NATIONAL ENERGY TECHNOLOGY LABORATORY

Role of Alternative Energy Sources: Solar Thermal Technology Assessment

August 28, 2012

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Acronyms and Abbreviations

ASTM	American Society for Testing and Materials
BLM	Bureau of Land Management
CH_4	Methane
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
COE	Cost of electricity
DOE	Department of Energy
ECF	Energy conversion facility
EIA	Energy Information Administration
EIS	Environmental impact statement
EPA	Environmental Protection Agency
EROI	Energy Return on Investment
GHG	Greenhouse gas
GW	Gigawatt
GWh	Gigawatt-hour
Hg	Mercury
HTF	Heat transfer fluid
IEA	International Energy Agency
IPCC	Intergovernmental Panel on Climate Change
IRROE	Internal rate of return on equity
ISO	International Organization for Standardization
ITC	Investment tax credit
kg	kilogram
km	kilometer
kW	kilowatt
kWh	kilowatt-hour
$kWh/m^2/day$	kilowatt-hour per square meter per day
lb.	pounds
LC	Life cycle
LCA	Life cycle analysis
LCC	Life cycle cost
LCOE	Levelized cost of electricity
m^2	square meter
MACRS	Modified accelerated cost recovery system
MW	Megawatt
MWh	Megawatt-hour
N_2O	Nitrous oxide
NETL	National Energy Technology Laboratory
NGCC	Natural gas combined cycle
NOx	Nitrogen oxides
NREL	National Renewable Energy Laboratory
O&M	Operating and maintenance
Pb	Lead
PM	Particulate matter
PSFM	Power Systems Financial Model
PT	Product transport
RFS2	Renewable Fuel Standards 2
RMA	Raw material acquisition
RMT	Raw material transport
SEGS	Solar electric generating systems
SF_6	Sulfur hexafluoride
SO_2	Sulfur dioxide
STE	Solar energy to electricity
T&D	Transmission and distribution
U.S.	United States
USDA	United States Department of Agriculture
VOC	Volatile organic compounds

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Executive Summary

Solar thermal power is viewed as a clean, renewable alternative to conventional fossil fuels for electricity generation. However, the resource base of solar thermal power is limited by the availability of direct sunlight at any given location and the best solar thermal resources are located in areas that are distant from existing population centers. Despite this, there is potential for solar thermal power to support a significant portion of the United States (U.S.) electricity demand. However, the high cost of solar collectors to support utility-level output, the water scarcity in areas of high solar potential, and the lack of proximity of resources to population centers make it likely that high-quality solar thermal resources are expected to remain largely untapped for the foreseeable future. Hybrid facilities, which could support baseload electricity demands, have been discussed to a small degree in recent industry literature, including two fossil-solar-thermal hybrid power plants that have been approved in California. This report discusses the role of solar thermal power in meeting the energy needs of the U.S. This includes an analysis of key issues related to solar thermal power and, where applicable, the modeling of the environmental and cost aspects of solar thermal power.

The U.S. has a large resource base of solar energy but this resource base is limited by several factors. Key factors for solar thermal power are latitude, humidity, cloud cover, and, to a lesser extent, altitude (NREL, 2011a). In most areas of the continental U.S., daily solar radiation ranges from 1 to 7 kWh/m^2/day, on an average annual basis, with the highest values located in the Desert Southwest and the substantially lower values located across much of the Midwest, Lake States, South, Northeast, and the westernmost portions of the Pacific Northwest.

Solar power deployed across approximately 1.5 percent of the total land area available in the Southwest would be sufficient to provide at least four million GWh per year, which is enough to power the entire U.S. (DOE, 2009). This projection is based on land that has a slope of less than one percent, a solar capacity of 5 acres/MW, and an annual capacity factor of 27 percent (DOE, 2009).

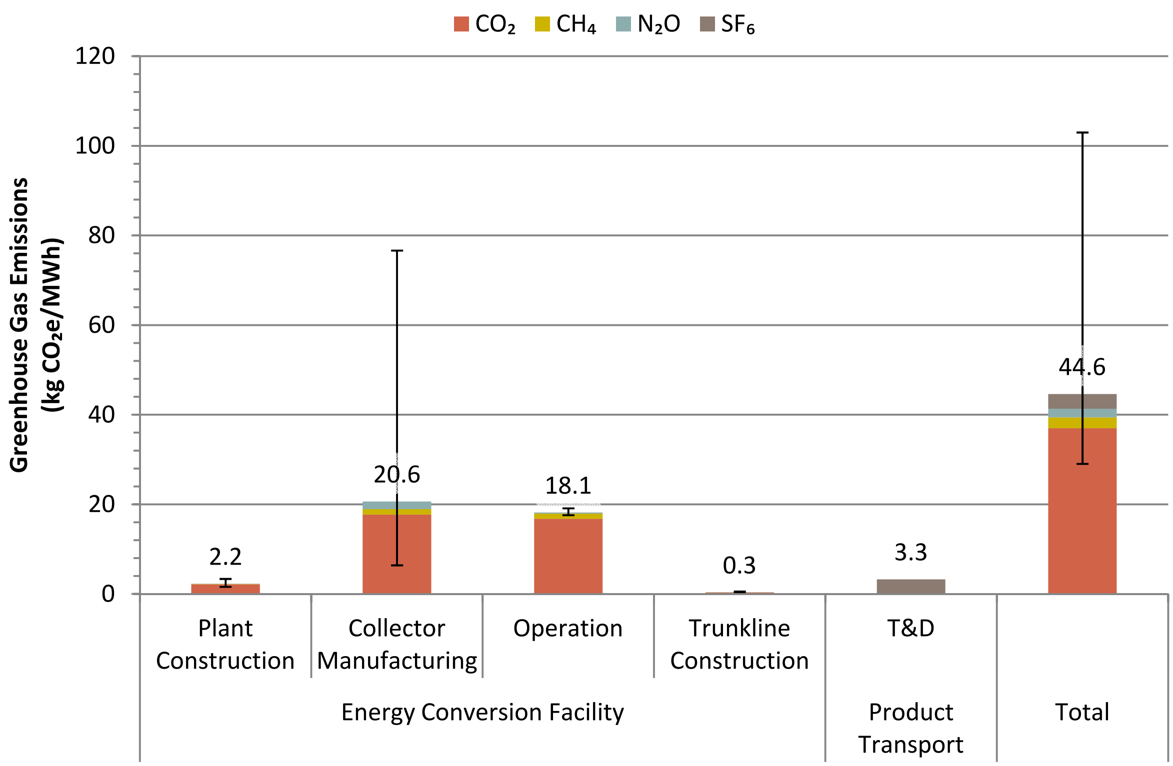
The resource base of solar power also varies considerably on a seasonal basis. For instance, resource availability in central Nevada may reach 10 kWh/m^2/day or higher during July, while January average values may be as low as 3 kWh/m^2/day, or even zero on a daily basis as a result of cloud cover (NREL, 2011a). Additionally, a large portion of the plains states receive reasonable quality sunlight during July, but this quickly recedes with the approach of autumn.

The growth of solar thermal capacity in the U.S. has not been significant in the last 10 years. Total U.S. solar thermal power output was nearly constant from 2000 through 2006. The contribution of solar power to the total U.S. power supply was 0.1 percent in 2010, of which 64 percent was from photovoltaic cells and the remaining 36 percent (744 GWh) was from solar thermal power. All operating utility-scale (i.e., 10 MW and above) solar thermal plants in the U.S. use parabolic trough technology and have a total capacity of 493 MW. Most of the existing capacity, 354 MW, is located in southeastern California, as part of the Solar Electric Generating Systems (SEGS) project, which was installed incrementally from 1984 through 1990. The average capacity factor of installed solar thermal power assets in the U.S. ranges from 21 to 25 percent (DOE, 2010; Lenzen, 2010). The more recent Nevada Solar One was installed in 2007. The Martin Next Generation Solar Energy Center was completed at the end of 2010 and, as of the time of publication of this document, is the most recently installed utility-scale solar thermal plant in the U.S.

A screening life cycle analysis (LCA) was conducted to assess the environmental characteristics of solar thermal power. A screening LCA quickly identifies the key variables that drive the life cycle (LC) environmental results of a system and uses proxy data as a way of reducing data collection

efforts. The boundaries of the LCA account for the cradle-to-grave energy and material flows for solar thermal power. The boundaries include five LC stages, beginning with the raw material extraction, and then moving to the intermediate steps of raw material transport, energy conversion, and electricity transmission and distribution, and ending with the electricity delivery to the consumer. In contrast to fossil energy and some forms of renewable energy conversion, solar thermal power does not incur any environmental burdens for the acquisition and transport of primary fuel. Thus, the equipment manufacture, construction, and installation requirements of solar thermal power plants dominate the life cycle greenhouse gas (GHG) emissions for solar thermal power as shown in **Figure ES-1** in terms of 2007 IPCC 100-year global warming potentials (GWP). The functional unit of this analysis, which serves as the basis of comparison between systems, is 1 MWh of electricity delivered to the consumer. The analysis contained in this document focuses on greenhouse gas (GHG) emissions from the LC of solar thermal power; however, an extended set of metrics, including criteria air pollutants, other air emissions, water use and quality, and energy return on investment (EROI) were also modeled.

Figure ES-1: Life Cycle GHG Emissions for Solar Thermal Power



Using the Intergovernmental Panel on Climate Change (IPCC) 2007 100-yr global warming potentials (GWPs), the LC GHG emissions for solar thermal power from a 250 MW net power plant are 44.60 kg CO_2e/MWh. The majority of LC GHG emissions are from CO_2 at 82.9 percent, with the remainder split between CH_4, N_2O, and SF_6 at 5.4 percent, 4.4 percent, and 7.3 percent, respectively. Solar collector construction accounts for 46.3 percent of the LC GHG emissions for solar thermal power, while plant operation accounts for 40.7 percent. The construction of the plant and the trunkline contribute a combined 5.7 percent, while transmission and distribution (T&D) accounts for 7.3 percent.

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

A life cycle cost (LCC) analysis was conducted to assess the cost performance of solar thermal power. The cost of electricity (COE) from solar thermal power is $268.2/MWh. COE is defined as the revenue received by the generator per net MWh during the first year of operation. This result is based on a capital cost of $4,693/kW, a fixed O&M cost of $56,780/MW-yr, a capacity factor of 27.4 percent, and a 7 percent loss of electricity during transmission and delivery. Key financial assumptions behind this result include an internal rate of return (IRROE) of 12 percent, a 30-year plant life, and a modified accelerated cost recovery system (MACRS) depreciation. Solar thermal power does not require the purchase of fuel, so the operation and maintenance (O&M) costs for solar thermal power are low in comparison to power technologies that use fossil fuels or other non-renewable energy sources. Capital costs represent for 91.18 percent of the COE.

The barriers to implementation of solar thermal power include cost, water use, and grid connection. According to the Energy Information Administration (EIA) (2011b), high-temperature solar thermal collectors, such as those utilized for concentrating solar power, cost an average of $25.32/square foot, although some industry sources have estimated up to $55/square foot. Considering that the installation of one GW of utility-scale solar thermal can require over two square miles of solar fields, the importance of collector cost becomes immediately obvious. Water use is another potential barrier to the widespread implementation of utility-scale solar thermal power production. For example, the approved, but not yet constructed, Blythe Solar Power Plant, located in the Mojave Desert of southeastern California, has a nameplate generation capacity of 1,000 MW. During operations, the project would require approximately 600 acre-feet (195 million gallons) of water per year for cooling. An additional 4,100 acre-feet (1.3 billion gallons) of water would be required in support of project construction (BLM, 2010a). The water demands for operations and construction correspond to 0.0036 and 0.0243 percent of annual rainfall in the Mojave Desert (USGS, 2005). As discussed in the environmental impact statement (EIS) for the Blythe project (BLM, 2010a), the proposed water use would result in a small amount of groundwater drawdown, but would not be expected to result in permanent effects to the underlying reservoir, such as subsidence or substantial interference, with the hydrology of the nearby Colorado River. Availability of power transmission capacity, combined with the difficulty of constructing long-distance power-transmission lines, is another key barrier to the implementation of solar thermal power production. The best solar thermal resources are located in areas that are distant from existing population centers. Many high-quality solar thermal resources are expected to remain untapped for the foreseeable future, for the simple reason that new transmission facilities are (1) expensive to construct and (2) difficult to permit (Smith & Bruvsen, 2010).

The risks of implementation include land use change and habitat loss, water use and consumption, interference with natural drainage patterns, and aesthetic concerns. Habitat loss can be substantial for large solar thermal projects, such as the Blythe Solar Power Project, which is expected to have a generation capacity of around 1,000 MW and would strip the vegetative habit of approximately 11 square miles (BLM, 2010a). Water consumption rates for solar thermal are in line with other power generation technologies that use cooling towers, but since the best solar thermal facility sites are typically located in the desert, the acquisition of sufficient volumes of water can be problematic, and alternate cooling techniques may be required. Aesthetic concerns are driven by public opinion and, with respect to solar thermal power, focus on the permanent change to the visual character of desert corridors.

The opinions of solar thermal power experts include predictions that many solar thermal projects will come online in 2012 through 2014, driven by long-term extensions of the federal solar tax investment credit and the associated deadline to initiate construction by the end of 2011 (IREC, 2011). Hybrid facilities have been discussed to some degree in recent industry literature, including two fossil-solar thermal hybrid power plants that have been approved in California as well as support for biomass-solar thermal cogeneration. These hybrid technologies could support baseload electricity, but the research conducted in support of this document revealed that the two biomass-solar thermal facilities in California have not been constructed and are not currently being considered for permitting or approval; thus, fossil-solar facilities appear to have a higher probability of viability, at least in the near-term.

1 Introduction

This analysis evaluates the role of solar thermal power in the energy supply of the United States (U.S.). This objective is met by focusing on the resource base, growth, environmental characteristics, costs, barriers, and expert opinions surrounding solar thermal power. The criteria used by the National Energy Technology Laboratory (NETL) to evaluate the roles of energy sources are summarized in **Table 1-1**.

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

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

Solar thermal power harnesses energy from the sun by using solar collectors that concentrate sunlight on a fluid that is subsequently sent through a Rankine power cycle where a steam turbine generator system produces electricity. Sunlight can also be converted directly to electricity using photovoltaic panels, wherein photons increase the energy level of electrons to produce an electric current (EERE, 2011).

Solar thermal and photovoltaic power plants have different availability, scale, and cost characteristics. Solar thermal systems can store thermal energy, which allows them to balance the intermittency of sunlight. This is demonstrated by the higher availability of solar thermal power plants in contrast to photovoltaic power plants (Tidball, Bluestein, Rodrigues, & Knoke, 2010). Utility-scale solar thermal power plants have been proved commercially, while utility-scale photovoltaic power plants are an emerging technology (Tidball, et al., 2010). Finally, the historical costs of solar thermal power have been lower than photovoltaic power (Tidball, et al., 2010).

In the context of the above technology and cost characteristics, solar thermal power plants are favorable to photovoltaic systems for utility-scale electricity generation. While many of the issues discussed in this report are pertinent to both types of solar power systems, the environmental and cost analyses focus on solar thermal power exclusively.

2 Solar Thermal Power Technology Performance

Solar thermal power technologies rely on concentrating solar collectors. Concentrating solar collectors focus the sun's light onto a single point where heat is collected for power generation. In particular, the collector field for a parabolic trough power plant consists of a series of parabolic-shaped mirrors, as shown in **Figure 2-1**, that focus sunlight on a pipe containing a thermal fluid. The thermal fluid is heated by the concentrated sunlight, and is then routed to a central power plant that uses a steam cycle to generate electricity. All utility-scale solar thermal plants currently operating in the U.S. use parabolic trough technology and represent a total nameplate capacity of 493 MW.

Figure 2-1: Solar Thermal Parabolic Trough Collectors (DOE, 2012)

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

The environmental and cost models of this analysis are based on an environmental impact statement (EIS) prepared for a parabolic trough solar thermal power plant in southwestern California (BLM, 2010b). The facility has a total nameplate capacity of 250 net MW. The key cost and performance parameters for solar thermal power are shown in **Table 2-1**.

Table 2-1: Performance and Cost Parameters for Solar Thermal Power

Parameter	Units	Expected Value	Reference
Net Plant Capacity	MWnet	250	(Tidball, et al., 2010)
Capacity Factor	Percent	27.4%	(Tidball, et al., 2010)
Capital (Solar Collectors and Power Plant)	2007$/kW	4,693	(Tidball, et al., 2010)
Fixed O&M (Annual)	2007$/MW-yr.	56,780	(Tidball, et al., 2010)
Period of Construction	Years	2	(BLM, 2010b)
Plant Life	Years	30	(BLM, 2010b)

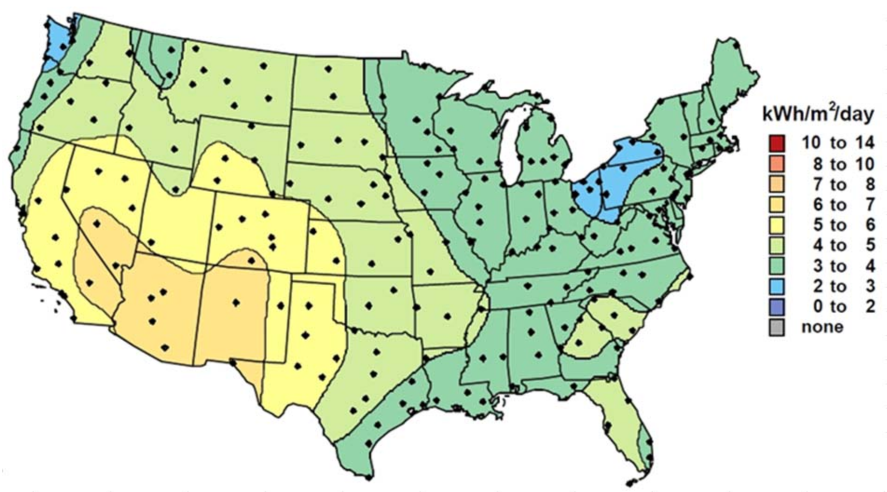
3 Resource Base and Potential for Growth

The resource availability of solar thermal power is limited by several factors, which inform the availability of direct sunlight at any given location. Key factors for solar thermal are latitude (which affects the angle and intensity of incoming sunlight), humidity, cloud cover, and, to a lesser extent, altitude (NREL, 2011a).

