending on the composition of the natural gas, approximately 48,000 J of energy are lost per gram of natural gas that leaks to the atmosphere (LHV basis). In the base case, this translates to 0.03 units of energy lost per unit of energy delivered to the grid (i.e., 0.032 J natural gas / J electricity, or 3.2%). Decreasing the loss to 0.5% reduces this source of energy loss to 0.011 J natural gas / J electricity. As discussed in section 5.0, the Natural Gas STAR Program is an industry consortium working to reduce methane emissions from natural gas production and distribution.

A feasible and economical option for reducing the environmental impact of the power industry, is to displace electricity from coal-fired power plants with that from NGCC systems. Because of the differences in feedstock composition, coal plants are noted for producing more CO_2, SO_x, NO_x, and particulates, in addition to a large amount of waste (ash and flue gas clean-up waste) per kWh of electricity produced. Table 17 compares results of an average coal-fired power plant from NREL's previous LCA (Spath and Mann, 1999) with this study, including the percent of the total emissions that are emitted from the power plant itself. DOE's Energy Information Administration has predicted a jump in electricity from natural gas from the current 14.7% to 33% by 2020 (U.S. DOE, December 1998). This is due primarily to the lower investment cost per MW of capacity for NGCC plants compared to other options. Additionally, the lower levels of criteria air pollutants result in lower capital and operating expenses associated with meeting air quality regulations.

Table 17: Comparison of Major Results for Coal versus Natural Gas

	Coal-fired system emissions (average plant)	% from power plant	Natural gas combined-cycle system emissions	% from power plant
NO_x (kg/GWh)	3,352	91%	750	17%
SO_x (kg/GWh)	6,700	96%	324	0.6%
Particulates (kg/GWh)	9,212	1%	133	46%
GWP (g CO_2-equiv/kWh)	1,042	96%	499	75%

Note: Three systems were studied in Spath and Mann, 1999: an average plant, an NSPS plant, and a low-emission boiler system (LEBS) plant.

12.0 Other Life Cycle Assessments on Power Production via Natural Gas Combined-Cycle

Before beginning this LCA, a literature search was done to see what previous LCA-related studies had been conducted on NGCC systems. The following is a brief summary of pertinent publications.

Rasheed (1997)
A large portion of this document describes LCA and contains information about power plant technology. The remainder of the document focuses on greenhouse gas emissions of CO_2, NO_x, and CH_4 and the energy requirement for natural gas extraction and gathering, processing, transmission, and the NGCC power plant. The power plant does not incorporate any kind of NO_x control, therefore the power plant NO_x emissions are higher than our base case emissions. The report has some useful information but at times it was difficult to follow and interpret some of the tables. No other stressors such as resources, water emissions, or wastes were examined in this LCA.

International Energy Agency Greenhouse Gas R&D Programme (1999)
This program studied greenhouse gas emissions for four different power generation options: pulverised coal boiler, natural gas fired combined-cycle, coal integrated gasification combined cycle, and CO_2 recycle coal boiler (oxygen blown coal boiler with recycled CO_2 for temperature control). The study examined the power plant emissions only. The website contains a 5-page summary of the NGCC system that they studied. Their turbine exhaust gas composition reveals that they assumed complete combustion of the natural gas feedstock and no sulfur emissions. Thus, the only air emissions from the power plant are CO_2 and NO_x. This is one aspect that is different from NREL's study. This work is part of a more detailed report that is not readily accessible. Apparently, this report is quite old and more up-to-date information will be available in the future (Freund, 1999). Additionally, this study was done for the sole purpose of examining greenhouse gases, therefore, no additional stressors were included.

Vattenfall (1996)
This document outlines the LCA work that Vattenfall has done for the following electricity generation systems: hydro, nuclear, oil condensing, NGCC, gas turbine, wind, and biofueled combined heat and power. The assessments are cradle-to-grave, incorporating aspects such as construction, demolition, and transportation, but only a select number of stressors were examined. Eleven resources were inventoried in these LCAs, the water emissions were recorded as the total amount of nitrogen, and the waste was categorized into radioactive, demolition and other. The only air emissions examined were NO_x, SO_2, CO, dust, HC, and CO_2. It is not clear what is included in the HC category but since CH_4 is one greenhouse gas that contributes to climate change it should probably be spelled out separately. The results of the life-cycle studies are being reviewed by Chalmers Contract Research Organization and the Swedish Environmental Research Institute. More recent publications regarding this work could not be found.

Waku *et al*. (1995)
Energy and CO_2 emissions were examined in a cradle-to-grave LCA for liquefied NGCC and coal IGCC systems incorporating CO_2 recovery and sequestration. This paper briefly summarizes these results which come from on going research activities sponsored by New Energy and Industrial Technology Development Organization. They define net energy ratio to be the total energy produced by the system divided by the total energy required for construction, operation, and maintenance of the system. This number does not include the energy in the natural gas or coal and therefore can only be compared to our external energy ratio. It appears that no other stressors have been examined but that their next step is to include inventories of air emissions such as NO_x and SO_x. More recent publications regarding this work could not be found.

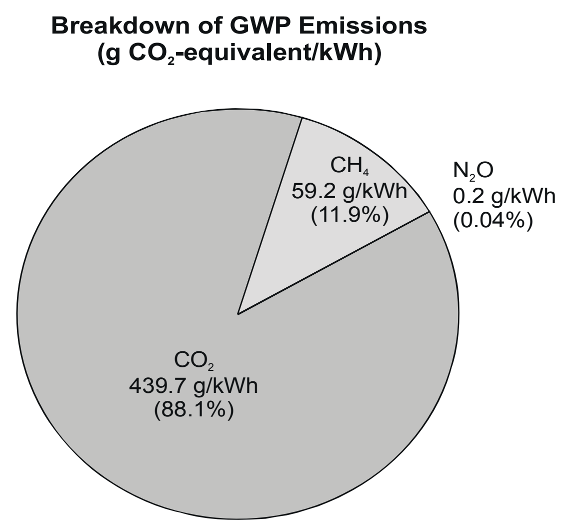
13.0 Summary of Results and Discussion

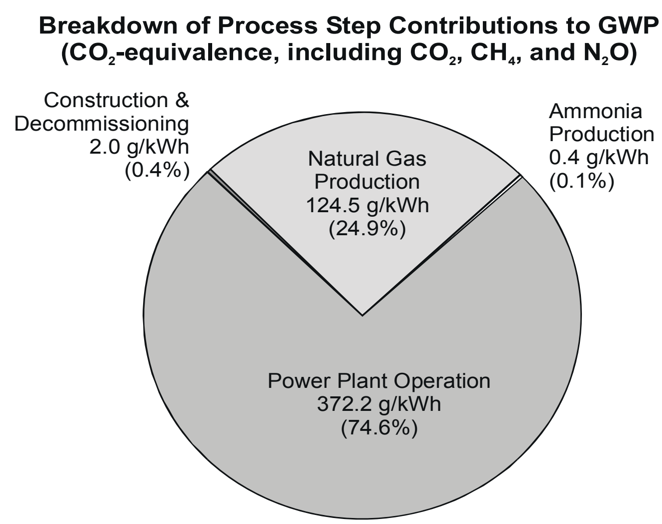
Using natural gas to generate electricity, particularly in higher efficiency combined cycle power systems, can reduce the environmental impact of energy usage in this country. If NGCC systems were to replace the major form of power production in the U.S., coal-fired power plants, one would expect that the higher efficiency and cleaner burning nature of natural gas would result in fewer SO_x and NO_x emissions, less resource consumption, and less solid waste generation. However, to get a complete picture of the benefits of this technology versus the status quo, a cradle-to-grave examination is important because the environmental consequences depend not only on the power generation facility itself, but on the upstream processes as well. The base case power plant emissions for this system are lower than those required by NSPS under the CFR for gas-fired power plants (see Table 6). As indicated in Table 18, however, upstream NO_x and SO_x emissions are much larger than those from the power plant, while upstream particulate emissions are approximately equal to those emitted from the power plant. Without taking a life cycle approach to examining the environmental effects of this system, the total magnitude of these air emissions would have been severely underestimated.

