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LIFE CYCLE ASSESSMENT OF EXISTING AND EMERGING DISTRIBUTED GENERATION TECHNOLOGIES IN CALIFORNIA

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Preface

The California Energy Commission's Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program conducts public interest research, development, and demonstration (RD&D) projects to benefit California.

The PIER Program strives to conduct the most promising public interest energy research by partnering with RD&D entities, including individuals, businesses, utilities, and public or private research institutions.

PIER funding efforts are focused on the following RD&D program areas:

- Buildings End-Use Energy Efficiency
- Energy Innovations Small Grants
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- Energy Systems Integration
- Environmentally Preferred Advanced Generation
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy Technologies
- Transportation

Life Cycle Assessment of Existing and Emerging Distributed Generation Technologies in California is the final report for the Life Cycle Assessment of Distributed Generation in California project (Contract Number 500-02-004, MR-026, WA No. MAQ-04-05) conducted by the National Renewable Energy Laboratory. The information from this project contributes to PIER's Energy-Related Environmental Research Program.

For more information about the PIER Program, please visit the Energy Commission's website at www.energy.ca.gov/pier or contact the Energy Commission at (916) 327-1551.

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Abstract

The National Renewable Energy Laboratory was funded by the California Energy Commission's Public Interest Energy Research Program and managed by the Institute of Energy and the Environment at the University of California Office of the President to conduct a life cycle assessment study on distributed generation. Life cycle assessment is an analytic method for identifying and evaluating the environmental impacts of emissions, resource consumption, and energy use associated with a specific process. In this study, the National Renewable Energy Laboratory examined the production of electricity by existing and emerging distributed generation technologies compared to a typical peaking power plant being built in California, a typical natural gas combined cycle power plant, and an integrated coal gasification combined cycle power plant.

With this study, policy makers will have a better understanding of the implications of recommending various options to use distributed generation technologies to meet California's growing electricity demand. The study was not designed to advocate one option over the other, but instead provides additional information about the true life cycle impacts of the alternatives.

Keywords: Life cycle assessment, LCA, distributed generation, DG, environmental impacts

Executive Summary

Introduction

The National Renewable Energy Laboratory conducted a life cycle assessment of the environmental impacts of distributed generation in California. *Distributed generation* is defined by the California Energy Commission as electricity production that is on-site or close to the load center and is interconnected to the utility distribution system.

Life cycle assessment is an analytic method for identifying and evaluating the environmental impacts of emissions, resource consumption, and energy use associated with a specific process; in the current analysis, the focus is on the generation of a kilowatt-hour of electricity. In life cycle assessment , material and energy balances are used to determine the environmental stressors (emissions, resource consumption, and energy use) of all required operations, including raw material extraction, transportation, processing, and final disposal of products and by-products. The results of this inventory are then used to evaluate the environmental impacts of the technology so that efforts can be focused on reducing negative effects.

This report summarizes the findings of the study for technologies generally considered to be current and future power generation options in California. The following distributed generation technologies were studied:

- Natural-gas combustion (simple-cycle) turbines
- Natural gas-fired microturbines
- Natural gas-fired reciprocating engines
- Photovoltaics
- Anaerobic digesters located at wastewater treatment plants feeding reciprocating engines
- Advanced diesel-fired generators
- Small-scale biomass gasification units feeding reciprocating engines, with residue biomass as the feedstock
- Anaerobic digesters using dairy waste, feeding reciprocating engines
- Molten carbonate fuel cells using natural gas
- Phosphoric acid fuel cells using natural gas
- Solid oxide fuel cells using natural gas
- Anaerobic digesters with fuel cells

For comparison, the following central generating technologies were also evaluated:

- Peaking power plant specific to California
- Natural gas combined cycle power plant
- Integrated coal gasification combined cycle power plant

Wind turbines were not considered to be distributed generation technology (and therefore not included) for this project because the majority of installations are not close to where the power is used.

Purpose

The National Renewable Energy Laboratory conducted a life cycle assessment of these technologies to determine the total environmental impact of delivering a kilowatt-hour to the consumer and to elucidate key conclusions for the use of decision makers in California.

Project Objectives

The project goal was to compare the overall environmental impacts and economic costs of distributed generation technologies and conventional power plants in California. Its intended audience is policy makers evaluating options to use distributed generation to help meet California's growing electricity demand. Insofar as environmental, economic, and political considerations affect the decisions that are made regarding energy, this study is aimed at providing detailed and interpreted information that can strengthen understanding of the environmental consequences of recommending various power generation technologies.

Methodology and Data Sources

All results were calculated based on the delivery of one kilowatt-hour of electricity to the consumer. As part of the calculations, the environmental stressors (emissions, resource consumption, and energy use) were also determined per kilowatt-hour produced by each electricity-generating technology. By presenting results in terms of the end user, losses associated with transmission and distribution are accounted for, and the mix of electricity used by a typical California consumer can be included in the analysis.

Generator operating emissions were taken from the literature and, where possible, based on field test data. Where distributed generation units were reported to have emissions higher than the allowed 2007 California permitting levels, emissions were capped at the standard maximum. This study does not determine whether the distributed generation technologies can meet these limits, but rather assumes that if they enter the marketplace, they will produce emissions below those allowed. Emissions of nitrogen oxides, carbon monoxide, and volatile organic compounds were limited for natural gas-fired microturbines, reciprocating engines, and gas turbines. Nitrogen oxide emissions were capped for anaerobic digester units. In addition to nitrogen oxides, carbon monoxide, and volatile organic compounds, sulfur dioxide, methane, nitrous oxide, 10 micron particulate matter, and 2.5 micron particulate matter were extracted from the literature and included in the model. In California, reciprocating engines and simple cycle gas turbines may be capped at the district limit instead of the Air Resources Board (ARB) limit. In general the district limit would be less stringent. All capping of emissions in this study are at the ARB limit for comparison.

In consideration of the importance of climate change discussions, the research team paid particular attention to the estimation of greenhouse gas emissions. Total greenhouse gases for each technology are calculated to be the combined effects of carbon dioxide, methane, and

nitrous oxide, weighted according to their global warming potential as specified by the Intergovernmental Panel on Climate Change.

Total energy use, defined as the amount of energy in the raw materials used to generate electricity plus the amount of energy used in all extraction, manufacturing, delivery, and disposal operations, was calculated for each technology. Renewable energy inputs to the system, such as solar energy and biomass energy, are not included in this metric because they are considered to be both created and used within the system boundaries.

Studying total energy acknowledges that raw energy sources are used to make useful energy, and that because of efficiency losses, more energy is consumed than is delivered as electricity. To complement energy results and to better understand the consumption of nonrenewable energy, individual resources such as coal, natural gas, and petroleum are accounted for. Additionally, due to its importance to the economy and well-being of California, the team included water consumption in the study of resource consumption.

The evaluation of distributed generation and conventional systems by life cycle assessment methodologies allows one to identify which environmental impacts are due to the generator itself and which are due to associated operations necessary for the generator to work. In this study, these operations include raw material acquisition, construction of equipment, transportation of equipment and fuels, and construction of the transmission and delivery system, as well as disposal. Of importance to decision makers regarding energy in California is an understanding of where the environmental effects from these systems will be felt. For example, smog-forming emissions, referred to as *photo-oxidants*, have local or regional impacts. That is, where these emissions occur is generally where the smog impacts will occur. Greenhouse gas emissions, on the other hand, have global impacts. In evaluating the relative environmental harm caused by competing technologies, it is important to appropriately compare local emissions for local impact categories and total emissions for global impact categories. Additionally, however, comparing total life cycle emissions of all impact categories can help users of an end product (in this case, electricity) take responsibility for the total environmental damage caused by their demand of that product, even if they do not feel the impacts themselves.

The major findings of this study can be broken into the following categories:

- Effect of generator efficiency
- Effect of natural gas production and distribution
- Local, regional, and global impacts
- Greenhouse gas emissions
- Effect of combined cooling, heating, and power

Within classes of technologies that use the same fuel, environmental impacts are reduced by choosing technologies that have the greatest generator efficiency. Greenhouse gases are most greatly reduced with the renewable technologies, although natural gas-fired distributed generation technologies can have lower greenhouse gas emissions than central power

generating facilities if the efficiency of the distributed generation systems are sufficiently high. The occurrence of natural gas leaks has a significant impact on total greenhouse gas emissions for natural gas-fired technologies. Additionally, total carbon monoxide and hydrocarbon emissions are increased because of natural gas leaks; however, these have local and regional air impacts rather than global impacts like greenhouse gases do. Inclusion of combined cooling, heating, and power in the system design can significantly reduce total greenhouse gas emissions, as normal methods for producing heat and cooling are avoided.

Air Emissions

Per kilowatt-hour of electricity produced by distributed generation and central plants and delivered to the consumer, natural gas-fired microturbines were responsible for the most carbon monoxide, greenhouse gases, sulfur dioxide, and non-methane organic compounds. Natural gas-fired reciprocating engines were found to be responsible for the greatest amount of total particulates—an emission linked to respiratory health. Of the natural gas-fired distributed generation technologies, fuel cells were generally found to have the lowest overall air emissions. Photovoltaics had the lowest air emissions, with those reported coming from the manufacturing and delivery processes.

Fossil Fuel and Water Consumption

Distributed generation technologies use little water because they do not involve a steam cycle. Integrated gasification combined cycle coal plants consumed much higher quantities of water than even the other central plant technologies studied. The integrated gasification combined cycle plants, included in the analysis as a reference technology, were obviously the largest consumers of coal, as well. Between the technologies that used natural gas, microturbines consumed the most fuel, followed by reciprocating engines. Differences in natural gas consumption are a direct result of generator efficiency. Thus, natural-gas combined cycle power plants consumed the lowest amount of fuel. Distributed generation diesel technologies consumed the most petroleum overall, for operation, and photovoltaic systems consumed the most petroleum for their manufacture. However, the amount of oil used is still low compared to the energy in the electricity produced. For total energy, microturbines consumed the most non-renewable energy per kilowatt-hour of electricity generated.

Greenhouse Gases

Total life cycle greenhouse gas emissions are shown in Figure ES-1. The lowest emissions are encountered in the biomass system due to avoided emissions of greenhouse gases associated with normal decomposition of the residue biomass. Similarly, the anaerobic digestion systems have low greenhouse gas emissions because of the avoided decomposition of wastewater treatment sludge and dairy waste. If the biomass is assumed to be sourced in a manner that does not assume avoided decomposition, but rather a cycling between photosynthetic absorption of carbon dioxide (CO_2) during its growth and emissions of CO_2 during combustion, greenhouse gas emissions from the biomass system are less than those of the wastewater treatment system, but higher than those of the dairy anaerobic digestion system and photovoltaics. The results of this case are shown in Figure ES-1 as a green point in the biomass column. Of the distributed generation technologies, microturbine distributed generation

systems have the highest rate of greenhouse gas emissions due to their low operating efficiency. Indeed, in comparing the natural gas-fired systems, efficiency is the sole reason for differences in life cycle greenhouse gas emissions.

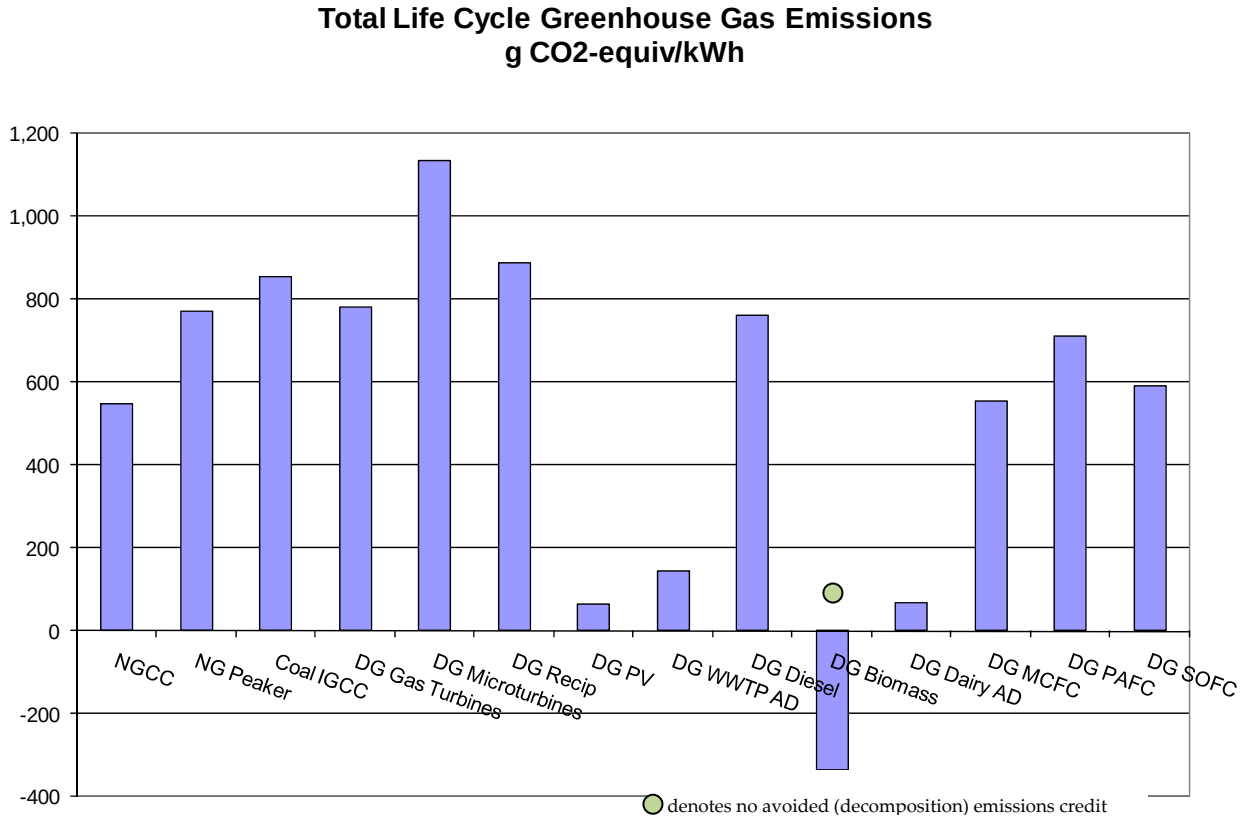


Figure ES-1. Total Life Cycle Greenhouse Gas Emissions

With respect to greenhouse gases, greater than 90 percent of the total life cycle emissions from coal integrated gasification combined cycle plants are emitted from the power plant itself. Thus, less than 10 percent are due to associated operations such as coal mining, coal transportation, power plant construction, and electrical transmission and delivery. For all of the natural gas-based technologies, the generator, or prime mover, is responsible for only about 60 percent of the total emissions per technology. The primary reason for this is the leakage of natural gas, which is primarily methane, during extraction and distribution to the power plants and distributed generation units; the global warming potential of methane is 21 times higher than that of carbon dioxide; so even a small amount of leaked natural gas increases the total greenhouse gases significantly. The operation of photovoltaics, which use renewable solar energy to generate electricity, is responsible for almost none of the total greenhouse gases in the photovoltaic system case; emissions are due almost exclusively to those from manufacturing and transportation. Total greenhouse gases for photovoltaics are significantly lower than those from other technologies.

Central power plants may have the possibility of carbon dioxide sequestration under future policies. Sequestration from small, distributed units is impractical and uneconomic. No sequestration scenarios are assumed in this study.

Smog-Forming Compounds

Photo-oxidants, which are primarily hydrocarbons (volatile organic compounds and non-methane organic compounds) and carbon monoxide affect local air quality and are responsible for smog formation.

Nitrogen oxides (NOx) and volatile organic compounds (VOCs) combine in atmosphere under the presence of sunlight to form smog (also known as ozone). Ozone formation does not occur unless all three of these components are present. Depending upon the relative amounts of NOx and VOCs, any region could be NOx limited or VOC limited. In simple terms, a NOx-limited region means that there are many more VOC compounds in the air compared with NOx, and therefore much of the VOC is not participating in the ozone production. Adding or taking away a moderate amount of VOC in a NOx-limited region will not affect the amount of ozone produced. In this case, NOx is the limiting reagent in the ozone production, and NOx levels must be reduced to reduce ozone levels. Similarly, in a VOC-limited regime, there is an excess of NOx in the atmosphere, and reducing ozone is best achieved by reducing VOC emissions. Many areas can switch between NOx- and VOC-limited areas, depending on time of day, year, or other factors.

Volatile organic compound emissions come from two sources: natural (such as from soil and trees) and anthropogenic (for example, from combustion and solvent evaporation). Therefore, VOCs in the atmosphere can be found almost everywhere. Nitrogen oxide emissions are almost all from combustion sources (such as vehicles and power generation), and therefore NOx levels tend to be highest around urban areas and traffic corridors and can be almost nonexistent in remote areas.

For the natural gas technologies studied, NOx and VOC emissions are primarily due to the upstream fuel delivery operations and not the operation of the power generator itself. However, because these emissions are dispersed and may not affect populated areas with background nitrogen oxide concentrations, actual impacts of hydrocarbon emissions on smog formation may not be significant. Volatile organic compounds from coal-integrated gasification combined cycle systems come from the power plant to a greater extent than in the natural gas systems but still account for less than 10 percent of these emissions from the entire coal-based system. At approximately 15 percent, wastewater treatment plant anaerobic digester systems have the highest percentage of photo-oxidants due to the plant itself. That is, 15 percent of the life cycle emissions of VOC come from plant operations. For the distributed generation technologies, then, the prime movers (electricity generators) are not responsible for the vast majority of smog-forming photo-oxidant emissions produced by the use of these technologies; most come from upstream operations such as fuel delivery.

Respiratory-Impact Emissions

Respiratory impacts, primarily due to the emissions of particulate matter and carbon monoxide, and ozone formation, are generally considered to be important from a local impact standpoint. However, the large dispersal of particulate matter may make particulates globally important as well. For all technologies studied, a large percentage of total respiratory effects are due to associated operations rather than the prime movers (generators) themselves. However, any addition in emissions to areas with increased background concentrations of particulate matter, carbon monoxide, and ozone make it harder to meet local standards. Relative to the goals of this study, evaluating and comparing respiratory-effect emissions from all parts of the life cycle can be relevant information for decision-makers who are trying to minimize local air impacts.

Emissions within this category are more easily controlled at large, central power generating facilities than at distributed generators. Thus, even though greater than two-thirds of the life cycle respiratory-impact emissions for each distributed generation technology are due to operations other than the generators, regulations pertaining to allowable emissions of particulate matter, carbon monoxide, and ozone are extremely important if distributed generation is to be widely implemented. Of all distributed generation technologies studied, reciprocating engines had the largest amount of particulate emissions, but the highest quantity of total respiratory-effects emissions were from microturbines (due to carbon monoxide). Of the central technologies studied (peaking power plants, natural gas combined cycle, and coal-integrated gasification combined cycle), coal-integrated gasification combinedcycle was found to be the greatest emitter of particulate matter and total respiratory-effects emissions. Carbon monoxide emissions from all technologies were of the same order of magnitude, although approximately 75 percent less were from photovoltaics and wastewater treatment plants using anaerobic digesters.

Acidification

Sulfur dioxide, nitrogen oxide, and ammonia are the primary compounds that can affect the pH of bodies of water and are included in the acidification impact category. Effects from this category are commonly referred to as *acid rain,* although *eutrophication,* which describes the bloom of flora and alga in lakes and rivers, is also included. In the case of the coal integrated gasification combined cycle system, nearly 70 percent of the life cycle acidification emissions are due to the power plant itself. However, because of emissions control technologies assumed to be installed on the coal plant, sulfur dioxide emissions from all central and natural gas-fired distributed generation technologies are about the same. Life cycle nitrogen oxide and sulfur dioxide emissions from photovoltaics and wastewater treatment plant systems are much lower and primarily due to associated operations. Microturbines have higher sulfur dioxide emissions than other technologies due to their lower efficiency compared to the other technologies. Wastewater treatment plant sulfur dioxide emissions are lower than natural gas-fired reciprocating engines because of the lower concentration of sulfur in biogas compared to natural gas.

Results Summary

When evaluating life cycle environmental impacts of competing technologies, it is extremely important to remember that no single metric can be developed to define the relative winner. Although various methods have been developed to calculate a "score" or set of scores to describe total environmental impacts, all have fallen short in that they include value judgments about which impacts are acceptable and unacceptable. For example, emissions of greenhouse gases might be acceptable to someone who is wrestling with options to reduce local smog. For someone who lives in a remote location or in a place more likely to suffer the effects predicted by climate change, smog-producing emissions may be less of a concern than greenhouse gases. In the end, each decision-maker must evaluate a variety of environmental stressors (emissions, resource consumption, and energy use) and impose one's own weighting criteria.

In the life cycle assessment of current and existing distributed generation and conventional electricity-generating options, several trends can be seen when comparing the life cycle emissions, energy use, and resource consumption. Table ES-1 ranks the technologies studied, according to several life cycle stressor amounts. No total score or combined ranking was calculated.

Conclusions

Although distributed generation technologies can provide significant benefits in terms of consumer choice and incremental installation opportunities, the environmental tradeoffs must be considered. The researchers drew the following conclusions from analysis of this project's research results.

- When the fuel is the same, the efficiency of the prime mover can have a significant effect on both generator and life cycle emissions.
- Natural gas leaks from production and pipeline delivery systems have a significant effect on life cycle greenhouse gas emissions.
- Any technology that uses natural gas suffers from higher greenhouse gas emissions than other fossil fuels. In addition, life cycle emissions of carbon monoxide, nitrogen oxides, and carbon dioxide are affected due to natural gas combustion compressors along the delivery pipeline.
- A higher rate of life cycle emissions does not necessarily result in a greater environmental impact because emissions that are spread out cannot be combined when assessing local environmental impacts. Thus, it is extremely important to study results in terms of the life cycle stage where the emissions occur.
- Because climate change impacts are global, a breakout of emissions by stage is useful for determining options for reducing emissions, but it is not useful for understanding local or regional effects. The global impact of these emissions is significantly influenced by methane emissions. Additionally, greenhouse gas emissions are influenced by the efficiency of the prime mover and by natural gas fugitive emissions.

- The natural gas-fired microturbine had the highest total emissions, if combined heat and power is not employed, due to the technology's lower operating efficiency.
- The integrated gasification combined cycle coal and reciprocating engine systems have approximately the same life cycle greenhouse gas emissions, although the engine is partially penalized by the influence of methane leaks during natural gas production and distribution.
- In general, equipment manufacture has little effect on greenhouse gas emissions, except for the photovoltaic system.
- The use of combined heat and power results in avoided emissions.
- Because they are applicable to more situations, improvements in system efficiency have the potential to have an even greater impact than combined heat and power.
- The use of anaerobic digesters at wastewater treatment plants results in the least amount of environmental stressors (emissions, resource consumption, and energy use). This is because it is a renewable energy resource, and the stressors that would have occurred during the normal disposal of treated waste are avoided, which results in a low net impact. Photovoltaic systems also perform well but are responsible for higher particulate matter emissions and water consumption during manufacture of both the cells and steel support structures.
- In terms of greenhouse gases, coal-integrated gasification combined cycle plants have higher greenhouse gas emissions than most natural gas systems. However, central plants such as these and natural gas combined cycle plants have the possible benefit of carbon dioxide sequestration under future policies.
- Natural gas peaking power plants, as they exist in California today, are responsible for fairly high environmental stressors, although new installations of this technology could have lower environmental profiles if they generate at higher efficiencies. Increasing the operating hours of these units may be more economically feasible than building new natural gas combined cycle plants, but doing so would result in greater environmental impacts.
- Distributed generation gas turbines compared favorably with central natural gas combined cycle plants; however, emissions from reciprocating engines and most microturbines are higher than those of central natural gas combined cycle plants.
- Despite the lower transmission and delivery line losses, life cycle and local air emissions are generally higher from natural gas-fired distributed generation technologies than from new, central natural gas-fired power plants. However, existing distributed generation technologies have the potential to be more environmentally benign than older central power plants, and may be an environmentally and economically attractive option for incrementally meeting increasing demand for electricity in California.

Table ES-1. Technology Ranking, According to Life Cycle Stressor Amounts

Environmental Stressors Ranked as: 1 = Highest Quantity per kilowatt-hour and 14 = Lowest Quantity per kilowatt-hour

	DG or Central	Greenhouse Gas Emissions	SO_2 Emissions	Coal Consumption	Natural Gas Consumption	Petroleum Consumption	Water Withdrawal	Energy Used
Combined-Cycle Natural Gas Power Plant	Central	10	10	10	5	11	3	5
California Peaking Power Plant	Central	5	4	4	3	5	2	3
Integrated Gasification Combined-Cycle Coal	Central	3	6	1	8	4	1	4
Gas Turbines	DG	4	7	8	3	8	8	3
Natural Gas-fired Microturbines	DG	1	2	4	1	4	6	1
Natural Gas-fired Reciprocating Engines	DG	2	3	6	1	5	6	1
Photovoltaics	DG	13	12	1	5	2	1	5
Wastewater Treatment Plant Anaerobic Digestion	DG	11	13	6	4	6	6	5
Advanced Diesel Internal Combustion Engine	DG	6	1	4	4	1	2	4
Biomass	DG	14	11	1	4	1	1	4
Dairy Anaerobic Digestion	DG	12	14	4	4	4	4	4
Molten Carbonate Fuel Cell	DG	9	9	3	2	3	3	2
Phosphoric Acid Fuel Cell	DG	7	5	1	1	1	1	1
Solid Oxide Fuel Cell	DG	8	8	1	1	1	1	1

Note: All tables, figures, and photos in this report were produced by the authors, unless otherwise noted.

1.0 Introduction

Distributed generation (DG) of electricity continues to make public and policy headlines as California seeks to find solutions in an ever-changing and often chaotic energy climate. The California Energy Commission (Energy Commission), in cooperation with the California Public Utilities Commission, has a long history of supporting DG technologies as a means to meet growing demands for power capacity (California Energy Commission 2007).

The term *distributed generation* has been defined in a number of ways. This study's research is based on a version from the California Energy Commission:

> "…electricity production that is on-site or close to the load center and is interconnected to the utility distribution system" (Rawson 2004).

Nominally, the maximum generator size for the DG technologies was assumed to be 50 megawatts (MW). Since results are normalized per kilowatt-hour (kWh) delivered to the end-use consumer, strictly defining the actual size of the DG unit is not required. However, this capacity defined the valid range of literature values used for operating emissions. Additionally, as there is some economy of scale in constructing most equipment, defining the size range allows for a more correct analysis of the raw materials required.

While DG offers several practical benefits, such as smaller investment increments, lower transmission and distribution infrastructure burdens, and a more diversified generating mix, widespread introduction of DG technologies may change the environmental impacts of electricity generation in the state.

The California Energy Commission's Public Interest Energy Research (PIER) Program funded the National Renewable Energy Laboratory (NREL) to conduct a life cycle assessment (LCA) study on distributed generation, to compare the overall environmental impacts and economic costs of DG technologies and conventional power plants in California.

Life cycle assessment is an analytic method for identifying and evaluating the environmental impacts of emissions, resource consumption, and energy use associated with a specific process. When such an assessment is performed in conjunction with an economic cost analysis, the total economic and environmental benefits and drawbacks of a process can be quantified. In LCA, material and energy balances are used to determine the environmental stressors (emissions, resource consumption, and energy use) of all required operations, including raw material extraction, transportation, processing, and final disposal of products and by-products. The results of this inventory are then used to evaluate the environmental impacts of the technology so that efforts can be focused on mitigating negative effects. The life cycle assessment process will be discussed in greater detail in Section 3 and Appendix A.

1.1. About the Study

This project was undertaken to provide decision-making information to policy makers on emerging and existing DG technologies. Researchers studied the production of electricity by existing and emerging DG technologies and compared that information to typical peaking

power plants being built in California, typical natural gas combined-cycle power plants, and possible coal-fired combined-cycle power plants. The study addressed existing DG technologies with known performance and a record of service, as well as several emerging DG technologies. Central power plant (i.e., simple- and combined-cycle) technologies represent the major sources of electricity generated in the state, and the discussion of central power plants in this report are for comparison purposes only.

This study provides policy makers with a better understanding of the implications of recommending various DG technologies to meet the growing demand for electricity in California. It is not designed to advocate one option over the other, but to provide additional information as to the true life cycle impacts of the alternatives.

Table 1 shows the technologies that were examined and the abbreviated names for those technologies used in subsequent results graphics and tables. Several of these technologies were studied with and without combined cooling/ heating and power.

Table 1. Technologies Studied

Electricity Generating Technology	Central or Distributed Generation	Abbreviated Name for this Report
Natural gas-fired combustion (simple-cycle) turbines	Distributed	Gas Turbines
Natural gas-fired microturbines	Distributed	Microturbines
Natural gas-fired reciprocating engines	Distributed	Recip
Photovoltaics (PV)	Distributed	PV
Anaerobic digestion of wastewater treatment waste coupled with a reciprocating engine	Distributed	WWTP AD
Advanced diesel engines	Distributed	Diesel
Small-scale biomass gasification coupled with a reciprocating engine	Distributed	Biomass
Anaerobic digestion of dairy waste coupled with a reciprocating engine	Distributed	Dairy AD
Molten carbonate fuel cells	Distributed	MCFC
Phosphoric acid fuel cells	Distributed	PAFC
Solid oxide fuel cells	Distributed	SOFC
Natural gas peaker plant (central)	Central	NG Peaker
Natural gas combined-cycle (central)	Central	NGCC
Integrated coal gasification combined-cycle (central)	Central	Coal IGCC

2.0 Background

2.1. Status of Electricity Generation in California

In 2006, nearly 50% of the electricity generated by California power plants came from natural gas and 11% from non-hydro renewables (DOE/EIA 2007). However, California's electricity demand outstrips its in-state supply, so 23% of the state's electricity is imported from nearby states, and is primarily generated from coal, hydroelectric, and natural gas. Natural gas accounts for nearly 30% of California's total energy use (California Energy Commission 2007), used in the production of electricity and heat, as well by industry. Additional use of natural gas, either in central power plants or by gas-fired DG units could put increased pressure on non-power sectors that currently use this fuel.

2.1.1. Transmission and Distribution System

The transmission and distribution (T&D) system is the circulation system of the electrical power industry. Its primary purpose is to deliver power to end users in a useable form. It is designed to provide reliable, uninterrupted power at the proper voltage; however, some of the power transmitted over the high-voltage transmission lines is lost. In the U.S.-wide electricity system, T&D losses are approximately 7% (USCCTP 2005). Because the grid in California is, on average, slightly newer, and distances over which electricity flows are lower, a 5% average loss for this study was assumed for electricity from central plants to end users. Because of their close proximity to the end user, DG systems do not suffer from such losses.

In this study, the greenhouse gas and criteria pollutant implications of new and upgraded T&D infrastructure were included as part of the overall system boundaries. Although DG technologies may be operated independently of the grid, it is more likely that they will be used for backup power and for sale of excess power to the grid during peak periods. In these cases, a connection to the T&D infrastructure would still be required. Other components of the T&D system such as the distribution lines, transformers, and substations were also included in our assessment, and line loss was examined.

2.1.2. Energy Demand and Peak Supply

According to the California Energy Commission (2004), the annual demand for electricity in California is roughly 270,000 gigawatt-hours (GWh), or an average of 30,800 megawatts per hour (MW/hr). More than 50,000 MW of generation capacity must exist to meet unusually high demands. Seasonal exchanges and programs designed to reduce consumption during peak hours can reduce the need for extra energy to a certain extent. However, peaking power plants in California are needed solely to provide energy for a handful of peak demand hours during the year (Figure 1).

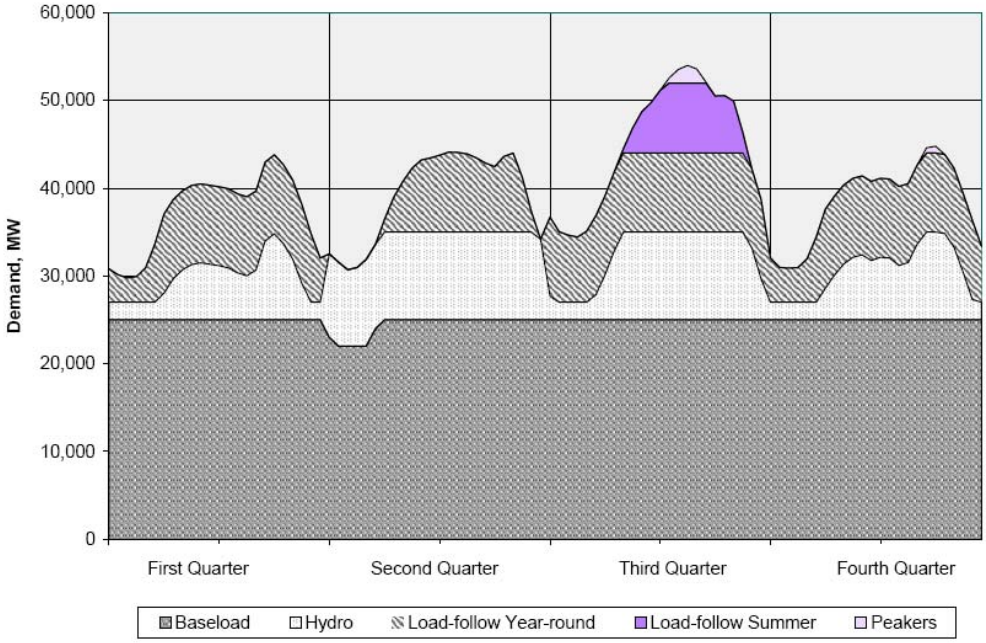


Figure 1. Hourly Profile of California Electric Demand and Supply

Source: California Energy Commission 2004.

Supplemental electricity needs are met using three types of power plants:

Baseload plants run at full output, around the clock, throughout the year. These plants are generally costly to build, but have relatively low fuel costs and are inexpensive to operate once constructed. They include nuclear and coal facilities, many renewable technologies (landfill gas, biomass), natural gas-fired cogeneration, and newer, more efficient natural gas-fired facilities, such as the large combined-cycle plants built in recent years.

Load-following units, many of which turn off at night or run at minimum levels when demand is low, increase output during the day as demand increases, then cut production in the early evening as industrial and commercial demand falls. The least efficient of these units will provide this service primarily in the summer, when demand is highest.

Peaking units often only operate during mid-afternoon in the summer. The least-efficient of these may only operate on the very hottest days, perhaps as few as four or five days a year, or not at all in some years. These units are relatively inexpensive to construct on a per-megawatt basis, but very expensive to operate. They require up to 20,000 British thermal units (Btu) of natural gas per kilowatt-hour of electricity generated—three times that of a new combined-cycle unit (California Energy Commission 2004). The distinction between load-following units and peaking units may be slight, and based only on the hours of operation. The higher use of natural gas per unit of electricity delivered is generally due to the operation of the plant in spinning reserve mode, where natural gas is being consumed but the generator is not engaged.

Most DG is used to meet peaking requirements.

2.2. Predictions for Electricity Demand Growth in California

According to the Energy Commission's 2007 Integrated Policy Report (CEC 2007), electricity consumption is forecast to grow between 1.2% and 1.5% annually, from 270,927 GWh in 2004 to between 310,716 and 323,372 GWh by 2016. California relies on natural gas for approximately 35% of its electricity, generated with simple-cycle and combined-cycle technologies.

Future peak demand is very difficult to predict because of California's size and diverse climates. Peak demand is expected to grow between 1.4% and 1.75%, which represents an increase from 56,435 MW in 2004 to between 66,656 and 69,473 MW in 2016. However, in 2004, the recorded peak demand was 3.3% higher than what had been forecast—a difference of more than 2,000 MW, the approximate capacity of the state's three largest fossil-fueled generators. Peak demand depends heavily on temperatures statewide, because air conditioning loads are generally responsible for its quantity and duration.

The Energy Commission estimates that by 2016, California will need to obtain approximately 24,000 MW of peak resources to replace expiring contracts and retiring power plants and to meet peak demand growth (Jones 2005).