The availability of solar radiation within the U.S. has been extensively studied by the U.S. government, including the Department of Energy (DOE), and also by universities and government-university partnerships. As a result, national-level solar radiation resource-availability data are readily available across the U.S. **Figure 3-1** provides an overview of solar radiation availability, as specifically relevant to concentrating solar collectors (NREL, 2011b). As shown, the potential availability of solar power across the U.S. varies significantly based on location, primarily as a result of the four factors described above. Average daily solar radiation ranges from approximately 1 to 7 kWh/m^2/day, on an average annual basis, with the higher values located in the Desert Southwest, and the substantially lower values across much of the Midwest, Lake States, South, Northeast, and the westernmost portions of the Pacific Northwest.

According to the U.S. DOE, concentrating solar power deployed across approximately 1.5 percent of the total land area available in the Southwest would be sufficient to provide at least 4 million GWh/year, which is enough to power the entire U.S. (DOE, 2009). This projection is based on land that has a slope of less than 1 percent, a solar capacity of 5 acres/MW, and an annual capacity factor of 27 percent (DOE, 2009). The availability of land and sunlight are the key factors behind this projection. The capital costs, water requirements, and grid integration (discussed in **Section 6** of this report) are key barriers that hinder the implementation of solar thermal power.

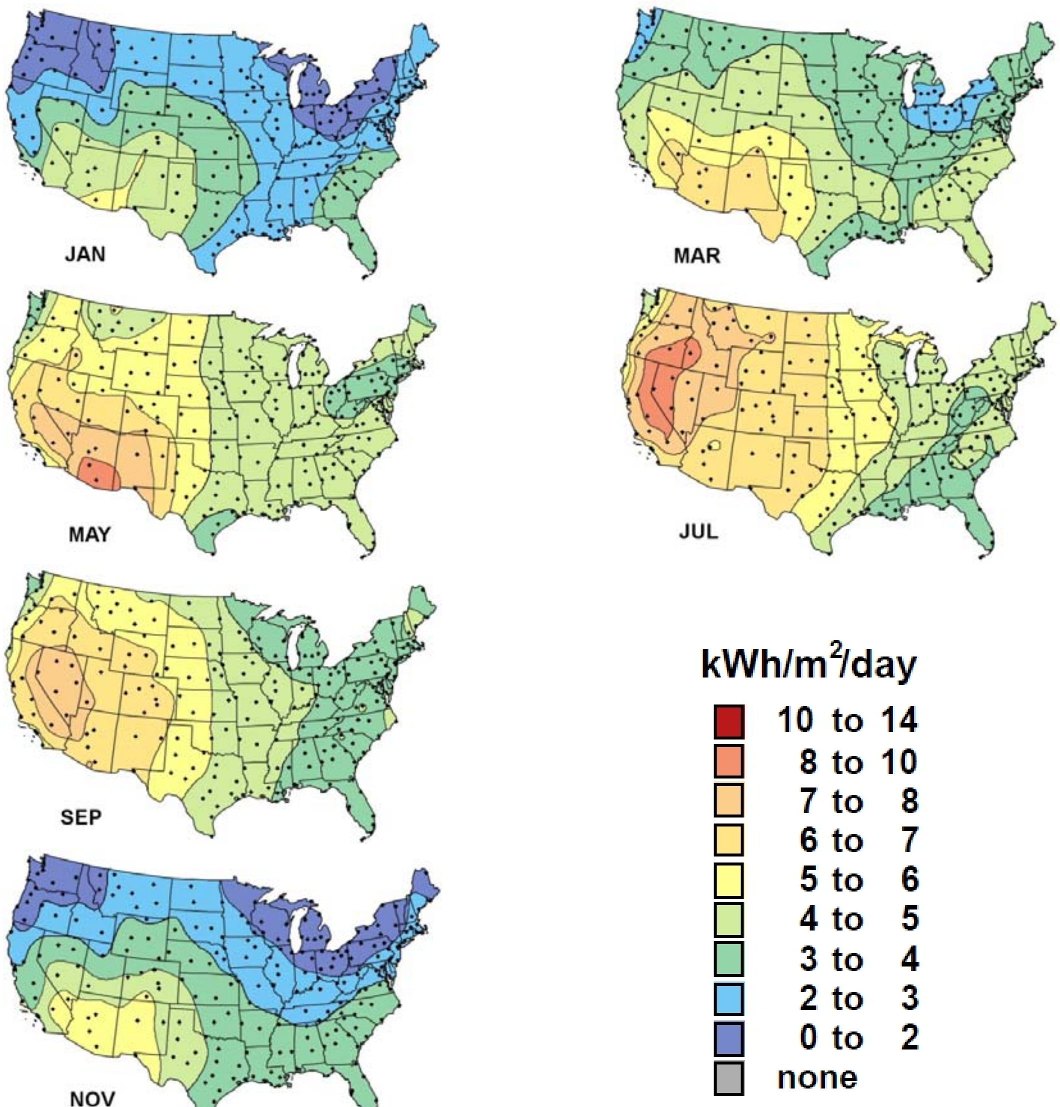
Figure 3-1: Average Daily Solar Radiation (NREL, 2011b)



Solar radiation availability also varies considerably on a seasonal basis. **Figure 3-2** shows U.S. concentrating solar resource availability on a monthly average basis. For instance, resource availability in central Nevada may reach 10 kWh/m^2/day or higher during July, while January average values may be as low as 3 kWh/m^2/day, or even zero on a daily basis as a result of cloud cover (NREL, 2011a). Additionally, a large portion of the plains states receive reasonable quality sunlight during July, but this quickly recedes with the approach of autumn.

Thus, the ability of a site to be developed for solar thermal power is based on a combination of spatial and temporal variability in the availability of a suitable resource. These resource availability factors are typically constrained by proximity to available infrastructure, including power lines and supply/access roads. These factors constrain the extent to which solar thermal power is developed within the U.S.

Figure 3-2: Concentrating Solar Power Average Daily Solar Radiation Per Month, 1961-1990 (NREL, 2011b)



The availability of water in order to support cooling during power generation is also a resource issue. Similar to fossil power plants, solar thermal plants must include a cooling system in order to support steam condensation and effective power production. Evaporative (water-based) cooling of power plants is generally much more effective and efficient than dry (air-based) cooling, because evaporative cooling has lower capital costs, higher thermal efficiency, and supports consistent efficiency levels year round. However, evaporative cooling also requires water – up to approximately 650 gallons/MWh – that might not be available in many portions of the Desert Southwest (DOE, 2009).

Air cooling, in contrast, is less effective during high temperatures because it results in lower net efficiency and is more costly to install and operate (DOE, 2009). However, the best available solar resources are located in the Desert Southwest, where water supplies are severely limited. While dry cooling reduces water consumption by about 90 percent, it also reduces net power generation by approximately 5 percent (WorleyParsons, 2008), and may increase generated electricity cost by approximately 2 to 9 percent (DOE, 2009).

Existing solar thermal power production capacity in the U.S. is limited. Presently installed utility-scale plants are shown in **Table 3-1**. As shown, all currently operating utility-scale (i.e., 10 MW and above) solar thermal plants in the U.S. utilize parabolic trough technology and total 493 MW nameplate capacity. Most of the existing capacity, 354 MW, is located in southeastern California, as part of the Solar Electric Generating Systems (SEGS) project, which was installed incrementally from 1984 through 1990. The average capacity factor of installed solar thermal power assets in the U.S. ranges from 21 to 25 percent (DOE, 2010; Lenzen, 2010).The more recent Nevada Solar One was installed in 2007. The Martin Next Generation Solar Energy Center was completed at the end of 2010, and as of the time of publication of this document, is the most recently installed utility-scale solar thermal plant in the U.S. A handful of other smaller-scale demonstration-level facilities have been installed across the U.S., including the Kimberlina Solar Thermal Energy Plant, in Bakersfield, California (5MW), the Sierra Sun Tower, in Lancaster, California (5 MW), and various others with lower capacities; however, these plants are not considered further in this evaluation due to their low power production capacities.

Table 3-1: Existing Utility-scale U.S. Solar Thermal Plants, as of 2011

Name	Location	Technology	Capacity (MW net)	Installation Year
Solar One/Solar Two (Decommissioned)	Near Barstow, CA	Tower	10	1981
Solar Electric Generating Systems (SEGS) I	Daggett, CA	Trough	14	1984
SEGS II	Daggett, CA	Trough	30	1985
SEGS III	Kramer Junction, CA	Trough	30	1986
SEGS IV	Kramer Junction, CA	Trough	30	1986
SEGS V	Kramer Junction, CA	Trough	30	1987
SEGS VI	Kramer Junction, CA	Trough	30	1988
SEGS VII	Kramer Junction, CA	Trough	30	1988
SEGS VIII	Harper Lake, CA	Trough	80	1989
SEGS IX	Harper Lake, CA	Trough	80	1990
Nevada Solar One	El Dorado Valley, NV	Trough	64	2007
Martin Next Generation Solar Energy Center	Martin County, FL	Parabolic Trough	75	2010

The fraction of total U.S. power generation from total solar power, including solar thermal and photovoltaic, is approximately 0.1 percent of 2010 electricity generation, as shown in **Figure 3-3**. Of that 0.1 percent, approximately 64 percent was provided by photovoltaic cells, while the remaining 36 percent (744 GWh/year) was provided by the solar thermal power plants listed in **Table 3-1**. On a year-to-year basis, total solar thermal power output remained near constant from 2000 through 2006. With the completion of Nevada Solar One, in 2007, total solar thermal capacity increased by approximately 18 percent. The recent completion of the Martin Next Generation Solar Energy Center, in Florida, increased total U.S. solar thermal capacity by an additional 18 percent, to current levels. Market interest in the installation of new solar thermal power capacity has been characteristically low over the last two decades; however, the recent installations in Nevada and Florida represent the beginning of what might be a key turning point for solar thermal power production in the U.S.

Figure 3-3: Fraction of 2010 Total U.S. Domestic Power Production (EIA, 2011a)

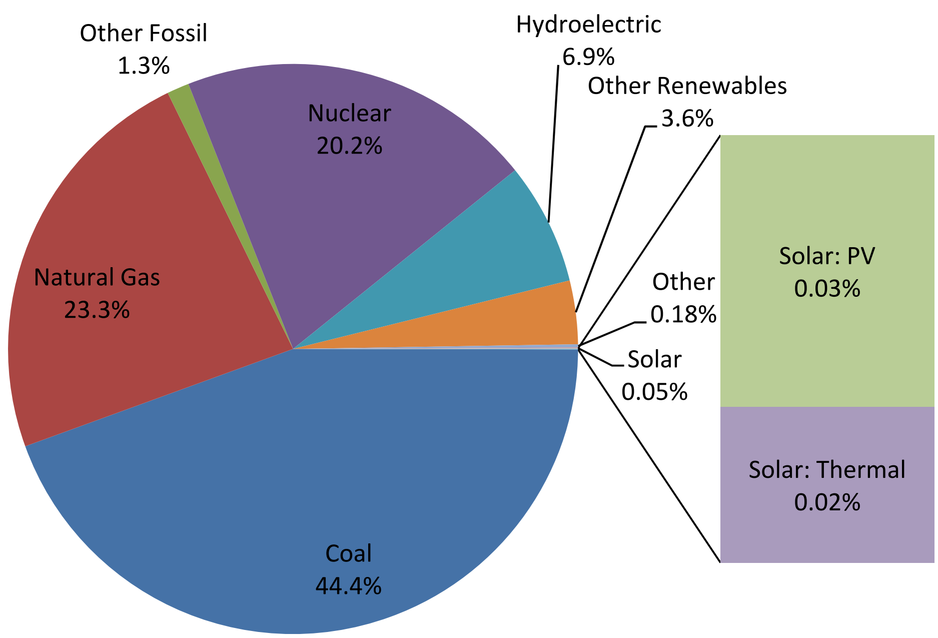


Figure 3-4 shows historic data for domestic shipments of solar thermal collectors (in square feet of collector area). As shown, domestic shipments were essentially non-existent from 2000 through 2005. The spike in 2006, presumably associated with construction of the Nevada Solar One project, represent the first major spike since the late 1980s. After falling off to near zero in 2007, shipments again began to ramp up slightly in 2008 and 2009 (EIA, 2011b). Although data were not available at the time of publication of this report, 2010 domestic shipments would have presumably exceeded 2009 levels, due to construction of the Martin Next Generation Solar Energy Center, in Florida.

Figure 3-4: Domestic Solar Thermal Shipments (EIA, 2011b)

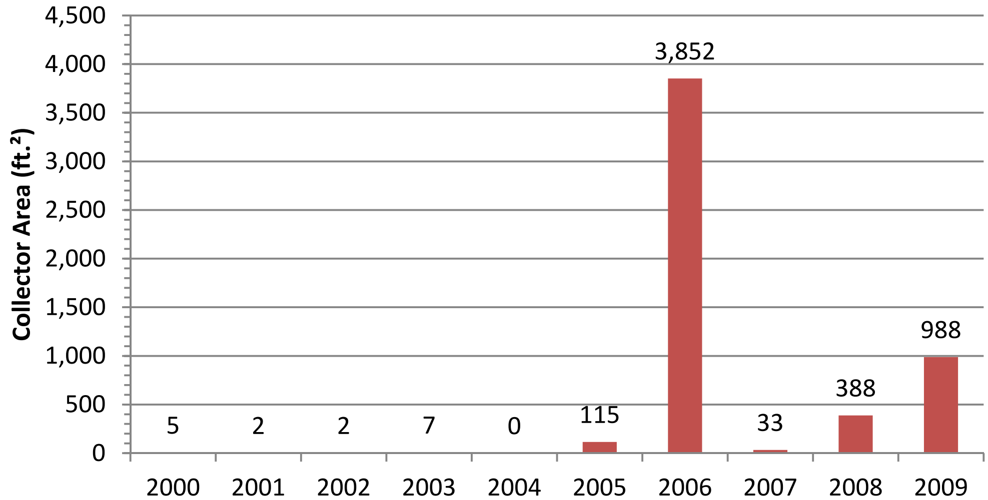


Table 3-2 provides a list of solar thermal projects that are under construction, have been approved by relevant agencies, or are currently undergoing environmental review (BLM, 2011; CEC, 2011; SEIA, 2011). These projects have a high to very high likelihood of implementation, and several have been forwarded as key projects anticipated to be approved by agencies (in particular the Bureau of Land Management) in the near-term. In total, these projects represent 6,363 MW of anticipated solar thermal power. In addition to these projects, a review of early stage projects that are under initial development and scoping revealed at least 2,000 MW of additional projects that could potentially move forward into the environmental-permitting phase in the near-term. Thus, while historic solar thermal installations in the U.S. have been minimal to non-existent over most of the last decade, the near-term domestic solar market is anticipated to be substantially more bullish.

Table 3-2: Summary of Approved and Pending Solar Thermal Projects (BLM, 2011; CEC, 2011; SEIA, 2011)

Project Name	Location	Technology	Estimated Capacity (MW net)	Status
Abengoa Mojave Solar (Mojave Solar)	Riverside County, CA	Parabolic Trough	250	Under Construction
Crescent Dunes Solar Energy Project	Nevada	Power Tower	100	Under Construction
Ivanpah Solar	San Bernardino County, CA	Power Tower	370	Under Construction
Amargosa Farm Road Solar Project	Nevada	Parabolic Trough	500	Approved November, 2010
Beacon Solar Energy Project	Kern County, CA	Parabolic Trough	250	Approved August, 2010
Calico Solar Project	Kern County, CA	Parabolic Trough	250	Approved August, 2010
City of Palmdale Hybrid Gas-Solar	Riverside County, CA	Parabolic Trough	50	Approved August, 2011
Genesis Solar	Riverside County, CA	Parabolic Trough	250	Approved September, 2010
Imperial Valley Solar Project	Imperial County, CA	Stirling Engine	709	Approved September, 2010
Solar Millennium Blythe	Riverside County, CA	Parabolic Trough	250	Approved September, 2010
Victorville 2 Hybrid Power Project	Victorville, CA	Parabolic Trough	50	Approved July, 2008
Ft. Irwin Solar Power Project	Ft. Irwin, CA	Parabolic Trough	500	Environmental Review
Hidden Hills Solar Electric Generating System	Inyo County, CA	Power Tower	500	Environmental Review
Kingman Project	Kingman, AZ	Parabolic Trough	200	Environmental Review
Palen Solar Project (Solar Millennium)	Riverside County, CA	Parabolic Trough	484	Environmental Review
Rice Solar Energy (Rice Solar Energy)	Riverside County, CA	Power Tower	150	Environmental Review
Rio Mesa Solar Electric Generating Facility	Riverside County, CA	Power Tower	750	Environmental Review
Solar Millennium Ridgecrest	Kern County, CA	Parabolic Trough	250	Environmental Review
Sonoran Solar Project (Next Era)	Maricopa County, AZ	Parabolic Trough	500	Environmental Review
Total Proposed Capacity			**6,363**	

4 Environmental Analysis of Solar Thermal Power

The operation of a solar thermal power plant does not result in direct emissions of greenhouse gases (GHG) or other air emissions; however, indirect environmental burdens are associated with the construction and operation of a solar thermal power plant. Energy is expended during the manufacture, transport, installation, and maintenance of solar thermal equipment. The construction of a trunkline that connects the power plant to the electricity grid also incurs environmental burdens, and air emissions result from the operation of an electricity transmission and distribution network. Life cycle analysis (LCA) is necessary to evaluate the environmental burdens from the entire life cycle (LC) of solar thermal power.