Table 18: Comparison of NO_x, SO_x, and Particulate Emission Levels

	NSPS limits (kg/GWh)	Base case				
		Emissions from power plant (kg/GWh)	% of total system emissions from power plant	Emissions from upstream processes (kg/GWh)	% of total system emissions from upstream processes	Total system emissions (kg/GWh)
NO_x	634	95	17%	475	83%	570
SO_x	634	2	1%	322	99%	324
Particulates	95	62	46%	71	54%	133

Of all air emissions, CO_2 is released at the highest rate (440 g/kWh). The GWP, a weighted combination of CO_2, CH_4, and N_2O, is 499 g CO_2-equivalent/kWh. CO_2 is therefore responsible for 88% of the system GWP, with the CO_2 from the power plant representing 75% of this GWP. Although CO_2 emissions are 65 times those of CH_4, the higher radiative forcing of CH_4 causes it to be responsible for 12% of the GWP. Natural gas losses during gas production and distribution account for 25% of the total greenhouse gases emitted by the system. The following figures present more detail on relative amounts and sources of greenhouse gases.





Similar to the findings of previous NREL LCAs, the total amount of water pollutants was small compared to other emissions. Additionally, because the only waste stream from the power plant itself is spent catalyst from the SCR unit, there is not a large amount of waste generated by the system as a whole. Although the majority of the natural gas pipeline compressors are driven by reciprocating engines and turbines which are fueled by the natural gas, there are some electrical machines and electrical requirements at the compressor stations. Ironically, the majority of the system waste (65%) is from coal-fired power plants that generate this needed electricity, where coal represents 51.7% of the U.S. average grid mix.

Although the power plant efficiency of the NGCC system is high (48.8%, HHV), the external energy efficiency (29.2%, LHV) and the external energy ratio (2.2, LHV) show that energy consumption from upstream processes, including natural gas production and distribution, is significant. Natural gas production and distribution accounts for 98% of the non-feedstock energy consumed by the system. Most of the energy consumption is a result of the energy requirements for extracting and transporting the natural gas. Diesel oil is combusted to supply electricity to the drilling equipment, and pipeline transport uses a combination of grid electricity and natural gas to move the natural gas from its point of origin to its destination. The energy results also show that for every MJ of fossil energy consumed by the system, 0.4 MJ of electricity produced.

The sensitivity analysis performed for this LCA shows that there are only two significant opportunities to lessen the environmental impacts of NGCC systems: increasing system efficiency and reducing natural gas losses. Increasing system efficiency would decrease the overall environmental impact of this system per kWh of electricity produced. However, it should be noted that NGCC is currently the most efficient and lowest energy-intensive technology available for large-scale electricity production. Mitigating natural gas losses during production and distribution increases the net energy balance and lowers the GWP.

This LCA examined the full chain of operations that must occur for a NGCC to produce electricity. These operations include the extraction, refining, and distribution of natural gas, construction of the pipeline and power plant, ammonia production and distribution, and upstream grid energy production. The emissions, energy consumption, and resource use associated with all of these operations were summed to provide a more accurate picture of the environmental impacts than can be understood from studying only the power plant. Overall, the number of environmental stressors from this system is few, and far less than those that result from today's coal-fired boilers. This, combined with the fact that these systems have high efficiencies, using NGCC to displace current coal-fired boilers is a sound method for reducing the environmental burden of power production.

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Appendix - Sensitivity Results Tables

SENSITIVITY ANALYSIS RESULTS: GWP

	Base case	cap_factor_75	cap_factor_90	cap_factor_95	efficiency_high	efficiency_low	ng_loss_low	ng_loss_high	pipeline_high	pipeline_low
CO2	439.69	439.82	439.47	439.37	398.82	489.90	439.07	441.54	439.97	439.41
CH4	59.24	59.24	59.24	59.24	53.73	66.00	30.64	144.85	59.24	59.24
N2O	0.22	0.23	0.22	0.22	0.20	0.25	0.22	0.23	0.23	0.22
GWP	499.15	499.29	498.92	498.82	452.75	556.15	469.94	586.61	499.43	498.86
% diff from base case										
CO2	N/A	0.0%	-0.1%	-0.1%	-9.3%	11.4%	-0.1%	0.4%	0.1%	-0.1%
CH4	N/A	0.0%	0.0%	0.0%	-9.3%	11.4%	-48.3%	144.5%	0.0%	0.0%
N2O	N/A	1.3%	-2.2%	-3.1%	-9.3%	11.4%	-0.7%	2.2%	3.0%	-3.0%
GWP	N/A	0.0%	0.0%	-0.1%	-9.3%	11.4%	-5.9%	17.5%	0.1%	-0.1%

SENSITIVITY ANALYSIS RESULTS: GWP (continued)

	Base case	NOx_Case1	NOx_Case2	NOx_Case3	NOx_Case4	NOx_Case5	NOx_Case6
CO2	439.69	437.92	439.77	437.92	439.94	440.71	437.92
CH4	59.24	59.22	59.24	59.22	59.24	59.27	59.22
N2O	0.22	0.22	0.22	0.22	0.22	0.23	0.22
GWP	499.15	497.36	499.23	497.36	499.41	500.21	497.36
% diff from base case							
CO2	N/A	-0.4%	0.0%	-0.4%	0.1%	0.2%	-0.4%
CH4	N/A	0.0%	0.0%	0.0%	0.0%	0.1%	0.0%
N2O	N/A	-0.5%	0.1%	-0.5%	0.3%	1.1%	-0.5%
GWP	N/A	-0.4%	0.0%	-0.4%	0.1%	0.2%	-0.4%

SENSITIVITY ANALYSIS RESULTS: ENERGY BALANCE

	Base case	cap_factor_75	cap_factor_90	cap_factor_95	efficiency_high	efficiency_low	ng_loss_low	ng_loss_high	pipeline_high	pipeline_low
Life cycle efficiency	-70.1%	-70.1%	-70.0%	-70.0%	-64.5%	-75.6%	-69.8%	-70.8%	-70.1%	-70.0%
External energy efficiency	29.9%	29.9%	30.0%	30.0%	35.5%	24.4%	30.2%	29.2%	29.9%	30.0%
Net energy ratio	0.44	0.44	0.44	0.44	0.48	0.39	0.44	0.43	0.44	0.44
External energy ratio	2.24	2.24	2.24	2.24	2.47	2.01	2.26	2.17	2.23	2.24
% diff from base case										
Life cycle efficiency	N/A	0.0%	0.1%	0.1%	7.9%	-7.9%	0.4%	-1.1%	-0.1%	0.1%
External energy efficiency	N/A	-0.1%	0.2%	0.2%	18.5%	-18.5%	0.8%	-2.5%	-0.2%	0.2%
Net energy ratio	N/A	0.0%	0.0%	0.0%	10.2%	-10.2%	0.2%	-0.6%	0.0%	0.0%
External energy ratio	N/A	-0.1%	0.2%	0.2%	10.2%	-10.2%	1.0%	-3.0%	-0.2%	0.2%
percentage point change from base case										
Life cycle efficiency	N/A	0.00	0.00	0.00	0.06	-0.06	0.00	-0.01	0.00	0.00
External energy efficiency	N/A	0.00	0.00	0.00	0.06	-0.06	0.00	-0.01	0.00	0.00

