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Methods for Estimating Water Consumption for Thermoelectric Power Plants in the United States

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U.S. Department of the Interior
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Cover. Aerial photographs of thermoelectric power plants in the United States from the U.S. Department of Agriculture (USDA) National Agriculture Imagery Program (NAIP), 2007. Refer to figures 2, 3, 5, and 6.

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By Timothy H. Diehl, Melissa A. Harris, Jennifer C. Murphy, Susan S. Hutson, and David E. Ladd

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Conversion Factors and Datum

Multiply	By	To obtain
	Length	
kilometer (km)	0.6214	mile (mi)
mile (mi)	1.609	kilometer (km)
	Area	
acre	4,047.0	square meter (m^2)
acre	0.4047	hectare (ha)
acre	0.4047	square hectometer (hm^2)
acre	0.004047	square kilometer (km^2)
square centimeter (cm^2)	0.001076	square foot (ft^2)
square centimeter (cm^2)	0.1550	square inch (ft^2)
square meter (m^2)	0.0002471	acre
square meter (m^2)	10.76	square foot (ft^2)
	Volume	
gallon (gal)	3.785	liter (L)
gallon (gal)	0.003785	cubic meter (m^3)
gallon (gal)	0.1337	cubic foot (ft^3)
liter (L)	33.82	ounce, fluid (fl. oz)
liter (L)	2.113	pint (pt)
liter (L)	1.057	quart (qt)
liter (L)	0.2642	gallon (gal)
liter (L)	0.0353	cubic foot (ft^3)
	Mass	
gram (g)	0.03527	ounce, avoirdupois (oz)
gram (g)	0.0022	pound, avoirdupois (lb)
kilogram (kg)	35.27	ounce, avoirdupois (oz)
kilogram (kg)	2.205	pound, avoirdupois (lb)
	Density	
gram per cubic centimeter (g/cm^3)	62.4220	pound per cubic foot (lb/ft^3)
	Pressure	
Bar	100	kilopascal (kPa)
Millibar	0.1	kilopascal (kPa)
	Energy	
British thermal unit (Btu)	1,055.06	joule (J)
British thermal unit (Btu)	252	calorie (cal)
British thermal unit (Btu)	0.0002931	kilowatthour (kWh)
calorie	4.184	joule (J)
joule (J)	0.2390057	calorie (cal)
joule (J)	0.0000002	kilowatthour (kWh)
kilowatt hour (kWh)	3.6×10^6	joule (J)
kilowatt hour (kWh)	3,412.14	British thermal unit (Btu)
megawatt (MW)	1.0×10^6	joule per second (J/s)
megawatt (MW)	8.6×10^8	calories per hour (cal/h)
megawatt hour (MWh)	3.6×10^9	joule (J)
megawatt hour (MWh)	3.4×10^6	British thermal unit (Btu)
million British thermal unit (MMBtu)	1.055×10^9	joule (J)

Multiply	By	To obtain
	Rate	
calorie per centimeter squared degrees Kelvin per day ($cal/cm^2°K/d$)	0.484259	kilogram degrees kelvin per cubic second ($kg°K/s^3$)
calorie per centimeter squared per second [$cal/(cm^2/s)$]	41,840	watts per meter squared (W/m^2)
calorie per gram (cal/g)	4,184	joule per kilogram (J/kg)
calorie per gram degrees Kelvin (cal/g°K)	4,184	joule per kilogram degrees Kelvin [J/(kg°K)]
gallon per kilowatt hour (gal/kWh)	1.0515×10^{-6}	liter per joule (L/J)
gallon per kilowatt hour (gal/kWh)	4.3995×10^{-6}	liter per calorie (L/cal)
gallon per megawatt hour (gal/MWh)	1.0515×10^{-9}	liter per joule (L/J)
gallon per megawatt hour (gal/MWh)	4.3995×10^{-9}	liter per calorie (L/cal)
megawatt per acre (MW/acre)	0.0059	calorie per square centimeter per second [$cal/(cm^2/s)$]
mile per hour (mi/h)	1.60934	kilometer per hour (km/h)

Temperature in degrees Celsius (°C) may be converted to degrees Fahrenheit (°F) as follows:

$$°F = (1.8 \times °C) + 32$$

Temperature in degrees Fahrenheit (°F) may be converted to degrees Celsius (°C) as follows:

$$°C = (°F - 32) / 1.8$$

Temperature in degrees Kelvin (°K) may be converted to degrees Celsius (°C) as follows:

$$°C = (°K - 273.15)$$

Temperature in degrees Kelvin (°K) may be converted to degrees Fahrenheit (°F) as follows:

$$°F = ((°K - 273.15) \times 1.8) + 32$$

Vertical coordinate information is referenced to the North American Vertical Datum of 1988 (NAVD 88).

Elevation, as used in this report, refers to distance above the vertical datum.

Abbreviations

Btu	British thermal units
CPPDB	Coal Power Plant Database
DEM	Digital Elevation Model
ECHO	USEPA database, Enforcement and Compliance History Online
eGRID	Emission and Generation Resource Integrated Database
FERC	Federal Energy Regulatory Commission
FGD	Flue-gas desulfurization
GIS	Geographic Information System
GLERL	Great Lakes Environmental Research Laboratory

GLSEA2	Great Lakes Surface Environmental Analysis
HRSGs	Heat-Recovery Steam Generators
HSIP	Homeland Security Infrastructure Program
ICIS	Integrated Compliance Information System
kWh	Kilowatt hour
L/G	Mass ratio of water flow to dry air flow in a cooling tower
MMBtu	Million British thermal units
MW	Megawatt
MWh	Megawatt hour
MWhe	Megawatt hour electric
NAICS	North American Industry Classification System
NEEDS	National Electric Energy Data System
NETL	National Energy Technology Laboratory
NHDPlus	National Elevation Dataset, Horizon Systems Corporation
NOAA	National Oceanic and Atmospheric Administration
NOx	Nitrogen Oxides
NPDES	National Pollutant Discharge Elimination System
PCS	Permit Compliance System
QCLCD	Quality Controlled Local Climatological Data; also *LCD*
USEIA	U.S. Energy Information Administration; also *EIA*
USEPA	U.S. Environmental Protection Agency; also *EPA*
USGS	U.S. Geological Survey

Methods for Estimating Water Consumption for Thermoelectric Power Plants in the United States

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Abstract

Water consumption at thermoelectric power plants represents a small but substantial share of total water consumption in the U.S. However, currently available thermoelectric water consumption data are inconsistent and incomplete, and coefficients used to estimate consumption are contradictory. The U.S. Geological Survey (USGS) has resumed the estimation of thermoelectric water consumption, last done in 1995, based on the use of linked heat and water budgets to complement reported water consumption. This report presents the methods used to estimate freshwater consumption at a study set of 1,284 power plants based on 2010 plant characteristics and operations data.

Power plants were categorized for estimation of water consumption in two tiers. First, generating units were assigned to categories based on the technology used to generate electricity. These generation-type categories are combustion steam, combined-cycle, nuclear, geothermal, and solar thermal. Second, cooling systems were separately categorized as either wet cooling towers or surface-water cooling systems, and the surface-water cooling systems were subcategorized as cooling ponds, lakes, and rivers.

Heat budgets were constructed for the first four generation-type categories; data at solar thermal plants were insufficient for heat budgets. These heat budgets yielded estimates of the amount of heat transferred to the condenser. The ratio of evaporation to the heat discharged through the condenser was estimated using existing heat balance models that are sensitive to environmental data; this feature allows estimation of consumption under different climatic conditions. These two estimates were multiplied to yield an estimate of consumption at each power plant.

Introduction

Thermoelectric water consumption[1] is the water evaporated or incorporated into by-products as a result of the production of electricity from heat. Evaporation from the **cooling system** accounts for most of the water consumption at most thermoelectric **plants** (U.S. Department of Energy, National Energy Technology Laboratory, 2010). In contrast to **thermoelectric water withdrawals**, which are the largest single water withdrawal category (Kenny and others, 2009), thermoelectric consumption has been estimated to be about 2 percent of total U.S. water consumption, though locally it can be greater (Solley and others, 1998). Thermoelectric water consumption is a critical water use in that thermoelectric plants cannot operate without consuming water, and shutting down power plants imposes costs on society (Eaton, 2012). At the same time, water consumed in thermoelectric power generation is unavailable for other uses.

Thermoelectric water consumption is projected to increase with increasing energy demand (U.S. Department of Energy, National Energy Technology Laboratory, 2010). Moreover, because it is dominated by evaporation, thermoelectric water consumption is inherently sensitive to ambient temperatures and likely to respond to heat waves and changing climate. However, existing reported values and estimates of thermoelectric water consumption do not provide the accuracy, transparency, and temperature sensitivity needed to monitor water consumption and predict its growth.

Available thermoelectric water use data are inconsistent and incomplete (Diehl, 2011). The available thermoelectric water use data are self-reported by plant operators, and techniques for measuring or estimating the main water flows are not standardized. The U.S. Energy Information Administration (EIA) maintains the most complete and consistent database of thermoelectric water use, but plants with water-using generation capacities of less than 100 megawatts (MW) are not required to report water consumption to the EIA, and in 2010 nearly half of the plants that were required to report consumption either did not report consumption or reported zero consumption (U.S. Department of Energy, Energy Information Administration, 2011a, 2011b).

Because reported values are incomplete and inconsistent, water consumption is frequently estimated by multiplying total net generation for various combinations of generating technology and **cooling-system types** by coefficients that are supposed to give average consumption in gallons per kilowatt hour for each plant category. However, published coefficients disagree widely with one another (Macknick and others, 2011). All are based on data subject to the limitations

[1] Words and phrases introduced in **bold** are listed in the Glossary.

discussed above; some are derived using poorly documented methods, and some are thermodynamically unrealistic (Diehl, 2011). Moreover, published coefficients relating typical evaporation to electric generation do not vary with environmental conditions; the coefficients cannot be used to estimate regional or seasonal variability or responses of water consumption to unusual weather or climate change.

In 2010, the U.S. Geological Survey (USGS) inititated a study to estimate water consumption by thermoelectric power plants as part of the USGS National Water Use Information Program and the agency's broader mission to provide scientific information to manage U.S. water resources. This study was motivated in part by recommendations of the Government Accountability Office (U.S. Government Accountability Office, 2009) that the USGS resume reporting thermoelectric water consumption in the U.S., last reported for 1995 (Solley and others, 1998). This study was undertaken with the support of the National Water Census and National Streamflow Information Program. The methods developed to estimate water consumption for this study based on **linked heat and water budgets** are part of the ongoing nationwide assessment of water supply and demand and complement existing recommended methods for quantifying water use (Hutson, 2007; Templin and others, 1999).

The methods in this report describe how electric-power generation technology and cooling system technology interact to determine the amount of water consumed. They can be used to estimate water consumption for individual plants, and to define ranges within which reported values of consumption are thermodynamically realistic. They reflect the dependence of water consumption on air temperatures, wind speed, water temperatures, flow, and plant characteristics and operations. They include **forced evaporation**—the additional evaporation downstream from power plants caused by heat added to water bodies by power plants, over and above the evaporation that would occur in the absence of artificially added heat.

Purpose and Scope

This report describes (1) methods for estimating consumptive **freshwater** use at thermoelectric plants, and (2) a two-tiered classification system for thermoelectric plants, based on generation technology and cooling technology.

This report develops **heat and water budget** models to estimate water consumption at U.S. power plants with water-using cooling systems and generating capacities greater than 1 megawatt (MW). Model development included three major tasks:

- Compiling data on selected plant characteristics, plant operations, and environmental conditions,
- Combining these data into budgets of the major flows of heat and water at the level of the plant or subunits of the plant, and
- Modeling water consumption based on these heat and water budgets.

Geographic areas include the 50 States and the District of Columbia. Power plants in Puerto Rico and the U.S. Virgin Islands are not surveyed by the Energy Information Administration.

A Heat Budget Approach to Thermoelectric Water Consumption

Heat budgets were used to model thermoelectric water consumption at the plant scale for 1,284 water-using power generation facilities in the U.S. A linked heat and water budget was constructed for all thermoelectric plants that provided enough information on plant characteristics and operations. In addition to the estimated most-likely consumption, high and low limit values were estimated based on estimated errors in the budget model. These limit values define a range of consumption values that are likely to be consistent with thermodynamic constraints. Reported values of consumption outside this range are unlikely to be correct based on apparent violation of the thermodynamic constraints. Where the reported amount of water consumption is consistent with the estimated consumption, the reported number can be considered validated. At plants without reported water use, the budget results provide a useful, if imprecise, estimate of thermoelectric water consumption.

For a given period of time at a given plant, the energy made available to drive water consumption through evaporation cannot exceed the difference between the energy contained in consumed fuel and that contained in the plant's electrical output. This difference represents total energy (or heat) dissipated to the environment—a large portion of which drives evaporation of water unless dry cooling is used. Heat-budget computations based on the conservation of mass and energy and records of fuel use and power generation can provide an important, independent means to constrain estimates of thermoelectric water consumption (Rutberg and others, 2011) within bounds determined by the availability of **waste heat** to evaporate water and the design of the cooling system.

Evaporation at thermoelectric plants depends on both the method by which electricity is generated (**generation type**) and the method by which waste heat is removed from the system (cooling-system type). Because generation type and cooling-system type represent two distinct and independent stages in the overall process of thermoelectric water consumption, it is useful to consider them separately. This leads to a two-tiered classification of thermoelectric plants that provides an analytical framework for estimation based on two key processes: the production of waste heat and the conversion of waste heat to evaporation.