4.1 LCA Scope and Boundaries

A screening LCA was conducted to assess the environmental characteristics of solar thermal power. A screening LCA quickly identifies the key variables that drive the LC environmental results of a system. A screening LCA does not spend as much effort on the collection of new data as a comprehensive LCA. The use of proxy data is one way of reducing data collection efforts. For example, this analysis uses data for glass fiber production as a proxy for glass panel production. The goal of proxy data is to provide a reasonable estimate for the environmental burdens of a process. Proxy data does not necessarily fulfill all the technical, temporal, or quality metrics that are expected for a comprehensive LCA. Screening LCAs may have lower data quality than other LCAs.

The boundaries of the LCA account for the cradle-to-grave energy and material flows for solar thermal power. The boundaries include five LC stages:

LC Stage #1: Raw Material Acquisition (RMA) accounts for fuels from the earth or forest. RMA is not relevant to solar thermal power because solar thermal energy is a natural resource that does not require anthropogenic inputs prior to power generation.

LC Stage #2: Raw Material Transport (RMT) accounts for the transport from RMA to the energy conversion facility. RMT is not relevant to solar thermal power because it uses a natural energy source that does not require anthropogenic inputs prior to power generation.

LC Stage #3: Energy Conversion Facility (ECF) includes the construction and operation of the solar thermal power plant and the trunkline that connects it to the electricity grid. The key activities at the solar thermal power plant include the construction and installation of the solar parabolic collectors, the construction and installation of the power generation equipment, and construction and operation of the trunkline. The steady state operation of the solar thermal power plant that requires diesel and natural gas are for combustion in auxiliary equipment, gasoline for use in the site maintenance vehicles, and makeup heat transfer fluid to account for small losses over the course of operation.

LC Stage #4: Product Transport (PT) accounts for the transmission of electricity from the point of generation to the final consumer. There is a seven percent loss associated with transmission and distribution (T&D) of electricity (representative of the U.S. average electricity grid). The only emission associated with this stage is the sulfur hexafluoride (SF_6) that is released by transmission and the distribution electrical equipment.

LC Stage #5: End Use represents the use of electricity by the consumer. No environmental burdens are incurred during this stage.

The use of a consistent functional unit is another convention that enforces comparability between LCAs. The functional unit of this analysis and other NETL power LCAs is the delivery of 1 MWh of electricity to the consumer.

An LCA model is an interconnected network of unit processes. The throughput of one unit process is dependent on the throughputs of upstream and downstream unit processes. These processes were assembled using the GaBi 4.0 software tool. **Figure 4-1** shows NETL's total LC approach to modeling solar thermal power.

Table 4-1 shows the important parameters used by NETL's LCA model of solar thermal power.

Figure 4-1: LCA Modeling Framework for Solar Thermal Power

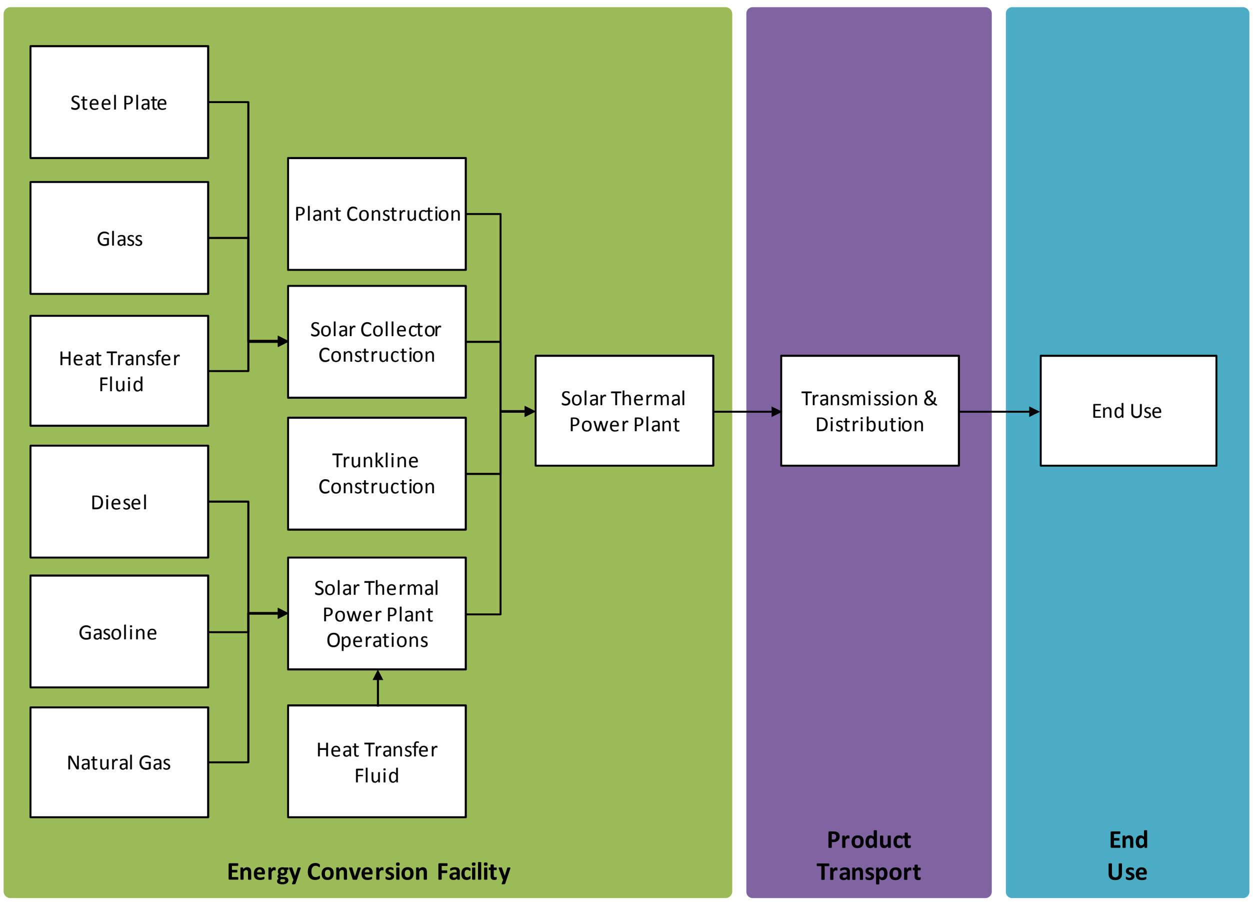


Table 4-1: Solar Thermal Power Modeling Parameters

Parameter	Expected Value	Units
Net Plant Capacity	250	MWnet
Capacity Factor	27.4%	Percent
Plant Life	30	Years
Trunkline Distance	40.2	km
Solar to Electric Conversion Efficiency	14.3%	Percent
Intensity of Solar Radiation (Insolation)	3.558E-04	MW/m^2
Solar Collector Density	28.50	kg/m^2
Share of Steel in Parabolic Trough	75%	Percent

4.2 LCA Data

The LCA model of this analysis uses a screening approach, which means that proxy data were used instead of developing new data specific to solar thermal systems. Four key processes were identified for the construction and operation of a solar thermal power plant:

- Solar collector construction and installation
- Power plant construction and installation
- Power plant operation
- Trunkline construction and operation

The data used for these four processes are described below.

4.2.1 Solar Collector Construction and Installation

The inputs to this unit process are steel plate and glass, which comprise the solar collectors. The total mass of the solar collectors is determined by the size of the plant, the conversion efficiency from solar energy to electricity (STE), the intensity of solar radiation (insolation), and the total area of solar collectors at the site. The unit process also includes inputs for the initial charge of heat transfer fluid (HTF) into the plant and water use during the construction of the solar thermal plant.

The energy and material flows for the upstream production and delivery of steel, glass, and HTF are not included in this unit process but are accounted for by other unit process. The process is based on the reference flow of one piece of solar collector construction and installation per 1 MWh of electricity produced.

4.2.2 Power Plant Construction and Installation

The scope of this unit process covers the construction and installation of a solar thermal power plant. The construction and installation of a single natural gas combined cycle (NGCC) power plant was used as a proxy for the solar thermal power plant. No data are available for the construction of a solar thermal power plant; however, the heat exchange equipment and turbines used by a natural gas power plant are similar to those used by a solar thermal power plant, so it was used as a proxy for the solar thermal power plant. Inputs to the unit process for the construction of the plant include steel plate, steel pipe, aluminum sheet, cast iron, and concrete. The energy and material flows for the upstream production and delivery of steel, concrete, aluminum, and cast iron are not included in this unit process but are accounted for by other unit processes. Diesel, water, and emissions associated with plant installation are also included. The process is based on the reference flow of one piece of solar thermal power plant construction and installation per 1 MWh of electricity produced.

4.2.3 Power Plant Operation

This unit process accounts for diesel, gasoline, and natural gas combustion for auxiliary processes at the solar thermal power plant. Diesel fuel is used to supply both a fire pump and an emergency generator. Natural gas is used to supply an auxiliary boiler. Gasoline is used to fuel maintenance vehicles at the facility. This unit process accounts for direct combustion emissions of all three fuels, but does not include upstream acquisition and transport. Those impacts are accounted for by other unit processes. The final input to this unit process is additional HTF that is added to account for system losses. An upstream unit process accounts for the emissions associated with the production of the heat transfer fluid.

4.2.4 Trunkline Construction and Installation

This unit process provides a summary of relevant input and output flows associated with the construction of a trunkline that connects the solar thermal power plant to the main electricity transmission grid. Key components include steel towers, concrete foundations, and steel-clad aluminum conductors. The lifetime electricity throughput of the trunkline is estimated in order to express the inputs and outputs on the basis of mass of materials per 1 MWh of electricity transport.

4.3 LCA Results

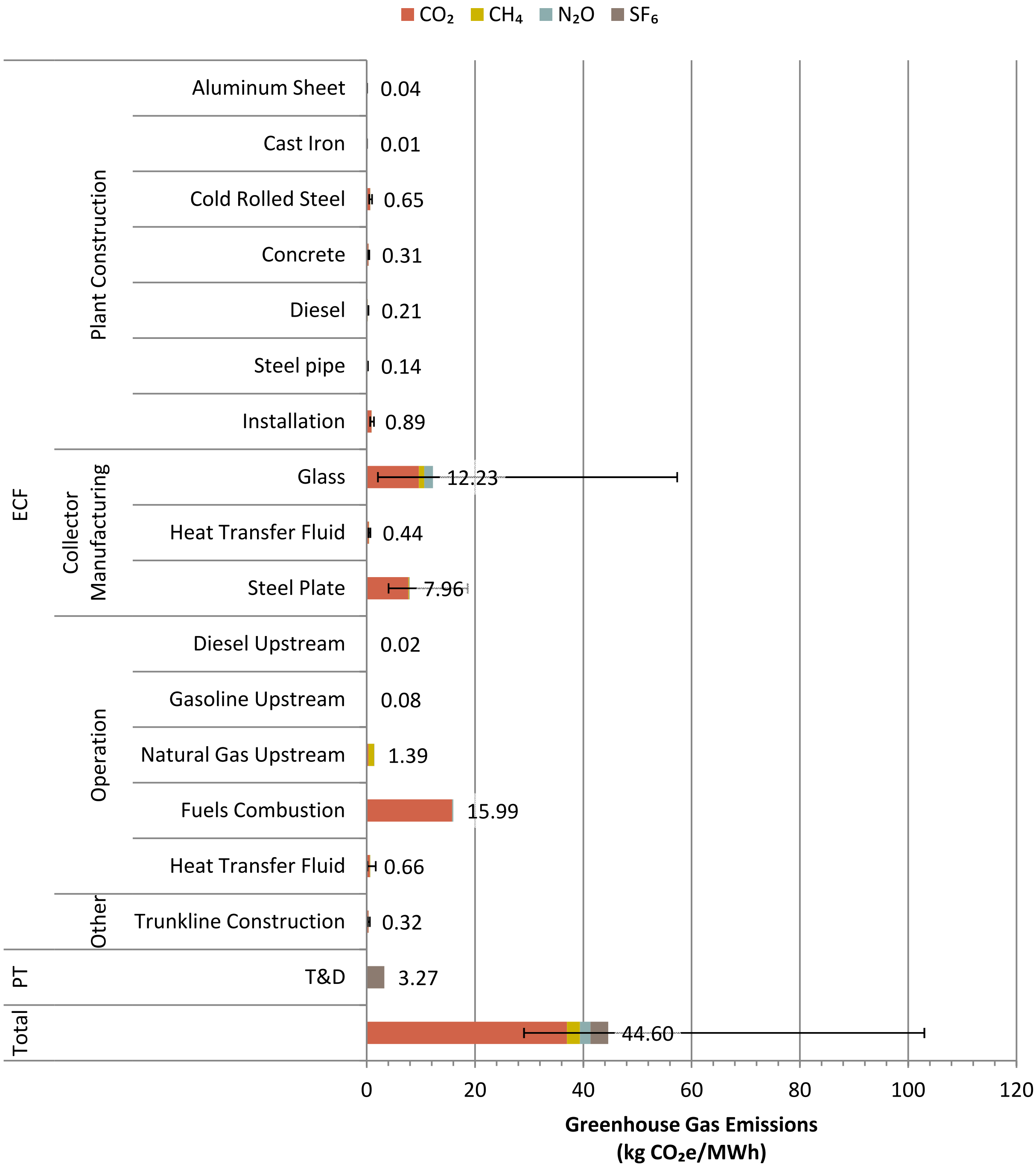
The LCA model of this analysis accounts for the air and water emissions of the LC of solar thermal power, including emissions from the construction and installation of solar thermal facilities and the transmission and distribution of electricity. All results are expressed on the basis of 1 MWh of electricity delivered to the consumer.

The LC GHG emissions for solar thermal power are 44.60 kg CO_2e/MWh and are shown in **Figure 4-2**. The majority of LC GHG emissions are from CO_2 at 82.9 percent, with the remainder split between CH_4, N_2O, and SF_6 at 5.4 percent, 4.4 percent, and 7.3 percent respectively. Solar collector construction accounts for 46.3 percent of the LC GHG emissions for solar thermal power, while plant operation accounts for 40.7 percent. The construction of the plant and the trunkline contribute a combined 5.7 percent, while transmission and distribution (T&D) accounts for 7.3 percent.

The construction of the solar collector includes upstream emissions related to the production of glass, steel, and heat transfer fluid. As shown in **Table 4-1**, the solar collector consists of 75 percent steel and 25 percent glass by mass. The LC GHG emissions from glass production are higher than those for steel production even at a much smaller share of the finished collector.

The operation of the solar thermal facility results in the combustion of diesel, gasoline, and natural gas in auxiliary systems. The combustion of natural gas accounts for 13 percent of the LC GHG emissions and the combustion of gasoline accounts for 19 percent. The amount of diesel combusted is much less than either of the other fuels; therefore, the contribution to LC GHG emissions is also much less significant, at only 4 percent. The operation of the solar thermal facility also requires heat transfer fluid; however, the GHG contribution is small relative to the other processes.

Figure 4-2: Life Cycle GHG Process Drilldown for Solar Thermal Power



Detailed GHG results for solar thermal power are shown in **Figure 4-2**. All values are expressed in kg of carbon dioxide equivalents (CO_2e) per MWh of delivered electricity. The CO_2e values are calculated from the GHG inventory results using 100-year global warming potentials (GWP) of 298 for N_2O, 25 for CH_4, and 22,800 for SF_6 (Forster et al., 2007).

Table 4-2: Life Cycle GHG Emissions for Solar Thermal Power (kg CO_2e/MWh)

Solar Thermal Power Stages, Substages, and Processes			CO_2	CH_4	N_2O	SF_6	Total
ECF	Plant Construction	Aluminum Sheet	3.515E-02	8.131E-08	1.442E-03	1.814E-04	3.677E-02
		Cast Iron	1.042E-02	1.261E-05	3.562E-04	4.519E-05	1.084E-02
		Cold Rolled Steel	6.268E-01	1.037E-07	1.837E-02	1.215E-03	6.464E-01
		Concrete	2.958E-01	7.889E-04	1.243E-02	7.736E-04	3.098E-01
		Diesel	1.809E-01	7.744E-09	2.888E-02	1.059E-03	2.108E-01
		Installation	1.375E-01	0.000E+00	3.641E-03	2.288E-03	1.434E-01
		Steel Pipe	8.807E-01	0.000E+00	1.266E-03	6.767E-03	8.887E-01
	Collector Construction	Glass	9.628E+00	9.459E-07	1.006E+00	1.601E+00	1.223E+01
		Heat Transfer Fluid	3.935E-01	1.941E-08	4.702E-02	1.448E-03	4.419E-01
		Steel Plate	7.693E+00	0.000E+00	1.459E-01	1.191E-01	7.958E+00
	Operation	Diesel	1.383E-02	5.921E-10	2.208E-03	8.096E-05	1.612E-02
		Gasoline	6.981E-02	3.160E-09	1.097E-02	4.124E-04	8.120E-02
		Natural Gas	3.425E-01	5.735E-05	1.041E+00	2.708E-03	1.386E+00
		Fuels Combustion	1.578E+01	0.000E+00	1.021E-02	2.032E-01	1.599E+01
		Heat Transfer Fluid	5.902E-01	2.911E-08	7.053E-02	2.172E-03	6.629E-01
	Trunkline	Trunkline	3.067E-01	1.030E-04	1.088E-02	1.234E-03	3.189E-01
PT	Transmission and Distribution	Transmission and Distribution	0.000E+00	3.268E+00	0.000E+00	0.000E+00	3.268E+00
Total			**3.698E+01**	**3.269E+00**	**2.411E+00**	**1.943E+00**	**4.460E+01**

In contrast to fossil energy and some forms of renewable energy conversion, solar thermal power does not incur any environmental burdens for the acquisition and transport of primary fuel. Thus, the equipment manufacture and construction and installation requirements of solar thermal power plants dominate the LCA results for solar thermal power.