SENSITIVITY ANALYSIS RESULTS: ENERGY BALANCE (continued

	Base case	NOx_Case1	NOx_Case2	NOx_Case3	NOx_Case4	NOx_Case5	NOx_Case6
Life cycle efficiency	-70.1%	-69.9%	-70.1%	-69.9%	-70.2%	-70.4%	-69.9%
External energy efficiency	29.9%	30.1%	29.9%	30.1%	29.8%	29.6%	30.1%
Net energy ratio	0.44	0.44	0.44	0.44	0.44	0.43	0.44
External energy ratio	2.24	2.25	2.24	2.25	2.23	2.21	2.25
% diff from base case							
Life cycle efficiency	N/A	0.2%	0.0%	0.2%	-0.1%	-0.5%	0.2%
External energy efficiency	N/A	0.5%	-0.1%	0.5%	-0.3%	-1.1%	0.5%
Net energy ratio	N/A	0.1%	0.0%	0.1%	-0.1%	-0.3%	0.1%
External energy ratio	N/A	0.6%	-0.1%	0.6%	-0.3%	-1.3%	0.6%
percentage point change from base case							
Life cycle efficiency	N/A	0.00	0.00	0.00	0.00	0.00	0.00
External energy efficiency	N/A	0.00	0.00	0.00	0.00	0.00	0.00

SENSITIVITY ANALYSIS RESULTS: AIR EMISSIONS

	Total (g/kWh)	% of Total in this table	% of Total in this table except CO2	% of Total from Construction & Decommisioning	% of Total from Natural Gas Production	% of Total from Ammonia Production	% of Total from Electricity Generation	% change from base case (total)
Base case								
(a) Ammonia (NH3)	2.10E-02	0.00%	0.43%	0.19%	0.00%	1.60%	98.21%	N/A
(a) Benzene (C6H6)	6.32E-02	0.01%	1.30%	0.00%	99.90%	0.10%	0.00%	N/A
(a) Carbon Dioxide (CO2)	4.40E+02	98.91%		0.46%	15.01%	0.10%	84.43%	N/A
(a) Carbon Monoxide (CO)	2.87E-01	0.06%	5.91%	1.59%	88.57%	0.55%	9.29%	N/A
(a) Non-methane Hydrocarbons (NMHCs)	6.28E-01	0.14%	12.94%	2.32%	95.84%	0.23%	1.62%	N/A
(a) Hydrogen Sulfide (H2S)	1.41E-08	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	N/A
(a) Methane (CH4)	2.82E+00	0.63%	58.08%	0.01%	98.39%	0.02%	1.57%	N/A
(a) Formaldehyde (CH2O)	8.57E-03	0.00%	0.18%	0.00%	0.00%	0.00%	100.00%	N/A
(a) Nitrogen Oxides (NOx as NO2)	5.70E-01	0.13%	11.75%	1.64%	81.54%	0.14%	16.68%	N/A
(a) Nitrous Oxide (N2O)	7.19E-04	0.00%	0.01%	19.35%	80.20%	0.45%	0.00%	N/A
(a) Particulates (unspecified)	1.33E-01	0.03%	2.73%	38.00%	15.57%	0.04%	46.39%	N/A
(a) Sulfur Oxides (SOx as SO2)	3.24E-01	0.07%	6.67%	15.44%	83.82%	0.16%	0.59%	N/A
cap_factor_75								
(a) Ammonia (NH3)	2.10E-02	0.00%	0.43%	0.20%	0.00%	1.60%	98.20%	0.01%
(a) Benzene (C6H6)	6.32E-02	0.01%	1.30%	0.00%	99.90%	0.10%	0.00%	0.00%
(a) Carbon Dioxide (CO2)	4.40E+02	98.91%		0.49%	15.01%	0.10%	84.41%	0.03%
(a) Carbon Monoxide (CO)	2.87E-01	0.06%	5.90%	1.69%	88.48%	0.55%	9.28%	0.11%
(a) Non-methane Hydrocarbons (NMHCs)	6.29E-01	0.14%	12.94%	2.47%	95.69%	0.23%	1.61%	0.15%
(a) Hydrogen Sulfide (H2S)	1.50E-08	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	6.67%
(a) Methane (CH4)	2.82E+00	0.63%	57.98%	0.01%	98.39%	0.02%	1.57%	0.00%
(a) Formaldehyde (CH2O)	8.57E-03	0.00%	0.18%	0.00%	0.00%	0.00%	100.00%	0.00%
(a) Nitrogen Oxides (NOx as NO2)	5.71E-01	0.13%	11.74%	1.74%	81.45%	0.14%	16.67%	0.11%
(a) Nitrous Oxide (N2O)	7.28E-04	0.00%	0.01%	20.38%	79.17%	0.45%	0.00%	1.29%
(a) Particulates (unspecified)	1.36E-01	0.03%	2.80%	39.53%	15.19%	0.03%	45.25%	2.53%
(a) Sulfur Oxides (SOx as SO2)	3.27E-01	0.07%	6.73%	16.30%	82.97%	0.15%	0.58%	1.03%
cap_factor_90								
(a) Ammonia (NH3)	2.10E-02	0.00%	0.43%	0.17%	0.00%	1.60%	98.23%	-0.02%
(a) Benzene (C6H6)	6.32E-02	0.01%	1.31%	0.00%	99.90%	0.10%	0.00%	0.00%
(a) Carbon Dioxide (CO2)	4.39E+02	98.91%		0.41%	15.02%	0.10%	84.48%	-0.05%
(a) Carbon Monoxide (CO)	2.86E-01	0.06%	5.91%	1.42%	88.73%	0.55%	9.31%	-0.18%
(a) Non-methane Hydrocarbons (NMHCs)	6.27E-01	0.14%	12.95%	2.06%	96.09%	0.23%	1.62%	-0.26%
(a) Hydrogen Sulfide (H2S)	1.25E-08	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	-11.11%
(a) Methane (CH4)	2.82E+00	0.63%	58.25%	0.01%	98.39%	0.02%	1.57%	0.00%
(a) Formaldehyde (CH2O)	8.57E-03	0.00%	0.18%	0.00%	0.00%	0.00%	100.00%	0.00%
(a) Nitrogen Oxides (NOx as NO2)	5.69E-01	0.13%	11.76%	1.46%	81.69%	0.14%	16.71%	-0.18%
(a) Nitrous Oxide (N2O)	7.03E-04	0.00%	0.01%	17.58%	81.96%	0.46%	0.00%	-2.15%
(a) Particulates (unspecified)	1.27E-01	0.03%	2.62%	35.26%	16.26%	0.04%	48.44%	-4.22%
(a) Sulfur Oxides (SOx as SO2)	3.18E-01	0.07%	6.58%	13.96%	85.28%	0.16%	0.60%	-1.72%

SENSITIVITY ANALYSIS RESULTS: AIR EMISSIONS (continued)

