Pacific Northwest National Laboratory

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Life Cycle Assessment of Buildings Technologies: High-Efficiency Commercial Lighting and Residential Water Heaters

S. L. Freeman

January 1997

MASTER

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Executive Summary

In this study the life cycle emissions and energy use are estimated for two types of energy technologies. The first technology evaluated is the sulfur lamp, a high-efficiency lighting system under development by the U.S. Department of Energy (DOE) and Fusion Lighting, the inventor of the technology. The sulfur lamp is compared with conventional metal halide high-intensity discharge lighting systems. The second technology comparison is between standard-efficiency and high-efficiency gas and electric water heaters. In both cases the life cycle energy use and emissions are presented for the production of an equivalent level of service by each of the technologies.

For both analyses, the energy use and emissions from the operation of the equipment are found to dominate the life cycle profile. This result is generally expected for energy technologies. For some emissions categories the emissions related to material use in the manufacture of the equipment are significant relative to emissions related to energy use. The primary example is mercury, which is used in conventional light manufacture. While mercury emissions from power production are not insignificant, the difference in life cycle emissions between the metal halide and sulfur lamp is greater for solid mercury, which is not used in the sulfur lamp, than for air emissions of mercury. The sulfur lamp is also more efficient than the metal halide lamp, and the emissions of most other pollutants are proportional to energy consumption.

The life cycle emissions for the water heating systems are much more complicated. The four systems compared include standard- and high-efficiency gas water heaters, standard electric resistance water heaters, and heat pump water heaters. As expected, the standard water heaters generally have higher emissions than the high-efficiency water heaters. For most emission categories, however, the standard gas water heater is superior to the heat pump water heater. For example emissions of the criteria pollutants SO_x , NO_x , and lead, as well as total criteria pollutant emissions, are greater for heat pump water heaters than for standard gas water heaters. This example illustrates that while on a direct btu input/btu output basis one technology may be far superior to another, it might not be superior from the environmental life cycle perspective.

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Contents

Executive Summary	iii
Acknowledgments	v
1.0 Introduction	1.1
2.0 Fuel Cycle Model	2.1
2.1 Coal	2.1
2.2 Petroleum	2.2
2.3 Natural Gas	2.2
2.4 Power Generation	2.3
2.5 Integrated Fuel Cycle Model	2.4
3.0 Sulfur Lamp Analysis	3.1
3.1 Assessment of Material and Process Energy Use and Emissions	3.1
3.1.1 Energy Use	3.2
3.1.2 Emissions	3.2
3.2 Life Cycle Emissions Estimates - Denver Post Office Sorting Facility	3.4
4.0 Water Heater Assessment	4.1
4.1 Water Heating Scenarios	4.1
4.2 Water Heater Material Use	4.1
4.3 Life Cycle Energy Use	4.3
4.4 Life Cycle Emissions	4.4
4.4.1 Criteria Pollutant Emissions	4.4
4.4.2 Greenhouse Gas Emissions	4.4
4.4.3 Solid Wastes Emissions	4.5

4.4.4 Waterborne Wastes	4.6
4.4.5 Toxics, Carcinogens, and Hazardous Wastes	4.6
5.0 Conclusions	5.1
6.0 References	6.1
Appendix A - Emission Inventories	A.1

Figures

2.1 Coal Production	2.1
2.2 Petroleum Fuels Production	2.2
2.3 Natural Gas Production	2.3

Tables

3.1 Materials Use in a 400-Watt Metal Halide System	3.2
3.2 Energy Use in the Manufacture of Common Lighting Technology Materials	3.2
3.3 Denver Post Office Design Options	3.4
4.1 Water Heater Models	4.2
4.2 Water Heater Energy Use to Provide 100 Million btu of Hot Water	4.3
4.3 Criteria Pollutant Emissions	4.5
4.4 Greenhouse Gas Emissions	4.5
4.5 Solid Waste Emissions	4.6
4.6 Waterborne Emissions	4.7
4.7 Toxic, Carcinogen, and Hazardous Waste Emissions	4.8
A.1 Power Generation Fuel Cycle Emissions Inventory	A.3
A.2 Fossil Fuel Cycle Emissions Inventories	A.5
A.3 Lighting Technology Life Cycle Inventories	A.7
A.4 Water Heater Scenario Life Cycle Inventories	A.9

1.0 Introduction

In order to fully understand the costs and benefits of new or emerging energy technologies, it is useful to look beyond simple estimates of steady-state or annual efficiency or performance. Direct energy consumption in the operation of the equipment and emissions resulting from this energy consumption are only a small part of the impact of operating an energy system. Associated with this energy consumption is additional energy use to extract, process, and transport raw fuels, and the process- and energy-related emissions associated with these activities (referred to as pre-combustion emissions and energy use). In addition, the production and disposal of the products themselves have associated energy and environmental costs. One technique for evaluating these costs and benefits is life cycle analysis (LCA).

LCA attempts to expand the boundaries of product system analysis to include all significant impacts associated with a product or process from cradle to grave. For energy technologies this includes evaluating in detail the major fuel cycles such as coal, oil, natural gas, and power generation, from resource extraction through to byproduct or residue disposal. The energy and environmental impacts of materials used in energy technologies are often much smaller than the impacts associated with fuel cycle energy consumption; nonetheless, it is usually necessary to evaluate these factors to determine which aspects of the product life cycle can be excluded from the boundaries of the study.

The first technology evaluation in this study is a comparison of a new lighting technology, the sulfur lamp, with a conventional metal halide high-intensity discharge lighting system. The sulfur lamp consists of a bulb and microwave generator. Light from the sulfur bulb is created by heating sulfur and an inert gas in a clear glass bulb using the microwave generator. Light from the bulb is focused by a reflector into a hollow plastic "light pipe," some of which is transmitted through the pipe walls over the length of the pipe. In the current stage of development the sulfur lamp is already about as efficient as some of the most efficient conventional systems. It also offers distinct advantages in light quality and maintenance costs over conventional lamps.

The second technology evaluation is a comparison of high-efficiency gas and electric residential water heaters. The current state-of-the-art water heaters include condensing gas water heaters and heat pump water heaters. Condensing gas water heaters have steady-state thermal efficiencies in the range of 95%, and annual efficiencies of around 86%.^(a) Residential heat pump water heater performance is measured by the coefficient of performance (COP), with current technology reaching steady-state COPs of about 3.0 (equivalent to a thermal efficiency of 300%). Annual performance is about COP of 2.6. Because of the energy losses associated with electricity generation, however, from a life cycle perspective it is not clear which system has greater impacts per unit of service delivered.

(a) Annual efficiency, measured as the energy factor (EF) for residual equipment, accounts for heat loss from stored hot water when the heater is in standby mode.

2.0 Fuel Cycle Model

The primary source of emissions and resource use estimates for this study is a detailed fuel cycle model developed at Pacific Northwest National Laboratory (PNNL), which characterizes both direct emissions and energy use for power generation, as well as upstream emissions and energy use in the extraction, processing, and transportation of fuels. The upstream fuel cycles which are modeled explicitly are coal, petroleum, and natural gas. The model includes detailed estimates of process energy use and emissions associated with the production of one unit of each of these fossil fuels. The model also includes gross estimates of the energy use and emissions associated with uranium extraction and processing. The individual fuel cycle modules are integrated with a power plant emissions model to estimate the total fuel cycle emissions and energy use associated with the production of one unit of electric power.

2.1 Coal

The coal fuel cycle includes segments characterizing surface mining, underground mining, and coal transportation. A flow diagram of the coal production process is presented in Figure 2.1 with some of the most important input and output streams.

The most important emissions categories for coal production include particulate emissions from surface mining and transportation, acid leachate from coal mine tailings, and methane emissions. There are also a wide variety of emissions associated with fuel use in coal production, primarily in mining and transportation equipment. On the basis of energy use per unit fuel energy produced, the coal mining sector is one of the most efficient, requiring only 2 btu per 100 btu of coal produced. The primary fuels used in coal mining are petroleum products, which account for more than 80% of direct fuel use. Electricity is also a major energy source in coal production.

Figure 2.1. Coal Production

2.2 Petroleum

The petroleum fuel cycle includes segments characterizing crude oil extraction, crude oil transport and storage, petroleum refining, and petroleum products transportation and storage. A flow diagram of the petroleum production process is presented in Figure 2.2 with some of the most important input and output streams.

