NATIONAL ENERGY TECHNOLOGY LABORATORY

Power Generation Technology Comparison from a Life Cycle Perspective

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Acronyms and Abbreviations

AEO	Annual Energy Outlook
ANL	Argonne National Laboratory
API	American Petroleum Institute
AWEA	American Wind Energy Association
BLM	Bureau of Land Management
Btu	British thermal unit
BWR	Boiling water reactor
C	Celsius
CAP	Criteria air pollutant
CBM	Coal bed methane
CCS	Carbon capture and sequestration
CH_4	Methane
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
COE	Cost of electricity
CTG	Combustion turbines/generators
D_2O	Deuterium oxide
DOE	Department of Energy
ECF	Energy conversion facility
EERE	Energy efficiency and renewable energy
eGRID	Emissions & Generation Resource Integrated Database
EGS	Enhanced geothermal systems
EIA	Energy Information Administration
EIS	Environmental impact statement
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
EROI	Energy return on investment
ESP	Electrostatic precipitator
EU	End use
EXPC	Existing pulverized coal
FERC	Federal Energy Regulatory Commission
FGD	Flue gas desulfurization
FR	Forest residue
GEA	Geothermal Energy Association
Gen II	Generation II
Gen III+	Generation III+
GHG	Greenhouse gas
GTSC	Gas turbine simple cycle
GWe	Gigawatt-electric
GWh	Gigawatt-hour
GWth	Gigawatt-thermal
GWP	Global warming potential
H_2O	Water
H_2S	Hydrogen sulfide
Hg	Mercury
HLW	High-level waste
HP	Hybrid poplar
HRSG	Heat recovery steam generator
IAEA	International Atomic Energy Agency
IEA	International Energy Agency
IGCC	Integrated gasification combined cycle
IHSGI	IHS Global Insight
INEEL/INL	Idaho National Engineering and Environmental Laboratory
IPCC	Intergovernmental Panel on Climate Change
IRROE	Internal rate of return on equity
kg	Kilogram
kJ	Kilojoule
kW, kWe	Kilowatt electric
kWh	Kilowatt-hour
$kWh/m^2/day$	kilowatt-hour per square meter per day
L	Liter
LC	Life cycle
LCA	Life cycle assessment
LCC	Life cycle cost
LLW	Low-level waste
LNG	Liquefied natural gas
LWR	Light water reactor
MACRS	Modified accelerated cost recovery system
MIT	Massachusetts Institute of Technology
MJ	Megajoule
MMBtu	Million British thermal units
MW	Megawatt
MWh	Megawatt-hour
NETL	National Energy Technology Laboratory
N	Nitrogen
N/A	Not applicable
N/D	No data
NEA	Nuclear Energy Agency
NETL	National Energy Technology Laboratory

NEI	Nuclear Energy Institute
NETL	National Energy Technology Laboratory
NGCC	Natural gas combined cycle
NGCC/ccs	Natural gas combined cycle with carbon capture and sequestration
NH_3	Ammonia
NHA	National Hydropower Association
NOx	Nitrogen oxides
N_2O	Nitrous oxide
NRC	Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory
O&M	Operating and maintenance
ORNL	Oak Ridge National Laboratory
Pb	Lead
PC	Pulverized coal
PM	Particulate matter
PT	Product transport
PUREX	Plutonium and uranium recovery by extraction
RPS	Renewable Portfolio Standard
RMA	Raw material acquisition
RMT	Raw material transport
SCPC	Supercritical pulverized coal
PWR	Pressurized water reactor
RFS2	Renewable Fuel Standards Final Rule
SEGS	Solar electric generating systems
SF_6	Sulfur hexafluoride
SO_2	Sulfur dioxide
SMR	Small modular reactor
SRWC	Short rotation woody crop
T&D	Transmission and distribution
Tcf	Trillion cubic feet
TPC	Total plant cost
TWh	Terawatt-hour
U	Uranium
U-235	Fissile isotope of uranium with isotope mass of 235 amu
U-238	Isotope of uranium with isotope mass of 238 amu
UO_2	Uranium dioxide
U_3O_8	Yellow cake
UF_6	Uranium hexafluoride
U.S.	United States
USACE	U.S. Army Corps of Engineers
USDA	United States Department of Agriculture
USGS	United States Geological Survey
VOC	Volatile organic compound
WNA	World Nuclear Association

Executive Summary

This analysis provides insight into key criteria for the feasibility of seven types of energy technologies. The seven types of technologies include electricity from natural gas, co-firing of coal and biomass, nuclear fuel, wind, hydropower, geothermal, and solar thermal resources. The key criteria for evaluating these technologies are defined in **Table ES-1**.

Table ES-1: Criteria for Evaluating Roles of Energy Sources

Criteria	Description
Resource Base	Availability and accessibility of natural resources for the production of energy feedstocks
Growth	Current market direction of the energy system. This could mean emerging, mature, increasing, or declining growth scenarios
Environmental Profile	Life cycle (LC) resource consumption (including raw material and water), emissions to air and water, solid waste burdens, and land use
Cost Profile	Capital costs of new infrastructure and equipment, operating and maintenance (O&M) costs, and cost of electricity (COE)
Barriers	Technical barriers that could prevent the successful implementation of a technology
Risks of Implementation	Financial, environmental, regulatory, and/or public perception concerns that are obstacles to implementation. Non-technical barriers
Expert Opinion	Opinions of stakeholders in industry, academia, and government

Natural gas is seen as a flexible and cleaner burning alternative to other fossil fuels, and is used in residential, industrial, and transportation applications in addition to an expanding role in power production. New technologies have allowed increased domestic production of natural gas as well as the development of natural gas formations that were not previously viable. The projected supply contributions afforded by new natural gas plays may keep the price of natural gas relatively low for the foreseeable future. However, since natural gas is comprised mostly of methane (CH_4), the control of fugitive emissions is imperative to reduce the greenhouse gas (GHG) footprint of natural gas extraction, processing, and transport. This is especially true for unconventional wells that have high initial pressures and the potential for high emissions during well completion.

Co-firing is seen as a way of reducing the GHG emissions of existing coal-fired power plants. However, the incorporation of biomass into an existing coal-fired system increases the complexity of feedstock acquisition. Further, the acquisition of biomass has unique GHG burdens that offset, in part, the GHG reductions from the displacement of coal with biomass. Due to the higher feedstock prices of biomass, the co-firing of biomass at a 10 percent share of feedstock energy can increase the cost of electricity (COE) by as much as 31 percent – a disproportionately large increase in comparison to the corresponding GHG reductions. Technical concerns include decreases in boiler efficiency, and degradation of coal combustion byproducts that are typically used in the production of construction materials. Other risks include regulatory uncertainty; without policies that encourage the use of renewable feedstocks, there is no incentive for producers to invest in co-fired systems.

Nuclear power provides a stable source of baseload power in the U.S. with a GHG emissions footprint that is similar to that of most renewable power sources. In the last decade, nuclear power plants have had an average capacity factor of 90 percent. Maintaining the existing share of the U.S. electricity demand with nuclear power depends on the number of existing facilities that receive operating license extensions and the number of planned and approved new reactors that are actually constructed. While the global supply of uranium (U) is large and stable, the high initial capital investment required for the construction of new reactors and historically low natural gas prices have slowed the nuclear renaissance in the U.S. The storage of spent nuclear fuel also continues to be a major concern since progress on the Yucca Mountain nuclear repository was officially halted in 2010. The growth and perception of nuclear power is also impacted by the three nuclear events that have occurred within recent history: the 1979 Three Mile Island accident, the 1986 Chernobyl accident, and the 2011 Fukushima accident. While the chances of adverse nuclear events are small, and newer nuclear technologies are inherently safer than older technologies, the scale of a nuclear event can have far-reaching environmental and societal risks.

Wind can be an important energy resource for the U.S., but as its contribution to total U.S. electricity generation increases, it will require a significant amount of fossil resources for backup power to maintain grid reliability. And while wind power has exhibited significant growth over the last decade, most of this growth was made possible through financial incentives such as temporary renewable energy tax credits. Technology advances that result in lower project costs and energy storage devices that enable better power reliability remain crucial research and development areas for the long-term integration of wind power.

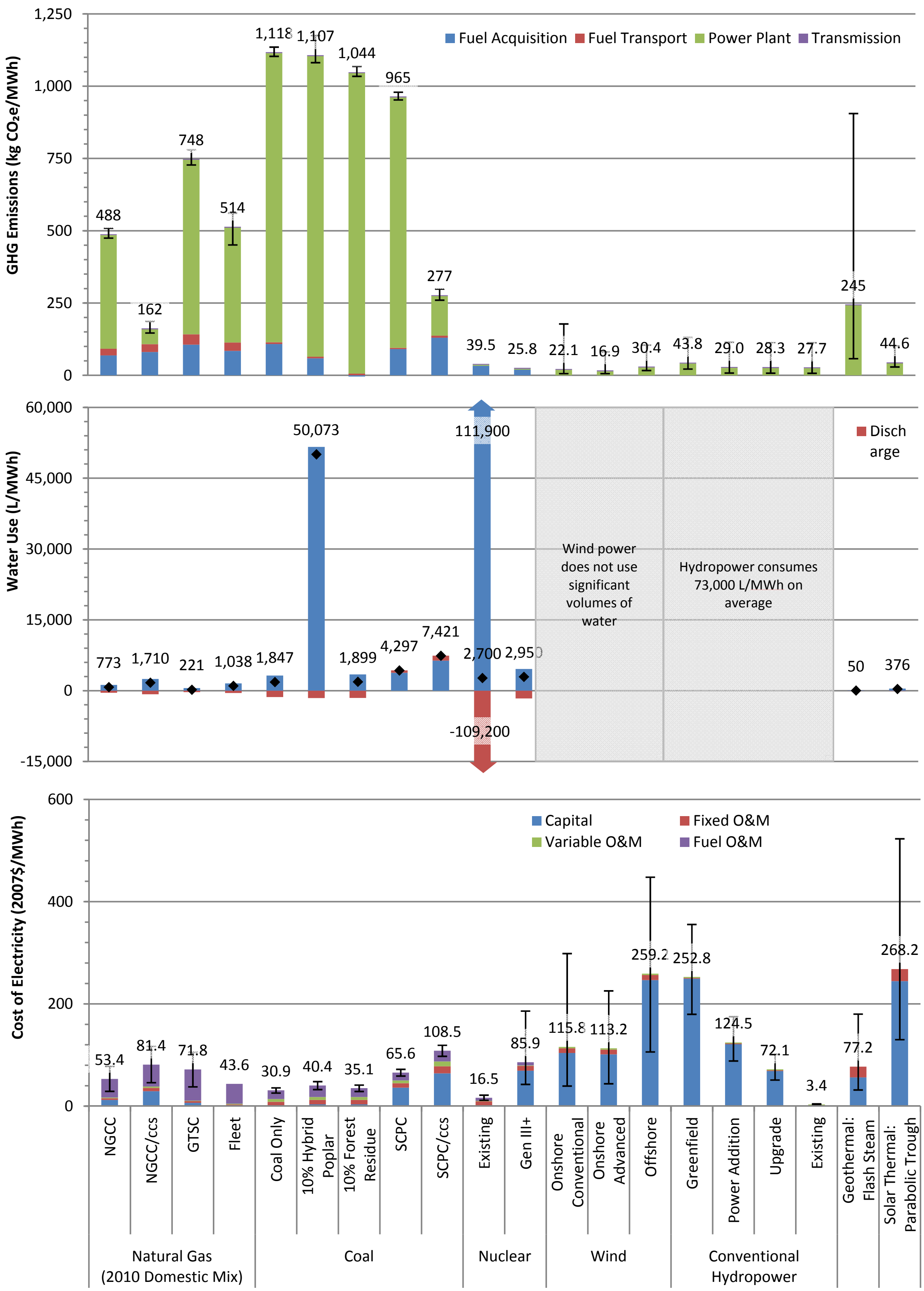
Hydropower is a proven technology that represents approximately 7 percent of U.S. electricity generation, but the resource base for large hydropower facilities has been fully developed and the growth potential for hydrokinetic hydropower is limited by the small capacities of hydrokinetic installations. There is potential for growth in the upgrading of existing power generation facilities and the addition of generation capability to existing dams. The GHG emissions of hydropower are low, but there are ecological impacts of hydropower that are outside the boundaries of the life cycle assessment (LCA) performed. Further, the benefits that dams provide with respect to flood control, irrigation, and navigability are difficult to compare on the same basis as hydroelectric power generation, complicating the calculation of the costs of hydropower.

Geothermal power is a proven technology with a large resource base, and the use of flash steam technology has relatively low capital costs that translate to a competitive COE. However, the characteristics of geologic formations are highly variable and are a barrier to broad implementation of geothermal power. The naturally-occurring CO_2 in geofluid leads to relatively high GHG emissions from geothermal power plants that use flash steam technology. In order for geothermal power to be a significant part of U.S. electricity generation, research and development efforts must find ways of cost-effectively mitigating the variability among geothermal formations and using energy conversion technologies that reduce (or prevent) the emission of CO_2 from geofluid.

Solar thermal power is viewed as a clean, renewable alternative to conventional fossil fuels for electricity generation. However, the resource base of solar thermal power is limited by several factors that inform the availability of direct sunlight at any given location. The best solar thermal resources are located in areas that are distant from existing population centers. There is potential for solar thermal power to support a significant portion of the U.S. electricity demand. However, the high cost of solar collectors to support utility level output, water scarcity in areas of high solar potential, and the lack of solar resources in close proximity to population centers make it likely that high-quality solar thermal resources are expected to remain untapped for the foreseeable future. Hybrid facilities, which could support baseload electricity demands, have been discussed to a small degree in recent industry literature, including two fossil-solar thermal hybrid power plants approved in California.

Key environmental and cost results for all technologies are shown together in Figure ES-1.

Figure ES-1: Comparison of GHG, Water, and COE Results for Alternative Power Systems



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1 Introduction

The role of an energy source in the national energy supply is determined by a combination of factors, including technical considerations, resource availability, environmental characteristics, economics, and other issues that may pose barriers or risks. The objective of this analysis is to conduct a broad assessment of power technologies using the list of seven criteria as summarized in **Table 1-1**.

Table 1-1: Criteria for Evaluating Roles of Energy Sources

Criteria	Description
Resource Base	Availability and accessibility of natural resources for the production of energy feedstocks
Growth	Current market direction of the energy system. This could mean emerging, mature, increasing, or declining growth scenarios
Environmental Profile	Life cycle (LC) resource consumption (including raw material and water), emissions to air and water, solid waste burdens, and land use
Cost Profile	Capital costs of new infrastructure and equipment, operating and maintenance (O&M) costs, and cost of electricity (COE)
Barriers	Technical barriers that could prevent the successful implementation of a technology
Risks of Implementation	Financial, environmental, regulatory, and/or public perception concerns that are obstacles to implementation. Non-technical barriers
Expert Opinion	Opinions of stakeholders in industry, academia, and government

This analysis investigates seven types of energy sources for power generation. These technologies include fossil fuel and nuclear technologies that already represent a significant share of U.S. electricity generation, and renewable energy technologies that are a small but growing share of current U.S. electricity generation. The seven energy sources are summarized below:

Natural gas power includes the acquisition and transport of natural gas from conventional and unconventional sources, and the construction and operation of simple and combined cycle power plants. The operating characteristics of fleet average natural gas power plants are also evaluated.

Co-fired power includes the acquisition of coal and biomass (hybrid poplar [HP] and forest residue) and their combustion in an existing pulverized coal (PC) boiler. The operating characteristics of a PC boiler using only coal are also evaluated to provide a basis for comparison.

Nuclear power includes the acquisition of uranium (U), using a mix of enrichment technologies, followed by the operation of existing and advanced (Generation III+) nuclear power plants. Short-term and long-term nuclear waste management scenarios are also evaluated.

Wind power includes the construction and operation of conventional and advanced onshore wind farms as well as offshore wind farms.

Hydropower includes different construction and operating scenarios for conventional hydropower facilities, as well as a brief assessment of hydrokinetic (run-of-river) hydropower potential.

Geothermal power includes the construction and operation of a flash steam, geothermal power facility.

Solar thermal power includes the construction and operation of a concentrated solar power plant using parabolic trough reflectors.

2 Technology Performance

There is usually more than one way of extracting energy from a given energy source. For example, natural gas power plants use simple or combined cycle systems to convert thermal energy to electricity, co-fired power can use different types and ratios of coal and biomass, nuclear power plants represent a wide range of safety technologies and thermal efficiencies, and renewable energy technologies have unique issues with respect to capacity and resource availability. The following discussion describes the energy conversion technologies considered in this analysis.

2.2 Natural Gas

This study evaluates four natural gas power technologies:

- Natural Gas Combined Cycle (NGCC)
- Natural Gas Combined Cycle with Carbon Capture and Sequestration (NGCC/ccs)
- Gas Turbine Simple Cycle (GTSC)
- U.S. Fleet Baseload Average (Fleet Baseload)

The performance of natural gas power plants is detailed in NETL's bituminous baseline (NETL, 2010a), which includes cases for NGCC technologies. The NGCC power plant in NETL's bituminous baseline is a 555-megawatt (MW) (net power output) thermoelectric generation facility that uses two parallel, advanced F-Class natural gas-fired combustion turbines/generators (CTG). Each CTG is followed by a heat recovery steam generator (HRSG), and all net steam produced in the two HRSGs flows to a single steam turbine. This technology has net plant efficiency of 50.2 percent and an 85 percent capacity factor.

It is possible to configure the above NGCC technology with a carbon recovery system. In this study, the Fluor Econamine℠ carbon capture technology is modeled. It uses system steam for solvent regeneration and also consumes power for pumps and other auxiliary equipment. The carbon capture system captures 90 percent of the CO_2 in the flue gas, with the trade-off being a 14.6 percent reduction in net power from 555 MW to 474 MW. This technology has net plant efficiency of 42.8 percent and an 85 percent capacity factor.

A GTSC plant is also considered in this study. The GTSC plant uses two parallel, advanced F-Class natural gas-fired CTG. The performance of the GTSC plant was adapted from NETL's baseline of NGCC power by considering only the streams that enter and exit the CTG and not accounting for any process streams related to the heat recovery systems used by combined cycles. The GTSC plant has a net output of 360 MW, a net plant efficiency of 30.0 percent, and operates at an 85 percent capacity factor.

This analysis also considers the characteristics of an average baseload natural gas plant, which is based on efficiency data from Emissions & Generation Resource Integrated Database (eGRID) (EPA, 2010). The average heat rate was calculated for plants with a capacity factor over 60 percent to represent those plants performing a baseload role. Another average, weighted by production (so the efficiency of larger, more productive plants had more weight), was calculated as 47.1 percent. This efficiency is used to generate results for average natural gas power in the U.S. An energy content ranging between 990 and 1,030 Btu/scf and a carbon content between 72 percent and 80 percent by mass were used to calculate the feed rate of natural gas and CO_2 emissions from natural gas combustion.

2.3 Co-firing

This study evaluates two co-firing technologies in addition to a coal-only technology that serves as a basis for comparison:

- Coal in an Existing PC Boiler
- Co-firing of Coal and HP in a PC Boiler
- Co-firing of Coal and Forest Residue (FR) in a PC Boiler

A co-fired power plant burns two types of fuels in the same boiler. The co-firing of coal and biomass uses the same mills and burners for coal and biomass. New plants can be designed for co-firing, but most co-fired plants are retrofits to existing coal-fired systems. Co-firing of coal and biomass is a proven technology. As of 2005, there were four coal and biomass co-firing facilities that were operational in the U.S., along with at least 38 other coal power plants where coal/biomass co-firing had been tested (IEA, 2009a).

The co-fired power plant of this analysis has a PC boiler and a net output of 550 MW. The net efficiency of the coal-only power plant is 33.0 percent, which is equivalent to a heat rate of 10,909 kJ/kWh. The co-firing scenario is based on a feedstock input with 10 percent biomass by energy, which is equivalent to a net plant efficiency of 32.8 percent (10,985 kJ/kWh). The power plant has a flue gas desulfurization (FGD) unit that removes 98 percent of the SO_2 emissions in the flue gas. The power plant also has an electrostatic precipitator (ESP) unit that removes particulate matter.

The efficiency of a PC boiler decreases when biomass is introduced as a feedstock (Ortiz, Curtright, Samaras, Litovitz, & Burger, 2011). In 2000, research conducted by Foster Wheeler led to the development of a correlation between biomass co-firing rate and the decline in net plant efficiency (Ortiz, et al., 2011). Based on this correlation, the net efficiency of the power plant decreases from 33.0 percent to 32.8 percent when biomass is co-fired at a 10 percent share of total feedstock energy.

The co-fired power plant in this analysis is an existing facility. New construction is not necessary for the coal-only scenario. The co-firing scenario requires minor boiler modifications and the addition of biomass handling equipment. Any energy required for the operation of biomass handling equipment is provided by either waste heat or electricity generated by the power plant; the energy used for the operation of biomass handling equipment is accounted for in the net plant efficiency.

The physical properties of Illinois No. 6 coal and HP were used to determine feedstock rates and CO_2 emissions. The heat rate is determined by dividing the composite heating value of the feedstocks by the boiler efficiency. CO_2 emissions are calculated by balancing the carbon inputs and outputs of the PC boiler. The key factors of the carbon balance are a 99 percent conversion rate of carbon to CO_2, and a molar ratio of 44/12 between CO_2 and carbon.

This analysis also includes a scenario that uses forest residue as a biomass feedstock instead of HP. The physical properties of HP and forest residue are the same, so the performance of the power plant does not change if forest residue is used instead of HP.

The emission of non-green house gas (GHG) gases is based on emission factors from similar systems and on the performance of environmental control equipment. NO_X emissions decrease when a coal-fired boiler is retrofitted to co-fire biomass because of the lower nitrogen content of biomass feedstocks in comparison to coal and the lower flame temperatures caused by the relatively high moisture of the biomass (EPRI/DOE, 1997). SO_2 emissions are a function of the sulfur content of the feedstocks and the efficiency of the FGD unit (EPRI/DOE, 1997). Particulate matter (PM) emissions are controlled by an ESP unit (EPRI/DOE, 1997). Mercury (Hg) emissions are based on the performance of a PC boiler with FGD and ESP controls (NETL, 2010a).

2.4 Nuclear

This study evaluates two nuclear power technologies:

- Existing Nuclear Power
- Generation III+ (Gen III+) Nuclear Power

Nuclear capacity in the U.S. consists of 104 light water reactors located on 65 different sites. These reactors use ordinary water (H_2O) as a moderator to reduce the kinetic energy of neutrons released during fission, enabling a sustained nuclear reaction. In contrast, heavy water reactors, used primarily in Canada, moderate neutrons with deuterium oxide (D_2O) and can operate using uranium that has not been enriched, or even using recycled fuel from light water reactors (LWR) (Ragheb, 2008). A water-filled steel pressure vessel holds the reactor core of an LWR, allowing the water to serve both as moderator for the reaction and as coolant for the reactor core. Sixty-six percent of operating nuclear reactors in the U.S. are pressurized water reactors (PWR), and the remaining 34 percent are boiling water reactors (BWR) (EIA, 2010b). In a BWR, steam produced in the reactor vessel is fed directly to a turbine, condenser, and feedwater pump. In a PWR, hot water from the reactor vessel is fed through a pressurized loop that passes through a heat exchanger that transfers heat to a secondary steam loop. Steam from the secondary loop is used to drive the turbine, thus isolating water that comes into contact with the reactor core from water used for the steam cycle (Nave, 2010).

The average operating reactor in the United States (U.S.) in 2009 had a capacity of 926 MW and operated with a 92 percent capacity factor (EIA, 2010b). Variation in plant size ranges from 482 MW to 1,314 MW, with 3.5 GWh to 10.7 GWh of electricity production per year. Significant increases in nuclear capacity factors since the 1990s are due in part to power uprating at many plants, which resulted in increased steam output from reactors (NEI, 2011). The average capacity factor of plants operating over the last 40 years is 70.7 percent.

Gen III+ plant designs build upon existing technology by incorporating passive safety systems such that no operator control or auxiliary power is necessary in the event of a malfunction. The plants have higher fuel burn-up rates and higher thermal efficiencies. Makers of Gen III+ plants also claim that the designs are favorable because of reduced capital cost, reduced construction time, easier operation, and reduced likelihood of operational problems or failure incidents. Gen III+ plants also have a longer reactor life (60 years).

No Gen III+ reactors are currently in operation in the U.S., but a small number are operating abroad. NETL’s life cycle assessment (LCA) of Gen III+ is representative of proposed plants that have pending license applications with the Nuclear Regulatory Commission (NRC).

2.5 Wind

This study evaluates three wind power technologies:

- Onshore Conventional Wind Power
- Onshore Advanced Wind Power
- Offshore Wind Power

The onshore *conventional* wind farm of this analysis has a total capacity of 200 MW. A conventional, onshore wind turbine has a capacity of 1.50 MW, so 134 turbines are required for a 200 MW facility. The onshore *advanced* wind farm of this analysis also has a total capacity of 200 MW. Advanced wind turbines have larger rotor diameters than conventional turbines, which increases their per turbine capacity. An advanced turbine has a capacity of 6 MW, so 34 turbines are required for a 200 MW facility. The average capacity factor for onshore wind power is 30.0 percent, and ranges from 25.0 percent to 33.0 percent (Wiser & Bolinger, 2011).

The offshore wind project is representative of the Cape Wind project, which has a total capacity of 468 MW. A single offshore wind turbine has a capacity of 3.6 MW. The expected capacity factor for the Cape Wind project is 39.0 percent (MMS, 2009b). This analysis assumes that the capacity factor for offshore wind power ranges from 95.0 percent to 105 percent of the expected value capacity factor (i.e., 36.2 percent to 40.0 percent). A 12-mile submarine cable is required to connect the offshore wind project with an onshore trunkline (MMS, 2009b).

2.6 Hydro

This analysis includes four scenarios for conventional hydropower:

- Greenfield Hydropower Dam
- Power Addition to Existing Dam
- Power Upgrade to Existing Hydropower Dam
- Existing Hydropower Dam Operation

Conventional hydropower is distinguished from other types of hydropower by its relatively large power generation capacities and its use of hydraulic head, stored by a dammed reservoir, for the generation of electricity. Conventional hydropower uses a large-scale dam or other impoundment, combined with a controlled release mechanism and turbine/generator train. Water is collected into the reservoir behind the dam. Water is then released at the toe of the dam, through a series of tunnels, penstocks, or other facilities, routed through hydroelectric turbines, and released to the river downstream. The hydraulic head (height of the reservoir surface above the turbines) from the reservoir drives the turbines and generators, providing electricity that can be exported to the electricity grid. The operation of a hydropower facility does not involve the combustion of fuels, so no air emissions are produced from the operation of the hydropower facility. However, the slow decay of plant matter in the dam reservoir produce CO_2 and CH_4. The conventional hydropower facility of this analysis has a capacity of 2,080 MW and a capacity factor of 37.0 percent.

The four conventional hydropower scenarios in this analysis all account for the operation of conventional hydropower facilities, but represent a range of construction scenarios. The greenfield case includes the construction of an entire dam and power generation facility; the power addition scenario includes the construction of a turbine, generator, and other equipment necessary for the conversion of an existing dam to a hydropower facility; the power upgrade scenario involves the replacement of turbines and modifications to other power systems used by an existing hydropower facility; finally, the existing hydropower scenario does not model any construction activity.

Hydrokinetic power has been used for centuries to turn waterwheels to drive mills and other facilities. Recently it has emerged as an energy source that can be installed along rivers for power generation. Much like wind turbines, hydrokinetic systems harness the energy that is contained in water as it moves past a fixed point. Hydrokinetic systems employ in-stream turbines that typically resemble small-scale horizontal axis wind turbines. These may be installed individually or in arrays, sited in areas of a river so as not to interfere with navigation. Hydrokinetic technologies can be employed virtually wherever water is flowing sufficiently fast (above about 5-6 miles/ hour, although some small-scale technologies are applicable to flows below this range) with sufficient depth to cover the turbine, without interfering with other beneficial uses along the river (DOE, 2011b). Hydrokinetic turbines can be installed directly into a channel bottom as permanent installations, or on the underside of a barge, which can be moved as in-stream conditions change or to allow for passage of ships (DOE, 2011b). Hydrokinetic power is not evaluated by the environmental or cost profiles of this analysis, but is discussed within the context of other metrics such as resource base and growth potential.

2.7 Geothermal

This analysis focuses on geothermal power from flash steam systems.

Most of the existing U.S. geothermal capacity consists of flash geothermal power plants; however, more binary systems are being constructed because they can take advantage of lower energy reservoirs. Binary systems use heat exchangers to transfer heat from geothermal wells to a fluid that drives an organic Rankine cycle. Binary systems have lower capacities than flash systems, require the use of a heat exchange fluid, and, since they do not have any steam condensate, must withdraw cooling water makeup from surface water or groundwater sources. This analysis focuses on flash geothermal systems because they represent the largest share of currently installed U.S. geothermal capacity.

The geothermal power plant of this analysis has a net capacity of 50 MW and is representative of the flash steam geothermal technology. A 50 MW flash steam geothermal power plant consists of 25 production wells, each having a depth of up to two miles. The production wells contain hot water at high pressure; when the water is brought to the surface, it is expanded in a flash vessel to produce steam that is used to drive a steam turbine. Steam condensate from the flash process is used to provide makeup water to the power plant's cooling water system, and thus it is not necessary to withdraw cooling water from other sources. All water that is recovered from the system is returned to the ground using injection wells. A 50 MW geothermal power plant has approximately 10 injection wells.

The expected value capacity factor for geothermal power is 90 percent (EERE, 2006; Tidball, Bluestein, Rodrigues, & Knoke, 2010). The capacity factor for geothermal can be as high as 98 percent (EERE, 2006). A low capacity factor of 85 percent is used by this analysis; this low capacity factor is representative of one of the six data sources accounted for by Tidball et al. (2010). The lifetime of a geothermal power plant ranges from 20 to 30 years (Kagel, 2006; Tidball, et al., 2010).

The liquid from a geothermal formation (called "geofluid") contains noncondensible gases such as CO_2, hydrogen sulfide (H_2S), CH_4, and ammonia (NH_3) (Sullivan, Clark, Han, & Wang, 2010). If binary geothermal power technology is used, the geofluid is in a closed system that is reinjected into the ground after all useful energy has been extracted from the geofluid. If flash steam geothermal technology is used, the noncondensible gases are released to the atmosphere. The composition of geofluid is mostly water, but the composition of noncondensible gases is highly variable from one geologic formation to another.

2.8 Solar Thermal

This analysis focuses on solar thermal power from parabolic trough systems.

Solar thermal power technologies rely on concentrating solar collectors that focus the sun's light onto a single point where heat is collected for power generation. In particular, the collector field for a parabolic trough power plant consists of a series of parabolic-shaped mirrors that focus sunlight on a pipe containing thermal fluid. The thermal fluid is heated by the concentrated sunlight, and is then routed to a central power plant that uses a steam cycle to generate electricity. All utility-scale solar thermal plants currently operating in the U.S. use parabolic trough technology.

The expected value capacity factor for a solar thermal power facility is 27.4 percent (Tidball, et al., 2010), which is low in comparison to baseload power generation technologies like coal and nuclear power (which can run more than 80 percent of the time) but is comparable to other renewable technologies such as wind and hydro power. The capacity factor of solar thermal power depends on the intensity of solar radiation the degree of cloud cover. Solar thermal power production is particularly sensitive to cloud cover relative to photovoltaic technologies because scattered light cannot be effectively concentrated by solar thermal collectors. The solar radiation across most of the U.S. ranges from approximately 1 to 7 $kWh/m^2/day$, with the higher values located in the Desert Southwest, and the substantially lower values across the Midwest, Lake States, South, Northeast, and western portions of the Pacific Northwest.

The key parameters for all technologies are summarized in **Table 2-1**.

Table 2-1: Technology Performance Summary

Energy Source	Power Plant Technology	Net Plant Power (MW)	Capacity Factor (%)	Heat Rate (MJ/MWh)	Thermal Efficiency (%)	Water (kL/MWh)		Greenhouse Gas Emissions (kg/MWh)		
						Withdrawal	Consumption	CO_2	CH_4	N_2O
Natural Gas	NGCC	555	85.0%	7,171	50.2%	0.96	0.75	365	7.4E-06	2.1E-06
	NGCC/ccs	474	85.0%	8,411	42.8%	1.91	1.43	47.1	8.8E-06	2.4E-06
	GTSC	360	85.0%	11,984	30.0%	0	0	560	N/A	N/A
	Fleet Baseload	N/A	N/A	7,643	47.1%	N/A	N/A	368	N/A	N/A
Co-firing (Coal and Biomass)	Coal Only	550	85.0%	10,907	33.0%	2.5	1.9	930	N/D	N/D
	Co-fired Coal and Biomass	550	85.0%	10,983	32.8%	2.5	1.9	943	N/D	N/D
Nuclear	Existing	796	70.7%	11,392	31.6%	105	2.5	0	0	0
	Gen III+	2,060	94.0%	10,526	34.2%	4.3	2.7	0	0	0
Wind	Onshore Conventional (1.5 MW Turbine)	200	30.0%	N/A	N/A	N/A	N/A	0	0	0
	Onshore Advanced (6.0 MW Turbines)	200	30.0%	N/A	N/A	N/A	N/A	0	0	0
	Offshore (3.6 MW Turbines)	468	39.0%	N/A	N/A	N/A	N/A	0	0	0
Hydro	Conventional Dam	2,080	37.0%	N/A	N/A	6.85	6.83	17	0.233	0
Geo-thermal	Flash Steam	50	90.0%	21,100	17.1%	38.0	38.0	214	0.4	0
Solar-thermal	Parabolic Trough	250	27.4%	N/A	N/A	0.41	0.35	0	0	0

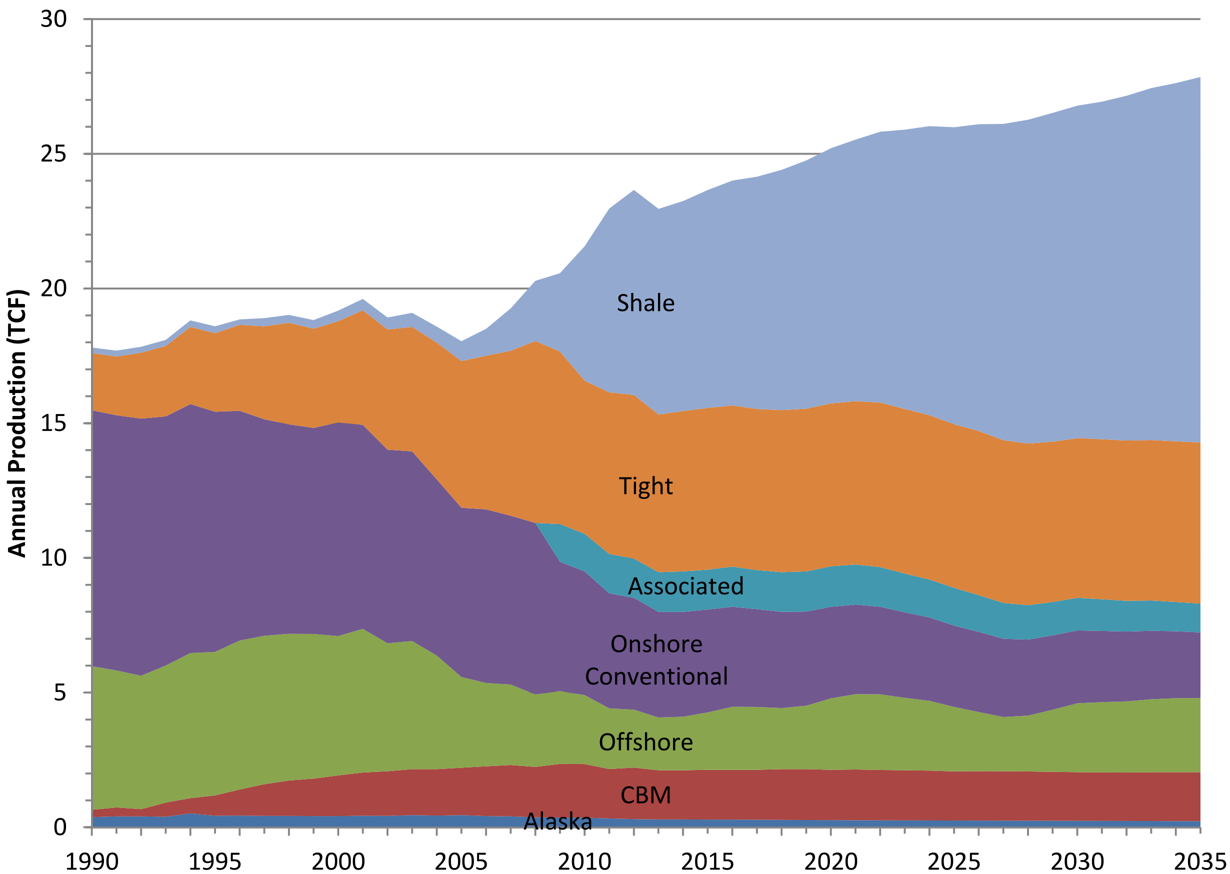
3 Resource Base and Growth

The resource base assesses the availability and accessibility of natural resources for the production of energy feedstocks. The growth of a power technology is a function of the resource base.

3.1 Natural Gas

The total U.S. demand for natural gas was 24.1 trillion cubic feet (Tcf) in 2010 and is projected to grow to 26.5 Tcf by 2035. This demand is balanced by conventional and unconventional supply sources, including an increasing share of shale gas as well as a small share of imports. Shale gas comprised 14 percent of the U.S. natural gas supply in 2009, 24 percent in 2010, and is projected to comprise 45 percent of the supply in 2035 (EIA, 2012a). **Figure 3-1** shows the projected growth in natural gas production.

Figure 3-1: Time Series Profile for U.S. Natural Gas Production (EIA, 2012a; Newell, 2011)

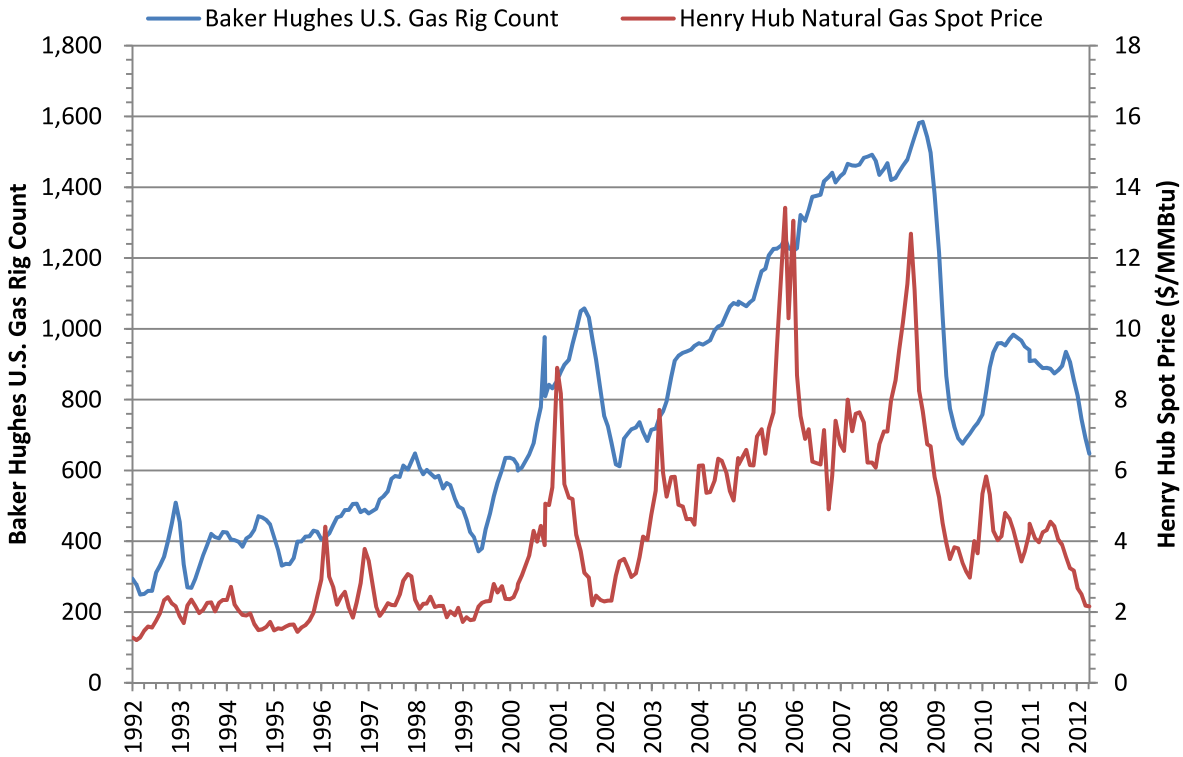


The U.S. resource base for natural gas has exhibited recent growth, and is expected to continue to expand in the near term, due to increased extraction potential of various shale gases. In particular, the Marcellus Shale is a shale formation that traverses Ohio, West Virginia, Pennsylvania, and New York. New horizontal drilling technology and hydraulic fracturing ("hydrofracking") allow the recovery of natural gas from Marcellus Shale, which could provide 20 years of natural gas supply to the U.S. (Engelder, 2009). In 2011, the U.S. Geological Survey (USGS) used the latest geologic information and engineering data to estimate 84 Tcf of technically recoverable gas from the Marcellus Shale (Pierce, Colman, & Demas, 2011). Terry Engelder, a leading authority on Marcellus Shale and professor of geosciences at Pennsylvania State University, estimates that 489 Tcf of natural gas can be recovered from the Marcellus Shale (Engelder, 2009).

The above estimates of the volume of natural gas in the Marcellus Shale are technically recoverable estimates, not *economically* recoverable estimates. According to an MIT report on the future of natural gas, approximately 60 percent of the technically recoverable shale gas can be produced at a wellhead price of $6/MMBtu or less (MIT, 2010). MIT's estimate of economically recoverable shale gas is based on a mean projection of 650 Tcf of technically recoverable gas from all shale gas plays in the U.S., so it is not directly comparable to the Marcellus Shale gas play.

The price of natural gas has been volatile over the last decade, and has been affected by natural gas supply uncertainty as well as global economic factors (such as the 2008 economic downturn). Total U.S. natural gas production increased by 1.4 percent from 2008 to 2009. During the same period, there was a 44 percent drop in the U.S. gas rig count and a 54 percent drop in U.S. natural gas prices (Baker-Hughes, 2012; EIA, 2012a). Natural gas prices stayed low in 2010, but U.S. dry gas production climbed 4.9 percent and the Baker Hughes U.S. natural gas rig counts rose 22 percent (Baker-Hughes, 2012). The increase in rig count and gas production during a period of low gas prices indicated an adherence to lease and drilling contracts, and reduced finding and development costs for certain "sweet spot" shale gas plays. The high production rates and declining natural gas prices are due in part to the improved recovery rates of natural gas, which have been made possible by new technologies, specifically horizontal drilling, seismic testing, and hydrofracking. Historical trends for well development and natural gas prices are shown in **Figure 3-2**.

Figure 3-2: Natural Gas Spot Price vs. U.S. Gas Rig Count (Baker-Hughes, 2012; EIA, 2012a)



3.2 Co-firing

The resource base of co-fired power depends on the availability of coal and the various biomass feedstocks, as well as the proximity of biomass sources to coal-fired power plants. In addition to a viable resource base, the growth of co-fired power depends on policies that encourage renewable energy portfolios.

As of 2011, active U.S. mines had 17.5 billion tons of coal ready for recovery. However, if current mining technologies are applied to the total resource base, the U.S. has estimated recoverable reserves of 261 billion tons of coal. Ninety-three percent of U.S. coal demand is for electricity generation (EIA, 2012a). The U.S. has an extensive rail network that allows for economical, reliable transport of coal between mines and energy conversion facilities. Coal mines in the Western U.S. provide more than half of the U.S. coal supply (54 percent in 2011), followed by Appalachian and Interior mines (EIA, 2012a).

The three types of biomass that can be used for co-fired power are agricultural residues, forest residues and thinnings, and herbaceous and woody energy crops.

- Agricultural residues include barley straw, corn stover, oat straw, sorghum stubble, and wheat straw. At a roadside cost of $50/dry ton, approximately 90 million dry tons of agricultural residue can be produced annually, with Iowa, Nebraska, and other Midwest states as key leaders (ORNL, 2011).
- Most forest resources are used by the forest products industry, which is dominated by large producers such as Georgia Pacific and Weyerhaeuser, as well as thousands of small

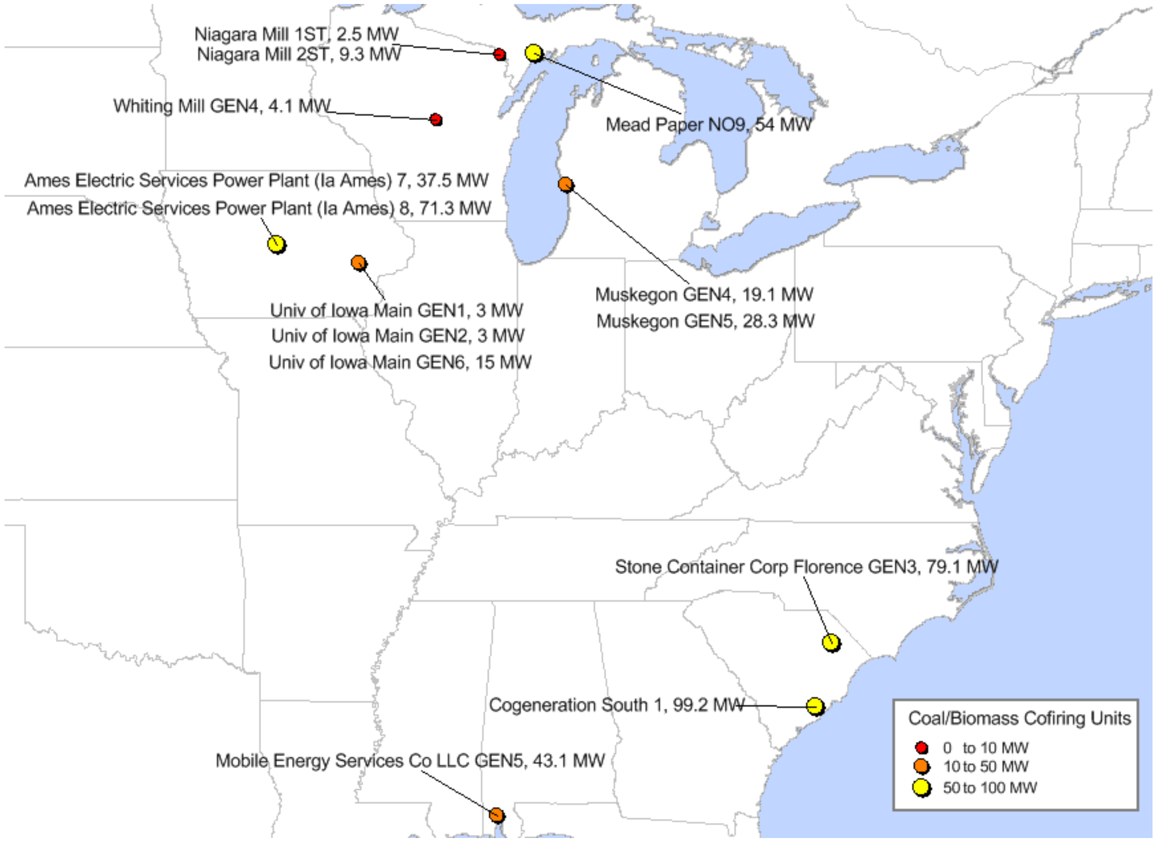
businesses that make paper and wood products. These producers add much more value to woody biomass than can be added by the energy sector; wood-to-paper conversion is more profitable than wood-to-fuel conversion. These producers use at least 70 percent of available woody biomass, leaving the remaining 30 percent for other uses such as bioenergy. At a roadside cost of $50 per dry ton, approximately 46 million dry tons of woody biomass for bioenergy can be produced annually (ORNL, 2011). The temperate hardwood forests across Appalachia and the Midsouth show the most resource potential for woody biomass for bioenergy, followed by California and the Pacific Northwest (ORNL, 2011).

- Energy crops are categorized as either herbaceous or short rotation wood crops (SRWC). Switchgrass is one example of a herbaceous crop, and HP is an example of a SRWC. Both types of crops offer the potential of sustainable, consistent, high density biomass production on land that may not be suitable for primary crop production. At a roadside cost of $50 per dry ton, herbaceous energy crops can produce approximately 136 million dry tons of biomass annually (ORNL, 2011); Kansas, Oklahoma, and Texas have enormous potential to grow switchgrass and other herbaceous energy crops. At a roadside cost of $50 per dry ton, the U.S. can produce approximately 62 million dry tons SRWC annually; the Southeast and Mid-Atlantic states show the greatest potential for the production of SRWC (ORNL, 2011).

The logistical challenges of biomass transport are a barrier to the economical acquisition of biomass. Large collection centers can act as large preprocessing centers. Pelleting, torrefaction, or other pretreatment processes can be used to increase the physical density, carbon density, or both. Torrefaction, if economical, can be performed at these large collection depots that not only increase carbon density but, combined with pelleting, can also give biomass both a physical and carbon density close to coal as well as provide biomass with similar crushability and the ability to be stored outside indefinitely.

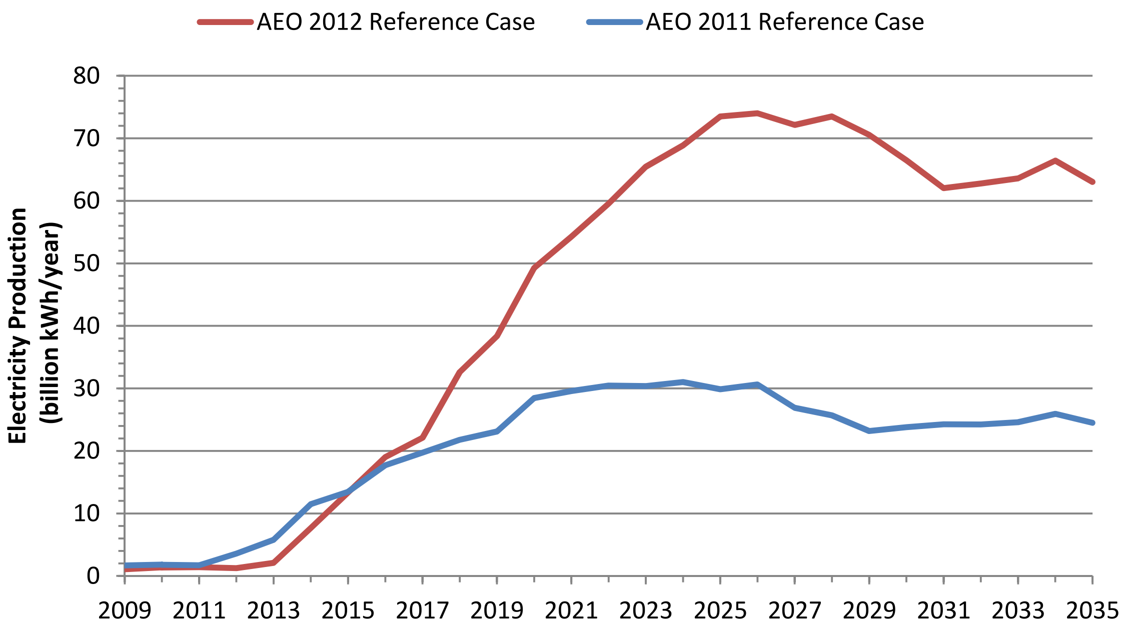
In 2010, the combustion of biomass accounted for 11.5 billion kWh of electricity generation (EIA, 2012a), which is a value that includes biomass combustion in several forms, such as the operation of boilers designed to burn biomass exclusively or boilers that burn black liquor (a biomass byproduct of pulp and paper production). This analysis does not focus on dedicated biomass boilers, but focuses on the co-firing of coal and biomass. The co-firing of coal and biomass in the U.S. generated 1.36 billion kWh of electricity in 2010, representing a small share of total renewable electricity generation (430 billion kWh) and an even smaller share of total electricity generation (3,998 billion kWh) (EIA, 2012a). U.S. power plants that co-fire coal and solid biomass comprise 469 MW of installed capacity. As shown in **Figure 3-3**, these power plants are located in the Eastern U.S. and have single-boiler capacities ranging from 3 to 99 MW. These power plants include facilities in the electric power sector and the industrial sector. Pulp and paper mills, which have biomass waste streams that can be combusted for energy recovery, are an example of an industrial producer of co-fired power.

Figure 3-3: Facilities with Coal and Biomass Co-Firing in 2010



Energy Information Administration's (EIA) Annual Energy Outlook (AEO) for 2012 projects significant growth in coal and biomass co-firing (EIA, 2012a). As shown in **Figure 3-4**, the 2011 reference case shows a peak of 31 billion kWh per year in 2024, and the 2012 reference case is even more aggressive, showing a peak of 74 billion kWh per year in 2026. These peaks are 22 to 53 times higher than current levels of co-fired electricity generation. EIA's projected increase in biomass co-firing for electricity generation is driven by state Renewable Portfolio Standard (RPS) requirements that encourage the use of renewables and low-cost projections for biomass feedstocks.

Figure 3-4: EIA AEO Reference Case – Electricity Generation from Biomass Co-firing



The potential for near-term growth in coal and biomass co-firing is limited by the number of existing power plants that are capable of switching from coal-only feedstocks to a mix of coal and biomass. The U.S. currently has 5,080 MW of potential coal and biomass co-firing capacity (Ortiz, et al., 2011). This potential capacity was estimated by sorting EIA's database of power plants according to the boiler types listed in NETL's Coal Power Plant Database (Ortiz, et al., 2011). If the potential expansion in coal and biomass co-fired capacity (5,080 MW) is added to the current capacity (469 MW), the U.S. could have a total coal and biomass co-firing capacity of 5,549 MW. This total capacity would be comprised solely from the conversion of existing facilities. To match the peak production of 31 billion kWh per year (as projected by the AEO 2011 reference case) the potential co-firing capacity of 5,550 MW would require an average capacity factor of 64 percent. The peak production of 74 billion kWh (as projected by the AEO 2012 reference case) could not be achieved by the hypothetical fleet of 5,549 MW, which means that greenfield co-firing facilities would have to be constructed to attain such a production rate.

3.3 Nuclear

The U.S. resource base of nuclear power includes domestic and imported sources of U. The U.S. consumes 16,500 tonnes of uranium per year (IEA/NEA, 2010). With domestic resources of 207,000 tonnes of U, current consumption rates will deplete the domestic supply within 12 years, if imports are excluded. Fortunately, the majority of the global supply of uranium is politically stable, so the U.S. can continue to rely on imported uranium originating mostly from Australia, Kazakhstan, Canada, and Russia. Based on the current world demand and known recoverable reserves, there are approximately 80 years of virgin supply at a recoverable cost of less than $130/kg U. If demand were to increase to the level of the International Atomic Energy Agency (IAEA) 2030 forecasted high of 807 GWe of nuclear generating capacity, there would be 40 years of virgin supply at a recoverable cost of less than $130/kg uranium based on known recoverable reserves. Additionally, recent reports by the nuclear industry indicate that the discovery of new conventional sources of uranium is likely. The supply outlook for uranium is not a key driver in the stability of the nuclear supply chain. This is demonstrated by the sensitivity of the cost of nuclear power to increase in uranium prices. If the price of uranium increases by 100 percent, the corresponding cost increase of nuclear power will be only 10 percent.