	Total (g/kWh)	% of Total in this table	% of Total in this table except CO2	% of Total from Construction & Decommisioning	% of Total from Natural Gas Production	% of Total from Ammonia Production	% of Total from Electricity Generation	% change from base case (total)
cap_factor_95								
(a) Ammonia (NH3)	2.10E-02	0.00%	0.43%	0.16%	0.00%	1.60%	98.24%	-0.03%
(a) Benzene (C6H6)	6.32E-02	0.01%	1.31%	0.00%	99.90%	0.10%	0.00%	0.00%
(a) Carbon Dioxide (CO2)	4.39E+02	98.91%		0.38%	15.02%	0.10%	84.49%	-0.07%
(a) Carbon Monoxide (CO)	2.86E-01	0.06%	5.92%	1.34%	88.80%	0.55%	9.31%	-0.25%
(a) Non-methane Hydrocarbons (NMHCs)	6.26E-01	0.14%	12.95%	1.96%	96.19%	0.23%	1.62%	-0.37%
(a) Hydrogen Sulfide (H2S)	1.18E-08	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	-15.79%
(a) Methane (CH4)	2.82E+00	0.63%	58.32%	0.01%	98.39%	0.02%	1.57%	0.00%
(a) Formaldehyde (CH2O)	8.57E-03	0.00%	0.18%	0.00%	0.00%	0.00%	100.00%	0.00%
(a) Nitrogen Oxides (NOx as NO2)	5.69E-01	0.13%	11.76%	1.38%	81.75%	0.14%	16.73%	-0.26%
(a) Nitrous Oxide (N2O)	6.97E-04	0.00%	0.01%	16.81%	82.72%	0.47%	0.00%	-3.06%
(a) Particulates (unspecified)	1.25E-01	0.03%	2.58%	34.04%	16.57%	0.04%	49.36%	-6.00%
(a) Sulfur Oxides (SOx as SO2)	3.16E-01	0.07%	6.54%	13.32%	85.91%	0.16%	0.60%	-2.44%
efficiency_high								
(a) Ammonia (NH3)	1.90E-02	0.00%	0.43%	0.19%	0.00%	1.60%	98.21%	-9.30%
(a) Benzene (C6H6)	5.74E-02	0.01%	1.30%	0.00%	99.90%	0.10%	0.00%	-9.30%
(a) Carbon Dioxide (CO2)	3.99E+02	98.91%		0.46%	15.01%	0.10%	84.43%	-9.30%
(a) Carbon Monoxide (CO)	2.60E-01	0.06%	5.91%	1.59%	88.57%	0.55%	9.29%	-9.30%
(a) Non-methane Hydrocarbons (NMHCs)	5.70E-01	0.14%	12.94%	2.32%	95.84%	0.23%	1.62%	-9.30%
(a) Hydrogen Sulfide (H2S)	1.28E-08	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	-9.30%
(a) Methane (CH4)	2.56E+00	0.63%	58.08%	0.01%	98.39%	0.02%	1.57%	-9.30%
(a) Formaldehyde (CH2O)	7.77E-03	0.00%	0.18%	0.00%	0.00%	0.00%	100.00%	-9.30%
(a) Nitrogen Oxides (NOx as NO2)	5.17E-01	0.13%	11.75%	1.64%	81.54%	0.14%	16.68%	-9.30%
(a) Nitrous Oxide (N2O)	6.52E-04	0.00%	0.01%	19.35%	80.20%	0.45%	0.00%	-9.30%
(a) Particulates (unspecified)	1.20E-01	0.03%	2.73%	38.00%	15.57%	0.04%	46.39%	-9.30%
(a) Sulfur Oxides (SOx as SO2)	2.94E-01	0.07%	6.67%	15.44%	83.82%	0.16%	0.59%	-9.30%
efficiency_low								
(a) Ammonia (NH3)	2.34E-02	0.00%	0.43%	0.19%	0.00%	1.60%	98.21%	11.42%
(a) Benzene (C6H6)	7.05E-02	0.01%	1.30%	0.00%	99.90%	0.10%	0.00%	11.42%
(a) Carbon Dioxide (CO2)	4.90E+02	98.91%		0.46%	15.01%	0.10%	84.43%	11.42%
(a) Carbon Monoxide (CO)	3.20E-01	0.06%	5.91%	1.59%	88.57%	0.55%	9.29%	11.42%
(a) Non-methane Hydrocarbons (NMHCs)	7.00E-01	0.14%	12.94%	2.32%	95.84%	0.23%	1.62%	11.42%
(a) Hydrogen Sulfide (H2S)	1.57E-08	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	11.42%
(a) Methane (CH4)	3.14E+00	0.63%	58.08%	0.01%	98.39%	0.02%	1.57%	11.42%
(a) Formaldehyde (CH2O)	9.54E-03	0.00%	0.18%	0.00%	0.00%	0.00%	100.00%	11.42%
(a) Nitrogen Oxides (NOx as NO2)	6.36E-01	0.13%	11.75%	1.64%	81.54%	0.14%	16.68%	11.42%
(a) Nitrous Oxide (N2O)	8.01E-04	0.00%	0.01%	19.35%	80.20%	0.45%	0.00%	11.42%
(a) Particulates (unspecified)	1.48E-01	0.03%	2.73%	38.00%	15.57%	0.04%	46.39%	11.42%
(a) Sulfur Oxides (SOx as SO2)	3.61E-01	0.07%	6.67%	15.44%	83.82%	0.16%	0.59%	11.42%

SENSITIVITY ANALYSIS RESULTS: AIR EMISSIONS (continued)