Figure 2.2. Petroleum Fuels Production

Crude oil is produced both from oil wells and from wells producing both oil and natural gas. In the fuel cycle model, fuel consumption and emissions from coproducing wells are allocated between the natural gas and oil produced. Crude oil is processed into a wide variety of petroleum products. Though each refinery product requires distinct processing operations, and hence has distinct energy requirements and emissions, insufficient information is available to accurately characterize each of these products. Instead, energy use and emissions are allocated between refinery products on a volumetric basis. Where possible, emissions from processes associated with highly refined specialty products are excluded from the inventory. In this way some attempt is made to tailor the inventory towards fuel oils and gasoline, the primary fuels of interest.

The petroleum production process is characterized by an extremely wide variety of emissions categories including several types of organic and other compounds, some of which are considered carcinogens or hazardous wastes. The petroleum production process is also very energy intensive, requiring more than 16 btu for every 100 btu of energy product output. Combustion-related emissions are thus an important contributor to the petroleum fuel cycle emissions inventory. The primary fuels used in petroleum production are petroleum derived fuels (57%) and natural gas (30%).

2.3 Natural Gas

The natural gas fuel cycle includes segments characterizing natural gas extraction; sweetening and dehydration; raw gas transportation; natural gas processing; and finished gas transportation, distribution, and storage. A flow diagram of the natural gas production process is presented in Figure 2.3 with some of the most important input and output streams.

Figure 2.3. Natural Gas Production

Natural gas is extracted both from natural gas wells and from wells producing both oil and natural gas. In the fuel cycle model, fuel consumption and emissions from coproducing wells are allocated between the natural gas and oil produced. After separation of gas and oil, raw natural gas is processed to remove water, hydrogen sulfide, carbon dioxide, and other non-methane hydrocarbon fuels. These processing operations may occur at different stages in the process depending on the quality of the raw gas. For purposes of simplicity, sweetening and dehydration (sulfur and water removal) and natural gas processing (carbon dioxide and non-methane hydrocarbon removal) are treated as separate distinct processes. The transportation of raw natural gas, as well as transportation and distribution of refined natural gas, are also treated as distinct processes though several separate transportation stages may be included in the actual process.

Some of the major emissions categories in the natural gas production process are methane, non-methane organic compounds, and water coproduced in natural gas wells. Natural gas processing operations include the use of several types of internal combustion drilling equipment and compressors, some of which have very high emission factors for pollutants such as carbon monoxide and nitrogen oxides. Overall the production of natural gas requires about 9 btu for every 100 btu of finished natural gas produced. Natural gas supplies about 95% of the fuel used in natural gas production.

2.4 Power Generation

The direct emissions from electricity generation are estimated using a model which relates fuel- and technology-specific emissions factors to the performance and characteristics of existing large utility boilers in the United States (Freeman 1996). The model relies primarily on a database of plant level characteristics of large fossil-steam utility power plants, developed by the Edison Electric Institute (EEI) (EEI 1995). Power plant energy use, fuel quality, operating characteristics, and control technology characteristics are mapped to emission factors and control efficiencies to estimate controlled emissions of the pollutants SO_x , NO_x , CO , CO_2 , particulate, PM_{10} , methane, and non-methane organic compounds. The emission factors are derived primarily from data developed by the U.S. Environmental Protection Agency (EPA) (EPA 1995a). Emission intensities are then estimated on a regional basis by dividing emissions by the net generation from coal, gas, and oil steam power plants, plus generation from nuclear and hydroelectric plants. Together these facilities account for nearly 90% of total electricity generation in the United States.

The EEI database also has information on the production and disposal of waste byproducts such as fly ash, bottom ash, boiler slag, and flue gas desulfurization byproducts. These data, as well as supplemental information on the nuclear fuel cycle (U.S. Department of Energy [DOE] 1993, 1995b, 1995c), are used to characterize direct solid waste from power generation.

2.5 Integrated Fuel Cycle Model

Each of the individual fuel cycles requires, as an input, fuels from other fuel cycles. Since each of these fuels themselves have associated emissions, the assessment of the total emissions associated with the consumption of one unit of fuel or power requires that the models be linked and solved iteratively. Total energy use must be estimated in the same fashion. Because of the complexity of the models it is useful to limit the iterative relationships to the primary fuels used in each fuel model. For example, the natural gas fuel cycle uses natural gas, petroleum, and electricity as the primary energy sources. Emissions associated with one unit of natural gas use are estimated from direct emissions from the production of natural gas, indirect emissions associated with the consumption of petroleum products, and indirect emissions associated with the consumption of electricity. Similarly the petroleum model is linked to natural gas and electricity, the coal model to petroleum and electricity, and the uranium model to petroleum.

The power generation model is also linked to each of the fuel cycle models (which completes the iterative loop). Pre-combustion emissions from the consumption of coal, oil, natural gas, and uranium are added to direct emissions. For the purposes of this study the national fuel mix was used. When all pre-combustion energy use is included, the primary energy mix for the production of electricity consists of 57% from coal, 23% from uranium, 10% from natural gas, 5% from petroleum, and 4% from hydroelectric plants, based on total btu of fuel input.

The resulting fuel cycle emissions inventory includes 29 categories of air emissions, 20 categories of solid wastes, and 16 categories of liquid wastes. The emissions factors are related to the consumption of one unit of fuel or energy (either btu for coal, oil, and natural gas or kWh for electricity). The integrated power generation inventory is presented in Appendix A, Table A.1. The individual fuel cycle inventories are presented in Table A.2.

3.0 Sulfur Lamp Analysis

The sulfur lamp analysis is based on a DOE-sponsored study of the estimated life cycle costs of various potential lighting systems for the Denver Post Office sorting facility (Richman and Jones 1996). In this study, lighting designs are developed for several conventional lamp systems as well as for the sulfur lamp. The designs are developed to provide equivalent lighting levels in the facility by each of the systems. Material, installation, and energy costs are then compared over a given lifetime to assess the relative costs of each of the systems.

Because the design parameters are well specified (i.e., number and types of lamps and fixtures, annual energy use, etc.), the full life cycle profile can be evaluated, including material-related emissions for the manufacture of the lamps, fixtures, and ballasts. Not included in the assessment are qualitative measures of performance, such as light quality. The comparative system used here, however, metal halides lamps, has roughly comparable light quality to the sulfur lamp. Hence the two systems can be considered to provide the same level and quality of service.

The performance parameters used in the DOE study reflect the development of the sulfur lamp at the time of the study. Because the sulfur lamp is a developing technology, the performance is expected to improve significantly over time. In fact, conversations with the authors of the DOE study resulted in a revision of the sulfur lamp performance for use in this assessment. In general, the results of this analysis present a worst-case assessment of the sulfur lamp technology.

The following section describes the evaluation of the emissions and energy use associated with the materials used in lamp, fixture, and ballast manufacture. Based on previous work for energy technologies, we generally assume that most impact categories (i.e., energy use and emissions) will be dominated by the energy used to operate the system over its life. For those categories of impacts for which material and process-related impacts are negligible, a detailed assessment of the relative impacts is not carried out.

3.1 Assessment of Material and Process Energy Use and Emissions

In order to assess the relative importance of emissions and energy use associated with the processing of materials used in the manufacture of lighting systems, it is necessary to first characterize the quantity of materials and life expectancy of the systems. This can be illustrated by looking at the metal halide system used in the Denver Post Office study (Richman and Jones 1996). The 400-watt metal halide lamp has an operating wattage of 460 watts, a lamp life of 20,000 hours, and a ballast life of 45,000 hours. To simplify the comparison of direct energy use over the life of the system with materials-related energy use, a 180,000-hour period is used (4 ballasts, one fixture, and 9 lamps). Typical weights of the components of this system were developed from dealer catalogs (Advance Transformer Co. 1995; Grainger 1992; National Electric Manufacturers Association [NEMA] 1994). The weights given are shipping weights, which overestimate actual material use. These are presented in Table 3.1. Thus for an 180,000-hour scenario the metal halide system will include 56 lbs of ballast, 29 lbs of fixture, and 5 lbs of lamp.

Table 3.1. Materials Use in a 400-Watt Metal Halide System

Component	Mass (lb)	Primary Materials
Lamps (9)	4.9	Glass, copper, lead, nickel
Ballasts (4)	56.0	Copper, aluminum, steel
Fixtures (1)	28.7	Aluminum, acrylic finish

3.1.1 Energy Use

The energy use associated with producing the materials for the metal halide lamp can be roughly estimated from industry and other data on energy use and productivity for the industrial sector (American Iron and Steel Institute [AISI] 1995; Aluminum Association 1991; Babcock et al. 1988; DOE 1994). Table 3.2 presents energy use estimates for some typical commodities. The estimates for steel and copper only include the energy used to produce crude materials, as they are based on energy use in facilities classified as primarily producing blast furnace and steel mill products, and primary copper smelting products. This is suitable for making a first order approximation of energy use. Using rough assumptions about the fractions of each of these materials in each component, the embodied energy use is estimated. Note that the most important assumption is the fraction of aluminum, since the other materials have similar energy intensity estimates.