The share of fuel energy converted to waste heat depends for the most part on the generation type and design but is little affected by cooling-system type, plant elevation, and environmental conditions. Generation type represents a complex of various systems that convert fuel to heat or otherwise capture heat, and convert heat to electricity and waste heat. In typical steam plants, these systems include a boiler, steam turbine, condenser, and auxiliary equipment. Combined-cycle plants also include combustion turbines. In either case, distilled water is converted to high-pressure steam in a boiler and drives a steam turbine before being re-condensed and returned to the boiler in a closed loop. The heat removed from the steam and transferred to cooling water by a condenser is the majority of waste heat and is defined as the **condenser duty** of the plant. Five generation types classified by electrical generation technology and energy source (table 1) produce distinct estimates of condenser duty. Plants in each of these types report different kinds of information at different levels of aggregation to the EIA. These differences, combined with known technological characteristics of each type, make it necessary to estimate condenser duty with different techniques for each generation type.

The share of condenser duty that goes to produce evaporation depends on cooling-system type as well as a number of environmental conditions, such as plant elevation, air temperature, humidity, wind speed, and ambient water temperature. Generally, cooling systems transfer the bulk of condenser duty to the atmosphere through evaporation and the rest is lost through conduction and radiation (Huston, 1975). Six cooling-system types are common (table 2), of which only three consume freshwater. Of these, most thermoelectric plants built recently have one or more **wet cooling towers**. Inside these towers, hot water is exposed to flowing air over a large surface area. Heat in the cooling water is transferred to air mostly as latent heat through vaporization and to a lesser extent as sensible heat through conduction. These two processes warm the air as it passes through the tower and leave it approximately saturated with moisture. The main alternative to the use of wet cooling towers is **surface-water cooling**, whereby heat is transferred to the atmosphere from the free surface of an extensive body of open water. Though a greater portion of waste heat may leave as convection and long-wave radiation from surface-water cooling systems, a substantial portion remains to be accounted for in evaporation.

For any given cooling system, the fraction of condenser duty that goes to produce evaporation is expressed as the **evaporation ratio** of that system. Because all systems lose at least some waste heat through other processes, evaporation ratios have values less than one. Evaporation ratios for towers are primarily sensitive to ambient vapor pressure and air temperature (wet bulb and dry bulb); ratios for surface-water cooling systems are primarily sensitive to ambient water temperature and wind speed.

Based on the characterizations and analyses described above, a heat-budget approach can be applied in four steps: (1) model the condenser duty for each **generating unit** independent of the type of cooling system; (2) model the evaporation ratio for the various types of cooling systems used by the generating unit; (3) compute the heat transferred to the atmosphere as the product of condenser duty and evaporation ratio; and (4) compute the weight of evaporated water and its liquid volume from the water temperature and the specific heat of evaporation. Each of these steps requires specific information, which may be available in varying degrees of quality and completeness. The available heat in the fuel entering the plant and the energy in the electricity that leaves the plant are well measured at most plants, and the difference between them is the heat rejected by the plant. Condenser duty is the largest component of heat rejection, and the other components, losses from auxiliary equipment and heat in the exhaust gas, are estimated based on generation type. Environmental variables and the type of cooling system control the evaporation ratio. The cooling system models use monthly averages of dry bulb air temperature, wet bulb air temperature, ambient surface-water temperature, and wind speed, as well as plant elevation data. Verified plant locations were used to validate cooling-system types and to link environmental variables and elevations to plants.

Table 1. Generation-type classification categories used to estimate condenser duty.

[The prime mover is the turbine that converts the energy in heated gases to mechanical energy.]

<table>
<tr><th>Generation type</th><th>Prime mover</th><th>Energy source</th><th>Condenser duty estimation method</th></tr>
<tr><td>Combustion steam</td><td>Steam</td><td>All combustible fuels used in steam prime movers; dominated by coal</td><td rowspan="6">Linked heat and water budgets, with evaporation modeling approach determined by cooling-system type</td></tr>
<tr><td rowspan="3">Combined cycle</td><td>Combined cycle combustion turbine part</td><td rowspan="3">All fuels used in combined-cycle prime movers; dominated by natural gas</td></tr>
<tr><td>Combined cycle steam part</td></tr>
<tr><td>Combined cycle single shaft</td></tr>
<tr><td>Nuclear</td><td>Steam</td><td>Nuclear</td></tr>
<tr><td>Geothermal</td><td>Steam</td><td>Geothermal</td></tr>
<tr><td>Solar thermal</td><td>Steam</td><td>Solar</td><td>Water-consumption coefficient</td></tr>
</table>

Table 2. Cooling-system type classification categories used to estimate evaporation.

Cooling-system type	Evaporation modeling approach
Wet freshwater recirculating cooling tower	Wet tower evaporation model
Recirculating pond or canal	Water surface evaporation model
Once-through freshwater	
Wet saline recirculating cooling tower	Not modeled
Once-through saline water	
Dry cooling systems	

Data Compilation and Quality Assurance

Classifying power plant technologies and developing methods for estimating water consumption required specific thermoelectric plant-characteristic, operational, locational, and environmental data. Data were compiled from EIA, the U.S. Environmental Protection Agency (USEPA), the National Energy Technology Laboratory (NETL), the National Oceanic and Atmospheric Administration (NOAA), and USGS national databases. The data were incorporated into the classifications and methods either as initially reported, or as variables to calculate numerical values needed to estimate condenser duty and evaporation.

Plant Master List

The final list of plants for this study (herein referred to as the plant Master List) has 1,284 thermoelectric, water-using power plants. These plants were identified using plant-characteristic data from the 2010 EIA-860 Annual Electric Generator Report database (Appendix 1). For this study, power plants were limited to electricity-generating facilities that have been assigned unique plant codes by the EIA. At the broadest level, power plants with existing generators (as opposed to plants with retired or proposed generators) had 5,824 unique records in the EIA-860 database. Eliminating plants with existing generators that were not active in 2010 narrowed the group to 5,344 plants. Of these, 1,713 were identified as having water-using thermoelectric generators based on **prime mover**, which is the turbine that converts the energy in heated gases to mechanical energy. Based on the North American Industry Classification System (NAICS) codes (U.S. Census Bureau, 2007), water-using thermoelectric generators can be further subdivided into industrial and commercial facilities and electric utilities. After eliminating industrial and commercial facilities, which are grouped by the USGS in separate water use categories, 1,329 electric utility power plants remained. Some of these plants use **dry cooling systems**, which do not evaporate water, and therefore were removed leaving a revised total of 1,284 plants that fit all study criteria. Within the final Master List, 217 plants were described as **combined heat and power** plants and required a modified water consumption estimation model.

Generation Data

Generation data, compiled from the 2010 EIA-860 Annual Electric Generator Report and the EIA-923 Power Plant Operations Report databases, include both the plant-characteristic data used to classify generation types and operational data used to model condenser duty (Appendix 2, table 1). Plant-characteristic data, including prime mover, energy source, **boiler efficiency**, interconnections (associations) between boilers and generators, and flue-gas desulfurization (FGD) types, are generally the same from year to year and are not dependent on annual operations unless entire boilers, generators, or cooling systems are brought on or off line. Operational data including the amount of fuel consumed (electric and total fuel heat produced) and the net amount of electricity generated by each plant will typically vary by month and year.

The portion of fuel heat converted to condenser duty depends on the design of each plant. Five generation types have been identified based on prime mover and energy source: combustion steam, combined-cycle, nuclear, geothermal, and solar thermal (table 1). Steam turbines, which are associated with water-using cooling systems, are used with all of these generation types but are fueled by different energy sources. Whereas coal provides most of the heat to combustion steam turbines, a wide variety of other fuels also is used. Steam turbines at nuclear, geothermal, and solar thermal plants are powered by their respective noncombustive energy sources. Combined-cycle plants use a combination of combustion turbines and steam turbines to generate electricity in which exhaust from a combustion turbine (commonly powered by natural gas) boils water to power a steam turbine. Each generation type has a condenser duty range that is contingent upon the amount of fuel heat used to generate electricity. Detailed lists of prime movers, energy sources, and associated EIA codes are given in Appendix 2, tables 2 and 3.

Data on fuel consumption, electric generation, and plant characteristics are fundamental to the heat-budget approach, but the availablility and quality of these data vary widely among different generation types. In general, reported net electric generation data for all generation types were of good quality, principally because the amount of electricity transmitted to the electrical distribution grid is well measured. Fuel-consumption data, on the other hand, were of consistently good quality only for combustion-steam and combined-cycle plants. Because total heat values from fuel consumption in nuclear, geothermal, and solar thermal plants are difficult to define and measure, reported values for these plants were nominal at best (producing unrealistic thermal efficiencies) and had to be estimated. Boiler efficiencies reported for most combustion-steam plants were thermodynamically realistic, but at some plants boiler efficiency had to be estimated based on the types of fuels burned. The boiler efficiencies reported for combined-cycle plants were thermodynamically unrealistic and were not used in heat budgets. FGD-type data reported for combustion-steam plants were assumed to be accurate. Electric-fuel consumption data reported for combined heat and power plants were generally of adequate quality for computing the amount of heat exported to associated heat-using processes.

Cooling System Data

Cooling system data are the plant characteristics used to classify cooling-system types, interconnections between cooling systems and boilers, and the locational and environmental data used to estimate water consumption. The amount of waste heat transferred from the condenser to the atmosphere through evaporation depends on the cooling-system technology and the environmental variables associated with the plant locations.

Power Plant Locations and Elevations

Locations for each thermoelectric plant link aerial imagery, plant elevation, environmental data, and catchment areas necessary to estimate power plant-specific water consumption. To ensure correct links among these datasets, multiple, often conflicting, power plant locations from EIA, NETL, and USEPA databases were evaluated using standard geographic information system (GIS) procedures (U.S. Department of Energy, Energy Information Administration, 2001, 2009, 2011a; U.S. Department of Energy, National Energy Technology Laboratory, 2007b; U.S. Environmental Protection Agency, 2007a, [n.d.]). Power plant locations were verified and then matched to USEPA's National Hydrography Dataset Plus (NHDPlus) to determine elevation and assign river catchments (U.S. Environmental Agency, 2007b). Those locations and associated metadata were stored in an internal USGS GIS database.

Locations of record for power plants were verified by inspecting digitally mapped site locations using GIS and other computer-aided techniques. A point-data layer was created from seven sets of coordinates composed of 19,496 power plant locations. The sets of coordinates were from four U.S. Department of Energy (DOE) databases: the 2000, 2008, and 2010 Form EIA-860 databases (U.S. Department of Energy, Energy Information Administration 2001, 2009, 2011a), and the NETL Coal Power Plant Database [CPPDB] (U.S. Department of Energy, National Energy Technology Laboratory, 2007b), and two USEPA databases: the Enforcement and Compliance History Online [ECHO], which is composed of two datasets (U.S. Environmental Protection Agency, [n.d.]), and the Emissions & Generation Resource Integrated Database [eGRID] (U.S. Environmental Protection Agency, 2007a). In many instances, these different sources produced more than one location for each power plant. To reconcile those locations, a second data layer containing the mean center location for sites with multiple locations was created. Mean center locations for each plant were then adjusted in a final point layer based on GIS-facilitated analysis of aerial imagery and other available information. A reference layer of power plants was extracted from the 2011 Homeland Security Infrastructure Program (HSIP) Gold database (Appendix 3) and used for visual site verification. This information, however, could not be directly linked to EIA, NETL, or USEPA location datasets by plant name or EIA plant code. Linkages were made using other location information provided in several base layers obtained from USGS topographic maps at various scales, road maps, aerial photography, and satellite imagery as well as GIS-facilitated internet searches of publically available mapping services.

The location verification procedure involved a series of power plant-specific queries within the GIS display points by plant code number. This reduced the number of points by eliminating all other power plants from the screen so that only the multiple locations of the queried power plant were displayed. The reduced area provided a general location of a plant from which a search could be conducted. The search began by finding the HSIP power plant location, and determining its proximity to the mean center location. If a plant could not be located and verified by aerial imagery, the plant's address was used to conduct a visual search in the area defined by the extent of all points with the same EIA power plant code, and to execute an internet search for any other information about the plant that could be used to find its actual location (fig. 1). Power plant locations were then overlain with NHDPlus version 1.1 data to determine elevation and river catchment area (U.S. Environmental Protection Agency, 2007b).

Cooling-System Type Validation

Cooling-system types were classified into two basic categories: wet cooling towers and surface-water cooling systems (table 2). Power plants that have water-using generation capacities of 100 MW or greater are required to report cooling-system types to the EIA; 802 Master List plants fit this criterion. However, this information is sometimes inaccurate or is incomplete, as is the case with the 482 Master List plants not required to report. Therefore, verified power plant locations and internet searches were used to validate the cooling-system types for the Master List power plants.