	Total (g/kWh)	% of Total in this table	% of Total in this table except CO2	% of Total from Construction & Decommisioning	% of Total from Natural Gas Production	% of Total from Ammonia Production	% of Total from Electricity Generation	% change from base case (total)
ng_loss_low								
(a) Ammonia (NH3)	2.10E-02	0.00%	0.62%	0.19%	0.00%	1.60%	98.21%	0.00%
(a) Benzene (C6H6)	6.27E-02	0.01%	1.86%	0.00%	99.90%	0.10%	0.00%	-0.90%
(a) Carbon Dioxide (CO2)	4.39E+02	99.24%		0.46%	14.89%	0.10%	84.55%	-0.14%
(a) Carbon Monoxide (CO)	2.85E-01	0.06%	8.44%	1.60%	88.48%	0.55%	9.37%	-0.80%
(a) Non-methane Hydrocarbons (NMHCs)	5.12E-01	0.12%	15.21%	2.84%	94.90%	0.28%	1.98%	-18.46%
(a) Hydrogen Sulfide (H2S)	1.41E-08	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%
(a) Methane (CH4)	1.46E+00	0.33%	43.31%	0.02%	96.89%	0.05%	3.04%	-48.27%
(a) Formaldehyde (CH2O)	8.57E-03	0.00%	0.25%	0.00%	0.00%	0.00%	100.00%	0.00%
(a) Nitrogen Oxides (NOx as NO2)	5.66E-01	0.13%	16.80%	1.65%	81.40%	0.14%	16.81%	-0.74%
(a) Nitrous Oxide (N2O)	7.14E-04	0.00%	0.02%	19.49%	80.05%	0.45%	0.00%	-0.73%
(a) Particulates (unspecified)	1.32E-01	0.03%	3.93%	38.05%	15.45%	0.04%	46.46%	-0.14%
(a) Sulfur Oxides (SOx as SO2)	3.22E-01	0.07%	9.54%	15.55%	83.70%	0.16%	0.59%	-0.76%
ng_loss_high								
(a) Ammonia (NH3)	2.10E-02	0.00%	0.23%	0.19%	0.00%	1.60%	98.21%	0.00%
(a) Benzene (C6H6)	6.50E-02	0.01%	0.70%	0.00%	99.90%	0.10%	0.00%	2.71%
(a) Carbon Dioxide (CO2)	4.42E+02	97.94%		0.45%	15.37%	0.10%	84.08%	0.42%
(a) Carbon Monoxide (CO)	2.94E-01	0.07%	3.15%	1.55%	88.84%	0.54%	9.07%	2.40%
(a) Non-methane Hydrocarbons (NMHCs)	9.76E-01	0.22%	10.48%	1.49%	97.32%	0.15%	1.04%	55.26%
(a) Hydrogen Sulfide (H2S)	1.41E-08	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%
(a) Methane (CH4)	6.90E+00	1.53%	74.09%	0.01%	99.34%	0.01%	0.64%	144.52%
(a) Formaldehyde (CH2O)	8.57E-03	0.00%	0.09%	0.00%	0.00%	0.00%	100.00%	0.00%
(a) Nitrogen Oxides (NOx as NO2)	5.83E-01	0.13%	6.26%	1.60%	81.94%	0.14%	16.32%	2.21%
(a) Nitrous Oxide (N2O)	7.34E-04	0.00%	0.01%	18.94%	80.61%	0.44%	0.00%	2.17%
(a) Particulates (unspecified)	1.33E-01	0.03%	1.43%	37.84%	15.93%	0.04%	46.20%	0.42%
(a) Sulfur Oxides (SOx as SO2)	3.31E-01	0.07%	3.56%	15.09%	84.18%	0.16%	0.57%	2.27%
pipeline_high								
(a) Ammonia (NH3)	2.10E-02	0.00%	0.43%	0.22%	0.00%	1.60%	98.18%	0.03%
(a) Benzene (C6H6)	6.32E-02	0.01%	1.30%	0.00%	99.90%	0.10%	0.00%	0.00%
(a) Carbon Dioxide (CO2)	4.40E+02	98.91%		0.52%	15.00%	0.10%	84.38%	0.06%
(a) Carbon Monoxide (CO)	2.87E-01	0.06%	5.90%	1.67%	88.50%	0.55%	9.28%	0.08%
(a) Non-methane Hydrocarbons (NMHCs)	6.31E-01	0.14%	12.97%	2.67%	95.49%	0.23%	1.61%	0.37%
(a) Hydrogen Sulfide (H2S)	1.62E-08	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	14.94%
(a) Methane (CH4)	2.82E+00	0.63%	58.01%	0.01%	98.39%	0.02%	1.57%	0.00%
(a) Formaldehyde (CH2O)	8.57E-03	0.00%	0.18%	0.00%	0.00%	0.00%	100.00%	0.00%
(a) Nitrogen Oxides (NOx as NO2)	5.71E-01	0.13%	11.74%	1.73%	81.46%	0.14%	16.67%	0.09%
(a) Nitrous Oxide (N2O)	7.41E-04	0.00%	0.02%	21.72%	77.84%	0.44%	0.00%	3.03%
(a) Particulates (unspecified)	1.34E-01	0.03%	2.76%	38.83%	15.36%	0.04%	45.77%	1.36%
(a) Sulfur Oxides (SOx as SO2)	3.25E-01	0.07%	6.69%	15.76%	83.50%	0.16%	0.59%	0.38%

SENSITIVITY ANALYSIS RESULTS: AIR EMISSIONS (continued)

	Total (g/kWh)	% of Total in this table	% of Total in this table except CO2	% of Total from Construction & Decommisioning	% of Total from Natural Gas Production	% of Total from Ammonia Production	% of Total from Electricity Generation	% change from base case (total)
pipeline_low								
(a) Ammonia (NH3)	2.10E-02	0.00%	0.43%	0.15%	0.00%	1.60%	98.25%	-0.03%
(a) Benzene (C6H6)	6.32E-02	0.01%	1.30%	0.00%	99.90%	0.10%	0.00%	0.00%
(a) Carbon Dioxide (CO2)	4.39E+02	98.91%		0.39%	15.02%	0.10%	84.49%	-0.06%
(a) Carbon Monoxide (CO)	2.87E-01	0.06%	5.91%	1.51%	88.64%	0.55%	9.30%	-0.08%
(a) Non-methane Hydrocarbons (NMHCs)	6.26E-01	0.14%	12.91%	1.96%	96.20%	0.23%	1.62%	-0.37%
(a) Hydrogen Sulfide (H2S)	1.20E-08	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	-14.94%
(a) Methane (CH4)	2.82E+00	0.63%	58.15%	0.01%	98.39%	0.02%	1.57%	0.00%
(a) Formaldehyde (CH2O)	8.57E-03	0.00%	0.18%	0.00%	0.00%	0.00%	100.00%	0.00%
(a) Nitrogen Oxides (NOx as NO2)	5.70E-01	0.13%	11.75%	1.54%	81.62%	0.14%	16.70%	-0.09%
(a) Nitrous Oxide (N2O)	6.97E-04	0.00%	0.01%	16.84%	82.70%	0.47%	0.00%	-3.03%
(a) Particulates (unspecified)	1.31E-01	0.03%	2.70%	37.14%	15.79%	0.04%	47.03%	-1.36%
(a) Sulfur Oxides (SOx as SO2)	3.23E-01	0.07%	6.65%	15.11%	84.14%	0.16%	0.59%	-0.38%
NOx_Case1								
(a) Ammonia (NH3)	3.91E-05	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	-99.81%
(a) Benzene (C6H6)	6.32E-02	0.01%	1.05%	0.00%	100.00%	0.00%	0.00%	-0.10%
(a) Carbon Dioxide (CO2)	4.38E+02	98.64%		0.46%	15.07%	0.00%	84.47%	-0.40%
(a) Carbon Monoxide (CO)	1.15E+00	0.26%	19.04%	0.40%	22.15%	0.00%	77.45%	299.84%
(a) Non-methane Hydrocarbons (NMHCs)	6.27E-01	0.14%	10.41%	2.32%	96.06%	0.00%	1.62%	-0.23%
(a) Hydrogen Sulfide (H2S)	1.41E-08	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%
(a) Methane (CH4)	2.82E+00	0.64%	46.82%	0.01%	98.41%	0.00%	1.57%	-0.02%
(a) Formaldehyde (CH2O)	0.00E+00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-100.00%
(a) Nitrogen Oxides (NOx as NO2)	9.09E-01	0.20%	15.10%	1.03%	51.15%	0.00%	47.83%	59.43%
(a) Nitrous Oxide (N2O)	7.16E-04	0.00%	0.01%	19.44%	80.56%	0.00%	0.00%	-0.45%
(a) Particulates (unspecified)	1.33E-01	0.03%	2.20%	38.01%	15.58%	0.00%	46.41%	-0.04%
(a) Sulfur Oxides (SOx as SO2)	3.24E-01	0.07%	5.37%	15.46%	83.95%	0.00%	0.59%	-0.16%
NOx_Case2								
(a) Ammonia (NH3)	2.11E-02	0.00%	0.44%	0.19%	0.00%	1.90%	97.91%	0.31%
(a) Benzene (C6H6)	6.33E-02	0.01%	1.32%	0.00%	99.88%	0.12%	0.00%	0.02%
(a) Carbon Dioxide (CO2)	4.40E+02	98.92%		0.46%	15.01%	0.12%	84.42%	0.02%
(a) Carbon Monoxide (CO)	2.87E-01	0.06%	6.00%	1.59%	88.48%	0.65%	9.28%	0.11%
(a) Non-methane Hydrocarbons (NMHCs)	6.29E-01	0.14%	13.15%	2.32%	95.80%	0.27%	1.61%	0.04%
(a) Hydrogen Sulfide (H2S)	1.41E-08	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%
(a) Methane (CH4)	2.82E+00	0.63%	58.98%	0.01%	98.38%	0.03%	1.57%	0.00%
(a) Formaldehyde (CH2O)	8.57E-03	0.00%	0.18%	0.00%	0.00%	0.00%	100.00%	0.00%
(a) Nitrogen Oxides (NOx as NO2)	4.96E-01	0.11%	10.36%	1.88%	93.86%	0.19%	4.06%	-13.12%
(a) Nitrous Oxide (N2O)	7.19E-04	0.00%	0.02%	19.34%	80.13%	0.54%	0.00%	0.09%
(a) Particulates (unspecified)	1.33E-01	0.03%	2.77%	38.00%	15.57%	0.04%	46.39%	0.01%
(a) Sulfur Oxides (SOx as SO2)	3.24E-01	0.07%	6.78%	15.43%	83.79%	0.19%	0.59%	0.03%