Table 3.2. Energy Use in the Manufacture of Common Lighting Technology Materials

Commodity	Energy Intensity (Btu/lb)	Notes
Raw Steel	7,466	Production of raw steel only
Aluminum	76,093	Includes smelting, holding and casting, and mill products energy use
Copper	8,876	Primary copper refining
Glass	8,845	Blown glass production

The resulting embodied energy estimate is 1.9 million btu for the system. Over the course of its 180,000-hour life the system will directly consume 82,800 kWh. The primary energy needed to produce this electricity (from the electricity fuel cycle model) is 821 million Btu. Thus the embodied energy of the system is only 0.23% of the direct energy use over the life of the system, which is negligible. The results are similar for the other conventional lamp systems included in the Denver Post Office study.

3.1.2 Emissions

A similar exercise can be carried out to assess materials-production-related emissions. For many pollutant categories (e.g., SO_x, NO_x, etc.), emissions related to the combustion of fuels used to manufacture

and operate the lamps will typically dominate the total emissions profile. In this case the material-related emissions will be roughly proportional to energy use to manufacture the materials and, hence, can be assessed purely on the basis of the relative importance of embodied energy use. Alternatively, process emissions intensities can be estimated and compared with emissions related to direct consumption of electricity in the lamps.

The EPA publishes both aggregate industry estimates of emissions of some pollutants (EPA 1995b) and process-specific emission factors for the glass, aluminum, copper, and steel industries (EPA 1995a). These data can be used to estimate emissions intensities for the materials and, employing the same materials use data presented in Table 3.1, total life cycle emissions estimates for comparison with emissions from the consumption of electricity. As with energy use, the emissions from materials production are typically much smaller than the emissions related to electricity consumption. For example, for the metal halide light system illustrated above, the emissions of NO_x, SO_x, CO, and organic compounds are less than 1% of the direct emissions related to the use of electricity in the lamp.

Some materials-production-related emissions are not small with respect to electricity-related emissions, however. Lead is used in the manufacture of metal halide lamps and becomes a solid waste when the lamps are discarded. These solid emissions are far greater than the power generation emissions of lead to the air, though potentially easier to control through recovery and recycling. Air emissions of lead from materials processing (especially copper and lead production) are also non-negligible. Mercury is also a constituent of all of the conventional lamp systems, and hence appears as a solid waste from conventional systems.

Because the sulfur lamp is a developing technology it is more difficult to precisely characterize the material inputs to the lamp. The 1,000-watt sulfur lamp (1,350 operating watts) components include the lamp module (13.2 lb), the power supply (48.5 lb), and light pipes (64 feet per lamp at 3 lb/lineal foot) (Richman and Jones 1996). The lamp system life is estimated at 45,000 hours while the filter and magnetron have a lifetime of 15,000 hours (Fusion Lighting 1996). Since the sulfur lamp mass-per-kilowatt hour lifetime energy use is similar to that for the metal halide lamp, it can be assumed that the materials-related emissions and energy use are also small with respect to lifetime electricity-related emissions for most pollutants. Also, the sulfur lamp contains no mercury, so mercury-related emissions can be well characterized for both systems.

Life cycle lead emissions are neither negligible, nor easy to quantify. Lead emissions to air are associated with copper, zinc, lead, steel, and iron production, as well as with the mining of some of these metals. Lead emission factors are also different for primary and secondary metals production for the lead and copper industries. An accurate assessment of the life cycle lead emissions associated with lamp manufacture would require a precise characterization of the mass of each of the lamp materials, as well as assumptions about the source of the materials in the components (i.e., primary or secondary manufacture). For complex components such as ballasts, this would be difficult even for conventional lighting technologies. Characterizing a developing technology such as the sulfur lamp, would be even more difficult. For this reason, characterization of life cycle lead emissions is considered beyond the scope of the current effort.

The following section discusses the life cycle inventories for the remaining emission categories.

3.2 Life Cycle Emissions Estimates - Denver Post Office Sorting Facility

The Denver Post Office life cycle cost comparison is used to evaluate relative life cycle emissions from the sulfur lamp and a conventional metal halide system. Annual energy use was estimated for each of the various lamp types used in the study. Energy use for the sulfur lamp was updated from the original estimates in the study to account for improvements in the sulfur lamp performance.^(a) Some of the basic parameters of the systems are presented in Table 3.3.

Table 3.3. Denver Post Office Design Options

Type	Number of Systems	Operating Watts	Annual Energy Use (kWh)
1,000-Watt Sulfur Lamp	24	32,400	255,442
400-Watt High Pressure Sodium Lamp	66	30,096	268,844
400-Watt Metal Halide Lamp	93	42,780	374,753
2-Lamp, 8-Foot Standard Fluorescent with Energy Efficient Ballasts	233	37,280	326,573
2-Lamp, 8-Foot High Output Fluorescent with Electronic Ballasts	233	31,222	273,505
2-Lamp, 8-Foot Standard Fluorescent with Energy Efficient Ballasts	169	40,053	350,864
2-Lamp, 8-Foot High Output Fluorescent with Electronic Ballasts	169	32,110	281,284

The life cycle assessment of emissions from the metal halide and sulfur lamp systems is carried out on an annual basis using the annual electricity use for each lamp system multiplied by the fuel cycle emissions factor per unit of electricity produced. This inventory is modified to account for solid mercury wastes from

- (a) The original study (Richman and Jones 1996) assumed a sulfur lamp efficacy of 95 lumens per watt. The current performance is estimated at 105 lumens per watt. Annual energy use was scaled by the ratio of efficacy (95/105) to estimate the reduction in energy use that would have occurred had the higher efficacy value been used in the study.

the metal halide lamps. The full inventory is presented in Appendix A, Table A.3 for the metal halide and sulfur lamp systems along with the difference in annual emissions.

For some impact categories, life cycle emissions are dominated by emissions from fuel combustion in power plants. These include CO₂, SO_x, and NO_x. For other impact categories emissions associated with extraction and processing of fuels consumed in the powerplants are significant, including CO, particulate, organic compounds, and methane. A wide variety of additional emissions categories are exclusively related to these fuel extraction and processing activities. With the exception of mercury emissions, the metal halide and sulfur lamp emissions are proportional to electricity use (i.e., the emissions are estimated entirely on the basis of electricity consumption in the lamps and an emission factor per unit electricity consumption). As noted above, however, these emissions are significantly greater than power plant emissions from fuel combustion for most of the emissions categories.

4.0 Water Heater Assessment

The water heater life cycle assessment provides an interesting comparison of currently available technologies for meeting residential water heating needs. Water heating can be provided by a wide variety of technologies, with varying efficiencies and fuel types. While the direct environmental costs and benefits associated with any particular option can be evaluated fairly easily, the life cycle environmental costs and benefits are unclear without a thorough evaluation of fuel cycle emissions and energy use. The scenarios described below provide some basis for comparing the relative merits of the various systems.

4.1 Water Heating Scenarios

The water heating scenarios describe the equipment and direct energy requirements for four typical residential systems that are currently available. Based on these characteristics the input requirements necessary to provide 100 million btu of hot water are estimated. The four scenarios include standard- and high-efficiency gas water heaters, a standard electric resistance water heater, and a heat pump water heater. While the specific units chosen to represent each of these technologies do not provide the same levels of service (i.e., they have slightly different recovery rates and storage capabilities), because the scenarios are based on an equivalent output of hot water, the scenarios have been normalized to an equivalent basis. The characteristics of the water heater models used in this analysis are presented in Table 4.1.

4.2 Water Heater Material Use

The potential contribution of the embodied energy used in the manufacture of the water heater to the life cycle energy use and emissions can be assessed roughly by making some assumptions about the materials used in water heaters. For storage water heaters the main components are the burner, tank, insulation, and shell. For standard water heaters the tank is made of steel plate that is coated on the inside with a ceramic glaze to prevent corrosion. The condensing gas model used in this analysis has a stainless steel tank. The tank shells are also typically made of thin steel sheet.