Analysts were trained to identify the various types of cooling systems using aerial imagery in Google Earth and Bing Maps. Wet cooling towers include natural-draft towers and two types of mechanical-draft towers, induced-draft and forced-draft towers, which are all readily identifiable from aerial imagery. Natural-draft towers are identifiable as large, hyperboloid structures with pronounced top openings (fig. 2); air flow through natural-draft towers is driven by

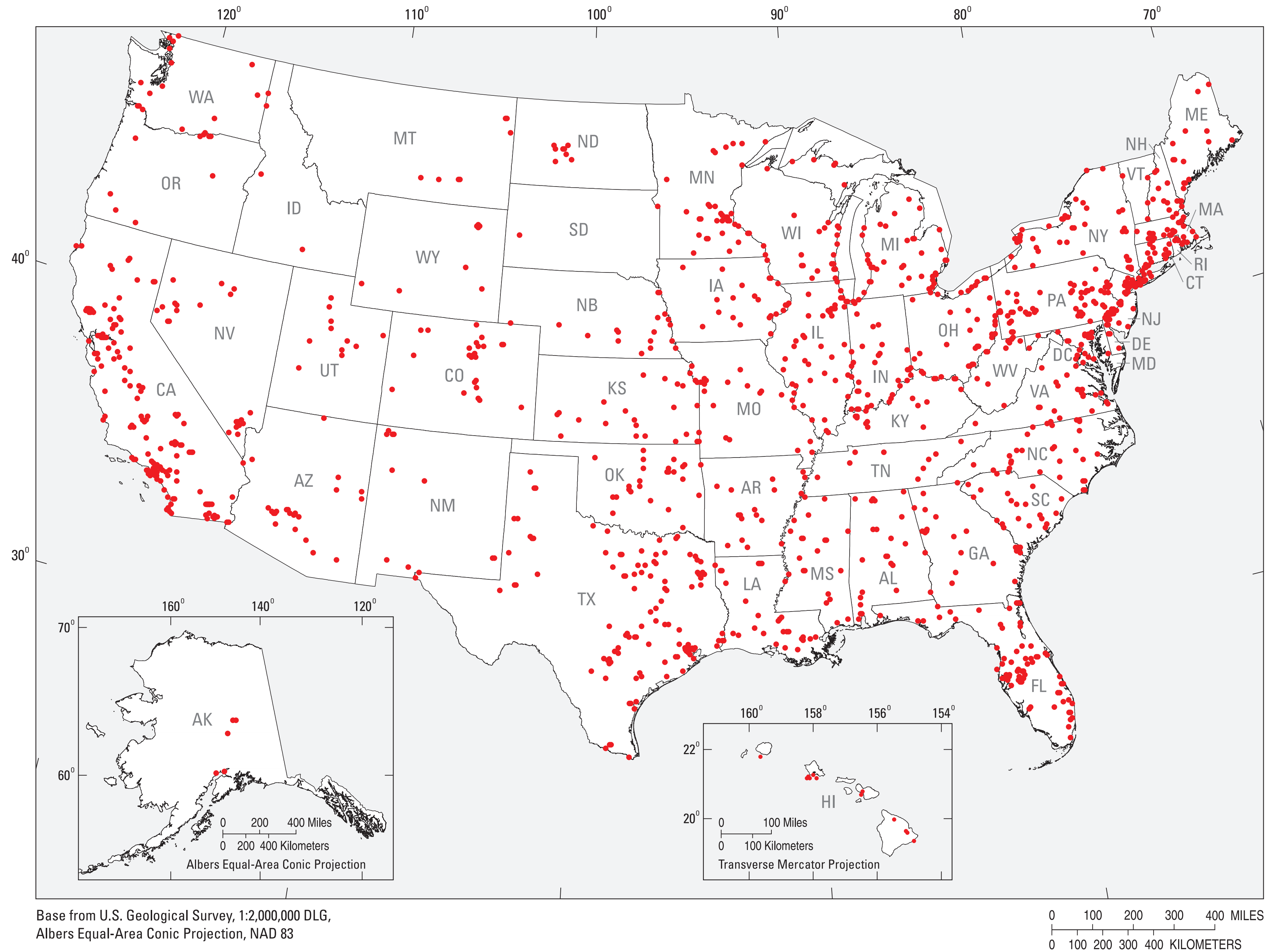


Figure 1. Geographic distribution of the 1,284 thermoelectric plants one megawatt nameplate capacity or greater with water-cooling systems in the United States, 2010. [Power plants in Puerto Rico and the U.S. Virgin Islands are not surveyed by the Department of Energy, Energy Information Administration.]

National Agricultural Imagery Program (NAIP),
U.S. Department of Agriculture (USDA), 2007

0 100 200 300 400 500 FEET
0 20 40 60 80 100 120 METERS

Figure 2. Natural-draft cooling towers and one of two intake screens and associated pumps for the Tennessee Valley Authority, Sequoyah Nuclear Power Plant, Tennessee. Natural-draft tower airflow is drawn through the packing or fill (distributed at the base) by means of the small density difference between the warm moist air inside the tower and the cooler ambient air outside the tower (Stultz and Kitto, 1992). Because of the small temperature and density difference, these cooling towers tend to be tall. These towers are relatively open cylindrical structures. Modern units are sometimes referred to as hyperbolic towers because of their shape. The heat rejected from the steam to the cooling water is circulated through the cooling tower where the heat is rejected to the atmosphere as latent and sensible heat.

convection. Induced-draft towers have large fans on top of the tower structure that pull air up through the tower (fig. 3). Forced-draft towers are generally rectangular and have a radiator-like appearance across the top; the fans are located in the bottom of these towers and push air up through the tower structure (fig. 4). Many dry cooling systems, known as air-cooled condensers, also have a radiator-like appearance, but most have large pipes running the length of the structure that aid in identification (fig. 5). Surface-water cooling systems include **once-through cooling systems** and **recirculating cooling** pond or canal systems. Once-through cooling systems take water from a surface-water body, transfer heat into it, and discharge the water to a surface-water body; little or none of this discharged water is recirculated through the condenser. Recirculating ponds and canals are similar but have much smaller surface-water inflows and outflows, so that the water in them is recirculated many times through the condenser. Once-through cooling systems were identified by the cooling-water intake structures that feature intake pumps and screens located in and beside water bodies (fig. 6) and discharge outlets (fig. 3) characterized by concentrated, fast-flowing water with visible foam. Once-through cooling systems can be located on coastal waters, rivers, lakes, or ponds. Because the type of water body determined the surface-water evaporation model that was used, the areas of lakes and ponds were measured to assist in establishing a surface-water cooling subcategory (coastal waters and rivers are evident). Ponds were distinguished from lakes at this stage as being smaller than lakes and lacking irregular natural shorelines (fig. 7). Both natural lakes and reservoirs were assigned to the lakes

Figure 3. Mechanical induced-draft cooling towers (wet cooling towers) and the discharge outlet for Entergy Vermont, Vermont Yankee Nuclear Power Plant, Vermont. With the mechanical induced-draft cooling towers, the fan is located downstream of the air and water interface and the air is drawn through the cooling tower (Stultz and Kitto, 1992). Airflow distribution is typically more uniform and less prone to ground interference or recirculation. The heat rejected from the steam to the cooling water is then circulated through the cooling tower where the heat is rejected to the atmosphere as latent and sensible heat.

subcategory (fig. 8). Later, several lakes were redefined as ponds on the basis of high **heat loading**. A list of the cooling-system types and their associated EIA codes is presented in Appendix 2, table 4.

Determining cooling-system types for some plants proved more difficult and professional judgement was needed for identification. Some once-through plants, for example, have intakes or outlets that are submerged and cannot be located using aerial imagery. In such cases, if no other cooling system could be identified (for example, towers) and the plant was located next to a river, lake, or coastal water body, it was determined to have a once-through system. Some dry cooling systems known as heat exchangers have a similar appearance to wet cooling towers and are difficult to identify. Additionally, locating and linking cooling systems to plants within industrial complexes or within close proximity of another plant relied on subjective decisions.

After validating cooling-system types, most of the reported forced-draft cooling towers were reclassified as induced-draft cooling towers. For the non-reporting plants, the majority of the cooling-system types were identified as induced-draft cooling towers. Overall, of the 1,284 power plants in the Master List, most were classified as wet tower systems (fig. 9). Some, with multiple cooling-system types, were classified as complicated and consumption by each cooling-system type was modeled separately.

Environmental Data

The evaporation models require several environmental input variables that are specific to each power plant. The environmental inputs needed for the surface-water evaporation model include: site elevation, monthly mean wet bulb and dry

Figure 4. A mechanical forced-draft tower for the City of Tallahassee, Arvah B. Hopkins Power Generating Station, Florida. In mechanical forced-draft cooling towers, fans are typically located upstream of the air/water interface (Stultz and Kitto, 1992). In this case the air is drawn through the cooling tower. The heat rejected from the steam to the cooling water is then circulated through the cooling tower where the heat is rejected to the atmosphere as latent and sensible heat.

bulb air temperatures, monthly mean water temperature, and monthly mean wind speed. Environmental inputs needed for the tower evaporation model include: elevation, monthly mean wet bulb and dry bulb temperatures. Acquisition of elevation data has been described previously; the following discussion focuses on the data sources and determination methods of climate inputs (wet bulb and dry bulb temperatures, and wind speed) and water temperature inputs.

Data Sources

Land-surface observations from Quality Controlled Local Climatological Data (QCLCD or LCD) collected by the NOAA, National Climatic Data Center (Appendix 3) serve as the foundation for dry bulb, wet bulb, and wind speed determinations. LCD consists of hourly, daily, and monthly summaries of meteorological observations collected at major airports nationwide. In 2010, the LCD network consisted of 1,152 weather stations reporting at least 1 month of meteorological observations.

USGS water temperature measurements, EIA plant-reported values, and satellite imagery were the basis for water-temperature determinations, depending on plant location. For plants located on one of the Great Lakes, satellite imagery provided water temperature information. The NOAA Great Lakes Environmental Research Laboratory (GLERL) produces the Great Lakes Surface Environmental Analysis (GLSEA2), which is a daily digital map of lake-surface temperatures and ice cover derived from imagery collected by the NOAA polar-orbiting satellite (Appendix 3). For all other plants, temperature measurements of lakes and rivers from USGS water temperature stations and plant-reported intake temperatures provided by the EIA were used for water-temperature determinations. In 2010, approximately 700 USGS streamgaging

Figure 5. Dry cooling towers for the ONCOR, Midlothian Power Plant, Texas. An air-cooled system may be mechanical or natural draft (Stultz and Kitto, 1992). All the heat rejected from the steam is absorbed in the form of sensible heat gain in the ambient air.

stations recorded daily mean water temperature in the U.S. Monthly mean water temperatures were calculated from this record for months in which fewer than seven daily values were missing. The EIA also collects plant-reported average monthly intake water temperatures (using Form EIA-923) for facilities generating greater than 100 MW, which accounted for 381 power plants nationwide in 2010.

Data Quality

The quality of the LCD data (dry bulb temperature, wet bulb temperature, and wind speed) is controlled by NOAA, and no additional filtering based on data quality was required. Only stations with complete monthly observations for 2010 were used, and only stations with both dry bulb and wet bulb temperature observations were retained. Of the 1,152 weather stations reporting meteorological observations, 554 stations reported 12 months of monthly mean dry bulb and wet bulb temperatures, and 727 stations reported 12 months of monthly mean wind speed. Stations missing 1 or more months of observations were compiled in separate validations for dry bulb and wet bulb temperature or wind speed and used in an analysis of uncertainty. The geographic distribution of dry bulb and wet bulb stations and wind speed stations used for input determination was fairly uniform across the U.S. (figs. 10 and 11).

No additional quality control was performed on the Great Lakes water temperature map (GLSEA2), however several filtering processes were used to check the quality of USGS and EIA measurements of water temperature. There were 622 USGS water temperature stations after filtering. USGS monthly mean water temperatures were filtered through an iterative process. First, monthly temperatures were screened for extreme values and irregular seasonal patterns such as deviations from a generally sinusoidal curve. Sites that were flagged during this process were visually evaluated and removed from the dataset if they were located in a geothermal

Figure 6. Intake screen and pumps used for once-through cooling at the Tennessee Valley Authority, Browns Ferry Nuclear Plant, Alabama. The discharge outlet is not shown. In once-through cooling, water is withdrawn from a source, circulated through the condenser, and then returned to a body of water at a higher temperature (Kenny and others, 2009). The heat is rejected as latent and sensible heat (Stultz and Kitto, 1992).

area or below a dam. Leave-one-out cross-validation (Breiman and Spector, 1992) was used to identify possible errors in water temperature at remaining sites and a site was flagged if its error was greater than two standard deviations from the mean error of the cross-validated estimates. Flagged sites were then visually evaluated to determine their appropriateness for the dataset.

Plant-reported, monthly average intake water temperatures collected by EIA were initially filtered based on the method of measurement. Only plants that indicated water temperature was measured at intervals (for example, daily) with a thermometer or measured continuously with a thermometer were retained. Furthermore, only plants that reported once-through freshwater cooling systems were retained. Remaining sites were then screened for extreme values and irregular seasonal patterns and subjected to the same cross-validation process described above. There were 133 plants with monthly mean intake water temperature after filtering. Monthly temperature data from the USGS were combined with plant-reported EIA data and the water temperature dataset used for input determination contained 755 sites with at least 1 month of water temperature in 2010. The geographic distribution of water temperature sites varies by month and is not uniform across the U.S., particularly in the Southwest, where water temperature information is sparse (fig. 12).

Methods of Determination for Environmental Input Variables

For each plant, climate inputs were determined by interpolation among nearby weather stations with dry bulb and wet bulb observations (fig. 10) or wind speeds (fig. 11). Using a 100-mile search radius, the distances from each plant to the nearest three weather stations were determined and used to compute a weighted mean of climate variables based on the inverse of distance from the respective plant.