SENSITIVITY ANALYSIS RESULTS: AIR EMISSIONS (continued)

	Total (g/kWh)	% of Total in this table	% of Total in this table except CO2	% of Total from Construction & Decommisioning	% of Total from Natural Gas Production	% of Total from Ammonia Production	% of Total from Electricity Generation	% change from base case (total)
NOx_Case3								
(a) Ammonia (NH3)	3.91E-05	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	-99.81%
(a) Benzene (C6H6)	6.32E-02	0.01%	1.02%	0.00%	100.00%	0.00%	0.00%	-0.10%
(a) Carbon Dioxide (CO2)	4.38E+02	98.60%		0.46%	15.07%	0.00%	84.47%	-0.40%
(a) Carbon Monoxide (CO)	1.15E+00	0.26%	18.43%	0.40%	22.15%	0.00%	77.45%	299.84%
(a) Non-methane Hydrocarbons (NMHCs)	6.27E-01	0.14%	10.08%	2.32%	96.06%	0.00%	1.62%	-0.23%
(a) Hydrogen Sulfide (H2S)	1.41E-08	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%
(a) Methane (CH4)	2.82E+00	0.63%	45.32%	0.01%	98.41%	0.00%	1.57%	-0.02%
(a) Formaldehyde (CH2O)	0.00E+00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-100.00%
(a) Nitrogen Oxides (NOx as NO2)	1.11E+00	0.25%	17.82%	0.84%	41.95%	0.00%	57.21%	94.40%
(a) Nitrous Oxide (N2O)	7.16E-04	0.00%	0.01%	19.44%	80.56%	0.00%	0.00%	-0.45%
(a) Particulates (unspecified)	1.33E-01	0.03%	2.13%	38.01%	15.58%	0.00%	46.41%	-0.04%
(a) Sulfur Oxides (SOx as SO2)	3.24E-01	0.07%	5.20%	15.46%	83.95%	0.00%	0.59%	-0.16%
NOx_Case4								
(a) Ammonia (NH3)	2.12E-02	0.00%	0.43%	0.18%	0.00%	2.52%	97.30%	0.94%
(a) Benzene (C6H6)	6.33E-02	0.01%	1.28%	0.00%	99.84%	0.16%	0.00%	0.06%
(a) Carbon Dioxide (CO2)	4.40E+02	98.89%		0.46%	15.00%	0.16%	84.39%	0.06%
(a) Carbon Monoxide (CO)	2.88E-01	0.06%	5.84%	1.58%	88.29%	0.87%	9.26%	0.32%
(a) Non-methane Hydrocarbons (NMHCs)	6.29E-01	0.14%	12.78%	2.31%	95.72%	0.36%	1.61%	0.13%
(a) Hydrogen Sulfide (H2S)	1.41E-08	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%
(a) Methane (CH4)	2.82E+00	0.63%	57.29%	0.01%	98.38%	0.04%	1.57%	0.01%
(a) Formaldehyde (CH2O)	8.57E-03	0.00%	0.17%	0.00%	0.00%	0.00%	100.00%	0.00%
(a) Nitrogen Oxides (NOx as NO2)	6.35E-01	0.14%	12.90%	1.47%	73.22%	0.20%	25.11%	11.37%
(a) Nitrous Oxide (N2O)	7.21E-04	0.00%	0.01%	19.30%	79.98%	0.72%	0.00%	0.27%
(a) Particulates (unspecified)	1.33E-01	0.03%	2.69%	37.99%	15.57%	0.06%	46.38%	0.02%
(a) Sulfur Oxides (SOx as SO2)	3.24E-01	0.07%	6.59%	15.42%	83.74%	0.25%	0.59%	0.09%
NOx_Case5								
(a) Ammonia (NH3)	2.18E-02	0.00%	0.42%	0.18%	0.00%	5.20%	94.62%	3.80%
(a) Benzene (C6H6)	6.34E-02	0.01%	1.24%	0.00%	99.67%	0.33%	0.00%	0.23%
(a) Carbon Dioxide (CO2)	4.41E+02	98.85%		0.46%	14.98%	0.33%	84.24%	0.23%
(a) Carbon Monoxide (CO)	2.91E-01	0.07%	5.66%	1.57%	87.44%	1.82%	9.17%	1.30%
(a) Non-methane Hydrocarbons (NMHCs)	6.32E-01	0.14%	12.32%	2.30%	95.33%	0.76%	1.61%	0.54%
(a) Hydrogen Sulfide (H2S)	1.41E-08	0.00%	0.00%	99.99%	0.00%	0.01%	0.00%	0.00%
(a) Methane (CH4)	2.82E+00	0.63%	55.03%	0.01%	98.33%	0.08%	1.57%	0.06%
(a) Formaldehyde (CH2O)	8.57E-03	0.00%	0.17%	0.00%	0.00%	0.00%	100.00%	0.00%
(a) Nitrogen Oxides (NOx as NO2)	8.32E-01	0.19%	16.22%	1.12%	55.93%	0.32%	42.63%	45.80%
(a) Nitrous Oxide (N2O)	7.27E-04	0.00%	0.01%	19.15%	79.34%	1.51%	0.00%	1.07%
(a) Particulates (unspecified)	1.33E-01	0.03%	2.59%	37.97%	15.56%	0.12%	46.36%	0.08%
(a) Sulfur Oxides (SOx as SO2)	3.25E-01	0.07%	6.34%	15.38%	83.51%	0.53%	0.59%	0.37%

SENSITIVITY ANALYSIS RESULTS: AIR EMISSIONS (continued)

	Total (g/kWh)	% of Total in this table	% of Total in this table except CO2	% of Total from Construction & Decommisioning	% of Total from Natural Gas Production	% of Total from Ammonia Production	% of Total from Electricity Generation	% change from base case (total)
NOx_Case6								
(a) Ammonia (NH3)	3.91E-05	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	-99.81%
(a) Benzene (C6H6)	6.32E-02	0.01%	1.09%	0.00%	100.00%	0.00%	0.00%	-0.10%
(a) Carbon Dioxide (CO2)	4.38E+02	98.70%		0.46%	15.07%	0.00%	84.47%	-0.40%
(a) Carbon Monoxide (CO)	1.15E+00	0.26%	19.81%	0.40%	22.15%	0.00%	77.45%	299.84%
(a) Non-methane Hydrocarbons (NMHCs)	6.27E-01	0.14%	10.83%	2.32%	96.06%	0.00%	1.62%	-0.23%
(a) Hydrogen Sulfide (H2S)	1.41E-08	0.00%	0.00%	100.00%	0.00%	0.00%	0.00%	0.00%
(a) Methane (CH4)	2.82E+00	0.64%	48.71%	0.01%	98.41%	0.00%	1.57%	-0.02%
(a) Formaldehyde (CH2O)	0.00E+00	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	-100.00%
(a) Nitrogen Oxides (NOx as NO2)	6.76E-01	0.15%	11.67%	1.38%	68.82%	0.00%	29.80%	18.49%
(a) Nitrous Oxide (N2O)	7.16E-04	0.00%	0.01%	19.44%	80.56%	0.00%	0.00%	-0.45%
(a) Particulates (unspecified)	1.33E-01	0.03%	2.29%	38.01%	15.58%	0.00%	46.41%	-0.04%
(a) Sulfur Oxides (SOx as SO2)	3.24E-01	0.07%	5.59%	15.46%	83.95%	0.00%	0.59%	-0.16%