The growth of nuclear power in the U.S. depends on how many existing nuclear power plants will undergo license renewals, how many are commissioned, and how many are decommissioned, as there is little room for increased output from existing facilities. There are 104 nuclear reactors licensed by the NRC in the U.S. located on a total of 65 different sites. These reactors were granted original licenses of 40 years, with renewal application review beginning in 1998. The operators of 59 reactors in the U.S. (57 percent of the total fleet) have received 20 year operating renewals from the NRC. The operators of 18 reactors (17 percent of the total fleet) have submitted renewal applications, and the operators of 19 reactors (18 percent of the total fleet) have submitted intentions to submit renewal applications. This is a total of 96 out of 104 reactors, or 92 percent of the total fleet. The NRC and Nuclear Energy Institute (NEI) both expect that 100 percent of reactors will eventually apply for renewal. Nuclear reactors are, on average, about 27-28 years old when renewal applications are submitted.

The 2010 U.S. nuclear power capacity was 101 GW. Projections by the EIA and other organizations (IAEA, IHS Global Insight [IHSGI], and WNA) forecast nuclear capacities ranging from 110 to 180 GW in 2035. These projections are shown on the basis of total capacity in **Figure 3-5** and on the basis of U.S. electricity supply contribution in **Figure 3-6**. The WNA provided a range of projected nuclear generating capacity in the U.S. in 2030 between 120 and 180 GWe, which is shown as a band over the range in the following figures.

Figure 3-5: U.S. Baseload Nuclear Power Capacity Projections

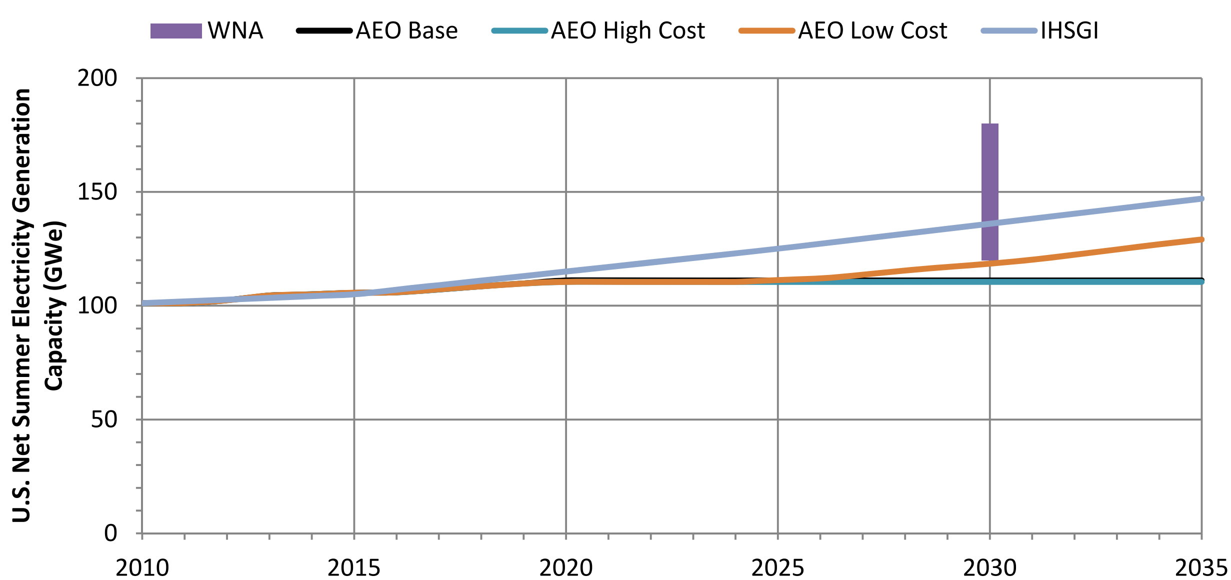
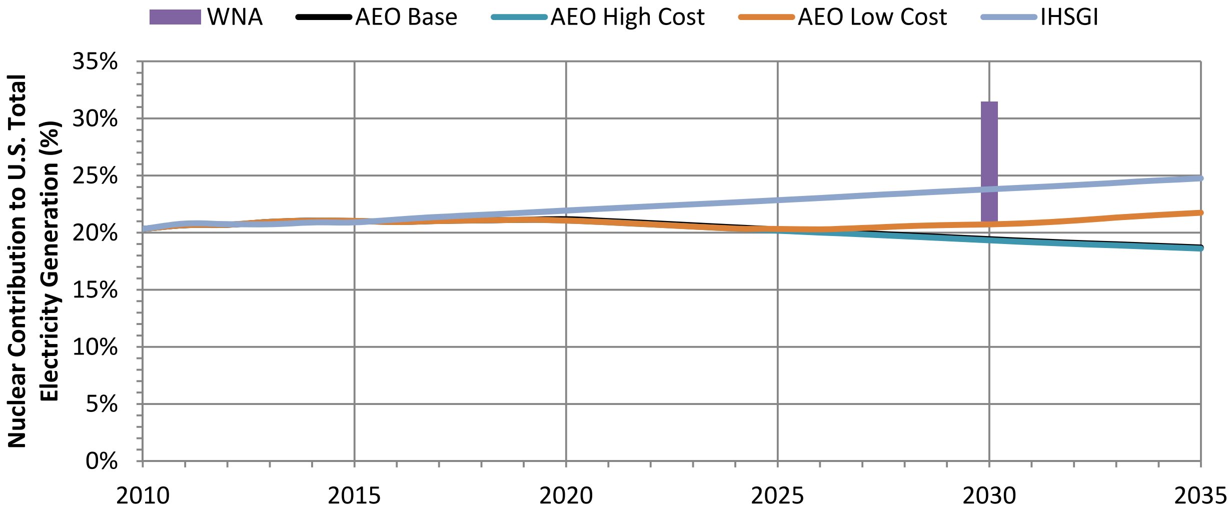


Figure 3-6: Portion of U.S. Power Supported by Nuclear Capacity



IAEA also projected the growth of nuclear power through 2030. However, the forecast was broken down by continent, not country, so no direct comparison could be made to the projections made by other organizations. The IAEA projects the nuclear generating capacity in North America to be between 127-168 GWe in 2030. According to the WNA, the current generating capacity in Canada is 13 GWe and 1 GWe in Mexico. Based on the assumption of modest increases of nuclear generating capacity in those countries, it is likely that the U.S. portion of the IAEA 2030 projection is consistent with the other forecasts by EIA, WNA, and IHSGI. It is important to note that all of the nuclear projections referenced in this analysis were made prior to the events at the Fukushima nuclear plant.

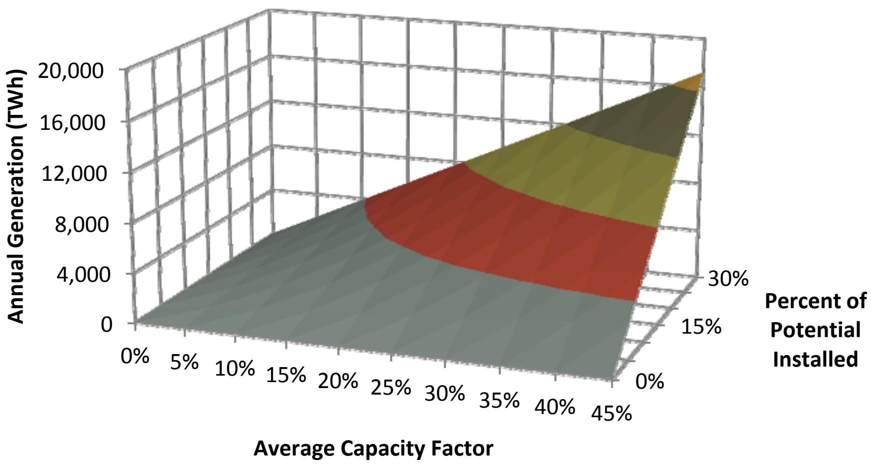
3.4 Wind

The resource base of onshore wind power is estimated to be sufficient to supply approximately 10,400,000 MW of wind power capacity, although much of this capacity is located in remote areas (AWEA, 2011). High onshore wind speeds are abundant within the southern, central, and northern plain states, across the lake states, and in southern Texas. Consistent onshore winds sufficient to drive turbines are also available at regional and local areas across the mountain states and the West, and within portions of the Northeast. Sufficient onshore wind resources are also available across much of the western fringe of Alaska and, to a lesser extent, Hawaii. Onshore wind resources are generally lacking in the south.

In general, offshore wind speeds reach higher persistent velocities as compared to onshore wind. U.S. offshore wind resources are estimated to be sufficient to support approximately 4,150,000 MW of power production (AWEA, 2011), with the highest average wind speeds off the coasts of the Northwest and Northeast U.S.

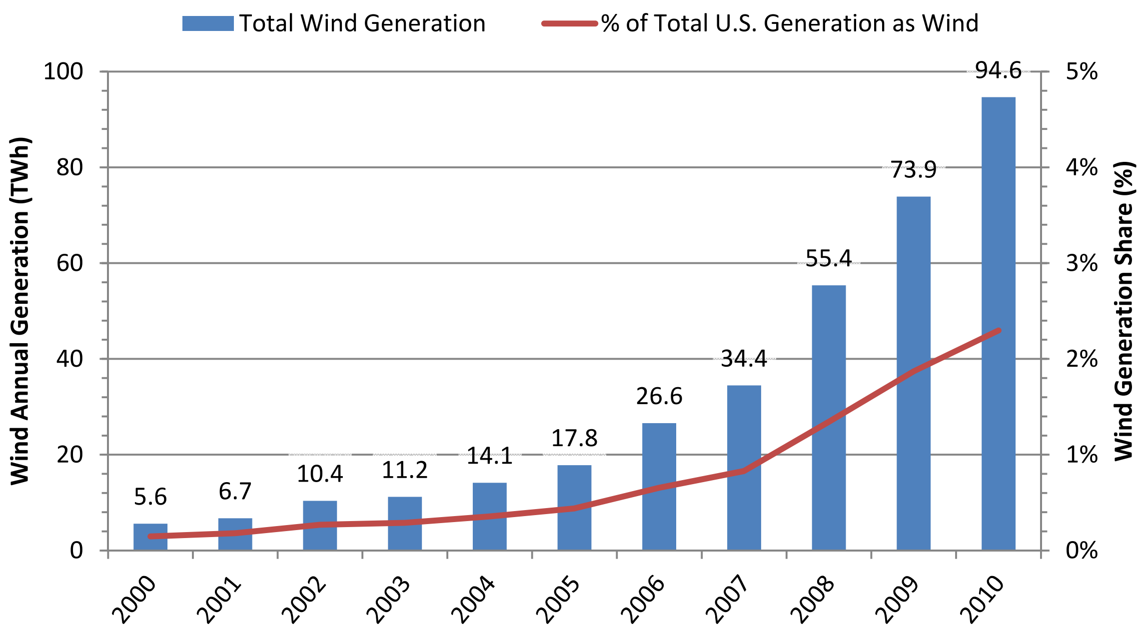
The above estimates of wind resources, like similar estimates for tidal, solar, and geothermal potential energy, are misleading because not all of the resource is economically accessible. There is a large amount of uncertainty about what percent of the capacity will be installed and, further, what amount of electricity will be generated from that installed capacity. **Figure 3-7** shows the potential generation from wind power given the estimates of potential capacity and assumptions about average capacity factor. The conclusion is that even with poorly performing turbines (at capacity factors lower than 20), and with very low utilization of the potential resource, (below 10 percent), large amounts of electricity can be generated relative to the demand in the U.S. Again, this should not be taken to mean that this can be done cheaply or reliably, but rather as an important context for the amount of wind resource.

Figure 3-7: Potential Wind Generation



The fraction of total U.S. power generation from wind power has increased from approximately 0.1 percent in 2000, to approximately 2.3 percent in 2010. **Figure 3-8** shows the growth in U.S. wind power from 2000 through 2010, indicating consistent and near exponential growth during that period. Overall, wind power generation has increased from 5.6 TWh in 2000 to 95 TWh in 2010 (EIA, 2011d), equivalent to a compound annual growth rate of 32.7 percent.

Figure 3-8: Annual Wind Generation and Share (EIA, 2011d)

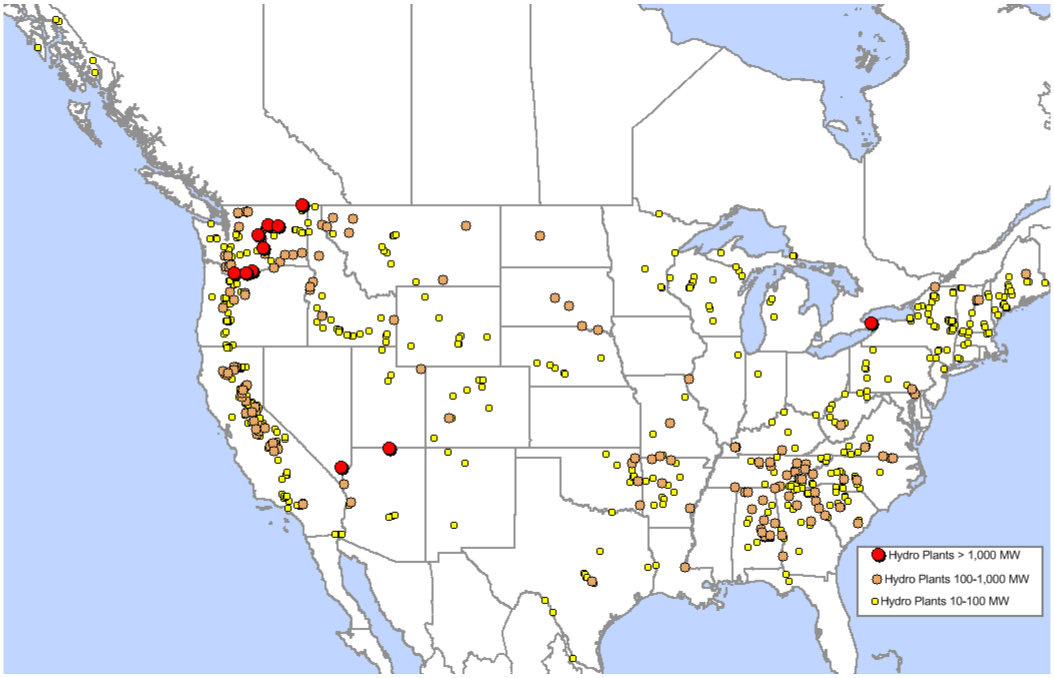


Current U.S. wind power generation capacities are predominantly provided by independently owned power producers, which is a reflection of onshore wind power's relatively recent commercial scale emergence and rapid development in the U.S. As of 2010, Texas had the highest wind power production gross capacity in the U.S., at 10.1 GW, followed by Iowa (3.68 GW), and California (3.25 GW) (Wiser & Bolinger, 2011). As of May 2011, 7 GW of domestic wind power projects were under construction or in site preparation (Wiser & Bolinger, 2011). Of these, the highest projected capacity of new wind projects was located in the state of Washington (735 MW). The Northeast as a whole is scheduled to add 554 MW of wind capacity, while the South is expected to add 158 MW (AWEA, 2011). These projections are based on data collected by the American Wind Energy Association (AWEA), which may be more optimistic in its projections than non-trade organizations. Unexpected shifts in financing, permitting, or grid integration barriers could easily hinder growth in wind power capacity. For example, the expiration of the electricity production tax credit (PTC) at the end of 2012 will reduce the incentive for installing new wind farms.

3.5 Hydropower

The resource base for very large hydropower sites in the U.S. has already been developed. However, many smaller conventional hydropower sites, such as those with capacities up to 400 MW, are still available. In 2009, conventional hydropower in the U.S. produced 253 terawatt hours of electricity, equivalent to 72 percent of total renewable power generation and approximately 7 percent of total power generation. The capacity of installed hydropower has remained relatively flat since 2000, maintaining a capacity near 77 GW. **Figure 3-9** shows the existing hydropower installations in the U.S. by size of installed capacity, with the majority of the large installations in the Western and Southeast U.S.

Figure 3-9: U.S. Hydropower Installations by Capacity



The Federal Energy Regulatory Commission (FERC), which licenses hydropower projects, has approved preliminary permits for the installation of nearly 3.1 GW of new conventional hydropower, comprising nearly 260 separate facilities (FERC, 2011). There are an additional 122 projects with pending preliminary permits with a total capacity of 1.6 GW. Preliminary permits give the applicant approval to study the site; however, they do not authorize construction (FERC, 2011). These new proposals appear to be driven substantially by recent regulatory and cultural shifts toward implementation of renewable energy technologies.

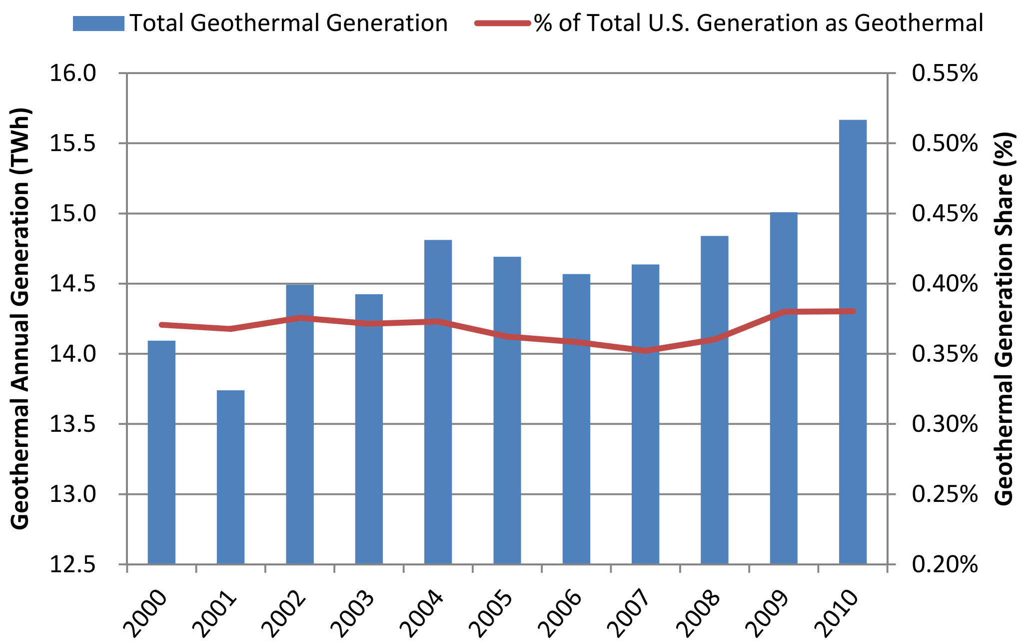
New hydrokinetic turbines are currently being installed along the Mississippi River system, and FERC has approved preliminary permits for an additional 3.6 GW (spread over 36 projects) of proposed hydrokinetic power installations on rivers across the U.S. There are an additional 8.7 GW of hydrokinetic river-based capacity spread over 87 projects that are pending preliminary permits (FERC, 2011).

3.6 Geothermal

The U.S. has a large resource base of geothermal energy, but there are barriers to developing this resource. Assuming that sufficient technology is, or were to become, available to support geothermal resource extraction, the total resource base within the U.S. is enormous. Development of only one percent of this resource would be equivalent to over 1,000 times the annual consumption of primary energy in the U.S. (INL, 2006). However, the harnessing of a geothermal resource is constrained by several factors, including the character of geologic formations on site (which can affect cost and feasibility of drilling), temperature and depth of the resource, and the proximity of the resource to available infrastructure, including power lines and supply/access roads. These factors have historically posed significant limitations with respect to the ongoing development of domestic geothermal resources.

Geothermal power has not exhibited significant growth within the last decade. The fraction of total U.S. power generation from geothermal power has remained essentially constant since 2000, fluctuating from approximately 0.36 to 0.38 percent, representing only a very small portion of total domestic power generation capacity. **Figure 3-10** provides a summary of U.S. geothermal power generation from 2000 through 2010, indicating a modest increase in net generation over time. Overall, geothermal power generation has increased from approximately 14.1 TWh in 2000, to approximately 15.7 TWh in 2010 (EIA, 2011c), equivalent to a compound annual growth rate of only 1.1 percent. This rate of growth represents a lackluster interest in geothermal development over the previous decade, wherein a substantial portion of project expansions were supported, at least in part, by government grants, loan programs, or other public sector incentives.

Figure 3-10: Annual Generation and Fraction of U.S. Power Provided by Geothermal Energy (EIA, 2011b)



Recent trends indicate resurging interest in geothermal energy. The installation of new and expanded geothermal capacity increased from 2007 through 2009, with new projects and expansions increasing from 34 MW in 2006 to 176 MW in 2009 (GEA, 2011). These projections are based on data compiled by the Geothermal Energy Association (GEA), a trade organization that is more likely to be optimistic than other organizations with respect to the future of geothermal power. Any investments in geothermal and other alternative energy technologies are tempered by the current global economic downturn and are also dependent on the implementation of policies that encourage the development of renewable energy.

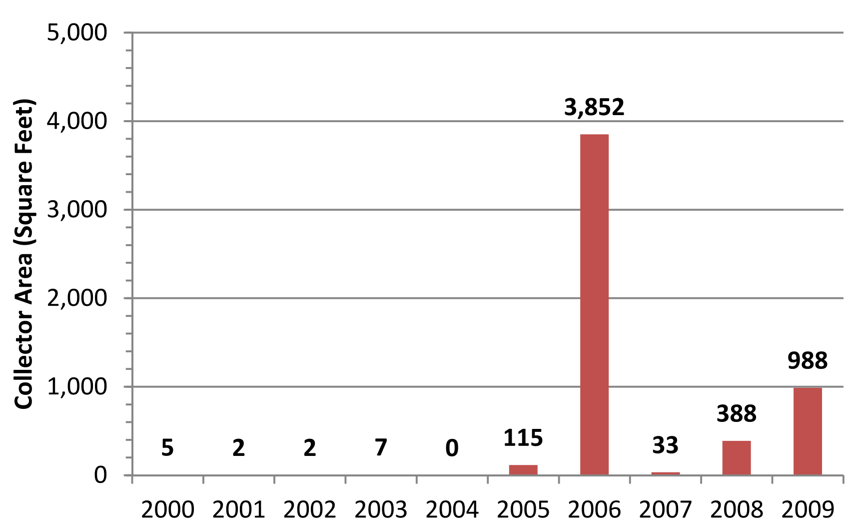
3.7 Solar Thermal

The resource base of solar thermal power is limited by several factors that inform the availability of direct sunlight at any given location. Key factors for solar thermal are latitude (which affects the angle and intensity of incoming sunlight), humidity, cloud cover, and, to a lesser extent, altitude (NREL, 2011). Average daily solar radiation ranges from 1 to 7 kWh/m^2/day, on an average annual basis, with the highest values located in the Desert Southwest, and the substantially lower values across much of the Midwest, Lake States, South, Northeast, and the westernmost portions of the Pacific Northwest. Solar power deployed across approximately 1.5 percent of the total land area available in the Southwest would be sufficient to provide at least four million GWh per year, which is enough to power the entire U.S. (DOE, 2009). This projection is based on land that has a slope of less than 1 percent, a solar capacity of 5 acres/MW, and a capacity factor of 27 percent (DOE, 2009). The resource base of solar power also varies considerably on a seasonal basis. For instance, resource availability in central Nevada may reach 10 kWh/m^2/day or higher during July, while January average values may be as low as 3 kWh/m^2/day, or even zero on a daily basis as a result of cloud cover (NREL, 2011). Additionally, a large portion of the plain states receive reasonable quality sunlight during July, but this quickly recedes with the approach of autumn.

The growth of solar thermal capacity in the U.S. has not been significant in the last 10 years. Total U.S. solar thermal power output was nearly constant from 2000 through 2006. The contribution of solar power to the total U.S. power supply was 0.1 percent in 2010, of which 64 percent was from photovoltaic cells and the remaining 36 percent (744 GWh) was from solar thermal power.

All operating utility-scale (i.e., 10 MW and above) solar thermal plants in the U.S. use parabolic trough technology and have a total capacity of 493 MW. Most of the existing capacity, 354 MW, is located in southeastern California, as part of the Solar Electric Generating Systems (SEGS) project, which was installed incrementally from 1984 through 1990. The more recent Nevada Solar One was installed in 2007. The Martin Next Generation Solar Energy Center was completed at the end of 2010, and at the time of publication of this document, is the most recently installed utility-scale solar thermal plant in the U.S. **Figure 3-11** shows historic data for domestic shipments of solar thermal collectors (in square feet of collector area). As shown, domestic shipments were essentially non-existent from 2000 through 2005. The spike in 2006, presumably associated with construction of the Nevada Solar One project, represents the first major spike since the late 1980s. After falling off to near zero in 2007, shipments again began to increase slightly in 2008 and 2009 (EIA, 2011e). Although data were not available at the time of publication of this report, 2010 domestic shipments would presumably exceed 2009 levels, due to construction of the Martin Next Generation Solar Energy Center, in Florida.

Figure 3-11: Domestic Solar Thermal Shipments (EIA, 2011e)



Few solar thermal facilities have been installed in the U.S. during the last decade, but the near-term domestic solar market is anticipated to be substantially more bullish. Approximately 720 MW of solar thermal power is under construction in California and Nevada, approximately 2,300 MW of solar thermal power was approved in 2010, and an additional 3,300 are currently in the environmental review phase (BLM, 2011; CEC, 2011; SEIA, 2011).

4 Environmental Profile

The environmental profile accounts for the life cycle (LC) resource consumption (including raw materials and water), emissions to air and water, solid wastes, and land use of each power technology. GHG emissions from land use changes are also included in this analysis. Land use effects can be roughly divided into direct and indirect. In the context of this study, direct land use effects occur as a result of processes within the life cycle boundary. Direct land use change is determined by tracking the change from an existing land use type (native vegetation or agricultural lands) to a new land use that supports production; examples include gas wells, regasification facilities, biomass feedstock cropping, and energy conversion facilities. This assessment of GHG emissions from land use change includes those emissions that would result from the direct and indirect activities associated with the following:

- Quantity of GHGs emitted due to biomass clearing
- Quantity of GHGs emitted due to oxidation of soil carbon and underground biomass following land transformation
- Evaluation of ongoing carbon sequestration that would have occurred under existing conditions, but did not occur under study/transformed land use conditions

GHG emissions from indirect land use are quantified only for the displacement of agriculture, and not for the displacement of other land uses. EPA's GHG emission factors for land use conversion were applied to the indirect land transformation values, according to transformed land type.

The environmental boundaries of each power technology account for the cradle-to-grave energy and material flows for electricity. The boundaries include five LC stages:

LC Stage #1, Raw Material Acquisition (RMA): Extraction of the primary fuel from the ground, field, or forest. Primary fuels include coal, natural gas, U, HP, and forest residue. Wind, water, solar, and geothermal energy do not require acquisition or transport, so they are not included in this stage.

LC Stage #2, Raw Material Transport (RMT): Transport of the primary energy source from the point of extraction to the energy conversion facility. Wind, water, solar, and geothermal energy do not require acquisition or transport, so they are not included in this stage.

LC Stage #3, Energy Conversion Facility (ECF): Conversion of primary energy source to electricity.

LC Stage #4, Product Transport (PT): Transmission and distribution of electricity from the energy conversion facility to the end user.

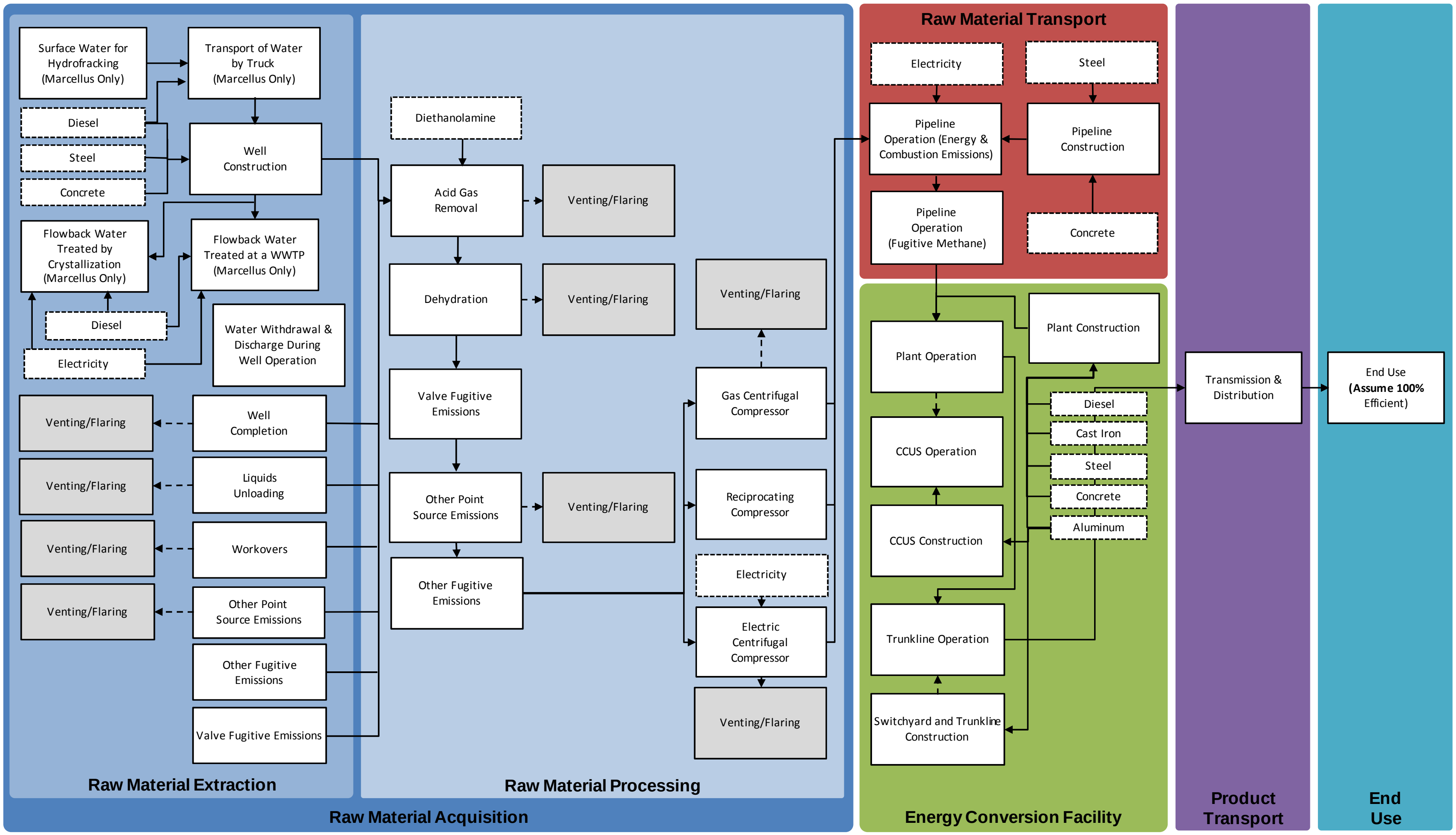
LC Stage #5, End Use (EU): Consumption of electricity (this stage does not have any energy or material flows and thus serves as a placeholder in the model).

To establish a basis for comparison, a functional unit of 1 MWh of electricity delivered to the consumer. The functional unit is the basis of comparison among all power technologies discussed in this report.

4.1 Environmental Analysis of Natural Gas

The environmental analysis of natural gas power accounts for key construction and operation activities from raw material acquisition through delivery of electricity to the consumer. **Figure 4-1** shows the processes inventoried by the natural gas model.

Figure 4-1: Natural Gas LCA Modeling Structure



The primary unit processes of the natural gas model are based on data developed by NETL.

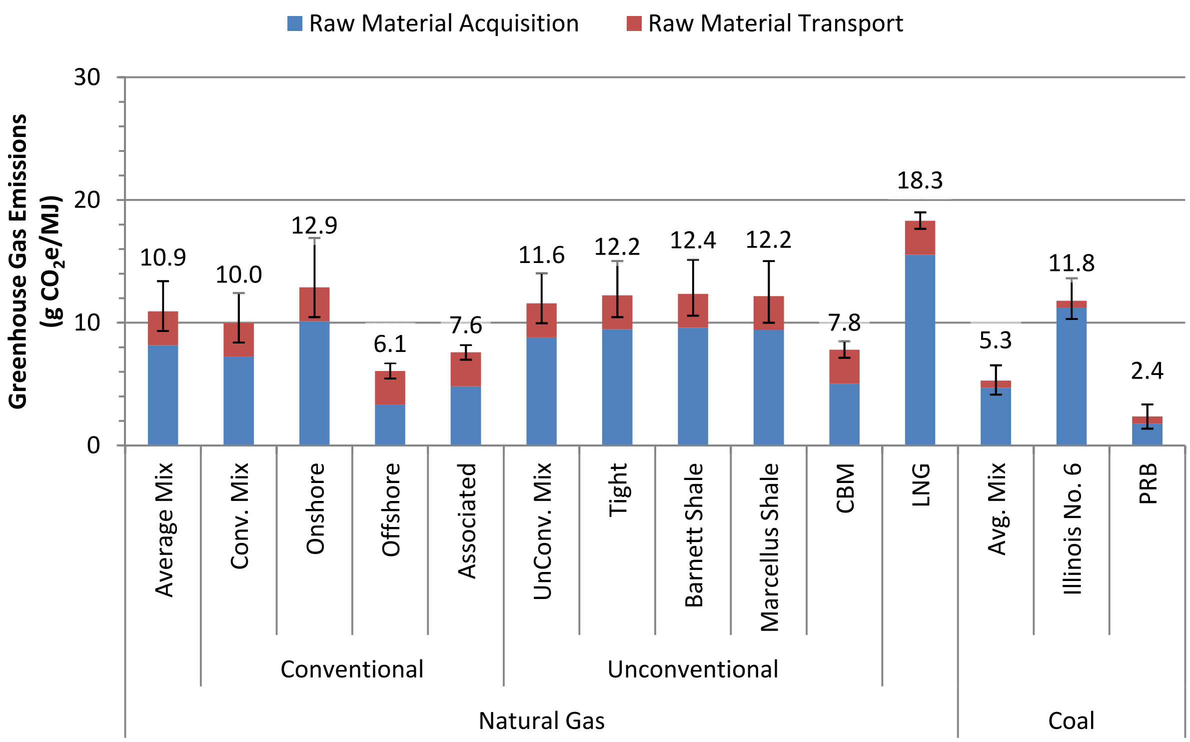
- Environmental Protection Agency (EPA) technical guidance documents were used to develop emission factors for well completion and maintenance (EPA, 2011a).
- Emissions from steady state operations (fugitive emissions from valves and other sources and point source emissions that are controlled by flaring) were also developed from the EPA technical guidance documents (EPA, 2011a).
- Data for water use and water quality are based on reports published by government agencies (ANL, 2004; DOE, 2006), as well as reports authored by independent consultants (GWPC & ALL, 2009)
- The production rates of wells are necessary for apportioning environmental burdens per unit of natural gas produced; EIA data were used to determine the production rates of conventional wells (EIA, 2010b) and the production rates of unconventional wells were determined by searching current industry literature.
- The operation of natural gas power plants are based on NETL's bituminous baseline report (NETL, 2010a) and data from EPA eGRID database (EPA, 2010).
- Peripheral unit processes that account for materials that are secondary to the primary supply chain, such as steel and concrete used for construction, or amine solvents used for gas processing, are based on third-party data.

4.1.1 Environmental Results for Natural Gas

GHG emissions associated with RMA and RMT of natural gas range from a low of 6.1 g CO_2e/MJ for conventional offshore natural gas production to 18.3 g CO_2e/MJ for LNG supplied from foreign sources. The 2010 domestic natural gas mix profile has emissions of 10.9 g CO_2e/MJ. RMA is most sensitive to well production rate, with conventional onshore extraction highly sensitive to liquid unloading frequency and venting rate and shale gas extraction highly sensitive to workover frequency and workover vent rate. The GHG results for natural gas RMT are sensitive to the distance for pipeline transport.

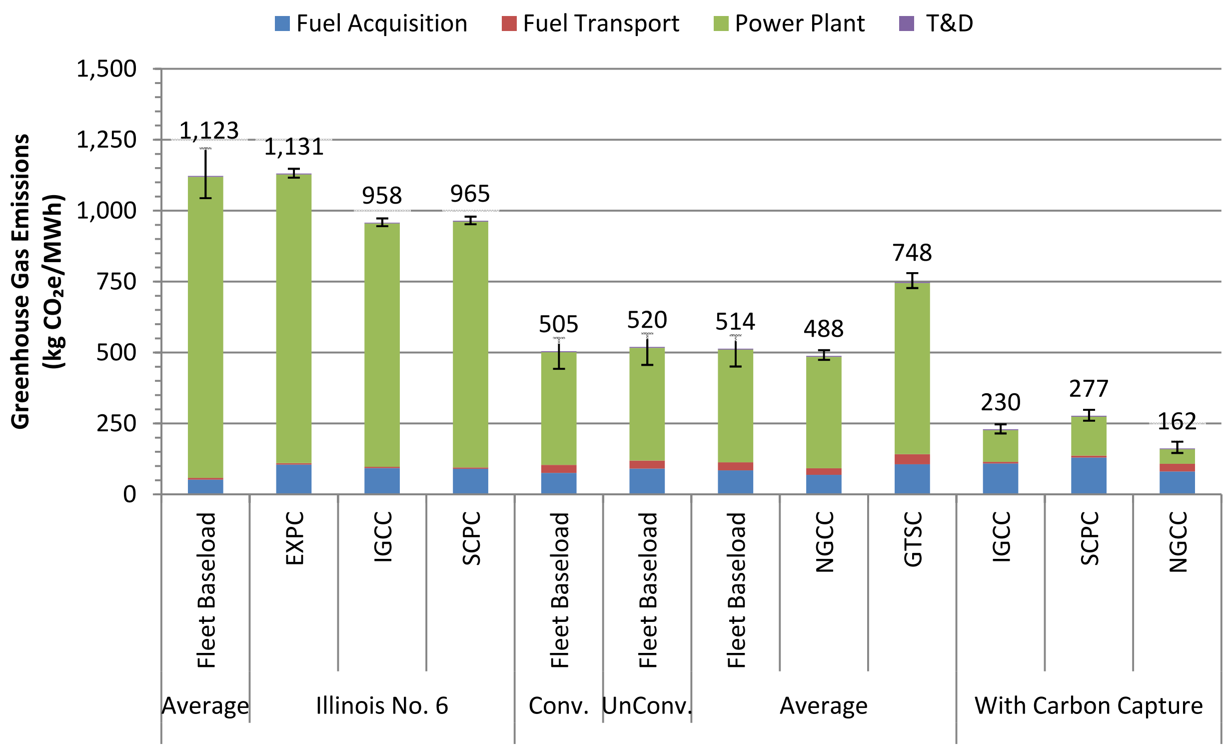
Compared on an upstream energy basis, natural gas has higher GHG emissions than coal. Comparing the average mixes from **Figure 4-2**, the expected GHG results for natural gas are more than 2 times greater than those for average coal (10.9 vs. 5.3 g CO_2e/MJ). Gassier bituminous coal, such as Illinois No. 6, is more comparable, but only makes up 31 percent of domestic consumption on an energy basis.

Figure 4-2: Comparison of Upstream GHG Emissions for Various Feedstocks



The per unit energy upstream emissions comparisons shown above are somewhat misleading in that a unit of coal and natural gas often provide different services. If they do provide the same service, they often do so with different efficiencies—it is more difficult to get useful energy out of coal than natural gas. To provide a common basis of comparison, different types of natural gas and coal are run through various power plants and converted to electricity. Note that there are alternative uses of both fuels and different bases on which they could be compared. However, in the U.S., the vast majority of coal is used for power production, so it provides the most relevant comparison. **Figure 4-3** compares results for natural gas and coal power on the basis of 1 MWh of electricity delivered to the consumer.

Figure 4-3: Life Cycle GHG Emissions for Electricity Generation



In contrast to the upstream results, which showed significantly higher GHGs for natural gas than coal, these results show that natural gas power, on a 100-year GWP basis, has a much lower impact than coal power without capture, even when using unconventional natural gas. When using less efficient simple cycle turbines, which provide peaking power to the grid, there are far fewer GHGs emitted than for coal-fired power. Because of the different roles played by these plants, the fairest comparison is the domestic mix of coal run through an average baseload coal power plant with the domestic mix of natural gas run through the average baseload natural gas plant. In that case, the coal-fired plant has emissions of 1,123 kg CO_2e/MWh, more than double the emissions of the natural-gas fired plant at 514 kg CO_2e/MWh. **Figure 4-4** shows the same results but applying and comparing 100- and 20-year Intergovernmental Panel on Climate Change (IPCC) global warming potentials to the inventoried GHGs.

Figure 4-4: LC GHG Emissions for Various Power Technologies by GWP

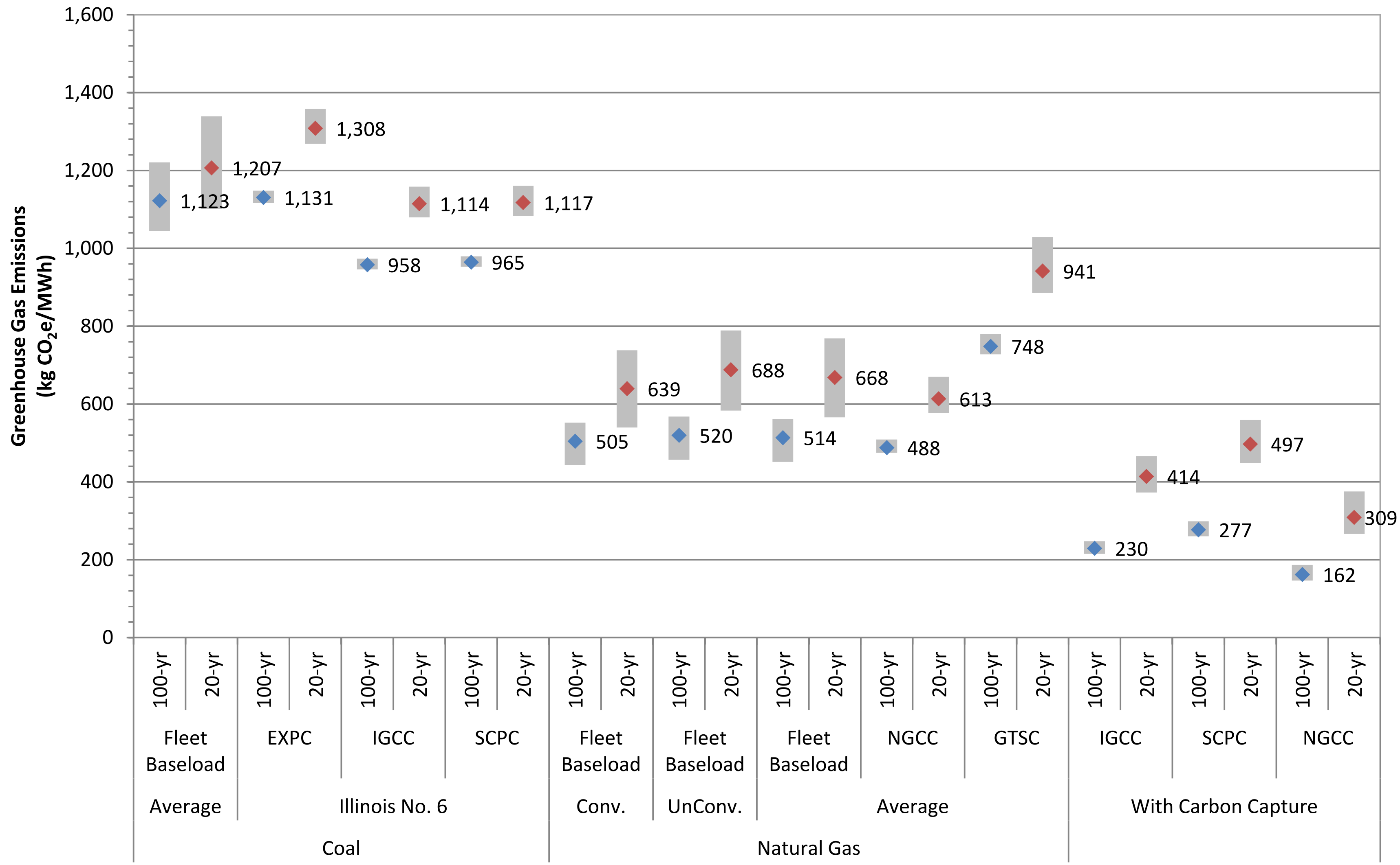


Figure 4-4 shows that even when using a GWP of 72 for CH_4 to increase the relative impact of upstream methane (CH_4) from natural gas, gas-fired power still has lower GHGs than coal-fired power. This conclusion holds across a range of fuel sources (conventional vs. unconventional for natural gas, bituminous vs. average for coal) and a range of power plants (GTSC, NGCC, average for natural gas, and IGCC, SCPC, EXPC, and average for coal). The one situation where this conclusion changed is the use of unconventional natural gas in an NGCC unit with carbon capture compared to an integrated gasification combined cycle (IGCC) unit with carbon capture. The high end of the range overlaps the expected value for IGCC in this situation.

Using the 2010 domestic mix of natural gas, **Table 4-1** shows the LC results for non-GHG emissions using the functional unit of 1 MWh of delivered electricity. In general, the LC emissions increase with decreased power plant efficiency. The addition of carbon capture and sequestration (CCS) does not result in a significant change to the non-GHG emissions. The slightly higher non-GHG emissions from the CCS cases are due to the normalization of the LC results to the functional unit of 1 MWh of delivered electricity (due to the decreased NGCC efficiency caused by the CCS system, more natural gas is combusted by the NGCC with CCS than NGCC *without* CCS).

Table 4-1: Other Life Cycle Air Emissions for Natural Gas Power Using Domestic NG Mix

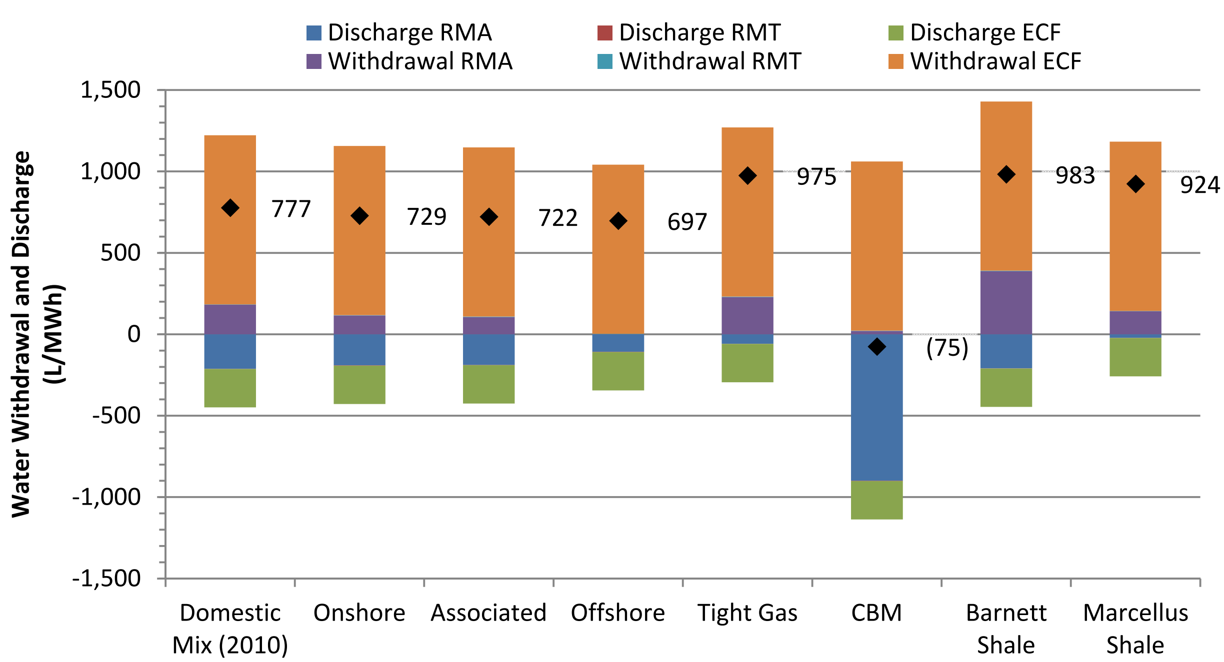
Technology	Emission (kg/MWh)	RMA	RMT	ECF	Total
NGCC	Pb	1.98E-06	1.65E-07	2.71E-06	4.86E-06
	Hg	6.80E-08	5.17E-09	2.46E-08	9.77E-08
	NH_3	8.98E-07	1.99E-06	1.88E-02	1.88E-02
	CO	4.38E-02	6.23E-04	3.12E-03	4.76E-02
	NO_X	4.85E-01	7.80E-04	3.05E-02	5.16E-01
	SO_2	5.06E-03	3.18E-04	1.19E-03	6.56E-03
	VOC	4.73E-01	1.59E-05	3.72E-05	4.73E-01
	PM	4.80E-03	6.55E-05	2.17E-03	7.04E-03
NGCC/ccs	Pb	2.32E-06	1.94E-07	3.09E-06	5.61E-06
	Hg	7.97E-08	6.06E-09	3.50E-08	1.21E-07
	NH_3	1.05E-06	2.33E-06	2.03E-02	2.03E-02
	CO	5.14E-02	7.31E-04	4.50E-03	5.66E-02
	NO_X	5.68E-01	9.14E-04	3.42E-02	6.03E-01
	SO_2	5.93E-03	3.72E-04	1.67E-03	7.97E-03
	VOC	5.55E-01	1.86E-05	4.74E-05	5.55E-01
	PM	5.63E-03	7.67E-05	2.47E-03	8.18E-03
GTSC	Pb	3.05E-06	2.55E-07	6.27E-07	3.94E-06
	Hg	1.05E-07	7.96E-09	7.08E-09	1.20E-07
	NH_3	1.38E-06	3.07E-06	2.90E-02	2.90E-02
	CO	6.75E-02	9.61E-04	5.48E-03	7.40E-02
	NO_X	7.47E-01	1.20E-03	4.87E-02	7.97E-01
	SO_2	7.79E-03	4.89E-04	1.53E-03	9.81E-03
	VOC	7.29E-01	2.45E-05	1.64E-04	7.30E-01
	PM	7.40E-03	1.01E-04	2.75E-03	1.03E-02

The LC water withdrawal and discharge for natural gas power from seven sources of natural gas are shown in **Figure 4-5**. This figure is based on a functional unit of 1 MWh of delivered electricity, is representative of an NGCC power plant (without CCS), and accounts for a 7 percent transmission and distribution (T&D) loss between the power plant and consumer. Water withdrawals are shown as positive values, discharges are shown as negative values, and net consumption is shown by the black diamond on each data series.

As shown by **Figure 4-5** on the basis of 1 MWh of delivered electricity, the magnitude of water withdrawals and discharges is greatest for the energy conversion facility for all natural gas profiles considered. Net water consumption varies considerably based on the natural gas source that is considered. Net water consumption rates for conventional onshore (729 L/MWh), conventional offshore (697 L/MWh), and onshore associated natural gas (722 L/MWh) are essentially similar in terms of net water consumption. However, due to elevated water requirements for hydrofracking, water consumption for the shale and tight gas is elevated. For instance, in comparison to conventional onshore natural gas production (729 L/MWh), tight gas requires 34 percent more water (975 L/MWh), Marcellus Shale requires 27 percent more water (924 L/MWh), and Barnett Shale requires 35 percent more water (983 L/MWh).

The acquisition of coal bed methane (CBM) natural gas does not consume water. CBM extraction involves the removal of naturally occurring water from the formation. The LC of an NGCC system using natural gas from CBM results in more water discharges than withdrawals.

Figure 4-5: LC Water Withdrawal & Discharge for NGCC Power Using Various Sources of NG

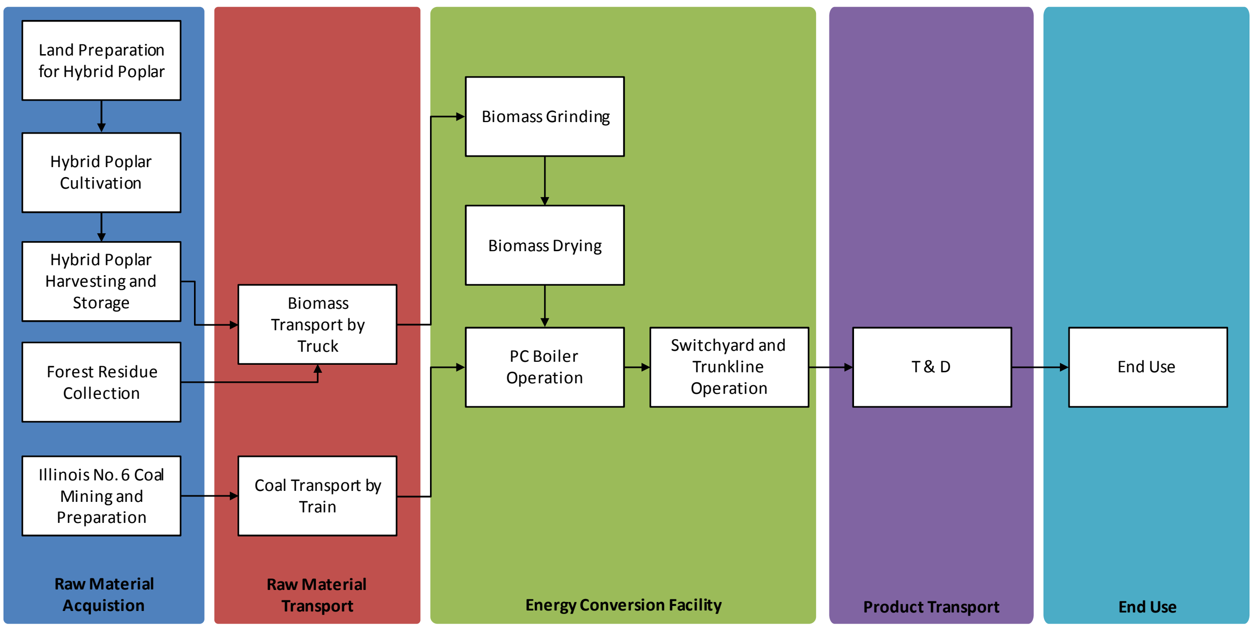


The LC water consumed by the cases with CCS is approximately 1.8 times higher than the LC water consumed by the cases without CCS. This difference is due to the water requirements of the CCS system, associated with increased cooling requirements. The Econamine FG Plus℠ process requires cooling water to reduce the flue gas temperature from 57°C to 32°C, cool the solvent (the reaction between CO_2 and the amine solvent is exothermic), remove the heat input from the additional auxiliary loads, and remove the heat in the CO_2 compressor intercoolers (NETL, 2010a; Reddy, Johnson, & Gilmartin, 2008).

4.2 Environmental Analysis of Co-Firing

The environmental analysis of co-fired power accounts for key construction and operation activities from raw material acquisition through delivery of electricity to the consumer. **Figure 4-6** shows the processes inventoried by the co-firing model.

Figure 4-6: Primary Unit Process Network for LCA of Co-fired Power with Coal and Biomass



The primary unit processes of the co-firing model are based on data developed by NETL.