Since the primary material used appears to be steel, the embodied energy can be approximated by multiplying the total water heater weight by the energy intensity of steel manufacture. According to AISI the steel industry consumed 1,567 trillion btu of energy in 1995 and produced 104,930 thousand short tons of raw steel (AISI 1996) or an energy intensity of 7,466 btu/lb. Other common manufacturing materials have similar energy intensities (e.g., glass and copper) (see Table 3.2).

Thus if the embodied energy of the water heater is estimated as the energy content of raw steel of the weight of the water heater, for the gas and electric resistance water heaters in Table 4.1, the embodied energy is estimated at between 1.4 and 2.0 million btu. This can be compared to the lifetime energy

Table 4.1. Water Heater Models

	Manufacturer			
	American ^(a)	Rheem ^(b)	Lochinvar ^(c)	E-Tech ^(d)
Fuel Type	Gas	Gas	Electric	Electric
Equipment Type	Condensing	Standard	Resistance	Heat Pump
Storage Volume (Gallons)	50	50	80	52
Energy Input Rate (kBtu or Kw)	100	98	9	0.5
Weight (lb)	190	268	192	-
Recovery (Gallons/hour)	161	140	81	46
Standby Loss Rate (%)	0.97	2.98	0.29	
Thermal Efficiency (%)	94	80	98	-
Energy Factor	0.86	0.60	0.92	2.60
Lifetime (Years)	10	10	12	12
(a) Data from manufacturer literature (American Water Heater 1994) and the California Energy Commission (CEC 1993). (b) Data from manufacturer literature (Rheem Manufacturing Co. 1992) and the California Energy Commission (CEC 1993). (c) Data from manufacturer literature (Lochinvar 1994) and the California Energy Commission (CEC 1993). (d) The performance of the heat pump water heater is taken from a technology characterization performed by ADL for the DOE (ADL 1995) and from a report by E-Source (Nisson and Shepard 1994).				

consumption of these water heaters of more than 400 million btu of primary energy (assuming a capacity factor of 5%).^(a) Thus the embodied energy using this crude method is less than one half of one percent of the total energy use over the life of the water heater.

While this estimate is fairly rough, even if total embodied energy were two to three times greater, the embodied energy would only represent on the order of 1% of the total life cycle energy use. The

(a) Capacity factor is a measure of the level of service required of a piece of equipment relative to the potential service that would be delivered if the equipment were operated at full capacity. For water heaters this can be calculated as the annual energy use divided by the product of rated energy use input per hour and the number of hours in a year. Residential water heaters typically have very low capacity factors. The value used here is considered conservative.

differential embodied energy use between water heater systems would be even smaller. Combustion-dominated emissions categories would also be negligibly impacted by emissions from material use. Thus the differences in embodied energy and emissions will be assumed negligible in the comparison of the water heater technologies.^(a)

4.3 Life Cycle Energy Use

The energy use for the comparative scenarios is estimated as the energy required to provide 100 million btu of hot water using each of the respective technologies. The direct energy use is estimated simply by dividing 100 million btu by the energy factor, which represents the btu of useful hot water output per btu input over the course of a year. The total energy use is then estimated by multiplying the direct energy use by the fuel cycle energy use required to produce 1 unit of fuel. For the electric water heaters the direct energy use must be converted to kwh. Since the fuel cycle energy use estimates are given in terms of primary energy by fuel type, a detailed estimate of primary fuels can be made. These are presented for the four scenarios in Table 4.2.

Table 4.2. Water Heater Energy Use to Provide 100 Million btu of Hot Water (million btu)

Fuel	Gas Condensing	Gas Standard	Electric Resistance	Electric Heat Pump
Natural Gas	125.71	180.18	32.59	11.53
Coal	0.52	0.75	187.96	66.51
Petroleum	0.27	0.39	17.70	6.26
Uranium	0.21	0.30	76.15	26.94
Hydro potential	0.04	0.06	14.36	5.08
Total	126.76	181.99	328.76	116.33

From these results it can be seen that natural gas is the primary fuel used in the production of natural gas. Small quantities of hydroelectric and uranium energy use are associated with electricity use in natural gas production. For electric water heaters the primary fuels are more evenly distributed among fuel types. Coal is the dominant fuel source, accounting for about 57% of the total energy input.

(a) Heat pump water heaters have additional associated emissions of refrigerants, which are greenhouse gases. This category is discussed further in Appendix A.

In terms of overall energy use, the heat pump is the least energy intensive. A small proportion of the energy use (4.4%) is also from hydroelectric power, a renewable energy source. The gas condensing water heater requires about 9% more energy than the heat pump, while the standard gas water heater requires 56% more. Finally the electric resistance water heater requires 2.83 times as much energy, which is simply the ratio of the energy factors of the two technologies (2.6/0.92).^(a)

4.4 Life Cycle Emissions

The life cycle emissions for the four water heater technologies are a function of both fuel use and fuel type. For the gas water heaters, emissions include both emissions from the combustion of natural gas in the water heaters, as well as emissions from the extraction and processing of natural gas. For the electric water heaters emissions include power plant emissions from fuel combustion as well as emissions from the extraction and processing of fuels consumed in the power plants. Because of the wide variety of pollutants involved it is useful to group individual pollutants into categories. Emissions from each of these categories are discussed below. The complete emissions inventories are presented in Appendix A, Table A.4.

4.4.1 Criteria Pollutant Emissions

Criteria pollutant emissions are dominated by emissions of NO_x and SO_x . Total criteria pollutant emissions are much greater for the electric technologies than for the gas technologies, primarily due to the heavy use of coal in power generation. Emissions of NO_x and SO_x are higher for coal combustion than for natural gas combustion even with the use of emissions control devices. Emissions of particulate and lead are also higher for the electric technologies. Total emissions of criteria pollutants for the delivery of 100 million btus of hot water are presented in Table 4.3. While the gas technologies have lower overall emissions of criteria pollutants, the heat pump water heater has lower emissions than both gas technologies for the pollutants CO , PM_{10} , and non-methane organic compounds. The higher levels of organic compound emissions for the gas technologies are in part due to the natural gas dehydration process, which emits a class of organic compounds known as BTEX (benzene, toluene, ethyl benzene, and xylene). BTEX emissions for the high-efficiency gas water heater are about a factor of 10 higher than BTEX emissions for the heat pump water heater.

4.4.2 Greenhouse Gas Emissions

The emissions of greenhouse gases are fairly similar between the high-efficiency gas and electric technologies, with the electric resistance water heater having much greater emissions than the other equipment types. While the high-efficiency gas water heater has somewhat smaller CO_2 emissions than the heat pump water heater, the heat pump water heater has methane emissions that are about a factor of two smaller than the high-efficiency gas water heater. Total emissions slightly favor the high efficiency gas

(a) The energy factor of 2.6 used for the heat pump water heater is adjusted to account for both a cooling credit and a heating debit, which is necessary because the heat pump draws energy from the conditioned space.

Table 4.3. Criteria Pollutant Emissions (lb)

Pollutant	Condensing Gas (EF = 0.86)	Standard Gas (EF = 0.60)	Standard Electric (EF = 0.92)	Heat Pump (EF = 2.60)
CO	8.75	12.6	10.0	3.55
Particulate	1.55	2.23	46.3	16.4
PM ₁₀	1.43	2.05	2.07	0.73
TNMOC ^(a)	5.27	7.55	3.95	1.40
Lead	5.47E-07	7.85E-07	1.94E-04	6.86E-05
NO _x	30.4	43.5	187	66.1
SO _x	2.88	4.13	340	120
Total	50.3	72.1	589	208
(a) TNMOC = total non-methane organic compounds. The EPA uses volatile organic compounds (VOCs) as its organic compound criteria pollutant measure. Because of questions regarding the precise definition of VOCs, as well as variability in emissions factor organic compound classifications, TNMOC is reported here.				

water heater over the heat pump water heater, even when the global warming potential of methane is accounted for (see EIA 1995 for discussion of global warming potential). The difference may not be significant, however. Greenhouse gas emissions are presented in Table 4.4.