SENSITIVITY ANALYSIS RESULTS: RESOURCES

	Total (g/kWh)	% of Total in this table	% of Total from Construction & Decommisioning	% of Total from Natural Gas Production	% of Total from Ammonia Production	% of Total from Electricity Generation	% change from base case (total)
Base case							
(r) Coal (in ground)	1.78	1.02%	33.79%	65.47%	0.75%	0.00%	N/A
(r) Iron (Fe, ore)	0.58	0.34%	100.00%	0.00%	0.00%	0.00%	N/A
(r) Limestone (CaCO3, in ground)	0.62	0.36%	100.00%	0.00%	0.00%	0.00%	N/A
(r) Natural Gas (in ground)	169.25	97.56%	0.01%	99.89%	0.10%	0.00%	N/A
(r) Oil (in ground)	0.62	0.36%	32.18%	67.66%	0.16%	0.00%	N/A
Iron Scrap	0.63	0.36%	100.00%	0.00%	0.00%	0.00%	N/A
cap_factor_75							
(r) Coal (in ground)	181.58%	1.05%	35.24%	64.03%	0.73%	0.00%	2.3%
(r) Iron (Fe, ore)	0.62	0.36%	100.00%	0.00%	0.00%	0.00%	6.7%
(r) Limestone (CaCO3, in ground)	0.66	0.38%	100.00%	0.00%	0.00%	0.00%	6.7%
(r) Natural Gas (in ground)	169.25	97.47%	0.01%	99.89%	0.10%	0.00%	0.0%
(r) Oil (in ground)	0.63	0.36%	33.60%	66.24%	0.16%	0.00%	2.1%
Iron Scrap	0.67	0.39%	100.00%	0.00%	0.00%	0.00%	6.7%
cap_factor_90							
(r) Coal (in ground)	1.71	0.99%	31.20%	68.02%	0.78%	0.00%	-3.8%
(r) Iron (Fe, ore)	0.52	0.30%	100.00%	0.00%	0.00%	0.00%	-11.1%
(r) Limestone (CaCO3, in ground)	0.55	0.32%	100.00%	0.00%	0.00%	0.00%	-11.1%
(r) Natural Gas (in ground)	169.24	97.73%	0.01%	99.89%	0.10%	0.00%	0.0%
(r) Oil (in ground)	0.60	0.34%	29.66%	70.17%	0.17%	0.00%	-3.6%
Iron Scrap	0.56	0.32%	100.00%	0.00%	0.00%	0.00%	-11.1%
cap_factor_95							
(r) Coal (in ground)	1.68	0.97%	30.05%	69.16%	0.79%	0.00%	-5.3%
(r) Iron (Fe, ore)	0.49	0.28%	100.00%	0.00%	0.00%	0.00%	-15.8%
(r) Limestone (CaCO3, in ground)	0.52	0.30%	100.00%	0.00%	0.00%	0.00%	-15.8%
(r) Natural Gas (in ground)	169.24	97.80%	0.01%	99.89%	0.10%	0.00%	0.0%
(r) Oil (in ground)	0.59	0.34%	28.55%	71.28%	0.17%	0.00%	-5.1%
Iron Scrap	0.53	0.31%	100.00%	0.00%	0.00%	0.00%	-15.8%

SENSITIVITY ANALYSIS RESULTS: RESOURCES (continued)

	Total (g/kWh)	% of Total in this table	% of Total from Construction & Decommisioning	% of Total from Natural Gas Production	% of Total from Ammonia Production	% of Total from Electricity Generation	% change from base case (total)
efficiency_high							
(r) Coal (in ground)	1.61	1.02%	33.79%	65.47%	0.75%	0.00%	-9.3%
(r) Iron (Fe, ore)	0.53	0.34%	100.00%	0.00%	0.00%	0.00%	-9.3%
(r) Limestone (CaCO3, in ground)	0.56	0.36%	100.00%	0.00%	0.00%	0.00%	-9.3%
(r) Natural Gas (in ground)	153.51	97.56%	0.01%	99.89%	0.10%	0.00%	-9.3%
(r) Oil (in ground)	0.56	0.36%	32.18%	67.66%	0.16%	0.00%	-9.3%
Iron Scrap	0.57	0.36%	100.00%	0.00%	0.00%	0.00%	-9.3%
efficiency_low							
(r) Coal (in ground)	1.98	1.02%	33.79%	65.47%	0.75%	0.00%	11.4%
(r) Iron (Fe, ore)	0.65	0.34%	100.00%	0.00%	0.00%	0.00%	11.4%
(r) Limestone (CaCO3, in ground)	0.69	0.36%	100.00%	0.00%	0.00%	0.00%	11.4%
(r) Natural Gas (in ground)	188.57	97.56%	0.01%	99.89%	0.10%	0.00%	11.4%
(r) Oil (in ground)	0.69	0.36%	32.18%	67.66%	0.16%	0.00%	11.4%
Iron Scrap	0.70	0.36%	100.00%	0.00%	0.00%	0.00%	11.4%
ng_loss_low							
(r) Coal (in ground)	1.77	1.03%	33.99%	65.26%	0.75%	0.00%	-0.6%
(r) Iron (Fe, ore)	0.58	0.34%	100.00%	0.00%	0.00%	0.00%	0.0%
(r) Limestone (CaCO3, in ground)	0.62	0.36%	100.00%	0.00%	0.00%	0.00%	0.0%
(r) Natural Gas (in ground)	167.72	97.55%	0.01%	99.89%	0.10%	0.00%	-0.9%
(r) Oil (in ground)	0.61	0.36%	32.38%	67.46%	0.16%	0.00%	-0.6%
Iron Scrap	0.63	0.37%	100.00%	0.00%	0.00%	0.00%	0.0%
ng_loss_high							
(r) Coal (in ground)	1.81	1.01%	33.20%	66.07%	0.73%	0.00%	1.8%
(r) Iron (Fe, ore)	0.58	0.33%	100.00%	0.00%	0.00%	0.00%	0.0%
(r) Limestone (CaCO3, in ground)	0.62	0.35%	100.00%	0.00%	0.00%	0.00%	0.0%
(r) Natural Gas (in ground)	173.83	97.60%	0.01%	99.89%	0.10%	0.00%	2.7%
(r) Oil (in ground)	0.63	0.35%	31.60%	68.24%	0.16%	0.00%	1.8%
Iron Scrap	0.63	0.35%	100.00%	0.00%	0.00%	0.00%	0.0%

SENSITIVITY ANALYSIS RESULTS: RESOURCES (continued)