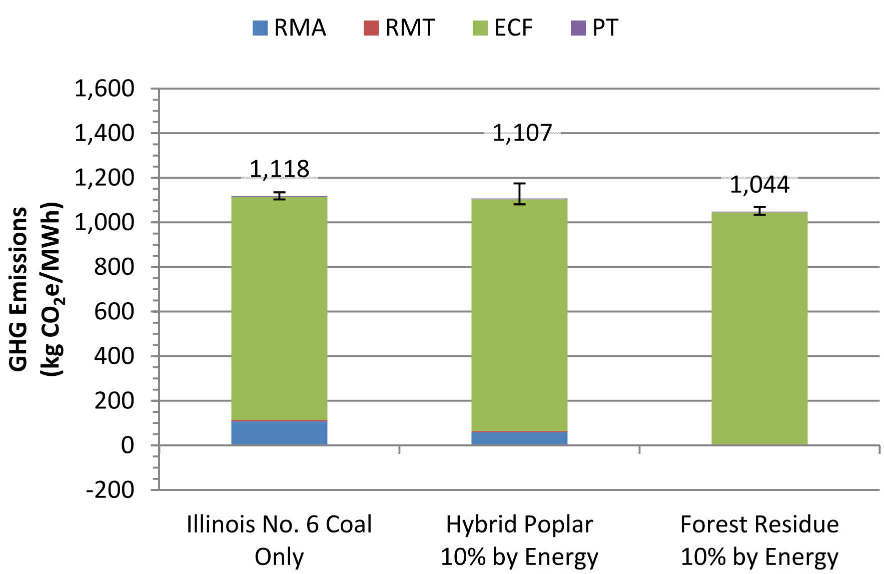
- Data for coal extraction are representative of Illinois No. 6 coal and are based on conversations with personnel at the Galatia Mine in Saline County, Illinois. Coal mine methane is a key parameter for coal extraction; an expected value of 422 scf/ton (with low and high values of 360 to 500 scf/ton) is used in this analysis (EPA, 2011b).
- Data for biomass acquisition include the land preparation, cultivation, and harvesting activities for HP, and the collection activities for forest residue. These biomass acquisition activities include the construction and operation of heavy equipment; they are based on equipment specifications published by heavy equipment manufacturers and are apportioned per unit of biomass production according to the expected life of equipment, total acreage of a single farm, and annual biomass yield rate.
- The energy and emissions for the rail transport of coal from the mine to the energy conversion facility are representative of a locomotive with a 4,400 horsepower diesel engine (GE, 2008) and rail cars with a 100-ton capacity. Similarly, the road transport of biomass is based on a diesel truck and trailer combination with a gross weight of 60,000 lbs. when fully loaded.

- The feed rates and air emissions of the energy conversion facilities are based on the combustion chemistry and net efficiencies of the power plants. The energy and material flows of the energy conversion facility are representative of a 550 MW PC boiler with a net plant efficiency of 33 percent when firing coal only. There is a slight decrease in efficiency when biomass is introduced to the system; the plant efficiency of the co-fired scenario system is 32.8 percent (Ortiz, et al., 2011).
- Peripheral unit processes that account for materials that are secondary to the primary supply chain, such as steel and concrete used for construction, are based on third-party data.

4.2.1 Environmental Results for Co-Firing

The conversion of an existing 550 MW PC boiler to a system which co-fires HP at a 10 percent share of feedstock energy reduces LC GHG emissions by only one percent (1,118 kg CO_2e/MWh vs. 1,107 kg CO_2e/MWh). Most of the GHG reductions due to the displacement of coal are offset by the land use, fertilizer use, and efficiency losses of co-firing. The co-firing of forest residue is more effective at reducing GHG emissions than HP; when forest residue is co-fired at a 10 percent share of the feedstock, the LC GHG emissions are reduced by 6.6 percent. The key advantage of forest residue, in comparison to HP, is its low GHG emissions for material acquisition. The GHG results for the three scenarios of the co-firing analysis are shown by LC stage in **Figure 4-7**.

Figure 4-7: GHG Results for Power Generation from Coal and Biomass



As shown in **Table 4-2**, this analysis accounts for criteria air pollutants and other air emissions of concern from co-fired systems.

Table 4-2: Other Life Cycle Air Emissions for Coal and Biomass Power Systems

Scenario	Emission (kg/MWh)	RMA	RMT	ECF	Total
100% Illinois No. 6 Coal	Pb	1.49E-06	6.47E-08	2.64E-09	1.55E-06
	Hg	2.65E-07	5.11E-09	3.76E-05	3.79E-05
	NH_3	2.54E-05	2.00E-04	0.00E+00	2.26E-04
	CO	1.00E-02	1.68E-02	1.53E+00	1.55
	NO_X	1.68E-02	1.41E-02	1.07E+00	1.10
	SO_2	3.33E-02	5.52E-03	4.12E-01	4.51E-01
	VOC	2.87E-03	2.61E-03	-5.16E-15	5.49E-03
	PM	1.49E-03	1.79E-02	2.60E-01	2.79E-01
10% Hybrid Poplar	Pb	3.05E-06	1.18E-07	1.25E-07	3.30E-06
	Hg	3.62E-07	8.08E-09	3.43E-05	3.46E-05
	NH_3	8.47E-03	1.84E-04	7.29E-06	8.67E-03
	CO	3.53E-02	1.63E-02	1.44E+00	1.50
	NO_X	4.05E-02	1.31E-02	9.28E-01	9.81E-01
	SO_2	4.70E-02	5.88E-03	4.00E-01	4.53E-01
	VOC	5.00E+00	2.79E-03	3.30E-02	5.04
	PM	7.61E-02	1.63E-02	2.41E-01	3.33E-01
10% Forest Residue	Pb	1.57E-06	1.18E-07	1.25E-07	1.81E-06
	Hg	2.54E-07	8.08E-09	3.43E-05	3.45E-05
	NH_3	3.27E-05	1.84E-04	7.29E-06	2.24E-04
	CO	2.51E-02	1.63E-02	1.44E+00	1.49E+00
	NO_X	1.83E-02	1.31E-02	9.28E-01	9.59E-01
	SO_2	3.33E-02	5.88E-03	4.00E-01	4.39E-01
	VOC	4.71E-03	2.79E-03	3.30E-02	4.05E-02
	PM	6.79E-02	1.63E-02	2.41E-01	3.25E-01

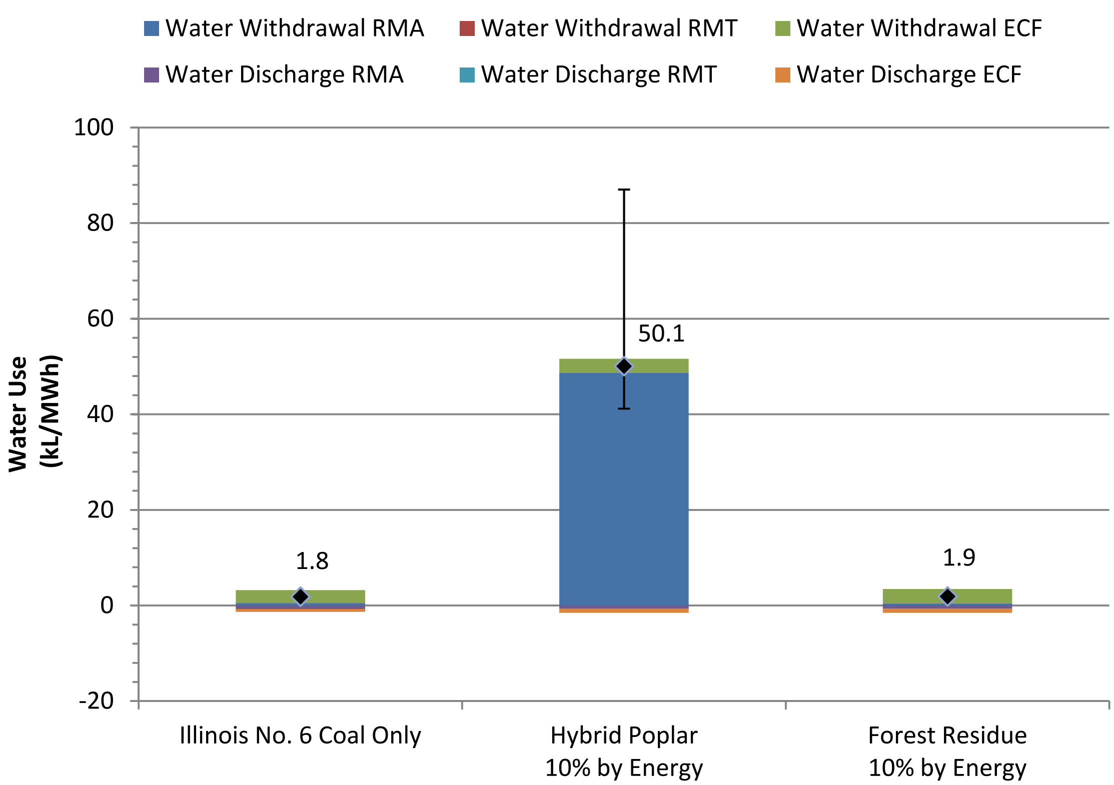
The co-firing of coal and biomass is effective at reducing SO_2 emissions at a power plant, in comparison with standalone coal firing. However, SO_2 emissions are also released at other stages of the LC, including RMA. For instance, the co-firing scenario for HP has lower ECF SO_2 emissions than the coal-only case, but higher RMA SO_2 emissions than the coal-only case, making the total SO_2 emissions of the two cases virtually equal. In fact, the LC SO_2 emissions of the three scenarios of this analysis all fall within a narrow range; the percent difference between the highest and lowest SO_2 emissions is only 3.1 percent.

The grinding and drying of biomass, which is necessary for effective biomass combustion in a PC boiler, produces significant emissions of PM. PM is also produced from land disturbance during the cultivation and harvesting of biomass, as well as from the combustion of diesel in farming and other equipment during the cultivation and harvesting of biomass.

NH_3 and volatile organic compounds (VOC) are two air emissions produced during the cultivation of biomass and are an order of magnitude higher for the HP scenario than for the other scenarios of this analysis. HP is the only feedstock of this analysis that requires fertilizer. NH_3 and VOC emissions are released during the production and use of fertilizer, so the co-firing scenario with HP has significantly higher NH_3 and VOC emissions than the other scenarios.

The acquisition of HP withdraws more water than other processes of this analysis. Coal extraction consumes relatively low volumes of water. Forest residue is a byproduct of another industry and, from a LCA perspective, does not consume significant volumes of water during RMA. The cultivation of HP accounts for the majority of water withdrawal during RMA. At an annual yield of 6.8 tons/acre, the cultivation of HP withdraws 431 L of water per kg of harvested biomass. The co-firing of HP (at 10 percent by energy in a 550 MW PC boiler) requires the harvesting 111 kg of biomass for the delivery of 1 MWh of electricity. Factoring these water withdrawal and biomass consumption rates gives a total RMA water withdrawal rate of 47,800 L/MWh, which accounts for 98 percent of RMA water withdrawal shown by the HP scenario. The LC water use for the coal and biomass power systems is shown in **Figure 4-8**. Water withdrawals are shown as positive values, and water discharges are shown as negative values.

Figure 4-8: Water Use by Coal and Biomass Power Systems

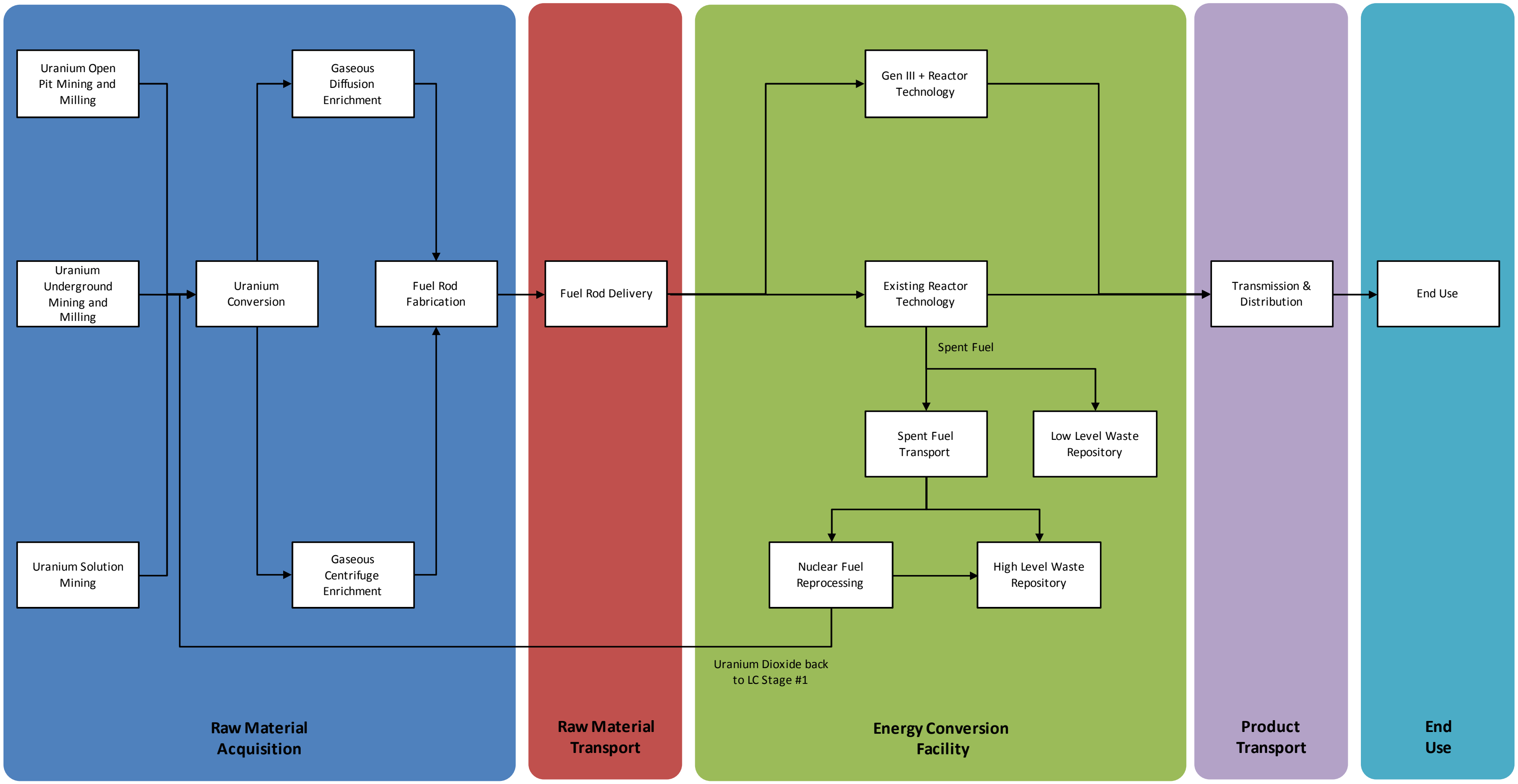


Uncertainty in water use for the co-firing of HP is driven by the possible yield rates of biomass. The ratio of the highest and lowest biomass yield rates is 2.2; similarly, the ratio of high and low water use for the co-firing of HP biomass case is 2.1.

4.3 Environmental Analysis of Nuclear Power

The environmental analysis of nuclear power accounts for key construction and operation activities from raw material acquisition through delivery of electricity to the consumer. **Figure 4-9** shows the processes inventoried by the nuclear model.

Figure 4-9: LCA Modeling Framework for Nuclear Power



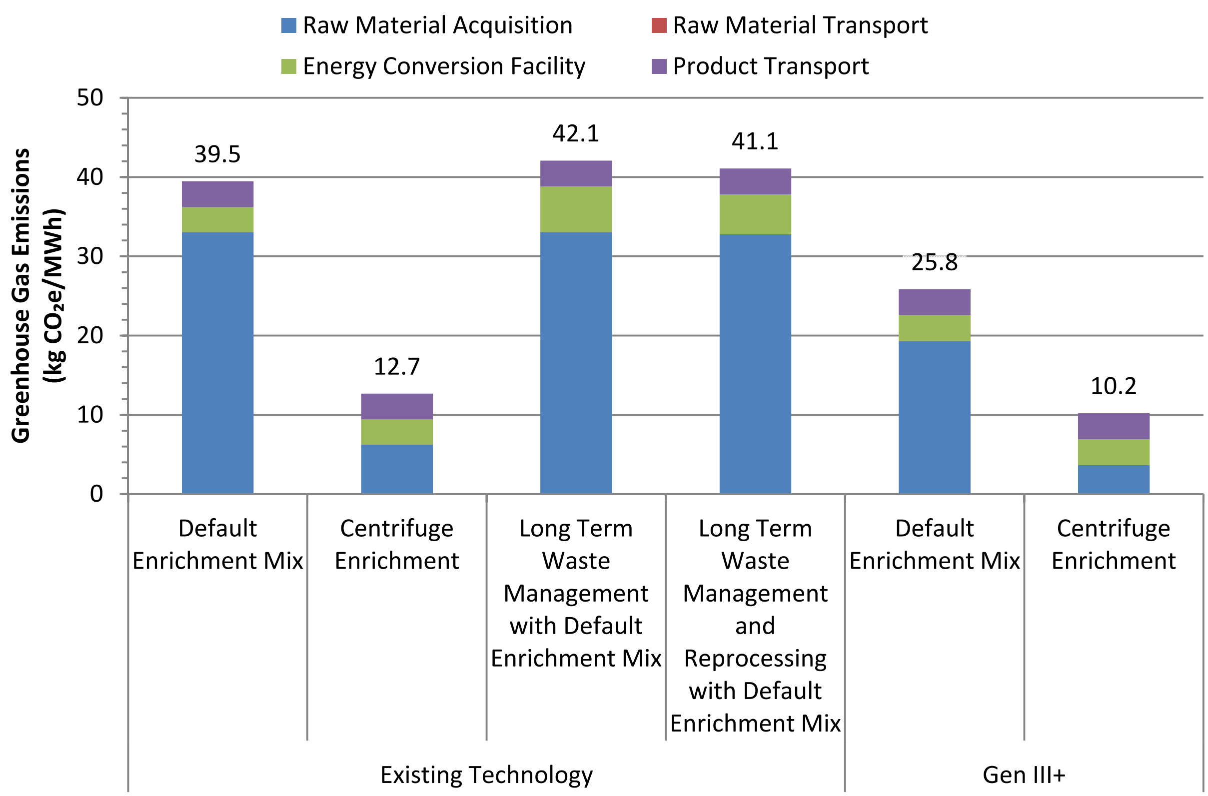
The primary unit processes of the nuclear model are based on data developed by NETL. The key data used for modeling the energy and material flows of nuclear fuel acquisition and consumption are summarized below:

- Three technologies are used for mining uranium ore: underground, in situ, and open pit mining. Data for underground mining of uranium are based on the construction of a room and pillar mine, similar to that previously developed by NETL for Illinois No. 6 coal mines (NETL, 2010b). The energy requirements for in situ mining include electricity and natural gas used for injection and recovery of fluid, as well as for the remediation of process water by reverse osmosis before it is returned to the ground (NRC, 2009). The energy requirements for open pit mining of uranium are based on data for the Ranger Mine, which is located in Australia and currently produces 12 percent of the world's uranium (Leeuwen, 2007). Global production data was used to determine the mass proportion of uranium mined by each method (Mining-Technology, 2010) (WNA, 2009).
- Uranium conversion is the process of converting solid U_3O_8 to UF_6. Conversion is necessary in order to convert solid U_3O_8 to gaseous UF_6, which is easier to enrich to elevated levels of U-235. The significant operation activities for uranium conversion include the input of U_3O_8 (yellowcake) and the combustion of process fuels (Rotty, Perry, & Reister, 1975), while air emissions from operations are based on an annual environmental compliance report for a uranium conversion facility in Canada (Cameco, 2009).
- Enrichment is necessary to increase the concentration of fissile uranium in nuclear fuel. Gaseous diffusion is currently used in the U.S. and uses a long series of semi-permeable membranes; gas centrifugation is the predominant enrichment technology in Europe and uses a long series of rotating centrifuges to exploit the mass difference between U-235 and U-238 isotopes. The operation activities for gaseous diffusion enrichment are based on the profiles of the gaseous diffusion facility in Paducah, Kentucky, which is the only operating gaseous diffusion facility in the U.S. (ATSDR, 2001; DOE, 2004). The operation activities for gas centrifuge enrichment are based on an EIS for a proposed enrichment facility (NRC, 2005).
- Uranium fuel fabrication converts gaseous UF_6 to solid UO_2, and then sinters the UO_2 into cylindrical pellets that are assembled into metal-encased fuel rods. The significant operation activities for uranium fuel fabrication are the input of enriched UF_6 and the combustion of process fuels; the LC burdens for the other components of a fuel rod assembly are assumed to be negligible in comparison to the LC burdens of the uranium supply chain and are thus not accounted for in this analysis.
- The operation of existing nuclear power facilities is based on Energy Information Administration records for electricity production, fuel use, and capacity (EIA, 2010b). The average operating reactor in the U.S. in 2009 was 926 MW operating with a 92 percent capacity factor. Variations in plant size ranged from 482 MW to 1,314 MW, with 3.5 GWh to 10.7 GWh of electricity production per year. The operation data for a Gen III+ nuclear power plant were developed by compiling the capacity factors and thermal efficiencies of proposed nuclear power plants and scaling the inputs and outputs of existing nuclear power plants accordingly.
- Peripheral unit processes that account for materials that are secondary to the primary supply chain, such as steel and concrete used for construction, are based on third-party data.

4.3.1 Environmental Results for Nuclear Power

Figure 4-10 shows LC GHG emissions for nuclear power. At 39.5 kg of carbon dioxide equivalents (CO_2e)/MWh generated by existing reactors, and 25.8 kg CO_2e/MWh for Gen III+ reactors, the LC GHG emissions of nuclear power are a factor of 10 lower than integrated gasification combined cycle (IGCC) power plants with CCS and a factor of 30 to 40 lower than existing pulverized coal (EXPC) power plants. Gen III+ reactors achieve an approximately 13.7 kg CO_2e/MWh reduction in LC emissions over existing reactors, primarily due to an average of 1.7 times lower fuel input rates and a 2.6 percent higher thermal efficiency.

Figure 4-10: Life Cycle GHG Profile for Existing and Gen III+ Nuclear Power Including Various Enrichment and Waste Management Scenarios



The energy required for enrichment of uranium fuel accounts for the majority of LC GHG emissions in the existing U.S. nuclear reactor fleet. Gaseous diffusion enrichment is currently the only type used in the U.S., where 52 percent of uranium dioxide (UO_2) delivered to U.S. reactors is enriched. If the proposed centrifuge enrichment facility in Lea County, New Mexico were used for U.S. enriched fuel, the LC GHG emissions of existing nuclear power would be reduced to approximately 12.7 kg CO_2e/MWh for existing reactors and 10.2 kg CO_2e/MWh for Gen III+ reactors.

The addition of long-term waste (which includes LLW and HLW) disposition to the existing nuclear power case increases the GHG results of nuclear power by 6.6 percent (42.1 compared to 39.5 kg CO_2e/MWh). The only difference between the baseline scenario and the long-term waste management scenario is the transport and construction requirements of long-term waste management. The addition of fuel reprocessing to the nuclear fuel cycle reduces the consumption of uranium 20 to

30 percent (IAEA, 2008). However, this reduction only reduces the burdens contributed by uranium mining and milling. Reprocessed uranium requires re-enrichment in order to increase its U-235 concentration to a level appropriate for LWR operation. The total reduction in the GHG emissions of LC Stage #1 is only 1.0 percent. When the entire LC is considered, reprocessing of nuclear fuel increases the GHG results by 4.1 percent (41.1 compared to 39.5 kg CO_2e/MWh). A choice to construct a centrifuge enrichment facility in the U.S. would be much more effective at reducing nuclear power LC GHG emissions than constructing a PUREX reprocessing facility.

The results in the above paragraph do not account for the GHG emissions from land use change. The GHG emissions from direct and indirect land use change range from 0.094 to 0.65 kg CO_2e/MWh depending for Gen III+ and existing plants, respectively. Thus, the land use GHG emissions for nuclear power increases the baseline scenario GHG emissions from 39.5 to 40.2 kg CO_2e/MWh.

LC criteria and other air pollutant species of interest are also dominated by gaseous diffusion operation and power plant construction emissions. The emissions contribution from these processes relative to all other processes in the lifecycle is shown in **Table 4-3**. Combustion emissions come from hard coal electricity provided to the diffusion enrichment plant as well as diesel combustion in the construction and decommissioning processes. Hg is heavily emitted as an effect of copper mining for power plant construction materials. PM is generated in installation and decommissioning activities. Mining emissions also contribute significantly to PM and VOC emissions, but are an order of magnitude below enrichment and construction emissions. In general, the Gen III+ LC has lower air emissions than the existing plants due to higher UO_2 burnup rates of Gen III+ reactors and higher thermal efficiency.

Table 4-3: Other Life Cycle Air Emissions for Nuclear Power

Technology	Emissions (kg/MWh)	RMA	RMT	ECF	Total
Existing	Pb	1.52E-06	9.59E-13	4.98E-07	2.02E-06
	Hg	3.32E-07	7.96E-14	1.80E-08	3.50E-07
	NH_3	1.58E-03	5.43E-10	1.52E-05	1.59E-03
	CO	2.25E-02	9.53E-08	1.43E-02	3.68E-02
	NO_X	7.36E-02	5.83E-08	2.35E-03	7.59E-02
	SO_2	1.86E-01	1.12E-07	6.08E-03	1.92E-01
	VOC	8.19E-03	1.19E-07	1.76E-03	9.95E-03
	PM	3.91E-03	9.77E-10	3.25E-04	4.23E-03
Gen III+	Pb	8.89E-07	5.60E-13	2.36E-07	1.12E-06
	Hg	1.94E-07	4.65E-14	1.67E-08	2.11E-07
	NH_3	9.22E-04	3.17E-10	1.20E-05	9.34E-04
	CO	1.32E-02	5.57E-08	1.26E-02	2.57E-02
	NO_X	4.30E-02	3.41E-08	2.05E-02	6.35E-02
	SO_2	1.09E-01	6.53E-08	6.92E-03	1.16E-01
	VOC	4.79E-03	6.96E-08	3.51E-03	8.30E-03
	PM	2.28E-03	5.71E-10	9.73E-04	3.26E-03

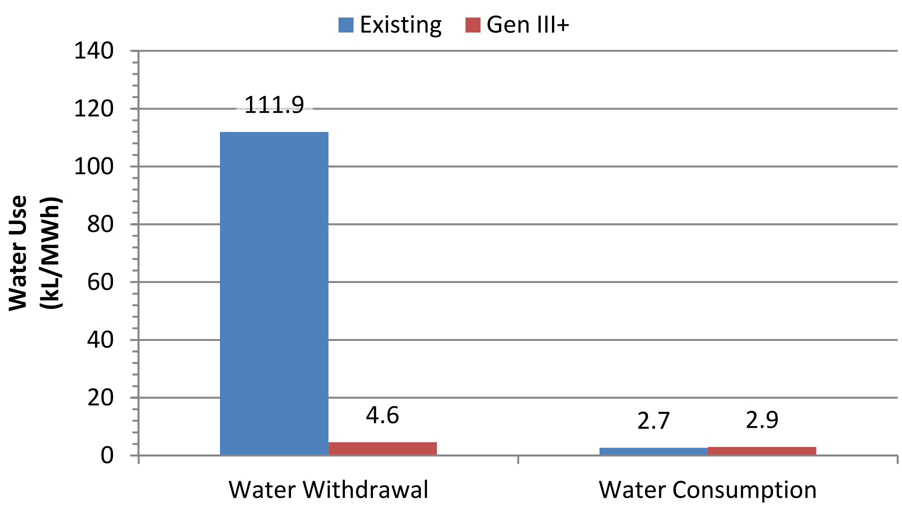
As shown in **Table 4-4** and **Figure 4-11**, water withdrawal is significantly higher for existing plants than for Gen III+ technologies. Of the 104 LWRs operating in the U.S., 43.6 percent utilize wet recirculating cooling, 38.1 percent use once through cooling, and the remaining 18.3 percent use cooling ponds (NETL, 2008). The water use for existing plants is based on the weighted average of cooling technologies in place. It is assumed that Gen III+ facilities would be designed with cooling towers.

In general, the consumption of water for once-through cooling is higher for nuclear plants than for fossil fuel plants. The LC water consumption value for EXPC plants was determined to be 2000 L/MWh, which is 35 percent lower than the value determined for nuclear. This difference is consistent with the results of a 2002 Electric Power Research Institute (EPRI) study that compared the water consumption of various types of electricity generation (EPRI, 2002). In comparison to coal-fired power plants, nuclear plants consume more water because of the thermodynamic constraints of the fuel assemblies. Therefore, nuclear plants have higher steam circulation rates and corresponding water withdrawal rates to satisfy a given power output.

Table 4-4: Average Life Cycle Water Use for Nuclear Power Technologies

Reactor Generation	Water Withdrawal (kL/MWh)	Water Discharge (kL/MWh)	Net Water Consumption (kL/MWh)
Existing	111.9	109.2	2.7
Gen III+	4.6	1.7	2.9

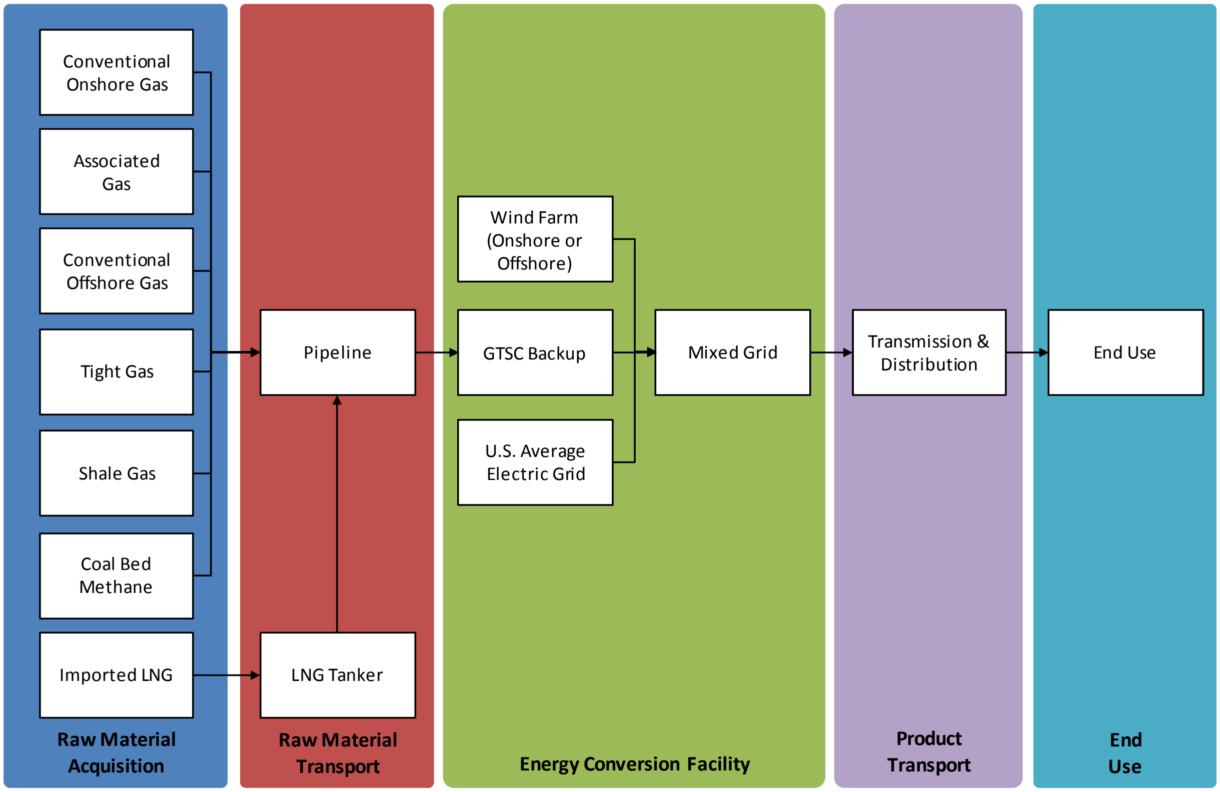
Figure 4-11: Average Life Cycle Water Use for Nuclear Power Technologies



4.4 Environmental Analysis of Wind Power

The environmental analysis of wind power accounts for key construction and operation activities at the wind farm and the transmission and delivery of electricity to the consumer. **Figure 4-12** shows the processes inventoried by the wind model.

Figure 4-12: LCA Modeling Framework for Wind Power



The primary unit processes of the wind model are based on data developed by NETL. The key data used for modeling the energy and material flows of wind power are summarized below:

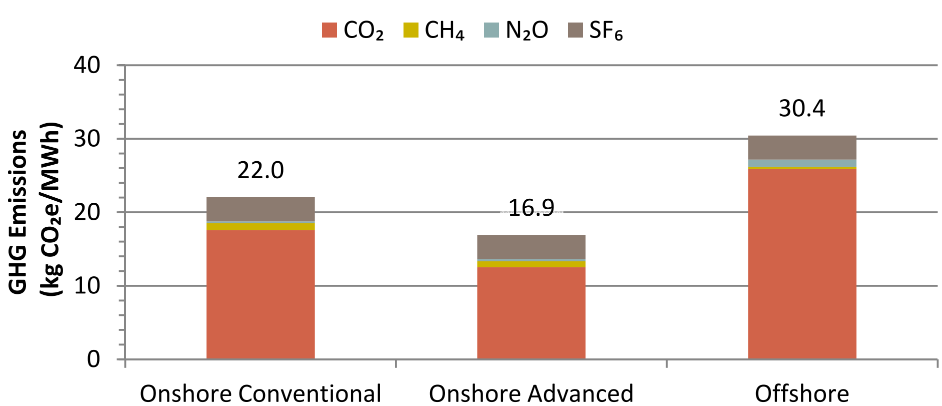
- The mass of wind turbine components are based on scaling equations developed by NREL (NREL, 2006). These scaling equations provide the mass of a single component as a function of rotor diameter and allow the dynamic modeling of material requirements with changes in wind turbine capacity. In addition to the mass of individual turbine components, the types of materials (steel, glass reinforced plastic, carbon fiber, and resin glue) used for each turbine component is necessary; these material profiles are also based on data published by NREL (NREL, 2006)
- The construction of onshore wind farms includes the construction of access roads, which are based on gravel requirements (Simetric, 2009) and road installation emissions (Chappat & Bilal, 2003; Loeffler, 2009).Offshore wind farms have additional construction requirements, including monopile foundations and special surface coatings (MMS, 2009a). Marine vessels are used for material transport and as construction platforms during offshore wind farm construction. The operating characteristics of marine vessels are based on engine load, fuel consumption, and emission factors developed by the EPA (EPA, 2000).
- The construction of electrical cables used to connect individual wind turbines to the central switchyard of a wind farm is based on material specifications published by manufacturers (Energex, 2010) Additionally, offshore wind farms have submarine cables that connect to an onshore trunkline. Submarine cables have a copper core sheathed in durable plastic (CWA, 2004).

- The operation of wind farms involves the consumption of lubricating oil for gearboxes (SMC, 2010). Onshore wind farms have maintenance vehicles that consume diesel at a rate of 8 miles per gallon and travel approximately 1,000 miles per year; the associated air emissions are based on diesel emission factors (DOE, 2006) and there are dust emissions from vehicle travel on unpaved roads (EPA, 2006). Offshore wind farms use marine vessels for maintenance procedures; the operating characteristics of marine vessels are based on engine load, fuel consumption, and emission factors developed by the EPA (EPA, 2000)
- The end-of-life management of turbines also generates recyclable materials, which are recovered at a 90 percent rate. All recyclable materials that are recovered during turbine manufacture and end-of-life management are assumed to displace similar material streams that are outside the boundaries of this analysis. System expansion is used to model the interaction between the recycled materials of wind power and the material streams of other supply chains.
- Peripheral unit processes that account for materials that are secondary to the primary supply chain, such as steel and concrete used for construction, are based on third-party data.

4.4.1 Environmental Results for Wind

The LC GHG emissions for wind power from conventional and advanced onshore wind power are 22.0 and 16.9 kg CO_2e per MWh and are 30.4 kg CO_2e per MWh for offshore wind power. The advanced onshore system has lower GHG emissions than the conventional system due to the higher economy of scale between turbine materials and turbine rating (MW) for the advanced systems. There is a nonlinear relationship between turbine materials and turbine rating (MW); for the rotor diameters modeled in this analysis, the ratio of turbine materials to turbine output decreases with increasing turbine capacity. Offshore wind power has higher LC GHG emissions than both onshore scenarios due to added complexity of installing, maintaining, and connecting wind turbines 20 km from the shoreline. The LC GHG emissions for wind power are shown in **Figure 4-13**.

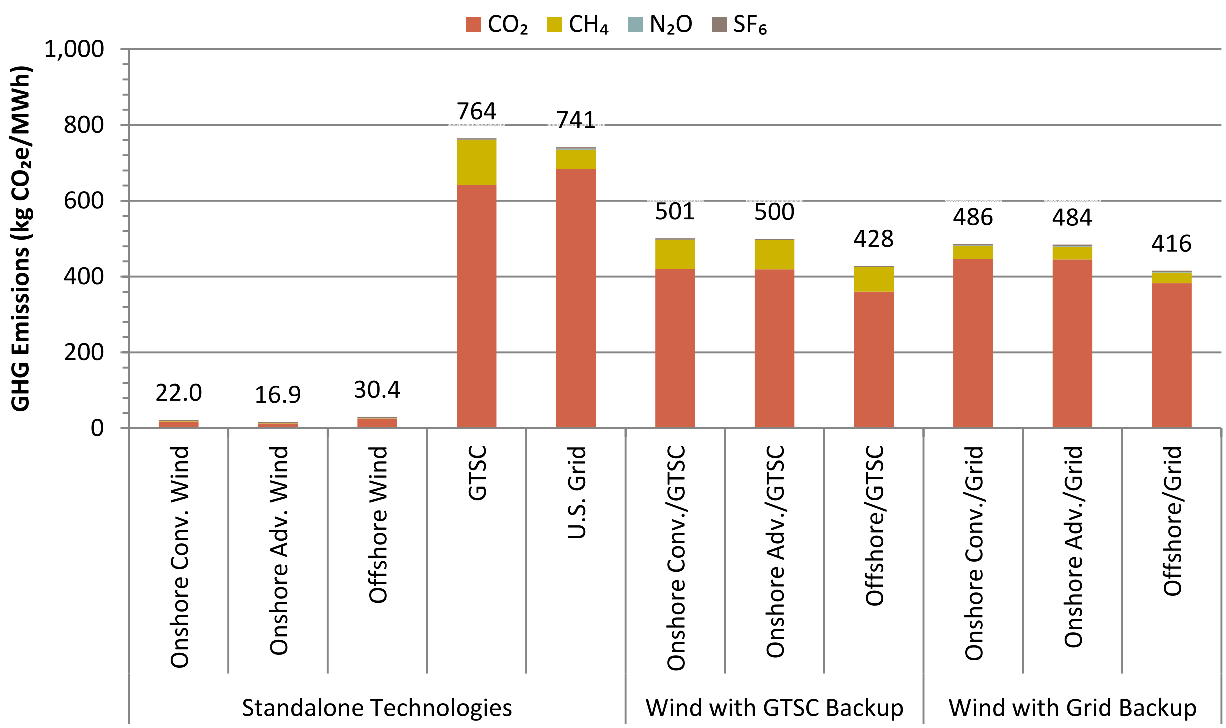
Figure 4-13: Life Cycle GHG Profile for Wind Power



When the reliability of power generation is considered, the need for backup power increases the LC GHG emissions of wind power. When a GTSC power plant provides backup power to an *onshore* wind farm, the LC GHG emissions are 501 kg CO_2e per MWh. Similarly, when a GTSC power plant provides backup power to an *offshore* wind farm, the LC GHG emissions are 428 kg CO_2e per MWh.

For comparison, an advanced fossil combustion technology such as an IGCC plant with a CCS system has LC GHG emissions of 218 kg of CO_2e/MWh (NETL, 2010a). The LC GHG emissions (in CO_2e per delivered MWh) for the stand-alone and backup scenarios are shown in **Figure 4-14** for onshore conventional, onshore advanced and offshore wind power.

Figure 4-14: LC GHG Emissions for Wind with Backup Scenarios



When considering land use GHG emissions in addition to the other GHG emissions, the land use GHG emissions increase total LC GHG by 12 percent (22.0 to 24.7 kg CO_2e/MWh) for onshore conventional wind power, by 4.3 percent of onshore advanced wind power (16.9 to 17.6 kg CO_2e/MWh), and by 2.4 percent for offshore wind power (30.4 to 31.1 kg CO_2e/MWh). Systems with backup power also have GHG emissions from land use change, but they are dominated by combustion emissions, making land use change a smaller share of total GHG emissions.

Table 4-5 shows the criteria air pollutants and other air emissions associated with the LC of one MWh of wind power delivered to the consumer. It includes three technology categories (onshore conventional, onshore advanced, and offshore wind power) and organizes the results according to key processes within LC Stage #3. Wind power does not require the acquisition and delivery of fuel, so there are no environmental burdens in LC Stages #1 and #2. The only environmental emissions from LC Stages #4 and #5 are SF_6 emissions from electricity T&D.

Table 4-5: Other Life Cycle Air Emissions for Standalone Wind Power

Technology	Emission (kg/MWh)	Switchyard/ Trunkline Construction	Domestic Turbine Manufacture	Foreign Turbine Manufacture	Wind Farm Construction	Wind Farm Operation	Landfill Waste	Recycling	Total
Onshore Conventional	Pb	1.06E-06	3.02E-06	3.72E-06	1.46E-06	8.89E-10	2.90E-10	-1.88E-05	-9.51E-06
	Hg	6.13E-09	6.56E-08	8.30E-08	1.14E-09	1.45E-10	2.93E-11	-1.06E-08	1.45E-07
	NH_3	3.25E-06	8.44E-06	3.28E-04	4.47E-04	3.91E-05	1.66E-08	-5.55E-06	8.20E-04
	CO	7.61E-03	1.12E-02	3.75E-02	1.01E-02	3.48E-03	5.42E-05	-2.01E-02	5.00E-02
	NO_X	1.60E-03	7.39E-03	3.03E-02	4.80E-04	8.31E-03	6.29E-05	-3.48E-03	4.47E-02
	SO_2	2.49E-03	1.27E-02	1.94E-02	5.58E-04	1.31E-04	2.77E-05	-6.73E-03	2.86E-02
	VOC	1.57E-04	2.07E-03	6.61E-03	5.65E-04	3.03E-04	1.48E-05	-9.16E-04	8.81E-03
	PM	1.18E-03	2.61E-03	3.22E-03	3.53E-03	1.77E-02	1.74E-04	-1.21E-03	2.72E-02
Onshore Advanced	Pb	1.06E-06	4.57E-06	5.59E-06	3.71E-07	6.24E-10	3.85E-10	-1.08E-05	7.83E-07
	Hg	6.13E-09	7.76E-08	9.56E-08	3.35E-10	1.23E-10	3.88E-11	-1.17E-08	1.68E-07
	NH_3	3.25E-06	1.26E-05	9.60E-05	4.46E-04	1.01E-05	2.20E-08	-4.19E-06	5.64E-04
	CO	7.61E-03	2.02E-02	3.07E-02	9.53E-03	1.36E-03	7.18E-05	-3.13E-02	3.81E-02
	NO_X	1.60E-03	9.51E-03	1.70E-02	3.15E-04	2.15E-03	8.35E-05	-3.90E-03	2.68E-02
	SO_2	2.49E-03	1.51E-02	1.94E-02	2.01E-04	9.35E-05	3.68E-05	-7.45E-03	2.99E-02
	VOC	1.57E-04	2.97E-03	4.67E-03	5.43E-04	1.23E-04	1.96E-05	-1.24E-03	7.24E-03
	PM	1.18E-03	3.82E-03	4.67E-03	3.37E-03	4.51E-03	2.31E-04	-9.47E-04	1.68E-02
Offshore	Pb	1.06E-06	3.14E-06	3.85E-06	9.19E-06	5.48E-07	2.91E-10	-8.42E-06	9.38E-06
	Hg	6.13E-09	5.37E-08	6.65E-08	5.06E-07	3.54E-08	2.94E-11	-1.34E-08	6.54E-07
	NH_3	3.25E-06	8.55E-06	1.11E-04	4.61E-07	1.70E-04	1.66E-08	-4.02E-06	2.90E-04
	CO	7.61E-03	1.34E-02	2.40E-02	3.44E-02	4.93E-02	5.43E-05	-3.98E-02	8.89E-02
	NO_X	1.60E-03	6.63E-03	1.49E-02	6.96E-03	1.51E-01	6.31E-05	-4.49E-03	1.76E-01
	SO_2	2.49E-03	1.06E-02	1.42E-02	9.51E-03	1.48E-02	2.78E-05	-8.42E-03	4.33E-02
	VOC	1.57E-04	2.00E-03	3.74E-03	1.73E-05	6.20E-03	1.48E-05	-1.51E-03	1.06E-02
	PM	1.18E-03	2.57E-03	3.16E-03	1.06E-03	2.44E-03	1.75E-04	-9.29E-04	9.66E-03

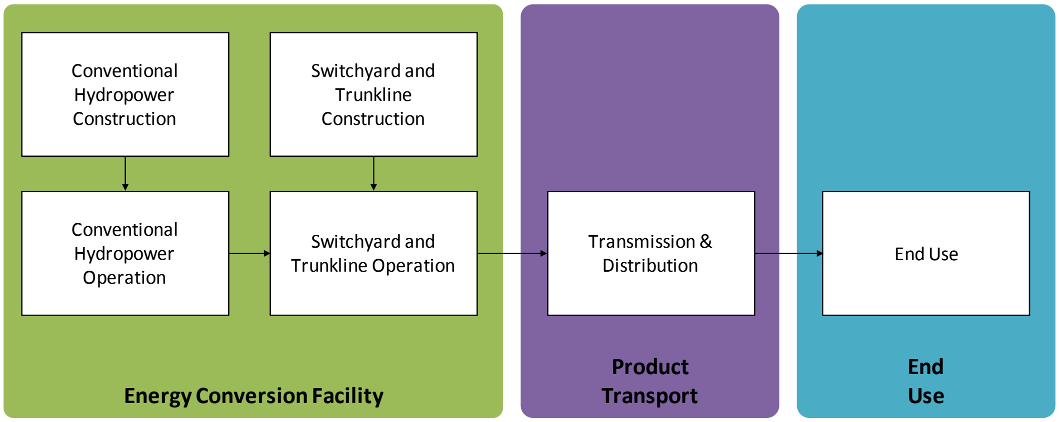
For standalone onshore wind power, the manufacture of wind turbines account for the majority of criteria air pollutants and other air emissions. For offshore wind power, the operation of the wind farm accounts for the majority of criteria air pollutants and other air emissions.

The LC of a wind farm does not involve significant water use.

4.5 Environmental Analysis of Hydropower

The environmental analysis of hydropower accounts for key construction and operation activities at the hydropower facility and the transmission and delivery of electricity to the consumer. **Figure 4-15** shows the processes inventoried by the hydropower model.

Figure 4-15: Hydropower LCA Modeling Structure



The primary unit processes of the hydropower model are based on data developed by NETL. The key data used for modeling the energy and material flows of wind power are summarized below:

- Conventional dams include concrete and earthen structures. Data for construction of the concrete dam was taken from available documentation on Hoover Dam, located along the Colorado River in Arizona. Hoover Dam was selected as a representative dam due to its intermediate to large size, combined with a high availability of construction materials data for the dam. Earthen dam construction was evaluated based on construction emissions required for the movement of clay and other soils from the newly formed reservoir bottom to the dam, for dam construction. Emission values were based on data available for the construction of the Los Vaqueros Reservoir, an earthen dam that was constructed in the 1990s, that is currently undergoing expansion (Contra Costa Water District, 2011)
- Capacity factor is a key adjustable parameter in support of this unit process, because it strongly influences the amount of electricity that can be generated over a dam's lifetime. Capacity factor was calculated based on regional average capacity factors for the U.S. West, Southwest, South, Midwest, and Northeast. Location and capacity factor were queried for approximately 150 U.S. reservoirs, having nameplate capacities of at least 100 MW. Data were acquired for 2002 through 2010, and average capacity factors were generated for each U.S. region. The average capacity factor of conventional hydropower in the U.S. is 37 percent.

- Reservoir surface area is a key factor used for calculating carbon dioxide (CO_2) and CH_4 emissions from the reservoir. Literature values for these emission factors are provided based on emissions from a single square meter during one day.
- Evaporation occurs as a natural process along rivers and other waterways. When water is that would otherwise have been allowed to pass downstream is held in a reservoir, additional evaporation occurs within the reservoir. Presumably, following release from the reservoir, water will travel down the remainder of the river, where evaporation rates would be similar to natural baseline values. NREL (2002) quantified water evaporation rates from reservoirs, in support of power generation. NREL's data include reservoirs across five U.S. regions, with evaporation rates varying from approximately 23,300 (Northeast) to 340,000 kg/MWh (Southwest) of power generated. These values were calculated based on data from individual reservoirs within each region.
- Peripheral unit processes that account for materials that are secondary to the primary supply chain, such as steel and concrete used for construction, are based on third-party data.

4.5.1 Environmental Results for Hydropower

The expected values for all scenarios range from 27.7 to 43.8 kg CO_2e/MWh. CO_2 and CH_4 emissions from the reservoir during hydropower operations dominate the LC GHG emissions and range from 56 to 88 percent of total GHG emissions. GHG emissions from land use account for 22 percent of the GHG from greenfield hydropower (the greenfield scenario is the only scenario that includes land use emissions). Land use GHG emissions increase the total GHG emissions from 34.4 to 43.8 kg CO_2e/MWh. The GHG emissions from direct and indirect land use change range are 7.3 to 14.5 kg CO_2e/MWh for conventional hydropower, depending on location, and 19.5 kg CO_2e/MWh for hydrokinetic. Thus, the land use GHG emissions for hydropower increases the total LC GHG emissions from 33.0 to 44.5 kg CO_2e/MWh for conventional hydropower and from 75.8 to 95.3 kg CO_2e/MWh for hydrokinetic installations. **Figure 4-16** shows the LC GHG emissions of the four conventional hydropower scenarios. The expected value for all scenarios falls within range from 27.7 to 43.8 kg CO_2e/MWh.

Figure 4-16: Greenhouse Gas Emissions from Hydropower

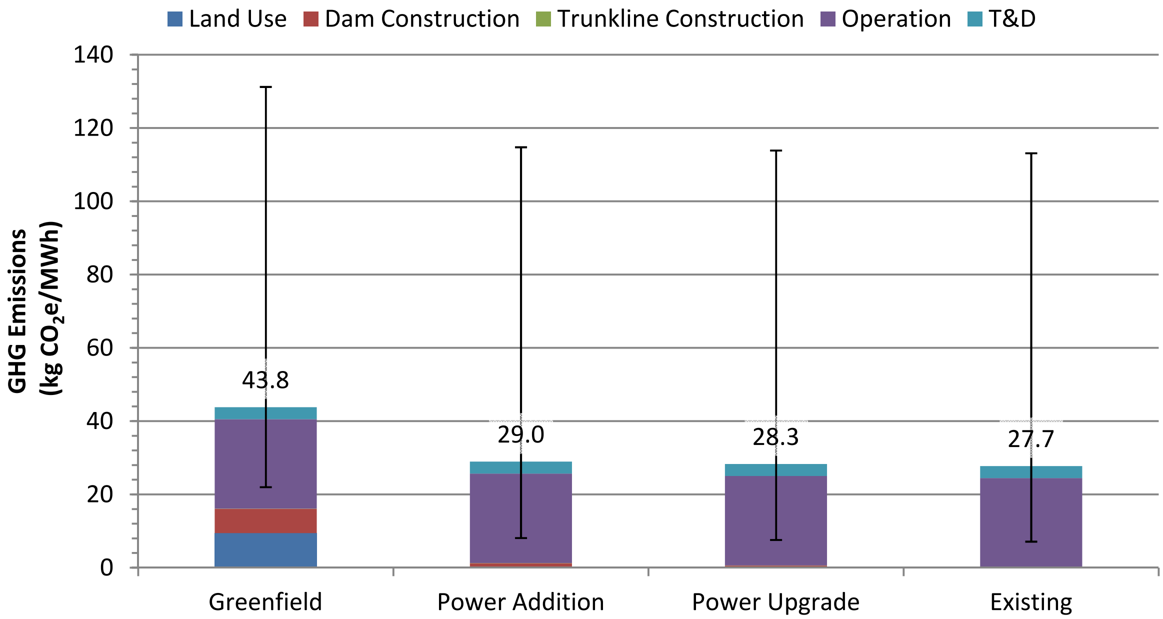


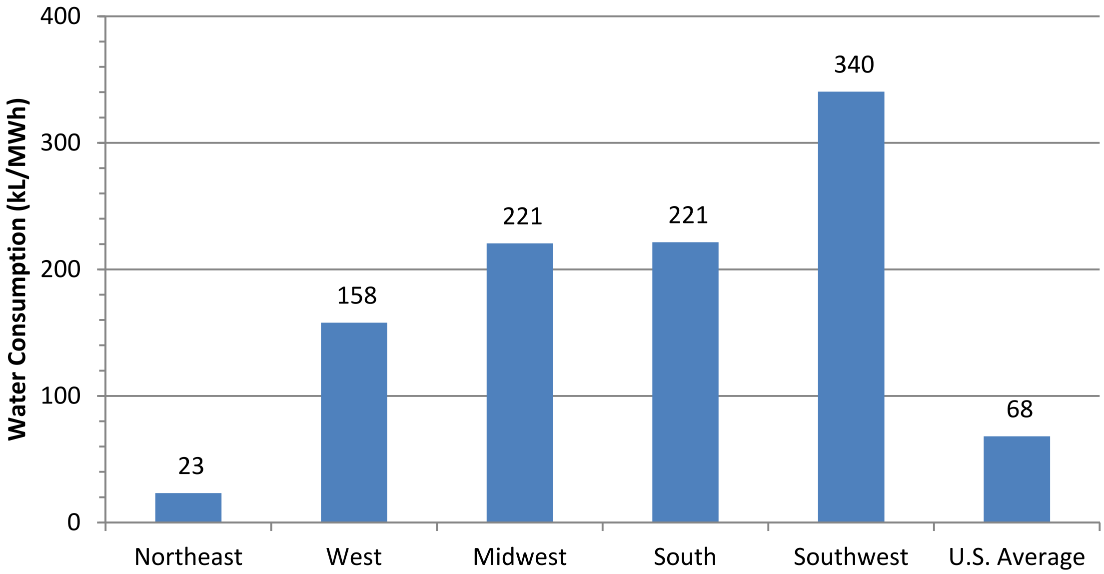
Table 4-6 shows the LC results for a selected group of air pollutants, including criteria air pollutants, NH_3, and Hg. All of these emissions are produced by construction or installation activities. The greenfield hydropower scenario has the most construction activity, so it has the highest inventory of these air emissions. The existing hydropower scenario does have any construction activities, so it does not release any of these emissions.

Table 4-6: Other Life Cycle Air Emissions for Hydropower

Scenario	Emission (kg/MWh)	ECF Construction	Trunkline Construction	Hydropower Operation	Total
Greenfield	Pb	4.49E-07	3.43E-08	0.00E+00	4.83E-07
	Hg	5.24E-08	2.62E-10	0.00E+00	5.26E-08
	NH_3	2.41E-06	1.40E-07	0.00E+00	2.55E-06
	CO	1.19E-02	3.38E-04	0.00E+00	1.22E-02
	NO_X	1.72E-02	6.95E-05	0.00E+00	1.73E-02
	SO_2	1.11E-02	1.07E-04	0.00E+00	1.12E-02
	VOC	5.90E-04	6.60E-06	0.00E+00	5.97E-04
	PM	5.22E-03	5.05E-05	0.00E+00	5.27E-03
Power Addition	Pb	3.26E-07	3.43E-08	0.00E+00	3.61E-07
	Hg	1.31E-08	2.62E-10	0.00E+00	1.34E-08
	NH_3	2.15E-07	1.40E-07	0.00E+00	3.55E-07
	CO	2.00E-03	3.38E-04	0.00E+00	2.33E-03
	NO_X	1.18E-03	6.95E-05	0.00E+00	1.25E-03
	SO_2	3.29E-04	1.07E-04	0.00E+00	4.36E-04
	VOC	9.45E-06	6.60E-06	0.00E+00	1.60E-05
	PM	6.55E-05	5.05E-05	0.00E+00	1.16E-04
Power Upgrade	Pb	6.52E-08	N/A	0.00E+00	6.52E-08
	Hg	7.58E-10	N/A	0.00E+00	7.58E-10
	NH_3	9.77E-08	N/A	0.00E+00	9.77E-08
	CO	3.56E-04	N/A	0.00E+00	3.56E-04
	NO_X	1.15E-04	N/A	0.00E+00	1.15E-04
	SO_2	5.42E-05	N/A	0.00E+00	5.42E-05
	VOC	4.29E-06	N/A	0.00E+00	4.29E-06
	PM	1.97E-05	N/A	0.00E+00	1.97E-05

LC water consumption for conventional hydropower was quantified based on anticipated evaporation, per a regional evaluation of evaporation potential from reservoirs, completed by NREL (NREL, 2003). NREL's analysis evaluated water evaporation rates within 18 U.S. states, located in all regions considered in this analysis, normalized to net hydropower production. These factors were averaged regionally for the U.S. Northeast, Midwest, South, West, Southwest, and an overall U.S. Average. Evaporation rates vary regionally based on climate, and **Figure 4-17** shows the regional and U.S. average evaporation values, which range from a minimum of 23,261 L/MWh (Northeast) to a maximum of 340,447 L/MWh (Southwest) values.