2.3. Distributed Generation Overview

Distributed generation offers several potential advantages to traditional large-scale central power generation:

- Improved power quality
- Improved reliability
- Peak shaving
- Gain of T&D line-losses
- Reduced strain on the T&D system
- Reduced strain on conventional generators
- Reduction in emissions and energy consumption
- Greater use of alternative and renewable energy generation technologies
- Smaller incremental investment costs
- Greater competition in electrical supply markets
- Improved efficiency through the use of waste heat
- Increased energy security

The degree to which these benefits are realized will depend on the distributed energy technology, the fuel source, the hours that the generator is operated, and the policy climate under which the technology is installed. While many of these benefits apply to power generators and consumers, some benefits are in conflict. For example, a reduction in emissions is not guaranteed if units are installed and operated for the purpose of improved reliability and quality, or if the units are poorly maintained.

2.3.1. DG Definitions

As indicated previously, this study used the following definition of DG from the California Energy Commission:

> "…electricity production that is on-site or close to the load center and is interconnected to the utility distribution system" (Rawson 2004).

However, this is just one definition among many. Some examples illustrate the divergent opinions on what constitutes a DG technology:

- "All generation units with a maximum capacity of 50 MW to 100 MW that are usually connected to the distribution network and are neither centrally planned nor dispatched." The International Council on Large Electric Systems (CIGRE) (Dondi et al. 2002).
- "The generation of electricity by facilities that are sufficiently smaller than central generating plants in order to allow interconnection at nearly any point in a power system." The Institute of Electrical and Electronics Engineers (IEEE) . (Pepermans et al. 2005).
- "A small source of electric power generation or storage ranging from a kW to tens of MW that is not part of a large central power system and is located close to the consumer." Dondi. (Dondi et al. 2002).
- "Relatively small generation units of 30 MW or less whose units are located near consumer sites to meet specific consumer needs, support economic operation of the distribution grid, or both." (Pepermans et al. 2005).
- "DG is electric generation connected to the distribution level of the transmission and distribution grid usually located at or near the intended place of use." Energy Commission Distributed Generation Strategic Plan.
- "DG Energy Station is a system that co-generates electric power, thermal energy for heating and cooling and hydrogen for vehicle fueling. DG denotes the fact that the station produces power independent of, or in parallel with, the electric grid. DG is gaining importance in electricity grid planning as a means to enhance service reliability by adding new generation capacity at (or near) the point of use." Implementation Plan for Developing a California Hydrogen Highway Network Blueprint.

A compilation of the definitions from various agencies ranging from CIGRE to IEEE all agree that DG units are located close to the load, or in other words, are on the customer side of the power meter (Thomas Ackermann 2001).

2.3.2. DG Benefits

Energy suppliers can use DG to personalize power consumption by allowing consumers to choose the electricity service that best fits their needs. Distributed generation technologies also allow electricity providers to respond flexibly to changing market conditions. This is possible

because DG units generally take considerably less time to construct in comparison to large, centralized power plants (Pepermans et al. 2005).

Distributed generation has the potential to save consumers money. A major benefit of DG technology is its potentially diverse fuel supply, which can serve as a buffer against energy price fluctuations (Pepermans et al. 2005). Distributed generation also serves as a cost-effective source of peak demand power (Dondi et al. 2002) because DG-unit owners may sell excess energy to the power grid. Additionally, DG's relative ease of installation has the potential to save consumers money by avoiding investments in transmission and distribution capacity (Clark and Isherwood 2004). Average transmission losses in the United States are approximately 7% and DG can compensate for that power loss via on-site generation (Dondi et al. 2002). Losses in California are expected to be lower than the national average, as most generation is closer to point-of-use, and the T&D infrastructure is of relatively newer construction. A milder climate reduces total losses, as well. A 5% T&D loss was assumed for this study.

Additionally, the proximity of DG units to the consumers can lead to increased efficiency by enabling them to utilize the heat created by the DG unit. Distributed generation consumers can use this heat from their generator to heat and/or cool their building. This contrasts with the traditional method of purchasing energy to heat a boiler to provide building heat or drive a compress to provide building air conditioning. The energy conservation from combined heating and power contributes to 10% to 30% in savings, a very attractive prospect for consumers in areas that are in constant demand for building heat (Pepermans et al. 2005). Similar savings are achieved with cooling.

In addition to economic benefits, DG can improve power quality for the consumer. Distributed generation units accomplish this by virtue of numerous power generation units in place of one central unit. Careful installation of DG units can enable grid operators to more easily stabilize the grid's frequency and voltage. This also gives the grid operator additional flexibility to distribute power, especially at times when power demand is high (Pepermans et al. 2005). Distributed generation also mitigates the effects of grid disruptions (Rawson 2004). The energy crisis of California, the threats to energy infrastructures after the 9-11 attacks, the blackouts in the northeast United States, southern Canada, and Europe in the summer of 2003 make the flexible DG system appealing for supplying reliable energy (Clark and Isherwood 2004). Reliable energy is especially useful to consumers who need a constant supply of energy, such as hospitals and computer centers. Table 2 summarizes some of the relevant pros and cons of DG technologies.

Table 2. Advantages and Disadvantages of Distributed Generation

Pros		Cons	
Consumers	**Energy Suppliers**	**Consumers**	**Energy Suppliers**
Ability to choose electricity service that best fits needs	Ability to respond flexibly to changing market conditions	High capital costs of many technologies	Compatibility problems between DG and power grid
Serve as a buffer in price fluctuations	Can make it easier for grid operators to stabilize frequency and voltage	May be less efficient than central power plants	Loss in revenue to consumer self generation
Can substitute for upgrades in transmission capacity	Ability to meet renewable generation standards	Fuel supply can be more expensive	
Waste heat recovery can reduce operating cost		Some non-renewable DG technologies could adversely affect the environment	
Certain technologies can have a positive environmental impact			
The energy supply is more reliable			

When using clean technologies, DG can reduce the environmental impact of power generation. The European Union-commissioned *European Renewable Energy Study* indicated that around 60% of the renewable energy potential that can be used until 2010 to meet carbon dioxide (CO_2) reduction goals can be categorized as DG power sources (Thomas Ackermann 2001). Also, a study of a small town powered by DG technology found that if optimized energy storage devices are added to the renewable energy-powered generators, fossil fuel consumption could be reduced to almost zero (Clark and Isherwood 2004). This is positive for the energy suppliers because it allows them to meet renewable generation standards by implementing renewable DG (Rawson 2004).

Although DG technologies present a potential loss in revenue for power companies as consumers generate their own electricity, energy companies also support DG technologies (Rawson 2004). Xcel Energy believes that "DG promises many potential benefits including peak shaving, fuel shaving, and improved power quality" (Xcel Energy 2006). Xcel further stated that the increased quality and reliability of power provided by DG make it "an important strategy for the commercial building manager to follow" (Xcel Energy 2006).

Southern California Edison offers incentives to customers who install DG technologies, ranging from $0.60 per kilowatt to $4.50 per kilowatt, depending on the technology (Southern California Edison 2010). Pacific Gas and Electric's (PG&E's) Self-Generation Incentive Program provides financial incentives to customers who install new "clean" on-site DG facilities up to 5 MW

(PG&E 2006). The incentives range from $1.50/watt (W) for wind turbines to $4.50/W for renewable fuel cells (PG&E 2010). The California Energy Commission has a similar incentive program for smaller scale DG units. For most units with a capacity below 30 kW, incentives range from $1.50/W to $3.0/W for wind, and $3.00/W for fuel cells (Consumer Energy Center 2010). Incentives for solar are based on a variety of factors and are tied to the California Solar Initiative.

2.3.3. DG Drawbacks

Despite all of the positive aspects of DG, there are also many potential obstacles facing DG implementation, having to do with capital costs, emissions, fuel diversity, and compatibility.

First and foremost, certain DG technologies have relatively high capital costs per kilowatt in comparison to large, centralized power plants. However, it should be noted that there are large discrepancies in capital costs among different DG technologies. For example, a fuel cell is more expensive than a combustion turbine. Additionally, since smaller DG plants can be less efficient than larger, centralized power plants, widespread implementation of DG could actually lead to a net increase in emissions (Pepermans et al. 2005). Operating DG technologies in a combined heat and power mode may mitigate this effect by meeting some of the heating/cooling demand with waste energy.

Non-renewable implementation could decrease the fuel diversity for consumers. The higher appeal and availability of gas-based DG technologies could replace a significant portion of state-imported coal-based generation. Consequently, this could increase America's reliance on and demand for natural gas (Pepermans et al. 2005), making a primary fuel supply for DG applications more costly than central generation. Additionally, increased use of natural gas for DG may make imported liquefied natural gas more attractive.

There are also compatibility issues with DG generators and the existing power grid. Many DG technologies such as photovoltaic systems and fuel cells produce DC current and must be connected to the power grid via a DC-AC interface, increasing the price of the DG technology (Pepermans et al. 2005). Although small-scale introduction of DG can increase the reliability of the power network, large-scale introduction of DG can decrease the quality of energy supplied to the consumer. This occurs because DG power plants may cause voltage instability via bidirectional power flow in the grid (Dondi et al. 2002). However, proper planning can avoid this difficulty.

Additionally, electricity generation technology and the grid connection of DG technologies differ from traditional centralized power generation. DG technologies often use asynchronous generators, which are not capable of providing reactive power when directly connected to the grid. These asynchronous generators generally require reactive power from the grid during start up and operation. There are, however, various technical options that can be used to increase the compatibility of asynchronous generators with the distribution grid. Micro DG systems such as PV modules, batteries, and micro hydro turbines generally produce DC current and must be connected to the grid via converter. In rare cases, this could alter the oscillating AC

current, which would lead to power fluctuations in the distribution networks (Thomas Ackermann 2001).

2.3.4. Existing DG in California

In 2001, California had approximately 2,500 MW of small-scale renewable and non-renewable DG and has added an average of 100 MW of new small-scale DG every year since then (California Energy Commission 2006). According to the Energy Commission, California has approximately 770 combined heat and power (CHP) projects, totaling 9,000 MW. Nearly 90% of this capacity comes from systems greater than 20 MW. Statewide generation is approximately 60,000 MW, with 9,000 MW of CHP accounting for 17% of the state's generation. Combined heat and power systems smaller than 5 MW account for about 3% of the total CHP capacity in the state (Jones et al. 2005).

2.3.5. DG Technology Descriptions

This study evaluates both existing DG technologies with known performance and a record of service, as well as emerging DG technologies which are generally thought to be viable for future entry into the DG market. No assessment of the necessary criteria for market entry is made in this study, however. All DG technologies are evaluated against reference baseload (NGCC and coal IGCC) and peaking generation technologies. Wind turbines were not considered to be a DG technology (and therefore not included) for this project because the significant majority of installations are not located close to where the power is used.

Unless otherwise noted, the descriptions of each technology below were drawn from the California Energy Commission's Distributed Energy Resource Guide website, at www.energy.ca.gov/distgen/. For more details on the materials used for each of these technologies, see Appendix D.

Gas Turbines

Distributed generation combustion turbines (also referred to as simple-cycle or combustion turbines) are a mature technology that range in size from 500 kW to 25 MW. For this study, they are assumed to operate on natural gas and to have an efficiency of 38%.

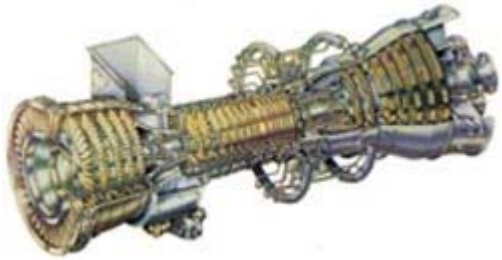


Figure 2. Gas Turbine
Source: University of Florida

Microturbines

Microturbines are small combustion turbines that range in capacity from 25 kW to 500 kW and can run on a variety of fuels. For this study, the microturbines are assumed to operate on natural gas, with an efficiency of 26%.

Figure 3. Microturbines

Source: Capstone

Reciprocating Engines

Reciprocating engines are the most common DG technology and are available in capacities ranging from as small as 5 kW to as much as 7 MW. They work by combusting a variety of fuels including natural gas, diesel, landfill gas, or digester gas. In this study, reciprocating engines are the prime movers for the biomass, dairy anaerobic digestion (AD), and wastewater treatment plant anaerobic digestion (WWTP AD) cases, with total system operating efficiencies of 23%, 30%, and 30%, respectively. The reciprocating engines used as standalone prime movers operating on natural gas are assumed to have an efficiency of 33% on a lower heating value basis.

Figure 4. Reciprocating Engine

Source: Fair Manufacturing, Inc.

Photovoltaics

Photovoltaic (PV) cells convert sunlight directly into electricity without moving parts or emissions. Individual panels can range from less than 1 kW to 100 kW.

There are three main types of materials used for PV cells: (1) silicon (including single-crystalline, multicrystalline, and amorphous silicon), (2) polycrystalline thin films (such as copper indium diselenide, cadmium telluride, and thin-film silicon), and (3) single-crystalline thin films, including those with high-efficiency materials such as gallium arsenide. (U.S. DOE 2005).

This study assumes that 50% of PV cells will be multicrystalline, with an efficiency of 13%, and the other 50% will be thin-film cells, with an efficiency of 7%. The combination of these technologies leads to an overall PV average efficiency of 10%.

Figure 5. Photovoltaic Cells
Source: NREL photo exchange

Anaerobic Digesters

Anaerobic digesters burn the biogas, a combination of methane and carbon dioxide, produced by microbes that digest organic wastes (e.g., wastewater and animal manure) in the absence of oxygen. The burning of this biogas not only supplies additional electricity to on-site facilities but also prevents the release of additional greenhouse gases (GHGs) to the atmosphere. The digesters in this study are assumed to operate at wastewater treatment facilities and dairy farms. The combustion technology is a reciprocating engine, which will have a lower efficiency because biogas has a significantly lower Btu than natural gas. For this study, both wastewater treatment plant anaerobic digesters and dairy anaerobic digesters are assumed to have an efficiency of 30%.

Figure 6. Anaerobic Digesters

Source: www.water-technology.net/projects/reading_sewage/reading_sewage2.html

Advanced Diesel-Fired Generators

Diesel-fired generators have, to-date, had a difficult time meeting emissions standards for California. Due to a significant amount of testing and development, emissions from mobile diesel engines for large tractor-trailers have been reduced. As a result, many believe that stationary diesel engines will be able to be designed to meet standards, particularly with advanced controls systems. In this report, the term, ”advanced,“ refers to the fact that no acceptable units are currently available in the marketplace. Future systems are studied, though, as a comparison of diesel-fueled DG units to renewables and those running on natural gas. A lower heating value of 38% was used for advanced diesel-fired generators in the base case.

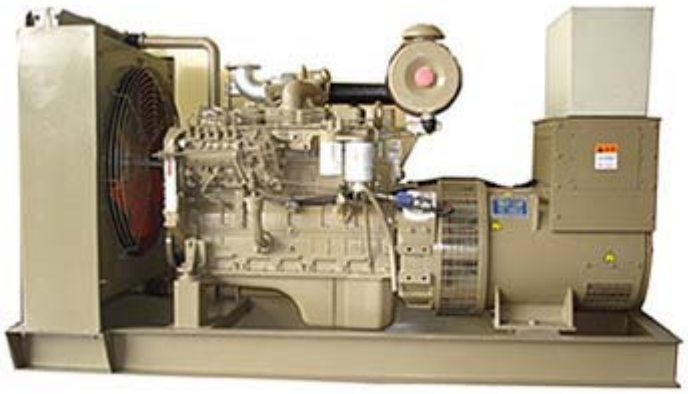


Figure 7. Diesel Generator

Source: http://www.cumminspower.com/en/products/generators/diesel/

Small-Scale Biomass Gasification

Biomass gasification is a process where solid biomass feedstocks (e.g., agricultural or forest residues, energy crops, municipal solid waste, or animal wastes are converted into a gaseous mixture of hydrogen, carbon monoxide, carbon dioxide, and other compounds (DOE 2008). These gases are then combusted in a reciprocating engine to drive a generator to produce electricity. For this study, the biomass generator was assumed to operate on residue woody biomass (e.g., agriculture and forest residues) and to have an efficiency of 23%.

Figure 8: Distributed Biomass Gasifier Bank

Source: Community Power Corporation

Fuel Cells

Like a battery, a fuel cell uses an electrochemical reaction to create electric current. However, it differs from a battery because it uses a gas that can be replenished as a reactant, so it will not run down unless it runs out of fuel.

Both high- and low-temperature fuel cells are appropriate for baseload use, but only high-temperature fuel cells can by used with CHP. Because they do not ramp up quickly, they have limited use for peaking power.

Figure 9. External View of a DG Fuel Cell System

Source: NYSERDA

Molten Carbonate Fuel Cell

Molten carbonate fuel cells (MCFC) are commercially available fuel cells in the 250 kW–10 MW range that can be fueled by natural gas or hydrogen. They can cogenerate hot water or low- or high-pressure steam. According to the U. S. Department of Energy, molten carbonate fuel cells operate at about 650°C (1,200°F)—higher than phosphoric acid fuel cells (giving them higher fuel-to-electricity and overall energy use efficiencies), but lower than solid oxide fuel cells (U.S. DOE, no date). For this study, they are assumed to operate on natural gas and to have an efficiency of 47%.

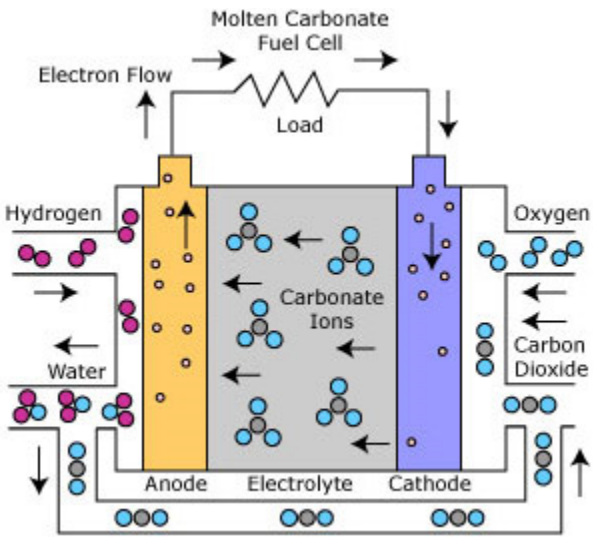


Figure 10. Molton Carbonate Fuel Cell Schematic

Source: FCTec

Phosphoric Acid Fuel Cell

Phosphoric acid fuel cells (PAFCs) are also commercially available, in the 100kW–200kW range. They can use natural gas, landfill gas, digester gas, or propane as a fuel and can cogenerate hot water. PAFCs were the first fuel cells to become commercial, and many have been operating for more than 8 million hours. They operate at between 150°C to 200°C (about 300°F to 400°F), so the water that is expelled from the fuel cell can be converted to steam for space and water heating (U.S. DOE, no date). For this study, they are assumed to operate on natural gas and to have an efficiency of 40%.

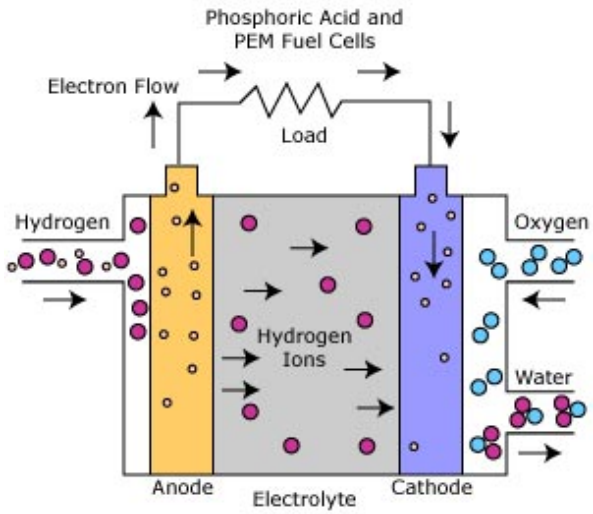


Figure 11. Phosphoric Acid Fuel Cell Schematic

Source: FCTec

Solid Oxide Fuel Cell

Solid oxide fuel cells (SOFCs) are not likely to reach commercialization for another couple of years. Capacities for non-commercial versions range from 1kW–10MW. Unlike MAFCs and PAFCs, solid oxide fuel cells are made from solid-state (ceramic) materials and they operate at hotter temperatures than any other fuel cell (as high as 1,000°C [1,800°F]). The resulting high-temperature exhaust gases can be used in combined heat and power applications (U.S. DOE, no date). SOFCs can operate on natural gas or hydrogen, and they can cogenerate hot water or low- or high-pressure steam. For this study, they are assumed to operate on natural gas and to have an efficiency of 48%.

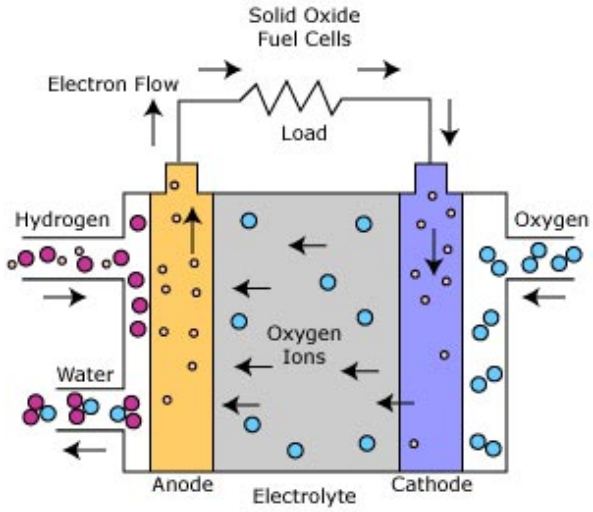


Figure 12. Solid Oxide Fuel Cell Schematic

Source: FCTec

Combined-Cycle Natural Gas Power Plants

Combined-cycle power plants generate electricity by burning gas in a gas turbine that drives a generator directly (gas cycle). Hot gases exiting the gas turbine are used to heat or boil the water in the steam cycle, thereby combining the two cycles. In this study, the plant is assumed to operate on natural gas, with an electric generation efficiency of 49%.

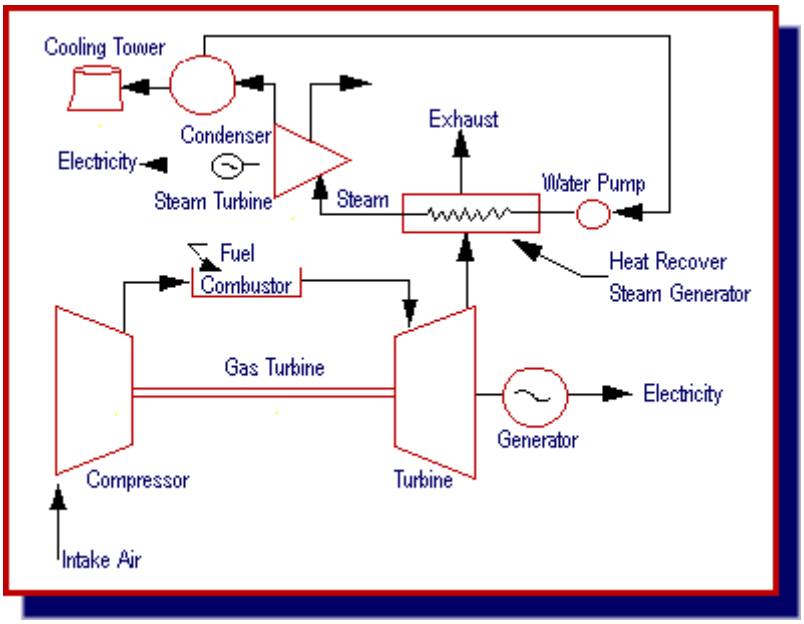


Figure 13. Combined-Cycle Natural Gas Power Plant

Source: www.cogeneration.net/Combined_Cycle_Power_Plant.htm

Peaking Power Plants

Peaking power plants for California are assumed to be simple-cycle gas turbines. These turbines can be activated quickly to adapt to changing demand. The peaking power plants in this study are assumed to operate on natural gas, with an electricity generation efficiency of 38%. While some peaking power plants are operated in spinning reserve mode, consuming natural gas but not generating sellable electricity, the assumption for this study is that these plants are turned on to meet peak demands and not run in reserve mode.

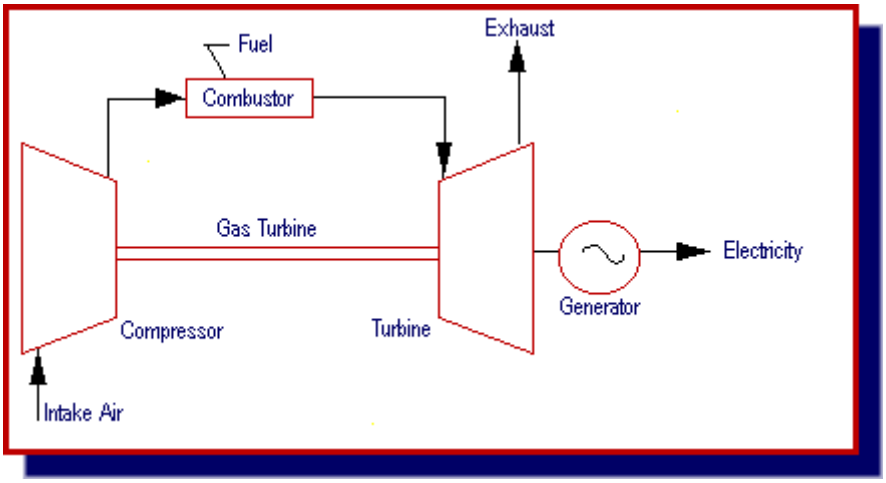


Figure 14. Peaking Power Plant

Source: www.cogeneration.net/Combined_Cycle_Power_Plant.htm

Integrated Gasification Combined-Cycle (IGCC) Coal Power Plants

Integrated Gasification Combined-Cycle (IGCC) power plants operate by gasifying coal into a synthesis gas (syngas) and then combusting the syngas in a gas turbine. A heat recovery section of the plant produces steam that is passed through a steam turbine. IGCCs are not ideal for the high moisture content/low heating value of western coal and do not operate as efficiently at elevation. Despite these limitations, the higher efficiency of IGCC compared to standard steam-cycle coal combustion results in a lower cost of electricity, making it the most likely technology for increased coal generation capacity. This study assumes an electricity generation efficiency of 34%, which accounts for the limitations of western coal. See Section 4.5 for more information on IGCC and its operation with western coal.

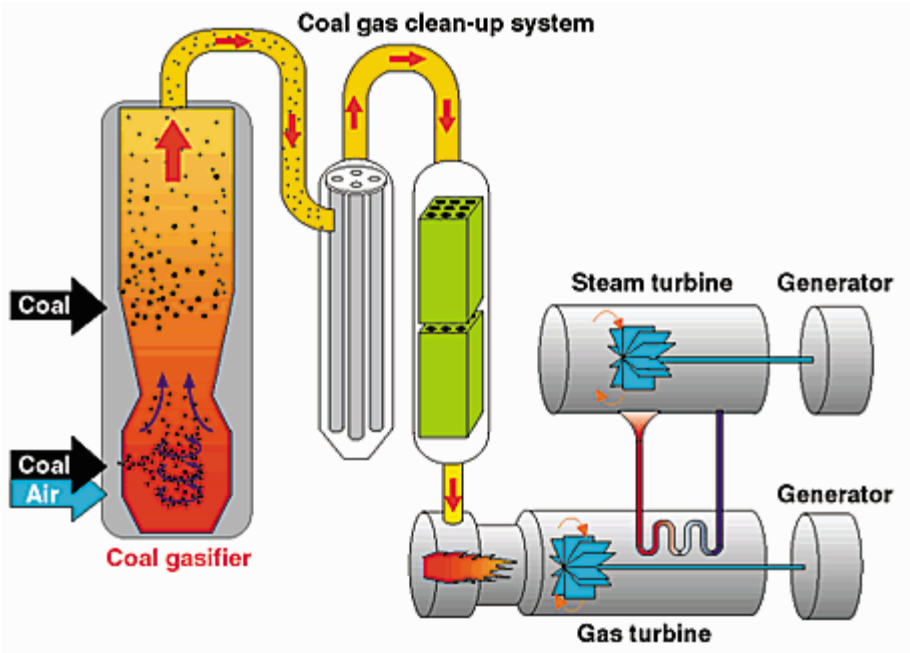


Figure 15. Integrated Gasification Combined-Cycle (IGCC) Coal Power Plant

Source: Central Research Institute of Electric Power Inudstry (CREIPI)

3.0 Study Methodology

3.1. Stages of a Life Cycle Assessment

The four stages of a life cycle assessment (Figure 16) are:

1. Goal and scope definition: Stating the purpose of the study and identifying the appropriate boundaries.
2. Life cycle inventory analysis (LCI): Quantifying the material and energy use along with the environmental emissions associated with the life cycle of the product or process.
3. Life cycle impact assessment (LCIA): Grouping the results of the analysis to determine impacts on human health and the environment.
4. Interpretation: Evaluating opportunities to improve the environmental performance of the process or product by reducing environmental impacts.

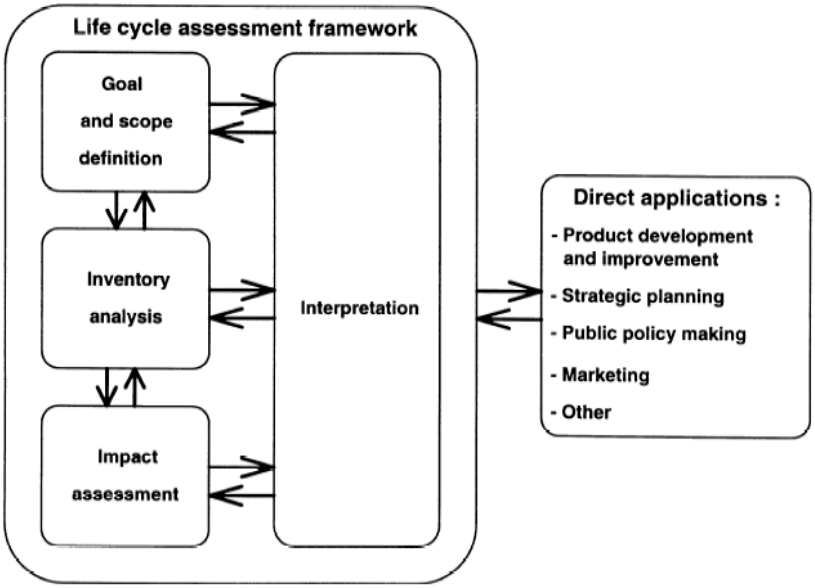


Figure 16. Life Cycle Assessment Framework

Source: ISO 2006

This document follows the guidelines in ISO 14040 and ISO 14041. As shown in the preceding figure, interpretation is conducted throughout the study and report.

3.1.1. Goal and Scope Definition

The goal of this study is to compare the overall environmental impacts and economic costs of DG technologies and conventional power plants in California. Its purpose is to provide decision-making information to policy makers on emerging and existing DG technologies.

3.1.2. Life Cycle Inventory Analysis (LCI)

The life cycle inventory analysis is the most labor-intensive part of a life cycle assessment because it involves gathering data for the inventory of emissions, resource consumption, and energy use. The life cycle inventory results are generally presented as a large table of environmental stressors, often grouped into emissions, resource consumption, and energy use. These numbers can be mystifying to decision makers who may not understand how the stressors affect the environment or how choices can to be made to reduce the impacts; therefore, the assessment and interpretation stages of the process are important in making the results more accessible and usable.

3.1.3. Life Cycle Impact Assessment (LCIA)

The life cycle impact assessment phase is designed to give context to the environmental stressors and to identify how the emissions from a product or process are likely to affect the natural environment or human health. Unfortunately, the impact stage of a life cycle assessment is often the most controversial and can be fraught with the greatest amount of uncertainty. It also offers the greatest opportunity for the introduction of bias and assumptions into the assessment.

For this study, NREL strove to strike a balance between clarity of results and scientific basis. For the purpose of this study, the researchers conducted a mid-point, rather than end-point, assessment because it strikes a balance between accepted practice and loss of data granularity. Midpoint assessments focus on the actions (e.g., emissions release, resource extraction) that can cause environmental damages; whereas endpoint assessments quantify the ultimate environmental damage attributable to the actions. While it may seem attractive to decision makers to have results in terms of final impacts, the data resolution (most importantly, site-specific data) and causal links to these final impacts are generally not present in life cycle assessment. Midpoint assessments are more scientifically certain than endpoint assessments because the data are drawn directly from measurable actions. For example, it is more likely to accurately determine the nitrogen oxides (NOx) coming out of a power plant than to predict the health impacts of the smog that may form from the NOx.

Moreover, the data obtained for the inventory step of the LCA, and the scientific basis for evaluating the full environmental impacts from such data, are often not sufficient to support the scoring step of an endpoint assessment. This is especially true when site-specific data and dispersion modeling are required. Such studies are being conducted, most notably by researchers at the University of California, Irvine (Samuelson et al. 2005), and the results will provide valuable information on the local air quality impacts of distributed generation. Information from this midpoint assessment will provide California's policy makers with a better sense of the opportunities for distributed generation technologies to impact the environment positively while meeting the state's growing need for electrical generation capacity.

3.1.4. Functional Unit and Units of Measure

A *functional unit* is the measure against which all products, materials, emissions, resources, and energy are normalized. The primary purpose of a functional unit is to provide a reference for the inputs and outputs. In reporting the results of the study, the functional unit is the denominator in the units given to each input and output. The functional unit depends on the purpose of the study.

For this study, results are presented in terms of the energy (kWh) delivered to the consumer. By presenting results in this way, transmission and distribution (T&D) construction and line losses are taken into account. Transmission and distribution losses of 5% are included to convert between electricity generated at central power plants and that delivered to the consumer. The DG technologies do not suffer this loss, which results in an effective increase in system efficiency.

3.1.5. System Boundaries

The *system boundaries* define the unit processes to be included in the study. Figure 17 provides a description of the system in the context of LCA methodologies. Although the process of interest can be isolated in an analysis of the economic value of a technology, in evaluating the environmental impact it is necessary to study all unit operations that are required for the process of interest to operate.

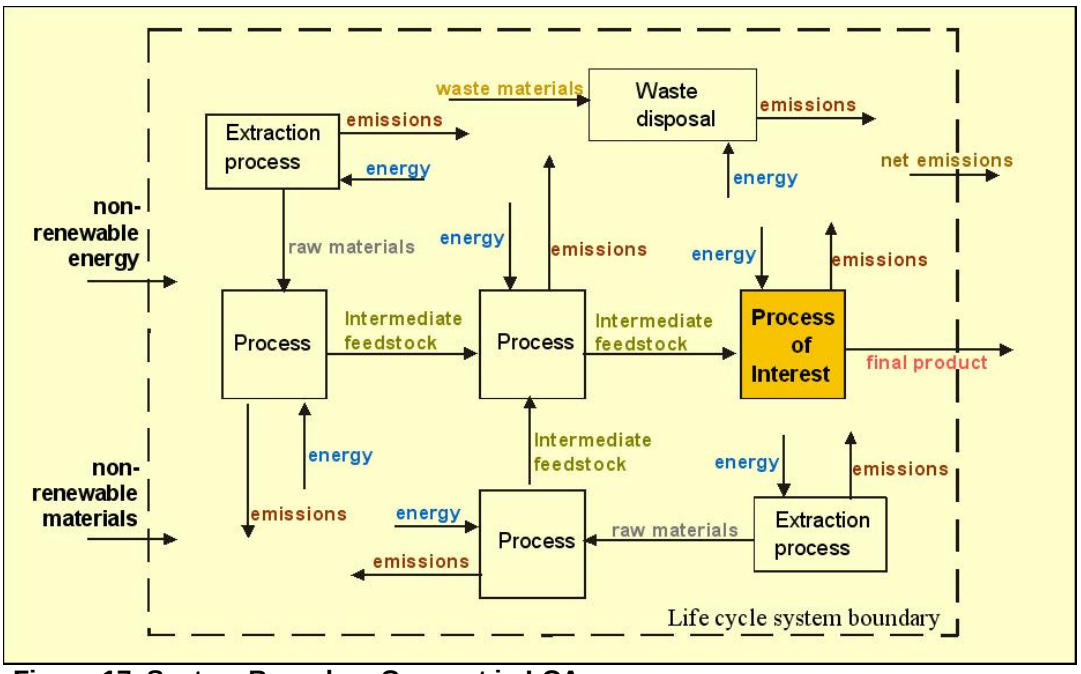


Figure 17. System Boundary Concept in LCA

For both DG and central power plants, this study identified the environmental impacts for the following operations:

- Obtaining raw materials and fuels

- Manufacturing equipment and components
- Siting and constructing the units
- Construction of T&D infrastructure
- Line losses in T&D infrastructure for central power plants
- Emissions from operating the electricity generating units
- Impacts of transporting materials, fuels, and waste
- Disposing of the units at the end of life

3.1.6. Allocation Procedures

When a system produces more than one product, the environmental stressor (emissions, resource consumption, and energy use) results must be allocated between the products. Different methodologies exist for allocation in LCA, and these are detailed in the ISO publications. In general, they can be described as following three approaches, in order of preference by the LCA community: (1) avoided impacts allocation, (2) economic allocation, and (3) physical properties allocation.