	Total (g/kWh)	% of Total in this table	% of Total from Construction & Decommisioning	% of Total from Natural Gas Production	% of Total from Ammonia Production	% of Total from Electricity Generation	% change from base case (total)
pipeline_high							
(r) Coal (in ground)	1.87	1.08%	37.27%	62.03%	0.71%	0.00%	5.5%
(r) Iron (Fe, ore)	0.69	0.40%	100.00%	0.00%	0.00%	0.00%	18.9%
(r) Limestone (CaCO3, in ground)	0.63	0.36%	100.00%	0.00%	0.00%	0.00%	1.8%
(r) Natural Gas (in ground)	169.25	97.37%	0.02%	99.89%	0.10%	0.00%	0.0%
(r) Oil (in ground)	0.63	0.36%	33.13%	66.71%	0.16%	0.00%	1.4%
Iron Scrap	0.75	0.43%	100.00%	0.00%	0.00%	0.00%	18.9%
pipeline_low							
(r) Coal (in ground)	1.68	0.97%	29.89%	69.32%	0.79%	0.00%	-5.5%
(r) Iron (Fe, ore)	0.47	0.27%	100.00%	0.00%	0.00%	0.00%	-18.9%
(r) Limestone (CaCO3, in ground)	0.61	0.35%	100.00%	0.00%	0.00%	0.00%	-1.8%
(r) Natural Gas (in ground)	169.24	97.76%	0.01%	99.89%	0.10%	0.00%	0.0%
(r) Oil (in ground)	0.61	0.35%	31.20%	68.64%	0.16%	0.00%	-1.4%
Iron Scrap	0.51	0.30%	100.00%	0.00%	0.00%	0.00%	-18.9%
NOx_Case1							
(r) Coal (in ground)	1.76	1.02%	34.04%	65.96%	0.00%	0.00%	-0.7%
(r) Iron (Fe, ore)	0.58	0.34%	100.00%	0.00%	0.00%	0.00%	0.0%
(r) Limestone (CaCO3, in ground)	0.62	0.36%	100.00%	0.00%	0.00%	0.00%	0.0%
(r) Natural Gas (in ground)	169.08	97.57%	0.01%	99.99%	0.00%	0.00%	-0.1%
(r) Oil (in ground)	0.62	0.36%	32.23%	67.77%	0.00%	0.00%	-0.2%
Iron Scrap	0.63	0.36%	100.00%	0.00%	0.00%	0.00%	0.0%
NOx_Case2							
(r) Coal (in ground)	1.78	1.02%	33.74%	65.37%	0.89%	0.00%	0.1%
(r) Iron (Fe, ore)	0.58	0.34%	100.00%	0.00%	0.00%	0.00%	0.0%
(r) Limestone (CaCO3, in ground)	0.62	0.36%	100.00%	0.00%	0.00%	0.00%	0.0%
(r) Natural Gas (in ground)	169.28	97.56%	0.01%	99.87%	0.12%	0.00%	0.0%
(r) Oil (in ground)	0.62	0.36%	32.17%	67.64%	0.19%	0.00%	0.0%
Iron Scrap	0.63	0.36%	100.00%	0.00%	0.00%	0.00%	0.0%

SENSITIVITY ANALYSIS RESULTS: RESOURCES (continued)

	Total (g/kWh)	% of Total in this table	% of Total from Construction & Decommisioning	% of Total from Natural Gas Production	% of Total from Ammonia Production	% of Total from Electricity Generation	% change from base case (total)
NOx_Case3							
(r) Coal (in ground)	1.76	1.02%	34.04%	65.96%	0.00%	0.00%	-0.7%
(r) Iron (Fe, ore)	0.58	0.34%	100.00%	0.00%	0.00%	0.00%	0.0%
(r) Limestone (CaCO3, in ground)	0.62	0.36%	100.00%	0.00%	0.00%	0.00%	0.0%
(r) Natural Gas (in ground)	169.08	97.57%	0.01%	99.99%	0.00%	0.00%	-0.1%
(r) Oil (in ground)	0.62	0.36%	32.23%	67.77%	0.00%	0.00%	-0.2%
Iron Scrap	0.63	0.36%	100.00%	0.00%	0.00%	0.00%	0.0%
NOx_Case4							
(r) Coal (in ground)	1.78	1.03%	33.64%	65.18%	1.18%	0.00%	0.4%
(r) Iron (Fe, ore)	0.58	0.34%	100.00%	0.00%	0.00%	0.00%	0.0%
(r) Limestone (CaCO3, in ground)	0.62	0.36%	100.00%	0.00%	0.00%	0.00%	0.0%
(r) Natural Gas (in ground)	169.34	97.56%	0.01%	99.83%	0.16%	0.00%	0.1%
(r) Oil (in ground)	0.62	0.36%	32.15%	67.59%	0.26%	0.00%	0.1%
Iron Scrap	0.63	0.36%	100.00%	0.00%	0.00%	0.00%	0.0%
NOx_Case5							
(r) Coal (in ground)	1.81	1.04%	33.20%	64.33%	2.47%	0.00%	1.8%
(r) Iron (Fe, ore)	0.58	0.34%	100.00%	0.00%	0.00%	0.00%	0.0%
(r) Limestone (CaCO3, in ground)	0.62	0.35%	100.00%	0.00%	0.00%	0.00%	0.0%
(r) Natural Gas (in ground)	169.64	97.55%	0.01%	99.66%	0.33%	0.00%	0.2%
(r) Oil (in ground)	0.62	0.36%	32.06%	67.40%	0.54%	0.00%	0.4%
Iron Scrap	0.63	0.36%	100.00%	0.00%	0.00%	0.00%	0.0%
NOx_Case6							
(r) Coal (in ground)	1.76	1.02%	34.04%	65.96%	0.00%	0.00%	-0.7%
(r) Iron (Fe, ore)	0.58	0.34%	100.00%	0.00%	0.00%	0.00%	0.0%
(r) Limestone (CaCO3, in ground)	0.62	0.36%	100.00%	0.00%	0.00%	0.00%	0.0%
(r) Natural Gas (in ground)	169.08	97.57%	0.01%	99.99%	0.00%	0.00%	-0.1%
(r) Oil (in ground)	0.62	0.36%	32.23%	67.77%	0.00%	0.00%	-0.2%
Iron Scrap	0.63	0.36%	100.00%	0.00%	0.00%	0.00%	0.0%

SENSITIVITY ANALYSIS RESULTS: WASTE

Non-hazardous miscellaneous waste	Total (g/kWh)	% of Total from Construction & Decommisioning	% of Total from Natural Gas Production	% of Total from Ammonia Production	% of Total from Electricity Generation	% diff from base case (total)
Base case	6.52	6.2%	93.6%	0.2%	0.0%	0.0%
cap_factor_75	6.55	6.6%	93.3%	0.2%	0.0%	0.4%
cap_factor_90	6.48	5.5%	94.3%	0.2%	0.0%	-0.7%
cap_factor_95	6.46	5.3%	94.6%	0.2%	0.0%	-1.0%
efficiency_high	5.91	6.2%	93.6%	0.2%	0.0%	-9.3%
efficiency_low	7.26	6.2%	93.6%	0.2%	0.0%	11.4%
ng_loss_low	6.47	6.2%	93.6%	0.2%	0.0%	-0.8%
ng_loss_high	6.69	6.0%	93.8%	0.2%	0.0%	2.5%
pipeline_high	6.58	7.1%	92.7%	0.2%	0.0%	1.0%
pipeline_low	6.46	5.2%	94.6%	0.2%	0.0%	-1.0%
NOx_Case1	6.51	6.2%	93.8%	0.0%	0.0%	-0.2%
NOx_Case2	6.52	6.2%	93.6%	0.2%	0.0%	0.0%
NOx_Case3	6.51	6.2%	93.8%	0.0%	0.0%	-0.2%
NOx_Case4	6.53	6.2%	93.5%	0.3%	0.0%	0.1%
NOx_Case5	6.55	6.1%	93.2%	0.6%	0.0%	0.4%
NOx_Case6	6.51	6.2%	93.8%	0.0%	0.0%	-0.2%

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Natural gas is used for steam and heat production in industrial processes, residential and commercial heating, and electric power generation. Because of its importance in the power mix, a life cycle assessment on electricity generation via a natural gas combined cycle system has been performed.

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