Figure 4-17: Conventional Hydropower Life Cycle Water Consumption by Region (NREL, 2003)

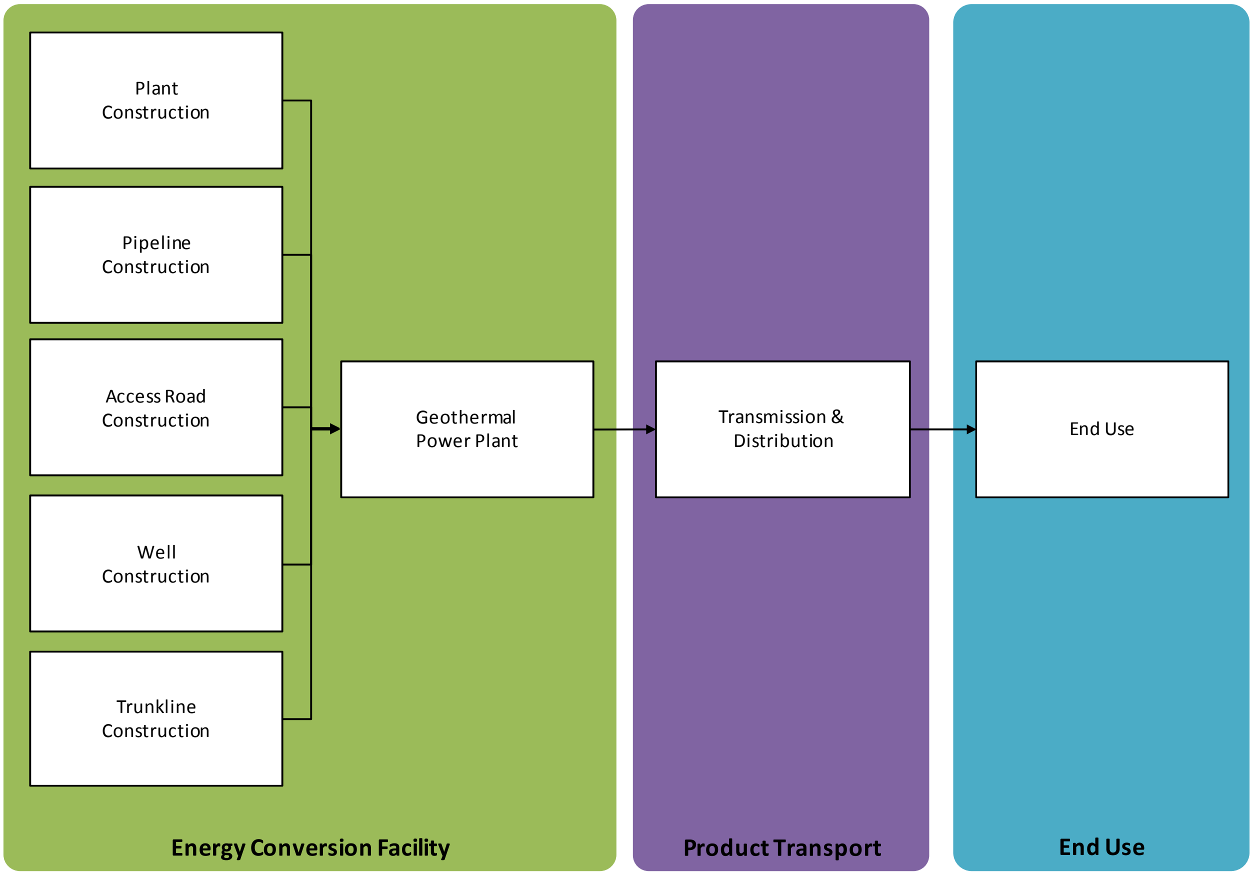


Net water consumption during hydropower construction is negligible when compared to the water consumption during hydropower operation. Water used during construction is primarily related to dust control and/or cement production, during the construction process for the reservoir and trunkline. The water consumed by operations is nearly 1,000 times greater than consumed during construction.

4.6 Environmental Analysis of Geothermal Power

The environmental analysis of geothermal power accounts for key construction and operation activities at the geothermal facility and the transmission and delivery of electricity to the consumer. **Figure 4-18** shows the processes inventoried by the geothermal model.

Figure 4-18: LCA Modeling Framework for Geothermal Power



The primary unit processes of the geothermal model are based on data developed by NETL. The key data used for modeling the energy and material flows of wind power are summarized below:

- The construction of a geothermal well requires steel pipe and concrete (used as casing materials for the well) and diesel (combusted in drilling equipment during well installation).
- The geothermal facility has a network of pipelines that transports water from wells to the power plant. The total length of this pipeline is 2.42 to 11.3 km (1.50 to 7.00 miles) (BLM, 2008). The pipeline is 24 to 36 inches in diameter (BLM, 2008) and is constructed from steel.
- An access road is constructed entirely of gravel. Installation of the road requires conventional diesel fuel for the use of grading and other construction equipment.
- A geothermal power plant is similar to steam cycle used by an NGCC facility. The construction and installation of a single NGCC power plant was used as a proxy for the geothermal power plant. Inputs to the unit process for the construction of the plant include steel plate, steel pipe, aluminum sheet, cast iron, and concrete.
- The liquid from a geothermal formation (called "geofluid") contains noncondensible gases such as CO_2, H_2S, CH_4, and NH_3 (Sullivan, et al., 2010). On a mass basis, the geofluid is 97.6 percent water, 2.4 percent CO_2, 0.022 percent H_2S, 0.004 percent CH_4, and 0.005 percent NH_3 (Bloomfield & Moore, 1999; Bloomfield, Moore, & Neilson, 2003). Based on

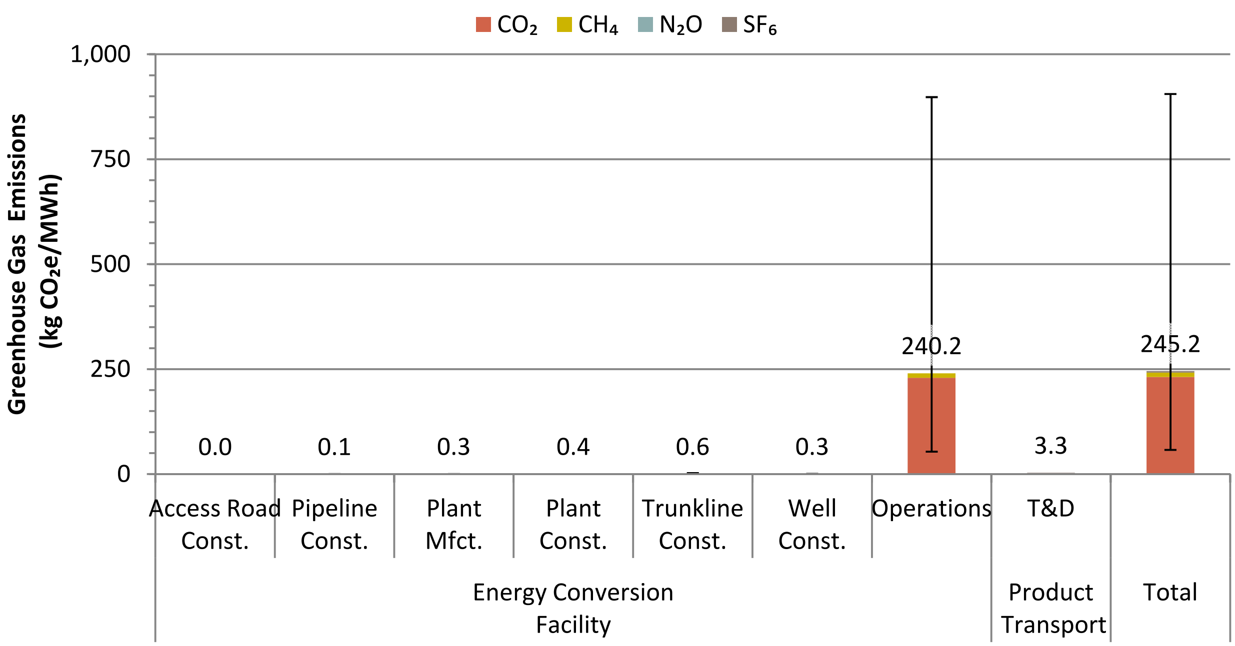
specifications for a 10 MW geothermal power plant (Bloomfield, 1999) and a steam enthalpy of 1,000 Btu per lb., the generation of 1 MWh of electricity requires 20,000 lbs. (9,070 kg) of geofluid.

- Peripheral unit processes that account for materials that are secondary to the primary supply chain, such as steel and concrete used for construction, are based on third-party data.

4.6.1 Environmental Results for Geothermal

The LC GHG emissions for the geothermal power system in this analysis are 245 kg CO_2e/MWh. The GHG profile for geothermal power is dominated by CO_2 emissions. The main source of these CO_2 emissions is noncondensible gases released by the flash steam geothermal power plant. Water from geological formations (called "geofluid") has naturally-occurring CO_2 and other gases that are released by the flash steam process. The CO_2 emitted by the flash steam geothermal power plant accounts for 93.6 percent of total LC GHG emissions. The expected GHG emissions are 245 kg CO_2e/MWh, but when the uncertainty of all parameters is combined, the GHG emissions range from 57.8 to 906 kg CO_2e/MWh. This wide range of uncertainty is mostly driven by variability in the portion of noncondensible gas in the geofluid. This analysis accounts for uncertainties in other parameters, such as plant life, number of wells per unit of power plant capacity, distance of access roads, and well depth; the GHG results of the analysis are more sensitive to changes in geofluid composition than to other parameters. The GHG results are also sensitive to changes in power plant efficiency, which is related to the amount of geofluid used by the system. As shown in **Figure 4-19**, the GHG profile for geothermal power is dominated by CO_2 from operation of the geothermal power plant.

Figure 4-19: Life Cycle GHG Profile for Geothermal Power



The results in the above paragraph do not account for the GHG emissions from land use change. The GHG emissions from direct and indirect land use change range are 2.00 kg CO_2e/MWh. The land use GHG emissions for geothermal power increase the total LC GHG emissions by only 0.8 percent.

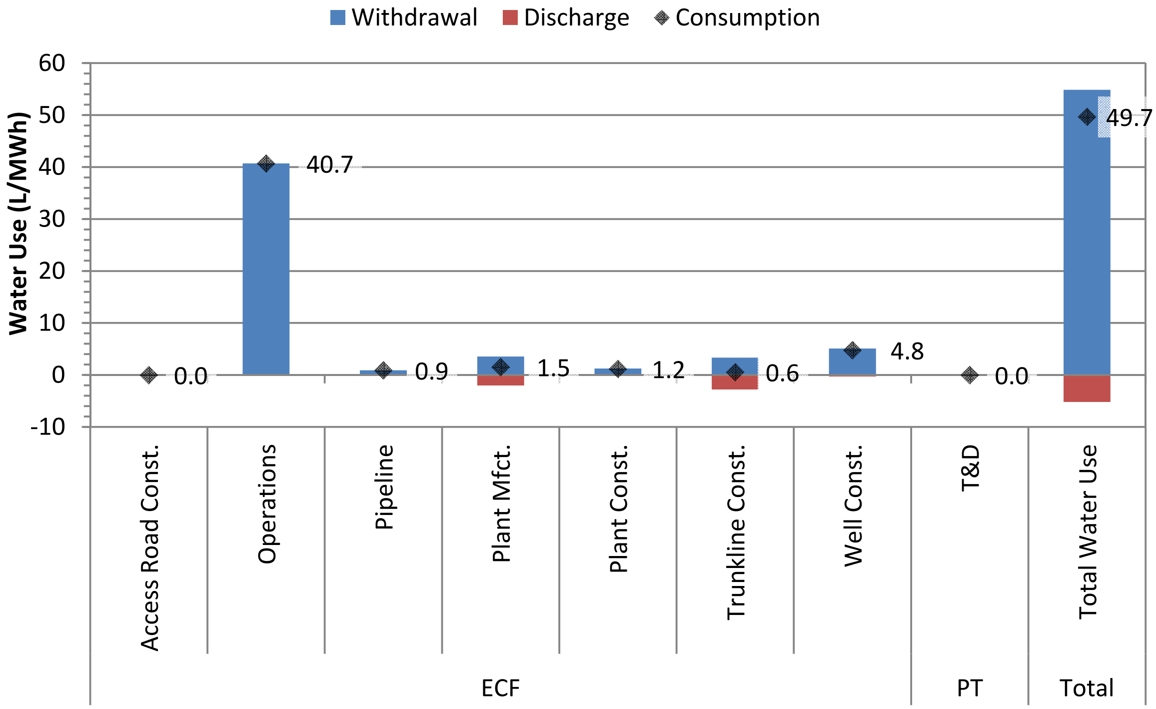
In addition to GHG emissions, this analysis includes an extended set of air and water emissions. The analysis of geothermal power was not performed as a comparative analysis, so there are no reference values for the emissions to other power generation technologies. NH_3 is a component of the geofluid and is released during the operation of the power plant. The majority of lead and Hg emissions results from the production of steel used for power plant construction. The combustion of fuels for the construction of the geothermal facility produces most of the CO and NO_X emissions. Other than SF_6, a GHG emission, there are no emissions from transmission and distribution of electricity. The transmission and distribution infrastructure is an existing system, so it does not have any construction burdens within the boundaries of this analysis. **Table 4-7** shows the LC results for a selected group of air pollutants, including criteria air pollutants.

Table 4-7: Other Life Cycle Air Emissions for Geothermal Power

Emission (kg/MWh)	ECF							Total
	Access Road Const.	Operation	Pipeline Const.	Plant Mfct.	Plant Const.	Trunkline Const.	Well Const.	
Pb	3.35E-12	0	2.47E-07	4.39E-07	1.64E-09	4.70E-07	1.87E-07	1.34E-06
Hg	2.78E-13	0	6.53E-09	2.32E-08	1.54E-10	3.58E-09	5.12E-09	3.86E-08
NH_3	3.66E-07	4.53E-01	2.26E-07	1.12E-07	1.55E-05	1.92E-06	9.14E-09	4.53E-01
CO	2.68E-05	0	6.23E-04	1.77E-03	1.66E-02	4.63E-03	1.50E-03	2.51E-02
NO_X	7.80E-05	0	2.00E-04	5.87E-04	6.04E-03	9.52E-04	4.67E-03	1.25E-02
SO_2	4.79E-07	0	2.34E-04	8.49E-04	3.41E-04	1.46E-03	2.23E-04	3.11E-03
VOC	2.27E-06	0	2.91E-06	1.99E-05	2.03E-04	9.04E-05	1.24E-04	4.42E-04
PM	1.67E-04	0	9.50E-05	2.65E-04	1.67E-06	6.93E-04	9.54E-05	1.32E-03

Flash steam geothermal power consumes 49.7 liters of water per MWh of delivered electricity. The majority of water consumption (40.7 liters per MWh) occurs during the operation of the power plant and represents the loss of water from the flash process. A significant volume of water (9.0 liters per MWh) is also used during the construction of the geothermal power plant; water is necessary for dust suppression during construction and is also used for the production of construction materials. **Figure 4-20** shows the water use associated with geothermal power.

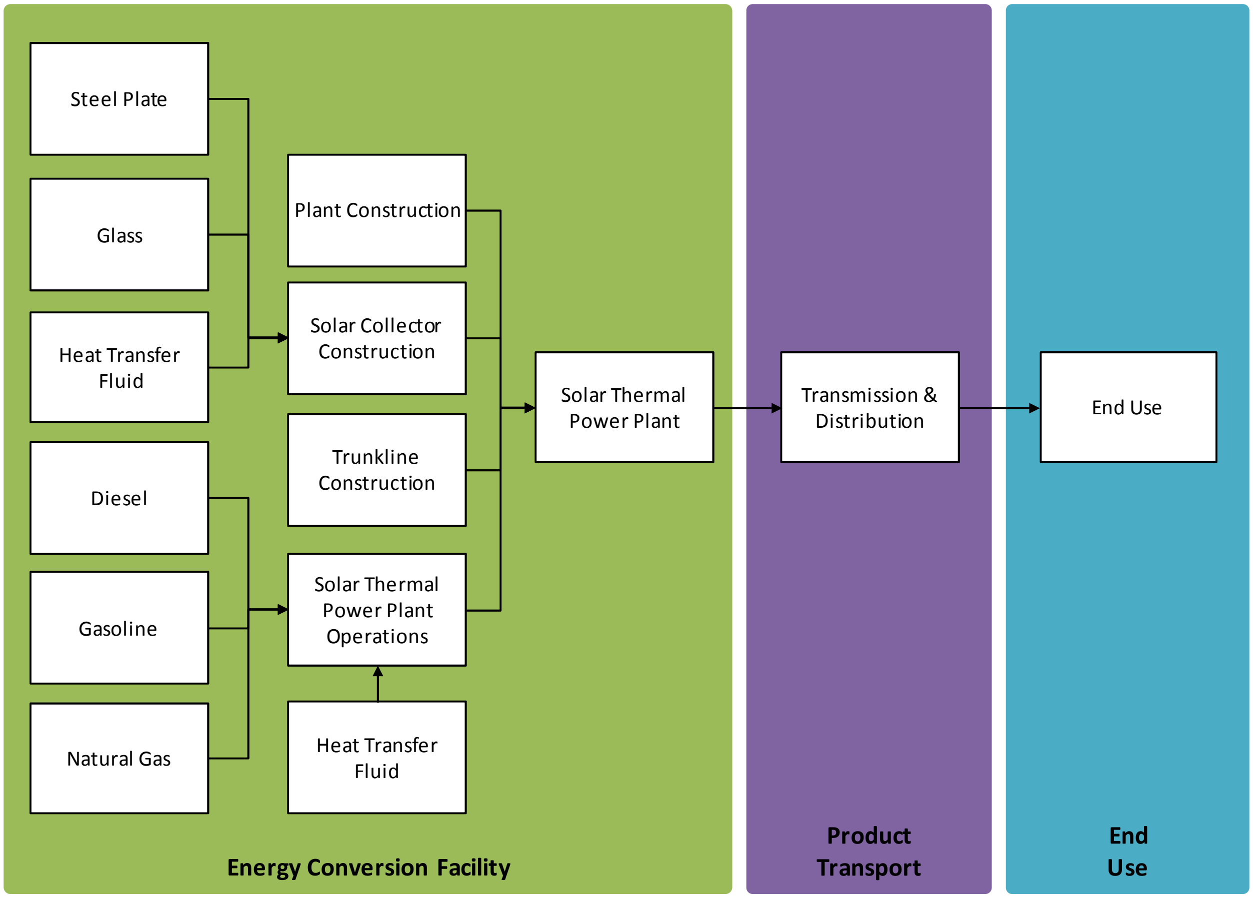
Figure 4-20: Water Used by Geothermal Power



4.7 Environmental Analysis of Solar Thermal Power

The environmental analysis of solar thermal power accounts for key construction and operation activities at the solar thermal facility and the transmission and delivery of electricity to the consumer. **Figure 4-21** shows the processes inventoried by the solar thermal model.

Figure 4-21: LCA Modeling Framework for Solar Thermal Power



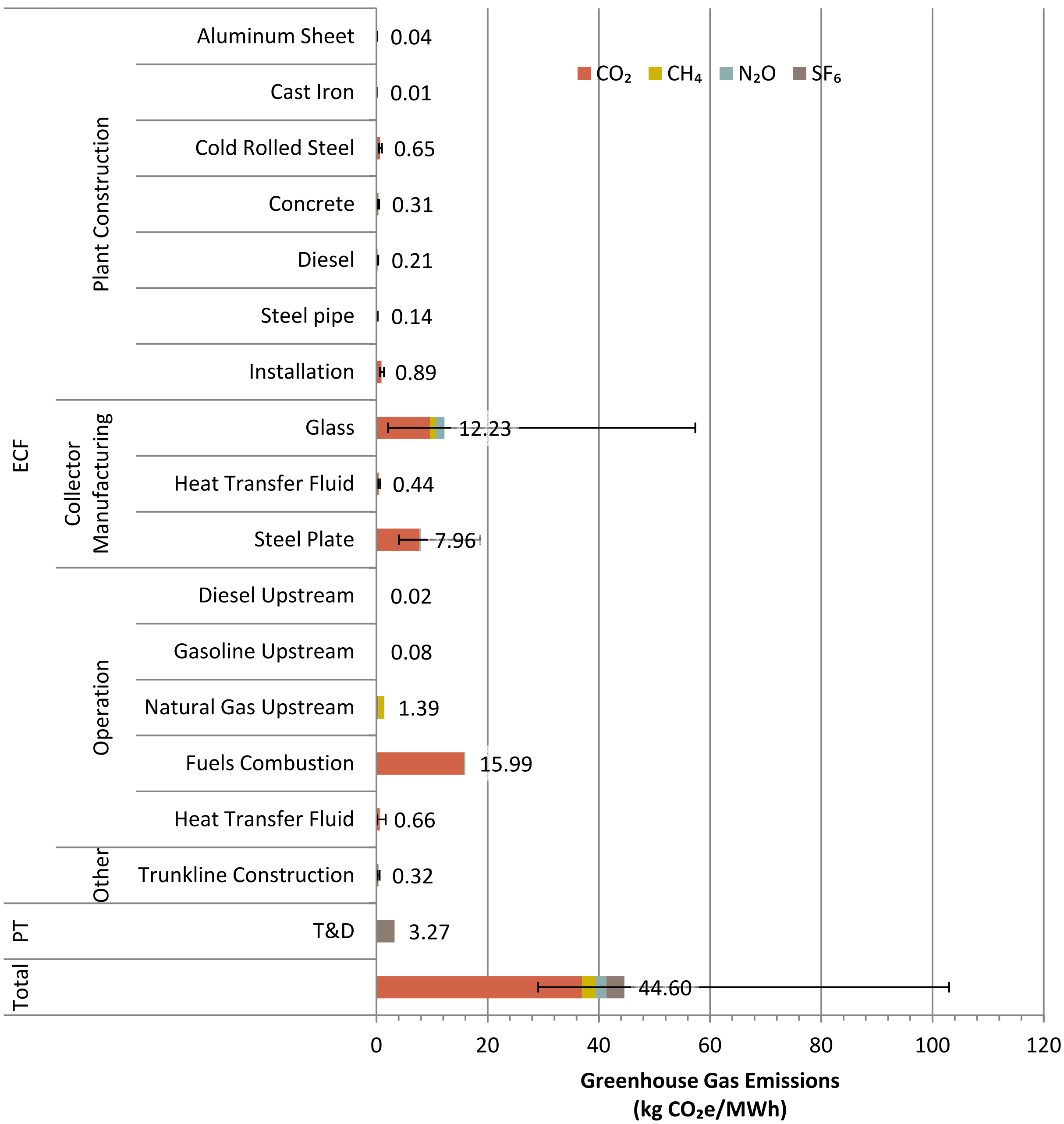
The primary unit processes of the solar thermal model are based on data developed by NETL. The key data used for modeling the energy and material flows of wind power are summarized below:

- The construction of solar thermal collectors includes inputs of steel plate and glass. The total mass of solar collectors is determined by the size of the plant, the conversion efficiency from solar energy to electricity, the intensity of solar radiation, and the total area of the solar collectors at a facility.
- A solar thermal power plant is similar to steam cycle used by an NGCC facility. The construction and installation of a single NGCC power plant was used as a proxy for the geothermal power plant. Inputs to the unit process for the construction of the plant include steel plate, steel pipe, aluminum sheet, cast iron, and concrete.
- The operation of a solar thermal facility also requires inputs of fuels and process fluid. Diesel fuel is used to supply both a fire pump and an emergency generator. Natural gas is used to supply an auxiliary boiler. Gasoline is used to fuel maintenance vehicles. Heat transfer fluid circulates between the solar collectors and power plant.
- Peripheral unit processes that account for materials that are secondary to the primary supply chain, such as steel and concrete used for construction, are based on third-party data.

4.7.1 Environmental Results for Solar Thermal Power

The majority of LC GHG emissions are from CO_2 at 82.3 percent, with the remainder split between CH_4, N_2O, and SF_6 at 5.6 percent, 4.5 percent, and 7.6 percent, respectively. Solar collector construction accounts for 48 percent of the LC GHG emissions for solar thermal power, while plant operation accounts for 38 percent. The construction of the power generation equipment and the trunkline contribute a combined 6 percent, while T&D accounts for 8 percent. **Figure 4-22** shows the LC GHG results for solar thermal power, broken down by key processes.

Figure 4-22: Life Cycle GHG Process Drilldown for Solar Thermal Power



The results above do not account for the GHG emissions from land use change. The GHG emissions from direct land use change range are an additional 4.4 kg CO_2e/MWh. There is no indirect land use change since no agricultural land was displaced by the solar thermal facility. The land use GHG emissions for solar thermal power increase the total LC GHG emissions from 44.6 to 49.0 kg CO_2e/MWh.

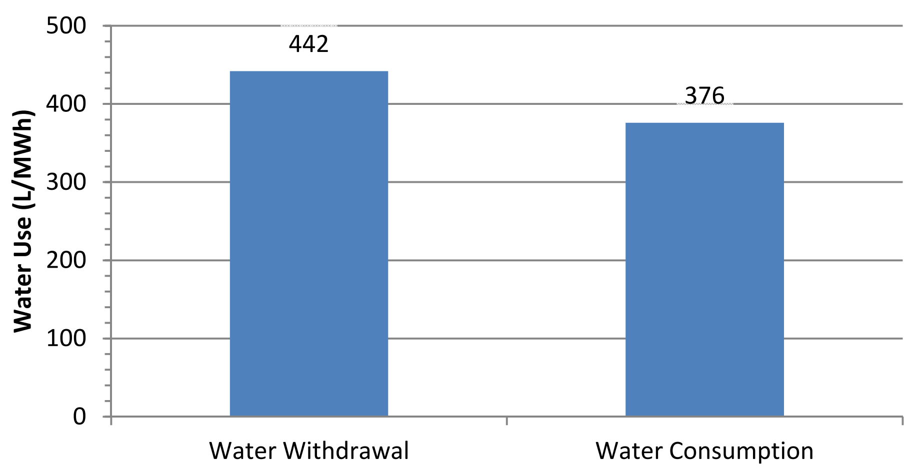
This study was not performed as a comparative analysis, so there are no reference values for the emissions to other power generation technologies. The majority of lead and Hg emissions result from the fabrication processes to make steel for the facility and collectors. Glass manufacturing accounts for a significant portion of the NH_3, PM, SO_2, and VOC emissions. Fuels combustion in support of the operation of the solar thermal facility comprises most of the CO and NO_X emissions. The LC emissions criteria air pollutants and other air emissions are shown in **Table 4-8**.

Table 4-8: Other Life Cycle Air Emissions for Solar Thermal Power

Emission (kg/MWh)	Plant Construction	Collector Construction	Operation	Trunkline	Total
Pb	1.56E-06	1.55E-05	4.74E-08	2.57E-07	1.73E-05
Hg	1.65E-08	9.92E-07	2.75E-09	1.96E-09	1.01E-06
NH_3	4.10E-05	1.86E-05	5.79E-06	1.05E-06	6.64E-05
CO	4.88E-02	6.95E-02	4.87E-01	2.54E-03	6.07E-01
NOx	1.72E-02	3.53E-02	4.13E-02	5.21E-04	9.44E-02
SO_2	3.15E-03	5.28E-02	2.39E-03	8.01E-04	5.92E-02
VOC	6.50E-04	2.95E-02	7.41E-03	4.95E-05	3.76E-02
PM	4.78E-03	2.91E-02	4.98E-04	8.77E-04	3.52E-02

The majority of water consumption results from construction and operations activities at 51 percent and 32 percent, respectively, and steel plate manufacturing for solar collector fabrication at 11 percent. Within the operation activities, water is consumed for cooling water makeup, process water makeup, and mirror washing (BLM, 2010b). **Figure 4-23** shows the water use associated with solar thermal power production.

Figure 4-23: Solar Thermal Power Water Use



4.8 Comparative Environmental Results

The LC GHG results for all technologies are shown in **Figure 4-24**. The GHG emissions associated with the ECF account for the majority of GHG emissions for most technologies. For fossil fuel and biomass combustion technologies, the key source of GHG emissions is the combustion of fuel at the ECF. For hydropower, the key source of GHG emission is the slow decay of plant residue in the reservoir. The release of naturally-occurring CO_2 from geofluid is the key source of GHG emissions from flash steam geothermal power. Wind and solarthermal power are unique because their key source of GHG emissions is not the steady-state operation of the ECF, but the GHG emissions from the manufacture of equipment and construction of the ECF.

Nuclear power is the only technology that has higher GHG emissions for RMA than for the ECF. The energy intensity of uranium enrichment makes the RMA for existing and Gen III+ nuclear power the largest source of GHG emissions for nuclear power.

The renewable energy technologies have the greatest range of uncertainty in GHG results. This uncertainty is driven mostly by variability in plant operating characteristics. The GHG emissions of wind power involve the apportionment of manufacturing and construction emissions per unit of electricity produced during the lifetime of a wind farm, so the LC GHG emissions of wind power will decrease as the capacity factor, wind speed, and other performance-related parameters improve. A similar conclusion can be made for solar thermal power; a higher-than-expected capacity factor for a solar thermal facility will reduce the portion of manufacturing and construction activities apportioned to each unit of electricity produced. The wide uncertainty range for the GHG emissions from hydropower is explained by the variability of reservoirs with changes in latitude. The uncertainty in geothermal power is driven by variability in the composition of the geofluid. The expected value for the CO_2 composition of geofluid is one percent by volume (the remaining 99 percent is water), but a slight change to a 2 percent CO_2 composition can double the CO_2 emissions from the flash steam geothermal facility. In contrast to the renewable energy technologies, the natural gas, biomass, and nuclear systems have ECFs that operate within a narrow performance range and are not subject to the fuel supply and performance fluctuations inherent to most renewable energy technologies.

Figure 4-24: Comparative Results for GHG Emissions

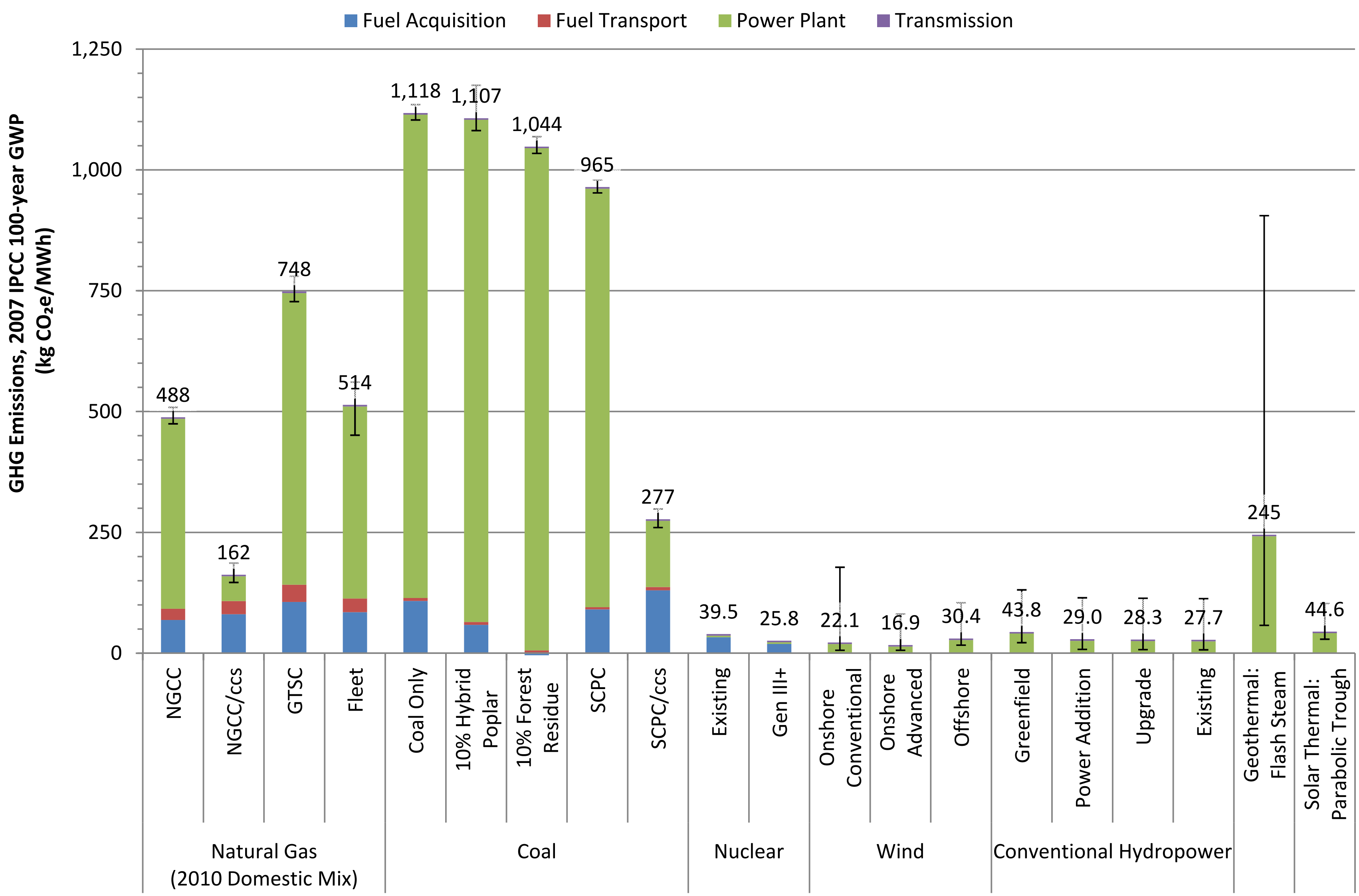


Table 4-9 shows the contribution of land use change to the LC GHG emissions of each technology. In general, land use change is a bigger contributor to LC GHG emissions from renewable energy than other energy sources. One exception to this conclusion is geothermal power, which has a relatively small footprint and is located in regions with relatively low GHG factors for land transformation.

Table 4-9: Land Use Contribution to GHG Emissions

Energy Source	Technology	LC GHG Emissions w/o Land Use (kg/MWh)	Land Use GHG Emissions (kg/MWh)	Total LC GHG Emissions (kg/MWh)	Land Use Contribution to LC GHG Emissions (%)
Natural Gas (2010 Domestic Mix)	NGCC	488.2	2.7	490.9	0.5%
	NGCC/ccs	162.3	3.2	165.5	1.9%
	GTSC	748.5	4.5	753.0	0.6%
	Fleet	513.8	3.0	516.7	0.6%
Co-firing	Coal Only	1,117.7	0.0	1,117.7	0.0%
	10% HP	1,067.4	39.7	1,107.1	3.6%
	10% Forest Residue	1,044.1	N/A	1,044.1	N/A
Nuclear	Existing	39.5	0.7	40.1	1.6%
	Gen III+	25.8	0.1	25.9	0.4%
Wind	Onshore Conventional	22.1	2.7	24.8	10.9%
	Onshore Advanced	16.9	2.7	19.7	13.8%
	Offshore	30.4	0.7	31.2	2.3%
Conventional Hydropower	Greenfield	43.8	9.4	53.2	17.7%
	Power Addition	29.0	N/A	29.0	N/A
	Upgrade	28.3	N/A	28.3	N/A
	Existing	27.7	N/A	27.7	N/A
Geothermal	Flash Steam	245.2	2.0	247.2	0.8%
Solarthermal	Parabolic Trough	44.6	4.4	49.0	9.0%

Table 4-10 is a compilation of criteria air pollutants and other air emissions of concern. Impact assessment was not performed on these metrics, so comparisons among different species of emissions should not be made. A few anomalies in these results are worth mentioning:

- Negative Pb emissions for onshore conventional wind power are due to displacements caused by recycling.
- Existing conventional hydropower does not have any construction and installation activities, which are the only sources of CAPs and other non-GHG air emissions in the hydropower model.
- High NH_3 emissions from geothermal power are from naturally-occuring NH_3 in the geofluid.
- Co-firing with HP has high VOC emissions from fertilizer production and use.

Table 4-10: Criteria Air Pollutants and Other Air Emissions for All Technologies

Energy Source	Technology	Pb (kg/MWh)	Hg (kg/MWh)	NH_3 (kg/MWh)	CO (kg/MWh)	NO_X (kg/MWh)	SO_2 (kg/MWh)	VOC (kg/MWh)	PM (kg/MWh)
Natural Gas (2010 Domestic Mix)	NGCC	4.82E-06	1.02E-07	1.88E-02	4.72E-02	5.13E-01	7.37E-03	3.81E-01	1.46E-03
	NGCC/ccs	5.56E-06	1.25E-07	2.03E-02	5.62E-02	6.00E-01	8.91E-03	4.47E-01	1.82E-03
	GTSC	3.87E-06	1.26E-07	2.90E-02	7.34E-02	7.92E-01	1.11E-02	5.87E-01	2.25E-03
	Fleet	2.59E-06	9.48E-08	3.81E-06	5.47E-02	8.89E-01	1.18E-02	4.69E-01	1.33E-03
Co-firing	Coal Only	1.55E-06	3.79E-05	2.26E-04	1.55E+00	1.10E+00	4.51E-01	5.49E-03	2.79E-01
	10% HP	3.30E-06	3.46E-05	8.67E-03	1.50E+00	9.81E-01	4.53E-01	5.04E+00	3.33E-01
	10% Forest Residue	1.81E-06	3.45E-05	2.24E-04	1.49E+00	9.59E-01	4.39E-01	4.05E-02	3.25E-01
Nuclear	Existing	2.02E-06	3.50E-07	1.59E-03	3.68E-02	7.59E-02	1.92E-01	9.95E-03	4.23E-03
	Gen III+	1.12E-06	2.11E-07	9.34E-04	2.57E-02	6.35E-02	1.16E-01	8.30E-03	3.26E-03
Wind	Onshore Conventional	-9.51E-06	1.45E-07	8.20E-04	5.00E-02	4.47E-02	2.86E-02	8.81E-03	2.72E-02
	Onshore Advanced	7.83E-07	1.68E-07	5.64E-04	3.81E-02	2.68E-02	2.99E-02	7.24E-03	1.68E-02
	Offshore	9.38E-06	6.54E-07	2.90E-04	8.89E-02	1.76E-01	4.33E-02	1.06E-02	9.66E-03
Conventional Hydropower	Greenfield	4.83E-07	5.26E-08	2.55E-06	1.22E-02	1.73E-02	1.12E-02	5.97E-04	5.27E-03
	Power Addition	3.61E-07	1.34E-08	3.55E-07	2.33E-03	1.25E-03	4.36E-04	1.60E-05	1.16E-04
	Upgrade	6.52E-08	7.58E-10	9.77E-08	3.56E-04	1.15E-04	5.42E-05	4.29E-06	1.97E-05
	Existing	0	0	0	0	0	0	0	0
Geothermal	Flash Steam	1.34E-06	3.86E-08	4.53E-01	2.51E-02	1.25E-02	3.11E-03	4.42E-04	1.32E-03
Solar Thermal	Parabolic Trough	1.73E-05	1.01E-06	6.64E-05	6.07E-01	9.44E-02	5.92E-02	3.76E-02	3.52E-02

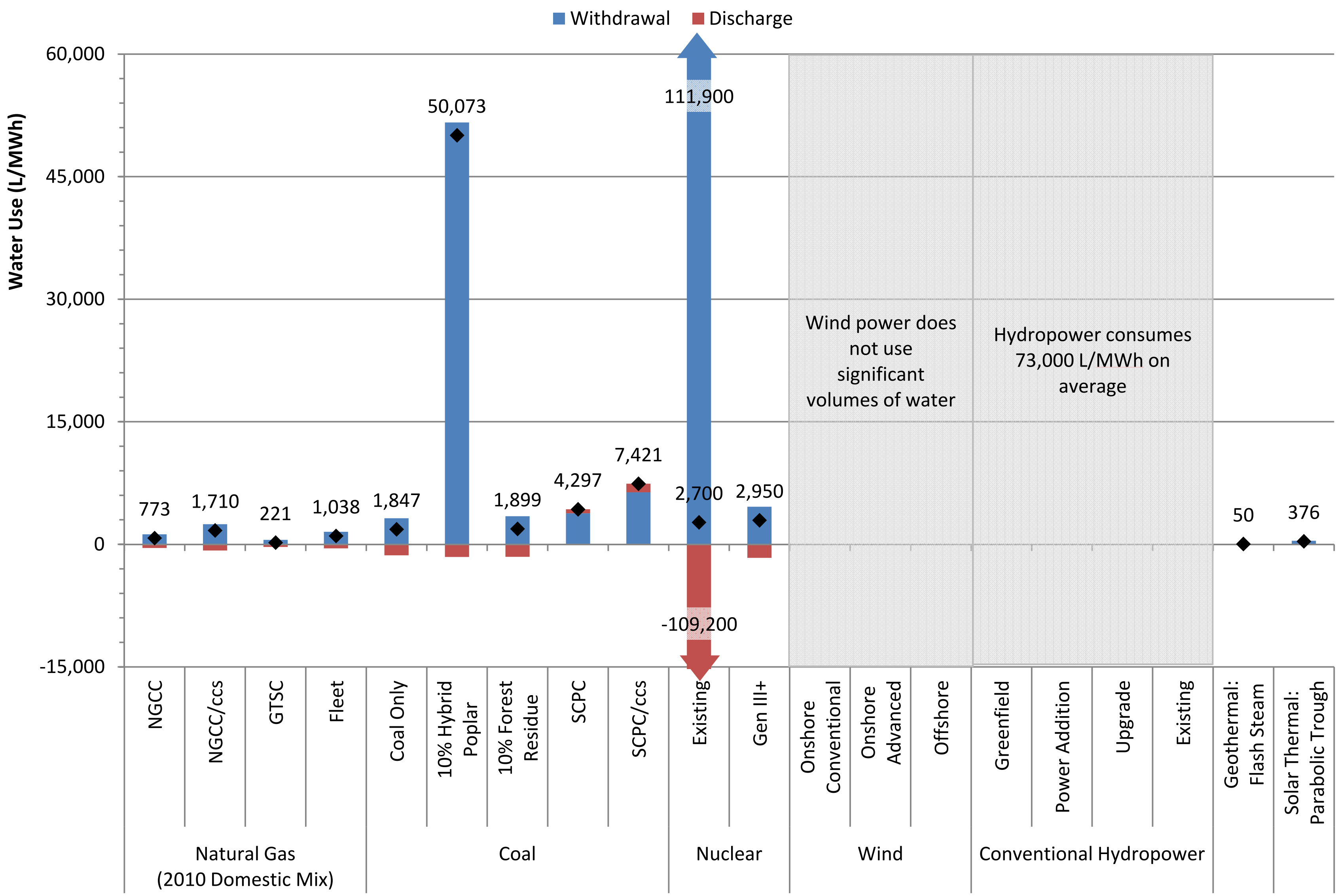
Figure 4-25 shows the water flows of all power systems of this analysis. The withdrawal and discharge results for existing nuclear power are truncated to allow a reasonable scale for the results of other technologies.

Existing nuclear power is located near rivers and uses once through cooling, while the other thermoelectric systems of this analysis use cooling towers that allow water recirculation. As shown in **Figure 4-25**, the scale of water withdrawal and discharge for existing nuclear power is two orders of magnitude greater than the withdrawal and discharge of the natural gas, coal only, and Gen III+ nuclear scenarios. However, the net water consumption of existing nuclear power is on the same order of magnitude as the other thermoelectric systems.

The use of biomass from a dedicated energy crop significantly increases the withdrawal and consumption of water by a co-fired system. The 10 percent HP co-firing case is the only system of this analysis that uses a feedstock from a dedicated energy crop. The only difference between the 10 percent HP and 10 percent forest residue co-firing cases is the source of biomass. HP and other dedicated energy crops use water during cultivation, but forest residue does not have any cultivation burdens. As shown in **Figure 4-25**, changing from forest residue to HP can increase net water consumption from approximately 1,900 to 50,000 L/MWh.

Renewable energy technologies have diverse water use patterns. Wind power does not have significant water flows because it is not a thermoelectric process and does not interfere with natural water flows. Hydropower, by definition, uses large volumes of water. This analysis does not track water withdrawal and discharge for hydropower, but it does account for water consumed by hydropower. Hydropower consumes 73,000 L/MWh on average, most of which is the evaporation of water from the reservoir. Evaporation rates vary by latitude. Within the U.S., evaporative losses from hydropower range from 25,000 to 370,000 L/MWh. The water consumed by geothermal and solarthermal technologies are relatively low. The loss of water vapor during the operation of a flash steam power plant accounts for most of the water consumed by geothermal power. The cooling requirements of a steam turbine and cleaning requirements of reflectors account for most of the water consumed by solarthermal power.

Figure 4-25: Comparative Results for Water Use

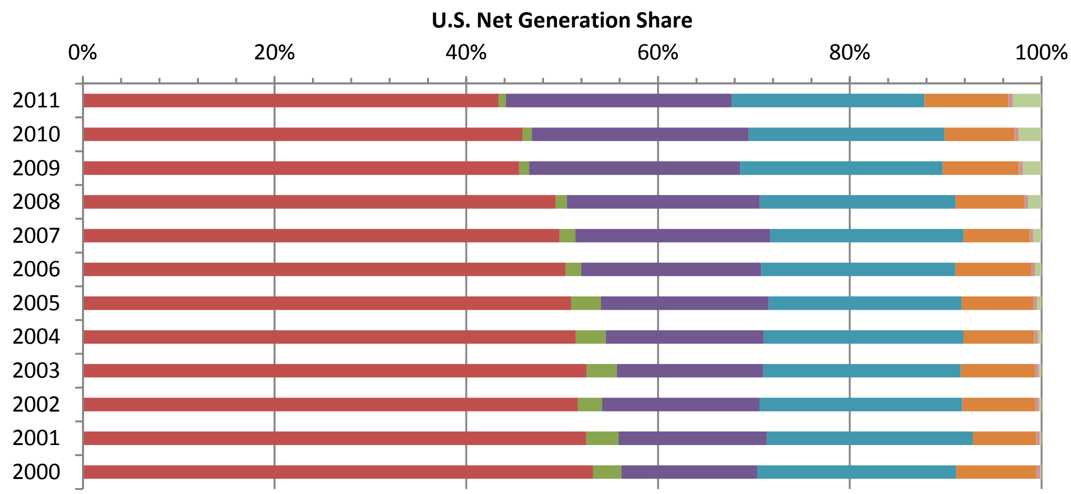


4.9 Environmental Analysis of U.S. Electricity Grid Mix

With the completion of the LCAs in this study, it is possible to build a complete LC model of the U.S. or North American mix of power generation populated almost entirely with data developed as part of this analysis and presented in this report. There are some limitations, mostly with the extent to which the renewable technologies modeled are representative of the wide range of technologies installed. However, given that the LC results are dominated by the air emissions from fossil fuel combustion, the uncertainty introduced by the model of renewable technologies is small. Exercising the model of the mix of power generation technologies ("power mixer"), especially over time and with various geographic boundaries can yield some interesting results.

Figure 4-26 shows the change in U.S. net generation (consumption) mix over the last decade (EIA, 2011a, 2012b; EPA, 2008; Statistics Canada, 2009, 2011). Net generation includes imports and exports from Canada and Mexico. Several trends are visible: the decrease in the contribution of coal-fired power generation from over 53 percent in 2000 to 43 percent in 2011, the increase of natural gas power from a low of 14 percent in 2000 to a high of 21 percent in 2009, and the increased contribution of non-hydro renewables, from 0.6 percent in 2000 to 3.4 percent in 2011, nearly a six-fold increase.

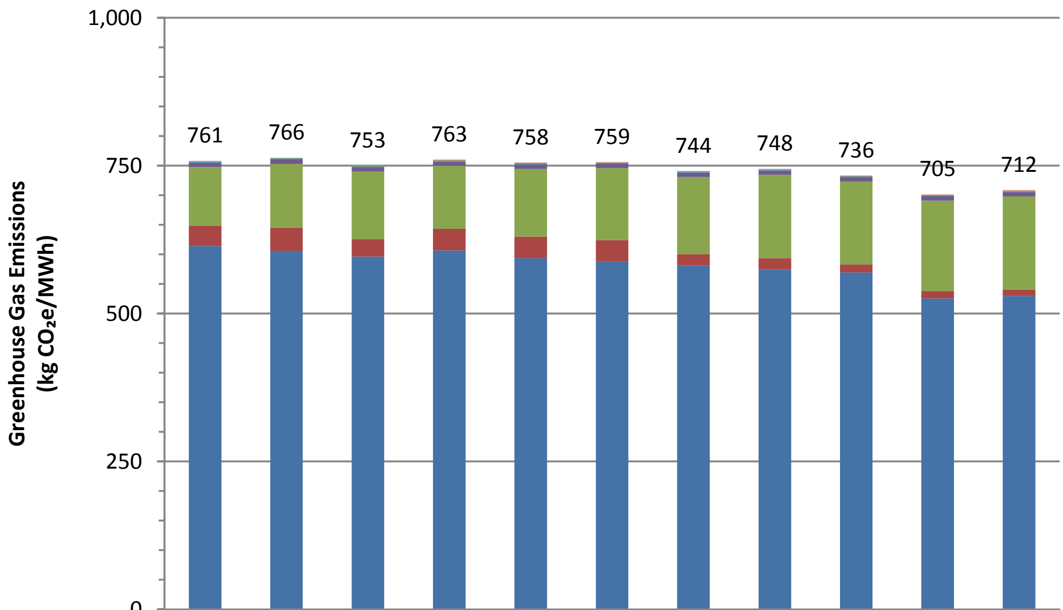
Figure 4-26: U.S. Net Generation Mix Data, 2000-2011 by Fuel Type



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Coal	53.2%	52.5%	51.6%	52.5%	51.4%	51.0%	50.3%	49.7%	49.3%	45.5%	45.9%	43.4%
Petroleum	3.0%	3.4%	2.5%	3.2%	3.1%	3.1%	1.6%	1.6%	1.2%	1.0%	0.9%	0.7%
Natural Gas	14.2%	15.5%	16.4%	15.3%	16.5%	17.5%	18.8%	20.3%	20.1%	22.0%	22.7%	23.6%
Nuclear	20.7%	21.5%	21.1%	20.6%	20.8%	20.1%	20.2%	20.2%	20.4%	21.1%	20.4%	20.1%
Hydro	8.4%	6.6%	7.6%	7.7%	7.4%	7.5%	7.9%	6.9%	7.2%	8.0%	7.3%	8.7%
Solar	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Geothermal	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%	0.4%
Wind	0.2%	0.2%	0.3%	0.3%	0.4%	0.5%	0.7%	0.9%	1.4%	1.9%	2.4%	3.0%

LC GHG emissions from power generation have decreased as the mix has shifted away from more carbon intensive fuels such as coal and petroleum. **Figure 4-27** shows the change in LC GHG emissions per megawatt-hour of electricity delivered over the last decade.

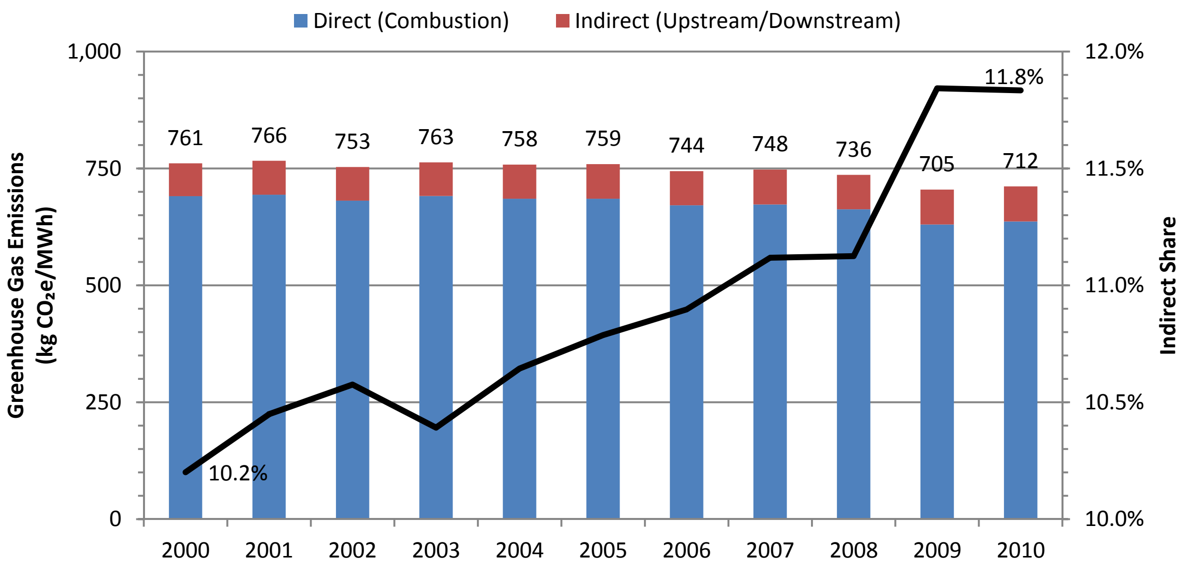
Figure 4-27: Life Cycle Greenhouse Gas Emissions from U.S. Net Generation Mix



	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010
Subtotal	761	766	753	763	758	759	744	748	736	705	712
Wind	0.0	0.0	0.1	0.1	0.1	0.1	0.1	0.2	0.3	0.4	0.5
Solar	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.01	0.01	0.01	0.01
Geothermal	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9	0.9
Hydro	2.0	1.6	1.9	1.9	1.8	1.8	1.9	1.7	1.8	1.9	1.8
Nuclear	7.3	7.5	7.4	7.2	7.3	7.1	7.1	7.1	7.2	7.4	7.2
Nat Gas	99	108	114	106	115	122	131	141	140	153	158
Fuel oil	35	39	29	37	36	36	19	19	14	12	11
Coal	614	606	596	607	594	588	581	574	569	526	530

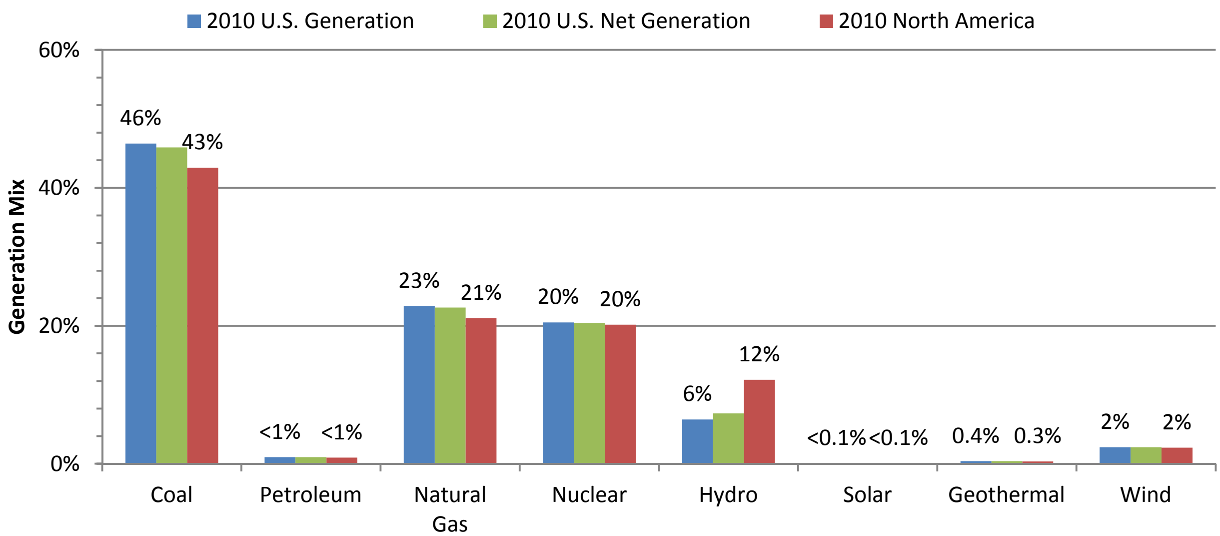
As the GHG intensity decreases and the share of generation coming from fossil fuel combustion decreases, there is a subtle, but interesting effect on a measure of the relative importance of upstream and downstream emissions. Essentially, as fewer GHGs are emitted from combustion per unit of electricity delivered, the share of the total emissions coming from extracting, preparing, and delivering fuel; manufacturing and constructing power plants; and delivering the power increases. **Figure 4-28** shows this effect for U.S. consumption, or net generation from 2000 to 2010. The line shows the small, but significant, increase in the share of LC GHG emissions coming from upstream and downstream sources in the supply chain rather than from direct combustion emissions from the power plant stack, from 10 percent in 2000 to 12 percent in 2010.