Figure 7. The approximately 2.5-mile-long cooling pond for the Entergy Texas, Lewis Creek Generating Plant, Texas. Water is withdrawn and returned to Lewis Creek Reservoir.

Empirical Bayesian kriging (Krivoruchko, 2012; Pilz and Spock, 2007) produced an interpolated water-temperature surface for the continental U.S. by month based on both USGS and EIA data. Water-temperature inputs for plants located on rivers, lakes, and reservoirs were determined based on their location. An inverse-distance weighted average was not used for water temperature because the geographic distribution of water temperature sites was not uniform across the U.S. (fig. 12). Empirical Bayesian kriging was used because it accounts for the error introduced by the selection of an underlying model of variation (semivariogram), providing smaller standard errors of prediction than other kriging methods (Esri, 2012). Additionally, a subsetting process allows for accurate predictions of moderately nonstationary data (Esri, 2012). Using tools included in the ArcGIS 10.1 Geostatistical Analyst Toolbar and Toolbox (Esri, 2012), observed temperature data were divided into local subsets. For each subset, a semivariogram model was estimated. Using this semivariogram, estimates of water temperature were simulated for each of the locations in the subset. The empirical Bayesian kriging tool iterated through this computation a specified number of times to produce a distribution of semivariograms for each subset. Local models were then derived from those distributions to produce a final predictive model (surface map) of average water temperature by month.

Empirical Bayesian kriging did not work well for plants located on the Great Lakes. An initial trial using a kriged surface to determine water temperatures for the Great Lakes resulted in large differences from observed water temperatures. Therefore, remotely sensed water-temperature

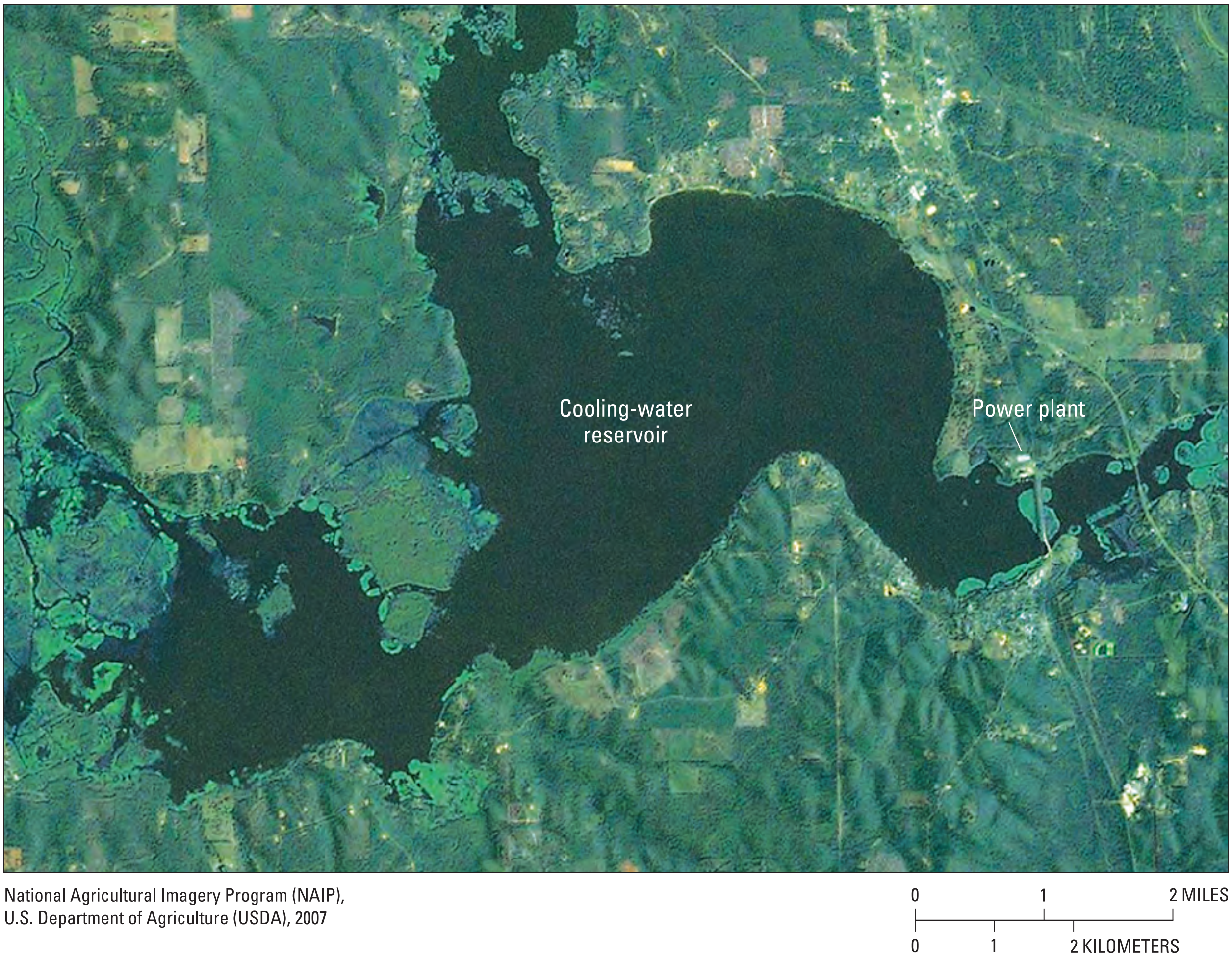


Figure 8. The approximately 8-mile-long cooling-water reservoir for the Southwestern Electric Power, Lieberman Power Plant, Louisiana. Water is withdrawn and returned to Caddo Lake. In once-through cooling, water is withdrawn from a source, circulated through the heat exchangers, and then returned to a body of water at a higher temperature (Kenny and others, 2009). In once-through cooling, the heat is rejected to a body of water as latent and sensible heat (Stultz and Kitto, 1992).

information (GLSEA2) provided by the NOAA GLERL was used to determine water temperatures. Daily average water temperatures at the location of each plant on the Great Lakes were retrieved from satellite imagery and aggregated to a monthly mean.

Uncertainty Analysis

The uncertainty associated with the three input determination methods described above was assessed by comparison to a validation dataset of sites that were dropped from model development because of missing data. Using the same basic approach applied to power plants, dry bulb temperature, wet bulb temperature, and wind speed were estimated for each validation weather station and compared to observed record to determine estimation error. Based on that analysis, approximately 95 percent (two standard deviations) of dry bulb validation temperatures were within plus or minus 3.2 degrees Celsius (°C) (5.8 degrees Fahrenheit or °F). Similarly, approximately 95 percent of wet bulb validation temperatures were within plus or minus 2.0°C (3.6°F). Wind speeds were typically within plus or minus 3.7 miles per hour (mph). The dry bulb/wet bulb validation dataset consisted of 598 weather stations that had fewer than 12 months of 2010 observations, which accounted for 4,551 monthly observations across the validation dataset. The wind speed validation set included 424 weather stations missing 1 or more months of data, which accounted for 1,800 monthly observations across the validation dataset.

Uncertainty associated with water-temperature estimates derived from kriged surfaces was assessed using leave-one-out

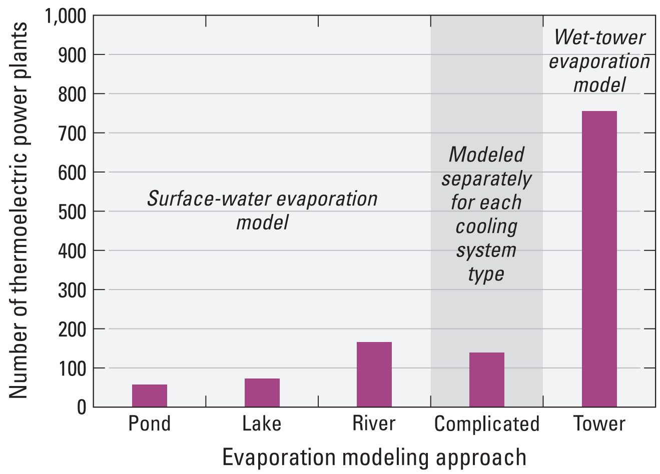


Figure 9. The distribution of cooling-water types for modeling evaporation for 1,284 thermoelectric plants. Complicated refers to multiple cooling types for a single plant. Tower refers to wet recirculating cooling tower.

cross-validation within ArcGIS. Kriged water temperatures were within plus or minus 3.6°C (6.5°F) of those observed. Remotely sensed water temperatures were assessed for uncertainty by comparison to observed temperatures at plants on the Great Lakes. Approximately 95 percent of remotely sensed water temperatures were within plus or minus 6.3°C (11.3°F) of the observed temperatures. The greater uncertainty of remotely sensed data on the Great Lakes may result from the recirculation of heated discharge water in the vicinity of plant intakes. This effect may occur at such a small scale that it is not captured in satellite imagery.

Supplemental Methods

For a few plants, environmental conditions could not be determined using the methods described above and the uncertainty in these estimates is difficult to evaluate. Based on the quality of nearby records, dry bulb or wet bulb temperatures could not be estimated at six plants, and because the kriged surface did not extend to Alaska and Hawaii, water temperatures could not be estimated for 19 plants. For the six plants at which the previously described methods did not yield estimates of dry bulb and wet bulb temperatures, the nearest weather stations that were missing 1 or more months of observations were used. Values for the the missing months at these stations were estimated by averaging the preceding and following monthly observations. Also, in a few instances, estimated wet bulb temperatures were higher than dry bulb temperatures so the two were set to equal dry bulb temperatures. For plants in Alaska and Hawaii, records from the nearest USGS water temperature stations were used to estimate water temperatures.

Computing Heat and Water Budgets

Water consumption at most power plants was modeled by heat and water budgets constructed in three independent steps: (1) the organization of systems within the plant was analyzed, and the plant was disaggregated where possible into modeling units containing a single generation type or cooling type, (2) condenser duty was estimated for groups of boilers and generators, and (3) water consumption was estimated for groups of boilers, generators, and cooling systems, using estimated condenser duty as input. Water consumption at solar thermal power plants was calculated on the basis of consumption coefficients found in the literature, because reported plant data were insufficient for construction of heat budgets.

To simplify computation of heat and water budgets, plants were disaggregated into groupings of boilers, generators, and cooling systems for which energy can be budgeted. For estimation of condenser duty, this required identifying groups of boilers and generators that are connected by the physical transfer of steam such that the fuel used by boilers in a particular boiler-generator group can be associated with the electricity generated by the generators in the same group. At nearly all plants, it was possible to construct boiler-generator groups with a single generation type (table 1). Because reported information on plant characteristics, the types and amounts of fuel consumed by a given plant, and electrical generation vary among generation types, separate heat-budget models were developed for each major generation type.

The water evaporated for cooling was estimated for each cooling-system group at each plant using a heat and water budget model with estimated condenser duty as input. A cooling-system group has one or more cooling systems and the associated boiler-generator groups that provide condenser duty to these cooling systems. Evaporation was modeled differently for cooling towers and surface-water cooling systems independently of generation type.

Disaggregation below the plant scale reduced the need to model mixed systems including multiple types of generation or cooling. Most thermoelectric water consumption was modeled as a single generation type transferring condenser duty to a single cooling type.

Many plants contain only a single cooling-system group, and others did not provide sufficient information to distinguish more than one cooling-system group. Nearly 500 plants reported no cooling system or operations information and so were necessarily treated as plants with a single cooling-system group. Where cooling-system groups included multiple types of cooling, the condenser duty was allocated between the two cooling models using professional judgement.

Error analysis established the upper and lower limit values for evaporation associated with cooling. It was assumed that errors from different sources were independent. Error from some sources such as environmental variables could be quantified, but other sources such as the estimation of exhaust heat at combined-cycle power plants contribute unknown amounts of error.