The third approach splits the stressors according to a measurable physical quality of each product. Examples include weight, energy content, and volume. This is generally the least-preferred approach because it implies a correlation between physical properties and environmental impact; such relationships do not generally exist for all domains of the environment. The second approach similarly assumes a correlation between the market value of a product and its impact on the environment. In a world in which all environmental impacts were properly internalized in the market value or economic worth of a product, this approach might make sense. As it is, however, using this allocation method allows materials that have a significant worth to pollute more and consume more resources. These two approaches, while not preferred, are often necessary, e.g., petroleum refineries which produce products not obtainable through other means.

The first approach includes in the system boundary processes that would normally be used to generate all but one of the products, so the stressors that would have been produced are subtracted from the total stressors generated by the system. This notion represents the fact that because the system we are studying is producing the products, the stressors normally produced by the conventional technology are not produced; they are *avoided*. For example, combined cooling, heating, and power is included in the present assessment. Because the product of primary interest is electricity, conventional technologies to provide cooling and heat are included in the system boundaries. Their stressors were subtracted, or taken as a credit, from the total stressors of the DG system to reflect that outside of the system, the conventional heating and cooling technologies will not have to be operated.

Distributed generation technologies were studied here as a means of meeting increasing demand rather than replacing generation for existing, constant demand. Therefore, in this study, they are not credited for avoiding generation or emissions from existing grid-tied technologies.

4.0 Study Assumptions

All assumptions and variable values, as entered into the LCA software model, are shown in Appendix B. Discussions on the major assumptions follow.

A key aim of this study is to place each DG technology on a standard basis. To accomplish this, all results are presented in terms of a kilowatt-hour of delivered electricity. Equipment construction is amortized over a 20-year generating life. If the equipment has a shorter life than this, the model includes manufacture and transport of new equipment to ensure that the system lasts for the full life; longer equipment lifetimes are handled with a manufacturing credit in the model. Transmission and distribution losses for central power generators are assumed to be 5%; the DG units do not suffer this loss, as they are assumed to be located close to the demand.

The size of any actual piece of generating equipment is not specified in the model. Instead, the model assumes the required kWh generation, unit lifetime, and expected capacity factors to back-calculate the number of installed kilowatts of capacity required to meet demand. Other impacts, such as steel required, are then calculated on a per-kilowatt of installed capacity basis, as opposed to a per-generation unit basis. This methodology was selected because the literature search revealed a wide range of potential unit sizes. The decision was made to normalize all emissions and material requirements to the common functional unit of energy delivered to the consumer. Averages, maximums, minimums, and standard deviations were then calculated based on this normalized data to provide a statistical representation of likely emissions from installed DG units.

Electricity losses over the transmission and distribution lines from the central power plants to the end users are assumed to average 5%. The DG technologies, because they are located at the point of electricity consumption, do not suffer from such losses.

4.1. Generator Efficiencies and Fuels

Table 3 shows the assumed efficiencies, fuels, and capacity factors for the technologies examined. The capacity factor for the natural gas peaker was set at 4%, based on evaluation of the average of the operating capacity factors of peaker power plants in California, according to DOE/EIA (2009). The PV system was assigned a capacity factor of 23% to represent a solar capacity factor typical of Southern California, where PV is more likely to be economic. A standard approximate capacity factor value of 80% was used for the other technologies, to place them on a consistent basis. Varying this value affects the percent of total inventory stressors attributed to construction operations, as a lower capacity factor results in the construction impacts being averaged over fewer kilowatt-hours. However, construction emissions are generally small in comparison to operating emissions. Capacity factor was varied in the sensitivity analysis to ensure that inaccurate assumptions did not change the overall results and conclusions.

Table 3. Generator Efficiencies and Fuels

System Studied	Central or DG	Prime Mover/Generator	Fuel	Electricity Generation Efficiency* (%)	Capacity Factor (%)
Gas Turbines	DG	Simple cycle gas turbine	Natural gas	38	80
Microturbines	DG	Microturbine	Natural gas	26	80
Recip	DG	Reciprocating engine	Natural gas	33	80
PV	DG	Photovoltaic panel	N/A	10	23
WWTP AD	DG	Reciprocating engine	WWTP digester gas	30	80
Diesel	DG	Diesel cycle engine	Diesel	38	80
Biomass	DG	Gasifier/reciprocating engine	Residue biomass	23	80
Dairy AD	DG	Reciprocating engine	Dairy digester gas	30	80
MCFC	DG	Fuel cell with internal reformer	Natural gas	48	80
PAFC	DG	Fuel cell with external reformer	Natural gas	40	80
SOFC	DG	Fuel cell with internal reformer	Natural gas	47	80
NGCC	Central	Combined cycle	Natural gas	49	80
NG Peaker	Central	Simple cycle gas turbine	Natural gas	38	4
Coal IGCC	Central	Gasifier/combined cycle	Coal	34	80

* Consistent with the U.S. power industry standard, *efficiency* is defined as the electricity delivered divided by the higher heating value of the fuel consumed by the prime mover. Consistent with LCA standards, however, the lower heating value of the fuels was used in the LCA calculations.

4.2. Generator Operating Emissions

Emissions from each electricity-generating technology were taken as the average of values found in multiple literature sources, with values outside of two standard deviations discarded. However, with respect to DG combustion technologies, a decision was made to cap generating emission inputs at the permitted values adopted by California's Air Resources Board (ARB). According to California State Senate Bill 1298,[1]

[1] SB 1298 (Bowen and Peace), Chapter 741, Statutes of 2000.

distributed generation in California should have minimal impact on the environment and must ultimately meet central power station emission standards. The statute required that, starting in 2003, every DG unit had to be either permitted by the local air district or certified by the ARB. The ARB was charged with developing certification requirements for DG equipment manufacturers; standards were developed for the years 2003 and 2007 (see www.arb.ca.gov/regact/dg01/finreg.pdf). The 2007 standards are set for the criteria pollutants NOx, carbon monoxide (CO), and volatile organic compounds (VOCs).

The ARB standards apply to equipment not permitted by air districts. The ARB standards required that all DG technologies fueled by natural gas meet the 2007 standards by November 1, 2007. For anaerobic digesters, emissions had to meet the original 2003 standards by November 1, 2007, and the current 2007 standards no later than November 1, 2012.

For this study, ARB 2007 standards were used to evaluate all DG technologies fueled by natural gas (including reciprocating engines, gas turbines, and microturbines). Based on the timing of this life cycle assessment, it is assumed that the installed natural gas and anaerobic emission standards were required to meet their respective standards for November 1, 2007. The literature search for microturbines, reciprocating engines, and gas turbines yielded emissions that were in excess of the 2007 standards. Therefore, emissions in the model for these technologies have been capped at NOx = 0.032 grams per kilowatt-hour (g/kWh), CO = 0.045 g/kWh, and VOC = 0.009 g/kWh. The anaerobic digester literature search revealed CO (0.32 g/kWh) and VOC (0.26 g/kWh) emission levels that were below the 2003 standard levels. Nitrogen oxide emissions were higher than the standard and were therefore capped in the model at 0.23 g/kWh.

Table 4 provides the generating emissions from the combustion-based technologies. Details on values obtained from the literature are provided in Appendix C. Blank cells indicate data that could not be located and thus were not included in the model.

Table 4. Fossil-fuel Combustion-based Technologies Generating Emissions Factors (g/kWh)

	NG Combined Cycle	Peaking Power Plant	Coal IGCC	DG NG Turbines	NG Microturbine	NG Reciprocating Engine	Diesel-Fired Diesel Engine
NOx Avg.	0.19	0.42	0.67	0.05	0.33	1.12	5.59
NOx Hi	0.55	2.08	1.00	0.55	0.63	20.01	18.85
NOx Lo	0.02	0.06	0.40	0.02	0.07	0.23	0.93
# of refs	11	39	6	6	15	16	19
SO_2 Avg.	0.00	0.01	0.23	0.01	0.01	0.00	0.42
SO_2 Hi	0.01	0.15	0.33	0.01	0.01	0.00	4.92
SO_2 Lo	0	0	0.07	0	0	0	0
# of refs	9	39	4	4	8	4	12
PM_{10} Avg.	0.02	0.03	0.03	0.02	0.04	0.09	0.32
PM_{10} Hi	0.02		0.06		0.07	0.27	1.36
PM_{10} Lo	0.02		0.01		0.04	0.00	0.01
# of refs	1	1	5	1	6	8	12
$PM_{2.5}$ Avg.	0.01			0.01	0.04	2.15	1.07
$PM_{2.5}$ Hi	0.01			0.01	0.04	2.15	1.36
$PM_{2.5}$ Lo	0.01			0.01	0.04	2.154	0.22
# of refs	3	0	0	3	3	2	4
CO Avg.	0.08	0.18	0.13	0.06	0.79	3.24	6.11
CO Hi	0.08			0.08	1.29	16.1	14.6
CO Lo	0.08			0.05	0.05	0.00	0.16
# of refs	3	1	0	4	12	9	13
CH_4 Avg.	0.02	0.03	0.06	0.03	0.04	4.58	No data
CH_4 Hi	0.02	0.04	0.08	0.04	0.03	6.81	
CH_4 Lo	0.03	0.02	0.03	0.02	0.05	1.08	
# of refs	3	3	4	3	3	3	No data
VOC Avg.	0.05	0.01	0.15	0.05	0.04	0.93	0.77
VOC Hi	0.05	0.01		0.05	0.19	1.87	0.91
VOC Lo	0.05	0.01		0.05	0.02	0.27	0.02
# of refs	3	2	1	3	8	7	8

4.3. Fuel Composition and Transport

4.3.1. Natural Gas

Natural gas is assumed to transported via pipeline over 1,200 kilometers (km), approximating the distance between the major natural gas fields in Canada and mid-Southern California. Natural gas is assumed to be sweetened and dried[2] at the wellhead prior to distribution through the pipeline system. Natural gas combustor compressors, which are largely fueled by reciprocating engines, along the length of the pipeline create the necessary pipeline pressure. Table 5 provides data on assumed natural gas composition and heating value.

Table 5. Natural Gas Composition and Heating Value

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

(a) Taken from SRI 1994.
(b) Taken from *Chemical Economics Handbook* (Lacson 1999) and adjusted to include hydrogen sulfide (H_2S).
(c) Taken from *Ullmann's Encyclopedia of Industrial Chemistry*, 1986.

[2] "Sweetened and dried" means that sulfur content has been reduced to a very low level and the water content has also been reduced.

4.3.2. Diesel

The diesel fuel used in the advanced diesel engine case is derived from petroleum refined in California, with an assumed carbon-to-hydrogen ratio of 1:2 and refined to be characterized as ultra-low sulfur diesel (< 15 ppm sulfur). Transportation and distribution of this diesel fuel is minimal, as it is refined in California. Transportation of the petroleum to the California refinery is included in the assessment.

4.3.3. Biomass and Landfill Gas

The biomass used in the DG biomass gasification case is assumed to be residue wood, gathered from agricultural operations, forest maintenance (not forest harvest), urban tree pruning, and mill operations. Milbrandt (2005) reports that 11.9 million metric tonnes of biomass in these classes are produced in California. The composition of the biomass assumed for this study is shown in Table 6. Variation in composition will affect the gasification efficiency somewhat, but within the class of wood and wood-like biomass, the impact on the overall study results will be minimal.

Table 6. Biomass Composition (Ultimate Analysis)

Component:	Carbon	Oxygen	Hydrogen	Nitrogen	Sulfur	Chlorine	Ash
wt %, dry basis:	50.88	41.90	6.04	0.17	0.09	0.00	0.92
Moisture, as fed to gasifier = 15%							
Heat of combustion, LHV = 18,607 kJ/kg (8,007 Btu/lb)							
Heat of combustion, HHV = 19,827 kJ/kg (8,533 Btu/lb)							

kJ/kg = kilojoules per kilogram

Because the biomass used by the DG gasifier and fired in the reciprocating engine is not grown for the purpose of electricity production, a credit is not taken for the absorption of CO_2 during the growing cycle (see Mann and Spath 1997). Rather, the emissions, resource consumption and energy use that would have occurred during the normal routes of biomass disposal are avoided and credited in the life cycle inventory (note: the following comes from a study detailed in Mann and Spath 2001). Using data from Wiltsee (1998), it was assumed that 46% of the biomass would have been landfilled, and 54% would have been mulched or converted to other short-lived products. In the case of mulch, it is likely that most decomposition occurs under aerobic conditions, although decomposition at the interior and bottom of mulch piles will be anaerobic. Additionally, chipping and mulching wood increases the surface area subject to degradation both by microorganisms and air oxidation. Pier and Kelly (1997) found that 20% of the gas coming off of sawdust piles was methane; of the total carbon in the biomass, 13.9% ends up as methane. For this assessment, all of the mulch normally disposed of was assumed to decompose, with 10% of the carbon going to methane and 90% to CO_2.

Unlike mulch, decomposition in landfills occurs under mostly anaerobic conditions, resulting in a gas that can be approximated as a mixture of approximately 50% CO_2 and 50% CH_4 (McBean et al. 1995; Barlaz 1998; U.S. EPA 1998b). Because lignin is resistant to microbial degradation under anaerobic conditions (Ham et al. 1993; Tong et al. 1990; Micales and Skog 1997), only non-lignin compounds (e.g., cellulose, hemicellulose, acetate) were assumed to be subject to decomposition in the landfill.

It is difficult to determine the extent to which these compounds decompose, however. In key laboratory experiments on the decomposition of components of the municipal solid waste stream, Barlaz et al. (1989) found that 71% of the cellulose and 77% of the hemicellulose will degrade. However, lignin, in addition to being resistant to microbial attack, can retard the decomposition of closely associated cellulose and hemicellulose (Young and Frazer 1987). Because softwood and hardwood are approximately 28.5% and 27.0% (dry basis) lignin, respectively, the extent of decomposition of wood in landfills will be less than that of the waste stream as a whole. Barlaz (1998) reports that for branches, 55.6% of the non-lignin species decompose. In shorter experiments, Eleazer et al. (1997) report that 48% of the cellulose and 41% of the hemicellulose in branches decomposed. It is important to note, however, that branches have significantly higher lignin contents (~33%) than the wood that is assumed for the power plant; therefore, the extent of decomposition of residue wood will be higher.

To take into account the full lifetime in which landfilled wood will contribute to climate change, the cellulose and hemicellulose fractions of the biomass were assumed to be 50% degraded, while the lignin was assumed to remain intact.

Two processes combine to reduce the total amount of methane that is actually released from the landfill. First, microbes in the soil close to the surface oxidize approximately 10% of the methane to CO_2 (Bogner 1992). Secondly, to comply with air regulations, a fraction of the gas that is produced at U.S. landfills is collected and burned. Regulations for landfill gas are aimed at reducing non-methane organic compounds, but indirectly result in a reduction in methane emissions. Approximately 5% of all current and projected landfills are required to collect and process the gas (McGuigam 1998). Because such requirements fall only on landfills greater than a certain size (2,500 kg and 2.5 million square meters (m^3), producing more than 50,000 kg of non-methane organic compounds per year), collection of gas at 5% of sites results in a 39% reduction in the total amount of methane emitted from U.S. landfills (Meadows et al. 1997). The U.S. Environmental Protection Agency (U.S. EPA) (1998b) stated that by the year 2000, 54% of landfill methane would be generated at landfills with recovery systems, with an average collection efficiency of 75%. This results in a collection of 40.5% of the methane generated in landfills. Although the two numbers available were very close, the more conservative estimate of 40.5% was assumed in this analysis.

Figure 18 summarizes the assumptions regarding the fate of the carbon in the biomass if it is not used for electricity production. The total CO_2 and methane avoided per 100 kg of biomass is 111.7 kg and 6.5 kg, respectively.

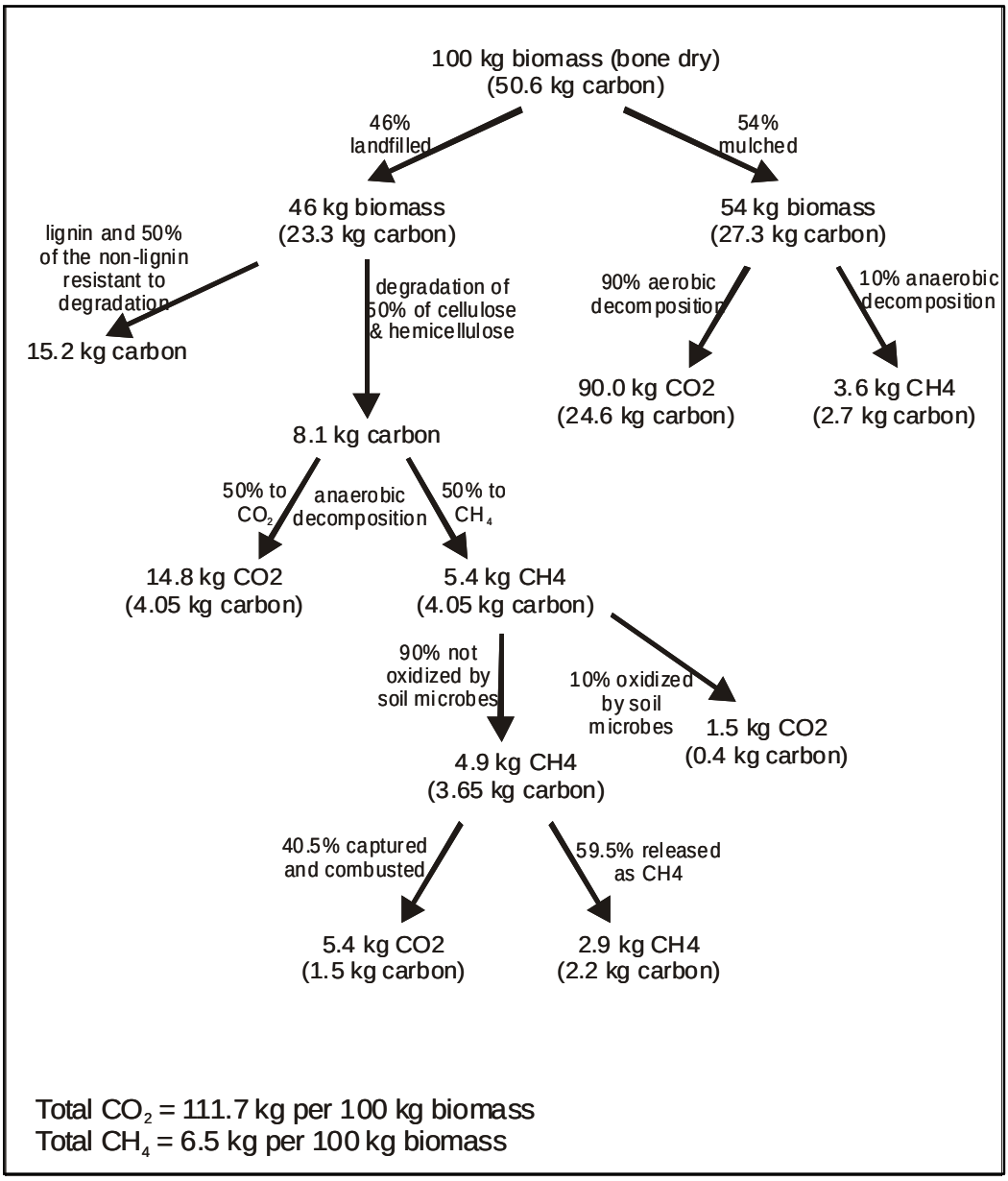


Figure 18. Avoided Fate of Biomass

Source: Mann and Spath 2001

A case assuming that the CO_2 generated during combustion of the biomass is equal to the CO_2 absorbed during photosynthesis was also tested. The biomass is assumed to also be a residue, and not grown as an energy crop. As avoided emissions are meant to represent a deviation from a status-quo operation, long-term use of a residue that would have earlier been disposed of as described in Figure 18, can be said to change the status quo. Thus, the long-term definition of the life cycle boundary is that of a cycle between

photosynthesis and combustion. Note that fossil fuel use for procuring, delivering, and preparing the biomass for use at the DG facility remains the same, resulting in a net positive greenhouse gas emission balance.

4.4. Natural Gas Losses

Fugitive emissions from equipment leaks are the largest source of methane emissions from the production and distribution of natural gas at U.S. wells (U.S. EPA 2004). Fugitive methane emissions from the natural gas industry account for approximately 20% of total U.S. methane emissions and about 2% of total U.S. GHG emissions. Overall, about half of the GHG emissions from the natural gas industry are from the release of methane (U.S. EPA 2007).

Over the past three decades, the U.S. EPA, the natural gas industry, and public-sector researchers have tried to better quantify the amount of methane emissions lost to the atmosphere during the extraction, processing, transmission, storage, and distribution of natural gas. According to the U.S. EPA, transmission and storage account for the largest portion of the total methane emissions at 37% followed by extraction at 27%, distribution at 24%, and processing contributing the least at 12% (Harrison et al. 1997). In the late 1980s U.S. EPA, the Gas Research Institute (GRI), and the American Gas Association (AGA) initiated a study which estimated the methane emitted to the atmosphere from U.S. natural gas operations to be 1.4% +/- 0.5% of the gross natural gas produced (Harrison et al. 1997). Another publication (Kirchgessner et al. 1997), which includes several authors of the U.S. EPA/GRI/AGA study, states that numerous estimates of methane emissions are available and that the most commonly cited leakage rates range from 1%–4%.

Newer reports on the emissions of greenhouse gases from natural gas production and distribution systems have essentially confirmed the earlier studies, but with additional granularity and confidence. The U.S. EPA (2007) reports the total methane and CO_2 emissions from this industry as 4,877 and 28,504 billion grams, respectively. The definitions this report uses for different stages in the production and distribution train, however, are inconsistent with those used by the DOE's Energy Information Administration, making a calculation of the percentage that leaks difficult.

Hayes (2004) states that fugitive emissions from natural gas operations could range between 2%–4% of the total gas used, and that methane emissions are underreported based on emissions audits. Because of the oft-cited nature of the U.S. EPA estimates, the base case of this LCA assumed that 1.4% of the natural gas that is extracted is lost to the atmosphere due to fugitive emissions. To determine the effect that natural gas losses have on the results and specifically on the system's total greenhouse gas emissions, a sensitivity analysis was performed on this variable.

4.5. Coal Mining and Conversion

The coal-fired power plant in this study is assumed to use western coal, typified by that found in the Powder River Basin (PRB) of Montana and Wyoming. Apart from its close proximity to California and the states that have transmission lines into California, the primary advantages of using western coal for electricity generation are its low production costs and low sulfur content. These characteristics lead to both economic and environmental advantages. The primary option for generating electricity from western coal is currently the pulverized coal (PC) power plant. Integrated gasification combined-cycle (IGCC) plants have numerous advantages over PC plants, however, and may be the dominant technology for new coal utilization.

In general, IGCC plants have higher efficiency, fewer emissions, less solid waste, and lower water usage (a critical consideration in the arid western United States). Criteria pollutant emissions may be significantly lower with IGCC technologies than with PC technologies, as scrubbing and ammonia injection are aided in the intermediate processing of syngas prior to combustion. IGCC plants also allow for the possibility of CO_2 capture and sequestration at a lower cost than PC plants. Although capital costs are higher for IGCC plants compared to PC plants, the higher efficiency results in a lower levelized cost of electricity.

Western lignite and subbituminous coal (such as PRB coal) have higher moisture contents and lower heating values than eastern bituminous coals. In general, IGCCs perform better on coal with lower moisture content and higher heating values; however, the technical feasibility of using PRB in IGCC plants was established by the Louisiana Gasification Technology Incorporated plant in Plaquemine, Louisiana, which operated successfully from 1987 to 1995 using PRB subbituminous coal in an IGCC facility.

An IGCC case was included in this study to provide a conservative baseline for comparison against the DG technologies. The substitution of a pulverized coal plant for the IGCC would exacerbate any identified environmental impacts, as the environmental impacts of IGCC units are lower than PC plants.

5.0 Results

Because of the vast amount of results generated from a life cycle study of this size, results reporting is organized according to major findings. The primary results are provided in Table 7, which documents results with CHP and Table 8, which documents results without CHP. The major findings, and the sections in which these are described are as follows:

- Effect of generator efficiency: Section 5.1
- Effect of natural gas production and distribution: Section 5.2
- Local, regional, and global impacts: Section 5.3
- Greenhouse gas emissions: Section 5.4
- Effect of combined cooling, heating, and power: Section 5.5

Table 7. Study Results, Details with CHP

			Results/kWh Generated - CHP System													
Inputs:	Flow	Units	**NGCC**	**NG Peaker**	**Coal IGCC**	**DG Gas Turbines**	**DG Microturbines**	**DG Recip**	**DG PV**	**DG WWTP AD**	**DG Diesel**	**DG Biomass**	**DG Dairy AD**	**DG MCFC**	**DG PAFC**	**DG SOFC**
Fossil Fuels	(r) Coal (in ground)	kg	1.71E-03	5.11E-03	6.74E-01	7.14E-04	1.34E-03	8.84E-04	6.88E-02	-1.20E-04	1.6.E-03	4.5.E-03	-3.4.E-02	9.4.E-04	2.3.E-03	2.2.E-03
	(r) Natural Gas (in ground)	kg	2.36E-01	2.41E-01	4.86E-03	9.67E-02	1.84E-01	1.19E-01	9.42E-04	-1.15E-01	-6.6.E-02	-1.3.E-01	-2.1.E-01	1.3.E-01	1.7.E-01	1.5.E-01
	(r) Oil (in ground)	kg	5.93E-04	9.32E-04	1.22E-03	2.44E-04	4.62E-04	3.00E-04	9.39E-03	-2.76E-04	2.2.E-01	3.0.E-03	-7.4.E-03	3.3.E-04	6.0.E-04	5.6.E-04
Water Use	Water Used (total)	litre	3.97E-01	4.54E-01	1.13E+00	9.84E-03	1.74E-02	1.26E-02	1.16E-01	-2.32E-04	8.2.E-02	4.0.E-01	-2.6.E+00	9.1.E-03	3.8.E-02	3.7.E-02
Outputs:																
Air Emissions:																
	(a) Carbon Monoxide (CO)	g	0.43	0.55	0.46	0.21	0.34	0.25	0.09	(0.10)	0.02	(0.12)	(0.09)	0.21	0.28	0.24
	(a) Nitrogen Oxides (NOx as NO2)	g	0.84	1.10	0.98	0.36	0.60	0.42	0.33	(0.20)	0.30	(0.24)	(1.01)	0.41	0.49	0.44
Greenhouse Gas Emissions:	(a) Carbon Dioxide (CO2, fossil)	g	483.73	559.62	776.42	206.31	408.85	256.79	127.14	(154.49)	551.54	412.23	(1,897.75)	290.89	436.07	387.16
	(a) Nitrous Oxide (N2O)	g	0.00	0.01	0.00	0.01	0.00	0.00	0.00	(0.00)	0.01	0.00	(7.01)	0.00	0.00	0.00
	(a) Methane (CH4)	g	9.77	9.95	3.79	4.02	7.57	4.90	0.65	(4.73)	(1.48)	(53.86)	(78.25)	2.96	3.87	3.43
	Total GHG	g CO2-equiv	689.17	772.43	856.07	294.16	568.08	359.73	140.82	(254.04)	523.43	(718.56)	(5,714.88)	353.40	517.82	459.71
	% of Total GHG from CO2		0.70	0.72	0.91	0.70	0.72	0.71	0.90	0.61	1.05	(0.57)	0.33	0.82	0.84	0.84
	% of Total GHG from N2O		0.00	0.01	0.00	0.01	0.00	0.00	0.00	0.00	0.01	(0.00)	0.38	0.00	0.00	0.00
	% of Total GHG from CH4		0.30	0.27	0.09	0.29	0.28	0.29	0.10	0.39	(0.06)	1.57	0.29	0.18	0.16	0.16
	CO2, g CO2-equiv/kWh		483.73	559.62	776.42	206.31	408.85	256.79	127.14	(154.49)	551.54	412.23	(1,897.75)	290.89	436.07	387.16
	N2O, g CO2-equiv/kWh		0.26	3.92	0.08	3.53	0.20	0.13	0.01	(0.12)	3.05	0.23	(2,173.79)	0.40	0.53	0.51
	CH4, g CO2-equiv/kWh		205.18	208.89	79.57	84.32	159.03	102.81	13.68	(99.43)	(31.15)	(1,131.02)	(1,643.34)	62.11	81.22	72.04
Particulate Matter:	(a) Particulates (PM 10)	g	0.02	0.03	0.03	0.03	0.04	0.03	0.04	-	0.31	0.00	(1.80)	0.00	0.00	0.00
	(a) Particulates (PM2.5)	g	0.01	-	-	-	0.04	0.02	-	-	1.02	0.00	2.08	-	-	-
	(a) Particulates (unspecified)	g	0.00	0.06	0.62	0.00	0.00	0.00	0.08	0.00	0.08	0.36	0.54	0.00	0.07	0.07
	(a) Particulates (unspecified)	g	0.03	0.03	-	0.01	0.02	0.01	0.09	(0.01)	(0.01)	(0.02)	(0.01)	0.02	0.02	0.02
	(a) Total Particulates (sum of above)	g	0.06	0.12	0.65	0.04	0.11	0.07	0.21	(0.01)	1.40	0.34	0.82	0.02	0.09	0.09
Sulfur Oxides:	(a) Sulfur Oxides (SOx as SO2)	g	0.38	0.44	0.23	0.16	0.30	0.19	0.05	(0.17)	0.70	(0.10)	(0.71)	0.21	0.30	0.27
NMOCs	(a) VOC (Volatile Organic Compounds)	g	0.05	0.01	-	0.01	0.01	0.01	0.09	0.01	0.09	0.01	(3.34)	0.01	0.01	0.01
	(a) Hydrocarbons (except methane)	g	0.16	0.24	0.06	0.07	0.12	0.08	0.01	(0.08)	1.33	0.04	(0.74)	0.09	0.14	0.12
	(a) Hydrocarbons (unspecified)	g	1.33E-04	5.09E-03	4.82E-03	7.25E-05	1.12E-04	9.89E-05	2.71E-02	1.18E-04	8.2.E-04	7.6.E-03	-2.9.E-03	4.9.E-05	1.4.E-03	1.4.E-03
	(a) Ethane (C2H6)	g	0.54	0.55	0.01	0.22	0.42	0.27	0.00	(0.26)	(0.08)	(0.15)	(0.10)	0.15	0.20	0.17
	(a) Propane (C3H8)	g	0.13	0.13	0.00	0.05	0.10	0.06	0.00	(0.06)	(0.02)	(0.04)	(0.02)	0.04	0.05	0.04
	(a) Butane (n-C4H10)	g	0.03	0.03	0.00	0.01	0.03	0.02	0.00	(0.02)	(0.00)	(0.01)	(0.01)	0.01	0.01	0.01
	(a) Alkane (unspecified)	g	-	-	0.00	-	-	-	0.00	0.00	-	0.00	(0.00)	-	-	-
	Total Non-Methane Organic Compounds	g	0.91	0.97	0.07	0.37	0.68	0.45	0.12	(0.40)	1.32	(0.13)	(4.22)	0.30	0.41	0.36
Energy Use:	E Feedstock Energy	MJ	10.21	10.46	10.78	4.19	7.95	5.14	1.49	(4.96)	5.89	(5.64)	(4.52)	5.66	7.40	6.57
	E Fuel Energy	MJ	2.19	2.31	1.45	0.90	1.70	1.10	0.18	(1.06)	0.28	(1.10)	(7.17)	1.21	1.62	1.44
	E Non Renewable Energy	MJ	12.40	12.76	12.23	5.08	9.65	6.24	1.66	(6.02)	6.17	(6.74)	(11.66)	6.87	9.02	8.01
	E Renewable Energy	MJ	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	0.00	0.00	(0.04)	0.00	0.00	0.00
	E Total Primary Energy	MJ	12.40	12.76	12.23	5.08	9.65	6.24	1.66	(6.03)	6.18	(6.74)	(11.70)	6.87	9.03	8.01
	E Total Primary Energy	kWh	12.40	12.76	12.23	5.08	9.65	6.24	1.66	(6.03)	6.18	(6.74)	(11.70)	6.87	9.03	8.01

Table 8. Study Results Details, without CHP

			Results/kWh Generated - No CHP System													
Inputs:	Flow	Units	**NGCC**	**NG Peaker**	**Coal IGCC**	**DG Gas Turbines**	**DG Microturbines**	**DG Recip**	**DG PV**	**DG WWTP AD**	**DG Diesel**	**DG Biomass**	**DG Dairy AD**	**DG MCFC**	**DG PAFC**	**DG SOFC**
Fossil Fuels	(r) Coal (in ground)	kg	1.71E-03	5.11E-03	6.74E-01	1.70E-03	2.49E-03	1.95E-03	6.88E-02	7.35E-04	2.1.E-03	5.5.E-03	-3.3.E-02	1.3.E-03	2.7.E-03	2.4.E-03
	(r) Natural Gas (in ground)	kg	2.36E-01	2.41E-01	4.86E-03	2.41E-01	3.50E-01	2.74E-01	9.42E-04	9.37E-03	8.9.E-04	4.6.E-04	-1.3.E-01	1.9.E-01	2.2.E-01	1.8.E-01
	(r) Oil (in ground)	kg	5.93E-04	9.32E-04	1.22E-03	6.00E-04	8.75E-04	6.85E-04	9.39E-03	3.18E-05	2.2.E-01	3.3.E-03	-7.2.E-03	4.7.E-04	7.4.E-04	6.4.E-04
Water Use	Water Used (total)	litre	3.97E-01	4.54E-01	1.13E+00	1.88E-02	2.78E-02	2.23E-02	1.16E-01	7.54E-03	8.6.E-02	4.1.E-01	-2.6.E+00	1.3.E-02	4.1.E-02	3.9.E-02
Outputs:																
Air Emissions:																
	(a) Carbon Monoxide (CO)	g	0.43	0.55	0.46	0.43	0.59	0.48	0.09	0.08	0.12	0.08	0.04	0.30	0.36	0.29
	(a) Nitrogen Oxides (NOx as NO2)	g	0.84	1.10	0.98	0.75	1.06	0.85	0.33	0.14	0.48	0.13	(0.78)	0.56	0.64	0.53
Greenhouse Gas Emissions:	(a) Carbon Dioxide (CO2, fossil)	g	483.73	559.62	776.42	570.17	830.89	649.74	127.14	159.87	721.65	752.45	(1,691.93)	436.91	569.57	470.17
	(a) Nitrous Oxide (N2O)	g	0.00	0.01	0.00	0.01	0.00	0.00	0.00	0.00	0.01	0.00	(7.01)	0.00	0.00	0.00
	(a) Methane (CH4)	g	9.77	9.95	3.79	9.95	14.45	11.30	0.65	0.39	0.04	(50.82)	(76.41)	4.26	5.06	4.17
	Total GHG	g CO2-equiv	689.17	772.43	856.07	782.73	1,134.77	887.36	140.82	168.06	725.56	(314.30)	(5,470.32)	526.90	676.45	558.35
	% of Total GHG from CO2		0.70	0.72	0.91	0.73	0.73	0.73	0.90	0.95	0.99	(2.39)	0.31	0.83	0.84	0.84
	% of Total GHG from N2O		0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	(0.00)	0.40	0.00	0.00	0.00
	% of Total GHG from CH4		0.30	0.27	0.09	0.27	0.27	0.27	0.10	0.05	0.00	3.40	0.29	0.17	0.16	0.16
	CO2, g CO2-equiv/kWh		483.73	559.62	776.42	570.17	830.89	649.74	127.14	159.87	721.65	752.45	(1,691.93)	436.91	569.57	470.17
	N2O, g CO2-equiv/kWh		0.26	3.92	0.08	3.68	0.38	0.29	0.01	0.02	3.12	0.38	(2,173.70)	0.46	0.59	0.55
	CH4, g CO2-equiv/kWh		205.18	208.89	79.57	208.87	303.50	237.32	13.68	8.18	0.79	(1,067.12)	(1,604.69)	89.53	106.29	87.63
Particulate Matter:	(a) Particulates (PM 10)	g	0.02	0.03	0.03	0.03	0.04	0.03	0.04	-	0.31	0.00	(1.80)	0.00	0.00	0.00
	(a) Particulates (PM2.5)	g	0.01	-	-	-	0.04	0.02	-	-	1.02	0.00	2.08	-	-	-
	(a) Particulates (unspecified)	g	0.00	0.06	0.62	0.00	0.00	0.00	0.08	0.00	0.08	0.36	0.54	0.00	0.07	0.07
	(a) Particulates (unspecified)	g	0.03	0.03	-	0.03	0.04	0.03	0.09	0.00	-	-	-	0.02	0.03	0.02
	(a) Total Particulates (sum of above)	g	0.06	0.12	0.65	0.06	0.13	0.09	0.21	0.00	1.41	0.36	0.83	0.03	0.10	0.10
Sulfur Oxides:	(a) Sulfur Oxides (SOx as SO2)	g	0.38	0.44	0.23	0.39	0.57	0.45	0.05	0.03	0.81	0.12	(0.58)	0.30	0.38	0.32
NMOCs	(a) VOC (Volatile Organic Compounds)	g	0.05	0.01	-	0.01	0.01	0.01	0.09	0.01	0.09	0.01	(3.34)	0.01	0.01	0.01
	(a) Hydrocarbons (except methane)	g	0.16	0.24	0.06	0.16	0.24	0.18	0.01	0.01	1.38	0.13	(0.69)	0.13	0.17	0.15
	(a) Hydrocarbons (unspecified)	g	1.33E-04	5.09E-03	4.82E-03	7.25E-05	1.12E-04	9.89E-05	2.71E-02	1.18E-04	8.2.E-04	7.6.E-03	-2.9.E-03	4.9.E-05	1.4.E-03	1.4.E-03
	(a) Ethane (C2H6)	g	0.54	0.55	0.01	0.55	0.80	0.63	0.00	0.02	0.00	0.00	(0.01)	0.22	0.26	0.21
	(a) Propane (C3H8)	g	0.13	0.13	0.00	0.13	0.19	0.15	0.00	0.01	0.00	0.00	(0.00)	0.05	0.06	0.05
	(a) Butane (n-C4H10)	g	0.03	0.03	0.00	0.03	0.05	0.04	0.00	0.00	-	0.00	(0.00)	0.01	0.02	0.01
	(a) Alkane (unspecified)	g	-	-	0.00	-	-	-	0.00	0.00	-	0.00	(0.00)	-	-	-
	Total Non-Methane Organic Compounds	g	0.91	0.97	0.07	0.89	1.29	1.01	0.12	0.05	1.47	0.16	(4.04)	0.42	0.52	0.43
Energy Use:	E Feedstock Energy	MJ	10.21	10.46	10.78	10.41	15.17	11.86	1.49	0.42	8.81	0.18	(1.00)	8.16	9.69	7.99
	E Fuel Energy	MJ	2.19	2.31	1.45	2.23	3.25	2.54	0.18	0.09	0.91	0.15	(6.41)	1.75	2.11	1.75
	E Non Renewable Energy	MJ	12.40	12.76	12.23	12.64	18.42	14.40	1.66	0.51	9.71	0.33	(7.38)	9.90	11.80	9.73
	E Renewable Energy	MJ	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.00	(0.04)	0.00	0.00	0.00
	E Total Primary Energy	MJ	12.40	12.76	12.23	12.64	18.42	14.41	1.66	0.51	9.71	0.33	(7.42)	9.90	11.80	9.73
	E Total Primary Energy	kWh	12.40	12.76	12.23	12.64	18.42	14.41	1.66	0.51	9.71	0.33	(7.42)	9.90	11.80	9.73

In the following sections, figures are presented as *examples* of the findings shown in the preceding tables. In order to make the figures easier to read, not each figure presents results for all technologies, but instead focuses on those which highlight the results being discussed. All results are normalized on a per kWh-delivered basis for easy comparison. Transmission and distribution construction and line losses are included for the central technologies but not for the DG technologies. Appendix C contains the inventory analysis results that were used to generate the following graphs.