In addition to GHG emissions, the LC model also included an extended set of air and water emissions. **Table 4-3** provides the LC results for a selected group of air pollutants, including criteria air pollutants. This study was not performed as a comparative analysis, so there are no reference values for the emissions to other power generation technologies. The majority of lead and mercury emissions results from the fabrication processes to make steel for the facility and collectors. Glass manufacturing accounts for a significant portion of the ammonia, particulate matter (PM), sulfur dioxide (SO_2), and volatile organic compound (VOC) emissions. Fuels combustion in support of the operation of the solar thermal facility composes most of the carbon monoxide (CO) and nitrogen oxides (NO_X) emissions. A comprehensive list of metrics (GHG emissions, criteria and other air pollutants of concern, water use, water quality, and energy resources) and the corresponding values for each of the LC sub-stages are presented in **Appendix C.**

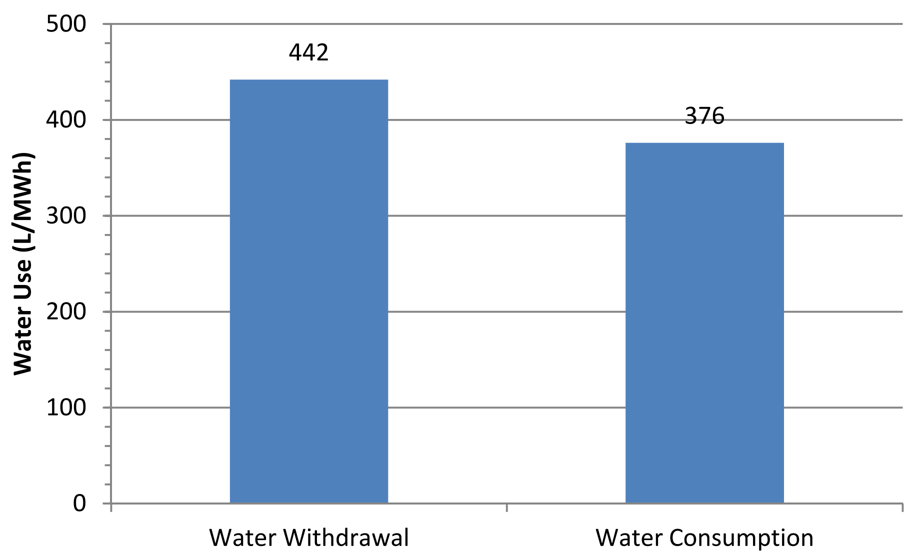
The energy return on investment (EROI) was also calculated for solar thermal. EROI is defined as the ratio of usable, acquired energy to energy expended. For solar thermal power generation the value is 8.2:1.

Table 4-3: Other Life Cycle Air Emissions for Solar Thermal Power (kg/MWh)

Air Emission	Plant Construction	Collector Construction	Operation	Trunkline	Total
Pb	1.561E-06	1.546E-05	4.737E-08	2.572E-07	1.733E-05
Hg	1.648E-08	9.915E-07	2.750E-09	1.962E-09	1.013E-06
NH_3	4.102E-05	1.858E-05	5.793E-06	1.050E-06	6.644E-05
CO	4.883E-02	6.954E-02	4.865E-01	2.535E-03	6.074E-01
NO_X	1.718E-02	3.533E-02	4.134E-02	5.212E-04	9.437E-02
SO_2	3.147E-03	5.284E-02	2.389E-03	8.005E-04	5.917E-02
VOC	6.499E-04	2.947E-02	7.411E-03	4.952E-05	3.758E-02
PM	4.783E-03	2.906E-02	4.978E-04	8.767E-04	3.522E-02

Figure 4-3 shows the water use associated with solar thermal power production. Water consumption is approximately 85 percent of the total of water withdrawals. The majority of water consumption results from construction and operations activities at 51 percent and 32 percent, respectively, and steel plate manufacturing for solar collector fabrication at 11 percent. Within the operation activities, water is consumed for cooling water makeup, process water makeup, and mirror washing (BLM, 2010b).

Figure 4-3: Solar Thermal Power Water Use



4.3.1 Sensitivity and Uncertainty for Solar Thermal Power

Table 4-4 shows the parameters that were evaluated to understand the sensitivity and uncertainty in the LCA model for solar thermal power.

Table 4-4: Solar Thermal LCA Modeling Parameters

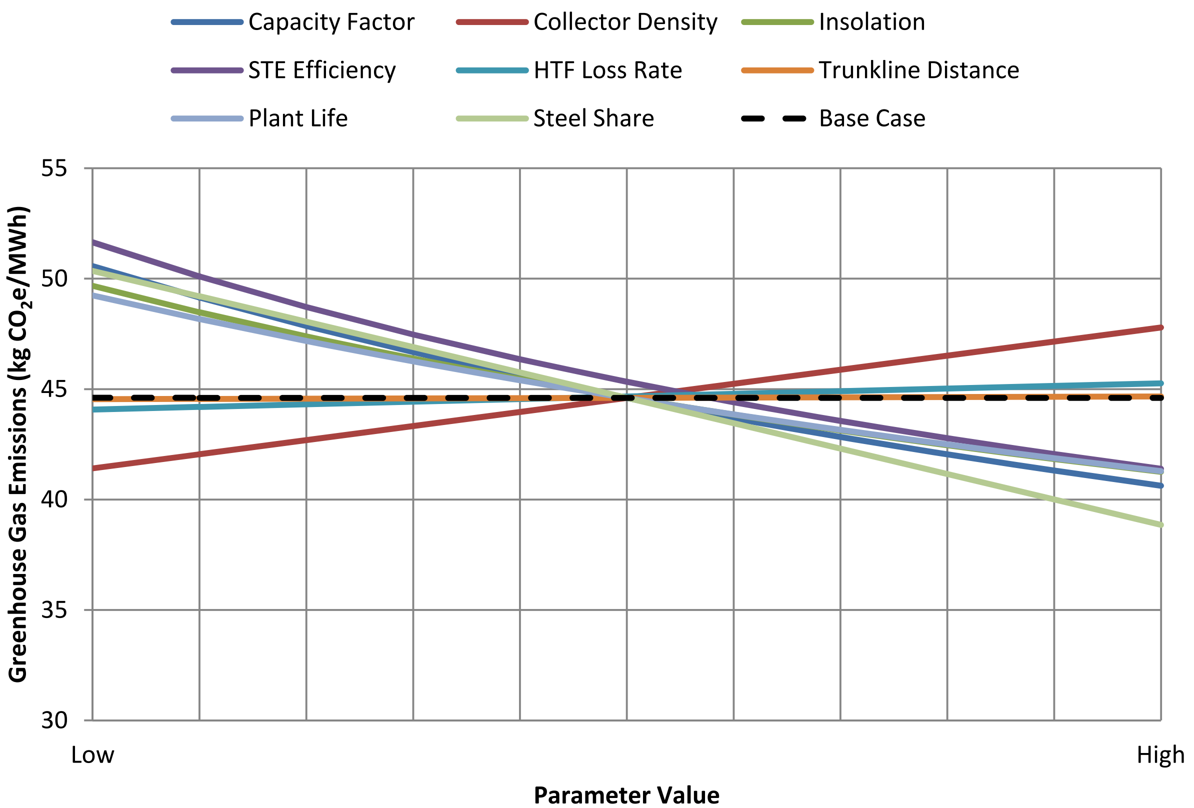
Parameter	Low Value	Expected Value	High Value	Units
Capacity Factor	21.9%	27.4%	32.9%	Percent
Solar Collector Density	24	28.5	33	kg/m^2
Intensity of Solar Radiation (Insolation)	2.69E-04	3.36E-04	4.03E-04	MW/m^2
Solar to Electric Conversion Efficiency	10.6%	14.3%	17.0%	Percent
Heat Transfer Fluid Loss Rate	1.0%	5.0%	10%	Percent
Trunkline Distance	32	40.2	48	km
Plant Life	25	30	35	Years
Share of Steel in Parabolic Trough	60%	75%	90%	Percent

Figure 4-4 shows the range of LC GHG emissions for solar thermal power as a function of the range of values for the model input parameters shown in **Table 4-4**. The expected value base case result of 44.60 kg CO_2e/MWh is shown for reference as a dashed line. The figure also indicates where in the range of parameter values the expected value input is located at the point where the parameter line crosses the base-case line. Only one parameter is varied at a time, with the other parameters remaining at the expected value used in the model. Therefore, the figure does not show any interaction between certain parameters.

The figure shows that the most important parameters with respect to the LC GHG profile for solar thermal power are the STE efficiency, intensity of solar radiation, capacity factor, plant life, and steel share of the solar collector materials. The first four parameters directly affect the amount of power that is generated from the plant over the lifetime. With an increase in the plant lifetime, the same construction and infrastructure burdens are appropriated to an increased lifetime power generation, which decreases the overall LC GHG emissions. As illustrated by **Figure 4-2**, the production of the steel and glass that makeup the solar collectors are significant in the overall LC of solar thermal power. In the base case, the steel share of the solar collector mass is 75 percent and the glass share is 25 percent. **Figure 4-2** shows that the GHG emissions for glass production are higher than for steel and include more CH_4 and N_2O, even at a share of only 25 percent of the collector. Thus, the model is sensitive to the exact material makeup of the solar collector with a lower share of glass resulting in lower LC GHG emissions.

Parameters that are not directly associated with the power output of the solar thermal plant are not as sensitive in the model. Specifically, the trunkline distance and the HTF loss rate do not significantly impact the LC GHG profile for solar thermal power. The solar collector density is important, but to a smaller degree than the parameters that directly affect power output.

Figure 4-4: Uncertainty and Sensitivity of Solar Thermal Power LC GHG Emissions



4.4 Land Use Change

Analysis of land use effects is considered a central component of an LCA under both the International Organization for Standardization (ISO) 14044 and the American Society for Testing and Materials (ASTM) standards. Additionally, the U.S. Environmental Protection Agency (EPA) released a final version of the Renewable Fuel Standard Program (EPA 2010). Included in the Renewable Fuel Standards 2 (RFS2) is a method for assessing land use change and associated GHG emissions relevant to this LCA. The land use analysis presented in this study is consistent with the method presented in the RFS2. It quantifies both the area of land changed as well as the GHG emissions associated with that change, for direct and select indirect land use impacts.

4.4.1 Definition of Direct and Indirect Impacts

Land use effects can be roughly divided into direct and indirect. In the context of this study, direct land use effects occur as a direct result of the LC processes needed to produce electricity through solar thermal power production. Direct land use change is determined by tracking the change from an existing land use type (native vegetation or agricultural lands) to a new land use that supports production.

Indirect land use effects are changes in land use that occur as a result of the direct land use effects. For instance, if the direct effect is the conversion of agricultural land to land used for energy production, an indirect effect might be the conversion of native vegetation to new farmland, but at a remote location, in order to meet ongoing food supply/demand. This specific case of indirect land use change has been studied in detail by the U.S. EPA (EPA 2010) and other investigators, and sufficient data are available to enable its consideration within this study. There are also many other types of indirect land use change that could result from installation and operation of new energy production and conversion facilities. The installation of new agricultural production for energy cropping in a rural location could result in the migration of employees closer to the site, causing increased urbanization in surrounding areas. However, due to high uncertainty in predicting and quantifying this and other less studied indirect effects, only the displacement of agricultural lands resulting in conversion of other land uses to agriculture was considered within the scope of this study.

4.4.2 Land Use Metrics

A variety of land use metrics, which seek to numerically quantify changes in land use, have been devised in support of LCAs. Two common metrics in support of a process-oriented LCA are transformed land area (square meters of land transformed) and GHG emissions (kg CO_2e). The transformed land area metric estimates the area of land that is altered from a reference state, while the GHG metric quantifies the amount of carbon emitted in association with that change. **Table 4-5** summarizes the land use metrics included in this study.

Table 4-5: Primary Land Use Change Metrics Considered in this Study

Metric Title	Description	Units	Type of Impact
Transformed Land Area	Area of land that is altered from its original state to a transformed state during construction and operation of the advanced energy conversion facilities and biomass production	m^2 (Acres)	Direct and Indirect
Greenhouse Gas Emissions	Emissions of GHGs associated with land clearing/transformation, including emissions from aboveground biomass, belowground biomass, and soil organic matter	kg CO_2e (lbs CO_2e)	Direct and Indirect

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

1. Quantity of GHGs emitted due to biomass clearing during construction of each facility.
2. Quantity of GHGs emitted due to oxidation of soil carbon and underground biomass following land transformation.
3. Evaluation of ongoing carbon sequestration that would have occurred under existing conditions, but did not occur under study/transformed land use conditions.

Additional land use metrics, such as potential damage to ecosystems or species, water quality changes, changes in human population densities, quantification of land quality (e.g. farmland quality), and many other land use metrics, may conceivably be included in the land use analysis of an LCA. However, data needed to support accurate analysis of these metrics are severely limited in availability (Canals et al., 2007; Koellner & Scholz, 2007), or otherwise outside the scope of this study. Therefore, only transformed land area and GHG emissions are quantified for this study.

4.4.3 Land Use Calculation Methods

As previously discussed, the land use metrics used for this analysis quantify the land area that is transformed from its original state due to construction and operation of the facilities required for the solar thermal case considered in this study. Results from the analysis are presented as per the reference flow for each relevant LC stage, or per MWh when considering the additive results of all stages.

4.4.3.1 Transformed Land Area

The transformed land area metric was assessed using data available from the U.S. Bureau of Land Management (BLM, 2010b), based on an environmental impact statement prepared for a parabolic trough solar thermal power plant in southwestern California. The EIS provided a detailed estimate of land-area requirements, combined with an evaluation of direct land-use emissions, including loss of on-site vegetation and lost sequestration. Existing land uses were apportioned according to state-level land use data available from the United States Department of Agriculture (USDA) (2005). Assumed facility locations are shown in **Table 4-6**. The facility sizes, locations, and other parameters for production of power from solar thermal used elsewhere in this LCA were incorporated into the transformed land area metric for consistency. It is assumed that the U.S. power grid system was pre-existing, and no construction or other changes would occur under LC Stage #5 that would be relevant to land use.

Table 4-6: Solar Thermal Power Facility Location

LC Stage	Facility	Location
ECF	Solar Thermal Field	U.S. Desert Southwest
T&D	Solar Thermal Trunkline	U.S. Desert Southwest

There was no indirect land use change since no agricultural land was displaced by the solar thermal facility modeled in this study.

4.4.3.2 Greenhouse Gas Emissions

GHG emissions due to land use change were evaluated based upon the U.S. EPA's methodology for the quantification of GHG emissions, in support of RFS2 (EPA, 2010). Briefly, EPA's analysis quantifies GHG emissions that are expected to result from land use changes from forest, grassland, savanna, shrubland, wetland, perennial, or mixed land use types to agricultural cropland, grassland, savanna, or perennial land use types. Relying on an evaluation of historic land use change completed by Winrock, EPA calculated a series of GHG emission factors for the following criteria: change in biomass carbon stocks, lost forest sequestration, annual soil carbon flux, methane emissions, nitrous oxide emissions, annual peat emissions, and fire emissions that would result from land conversion over a range of timeframes. EPA's analysis also includes calculated reversion factors for the reversion of land use from agricultural cropland, grassland, savanna, and perennial, to forest, grassland, savanna, shrub, wetland, perennial, or mixed land uses. Emission factors considered for reversion were change in biomass carbon stocks, change in soil carbon stocks, and uptake of annual soil carbon over a variety of timeframes. Each of these emission factors, for land conversion and reversion, was included for a total of 756 global countries and regions within countries, including the 48 contiguous states.

Based on the land use categories (grassland and pasture) that were affected by study facilities, EPA's emission factors were applied on a statewide or regional basis. For a more extensive review of the methods used to evaluate GHG emissions from land use change used by EPA for RFS2, please refer to EPA (2010). There were no indirect land use GHG emissions since no agricultural land was displaced by the solar thermal facility modeled in this study.

4.4.4 Land Use Results

Results from the analysis of transformed land area are illustrated in **Figure 4-5**. As shown, solar thermal power production results in approximately 0.43 m^2/MWh of transformed land area. Land transformation is caused almost exclusively by installation of the solar field and generation block, which together consume 1,720 acres of land area for a 250 MW net facility. Based on the facility's location within the Desert Southwest, the primary existing land types are dominated by grassland, dry pasture, and desert scrub (considered together as grassland in the figure below). There was no existing agricultural land use.

Figure 4-5: Transformed Land Area from Direct Land Use

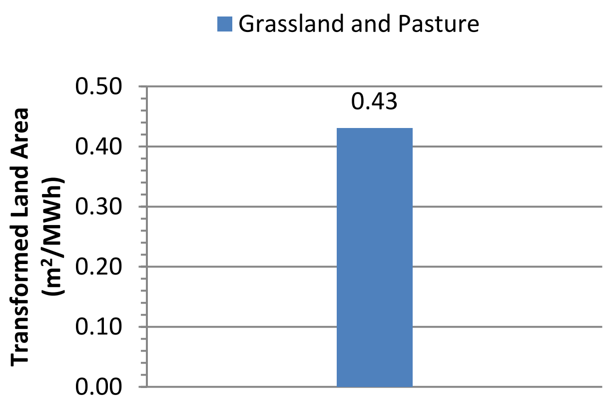
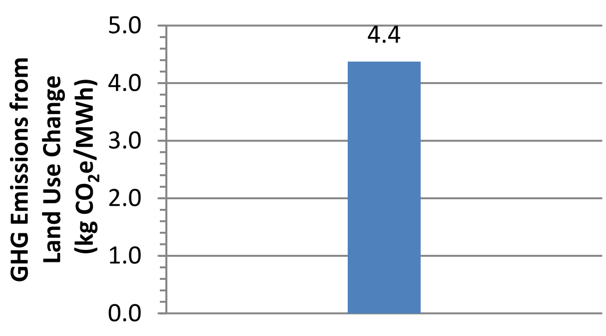


Figure 4-6 shows results from the analysis of GHG emissions from direct land use. Direct land use GHG emissions account for 4.4 kg CO_2e/MWh, or approximately 10 percent of non-land-use LC GHG emissions for solar thermal power production. Direct land use results primarily from a high estimate of GHG emissions associated with loss of onsite vegetation and disturbance to soils, as documented by BLM (2010b).

Figure 4-6: Direct Land Use GHG Emissions



5 Cost Analysis of Solar Thermal Power

The life cycle costs (LCC) of solar thermal power were calculated by performing a discounted cash flow analysis over the lifetime of a solar thermal power plant.