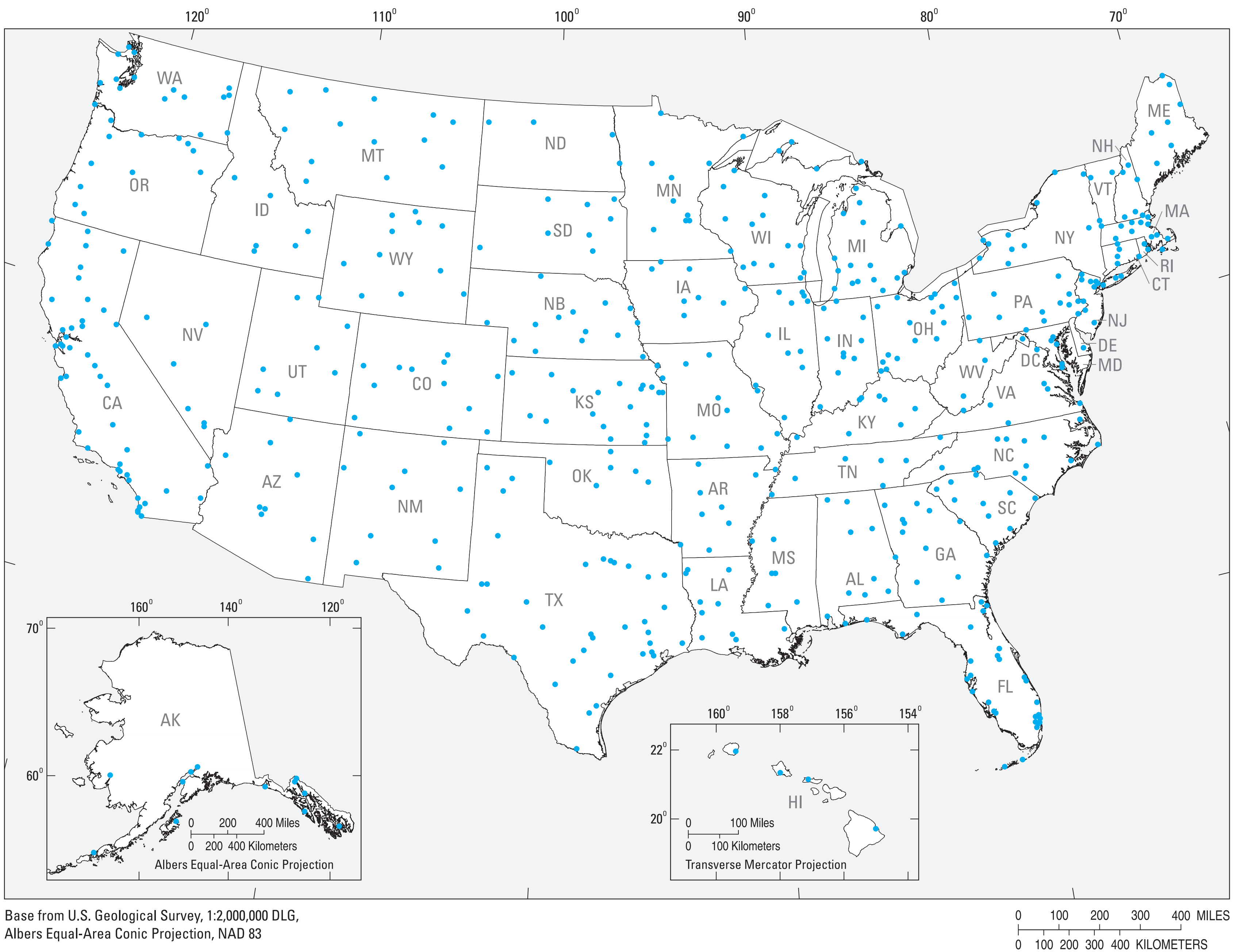
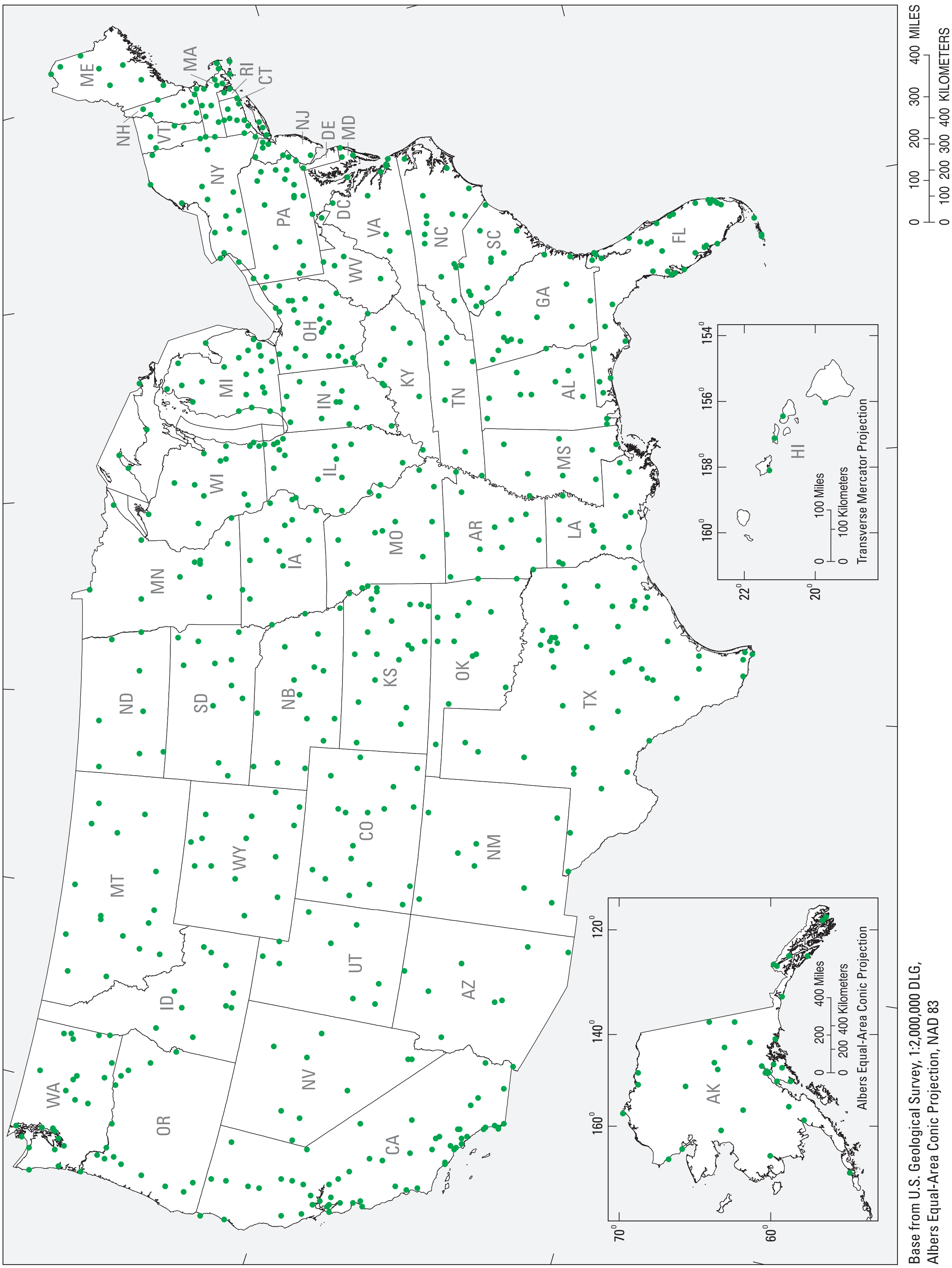
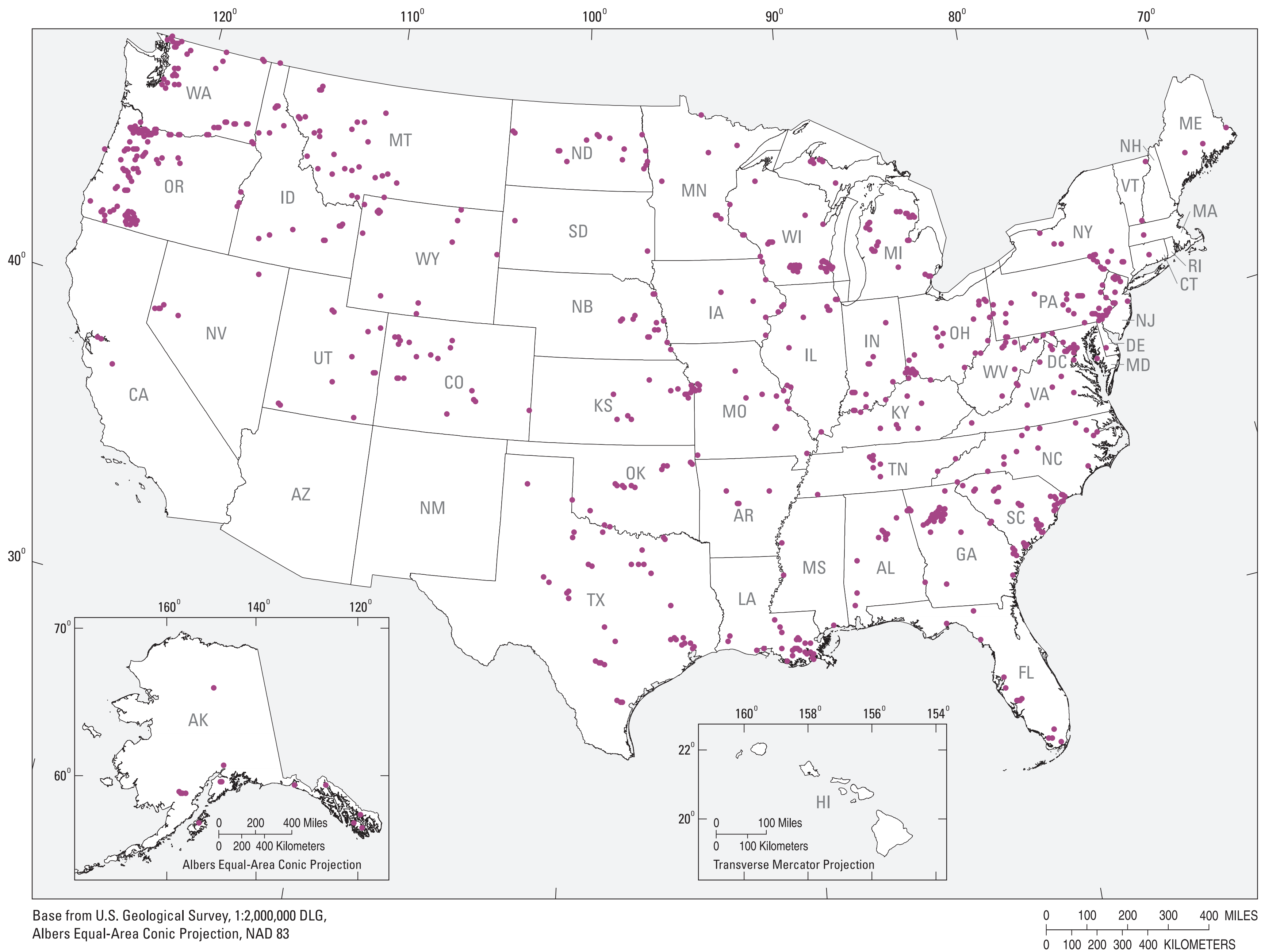


Figure 10. Geographic distribution of the 554 weather stations containing 12 months of monthly mean dry bulb and wet bulb temperatures in 2010.



Base from U.S. Geological Survey, 1:2,000,000 DLG,
Albers Equal-Area Conic Projection, NAD 83

Figure 11. Geographic distribution of the 727 weather stations containing 12 months of monthly mean wind speed in 2010.



Base from U.S. Geological Survey, 1:2,000,000 DLG,
Albers Equal-Area Conic Projection, NAD 83

Figure 12. Geographic distribution of the 755 water temperature stations (U.S. Geological Survey stations and greater than 100 megawatt power plants reporting intake temperature) with at least one month of monthly mean water temperature in 2010.

Estimation of Condenser Duty by Generation Type

Generator-boiler groups were assigned to five generation-type categories (table 1) based on energy source and prime mover:

1. Combustion steam groups have steam turbines (prime mover type ST; Appendix 2, table 2) and burn a variety of fuels as discussed below.

2. Combined-cycle groups have either a combination of combustion turbines and steam turbines driven by heat from the combustion turbines' exhaust, or a combined-cycle single-shaft turbine (prime mover types CT, CA, and CS, respectively). Nearly all of them burn primarily natural gas.

3. Nuclear groups have steam turbines and a nuclear energy source (energy source type NUC; Appendix 2, table 3).

4. Geothermal groups have steam turbines and a geothermal energy source (energy source type GEO).

5. Solar thermal groups have steam turbines and a solar energy source (energy source type SUN).

Condenser duty for boiler-generator groups of the first four types was estimated using heat budgets; condenser duty could not be estimated at solar-thermal plants.

The heat budget of a boiler-generator group can be described by the following equation:

$$CD = TH - SL - NE - AL - XH \qquad (1)$$

where

CD = condenser duty;
TH = total heat introduced into the plant, from fuel or other sources;
SL = heat lost through the stack (exhaust);
NE = net electrical generation;
AL = heat lost to the air from plant equipment; and
XH = heat exported from combined heat and power plants.

All terms are normally in units of million British thermal units (MMBtu) in conformity with EIA reporting.

Although equation (1) is broadly applicable to thermoelectric plants in general, methods for calculating the terms in this equation differ among generation types, reflecting differences in physical characteristics and available information. Whereas reasonable values of *TH* are generally reported for combustion-steam and combined-cycle boiler-generator groups, reported values of *TH* for nuclear or geothermal boiler-generator groups are nominal, so *TH* had to be estimated for these groups. Values of *SL* were estimated by different methods for combustion-steam and combined-cycle boiler-generator groups, whereas *SL* was zero for nuclear and geothermal boiler-generator groups. Reported values of *NE* were used for all types of boiler-generator groups.

AL was estimated at all plants by assuming that heat loss to the atmosphere is a constant 2 percent of total heat:

$$AL = TH * 0.02 \qquad (2)$$

Although values of *AL* are reported to range from 1 percent to 4 percent for individual plants (U.S. Department of Energy, National Energy Technology Laboratory, 1999, 2007a; International Atomic Energy Agency, 2009; International Energy Agency, 2008; Electric Power Research Institute, 2011; U.S. Department of Energy, Energy Information Administration, 2013), there is not a strong basis for assigning different values of *AL* to individual boiler-generator groups or to different generation types.