5.1. Results Findings: Effect of Generator Efficiency

In all cases, the environmental impact of building and decommissioning the power generator is small compared to the impact from its operation. Thus, when the fuel is the same, the efficiency of the generator was found to have the greatest impact on emissions results. A lower generator efficiency will, in general, result in higher generator emissions, particularly between systems that have similar emissions control equipment. An inverse relationship between efficiency and life cycle emissions is also seen, due to the added fuel that must be extracted, delivered, and combusted to achieve the same rate of electricity production. Figures 19, 20, and 21 show the effect that generator efficiency has on operating emissions and life cycle emissions for NOx, CO, and GHGs, respectively. Only those technologies using natural gas as the fuel are shown in these figures. The category labeled, "Fuel Acquisition and Delivery" represents the process steps required to extract natural gas from the ground and deliver it to the generator, but does not include fugitive natural gas emissions.

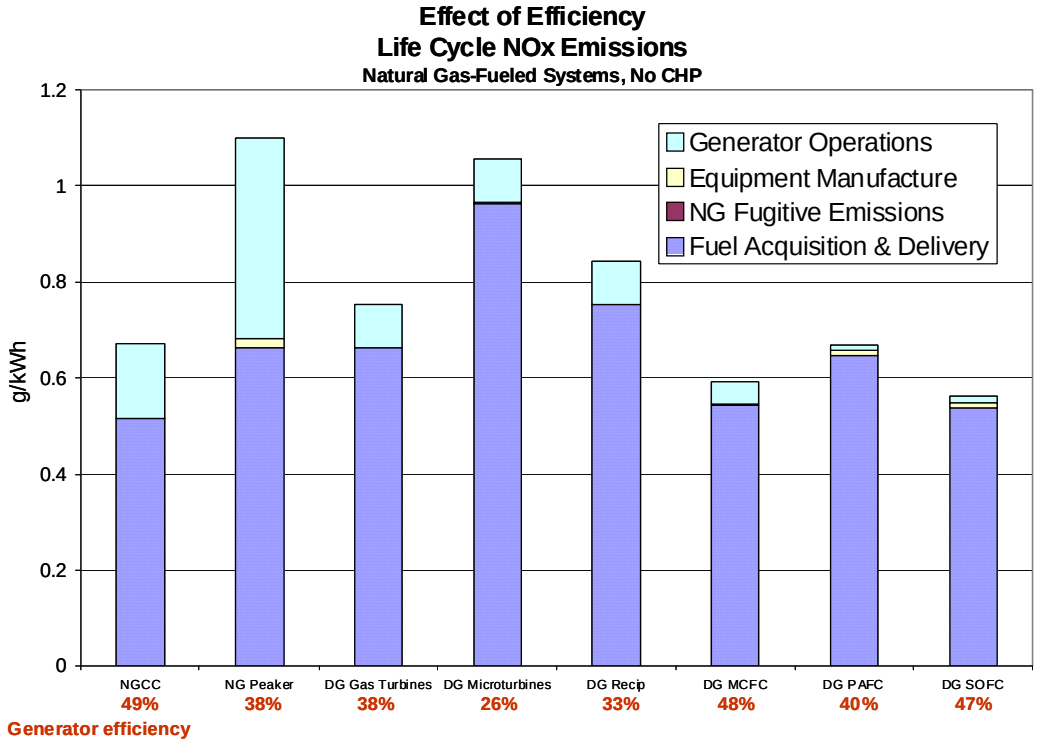


Figure 19. Effect of Efficiency on Life Cycle NOx Emissions

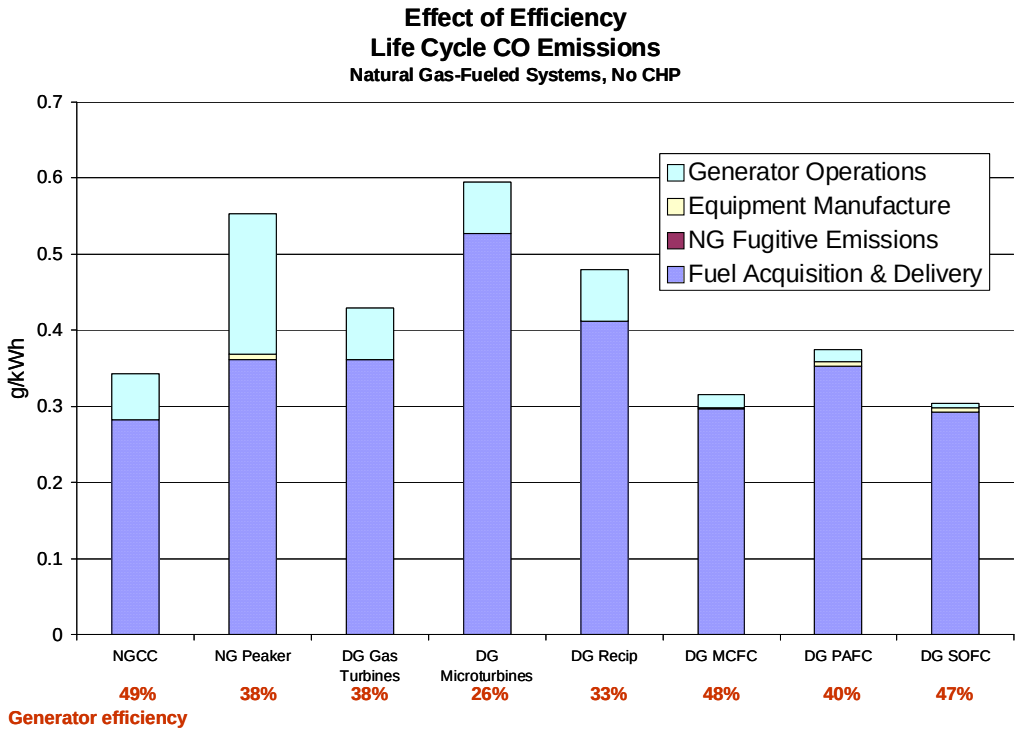


Figure 20. Effect of Efficiency on Life Cycle CO Emissions

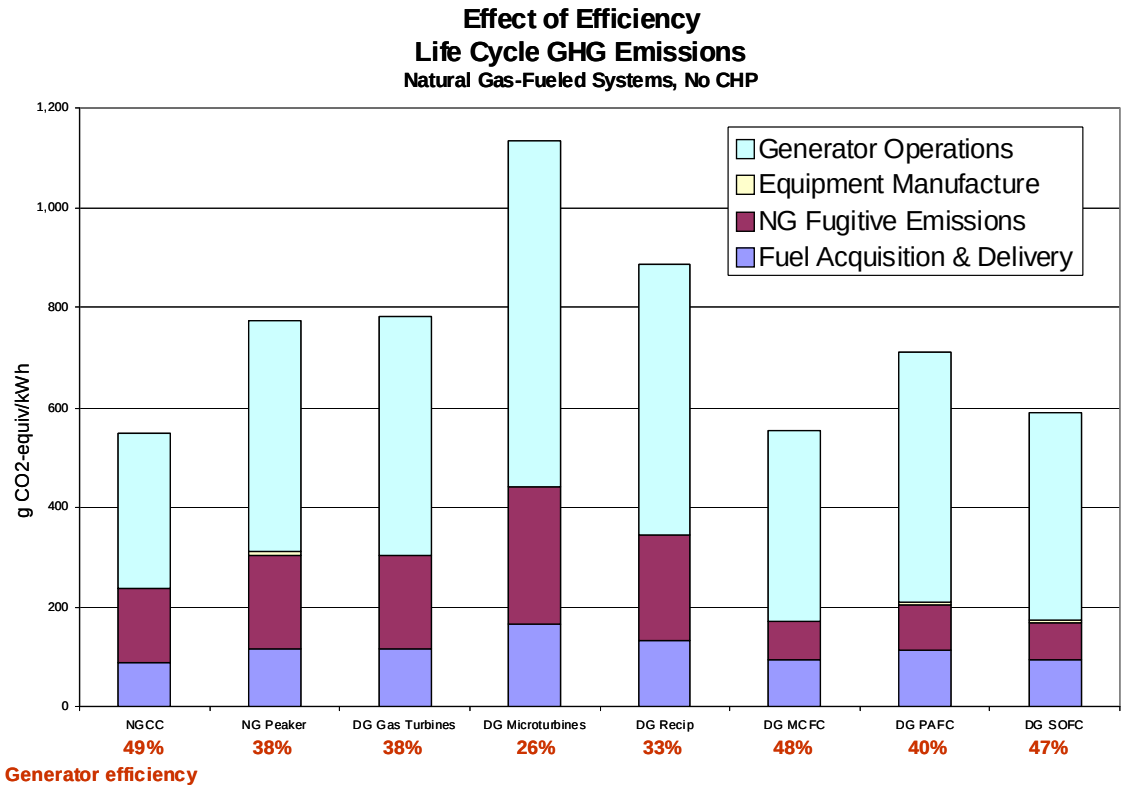


Figure 21. Effect of Efficiency on Life Cycle GHG Emissions

The majority of the NOx and CO emissions are seen in the "Fuel Acquisition and Delivery" category and are generated by the combustor compressors operating along the length of the natural gas pipelines. More discussion will be presented on the impact of these emissions in Section 5.3. The GHG emissions from this category are due to fuel combustion for operation of extraction and delivery processes.

As can be seen from these charts, total life cycle CO, VOC, and GHG emissions are lower for those technologies that have the highest generator efficiencies. Fuel cells and natural gas combined-cycle plants, all with efficiencies greater than 40%, demonstrate the lowest total emissions. Microturbines, which have the lowest generator efficiency, have the highest emissions of these stressors on a life cycle basis.

Emissions associated with fuel acquisition and delivery track directly with operating efficiency, as a higher efficiency means that less fuel is required per kWh generated. The same can be said for fugitive GHG emissions, as less fuel results in lower quantities of leaked natural gas.

Note that the equipment manufacturing stage shows up for peaking plants and not for the other systems because the capacity factor is much lower, causing emissions to be averaged over far fewer kilowatt-hours. Despite this effect, however, construction emissions are a minor component to the total CO, VOC, and GHG emissions for this system.

5.2. Results Findings: Effect of Natural Gas Production and Distribution

As described in Section 6.0 (Study Assumptions), natural gas production and distribution systems in operation today incur some loss of natural gas due to leaks and incomplete flaring. The base case of this study assumed a leak rate of 1.4% of the gross amount of fuel extracted. The higher global warming potential (GWP) of methane compared to CO_2 (21:1, on a mass basis) means that any leaks will have a significant impact on total GHG emissions because natural gas is primarily composed of methane. Thus, any technologies that use natural gas suffer from higher GHG emissions than would be expected solely from the combustion of the fuel throughout the life cycle, due to even small amounts of leaking fuel.

Figure 22 shows the base case life cycle GHG emissions for the fossil-fueled technologies examined, broken out according to emission source. Because GHGs have a global impact, all emissions across the life cycle are additive. The fugitive emissions are delineated as a separate section of the bars for the technologies that use natural gas as their primary fuel.

Error bars have been placed on the fugitive emissions portion of these results to demonstrate the range of total GHG emissions that might occur based on varying values of leak rates reported in the literature. If the natural gas lost to the atmosphere from leaks during production, pipeline transport, and distribution are as high as some sources

say (~4%), total GHG emissions from the natural gas-fired systems could be significantly higher than those resulting from combustion alone. However, as efforts such as U.S. EPA's Natural Gas STAR Program continue to reduce emissions, perhaps only a small amount of the total GHG emissions will be attributable to the leaking methane. No one expects the rate of leaks to be zero, though, and due to the higher GWP of methane, even small leaks will have an appreciable effect. The lower portion of the error bars in this figure represent a leak rate of 0.5% by mass.

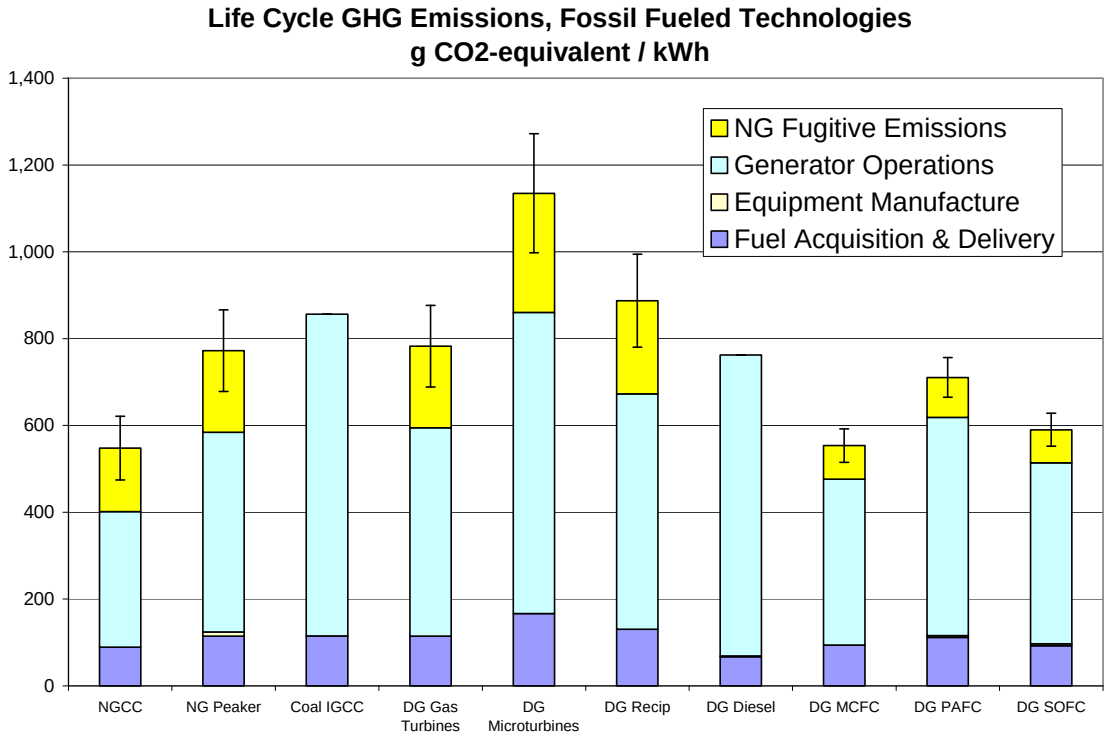


Figure 22. Life Cycle GHG Emissions with Uncertainty in Fugitive Emissions, in Grams of CO_2-equivalent per Kilowatt-hour

Figure 23 shows the same results as the previous figure, but displayed according to the primary GHG species affecting these systems (CO_2, methane, and nitrous oxide [N_2O]). A comparison between the natural gas-fired technologies and the others (IGCC and advanced diesel) demonstrates the importance of the methane emissions on total GHG emissions.

Without taking into account the emissions associated with natural gas leaks, the GHG emissions from the advanced diesel system would be considered to be higher than those from many of the natural gas-fired technologies (peaker, combined-cycle, and gas turbines). However, because of the methane emitted during the production and distribution of natural gas, the total GHG emissions of these technologies are higher than those of the advanced diesel system.

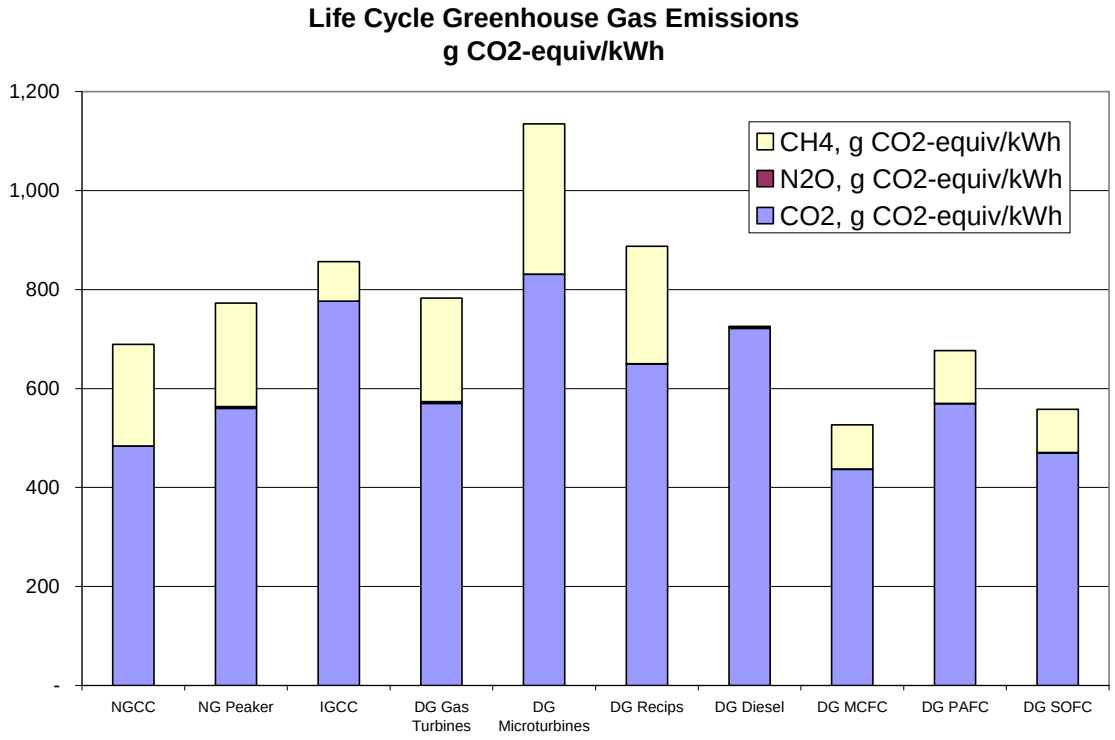


Figure 23. Life Cycle GHG Emissions of NG Technologies, by Species, in Grams of CO_2-equivalent per Kilowatt-hour

Life cycle CO emissions are also affected by the natural gas production and distribution subsystem, in that the combustor compressors along the length of the pipeline are operated fairly inefficiently, resulting in incomplete combustion of natural gas. Figure 24 shows this result graphically.

5.3. Results Findings: Local, Regional, and Global Impacts

Environmental stressors impact the environment at different distances from their primary point of use (in the case of resource consumption) or emission. The impacts from air emissions such as CO, VOCs, NOx, and particulates are felt close to where they are emitted, either locally or regionally, and are generically classified as being less than and greater than 50 miles, respectively. Emissions to water initially have a very localized impact, but can disperse through above- and below-ground water systems to have a more regional impact. Chemical releases into soil are almost always limited to local effects, although movement to groundwater can be a concern. Those that have global impacts are generally related to resource consumption (fossil fuels, water, minerals, metals), although impacts from GHGs and ozone depletion compounds are obviously global in nature.

Within the context of LCA methodologies, the concept of locational impact is extremely relevant to analyzing results and drawing conclusions. Higher emission rates do not necessarily mean that there is a greater impact on the environment. If emissions are released over a large area, all sources of emissions cannot be added together to determine the total rate of emission and impact. For example, CO emitted by the combustor compressors along the length of the pipeline in natural gas production and distribution systems are not additive because CO impacts only the region in which it is emitted. However, adding up "non-additive" stressors (or those that do not make a cumulative impact when emitted at different locations) can still highlight areas in which technology improvements should be targeted for greater total reduction in environmental impacts and more efficient natural resource use. Additionally, as the total installed capacity of alternative energy technologies increases, the rate of addition of stressors to the atmosphere may become great enough to increase the distance from the point of emission at which an environmental impact occurs. This consideration is of special importance to distributed generation technologies such as those studied here.

5.3.1. Carbon Monoxide

Figure 24 shows the life cycle carbon monoxide emissions by life cycle stage. As mentioned before, the total emissions are primarily driven by incomplete combustion by the combustion compressors along the length of the pipeline. Although these emissions are produced in different locations, it is interesting to note that the total quantity is large and presents an opportunity for better maintenance along the pipeline.

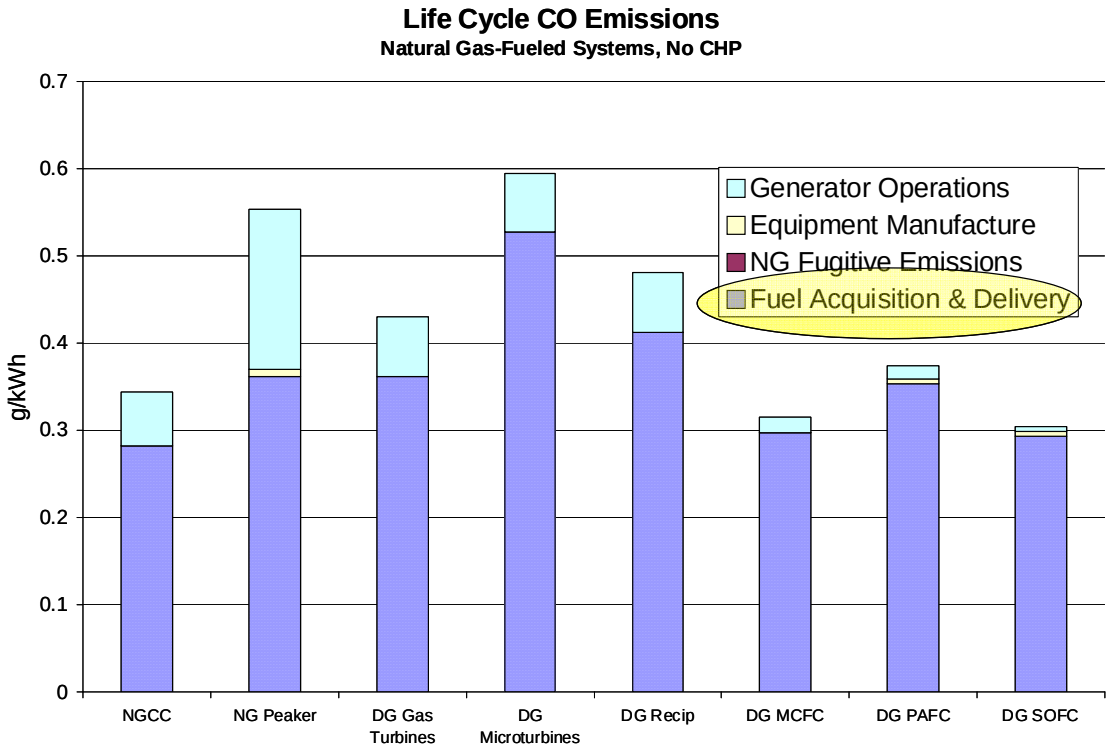


Figure 24. Life Cycle CO Emissions

5.3.2. Volatile Organic Compounds

Figure 25 shows the emissions of VOCs (non-methane) according to the stage of the life cycle in which they were produced. Those portions of the life cycle that occur at different locations are shown as dotted bars because VOC emissions have impacts on the local environment, as tropospheric ozone precursors. Thus, VOCs that are produced at different locations may not be combined to contribute to the same impact and therefore cannot be added together to determine total effects.

As shown in this figure, the primary source of VOC emissions in the natural gas-fired systems is from natural gas fugitive emissions, as natural gas contains approximately 4% (by volume) non-methane volatile organic compounds. Thus, as natural gas leaks from the system, VOCs are emitted to the atmosphere. Additional sources of VOCs in natural gas systems are the compressors along the length of the pipeline, in concert with CO emissions from incomplete combustion of natural gas. While these emissions do not take place at the same location, their large total amounts indicate the importance of reducing natural gas leaks and improving the performance of pipeline compression.

The very high VOC emissions associated with diesel fuel acquisition and delivery in the advanced diesel case represent the emissions of hydrocarbons from petroleum extraction and refining. These emissions may actually take place in more concentrated locations than those associated with natural gas delivery. The impact from VOCs is ozone formation in the presence of NOx; therefore, actual impact on human health depends on the locations of the well and refinery and the correct conditions for ozone formation.

Emissions that would have normally been produced from the decomposition of dairy waste are avoided through the operation a dairy AD system, with the result being negative emissions of VOCs from the dairy. Volatile organic compound emissions from the IGCC plant are the result of petroleum production and combustion in the mining and delivery of the coal to the power plant.

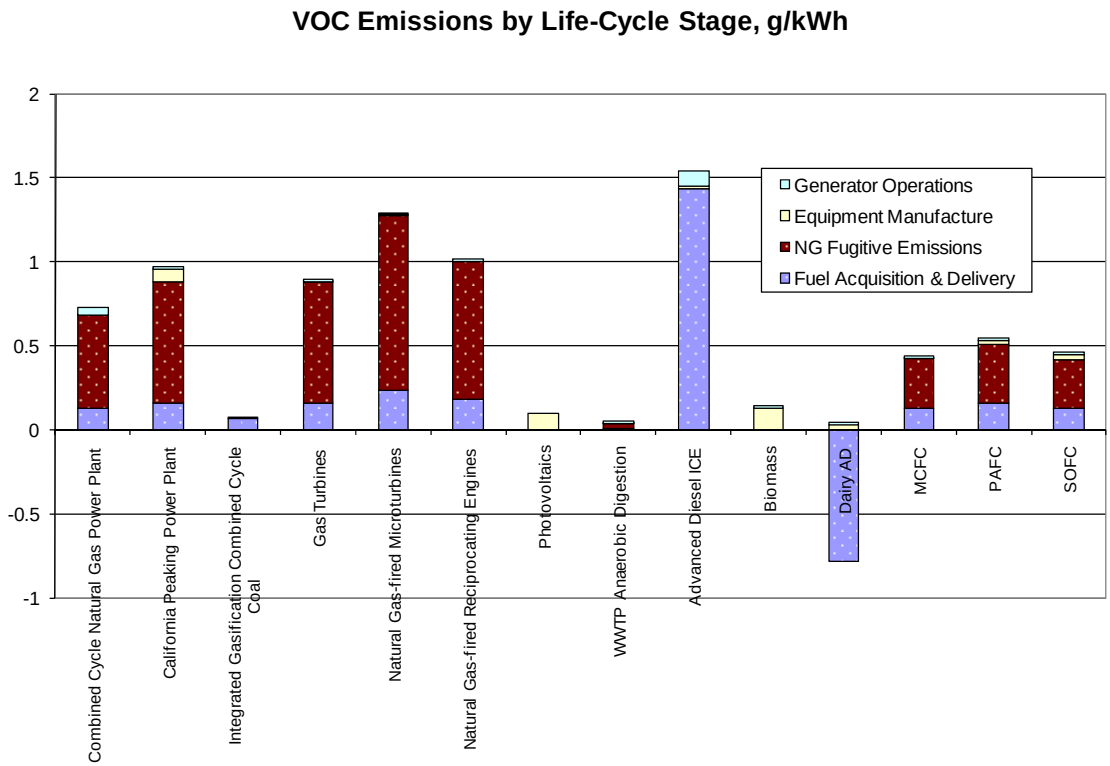


Figure 25. Life Cycle VOC Emissions

5.3.3. Nitrogen Oxides

The issues surrounding the location of NOx emissions are the same as those for VOCs. Nitrogen oxides and VOCs interact to form tropospheric ozone, which is responsible for smog formation and respiratory impacts on human health. Figure 26 shows NOx emissions as a function of life cycle stage. With the exception of the coal and peaker plants, most NOx emissions across the life cycle of these systems are not the result of generator operations. In the case of the peaker plants, the non-baseload operations and lower efficiency of the simple-cycle gas turbines result in higher normalized production of NOx (i.e., per kWh delivered to the customer) at the power plant itself. The generation of NOx by the IGCC plant is a consequence of coal combustion, and it may be lower with more advanced control technologies (e.g., ammonia injection).

Nitrogen oxide emissions associated with fuel acquisition and delivery for the natural gas-fired systems are due to the inefficient combustor compressors along the pipeline.

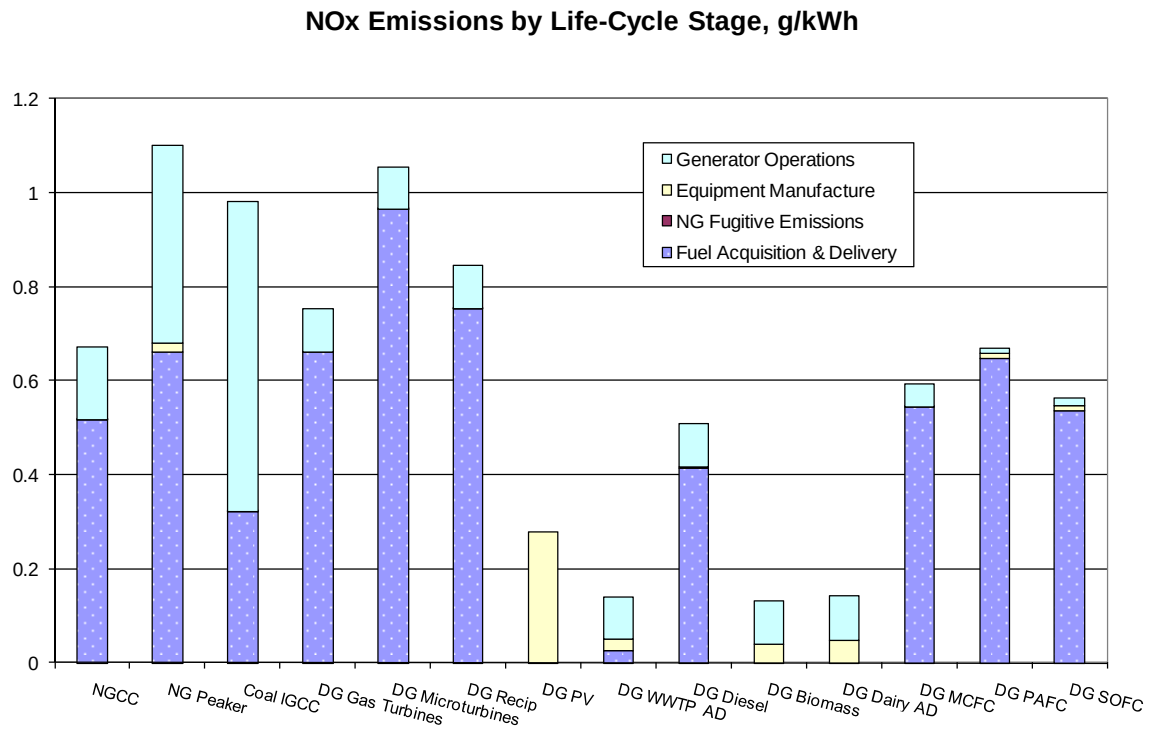


Figure 26. Life Cycle NOx Emissions

5.3.4. Particulate Matter

Particulate matter impacts are also highly dependent upon the location at which they are emitted, although, compared to other air pollutants, they were more likely produced by the DG unit itself, rather than other stages of the life cycle. Particulate matter of 10 microns or smaller (PM_{10}), is usually in the form of soot, dust, and dirt. The smaller particulates, $PM_{2.5}$ and ultrafines, can be produced from natural gas combustion in the form of aerosolized organic compounds that result from incomplete combustion. Greater health impacts are associated with these ultrafine particulates, and newer U.S. EPA regulations will require measurement of $PM_{2.5}$ not previously tracked. Particulate matter results reported in this study generally represent data available for PM_{10}. In general, natural gas combustion results in particles in the $PM_{2.5}$ and ultrafine size range and in very low PM mass emissions.

Figure 27 shows PM emissions by stage of the life cycle. Of all systems examined, the advanced diesel system had the highest rate of PM mass emissions, due to generator operations. The toxicity of diesel particulate matter is the item of greatest concern with regard to diesel combustion, and may limit the policy approvals for diesel in DG applications. The IGCC system also was found to have high PM emissions, due almost exclusively to coal mining operations and movement of the coal at the power plant. As particulate matter has local and regional impacts, this higher rate of emissions does not

necessarily mean that the coal IGCC system would have a greater particulate-induced impact on the community using the electricity.