5.1 LCC Approach and Financial Assumptions

The LCC analysis accounts for the significant capital and O&M expenses incurred by the solar thermal power systems. The LCC calculates the cost of electricity (COE), which is the revenue received by the generator per net MWh during the first year of operation. The COE is the preferred cost metric of NETL's bituminous baseline (NETL, 2010); however, the LCOE is also calculated in this analysis to provide a basis of comparison against past LCC analyses. The LCC calculations were performed using NETL's Power Systems Financial Model (PSFM), which calculates the capital charge factors necessary for apportioning capital costs per unit of production.

Cash flow is affected by several factors, including cost (capital, O&M, replacement, and decommissioning or salvage), book-life of equipment, federal and state income taxes, equipment depreciation, interest rates, and discount rates. Modified accelerated cost recovery system (MACRS) depreciation rates are used in this analysis. O&M costs are assumed to be consistent over the study period except for the COE and feedstock materials determined by the Energy Information Administration (EIA).

Capital investment costs are defined as equipment, materials, labor (direct and indirect), engineering and construction management, and contingencies (process and project). Capital costs are assumed to be "overnight costs" (not incurring interest charges) and are expressed in 2007 constant dollars. Accordingly, all cost data are normalized to 2007 dollars.

The boundaries of the LCC are consistent with the boundaries of the environmental portion of the LCA, ending with the delivery of 1 MWh of electricity to a consumer. The capital costs for the solar thermal power facilities account for all upstream economic activities related to the extraction, processing, and delivery of construction materials. The O&M costs of solar thermal power do not require the purchase of a primary fuel, but do account for labor and maintenance costs. Finally, all costs at the solar thermal power facility are scaled according to the delivery of 1 MWh of electricity to the consumer, which includes a seven percent transmission and distribution loss between the power facility and the consumer.

The calculation of LCC also requires the specification of financial assumptions. The expected value case of this cost analysis is a low-risk, investor-owned utility with a 50/50 debt-to-equity ratio, a 4.5 percent interest rate, and an internal rate of return on equity of 12 percent. The low cost and high cost cases were modeled by varying the internal rate of return on equity from 6 percent to 18 percent. The financial assumptions for the low, expected value, and high cost cases are shown in **Table 5-1**.

Table 5-1: Financial Parameters for Solar Thermal Power

Financial Parameter	Low Cost Case	Expected Value Cost Case	High Cost Case
Financial Structure Type	Low-risk Investor-owned Utility with Low Return on Equity	Low-risk Investor-owned Utility	Low-risk Investor-owned Utility with High Return on Equity
Debt Fraction (1 - equity), Percent		50%	
Interest Rate, Percent		4.5%	
Debt Term, Years		15	
Plant Life, Years	30	30	25
Depreciation Period (MACRS)		20	
Tax Rate, Percent		38%	
O&M Escalation Rate, Percent		3%	
Capital Cost Escalation During the Capital Expenditure Period, Percent		3.6%	
Base Year		2007	
Required Internal Rate of Return on Equity (IRROE)	6.0%	12.0%	18.0%

5.2 Power Cost Data

The key source of cost data for solar thermal power is *Cost and Performance Assumptions for Modeling Electricity Generation Technologies* (Tidball, et al., 2010). It includes cost data for key renewable energy technologies and compares them to fossil and nuclear technologies. It compares the solar thermal capital costs reported by six data sources and also reports fixed O&M costs.

5.2.1 Capital Costs

The range of solar thermal capital costs reported by Tidball, et al. is used for the cost model of this analysis. The capital costs reported range from $4,500/kW to $5,000/kW and have an expected value cost of $4,693/kW (Tidball, et al., 2010). These costs are in 2007 dollars.

Power lines are required to connect the solar thermal power plant to the electricity grid (referred to as a trunkline). This analysis uses 25 miles as an expected value trunkline distance, as indicated by the EIS for the Genesis Solar Thermal Project (BLM, 2010). An uncertainty range of +/- 20 percent was applied to this expected value trunkline distance, giving a low value of 20 miles and a high value of 30 miles. At a per-mile cost of $912 thousand, a 20-mile trunkline is $18.2 million, a 25-mile trunkline is $22.8 million, and a 30-mile trunkline is $27.4 million.

A two-year construction period is assumed for a solar thermal facility. This includes site preparation, installation of the collector field, construction and installation of the power plant, and construction of the installation of the trunkline.

5.2.2 Decommissioning

This analysis estimates that the decommissioning of solar thermal power plants are 10 percent of the capital costs of initial construction. The cost model of this analysis capitalizes decommissioning costs, but does not consider them a depreciable asset.

5.2.3 O&M Costs

The expected value fixed O&M costs for solar thermal power are $56.78/kW (Tidball, et al., 2010). These costs are in 2007 dollars. None of the data sources include variable O&M costs. Fixed O&M costs account for the majority of O&M costs of solar thermal power.

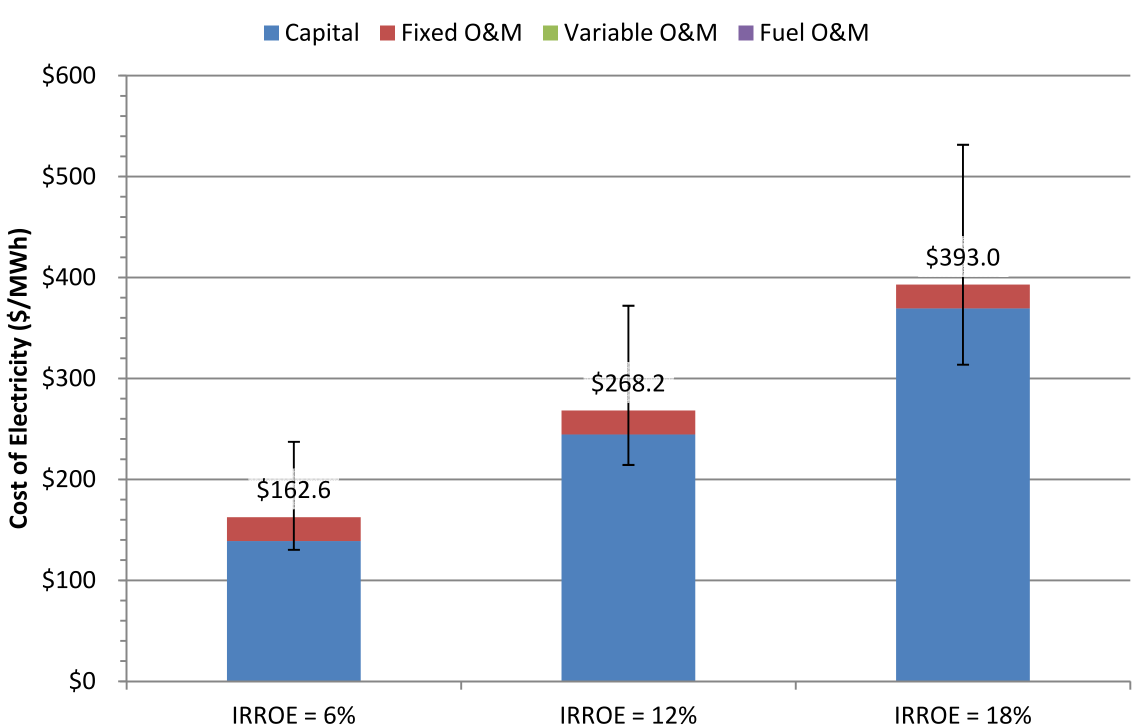
Table 5-2: Cost Summary for Solar Thermal Power

Parameter	Units	Low Cost Case	Expected Value Cost Case	High Cost Case
Capital (Solar Collectors and Power Plant)	2007$/kW	4,500	4,693	5,000
Capital (Trunkline)	2007$/kW	72.9	91.2	109
Decommissioning	2007$/kW	457	478	511
Fixed O&M (Annual)	2007$/MW-yr		56,780	
Plant Life	Years	30	30	25
Net Plant Capacity	MWnet		250	
Capacity Factor	Percent	32.9%	27.4%	21.9%

5.3 LCC Results

The COE of solar thermal power at the expected IRROE of 12 percent is $268.2/MWh, as shown in **Figure 5-1**. This value is representative of the expected value financial assumptions shown in **Table 5-1** and the expected value cost parameters shown in **Table 5-2**. It accounts for a seven percent electricity loss during transmission and distribution and is expressed in 2007 dollars.

Figure 5-1: Life Cycle COE of Solar Thermal Power at Different Rates of Return



Solar thermal power does not require the purchase of fuel, so the O&M costs for solar thermal power are low in comparison to power technologies that use fossil fuels or other non-renewable energy sources. Capital costs dominate the COE for solar thermal power, comprising 91.18 percent of the COE of solar thermal power.

The cost characteristics of solar thermal power, like other renewable energy technologies, are site specific, which contributes to the uncertainty in COE. The uncertainty in COE for solar thermal power includes ranges in capital costs, plant lifetimes, O&M costs, and capacity factors. When these parameters are adjusted to a best-case cost scenario, the COE for solar thermal power is \$214.4/MWh. When all of these parameters are adjusted to a worst-case cost scenario, the COE for solar thermal power is \$372.1/MWh. The internal rate of return on equity (IRROE) for this uncertainty analysis was held constant at 12 percent.

This analysis uses the IRROE as a parameter for modeling financial risk scenarios. The expected value IRROE is 12 percent. However, if investors consider solar thermal power a low-risk proposition, then the IRROE could be as low as 6 percent. Conversely, if investors consider solar thermal power a high-risk proposition, then the IRROE could be as high as 18 percent. **Figure 5-1** shows the effect of IRROE on the COE of solar thermal power. The three scenarios in **Figure 5-1** show an IRROE of 6, 12, and 18 percent; the error bars for each scenario represent the low and high parameters as shown above in **Table 5-2**.

6 Barriers to Implementation

Key barriers to the implementation of solar thermal power include cost, water use, and grid connection.

6.1 Cost

Cost is a key factor in the consideration of solar thermal power. According to the EIA (2011b), high temperature solar thermal collectors, such as those utilized for concentrating solar power, cost an average of $25.32/square foot, although some industry sources have estimated up to $55/square foot. Considering that the installation of one GW of utility-scale solar thermal can require over two square miles of solar fields, the importance of collector cost becomes immediately obvious. Add to this the cost of the power block, thermal storage (as relevant), installation costs, operation costs, and various other costs, and it becomes evident that the price of installing solar thermal can be a key limiting factor.

High capital costs translate into either high-debt servicing costs or demand for significant amounts of investor capital. To avoid these issues, many successful utility-scale solar thermal development firms have partnered with large engineering and construction corporations, which are able to finance solar power development in exchange for a share of eventual sales. This and similar strategies have allowed solar thermal developers to move forward even though available capital has been impacted since the start of the global economic downturn in 2008. Over time, as capital becomes more readily available, and (presumably) as solar thermal collectors and associated facilities continue to drop in price, solar thermal power production is expected to become more easily implemented under other financing schemes.

6.2 Water Use and Water Consumption

Water use is another potential barrier to the widespread implementation of utility-scale solar thermal power production. For example, the approved (but not yet constructed) Blythe Solar Power Plant, located in the Mojave Desert of southeastern California, has a nameplate generation capacity of 1,000 MW. During operations, the project would require approximately 600 acre-feet (195 million gallons) of water-per-year for cooling. An additional 4,100 acre-feet (1.3 billion gallons) of water would be required in support of project construction (BLM, 2010a). The water demands for operations and construction correspond to 0.0036 and 0.0243 percent of annual rainfall in the Mojave Desert (USGS, 2005). If located in the Northwest, East, South, or other areas of the country where water is comparatively plentiful, such water use is not likely to be a primary issue of concern; however, the Blythe project, like nearly all of the proposed or approved solar thermal projects listed previously, is located in the desert southwest where very minimal water resources are available.

Over the 30-year lifetime of the Blythe project, the facility would use about 22,100 acre-feet of water. This is about the amount of water needed to serve 44,000 households for a 1-year period, or approximately 1,450 households annually for 30 years. As discussed in the EIS for the Blythe project (BLM, 2010a), the proposed water use would result in a small amount of groundwater drawdown, but would not be expected to result in permanent effects to the underlying reservoir, such as subsidence or substantial interference, with the hydrology of the nearby Colorado River. These figures are based on the use of cooling towers that evaporate water to provide cooling. However, in order to reach final approval for the Blythe project, regulators required that the project's cooling system be redesigned to instead utilize dry-cooling technology (IEEE Spectrum, 2010). Dry cooling avoids the need for water, but results in lower net power production and lower net efficiency, especially during the hottest periods (often when solar resources are best for generating power). Thus, the availability of sufficient water for cooling is considered a key limiting factor for solar thermal in areas where water is scarce, both in terms of cooling technologies applied, as well as overall plant efficiency and the location in which the plant can be installed.

6.3 Grid Connection

Availability of power transmission capacity, combined with the difficulty of constructing long-distance power transmission lines, is another key barrier to the implementation of solar thermal power production. As shown in **Figure 3-1**, much of the best solar thermal resources are in many cases located in the desert southwest, in areas that are distant from existing population centers. Many areas with good solar thermal resources are also distant from existing power transmission lines that are needed to carry energy onto the power grid. However, like other renewables, such as wind, geothermal, and hydropower, achieving reasonable access to potential sites and connecting to existing transmission lines are major barriers to the implementation of additional solar thermal capacity. As a result, many high quality solar thermal resources in the southwest are expected to remain untapped for the foreseeable future, for the simple reason that new transmission facilities are (1) expensive to construct and (2) difficult to permit (Smith & Bruvsen, 2010). For remote solar thermal resources, sharing transmission line construction and permitting efforts among many facilities, or with other renewables projects, may be the only workable scenario. However, implementing such agreements requires long-term planning due to long lead times for major transmission facility permitting and installation requirements, making such agreements difficult to reach and administer.

7 Risks of Implementation

Based on a review of public comments received on solar thermal power projects that were recently approved in southeastern California, many of the proposed solar thermal installations are a source of considerable public concern. Key issues that are consistently raised across many projects include:

- Loss of biological resources/habitat
- Water use and consumption
- Interference with water supply
- Aesthetic concerns
- Interference with geologic or geomorphic processes, such as sand migration and erosion
- Flooding associated with desert washes
- Airborne emissions (primarily dust but also other air pollutants)
- Concerns regarding GHG emissions during construction
- Potential to exacerbate secondary effects of climate change, such as heat waves

Among these, land use change/habitat loss, water use and consumption, interference with natural drainage patterns, and aesthetic concerns were most frequently commented on.

Habitat loss can be substantial for large solar thermal projects. For instance, the Blythe Solar Power Project, which has been approved and is expected to have a generation capacity of around 1,000 MW, would result in disturbance to approximately 7,025 acres of land area, equivalent to nearly 11 square miles of land area (BLM, 2010a). Most of this land area would be used for the solar field, but other uses would include generation facilities, transmission lines, and various appurtenances. The facility would be stripped of existing desert vegetation and fenced, resulting in the loss of vegetative habitat within these areas. Other effects include loss of desert tortoise habitat and migration corridors, and loss of habitat for other desert wildlife.

Water consumption rates for solar thermal are in line with other power generation technologies that utilize cooling towers, such as natural gas. However, because the best solar thermal facility sites are typically located in the desert, sourcing the necessary water volumes can be problematic to impossible, and alternate cooling techniques might be required. Key concerns included potential for interference with Colorado River flows and the consumption of water that could otherwise be utilized for agricultural, residential, or other purposes.

Interference with desert hydrology and drainage was another key concern among the projects reviewed. Of course, most of the time there is no surface water in the vicinity of the projects. However, the region where they are proposed is subject to infrequent but very high-intensity monsoonal events. During a monsoonal event, flash flooding can occur, which causes inundation of desert washes (deep overland flow of water, outside of defined streambeds). In order to protect the solar facilities from inundation during flood events, many projects have proposed installation of rip-rap- and levee-like features, flood control channels, and other modifications to re-route existing drainages around project sites. These structures can result in changes downstream, including changes in the distribution of vegetation, as well as altered erosional and sediment transport processes.

Finally, aesthetic concerns were also frequently voiced. As discussed above, large-capacity solar thermal installations are quite sizable – most require several square miles of land area. Installation of the facilities would result in permanent change to the existing visual character of the desert corridors where they would be installed. This is a concern to residents, but also to motorists who drive through the area.

8 Expert Opinions

Opinions on the future of solar thermal power include perspectives on tax incentives, cost uncertainty, and new technologies.

A significant ramp-up in activity within the utility-scale solar thermal market occurred during 2011 and passing into 2012, largely based on the long-term extension of the federal solar investment tax credit (ITC), combined with a deadline to initiate project construction by the end of 2011 in order to participate. Industry experts are predicting that many of these projects will come online during 2012-2014 (IREC, 2011). Several projects on public lands have also been fast-tracked through the government permitting and environmental review process (expedited government processing, without a lessening of environmental compliance requirements), supported by Secretary of the Interior Ken Salazar's "Fast Track" initiative for solar project applications (SEIA, 2011).

The price of solar thermal power production has dropped significantly over the last decade, and utilities predict that these prices will continue to decrease. In 2001 the price of utility-scale solar thermal power was approximately \$0.35/kWh, while in 2008 the Nevada Solar One project was reported to be producing power at approximately \$0.17/kWh. Some experts have estimated that by 2015 solar thermal prices could drop as low as \$0.05/kWh (Environmental News Network, 2008). The accuracy of such predictions is difficult to assess without knowing the underlying financial assumptions or whether the account for production tax credits. Without more details on financial assumptions or the role of tax credits, the COE calculated in this analysis (\$0.21 to \$0.37/kWh) cannot be compared directly to prices reported in literature.

Energy analysts point out that there is significant variability in the costs of solar thermal power. According to the International Energy Agency (IEA) (IEA, 2009), solar thermal investment costs range from \$4,200 to \$8,400/kW with levelized costs of electricity (LCOEs) ranging from \$0.17 to \$0.25/kWh. The volatility of the energy market is one explanation for this cost variability. For example, BrightSource energy successfully raised capital for a 392-MW solar thermal power plant in California, but has had to stall its plans because the costs of competing energy technologies, including natural gas and photovoltaic solar power, have plummeted (Cardwell, 2012).