Figure 4-28: Direct vs. Indirect Emissions for U.S. Power Consumption (2000-2010)



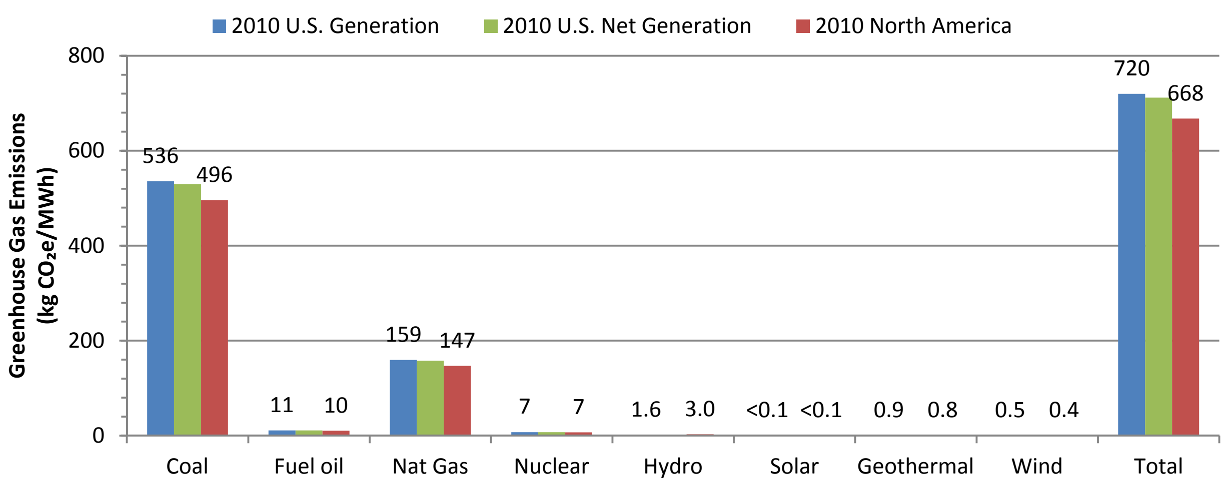
Finally, it is useful to look at the importance of various geographic boundaries in a given year; in this case, 2010. In LCA, it is a challenge to determine the proper boundary for the mix of power generation, since the product of interest ignores political and even grid administration boundaries. **Figure 4-29** below shows the change in fuel type mix as geographic boundaries change. The U.S. Generation bar is a commonly used national boundary value, but it ignores the large amount of cross-border transmission occurring between the U.S. and Canada. The U.S. Net Generation bar shows a decrease in the share of coal power as western U.S. generation is shipped north to western provinces, and an increase in the share of hydro as power from Ontario and Quebec is shipped to New England and the Mid-Atlantic region.

Figure 4-29: 2010 Generation Mixes for U.S and North America



Even when the boundary is expanded to include all generation in North America, which assumes political boundaries are completely fluid with respect to transmission, the change to the mix is relatively small, with the most significant change coming in the increase in hydropower to account for a majority of Canadian power coming from that power type.

Figure 4-30: Contribution by Fuel Type to LC Greenhouse Gas Intensity



The effect on the LC GHG intensity per unit of electricity delivered is also small, since the results are still dominated by the carbon released at the power plant from fossil fuel combustion, which still accounts for about 60 percent of the mix. **Figure 4-30** shows the change in LC GHG intensity for the various geographic mixes. There is an overall 7 percent decrease in emissions per megawatt-hour when considering U.S. generation versus North American Generation.

5 Cost Profile

The cost model accounts for capital costs of new infrastructure and equipment, operating and maintenance (O&M) costs, and cost of electricity (COE). The COE represents the cost of electricity during the first year of power plant operation and is calculated using a discounted cash flow model over the economic life of a power plant. All cost results are expressed in 2007 dollars, the first year of construction.

5.1 Cost Data and Financial Assumptions

Cash flow is affected by several factors, including cost (capital, O&M, replacement, and decommissioning or salvage), book life of equipment, federal and state income taxes, equipment depreciation, interest rates, and discount rates. For NETL LCC assessments, modified accelerated cost recovery system (MACRS) depreciation schedules are used. The financial assumptions used by the cost model are shown in **Table 5-1**. These are the default financial assumptions for all systems of this analysis, except for nuclear power, which has financial parameters based on a detailed survey of nuclear experts. (More details on the financial parameters for nuclear power are provided in **Section 5.2.3**.)

Table 5-1: Financial Assumptions for Cost Analysis of Power Systems

Financial Parameter	Expected Cost Case
Financial Structure Type	Low Risk Investor-Owned Utility
Debt Fraction (1 - Equity), %	50%
Interest Rate, %	4.5%
Debt Term, Years	15
Depreciation Period (MACRS)	20
Tax Rate, %	38%
O&M Escalation Rate, %	3%
Capital Cost Escalation During Capital Expenditure, %	3.6%
Base Year	2007
Required Internal Rate of Return on Equity (IRROE)	12%

The cost parameters include capital, O&M, and fuel costs. COE is also a function of capacity factor and plant life, which vary among technologies. The key sources of cost data are listed below.

- Natural gas plant costs are based on NETL's bituminous baseline report, which provides performance details on coal and natural gas technologies (NETL, 2010a). CO_2 pipeline costs, which apply only to the NGCC with CCS case, are based on NETL's quality guidelines for CO_2 transport and storage costs (NETL, 2010f). The delivered price of natural gas is $4.74/GJ ($5.00/MMBtu) and is based on AEO reference case projections through 2035 (EIA, 2012a); the uncertainty range around this price is +/-50%.
- Co-firing plant costs are based on data developed by NETL during a recent study on supercritical boilers designed to co-fire biomass. The original data were representative of a facility with the same capacity (550 MW) as the energy conversion facility of this analysis, but were scaled according to a change in net plant efficiency from 39 percent efficiency to 33 percent to be consistent with the boiler performance of this analysis. The fuel prices for coal,

HP, and forest residue are \$1.64/GJ, \$4.27/GJ, and \$1.73/GJ; an uncertainty range around these prices is +/-30%.

- Nuclear plant costs are based on literature published by Idaho National Laboratory (INL) and MIT, as well as a detailed survey of nuclear cost experts conducted by NETL in 2011. The nuclear cost experts included representatives of Argonne National Laboratory, MIT, NEI, Oak Ridge National Laboratory, and the U.S. DOE, Office of Nuclear Energy. The expected price of nuclear fuel is \$0.61/MMBtu, with uncertainty ranges of \$0.36 to \$0.86/MMBtu. The COE for existing nuclear, for which all capital costs have been paid off, is based on the fuel and O&M costs of Gen III+ nuclear.
- The capital cost data for wind power are based on the *2010 Wind Technologies Market Report* published by the U.S. DOE (Wiser & Bolinger, 2011), which include costs and other performance factors for U.S. wind power over the last 20 years. The costs for offshore wind power are based on *Updated Capital Cost Estimates for Electricity Generation Plants* published by the Department of Energy (EIA, 2010a).
- The capital and operating costs data for this analysis are based on a 2003 report by INEEL (Hall, Hunt, Reeves, & Carroll, 2003), which uses data collected by FERC and EIA. It provides data for the greenfield construction of conventional dams with hydropower facilities, as well as power addition to existing dams, and upgrades to existing hydropower facilities. The O&M costs from this data source are used to model the cost of existing hydropower (i.e., the COE of hydropower if all capital costs have already been paid).
- Geothermal cost data are representative of cost and performance characteristics reported by the EIA *Annual Energy Outlook*, the Department of Energy's Office of Energy Efficiency and Renewable Energy (EERE), the NREL, and the Geothermal Energy Association. Of these five data sources, the NREL report (Tidball, et al., 2010) is the most comprehensive source of geothermal cost data, while the other data sources provide supporting details.
- The key source of cost data for solar thermal power is *Cost and Performance Assumptions for Modeling Electricity Generation Technologies* (Tidball, et al., 2010). It represents the solar thermal capital costs reported by six data sources and also reports fixed O&M costs.

The cost of new infrastructure is also accounted for in the capital costs of each scenario. As discussed above, NGCC with CCS requires the construction of a CO_2 pipeline. Other infrastructure costs include a switchyard and trunkline that connect the power plant to the existing electricity grid; a switchyard and trunkline is required for all greenfield cases of this analysis, but not for the exsiting power plants. A typical switchyard has gas circuit breakers and disconnect switches, and costs approximately \$1,000,000 (Zecchino, 2008). A typical trunkline system is made up of approximately 300 towers and three aluminum-clad steel reinforced conductors spanning 80 kilometers (50 miles). The cost of the entire trunkline system is approximately to be \$46,000,000 (ICF Consulting Ltd, 2002).The switchyard and trunkline life is the same as the plant life, so no capital replacement costs are considered for the switchyard and trunkline system. These costs are converted to a kW basis of net plant capacity and included in the total overnight capital costs. The cost parameters for each case technology are summarized in **Table 5-2**.

Table 5-2: Cost Parameters for Alternative Power Systems

Energy Source	Technology	Capacity Factor (%)	Plant Life (Years)	Capital Cost (Total Overnight Capital) ($/kW)	Variable O&M ($/MWh)	Fixed O&M ($/MW-yr.)	Fuel Price ($/GJ)	Fuel Cost ($/MWh)
Natural Gas	NGCC	85.0%	30	$802	$1.32	$22,065	$4.74	$34.2
	NGCC/ccs	85.0%	30	$1,913	$2.68	$44,222	$4.74	$40.1
	GTSC	85.0%	30	$428	$0.96	$22,065	$4.74	$57.1
	Fleet	N/A	N/A	N/A	$1.32	$22,065	$4.74	$36.4
Co-firing	Coal only	85.0%	30	N/A	$7.65	$86,600	$1.64	$15.8
	10% HP	85.0%	30	$230	$7.65	$86,600	$1.64 (I-6 Coal); $4.27 (HP)	$21.1
	10% Forest Residue	85.0%	30	$230	$7.65	$86,600	$1.73	$16.1
Nuclear	Existing	90.6%	N/A	N/A	$0.86	$69,100	$0.61	$5.68
	Gen III+	90.6%	49	$4,267	$0.86	$69,100	$0.61	$5.68
Wind	Onshore Conventional	30.0%	20	$1,970	$2.62	$24,050	N/A	N/A
	Onshore Advanced	30.0%	20	$1,920	$2.62	$24,050	N/A	N/A
	Offshore	39.0%	20	$5,470	$2.62	$34,188	N/A	N/A
Hydropower	Greenfield	37.1%	80	$6,300	$1.86	$4,120	N/A	N/A
	Power Addition	37.1%	80	$3,200	$1.86	$4,120	N/A	N/A
	Upgrade	37.1%	80	$1,900	$1.86	$4,120	N/A	N/A
	Existing	37.1%	80	$0	$1.86	$4,120	N/A	N/A
Geothermal	Flash Steam	90.0%	25	$3,000	$0.00	$164,640	N/A	N/A
Solar Thermal	Parabolic Trough	27.4%	30	$4,693	$0.00	$56,780	N/A	N/A

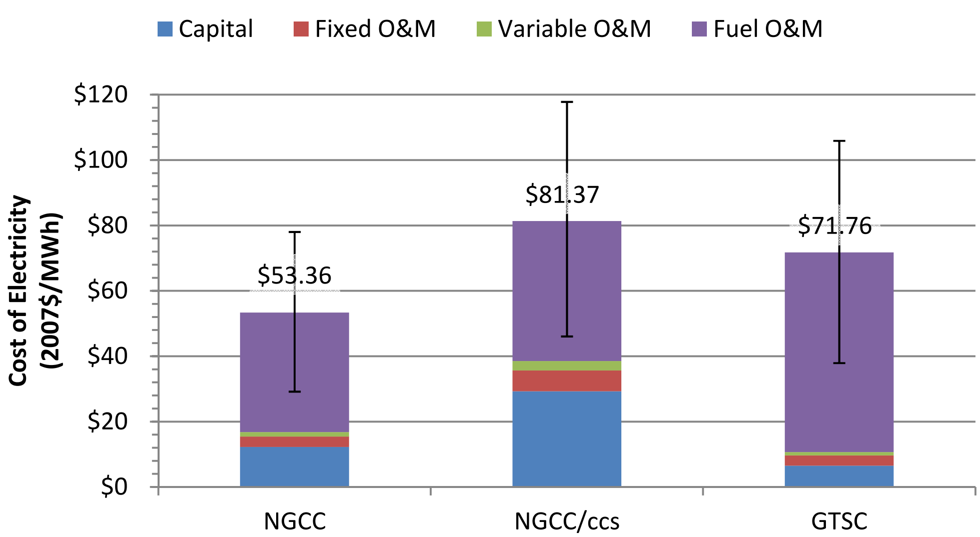
5.2 Cost Results

The cost results are expressed on the basis of COE, which represents the cost of electricity during the first year of power plant operation and is calculated using a discounted cash flow model over the economic life of a power plant. The capital and O&M components of COE for each technology are summarized below.

5.2.1 Natural Gas

The COE for the three natural gas power scenarios are shown in **Figure 5-1**. At $53.36/MWh, the NGCC case (without CCS) has a lower COE than the other natural gas power cases. Compared to GTSC, NGCC has higher capital costs but lower fuel costs. The relatively high efficiency of an NGCC power plant results in relatively low fuel requirements that offset the relatively high capital costs of NGCC power. The COE of NGCC power is increased by 52 percent when a CCS system is added; this increase is due to the capital requirements of CCS and the reduced power plant efficiency caused by CCS.[1]

Figure 5-1: LCC Results for Natural Gas Power



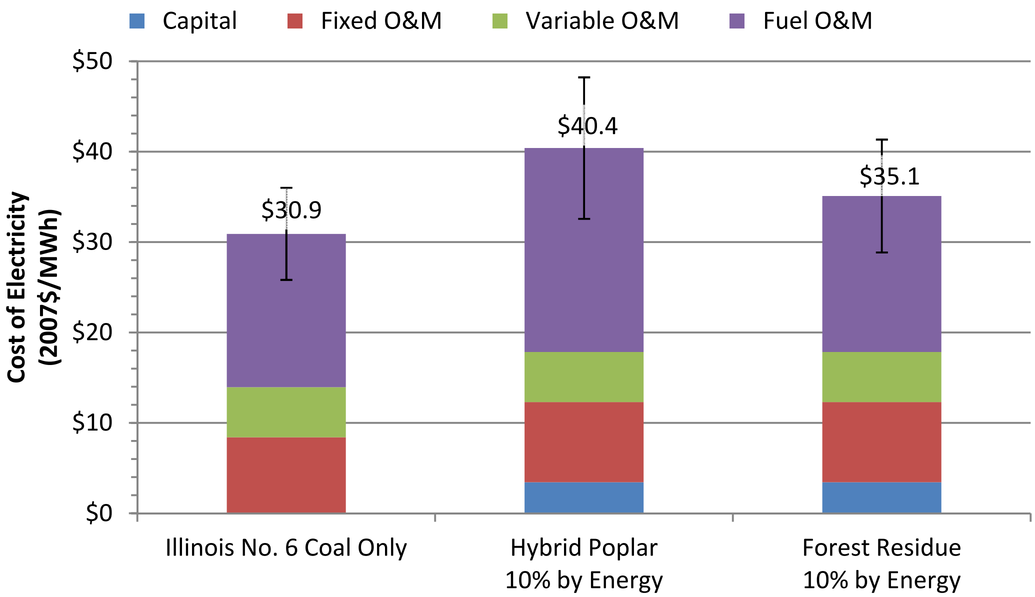
The error bars in **Figure 5-1** represent uncertainties in capital costs, the price of natural gas, capacity factor, total tax rate, and variable O&M costs. The price of natural gas has an expected value of $5.00/MMBtu, but ranges from $2.50 to $7.00/MMBtu and introduces the most uncertainty to the COE results, followed by uncertainties in capital costs, tax rates, capacity factor, and variable O&M.

[1] When the LCC COE is calculated using a natural gas price of $6.55/MMBtu, the same value used by NETL's baseline (NETL, 2010a), the COE of NGCC and NGCC/CCS are $64.69/MWh and $94.66/MWh, respectively. These results are approximately 10% higher than the baseline results due to the 7 percent electricity T&D loss and additional capital costs for the switchyard and trunkline.

5.2.2 Co-firing

The retrofit of an existing PC plant to co-fire HP at a 10 percent share of feedstock energy increases the COE from $30.9/MWh to $40.4/MWh (a 31 percent increase). If forest residue is co-fired instead of HP, the increase in COE is only 14 percent. The capital costs of the co-fired systems account for a small share (approximately 8 percent) of the COE because this analysis assigns capital costs only to new equipment, not existing equipment. The key drivers of cost uncertainty are the feedstock prices for coal and biomass. The COE results for the co-firing scenarios are shown in **Figure 5-2**.

Figure 5-2: LCC Results for Coal and Biomass Co-firing



5.2.3 Nuclear

The ranges chosen for the nuclear cost parameters are based on a detailed survey of nuclear cost experts and are more complex than for other LCC analyses. The ranges for the nuclear financial and cost parameters are shown in **Table 5-3** and **Table 5-4**, respectively.

Table 5-3: LCC Financial Parameter Inputs for Gen III+ Nuclear COE Calculation Scenarios

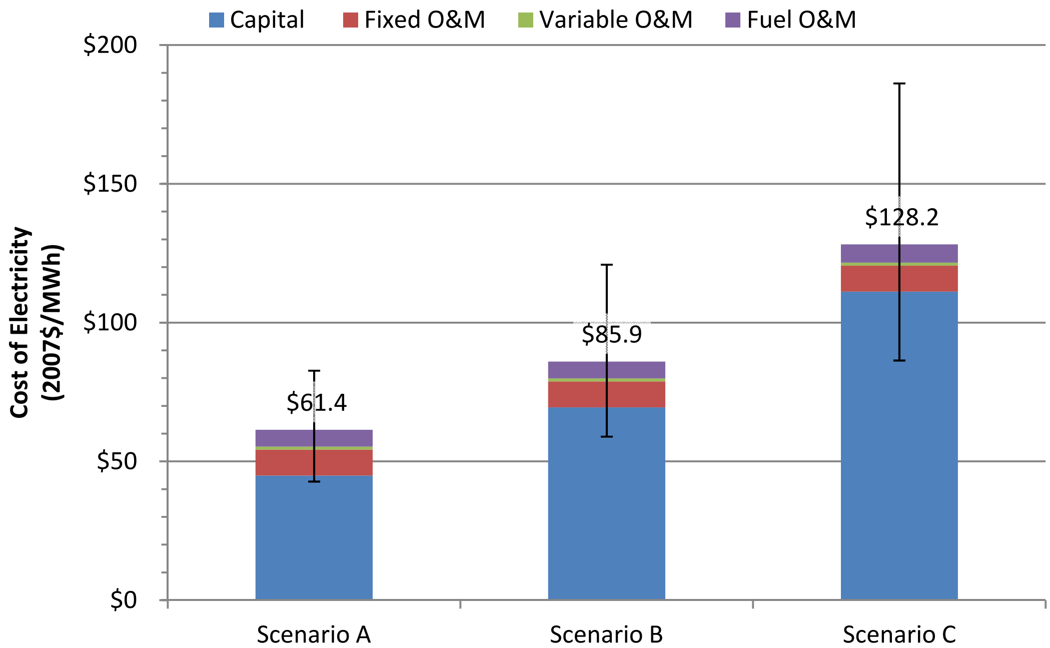
Financial Parameter	Scenario A Minimize COE	Scenario B Expected COE	Scenario C Maximize COE
Debt Fraction (1 - Equity)	0.71	0.58	0.44
Interest Rate (%)	5.3%	6.5%	7.8%
Debt Term (Years)	29	23	17
Plant Life (Years)	59	49	38
Depreciation Period (MACRS)	10	15	15
Tax Rate (%)	36%	39%	41%
IRROE (%)	12%	14%	16%

Table 5-4: LCC Cost Parameters for Gen III+ Nuclear COE Calculation Scenarios

Operations Parameter	Low	Expected	High
Net Plant Capacity (MW Net)	983	1400	1817
Capacity Factor (%)	86.9%	90.6%	94.4%
Thermal Efficiency (%)	31.0%	33.4%	35.8%
Construction Period (Years)	4.2	5.6	7.1
Capital ($/kW)	3,269	4,267	5,264
Decommissioning Costs (% of TOC)	6%	9%	12%
Fixed O&M ($/kW/year)	57.0	69.1	81.2
Non-fuel Variable O&M ($/kW/year)	0.80	1.00	1.30
Fuel Price ($/MMBtu)	0.36	0.61	0.86
Waste Fee ($/kWh)	0.0007	0.0012	0.0017

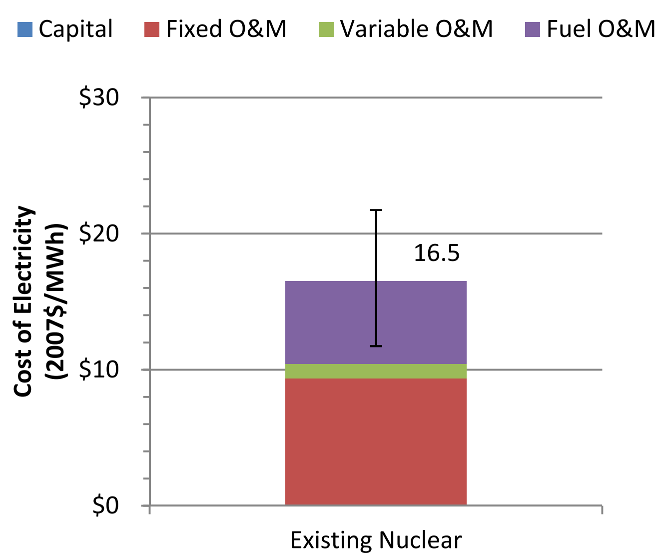
The expected COE for Gen III+ nuclear power is based on a capital cost of $4,267/kW, a capacity factor of 90.4 percent, and a seven percent loss of electricity during transmission and delivery. Nuclear power is capital intensive and the breakdown of the expected COE indicates that the capital portion accounts for 81 percent. The remaining cost components compose the remaining 19 percent of the $85.9/MWh, with 11 percent coming from fixed O&M, 1 percent from variable O&M, and 7 percent from fuel costs. The COE ranges from $42.8 to $186.2/MWh across the range of financial and operations parameters. The expected COE for Gen III+ nuclear power is shown in **Figure 5-3**.

Figure 5-3: LCC Results for Gen III+ Nuclear Power



The expected COE for existing nuclear power is shown in **Figure 5-4**. These results do not include capital costs because all capital costs have already been paid for the existing nuclear facility.

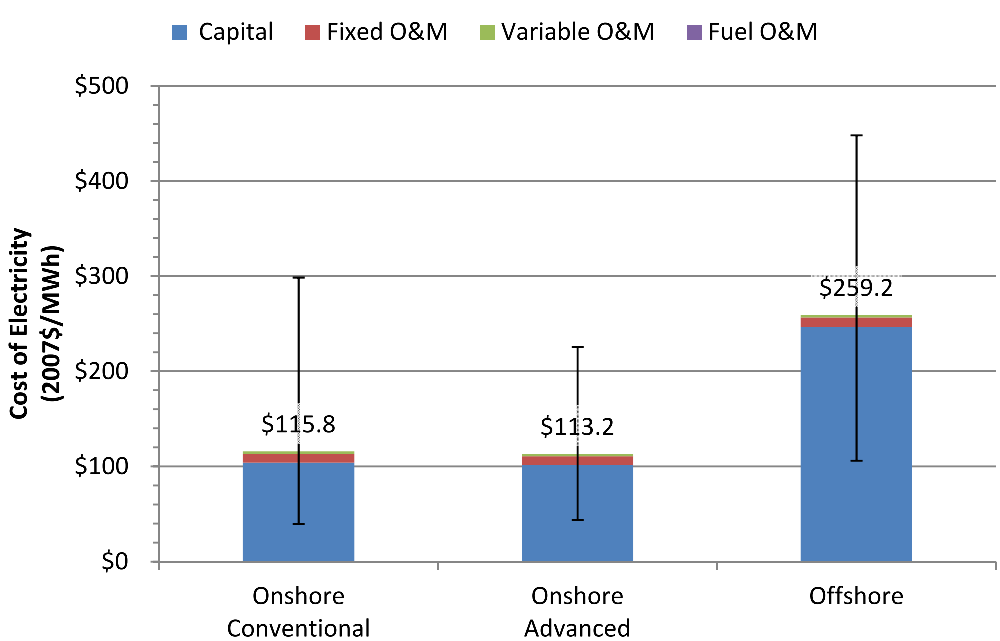
Figure 5-4: LCC Results for Existing Nuclear Power



5.2.4 Wind

Compared to offshore wind power, onshore wind power has lower capital and O&M costs per kilowatt of power. However, offshore wind power has a higher average capacity factor than onshore wind power, which helps reduce its costs in comparison to onshore wind power. The cost results are dominated by capital costs. When the same financial assumptions are applied to standalone wind power, the COE is $115/MWh for onshore conventional, $113/MWh for onshore advanced, and $259/MWh for offshore. The expected cost results show that onshore wind power has a lower COE than offshore wind power, but the overlapping uncertainties of these results indicate that if offshore wind power has better-than-expected performance, or a financing structure with low expected returns, it can be cost competitive with onshore wind power. However, as tax credits and other financial incentives for wind power expire, it is likely that investments in new wind power projects will slow down significantly, and with no long-term federal policies for renewable energy investments, it is difficult for producers to secure power purchase agreements. The COE results for wind power are shown in **Figure 5-5**.

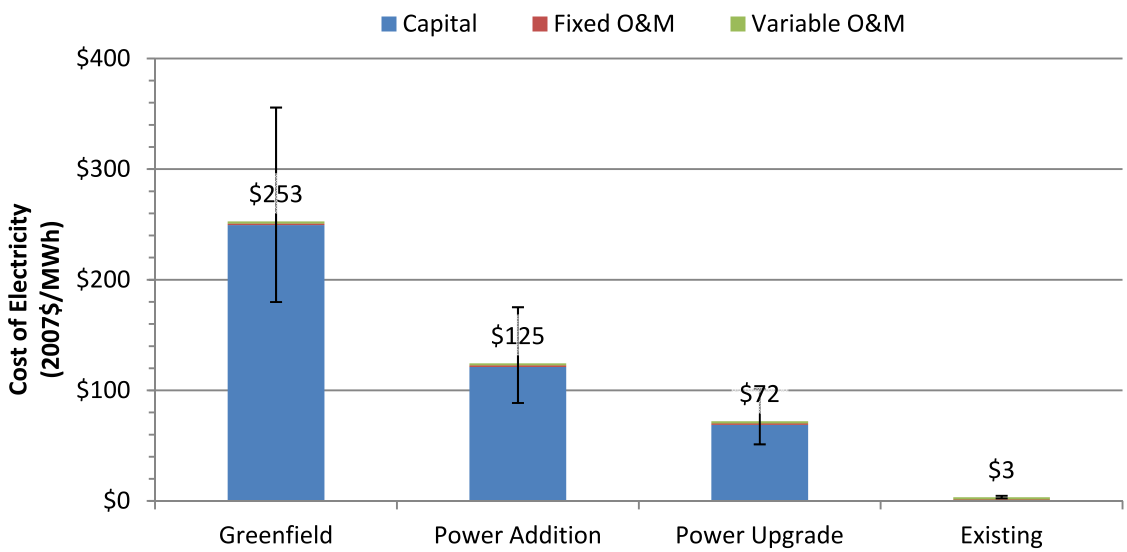
Figure 5-5: LCC Results for Wind Power



5.2.5 Hydropower

The cost profile of hydropower shows that capital costs are the key component of the greenfield, power addition, and power upgrade scenarios; the total COE for these scenarios are $253, $125, and $72 per MWh, respectively. For these three scenarios, between 95 and 99 percent of the total COE is due to capital costs. As a renewable energy technology, hydropower does not require the purchase of fuel for operation, and other operating and maintenance costs are small in comparison to the annualized capital costs. Thus, the COE of the existing scenario is particularly low ($3/MWh) because it does not have any capital burdens. The COE results for hydropower are shown in **Figure 5-6**.

Figure 5-6: LCC Results for Hydropower



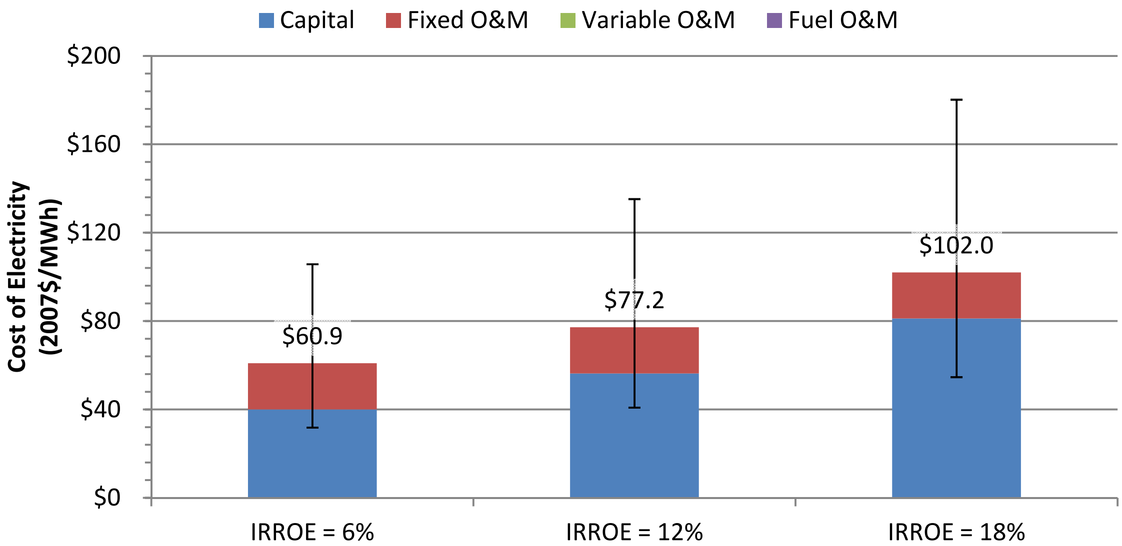
An important aspect of the hydropower cost results is that the conventional hydropower scenarios are assigned the full capital costs of site preparation and dam construction. In addition to power generation, conventional dams also provide irrigation control and recreation. The metrics for measuring irrigation control and recreation are different from the metric for measuring power output (i.e., MW), and thus it is difficult to develop a fair scheme for apportioning cost burdens among the services provided by a conventional dam.

5.2.6 Geothermal

The expected value capital costs for a geothermal power plant are $3,000/kW and the expected value O&M costs for geothermal power are $164,600/MW-year (Tidball, et al., 2010). The expected value COE for geothermal power is $77.19/MWh.

Figure 5-7 shows the COE results for geothermal power and includes scenario for a low risk scenario (6 percent IRROE) and a high risk scenario (18 percent IRROE) in addition to an expected scenario (12 percent IRROE). The error bars on these results are due to uncertainties in capital and O&M costs, plant lifetimes, O&M costs, and capacity factor.

Figure 5-7: LCC Results for Geothermal Power

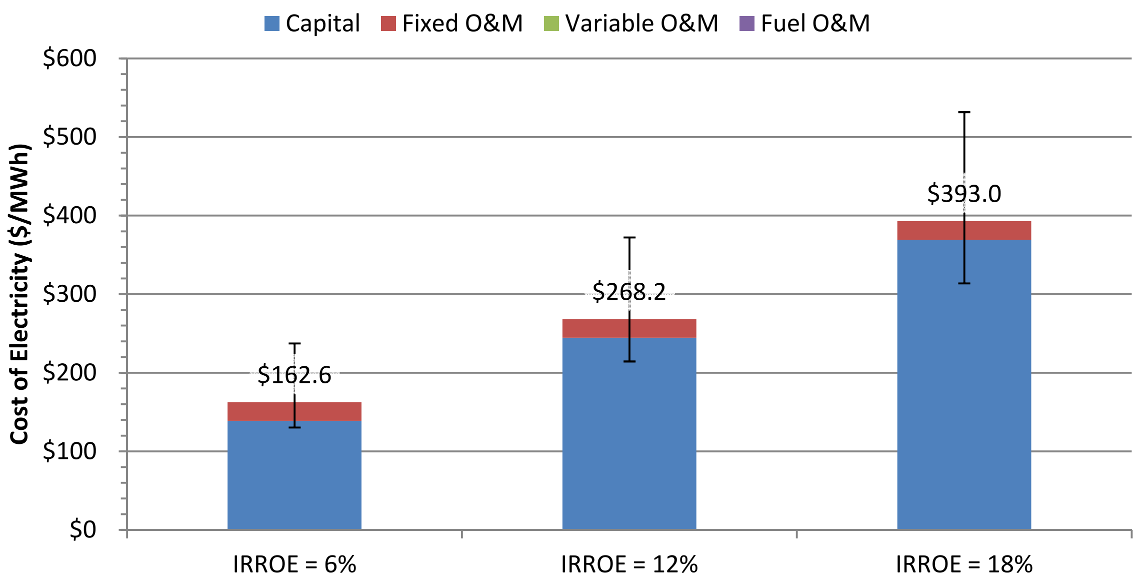


5.2.7 Solar Thermal

The cost profile of solar thermal power calculated a COE of $268.2/MWh for solar thermal power. The COE results are based on a capital cost of $4,693/kW, a fixed O&M cost of $56,780/MW-yr., a capacity factor of 27.4 percent, and a seven percent loss of electricity during transmission and delivery. The expected value COE for geothermal power is $268.2/MWh.

Figure 5-8 shows the COE results for solar thermal power and includes scenario for a low risk scenario (6 percent IRROE) and a high risk scenario (18 percent IRROE) in addition to an expected scenario (12 percent IRROE). The error bars on these results are due to uncertainties in capital costs, plant life, and capacity factor.

Figure 5-8: LCC Results for Solar Thermal Power



5.3 Comparative Cost Results

Capital costs are a significant component of most power systems, except for existing systems, which do not have new capital expenditures. Capital costs are still significant for the three greenfield natural gas power scenarios (NGCC, NGCC with CCS, and GTSC), but fuel costs account for the majority of COE for these three cases. Even the fuel costs of NGCC with CCS (which has high capital costs for CO_2 recovery, transport, and sequestration) account for 53 percent of the COE. The co-firing cases do not have significant capital costs, so fuel costs account for the majority of the COE for these cases.

The COE of power from renewable energy sources are, in general, higher than those for other technologies due to their higher capital costs and lower capacity factors. One exception is geothermal power using flash steam technology. Geothermal power has a high capacity factor (90 percent), which reduces the share of capital requirements per unit of electricity produced.

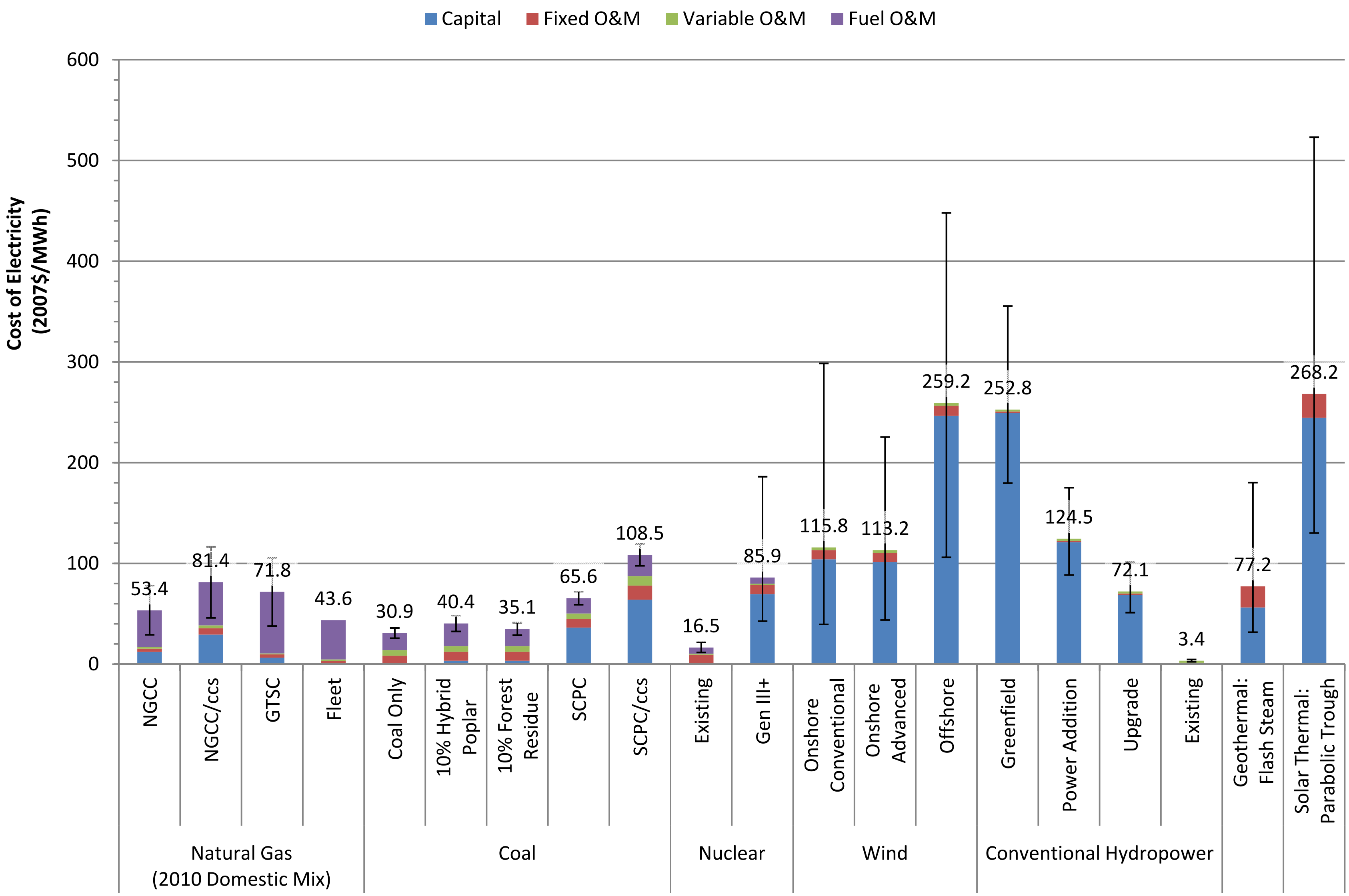
Uncertainty in fuel prices and capital costs account for most of the uncertainty in the COE results for natural gas and co-fired systems. As discussed earlier, natural gas price volatility accounts for the majority of COE uncertainty for natural gas power systems. In contrast, while the price of biomass is highly variable, the co-fired systems have a relatively narrow range of uncertainty. The price of delivered biomass is highly uncertain, but since it accounts for only 10 percent of feedstock energy, the extent of biomass cost uncertainty is diminished per unit of electricity production. Almost all of the uncertainty in the COE of nuclear power is based on uncertainty of capital costs (fuel costs account for only 7 percent of the expected COE for nuclear power).

The uncertainty in the COE of renewable energy systems are due to uncertainties in capital costs and are not affected by uncertainty in fuel prices. New renewable technologies such as offshore wind or solar thermal power are likely to have unexpected costs during construction, which leads to unanticipated increases in capital costs. Similarly, the drilling of a geothermal well may encounter barriers, such as harder-than-expected geological formations, that increase development costs.

For investor owned projects – which is likely for wind, solar thermal, and geothermal power – the relatively high risk of the projects is balanced by a higher IRROE than projects managed by publicly owned utilities.

The COE results for all technologies are shown in **Figure 5-9**.

Figure 5-9: Comparative LCC Results



6 Barriers to Implementation

Barriers include technical issues that could prevent or delay the implementation of a technology.

6.1 Natural Gas

The limited capacity of the existing pipeline transmission network is a possible barrier to the growth of natural gas extraction from Marcellus Shale. The natural gas transmission network transports large quantities of natural gas from the southern U.S. to markets in the Northeast, and recently, additional capacity has been added for transporting natural gas across the Rocky Mountain region, making it easier to transport gas from west to east. However, a surge in natural gas production in the Marcellus Shale region could exceed the existing pipeline capacity in the Northeast. According to a representative of El Paso Pipeline Partners (Langston, 2011), there are two ways of expanding natural gas pipeline capacity. The first is the installation of new compressor stations along the pipeline network, which increases the overall pressure of the network and allows more gas to be transported. Alternatively, new pipelines can be installed alongside existing pipelines. New pipelines may be costly, but one advantage of laying new pipelines next to existing pipelines is that pipeline companies have fewer barriers in establishing pipeline right-of-way (Langston, 2011).

6.2 Co-firing

The barriers to implementing co-fired systems include adverse changes to the operating characteristics of boiler systems as well as unexpected changes in the biomass supply chain. The moisture content of the biomass feedstock can lower the efficiency of a boiler, alter the residence time of fuel in a boiler, and, in turn, result in incomplete biomass combustion, although the latter is usually not as much of an issue (Ortiz, et al., 2011). The introduction of biomass to a system that was originally designed to burn coal can also result in a significant increase in slagging, fouling, and ash deposition. However, power plants that have co-fired biomass have been able to adjust conditions to minimize the technical issues that co-firing biomass present.

The uncertainties in the biomass supply chain are due to competing markets for both forest and herbaceous crops. Extreme weather can also cause supply disruptions or change the quality of biomass feedstocks. Finally, land ownership issues can complicate the procurement of biomass feedstocks. Torrefaction is a technology that can reduce the supply chain uncertainty of biomass. Torrefaction can be performed at large collection depots that not only increase carbon density but, when combined with pelleting, can give biomass a carbon density similar to coal. Torrefied biomass can also be stored longer than untreated biomass. The improved physical characteristics of torrefied biomass make long-distance transport more economical, which increases the radius of collection for biomass and, in turn, reduces supply chain uncertainty. However, while torrefaction improves the supply characteristics of biomass, it does not significantly improve the LC GHG profile of co-fired systems. The LC GHG emissions from the co-firing of torrefied poplar at a 10 percent share of feedstock energy are 1,071 kg CO_2e/MWh. Compared to the three scenarios in the environmental portion of this analysis, this result is 4.2 percent lower than the combustion of 100 percent coal, 3.3 percent lower than the co-firing of HP, and 2.6 percent *higher* than the co-firing of forest residue.

6.3 Nuclear

The main barrier to new nuclear power is the issue of storage of spent nuclear fuel. The Nuclear Waste Policy Act (NWPA) directed the DOE to site, construct, and operate deep geologic repositories to “provide a reasonable assurance that the public and the environment will be adequately protected from the hazards” of high-level radioactive waste (a by-product of U.S. nuclear weapons production), and spent nuclear fuel (removed from commercial power reactors). The NWPA limited the capacity of the first repository to 70,000 metric tons heavy metal (MTHM).

In 2008, DOE submitted the license application to the NRC for authorization to construct the repository at Yucca Mountain (NRC, 2012). NRC started the years-long licensing proceeding. In March 2010, DOE filed a motion with the NRC’s Atomic Safety and Licensing Board seeking permission to withdraw its 2008 application. In October 2010, the NRC began closure of its Yucca Mountain activities, and in 2011 suspended the licensing proceeding (NRC, 2011b).

In early 2010, President Obama directed the Secretary of Energy to form a Blue Ribbon Commission (BRC) on America’s Nuclear Future. The BRC was to “conduct a comprehensive review of policies for managing the back end of the nuclear fuel cycle, including all alternatives for the storage, processing, and disposal of civilian and defense used nuclear fuel and nuclear waste” (Obama, 2010). The BRC final report released in January 2012 (BRC, 2012) included an estimate, prepared by EPRI, of current and projected amounts of spent nuclear fuel from nuclear power plants. The EPRI estimate was 65,000 metric tons uranium (MTU) in 2010, increasing to 133,000 MTU by 2050 (BRC, 2012).

6.4 Wind

The barriers to wind power include uncertainties in construction schedules, especially for offshore wind projects. Onshore wind farms have enjoyed much shorter planning and construction horizons, as compared to fossil fueled power plants, with a typical planning cycle of approximately 3-4 years (EIA, 2011c). The offshore wind industry, in contrast, lags behind the onshore wind industry in these aspects. For instance, the first major offshore wind project in the U.S. was approved after about a decade of planning and compliance procedures, in April, 2010 (Cape Wind, 2010). Availability of power transmission capacity, combined with the difficulty of constructing long distance power transmission lines, is another barrier to the implementation of wind power.

Even if transmission lines are near a wind farm, the intermittent production of the wind farm may prevent it from meeting the capacity requirements of its market. For example, the California Independent System Operator (CA ISO) calculates a net qualifying capacity based on the adjusted output that the intermittent resources exceed in 70 percent of peak hours during each month over the last three years (CA-ISO, 2011). Further, if wind power becomes a greater share of total grid power, grid operators will have to spend more time scheduling additional operating reserves. In other words, at low wind power penetration, the intermittency of wind power has a negligible impact on the stability of the grid, but at high wind power penetration, grid operators must plan for wind power intermittency.

6.5 Hydropower

The barriers to conventional hydropower include its dependence on natural flow and water storage volumes. In drought years, the total volume of water is reduced, and therefore the effective generation capacity of the reservoir is also reduced. Water availability for power generation is also affected by various other factors, including competing use for water supply and flood control. Climate change is also expected to alter natural weather patterns in many regions. Because they are installed into flowing rivers, hydrokinetic technologies may be subject to substantial damage from debris or washout, especially during high flow or flood events. These concerns could potentially increase the lifetime cost of hydrokinetic installations substantially, depending upon turbine design and site selection. Like conventional hydropower, hydrokinetic technologies are also subject to variation in river flows and water availability.

6.6 Geothermal

Key barriers to the implementation of geothermal power include resource availability and associated technological and cost constraints. Resource availability depends on accessibility of the potential resource, the temperature of the potential resource, and the depth of the potential resource. Readily available surficial geothermal resources, such as those available at The Geysers geothermal complex (located north of San Francisco, CA), are easy to capture and utilize for power generation. However, easily accessible near-surface resources are extremely rare. The Geysers is a particularly exceptional example. Based on a dry steam resource (steam is produced directly from the resource), it is the largest geothermal field in the world, and has a total nameplate capacity of 1.5 GW, with a typical capacity factor of around 60 percent (~950 MW). Most other potential geothermal fields, known to be accessible with currently available technologies and at reasonable cost, are remotely located and have much smaller potential.

Geothermal well drilling costs can be substantial and commonly constitute one third to one half of total overnight capital costs for a new geothermal plant. Well drilling costs are driven by the specific characteristics of the geothermal system being exploited (EERE, 2006; IEA/NEA, 2010). Deeper wells are, of course, more costly. However, many geothermal resources are located in granitic, basaltic, or other hard rock formations. These formations are hard to drill through. Also, geothermal resources are commonly available along deep rock fracture lines. Accessing a suitably sized network of such fractures is required to enable extraction of sufficient heat from the system. However, there is no guarantee that a given well will sufficiently intersect a fracture network, and several wells (injection and extraction) may be needed for a single power plant. Advanced technologies such as enhanced geothermal systems (EGS) promise high generation potential based on a theoretically large resource base. To date, however, EGS has been proposed only in a handful of locations, due to cost and technological constraints, where drilling cost is often the primary constraint.

Connecting geothermal facilities to the electricity grid is another barrier to implementation. The best geothermal resources are in many cases located far from existing population centers, and distant from existing power transmission lines needed to carry energy onto the power grid. For instance, quality geothermal resources are located throughout much of the sparsely populated Rocky Mountain region. As a result, many high quality geothermal resources in the U.S. West are expected to remain untapped for the foreseeable future, for the simple reason that new transmission facilities are expensive to construct and difficult to permit (Smith & Bruvsen, 2010).

6.7 Solar Thermal

Barriers to implementation of solar thermal power include cost, water use, and grid connection. According to the EIA (2011e), high temperature solar thermal collectors, such as those utilized for concentrating solar power, cost an average of $25.32/square foot, although some industry sources have estimated up to $55/square foot. Considering that the installation of one GW of utility-scale solar thermal can require over two square miles of solar fields, the importance of collector cost becomes immediately obvious. Water use is another potential barrier to the widespread implementation of utility-scale solar thermal power production. The approved (but not yet constructed) Blythe Solar Power Plant, located in the Mojave Desert of southeastern California, has a nameplate generation capacity of 1,000 MW. During operations, the project would require approximately 600 acre-feet of water per year for cooling. An additional 4,100 acre-feet of water would be required in support of project construction (BLM, 2010a). Availability of power transmission capacity, combined with the difficulty of constructing long-distance power transmission lines, is another key barrier to the implementation of solar thermal power production. The best solar thermal resources are located in areas that are distant from existing population centers. Many high-quality solar thermal resources are expected to remain untapped for the foreseeable future, for the simple reason that new transmission facilities are (1) expensive to construct and (2) difficult to permit (Smith & Bruvsen, 2010).

Table 6-1 summarizes the barriers for all technologies.

Table 6-1: Summary of Barriers for Alternative Energy Technologies

Technology	Barriers
Natural Gas	Pipeline capacity near new natural gas sources
Co-firing	Biomass supply chain logistics
Nuclear	Long-term storage of spent fuel
Wind	Construction schedules; Intermittent wind supply
Hydropower	Water availability
Geothermal	Cost and resource accessibility
Solar Thermal	Cost and resource accessibility; Water availability

7 Risks of Implementation

Risks of implementation include financial, environmental, regulatory, and/or public perception concerns that are obstacles to implementation.

7.1 Natural Gas

Legislative uncertainty is a key risk of implementing natural gas power systems. In 2010, New York placed a moratorium on horizontal drilling of natural gas wells (NYSDEC, 2010). In June 2011, the New York State Department of Environmental Conservation released new recommendations that favored high-volume fracking on privately-owned land as long as it is not near aquifers (NYSDEC, 2011). These new recommendations were faced with opposition, including a New York State Supreme Court ruling in February 2012 that enforced the right of municipalities to use zoning laws to prohibit oil and natural gas drilling (Navarro, 2012).

Pennsylvania has also faced legislative uncertainty with respect to natural gas extraction. For instance, on June 28, 2011, the Pennsylvania House of Representatives canceled a vote on an impact fee on gas extracted from the Marcellus Shale. The proposed legislation would have assessed $50,000 per well for the first year of operation, followed by $25,000 in the second and third years, and $10,000 a year thereafter through the tenth year of operation (Scolforo, 2011). After months of controversy, in February 2012, Pennsylvania approved legislation that taxes the shale gas industry and sets standards for developing gas wells. Proponents of the legislation see it as a way for state and local governments to take advantage of a valuable revenue stream. Critics argue that the new laws do not adequately address the environmental and safety issues of shale gas extraction (Tavernise, 2012).

7.2 Co-firing

The risks of implementing co-fired systems include regulatory uncertainties. State level directives and plans, such as California's Bioenergy Action Plan, help move government toward regionalized support for increased biomass collection and utilization. Additional statewide and national requirements and incentives are still developing. However, since sourcing of biomass is a major concern for many energy facilities that rely on biomass (Ortiz, et al., 2011), additional regulatory developments that further support biomass collection and use would help to support growth of biomass co-firing. The future of co-firing is dependent on the facilities being able to receive renewable energy credits for the practice because of the operating and capital costs of biomass relative to coal. (Ortiz, et al., 2011)

Biomass may be gathered from a range of potential sources. In particular, the use of forest thinnings has garnered both support and strong opposition from environmental groups. Forest thinning has been touted as a potential requirement in order to prevent rampant forest fires, and also as a carbon management solution to increase the carbon sequestration rate of forests. However, many environmental groups have taken active positions against forest thinning. Overall, research is conflicting in terms of costs and benefits of forest thinning. Forest dynamics vary significantly from region to region, as do the environmental impacts or benefits of thinning.

7.3 Nuclear

The risks of implementing nuclear power are rooted in the uncertainties in long-term waste management and safety concerns. Current U.S. nuclear policy has not resolved the long-term uncertainties for spent fuel disposition and reprocessing. NETL's LCA of nuclear power demonstrates that spent fuel disposition does not introduce significant environmental burdens to the LC of nuclear power, and from a GHG perspective, a change in uranium enrichment technologies would be more beneficial than fuel reprocessing. Other uncertainties include the costs of nuclear power, which are affected by security and safety concerns that are unique to the nuclear fuel cycle. Until there is more certainty on waste management, security, and safety concerns, investors will shy away from nuclear power. Finally, even if the issues of long-term waste disposition and cost uncertainty are resolved, perception-based issues will be the final barrier to additional implementation of nuclear power.

The perception of nuclear power is anchored in three nuclear events that have occurred within recent history: the 1979 Three Mile Island accident, the 1986 Chernobyl accident, and the 2011 Fukushima accident. A comparison of the U.S. and Japanese nuclear programs shows that the U.S. has implemented safety systems that have not yet been implemented in Japan. Public concerns about nuclear power are also rooted in fears of terrorist attacks and nuclear weapon proliferation. Again, LCA demonstrates that the environmental burdens of steady-state nuclear operations do not pose a significant risk. Additionally, the levels of radiation from steady-state nuclear power are the same magnitude as radiation from natural sources and are hundreds of times lower than the exposure threshold for cancer risks (NRC, 2011a). However, the potentially high impacts of adverse nuclear events overshadow the fact that their occurrence is rare.

Risks also include failures of nuclear power systems that could lead to radiological releases or other nuclear events. From an LCA perspective, the environmental burdens of the steady-state nuclear power LC do not pose a significant environmental risk. However, while the chances of adverse nuclear events are small and newer nuclear technologies are inherently safer than older technologies, the scale of a nuclear event can have far-reaching environmental and societal risks.

7.4 Wind

The risks of implementing wind power include various environmental impacts that are unique to wind power, including increases in bird and bat strikes. In mountainous western regions, wind farms have been installed along mountain passes and other areas having high wind potential, and many of these locations also serve as key migratory routes for various species of birds. In some cases, collision-related mortality can result in population level effects on certain high-incidence bird species (Drewitt & Langston, 2008). Various site-specific mitigation and avoidance measures have been implemented, including modifications to turbine heights, spacing, and positioning. In the case of offshore wind power, interference with marine navigation, loss of benthic biota, and interference with cultural and visual resources (USACE, 2006) are further risks are implementation.