Photovoltaic systems have higher particulate matter emissions than the natural gas DG systems. This is due to equipment manufacture, partially because of the electricity used, but also because of mining and transportation operations; not all of the PV particulate emissions are produced at the manufacturing facility itself. The diesel DG system has the highest emissions of all DG systems studied, due in large part to the operation of the generator itself. The particulate emissions from the DG biomass gasifier/recip engine are largely attributable to preparation (grinding and chipping) of the biomass, and partially due to transportation of the biomass. The dairy AD system results in negative PM emissions because of the avoided fertilizer manufacture and use.

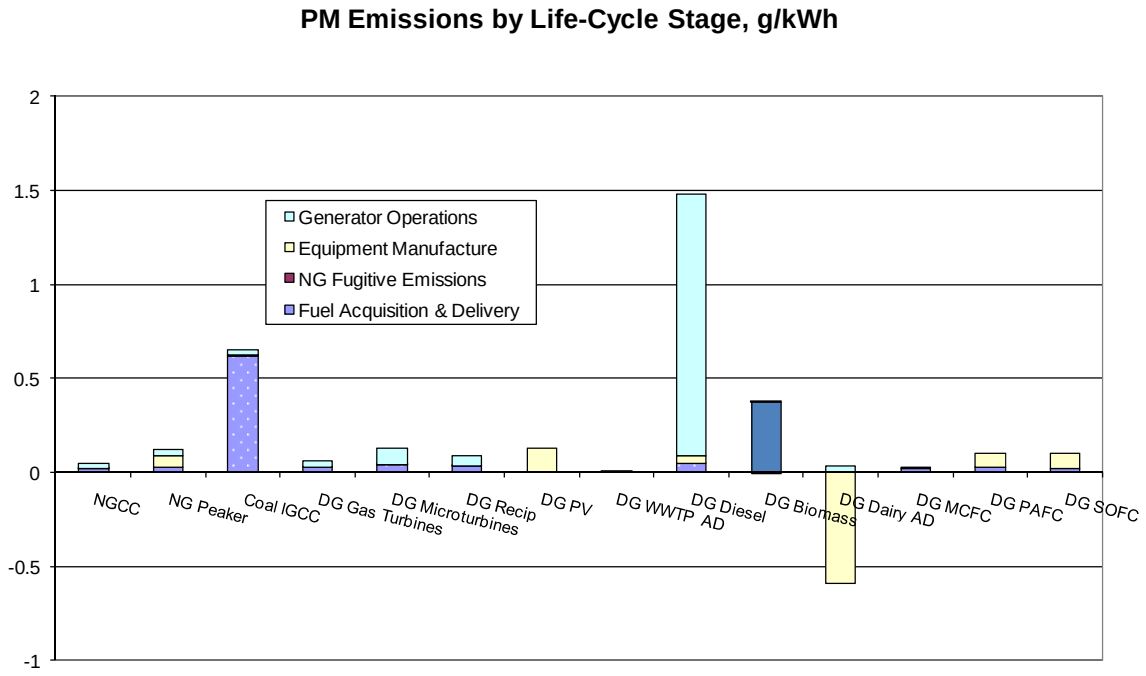


Figure 27. Life Cycle Particulate Matter Emissions

5.4. Greenhouse Gas Emissions

Greenhouse gas emissions are of particular interest in current environmental analyses and discussions. While the potential magnitude of impacts is debated, the scientific community is in general consensus regarding the reality of climate change (Pachauri and Reisinger 2007). Several distributed generation technologies, if properly operated, can produce fewer GHGs than conventional fossil-based central generators. However, commonly-cited benefits of DG, including transmission and distribution loss reduction

and the ability to include CHP in the design, do not provide automatic reductions in GHG emissions. Rather, because of the total life cycle emissions, the total GHGs vary considerably across DG technologies.

Figure 28 shows the total life cycle GHG emissions for all technologies studied. The lowest emissions are encountered in the biomass system because of avoided emissions of GHGs associated with normal decomposition of biomass. Similarly, the anaerobic digestion systems have low GHG emissions because of the avoided decomposition of wastewater treatment sludge and dairy waste. Variations in feedstock assumptions have significant impacts on results for these three systems, however, as documented in the sensitivity analysis. The total GHG emissions of the PV system are attributable to the manufacturing and disposal stage of the life cycle.

As discussed in Section 5.1, generator efficiency has an important impact on total emissions, as can be seen when comparing the GHG emissions of the fuel cell systems to those of other systems. Similarly, the microturbine DG systems have the highest rate of GHG emissions because of their low operating efficiency. Indeed, in comparing the natural gas-fired systems, efficiency is the sole reason for differences in life cycle GHG emissions. Among combustion technologies, NGCC plants tend to emit the lowest GHG emission levels, despite the fact that this central technology suffers from T&D efficiency losses. Despite its efficiency improvements over conventional pulverized coal combustion, the coal IGCC system has higher GHG emissions than most of the natural gas systems. This is due to the fact that coal has a lower energy content than natural gas. It is worth noting, however, that the lowest efficiency natural gas-fired DG technology, microturbines, have a significantly higher GHG profile than even the coal IGCC and diesel systems.

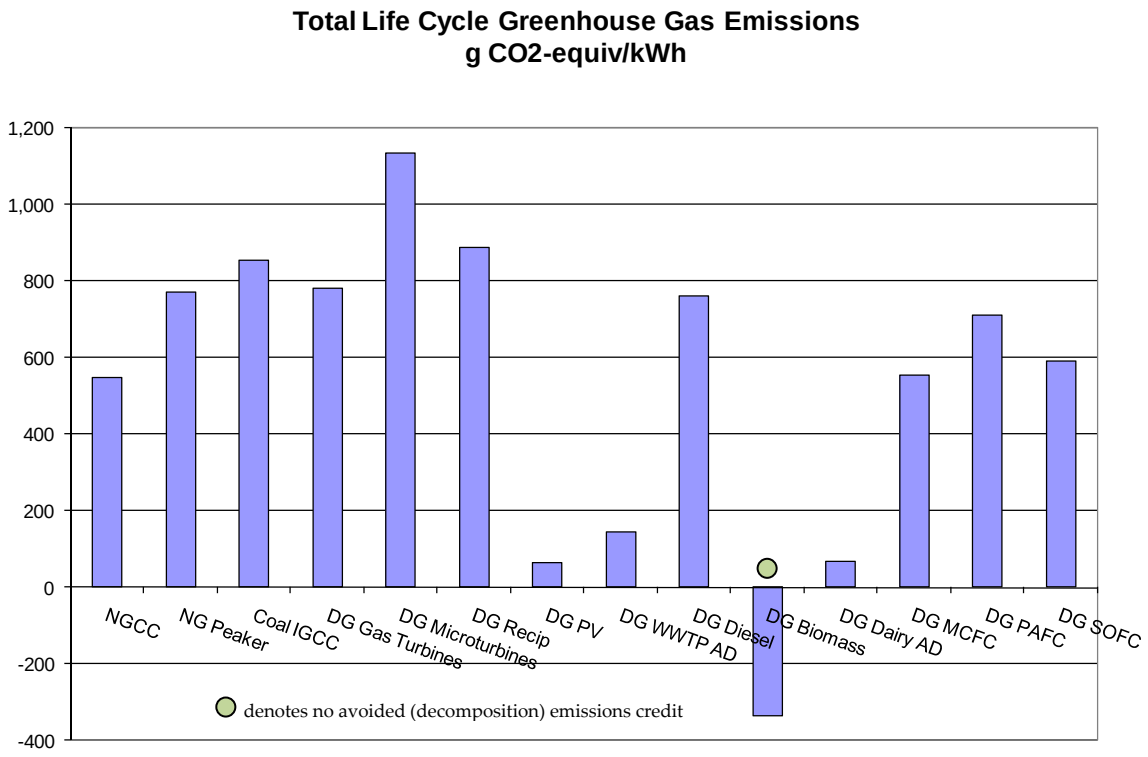


Figure 28. Total Life Cycle Greenhouse Gas Emissions

The effect that generator efficiency has on GHG emissions is certainly the driver of which technology has the highest impacts. However, as discussed in Section 5.2, natural gas fugitive emissions are an exceptionally important contributor to the total GHGs of the natural gas systems. Figure 29 shows the total life cycle GHG emissions of the fossil-fueled technologies, broken out according to life cycle stage, and Figure 30 shows life cycle GHG emissions broken out by greenhouse gas. Without the contribution of the fugitive emissions, all natural gas-fired technologies, including those that are less efficient (microturbines and reciprocating engines) would have a lower total rate of GHG emissions than the coal and diesel systems. Note that the assumed leak rate of 1.4% of the gross amount extracted is considerably less than some values reported in the literature, and may under-represent leaks during natural gas extraction in other parts of the world. Thus, it is clear that fugitive emissions have an important impact on total GHG emissions of the technologies studied.

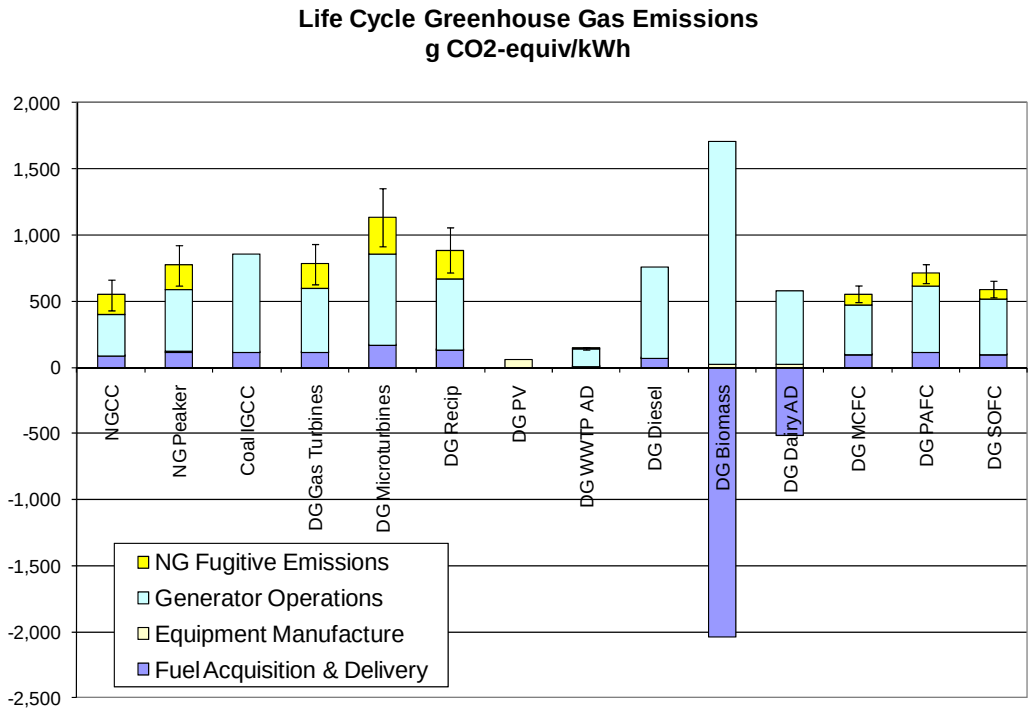


Figure 29. Life Cycle Greenhouse Gas Emissions, by Life Cycle Stage

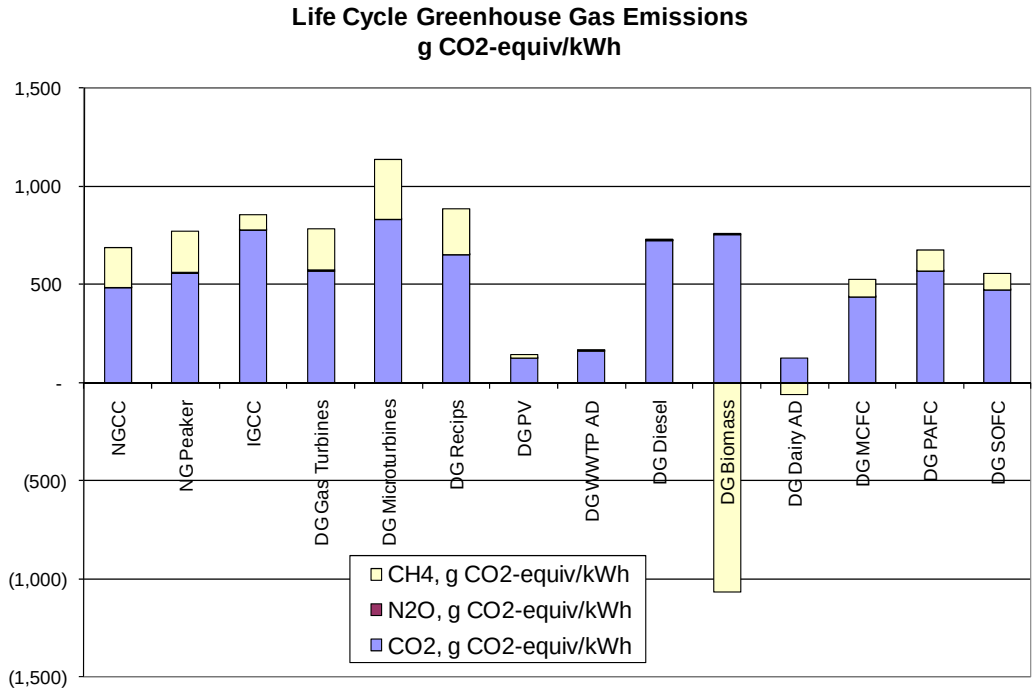


Figure 30. Life Cycle Greenhouse Gas Emissions, by Greenhouse Gas Species

Total greenhouse gas emissions are calculated as the sum of the CO_2, methane, and N_2O emissions, weighted according to their global warming potential. Note that the N_2O emissions, while included in the inventory, are too small to be visible on the charts. The significant contribution to total GHG of methane emissions illustrates the importance of looking beyond the more commonly discussed carbon dioxide. Because of the higher GWP of methane, any system using natural gas suffers from higher GHG emissions because of the leakage during production and distribution of the fuel.

5.5. Results Findings: Effect of Combined Cooling, Heating, and Power (CHP)

The United States does not have significant infrastructure to deliver heat from central power plants to homes and businesses. Thus, heat remaining after the condensing cycle is generally rejected to the atmosphere (the steam plume seen on cold days), resulting in lower overall efficiency and greater consumption of fossil fuels for local heating and cooling. One of the primary advantages of DG technologies is the potential for capture of the waste heat from the generator, for use in on-site heating and cooling. Heating is accomplished through the distribution of steam or hot air throughout a building's ducting, following the exchange of heat from the waste combustion gases of the prime mover. Cooling may be accomplished through adsorption chilling, which takes advantage of the cooling effect of water evaporation through the use of waste heat. While some combined heating and power (CHP) applications may be economically viable in California, its mild climate and high cooling requirements are likely to gain more benefit from combined *cooling* and power systems. As the cooling is generated through direct use of waste heat, for simplicity, CHP is presented as a representation of cooling and heating.

As discussed in the assumptions section, the reductions in system emissions, resource consumption, and energy use from CHP were studied for the DG technologies. In general, CHP (and by extension, combined cooling, heating, and power) can result in significant reductions in the environmental stressors that result from energy generation of DG technologies.

The following charts show other key emissions from the technologies on a per kWh basis for the non-CHP and CHP cases. The central power plants (coal IGCC, NGCC, and peaker) are shown in these charts for comparison purposes, but are not eligible for CHP because of the lack of heat distribution infrastructure.

5.5.1. Carbon Dioxide

Figure 31 shows the life cycle CO_2 emissions for the non-CHP and CHP cases. The non-CHP cases result in CO_2 emissions from the natural gas-fired DG technologies that are, on average, higher than those from central technologies. CHP, however, reduces total CO_2 emissions for these DG technologies such that they are significantly less than those from the central technologies. The reduction is due to the avoidance of emissions that would otherwise have been produced by combusting natural gas to generate steam for

heat. With CHP, the WWTP AD system has negative CO_2 emissions, as the avoided emissions are greater than those normally produced by the system. Even though CHP is not an option for the central plants and PV, they are shown on this figure for comparison purposes.

Carbon dioxide emissions for the biomass system are significant because the methane emissions (Figure 32) that would normally result from decomposition of the feedstock (the avoided emissions) are not taken into account in this graph. Refer to Figure 33 for the total greenhouse gas emissions of the biomass system. This graph should not be interpreted to mean that biomass systems result in higher greenhouse gas emissions than fossil fuel systems.

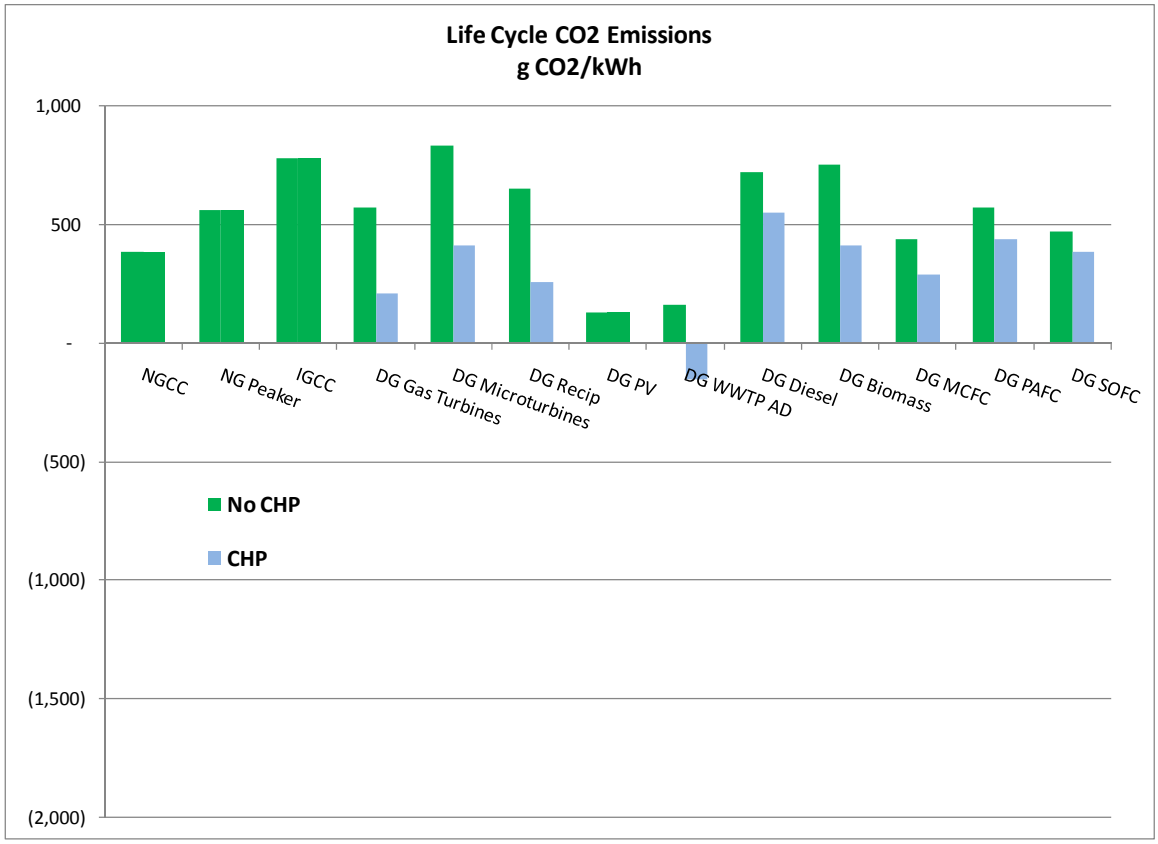


Figure 31. Life Cycle CO_2 Emissions with and without CHP

5.5.2. Methane

Life cycle methane emissions are shown in Figure 32. Because of leaks associated with the production and distribution of natural gas, those technologies that use natural gas have higher methane emissions. By avoiding the combustion of natural gas, CHP cases have greatly reduced methane emissions that normally leak during the production and distribution of the fuel used for steam/heat generation. Thus, even without CHP, the

coal IGCC and PV cases, plus the WWTP AD with and without CHP, have lower methane emissions than any of the natural gas-fired technologies. In the case of the WWTP AD system, this CHP effect results in negative methane emissions because of the avoidance of methane that would have normally been produced during decomposition of the WWTP sludge. The biomass system similarly has negative methane emissions because of the avoided decomposition of the feedstock.

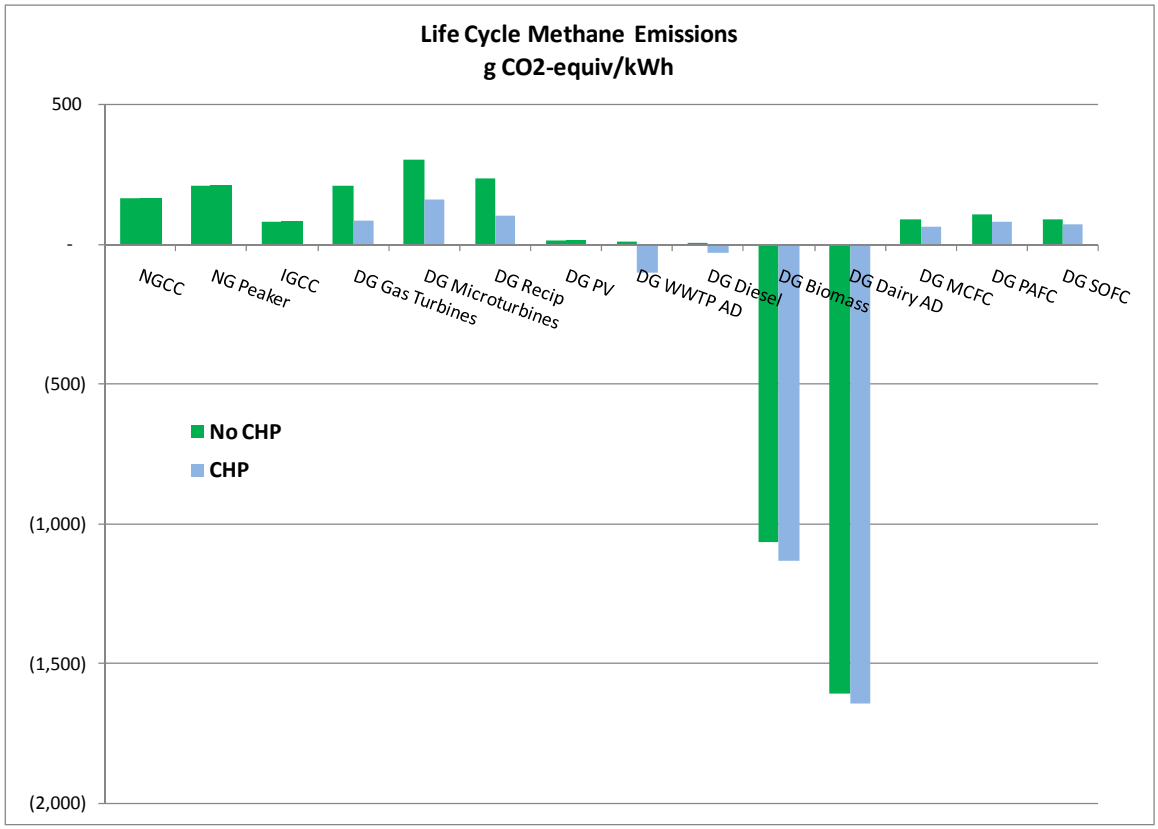


Figure 32. Life Cycle Methane Emissions (g/kWh)

5.5.3. Greenhouse Gases

Total GHG emissions are reduced by the use of CHP because of the avoidance of CO_2 and methane that normally would have been produced during combustion of natural gas for steam/heat. Figure 33 shows the total GHG emissions, with the non-CHP and CHP cases shown next to each other. Without CHP, microturbines have the highest GHG emissions, due to their relatively low efficiency. With CHP, however, even microturbine systems emit lower amounts of GHGs. The primary source of GHGs is combustion of fuel by the generator. Methane emissions resulting from natural gas fugitive emissions, however, represent a significant portion of the total GHGs for the natural gas-based technologies. The fuel acquisition and delivery part of these bars

represents the GHG emissions produced by combustion compressors along the length of the natural gas pipeline.

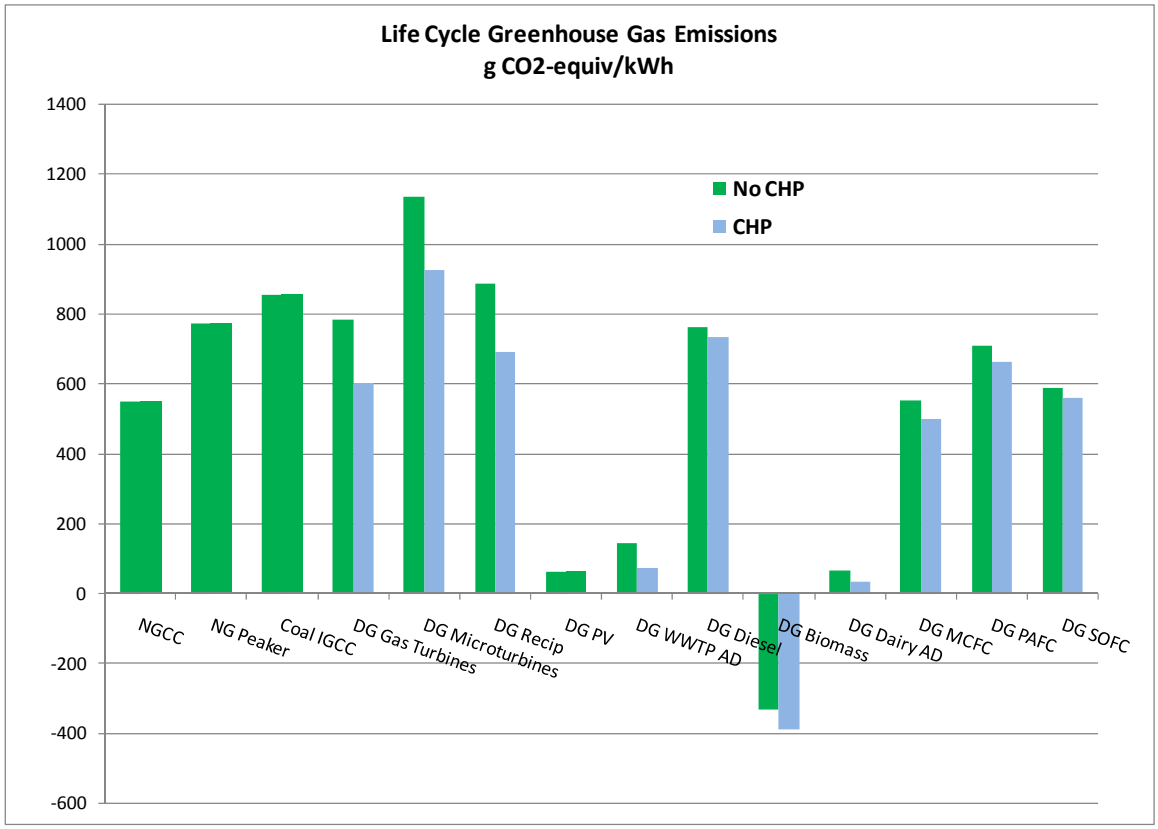


Figure 33. Life Cycle Greenhouse Gas Emissions with and without CHP

Without CHP, natural-gas fired microturbines have the highest GHG emissions. Among combustion technologies, NGCC systems tend to emit the lowest levels. The total GHG emissions of the natural gas-fired systems roughly correspond to the efficiency of the generator; higher efficiency means that less fuel is produced and combusted to generate a kilowatt-hour of electricity. This effect is more pronounced with the CHP cases because the acquisition and combustion of natural gas for heat is also avoided. Thus, microturbines with and without CHP have the highest GHG emissions for all technologies evaluated here. Greenhouse gas emissions for non-NG technologies improve only slightly when CHP is added since a reduction in natural gas fuel in the natural gas technologies results in lower amounts of leaking methane.

5.5.4. Carbon Monoxide

In Figure 34, most CO emissions are the result of non-generator operations, and because they are produced over a more dispersed area, are shown in the dotted bars. As discussed in Section 5.3, the impact on the environment from these emissions is not additive. CHP results in a dramatic reduction in life cycle CO emissions for the natural gas technologies because less gas is required to produce heat for the system, meaning

less CO is produced by the combustor compressors over the length of the pipeline. Although the total quantity of CO produced along the pipeline is not additive to a single impact, some of these avoided emissions of CO may be reduced in locations already suffering from local air pollution. There is no appreciable change in CO emissions with and without CHP for WWTP anaerobic digesters, advanced diesels DG, biomass DG, and dairy anaerobic digesters.

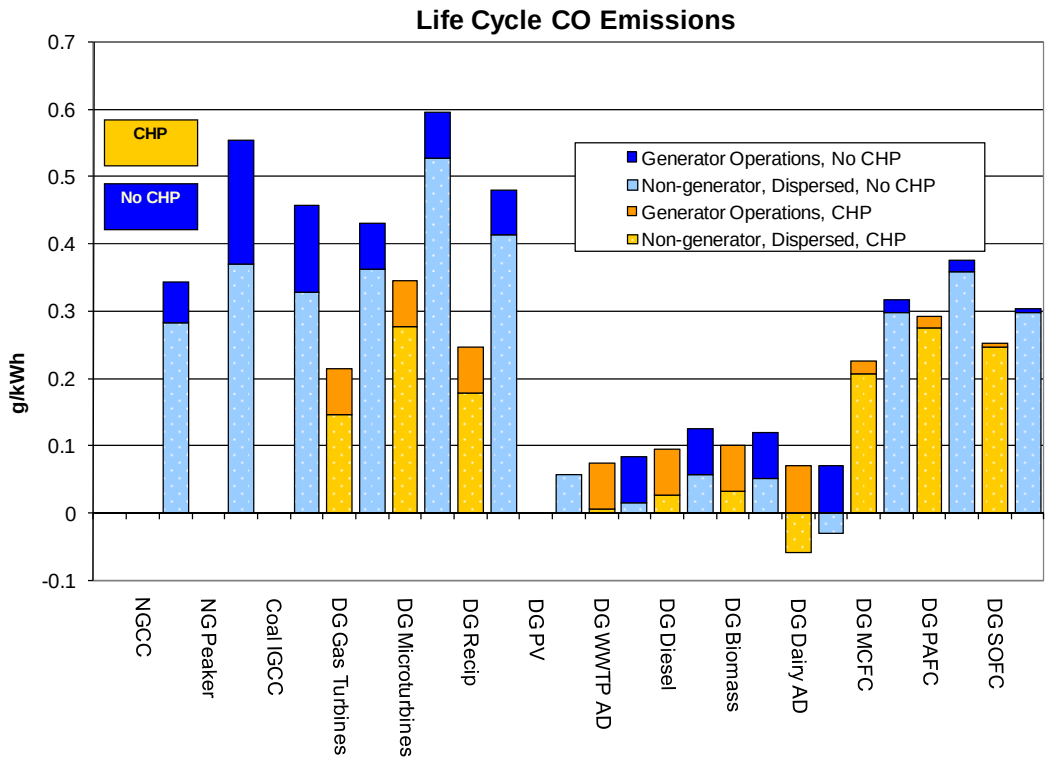


Figure 34. Life Cycle Carbon Monoxide Emissions (g/kWh)

5.5.5. Particulate Matter

Total life cycle emissions of particulate matter are presented in Figure 35. Generally, because natural gas combustion for steam generation is the avoided operation with CHP, particulate matter emissions do not significantly change when CHP is added to the system. As in Figure 27, DG diesel has the highest rate of particulate matter emissions. Particulate matter in the biomass and coal cases is from fuel acquisition, preparation, handling, and delivery to the boiler. Emissions from the DG dairy AD system are negative because of avoided fertilizer manufacture and use.

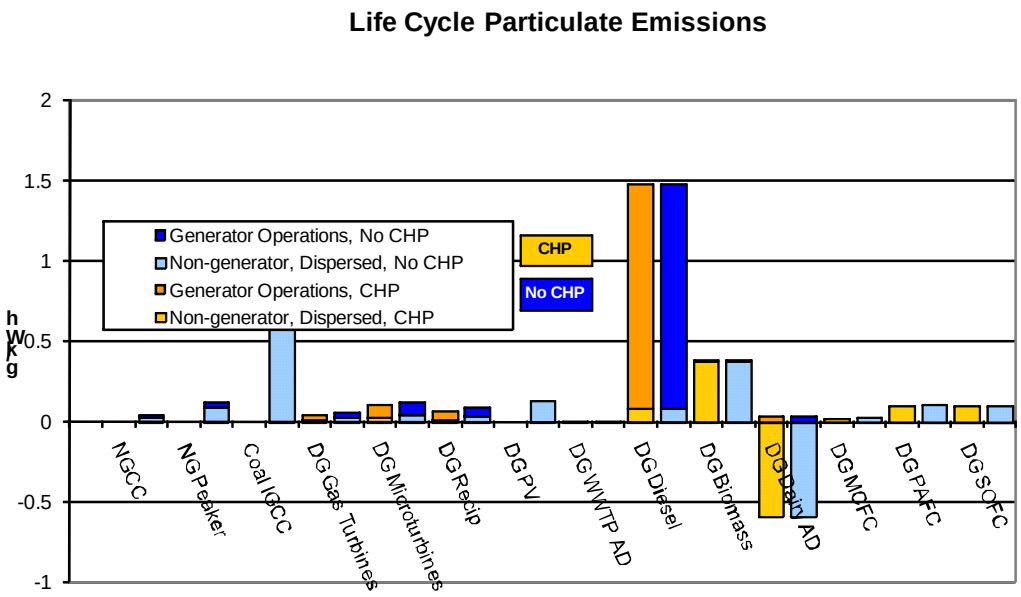


Figure 35. Life Cycle Total Particulate Matter Emissions (g/kWh)

5.5.6. Nitrogen Oxides

Figure 36 presents total life cycle NOx emissions. Nitrogen oxides are associated with the formation of smog (ground-level ozone) in the presence of volatile organic compounds (also known as non-methane organic compounds), and can contribute to acid rain impacts. Except for microturbines, which suffer from low generating efficiency, the central technologies emit more NOx than the DG technologies. However, note that the generator NOx emissions of the DG technologies in this study was limited to the allowed permitted maximum; emissions from these units may be higher in practice, particularly without maintenance and permit review.

Figure 26 shows that the majority of NOx from the natural gas-fired DG and central technologies results from fuel acquisition and delivery. CHP significantly reduces the NOx produced by these systems because less natural gas is required when steam/heat production is offset. Most fuel acquisition and delivery NOx is a direct result of NOx from the combustion compressors along the pipeline. The majority of NOx emitted by the coal IGCC system is from the power plant itself.

Like CO, NOx has local and regional impacts, rather than global impacts, on the environment. Thus, all NOx cannot be added together to provide an indication of the likely impact, especially if the emissions occur over a large geographic area. However, since most of the NOx from the coal IGCC system comes from the power plant, the total

NOx-related impact will be higher from this system than from all others, because it is local. For the combustion DG technologies, the differences in generator NOx emissions between the CHP and non-CHP cases are slight because low-NOx burners are assumed for the natural gas boilers and DG generators. The generator operation's NOx emissions for the fuel cell cases vary more significantly, although still by small amounts, because of the difference in efficiency of the fuel cells compared to the natural gas boiler.