Technical experts have proposed hybrid facilities as a viable technology mix for baseload power generation. These facilities would use a combination of solar energy and conventional fuels. Two fossil-solar thermal hybrid power plants have been approved in California, totaling 100 MW of solar power (as shown in **Table 3-2**). Others in the industry have posited solar thermal/biomass cogeneration, to support baseload power, and two such plants were briefly considered by Pacific Gas and Electric (a utility), in California, as recently as 2008 (GTM Research, 2009). No announcements have been made regarding the approval or successful permitting of these solar thermal/biomass power plants.

9 Summary

This analysis provides insight into the role of solar thermal as a future energy source in the U.S. The criteria used for evaluating the role of solar thermal power are as follows:

- Resource Base
- Growth
- Environmental Profile
- Cost Profile
- Barriers to Implementation
- Risks of Implementation
- Expert Opinions

Key conclusions for these criteria are summarized below.

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

The **growth** of solar thermal capacity in the U.S. has not been significant in the last 10 years. Total U.S. solar thermal power output was nearly constant from 2000 through 2006. The contribution of solar power to the total U.S. power supply was 0.1 percent in 2010, of which 64 percent was from photovoltaic cells and the remaining 36 percent (744 GWh) was from solar thermal power. All operating utility-scale (i.e., 10 MW and above) solar thermal plants in the U.S. use parabolic trough technology and have a total capacity of 493 MW. Most of the existing capacity, 354 MW, is located in southeastern California, as part of the Solar Electric Generating Systems (SEGS) project, which was installed incrementally from 1984 through 1990. The more recent Nevada Solar One was installed in 2007. The Martin Next Generation Solar Energy Center was completed at the end of 2010, and as of the time of publication of this document, is the most recently installed utility-scale solar thermal plant in the U.S.

The **environmental profile** of this analysis focuses on the LC GHG emissions of solar thermal power. The LC GHG emissions for solar thermal power from a 250 MW net power plant are 44.6 kg CO_2e/MWh, based on 2007 IPCC 100-year GWP factors (Forster, et al., 2007). The majority of LC GHG emissions are from CO_2 at 82.3 percent, with the remainder split between CH_4, N_2O, and SF_6 at 5.6 percent, 4.5 percent, and 7.6 percent, respectively. Solar collector construction accounts for 48 percent of the LC GHG emissions for solar thermal power, while plant operation accounts for 38 percent. The construction of the plant and the trunkline contribute a combined 6 percent, while T&D accounts for 8 percent.

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

This study was not performed as a comparative analysis, so there are no reference values for the emissions to other power generation technologies. The majority of lead and mercury emissions results from the fabrication processes to make steel for the facility and collectors. Glass manufacturing accounts for a significant portion of the ammonia, PM, SO_2, and VOC emissions. Fuels combustion in support of the operation of the solar thermal facility comprises most of the CO and NOx emissions. The EROI was also calculated for solar thermal. EROI is defined as the ratio of usable, acquired energy to energy expended. For solar thermal power generation the value is 8.21.

The **cost profile** of solar thermal power was based on a discounted cash flow analysis that calculates a COE of $268.2/MWh for solar thermal power. (COE is defined as the revenue received by the generator per net MWh during the first year of operation.) This result is based on a capital cost of $4,693/kW, a fixed O&M cost of $56,780/MW-yr, a capacity factor of 27.4 percent, and a seven percent loss of electricity during transmission and delivery. Key financial assumptions behind this result include an IRROE of 12 percent, a 30-year plant life, and MACRS depreciation. Solar thermal power does not require the purchase of fuel, so the O&M costs for solar thermal power are low in comparison to power technologies that use fossil fuels or other non-renewable energy sources. Capital costs represent for 91 percent of the COE.

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

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

The opinions of **solar thermal power experts** include predictions that many solar thermal projects will come online in 2012 through 2014, driven by long-term extensions of the federal solar tax investment credit and the associated deadline to initiate construction by the end of 2011 (IREC, 2011). Hybrid facilities have been discussed to some degree in recent industry literature, including two fossil-solar thermal hybrid power plants that have been approved in California as well as support for biomass-solar thermal cogeneration. These hybrid technologies could support baseload electricity, but the research conducted in support of this document revealed that the two biomass-solar thermal facilities in California have not been constructed and are not currently being considered for permitting or approval. Thus, fossil-solar facilities appear to have a higher probability of viability, at least in the near-term.

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

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Appendix A: Constants and Unit Conversion Factors

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Table A-1: Common Unit Conversions

Category	Input			Output	
	Value	Units		Value	Units
Mass	1	Lb.	=	0.454	kg
	1	Short Ton	=	0.907	Tonne
Distance	1	Mile	=	1.609	km
	1	Foot	=	0.305	m
Area	1	$ft.^2$	=	0.093	m^2
	1	acre	=	43,560	$ft.^2$
Volume	1	gallon	=	3.785	L
	1	$ft.^3$	=	28.320	L
	1	$ft.^3$	=	7.482	Gallons
Energy	1	Btu	=	1,055.056	J
	1	MJ	=	947.817	Btu
	1	kWh	=	3,412.142	Btu
	1	MWh	=	3,600	MJ

Table A-2: IPCC Global Warming Potential Factors (Forester, et al., 2007)

IPCC GWP Factor	Vintage	20 Year	100 Year	500 Year
CO_2	2007	1	1	1
CH_4	2007	72	25	7.6
N_2O	2007	289	298	153
SF_6	2007	16,300	22,800	32,600
CO_2	2001	1	1	1
CH_4	2001	62	23	7
N_2O	2001	275	296	156
SF_6	2001	15,100	22,200	32,400

Appendix B: Data for Solar Thermal Power Modeling

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B.1 Solar Thermal Construction

The scope of this unit process covers the construction of the energy conversion facility (ECF), in this case the solar thermal power plant. The inputs include construction materials (specifically, glass and steel) as well as an initial charge of heat transfer fluid (HTF). The output of this unit process is 1 MWh of electricity and is delivered to the life cycle (LC) Stage #4, or Transmission and Distribution (T&D), boundary.

This unit process accounts for the construction of a collector field for a 250 MW net solar thermal facility, which is part of an energy conversion facility categorized by LC Stage #3 of NETL's LCA framework. The collector field consists of parabolic trough collectors (made of steel and glass) that focus solar energy on a pipe that circulates HTF between the collector field and a power generation system. This unit process accounts for the construction of the collector field only, not the associated power generation system.

The average capacity factor of a solar thermal power plant is 27.4 percent. For a 250 MW net installation, this translates to 600,000 MWh of electricity produced per year. The plant has an operating life of 30 years (BLM 2010). All construction materials and installation requirements are divided by the lifetime electricity production (30 years times 600,000 MWh/yr) to arrive at the share of construction and installation burdens per unit of solar thermal electricity production.

Water is used during the construction of the solar thermal facility for dust suppression. According to the environmental impact statement for the Genesis Solar Energy Project (BLM 2010), 2,600 acre-feet of groundwater are used during the construction of a 250 MW net facility. An acre-foot of water is equal to 1,234,000 kg of water. Applying this conversion factor to the report, volume of groundwater translates to 3.207 billion kg of water for the construction of the facility.

The environmental impact statement (EIS) for the Genesis Solar Energy Project (BLM 2010) provides information on the HTF used by the solar thermal facility (BLM 2010).

The total volume of HTF for a 250 MW net facility is 2 million gallons of Therminol, a proprietary HTF composed of a mix of organic compounds (BLM 2010; Solutia Inc. 2011). No LC data are available for the production of Therminol, and thus this analysis uses LC data for the production of benzene as a proxy for Therminol. The density of Therminol is 1,005 kg/m^3 (8.39 lb/gal) (Solutia Inc. 2011). Factoring the total volume (2 million gallons) and density (8.39 lb/gal) and converting to metric units gives a total mass of 7.610 million kg of HTF that is contained by the solar thermal system.

The mass per unit area of a solar collector ranges from 24.0 to 33.0 kg/m^2 (Sagent & Lundy LLC Consulting Group 2003) with 28.5 kg/m^2 as the midpoint. The average solar radiation (insolation) of a solar thermal power plant in the Southwest U.S. is 8.054 kWh/m^2/day (Sagent & Lundy LLC Consulting Group 2003). In terms of power per unit area, this insolation is equivalent to 3.36E-04 MW/m^2. The solar-to-electric efficiency of a solar thermal system is 14.3 percent, with low and high bounds of 10.6 and 17.0 percent, respectively (Sagent & Lundy LLC Consulting Group 2003). All of these factors are parameterized in the unit process so the total collector area per MWh of electricity production can be calculated.

No data are available for a detailed material profile of a parabolic trough. This analysis assumes that 75 percent of the collector is comprised of carbon steel, and the remaining 25 percent is comprised of glass. These material shares are parameterized in the unit process to facilitate sensitivity analysis.

Table B-1 shows key parameters for a solar thermal power facility, and **Table B-2** shows the input and output flows of this unit process.

Table B-1: Solar Thermal Collector (Parabolic Trough) Construction Modeling Parameters

Parameter	Expected Value	Units
Net Plant Capacity	250	MW Net
Capacity Factor	27.4%	Percent
Annual Electricity Production	600,000	MWh
Plant Life	30	Years
Total Mass of Heat Transfer Fluid in System	7.610E+06	kg
Parabolic Trough Mass Per Unit Area	28.5	kg/m^2
Average Solar Radiation (Insolation)	8.054	$kWh/m^2/day$
Solar to Electric Conversion Efficiency	14.3%	Percent
Share of Steel in Parabolic Trough	75%	Percent
Share of Glass in Parabolic Trough	25%	Percent

Table B-2: Solar Thermal Construction Unit Process Input and Output Flows

Flow Name	Value	Units (Per Reference Flow)
Inputs		
Heat Transfer Fluid	4.243E-01	kg
Steel	6.208E+00	kg
Glass	2.069E+00	kg
Water (Ground Water)	1.788E+02	kg
Outputs		
Solar Thermal Electricity Generation	1	MWh

B.2 Solar Thermal Operation

The scope of this unit process covers the operation of the ECF, in this case the solar thermal power plant. The output of this unit process is 1 MWh of electricity and is delivered to the LC Stage #4, or T&D, boundary.

LC Stage #1, or raw material acquisition (RMA), is not relevant to solar thermal power because solar energy is a natural resource that does not require anthropogenic inputs prior to power generation. LC Stage #2, or raw material transport (RMT), is not relevant to solar thermal power because solar energy is a natural energy source that does not require anthropogenic inputs prior to power generation.

This unit process accounts for the steady state operation of a 250 MW net solar thermal facility, an energy conversion facility categorized by LC Stage #3 of NETL's LCA framework.

The LCA model of this analysis uses a screening approach, which means that proxy data were used instead of developing new data specific to geothermal systems. Four key existing unit processes were identified for the operation of a solar thermal power plant:

- Natural gas combusted in an auxiliary boiler
- Diesel combusted in industrial equipment
- Gasoline combusted in a maintenance vehicle
- Heat transfer fluid (HTF)

The data used for these four processes are described below.

The EIS for the Genesis Solar Energy Project (BLM 2010) specifies two auxiliary boilers that combust 30 million Btu/hr of natural gas each. These boilers operate for 1,000 hr/yr (BLM 2010). Factoring the per-boiler energy-consumption rate by the number of boilers and annual operating hours results in an annual natural gas consumption rate of 6.00E+10 Btu/yr. The heating value of natural gas is 1,027 Btu/scf and the density of natural gas is 0.042 lb/scf; applying these conversion factors to the above consumption rate (6.00+10 Btu/yr) translates to 1.11E+06 kg of natural gas combusted per year. At an expected value capacity factor of 27 percent, the 250 MW net solar thermal facility produces 600,000 MWh/yr. Dividing the natural gas consumption rate by the electricity production rate gives 1.855 kg NG/MWh. The emission factors for the combustion of natural gas in an auxiliary boiler are not accounted for in this unit process, but are accounted for by an upstream unit process (*NETL Life Cycle Inventory Data – Unit Process: NG Auxiliary Boiler*).

The EIS for the Genesis Solar Energy Project (BLM, 2010) specifies fire-pump engines and emergency generators, both fueled by diesel. The 250 MW net facility has two 315 horsepower fire-pump engines and two 1,341 horsepower emergency generators, for a total of 3,312 horsepower of diesel-fueled equipment. Using a conversion factor of 2,544 Btu/(horsepower-hr), 3,312 horsepower translates to 8,426,000 Btu/hr. The diesel-fueled equipment runs 52 hr/yr (BLM 2010) and is assumed to convert 85 percent of input-diesel energy to useful energy. Factoring the above energy rate (8,426,000 Btu/hr) by annual operating hours (52 hr/yr) and the assumed efficiency (85 percent) the rate of diesel consumption is 515,500,000 Btu/yr. Using a conversion factor of 42,560 Btu/kg of diesel, this rate of diesel consumption is equivalent to 12,110 kg of diesel per year. At an expected value capacity factor of 27 percent, the 250 MW net solar thermal facility produces 600,000 MWh/yr. Dividing the diesel consumption rate by the electricity production rate gives 0.0202 kg diesel/MWh. The emission factors for the combustion of diesel are not accounted for in this unit process, but are accounted for by another unit process that was previously developed by NETL (*NETL Life Cycle Inventory Data – Unit Process: Combustion of Diesel in a Passenger Vehicle*). This unit process was used as a proxy for combustion of diesel in industrial equipment.

The EIS for the Genesis Solar Energy Project (BLM, 2010) specifies a gasoline storage tank used for holding gasoline that is used by onsite maintenance vehicles (trucks). The inventory around this gasoline storage tank is 21,536 gal/yr (BLM, 2010). A gallon of gasoline has a mass of 2.8 kg, and thus the annual gasoline use rate converts to 60,311 kg gasoline per year. The emission factors for the combustion of gasoline are not accounted for in this unit process, but are accounted for by another unit process that was previously developed by NETL (*NETL Life Cycle Inventory Data – Unit Process: Combustion of Gasoline in a Passenger Vehicle*).

The solar thermal facility uses HTF to carry heat from the collector field to the steam system. The EIS for the Genesis Solar Energy Project (BLM, 2010) specifies 2,000,000 gal of HTF for the 250 MW net facility. Most of this fluid is recirculated, but some degrades to a vapor that is vented from the system. This unit process has a parameter that allows variation of the heat transfer loss rate; the default loss rate is 5 percent per year. The actual HTF is a mix of organic fluids for which no LC data are available. This analysis uses benzene as a proxy for the production of the HTF. The energy and material flow for the production of benzene are not accounted for in this unit process, but are accounted for by third party data provided by PE International as part of the GaBi software license.

The EIS for the Genesis Solar Energy Project (BLM, 2010) specifies a water consumption rate of 1,644 acre-feet per year, drawn from a groundwater source. This volume of water is equivalent to an annual water consumption of 2,027 million kg (1 acre-foot of water per 1.233 million kg of water). At an expected value capacity factor of 27 percent, the 250 MW net solar thermal facility produces 600,000 MWh/yr. Dividing the water use by the electricity production rate gives 112.7 kg of water per MWh of electricity produced.

Table B-3 shows key parameters for a solar thermal power facility, and **Table B-4** shows the input and output flows of this unit process.

Table B-3: Solar Thermal Power Plant Operation Modeling Parameters

Parameter	Expected Value	Units
Net Plant Capacity	250	MWnet
Capacity Factor	27.4%	Percent
Annual Electricity Production	600,000	MWh
Auxiliary Natural Gas Boilers	60	MMBtu/hr.
Fire Pumps	630	hp
Emergency Generators	2,682	hp
Gasoline for Maintenance Vehicles	21,536	gal/yr.
Heat Transfer Fluid (Total Amount in System)	2,000,000	Gallon
Heat Transfer Fluid Loss Rate	5%	Percent/yr.

Table B-4: Solar Thermal Operation Unit Process Input and Output Flows

Flow Name	Value	Units (Per Reference Flow)
Inputs		
Natural Gas Combusted in an Auxiliary Boiler	1.855E+00	kg
Diesel Combusted in Industrial Equipment	2.019E-02	kg
Gasoline Combusted in a Maintenance Vehicle	1.005E-01	kg
Water (Ground Water)	1.127E+02	kg
Heat Transfer Fluid	6.342E-01	kg
Outputs		
Solar Thermal Electricity Generation	1	MWh

B.3 Solar Thermal Assembly

The scope of this unit process covers the construction and installation of the ECF, in this case the solar thermal power plant, along with the supporting infrastructure required to operate the plant and connect it to the electrical grid. At the end, 1 MWh of electricity is delivered to the LC Stage #4, or T&D, boundary.

LC Stage #1, or RMA, is not relevant to solar thermal power because solar thermal energy is a natural resource that does not require anthropogenic inputs prior to power generation. LC Stage #2, or RMT, is not relevant to solar thermal power because it uses a natural energy source that does not require anthropogenic inputs prior to power generation.

Four key unit processes were identified for the construction and operation of a solar thermal power plant:

- Solar thermal collector construction and installation
- Power plant construction and installation (NETL, 2010a)
- Solar thermal power plant operation
- Trunkline construction and operation (NETL, 2010b)

The data used for these four processes are described below.

The inputs to the solar thermal collector construction unit process are steel plate and glass, which comprise the solar collector. The total mass of the solar collectors is determined by the size of the plant, the conversion efficiency from solar energy to electricity (STE), the intensity of solar radiation (insolation), and the total area of solar collectors at the site. The unit process also includes inputs for the initial charge of HTF into the plant and water use during the construction of the solar thermal plant. The energy and material flows for the upstream production and delivery of steel, glass, and HTF are not included in this unit process but are accounted for by other unit processes. The process is based on the reference flow of one piece of solar-collector construction and installation per 1 MWh of electricity produced.