Table 4.4. Greenhouse Gas Emissions (lb)

Pollutant	Condensing Gas (EF = 0.86)	Standard Gas (EF = 0.60)	Standard Electric (EF = 0.92)	Heat Pump (EF = 2.60)
CO ₂	14,951	21,429	45,602	16,136
Methane	76	109	102	36
Total	15,026	21,538	45,704	16,172

4.4.3 Solid Wastes Emissions

Solid waste emissions, in terms of total volume, are dominated by mining residues from coal and uranium production, and by fly ash, bottom ash, and flue gas desulfurization (FGD) sludge from power generation. As a result, the emissions from electric water heaters are generally 1 to 2 orders of magnitude higher than those for gas water heaters. These emissions are presented in Table 4.5. The emissions

Table 4.5. Solid Waste Emissions (lb)

Category	Condensing Gas (EF = 0.86)	Standard Gas (EF = 0.60)	Standard Electric (EF = 0.92)	Heat Pump (EF = 2.60)
Mining & Drilling Residues	30.4	43.5	4,237	1,499
Fly Ash	3.05	4.37	1,079	382
Bottom Ash	0.96	1.37	339	120
FGD Sludge	0.96	1.38	342	121

inventory also includes a wide variety of refinery-related solid residuals, many of which are toxic wastes or carcinogens, including species such as ammonia, cyclohexane, and BTEX emissions. These are discussed in later sections.

4.4.4 Waterborne Wastes

There are a wide variety of waterborne wastes associated with natural gas production, petroleum refining, and coal and uranium mining. On a btu basis, petroleum refining emissions are higher for many categories than for either coal or natural gas production. Because petroleum fuels provide only a small fraction of total energy to the natural gas and electric fuel cycles, however, the petroleum fuel cycle contribution to total emissions is generally small.

Overall the inefficiency of electricity production tends to magnify electric water heater emissions with respect to the natural gas-related emissions. Natural gas water heaters have the highest total waterborne emissions due to the co-production of water in natural gas wells, some of which is discharged to surface waters. Sulfuric acid and iron emissions from coal and uranium mining operations dominate the emissions categories in magnitude, and are highest for the electric water heaters.^(a) Comparing the two high-efficiency water heaters, the gas water heater has higher emissions in 5 categories while the heat pump water heater has higher emissions in 10 categories. Table 4.6 presents water emissions for each water heater.

4.4.5 Toxics, Carcinogens, and Hazardous Wastes

Many of the airborne, solid, and waterborne wastes are toxic, carcinogenic, or hazardous wastes. The emissions, regrouped into these three categories are presented in Table 4.7. The electric technologies generally have higher emissions in these categories; however, the heat pump water heater has slightly lower emissions of solid hazardous wastes and waterborne toxics than the high-efficiency gas water heater. Overall the gas water heaters have the lowest total carcinogen emissions.

(a) See discussion of uncertainty in sulfuric acid and iron emissions in Appendix A.

Table 4.6. Waterborne Emissions (lb)

Pollutant	Condensing Gas (EF = 0.86)	Standard Gas (EF = 0.60)	Standard Electric (EF = 0.92)	Heat Pump (EF = 2.60)
Discharged Water	.35.6	51.0	9.09	3.22
Dissolved Solids	24.8	35.6	12.49	4.42
Suspended Solids	1.12E-04	1.60E-04	3.96E-02	1.4E-02
Sulfuric Acid	0.10	0.15	36.4	12.9
Iron	9.21E-02	2.97E-04	32.6	11.5
BOD ^(a)	7.30E-05	1.05E-04	2.59E-02	9.15E-03
COD ^(b)	2.07E-04	2.97E-04	7.33E-02	2.59E-02
Phenol	1.85E-05	2.66E-05	6.57E-03	2.32E-03
Sulfide	1.85E-05	2.66E-05	6.57E-03	2.32E-03
Other Acids	3.71E-05	5.32E-05	1.31E-02	4.65E-03
Metals	1.85E-05	2.66E-05	6.57E-03	2.32E-03
Oil	732.E-05	1.05E-04	1.31E-02	4.65E-03
Ammonia	10.7E-05	1.53E-05	1.92E-05	6.81E-06
Methanol	2.07E-07	2.97E-07	3.73E-07	1.32E-07
Methyl Tertiary Butyl Ether	6.45E-07	9.25E-07	1.16E-06	4.11E-07
(a) BOD = Biochemical Oxygen Demand.				
(b) COD = Chemical Oxygen Demand.				

These results reveal that while heat pump water heaters are dramatically more efficient on an energy factor basis, the inefficiency of electricity generation leads to higher impacts from these water heaters than from high-efficiency, and in some cases standard gas water heaters, for many emission categories. In particular, heat pump water heaters have greater emissions of several criteria pollutants, solid wastes, and several types of toxic or carcinogenic wastes.

Table 4.7. Toxic, Carcinogen, and Hazardous Waste Emissions (lb)

Category	Condensing Gas (EF = 0.86)	Standard Gas (EF = 0.60)	Standard Electric (EF = 0.92)	Heat Pump (EF = 2.60)
Air Toxics	1.96E-04	2.81E-04	7.52E-03	2.66E-03
Air Carcinogens	4.26E-06	6.11E-06	1.64E-04	5.79E-05
Solid Carcinogens	3.97E-07	5.69E-07	1.25E-05	5.39E-06
Solid Hazardous	4.67E-04	6.69E-04	8.39E-04	2.97E-04
Water Carcinogens	1.58E-07	2.26E-07	2.83E-07	1.00E-07
Total Carcinogens	4.82E-06	6.90E-06	1.79E-04	6.34E-05

5.0 Conclusions

In this study, life cycle assessments of two different buildings technologies were conducted. The first assessment evaluates the relative impacts of two commercial lighting technologies: conventional metal halide lamps and the sulfur lamp, a new lighting technology under development by the DOE and Fusion Lighting. Life cycle emissions estimates are made, on an per annum basis, for comparative systems designed to illuminate the Denver Post Office sorting facility. The second assessment evaluates the relative impacts of four commercially available residential water heating systems: standard efficiency gas and electric resistance water heaters, condensing gas water heaters, and electric heat pump water heaters. The life cycle emissions estimates are developed for each system for the production of 100 million btu of hot water.

In both assessments, the contribution of materials-related emissions to the life cycle emissions profile is found to be negligible for most pollutants. This is an intuitive result for energy systems: the energy used over the life of the system, even at low utilization rates, is large relative to the embodied energy of the materials used in the system. Since combustion-related emissions are a primary contributor to emissions impacts, the same is true for life cycle emissions. For the lighting and water heating scenarios in this study, embodied energy use estimates are generally less than 1% of total energy use. Hence, even given the rough approximations used to develop these estimates, the impact of embodied energy use and emissions on the life cycle estimates is likely to be negligible.

For some emission categories, combustion-related emissions are not the dominant source. For example only about 1% of lead emissions in the United States are from electric utility combustion (compared to 70% of SO_x emissions), while the metals processing industries contribute about 38% of the total (EPA 1995b). Materials such as mercury and lead are also used in the manufacture of many types of lamps and, hence, appear as solid wastes from lamp disposal. In these cases an accurate assessment of materials-related emissions is necessary to precisely characterize the life cycle emissions profile. In the lighting technology assessments, materials-related emissions of mercury were included in the analysis. Because of the complexity in evaluating the life cycle lead emissions, they were considered beyond the scope of this project.

For the lighting scenarios, because the materials-related emissions are negligible, the life cycle emissions are proportional to electricity use for most pollutants. The sulfur lamp annual electricity use is estimated to be 32% less than for the metal halide system. The resulting estimates of emissions reductions are much larger, however, than simply the emissions reductions from reduced fuel consumption at the power plants. For example, only 61% of CO emissions and 30% of non-methane organic compound emissions are from fuel combustion at the powerplants. The balance of emissions are from the extraction and processing of fuels used in the powerplants. The annual emissions savings estimates for the sulfur lamp compared to the metal halide lamp include 171,000 lb of CO_2 , 1,300 lb of SO_x , and 700 lb of NO_x . Interestingly, the reductions in mercury emissions from combustion are significant relative to solid mercury emissions from lamp disposal. About 32% of the total mercury emission reduction for the sulfur lamp is due to airborne emissions related to coal-fired power production. If a significant fraction of conventional

lamps were recycled (and hence the mercury recovered), combustion-related mercury emissions could become the primary environmental impact for mercury. Current regulations allow the disposal of mercury-containing lamps to landfills, however, and industry estimates of the recovery rate for metal halide lamps are only on the order of 10%.^(a)

The results of the water heater assessments are much more complicated. As with the lighting technologies, the energy use and emissions from materials used in the water heaters are estimated to be negligible. Though from an on-site or delivered energy perspective the heat pump water heater is by far the most efficient (energy factor of 2.6 compared to 0.86 for the high-efficiency gas furnace, a factor of 3 difference), after the efficiency of electricity generation is considered, as well as fuel cycle energy use, the heat pump water heater uses only 8% less primary energy than the high-efficiency gas furnace. Since gas is a relatively clean burning fuel, for combustion-related emissions categories the high-efficiency gas furnace, and even in some cases the standard-efficiency gas furnace, has lower emissions than the heat pump water heater.