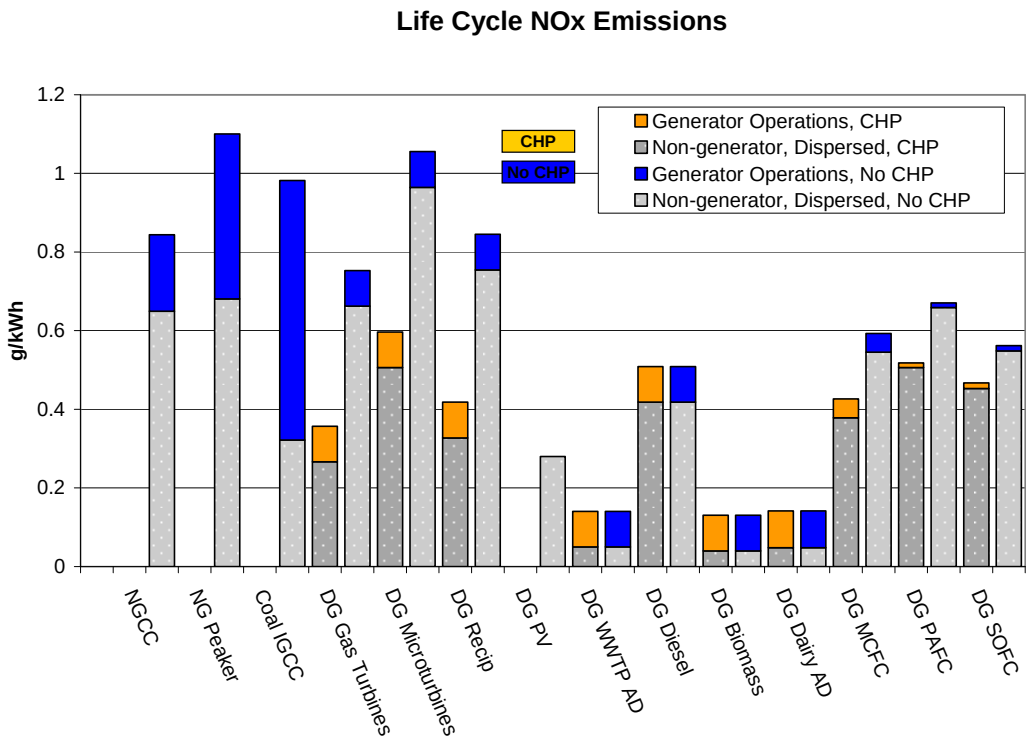


Figure 36. Life Cycle NOx Emissions (g/kWh)

5.5.7. Sulfur Dioxide

Life cycle sulfur dioxide (SO_2) emissions are shown in Figure 37. Among the natural gas technologies, microturbines, because of their low operating efficiency, have the greatest rate of SO_2 emissions. The use of CHP reduces total SO_2 because of the avoidance of SO_2 during the normal combustion of natural gas for steam/heat generation. However, it should be noted that natural gas contains very little sulfur, and thus the natural gas technologies result in low SO_2 emissions. Of all technologies, diesel and coal-fired plants are likely to have the greatest rates of SO_2 emissions, depending on the sulfur in the fuel. As shown in this figure, nearly all of the SO_2 in the natural gas systems is due to fuel production and delivery. Greater than half of the SO_2 from the coal IGCC system comes from the power plant. As with NOx and CO, SO_2 has local and regional impacts. Thus, the technology with the most geographically concentrated production of SO_2 will have the greatest SO_2-related impact on the environment.

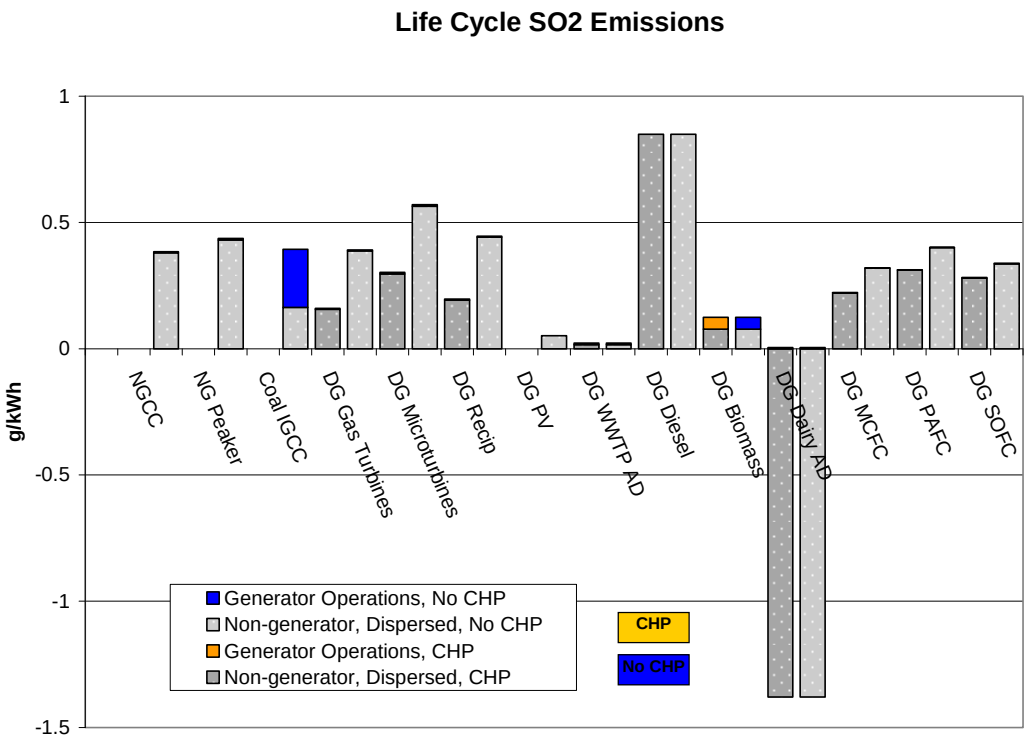


Figure 37. Life Cycle SO_2 Emissions (g/kWh)

5.5.8. Volatile Organic Compounds

Figure 38 describes the emissions of non-methane organic compounds, or volatile organic compounds (VOCs), by the technologies examined. Advanced generation diesel DG has the highest emissions of VOCs, followed by natural gas-fired technologies. Almost all emissions of VOCs come from natural gas leakage during production and delivery, as verified in Figure 38. As shown in Table 5, natural gas is primarily methane, but also includes non-methane compounds such as ethane and propane. These compounds react with NOx to form ground-level ozone, or smog.

The normal combustion of gas produced by anaerobic digestion at the WWTP produces only small amounts of VOCs. Thus, when natural gas production and distribution are avoided in the case of CHP offset of steam/heat production, total VOC emissions for this system become negative. This is not due to lower VOC emissions from the WWTP gas combustion, but rather, because less natural gas needs to be procured for heating.

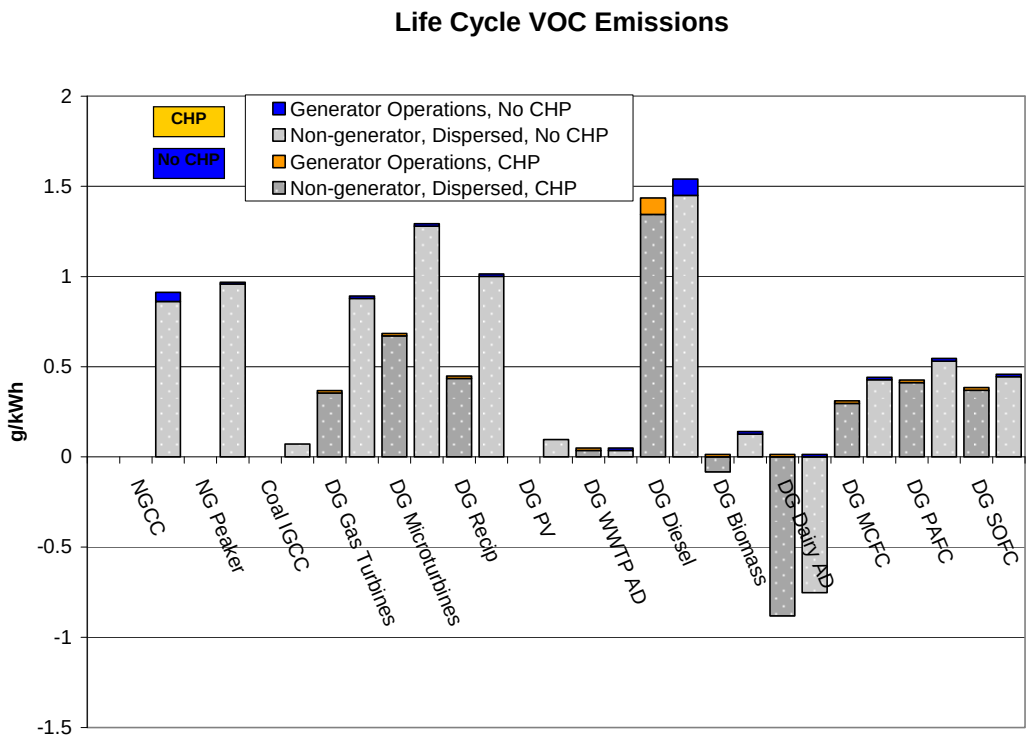
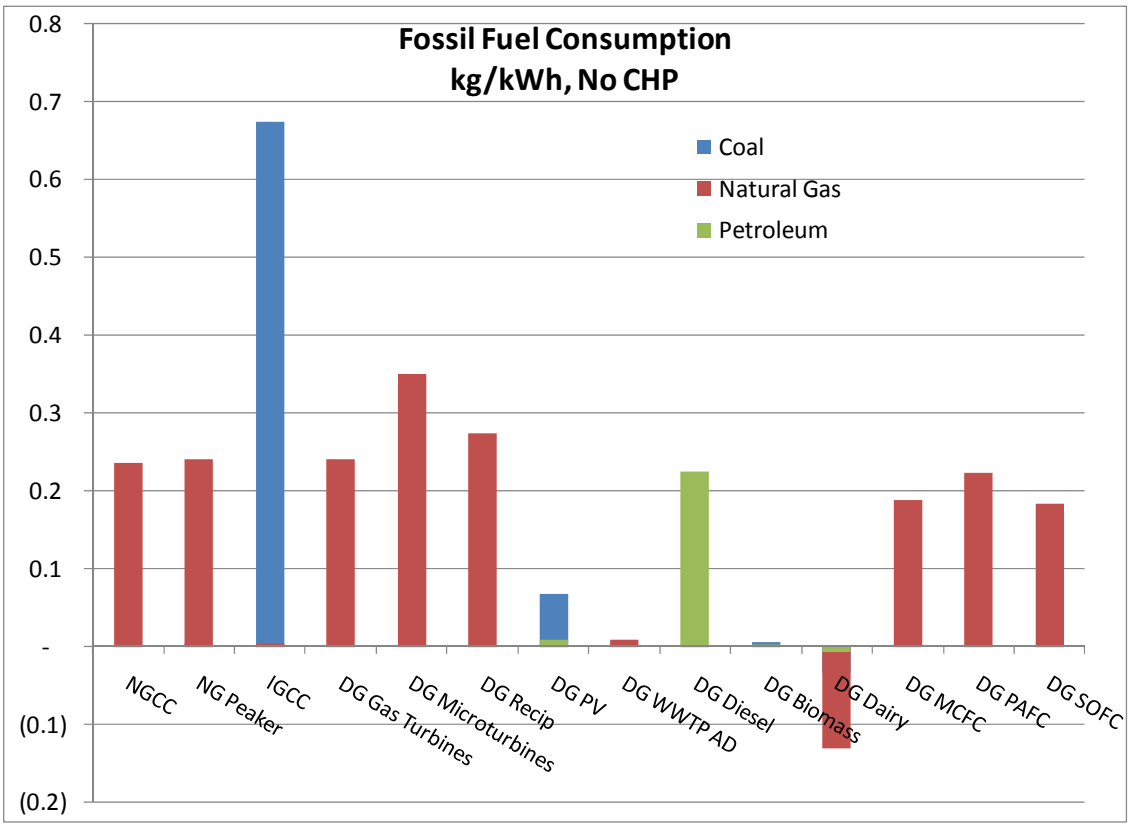


Figure 38. Life Cycle Non-methane Organic Compound Emissions (g/kWh)

5.6. Results Findings: Resource Consumption

Figure 39 highlights both the amounts and types of fossil fuels consumed for the non-CHP and CHP scenarios. The negative consumption in the DG Dairy system reflects the avoided production of fertilizer from natural gas, as the solid effluents from the system are assumed to be land applied to return nutrients. The DG systems able to incorporate CHP into their design show a marked decrease in total natural gas consumption, reflecting the avoided natural gas use for heat and cooling. As expected, the coal IGCC system uses the most coal, while of the DG technologies, the microturbine system uses the most natural gas because of its lower efficiency. Distributed generation diesel technologies consumed the most petroleum overall. Among the renewable energy technologies, the PV system uses the most oil because of the consumption of petroleum-derived plastics.



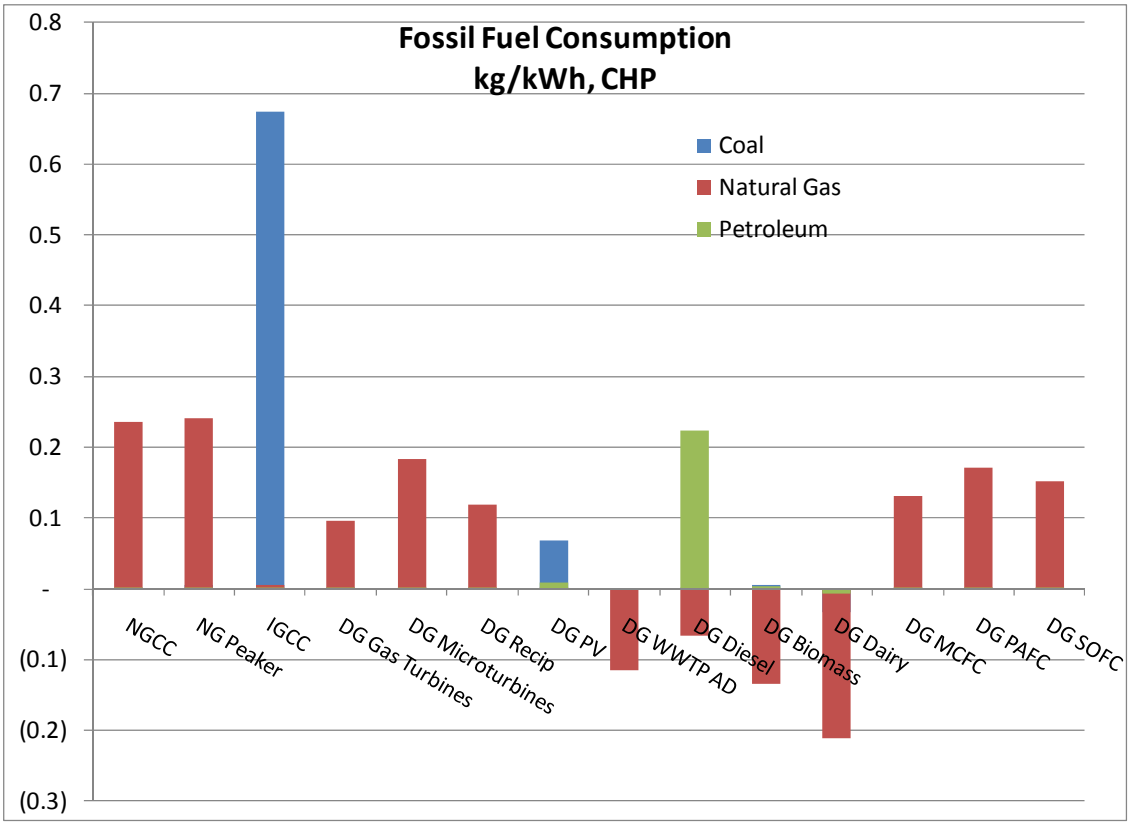


Figure 39. Fossil Fuel Consumption (kg/kWh)

Figure 40 shows total water withdrawals. The central power plant systems (IGCC, peaking, and NGCC) need the most water because of cooling, boiler feedwater, and makeup water requirements; it should be noted, however, that the majority of the water withdrawn by these plants for cooling is returned rather than lost through evaporation. In general DG technologies do not use water, although some water is consumed by processes upstream and downstream of the prime mover. The water requirements for the dairy system are negative because of the assumption that treatment of the waste through anaerobic digestion mitigates management and cleaning of the lagoons.

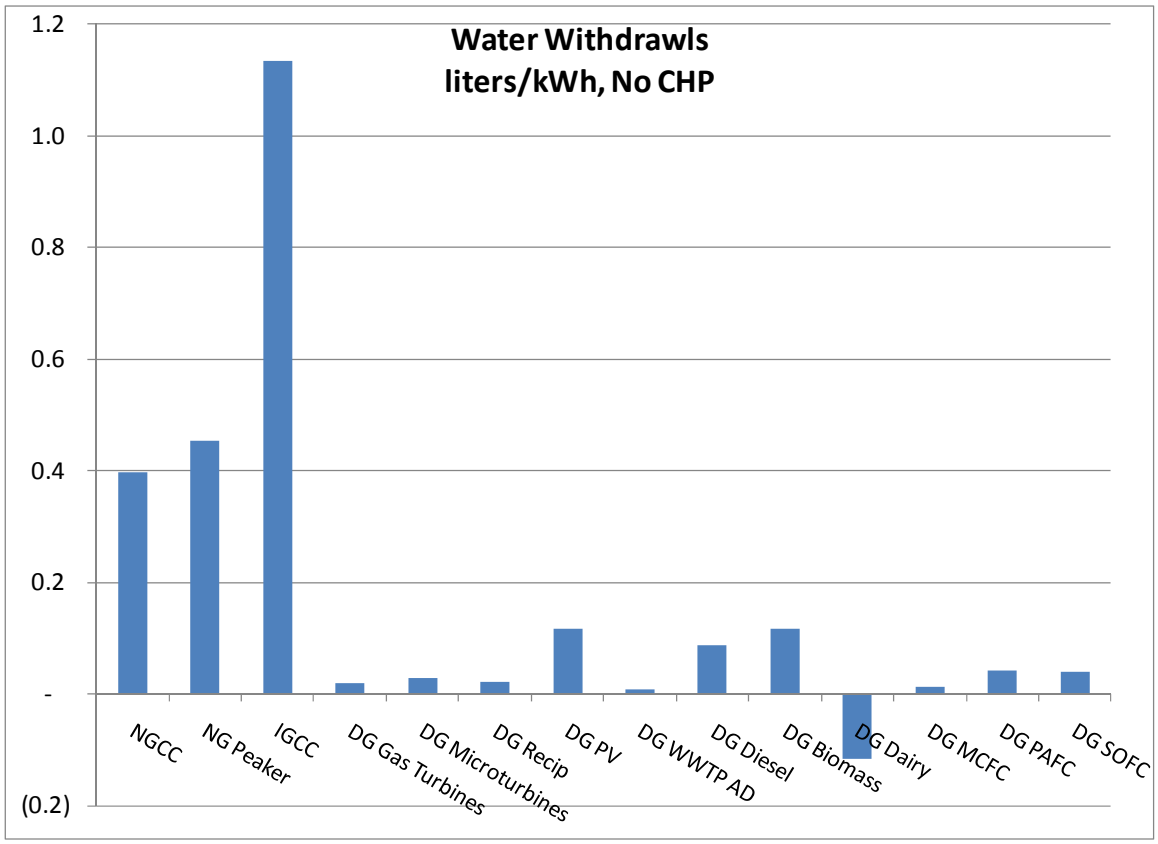


Figure 40. Comparison of Water Withdrawals

Total primary energy consumption results are a direct result of the efficiency of the generator technology.

5.7. Results Findings: Energy Consumption

Figure 41 shows the life cycle energy use for all technologies studied. The energy is calculated as the total amount of non-renewable (fossil) energy consumed throughout the system divided by the energy of the electricity delivered to the end user (i.e., including T&D losses for the central plants). The total energy consumed includes all stages of the life cycle and is based on the lower heating value heat of combustion of all

fuels consumed. Negative values reflect situations where the avoided fossil energy consumption (due to CHP) is greater than the total amount of fossil energy required to operate the system without CHP. For example, the total fossil energy to collect and manage dairy waste, build the system equipment, and deliver the electricity to the consumer, is less than the energy in the natural gas that is normally combusted to provide the heat now offered with the CHP option. This situation is true for the WWPT AD, biomass, and dairy systems, as few fossil-based resources are consumed in their life cycle.

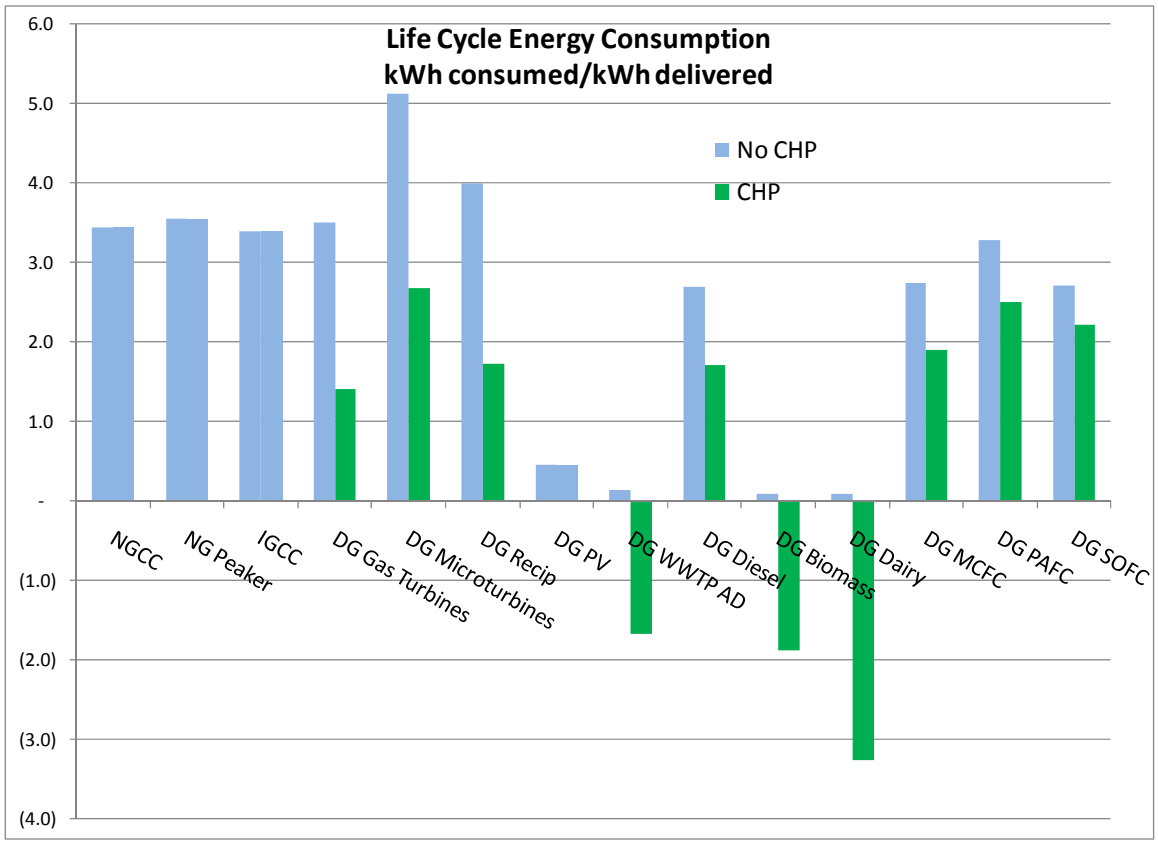


Figure 41. Life Cycle Energy Consumption

5.8. Results Findings: Transmission and Delivery

The avoidance of transmission and delivery efficiency losses and construction/ maintenance requirements are often cited as a benefits of DG systems. Our analysis shows, however, that the emissions of GHGs and criteria air pollutants associated with construction and maintenance of T&D lines, for DG or central power plants, are extremely small. This is largely because the emissions of construction and maintenance are normalized over the total amount of electricity carried over the lines during their lifetimes. For example, a 115 kilovolt (kV) transmission line carrying (on average) half of its maximum amperage (approximately 900 amps), would carry 453 million kilowatt-hours (kWh) each year. The lifetime of transmission lines can range between 30 years for

underground lines to 70 years for overhead lines. Over its lifetime, the transmission line would thus carry between 13.6 billion kWh and 31.7 billion kWh. Thus, as with the generator itself, because of the large amount of electricity handled over the equipment lifetime, construction and maintenance emissions were found to be small.

Line loss from the T&D infrastructure, estimated to range between 3% and 7% depending on system configuration and load, has a greater impact on the comparison of DG to central power generation. By consuming the electricity close to its generation, DG units benefit from what amounts to an increase in efficiency relative to the central plants. This increased system efficiency decreases total emissions by increasing the amount of usable electricity delivered to the load.

6.0 Expanded Sensitivity Discussion

The results of LCA studies can be highly dependent upon the set of assumptions made throughout the system boundary. However, with sufficiently large system boundaries, LCA results have inherent stability and results are likely to vary significantly for only a few key parameters. This study has attempted to evaluate the sensitivity of the results to several parameters through the design of the scenarios and choice of technologies evaluated. As described in detail in Section 5.0, prime mover efficiency and the option for incorporating CHP in the design can have significant impacts on the relative merits of different DG systems. As shown in Figure 22, the rate of fugitive emissions from the natural gas production and distribution can alter the greenhouse gas emissions profiles of distributed natural gas technologies compared to central coal and DG diesel.

In tandem with the results showing prime mover efficiency to be important, T&D losses can swing the relative rank of DG technologies compared to central technologies. As shown in Table 3, the efficiencies of several DG options compare favorably to those of central coal IGCC and NGCC; in circumstances with high enough T&D losses, and particularly when the DG technology can sell electricity to the grid, a total system benefit is realized with these options.

The system with the highest degree of variation in GHG emissions is the biomass system. Rather than a measure of uncertainty, this variation is due to a change in the status quo of biomass disposal and use. Initially, a DG operation using a residue biomass that is typically disposed of in a landfill and as mulch (as described in Section 4.3.3) can take a credit for the avoided emissions that would have resulted in decomposition of that biomass. However, after continued operation, the status quo for disposal of the biomass will evolve to one reflecting the standard practice of using the biomass in the DG unit. Thus, the system boundary changes from one of avoided emissions to one of a cycling of the CO_2 between photosynthetic absorption during plant growth and emission during biomass combustion. Greenhouse gas emissions associated with procuring, delivering, and preparing the biomass for the DG unit remain the same; only the avoided decomposition emissions are varied. This change in status quo (and life cycle boundary) reduces GHG emissions from -333 g/kWh to 104 g/kWh. Although a significant percentage increase, total GHG emissions from the biomass system are still markedly lower than those of the fossil-based systems. A graphical representation of this result can be seen in Figure 28. The timeframe over which this change occurs has not been agreed upon, but it is important to recognize that both situations are valid for an operation using residue biomass.

In evaluating impacts from DG units, it is of particular importance to study the addition of criteria air pollutants to ambient levels on a local basis. Since the purpose of this study was not to determine the air quality merits of DG compared to central generators, assumptions regarding criteria air pollutant emissions for DG units should be seen as reflections of research and testing literature only. Actual field emissions, and stack control regulations may significantly vary from those assumed in this study. However,

as operating emissions from the DG units were generally small compared to those identified as resulting from fuel production and distribution, total reported values per technology hold. An important exception to this is the diesel generator, which should be evaluated closely for compliance with local air quality regulations.

7.0 Emissions Relative to the Cost of Electricity

As an extension to the normal LCA methodology, the cost of electricity was calculated for each system, based on literature values of capital and operating and maintenance costs. The life cycle emissions were then normalized to these costs to determine the cheapest and most expensive way to obtain emissions reductions.

Table 9 shows the cost assumptions and levelized cost of electricity (LCOE) calculated. The model developed for the Western Governors Association study of renewable energy in 2006 was used for the calculations. Capital costs were obtained from the literature (see Appendix B). Fuel cost was obtained from the Energy Information Administration for values in March 2008.

Table 9. Cost Assumptions and Electricity Cost Results

	Capital Cost ($/kW)	Heat Rate (Btu/kWh)	Capacity Factor (%)	LCOE ($/kWh, 2008$, Real)
DG Biomass	1,600	14,835	80	0.06
Coal IGCC	3,000	10,080	80	0.05
DG Diesel	400	8,891	80	0.07
DG Recip	1,000	10,235	80	0.09
DG Microturbines	1,600	13,089	80	0.12
DG Gas Turbines	1,200	8,982	80	0.09
NGCC	900	8,809	80	0.08
DG PAFC	4,000	8,545	80	0.14
DG SOFC	3,500	7,087	80	0.12
DG MCFC	5,000	7,199	80	0.16
NG Peaker	1,000	8,982	4	0.27
DG WWTP AD	1,600	11,344	80	0.11
DG PV	3,000	N/A 10% solar efficiency	23	0.15
DG Dairy AD	1,600	11,344	80	0.11

Figure 42 shows the ranking of all technologies for all air emissions. The values going into these rankings were calculated by dividing the grams of each air pollutant by the cents spent on electricity—that is, g/kWh divided by cents/kWh. The technologies are ranked lowest to highest cost per amount of pollutant (#1 has the lowest g/cent emitted). This metric can be described as the cost efficiency of emissions reduction. The

technologies that rank toward the top for a given emission represent those that are the cheapest way to reduce emissions. An exception to this is the peaker plant, which has high emissions, but also has a high LCOE.

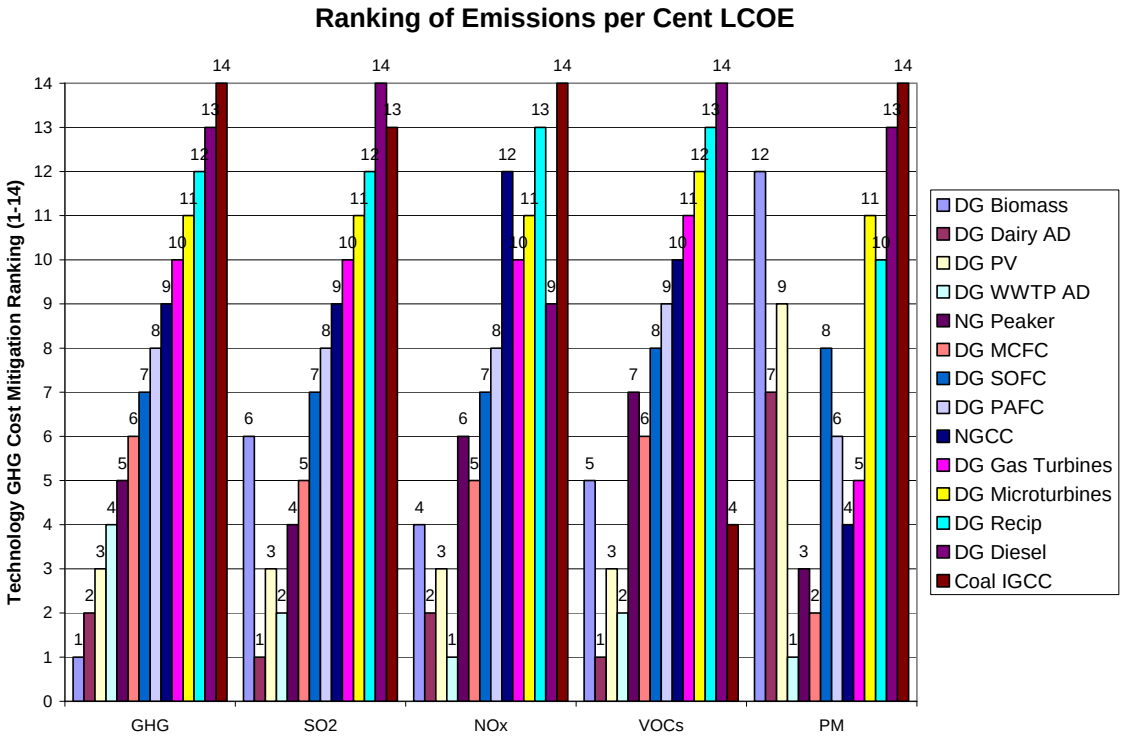


Figure 42. Ranking of Technologies by Cost per Air Pollutant Emissions

Figure 43 shows the life cycle GHG emissions per cent of levelized cost of electricity for each technology (g CO_2-equiv/cent). The biomass system, because of its negative total emissions, has the lowest rate of emissions per cent spent on electricity. If the biomass resource were not to have been destined for decomposition in a landfill, the emissions would be slightly positive, as decomposition would have occurred through aerobic digestion to CO_2 and not to methane. Alternatively, if the biomass had been grown for the purpose of generating electricity, its total GHG emissions would also be slightly positive, although still very low.

The other three renewable energy technologies (dairy AD, PV, and WWTP AD) produce few emissions per cent spent on electricity by the consumer. The peaker plant, because of its high cost, appears on the left side of this chart, despite the fact that it has relatively high emissions (i.e., the denominator is large, making the result small).

Fuel cells, with their high capital costs, are more expensive than the other natural gas-fueled DG technologies, but have relatively low GHG emissions due to high operating efficiencies. This makes them a cost-efficient means of reducing GHG emissions. Natural gas combined-cycle, with its high efficiency and relatively low life cycle GHG emissions,

is a cheaper way to reduce emissions than the other natural-gas DG technologies, DG diesel, and coal IGCC.

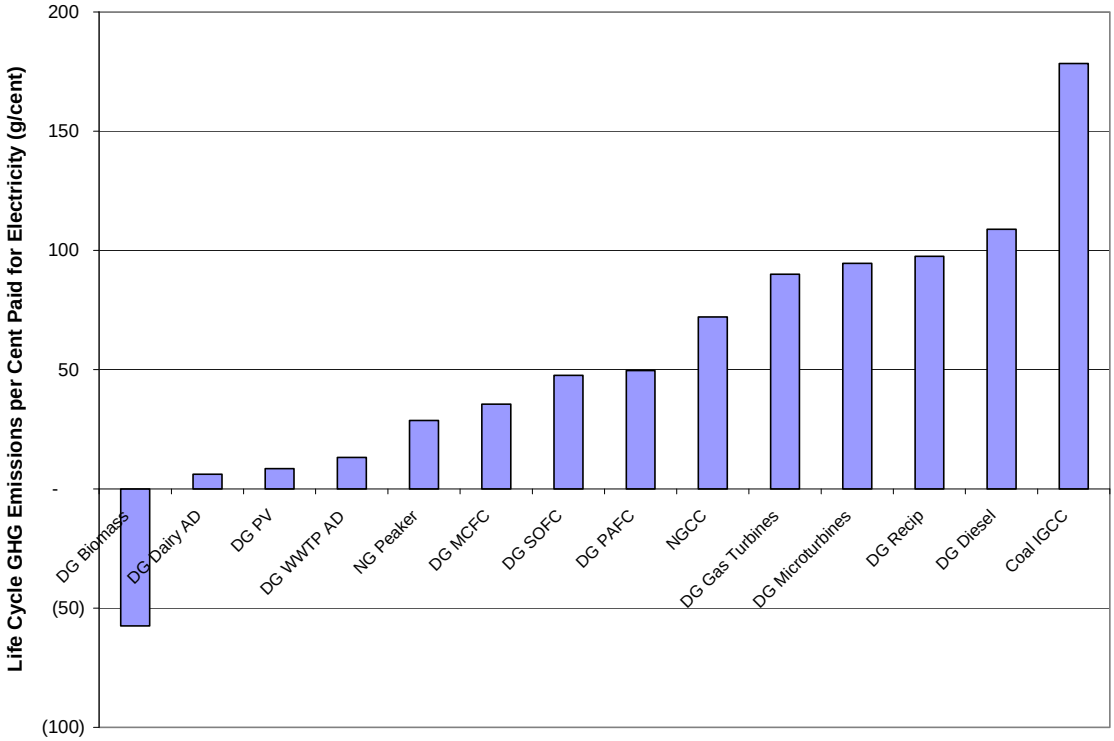


Figure 43. GHG Emissions per Cent of Levelized Cost of Electricity

The bottom-line result for the combined analysis of GHG emissions and cost is that renewables should first be encouraged, followed by high-efficiency systems, and high-emitting coal IGCC last.

8.0 Conclusions

The National Renewable Energy Laboratory, under the direction of the California Energy Commission's Public Interest Energy Research (PIER) Program, conducted a life cycle assessment to provide information on the overall environmental impacts and economic costs of using DG technologies compared to conventional power plants in California to produce electricity. This study examined the following DG technologies:

- Natural-gas combustion (simple-cycle) turbines
- Natural gas-fired microturbines
- Natural gas-fired reciprocating engines
- Photovoltaics (PV)
- Anaerobic digesters located at wastewater treatment plants feeding reciprocating engines (WWTP AD)
- Advanced diesel-fired generators
- Small-scale biomass gasification units feeding reciprocating engines
- Anaerobic digesters using dairy waste, feeding reciprocating engines
- Molten carbonate fuel cells (MCFC) using natural gas
- Phosphoric acid fuel cells (PAFC) using natural gas
- Solid oxide fuel cells (SOFC) using natural gas

For comparison purposes, the following central generating technologies were also evaluated:

- Peaking power plant specific to California
- Natural gas combined-cycle power plant
- Integrated coal gasification combined-cycle power plant

Each technology was studied independently; like operations between technologies were not excluded from the assessment. Additionally, the LCA included emissions and costs from transmission and distribution systems.