7.5 Hydropower

The risks of implementing hydropower include the characteristically difficult environmental review and permitting of large conventional hydropower in the U.S. Environmental review and acquisition of needed permits can take 5 to 10 years or more, which has substantially slowed development of new hydropower in the U.S. (Contra Costa Water District, 2011)

In contrast with large conventional hydropower, environmental review and permitting for hydrokinetic installations have proven to be much less arduous based on streamlining initiatives implemented by FERC. FERC has initiated programs to streamline the permitting process for these types of installations (FERC, 2010). The systems are low profile and turbines are installed underwater without the need for a dam or other impoundment. As a result, projects to date have not realized the same level of public scrutiny as large conventional hydropower installations. In terms of environmental issues, hydrokinetic installations do not result in the blocking of waterways, and therefore do not have the same effects on hydrology or fisheries that occur with conventional hydropower. However, hydrokinetic turbines are expected to interfere with fish migration and passage, as fish could become trapped in turbine blades. Hydrokinetic facilities may also restrict the movement of river-borne vessels.

7.6 Geothermal

The risks of implementing geothermal power include public objections based on the potential interference with aesthetic resources and water resources. Aesthetic issues are a matter of perception and are difficult to address. Long-term degradation of groundwater quality due to geothermal power production has not been widely documented. However, short-term degradation may occur during the construction process. There is also a growing public awareness regarding potential for induction of seismic activity due to geothermal power production.

7.7 Solar Thermal

The risks of implementing solar thermal power include land use change and habitat loss, water use and consumption, interference with natural drainage patterns, and aesthetic concerns. Habitat loss can be substantial for large solar thermal projects, such as the Blythe Solar Power Project, which is expected to have a generation capacity of around 1,000 MW and would strip the vegetative habit of 11 square miles (BLM, 2010a). Water consumption rates for solar thermal are in line with other power generation technologies that utilize cooling towers, such as natural gas, but since the best solar thermal facility sites are typically located in the desert, sourcing the necessary water volumes can be problematic to impossible, and alternate cooling techniques might be required. Key concerns included potential for interference with Colorado River flows and potential for using up water that could otherwise be utilized for agricultural, residential, or other purposes. Aesthetic concerns are driven by public opinion and, with respect to solar thermal power, focus on the permanent change to the visual character of desert corridors.

Table 7-1 summarizes the risks for all technologies.

Table 7-1: Summary of Risks for Alternative Energy Technologies

Technology	Risks
Natural Gas	Legislative uncertainty regarding hydrofracking
Co-firing	Legislative uncertainty regarding renewable energy incentives
Nuclear	Security and safety concerns
Wind	Aesthetic concerns; Bird and bat strikes
Hydropower	Lengthy environmental review and approval processes
Geothermal	Aesthetic concerns; Induced seismic activity
Solar Thermal	Aesthetic concerns; Land use change and habitat loss

8 Expert Opinions

Expert opinions include the perspectives of stakeholders in industry, academia, and government.

8.1 Natural Gas

Expert opinions include the outlook of natural gas industry players and experts, most of which are currently expressing positive forecasts for future natural gas resource availability. The USGS recently estimated that the Marcellus Shale holds 84 Tcf of technically recoverable natural gas (Pierce, et al., 2011). Terry Engelder, a leading authority on Marcellus Shale and a professor of geosciences at Pennsylvania State University, has a significantly higher estimate. Engelder estimates that the formation holds 489 Tcf of recoverable natural gas (Engelder, 2009).

In response to concerns about the limitations of current infrastructure for natural gas transmission, a representative of a major pipeline company claims it is possible to increase the capacity of an existing pipeline by adding new compressor stations or, if necessary, installing new pipelines alongside existing pipelines (Langston, 2011).The collection networks from new natural gas wells can be connected to existing pipeline networks using “bolt on” manifolds between collection and transmission pipelines (Langston, 2011).

8.2 Co-firing

The opinions of plant operators and policy makers provide perspective on the sustainability of co-firing of coal and biomass. According to RAND’s interviews of plant operators, the long-term effects of biomass co-firing on existing process equipment are not known (Ortiz, et al., 2011). The managers of coal-fired power plants are reluctant to co-fire any type of biomass (woody or herbaceous), because their power plants were designed to burn coal exclusively. The long-term effects of biomass co-firing on installed process equipment are still not known since most testing has been on a relatively short time-scale.

The future of co-firing is dependent on the facilities being able to receive renewable energy credits (REC) to offset the higher costs of biomass systems in comparison to coal systems. Many states have RPSs, but only California and a region of New England have markets for RECs (Ortiz, et al., 2011). Unfortunately, these two areas of the country do not have a significant resource base of biomass, and the current market price of RECs in New England is too low to encourage utilities to switch to biomass (Ortiz, et al., 2011).

8.3 Nuclear

SMRs are an example of a Gen IV innovation and are receiving a lot of attention by nuclear industry experts. Some of the modular reactor designs that are currently under development are similar to Generation III or III+ light water reactors but are smaller in size. As a result of their smaller size, SMRs have a lower cost per plant, which makes them potentially viable in smaller markets or developing countries. The cost gap between SMRs and conventional large-scale nuclear reactors has narrowed as the cost of new Gen III+ plants has escalated substantially. Other advantages include efficiencies in fabrication and transportation and increased operation time between refueling. SMRs are also being mentioned as a possible replacement for aging coal facilities (DOE, 2011a). In this replacement scenario, SMRs may utilize some of the existing site infrastructure, which further reduces costs (Mowry, 2011).

According to nuclear industry analysts at Standard & Poor’s, the cost of natural gas needs to be higher than $6/MMBtu for new nuclear power generation to be economically favorable (2010). Overnight capital costs for nuclear facilities range from $3,000-5,000/kW, and the installation of cooling systems and other site-specific requirements can push those costs to as high as $6,000/kW. Estimated construction costs have been increasing at a rate of 15 percent per year (MIT, 2009). These high costs relative to other power production options have halted several projects and resulted in temporary setbacks at proposed new nuclear installations. In addition to the high capital costs associated with new nuclear reactor construction, the other dominant factor that has stalled an increase in nuclear capacity has been the low cost of natural gas.

8.4 Wind

The opinions of wind power experts include the outlooks of wind developers and industry associations. Fearful of entering into a serial boom-bust scenario, many wind developers are currently calling for additional federal policies to support continued wind development. Onshore wind development has, in some cases, reached cost competitiveness with natural gas based power production, on a per kWh basis. However, according to AWEA, wind power lacks predictable federal policies needed to drive consistent wind power growth.

Some analysts are predicting that wind growth may shift towards offshore installations in the near to midterm. Based largely on the recent release of the Obama Administration’s *A National Offshore Wind Strategy* (EERE, 2011), economists are anticipating a surge in offshore wind installations (Reuters, 2010). In terms of offshore wind farm locations, a review of U.S. permit applications, as well as analysis completed by NREL, indicate that most offshore wind projects in the near term will likely be in the Northeast and Mid-Atlantic regions, with additional projects considered in the Gulf Coast, Great Lakes, and West Coast. Water depth is, however, a key factor, and is expected to preclude near term deployment on the west coast, where deep water turbines are not yet readily or commercially available (NREL, 2010).

8.5 Hydropower

Expert opinions surrounding hydropower include the experience of USACE, EPRI projections, and NHA interests. Since 1999, the number of hours for forced outages for USACE hydropower assets has more than doubled as the age of the facilities continues to increase. Modernization efforts for some USACE assets could yield an 8 percent increase in electricity production output; however, federal funding for even the most promising rehabilitation projects is difficult to secure because of competing priorities. EPRI compares the potential expansion of hydropower, particularly hydrokinetics, to the expansion of wind energy that has taken place over the last 10 years. The expansion in the case of wind installations appears to be a combination of the commitment to research, development, demonstration, and deployment by the public and private sectors along with extensions to the production tax credit and clean renewable energy bond programs. In order to spur development of these projects, the NHA is lobbying to extend the same level of tax credits to hydropower that are available to other renewable sources. Currently, new hydropower electricity generation, either via efficiency gains and upgrades at conventional facilities or new hydrokinetic installations, qualifies for half of the value of the renewable electricity production tax credit (IRS, 2010).

8.6 Geothermal

Expert opinions regarding geothermal power include the outlook of geothermal industry players, who are currently expressing positive forecasts for geothermal power production. The surge in optimism comes after decades of sluggish interest in geothermal energy, and has been driven by recent pilot scale applications of new technologies as well as discovery of new resources. New technologies include enhanced geothermal systems (EGS). According to the U.S. Geological Survey (2008), EGS can reach a power capacity of 500 GW in the U.S. However, EGS is a nascent technology, and is still under development. A report by the Massachusetts Institute of Technology (MIT, 2006) estimates that full-scale implementation will not begin to occur for another 15 years.

8.7 Solar Thermal

The opinions of solar thermal power experts include predictions that many solar thermal projects will come online in 2012 through 2014, driven by long-term extensions of the federal solar tax investment credit and the associated deadline to initiate construction by the end of 2011 (IREC, 2011). The future of solar thermal power, beyond the current round of tax incentives, is uncertain, and the question remains as to whether or not the generation costs for solar thermal power will drop to levels that are able to support a self-sustaining market for utility-scale solar thermal power. While photovoltaic systems dropped significantly in price during 2008-2011, production of solar thermal collectors and associated materials is just starting to increase. According to the International Energy Agency (IEA) (IEA, 2009b), solar thermal investment costs range from $4,200/kW to $8,400/kW with electricity costs ranging from $0.17 to $0.25/kWh.

Hybrid facilities have been discussed to some degree in recent industry literature, including two fossil-solar thermal hybrid power plants that have been approved in California as well as support for biomass-solar thermal cogeneration. These hybrid technologies could support baseload electricity, but the research conducted in support of this analysis reveal that the two biomass-solar thermal facilities in California have not been constructed and are not currently being considered for permitting or approval.

Table 8-1 summarizes the expert opinions for all technologies.

Table 8-1: Summary of Expert Opinions for Alternative Energy Technologies

Technology	Expert Opinions
Natural Gas	Positive forecasts of Marcellus Shale resource base; Pipeline capacity can be increased easily
Co-firing	Unknown long term effects of biomass on systems designed to burn coal ; Future of co-firing depends on policy that favors renewables
Nuclear	Small modular reactors (SMR) have fewer barriers than large-scale nuclear power systems; Cost of natural gas is a determinant of growth in nuclear power capacity
Wind	Industry is fearful of boom and bust scenarios; New development may shift from onshore to offshore
Hydropower	Modernization of existing facilities is necessary, but a lower priority than other infrastructure improvements; Production tax credits will drive new hydropower capacity, including hydrokinetic power
Geothermal	Geothermal industry is optimistic about geothermal capacity growth; Enhanced geothermal systems (EGS) have a high capacity potential but are 15 years from implementation
Solar Thermal	Solar Thermal industry forecasts are optimistic and are based on extensions of tax incentives for renewable power; High capital costs and lengthy permitting approval will prevent near-term development of solar thermal power

9 Summary

This analysis provides insight into key criteria for the feasibility of seven types of energy technologies. These criteria include:

- Resource base
- Growth
- Environmental profile
- Cost profile
- Barriers to implementation
- Risks of implementation
- Expert opinions

Natural gas is seen as a cleaner burning and flexible alternative to other fossil fuels, and is used in residential, industrial, and transportation applications in addition to an expanding role in power production. New technologies have allowed increased domestic production of natural gas and the development of natural gas formations that were not previously viable. The projected supply contributions afforded by new natural gas plays may keep the price of natural gas relatively low for the foreseeable future. However, since natural gas is comprised mostly of CH_4, the control of fugitive emissions is imperative to reduce the GHG footprint of natural gas extraction, processing, and transport. This is especially true for unconventional wells that have high initial pressures and the potential for high emissions during well completion.

Co-firing is seen as a way of reducing the GHG emissions of existing coal-fired power plants without implementing carbon capture technology. However, the incorporation of biomass into an existing coal-fired system increases the complexity of feedstock acquisition. Further, the acquisition of biomass has unique GHG burdens that offset, in part, the GHG reductions from the displacement of coal with biomass. Due to the higher feedstock prices of biomass, the co-firing of biomass at a 10 percent share of feedstock energy can increase the COE by as much as 31 percent – a disproportionately large increase in comparison to the corresponding GHG reductions. Technical concerns include decreases in boiler efficiency and degradation of coal combustion byproducts that are typically used in the production of construction materials. Other risks include regulatory uncertainty; without policies that encourage the use of renewable feedstocks, there is no incentive for producers to invest in co-fired systems.

Nuclear power provides a stable source of baseload power in the U.S. with a GHG emissions footprint that is similar to that of most renewable power sources. In the last decade, nuclear power plants have had an average capacity factor 90 percent. Maintaining the existing share of the U.S. electricity demand with nuclear power depends on the number of existing facilities that receive operating license extensions and the number of planned and approved new reactors that are actually constructed. While the global supply of uranium is large and stable, the high initial capital investment required for the construction of new reactors, historically low natural gas prices have slowed the nuclear renaissance in the U.S. The storage of spent nuclear fuel also continues to be a major concern since progress on the Yucca Mountain nuclear repository was officially halted in 2010. The growth and perception of nuclear power is also impacted by the three nuclear events that have occurred within recent history: the 1979 Three Mile Island accident, the 1986 Chernobyl accident, and the 2011 Fukushima accident. While the chances of adverse nuclear events are small and newer nuclear technologies are inherently safer than older technologies, the scale of a nuclear event can have far-reaching environmental and societal risks.

Wind can be an important energy resource for the U.S., but as its contribution to total U.S. electricity generation increases, it will require a significant amount of fossil resources for backup power to maintain grid reliability. And while wind power has exhibited significant growth over the last decade, most of this growth was made possible through financial incentives such as temporary renewable energy tax credits. Technology advances that result in lower project costs and energy storage devices that enable better power reliability remain crucial research and development areas for the long-term integration of wind power.

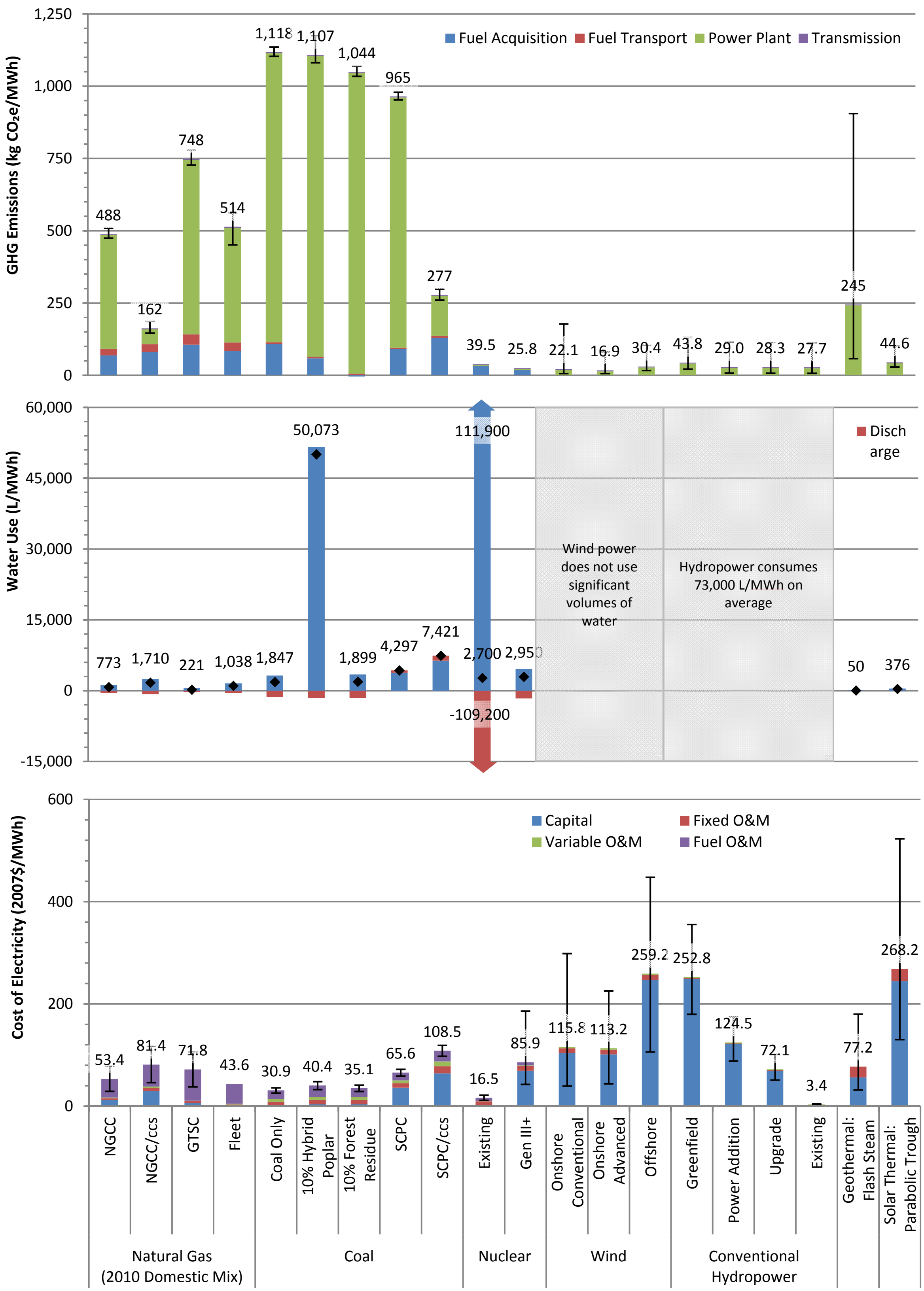
Hydropower is a proven technology that represents approximately 7 percent of U.S. electricity generation, but the resource base for large hydropower facilities has been fully developed and the growth potential for hydrokinetic hydropower is limited by the small capacities of hydrokinetic installations. There is potential for growth in the upgrading of existing power generation facilities and the addition of generation capability to existing dams. The GHG emissions of hydropower are low, but there are ecological impacts of hydropower that are outside the boundaries of the LCA performed. Further, the benefits that dams provide with respect to flood control, irrigation, and navigability are difficult to compare on the same basis as hydroelectric power generation, complicating the calculation of the costs of hydropower.

Geothermal power is a proven technology with a large resource base, and the use of flash steam technology has relatively low capital costs that translate to a competitive COE. However, the characteristics of geologic formations are highly variable and are a barrier to broad implementation of geothermal power. Further, the naturally-occurring CO_2 in geofluid leads to relatively high GHG emissions from geothermal power plants that use flash steam technology. In order for geothermal power to be a significant part of U.S. electricity generation, research and development efforts must find ways of cost-effectively mitigating the variability among geothermal formations and using energy conversion technologies that reduce (or prevent) the emission of CO_2 from geofluid.

Solar thermal power is viewed as a clean, renewable alternative to conventional fossil fuels for electricity generation. However, the resource base of solar thermal power is limited by several factors that inform the availability of direct sunlight at any given location. The best solar thermal resources are located in areas that are distant from existing population centers. There is potential for solar thermal power to support a significant portion of the U.S. electricity demand. However, the high cost of solar collectors to support utility level output, water scarcity in areas of high solar potential, and the lack of proximity of resources to population centers make it likely that high-quality solar thermal resources are expected to remain untapped for the foreseeable future. Hybrid facilities, which could support baseload electricity demands, have been discussed to a small degree in recent industry literature, including two fossil-solar thermal hybrid power plants that have been approved in California.

Key environmental and cost results for all technologies in this analysis are shown together in **Figure 9-1**.

Figure 9-1: Comparison of GHG, Water, and COE Results for Alternative Power Systems



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Appendix A
Detailed LCA Results

List of Tables

Table A-1: Detailed LCA Results – NGCC Power Using the 2010 Domestic NG Mix

Category (Units)	Material or Energy Flow	NGCC with 2010 Domestic Average NG					NGCC with CCS and 2010 Domestic Average NG				
		RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total
GHG (kg/MWh)	CO_2	2.08E+01	3.95E+00	3.93E+02	0.00E+00	4.18E+02	2.44E+01	4.62E+00	5.13E+01	0.00E+00	8.03E+01
	N_2O	6.73E-04	4.93E-06	1.51E-05	0.00E+00	6.93E-04	7.89E-04	5.78E-06	2.35E-05	0.00E+00	8.18E-04
	CH_4	1.91E+00	7.69E-01	5.94E-04	0.00E+00	2.68E+00	2.24E+00	9.01E-01	7.78E-04	0.00E+00	3.14E+00
	SF_6	2.33E-07	8.99E-09	3.42E-07	1.43E-04	1.44E-04	2.73E-07	1.05E-08	4.00E-07	1.43E-04	1.44E-04
	CO_2e (IPCC 2007 100-yr GWP)	6.88E+01	2.32E+01	3.93E+02	3.27E+00	4.88E+02	8.06E+01	2.71E+01	5.13E+01	3.27E+00	1.62E+02
Other Air (kg/MWh)	Pb	1.94E-06	1.65E-07	2.71E-06	0.00E+00	4.82E-06	2.27E-06	1.94E-07	3.09E-06	0.00E+00	5.56E-06
	Hg	7.18E-08	5.17E-09	2.46E-08	0.00E+00	1.02E-07	8.42E-08	6.06E-09	3.50E-08	0.00E+00	1.25E-07
	NH_3	1.10E-06	1.99E-06	1.88E-02	0.00E+00	1.88E-02	1.29E-06	2.33E-06	2.03E-02	0.00E+00	2.03E-02
	CO	4.35E-02	6.23E-04	3.12E-03	0.00E+00	4.72E-02	5.10E-02	7.31E-04	4.50E-03	0.00E+00	5.62E-02
	NO_X	4.82E-01	7.79E-04	3.05E-02	0.00E+00	5.13E-01	5.65E-01	9.13E-04	3.42E-02	0.00E+00	6.00E-01
	SO_2	5.87E-03	3.15E-04	1.19E-03	0.00E+00	7.37E-03	6.88E-03	3.69E-04	1.66E-03	0.00E+00	8.91E-03
	VOC	3.81E-01	1.59E-05	3.72E-05	0.00E+00	3.81E-01	4.47E-01	1.86E-05	4.74E-05	0.00E+00	4.47E-01
	PM	1.02E-03	6.50E-05	3.74E-04	0.00E+00	1.46E-03	1.19E-03	7.61E-05	5.53E-04	0.00E+00	1.82E-03
Solid Waste (kg/MWh)	Heavy metals to industrial soil	7.33E-03	2.83E-04	5.26E-04	0.00E+00	8.13E-03	8.59E-03	3.31E-04	5.62E-04	0.00E+00	9.48E-03
	Heavy metals to agricultural soil	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Water Use (L/MWh)	Withdrawal	1.81E+02	2.12E+00	1.04E+03	0.00E+00	1.22E+03	2.12E+02	2.48E+00	2.06E+03	0.00E+00	2.28E+03
	Discharge	2.11E+02	1.39E+00	2.36E+02	0.00E+00	4.48E+02	2.48E+02	1.63E+00	5.22E+02	0.00E+00	7.71E+02
	Consumption	-3.08E+01	7.30E-01	8.03E+02	0.00E+00	7.73E+02	-3.61E+01	8.56E-01	1.54E+03	0.00E+00	1.51E+03
Water Quality (kg/MWh)	Aluminum	4.45E-05	2.55E-06	2.15E-06	0.00E+00	4.92E-05	5.22E-05	2.99E-06	6.88E-06	0.00E+00	6.20E-05
	Arsenic (+V)	2.95E-06	1.37E-07	1.84E-07	0.00E+00	3.27E-06	3.45E-06	1.61E-07	3.25E-07	0.00E+00	3.94E-06
	Copper (+II)	3.84E-06	1.82E-07	2.36E-07	0.00E+00	4.25E-06	4.50E-06	2.14E-07	4.39E-07	0.00E+00	5.15E-06
	Iron	2.46E-04	9.80E-06	2.65E-05	0.00E+00	2.82E-04	2.88E-04	1.15E-05	4.54E-05	0.00E+00	3.45E-04
	Lead (+II)	4.50E-06	2.63E-07	2.92E-07	0.00E+00	5.05E-06	5.27E-06	3.09E-07	7.88E-07	0.00E+00	6.37E-06
	Manganese (+II)	2.68E-03	9.79E-08	2.16E-07	0.00E+00	2.68E-03	3.14E-03	1.15E-07	2.46E-07	0.00E+00	3.14E-03
	Nickel (+II)	1.11E-04	4.94E-06	7.22E-06	0.00E+00	1.24E-04	1.31E-04	5.79E-06	1.12E-05	0.00E+00	1.48E-04
	Strontium	1.52E-07	7.54E-09	5.66E-08	0.00E+00	2.16E-07	1.78E-07	8.84E-09	7.28E-08	0.00E+00	2.60E-07
	Zinc (+II)	7.95E-05	4.16E-06	4.37E-06	0.00E+00	8.80E-05	9.31E-05	4.88E-06	1.07E-05	0.00E+00	1.09E-04
	Ammonium/ammonia	1.81E-04	6.98E-06	1.32E-05	0.00E+00	2.01E-04	2.12E-04	8.18E-06	1.41E-05	0.00E+00	2.34E-04
	Hydrogen chloride	1.72E-11	7.34E-13	4.54E-12	0.00E+00	2.25E-11	2.02E-11	8.61E-13	5.48E-12	0.00E+00	2.65E-11
	Nitrogen (as total N)	8.74E-04	2.76E-08	5.14E-08	0.00E+00	8.74E-04	1.02E-03	3.24E-08	5.48E-08	0.00E+00	1.02E-03
	Phosphate	7.38E-09	2.97E-10	1.17E-08	0.00E+00	1.94E-08	8.65E-09	3.49E-10	1.33E-08	0.00E+00	2.23E-08
	Phosphorus	5.45E-05	2.45E-06	2.60E-06	0.00E+00	5.96E-05	6.39E-05	2.87E-06	7.10E-06	0.00E+00	7.39E-05
Resource Energy (MJ/MWh)	Crude oil	2.70E+00	1.78E-01	6.90E-01	0.00E+00	3.56E+00	3.16E+00	2.08E-01	1.08E+00	0.00E+00	4.45E+00
	Hard coal	1.33E+01	7.21E-01	2.59E+00	0.00E+00	1.66E+01	1.56E+01	8.46E-01	3.58E+00	0.00E+00	2.00E+01
	Lignite	5.22E-03	2.56E-04	6.36E-02	0.00E+00	6.91E-02	6.12E-03	3.00E-04	7.35E-02	0.00E+00	7.99E-02
	Natural gas	9.44E+03	4.55E-01	1.11E+00	0.00E+00	9.44E+03	1.11E+04	5.34E-01	1.56E+00	0.00E+00	1.11E+04
	Uranium	3.10E-02	1.50E-03	2.06E-01	0.00E+00	2.38E-01	3.64E-02	1.76E-03	2.35E-01	0.00E+00	2.73E-01
	Total resource energy	9.45E+03	1.36E+00	4.66E+00	0.00E+00	9.46E+03	1.11E+04	1.59E+00	6.52E+00	0.00E+00	1.11E+04
Energy Return on Investment		N/A	N/A	N/A	N/A	61.4%	N/A	N/A	N/A	N/A	0.481

Table A-2: Detailed LCA Results – GTSC and Fleet Average Natural Gas Power Using the 2010 Domestic NG Mix

Category (Units)	Material or Energy Flow	GTSC with 2010 Domestic Average NG					Fleet Average Baseload NG Power with 2010 Domestic Average NG				
		RMA	RMT	ECF	PT	Total	RMA	RMT	ECF	PT	Total
GHG (kg/MWh)	CO_2	3.21E+01	6.08E+00	6.04E+02	0.00E+00	6.42E+02	2.57E+01	4.86E+00	3.97E+02	0.00E+00	4.27E+02
	N_2O	1.04E-03	7.59E-06	1.30E-05	0.00E+00	1.06E-03	8.29E-04	6.07E-06	1.11E-03	0.00E+00	1.94E-03
	CH_4	2.94E+00	1.18E+00	1.20E-03	0.00E+00	4.13E+00	2.35E+00	9.47E-01	1.11E-02	0.00E+00	3.31E+00
	SF_6	3.59E-07	1.38E-08	1.97E-08	1.43E-04	1.44E-04	2.87E-07	1.11E-08	0.00E+00	1.43E-04	1.44E-04
	CO_2e (IPCC 2007 100-yr GWP)	1.06E+02	3.57E+01	6.04E+02	3.27E+00	7.48E+02	8.47E+01	2.85E+01	3.97E+02	3.27E+00	5.14E+02
Other Air (kg/MWh)	Pb	2.99E-06	2.55E-07	6.27E-07	0.00E+00	3.87E-06	2.39E-06	2.04E-07	0.00E+00	0.00E+00	2.59E-06
	Hg	1.11E-07	7.96E-09	7.08E-09	0.00E+00	1.26E-07	8.85E-08	6.37E-09	0.00E+00	0.00E+00	9.48E-08
	NH_3	1.70E-06	3.07E-06	2.90E-02	0.00E+00	2.90E-02	1.36E-06	2.45E-06	0.00E+00	0.00E+00	3.81E-06
	CO	6.70E-02	9.61E-04	5.48E-03	0.00E+00	7.34E-02	5.36E-02	7.68E-04	3.35E-04	0.00E+00	5.47E-02
	NO_X	7.42E-01	1.20E-03	4.87E-02	0.00E+00	7.92E-01	5.93E-01	9.59E-04	2.95E-01	0.00E+00	8.89E-01
	SO_2	9.05E-03	4.85E-04	1.53E-03	0.00E+00	1.11E-02	7.23E-03	3.88E-04	4.14E-03	0.00E+00	1.18E-02
	VOC	5.87E-01	2.45E-05	1.64E-04	0.00E+00	5.87E-01	4.69E-01	1.96E-05	0.00E+00	0.00E+00	4.69E-01
	PM	1.57E-03	1.00E-04	5.77E-04	0.00E+00	2.25E-03	1.25E-03	8.00E-05	0.00E+00	0.00E+00	1.33E-03
Solid Waste (kg/MWh)	Heavy metals to industrial soil	1.13E-02	4.36E-04	6.22E-04	0.00E+00	1.23E-02	9.02E-03	3.48E-04	0.00E+00	0.00E+00	9.37E-03
	Heavy metals to agricultural soil	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Water Use (L/MWh)	Withdrawal	2.78E+02	3.26E+00	5.07E+00	0.00E+00	2.87E+02	2.22E+02	2.61E+00	1.12E+03	0.00E+00	1.34E+03
	Discharge	3.26E+02	2.14E+00	4.03E+00	0.00E+00	3.32E+02	2.60E+02	1.71E+00	2.52E+02	0.00E+00	5.14E+02
	Consumption	-4.75E+01	1.12E+00	1.03E+00	0.00E+00	-4.53E+01	-3.79E+01	8.99E-01	8.63E+02	0.00E+00	8.26E+02
Water Quality (kg/MWh)	Aluminum	6.86E-05	3.92E-06	6.64E-08	0.00E+00	7.26E-05	5.48E-05	3.14E-06	0.00E+00	0.00E+00	5.80E-05
	Arsenic (+V)	4.54E-06	2.12E-07	1.68E-07	0.00E+00	4.92E-06	3.63E-06	1.69E-07	0.00E+00	0.00E+00	3.80E-06
	Copper (+II)	5.91E-06	2.81E-07	6.02E-07	0.00E+00	6.79E-06	4.72E-06	2.24E-07	0.00E+00	0.00E+00	4.95E-06
	Iron	3.79E-04	1.51E-05	4.07E-05	0.00E+00	4.35E-04	3.03E-04	1.21E-05	0.00E+00	0.00E+00	3.15E-04
	Lead (+II)	6.93E-06	4.06E-07	1.45E-07	0.00E+00	7.48E-06	5.54E-06	3.24E-07	0.00E+00	0.00E+00	5.86E-06
	Manganese (+II)	4.13E-03	1.51E-07	3.73E-07	0.00E+00	4.13E-03	3.30E-03	1.21E-07	0.00E+00	0.00E+00	3.30E-03
	Nickel (+II)	1.72E-04	7.60E-06	6.74E-06	0.00E+00	1.86E-04	1.37E-04	6.08E-06	0.00E+00	0.00E+00	1.43E-04
	Strontium	2.34E-07	1.16E-08	2.41E-06	0.00E+00	2.65E-06	1.87E-07	9.29E-09	0.00E+00	0.00E+00	1.97E-07
	Zinc (+II)	1.22E-04	6.42E-06	2.00E-06	0.00E+00	1.31E-04	9.79E-05	5.13E-06	0.00E+00	0.00E+00	1.03E-04
	Ammonium/ammonia	2.79E-04	1.08E-05	1.63E-05	0.00E+00	3.06E-04	2.23E-04	8.60E-06	0.00E+00	0.00E+00	2.31E-04
	Hydrogen chloride	2.65E-11	1.13E-12	7.55E-11	0.00E+00	1.03E-10	2.12E-11	9.04E-13	0.00E+00	0.00E+00	2.21E-11
	Nitrogen (as total N)	1.35E-03	4.26E-08	6.07E-08	0.00E+00	1.35E-03	1.08E-03	3.40E-08	0.00E+00	0.00E+00	1.08E-03
	Phosphate	1.14E-08	4.58E-10	3.02E-07	0.00E+00	3.14E-07	9.09E-09	3.66E-10	0.00E+00	0.00E+00	9.45E-09
	Phosphorus	8.40E-05	3.78E-06	1.25E-07	0.00E+00	8.79E-05	6.72E-05	3.02E-06	0.00E+00	0.00E+00	7.02E-05
Resource Energy (MJ/MWh)	Crude oil	4.16E+00	2.74E-01	1.21E+00	0.00E+00	5.64E+00	3.32E+00	2.19E-01	0.00E+00	0.00E+00	3.54E+00
	Hard coal	2.05E+01	1.11E+00	4.06E+00	0.00E+00	2.56E+01	1.64E+01	8.88E-01	0.00E+00	0.00E+00	1.72E+01
	Lignite	8.04E-03	3.95E-04	1.63E-01	0.00E+00	1.71E-01	6.43E-03	3.15E-04	0.00E+00	0.00E+00	6.74E-03
	Natural gas	1.45E+04	7.02E-01	1.22E+01	0.00E+00	1.46E+04	1.16E+04	5.61E-01	0.00E+00	0.00E+00	1.16E+04
	Uranium	4.78E-02	2.32E-03	3.77E-01	0.00E+00	4.27E-01	3.82E-02	1.85E-03	0.00E+00	0.00E+00	4.01E-02
	Total resource energy	1.46E+04	2.09E+00	1.81E+01	0.00E+00	1.46E+04	1.16E+04	1.67E+00	0.00E+00	0.00E+00	1.16E+04
Energy Return on Investment		N/A	N/A	N/A	N/A	32.8%	N/A	N/A	N/A	N/A	0.447

Table A-3: Detailed LCA Results – Biomass Co-firing

Category	Metric	100% Illinois No. 6 Coal					10% Hybrid Poplar					10% Forest Residue				
		RMA	RMT	ECF	T&D	Total	RMA	RMT	ECF	T&D	Total	RMA	RMT	ECF	T&D	Total
GHG Emissions (kg/MWh)	CO_2	1.144E+01	5.712E+00	1.000E+03	0	1.018E+03	-4.425E+01	5.565E+00	1.036E+03	0	9.974E+02	-9.208E+01	5.565E+00	1.036E+03	0	9.496E+02
	N_2O	2.005E-04	1.392E-04	6.913E-08	0	3.398E-04	5.045E-02	1.356E-04	2.174E-04	0	5.080E-02	2.954E-04	1.356E-04	2.174E-04	0	6.483E-04
	CH_4	3.863E+00	6.585E-03	1.009E-06	0	3.870E+00	3.516E+00	7.076E-03	1.257E-01	0	3.649E+00	3.507E+00	7.076E-03	1.257E-01	0	3.639E+00
	SF_6	2.051E-06	2.345E-11	0	1.433E-04	1.454E-04	1.942E-06	2.599E-11	1.609E-06	1.433E-04	1.469E-04	1.859E-06	2.599E-11	1.609E-06	1.433E-04	1.468E-04
	CO_2e (IPCC 2007 100-yr GWP)	1.081E+02	5.918E+00	1.000E+03	3.268E+00	1.118E+03	5.874E+01	5.783E+00	1.039E+03	3.268E+00	1.107E+03	-4.278E+00	5.783E+00	1.039E+03	3.268E+00	1.044E+03
Other Air Emissions (kg/MWh)	Pb	1.487E-06	6.474E-08	2.635E-09	0	1.555E-06	3.054E-06	1.185E-07	1.246E-07	0	3.297E-06	1.569E-06	1.185E-07	1.246E-07	0	1.812E-06
	Hg	2.649E-07	5.107E-09	3.761E-05	0	3.788E-05	3.617E-07	8.080E-09	3.426E-05	0	3.463E-05	2.543E-07	8.080E-09	3.426E-05	0	3.452E-05
	NH_3	2.545E-05	2.002E-04	0	0	2.257E-04	8.475E-03	1.842E-04	7.287E-06	0	8.666E-03	3.265E-05	1.842E-04	7.287E-06	0	2.242E-04
	CO	1.003E-02	1.683E-02	1.527E+00	0	1.554E+00	3.525E-02	1.631E-02	1.445E+00	0	1.497E+00	2.511E-02	1.631E-02	1.445E+00	0	1.486E+00
	NO_x	1.683E-02	1.406E-02	1.072E+00	0	1.103E+00	4.049E-02	1.313E-02	9.277E-01	0	9.813E-01	1.831E-02	1.313E-02	9.277E-01	0	9.591E-01
	SO_x	3.326E-02	5.519E-03	4.123E-01	0	4.511E-01	4.704E-02	5.879E-03	3.996E-01	0	4.525E-01	3.329E-02	5.879E-03	3.996E-01	0	4.388E-01
	VOC	2.870E-03	2.615E-03	-5.160E-15	0	5.485E-03	5.002E+00	2.793E-03	3.303E-02	0	5.038E+00	4.705E-03	2.793E-03	3.303E-02	0	4.053E-02
	PM	1.490E-03	1.792E-02	2.597E-01	0	2.791E-01	7.606E-02	1.635E-02	2.409E-01	0	3.333E-01	6.791E-02	1.635E-02	2.409E-01	0	3.252E-01
Solid Waste (kg/MWh)	Heavy Metals to Industrial Soil	6.415E-02	6.063E-05	0	0	6.421E-02	6.101E-02	6.673E-05	5.032E-02	0	1.114E-01	5.819E-02	6.673E-05	5.032E-02	0	1.086E-01
	Heavy Metals to Agricultural Soil	6.322E-16	0	0	0	6.322E-16	1.536E-03	0	0	0	1.536E-03	5.729E-16	0	0	0	5.729E-16
Water Use (L/MWh)	Water withdrawal	4.920E+02	4.897E+00	2.702E+03	0	3.199E+03	4.864E+04	5.790E+00	2.978E+03	0	5.163E+04	4.493E+02	5.790E+00	2.978E+03	0	3.433E+03
	Water discharge	7.417E+02	1.940E+00	6.085E+02	0	1.352E+03	6.932E+02	2.142E+00	8.594E+02	0	1.555E+03	6.729E+02	2.142E+00	8.594E+02	0	1.534E+03
	Water consumption	-2.496E+02	2.957E+00	2.093E+03	0	1.847E+03	4.795E+04	3.648E+00	2.119E+03	0	5.007E+04	-2.236E+02	3.648E+00	2.119E+03	0	1.899E+03
Water Quality (kg/MWh)	Aluminum	6.029E-05	6.700E-04	0	0	7.303E-04	6.365E-04	7.112E-04	1.152E-05	0	1.359E-03	6.021E-04	7.112E-04	1.152E-05	0	1.325E-03
	Arsenic (+V)	1.635E-05	1.908E-05	0	0	3.543E-05	3.367E-05	2.026E-05	1.180E-05	0	6.573E-05	3.042E-05	2.026E-05	1.180E-05	0	6.248E-05
	Copper (+II)	1.985E-05	2.796E-05	0	0	4.781E-05	5.180E-05	2.969E-05	1.407E-05	0	9.556E-05	4.086E-05	2.969E-05	1.407E-05	0	8.461E-05
	Iron	5.077E-04	1.473E-03	4.299E-08	0	1.981E-03	2.145E-03	1.568E-03	2.420E-04	0	3.955E-03	1.630E-03	1.568E-03	2.420E-04	0	3.440E-03
	Lead (+II)	5.565E-06	6.426E-05	5.480E-10	0	6.983E-05	6.835E-05	6.823E-05	7.300E-07	0	1.373E-04	5.764E-05	6.823E-05	7.300E-07	0	1.266E-04
	Manganese (+II)	2.308E-05	2.169E-07	0	0	2.330E-05	2.253E-05	2.398E-07	9.975E-05	0	1.225E-04	2.099E-05	2.398E-07	9.975E-05	0	1.210E-04
	Nickel (+II)	7.207E-04	5.084E-04	7.435E-11	0	1.229E-03	1.126E-03	5.397E-04	5.383E-04	0	2.204E-03	1.069E-03	5.397E-04	5.383E-04	0	2.147E-03
	Strontium	7.849E-07	6.481E-07	0	0	1.433E-06	2.810E-06	7.364E-07	3.938E-07	0	3.940E-06	1.095E-06	7.364E-07	3.938E-07	0	2.225E-06
	Zinc (+II)	2.532E-04	8.823E-04	3.275E-10	0	1.136E-03	1.009E-03	9.366E-04	1.515E-04	0	2.097E-03	9.515E-04	9.366E-04	1.515E-04	0	2.040E-03
	Ammonium/Ammonia	2.214E-03	7.244E-03	4.179E-08	0	9.457E-03	1.074E-02	7.691E-03	1.339E-03	0	1.977E-02	7.936E-03	7.691E-03	1.339E-03	0	1.697E-02
	Hydrogen chloride	1.348E-10	1.930E-10	0	0	3.278E-10	3.751E-10	2.062E-10	9.175E-11	0	6.730E-10	2.691E-10	2.062E-10	9.175E-11	0	5.670E-10
	Nitrogen (as total N)	8.926E-05	2.608E-08	0	0	8.929E-05	9.918E-04	9.827E-07	9.968E-05	0	1.092E-03	8.090E-05	9.827E-07	9.968E-05	0	1.816E-04
	Phosphate	1.331E-07	6.532E-08	0	0	1.984E-07	4.078E-06	9.672E-08	4.476E-08	0	4.220E-06	1.380E-07	9.672E-08	4.476E-08	0	2.795E-07
	Phosphorus	5.830E-05	6.390E-04	4.478E-09	0	6.973E-04	8.287E-03	6.789E-04	1.032E-05	0	8.976E-03	5.760E-04	6.789E-04	1.032E-05	0	1.265E-03
Resources (MJ/MWh)	Crude oil	1.077E+01	5.908E+01	2.919E-03	0	6.985E+01	7.509E+01	6.311E+01	2.834E+00	0	1.410E+02	5.769E+01	6.311E+01	2.834E+00	0	1.236E+02
	Hard coal	1.187E+04	1.631E+00	1.273E-02	0	11,875	1.078E+04	1.973E+00	2.447E+01	0	1.080E+04	1.076E+04	1.973E+00	2.447E+01	0	1.079E+04
	Lignite	5.520E-02	2.798E-01	0	0	0	2.581E+00	3.193E-01	1.284E-02	0	2.913E+00	7.566E-02	3.193E-01	1.284E-02	0	4.078E-01
	Natural gas	4.586E+01	7.159E+00	2.539E-03	0	53	1.446E+02	7.939E+00	3.005E+02	0	4.531E+02	4.713E+01	7.939E+00	3.005E+02	0	3.556E+02
	Uranium	2.443E-01	1.221E+00	0	0	1	4.346E+00	1.363E+00	4.742E-02	0	5.756E+00	5.623E-01	1.363E+00	4.742E-02	0	1.973E+00
	Biomass	0	0	0	0	0	1.181E+03	0	0	0	1.181E+03	1.181E+03	0	0	0	1.181E+03
Energy Return on Investment (dimensionless)		N/A	N/A	N/A	N/A	0.43	N/A	N/A	N/A	N/A	0.40	N/A	N/A	N/A	N/A	0.41

Table A-4: Detailed LCA Results – Existing Nuclear with Default Enrichment & No Long Term Waste Management

Category (Units)	Material or Energy Flow	RMA	RMT	ECF	PT	Total
GHG (kg/MWh)	CO_2	3.07E+01	6.64E-05	2.98E+00	0.00E+00	3.37E+01
	N_2O	4.93E-04	1.45E-09	1.75E-05	0.00E+00	5.11E-04
	CH_4	8.67E-02	2.72E-07	6.14E-03	0.00E+00	9.28E-02
	SF_6	1.83E-07	7.99E-17	1.99E-08	1.43E-04	1.44E-04
	CO_2e (IPCC 2007 100-yr. GWP)	3.31E+01	7.36E-05	3.14E+00	3.27E+00	3.95E+01
Other Air (kg/MWh)	Pb	1.52E-06	9.59E-13	4.98E-07	0.00E+00	2.02E-06
	Hg	3.32E-07	7.96E-14	1.80E-08	0.00E+00	3.50E-07
	NH_3	1.58E-03	5.43E-10	1.52E-05	0.00E+00	1.59E-03
	CO	2.25E-02	9.53E-08	1.43E-02	0.00E+00	3.68E-02
	NO_X	7.36E-02	5.83E-08	2.35E-03	0.00E+00	7.59E-02
	SO_2	1.86E-01	1.12E-07	6.08E-03	0.00E+00	1.92E-01
	VOC	8.19E-03	1.19E-07	1.76E-03	0.00E+00	9.95E-03
	PM	3.91E-03	9.77E-10	3.25E-04	0.00E+00	4.23E-03
Solid Waste (kg/MWh)	Heavy Metals to Industrial Soil	4.70E+01	2.59E-09	6.51E-04	0.00E+00	4.70E+01
	Heavy Metals to Agricultural Soil	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Water Use (L/MWh)	Withdrawal	3.75E+02	1.57E-04	1.12E+05	0.00E+00	1.12E+05
	Discharge	2.96E+02	3.82E-05	1.09E+05	0.00E+00	1.09E+05
	Consumption	7.95E+01	1.19E-04	2.59E+03	0.00E+00	2.67E+03
Water Quality (kg/MWh)	Aluminum	6.77E-06	0.00E+00	2.73E-07	0.00E+00	7.04E-06
	Arsenic (+V)	7.20E-06	8.83E-10	5.30E-03	0.00E+00	5.30E-03
	Copper (+II)	5.64E-06	1.29E-09	6.28E-03	0.00E+00	6.29E-03
	Iron	3.75E-04	6.60E-08	8.73E-02	0.00E+00	8.77E-02
	Lead (+II)	8.06E-06	2.97E-09	3.17E-05	0.00E+00	3.97E-05
	Manganese (+II)	2.70E-04	3.96E-12	2.43E-06	0.00E+00	2.72E-04
	Nickel (+II)	4.98E-01	2.35E-08	2.57E-04	0.00E+00	4.98E-01
	Strontium	5.30E-05	2.17E-11	2.63E-07	0.00E+00	5.33E-05
	Zinc (+II)	1.23E-04	4.09E-08	6.58E-02	0.00E+00	6.59E-02
	Ammonium/Ammonia	1.15E+00	3.35E-07	3.58E-03	0.00E+00	1.15E+00
	Hydrogen Chloride	3.14E-09	8.31E-15	8.98E-11	0.00E+00	3.23E-09
	Nitrogen (as Total N)	1.61E-05	0.00E+00	8.36E-07	0.00E+00	1.69E-05
	Phosphate	5.61E-06	9.82E-13	2.33E-08	0.00E+00	5.64E-06
	Phosphorus	7.65E-05	2.96E-08	1.50E-03	0.00E+00	1.58E-03
Resource Energy (MJ/MWh)	Crude Oil	1.94E+01	2.91E-03	3.15E+01	0.00E+00	5.08E+01
	Hard Coal	2.88E+02	3.90E-05	2.41E+00	0.00E+00	2.91E+02
	Lignite	1.59E+00	2.89E-06	6.29E-02	0.00E+00	1.65E+00
	Natural Gas	1.05E+03	4.11E-04	1.34E+01	0.00E+00	1.07E+03
	Uranium	1.07E+01	2.98E-05	3.51E-01	0.00E+00	1.10E+01
	Total Resource Energy	1.37E+03	3.40E-03	4.77E+01	0.00E+00	1.42E+03
Energy Return on Investment		N/A	N/A	N/A	N/A	2.53E+00

Table A-5: Detailed LCA Results – Gen III+ Nuclear with Default Enrichment & No Long Term Waste Management

Category (Units)	Material or Energy Flow	RMA	RMT	ECF	PT	Total
GHG (kg/MWh)	CO_2	1.80E+01	3.88E-05	3.01E+00	0.00E+00	2.10E+01
	N_2O	2.88E-04	8.46E-10	1.73E-05	0.00E+00	3.06E-04
	CH_4	5.07E-02	1.59E-07	9.87E-03	0.00E+00	6.05E-02
	SF_6	1.07E-07	4.67E-17	4.87E-08	1.43E-04	1.43E-04
	CO_2e (IPCC 2007 100-yr. GWP)	1.93E+01	4.30E-05	3.26E+00	3.27E+00	2.58E+01
Other Air (kg/MWh)	Pb	8.89E-07	5.60E-13	2.36E-07	0.00E+00	1.12E-06
	Hg	1.94E-07	4.65E-14	1.67E-08	0.00E+00	2.11E-07
	NH_3	9.22E-04	3.17E-10	1.20E-05	0.00E+00	9.34E-04
	CO	1.32E-02	5.57E-08	1.26E-02	0.00E+00	2.57E-02
	NO_X	4.30E-02	3.41E-08	2.05E-02	0.00E+00	6.35E-02
	SO_2	1.09E-01	6.53E-08	6.92E-03	0.00E+00	1.16E-01
	VOC	4.79E-03	6.96E-08	3.51E-03	0.00E+00	8.30E-03
	PM	2.28E-03	5.71E-10	9.73E-04	0.00E+00	3.26E-03
Solid Waste (kg/MWh)	Heavy Metals to Industrial Soil	2.75E+01	1.51E-09	1.54E-03	0.00E+00	2.75E+01
	Heavy Metals to Agricultural Soil	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Water Use (L/MWh)	Withdrawal	2.19E+02	9.17E-05	4.38E+03	0.00E+00	4.60E+03
	Discharge	1.73E+02	2.23E-05	1.48E+03	0.00E+00	1.65E+03
	Consumption	4.64E+01	6.94E-05	2.90E+03	0.00E+00	2.94E+03
Water Quality (kg/MWh)	Aluminum	3.95E-06	0.00E+00	1.66E-06	0.00E+00	5.62E-06
	Arsenic (+V)	4.21E-06	5.16E-10	7.95E-06	0.00E+00	1.22E-05
	Copper (+II)	3.30E-06	7.56E-10	5.41E-05	0.00E+00	5.74E-05
	Iron	2.19E-04	3.86E-08	1.22E-03	0.00E+00	1.44E-03
	Lead (+II)	4.71E-06	1.74E-09	2.57E-05	0.00E+00	3.04E-05
	Manganese (+II)	1.58E-04	2.32E-12	6.13E-06	0.00E+00	1.64E-04
	Nickel (+II)	2.91E-01	1.38E-08	2.19E-04	0.00E+00	2.91E-01
	Strontium	3.10E-05	1.27E-11	1.99E-07	0.00E+00	3.12E-05
	Zinc (+II)	7.20E-05	2.39E-08	5.63E-04	0.00E+00	6.35E-04
	Ammonium/Ammonia	6.72E-01	1.96E-07	3.32E-03	0.00E+00	6.76E-01
	Hydrogen Chloride	1.84E-09	4.86E-15	7.43E-11	0.00E+00	1.91E-09
	Nitrogen (as Total N)	9.38E-06	0.00E+00	1.82E-03	0.00E+00	1.83E-03
	Phosphate	3.28E-06	5.74E-13	9.73E-09	0.00E+00	3.29E-06
	Phosphorus	4.47E-05	1.73E-08	1.05E-03	0.00E+00	1.10E-03
Resource Energy (MJ/MWh)	Crude Oil	1.13E+01	1.70E-03	2.58E+01	0.00E+00	3.71E+01
	Hard Coal	1.69E+02	2.28E-05	3.85E+00	0.00E+00	1.72E+02
	Lignite	9.28E-01	1.69E-06	9.00E-02	0.00E+00	1.02E+00
	Natural Gas	6.16E+02	2.40E-04	2.60E+01	0.00E+00	6.42E+02
	Uranium	6.23E+00	1.74E-05	2.58E-01	0.00E+00	6.49E+00
	Total Resource Energy	8.03E+02	1.98E-03	5.60E+01	0.00E+00	8.59E+02
Energy Return on Investment		N/A	N/A	N/A	N/A	4.19E+00