Examples of emissions categories for which the high-efficiency gas furnace has lower emissions than the heat pump water heater include total criteria pollutants, all categories of power plant solid wastes such as fly ash and flue gas desulfurization sludge, and airborne toxic and carcinogenic emissions. Criteria pollutant emissions are dominated by SO_x and NO_x, and are far larger for the heat pump water heater than for even the standard gas water heater. The heat pump water heater does have lower emissions of the criteria pollutants CO and non-methane organic compounds.

In the category of waterborne emissions, total emissions of liquid waste are lowest for the heat pump water heater. This is primarily the result of the co-production of water from natural gas wells, some of which is discharged to surface waters. Because of this co-produced water, the total liquid waste associated with natural gas consumption, and hence natural gas water heaters, is high. For the majority of waterborne pollutants, however, the high-efficiency gas water heater has the lowest emissions. The exceptions are trace emissions of the pollutants ammonia, methanol, and methyl tertiary butyl ether.

Neither technology has a clear advantage with regards to emissions of greenhouse gases. The heat pump water heater has higher emissions of carbon dioxide, but the high-efficiency gas water heater has more than double the emissions of methane. Total emissions slightly favor the high-efficiency gas water heater, even when the global warming potential of methane is considered, but the difference is probably not significant.

Overall, the results of the two assessments demonstrate the need to consider life cycle emissions when comparing energy technologies. Life cycle emissions estimates generally differ significantly in both magnitude and breadth from direct combustion-related emissions. Focusing only on direct emissions will result in the underestimation of impacts, and will neglect many of the secondary emission categories related to fuel production and processing. More importantly, when comparing technologies using different

(a) Personal communication with Mercury Recovery Services, Inc., Monrovia, California, October 11, 1996.

fuels, life cycle emissions estimates reveal trade-offs that would be obscured in a simple direct energy use comparison. As the water heater assessment demonstrates, high efficiency does not necessarily lead to superior environmental performance.

These factors can have important implications for policy decision making. Heat pump water heaters are generally viewed as desirable technologies, yet policies that promote them without regard for opportunities in gas water heating neglect the full spectrum of impacts. While gas is not necessarily available in all locations, other possible fuels such as propane may be viable (and environmentally beneficial) substitutes. A complete understanding of the full impacts of these technologies is necessary to adequately address these issues. For technologies such as electric vehicles, the issues are even more complex. Appropriate policy decisions can only be made with a full understanding of the life cycle environmental costs and benefits of the competing technologies.

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Appendix A

Emission Inventories

Appendix A

Emission Inventories

The fuel cycle model in this report was developed using a wide variety of publicly available information sources. Direct emissions from power plants were estimated using a PNNL-developed model that relates individual power plant characteristics with EPA-developed emission factors (EPA 1995a). The power plant characteristics are taken from a database developed by the Edison Electrical Institute (EEI 1995). Precombustion emissions data come primarily from reports sponsored by the EPA, or from various fuel sector associations such as the Gas Research Institute (GRI) and the American Petroleum Institute (API). Much of the energy use information was derived from either DOE or U.S. Department of Commerce publications.

Each of the estimates derived from these sources has associated uncertainty. In some cases the magnitude of this uncertainty can be easily quantified (e.g., by the precision of field instruments, or the standard errors associated with a particular survey question). In other cases uncertainty may only be expressed qualitatively, as is common with EPA emission factors (EPA 1995a). In many cases no assessment of uncertainty is available at all from the raw data sources. After applying allocation schemes and transformations, the assessment of the error associated with any given estimate is itself highly uncertain. In this study, no systematic attempt was made to assign error bands to the inventory estimates. Instead, multiple references were used to identify and discard questionable estimates. In addition, highly uncertain estimates were noted. These are discussed below.

Some of the most important, yet difficult to estimate, fuel cycle emissions are associated with coal mining. Particulate emissions from surface mines and associated roads are large relative to other sources (such as combustion sources) but are rarely expressed as net emissions per ton of coal. Instead emissions factors are associated with a particular activity. While some activity factors are available, the dependence of some emission factors on soil properties and atmospheric conditions makes a comprehensive estimate difficult. Emissions of sulfuric acid from mines are also substantial, yet difficult to quantify. Current mining operations are subject to strict limitations of sulfuric acid emissions, and as a result the bulk of acid emissions are from flooding of abandoned mines. Quantifying these emissions is difficult, and the question remains as to whether these emissions should be assigned to current coal production.

The second important area of uncertainty in the fuel cycle analysis relates to the allocation of energy use (and associated emissions) from the co-production of oil and gas. Lease fuel use is estimated by the

DOE for combined oil and gas production. Substantial quantities of lease fuel are used to repressurize oil wells, a use which should clearly be attributed to oil production. This allocation has been made following DeLuchi (1993); however, the assumptions involved are significant.

The materials-related emissions estimates are also subject to uncertainty. In this study rough estimates of materials-related emissions were made to demonstrate that for energy technologies the emissions inventory is dominated by fuel-related emissions. While a detailed analysis of materials-related emissions would have been preferred, it was beyond the scope of this project to carry out such a detailed assessment. Instead, efforts were focused on precisely characterizing fuel cycle emissions. Because materials-related energy use and emissions were found to be generally less than 1% of fuel consumption and fuel-related emissions, materials-related emissions do appear to be negligible.

One of the exceptions is emissions of lead. In 1994 about 38% of lead emissions to the air were from metals processing operations, including lead, copper, zinc, and iron and steel manufacture (EPA 1995b). Metals mining also emits significant quantities of lead. Because of the difficulty in characterizing the precise material requirements of the various technologies, especially the sulfur lamp, a precise inventory of lead emissions was considered beyond the scope of this study.

A second area of uncertainty has to do with emissions of refrigerants used in heat pump water heaters.^(a) Common refrigerants include chlorofluorocarbons (CFCs), hydrochlorofluorocarbons (HCFCs), and hydrofluorocarbons (HFCs). Though emitted in small quantities, these compounds, generally known as halocarbons, are estimated to have global warming potentials thousands of times greater than carbon dioxide. Several international agreements have focused on reducing the use and emissions of certain categories of these compounds.

Despite the scientific interest in halocarbons, the actual global warming impacts of these compounds are not easy to characterize. CFCs and HCFCs contain chlorine, which contributes to stratospheric ozone depletion, leading to an indirect cooling effect, the precise magnitude of which is not known. As certain compounds are phased out, a wide variety of replacements step in to fill the market. These rapid changes in the refrigerant market, coupled with the existence of a black market in refrigerants, make the evaluation of refrigerant emissions impacts difficult.

Residential heat pump water heaters generally rely on either R-22 (HCFC-22; 100 year GWP = 1,700) or R-134a (HFC-134a; 100 year GWP=1,300) as refrigerants. In addition, other halocarbons are used as blowing agents for foam insulation used on water heaters, such as CFC-11 (100 year GWP=4,000) and HFC-152a (100 year GWP=140). Evaluating the global warming impacts of these compounds is further complicated by secondary effects (e.g., replacement compounds may not be as effective). Any reduction in heat pump performance due to refrigerant changes will result in changes in fuel use, and hence CO₂ emissions. Similarly changes in insulation performance will impact standby losses, fuel use, and again

(a) For a more thorough discussion see DOE 1995.

CO₂ emissions. Because of these complications, a thorough evaluation of halocarbon impacts has not been carried out. However, HFCs and perfluorocarbons (PFCs) are estimated to account for only about 1% of global warming potential in 1993, while CO₂ and methane account for 86% and 11% respectively.

Tables A.1 and A.2 present emissions inventories for the power generation fuel cycle, and the fossil fuel cycles. Table A.3 presents the lighting technology life cycle inventories and Table A.4 presents the water heater scenario life cycle inventories.