8.1. Conclusions: Prime Mover Efficiency

When the fuel is the same, the efficiency of the prime mover can have a significant impact on both generator and life cycle emissions. When NOx emissions are examined, for example, it is clear that as efficiency decreases, NOx emissions increase. Nitrogen oxide emissions of gas turbines, natural gas-fired microturbines, and natural gas fired reciprocating engines can be predicted by the efficiency of the technology. Results for greenhouse gases, SO_2, particulates, VOCs, and energy consumption demonstrate the same trend.

8.2. Conclusions: Natural Gas Production and Delivery

The LCA results show that natural gas leaks from production and pipeline delivery systems have a significant impact on life cycle GHG emissions. For this study, NREL assumed a natural gas leak rate of 1.4% of gross natural gas extracted.

Because natural gas consists primarily of methane, which has a GWP 21 times greater than CO_2, this LCA found that any technologies that use natural gas suffer from higher GHG emissions. In addition, life cycle emissions of CO, NOx, and CO_2 were affected due to natural gas combustion compressors along the length of the delivery pipeline. Without production and delivery leaks, the total GHG emissions from technologies that use natural gas would be substantially lower.

8.3. Conclusions: Local Emissions Versus Global Emissions

The impacts of some emissions (e.g., CO, VOC) primarily affect local and regional environmental quality. In contrast, other emissions, such as greenhouse gases, have global impacts. It is important to note that when assessing the results of the LCA, a higher rate of life cycle emissions does not necessarily result in a greater impact on the environment, because emissions that are spread out cannot be combined when assessing local environmental impacts. Thus, studying results in terms of the life cycle stage that emissions result from is extremely important. Emissions of CO due to generator operations will have an impact at the location of the generator, while CO emissions due to fuel acquisition and delivery will have impacts distributed along the natural gas pipeline or at the coal mine, depending on the fuel.

Because climate change impacts are global, and not dependent on the location of the emissions, a breakout of emissions by stage is useful for determining options for reducing emissions, but it is not useful for understanding local or regional effects. Greenhouse gas emissions for each technology are additive, regardless of where they are emitted.

In assessing the impact of GHG emissions, NREL found that the global impact of these emissions is significantly influenced by methane emissions. Additionally, GHG emissions are influenced by the efficiency of the prime mover and by natural gas fugitive emissions.

The natural gas-fired microturbine had the highest total emissions, if CHP is not employed. This is because of the technology's lower operating efficiency. The IGCC coal and reciprocating engine systems have approximately the same life cycle GHG emissions, although the engine is partially penalized by the influence of methane leaks during natural gas production and distribution. In general, equipment manufacture has little effect on GHG emissions, except for the PV system. Generator emissions from the WWTP AD system are reduced by avoided emissions associated with the normal disposal and decomposition of wastewater treatment plant effluent.

8.4. Conclusions: CHP

The NREL life cycle analysis shows that CHP results in avoided emissions. In effect, emissions that would have occurred in the non-CHP system are subtracted from the CHP system emissions. Any emissions that result from the production, distribution, and combustion of natural gas during the normal generation of steam for heat are reduced in systems that can use CHP. However, electricity generators with higher operating efficiency benefit less from CHP because less waste heat is available to displace conventional heat production. On balance, however, because CHP (or combined *cooling*, heating and power) options will not be universally available and useful at all hours to those installing DG, improvements in system efficiency has the potential to have a greater impact.

8.5. Conclusions: Technology Comparisons

The use of anaerobic digesters at wastewater treatment plants results in the least amount of environmental stressors (emissions, resource consumption, and energy use). This is because it is a renewable energy resource, and the stressors that would have occurred during the normal disposal of treated waste are avoided, which results in a low net impact. Photovoltaic systems also perform well, but are responsible for higher particulate matter emissions and water consumption, during manufacture of both the cells and steel support structures.

In terms of greenhouse gases, coal-integrated gasification combined-cycle plants have higher greenhouse gas emissions than most natural gas systems. However, central plants such as these and natural gas combined-cycle plants have the possible benefit of carbon dioxide sequestration under future policies.

Natural gas peaking power plants, as they exist in California today, are responsible for fairly high environmental stressors, although new installations of this technology could have lower environmental profiles if they generate at higher efficiencies. Increasing the operating hours of these units may be more economically feasible than building new natural gas combined-cycle plants, but doing so would result in greater environmental impacts.

Distributed generation gas turbines compared favorably with central natural gas combined-cycle plants; however, emissions from reciprocating engines and most microturbines are higher than those of central natural gas combined-cycle plants.

Despite the lower transmission and delivery line losses, life cycle and local air emissions are generally higher from natural gas-fired distributed generation technologies than from new, central natural gas-fired power plants. However, existing distributed generation technologies have the potential to be more environmentally benign than older central power plants, and may be an environmentally and economically attractive option for incrementally meeting increasing demand for electricity in California.

9.0 Recommendations

This study shows that decision makers in California have several key measures by which they can evaluate distributed generation and central technologies for meeting the state's growing electricity demands while minimizing environmental impacts. To have the greatest impact on greenhouse gas emissions, policies should focus on using renewable energy technologies that have low emissions, adopting technologies that have high generating efficiency, and supporting the use of natural gas from sources that can demonstrate low fugitive emissions. Local air emissions can be reduced by concentrating on generator efficiency and optimal (clean) performance. Where applicable, CHP can reduce resource consumption, energy use, and emissions. The balance between DG and central technologies will depend on many factors, some of which are non-environmental. This study shows, however, that conventional DG technologies that rely on natural gas do not have a drastic negative or superlatively positive environmental impact.

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11.0 Acronyms and Abbreviations

ARB	Air Resources Board (California)
Btu	British thermal unit
CH_4	methane
CHP	combined cooling, heat and power
CIEE	California Institute of Energy and Environment
CIGRE	International Council on Large Electric Systems
CO	carbon monoxide
CO_2	carbon dioxide
DG	distributed generation
FERC	U.S. Federal Energy Regulatory Commission
GHG	greenhouse gas
GWh	gigawatt-hour
GWP	global warming potential
HHV	higher heating value
ICE	internal combustion engine
IEEE	Institute of Electrical and Electronics Engineers
IGCC	integrated gasification combined-cycle
ISO	International Organization for Standardization
kWh	kilowatt-hour
LCA	life cycle assessment
LCIA	life cycle impact assessment
LHV	lower heating value
MW	megawatt
N_2O	nitrous oxide
NGCC	natural gas combined-cycle
NMOC	non-methane organic compounds
NOx	nitrogen oxides

NREL	National Renewable Energy Laboratory
O_3	ozone
PC	pulverized coal
PCB	polychlorinated biphenyls
PIER	Public Interest Energy Research
PM	particulate matter
PRB	Powder River Basin
PV	photovoltaic
SO_2	sulfur dioxide
T&D	transmission and distribution
UNEP	United Nations Environment Programme
U.S. EPA	U.S. Environmental Protection Agency
VOC	volatile organic compounds
WWTP	wastewater treatment plant

Appendix A

ISO Requirements

Appendix A: ISO Requirements

In 1997, the International Organization for Standardization (ISO) defined the minimum requirements for conducting LCA studies. The following table shows the ISO documents that relate to LCA and were followed for this study.

Table A-1. ISO Documents Relevant to this Life Cycle Assessment

ISO Document Number	Publication Date	Document Name
14040	1997	Environmental Management – Life cycle assessment – Principles and framework
14041	1998	Environmental Management – Life cycle assessment – Goal and scope definition and inventory analysis
14042	2000	Environmental management – Life cycle assessment – Life cycle impact assessment
14043	2000	Environmental management – Life cycle assessment – Life cycle interpretation
14044	2006	Environmental management – Life cycle assessment – Requirements and guidelines
14047	2003	Environmental management – Life cycle impact assessment – Examples of application of ISO 14042
14049	2000	Environmental management – Life cycle assessment – Examples of application of ISO 14041 to goal and scope definition and inventory analysis

These documents can be obtained from the ISO website: www.iso.org/iso/en/CatalogueListPage.CatalogueList?ICS1=13&ICS2=20&ICS3=60&scopelist=#top.

ISO 14040 specifies that in defining the scope of an LCA study, the following items shall be described:

- The functions of the product system (i.e., what need the system exists to meet)
- The functional unit
- The product system boundaries
- Allocation procedures
- Types of impact and methodology of impact assessment

- Data requirements and assumptions
- Type of critical review, if any
- Type and format of the report required

Appendix B

Study Assumption Details

Appendix B: Study Assumption Details

Presented here are the variables and assumptions entered into the life cycle assessment model.

Life Cycle Assessment Model Variables and Assumptions

	Abbreviation	Formula Value	Formula
NG Emission PM (g/Btu)	NGPM	3.20E-06	3.20E-06
NG Emission SO2 (g/Btu)	NGSO2	4.50E-07	4.50E-07
NG Emission CO2 (g/BTU)	NGCO2	0.053	5.30E-02
Anaerobic Digester Electricity Input (kWh) in / kWh out	ADEI	8.00E-02	0.08
Anaerobic Digester VOC (g/kwh)	ADVOC	0.26	0.26
Anaerobic Digester Heat Rate	ADHR	8111.11	8111.111
Natural Gas Leak Rate	NGFUG	0.14	0.14
T&D Transmission loss	TDTL	0.05	0.05
WWTP Anaerobic Digester weight (kg/kW)	ADWT	15.111	15.111
NG Combined Cycle weight (kg/kW)	NGCCWT	2.01E+01	20.111
Peaking weight (kg/kW)	PPPWT	20.111	20.111
IGCC weight (kg/kW)	IGCCWT	20.111	20.111
PV weight (kg/kW)	PVWT	15.111	15.111
NG Gas turbine weight (kg/kW)	GTWT	1.10E+01	11
NGRE weight (kg/kW)	NGREWT	15	15
Microturbine weight (kg/kW)	NGMWT	17	17
Frontier Line Electricity Estimated Capacity	FLEE	2.10E+12	12000*1000*8760*PLT
Frontier Line Number Transformers	FLNT	11	11
Frontier Line length (km)	FLL	1300	1300

Frontier Line Transmission Loss	FLTL	0.05	0.05
Anaerobic Digestion N20	ADN2O	1.11E-05	0.00001111
Anaerobic Digestion CH4	ADCH4	0.00111	0.00111
Anaerobic Digestion PM2.5	ADPM25	0.001111	0.001111
Anaerobic Digestion PM10	ADPM10	0.001111	0.001111
Anaerobic Digestion NOx	ADNOX	0.26	0.26
Anaerobic Digestion SO2	ADSO2	0.006	0.006
Anaerobic Digestion CO	ADCO	0.32	0.32
WWTP Anaerobic Digestion CO2 (g/kWh)	ADCO2	133	133
Capacity Factor Peaking Power Plant	CFPPP	0.02	0.02
Capacity Factor NGCC	CFNGCC	0.8	0.8
Capacity Factor IGCC	CFIGCC	0.8	0.8
Capacity Factor Photovoltaics	CFPV	0.23	0.23
Capacity Factor WWTP Anaerobic Digestion	CFAD	0.7	0.7
Capacity Factor NGGT	CFGT	0.8	0.8
Capacity Factor NGRE	CFNGRE	0.8	0.8
Capacity Factor Microturbines	CFNGM	0.8	0.8
Gas Turbine PM 2.5 (g/kWh)	GTPM25	4.19E-05	9.23E-5/2.205
Transformer aluminum (kg/trans)	TRA	354	354
Transformer steel (kg/trans)	TRS	2720	2720
Spacing between Transmission towers (km)	TTS	0.45	0.45
ACSR Cable Aluminum (kg/km)	ACSRA	307	307
ACSR Cable Steel (kg/km)	ACSRS	670	670

Steel Lattice Tower Steel (kg/tower)	SLTS	40900	40900
Insulator Fiberglass (kg/insulator)	IFG	4.5	4.5
Insulator Silicone (kg / insulator)	IS	4.5	4.5
Insulators per tower	IPT	6	6
Gas Turbine Heat Rate (Btu/kWh)	GTHR	8982	8982
Gas Turbine N20	GTN20	0.01105	0.01105
Gas Turbine CH4	GTCH4	0.02874	0.02874
Gas Turbine PM10 (g/kWh)	GTPM10	0.0296	0.0296
Gas Turbine CO (g/kWh)	GTCO	0.045	0.045
Gas Turbine CO2 (g/kWh)	GTCO2	224.3	224.3
Gas Turbine SO2 (g/kWh)	GTSO2	1.92	1.92
Gas Turbine NOx (g/kWh)	GTNOX	0.032	0.032
Gas Turbine VOC (g/kWh)	GTVOC	0.009	0.009
VOC IGCC (g/kWh)	IGCCVOC	0	0
PM2.5 IGCC (g/kWh)	IGCCPM25	0	0
N2O IGCC (g/kWh)	IGCCN20	0	0
CH4 IGCC (g/kWh)	IGCCCH4	0	0
WY Coal Average Heating Value (Btu/kg)	HVC	26460	26460
PM10 IGCC (g/kWh	IGCCPM10	0.031	0.031
CO IGCC (g/kWh)	IGCCCO	0.13	0.13
CO2 IGCC (g/kWh)	IGCCCO2	741	741
SO2 IGCC (g/kWh)	IGCCSO2	0.23	0.23
NOx IGCC (g/kWh	IGCCNOX	0.66	0.66
IGCC Heat Rate (Btu/kWh)	IGCCHR	8600	8600

Avg Nat Gas Pipeline Distance (km)	NGPIPE	1800	1800
PAFC Heat Rate (Btu/kWh)	PAFCHR	8862	8862
Diesel ICE Heat Rate (Btu/kWh)	DICEHR	8871	8871
Peaking Power Plant Heat Rate (Btu/kWh)	PPPHR	8982	8982
Conventional NG Combined Cycle Heat Rate (Btu/kWh()	CNGCCHR	8809	8809
NG Microturbine Heat Rate	NGMHR	13089	13089
NGRE Heat Rate (Btu/kWh)	NGREHR	10235	10235
Heating Value Diesel (Btu/kg)	HVD	40793	40793
Heating Value Hydrogen (Btu/kg)	HVH2	113738	113738
Heating Value Natural Gas (Btu/kg)	HVNG	46967	46967
PM2.5 Phosphoric Acid Fuel Cells (g/kWhi)	PAFCPM25	0	0
PM2.5 Photovoltaics (g/kWhi)	PVPM25	0	0
PM2.5 NG Reciprocating Engine (g/kWhi)	NGREPM25	2.154	2.154
PM2.5 NG Microturbine (g/kWhi)	NGMPM25	0.04082	0.04082
PM2.5 Diesel ICE (g/kWh)	DICEPM25	1.07483	1.07483
PM2.5 Combined Heat Power (g/kWhi)	CHPPM25	0	0
PM2.5 Biomass Fired (g/kWhi)	BFPM25	0	0
PM2.5 Peaking Power Plant (g/kWh)	PPPPM25	0	0
PM2.5 Conventional NG Combined Cycle (g/kWhi)	CNGCCPM25	0.00907	0.00907
PM10 Stirling Engine (g/kWh)	SEPM10	0	0

PM10 Phosphoric Acid Fuel Cells (g/kWhi)	PAFCPM10	0	0
PM10 Photovoltaics (g/kWh)	PVPM10	0	0
PM10 NG Reciprocating Engine (g/kWh)	NGREPM10	0.087	0.087
PM10 NG Microturbine (g/kWh)	NGMPM10	0.04014	0.04014
PM10 Diesel ICE (g/kWh)	DICEPM10	0.3211	0.3211
PM10 Combined Heat Power (g/kWh)	CHPPM10	0	0
PM10 Biomass Fired (g/kWh)	BFPM10	0	0
PM10 Peaking Power Plant (g/kWh)	PPPPM10	0.02961	0.02960996
PM10 Conventional NG Combined Cycle (g/kWh)	CNGCCPM10	0.01814	0.01814
VOC Phosphoric Acid Fuel Cells (g/kWh)	PAFCVOC	0.004535	0.004535
VOC Photovoltaics (g/kWh)	PVVOC	0	0
VOC NG Reciprocating Engine (g/kWh)	NGREVOC	0.009	0.009
VOC Diesel ICE (g/kWh)	DICEVOC	0.7653	0.7653
VOC NG Microturbine (g/kWh)	NGMVOC	0.009	0.009
VOC Combined Heat Power (g/kWh)	CHPVOC	0	0
VOC Biomass Fired (g/kWh)	BFVOC	0	0
VOC Peaking Power Plant (g/kWh)	PPPVOC	0.0105645	0.010564511
VOC Conventional NG Combined Cycle (g/kWh)	CNGCCVOC	0.04989	0.04989
SO2 Photovoltaics (g/kWh)	PVSO2	0	0
SO2 Phosphoric Acid Fuel Cells (g/kWh)	PAFCSO2	0.001134	0.001134
SO2 NG Reciprocating Engine (g/kWh)	NGRESO2	0.0101225	0.0101225

SO2 NG Microturbine (g/kWh)	NGMSO2	0.0129452	0.0129452
SO2 Diesel ICE (g/kWh)	DICESO2	0.42465	0.42465
SO2 Combined Heat Power (g/kWh)	CHPSO2	0	0
SO2 Biomass Fired (g/kWh)	BFSO2	0	0
SO2 Peaking Power Plant (g/kWh)	PPPSO2	0.006206	0.006206
SO2 Conventional NG Combined Cycle (g/kWh)	CNGCCSO2	0.0037	0.0037
N20 Photovoltaics (g/kWh)	PVN2O	0	0
N20 Phosphoric Acid Fuel Cell (g/kWh)	PAFCN2O	0	0
N20 NG Reciprocating Engine (g/kWh)	NGREN2O	0	0
N20 NG Microturbine (g/kWh)	NGMN2O	0	0
N20 Diesel ICE (g/kWh)	DICEN2O	0	0
N20 Combined Heat Power (g/kWh)	CHPN2O	0	0
N20 Biomass-fired (g/kWh)	BFN2O	0	0
N20 Peaking Power Plant (g/kWh)	PPPN2O	0.0110503	0.011050271
N2O Conventional NG Combined Cycle (g/kWh)	CNGCCN2O	0	0
CH4 Photovoltaics (g/kWh)	PVCH4	0	0
CH4 Phosphoric Acid Fuel Cell (g/kWh)	PAFCCH4	0	0
CH4 NG Reciprocating Engine (g/kWh)	NGRECH4	0	0
CH4 NG Microturbine (g/kWh)	NGMCH4	0	0
CH4 Diesel ICE (g/kWh)	DICECH4	0	0
CH4 Combined Heat Power (g/kWh)	CHPCH4	0	0

CH4 Biomass-fired (g/kWh)	BFCH4	0	0
CH4 Peaking Power Plant (g/kWh)	PPPCH4	0.0287433	0.028743332
CH4 Conventional NG Combined Cycle (g/kWh)	CNGCCCH4	0.044	0.044
CO2 Photovoltaics (g/kWh)	PVCO2	0	0
CO2 Phosphoric Acid Fuel Cell (g/kWh)	PAFCCO2	478	478
CO2 NG Reciprocating Engine (g/kWh)	NGRECO2	511.4	511.4
CO2 NG Microturbine (g/kWh)	NGMCO2	675	675
CO2 Diesel ICE (g/kWh)	DICECO2	663	663
CO2 Combined Heat Power (g/kWh)	CHPCO2	0	0
CO2 Biomass Fired (g/kWh)	BFCO2	0	0
CO2 Peaking Power Plant (g/kWh)	PPPCO2	455.9	455.9
CO2 Conventional NG Combined Cycle (g/kWh)	CNGCCCO2	391.3	391.3
CO Diesel ICE (g/kWh)	DICECO	6.1103	6.1103
CO Peaking Power Plant (g/kWh)	PPPCO	0.183628	0.183628392
CO Conventional NG Combined cycle (g/kWh)	CNGCCCO	0.0771	0.0771
CO Biomass Fired (g/kWh)	BFCO	0	0
CO Combined Heat Power (g/kWh)	CHPCO	0	0
CO NG Reciprocating Engine (g/kWh)	NGRECO	0.045	0.045
CO NG Microturbine (g/kWh)	NGMCO	0.045	0.045
CO Phosphoric Acid Fuel Cell (g/kWh)	PAFCCO	0.01437	0.01437
CO Photovoltaics (g/kWh)	PVCO	0	0

NOx Photovoltaics (g/kWh)	PVNOX	0	0
NOx Phosphoric Acid Fuel Cell (g/kWh)	PAFCNOX	0.011414	0.011414
NOx NG reciprocation engine (g/kWh)	NGRENOX	0.032	0.032
NOx NG Microturbine (g/kWh)	NGMNOX	0.032	0.032
NOx Diesel ICE (g/kWh)	DICENOX	5.586	5.586
NOx Combined Heat Power (g/kWh)	CHPNOX	0	0
NOx Biomass-fired (g/kWh)	BFNOX	0	0
NOx Peaking Power Plant (g/kWh)	PPPNOX	0.419627	0.41962711

Appendix C

Literature Sources for Technology Operating Emissions

Appendix C: Literature Sources for Technology Operating Emissions

Microturbines

Citation	Air Emission	Air Emission Rates	Air Emission Rate Units
Freeman, B. Emissions Testing and Certification Guidelines for Distributed Generators. Palo Alto, CA: EPRI Solutions, December 2000.	10 micron particulates	nil	g/kWh
Ishii, Ronald D. and Greg Stevens. Evaluation of Self-Generation for Energy Efficiency Programs. Work performed by Alternative Energy Systems Consulting, Inc, Carlsbad, CA. Prepared for California Board for Energy Efficiency, October 6, 1998.	10 micron particulates	Negl.	lbs/kWh
Iannucci, J., S. Horgan, J. Eyer, and L. Cibulka. Air Pollution Emission Impacts Associated with Economic Market Potential of Distributed Generation in California. Work performed by Distributed Utility Associates, Livermore, CA, June 2000	10 micron particulates	0.000091	lb/kWh
Iannucci, J., Horgan, S, Eyer, J and Cibulka, L. Air Pollution Emission Impacts Associated with Economic Market Potential of Distributed Generation in California. Work performed by Distributed Utility Associates, Livermore, CA, June 2000	10 micron particulates	0.00009	lb/kWh
Honton, E. J. Environmental Challenges for New Generation Resource Dynamics Corporation CEC-EPRI Workshop, October 28, 1999	10 micron particulates	0.0001-0.0002	lb/kWh
Bluestein, J. Environmental Benefits of Distributed Generation Energy and Environmental Analysis, Inc. December 18, 2000.	10 micron particulates	0.08	lb/MWh
DG Emission Rate Estimate (Unknown Source)	10 micron particulates	0.0901	lb/MWh
Carter, Sheryl. Emissions from Distributed Generation California Energy Commission Siting Committee Workshop Evaluation Distributed Generation CEQA and Permit Streamlining, San Francisco, CA April 20, 2000.	10 micron particulates	>0.03	lb/MWh
Lents, J. and Allison, J. E. Can We Have Our Cake and Eat It, Too? Creating Distributed Generation Technology to Improve Air Quality. Work performed by University of California, Riverside. San Francisco, CA: The Energy Foundation, December 1, 2000.	2.5 micron particulates	9e-005	lbs/kWh
University of California. "The Four Es of DG Policy in California: Energy, Environment, Economics, and Education," Prepared for California Energy Commission, August 2003.	2.5 micron particulates	0.00009	lb/kWh
Allison, J., Arragon, J., and Lents, Dr. James. Integrating Distributed Generation with Air Quality Needs. CE-CERT, University of California, Riverside, June 20, 2000.	2.5 micron particulates	0.00009	lb/kWh

Technology Characterization: Microturbines Work performed by Energy Nexus Group Arlington, VA. Washington DC: Environmental Protection Agency, March 2002.	CO	0.72	lb/MWh
Technology Characterization: Microturbines Work performed by Energy Nexus Group Arlington, VA. Washington DC: Environmental Protection Agency, March 2002.	CO	0.49	lb/MWh
Ishii, Ronald D. and Stevens, Greg. Evaluation of Self-Generation for Energy Efficiency Programs. Work performed by Alternative Energy Systems Consulting, Inc, Carlsbad, CA. Prepared for California Board for Energy Efficiency, October 6, 1998.	CO	3-50	ppm
University of California. "The Four Es of DG Policy in California: Energy, Environment, Economics, and Education," Prepared for California Energy Commission, August 2003.	CO	0.00285 0.00285	lb/kWh
Assessment of Distributed Generation Technology Applications. Vienna, VA: Resource Dynamics Corporation, February 2001	CO	9-125	ppm
Assessment of Distributed Generation Technology Applications. Vienna, VA: Resource Dynamics Corporation, February 2001	CO	9-125	ppm
Greenhouse Gas Technology Center Southern Research Institute. "Environmental Technology Verification Report: Combined Heat and Power at a Commercial Supermarket - Capstone 60 kW Microturbine CHP System September 2003	CO	.000114	lb/kWh
Capstone Turbine Corporation "Capstone Low Emissions Microturbine Technology" White Paper. Chatsworth, CA March 6, 2000.	CO	0.603	g/kWh
Honton, E. J. Environmental Challenges for New Generation. Resource Dynamics Corporation CEC-EPRI Workshop, October 28, 1999	CO	0.0002- 0.002	lb/kWh
Freeman, B. Emissions Testing and Certification Guidelines for Distributed Generators Palo Alto, CA: EPRI Solutions, December 2000.	CO	0.13-0.8	g/kWh
DG Emission Rate Estimate (Unknown Source)	CO	1.2	lb/MWh
Technology Characterization: Microturbines. Work performed by Energy Nexus Group Arlington, VA. Washington DC: Environmental Protection Agency, March 2002.	CO	1.46	lb/MWh
Lents, J. and Allison, J. E. Can We Have Our Cake and Eat It, Too? Creating Distributed Generation Technology to Improve Air Quality. Work performed by University of California, Riverside. San Francisco, CA: The Energy Foundation, December 1, 2000.	CO	0.00285	lbs/kWh
Carter, Sheryl. Emissions from Distributed Generation California Energy Commission Siting Committee Workshop Evaluation Distributed Generation CEQA and Permit Streamlining, San Francisco, CA April 20, 2000.	CO	0.3-1.8	lb/MWh

Technology Characterization: Microturbines. Work performed by Energy Nexus Group Arlington, VA. Washington DC: Environmental Protection Agency, March 2002.	CO	1.46	lb/MWh
Iannucci, J., Horgan, S, Eyer, J and Cibulka, L. Air Pollution Emission Impacts Associated with Economic Market Potential of Distributed Generation in California. Work performed by Distributed Utility Associates, Livermore, CA, June 2000	CO	0.00265	lb/kWh
Iannucci, J., Horgan, S, Eyer, J and Cibulka, L. Air Pollution Emission Impacts Associated with Economic Market Potential of Distributed Generation in California. Work performed by Distributed Utility Associates, Livermore, CA, June 2000	CO	0.00285	lb/kWh
Allison, J., Arragon, J., and Lents, Dr. James. Integrating Distributed Generation with Air Quality Needs. CE-CERT, University of California, Riverside, June 20, 2000.	CO	0.00285	lb/kWh
University of California. "The Four Es of DG Policy in California: Energy, Environment, Economics, and Education," Prepared for California Energy Commission, August 2003.	CO_2	1.25	lb/kWh
Technology Characterization: Microturbines. Work performed by Energy Nexus Group Arlington, VA. Washington DC: Environmental Protection Agency, March 2002.	CO_2	1706	lb/MWh
Carter, Sheryl. Emissions from Distributed Generation California Energy Commission Siting Committee Workshop Evaluation Distributed Generation CEQA and Permit Streamlining, San Francisco, CA April 20, 2000.	CO_2	1300-1800	lb/MWh
Technology Characterization: Microturbines. Work performed by Energy Nexus Group Arlington, VA. Washington DC: Environmental Protection Agency, March 2002.	CO_2	1529	lb/MWh
DG Emission Rate Estimate (Unknown Source)	CO_2	1596	lb/MWh
Capstone Turbine Corporation. "Capstone Low Emissions Microturbine Technology." White Paper. Chatsworth, CA. March 6, 2000.	CO_2	724	g/kWh
Bluestein, J. Environmental Benefits of Distributed Generation Energy and Environmental Analysis, Inc. December 18, 2000.	CO_2	1477	lb/MWh
Lents, J. and Allison, J. E. Can We Have Our Cake and Eat It, Too? Creating Distributed Generation Technology to Improve Air Quality. Work performed by University of California, Riverside. San Francisco, CA: The Energy Foundation, December 1, 2000.	CO_2	1.25	lbs/kWh
Allison, J., Arragon, J., and Lents, Dr. James. Integrating Distributed Generation with Air Quality Needs. CE-CERT, University of California, Riverside, June 20, 2000.	CO_2	1.25	lb/kWh

Greenhouse Gas Technology Center Southern Research Institute. "Environmental Technology Verification Report: Combined Heat and Power at a Commercial Supermarket - Capstone 60 kW Microturbine CHP System. September 2003.	CO_2	1.49	lb/kWh
Iannucci, J., Horgan, S, Eyer, J and Cibulka, L. Air Pollution Emission Impacts Associated with Economic Market Potential of Distributed Generation in California Work performed by Distributed Utility Associates, Livermore, CA, June 2000.	CO_2	1.25	lb/kWh
Iannucci, J., Horgan, S, Eyer, J and Cibulka, L. Air Pollution Emission Impacts Associated with Economic Market Potential of Distributed Generation in California. Work performed by Distributed Utility Associates, Livermore, CA, June 2000.	CO_2	1.18833	lb/kWh
Technology Characterization: Microturbines. Work performed by Energy Nexus Group Arlington, VA. Washington DC: Environmental Protection Agency, March 2002.	CO_2	1774	lb/MWh
Technology Characterization: Microturbines. Work performed by Energy Nexus Group Arlington, VA. Washington DC: Environmental Protection Agency, March 2002.	CO_2	1928	lb/MWh
Technology Characterization: Microturbines. Work performed by Energy Nexus Group Arlington, VA. Washington DC: Environmental Protection Agency, March 2002.	NOx	0.50	lb/MWh
Technology Characterization: Microturbines. Work performed by Energy Nexus Group Arlington, VA. Washington DC: Environmental Protection Agency, March 2002.	NOx	0.54	lb/MWh
Iannucci, J., Horgan, S, Eyer, J and Cibulka, L. Air Pollution Emission Impacts Associated with Economic Market Potential of Distributed Generation in California. Work performed by Distributed Utility Associates, Livermore, CA, June 2000	NOx	0.00115	lb/kWh
Iannucci, J., Horgan, S, Eyer, J and Cibulka, L. Air Pollution Emission Impacts Associated with Economic Market Potential of Distributed Generation in California. Work performed by Distributed Utility Associates, Livermore, CA, June 2000	NOx	0.00125	lb/kWh
Assessment of Distributed Generation Technology Applications. Vienna, VA: Resource Dynamics Corporation, February 2001	NOx	9-125	g/kWh
Assessment of Distributed Generation Technology Applications. Vienna, VA: Resource Dynamics Corporation, February 2001	NOx	9-125	ppm

Ishii, Ronald D. and Stevens, Greg. Evaluation of Self-Generation for Energy Efficiency Programs. Work performed by Alternative Energy Systems Consulting, Inc, Carlsbad, CA. Prepared for California Board for Energy Efficiency, October 6, 1998.	NOx	3-50	ppm
Lents, J. and Allison, J. E. Can We Have Our Cake and Eat It, Too? Creating Distributed Generation Technology to Improve Air Quality. Work performed by University of California, Riverside. San Francisco, CA: The Energy Foundation, December 1, 2000.	NOx	0.0014	lbs/kWh
Technology Characterization: Microturbines. Work performed by Energy Nexus Group Arlington, VA. Washington DC: Environmental Protection Agency, March 2002.	NOx	0.53	lb/MWh
Technology Characterization: Microturbines. Work performed by Energy Nexus Group Arlington, VA. Washington DC: Environmental Protection Agency, March 2002.	NOx	0.80	lb/MWh
Gregerson, Joan and Van Holde, David. The Heat Is On: What's Cookin' with Large DG. E-Source DE-15, The McGraw-Hill Companies, Inc. September 2001.	NOx	0.14-0.61	g/hp-h
Carter, Sheryl. Emissions from Distributed Generation California Energy Commission Siting Committee Workshop Evaluation Distributed Generation CEQA and Permit Streamlining, San Francisco, CA April 20, 2000.	NOx	0.2-1.4	lb/MWh
Office of Industrial Technologies. Review of Combined Heat and Power Technologies. October 1999.	NOx	0.4-2.2	lb/MWh
Mirzakhalili, Ali. "Distributed Generation: Emissions and Regulation." Conference Presentation Enabling Demand Response and Distributed Generation. June 14-15, 2004.	NOx	0.4	lb/MWh
Honton, E. J. Environmental Challenges for New Generation Resource Dynamics Corporation CEC-EPRI Workshop, October 28, 1999	NOx	0.0003-0.001	lb/kWh
Capstone Turbine Corporation. "Capstone Low Emissions Microturbine Technology." White Paper. Chatsworth, CA. March 6, 2000.	NOx	0.223	g/kWh
DG Emission Rate Estimate (Unknown Source)	NOx	0.4	lb/MWh
Goldstein, L., Hedman, B., Knowles, D., Freedman, S., Woods, R., Schweizer, T. Gas-Fired Distributed Energy Resource Technology Characterizations NREL/TP 620-34783. Golden, CO: National Renewable Energy Laboratory, November 2003.	NOx	0.5-1.25	lb/MWh
Bluestein, J. Environmental Benefits of Distributed Generation Energy and Environmental Analysis, Inc. December 18, 2000.	NOx	0.41	lb/MWh

Greenhouse Gas Technology Center Southern Research Institute. "Environmental Technology Verification Report: Combined Heat and Power at a Commercial Supermarket - Capstone 60 kW Microturbine CHP System. September 2003.	NOx	.000147	lb/kWh
Allison, J., Arragon, J., and Lents, Dr. James. Integrating Distributed Generation with Air Quality Needs. CE-CERT, University of California, Riverside, June 20, 2000.	NOx	0.00140	lb/kWh
University of California. "The Four Es of DG Policy in California: Energy, Environment, Economics, and Education," Prepared for California Energy Commission, August 2003.	NOx	0.0014	lb/kWh
Freeman, B. Emissions Testing and Certification Guidelines for Distributed Generators Palo Alto, CA: EPRI Solutions, December 2000.	NOx	0.24-0.64	g/kWh
Allison, J., Arragon, J., and Lents, Dr. James. Integrating Distributed Generation with Air Quality Needs. CE-CERT, University of California, Riverside, June 20, 2000.	SO_2	0.00002	lb/kWh
Carter, Sheryl. Emissions from Distributed Generation California Energy Commission Siting Committee Workshop Evaluation Distributed Generation CEQA and Permit Streamlining, San Francisco, CA April 20, 2000.	SO_2	negl.	lb/MWh
Iannucci, J., Horgan, S, Eyer, J and Cibulka, L. Air Pollution Emission Impacts Associated with Economic Market Potential of Distributed Generation in California. Work performed by Distributed Utility Associates, Livermore, CA, June 2000	SO_2	0.00003	lb/kWh
Lents, J. and Allison, J. E. Can We Have Our Cake and Eat It, Too? Creating Distributed Generation Technology to Improve Air Quality. Work performed by University of California, Riverside. San Francisco, CA: The Energy Foundation, December 1, 2000.	SO_2	2e-005	lbs/kWh
Ishii, Ronald D. and Stevens, Greg. Evaluation of Self-Generation for Energy Efficiency Programs. Work performed by Alternative Energy Systems Consulting, Inc, Carlsbad, CA. Prepared for California Board for Energy Efficiency, October 6, 1998.	SO_2	Negl.	lbs/kWh
University of California. "The Four Es of DG Policy in California: Energy, Environment, Economics, and Education," Prepared for California Energy Commission, August 2003.	SO_2	0.00002	lb/kWh
Iannucci, J., Horgan, S, Eyer, J and Cibulka, L. Air Pollution Emission Impacts Associated with Economic Market Potential of Distributed Generation in California. Work performed by Distributed Utility Associates, Livermore, CA, June 2000	SO_2	0.00003	lb/kWh
DG Emission Rate Estimate (Unknown Source)	SO_2	0.0082	lb/MWh
Honton, E. J. Environmental Challenges for New Generation Resource Dynamics Corporation CEC-EPRI Workshop, October 28, 1999	SO_2	0.00003	lb/kWh