Combined heat and power plants report total fuel and electric fuel data. Total fuel is the actual fuel use, and the difference between total and electric fuel is the monthly amount of heat exported from the power plant to the associated heat-using process it supports. The **exported heat** was deducted from the condenser duty because this heat is dissipated by a second, non-thermoelectric process (fig. 13).
At all plants with exported heat, the exported heat *XH* is defined by

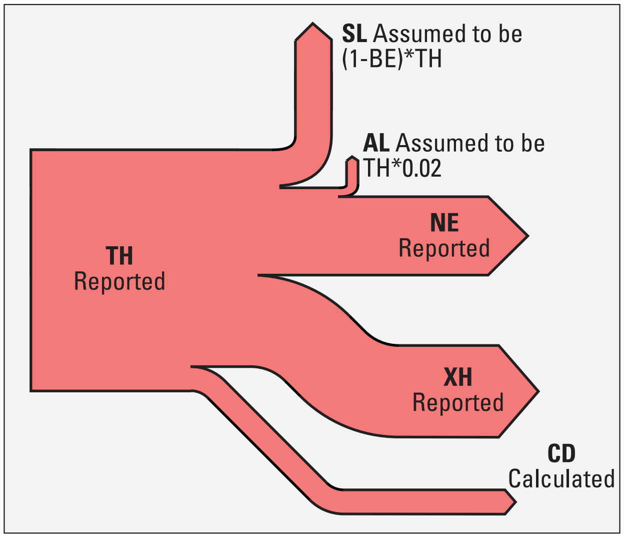
$$XH = TH - EH \qquad (3)$$

where *TH* is the total heat introduced into the plant and *EH* is the reported electric heat.

At several power plants, this deduction resulted in a budget with the total heat leaving the plant exceeding the total fuel heat entering the plant. This discrepancy indicates either misreported data or an inappropriately constructed heat budget. Due to lack of plant-specific data that would allow construction of a more detailed and accurate model, it was assumed that such plants export all their waste heat to the associated heat-using process.

Combustion-Steam Generation

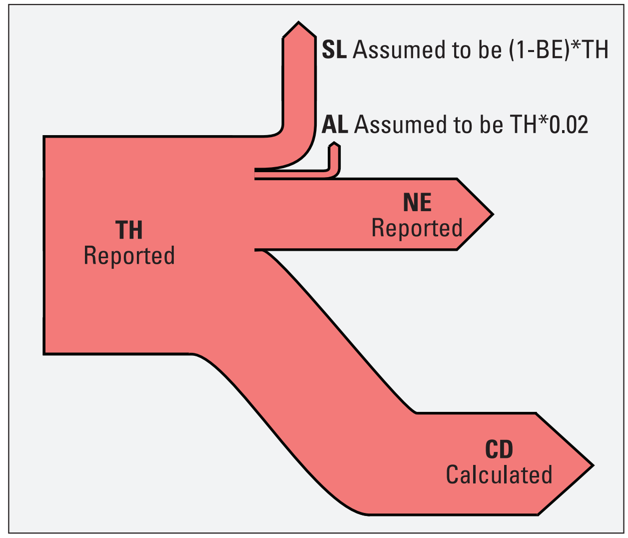
Plants categorized as combustion steam use a variety of fuels or, less commonly, waste heat from outside the plant to power steam turbines. Combustion steam plants transfer a substantial amount of heat to the atmosphere in the exhaust gases. Most of these plants report heat production by boiler and electric generation by generator, allowing construction of heat budgets for individual boiler-generator associations. Reported boiler efficiencies appear realistic at most plants, allowing estimation of exhaust-gas heat on a plant by plant basis (fig. 14). For combustion steam boiler-generator groups,



EXPLANATION

AL Heat lost to the air from plant equipment
BE Boiler efficiency at 100 percent load
CD Condenser duty
NE Net electrical generation
SL Heat lost through the stack (exhaust)
TH Total heat introduced into the plant
XH Heat exported from combined heat and power plants

Figure 13. Sankey diagram for an example combustion steam power plant with combined heat and power.



EXPLANATION

AL Heat lost to the air from plant equipment
BE Boiler efficiency at 100 percent load
CD Condenser duty
NE Net electrical generation
SL Heat lost through the stack (exhaust)
TH Total heat introduced into the plant

Figure 14. Sankey diagram for combustion steam plants.

the reported value of *TH* was used. Stack losses, *SL*, were estimated from reported or estimated boiler efficiency:

$$SL = TH * (1 - BE) \tag{4}$$

where *BE* is the reported or estimated boiler efficiency at 100 percent load.

Boiler efficiency was censored to range between 75 percent and 94 percent, based on the assumptions that (1) efficiencies above 94 percent are unlikely, because a minimum of about 6 percent of heat is lost up the stack (Sathyanathan, 2010), and (2) that a reported efficiency less than 75 percent more likely represents overall **thermal efficiency** (net electric generation divided by fuel heat) rather than boiler efficiency (steam heat divided by fuel heat).

Of the 1,997 steam-turbine (ST) boilers at 809 plants in the study set, 1,511 reported a boiler efficiency at 100 percent load, and 1,489 of these were between 75 percent and 94 percent. For each of these boilers, steam heat was estimated as total annual fuel heat times the reported boiler efficiency at 100 percent power. There were 1,413 boilers with reported efficiencies between 75 percent and 94 percent and non-zero fuel heat. At all of these, reported efficiency was used to calculate steam heat.

Of the various fuels that power steam turbines, 10 fuels were determined to be dominant: bituminous coal (BIT), black liquor (BLQ), distillate fuel oil (DFO), lignite (LIG), natural gas (NG), petroleum coke (PC), residual fuel oil (RFO), subbituminous coal (SUB), waste, other coal (WC), and wood, wood-waste solids (WDS); 1,311 boilers had at least 75 percent of their fuel heat coming from one of these fuels. A weighted average boiler efficiency was calculated for each of these 10 fuels as the total estimated steam heat in the fuel category divided by the total reported fuel heat. This weighted efficiency was dominated by the boilers with the most fuel heat. Unweighted average efficiencies differ from weighted efficiencies for each fuel, but except for RFO these differences were less than 1 percent (table 3).

There were 484 ST boilers with fuel heat but no valid reported boiler efficiency. At 316 of these boilers, the dominant fuel was one for which an average efficiency had been determined, and the boiler efficiency was assumed to be the average value for the dominant fuel. At 168 boilers that primarily burned other fuels—agriculture crop by-products/straw energy crops (AB), blast-furnace gas (BFG), landfill gas (LFG), municipal solid waste-biogenic (MSB), other biomass solids (OBS), other gas (OG), and tires (TDF)—the weighted average for all 1,311 boilers was used (table 3).

Table 3. Boiler efficiency, reported fuel heat, and estimated fuel heat by fuel type for combustion steam plants.

[%, percent; MMBtu, million British thermal units, BIT, bituminous coal; BLQ, black liquor; DFO, distillate fuel oil; LIG, lignite; NG, natural gas; PC, petroleum coke; RFO, residual fuel oil; SUB, subbituminous coal; WC, waste, other coal; WDS, wood, wood-waste solids; NA, not applicable]

Reported and estimated boiler efficiency by dominant fuel	Weighted average boiler efficiency (%)	Standard deviation (%)	Difference of fuel-specific average from all-fuels average (%)	Number of boilers with reported boiler efficiency for each dominant fuel type	Total fuel heat for boilers used to estimate average (MMBtu)	Number of boilers with estimated boiler efficiency and this dominant fuel	Total fuel heat at boilers with this dominant fuel and estimated efficiency (MMBtu)	Ratio of fuel heat with estimated boiler efficiency to total fuel heat for this fuel (%)
BIT	89.0	1.7	1.3	560	9,061,680,006	86	124,456,829	1.4
BLQ	85.5	NA	-2.1	1	7,631,743	0	0	0.0
DFO	85.6	0.8	-2.0	5	171,209	2	4,604	2.6
LIG	82.2	1.5	-5.4	20	576,523,031	1	3,980,593	0.7
NG	86.0	2.4	-1.6	306	905,289,900	87	28,059,638	3.0
PC	90.2	0.4	2.5	8	86,502,485	8	17,273,125	16.6
RFO	89.2	1.8	1.5	48	64,541,476	11	6,680,303	9.4
SUB	86.7	2.0	-1.0	357	7,859,995,116	23	60,398,686	0.8
WC	86.6	1.3	-1.0	5	67,469,755	19	91,097,729	57.5
WDS	85.2	NA	-2.4	1	4,686,306	79	178,471,770	97.4
Other fuels not listed, estimated from "all fuels" average	87.6	2.4	0.0	0	0	168	282,058,716	97.1
All fuels	87.6	2.4	0.0	1,311	18,634,491,025	484	792,481,994	5.5

One plant (EIA plant code 50271, Appendix 1) did not report net electrical generation, but did report heat used for electrical generation. At this plant, the heat used for electrical generation was divided by the **heat rate** derived from the National Electric Energy Data System (NEEDS) v4.10 (U.S. Environmental Protection Agency, 2006; Appendix 3) to estimate net electrical generation.

Reported boiler efficiency at 100 percent load is assumed to be accurate, but it may be the nameplate efficiency under conditions specified by the boiler supplier, not the actual efficiency achieved in the boiler during operation in 2010. Reported differences between efficiency at 50 percent and 100 percent load have a mean of near zero and a standard deviation of about 2 percent; most electricity is generated nearer to 100 percent load than 50 percent load, but plants operated intermittently or at partial load have an error in boiler efficiency that may be on the scale of this standard deviation.

For boilers without realistic reported efficiencies, the estimated efficiencies that were used are subject to greater error. Fuel categories containing more than 20 boilers had standard deviations of efficiency from 1.7 percent to 2.4 percent, suggesting an imprecision of about plus or minus 5 percent in addition to imprecision in the reported efficiencies as surrogates for actual efficiencies. There were relatively few plants with this additional error, so it has little effect on condenser duty aggregated over fuel categories.

Combined-Cycle Generation

Combined-cycle plants include both combustion turbines and steam turbines working in tandem. Natural gas provided about 99 percent of total fuel heat at combined-cycle plants. About two-thirds of a combined-cycle plant's electric output is generated in its combustion turbine(s). Exhaust heat from the combustion turbine(s) is used to boil water for the steam turbine and generates about one-third of the plant's electric output. The efficiency of combined-cycle plants is generally high. The shares of fuel heat leaving the plant as both electricity and heat in the exhaust are higher than in other plants, so the share of fuel heat that becomes condenser duty is smaller. Fuel use and generation associated with the combustion turbines are reported at the plant level, so the heat budget must be constructed for the plant as a whole (fig. 15). At combined-cycle plants, reported values of *TH* were used.

The reported boiler efficiencies for combined-cycle plants were not used in heat budgets. The boilers of prime mover type CA (Appendix 2, table 2) reporting boiler efficiency on the EIA 860 form are actually heat-recovery steam generators (HRSGs) using exhaust from combustion turbines to generate steam. Some have supplementary burners that add heat to this exhaust. Many combined-cycle steam boilers report efficiencies greater than 94 percent, whereas many others report efficiencies below 75 percent. Attempts to produce heat budgets based on these reported efficiencies resulted in contradictory results. In some cases, it was impossible to account for all of the fuel heat; in others, the model results in more heat leaving the system than the total fuel heat entering the system. Rather than use reported boiler efficiency to estimate *SL*, it was assumed that 20 percent of the fuel heat leaves combined-cycle plants in their exhaust gases:

$$SL = TH * 0.2 \tag{5}$$

This assumption is based on detailed heat budgets for three plants (U.S. Department of Energy, National Energy Technology Laboratory, 1999, 2007a) and is shared by Rutberg and others (2011). The three example plants are large, new plants with thermal efficiencies above 50 percent, at the upper end of the range for operating combined-cycle plants in 2010. Many existing plants are smaller, older, and less thermally efficient. Some plants were originally combustion turbines without heat recovery to which a HRSG and steam turbine have been retrofitted. The accuracy of the estimated 20-percent stack loss across the full range of combined-cycle plants has not been established.

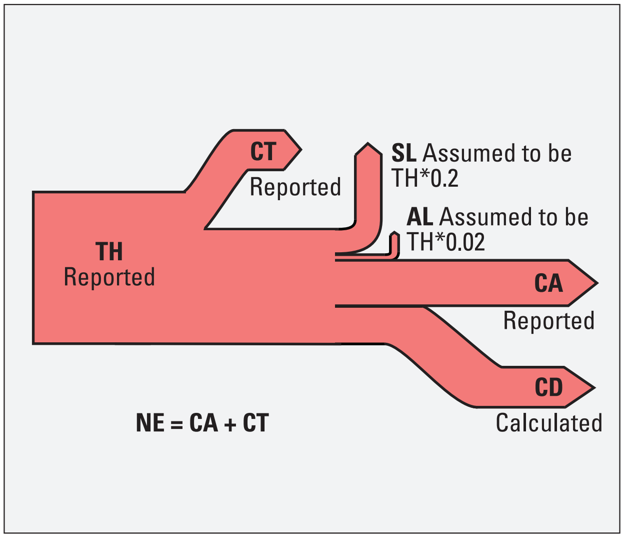
As at other plants, the amount of heat leaving the plant by conduction to the air, most of it representing losses from fans and pumps, was assumed to be 2 percent of fuel heat. Uncertainty in this number has a larger effect on condenser duty at combined-cycle plants than at other plants because condenser duty is a smaller percentage of fuel heat at combined-cycle plants than at other plants.