Table A.1. Power Generation Fuel Cycle Emissions Inventory (lb/Gwh)

Air Emissions	Direct	Pre-Combustion	Total
Aldehydes	-	2.41	2.41
CO	193	122	315
CO ₂	1,366,371	37,509	1,403,880
NO _x	5,419	444	5,863
Particulates	215	1,238	1,453
PM ₁₀	63.37	1.60	64.97
SO _x	10,323	350	10,673
Organic Compounds	-	3,282	3,282
Methane	-	3,200	3,200
Non-Methane	37.5	86.4	124.0
Benzene	-	1.55	1.55
Toluene	-	2.18	2.18
Ethylbenzene	-	0.39	0.39
Xylene	-	1.24	1.24
Total BTEX	-	5.36	5.36
n-Hexane	-	0.97	0.97
Isooctane	-	0.15	0.15
Other Organic Compounds	37.5	44.7	82.2
1,2,4-Trimethylbenzene	-	9.36E-03	9.36E-03
Ammonia	-	8.31E-02	8.31E-02
Cyclohexane	-	1.88E-02	1.88E-02
Ethylene	-	2.27E-02	2.27E-02
Methanol	-	8.84E-03	8.84E-03
Methyl Tertiary Butyl Ether	-	2.08E-02	2.08E-02
Propylene	-	7.26E-02	7.26E-02
Toxics	-	2.36E-01	2.36E-01
Carcinogens	-	5.14E-03	5.14E-03
Lead	4.31E-02	6.09E-03	4.92E-02
Mercury	4.02E-02	-	4.02E-02
Kerosene	-	0.41	0.41
Solid Wastes	Direct	Pre-Combustion	Total
Drilling Waste	-	149	149
Mine Tailings and Residues	-	132,747	132,747
Fly Ash	33,873	-	33,873
Bottom Ash/Slag	10,632	-	10,632
FGD Sludge	10,725	-	10,725
U ₂₃₈	1.76	-	1.76

Table A.1. (contd)

Solid Wastes	Direct	Pre-Combustion	Total
U ₂₃₆	0.007	-	0.007
U ₂₃₅	0.015	-	0.015
Pu (fissile)	0.012	-	0.012
Pu (nonfissile)	0.005	-	0.005
Fission Products	0.054	-	0.054
Spent Fuel Rod Total	3.224	-	3.224
1,2,4-Trimethylbenzene	-	9.55E-05	9.55E-05
Ammonia	-	1.11E-03	1.11E-03
Cyclohexane	-	1.92E-04	1.92E-04
Ethylbenzene	-	2.86E-04	2.86E-04
Toluene	-	9.01E-04	9.01E-04
Xylenes	-	1.24E-03	1.24E-03
Carcinogens	-	4.78E-04	4.78E-04
Refinery Residuals	-	6.95E-01	6.95E-01
Waterborne Emissions	Direct	Pre-Combustion	Total
Produced Water	-	285	285
Dissolved Solids	-	392	392
Suspended Solids	-	1.24	1.24
Sulfuric Acid	-	1,143	1,143
Iron	-	1,025	1,025
Biochemical Oxygen Demand	-	0.81	0.81
Chemical Oxygen Demand	-	2.30	2.30
Phenol	-	0.21	0.21
Sulfide	-	0.21	0.21
Acid	-	0.41	0.41
Metals	-	0.21	0.21
Oil and grease	-	0.41	0.41
Ammonia	-	6.04E-04	6.04E-04
Methanol	-	1.17E-05	1.17E-05
Methyl Tertiary Butyl Ether	-	3.64E-05	3.64E-05
Carcinogens	-	8.89E-06	8.89E-06

Table A.2. Fossil Fuel Cycle Emissions Inventories (lb/billion btu)

Air Emissions	Coal	Oil	Natural Gas
Aldehydes	0.37	0.12	0.07
CO	7.58	70.64	43.88
CO ₂	4,069	22,791	12,252
NO _x	36.67	101.50	127.24
Particulates	186.80	10.47	1.73
PM ₁₀	0.07	1.94	0.65
SO _x	11.63	62.09	24.21
Organic Compounds	421	119	690
Methane	418	73	650
Non-Methane	2.80	45.20	40.18
Benzene	3.10E-03	0.17	1.61
Toluene	5.69E-03	0.35	2.23
Ethylbenzene	9.27E-04	0.05	0.40
Xylene	3.63E-03	0.23	1.26
Total BTEX	1.33E-02	0.80	5.50
n-Hexane	9.04E-04	0.03	1.03
Isooctane	1.38E-04	4.06E-03	0.16
Other Organic Compounds	0.62	44.40	33.49
1,2,4-Trimethylbenzene	4.01E-04	3.08E-02	6.67E-05
Ammonia	3.56E-03	2.73E-01	5.92E-04
Cyclohexane	8.04E-04	6.19E-02	1.34E-04
Ethylene	9.70E-04	7.46E-02	1.62E-04
Methanol	3.78E-04	2.91E-02	6.30E-05
Methyl Tertiary Butyl Ether	8.92E-04	6.86E-02	1.49E-04
Propylene	3.11E-03	2.39E-01	5.18E-04
Toxics	1.01E-02	7.78E-01	1.68E-03
Carcinogens	2.20E-04	1.69E-02	3.66E-05
Lead	3.13E-05	2.14E-04	3.80E-05
Kerosene	2.59E-04	1.77E-03	3.15E-04
Solid Wastes	Coal	Oil	Natural Gas
Drilling Waste	86.46	133.75	261.14
Mine Tailings and Residues	19,800	578.89	102.66
Fly Ash	21.59	147.72	26.20
Bottom Ash/Slag	6.78	46.36	8.22
FGD Sludge	6.83	46.77	8.29

Table A.2. (contd)

Solid Wastes	Coal	Oil	Natural Gas
U ₂₃₈	1.12E-03	7.65E-03	1.36E-03
U ₂₃₆	4.71E-06	3.22E-05	5.72E-06
U ₂₃₅	9.42E-06	6.45E-05	1.14E-05
Pu (fissile)	7.65E-06	5.24E-05	9.29E-06
Pu (nonfissile)	2.94E-06	2.01E-05	3.57E-06
Fission Products	3.41E-05	2.34E-04	4.14E-05
Spent Fuel Rod Total	2.05E-03	1.41E-02	2.49E-03
1,2,4-Trimethylbenzene	4.09E-06	3.14E-04	6.81E-07
Ammonia	4.74E-05	3.65E-03	7.90E-06
Cyclohexane	8.21E-06	6.31E-04	1.37E-06
Ethylbenzene	1.22E-05	9.42E-04	2.04E-06
Toluene	3.86E-05	2.97E-03	6.43E-06
Xylenes	5.31E-05	4.09E-03	8.85E-06
Carcinogens	2.05E-05	1.58E-03	3.41E-06
Refinery Residuals	0.70	54.50	0.11
Hazardous Waste	2.65E-02	2.06	4.01E-03
Waterborne Emissions	Coal	Oil	Natural Gas
Produced Water	0.04	2.80	0.31
Dissolved Solids	3.09E-04	6.33E-03	2.14E-01
Suspended Solids	7.93E-07	5.43E-06	9.62E-07
Sulfuric Acid	7.28E-04	4.98E-03	8.84E-04
Iron	6.53E-04	4.47E-03	7.92E-04
Biochemical Oxygen Demand	5.17E-07	3.54E-06	6.28E-07
Chemical Oxygen Demand	1.47E-06	1.00E-05	1.78E-06
Phenol	1.31E-07	8.99E-07	1.59E-07
Sulfide	1.31E-07	8.99E-07	1.59E-07
Acid	2.63E-07	1.80E-06	3.19E-07
Metals	1.31E-07	8.99E-07	1.59E-07
Oil and grease	2.32E-06	1.62E-04	6.29E-07
Ammonia	6.07E-07	4.73E-05	9.20E-08
Methanol	1.18E-08	9.17E-07	1.78E-09
Methyl Tertiary Butyl Ether	3.67E-08	2.86E-06	5.55E-09
Carcinogens	8.95E-09	6.97E-07	1.36E-09

Table A.3. Lighting Technology Life Cycle Inventories (lb/yr)