Bluestein, J. Environmental Benefits of Distributed Generation Energy and Environmental Analysis, Inc. December 18, 2000.	SO_2	0.008	lb/MWh
Allison, J., Arragon, J., and Lents, Dr. James. Integrating Distributed Generation with Air Quality Needs. CE-CERT, University of California, Riverside, June 20, 2000.	VOC	0.00005	lb/kWh
Lents, J. and Allison, J. E. Can We Have Our Cake and Eat It, Too? Creating Distributed Generation Technology to Improve Air Quality. Work performed by University of California, Riverside. San Francisco, CA: The Energy Foundation, December 1, 2000.	VOC	5e-005	lbs/kWh
Iannucci, J., Horgan, S, Eyer, J and Cibulka, L. Air Pollution Emission Impacts Associated with Economic Market Potential of Distributed Generation in California. Work performed by Distributed Utility Associates, Livermore, CA, June 2000	VOC	0.000045	lb/kWh
University of California. "The Four Es of DG Policy in California: Energy, Environment, Economics, and Education." Prepared for California Energy Commission, August 2003.	VOC	0.00005	lb/kWh
Technology Characterization: Microturbines. Work performed by Energy Nexus Group Arlington, VA. Washington DC: Environmental Protection Agency, March 2002.	VOC	<0.19	lb/MWh
DG Emission Rate Estimate (Unknown Source)	VOC	0.42	lb/MWh
Technology Characterization: Microturbines. Work performed by Energy Nexus Group Arlington, VA. Washington DC: Environmental Protection Agency, March 2002.	VOC	0.19	lb/MWh
Technology Characterization: Microturbines. Work performed by Energy Nexus Group Arlington, VA. Washington DC: Environmental Protection Agency, March 2002.	VOC	<0.19	lb/MWh
Iannucci, J., Horgan, S, Eyer, J and Cibulka, L. Air Pollution Emission Impacts Associated with Economic Market Potential of Distributed Generation in California. Work performed by Distributed Utility Associates, Livermore, CA, June 2000	VOC	0.00004	lb/kWh
Technology Characterization: Microturbines. Work performed by Energy Nexus Group Arlington, VA. Washington DC: Environmental Protection Agency, March 2002.	VOC	0.17	lb/MWh

Natural Gas Reciprocating Engine

Citation	Air Emission	Air Emission Rates	Air Emission Rate Units
Freeman, B. Emissions Testing and Certification Guidelines for Distributed Generators. Palo Alto, CA: EPRI Solutions, December 2000.	10 micron particulates	0.0013-0.0053	g/kWh
Carter, Sheryl. Emissions from Distributed Generation California Energy Commission Siting Committee Workshop Evaluation Distributed Generation CEQA and Permit Streamlining, San Francisco, CA April 20, 2000.	10 micron particulates	0.6	lb/MWh
Bluestein, J. Environmental Benefits of Distributed Generation. Energy and Environmental Analysis, Inc. December 18, 2000.	10 micron particulates	0.03	lb/MWh
Carter, Sheryl. Emissions from Distributed Generation California Energy Commission Siting Committee Workshop Evaluation Distributed Generation CEQA and Permit Streamlining, San Francisco, CA April 20, 2000.	10 micron particulates	0.6	lb/MWh
Honton, E. J. Environmental Challenges for New Generation. Resource Dynamics Corporation CEC-EPRI Workshop, October 28, 1999	10 micron particulates	0.0002	lb/kWh
Bluestein, J. Environmental Benefits of Distributed Generation Energy and Environmental Analysis, Inc. December 18, 2000.	10 micron particulates	0.03	lb/MWh
Freeman, B. Emissions Testing and Certification Guidelines for Distributed Generators. Palo Alto, CA: EPRI Solutions, December 2000.	10 micron particulates	0.004	g/kWh
Michael, J. Future Emission Regulations. Detroit Diesel Corporation.	10 micron particulates	0.01	g/hp-hr
Michael, J. Future Emission Regulations. Detroit Diesel Corporation.	10 micron particulates	0.01	g/hp-hr
Lents, J. and Allison, J. E. Can We Have Our Cake and Eat It, Too? Creating Distributed Generation Technology to Improve Air Quality. Work performed by University of California, Riverside. San Francisco, CA: The Energy Foundation, December 1, 2000.	2.5 micron particulates	0.00475	lbs/kWh
Allison, J., Arragon, J., and Lents, Dr. James. Integrating Distributed Generation with Air Quality Needs. CE-CERT, University of California, Riverside, June 20, 2000.	2.5 micron particulates	0.00475	lb/kWh

Carter, Sheryl. Emissions from Distributed Generation California Energy Commission Siting Committee Workshop Evaluation Distributed Generation CEQA and Permit Streamlining, San Francisco, CA April 20, 2000.	CO	2-9	lb/MWh
Freeman, B. Emissions Testing and Certification Guidelines for Distributed Generators. Palo Alto, CA: EPRI Solutions, December 2000.	CO	0.82.7	g/kWh
Allison, J., Arragon, J., and Lents, Dr. James. Integrating Distributed Generation with Air Quality Needs. CE-CERT, University of California, Riverside, June 20, 2000.	CO	0.00800	lb/kWh
Freeman, B. Emissions Testing and Certification Guidelines for Distributed Generators. Palo Alto, CA: EPRI Solutions, December 2000.	CO	1.3-27	g/kWh
Michael, J. Future Emission Regulations. Detroit Diesel Corporation.	CO	0	g/hp-hr
Lents, J. and Allison, J. E. Can We Have Our Cake and Eat It, Too? Creating Distributed Generation Technology to Improve Air Quality. Work performed by University of California, Riverside. San Francisco, CA: The Energy Foundation, December 1, 2000.	CO	0.008	lbs/kWh
Assessment of Distributed Generation Technology Applications. Vienna, VA: Resource Dynamics Corporation, February 2001	CO	0.8-27	g/kWh
Technology Characterization: Reciprocating Engines. Work performed by Energy Nexus Group for the Environmental Protection Agency, February 2002.	CO	35.4	lb/MWh
Technology Characterization: Reciprocating Engines. Work performed by Energy Nexus Group for the Environmental Protection Agency, February 2002.	CO	5.31	lb/MWh
Technology Characterization: Reciprocating Engines. Work performed by Energy Nexus Group for the Environmental Protection Agency, February 2002.	CO	7.68	lb/MWh
Michael, J. Future Emission Regulations. Detroit Diesel Corporation	CO	2.12	g/hp-hr
Technology Characterization: Reciprocating Engines. Work performed by Energy Nexus Group for the Environmental Protection Agency, February 2002.	CO	8.27	lb/MWh

Technology Characterization: Reciprocating Engines. Work performed by Energy Nexus Group for the Environmental Protection Agency, February 2002.	CO	6.50	lb/MWh
Honton, E. J. Environmental Challenges for New Generation. Resource Dynamics Corporation CEC-EPRI Workshop, October 28, 1999	CO	0.004-0.006	lb/kWh
Carter, Sheryl. Emissions from Distributed Generation California Energy Commission Siting Committee Workshop Evaluation Distributed Generation CEQA and Permit Streamlining, San Francisco, CA April 20, 2000.	CO	1-6	lb/MWh
Technology Characterization: Reciprocating Engines. Work performed by Energy Nexus Group for the Environmental Protection Agency, February 2002.	CO_2	1,166	lb/MWh
Technology Characterization: Reciprocating Engines. Work performed by Energy Nexus Group for the Environmental Protection Agency, February 2002.	CO_2	1,139	lb/MWh lb/MWh
Technology Characterization: Reciprocating Engines. Work performed by Energy Nexus Group for the Environmental Protection Agency, February 2002.	CO_2	1,051	lb/MWh lb/MWh
Allison, J., Arragon, J., and Lents, Dr. James. Integrating Distributed Generation with Air Quality Needs. CE-CERT, University of California, Riverside, June 20, 2000.	CO_2	0.97	lb/kWh
Technology Characterization: Reciprocating Engines. Work performed by Energy Nexus Group for the Environmental Protection Agency, February 2002.	CO_2	1,338	lb/MWh
Carter, Sheryl. Emissions from Distributed Generation California Energy Commission Siting Committee Workshop Evaluation Distributed Generation CEQA and Permit Streamlining, San Francisco, CA April 20, 2000.	CO_2	950-1200	lb/MWh
Technology Characterization: Reciprocating Engines. Work performed by Energy Nexus Group for the Environmental Protection Agency, February 2002.	CO_2	1,316	lb/MWh
Carter, Sheryl. Emissions from Distributed Generation California Energy Commission Siting Committee Workshop Evaluation Distributed Generation CEQA and Permit Streamlining, San Francisco, CA April 20, 2000.	CO_2	980-1100	lb/MWh
Bluestein, J. Environmental Benefits of Distributed Generation. Energy and Environmental Analysis, Inc. December 18, 2000.	CO_2	1099	lb/MWh

Bluestein, J. Environmental Benefits of Distributed Generation. Energy and Environmental Analysis, Inc. December 18, 2000.	CO_2	1099	lb/MWh
Lents, J. and Allison, J. E. Can We Have Our Cake and Eat It, Too? Creating Distributed Generation Technology to Improve Air Quality. Work performed by University of California, Riverside. San Francisco, CA: The Energy Foundation, December 1, 2000.	CO_2	0.97	lbs/kWh
Lents, J. and Allison, J. E. Can We Have Our Cake and Eat It, Too? Creating Distributed Generation Technology to Improve Air Quality. Work performed by University of California, Riverside. San Francisco, CA: The Energy Foundation, December 1, 2000.	NOx	0.0032	lbs/kWh
Assessment of Distributed Generation Technology Applications. Vienna, VA: Resource Dynamics Corporation, February 2001	NOx	0.7-42	g/kWh
Gregerson, Joan and Van Holde, David. The Heat Is On: What's Cookin' with Large DG. E-Source DE-15, The McGraw-Hill Companies, Inc. September 2001.	NOx	1.0	g/hp-h
Gregerson, Joan and Van Holde, David. The Heat Is On: What's Cookin' with Large DG. E-Source DE-15, The McGraw-Hill Companies, Inc. September 2001.	NOx	0.17	g/hp-h
Gregerson, Joan and Van Holde, David. The Heat Is On: What's Cookin' with Large DG. E-Source DE-15, The McGraw-Hill Companies, Inc. September 2001.	NOx	0.55-8.95	g/hp-h
Michael, J. Future Emission Regulations. Detroit Diesel Corporation	NOx	1.53	g/hp-hr
Honton, E. J. Environmental Challenges for New Generation. Resource Dynamics Corporation CEC-EPRI Workshop, October 28, 1999	NOx	0.0015-0.037	lb/kWh
Technology Characterization: Reciprocating Engines. Work performed by Energy Nexus Group for the Environmental Protection Agency, February 2002.	NOx	1.48	lb/MWh
Mirzakhalili, Ali. "Distributed Generation: Emissions and Regulation." Conference Presentation Enabling Demand Response and Distributed Generation. June 14-15, 2004.	NOx	2.2	lb/MWh
Technology Characterization: Reciprocating Engines. Work performed by Energy Nexus Group for the Environmental Protection Agency, February 2002.	NOx	2.95	lb/MWh

Mirzakhalili, Ali. "Distributed Generation: Emissions and Regulation." Conference Presentation Enabling Demand Response and Distributed Generation. June 14-15, 2004.	NOx	0.5	lb/MWh
Technology Characterization: Reciprocating Engines. Work performed by Energy Nexus Group for the Environmental Protection Agency, February 2002.	NOx	5.91	lb/MWh
Technology Characterization: Reciprocating Engines. Work performed by Energy Nexus Group for the Environmental Protection Agency, February 2002.	NOx	1.48	lb/MWh
Freeman, B. Emissions Testing and Certification Guidelines for Distributed Generators. Palo Alto, CA: EPRI Solutions, December 2000.	NOx	13-42	g/kWh
Freeman, B. Emissions Testing and Certification Guidelines for Distributed Generators. Palo Alto, CA: EPRI Solutions, December 2000.	NOx	0.7-2.7	g/kWh
Carter, Sheryl. Emissions from Distributed Generation California Energy Commission Siting Committee Workshop Evaluation Distributed Generation CEQA and Permit Streamlining, San Francisco, CA April 20, 2000.	NOx	0.3-6.0	lb/MWh
Office of Industrial Technologies. Review of Combined Heat and Power Technologies. October 1999	NOx	2.2-28	lb/MWh
Allison, J., Arragon, J., and Lents, Dr. James. Integrating Distributed Generation with Air Quality Needs. CE-CERT, University of California, Riverside, June 20, 2000.	NOx	0.00320	lb/kWh
Bluestein, J. Environmental Benefits of Distributed Generation. Energy and Environmental Analysis, Inc. December 18, 2000.	NOx	2.07	lb/MWh
Bluestein, J. Environmental Benefits of Distributed Generation. Energy and Environmental Analysis, Inc. December 18, 2000.	NOx	0.59	lb/MWh
Technology Characterization: Reciprocating Engines. Work performed by Energy Nexus Group for the Environmental Protection Agency, February 2002.	NOx	44.3	lb/MWh
Carter, Sheryl. Emissions from Distributed Generation California Energy Commission Siting Committee Workshop Evaluation Distributed Generation CEQA and Permit Streamlining, San Francisco, CA April 20, 2000.	NOx	18-53	lb/MWh

Michael, J. Future Emission Regulations. Detroit Diesel Corporation	NOx	1.53	g/hp-hr
Introduction to CHP Technologies	NOx	0.8	lb/MWh
Bluestein, J. Environmental Benefits of Distributed Generation Energy and Environmental Analysis, Inc. December 18, 2000.	SO_2	0.006	lb/MWh
Bluestein, J. Environmental Benefits of Distributed Generation Energy and Environmental Analysis, Inc. December 18, 2000.	SO_2	0.006	lb/MWh
Carter, Sheryl. Emissions from Distributed Generation California Energy Commission Siting Committee Workshop Evaluation Distributed Generation CEQA and Permit Streamlining, San Francisco, CA April 20, 2000.	SO_2	negl	lb/MWh
Lents, J. and Allison, J. E. Can We Have Our Cake and Eat It, Too? Creating Distributed Generation Technology to Improve Air Quality. Work performed by University of California, Riverside. San Francisco, CA: The Energy Foundation, December 1, 2000.	SO_2	1e-005	lbs/kWh
Carter, Sheryl. Emissions from Distributed Generation California Energy Commission Siting Committee Workshop Evaluation Distributed Generation CEQA and Permit Streamlining, San Francisco, CA April 20, 2000.	SO_2	negl	lb/MWh
Allison, J., Arragon, J., and Lents, Dr. James. Integrating Distributed Generation with Air Quality Needs. CE-CERT, University of California, Riverside, June 20, 2000.	SO_2	0.00001	lb/kWh
Lents, J. and Allison, J. E. Can We Have Our Cake and Eat It, Too? Creating Distributed Generation Technology to Improve Air Quality. Work performed by University of California, Riverside. San Francisco, CA: The Energy Foundation, December 1, 2000.	VOC	0.0017	lbs/kWh
Technology Characterization: Reciprocating Engines. Work performed by Energy Nexus Group for the Environmental Protection Agency, February 2002.	VOC	4.13	lb/MWh
Technology Characterization: Reciprocating Engines. Work performed by Energy Nexus Group for the Environmental Protection Agency, February 2002.	VOC	0.59	lb/MWh

Allison, J., Arragon, J., and Lents, Dr. James. Integrating Distributed Generation with Air Quality Needs. CE-CERT, University of California, Riverside, June 20, 2000.	VOC	0.00170	lb/kWh
Technology Characterization: Reciprocating Engines. Work performed by Energy Nexus Group for the Environmental Protection Agency, February 2002.	VOC	1.18	lb/MWh
Technology Characterization: Reciprocating Engines. Work performed by Energy Nexus Group for the Environmental Protection Agency, February 2002.	VOC	2.07	lb/MWh
Technology Characterization: Reciprocating Engines. Work performed by Energy Nexus Group for the Environmental Protection Agency, February 2002.	VOC	2.95	lb/MWh

Natural Gas Combined Cycle

Citation	Equipment specific note from reviewer	Air Emission	Air Emission Rates	Air Emission Rate Units
Bluestein, J. Environmental Benefits of Distributed Generation. Energy and Environmental Analysis, Inc. December 18, 2000.		10 micron particulates	0.04	lb/MWh
Carter, Sheryl. Emissions from Distributed Generation California Energy Commission Siting Committee Workshop Evaluation Distributed Generation CEQA and Permit Streamlining, San Francisco, CA April 20, 2000.		10 micron particulates	0.03-0.3	lb/MWh
Allison, J., Arragon, J., and Lents, Dr. James. Integrating Distributed Generation with Air Quality Needs. CE-CERT, University of California, Riverside, June 20, 2000.		2.5 micron particulates	0.00002	lb/kWh
Lents, J. and Allison, J. E. Can We Have Our Cake and Eat It, Too? Creating Distributed Generation Technology to Improve Air Quality. Work performed by University of California, Riverside. San Francisco, CA: The Energy Foundation, December 1, 2000.		2.5 micron particulates	2e-005	lbs/kWh
University of California. "The Four Es of DG Policy in California: Energy, Environment, Economics, and Education," Prepared for California Energy Commission, August 2003.		2.5 micron particulates	0.00002	lb/kWh
Lents, J. and Allison, J. E. Can We Have Our Cake and Eat It, Too? Creating Distributed Generation Technology to Improve Air Quality. Work performed by University of California, Riverside. San Francisco, CA: The Energy Foundation, December 1, 2000.		CO	0.00017	lbs/kWh

Allison, J., Arragon, J., and Lents, Dr. James. Integrating Distributed Generation with Air Quality Needs. CE-CERT, University of California, Riverside, June 20, 2000.		CO	0.00017	lb/kWh
Carter, Sheryl. Emissions from Distributed Generation California Energy Commission Siting Committee Workshop Evaluation Distributed Generation CEQA and Permit Streamlining, San Francisco, CA April 20, 2000.		CO	0.05-1.0	lb/MWh
University of California. "The Four Es of DG Policy in California: Energy, Environment, Economics, and Education," Prepared for California Energy Commission, August 2003.		CO	0.00017	lb/kWh
Allison, J., Arragon, J., and Lents, Dr. James. Integrating Distributed Generation with Air Quality Needs. CE-CERT, University of California, Riverside, June 20, 2000.		CO_2	0.62	lb/kWh
Carter, Sheryl. Emissions from Distributed Generation California Energy Commission Siting Committee Workshop Evaluation Distributed Generation CEQA and Permit Streamlining, San Francisco, CA April 20, 2000.		CO_2	700-830	lb/MWh
Bluestein, J. Environmental Benefits of Distributed Generation. Energy and Environmental Analysis, Inc. December 18, 2000.		CO_2	776	lb/MWh
University of California. "The Four Es of DG Policy in California: Energy, Environment, Economics, and Education," Prepared for California Energy Commission, August 2003.		CO_2	0.62	lb/kWh
Lents, J. and Allison, J. E. Can We Have Our Cake and Eat It, Too? Creating Distributed Generation Technology to Improve Air Quality. Work performed by University of California, Riverside. San Francisco, CA: The Energy Foundation, December 1, 2000.		CO_2	0.62	lbs/kWh
Gregerson, Joan and Van Holde, David. The Heat Is On: What's Cookin' with Large DG. E-Source DE-15, The McGraw-Hill Companies, Inc. September 2001.	Technology comparison	NOx	0.02	g/hp-h
Lents, J. and Allison, J. E. Can We Have Our Cake and Eat It, Too? Creating Distributed Generation Technology to Improve Air Quality. Work performed by University of California, Riverside. San Francisco, CA: The Energy Foundation, December 1, 2000.		NOx	0.00013	lbs/kWh
University of California. "The Four Es of DG Policy in California: Energy, Environment, Economics, and Education," Prepared for California Energy Commission, August 2003.		NOx	0.00013	lb/kWh
Bluestein, J. Environmental Benefits of Distributed Generation Energy and Environmental Analysis, Inc. December 18, 2000.		NOx	0.06	lb/MWh

Mirzakhalili, Ali. "Distributed Generation: Emissions and Regulation." Conference Presentation Enabling Demand Response and Distributed Generation. June 14-15, 2004.		NOx	0.1	lb/MWh
Allison, J., Arragon, J., and Lents, Dr. James. Integrating Distributed Generation with Air Quality Needs. CE-CERT, University of California, Riverside, June 20, 2000.		NOx	0.00013	lb/kWh
Carter, Sheryl. Emissions from Distributed Generation California Energy Commission Siting Committee Workshop Evaluation Distributed Generation CEQA and Permit Streamlining, San Francisco, CA April 20, 2000.		NOx	0.11-0.9	lb/MWh
Allison, J., Arragon, J., and Lents, Dr. James. Integrating Distributed Generation with Air Quality Needs. CE-CERT, University of California, Riverside, June 20, 2000.		SO_2	0.00002	lb/kWh
Bluestein, J. Environmental Benefits of Distributed Generation. Energy and Environmental Analysis, Inc. December 18, 2000.		SO_2	0.004	lb/MWh
University of California. "The Four Es of DG Policy in California: Energy, Environment, Economics, and Education," Prepared for California Energy Commission, August 2003.		SO_2	0.00002	lb/kWh
Carter, Sheryl. Emissions from Distributed Generation California Energy Commission Siting Committee Workshop Evaluation Distributed Generation CEQA and Permit Streamlining, San Francisco, CA April 20, 2000.		SO_2	negl	lb/MWh
Lents, J. and Allison, J. E. Can We Have Our Cake and Eat It, Too? Creating Distributed Generation Technology to Improve Air Quality. Work performed by University of California, Riverside. San Francisco, CA: The Energy Foundation, December 1, 2000.		SO_2	2e-005	lbs/kWh
University of California. "The Four Es of DG Policy in California: Energy, Environment, Economics, and Education," Prepared for California Energy Commission, August 2003.		VOC	0.00011	lb/kWh
Allison, J., Arragon, J., and Lents, Dr. James. Integrating Distributed Generation with Air Quality Needs. CE-CERT, University of California, Riverside, June 20, 2000.		VOC	0.00011	lb/kWh
Lents, J. and Allison, J. E. Can We Have Our Cake and Eat It, Too? Creating Distributed Generation Technology to Improve Air Quality. Work performed by University of California, Riverside. San Francisco, CA: The Energy Foundation, December 1, 2000.		VOC	0.00011	lbs/kWh

Natural Gas Simple Cycle (from E-Grid)

Plant Name	CO_2 (lbs/MWh)	SO_2 (lbs/MWh)	NOx (lbs/MWh)	Heat Rate (Btu/kWh)
ARCO - FEE "C"	920.68	0	1.17	7,951
ARCO - FEE "A"	867.22	0	1.11	7,489
ARCO - FEE "B"	841.75	0.02	0.94	7,269
BADGER CREEK LTD.	930.32	0	0.45	8,034
BEAR MOUNTAIN LTD.	956.37	0	0.47	8,259
BIOLA UNIVERSITY	1,064.45	0	1.71	9,192
CHALK CLIFF COGEN	965.36	0	0.47	8,336
CORONA COGEN	968.97	0.03	0.16	8,368
CROCKETT COGEN	849.45	0	0.13	7,336
DAI/OILDALE COGEN	812.76	0.02	0.39	7,019
DOME PROJECT	2,456.84	0.01	3.7	21,216
DOUBLE "C" LTD.	923.44	0	0.45	7,975
FOSTER-WHEELER MARTINEZ COGEN L.P.	930.61	0	0.98	8,036
GOAL LINE	950.79	0	0.46	8,211
HARBOR COGEN	1,471.34	0.04	0.71	12,706
HIGH SIERRA LTD.	925.14	0	0.45	7,989
KEARNY	2,374.89	0.1	3.66	19,818
KERN FRONT LTD.	866.1	0	0.42	7,479
KERN RIVER COGEN	1,326.16	0.04	1.48	11,452
LIVE OAK COGEN	989.08	0	0.48	8,541
MIDSET COGEN	824.24	0	1.03	7,118
MOJAVE COGEN	1,013.93	0.03	0.48	8,756
MUNICIPAL COGEN	1,116.94	0.03	1.87	9,646
NORTH ISLAND	3,225.34	0.34	4.58	25,252
NORTH ISLAND ENERGY FACILITY	919.53	0.03	0.44	7,941

NORTH MIDWAY	932.42	0	1.11	8,052
OILDALE COGEN	850.81	0	0.96	7,347
OROVILLE COGEN	1,116.72	0.03	0.55	9,644
OXNARD I	819.41	0.02	0.39	7,076
PITCHESS COGEN	923.97	0	0.44	7,979
SAINT AGNES HOSPITAL	972.3	0.03	1.45	8,396
SALINAS RIVER COGEN	1,471.28	0.04	1.61	12,705
SAN JOSE COGEN	912.61	0	1.17	7,881
SARGENT CANYON COGEN	1,438.79	0.04	1.57	12,425
SOLANO COGEN	877.77	0	1.31	7,580
SYCAMORE COGEN	806.54	0	0.9	6,965
UNION-TRIBUNE PUBLISHING CO.	994.11	0.01	1.6	8,571
WELPORT PROJECT	1,664.47	0	2.68	14,374
YUBA CITY COGEN	974.69	0	1.32	8,417

Appendix D

Data Sources for Equipment Weight and Shipping Distances

Appendix D: Data Sources for Equipment Weight and Shipping Distances

Following are data sources used to determine equipment weight and shipping distances. Equipment weight is used in the LCA to determine the quantity of materials (steel, primarily) that the power generating equipment are made of. Distances were used to determine the quantity of diesel and oil used to transport the equipment from the manufacturer to California.

Generator Manufacturing and Shipping Data

Good Site for Pricing Info

www.genpropower.com/guardian_home_standby_12kw.html

GENERAC Power Systems Inc

- Manufacturing Plants http://www.generac.com/corporate/facilities.asp
    - Waukesha, Wisconsin – Corporate Headquarters and Water-Cooled Genset Production
        - Hwy 59 & Hillside Road
          Waukesha, WI 53187
          (262) 544-4811
    - Eagle, Wisconsin – Metal Fabrication & Water-Cooled Genset Final Assembly
        - 211 Murphy drive
          Eagle, WI 53119
          (262) 544-4811
    - Whitewater, Wisconsin – Air-Cooled Engine & Generator Production
        - 757 Newcomb Road
          Whitewater, WI 53190
          (262) 473-5514
    - Maquoketa, Iowa – Large Genset Production
        - 104 Generac Drive
          Maquoketa, IA 52060
          (563) 652-9781
- Shipping Method
- Materials from which Generators are Constructed
    - Enclosure Material http://www.generac.com/PublicPDFs/0166950SBY.pdf
        - ASTM A569 Surface Critical Steel
        - Optional materials in stainless steel and aluminum
        - Polyurethane foam

- Types of Generators http://www.guardiangenerators.com/products/guardian.asp?NavID=1

  - Model 04389 http://www.guardiangenerators.com/PublicPDFs/GPlus080104.pdf
    - Rating 7kW
    - Fuel ~ Natural Gas/LP Vapor
    - 375 lb
    - 48″ x 24″ x 28-1/4″
    - Fuel Consumption (Natural Gas)
      - Half Load ~ 66 cu. ft/hr
      - Full Load ~ 119 cu. ft/hr
  - Model 04456 http://www.guardiangenerators.com/PublicPDFs/GPlus080104.pdf
    - Rating 12 kW
    - Fuel ~ Natural Gas/Liquid Propane Vapor
    - 470 lb
    - 48″ x 24″ x 28-1/4″
    - Fuel Consumption (Natural Gas)
      - Half Load ~ 152 cu. ft/hr
      - Full Load ~ 215 cu. ft/hr
  - Model 04390 http://www.guardiangenerators.com/PublicPDFs/GPlus080104.pdf
    - Rating 15 kW
    - Fuel ~ Natural Gas/LP Vapor
    - 487 lb
    - 48″ x 24″ x 28-1/4″
    - Fuel Consumption (Natural Gas)
      - Half Load ~ 156 cu. ft/hr
      - Full Load ~ 220 cu. ft/hr
  - Model 04725
    - Guardian 25 kW http://www.guardiangenerators.com/support/guardian25kw.asp
    - Rating 25 kW

        - Fuel ~ Natural Gas/LP Vapor
        - 1010 lb
        - 68″ x 30″ x 40″
        - Fuel Consumption (Natural Gas)
            - Full Load ~ 442 cu. ft/hr (12.5 m^3/hr)
    - Typical Shipping Method = Factory Drop-Ship Truck Freight

GE Generators

- Type http://www.gepower.com/prod_serv/products/recip_engines/en/downloads/ge_jenbacher_en.pdf
    - Gas reciprocating engines
    - Power Range = 0.25 MW to 3 MW
    - Capacity to run CHP
    - Can run on alternative fuels (e.g., landfill gas, biogas, etc.)
- Type 2 Gas Engine http://www.gepower.com/prod_serv/products/recip_engines/en/type2.htm
    - 300-500 kW Power Range
    - Dimensions
        - (ft) 13.1 (l) x 4.6 (w) x 6.6 (h)
        - (mm) 4000 (l) x 1400 (w) x 2000 (h)
        - Weight 4400 kg (9700 lb)
- Type 3 Gas Engine http://www.gepower.com/prod_serv/products/recip_engines/en/type3.htm
    - 600 to 1100 kW range
    - Dimensions J312 GS
        - (ft) 14.8 x 5.6 x 7.5
        - (mm) 4500 x 1700 x 2300
        - Weight 7800 kg (17196 lb)
    - Dimensions J316 GS
        - (ft) 16.7 x 5.6 x 7.5
        - (mm) 5100 x 1700 x 2300
        - Weight 8800 kg (19401 lb)

- Type 4 Gas Engine http://www.gepower.com/prod_serv/products/recip_engines/en/type4.htm
    - 1.5 MW range
    - Dimensions
        - (ft) 21 x 5.9 x 7.2
        - (mm) 6400 x 1800 x 2200
        - Weight 15,500 kg (34,172 lb)
- Type 6 Generators http://www.gepower.com/prod_serv/products/recip_engines/en/type6.htm
    - 1.7 to 3 MW range
    - Dimensions J612 GS
        - (ft) 24 x 8.2 x 9.2
        - (mm) 7300 x 2500 x 2800
        - Weight 14500 kg (31967 lb)
    - Dimensions J616 GS
        - (ft) 26.2 x 8.2 x 9.2
        - (mm) 8000 x 2500 x 2800
        - Weight 21400 kg (47179 lb)
    - Dimensions J620 GS
        - (ft) 26.2 x 8.2 x 9.2
        - (mm) 8000 x 2500 x 2800
        - Weight 27000 kg (59525 lb)

- Kohler Power Generation http://www.kohlerpowersystems.com/onsite/onsite_gas_all.html
    - COM 6 http://www.kohlerpowersystems.com/pdfs/g3002.pdf
        - Rating~6kW
        - Dimensions
            - Length (in) 28.5 x 38.79 x 29.23
            - Weight (lb) 425
        - Fuel ~ Natural or LP Gas

    - Cylinder Head Material
        - Aluminum
    - Piston type
        - Permanent mold Aluminum
    - Cylinder Block Material
        - Forged Steel/Stellite
- 35RZG http://www.kohlerpowersystems.com/pdfs/g4074.pdf
    - Rating ~ 35 kW
    - Fuel Natural or LP Gas
    - Dimensions
        - Wide Skid (in) 86.6 x 40.9 x 46.1
        - Narrow Skid (in) 86.6 x 34.0 x 46.1
        - Weight (lb) 1246
    - Main Bearings
        - Babbitt
    - Cylinder Head Material
        - Cast Iron
    - Piston type and Material
        - High Silicon Aluminum
    - Crankshaft Material
        - Nodular Iron
    - Valve (exhaust) Material
        - Forged Steel
- 50RZGB http://www.kohlerpowersystems.com/pdfs/g4083.pdf
    - Rating ~ 50 kW
    - Fuel ~ Natural or LP Gas
    - Dimensions
        - Wide Skid (in) 86.6 x 40.9 x 46.1
        - Narrow Skid (in) 86.6 x 34.0 x 46.1

        - Weight (lb) 1570
    - Main Bearings
        - Copper Lead
    - Cylinder Head Material
        - Cast Iron
    - Piston Type and Material
        - High Silicon Aluminum
    - Crankshaft Material
        - Nodular Iron
    - Valve (exhaust) material
        - Forged Steel
- 80RZG http://www.kohlerpowersystems.com/pdfs/g4078.pdf
    - Rating ~ 80 kW
    - Fuel ~ Natural or LP Gas
    - Dimensions
        - Wide Skid (in) 94.5 x 40.9 x 58.4
        - Narrow Skid (in) 94.5 x 34.1 x 58.4
        - Weight (lb) 2500
    - Main Bearings
        - Aluminum Lead Silicon Alloy
    - Cylinder Head and Material
        - Cast Iron
    - Piston Type and Material
        - Strutless Flat Top, Hyper eutectic Cast Aluminum
    - Crankshaft Material
        - Cast Nodular Undercut Rolled Fillet
    - Valve (Exhaust) Material
        - Int. -A193 Exh. Inconel
- 125RZG http://www.kohlerpowersystems.com/pdfs/g4081.pdf

- Rating ~ 125 kW
- Fuel ~ Natural or LP Gas
- Dimensions
  - Wide Skid (in) 94.5 x 40.9 x 58.4
  - Narrow Skid (in) 94.5 x 34.1 x 58.4
  - Weight (lb) 2500
- Main Bearings
  - Aluminum Lead Silicon Alloy
- Cylinder Head Material
  - Cast Iron
- Piston Type and Material
  - Strutless Flat Top, Hypereutectic Cast Aluminum
- Crankshaft Material
  - Cast Nodular Undercut, Rollet Fillet
- Valve (exhaust) Material
  - Int. –A193 Exh. Inconel

Bowers Power (Baldor Generators) http://www.bowerspower.com/industrial_natural_gas.htm

- GLC30 http://www.bowerspower.com/pdfs/GLC30.pdf
  - Rating ~ 30 kW
  - Fuel ~ Natural or LP Gas
  - Dimensions
    - (in) 44 x 78 x 42.5
    - Weight (lb) 2500
  - Cooling Fan
    - Cast Alloy Aluminum
  - Windings
    - 100% Copper
  - Insulation Type
    - Class H

- GLC 60 http://www.bowerspower.com/pdfs/GLC60.pdf
    - Rating ~ 60 kW
    - Fuel ~ Natural or LP Fuel
    - Dimensions
        - (in) 44.0 x 88.0 x 50.5
        - (lb) 3500
    - Cooling Fan
        - Cast Alloy Aluminum
    - Windings
        - 100% Copper
    - Insulation Type
        - Class H
- GLC125 http://www.bowerspower.com/pdfs/GLC125.pdf
    - Rating ~ 125 kW
    - Fuel ~ Natural or LP Gas
    - Dimensions
        - (in) 44.0 x 88.0 x 57.0
        - (lb) 4000
    - Cooling Fan
        - Cast Alloy Aluminum
    - Windings
        - 100% Copper
    - Insulation Type
        - Class H

Typical Transformer Weights http://www.knovel.com/knovel2/Toc.jsp?BookID=660

- Table 12.1.1

12.1.1 Typical Transformer Weights (lb) by kVA

TABLE 12.1.1

Oil Filled 3 Phase 5/15 KV To 480/277			
kVA	Lbs.	kVA	Lbs.
150	1800	1000	6200
300	2900	1500	8400
500	4700	2000	9700
750	5300	3000	15000
Dry 240/480 To 120/240 Volt			
1 Phase		3 Phase	
kVA	Lbs.	kVA	Lbs.
1	23	3	90
2	36	6	135
3	59	9	170
5	73	15	220
7.5	131	30	310
10	149	45	400
15	205	75	600
25	255	112.5	950
37.5	295	150	1140
50	340	225	1575
75	550	300	1870
100	670	500	2850
167	900	750	4300

Source: Electrical Construction Databook. 2002. McGraw-Hill.