Nuclear Generation

In nuclear power plants, no heat leaves the plant in exhaust gases, and more heat leaves the plant as condenser duty than in combustion steam plants. The total heat values reported by EIA were not used, because the data are evidently estimated from net generation using a nominal heat rate of 10,460 Btu per kilowatt hour, corresponding to a nominal thermal efficiency of 32.6 percent at all plants. The actual reactor heat at each plant was estimated by assuming that the plant operator keeps the reactor close to its maximum permitted thermal power. This assumption results in a unique estimated thermal efficiency at each nuclear boiler-generator group (fig. 16).

It was assumed that the permitted thermal reactor outputs listed by the U.S. Nuclear Regulatory Commission (U.S. Nuclear Regulatory Commission, 2009, 2010, 2011) are used as operational targets by operators, and that the operators generally stay close to those limits (Joshua Trembley, Exelon, oral commun., 2012; James Riley, Nuclear Energy Institute, oral commun., 2012). This assumption produces the lowest reasonable thermal efficiency. Exceedances of maximum permitted thermal reactor power were assumed not to occur.

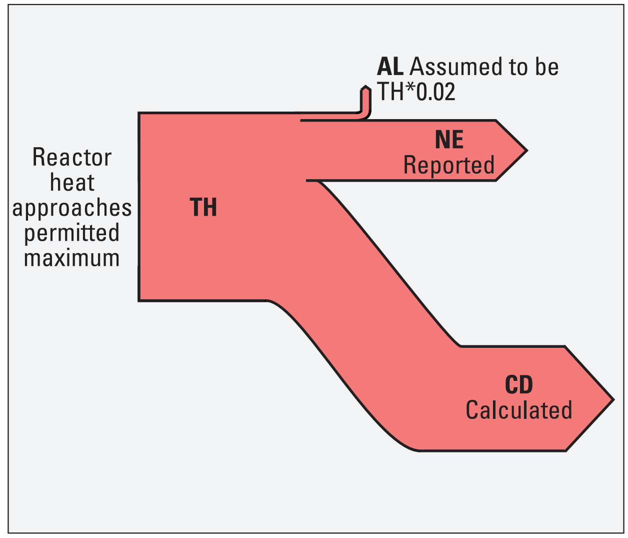
Monthly average power was calculated as reported net generation divided by the number of hours in each month. The ratio of monthly average power divided by the permitted maximum thermal output at each unit was calculated, and it was assumed that the maximum value of this ratio is the



EXPLANATION

AL Heat lost to the air from plant equipment
CA Combined cycle, steam plant
CD Condenser duty
CT Combined cycle, combustion turbine
NE Net electrical generation
SL Heat lost through the stack (exhaust)
TH Total heat introduced into the plant

Figure 15. Sankey diagram for combined cycle plants.



EXPLANATION

AL Heat lost to the air from plant equipment
CD Condenser duty
NE Net electrical generation
TH Total heat introduced into the plant

Figure 16. Sankey diagram for nuclear plants.

peak thermal efficiency for the unit. These maxima occurred in November, December, January, or February at nearly all units. Using the assumptions described above, mean thermal efficiency for nuclear power plants was estimated to be 32.9 percent, and thermal efficiency at individual plants ranged from 29.4 percent to 35.4 percent.

The monthly average power tended to decrease systematically in the summer, generally reflecting the difference between reported winter and summer maximum capacity. It was assumed that this decrease was caused by operators reducing reactor power during the summer to accommodate reduced cooling system capacity. Following this assumption, total reactor heat in each month was estimated by net generation divided by the peak efficiency. Estimated condenser duties ranged from 63 to 69 percent of total reactor heat and 176 to 233 percent of net generation.

An alternative assumption would be that thermal efficiency decreases in summer while thermal power remains near the permitted maximum. This approach would yield an estimated summer decline in thermal efficiency that is specific to each plant and based on a reported value. This decline was in the range of 0 percent to 6.5 percent from winter to summer, with a median of 2.5 percent. Using this approach would increase annual condenser duty (and water consumption) by a maximum of 3 percent and a median of 2 percent at individual nuclear units. Monthly values of condenser duty would remain about the same in winter, but would increase by a maximum of 10 percent and a median of 3 percent in the summer. Given the lack of specific information about reactor operations and the small effect of this more detailed approach at most plants, the simpler assumption of constant thermal efficiency was retained. At nuclear boiler-generator groups, total heat was estimated on the basis of the estimated thermal efficiency:

$$TH = NE / TE \tag{6}$$

where *TE* is the thermal efficiency estimated, as discussed above.

Geothermal Generation

Geothermal plants are analytically similar to nuclear plants although they use different heat sources (fig. 17). Their heat and generation are reported by fuel type at the plant level. Total heat reported by the EIA is nominal, evidently based on an assumed 35-percent thermal efficiency. In NEEDS v.4.10 (U.S. Environmental Protection Agency, 2006; Appendix 3), the thermal efficiency associated with geothermal plants is about 16 percent, lower and more realistic than the 35 percent used by EIA. Although actual efficiencies realized at geothermal plants are generally lower and depend on the temperature of the geothermal resource (DiPippo, 2004; Dagdas and others, 2005; Golub and others, 2006; Franco and Villani, 2009;

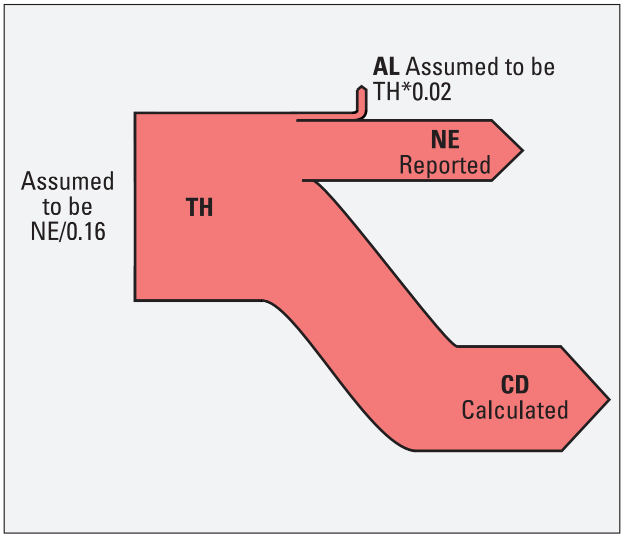


Figure 17. Sankey diagram for geothermal plants.

Drader and others, 2012), total heat at geothermal plants was estimated as net generation divided by the NEEDS thermal efficiency:

$$TH = NE / 0.16 \quad (7)$$

where 0.16 is the estimated thermal efficiency for this type of plant and *NE* is net electrical generation.

The methods used in this study for geothermal power plants are approximate and insensitive to the characteristics of individual plants; therefore, estimates of condenser duty are imprecise, but are believed to be less biased than if the reported total-heat values had been used. As geothermal plants are few and generally small, this imprecision has little impact on regional sums of consumption. Geothermal electric water consumption is about 2 percent of all U.S. thermoelectric water consumption.

For geothermal plants, published water-consumption coefficients vary over a range of more than three orders of magnitude (Ashwood and Bharathan, 2011; Clark and others, 2010; Dennen and others, 2007; Kagel and others, 2005; Larson and others, 2007; Mishra and others, 2011), and “definitional noise” (Dziegielewski and Kiefer, 2010) makes it difficult to generalize typical values. As an experiment, published values of water use were substituted at the plants they were derived from and at plants with similar cooling technology. These substitutions changed water consumption at plants representing 75 percent of the geothermal generation, reducing consumption to zero at some plants and increasing it by a factor of 6 at others. The net effect on water use by the geothermal electric sector was to increase it by 35 percent. This approach did not appear to be substantially better than using the NEEDS heat rate as described above, and was not used to produce the final estimates.

Estimating Thermoelectric Evaporation by Cooling-System Type

Heat and water budgets provide a transparent means to constrain estimates of evaporation from thermoelectric plants within thermodynamically realistic values. The heat and water budgets presented in this report require estimates of monthly condenser duty and information about cooling system characteristics and environmental variables as input. Monthly estimates of condenser duty are obtained using the method described above, based on a given plant’s generation type. Simple heat and water budget models were developed for the two cooling-system types that use substantial amounts of freshwater: (1) wet cooling towers, and (2) surface-water cooling systems. Both cooling system models require monthly averages of dry bulb air temperature, wet bulb air temperature, ambient surface-water temperature, and wind speed. For surface-water cooling systems, the parameters used to calculate one variable in the model, the wind function, are given different values for ponds, lakes, and rivers.

Most thermoelectric plants use evaporative cooling towers in which more than 60 percent (Solley and others, 1998) of the rejected heat typically leaves the tower as latent heat in evaporated water and the rest as sensible heat that increases the temperature of the air passing through the cooling tower. Evaporation in wet towers depends on tower design, condenser duty, and wet bulb and dry bulb air temperatures.

A single heat and water budget model was developed for all surface-water cooling systems, with somewhat different input data for recirculating ponds and once-through systems. The basic model for surface-water cooling systems takes as input water-surface area and monthly estimates of condenser duty, ambient water temperature, and wind speed. For recirculating ponds, water-surface area is equal to the surface area of the pond; for once-through systems, the water-surface area nominally represents the surface area of the plume created by the return flow of heated water that has passed through the condenser. Plants with once-through cooling (including ponds and canals without recirculation) typically report low water consumption within the plant, but evaporation from the plume represents consumption outside the plant boundaries that can account for more than half of the condenser duty (Ward, 1980; Huston, 1975). With once-through cooling, the receiving water body is generally not as hot as a typical cooling pond, so the percentage of heat that drives evaporation is lower.

Many plants have both towers and some form of water-surface cooling. These cooling-system types have different consumption rates relative to generation, so allocation of the available condenser duty among the available cooling-system types influences estimated consumption. At plants where the disparate cooling systems were connected to different boiler-generator groups, or where single-type cooling systems reported operations separately, distributing excess heat among different cooling-system types was straightforward.

At plants reporting one cooling system that used multiple types of cooling, plants with at least some boilers connected to multiple cooling systems of different types, or plants not reporting cooling operations, the allocation of condenser duty was estimated using professional judgment based on known plant characteristics. Estimated consumption at all such plants represented 17 percent of total estimated thermoelectric water consumption. These estimates were bracketed by estimates of maximum and minimum plausible thermoelectric water consumption at the plant scale. The maximum plausible consumption was estimated allocating all condenser duty to the cooling-system type with the most consumption (typically towers), and the minimum was estimated by allocating all condenser duty to the type with the least consumption (typically once-through systems).

Estimating Evaporation from Cooling Towers

The method described by Leung and Moore (1970, 1971) was used as the primary method for estimating evaporation from cooling towers. This method uses a heat balance through the tower, with the key assumption that the air leaving the tower is saturated with water vapor. Estimates made using the Leung and Moore method are likely accurate at baseload plants within plus or minus 5–15 percent (Strauss, 1978; Hu and others, 1978, 1981). Sensitivity testing confirmed that the model results are sensitive to wet bulb and, to a lesser extent, dry bulb air temperature and to plant elevation and design characteristics, but not to the temperature of water added to the tower to replace evaporated water (makeup water). A single model was used for all wet towers because the reported information on tower characteristics and operations did not support finer distinctions or justify using multiple models. To allow for the range of performance, a suite of tower characteristics was modeled and the maximum, minimum, and median evaporation for this suite were reported.

About two-thirds of thermoelectric plants in the plant Master List use wet recirculating cooling towers, and since 1980, nearly all new power plants have used wet towers. In wet cooling towers, hot water coming from the condenser moves slowly downward through a volume of fill, while air flows through the same volume. The fill takes many forms, but always is a structure of stationary elements that slow the descent of water and disperse it to maximize water-surface area, while minimizing resistance to air flow. The cooling water accumulates in a basin under the fill, from where it is pumped back to the condenser.

The air may be moved mechanically by fans at the air inlet (forced draft) or outlet (induced draft) or by convection (natural draft) (United Nations Environment Programme, 2006). These three cooling tower types encompass a range of consumption rates. Natural-draft (convection draft) towers have a wide variability in the mass ratio of water flow to dry air flow (L/G), whereas mechanical draft towers have near constant L/G.

The temperature to which the tower can cool the warm water from the condenser is limited by the wet bulb temperature of the ambient air. In a tower receiving warmed water, the water in the basin under it is warmer than the wet bulb temperature by an amount called the approach (Cheremisinoff and Cheremisinoff, 1981). The difference in temperature between the hot water entering the tower and the cooler water in the basin is called the range. The L/G ratio has a strong influence on these temperature characteristics. A dimensionless ratio called the Merkel tower characteristic describes the heat transfer process and is proportional to $C*(L/G)^n$, where C and n are empirical constants that depend on tower design.

The approach, the range, and the three terms that define the Merkel tower characteristic influence the results of the Leung and Moore model, but values of these variables are not reported to the EIA. Rather than select a single "typical" set of values for these variables, 34 combinations of values were modeled; some of these combinations of values may not correspond to real towers. Tower designs were chosen to cover an approach from 5 to 15°F, a range of 10 to 25°F (Cheremisinoff and Cheremisinoff, 1981), an L/G of 1 to 2, a coefficient "C" of 1.6 to 2.5, and an exponent "n" of -0.6 to -0.8.