Table A-6: Detailed LCA Results – Onshore Conventional Wind Power

Category (Units)	Material or Energy Flow	ECF																	
		Switchyard	Trunkline				Recycling			Domestic Turbine MFG					Foreign Turbine MFG				
			Electricity	Aluminum Sheet	Cold Rolled Steel	Concrete	Aluminum	Copper	Steel	Rotor	Tower	Transport	Nacelle	Transformer	Rotor	Tower	Transport	Nacelle	Transformer
GHG (kg/MWh)	CO_2	6.00E-02	6.13E-02	3.89E-01	3.80E-01	4.90E-02	-1.59E-01	-6.37E-01	-1.62E+00	7.02E-01	7.24E-01	2.80E-07	2.91E+00	1.41E-01	8.58E-01	8.85E-01	8.74E+00	3.55E+00	1.72E-01
	N_2O	1.27E-06	9.69E-07	8.43E-06	2.47E-06	0.00E+00	-2.46E-07	-2.79E-05	-1.67E-06	1.52E-04	5.27E-06	7.40E-12	8.89E-05	2.34E-06	1.86E-04	6.44E-06	2.15E-04	1.09E-04	2.86E-06
	CH_4	9.82E-05	1.85E-04	6.17E-04	4.46E-04	0.00E+00	-6.72E-04	-8.74E-04	-6.84E-04	2.19E-03	9.60E-04	8.17E-10	7.51E-03	2.78E-04	2.68E-03	1.17E-03	9.90E-03	9.18E-03	3.40E-04
	SF_6	1.72E-09	1.29E-08	4.93E-11	2.76E-12	0.00E+00	0.00E+00	-3.17E-11	0.00E+00	3.71E-08	1.26E-08	8.98E-19	4.30E-07	2.33E-12	4.54E-08	1.54E-08	2.74E-12	5.26E-07	2.85E-12
	CO_2e (IPCC 2007 100-yr GWP)	6.29E-02	6.65E-02	4.07E-01	3.92E-01	4.90E-02	-1.76E-01	-6.67E-01	-1.64E+00	8.03E-01	7.50E-01	3.03E-07	3.13E+00	1.49E-01	9.81E-01	9.17E-01	9.05E+00	3.83E+00	1.82E-01
Other Air (kg/MWh)	Pb	3.25E-07	4.06E-10	5.16E-08	6.86E-07	0.00E+00	-3.49E-08	-1.87E-05	-9.70E-09	1.62E-07	1.20E-06	7.01E-14	4.59E-07	1.20E-06	1.97E-07	1.47E-06	3.29E-08	5.61E-07	1.46E-06
	Hg	5.02E-10	1.13E-09	3.62E-09	8.77E-10	0.00E+00	-1.10E-09	-4.25E-09	-5.21E-09	9.17E-09	2.64E-09	3.92E-15	5.23E-08	1.50E-09	1.12E-08	3.23E-09	2.73E-09	6.40E-08	1.83E-09
	NH_3	2.39E-07	5.79E-08	1.72E-06	1.24E-06	0.00E+00	-9.15E-08	-4.52E-06	-9.46E-07	1.36E-06	2.22E-06	2.22E-12	4.15E-06	7.14E-07	1.66E-06	2.71E-06	3.17E-04	5.08E-06	8.73E-07
	CO	3.34E-04	1.19E-05	3.59E-03	3.61E-03	6.32E-05	-1.22E-04	-6.03E-04	-1.93E-02	1.11E-03	6.32E-03	6.71E-10	3.04E-03	7.80E-04	1.36E-03	7.73E-03	2.38E-02	3.71E-03	9.54E-04
	NOX	1.07E-04	9.39E-05	5.32E-04	7.20E-04	1.50E-04	-2.48E-04	-1.45E-03	-1.79E-03	1.23E-03	1.35E-03	2.30E-10	4.47E-03	3.38E-04	1.50E-03	1.65E-03	2.13E-02	5.47E-03	4.13E-04
	SO_2	1.97E-04	1.96E-04	1.46E-03	5.26E-04	1.14E-04	-1.31E-03	-2.30E-03	-3.12E-03	2.45E-03	1.11E-03	4.21E-10	8.54E-03	6.18E-04	3.00E-03	1.36E-03	3.83E-03	1.04E-02	7.55E-04
	VOC	1.46E-05	1.66E-05	7.12E-05	5.42E-05	0.00E+00	-5.14E-05	-1.86E-04	-6.79E-04	9.19E-04	1.11E-04	3.10E-10	9.75E-04	6.45E-05	1.12E-03	1.36E-04	4.08E-03	1.19E-03	7.88E-05
	PM	9.07E-05	2.51E-06	7.07E-04	2.32E-04	1.46E-04	-3.17E-05	-9.40E-04	-2.37E-04	9.79E-04	4.08E-04	2.04E-11	1.02E-03	1.97E-04	1.20E-03	4.99E-04	3.35E-05	1.25E-03	2.41E-04
Solid Waste (kg/MWh)	Heavy metals to industrial soil	5.39E-05	4.04E-04	1.74E-06	6.52E-07	0.00E+00	0.00E+00	-3.26E-06	0.00E+00	1.16E-03	3.96E-04	2.30E-12	1.35E-02	4.55E-07	1.42E-03	4.84E-04	2.34E-05	1.65E-02	5.57E-07
	Heavy metals to agricultural soil	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Water Use (L/MWh)	Withdrawal	6.53E-01	2.13E+00	2.23E+00	8.74E-01	2.10E-02	0.00E+00	-1.12E+01	0.00E+00	9.23E+00	3.61E+00	8.78E-07	7.55E+01	8.21E-01	1.13E+01	4.41E+00	5.38E+00	9.22E+01	1.00E+00
	Discharge	5.50E-01	1.97E+00	1.59E+00	8.03E-01	0.00E+00	0.00E+00	-9.61E+00	0.00E+00	7.77E+00	3.33E+00	1.41E-10	6.81E+01	6.84E-01	9.50E+00	4.06E+00	1.31E+00	8.33E+01	8.37E-01
	Consumption	1.02E-01	1.64E-01	6.35E-01	7.13E-02	2.10E-02	0.00E+00	-1.59E+00	0.00E+00	1.46E+00	2.85E-01	8.78E-07	7.36E+00	1.37E-01	1.78E+00	3.49E-01	4.07E+00	9.00E+00	1.67E-01
Water Quality (kg/MWh)	Aluminum	1.16E-09	8.70E-09	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.53E-08	8.51E-09	0.00E+00	2.91E-07	0.00E+00	3.09E-08	1.04E-08	0.00E+00	3.55E-07	0.00E+00
	Arsenic (+V)	4.14E-08	9.44E-08	1.34E-08	3.06E-09	0.00E+00	-4.31E-08	-1.70E-08	0.00E+00	3.01E-07	9.76E-08	2.17E-12	3.16E-06	1.97E-07	3.68E-07	1.19E-07	3.03E-05	3.87E-06	2.41E-07
	Copper (+II)	1.37E-07	1.12E-07	2.44E-08	1.17E-08	0.00E+00	-3.36E-08	-4.81E-06	0.00E+00	4.31E-07	1.30E-07	3.18E-12	3.84E-06	5.74E-07	5.26E-07	1.59E-07	4.44E-05	4.69E-06	7.02E-07
	Iron	1.02E-05	1.88E-06	8.70E-05	1.70E-05	0.00E+00	-1.26E-05	-7.70E-05	-1.91E-04	1.08E-04	3.16E-05	1.66E-10	2.00E-04	2.47E-05	1.32E-04	3.87E-05	2.26E-03	2.44E-04	3.01E-05
	Lead (+II)	1.65E-07	4.60E-09	4.40E-08	6.32E-09	0.00E+00	-6.39E-08	-4.10E-06	-1.08E-04	8.78E-08	1.56E-08	7.30E-12	2.12E-07	8.98E-07	1.07E-07	1.90E-08	1.02E-04	2.59E-07	1.10E-06
	Manganese (+II)	3.89E-08	1.45E-07	1.95E-07	1.58E-07	0.00E+00	0.00E+00	-1.90E-07	0.00E+00	5.85E-07	4.18E-07	1.71E-14	5.15E-06	3.15E-08	7.15E-07	5.11E-07	1.36E-07	6.30E-06	3.85E-08
	Nickel (+II)	1.32E-06	4.31E-06	1.50E-08	1.78E-08	0.00E+00	-3.44E-08	-5.80E-07	-1.18E-06	1.24E-05	4.24E-06	5.77E-11	1.44E-04	5.10E-06	1.52E-05	5.19E-06	8.07E-04	1.76E-04	6.23E-06
	Strontium	4.23E-08	3.13E-09	2.81E-07	7.54E-07	0.00E+00	-1.05E-05	-6.31E-07	0.00E+00	5.83E-06	1.32E-06	1.02E-13	2.73E-06	1.51E-06	7.13E-06	1.62E-06	7.44E-07	3.34E-06	1.84E-06
	Zinc (+II)	1.62E-06	1.20E-06	1.88E-08	1.72E-08	0.00E+00	-1.16E-07	-1.15E-05	5.16E-05	3.56E-06	1.20E-06	1.00E-10	4.00E-05	9.50E-06	4.35E-06	1.47E-06	1.40E-03	4.89E-05	1.16E-05
	Ammonium/ammonia	1.56E-06	1.01E-05	1.32E-06	7.79E-07	0.00E+00	-5.78E-09	-6.80E-06	9.78E-03	3.10E-05	1.12E-05	1.62E-12	3.49E-04	5.29E-07	3.79E-05	1.37E-05	2.71E-06	4.26E-04	6.47E-07
	Hydrogen chloride	2.72E-12	7.35E-13	2.57E-11	3.24E-12	0.00E+00	0.00E+00	-2.76E-11	0.00E+00	1.55E-10	6.38E-12	2.15E-17	4.25E-10	3.75E-12	1.89E-10	7.80E-12	2.85E-10	5.19E-10	4.58E-12
	Nitrogen (as total N)	4.05E-09	3.04E-08	0.00E+00	0.00E+00	0.00E+00	-1.44E-08	0.00E+00	-5.53E-04	9.38E-08	2.98E-08	0.00E+00	1.03E-06	7.21E-09	1.15E-07	3.64E-08	0.00E+00	1.26E-06	8.81E-09
	Phosphate	2.33E-08	3.59E-10	8.06E-08	4.07E-07	0.00E+00	0.00E+00	-7.16E-07	5.94E-06	1.04E-06	7.12E-07	3.14E-14	9.47E-07	8.31E-08	1.27E-06	8.71E-07	3.37E-08	1.16E-06	1.02E-07
	Phosphorus	9.32E-07	6.78E-08	1.35E-08	5.14E-09	0.00E+00	0.00E+00	-2.68E-08	-1.11E-05	2.04E-07	7.53E-08	7.32E-11	2.28E-06	6.36E-06	2.49E-07	9.20E-08	1.01E-03	2.78E-06	7.77E-06
Resource Energy (MJ/MWh)	Crude oil	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	Hard coal	6.44E-07	4.84E-06	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.39E-05	4.74E-06	0.00E+00	1.62E-04	0.00E+00	1.70E-05	5.79E-06	0.00E+00	1.97E-04	0.00E+00
	Lignite	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	Natural gas	3.55E-02	2.67E-01	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	8.12E-01	2.61E-01	0.00E+00	9.01E+00	0.00E+00	9.92E-01	3.19E-01	0.00E+00	1.10E+01	0.00E+00
	Uranium	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	Total resource energy	3.55E-02	2.67E-01	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	8.12E-01	2.61E-01	0.00E+00	9.01E+00	0.00E+00	9.92E-01	3.19E-01	0.00E+00	1.10E+01	0.00E+00
Energy Return on Investment		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Table A-6: Detailed LCA Results – Onshore Conventional Wind Power (Continued)

Category (Units)	Material or Energy Flow	ECF											PT	Total
		Wind Farm Operation					Wind Farm Construction					Landfill Waste	T&D	
		Electricity	Diesel Upstream	Lubricating Oil	Wind Farm	Cable	Concrete	Gravel Road	Steel	Diesel Upstream	Wind Farm			
GHG (kg/MWh)	CO_2	3.81E-04	5.25E-04	1.10E-02	2.57E-03	1.29E-01	6.33E-03	8.10E-02	3.17E-03	2.13E-02	1.04E-01	1.06E-02	0.00E+00	1.76E+01
	N_2O	6.02E-09	1.03E-08	5.79E-05	6.65E-08	3.89E-06	5.61E-08	2.44E-05	3.42E-09	4.18E-07	2.69E-06	8.74E-08	0.00E+00	8.41E-04
	CH_4	1.15E-06	3.35E-06	3.03E-03	3.68E-07	1.95E-04	1.07E-05	2.34E-04	1.36E-06	1.36E-04	1.49E-05	3.11E-04	0.00E+00	3.73E-02
	SF_6	8.02E-11	9.86E-16	1.08E-13	0.00E+00	1.26E-11	7.36E-10	2.96E-14	1.48E-16	3.99E-14	0.00E+00	2.63E-15	1.43E-04	1.44E-04
	CO_2e (IPCC 2007 100-yr GWP)	4.13E-04	6.12E-04	1.04E-01	2.60E-03	1.35E-01	6.63E-03	9.41E-02	3.21E-03	2.48E-02	1.05E-01	1.84E-02	3.27E+00	2.20E+01
Other Air (kg/MWh)	Pb	2.52E-12	1.18E-11	3.69E-10	0.00E+00	1.46E-06	3.37E-11	3.56E-10	2.08E-11	4.79E-10	0.00E+00	2.90E-10	0.00E+00	-9.51E-06
	Hg	7.05E-12	9.81E-13	5.36E-11	0.00E+00	1.07E-09	6.53E-11	2.95E-11	1.03E-11	3.98E-11	0.00E+00	2.93E-11	0.00E+00	1.45E-07
	NH_3	3.60E-10	6.70E-09	4.46E-04	0.00E+00	7.02E-07	3.52E-09	3.88E-05	1.89E-09	2.71E-07	0.00E+00	1.66E-08	0.00E+00	8.20E-04
	CO	7.38E-08	5.00E-07	9.31E-03	1.43E-05	7.86E-04	4.42E-06	2.84E-03	3.78E-05	2.03E-05	5.81E-04	5.42E-05	0.00E+00	5.00E-02
	NOX	5.83E-07	6.86E-07	2.57E-04	1.16E-06	2.21E-04	1.39E-05	8.27E-03	3.50E-06	2.78E-05	0.00E+00	6.29E-05	0.00E+00	4.47E-02
	SO_2	1.22E-06	1.38E-06	7.71E-05	2.45E-08	4.78E-04	1.78E-05	5.08E-05	6.11E-06	5.57E-05	9.91E-07	2.77E-05	0.00E+00	2.86E-02
	VOC	1.03E-07	1.47E-06	5.34E-04	5.42E-07	2.90E-05	9.66E-07	2.41E-04	1.33E-06	5.95E-05	0.00E+00	1.48E-05	0.00E+00	8.81E-03
	PM	1.56E-08	1.20E-08	5.86E-04	2.73E-03	2.18E-04	8.49E-06	1.77E-02	4.66E-07	4.88E-07	0.00E+00	1.74E-04	0.00E+00	2.72E-02
Solid Waste (kg/MWh)	Heavy metals to industrial soil	2.51E-06	8.41E-09	1.04E-07	0.00E+00	6.10E-07	2.30E-05	2.53E-07	6.30E-11	3.41E-07	0.00E+00	2.28E-07	0.00E+00	3.39E-02
	Heavy metals to agricultural soil	0.00E+00	0.00E+00	4.32E-08	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.32E-08
Water Use (L/MWh)	Withdrawal	1.32E-02	1.94E-03	3.22E-02	0.00E+00	1.32E+00	1.23E-01	5.82E-02	2.22E-05	7.84E-02	0.00E+00	2.33E-01	0.00E+00	2.00E+02
	Discharge	1.22E-02	4.71E-04	3.35E-02	0.00E+00	1.07E+00	1.12E-01	1.42E-02	2.72E-06	1.91E-02	0.00E+00	5.17E-01	0.00E+00	1.76E+02
	Consumption	1.02E-03	1.47E-03	-1.29E-03	0.00E+00	2.54E-01	1.07E-02	4.41E-02	1.94E-05	5.93E-02	0.00E+00	-2.85E-01	0.00E+00	2.41E+01
Water Quality (kg/MWh)	Aluminum	5.40E-11	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.96E-10	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	7.32E-07
	Arsenic (+V)	5.86E-10	1.09E-08	4.79E-10	0.00E+00	4.08E-09	5.38E-09	3.28E-07	3.40E-13	4.41E-07	0.00E+00	1.79E-10	0.00E+00	3.95E-05
	Copper (+II)	6.98E-10	1.60E-08	1.11E-08	0.00E+00	3.76E-07	6.42E-09	4.80E-07	2.92E-12	6.46E-07	0.00E+00	5.03E-09	0.00E+00	5.24E-05
	Iron	1.17E-08	8.14E-07	1.73E-06	0.00E+00	2.39E-05	1.10E-07	2.45E-05	3.74E-07	3.30E-05	0.00E+00	3.40E-06	0.00E+00	3.00E-03
	Lead (+II)	2.86E-11	3.67E-08	9.39E-08	0.00E+00	3.25E-07	2.69E-10	1.10E-06	2.12E-07	1.49E-06	0.00E+00	2.84E-10	0.00E+00	-4.23E-06
	Manganese (+II)	8.99E-10	4.89E-11	2.36E-09	0.00E+00	5.48E-08	8.25E-09	1.47E-09	1.23E-12	1.98E-09	0.00E+00	3.00E-09	0.00E+00	1.43E-05
	Nickel (+II)	2.68E-08	2.90E-07	9.38E-08	0.00E+00	4.79E-08	2.46E-07	8.73E-06	2.30E-09	1.18E-05	0.00E+00	2.85E-10	0.00E+00	1.20E-03
	Strontium	1.95E-11	2.68E-10	1.04E-08	0.00E+00	1.07E-07	3.08E-10	8.04E-09	2.28E-11	1.08E-08	0.00E+00	4.58E-09	0.00E+00	1.62E-05
	Zinc (+II)	7.45E-09	5.04E-07	4.70E-08	0.00E+00	8.88E-07	6.84E-08	1.52E-05	-1.01E-07	2.04E-05	0.00E+00	1.91E-10	0.00E+00	1.60E-03
	Ammonium/ammonia	6.25E-08	9.73E-10	2.65E-06	0.00E+00	7.96E-07	5.74E-07	2.93E-08	-1.91E-05	3.94E-08	0.00E+00	7.73E-08	0.00E+00	1.06E-02
	Hydrogen chloride	4.57E-15	1.03E-13	3.36E-13	0.00E+00	7.42E-12	4.50E-14	3.08E-12	5.44E-16	4.15E-12	0.00E+00	3.14E-14	0.00E+00	1.62E-09
	Nitrogen (as total N)	1.89E-10	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.74E-09	0.00E+00	1.08E-06	0.00E+00	0.00E+00	0.00E+00	0.00E+00	-5.50E-04
	Phosphate	2.23E-12	1.21E-11	8.58E-06	0.00E+00	7.19E-08	3.56E-11	3.64E-10	-1.16E-08	4.90E-10	0.00E+00	7.25E-09	0.00E+00	2.06E-05
	Phosphorus	4.21E-10	3.65E-07	8.09E-10	0.00E+00	4.87E-09	4.00E-09	1.10E-05	2.18E-08	1.48E-05	0.00E+00	4.85E-08	0.00E+00	1.05E-03
Resource Energy (MJ/MWh)	Crude oil	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	Hard coal	3.01E-08	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.76E-07	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.06E-04
	Lignite	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	Natural gas	1.66E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.52E-02	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.27E+01
	Uranium	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	Total resource energy	1.66E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.52E-02	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.27E+01
Energy Return on Investment		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1.58E+02

Table A-7: Detailed LCA Results – Onshore Advanced Wind Power

Category (Units)	Material or Energy Flow	ECF																	
		Switchyard	Trunkline				Recycling			Domestic Turbine MFG					Foreign Turbine MFG				
			Electricity	Aluminum Sheet	Steel Cold Rolled	Concrete	Aluminum	Copper	Steel	Rotor	Tower	Transport	Nacelle	Transformer	Rotor	Tower	Transport	Nacelle	Transformer
GHG (kg/MWh)	CO_2	6.00E-02	6.13E-02	3.89E-01	3.80E-01	4.90E-02	-1.39E-01	-3.66E-01	-2.59E+00	1.21E+00	1.75E+00	2.80E-07	2.43E+00	1.20E-01	1.48E+00	2.13E+00	2.22E+00	2.97E+00	1.46E-01
	N_2O	1.27E-06	9.69E-07	8.43E-06	2.47E-06	0.00E+00	-2.15E-07	-1.60E-05	-2.66E-06	3.06E-04	1.27E-05	7.40E-12	7.45E-05	1.99E-06	3.74E-04	1.55E-05	5.47E-05	9.11E-05	2.43E-06
	CH_4	9.82E-05	1.85E-04	6.17E-04	4.46E-04	0.00E+00	-5.86E-04	-5.03E-04	-1.09E-03	3.99E-03	2.31E-03	8.17E-10	5.83E-03	2.32E-04	4.88E-03	2.83E-03	2.51E-03	7.12E-03	2.83E-04
	SF_6	1.72E-09	1.29E-08	4.93E-11	2.76E-12	0.00E+00	0.00E+00	-1.82E-11	0.00E+00	5.08E-08	3.04E-08	8.98E-19	3.05E-07	1.99E-12	6.21E-08	3.72E-08	6.96E-13	3.73E-07	2.44E-12
	CO_2e (IPCC 2007 100-yr GWP)	6.29E-02	6.65E-02	4.07E-01	3.92E-01	4.90E-02	-1.54E-01	-3.83E-01	-2.61E+00	1.40E+00	1.81E+00	3.03E-07	2.60E+00	1.26E-01	1.71E+00	2.21E+00	2.30E+00	3.18E+00	1.54E-01
Other Air (kg/MWh)	Pb	3.25E-07	4.06E-10	5.16E-08	6.86E-07	0.00E+00	-3.05E-08	-1.08E-05	-1.55E-08	1.98E-07	2.89E-06	7.01E-14	4.54E-07	1.03E-06	2.42E-07	3.53E-06	8.35E-09	5.55E-07	1.25E-06
	Hg	5.02E-10	1.13E-09	3.62E-09	8.77E-10	0.00E+00	-9.59E-10	-2.45E-09	-8.32E-09	1.45E-08	6.37E-09	3.92E-15	5.55E-08	1.28E-09	1.77E-08	7.79E-09	6.93E-10	6.79E-08	1.57E-09
	NH_3	2.39E-07	5.79E-08	1.72E-06	1.24E-06	0.00E+00	-7.98E-08	-2.60E-06	-1.51E-06	2.61E-06	5.34E-06	2.22E-12	4.05E-06	6.00E-07	3.19E-06	6.53E-06	8.06E-05	4.95E-06	7.33E-07
	CO	3.34E-04	1.19E-05	3.59E-03	3.61E-03	6.32E-05	-1.07E-04	-3.47E-04	-3.09E-02	1.52E-03	1.52E-02	6.71E-10	2.73E-03	6.67E-04	1.86E-03	1.86E-02	6.04E-03	3.34E-03	8.15E-04
	NOX	1.07E-04	9.39E-05	5.32E-04	7.20E-04	1.50E-04	-2.16E-04	-8.32E-04	-2.86E-03	2.25E-03	3.25E-03	2.30E-10	3.71E-03	2.88E-04	2.75E-03	3.98E-03	5.41E-03	4.53E-03	3.52E-04
	SO_2	1.97E-04	1.96E-04	1.46E-03	5.26E-04	1.14E-04	-1.14E-03	-1.32E-03	-4.98E-03	4.49E-03	2.68E-03	4.21E-10	7.41E-03	5.26E-04	5.49E-03	3.28E-03	9.72E-04	9.06E-03	6.43E-04
	VOC	1.46E-05	1.66E-05	7.12E-05	5.42E-05	0.00E+00	-4.48E-05	-1.07E-04	-1.08E-03	1.86E-03	2.68E-04	3.10E-10	7.91E-04	5.24E-05	2.27E-03	3.27E-04	1.04E-03	9.67E-04	6.41E-05
	PM	9.07E-05	2.51E-06	7.07E-04	2.32E-04	1.46E-04	-2.76E-05	-5.40E-04	-3.79E-04	1.75E-03	9.84E-04	2.04E-11	9.16E-04	1.69E-04	2.14E-03	1.20E-03	8.51E-06	1.12E-03	2.06E-04
Solid Waste (kg/MWh)	Heavy metals to industrial soil	5.47E-05	4.04E-04	8.43E-06	3.28E-06	0.00E+00	0.00E+00	-8.44E-06	0.00E+00	1.60E-03	9.65E-04	8.83E-12	9.56E-03	1.62E-06	1.95E-03	1.18E-03	2.25E-05	1.17E-02	1.98E-06
	Heavy metals to agricultural soil	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Water Use (L/MWh)	Withdrawal	6.53E-01	2.13E+00	2.23E+00	8.74E-01	2.10E-02	0.00E+00	-6.44E+00	0.00E+00	1.45E+01	8.70E+00	8.78E-07	5.71E+01	6.99E-01	1.78E+01	1.06E+01	1.37E+00	6.97E+01	8.54E-01
	Discharge	5.50E-01	1.97E+00	1.59E+00	8.03E-01	0.00E+00	0.00E+00	-5.53E+00	0.00E+00	1.21E+01	8.02E+00	1.41E-10	5.00E+01	5.85E-01	1.48E+01	9.80E+00	3.33E-01	6.11E+01	7.15E-01
	Consumption	1.02E-01	1.64E-01	6.35E-01	7.13E-02	2.10E-02	0.00E+00	-9.14E-01	0.00E+00	2.41E+00	6.87E-01	8.78E-07	7.06E+00	1.14E-01	2.94E+00	8.40E-01	1.03E+00	8.63E+00	1.39E-01
Water Quality (kg/MWh)	Aluminum	1.16E-09	8.70E-09	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	3.45E-08	2.05E-08	0.00E+00	2.06E-07	0.00E+00	4.21E-08	2.51E-08	0.00E+00	2.52E-07	0.00E+00
	Arsenic (+V)	4.14E-08	9.44E-08	1.34E-08	3.06E-09	0.00E+00	-3.76E-08	-9.76E-09	0.00E+00	4.28E-07	2.35E-07	2.17E-12	2.25E-06	1.46E-07	5.23E-07	2.88E-07	7.70E-06	2.75E-06	1.78E-07
	Copper (+II)	1.37E-07	1.12E-07	2.44E-08	1.17E-08	0.00E+00	-2.93E-08	-2.77E-06	0.00E+00	6.99E-07	3.14E-07	3.18E-12	2.75E-06	4.58E-07	8.54E-07	3.84E-07	1.13E-05	3.37E-06	5.60E-07
	Iron	1.02E-05	1.88E-06	8.70E-05	1.70E-05	0.00E+00	-1.10E-05	-4.43E-05	-3.05E-04	2.27E-04	7.63E-05	1.66E-10	2.66E-04	1.94E-05	2.77E-04	9.32E-05	5.75E-04	3.25E-04	2.37E-05
	Lead (+II)	1.65E-07	4.60E-09	4.40E-08	6.32E-09	0.00E+00	-5.57E-08	-2.35E-06	-1.73E-04	1.69E-07	3.75E-08	7.30E-12	1.86E-07	6.92E-07	2.07E-07	4.58E-08	2.59E-05	2.27E-07	8.45E-07
	Manganese (+II)	3.89E-08	1.45E-07	1.95E-07	1.58E-07	0.00E+00	0.00E+00	-1.09E-07	0.00E+00	8.60E-07	1.01E-06	1.71E-14	3.84E-06	2.69E-08	1.05E-06	1.23E-06	3.45E-08	4.69E-06	3.28E-08
	Nickel (+II)	1.32E-06	4.31E-06	1.50E-08	1.78E-08	0.00E+00	-3.00E-08	-3.34E-07	-1.88E-06	1.71E-05	1.02E-05	5.77E-11	1.02E-04	3.75E-06	2.09E-05	1.25E-05	2.05E-04	1.25E-04	4.59E-06
	Strontium	4.23E-08	3.13E-09	2.81E-07	7.54E-07	0.00E+00	-9.14E-06	-3.63E-07	0.00E+00	1.04E-05	3.19E-06	1.02E-13	2.60E-06	1.29E-06	1.28E-05	3.89E-06	1.89E-07	3.18E-06	1.57E-06
	Zinc (+II)	1.62E-06	1.20E-06	1.88E-08	1.72E-08	0.00E+00	-1.01E-07	-6.59E-06	8.25E-05	4.93E-06	2.90E-06	1.00E-10	2.84E-05	7.07E-06	6.02E-06	3.54E-06	3.56E-04	3.47E-05	8.64E-06
	Ammonium/ammonia	1.56E-06	1.01E-05	1.32E-06	7.79E-07	0.00E+00	-5.04E-09	-3.91E-06	1.56E-02	4.56E-05	2.70E-05	1.62E-12	2.51E-04	4.51E-07	5.57E-05	3.30E-05	6.88E-07	3.06E-04	5.51E-07
	Hydrogen chloride	2.72E-12	7.35E-13	2.57E-11	3.24E-12	0.00E+00	0.00E+00	-1.59E-11	0.00E+00	2.55E-10	1.54E-11	2.15E-17	8.46E-10	3.02E-12	3.12E-10	1.88E-11	7.24E-11	1.03E-09	3.69E-12
	Nitrogen (as total N)	4.05E-09	3.04E-08	0.00E+00	0.00E+00	0.00E+00	-1.25E-08	0.00E+00	-8.84E-04	1.26E-07	7.17E-08	0.00E+00	7.30E-07	6.17E-09	1.54E-07	8.77E-08	0.00E+00	8.92E-07	7.54E-09
	Phosphate	2.33E-08	3.59E-10	8.06E-08	4.07E-07	0.00E+00	0.00E+00	-4.12E-07	9.49E-06	1.97E-06	1.72E-06	3.14E-14	1.36E-06	7.11E-08	2.41E-06	2.10E-06	8.55E-09	1.66E-06	8.69E-08
	Phosphorus	9.32E-07	6.78E-08	1.35E-08	5.14E-09	0.00E+00	0.00E+00	-1.54E-08	-1.78E-05	2.85E-07	1.82E-07	7.32E-11	1.63E-06	4.68E-06	3.49E-07	2.22E-07	2.58E-04	1.99E-06	5.71E-06
Resource Energy (MJ/MWh)	Crude oil	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	Hard coal	6.44E-07	4.84E-06	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.91E-05	1.14E-05	0.00E+00	1.15E-04	0.00E+00	2.33E-05	1.40E-05	0.00E+00	1.40E-04	0.00E+00
	Lignite	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	Natural gas	3.55E-02	2.67E-01	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.09E+00	6.29E-01	0.00E+00	6.40E+00	0.00E+00	1.33E+00	7.69E-01	0.00E+00	7.82E+00	0.00E+00
	Uranium	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	Total resource energy	3.55E-02	2.67E-01	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.09E+00	6.29E-01	0.00E+00	6.40E+00	0.00E+00	1.33E+00	7.69E-01	0.00E+00	7.82E+00	0.00E+00
Energy Return on Investment		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Table A-7: Detailed LCA Results – Onshore Advanced Wind Power (continued)

Category (Units)	Material or Energy Flow	ECF											PT	Total
		Wind Farm Operation					Wind Farm Construction					Landfill Waste	T&D	
		Electricity	Diesel Upstream	Lubricating Oil	Wind Farm	Cable	Concrete	Steel	Diesel Upstream	Wind Farm	Gravel Road			
GHG (kg/MWh)	CO_2	3.81E-04	5.25E-04	1.10E-02	2.57E-03	3.30E-02	6.33E-03	2.06E-02	3.17E-03	2.13E-02	1.04E-01	1.40E-02	0.00E+00	1.25E+01
	N_2O	6.02E-09	1.03E-08	5.79E-05	6.65E-08	9.90E-07	5.61E-08	6.21E-06	3.42E-09	4.18E-07	2.69E-06	1.16E-07	0.00E+00	9.95E-04
	CH_4	1.15E-06	3.35E-06	3.03E-03	3.68E-07	4.96E-05	1.07E-05	5.95E-05	1.36E-06	1.36E-04	1.49E-05	4.13E-04	0.00E+00	3.29E-02
	SF_6	8.02E-11	9.86E-16	1.08E-13	0.00E+00	3.21E-12	7.36E-10	7.53E-15	1.48E-16	3.99E-14	0.00E+00	3.49E-15	1.43E-04	1.44E-04
	CO_2e (IPCC 2007 100-yr GWP)	4.13E-04	6.12E-04	1.04E-01	2.60E-03	3.45E-02	6.63E-03	2.39E-02	3.21E-03	2.48E-02	1.05E-01	2.44E-02	3.27E+00	1.69E+01
Other Air (kg/MWh)	Pb	2.52E-12	1.18E-11	3.69E-10	0.00E+00	3.71E-07	3.37E-11	9.03E-11	2.08E-11	4.79E-10	0.00E+00	3.85E-10	0.00E+00	7.83E-07
	Hg	7.05E-12	9.81E-13	5.36E-11	0.00E+00	2.73E-10	6.53E-11	7.50E-12	1.03E-11	3.98E-11	0.00E+00	3.88E-11	0.00E+00	1.68E-07
	NH_3	3.60E-10	6.70E-09	4.46E-04	0.00E+00	1.79E-07	3.52E-09	9.87E-06	1.89E-09	2.71E-07	0.00E+00	2.20E-08	0.00E+00	5.64E-04
	CO	7.38E-08	5.00E-07	9.31E-03	1.43E-05	2.00E-04	4.42E-06	7.22E-04	3.78E-05	2.03E-05	5.81E-04	7.18E-05	0.00E+00	3.81E-02
	NOX	5.83E-07	6.86E-07	2.57E-04	1.16E-06	5.63E-05	1.39E-05	2.10E-03	3.50E-06	2.78E-05	0.00E+00	8.35E-05	0.00E+00	2.68E-02
	SO_2	1.22E-06	1.38E-06	7.71E-05	2.45E-08	1.22E-04	1.78E-05	1.29E-05	6.11E-06	5.57E-05	9.91E-07	3.68E-05	0.00E+00	2.99E-02
	VOC	1.03E-07	1.47E-06	5.34E-04	5.42E-07	7.38E-06	9.66E-07	6.12E-05	1.33E-06	5.95E-05	0.00E+00	1.96E-05	0.00E+00	7.24E-03
	PM	1.56E-08	1.20E-08	5.86E-04	2.73E-03	5.56E-05	8.49E-06	4.50E-03	4.66E-07	4.88E-07	0.00E+00	2.31E-04	0.00E+00	1.68E-02
Solid Waste (kg/MWh)	Heavy metals to industrial soil	2.51E-06	3.19E-08	4.18E-07	0.00E+00	7.31E-07	2.30E-05	2.44E-07	2.49E-10	1.29E-06	0.00E+00	2.86E-03	0.00E+00	3.03E-02
	Heavy metals to agricultural soil	0.00E+00	0.00E+00	4.32E-08	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.32E-08
Water Use (L/MWh)	Withdrawal	1.32E-02	1.94E-03	3.22E-02	0.00E+00	3.37E-01	1.23E-01	1.48E-02	2.22E-05	7.84E-02	0.00E+00	3.09E-01	0.00E+00	1.82E+02
	Discharge	1.22E-02	4.71E-04	3.35E-02	0.00E+00	2.72E-01	1.12E-01	3.60E-03	2.72E-06	1.91E-02	0.00E+00	6.86E-01	0.00E+00	1.58E+02
	Consumption	1.02E-03	1.47E-03	-1.29E-03	0.00E+00	6.46E-02	1.07E-02	1.12E-02	1.94E-05	5.93E-02	0.00E+00	-3.77E-01	0.00E+00	2.37E+01
Water Quality (kg/MWh)	Aluminum	5.40E-11	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.96E-10	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	5.91E-07
	Arsenic (+V)	5.86E-10	1.09E-08	4.79E-10	0.00E+00	1.04E-09	5.38E-09	8.32E-08	3.40E-13	4.41E-07	0.00E+00	2.37E-10	0.00E+00	1.51E-05
	Copper (+II)	6.98E-10	1.60E-08	1.11E-08	0.00E+00	9.59E-08	6.42E-09	1.22E-07	2.92E-12	6.46E-07	0.00E+00	6.68E-09	0.00E+00	1.91E-05
	Iron	1.17E-08	8.14E-07	1.73E-06	0.00E+00	6.08E-06	1.10E-07	6.22E-06	3.74E-07	3.30E-05	0.00E+00	4.51E-06	0.00E+00	1.69E-03
	Lead (+II)	2.86E-11	3.67E-08	9.39E-08	0.00E+00	8.28E-08	2.69E-10	2.80E-07	2.12E-07	1.49E-06	0.00E+00	3.77E-10	0.00E+00	-1.45E-04
	Manganese (+II)	8.99E-10	4.89E-11	2.36E-09	0.00E+00	1.39E-08	8.25E-09	3.73E-10	1.23E-12	1.98E-09	0.00E+00	3.99E-09	0.00E+00	1.32E-05
	Nickel (+II)	2.68E-08	2.90E-07	9.38E-08	0.00E+00	1.22E-08	2.46E-07	2.22E-06	2.30E-09	1.18E-05	0.00E+00	3.78E-10	0.00E+00	5.19E-04
	Strontium	1.95E-11	2.68E-10	1.04E-08	0.00E+00	2.72E-08	3.08E-10	2.04E-09	2.28E-11	1.08E-08	0.00E+00	6.08E-09	0.00E+00	3.07E-05
	Zinc (+II)	7.45E-09	5.04E-07	4.70E-08	0.00E+00	2.26E-07	6.84E-08	3.85E-06	-1.01E-07	2.04E-05	0.00E+00	2.54E-10	0.00E+00	5.56E-04
	Ammonium/ammonia	6.25E-08	9.73E-10	2.65E-06	0.00E+00	2.03E-07	5.74E-07	7.43E-09	-1.91E-05	3.94E-08	0.00E+00	1.02E-07	0.00E+00	1.63E-02
	Hydrogen chloride	4.57E-15	1.03E-13	3.36E-13	0.00E+00	1.89E-12	4.50E-14	7.83E-13	5.44E-16	4.15E-12	0.00E+00	4.16E-14	0.00E+00	2.58E-09
	Nitrogen (as total N)	1.89E-10	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.74E-09	0.00E+00	1.08E-06	0.00E+00	0.00E+00	0.00E+00	0.00E+00	-8.80E-04
	Phosphate	2.23E-12	1.21E-11	8.58E-06	0.00E+00	1.83E-08	3.56E-11	9.25E-11	-1.16E-08	4.90E-10	0.00E+00	9.62E-09	0.00E+00	2.96E-05
	Phosphorus	4.21E-10	3.65E-07	8.09E-10	0.00E+00	1.24E-09	4.00E-09	2.79E-06	2.18E-08	1.48E-05	0.00E+00	6.44E-08	0.00E+00	2.74E-04
Resource Energy (MJ/MWh)	Crude oil	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	Hard coal	3.01E-08	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.76E-07	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	3.28E-04
	Lignite	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	Natural gas	1.66E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.52E-02	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.84E+01
	Uranium	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	Total resource energy	1.66E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.52E-02	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.84E+01
Energy Return on Investment		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1.96E+02

Table A-8: Detailed LCA Results – Offshore Wind Power

Category (Units)	Material or Energy Flow	ECF																	
		Switchyard	Trunkline				Recycling			Domestic Turbine MFG					Foreign Turbine MFG				
			Electricity	Aluminum Sheet	Cold Rolled Steel	Concrete	Aluminum	Copper	Steel	Rotor	Tower	Transport	Nacelle	Transformer	Rotor	Tower	Transport	Nacelle	Transformer
GHG (kg/MWh)	CO_2	6.00E-02	6.13E-02	3.89E-01	3.80E-01	4.90E-02	-1.26E-01	-2.85E-01	-3.30E+00	7.77E-01	1.11E+00	2.16E-07	1.89E+00	9.56E-02	9.50E-01	1.36E+00	2.78E+00	2.31E+00	1.17E-01
	N_2O	1.27E-06	9.69E-07	8.43E-06	2.47E-06	0.00E+00	-1.95E-07	-1.25E-05	-3.40E-06	1.90E-04	8.09E-06	5.69E-12	5.89E-05	1.59E-06	2.32E-04	9.89E-06	6.84E-05	7.20E-05	1.94E-06
	CH_4	9.82E-05	1.85E-04	6.17E-04	4.46E-04	0.00E+00	-5.31E-04	-3.91E-04	-1.39E-03	2.54E-03	1.47E-03	6.29E-10	4.66E-03	1.86E-04	3.10E-03	1.80E-03	3.15E-03	5.69E-03	2.27E-04
	SF_6	1.72E-09	1.29E-08	4.93E-11	2.76E-12	0.00E+00	0.00E+00	-1.42E-11	0.00E+00	3.38E-08	1.94E-08	6.91E-19	2.52E-07	1.59E-12	4.14E-08	2.37E-08	8.71E-13	3.08E-07	1.94E-12
	CO_2e (IPCC 2007 100-yr GWP)	6.29E-02	6.65E-02	4.07E-01	3.92E-01	4.90E-02	-1.39E-01	-2.98E-01	-3.34E+00	8.98E-01	1.15E+00	2.33E-07	2.03E+00	1.01E-01	1.10E+00	1.41E+00	2.88E+00	2.48E+00	1.23E-01
Other Air (kg/MWh)	Pb	3.25E-07	4.06E-10	5.16E-08	6.86E-07	0.00E+00	-2.76E-08	-8.38E-06	-1.98E-08	1.29E-07	1.84E-06	5.39E-14	3.56E-07	8.17E-07	1.58E-07	2.25E-06	1.05E-08	4.35E-07	9.99E-07
	Hg	5.02E-10	1.13E-09	3.62E-09	8.77E-10	0.00E+00	-8.69E-10	-1.90E-09	-1.06E-08	9.38E-09	4.06E-09	3.02E-15	3.93E-08	1.02E-09	1.15E-08	4.96E-09	8.68E-10	4.80E-08	1.25E-09
	NH_3	2.39E-07	5.79E-08	1.72E-06	1.24E-06	0.00E+00	-7.24E-08	-2.02E-06	-1.93E-06	1.67E-06	3.40E-06	1.71E-12	3.00E-06	4.80E-07	2.04E-06	4.16E-06	1.01E-04	3.67E-06	5.87E-07
	CO	3.34E-04	1.19E-05	3.59E-03	3.61E-03	6.32E-05	-9.66E-05	-2.70E-04	-3.94E-02	9.89E-04	9.70E-03	5.17E-10	2.19E-03	5.31E-04	1.21E-03	1.19E-02	7.56E-03	2.68E-03	6.50E-04
	NOX	1.07E-04	9.39E-05	5.32E-04	7.20E-04	1.50E-04	-1.96E-04	-6.47E-04	-3.64E-03	1.43E-03	2.07E-03	1.77E-10	2.89E-03	2.30E-04	1.75E-03	2.53E-03	6.77E-03	3.54E-03	2.81E-04
	SO_2	1.97E-04	1.96E-04	1.46E-03	5.26E-04	1.14E-04	-1.04E-03	-1.03E-03	-6.36E-03	2.86E-03	1.71E-03	3.23E-10	5.65E-03	4.20E-04	3.49E-03	2.09E-03	1.22E-03	6.91E-03	5.13E-04
	VOC	1.46E-05	1.66E-05	7.12E-05	5.42E-05	0.00E+00	-4.06E-05	-8.30E-05	-1.38E-03	1.16E-03	1.70E-04	2.38E-10	6.28E-04	4.23E-05	1.41E-03	2.08E-04	1.30E-03	7.68E-04	5.17E-05
	PM	9.07E-05	2.51E-06	7.07E-04	2.32E-04	1.46E-04	-2.51E-05	-4.21E-04	-4.84E-04	1.10E-03	6.27E-04	1.57E-11	7.10E-04	1.34E-04	1.35E-03	7.66E-04	1.07E-05	8.68E-04	1.64E-04
Solid Waste (kg/MWh)	Heavy metals to industrial so	5.39E-05	4.04E-04	1.74E-06	6.52E-07	0.00E+00	0.00E+00	-1.46E-06	0.00E+00	1.06E-03	6.08E-04	1.77E-12	7.87E-03	3.00E-07	1.29E-03	7.43E-04	7.44E-06	9.62E-03	3.67E-07
	Heavy metals to agricultural s	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Water Use (L/MWh)	Withdrawal	6.53E-01	2.13E+00	2.23E+00	8.74E-01	2.10E-02	0.00E+00	-5.01E+00	0.00E+00	9.46E+00	5.54E+00	6.75E-07	4.58E+01	5.58E-01	1.16E+01	6.77E+00	1.71E+00	5.60E+01	6.81E-01
	Discharge	5.50E-01	1.97E+00	1.59E+00	8.03E-01	0.00E+00	0.00E+00	-4.30E+00	0.00E+00	7.91E+00	5.10E+00	1.09E-10	4.07E+01	4.66E-01	9.67E+00	6.24E+00	4.16E-01	4.97E+01	5.70E-01
	Consumption	1.02E-01	1.64E-01	6.35E-01	7.13E-02	2.10E-02	0.00E+00	-7.11E-01	0.00E+00	1.55E+00	4.38E-01	6.75E-07	5.18E+00	9.13E-02	1.90E+00	5.35E-01	1.30E+00	6.33E+00	1.12E-01
Water Quality (kg/MWh)	Aluminum	1.16E-09	8.70E-09	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.30E-08	1.31E-08	0.00E+00	1.70E-07	0.00E+00	2.81E-08	1.60E-08	0.00E+00	2.08E-07	0.00E+00
	Arsenic (+V)	4.14E-08	9.44E-08	1.34E-08	3.06E-09	0.00E+00	-3.41E-08	-7.59E-09	0.00E+00	2.83E-07	1.50E-07	1.67E-12	1.85E-06	1.21E-07	3.46E-07	1.83E-07	9.63E-06	2.27E-06	1.48E-07
	Copper (+II)	1.37E-07	1.12E-07	2.44E-08	1.17E-08	0.00E+00	-2.66E-08	-2.15E-06	0.00E+00	4.54E-07	2.00E-07	2.45E-12	2.26E-06	3.71E-07	5.55E-07	2.45E-07	1.41E-05	2.76E-06	4.54E-07
	Iron	1.02E-05	1.88E-06	8.70E-05	1.70E-05	0.00E+00	-9.93E-06	-3.45E-05	-3.89E-04	1.43E-04	4.86E-05	1.28E-10	1.76E-04	1.58E-05	1.75E-04	5.94E-05	7.20E-04	2.15E-04	1.93E-05
	Lead (+II)	1.65E-07	4.60E-09	4.40E-08	6.32E-09	0.00E+00	-5.05E-08	-1.83E-06	-2.21E-04	1.08E-07	2.39E-08	5.62E-12	1.41E-07	5.66E-07	1.32E-07	2.92E-08	3.24E-05	1.72E-07	6.92E-07
	Manganese (+II)	3.89E-08	1.45E-07	1.95E-07	1.58E-07	0.00E+00	0.00E+00	-8.50E-08	0.00E+00	5.66E-07	6.42E-07	1.31E-14	3.11E-06	2.14E-08	6.91E-07	7.84E-07	4.32E-08	3.80E-06	2.62E-08
	Nickel (+II)	1.32E-06	4.31E-06	1.50E-08	1.78E-08	0.00E+00	-2.72E-08	-2.60E-07	-2.40E-06	1.14E-05	6.51E-06	4.44E-11	8.41E-05	3.11E-06	1.39E-05	7.96E-06	2.57E-04	1.03E-04	3.80E-06
	Strontium	4.23E-08	3.13E-09	2.81E-07	7.54E-07	0.00E+00	-8.29E-06	-2.82E-07	0.00E+00	6.69E-06	2.03E-06	7.85E-14	1.99E-06	1.03E-06	8.17E-06	2.48E-06	2.36E-07	2.44E-06	1.25E-06
	Zinc (+II)	1.62E-06	1.20E-06	1.88E-08	1.72E-08	0.00E+00	-9.17E-08	-5.13E-06	1.05E-04	3.27E-06	1.85E-06	7.70E-11	2.34E-05	5.84E-06	4.00E-06	2.26E-06	4.45E-04	2.86E-05	7.14E-06
	Ammonium/ammonia	1.05E-05	3.96E-07	2.37E-09	8.42E-09	0.00E+00	-1.93E-06	-1.74E-08	-4.21E-07	2.57E-06	6.16E-07	6.32E-10	8.00E-06	4.41E-05	3.14E-06	7.53E-07	3.66E-03	9.78E-06	5.40E-05
	Hydrogen chloride	2.72E-12	7.35E-13	2.57E-11	3.24E-12	0.00E+00	0.00E+00	-1.23E-11	0.00E+00	1.64E-10	9.79E-12	1.66E-17	5.04E-10	2.44E-12	2.00E-10	1.20E-11	9.06E-11	6.15E-10	2.98E-12
	Nitrogen (as total N)	4.05E-09	3.04E-08	0.00E+00	0.00E+00	0.00E+00	-1.14E-08	0.00E+00	-1.13E-03	8.44E-08	4.57E-08	0.00E+00	6.02E-07	4.91E-09	1.03E-07	5.58E-08	0.00E+00	7.36E-07	6.01E-09
	Phosphate	2.33E-08	3.59E-10	8.06E-08	4.07E-07	0.00E+00	0.00E+00	-3.20E-07	1.21E-05	1.23E-06	1.09E-06	2.42E-14	9.00E-07	5.66E-08	1.50E-06	1.34E-06	1.07E-08	1.10E-06	6.92E-08
	Phosphorus	9.32E-07	6.78E-08	1.35E-08	5.14E-09	0.00E+00	0.00E+00	-1.20E-08	-2.27E-05	1.89E-07	1.16E-07	5.63E-11	1.34E-06	3.87E-06	2.31E-07	1.41E-07	3.23E-04	1.64E-06	4.73E-06
Resource Energy (MJ/MWh)	Crude oil	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	Hard coal	6.44E-07	4.84E-06	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.27E-05	7.27E-06	0.00E+00	9.45E-05	0.00E+00	1.55E-05	8.89E-06	0.00E+00	1.15E-04	0.00E+00
	Lignite	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	Natural gas	3.55E-02	2.67E-01	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	7.28E-01	4.01E-01	0.00E+00	5.28E+00	0.00E+00	8.90E-01	4.90E-01	0.00E+00	6.45E+00	0.00E+00
	Uranium	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	Total resource energy	3.55E-02	2.67E-01	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	7.28E-01	4.01E-01	0.00E+00	5.28E+00	0.00E+00	8.90E-01	4.90E-01	0.00E+00	6.45E+00	0.00E+00
Energy Return on Investment		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Table A-8: Detailed LCA Results – Offshore Wind Power (continued)

Category (Units)	Material or Energy Flow	ECF										PT	Total
		Wind Farm Operation					Wind Farm Construction				Landfill Waste	T&D	
		Marine Vessel Idling	Marine Vessel Travel	Electricity	Marine Vessel Construction	Lubricating Oil	Submarine Cable	Gravel	Coating	Steel Plate			
GHG (kg/MWh)	CO_2	6.47E+00	6.23E+00	2.55E-04	4.01E-01	3.53E-03	7.17E-02	8.38E-04	1.72E-04	4.06E+00	1.06E-02	0.00E+00	2.59E+01
	N_2O	2.16E-05	2.08E-05	4.03E-09	1.32E-05	1.85E-05	1.77E-06	0.00E+00	5.53E-10	2.11E-04	8.77E-08	0.00E+00	9.27E-04
	CH_4	7.02E-03	6.75E-03	7.72E-07	1.99E-04	9.70E-04	7.12E-05	0.00E+00	3.78E-07	3.08E-03	3.12E-04	0.00E+00	4.03E-02
	SF_6	2.06E-12	1.98E-12	5.37E-11	8.97E-14	3.46E-14	1.95E-12	4.60E-11	0.00E+00	0.00E+00	2.64E-15	1.43E-04	1.44E-04
	CO_2e (IPCC 2007 100-yr GWP)	6.66E+00	6.41E+00	2.77E-04	4.10E-01	3.33E-02	7.40E-02	8.39E-04	1.82E-04	4.20E+00	1.84E-02	3.27E+00	3.04E+01
Other Air (kg/MWh)	Pb	2.48E-08	2.38E-08	1.69E-12	4.99E-07	1.18E-10	1.14E-06	8.14E-10	1.37E-11	8.05E-06	2.91E-10	0.00E+00	9.38E-06
	Hg	2.05E-09	1.98E-09	4.72E-12	3.14E-08	1.72E-11	2.77E-10	7.13E-11	2.68E-12	5.05E-07	2.94E-11	0.00E+00	6.54E-07
	NH_3	1.40E-05	1.35E-05	2.41E-10	1.55E-08	1.43E-04	3.04E-07	1.56E-07	2.21E-10	0.00E+00	1.66E-08	0.00E+00	2.90E-04
	CO	2.70E-02	1.70E-02	4.95E-08	2.38E-03	2.99E-03	8.81E-05	3.25E-06	8.80E-08	3.43E-02	5.43E-05	0.00E+00	8.89E-02
	NOX	7.47E-02	7.52E-02	3.91E-07	7.29E-04	8.22E-05	1.54E-04	6.55E-06	4.49E-07	6.80E-03	6.31E-05	0.00E+00	1.76E-01
	SO_2	6.94E-03	6.67E-03	8.17E-07	1.16E-03	2.47E-05	2.62E-04	1.44E-06	1.19E-06	9.25E-03	2.78E-05	0.00E+00	4.33E-02
	VOC	3.08E-03	2.96E-03	6.92E-08	7.35E-07	1.71E-04	1.72E-05	0.00E+00	9.49E-08	-1.58E-11	1.48E-05	0.00E+00	1.06E-02
	PM	2.01E-03	2.43E-05	1.05E-08	2.21E-04	1.88E-04	8.86E-05	0.00E+00	1.03E-07	9.74E-04	1.75E-04	0.00E+00	9.66E-03
Solid Waste (kg/MWh)	Heavy metals to industrial so	1.76E-05	1.69E-05	1.68E-06	3.34E-08	3.32E-08	2.84E-07	0.00E+00	0.00E+00	0.00E+00	2.28E-07	0.00E+00	2.17E-02
	Heavy metals to agricultural s	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.39E-08	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.39E-08
Water Use (L/MWh)	Withdrawal	4.05E+00	3.90E+00	8.87E-03	2.49E+00	1.03E-02	9.19E-01	0.00E+00	0.00E+00	2.15E+01	2.34E-01	0.00E+00	1.72E+02
	Discharge	9.86E-01	9.48E-01	8.18E-03	1.39E-02	1.07E-02	5.97E-01	0.00E+00	0.00E+00	0.00E+00	5.19E-01	0.00E+00	1.24E+02
	Consumption	3.07E+00	2.95E+00	6.84E-04	2.48E+00	-4.14E-04	3.21E-01	0.00E+00	0.00E+00	2.15E+01	-2.85E-01	0.00E+00	4.77E+01
Water Quality (kg/MWh)	Aluminum	0.00E+00	0.00E+00	3.62E-11	5.71E-07	0.00E+00	1.10E-07	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.15E-06
	Arsenic (+V)	2.28E-05	2.19E-05	3.93E-10	7.43E-11	1.54E-10	1.46E-09	0.00E+00	1.30E-11	0.00E+00	1.79E-10	0.00E+00	5.98E-05
	Copper (+II)	3.34E-05	3.21E-05	4.68E-10	2.88E-10	3.57E-09	2.97E-07	0.00E+00	2.68E-11	0.00E+00	5.05E-09	0.00E+00	8.54E-05
	Iron	1.70E-03	1.64E-03	7.84E-09	1.28E-05	5.54E-07	6.20E-06	0.00E+00	6.07E-09	1.31E-04	3.41E-06	0.00E+00	4.75E-03
	Lead (+II)	7.68E-05	7.39E-05	1.92E-11	1.33E-07	3.01E-08	2.57E-07	0.00E+00	2.24E-11	1.67E-06	2.85E-10	0.00E+00	-3.52E-05
	Manganese (+II)	1.02E-07	9.84E-08	6.02E-10	1.85E-07	7.57E-10	4.80E-08	0.00E+00	0.00E+00	0.00E+00	3.01E-09	0.00E+00	1.06E-05
	Nickel (+II)	6.08E-04	5.85E-04	1.79E-08	2.09E-07	3.01E-08	7.69E-08	0.00E+00	1.05E-11	2.27E-07	2.86E-10	0.00E+00	1.69E-03
	Strontium	5.60E-07	5.39E-07	1.30E-11	2.14E-09	3.34E-09	5.64E-08	0.00E+00	2.90E-09	0.00E+00	4.60E-09	0.00E+00	2.00E-05
	Zinc (+II)	1.06E-03	1.01E-03	4.99E-09	1.55E-07	1.51E-08	7.19E-07	0.00E+00	7.38E-11	1.00E-06	1.92E-10	0.00E+00	2.70E-03
	Ammonium/ammonia	8.66E-03	8.33E-03	1.65E-09	1.08E-05	3.50E-07	5.62E-07	0.00E+00	7.77E-10	1.28E-04	1.63E-08	0.00E+00	2.09E-02
	Hydrogen chloride	2.15E-10	2.06E-10	3.06E-15	1.26E-13	1.08E-13	2.18E-12	0.00E+00	0.00E+00	0.00E+00	3.15E-14	0.00E+00	2.04E-09
	Nitrogen (as total N)	0.00E+00	0.00E+00	1.27E-10	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.72E-11	0.00E+00	0.00E+00	0.00E+00	-1.13E-03
	Phosphate	2.53E-08	2.44E-08	1.49E-12	4.16E-10	2.75E-06	4.56E-08	0.00E+00	0.00E+00	0.00E+00	7.27E-09	0.00E+00	2.24E-05
	Phosphorus	7.64E-04	7.35E-04	2.82E-10	9.75E-07	2.59E-10	2.68E-08	0.00E+00	0.00E+00	1.37E-05	4.87E-08	0.00E+00	1.83E-03
Resource Energy (MJ/MWh)	Crude oil	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	Hard coal	0.00E+00	0.00E+00	2.02E-08	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.60E-04
	Lignite	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	Natural gas	0.00E+00	0.00E+00	1.11E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.45E+01
	Uranium	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	Total resource energy	0.00E+00	0.00E+00	1.11E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.45E+01
Energy Return on Investment		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	2.48E+02