Air Emissions	Metal Halide	Sulfur Lamp	Difference
Aldehydes	0.90	0.62	-0.28
CO	118	80	-38
CO ₂	526,108	358,610	-167,498
NO _x	2,197	1,498	-699
Particulates	545	371	-174
PM ₁₀	24.36	16.60	-7.76
SO _x	4,000	2,726	-1,274
Organic Compounds	1,230	838	-392
Methane	1,199	817	-382
Non-Methane	46.45	31.66	-14.79
Benzene	0.58	0.40	-0.18
Toluene	0.82	0.56	-0.26
Ethylbenzene	0.15	0.10	-0.05
Xylene	0.46	0.32	-0.14
Total BTEX	2.01	1.37	-0.64
n-Hexane	0.36	0.25	-0.11
Isooctane	0.056	0.038	-0.018
Other Organic Compounds	30.81	21.00	-9.81
1,2,4-Trimethylbenzene	0.004	0.002	-0.002
Ammonia	0.031	0.021	-0.010
Cyclohexane	0.007	0.005	-0.002
Ethylene	0.009	0.006	-0.003
Methanol	0.003	0.002	-0.001
Methyl Tertiary Butyl Ether	0.008	0.005	-0.003
Propylene	0.027	0.019	-0.008
Toxics	0.088	0.060	-0.028
Carcinogens	0.002	0.001	-0.001
Kerosene	0.15	0.10	-0.05
Mercury	1.51E-02	1.03E-02	-4.80E-03
Solid Wastes	Metal Halide	Sulfur Lamp	Difference
Drilling Waste	56	38	-18
Mine Tailings and Residues	49,747	33,909	-15,838
Fly Ash	12,694	8,653	-4,041
Bottom Ash/Slag	3,984	2,716	-1,268
FGD Sludge	4,019	2,740	-1,279

Table A.3. (contd)

Solid Wastes	Metal Halide	Sulfur Lamp	Difference
U238	0.66	0.45	-0.21
U236	2.62E-03	1.79E-03	-8.30E-04
U235	5.62E-03	3.83E-03	-1.79E-03
Pu (fissile)	4.50E-03	3.07E-03	-1.43E-03
Pu (nonfissile)	1.87E-03	1.28E-03	-5.90E-04
Fission Products	2.02E-02	1.38E-02	-6.40E-03
Spent Fuel Rod Total	1.21	0.82	-0.39
1,2,4-Trimethylbenzene	3.58E-05	2.44E-05	-1.14E-05
Ammonia	4.16E-04	2.84E-04	-1.32E-04
Cyclohexane	7.20E-05	4.90E-05	-2.30E-05
Ethylbenzene	1.07E-04	7.31E-05	-3.39E-05
Toluene	3.38E-04	2.30E-04	-1.08E-04
Xylenes	4.65E-04	3.17E-04	-1.48E-04
Carcinogens	1.79E-04	1.22E-04	-5.70E-05
Refinery Residuals	0.26	0.18	-0.08
Mercury	6.11E-03	0	-6.11E-03
Waterborne Emissions	Metal Halide	Sulfur Lamp	Difference
Produced Water	107	73	-34.00
Dissolved Solids	147	100	-47.00
Suspended Solids	0.46	0.32	-0.14
Sulfuric Acid	428	292	-136
Iron	384	262	-122
BOD	0.30	0.21	-0.09
COD	0.86	0.59	-0.27
Phenol	0.079	0.054	-0.03
Sulfide	0.079	0.054	-0.03
Acid	0.154	0.105	-0.05
Metals	0.079	0.054	-0.03
Oil and Grease	0.154	0.105	-0.05
Ammonia	2.26E-04	1.54E-04	-7.20E-05
Methanol	4.38E-06	2.99E-06	-1.39E-06
Methyl Tertiary Butyl Ether	1.36E-05	9.30E-06	-4.30E-06
Carcinogens	3.33E-06	2.27E-06	-1.06E-06

Table A.4. Water Heater Scenario (100 million btu hot water) Life Cycle Inventories (lb)

Air Emissions	Condensing Gas	Standard Gas	Standard Electric	Heat Pump
Aldehydes	0.01	0.01	0.08	0.03
CO	8.75	12.55	10.03	3.55
CO ₂	14,951	21,429	44,723	15,825
NO _x	30.40	43.57	186.78	66.09
Particulate	1.55	2.23	46.30	16.38
PM ₁₀	1.43	2.05	2.07	0.73
SO _x	2.88	4.13	339.99	120.31
Organic Compounds	81.10	116.24	104.54	36.99
Methane	75.83	108.69	101.95	36.07
Non-Methane	5.27	7.55	3.95	1.40
Benzene	0.19	0.27	0.05	0.02
Toluene	0.26	0.37	0.07	0.02
Ethyl Benzene	0.05	0.07	0.01	0.00
Xylene	0.15	0.21	0.04	0.01
BTEX	0.64	0.92	0.17	0.06
n-Hexane	0.12	0.17	0.03	0.01
Isooctane	0.02	0.03	0.00	0.00
Other VOCs	3.89	5.58	2.62	0.93
1,2,4-Trimethylbenzene	7.76E-06	1.11E-05	2.98E-04	1.05E-04
Ammonia	6.89E-05	9.87E-05	2.65E-03	9.36E-04
Cyclohexane	1.56E-05	2.23E-05	5.99E-04	2.12E-04
Ethylene	1.88E-05	2.69E-05	7.22E-04	2.55E-04
Methanol	7.33E-06	1.05E-05	2.81E-04	9.96E-05
Methyl Tertiary Butyl Ether	1.73E-05	2.48E-05	6.64E-04	2.35E-04
Propylene	6.02E-05	8.63E-05	2.31E-03	8.19E-04
Toxics	1.96E-04	2.81E-04	7.52E-03	2.66E-03
Carcinogens	4.26E-06	6.11E-06	1.64E-04	5.79E-05
Kerosene	3.66E-05	5.24E-05	1.30E-02	4.59E-03
Solid Wastes	Condensing Gas	Standard Gas	Standard Electric	Heat Pump
Drilling Waste	30.36	43.52	4233.66	1498.07
Mine Tailings and Residues	11.94	17.11	4,229	1,496
Fly Ash	3.05	4.37	1,079	382
Bottom Ash/Slag	0.96	1.37	339	120
FGD Sludge	0.96	1.38	342	121

Table A.4. (contd)

Solid Wastes	Condensing Gas	Standard Gas	Standard Electric	Heat Pump
U ₂₃₈	1.58E-04	2.26E-04	5.59E-02	1.98E-02
U ₂₃₆	6.65E-07	9.53E-07	2.35E-04	8.33E-05
U ₂₃₅	1.33E-06	1.91E-06	4.71E-04	1.67E-04
Pu (fissile)	1.08E-06	1.55E-06	3.83E-04	1.35E-04
Pu (nonfissile)	4.15E-07	5.95E-07	1.47E-04	5.21E-05
Fission Products	4.82E-06	6.91E-06	1.71E-03	6.04E-04
Spent Fuel Rod Total	2.90E-04	4.16E-04	1.03E-01	3.63E-02
1,2,4-Trimethylbenzene	7.92E-08	1.13E-07	3.04E-06	1.08E-06
Ammonia	9.18E-07	1.32E-06	3.53E-05	1.25E-05
Cyclohexane	1.59E-07	2.28E-07	6.11E-06	2.16E-06
Ethylbenzene	2.37E-07	3.40E-07	9.11E-06	3.22E-06
Toluene	7.47E-07	1.07E-06	2.87E-05	1.02E-05
Xylenes	1.03E-06	1.48E-06	3.96E-05	1.40E-05
Carcinogens	3.97E-07	5.69E-07	1.52E-05	5.39E-06
Refinery Residuals	1.23E-02	1.77E-02	2.21E-02	7.84E-03
Hazardous Waste	4.67E-04	6.69E-04	8.39E-04	2.97E-04
Waterborne Wastes	Condensing Gas	Standard Gas	Standard Electric	Heat Pump
Discharged H ₂ O	35.62	51.05	9.09	3.22
Dissolved Solids	24.84	35.60	12.49	4.42
Suspended Solids	0.00	0.00	0.04	0.01
Sulfuric Acid	0.10	0.15	36.41	12.89
Iron	0.09	0.13	32.64	11.55
BOD	7.30E-05	1.05E-04	2.59E-02	9.15E-03
COD	2.07E-04	2.97E-04	7.33E-02	2.59E-02
Phenol	1.85E-05	2.66E-05	6.57E-03	2.32E-03
Sulfide	1.85E-05	2.66E-05	6.57E-03	2.32E-03
Acid	3.71E-05	5.32E-05	1.31E-02	4.65E-03
Metals	1.85E-05	2.66E-05	6.57E-03	2.32E-03
Oil	7.32E-05	1.05E-04	1.31E-02	4.65E-03
Ammonia	1.07E-05	1.53E-05	1.92E-05	6.81E-06
Methanol	2.07E-07	2.97E-07	3.73E-07	1.32E-07
Methyl Tertiary Butyl Ether	6.45E-07	9.25E-07	1.16E-06	4.11E-07
Carcinogens	1.58E-07	2.26E-07	2.83E-07	1.00E-07

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