The balance of the solar thermal power plant was modeled by using the natural gas combined cycle (NGCC) plant construction and installation unit process. Inputs to the unit process for the construction of the plant include steel plate, steel pipe, aluminum sheet, cast iron, and concrete. These inputs were scaled in the assembly based on the design capacity of the plant. The energy and material flows for the upstream production and delivery of steel, concrete, aluminum, and cast iron are not included in this unit process but are accounted for by other unit process. Diesel, water, and emissions associated with plant installation are also included and were also scaled based on the size of the plant. The NGCC construction unit process had a 50-mile trunkline already built into the model; however, in order to view the trunkline impacts separately and parameterize the distance, that trunkline was removed and replaced with the standalone unit process.

The solar thermal power plant operations unit process accounts for diesel, gasoline, and natural gas combustion for auxiliary processes at the solar thermal power plant. Diesel fuel is used to supply both a fire pump and an emergency generator. Natural gas is used to supply an auxiliary boiler. Gasoline is used to fuel maintenance vehicles at the facility. This unit process accounts for direct combustion emissions of all three fuels, but does not include upstream acquisition and transport. Those impacts are accounted for by other unit processes. The final input to this unit process is additional HTF that is added to account for system losses. An upstream unit process accounts for the emissions associated with the production of the HTF.

The trunkline unit process originally developed for modeling a 200 MW onshore wind farm was used as a proxy for the trunkline for the solar thermal power plant. The unit process was modified to include the parameterization of capacity factor, plant design net electricity output, and plant lifetime to reflect the difference between the solar thermal plant and the wind farm. The trunkline distance was already parameterized in the unit process. This unit process provides a summary of relevant input and output flows associated with the construction of a trunkline that connects the solar thermal power plant to the main electricity transmission grid. Key components include steel towers, concrete foundations, and steel-clad aluminum conductors. The lifetime electricity throughput of the trunkline is estimated in order to express the inputs and outputs on the basis of mass of materials per 1 MWh of electricity transport.

Table B-5 shows key parameters for a solar thermal power facility, and **Table B-6** shows the input and output flows of this unit process.

Table B-5: Solar Thermal Power Modeling Parameters

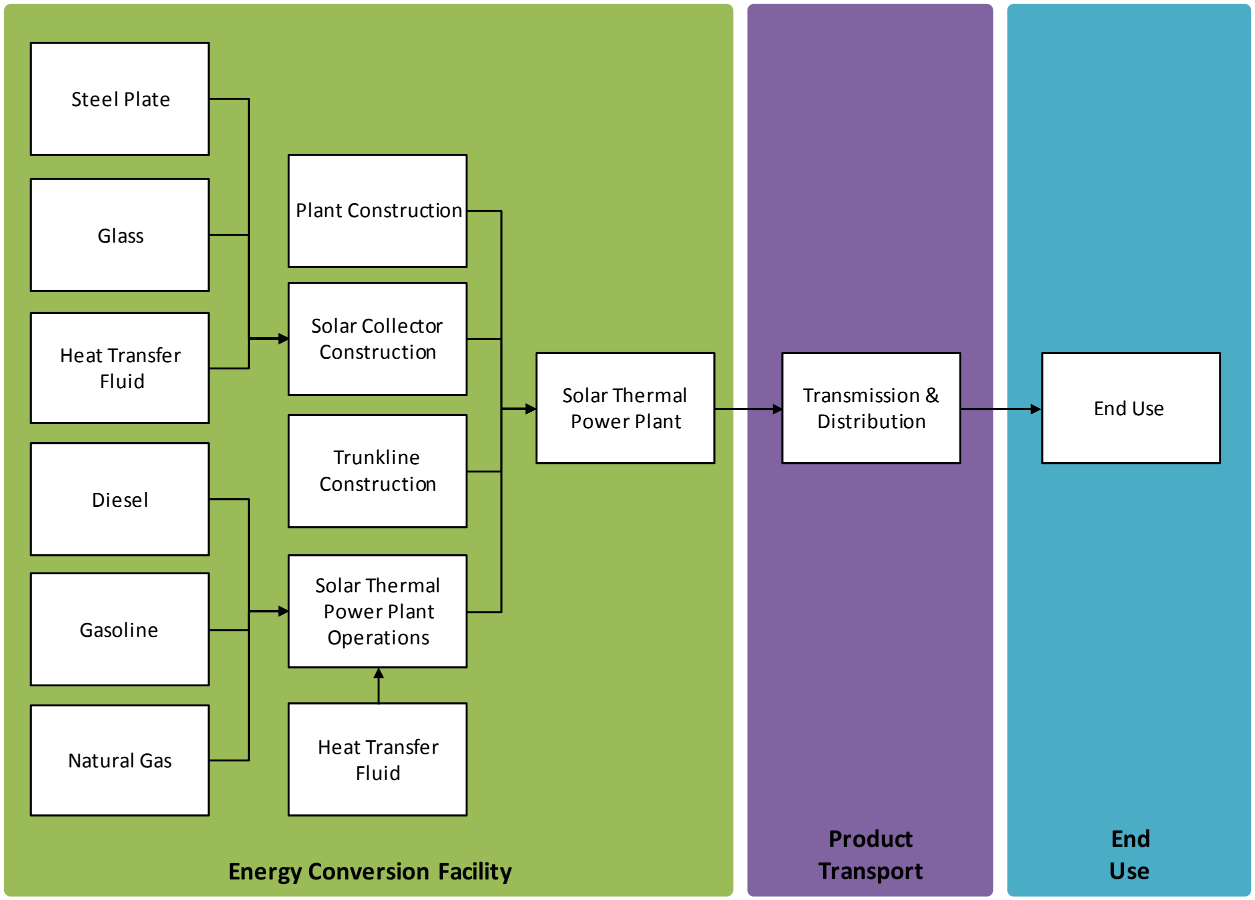
Parameter	Expected Value	Units
Net Plant Capacity	250	MW Net
Capacity Factor	27.4%	Percent
Plant Life	30	Years
Trunkline Distance	40.2	km
Solar to Electric Conversion Efficiency	14.3%	Percent
Intensity of Solar Radiation (Insolation)	3.558E-04	MW/m^2
Solar Collector Density	28.50	kg/m^2
Share of Steel in Parabolic Trough	75%	Percent

Table B-6: Solar Thermal Assembly Unit Process Input and Output Flows

Flow Name	Value	Units (Per Reference Flow)
Inputs		
Trunkline Construction (Installation)	5.575E-08	Pieces
Solar Thermal Collector Construction (Installation)	5.575E-08	Pieces
Plant Construction and Installation (Installation)	5.575E-08	Pieces
Solar Thermal Power Plant Operation (Operation)	5.575E-08	Pieces
Outputs		
Electricity (Valuable Substance)	1	MWh

The following diagram **(Figure B-1**) shows the relationship between the unit processes for the solar thermal power LC.

Figure B-1: LCA Modeling Framework for Solar Thermal Power



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Appendix C: Detailed Results Solar Thermal Power Modeling

List of Tables

Table C-1: Solar Thermal Power Plant Detailed LCA Results

Category (Units)	Material or Energy Flow	Energy Conversion Facility										
		Plant Construction							Collector Construction			
		Aluminum Sheet	Cast Iron	Cold Rolled Steel	Concrete	Diesel	Installation	Steel Pipe	Glass	Heat Transfer Fluid	Steel Plate	Dust Suppression During Construction
GHG (kg/MWh)	CO_2	3.52E-02	1.04E-02	6.27E-01	2.96E-01	1.81E-01	8.81E-01	1.38E-01	9.63E+00	3.93E-01	7.69E+00	0.00E+00
	N_2O	6.09E-07	1.52E-07	4.08E-06	2.60E-06	3.55E-06	2.27E-05	7.68E-06	5.37E-03	4.86E-06	4.00E-04	0.00E+00
	CH_4	5.77E-05	1.42E-05	7.35E-04	4.97E-04	1.16E-03	5.07E-05	1.46E-04	4.02E-02	1.88E-03	5.84E-03	0.00E+00
	SF_6	3.57E-12	5.53E-10	4.55E-12	3.46E-08	3.40E-13	0.00E+00	0.00E+00	4.15E-11	8.51E-13	0.00E+00	0.00E+00
	CO_2e (IPCC 2007 100-yr GWP)	3.68E-02	1.08E-02	6.46E-01	3.10E-01	2.11E-01	8.89E-01	1.43E-01	1.22E+01	4.42E-01	7.96E+00	0.00E+00
Other Air (kg/MWh)	Pb	5.65E-09	4.42E-10	1.13E-06	1.09E-09	4.07E-09	0.00E+00	4.19E-07	2.18E-07	1.09E-08	1.52E-05	0.00E+00
	Hg	4.57E-10	6.32E-11	1.45E-09	3.04E-09	3.38E-10	4.40E-11	1.11E-08	3.35E-08	1.07E-09	9.57E-07	0.00E+00
	NH_3	1.31E-07	1.89E-08	2.04E-06	1.55E-07	2.31E-06	3.64E-05	0.00E+00	1.55E-05	3.13E-06	0.00E+00	0.00E+00
	CO	3.03E-04	1.01E-05	5.95E-03	2.01E-04	1.72E-04	4.12E-02	1.02E-03	4.31E-03	3.39E-04	6.49E-02	0.00E+00
	NO_X	6.17E-05	1.03E-05	1.19E-03	6.53E-04	2.36E-04	1.48E-02	2.24E-04	2.17E-02	7.51E-04	1.29E-02	0.00E+00
	SO_2	1.94E-04	1.40E-05	8.68E-04	8.32E-04	4.74E-04	3.74E-04	3.91E-04	3.43E-02	1.01E-03	1.75E-02	0.00E+00
	VOC	7.13E-06	2.76E-06	8.94E-05	4.45E-05	5.06E-04	0.00E+00	-5.33E-13	2.91E-02	3.68E-04	-2.98E-11	0.00E+00
	PM	6.52E-05	1.25E-05	4.04E-04	4.12E-03	2.38E-05	0.00E+00	1.62E-04	2.72E-02	4.03E-05	1.84E-03	0.00E+00
Solid Waste (kg/MWh)	Heavy metals to industrial soil	7.78E-07	1.73E-05	5.41E-06	1.08E-03	1.10E-05	0.00E+00	0.00E+00	7.09E-05	2.04E-05	0.00E+00	0.00E+00
	Heavy metals to agricultural soil	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Water Use (L/MWh)	Withdrawal	2.43E-01	1.10E-01	1.44E+00	5.77E+00	6.67E-01	2.44E+00	1.54E+00	6.80E+01	6.81E-01	4.07E+01	1.92E+02
	Discharge	1.83E-01	9.14E-02	1.32E+00	5.27E+00	1.62E-01	0.00E+00	0.00E+00	5.41E+01	5.66E-01	0.00E+00	0.00E+00
	Consumption	6.00E-02	1.85E-02	1.18E-01	4.96E-01	5.05E-01	2.44E+00	1.54E+00	1.38E+01	1.15E-01	4.07E+01	1.92E+02
Water Quality (kg/MWh)	Aluminum	1.58E-07	8.85E-09	4.50E-07	2.15E-07	1.32E-04	0.00E+00	0.00E+00	1.37E-05	2.16E-07	0.00E+00	0.00E+00
	Arsenic (+V)	1.12E-09	4.09E-09	5.05E-09	2.53E-07	3.75E-06	0.00E+00	0.00E+00	1.63E-07	3.12E-08	0.00E+00	0.00E+00
	Copper (+II)	2.30E-09	4.97E-09	1.94E-08	3.01E-07	5.50E-06	0.00E+00	0.00E+00	2.92E-06	3.50E-07	0.00E+00	0.00E+00
	Iron	7.86E-06	4.33E-07	2.81E-05	5.05E-06	2.81E-04	0.00E+00	7.65E-06	2.08E-03	3.19E-05	2.49E-04	0.00E+00
	Lead (+II)	4.89E-09	3.43E-10	1.04E-08	1.23E-08	1.26E-05	0.00E+00	4.82E-08	1.00E-06	8.87E-08	3.17E-06	0.00E+00
	Manganese (+II)	2.15E-08	8.13E-09	2.61E-07	3.88E-07	1.68E-08	0.00E+00	0.00E+00	2.20E-06	4.70E-08	0.00E+00	0.00E+00
	Nickel (+II)	1.44E-09	1.85E-07	2.94E-08	1.16E-05	1.00E-04	0.00E+00	1.41E-08	8.97E-07	9.87E-08	4.30E-07	0.00E+00
	Strontium	2.95E-08	8.29E-09	1.24E-06	8.40E-09	9.22E-08	0.00E+00	0.00E+00	5.48E-06	3.14E-06	0.00E+00	0.00E+00
	Zinc (+II)	1.80E-09	5.16E-08	2.84E-08	3.22E-06	1.74E-04	0.00E+00	1.52E-08	7.57E-07	8.08E-08	1.89E-06	0.00E+00
	Ammonium/ammonia	1.31E-07	4.73E-07	1.30E-06	2.83E-05	1.43E-03	0.00E+00	8.83E-07	2.12E-05	1.10E-06	2.42E-04	0.00E+00
	Hydrogen chloride	2.21E-12	7.55E-14	5.34E-12	1.97E-12	3.53E-11	0.00E+00	0.00E+00	6.01E-10	6.16E-11	0.00E+00	0.00E+00
	Nitrogen (as total N)	0.00E+00	1.30E-09	0.00E+00	8.16E-08	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	Phosphate	7.24E-09	1.93E-10	6.72E-07	9.62E-10	4.17E-09	0.00E+00	0.00E+00	2.93E-05	4.49E-07	0.00E+00	0.00E+00
	Phosphorus	1.28E-09	2.96E-09	8.48E-09	1.82E-07	1.26E-04	0.00E+00	7.94E-09	1.49E-07	5.31E-08	2.59E-05	0.00E+00
Resource Energy (MJ/MWh)	Crude oil	1.28E-01	7.70E-03	7.07E-01	5.91E-02	1.15E+01	0.00E+00	2.33E-01	3.42E+00	2.04E+01	1.69E+01	0.00E+00
	Hard coal	1.20E-01	4.84E-02	6.43E+00	5.19E-01	1.68E-01	0.00E+00	9.65E-01	2.13E+01	3.35E-01	7.36E+01	0.00E+00
	Lignite	4.08E-02	2.08E-03	1.61E-01	2.74E-04	6.17E-03	0.00E+00	0.00E+00	1.57E+00	2.28E-02	0.00E+00	0.00E+00
	Natural gas	9.67E-02	1.63E-02	9.39E-01	7.36E-01	1.29E+00	0.00E+00	3.98E-01	9.50E+01	2.09E+00	1.47E+01	0.00E+00
	Uranium	1.32E-01	3.41E-03	1.88E-01	1.00E-03	8.20E-02	0.00E+00	0.00E+00	1.12E+01	1.65E-01	0.00E+00	0.00E+00
	Total resource energy	5.17E-01	7.79E-02	8.42E+00	1.32E+00	1.30E+01	0.00E+00	1.60E+00	1.33E+02	2.30E+01	1.05E+02	0.00E+00
Energy Return on Investment		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Table C-1: Solar Thermal Power Plant Detailed LCA Results (Continued)