Table A-9: Detailed LCA Results – Conventional Greenfield Hydropower

Category (Units)	Material or Energy Flow	ECF										PT	Total
		Hydro Trunkline Construction				Dam and Hydropower Facility Construction					Operation	T&D	
		Electricity	Cold Rolled Steel	Concrete	Aluminum Sheet	Electricity	Cold Rolled Steel	Concrete	Construction	Steel Plate			
GHG (kg/MWh)	CO_2	2.85E-03	1.77E-02	2.28E-03	1.81E-02	2.11E+00	1.26E-01	1.69E+00	2.42E+00	1.04E-01	1.81E+01	0.00E+00	2.46E+01
	N_2O	4.50E-08	1.15E-07	0.00E+00	3.92E-07	3.34E-05	8.22E-07	0.00E+00	0.00E+00	5.43E-06	0.00E+00	0.00E+00	4.02E-05
	CH_4	8.62E-06	2.07E-05	0.00E+00	2.87E-05	6.39E-03	1.48E-04	0.00E+00	0.00E+00	7.92E-05	2.51E-01	0.00E+00	2.57E-01
	SF_6	6.00E-10	1.28E-13	0.00E+00	2.29E-12	4.45E-07	9.17E-13	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.43E-04	1.44E-04
	CO_2e (IPCC 2007 100-yr GWP)	3.09E-03	1.82E-02	2.28E-03	1.89E-02	2.29E+00	1.30E-01	1.69E+00	2.42E+00	1.08E-01	2.44E+01	3.27E+00	3.44E+01
Other Air (kg/MWh)	Pb	1.89E-11	3.19E-08	0.00E+00	2.40E-09	1.40E-08	2.28E-07	0.00E+00	0.00E+00	2.07E-07	0.00E+00	0.00E+00	4.83E-07
	Hg	5.27E-11	4.08E-11	0.00E+00	1.68E-10	3.91E-08	2.92E-10	0.00E+00	0.00E+00	1.30E-08	0.00E+00	0.00E+00	5.26E-08
	NH_3	2.69E-09	5.74E-08	0.00E+00	7.98E-08	2.00E-06	4.11E-07	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.55E-06
	CO	5.53E-07	1.68E-04	2.94E-06	1.67E-04	4.09E-04	1.20E-03	2.18E-03	7.21E-03	8.81E-04	0.00E+00	0.00E+00	1.22E-02
	NOX	4.37E-06	3.35E-05	6.96E-06	2.47E-05	3.24E-03	2.39E-04	5.16E-03	8.38E-03	1.75E-04	0.00E+00	0.00E+00	1.73E-02
	SO_2	9.12E-06	2.45E-05	5.30E-06	6.78E-05	6.76E-03	1.75E-04	3.93E-03	0.00E+00	2.38E-04	0.00E+00	0.00E+00	1.12E-02
	VOC	7.72E-07	2.52E-06	0.00E+00	3.31E-06	5.72E-04	1.80E-05	0.00E+00	0.00E+00	-4.05E-13	0.00E+00	0.00E+00	5.97E-04
	PM	1.17E-07	1.08E-05	6.79E-06	3.29E-05	8.65E-05	7.71E-05	5.03E-03	0.00E+00	2.50E-05	0.00E+00	0.00E+00	5.27E-03
Solid Waste (kg/MWh)	Heavy metals to industrial soil	1.88E-05	3.03E-08	0.00E+00	8.07E-08	1.39E-02	2.17E-07	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.39E-02
	Heavy metals to agricultural soil	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Water Use (L/MWh)	Withdrawal	9.90E-02	4.06E-02	9.77E-04	1.04E-01	7.34E+01	2.91E-01	7.24E-01	0.00E+00	5.52E-01	7.33E+04	0.00E+00	7.33E+04
	Discharge	9.14E-02	3.73E-02	0.00E+00	7.40E-02	6.77E+01	2.67E-01	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	6.82E+01
	Consumption	7.63E-03	3.31E-03	9.77E-04	2.95E-02	5.66E+00	2.37E-02	7.24E-01	0.00E+00	5.52E-01	7.33E+04	0.00E+00	7.33E+04
Water Quality (kg/MWh)	Aluminum	4.04E-10	0.00E+00	0.00E+00	0.00E+00	3.00E-07	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	3.00E-07
	Arsenic (+V)	4.39E-09	1.42E-10	0.00E+00	6.24E-10	3.25E-06	1.02E-09	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	3.26E-06
	Copper (+II)	5.22E-09	5.45E-10	0.00E+00	1.14E-09	3.87E-06	3.90E-09	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	3.88E-06
	Iron	8.75E-08	7.92E-07	0.00E+00	4.04E-06	6.48E-05	5.67E-06	0.00E+00	0.00E+00	3.37E-06	0.00E+00	0.00E+00	7.88E-05
	Lead (+II)	2.14E-10	2.94E-10	0.00E+00	2.05E-09	1.59E-07	2.10E-09	0.00E+00	0.00E+00	4.30E-08	0.00E+00	0.00E+00	2.06E-07
	Manganese (+II)	6.72E-09	7.35E-09	0.00E+00	9.04E-09	4.98E-06	5.26E-08	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	5.06E-06
	Nickel (+II)	2.00E-07	8.27E-10	0.00E+00	6.97E-10	1.48E-04	5.92E-09	0.00E+00	0.00E+00	5.84E-09	0.00E+00	0.00E+00	1.49E-04
	Strontium	1.46E-10	3.50E-08	0.00E+00	1.31E-08	1.08E-07	2.51E-07	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.07E-07
	Zinc (+II)	5.58E-08	8.00E-10	0.00E+00	8.73E-10	4.13E-05	5.72E-09	0.00E+00	0.00E+00	2.57E-08	0.00E+00	0.00E+00	4.14E-05
	Ammonium/ammonia	4.67E-07	3.62E-08	0.00E+00	6.13E-08	3.46E-04	2.59E-07	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	3.47E-04
	Hydrogen chloride	3.42E-14	1.50E-13	0.00E+00	1.19E-12	2.53E-11	1.08E-12	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.78E-11
	Nitrogen (as total N)	1.41E-09	0.00E+00	0.00E+00	0.00E+00	1.05E-06	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.05E-06
	Phosphate	1.67E-11	1.89E-08	0.00E+00	3.74E-09	1.24E-08	1.35E-07	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.70E-07
	Phosphorus	3.15E-09	2.39E-10	0.00E+00	6.26E-10	2.34E-06	1.71E-09	0.00E+00	0.00E+00	3.51E-07	0.00E+00	0.00E+00	2.69E-06
Resource Energy (MJ/MWh)	Crude oil	1.02E-03	1.99E-02	0.00E+00	6.48E-02	7.59E-01	1.42E-01	0.00E+00	0.00E+00	2.29E-01	0.00E+00	0.00E+00	1.22E+00
	Hard coal	9.01E-03	1.81E-01	0.00E+00	4.92E-02	6.67E+00	1.29E+00	0.00E+00	0.00E+00	9.99E-01	0.00E+00	0.00E+00	9.21E+00
	Lignite	4.74E-06	4.53E-03	0.00E+00	2.41E-02	3.52E-03	3.24E-02	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	6.46E-02
	Natural gas	1.28E-02	2.65E-02	0.00E+00	5.85E-02	9.46E+00	1.89E-01	0.00E+00	0.00E+00	1.99E-01	0.00E+00	0.00E+00	9.95E+00
	Uranium	1.74E-05	5.30E-03	0.00E+00	5.43E-02	1.29E-02	3.79E-02	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.10E-01
	Total resource energy	2.28E-02	2.37E-01	0.00E+00	2.51E-01	1.69E+01	1.70E+00	0.00E+00	0.00E+00	1.43E+00	0.00E+00	0.00E+00	2.05E+01
Energy Return on Investment		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1.752E+02

Table A-10: Detailed LCA Results – Conventional Hydropower Addition

Category (Units)	Material or Energy Flow	ECF								PT	Total
		Hydropower Facility Construction			Hydro Trunkline Construction				Operation	T&D	
		Construction	Cold Rolled Steel	Steel Plate	Aluminum Sheet	Concrete	Electricity	Cold Rolled Steel			
GHG (kg/MWh)	CO_2	1.05E+00	6.62E-02	1.04E-01	1.81E-02	2.28E-03	2.85E-03	1.77E-02	1.81E+01	0.00E+00	1.94E+01
	N_2O	0.00E+00	4.31E-07	5.43E-06	3.92E-07	0.00E+00	4.50E-08	1.15E-07	0.00E+00	0.00E+00	6.41E-06
	CH_4	0.00E+00	7.76E-05	7.92E-05	2.87E-05	0.00E+00	8.62E-06	2.07E-05	2.51E-01	0.00E+00	2.51E-01
	SF_6	0.00E+00	4.81E-13	0.00E+00	2.29E-12	0.00E+00	6.00E-10	1.28E-13	0.00E+00	1.43E-04	1.43E-04
	CO_2e (IPCC 2007 100-yr GWP)	1.05E+00	6.83E-02	1.08E-01	1.89E-02	2.28E-03	3.09E-03	1.82E-02	2.44E+01	3.27E+00	2.90E+01
Other Air (kg/MWh)	Pb	0.00E+00	1.19E-07	2.07E-07	2.40E-09	0.00E+00	1.89E-11	3.19E-08	0.00E+00	0.00E+00	3.61E-07
	Hg	0.00E+00	1.53E-10	1.30E-08	1.68E-10	0.00E+00	5.27E-11	4.08E-11	0.00E+00	0.00E+00	1.34E-08
	NH_3	0.00E+00	2.15E-07	0.00E+00	7.98E-08	0.00E+00	2.69E-09	5.74E-08	0.00E+00	0.00E+00	3.55E-07
	CO	4.87E-04	6.29E-04	8.81E-04	1.67E-04	2.94E-06	5.53E-07	1.68E-04	0.00E+00	0.00E+00	2.33E-03
	NOX	8.77E-04	1.25E-04	1.75E-04	2.47E-05	6.96E-06	4.37E-06	3.35E-05	0.00E+00	0.00E+00	1.25E-03
	SO_2	0.00E+00	9.17E-05	2.38E-04	6.78E-05	5.30E-06	9.12E-06	2.45E-05	0.00E+00	0.00E+00	4.36E-04
	VOC	0.00E+00	9.45E-06	-4.05E-13	3.31E-06	0.00E+00	7.72E-07	2.52E-06	0.00E+00	0.00E+00	1.60E-05
	PM	0.00E+00	4.04E-05	2.50E-05	3.29E-05	6.79E-06	1.17E-07	1.08E-05	0.00E+00	0.00E+00	1.16E-04
Solid Waste (kg/MWh)	Heavy metals to industrial soil	0.00E+00	1.14E-07	0.00E+00	8.07E-08	0.00E+00	1.88E-05	3.03E-08	0.00E+00	0.00E+00	1.90E-05
	Heavy metals to agricultural soil	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Water Use (L/MWh)	Withdrawal	0.00E+00	1.52E-01	5.52E-01	1.04E-01	9.77E-04	9.90E-02	4.06E-02	7.33E+04	0.00E+00	7.33E+04
	Discharge	0.00E+00	1.40E-01	0.00E+00	7.40E-02	0.00E+00	9.14E-02	3.73E-02	0.00E+00	0.00E+00	3.43E-01
	Consumption	0.00E+00	1.24E-02	5.52E-01	2.95E-02	9.77E-04	7.63E-03	3.31E-03	7.33E+04	0.00E+00	7.33E+04
Water Quality (kg/MWh)	Aluminum	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.04E-10	0.00E+00	0.00E+00	0.00E+00	4.04E-10
	Arsenic (+V)	0.00E+00	5.34E-10	0.00E+00	6.24E-10	0.00E+00	4.39E-09	1.42E-10	0.00E+00	0.00E+00	5.69E-09
	Copper (+II)	0.00E+00	2.04E-09	0.00E+00	1.14E-09	0.00E+00	5.22E-09	5.45E-10	0.00E+00	0.00E+00	8.95E-09
	Iron	0.00E+00	2.97E-06	3.37E-06	4.04E-06	0.00E+00	8.75E-08	7.92E-07	0.00E+00	0.00E+00	1.13E-05
	Lead (+II)	0.00E+00	1.10E-09	4.30E-08	2.05E-09	0.00E+00	2.14E-10	2.94E-10	0.00E+00	0.00E+00	4.67E-08
	Manganese (+II)	0.00E+00	2.76E-08	0.00E+00	9.04E-09	0.00E+00	6.72E-09	7.35E-09	0.00E+00	0.00E+00	5.07E-08
	Nickel (+II)	0.00E+00	3.10E-09	5.84E-09	6.97E-10	0.00E+00	2.00E-07	8.27E-10	0.00E+00	0.00E+00	2.11E-07
	Strontium	0.00E+00	1.31E-07	0.00E+00	1.31E-08	0.00E+00	1.46E-10	3.50E-08	0.00E+00	0.00E+00	1.80E-07
	Zinc (+II)	0.00E+00	3.00E-09	2.57E-08	8.73E-10	0.00E+00	5.58E-08	8.00E-10	0.00E+00	0.00E+00	8.61E-08
	Ammonium/ammonia	0.00E+00	1.36E-07	0.00E+00	6.13E-08	0.00E+00	4.67E-07	3.62E-08	0.00E+00	0.00E+00	7.01E-07
	Hydrogen chloride	0.00E+00	5.64E-13	0.00E+00	1.19E-12	0.00E+00	3.42E-14	1.50E-13	0.00E+00	0.00E+00	1.94E-12
	Nitrogen (as total N)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.41E-09	0.00E+00	0.00E+00	0.00E+00	1.41E-09
	Phosphate	0.00E+00	7.09E-08	0.00E+00	3.74E-09	0.00E+00	1.67E-11	1.89E-08	0.00E+00	0.00E+00	9.36E-08
	Phosphorus	0.00E+00	8.96E-10	3.51E-07	6.26E-10	0.00E+00	3.15E-09	2.39E-10	0.00E+00	0.00E+00	3.56E-07
Resource Energy (MJ/MWh)	Crude oil	0.00E+00	7.47E-02	2.29E-01	6.48E-02	0.00E+00	1.02E-03	1.99E-02	0.00E+00	0.00E+00	3.90E-01
	Hard coal	0.00E+00	6.79E-01	9.99E-01	4.92E-02	0.00E+00	9.01E-03	1.81E-01	0.00E+00	0.00E+00	1.92E+00
	Lignite	0.00E+00	1.70E-02	0.00E+00	2.41E-02	0.00E+00	4.74E-06	4.53E-03	0.00E+00	0.00E+00	4.56E-02
	Natural gas	0.00E+00	9.92E-02	1.99E-01	5.85E-02	0.00E+00	1.28E-02	2.65E-02	0.00E+00	0.00E+00	3.96E-01
	Uranium	0.00E+00	1.99E-02	0.00E+00	5.43E-02	0.00E+00	1.74E-05	5.30E-03	0.00E+00	0.00E+00	7.94E-02
	Total resource energy	0.00E+00	8.90E-01	1.43E+00	2.51E-01	0.00E+00	2.28E-02	2.37E-01	0.00E+00	0.00E+00	2.83E+00
Energy Return on Investment		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	1.273E+03

Table A-11: Detailed LCA Results – Power Upgrade to Conventional Hydropower

Category (Units)	Material or Energy Flow	ECF				PT	Total
		Hydropower Facility Construction			Operation	T&D	
		Construction	Cold Rolled Steel	Steel Plate			
GHG (kg/MWh)	CO_2	5.26E-01	3.00E-02	5.54E-03	1.81E+01	0.00E+00	1.87E+01
	N_2O	0.00E+00	1.95E-07	2.88E-07	0.00E+00	0.00E+00	4.83E-07
	CH_4	0.00E+00	3.52E-05	4.20E-06	2.51E-01	0.00E+00	2.51E-01
	SF_6	0.00E+00	2.18E-13	0.00E+00	0.00E+00	1.43E-04	1.43E-04
	CO_2e (IPCC 2007 100-yr GWP)	5.26E-01	3.10E-02	5.73E-03	2.44E+01	3.27E+00	2.82E+01
Other Air (kg/MWh)	Pb	0.00E+00	5.42E-08	1.10E-08	0.00E+00	0.00E+00	6.52E-08
	Hg	0.00E+00	6.93E-11	6.89E-10	0.00E+00	0.00E+00	7.58E-10
	NH_3	0.00E+00	9.77E-08	0.00E+00	0.00E+00	0.00E+00	9.77E-08
	CO	2.44E-05	2.85E-04	4.67E-05	0.00E+00	0.00E+00	3.56E-04
	NOX	4.87E-05	5.69E-05	9.27E-06	0.00E+00	0.00E+00	1.15E-04
	SO_2	0.00E+00	4.16E-05	1.26E-05	0.00E+00	0.00E+00	5.42E-05
	VOC	0.00E+00	4.29E-06	-2.15E-14	0.00E+00	0.00E+00	4.29E-06
	PM	0.00E+00	1.83E-05	1.33E-06	0.00E+00	0.00E+00	1.97E-05
Solid Waste (kg/MWh)	Heavy metals to industrial soil	0.00E+00	5.15E-08	0.00E+00	0.00E+00	0.00E+00	5.15E-08
	Heavy metals to agricultural soil	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Water Use (L/MWh)	Withdrawal	0.00E+00	6.91E-02	2.93E-02	7.33E+04	0.00E+00	7.33E+04
	Discharge	0.00E+00	6.35E-02	0.00E+00	0.00E+00	0.00E+00	6.35E-02
	Consumption	0.00E+00	5.64E-03	2.93E-02	7.33E+04	0.00E+00	7.33E+04
Water Quality (kg/MWh)	Aluminum	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	Arsenic (+V)	0.00E+00	2.42E-10	0.00E+00	0.00E+00	0.00E+00	2.42E-10
	Copper (+II)	0.00E+00	9.28E-10	0.00E+00	0.00E+00	0.00E+00	9.28E-10
	Iron	0.00E+00	1.35E-06	1.79E-07	0.00E+00	0.00E+00	1.53E-06
	Lead (+II)	0.00E+00	5.00E-10	2.28E-09	0.00E+00	0.00E+00	2.78E-09
	Manganese (+II)	0.00E+00	1.25E-08	0.00E+00	0.00E+00	0.00E+00	1.25E-08
	Nickel (+II)	0.00E+00	1.41E-09	3.09E-10	0.00E+00	0.00E+00	1.72E-09
	Strontium	0.00E+00	5.96E-08	0.00E+00	0.00E+00	0.00E+00	5.96E-08
	Zinc (+II)	0.00E+00	1.36E-09	1.36E-09	0.00E+00	0.00E+00	2.72E-09
	Ammonium/ammonia	0.00E+00	6.16E-08	0.00E+00	0.00E+00	0.00E+00	6.16E-08
	Hydrogen chloride	0.00E+00	2.56E-13	0.00E+00	0.00E+00	0.00E+00	2.56E-13
	Nitrogen (as total N)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	Phosphate	0.00E+00	3.22E-08	0.00E+00	0.00E+00	0.00E+00	3.22E-08
	Phosphorus	0.00E+00	4.06E-10	1.86E-08	0.00E+00	0.00E+00	1.90E-08
Resource Energy (MJ/MWh)	Crude oil	0.00E+00	3.39E-02	1.21E-02	0.00E+00	0.00E+00	4.60E-02
	Hard coal	0.00E+00	3.08E-01	5.29E-02	0.00E+00	0.00E+00	3.61E-01
	Lignite	0.00E+00	7.71E-03	0.00E+00	0.00E+00	0.00E+00	7.71E-03
	Natural gas	0.00E+00	4.50E-02	1.06E-02	0.00E+00	0.00E+00	5.56E-02
	Uranium	0.00E+00	9.01E-03	0.00E+00	0.00E+00	0.00E+00	9.01E-03
	Total resource energy	0.00E+00	4.04E-01	7.56E-02	0.00E+00	0.00E+00	4.79E-01
Energy Return on Investment		N/A	N/A	N/A	N/A	N/A	7.511E+03

Table A-12: Detailed LCA Results – Existing Conventional Hydropower

Category (Units)	Material or Energy Flow	ECF	PT	Total
		Operation	T&D	
GHG (kg/MWh)	CO_2	1.81E+01	0.00E+00	1.81E+01
	N_2O	0.00E+00	0.00E+00	0.00E+00
	CH_4	2.51E-01	0.00E+00	2.51E-01
	SF_6	0.00E+00	1.43E-04	1.43E-04
	CO_2e (IPCC 2007 100-yr GWP)	2.44E+01	3.27E+00	2.77E+01
Other Air (kg/MWh)	Pb	0.00E+00	0.00E+00	0.00E+00
	Hg	0.00E+00	0.00E+00	0.00E+00
	NH_3	0.00E+00	0.00E+00	0.00E+00
	CO	0.00E+00	0.00E+00	0.00E+00
	NOX	0.00E+00	0.00E+00	0.00E+00
	SO_2	0.00E+00	0.00E+00	0.00E+00
	VOC	0.00E+00	0.00E+00	0.00E+00
	PM	0.00E+00	0.00E+00	0.00E+00
Solid Waste (kg/MWh)	Heavy metals to industrial soil	0.00E+00	0.00E+00	0.00E+00
	Heavy metals to agricultural soil	0.00E+00	0.00E+00	0.00E+00
Water Use (L/MWh)	Withdrawal	7.33E+04	0.00E+00	7.33E+04
	Discharge	0.00E+00	0.00E+00	0.00E+00
	Consumption	7.33E+04	0.00E+00	7.33E+04
Water Quality (kg/MWh)	Aluminum	0.00E+00	0.00E+00	0.00E+00
	Arsenic (+V)	0.00E+00	0.00E+00	0.00E+00
	Copper (+II)	0.00E+00	0.00E+00	0.00E+00
	Iron	0.00E+00	0.00E+00	0.00E+00
	Lead (+II)	0.00E+00	0.00E+00	0.00E+00
	Manganese (+II)	0.00E+00	0.00E+00	0.00E+00
	Nickel (+II)	0.00E+00	0.00E+00	0.00E+00
	Strontium	0.00E+00	0.00E+00	0.00E+00
	Zinc (+II)	0.00E+00	0.00E+00	0.00E+00
	Ammonium/ammonia	0.00E+00	0.00E+00	0.00E+00
	Hydrogen chloride	0.00E+00	0.00E+00	0.00E+00
	Nitrogen (as total N)	0.00E+00	0.00E+00	0.00E+00
	Phosphate	0.00E+00	0.00E+00	0.00E+00
	Phosphorus	0.00E+00	0.00E+00	0.00E+00
Resource Energy (MJ/MWh)	Crude oil	0.00E+00	0.00E+00	0.00E+00
	Hard coal	0.00E+00	0.00E+00	0.00E+00
	Lignite	0.00E+00	0.00E+00	0.00E+00
	Natural gas	0.00E+00	0.00E+00	0.00E+00
	Uranium	0.00E+00	0.00E+00	0.00E+00
	Total resource energy	0.00E+00	0.00E+00	0.00E+00
Energy Return on Investment		N/A	N/A	--

Table A-13: Detailed LCA Results – Geothermal

Category (Units)	Material or Energy Flow	ECF																	PT	Total
		Access Road Const.	Operations	Pipeline	Plant Construction								Power Plant Installation/ Deinstallation	Trunkline Const.	Well Construction/Installation				T&D	
					Aluminum Sheet	Balance of Plant Const.	Cast Iron	Concrete	Electricity	Heavy Fuel Oil	Steel Pipe	Steel Plate			Concrete	Electricity	Steel Pipe	Well Const.		
GHG (kg/MWh)	CO_2	7.64E-04	2.30E+02	8.85E-02	1.28E-02	0.00E+00	6.10E-02	4.80E-02	2.73E-03	1.20E-04	5.02E-02	1.43E-01	4.27E-01	5.60E-01	7.74E-03	9.67E-03	6.13E-02	2.19E-01	0.00E+00	2.31E+02
	N_2O	2.31E-07	0.00E+00	4.67E-06	2.22E-07	0.00E+00	9.64E-07	0.00E+00	3.92E-08	1.05E-09	2.80E-06	7.44E-06	1.06E-05	7.56E-06	0.00E+00	1.53E-07	3.42E-06	0.00E+00	0.00E+00	3.81E-05
	CH_4	2.21E-06	4.27E-01	9.26E-05	2.11E-05	0.00E+00	1.84E-04	0.00E+00	2.18E-06	1.24E-07	5.32E-05	1.09E-04	4.85E-04	7.95E-04	0.00E+00	2.92E-05	6.49E-05	1.20E-05	0.00E+00	4.29E-01
	SF_6	2.80E-16	0.00E+00	1.95E-15	1.30E-12	0.00E+00	1.28E-08	0.00E+00	9.30E-15	5.15E-17	0.00E+00	0.00E+00	1.36E-13	8.25E-09	0.00E+00	2.04E-09	0.00E+00	0.00E+00	1.43E-04	1.43E-04
	CO_2e (IPCC 2007 100-yr GWP)	8.88E-04	2.40E+02	9.22E-02	1.34E-02	0.00E+00	6.62E-02	4.80E-02	2.79E-03	1.23E-04	5.24E-02	1.48E-01	4.42E-01	5.83E-01	7.74E-03	1.05E-02	6.39E-02	2.19E-01	3.27E+00	2.45E+02
Other Air (kg/MWh)	Pb	3.35E-12	0.00E+00	2.47E-07	2.07E-09	0.00E+00	4.04E-10	0.00E+00	1.36E-10	1.95E-11	1.53E-07	2.84E-07	1.64E-09	4.70E-07	0.00E+00	6.41E-11	1.87E-07	0.00E+00	0.00E+00	1.34E-06
	Hg	2.78E-13	0.00E+00	6.53E-09	1.67E-10	0.00E+00	1.13E-09	0.00E+00	5.25E-12	9.01E-14	4.05E-09	1.78E-08	1.54E-10	3.58E-09	0.00E+00	1.79E-10	4.94E-09	0.00E+00	0.00E+00	3.86E-08
	NH_3	3.66E-07	4.53E-01	2.26E-07	4.79E-08	0.00E+00	5.76E-08	0.00E+00	5.29E-09	6.97E-10	0.00E+00	0.00E+00	1.55E-05	1.92E-06	0.00E+00	9.14E-09	0.00E+00	0.00E+00	0.00E+00	4.53E-01
	CO	2.68E-05	0.00E+00	6.23E-04	1.11E-04	0.00E+00	1.18E-05	6.19E-05	3.45E-06	4.41E-08	3.72E-04	1.21E-03	1.66E-02	4.63E-03	9.97E-06	1.87E-06	4.54E-04	1.04E-03	0.00E+00	2.52E-02
	NOX	7.80E-05	0.00E+00	2.00E-04	2.25E-05	0.00E+00	9.35E-05	1.47E-04	2.14E-06	1.37E-07	8.20E-05	2.40E-04	6.04E-03	9.52E-04	2.36E-05	1.48E-05	1.00E-04	4.53E-03	0.00E+00	1.25E-02
	SO_2	4.79E-07	0.00E+00	2.34E-04	7.10E-05	0.00E+00	1.95E-04	1.12E-04	1.53E-06	5.06E-07	1.43E-04	3.26E-04	3.41E-04	1.46E-03	1.80E-05	3.10E-05	1.74E-04	0.00E+00	0.00E+00	3.11E-03
	VOC	2.27E-06	0.00E+00	2.91E-06	2.60E-06	0.00E+00	1.65E-05	0.00E+00	7.13E-07	3.50E-08	-1.95E-13	-5.56E-13	2.03E-04	9.04E-05	0.00E+00	2.62E-06	-2.37E-13	1.21E-04	0.00E+00	4.43E-04
	PM	1.67E-04	0.00E+00	9.50E-05	2.18E-05	0.00E+00	2.50E-06	1.43E-04	4.47E-06	2.23E-09	5.90E-05	3.43E-05	1.67E-06	6.93E-04	2.30E-05	3.96E-07	7.20E-05	0.00E+00	0.00E+00	1.32E-03
Solid Waste (kg/MWh)	Heavy metals to industrial soil	9.05E-09	0.00E+00	6.32E-08	2.84E-07	0.00E+00	4.02E-04	0.00E+00	1.26E-08	1.31E-09	0.00E+00	0.00E+00	4.42E-06	2.65E-04	0.00E+00	6.37E-05	0.00E+00	0.00E+00	0.00E+00	7.35E-04
	Heavy metals to agricultural soil	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Water Use (L/MWh)	Withdrawal	5.49E-04	4.07E+01	9.12E-01	8.88E-02	0.00E+00	2.12E+00	2.06E-02	6.77E-03	4.29E-05	5.64E-01	7.57E-01	1.25E+00	3.35E+00	3.32E-03	3.36E-01	6.88E-01	4.07E+00	0.00E+00	5.49E+01
	Discharge	1.34E-04	0.00E+00	9.32E-04	6.69E-02	0.00E+00	1.96E+00	0.00E+00	2.60E-03	3.23E-05	0.00E+00	0.00E+00	6.52E-02	2.78E+00	0.00E+00	3.10E-01	0.00E+00	0.00E+00	0.00E+00	5.18E+00
	Consumption	4.16E-04	4.07E+01	9.12E-01	2.19E-02	0.00E+00	1.63E-01	2.06E-02	4.18E-03	1.06E-05	5.64E-01	7.57E-01	1.18E+00	5.68E-01	3.32E-03	2.59E-02	6.88E-01	4.07E+00	0.00E+00	4.97E+01
Water Quality (kg/MWh)	Aluminum	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	8.66E-09	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	5.54E-09	0.00E+00	1.37E-09	0.00E+00	0.00E+00	0.00E+00	1.56E-08
	Arsenic (+V)	3.09E-09	0.00E+00	2.16E-08	4.09E-10	0.00E+00	9.39E-08	0.00E+00	1.57E-11	2.88E-12	0.00E+00	0.00E+00	1.51E-06	7.06E-08	0.00E+00	1.49E-08	0.00E+00	0.00E+00	0.00E+00	1.71E-06
	Copper (+II)	4.53E-09	0.00E+00	3.16E-08	8.41E-10	0.00E+00	1.12E-07	0.00E+00	3.18E-11	2.28E-11	0.00E+00	0.00E+00	2.21E-06	9.46E-08	0.00E+00	1.77E-08	0.00E+00	0.00E+00	0.00E+00	2.47E-06
	Iron	2.31E-07	0.00E+00	6.11E-06	2.87E-06	0.00E+00	1.87E-06	0.00E+00	1.27E-07	1.79E-09	2.79E-06	4.63E-06	1.13E-04	6.75E-05	0.00E+00	2.97E-07	3.41E-06	0.00E+00	0.00E+00	2.03E-04
	Lead (+II)	1.04E-08	0.00E+00	1.01E-07	1.79E-09	0.00E+00	4.58E-09	0.00E+00	4.76E-11	5.67E-12	1.76E-08	5.90E-08	5.08E-06	3.50E-08	0.00E+00	7.26E-10	2.15E-08	0.00E+00	0.00E+00	5.33E-06
	Manganese (+II)	1.39E-11	0.00E+00	9.68E-11	7.87E-09	0.00E+00	1.44E-07	0.00E+00	7.01E-10	3.67E-12	0.00E+00	0.00E+00	6.77E-09	3.17E-07	0.00E+00	2.28E-08	0.00E+00	0.00E+00	0.00E+00	4.99E-07
	Nickel (+II)	8.24E-08	0.00E+00	5.83E-07	5.25E-10	0.00E+00	4.29E-06	0.00E+00	6.65E-11	6.75E-12	5.15E-09	8.01E-09	4.02E-05	2.77E-06	0.00E+00	6.80E-07	6.28E-09	0.00E+00	0.00E+00	4.86E-05
	Strontium	7.59E-11	0.00E+00	5.30E-10	1.08E-08	0.00E+00	3.12E-09	0.00E+00	2.79E-09	1.88E-10	0.00E+00	0.00E+00	3.70E-08	6.61E-07	0.00E+00	4.94E-10	0.00E+00	0.00E+00	0.00E+00	7.16E-07
	Zinc (+II)	1.43E-07	0.00E+00	1.01E-06	6.58E-10	0.00E+00	1.19E-06	0.00E+00	6.94E-11	5.79E-12	5.56E-09	3.53E-08	6.98E-05	7.87E-07	0.00E+00	1.89E-07	6.78E-09	0.00E+00	0.00E+00	7.32E-05
	Ammonium/ammonia	1.17E-06	0.00E+00	8.71E-06	4.77E-08	0.00E+00	1.05E-05	0.00E+00	7.65E-09	1.56E-10	3.23E-07	4.50E-06	5.73E-04	8.06E-06	0.00E+00	1.66E-06	3.94E-07	0.00E+00	0.00E+00	6.08E-04
	Hydrogen chloride	2.91E-14	0.00E+00	2.03E-13	8.06E-13	0.00E+00	7.31E-13	0.00E+00	1.17E-14	4.41E-15	0.00E+00	0.00E+00	1.42E-11	1.89E-11	0.00E+00	1.16E-13	0.00E+00	0.00E+00	0.00E+00	3.50E-11
	Nitrogen (as total N)	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	3.03E-08	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.94E-08	0.00E+00	4.80E-09	0.00E+00	0.00E+00	0.00E+00	5.45E-08
	Phosphate	3.43E-12	0.00E+00	2.40E-11	2.65E-09	0.00E+00	3.57E-10	0.00E+00	4.49E-11	1.99E-11	0.00E+00	0.00E+00	1.68E-09	3.11E-07	0.00E+00	5.66E-11	0.00E+00	0.00E+00	0.00E+00	3.16E-07
	Phosphorus	1.04E-07	0.00E+00	7.27E-07	4.69E-10	0.00E+00	6.75E-08	0.00E+00	1.61E-11	3.42E-12	2.90E-09	4.82E-07	5.05E-05	5.50E-08	0.00E+00	1.07E-08	3.54E-09	0.00E+00	0.00E+00	5.20E-05
Resource Energy (MJ/MWh)	Crude oil	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	Hard coal	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.82E-06	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	3.09E-06	0.00E+00	7.64E-07	0.00E+00	0.00E+00	0.00E+00	8.67E-06
	Lignite	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	Natural gas	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.66E-01	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.70E-01	0.00E+00	4.21E-02	0.00E+00	0.00E+00	0.00E+00	4.78E-01
	Uranium	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	Total resource energy	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.66E-01	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.70E-01	0.00E+00	4.21E-02	0.00E+00	0.00E+00	0.00E+00	4.78E-01
Energy Return on Investment		0.00E+00	N/A	0.00E+00	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	0.00E+00	0.00E+00	N/A	N/A	N/A	N/A	N/A	7,532

Table A-14: Detailed LCA Results – Solar Thermal

Category (Units)	Material or Energy Flow	Energy Conversion Facility										
		Plant Construction							Collector Construction			
		Aluminum Sheet	Cast Iron	Cold Rolled Steel	Concrete	Diesel	Installation	Steel Pipe	Glass	Heat Transfer Fluid	Steel Plate	Dust Suppression During Construction
GHG (kg/MWh)	CO_2	3.515E-02	1.042E-02	6.268E-01	2.958E-01	1.809E-01	8.807E-01	1.375E-01	9.628E+00	3.935E-01	7.693E+00	0.000E+00
	N_2O	6.087E-07	1.516E-07	4.077E-06	2.596E-06	3.553E-06	2.271E-05	7.677E-06	5.371E-03	4.860E-06	3.996E-04	0.000E+00
	CH_4	5.770E-05	1.425E-05	7.347E-04	4.970E-04	1.155E-03	5.065E-05	1.456E-04	4.024E-02	1.881E-03	5.835E-03	0.000E+00
	SF_6	3.566E-12	5.533E-10	4.549E-12	3.460E-08	3.396E-13	0.000E+00	0.000E+00	4.149E-11	8.511E-13	0.000E+00	0.000E+00
	CO_2e (IPCC 2007 100-yr GWP)	3.677E-02	1.084E-02	6.464E-01	3.098E-01	2.108E-01	8.887E-01	1.434E-01	1.223E+01	4.419E-01	7.958E+00	0.000E+00
Other Air (kg/MWh)	Pb	5.655E-09	4.419E-10	1.131E-06	1.089E-09	4.075E-09	0.000E+00	4.190E-07	2.181E-07	1.093E-08	1.524E-05	0.000E+00
	Hg	4.574E-10	6.325E-11	1.447E-09	3.041E-09	3.382E-10	4.398E-11	1.109E-08	3.353E-08	1.067E-09	9.569E-07	0.000E+00
	NH_3	1.312E-07	1.886E-08	2.038E-06	1.552E-07	2.307E-06	3.637E-05	0.000E+00	1.545E-05	3.131E-06	0.000E+00	0.000E+00
	CO	3.031E-04	1.009E-05	5.951E-03	2.013E-04	1.724E-04	4.117E-02	1.018E-03	4.312E-03	3.385E-04	6.489E-02	0.000E+00
	NO_X	6.172E-05	1.026E-05	1.187E-03	6.529E-04	2.364E-04	1.480E-02	2.244E-04	2.170E-02	7.508E-04	1.288E-02	0.000E+00
	SO_2	1.944E-04	1.399E-05	8.679E-04	8.317E-04	4.741E-04	3.741E-04	3.906E-04	3.433E-02	1.010E-03	1.750E-02	0.000E+00
	VOC	7.130E-06	2.759E-06	8.940E-05	4.454E-05	5.061E-04	0.000E+00	-5.326E-13	2.910E-02	3.680E-04	-2.983E-11	0.000E+00
	PM	6.523E-05	1.250E-05	4.040E-04	4.116E-03	2.379E-05	0.000E+00	1.615E-04	2.718E-02	4.031E-05	1.844E-03	0.000E+00
Solid Waste (kg/MWh)	Heavy metals to industrial soil	7.779E-07	1.734E-05	5.410E-06	1.082E-03	1.100E-05	0.000E+00	0.000E+00	7.088E-05	2.043E-05	0.000E+00	0.000E+00
	Heavy metals to agricultural soil	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00
Water Use (L/MWh)	Withdrawal	2.431E-01	1.099E-01	1.442E+00	5.766E+00	6.672E-01	2.437E+00	1.544E+00	6.798E+01	6.813E-01	4.066E+01	1.917E+02
	Discharge	1.832E-01	9.144E-02	1.324E+00	5.269E+00	1.623E-01	0.000E+00	0.000E+00	5.414E+01	5.664E-01	0.000E+00	0.000E+00
	Consumption	5.998E-02	1.849E-02	1.176E-01	4.964E-01	5.049E-01	2.437E+00	1.544E+00	1.384E+01	1.149E-01	4.066E+01	1.917E+02
Water Quality (kg/MWh)	Aluminum	1.580E-07	8.849E-09	4.498E-07	2.147E-07	1.317E-04	0.000E+00	0.000E+00	1.374E-05	2.163E-07	0.000E+00	0.000E+00
	Arsenic (+V)	1.120E-09	4.095E-09	5.053E-09	2.529E-07	3.754E-06	0.000E+00	0.000E+00	1.635E-07	3.122E-08	0.000E+00	0.000E+00
	Copper (+II)	2.303E-09	4.965E-09	1.935E-08	3.012E-07	5.500E-06	0.000E+00	0.000E+00	2.915E-06	3.505E-07	0.000E+00	0.000E+00
	Iron	7.858E-06	4.331E-07	2.812E-05	5.045E-06	2.805E-04	0.000E+00	7.645E-06	2.083E-03	3.193E-05	2.485E-04	0.000E+00
	Lead (+II)	4.888E-09	3.430E-10	1.043E-08	1.234E-08	1.264E-05	0.000E+00	4.824E-08	1.005E-06	8.870E-08	3.168E-06	0.000E+00
	Manganese (+II)	2.154E-08	8.128E-09	2.609E-07	3.878E-07	1.685E-08	0.000E+00	0.000E+00	2.202E-06	4.697E-08	0.000E+00	0.000E+00
	Nickel (+II)	1.437E-09	1.849E-07	2.936E-08	1.155E-05	1.001E-04	0.000E+00	1.409E-08	8.966E-07	9.866E-08	4.298E-07	0.000E+00
	Strontium	2.950E-08	8.293E-09	1.244E-06	8.398E-09	9.218E-08	0.000E+00	0.000E+00	5.483E-06	3.142E-06	0.000E+00	0.000E+00
	Zinc (+II)	1.802E-09	5.161E-08	2.838E-08	3.215E-06	1.736E-04	0.000E+00	1.521E-08	7.569E-07	8.075E-08	1.893E-06	0.000E+00
	Ammonium/ammonia	1.306E-07	4.733E-07	1.299E-06	2.826E-05	1.425E-03	0.000E+00	8.830E-07	2.124E-05	1.098E-06	2.416E-04	0.000E+00
	Hydrogen chloride	2.206E-12	7.554E-14	5.340E-12	1.970E-12	3.533E-11	0.000E+00	0.000E+00	6.014E-10	6.156E-11	0.000E+00	0.000E+00
	Nitrogen (as total N)	0.000E+00	1.305E-09	0.000E+00	8.159E-08	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00
	Phosphate	7.244E-09	1.927E-10	6.716E-07	9.619E-10	4.172E-09	0.000E+00	0.000E+00	2.932E-05	4.485E-07	0.000E+00	0.000E+00
	Phosphorus	1.284E-09	2.960E-09	8.480E-09	1.818E-07	1.258E-04	0.000E+00	7.944E-09	1.488E-07	5.308E-08	2.589E-05	0.000E+00
Resource Energy (MJ/MWh)	Crude oil	1.275E-01	7.699E-03	7.070E-01	5.909E-02	1.147E+01	0.000E+00	2.327E-01	3.418E+00	2.041E+01	1.687E+01	0.000E+00
	Hard coal	1.196E-01	4.844E-02	6.426E+00	5.193E-01	1.684E-01	0.000E+00	9.648E-01	2.130E+01	3.349E-01	7.357E+01	0.000E+00
	Lignite	4.078E-02	2.076E-03	1.609E-01	2.735E-04	6.167E-03	0.000E+00	0.000E+00	1.571E+00	2.276E-02	0.000E+00	0.000E+00
	Natural gas	9.668E-02	1.628E-02	9.391E-01	7.362E-01	1.291E+00	0.000E+00	3.982E-01	9.500E+01	2.086E+00	1.467E+01	0.000E+00
	Uranium	1.321E-01	3.410E-03	1.880E-01	1.002E-03	8.201E-02	0.000E+00	0.000E+00	1.122E+01	1.655E-01	0.000E+00	0.000E+00
	Total resource energy	5.167E-01	7.791E-02	8.421E+00	1.316E+00	1.302E+01	0.000E+00	1.596E+00	1.325E+02	2.302E+01	1.051E+02	0.000E+00
Energy Return on Investment		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Table A-14: Detailed LCA Results – Solar Thermal (Continued)

Category (Units)	Material or Energy Flow	Energy Conversion Facility						Product Transport	Total
		Operation					Trunkline		
		Diesel Upstream	Gasoline Upstream	Natural Gas Upstream	Fuels Combustion and Operation	Heat Transfer Fluid	Construction	T&D	
GHG (kg/MWh)	CO_2	1.383E-02	6.981E-02	3.425E-01	1.578E+01	5.902E-01	3.067E-01	0.000E+00	3.698E+01
	N_2O	2.717E-07	1.384E-06	9.089E-06	6.817E-04	7.290E-06	4.140E-06	0.000E+00	6.521E-03
	CH_4	8.833E-05	4.388E-04	4.165E-02	4.083E-04	2.821E-03	4.351E-04	0.000E+00	9.645E-02
	SF_6	2.597E-14	1.386E-13	2.516E-09	0.000E+00	1.277E-12	4.519E-09	1.433E-04	1.434E-04
	CO_2e (IPCC 2007 100-yr GWP)	1.612E-02	8.120E-02	1.386E+00	1.599E+01	6.629E-01	3.189E-01	3.268E+00	4.460E+01
Other Air (kg/MWh)	Pb	3.116E-10	1.557E-09	2.910E-08	0.000E+00	1.640E-08	2.572E-07	0.000E+00	1.733E-05
	Hg	2.586E-11	1.321E-10	9.916E-10	0.000E+00	1.600E-09	1.962E-09	0.000E+00	1.013E-06
	NH_3	1.764E-07	8.808E-07	3.913E-08	0.000E+00	4.697E-06	1.050E-06	0.000E+00	6.644E-05
	CO	1.318E-05	6.547E-05	6.025E-04	4.854E-01	5.078E-04	2.535E-03	0.000E+00	6.074E-01
	NO_X	1.808E-05	8.989E-05	6.581E-03	3.353E-02	1.126E-03	5.212E-04	0.000E+00	9.437E-02
	SO_2	3.625E-05	1.840E-04	7.281E-05	5.811E-04	1.514E-03	8.005E-04	0.000E+00	5.917E-02
	VOC	3.870E-05	1.857E-04	6.374E-03	2.612E-04	5.520E-04	4.952E-05	0.000E+00	3.758E-02
	PM	1.819E-06	8.607E-06	6.599E-05	3.609E-04	6.046E-05	8.767E-04	0.000E+00	3.522E-02
Solid Waste (kg/MWh)	Heavy metals to industrial soil	8.410E-07	4.868E-06	7.918E-05	0.000E+00	3.065E-05	1.448E-04	0.000E+00	1.468E-03
	Heavy metals to agricultural soil	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00	0.000E+00
Water Use (L/MWh)	Withdrawal	5.101E-02	2.808E-01	2.336E+00	1.212E+02	1.022E+00	1.831E+00	0.000E+00	4.400E+02
	Discharge	1.241E-02	6.407E-02	2.757E+00	0.000E+00	8.496E-01	1.520E+00	0.000E+00	6.694E+01
	Consumption	3.860E-02	2.167E-01	-4.210E-01	1.212E+02	1.724E-01	3.109E-01	0.000E+00	3.730E+02
Water Quality (kg/MWh)	Aluminum	1.007E-05	4.065E-08	6.415E-07	0.000E+00	3.245E-07	6.100E-07	0.000E+00	1.581E-04
	Arsenic (+V)	2.871E-07	1.654E-06	3.622E-08	0.000E+00	4.683E-08	3.865E-08	0.000E+00	6.275E-06
	Copper (+II)	4.205E-07	2.418E-06	4.782E-08	0.000E+00	5.257E-07	5.179E-08	0.000E+00	1.256E-05
	Iron	2.145E-05	1.233E-04	3.357E-06	0.000E+00	4.789E-05	3.693E-05	0.000E+00	2.926E-03
	Lead (+II)	9.666E-07	5.572E-06	6.431E-08	0.000E+00	1.331E-07	1.916E-08	0.000E+00	2.373E-05
	Manganese (+II)	1.288E-09	6.660E-09	3.327E-05	0.000E+00	7.045E-08	1.734E-07	0.000E+00	3.646E-05
	Nickel (+II)	7.650E-06	4.411E-05	1.322E-06	0.000E+00	1.480E-07	1.514E-06	0.000E+00	1.680E-04
	Strontium	7.048E-09	4.094E-08	1.969E-09	0.000E+00	4.713E-06	3.621E-07	0.000E+00	1.513E-05
	Zinc (+II)	1.328E-05	7.656E-05	1.062E-06	0.000E+00	1.211E-07	4.307E-07	0.000E+00	2.711E-04
	Ammonium/ammonia	1.090E-04	6.285E-04	8.895E-06	0.000E+00	1.647E-06	4.411E-06	0.000E+00	2.473E-03
	Hydrogen chloride	2.702E-12	1.256E-11	1.999E-13	0.000E+00	9.235E-11	1.034E-11	0.000E+00	8.261E-10
	Nitrogen (as total N)	0.000E+00	0.000E+00	1.215E-05	0.000E+00	0.000E+00	1.061E-08	0.000E+00	1.224E-05
	Phosphate	3.190E-10	1.594E-09	8.338E-11	0.000E+00	6.728E-07	1.702E-07	0.000E+00	3.130E-05
	Phosphorus	9.615E-06	5.544E-05	7.725E-07	0.000E+00	7.961E-08	3.014E-08	0.000E+00	2.180E-04
Resource Energy (MJ/MWh)	Crude oil	8.772E-01	4.430E+00	3.811E-02	0.000E+00	3.062E+01	6.435E-01	0.000E+00	8.992E+01
	Hard coal	1.288E-02	6.552E-02	1.623E-01	0.000E+00	5.024E-01	1.795E+00	0.000E+00	1.060E+02
	Lignite	4.716E-04	2.370E-03	6.837E-05	0.000E+00	3.414E-02	2.147E-01	0.000E+00	2.056E+00
	Natural gas	9.873E-02	4.707E-01	1.084E+02	0.000E+00	3.129E+00	7.330E-01	0.000E+00	2.280E+02
	Uranium	6.271E-03	3.277E-02	4.031E-04	0.000E+00	2.482E-01	4.468E-01	0.000E+00	1.253E+01
	Total resource energy	9.956E-01	5.001E+00	1.086E+02	0.000E+00	3.453E+01	3.833E+00	0.000E+00	4.385E+02
Energy Return on Investment		N/A	N/A	N/A	N/A	N/A	N/A	N/A	8.209E+00

Table A-15: Detailed LCA Results – 2010 U.S. Net Generation

Category (Units)	Material or Energy Flow	Cradle-to-Gate Electricity Production								T&D	Total
		Geothermal	Hydro	Wind	Solar	Coal	Natural Gas	Petroleum	Nuclear		
GHG (kg/MWh)	CO_2	7.94E-01	2.22E+00	4.18E-01	1.02E-02	4.73E+02	1.24E+02	1.00E+01	6.51E+00	0.00E+00	6.17E+02
	N_2O	1.38E-07	8.70E-08	1.98E-05	2.02E-06	8.89E-03	4.90E-04	1.37E-04	1.50E-04	0.00E+00	9.69E-03
	CH_4	1.47E-03	3.05E-02	9.90E-04	2.89E-05	7.86E-01	9.05E-01	1.19E-02	2.08E-02	0.00E+00	1.76E+00
	SF_6	8.16E-11	7.31E-11	2.95E-08	1.35E-11	3.56E-07	8.66E-08	4.91E-13	4.07E-08	1.43E-04	1.44E-04
	CO_2e (IPCC 2007 100-yr)	8.31E-01	2.98E+00	4.50E-01	1.15E-02	4.96E+02	1.47E+02	1.04E+01	7.08E+00	3.27E+00	6.68E+02
Other Air (kg/MWh)	Pb	2.73E-08	6.29E-08	1.46E-06	1.18E-08	2.90E-07	1.59E-06	6.73E-06	5.80E-07	0.00E+00	1.08E-05
	Hg	2.06E-10	2.14E-10	5.83E-09	3.43E-10	1.12E-05	4.96E-08	2.32E-08	2.73E-07	0.00E+00	1.16E-05
	NH_3	1.56E-03	2.36E-08	1.40E-05	3.04E-08	1.70E-04	1.12E-06	3.11E-05	4.03E-04	0.00E+00	2.18E-03
	CO	8.12E-05	2.86E-05	1.09E-03	1.87E-04	5.95E-02	1.79E-02	4.96E-03	7.20E-03	0.00E+00	9.09E-02
	NOX	4.39E-05	1.07E-05	1.11E-03	2.93E-05	6.75E-01	2.35E-01	2.24E-02	1.33E-02	0.00E+00	9.47E-01
	SO_2	1.15E-05	1.52E-05	7.76E-04	1.66E-05	1.85E+00	3.87E-03	6.02E-02	2.51E-02	0.00E+00	1.94E+00
	VOC	1.55E-06	8.81E-07	2.01E-04	1.16E-05	2.02E-03	1.35E-01	3.07E-03	1.98E-03	0.00E+00	1.42E-01
	PM	2.38E-06	8.41E-07	4.93E-04	7.62E-07	2.35E-02	7.09E-04	0.00E+00	1.38E-04	0.00E+00	2.48E-02
Solid Waste (kg/MWh)	Heavy Metals to Ind. Soil	2.95E-06	3.22E-06	9.74E-04	1.16E-06	1.12E-02	2.72E-03	1.63E-05	9.48E+00	0.00E+00	9.49E+00
	Heavy Metals to Ag. Soil	1.31E-10	3.30E-10	7.24E-09	2.92E-10	1.77E-08	6.22E-11	4.51E-07	6.16E-07	0.00E+00	1.09E-06
Water Use (L/MWh)	Withdrawal	4.93E+00	8.93E+03	1.46E+02	1.02E+00	2.15E+03	2.28E+02	3.78E+02	1.03E+03	0.00E+00	1.29E+04
	Discharge	2.49E-04	2.23E-04	9.21E-02	7.69E-04	2.83E+02	5.34E+01	0.00E+00	0.00E+00	0.00E+00	3.36E+02
	Consumption	4.93E+00	8.93E+03	1.46E+02	1.02E+00	1.87E+03	1.75E+02	3.78E+02	1.03E+03	0.00E+00	1.25E+04
Water Quality (kg/MWh)	Aluminum	3.69E-13	9.37E-13	1.63E-11	1.28E-13	2.99E-11	2.22E-14	1.87E-11	3.49E-11	0.00E+00	1.01E-10
	Arsenic (+V)	5.92E-09	6.80E-10	9.50E-07	2.08E-09	2.10E-05	1.15E-06	1.08E-06	1.07E-03	0.00E+00	1.09E-03
	Copper (+II)	8.54E-09	9.32E-10	1.25E-06	3.88E-09	2.72E-05	1.51E-06	3.31E-06	1.27E-03	0.00E+00	1.30E-03
	Iron	6.80E-07	5.65E-07	6.89E-05	3.00E-07	3.13E-03	1.10E-04	2.52E-05	1.77E-02	0.00E+00	2.10E-02
	Lead (+II)	1.83E-08	2.72E-10	-1.21E-07	7.27E-09	4.27E-05	1.96E-06	7.33E-07	8.01E-06	0.00E+00	5.33E-05
	Manganese (+II)	2.16E-07	5.37E-07	7.72E-06	1.13E-07	6.37E-04	9.60E-04	3.31E-05	7.21E-05	0.00E+00	1.71E-03
	Nickel (+II)	1.68E-07	2.47E-08	2.93E-05	5.20E-08	4.59E-04	4.30E-05	1.06E-06	1.00E-01	0.00E+00	1.01E-01
	Strontium	2.80E-09	6.84E-09	3.92E-07	2.38E-09	6.13E-07	6.03E-08	3.03E-06	1.01E-05	0.00E+00	1.42E-05
	Zinc (+II)	2.51E-07	7.12E-09	3.75E-05	8.37E-08	5.81E-04	3.22E-05	4.34E-07	1.33E-02	0.00E+00	1.40E-02
	Ammonium/ammonia	6.81E-08	6.75E-08	2.52E-04	2.96E-08	1.96E-03	6.73E-05	3.94E-06	2.32E-01	0.00E+00	2.34E-01
	Hydrogen chloride	5.62E-13	1.29E-12	3.36E-11	4.05E-13	1.90E-10	6.63E-12	3.42E-10	6.73E-10	0.00E+00	1.25E-09
	Nitrogen (as total N)	1.95E-14	1.75E-14	7.06E-12	3.24E-15	8.57E-11	2.09E-11	0.00E+00	9.81E-12	0.00E+00	1.24E-10
	Phosphate	4.03E-10	9.79E-10	4.05E-07	1.56E-09	9.43E-08	2.83E-09	7.36E-06	5.07E-07	0.00E+00	8.37E-06
	Phosphorus	1.80E-07	3.72E-09	2.45E-05	7.60E-08	4.44E-04	2.20E-05	2.81E-08	3.18E-04	0.00E+00	8.09E-04
Resource Energy (MJ/MWh)	Crude oil	2.19E-02	8.76E-03	2.32E+00	2.78E-02	3.44E+01	1.54E+00	1.14E+02	9.36E+00	0.00E+00	1.62E+02
	Hard coal	2.52E-02	3.80E-02	1.11E+00	3.23E-02	1.88E+03	6.93E+00	1.80E+00	5.70E+01	0.00E+00	1.95E+03
	Lignite	1.14E-03	2.82E-03	4.91E-02	4.90E-04	1.64E-01	2.09E-03	1.45E-01	1.06E-01	0.00E+00	4.71E-01
	Natural gas	9.87E-03	9.63E-03	1.34E+00	6.38E-02	1.74E+01	3.38E+03	1.22E+01	1.54E+02	0.00E+00	3.57E+03
	Uranium	2.16E-03	5.00E-03	1.25E-01	2.45E-03	7.49E-01	1.23E-02	6.93E-01	9.78E-01	0.00E+00	2.57E+00
	Total resource energy	6.03E-02	6.42E-02	4.94E+00	1.27E-01	1.94E+03	3.38E+03	1.29E+02	2.21E+02	0.00E+00	5.68E+03