Category (Units)	Material or Energy Flow	Energy Conversion Facility						Product Transport	Total
		Operation					Trunkline		
		Diesel Upstream	Gasoline Upstream	Natural Gas Upstream	Fuels Combustion and Operation	Heat Transfer Fluid	Construction	T&D	
GHG (kg/MWh)	CO_2	1.38E-02	6.98E-02	3.42E-01	1.58E+01	5.90E-01	3.07E-01	0.00E+00	3.70E+01
	N_2O	2.72E-07	1.38E-06	9.09E-06	6.82E-04	7.29E-06	4.14E-06	0.00E+00	6.52E-03
	CH_4	8.83E-05	4.39E-04	4.16E-02	4.08E-04	2.82E-03	4.35E-04	0.00E+00	9.64E-02
	SF_6	2.60E-14	1.39E-13	2.52E-09	0.00E+00	1.28E-12	4.52E-09	1.43E-04	1.43E-04
	CO_2e (IPCC 2007 100-yr GWP)	1.61E-02	8.12E-02	1.39E+00	1.60E+01	6.63E-01	3.19E-01	3.27E+00	4.46E+01
Other Air (kg/MWh)	Pb	3.12E-10	1.56E-09	2.91E-08	0.00E+00	1.64E-08	2.57E-07	0.00E+00	1.73E-05
	Hg	2.59E-11	1.32E-10	9.92E-10	0.00E+00	1.60E-09	1.96E-09	0.00E+00	1.01E-06
	NH_3	1.76E-07	8.81E-07	3.91E-08	0.00E+00	4.70E-06	1.05E-06	0.00E+00	6.64E-05
	CO	1.32E-05	6.55E-05	6.03E-04	4.85E-01	5.08E-04	2.54E-03	0.00E+00	6.07E-01
	NO_X	1.81E-05	8.99E-05	6.58E-03	3.35E-02	1.13E-03	5.21E-04	0.00E+00	9.44E-02
	SO_2	3.63E-05	1.84E-04	7.28E-05	5.81E-04	1.51E-03	8.00E-04	0.00E+00	5.92E-02
	VOC	3.87E-05	1.86E-04	6.37E-03	2.61E-04	5.52E-04	4.95E-05	0.00E+00	3.76E-02
	PM	1.82E-06	8.61E-06	6.60E-05	3.61E-04	6.05E-05	8.77E-04	0.00E+00	3.52E-02
Solid Waste (kg/MWh)	Heavy metals to industrial soil	8.41E-07	4.87E-06	7.92E-05	0.00E+00	3.06E-05	1.45E-04	0.00E+00	1.47E-03
	Heavy metals to agricultural soil	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Water Use (L/MWh)	Withdrawal	5.10E-02	2.81E-01	2.34E+00	1.21E+02	1.02E+00	1.83E+00	0.00E+00	4.40E+02
	Discharge	1.24E-02	6.41E-02	2.76E+00	0.00E+00	8.50E-01	1.52E+00	0.00E+00	6.69E+01
	Consumption	3.86E-02	2.17E-01	-4.21E-01	1.21E+02	1.72E-01	3.11E-01	0.00E+00	3.73E+02
Water Quality (kg/MWh)	Aluminum	1.01E-05	4.07E-08	6.42E-07	0.00E+00	3.24E-07	6.10E-07	0.00E+00	1.58E-04
	Arsenic (+V)	2.87E-07	1.65E-06	3.62E-08	0.00E+00	4.68E-08	3.86E-08	0.00E+00	6.27E-06
	Copper (+II)	4.21E-07	2.42E-06	4.78E-08	0.00E+00	5.26E-07	5.18E-08	0.00E+00	1.26E-05
	Iron	2.14E-05	1.23E-04	3.36E-06	0.00E+00	4.79E-05	3.69E-05	0.00E+00	2.93E-03
	Lead (+II)	9.67E-07	5.57E-06	6.43E-08	0.00E+00	1.33E-07	1.92E-08	0.00E+00	2.37E-05
	Manganese (+II)	1.29E-09	6.66E-09	3.33E-05	0.00E+00	7.05E-08	1.73E-07	0.00E+00	3.65E-05
	Nickel (+II)	7.65E-06	4.41E-05	1.32E-06	0.00E+00	1.48E-07	1.51E-06	0.00E+00	1.68E-04
	Strontium	7.05E-09	4.09E-08	1.97E-09	0.00E+00	4.71E-06	3.62E-07	0.00E+00	1.51E-05
	Zinc (+II)	1.33E-05	7.66E-05	1.06E-06	0.00E+00	1.21E-07	4.31E-07	0.00E+00	2.71E-04
	Ammonium/ammonia	1.09E-04	6.28E-04	8.89E-06	0.00E+00	1.65E-06	4.41E-06	0.00E+00	2.47E-03
	Hydrogen chloride	2.70E-12	1.26E-11	2.00E-13	0.00E+00	9.23E-11	1.03E-11	0.00E+00	8.26E-10
	Nitrogen (as total N)	0.00E+00	0.00E+00	1.21E-05	0.00E+00	0.00E+00	1.06E-08	0.00E+00	1.22E-05
	Phosphate	3.19E-10	1.59E-09	8.34E-11	0.00E+00	6.73E-07	1.70E-07	0.00E+00	3.13E-05
	Phosphorus	9.62E-06	5.54E-05	7.72E-07	0.00E+00	7.96E-08	3.01E-08	0.00E+00	2.18E-04
Resource Energy (MJ/MWh)	Crude oil	8.77E-01	4.43E+00	3.81E-02	0.00E+00	3.06E+01	6.43E-01	0.00E+00	8.99E+01
	Hard coal	1.29E-02	6.55E-02	1.62E-01	0.00E+00	5.02E-01	1.79E+00	0.00E+00	1.06E+02
	Lignite	4.72E-04	2.37E-03	6.84E-05	0.00E+00	3.41E-02	2.15E-01	0.00E+00	2.06E+00
	Natural gas	9.87E-02	4.71E-01	1.08E+02	0.00E+00	3.13E+00	7.33E-01	0.00E+00	2.28E+02
	Uranium	6.27E-03	3.28E-02	4.03E-04	0.00E+00	2.48E-01	4.47E-01	0.00E+00	1.25E+01
	Total resource energy	9.96E-01	5.00E+00	1.09E+02	0.00E+00	3.45E+01	3.83E+00	0.00E+00	4.39E+02
Energy Return on Investment		N/A	N/A	N/A	N/A	N/A	N/A	N/A	8.2:1

Table C-2: Solar Thermal Power Plant Detailed LCA Results in Alternate Units

Category (Units)	Material or Energy Flow	Energy Conversion Facility										
		Plant Construction							Collector Construction			
		Aluminum Sheet	Cast Iron	Cold Rolled Steel	Concrete	Diesel	Installation	Steel Pipe	Glass	Heat Transfer Fluid	Steel Plate	Dust Suppression During Construction
GHG (lb/MWh)	CO_2	7.75E-02	2.30E-02	1.38E+00	6.52E-01	3.99E-01	1.94E+00	3.03E-01	2.12E+01	8.67E-01	1.70E+01	0.00E+00
	N_2O	1.34E-06	3.34E-07	8.99E-06	5.72E-06	7.83E-06	5.01E-05	1.69E-05	1.18E-02	1.07E-05	8.81E-04	0.00E+00
	CH_4	1.27E-04	3.14E-05	1.62E-03	1.10E-03	2.55E-03	1.12E-04	3.21E-04	8.87E-02	4.15E-03	1.29E-02	0.00E+00
	SF_6	7.86E-12	1.22E-09	1.00E-11	7.63E-08	7.49E-13	0.00E+00	0.00E+00	9.15E-11	1.88E-12	0.00E+00	0.00E+00
	CO_2e (IPCC 2007 100-yr GWP)	8.11E-02	2.39E-02	1.42E+00	6.83E-01	4.65E-01	1.96E+00	3.16E-01	2.70E+01	9.74E-01	1.75E+01	0.00E+00
Other Air (lb/MWh)	Pb	1.25E-08	9.74E-10	2.49E-06	2.40E-09	8.98E-09	0.00E+00	9.24E-07	4.81E-07	2.41E-08	3.36E-05	0.00E+00
	Hg	1.01E-09	1.39E-10	3.19E-09	6.70E-09	7.46E-10	9.70E-11	2.44E-08	7.39E-08	2.35E-09	2.11E-06	0.00E+00
	NH_3	2.89E-07	4.16E-08	4.49E-06	3.42E-07	5.09E-06	8.02E-05	0.00E+00	3.41E-05	6.90E-06	0.00E+00	0.00E+00
	CO	6.68E-04	2.22E-05	1.31E-02	4.44E-04	3.80E-04	9.08E-02	2.24E-03	9.51E-03	7.46E-04	1.43E-01	0.00E+00
	NO_X	1.36E-04	2.26E-05	2.62E-03	1.44E-03	5.21E-04	3.26E-02	4.95E-04	4.78E-02	1.66E-03	2.84E-02	0.00E+00
	SO_2	4.29E-04	3.08E-05	1.91E-03	1.83E-03	1.05E-03	8.25E-04	8.61E-04	7.57E-02	2.23E-03	3.86E-02	0.00E+00
	VOC	1.57E-05	6.08E-06	1.97E-04	9.82E-05	1.12E-03	0.00E+00	-1.17E-12	6.42E-02	8.11E-04	-6.58E-11	0.00E+00
	PM	1.44E-04	2.76E-05	8.91E-04	9.07E-03	5.24E-05	0.00E+00	3.56E-04	5.99E-02	8.89E-05	4.07E-03	0.00E+00
Solid Waste (lb/MWh)	Heavy metals to industrial soil	1.72E-06	3.82E-05	1.19E-05	2.39E-03	2.42E-05	0.00E+00	0.00E+00	1.56E-04	4.50E-05	0.00E+00	0.00E+00
	Heavy metals to agricultural soil	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Water Use (gal/MWh)	Withdrawal	6.42E-02	2.90E-02	3.81E-01	1.52E+00	1.76E-01	6.44E-01	4.08E-01	1.80E+01	1.80E-01	1.07E+01	5.06E+01
	Discharge	4.84E-02	2.42E-02	3.50E-01	1.39E+00	4.29E-02	0.00E+00	0.00E+00	1.43E+01	1.50E-01	0.00E+00	0.00E+00
	Consumption	1.58E-02	4.88E-03	3.11E-02	1.31E-01	1.33E-01	6.44E-01	4.08E-01	3.66E+00	3.04E-02	1.07E+01	5.06E+01
Water Quality (lb/MWh)	Aluminum	3.48E-07	1.95E-08	9.92E-07	4.73E-07	2.90E-04	0.00E+00	0.00E+00	3.03E-05	4.77E-07	0.00E+00	0.00E+00
	Arsenic (+V)	2.47E-09	9.03E-09	1.11E-08	5.58E-07	8.28E-06	0.00E+00	0.00E+00	3.60E-07	6.88E-08	0.00E+00	0.00E+00
	Copper (+II)	5.08E-09	1.09E-08	4.27E-08	6.64E-07	1.21E-05	0.00E+00	0.00E+00	6.43E-06	7.73E-07	0.00E+00	0.00E+00
	Iron	1.73E-05	9.55E-07	6.20E-05	1.11E-05	6.18E-04	0.00E+00	1.69E-05	4.59E-03	7.04E-05	5.48E-04	0.00E+00
	Lead (+II)	1.08E-08	7.56E-10	2.30E-08	2.72E-08	2.79E-05	0.00E+00	1.06E-07	2.22E-06	1.96E-07	6.98E-06	0.00E+00
	Manganese (+II)	4.75E-08	1.79E-08	5.75E-07	8.55E-07	3.71E-08	0.00E+00	0.00E+00	4.85E-06	1.04E-07	0.00E+00	0.00E+00
	Nickel (+II)	3.17E-09	4.08E-07	6.47E-08	2.55E-05	2.21E-04	0.00E+00	3.11E-08	1.98E-06	2.18E-07	9.48E-07	0.00E+00
	Strontium	6.50E-08	1.83E-08	2.74E-06	1.85E-08	2.03E-07	0.00E+00	0.00E+00	1.21E-05	6.93E-06	0.00E+00	0.00E+00
	Zinc (+II)	3.97E-09	1.14E-07	6.26E-08	7.09E-06	3.83E-04	0.00E+00	3.35E-08	1.67E-06	1.78E-07	4.17E-06	0.00E+00
	Ammonium/ammonia	2.88E-07	1.04E-06	2.86E-06	6.23E-05	3.14E-03	0.00E+00	1.95E-06	4.68E-05	2.42E-06	5.33E-04	0.00E+00
	Hydrogen chloride	4.86E-12	1.67E-13	1.18E-11	4.34E-12	7.79E-11	0.00E+00	0.00E+00	1.33E-09	1.36E-10	0.00E+00	0.00E+00
	Nitrogen (as total N)	0.00E+00	2.88E-09	0.00E+00	1.80E-07	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	Phosphate	1.60E-08	4.25E-10	1.48E-06	2.12E-09	9.20E-09	0.00E+00	0.00E+00	6.46E-05	9.89E-07	0.00E+00	0.00E+00
	Phosphorus	2.83E-09	6.53E-09	1.87E-08	4.01E-07	2.77E-04	0.00E+00	1.75E-08	3.28E-07	1.17E-07	5.71E-05	0.00E+00
Resource Energy (Btu/MWh)	Crude oil	1.21E+02	7.30E+00	6.70E+02	5.60E+01	1.09E+04	0.00E+00	2.21E+02	3.24E+03	1.93E+04	1.60E+04	0.00E+00
	Hard coal	1.13E+02	4.59E+01	6.09E+03	4.92E+02	1.60E+02	0.00E+00	9.14E+02	2.02E+04	3.17E+02	6.97E+04	0.00E+00
	Lignite	3.87E+01	1.97E+00	1.52E+02	2.59E-01	5.85E+00	0.00E+00	0.00E+00	1.49E+03	2.16E+01	0.00E+00	0.00E+00
	Natural gas	9.16E+01	1.54E+01	8.90E+02	6.98E+02	1.22E+03	0.00E+00	3.77E+02	9.00E+04	1.98E+03	1.39E+04	0.00E+00
	Uranium	1.25E+02	3.23E+00	1.78E+02	9.50E-01	7.77E+01	0.00E+00	0.00E+00	1.06E+04	1.57E+02	0.00E+00	0.00E+00
	Total resource energy	4.90E+02	7.38E+01	7.98E+03	1.25E+03	1.23E+04	0.00E+00	1.51E+03	1.26E+05	2.18E+04	9.96E+04	0.00E+00
Energy Return on Investment		N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Table C-2: Solar Thermal Power Plant Detailed LCA Results in Alternate Units (Continued)

Category (Units)	Material or Energy Flow	Energy Conversion Facility						Product Transport	Total
		Operation					Trunkline	T&D	
		Diesel Upstream	Gasoline Upstream	Natural Gas Upstream	Fuels Combustion and Operation	Heat Transfer Fluid	Construction		
GHG (lb/MWh)	CO_2	3.05E-02	1.54E-01	7.55E-01	3.48E+01	1.30E+00	6.76E-01	0.00E+00	8.15E+01
	N_2O	5.99E-07	3.05E-06	2.00E-05	1.50E-03	1.61E-05	9.13E-06	0.00E+00	1.44E-02
	CH_4	1.95E-04	9.67E-04	9.18E-02	9.00E-04	6.22E-03	9.59E-04	0.00E+00	2.13E-01
	SF_6	5.73E-14	3.06E-13	5.55E-09	0.00E+00	2.81E-12	9.96E-09	3.16E-04	3.16E-04
	CO_2e (IPCC 2007 100-yr GWP)	3.55E-02	1.79E-01	3.06E+00	3.52E+01	1.46E+00	7.03E-01	7.20E+00	9.83E+01
Other Air (lb/MWh)	Pb	6.87E-10	3.43E-09	6.42E-08	0.00E+00	3.62E-08	5.67E-07	0.00E+00	3.82E-05
	Hg	5.70E-11	2.91E-10	2.19E-09	0.00E+00	3.53E-09	4.33E-09	0.00E+00	2.23E-06
	NH_3	3.89E-07	1.94E-06	8.63E-08	0.00E+00	1.04E-05	2.31E-06	0.00E+00	1.46E-04
	CO	2.91E-05	1.44E-04	1.33E-03	1.07E+00	1.12E-03	5.59E-03	0.00E+00	1.34E+00
	NO_X	3.99E-05	1.98E-04	1.45E-02	7.39E-02	2.48E-03	1.15E-03	0.00E+00	2.08E-01
	SO_2	7.99E-05	4.06E-04	1.61E-04	1.28E-03	3.34E-03	1.76E-03	0.00E+00	1.30E-01
	VOC	8.53E-05	4.09E-04	1.41E-02	5.76E-04	1.22E-03	1.09E-04	0.00E+00	8.29E-02
	PM	4.01E-06	1.90E-05	1.45E-04	7.96E-04	1.33E-04	1.93E-03	0.00E+00	7.76E-02
Solid Waste (lb/MWh)	Heavy metals to industrial soil	1.85E-06	1.07E-05	1.75E-04	0.00E+00	6.76E-05	3.19E-04	0.00E+00	3.24E-03
	Heavy metals to agricultural soil	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Water Use (gal/MWh)	Withdrawal	1.35E-02	7.42E-02	6.17E-01	3.20E+01	2.70E-01	4.84E-01	0.00E+00	1.16E+02
	Discharge	3.28E-03	1.69E-02	7.28E-01	0.00E+00	2.24E-01	4.02E-01	0.00E+00	1.77E+01
	Consumption	1.02E-02	5.72E-02	-1.11E-01	3.20E+01	4.55E-02	8.21E-02	0.00E+00	9.85E+01
Water Quality (lb/MWh)	Aluminum	2.22E-05	8.96E-08	1.41E-06	0.00E+00	7.15E-07	1.34E-06	0.00E+00	3.49E-04
	Arsenic (+V)	6.33E-07	3.65E-06	7.99E-08	0.00E+00	1.03E-07	8.52E-08	0.00E+00	1.38E-05
	Copper (+II)	9.27E-07	5.33E-06	1.05E-07	0.00E+00	1.16E-06	1.14E-07	0.00E+00	2.77E-05
	Iron	4.73E-05	2.72E-04	7.40E-06	0.00E+00	1.06E-04	8.14E-05	0.00E+00	6.45E-03
	Lead (+II)	2.13E-06	1.23E-05	1.42E-07	0.00E+00	2.93E-07	4.22E-08	0.00E+00	5.23E-05
	Manganese (+II)	2.84E-09	1.47E-08	7.33E-05	0.00E+00	1.55E-07	3.82E-07	0.00E+00	8.04E-05
	Nickel (+II)	1.69E-05	9.73E-05	2.91E-06	0.00E+00	3.26E-07	3.34E-06	0.00E+00	3.70E-04
	Strontium	1.55E-08	9.02E-08	4.34E-09	0.00E+00	1.04E-05	7.98E-07	0.00E+00	3.34E-05
	Zinc (+II)	2.93E-05	1.69E-04	2.34E-06	0.00E+00	2.67E-07	9.50E-07	0.00E+00	5.98E-04
	Ammonium/ammonia	2.40E-04	1.39E-03	1.96E-05	0.00E+00	3.63E-06	9.73E-06	0.00E+00	5.45E-03
	Hydrogen chloride	5.96E-12	2.77E-11	4.41E-13	0.00E+00	2.04E-10	2.28E-11	0.00E+00	1.82E-09
	Nitrogen (as total N)	0.00E+00	0.00E+00	2.68E-05	0.00E+00	0.00E+00	2.34E-08	0.00E+00	2.70E-05
	Phosphate	7.03E-10	3.51E-09	1.84E-10	0.00E+00	1.48E-06	3.75E-07	0.00E+00	6.90E-05
	Phosphorus	2.12E-05	1.22E-04	1.70E-06	0.00E+00	1.76E-07	6.64E-08	0.00E+00	4.81E-04
Resource Energy (Btu/MWh)	Crude oil	8.31E+02	4.20E+03	3.61E+01	0.00E+00	2.90E+04	6.10E+02	0.00E+00	8.52E+04
	Hard coal	1.22E+01	6.21E+01	1.54E+02	0.00E+00	4.76E+02	1.70E+03	0.00E+00	1.00E+05
	Lignite	4.47E-01	2.25E+00	6.48E-02	0.00E+00	3.24E+01	2.04E+02	0.00E+00	1.95E+03
	Natural gas	9.36E+01	4.46E+02	1.03E+05	0.00E+00	2.97E+03	6.95E+02	0.00E+00	2.16E+05
	Uranium	5.94E+00	3.11E+01	3.82E-01	0.00E+00	2.35E+02	4.24E+02	0.00E+00	1.19E+04
	Total resource energy	9.44E+02	4.74E+03	1.03E+05	0.00E+00	3.27E+04	3.63E+03	0.00E+00	4.16E+05
Energy Return on Investment		N/A	N/A	N/A	N/A	N/A	N/A	N/A	8.2:1