The Merkel tower characteristic was determined for each example tower design and was constrained between about 1 and 2.5. Evaporation ratios under design conditions ranged from 87 percent to 99 percent, with a median of 88 percent, and were generally higher for towers with low approach, low range, and low L/G.

The basic equation for the method is as follows:

$$L_{mu} = \frac{Q_p}{\left(\dfrac{H_{a2} - H_{a1}}{\omega_2 - \omega_1}\right) - h_{mu}} \tag{8}$$

where

L_{mu} = the mass of the water evaporated;
Q_p = the net heat rejected in the cooling tower;
H_{a1} = the specific heat of inflow air;
H_{a2} = the specific heat of outflow air;
ω_1 = the specific vapor content of inflow air;
ω_2 = the specific vapor content of outflow air; and
h_{mu} = the specific heat of the makeup water.

The quantity $\left(\dfrac{H_{a2} - H_{a1}}{\omega_2 - \omega_1}\right) - h_{mu}$ is the net heat added per mass of water evaporated.

As both H_{a2} and ω_2 are unknown, it is necessary to assume that the air leaving the cooling tower is saturated with water vapor. This allows H_{a2} to be defined in terms of the other variables, and the equation is solved iteratively to estimate L_{mu}.

For some plants, winter operations present a special case requiring adjustment of the method. When the wet bulb temperature is at or below freezing, cooling tower operations are changed to prevent ice formation in the fill, usually by decreasing air flow or concentrating hot water flow in one area of the fill. The effect of these changes is to keep the coldest water temperature in the fill at 40°F (4.4°C) or above; published recommendations for minimum water temperature in the basin below the tower range from 40°F (4.4°C) to 50°F (10°C) (Cheremisinoff and Cheremisinoff, 1981; The Cooling Tower Company, L.C., 2005; Cooling Technology Institute, 2010; Evapco, 2010; Marley, 2012). The best way to simulate winter operations within the simple structure of the Leung and Moore model was to artificially limit both wet bulb and dry bulb temperatures to a minimum of 35°F (1.7°C). The choice of 35°F (1.7°C) was conservative in the sense that a lower temperature could have been justified (Cheremisinoff and Cheremisinoff, 1981) and would have produced lower winter evaporation. Without this artificial minimum temperature, evaporation ratios become unrealistically low. This rough approximation adds uncertainty to the estimates, but winter operational changes vary among tower types and individual operators, so adding complexity to the model is unjustified.

The model was run for the suite of tower designs at many pairs of dry bulb and wet bulb temperatures spanning the range of conditions encountered at U.S. power plants. The estimated median, minimum, and maximum evaporation ratios changed smoothly over this temperature field, and linear interpolation was used to estimate nominal median, minimum, and maximum evaporation ratios at sea level, based on monthly average dry bulb and wet bulb temperatures for 2010 at U.S. power plants with wet towers. For each combination of dry bulb and wet bulb temperatures, the rates of decrease in median, minimum, and maximum evaporation ratios with the elevation of the plant were found to be approximately linear. These linear rates of decrease were estimated by interpolation based on dry bulb and wet bulb air temperatures for each month and were used in combination with the plant elevation to adjust the median, minimum, and maximum evaporation ratio for each month.

The method of Rutberg and others (2011) was used to generate an alternative estimate of the maximum evaporation ratio at each plant location. Rutberg and others (2011) raised the issue that the air leaving the cooling tower may be unsaturated during hot weather and supersaturated during cold weather, leading the Leung and Moore method to underestimate winter evaporation and overestimate summer evaporation. They developed a simplified method for estimating cooling-tower evaporation based solely on dry bulb air temperature:

$$ER = 1 - \left[\begin{array}{l} (-0.000279T_a^3 + 0.00109T_a^2 \\ -0.345T_a + 26.7)/100 \end{array} \right] \tag{9}$$

where ER is the ratio of the heat used to evaporate water to the total heat discharged through the tower, and T_a is the monthly average dry bulb air temperature in °C.

This equation produces estimates of evaporation that are higher than the highest estimates made with the Leung and Moore method in cool months. This equation was used as a supplemental method for estimating the upper limiting value of ER when its prediction exceeded the maximum Leung and Moore estimate. With the Rutberg and others estimate incorporated as an alternate maximum, the range between minimum and maximum estimated values of evaporation ratio exceeded the plus or minus 15 percent cited by Hu and others (1981) as the accuracy of the Leung and Moore method. More detailed modeling based on tower characteristics that are not reported to EIA might yield a different range of actual evaporation ratios.

The product of the estimated evaporation ratio and the estimated condenser duty is the estimated heat of evaporation for a given month. This is converted to a weight of water based on the latent heat of vaporization, then to a volume per month. The product of the maximum evaporation ratio and the maximum condenser duty gives the maximum likely evaporation, and the product of the minimum evaporation ratio and the minimum condenser duty gives the minimum likely evaporation.

Estimating Forced Evaporation from Surface Water

A simple heat balance model was used to estimate the evaporation ratio for surface-water cooling systems. This model, first developed by Harbeck (1964) for cooling ponds, was improved by Ward (1980). The model uses monthly data that can be estimated at most power plants: average natural water temperature, average wind speed, and the water-surface area over which heat is dissipated. This model is similar to the one presented by Diehl (2011).

Surface-water cooling systems draw water from lakes, rivers, and recirculating and once-through ponds. For the heat balance model, these water bodies were classified for analysis as lakes, rivers, and ponds, with many plants that reported lake to EIA classified in this analysis as pond due to high heat loading. The same model was used for all three types of water bodies, with each type using different parameters in the function relating wind to mass transfer away from the water surface.

Heat loading is estimated as the ratio of condenser duty to the area over which heat is dissipated. This area was estimated to be the entire area of ponds or small lakes, where this ratio produced heat-loading estimates exceeding 0.35 MW per acre (about 0.002 calories per square centimeter per second [(cal/(cm^2/s)]). For lakes that were larger relative to condenser duty, a heat loading of 0.1 MW per acre (about 0.0006 [cal/(cm^2/s)]) was assumed; forced evaporation is not sensitive to small differences in heat loading. For rivers, a heat loading of 0.2 MW per acre (about 0.001 [cal/(cm^2/s)]) was assumed.

This model does not estimate the non-forced evaporation from recirculating cooling ponds or reservoirs that would take place in the absence of added heat from the power plant's condenser; only the forced evaporation is modeled. Consumption is sometimes defined as including water withdrawn that is no longer available to be returned to a water source or all cooling water lost to evaporation (U.S. Government Accountability Office, 2009), implicitly including unforced evaporation from recirculating cooling ponds. Under such a definition, water consumption at plants with recirculating cooling ponds would be larger than the forced evaporation, with greater increases for ponds and reservoirs with low added heat per area, and in hot, dry regions.

Equations for heat loss were solved for both the natural and heated water temperatures, with the estimated heated-water temperature adjusted iteratively until the difference in heat loss at the two temperatures was equal to the added heat from the power plant. Monthly average values were used for environmental variables and monthly estimates of the percent of condenser duty that drives evaporation (evaporation ratio) were produced. In the following equations, the units used by Ward (1980) are preserved to facilitate comparison to his and Harbeck's (1964) publications.

The method used in this study for estimating forced evaporation is based on that of Ward (1980), with a few key revisions:

1. A heat loading (condenser duty per area) is estimated or measured, as discussed above.
2. A natural water temperature is estimated based on available water-temperature data.
3. The relevant heat balance equations are solved iteratively to estimate a heated water temperature.
4. The percent forced evaporation is given by the ratio of the difference in evaporation at the two water temperatures to the sum of differences in evaporation, conduction, and radiation at the two water temperatures.

The total heat loss from a water surface is the sum of heat loss through evaporation, conduction, and radiation expressed in terms of energy flux per unit area:

$$H(T) = E(T) + C(T) + R(T) \tag{10}$$

where $H(T)$ is heat loss from the water surface, $E(T)$ is heat loss through evaporation, $C(T)$ is conduction, and $R(T)$ is radiation, all in [cal/(cm^2/s)], and T is water temperature in °C.

The difference in heat loss between the natural water temperature (T) and heated water temperature (T'), equal to the heat loading, is given by the sum of differences in evaporation, conduction, and radiation at these two temperatures:

$$\begin{aligned}\left[H(T') - H(T)\right] &= \left[E(T') - E(T)\right] + \\ &\left[C(T') - C(T)\right] + \left[R(T') - R(T)\right]\end{aligned} \tag{11}$$

or:

$$\Delta H = \Delta E + \Delta C + \Delta R \tag{12}$$

Evaporation is given by:

$$E(T) = \rho L f(W)\left[e(T) - e_a\right] \tag{13}$$

where ρ is water density in grams per cubic centimeter, L is the latent heat of vaporization in calories per gram, $e(T)$ is the saturation vapor pressure in millibars at water-surface temperature T, e_a is the vapor pressure of the overlying atmosphere in millibars, and $f(W)$ is the wind function, for example the wind function of Ward (1980):

$$f(W) = 7.0 * 10^{-8}(W) \tag{14}$$

where W is wind speed in miles per hour. The values of ρ and L change little from T to T'; the effect of this change on forced evaporation can be ignored (Ward, 1980). The difference in evaporation from T to T' is given by:

$$\Delta E = \rho L f(W)\left[e(T) - e(T')\right] \tag{15}$$

Conduction is given by:

$$C(T) = f(W)\left(\frac{\rho p c_p}{\varepsilon}\right)\left(T - T_a\right) \tag{16}$$

where p is atmospheric pressure in millibars, c_p is the specific heat of air at a constant pressure, 0.24 calories per gram per degrees Kelvin, ε is the molecular weight ratio of water vapor to dry air, and T_a is air temperature in degrees Celsius. The difference in conduction from T to T' is given by:

$$\Delta C = f(W)\left(\frac{\rho p c_p}{\varepsilon}\right)\left(T' - T\right) \tag{17}$$

Radiation is given by:

$$R(T) = \varepsilon_r \sigma \left(T + 273\right)^4 \tag{18}$$

where σ is the Stefan-Boltzman constant ($1.17*10^{-7}$ calories per square centimeter per degrees Kelvin to the fourth power per day) and ε_r is the emissivity of the water surface, 0.97. The difference in radiation from T to T' is given by:

$$R(T) = \varepsilon_r \sigma \left[\left(T' + 273.15\right)^4 - \left(T + 273.15\right)^4\right] \tag{19}$$

The difference in the heat loss at the two temperatures ΔH is set equal to the condenser duty by iteratively adjusting the heated water temperature (T'). The ratio of forced evaporation to condenser duty is given by:

$$ER = \Delta E / \Delta H \tag{20}$$

Ward (1980) demonstrated that additional heat losses through evaporation, conduction, and radiation are approximately linear functions of an imposed increase in water temperature, and based on this approximation, the ratio of increased evaporation to the total increase in heat loss is a function of only water temperature and wind speed (fig. 18). If the imposed heat load is distributed over an assumed area, the heated temperature can be solved for iteratively, and the share of evaporation in the increased heat dissipation can be calculated directly. This solution is insensitive to air temperature, humidity, and the variation in water density and vapor pressure between the two temperatures.

The wind function is a coefficient of vertical mixing, and is used to calibrate heat budget models to measured evaporation data. A wide variety of wind functions have been determined for a variety of settings, including cooling ponds, natural lakes and ponds, rivers, and irrigation canals. Even for a given setting, experimentally determined coefficients vary widely. The choice of wind function strongly influences estimated water consumption (fig. 19).

Estimates of evaporation were based on the wind function of Brady and others (1969) for ponds, Webster and Sherman (1995) for lakes, and Gulliver and Stefan (1986) for rivers. The Brady and others (1969) wind function was developed for cooling ponds. The Anderson (1954), Harbeck (1964), and Ward (1980) wind functions are also derived from cooling ponds but are inappropriate for low wind speeds; Ward's formula is equation 3 in Diehl (2011), expressed here in different units. The parameter values of Fulford and Sturm (1984) and Gulliver and Stefan (1986) were derived from flowing water. Webster and Sherman (1995) studied lakes without added heat. Other wind functions are discussed in McJannet and others (2012), Majewski and Miller (1979), and Edinger and others (1974).

The values of some wind functions, for example those of Anderson (1954), Harbeck (1964), and Ward (1980) go to zero at a wind speed of zero. In practice, convective vertical mixing takes place in the absence of wind due to density differences between the water-saturated air in the surface film over the warm cooling pond and the overlying air. Wind functions that reach zero were not used to estimate water consumption.

The Forced Evaporation from Water Surface (FEWS) spreadsheet (Appendix 4, available online in an Excel file at *http://pubs.usgs.gov/sir/2013/5188/appendix/sir2013-5188_appendix4_fews_version_3.104.xlsx*), implements the heat balance model to estimate forced evaporation from water surfaces driven by heat from thermoelectric plants. The user enters power plant identification numbers, elevations, pond or lake area for lake and pond cooling systems, and mean monthly values of condenser duty, water temperature, and wind speed. Because of the sensitivity of output to the wind function, and the unsettled status of the wind function in published literature, selection of the appropriate wind function is left to the user.

The FEWS spreadsheet includes wind functions derived for rivers and lakes and reviewed by McJannet and others (2012), and the wind function of Brady and others (1969) developed for dedicated cooling lakes. The parameter values of Fulford and Sturm (1984) and Gulliver and Stefan (1986) were derived from flowing water. Webster and Sherman (1995) studied lakes without added heat. Other wind functions

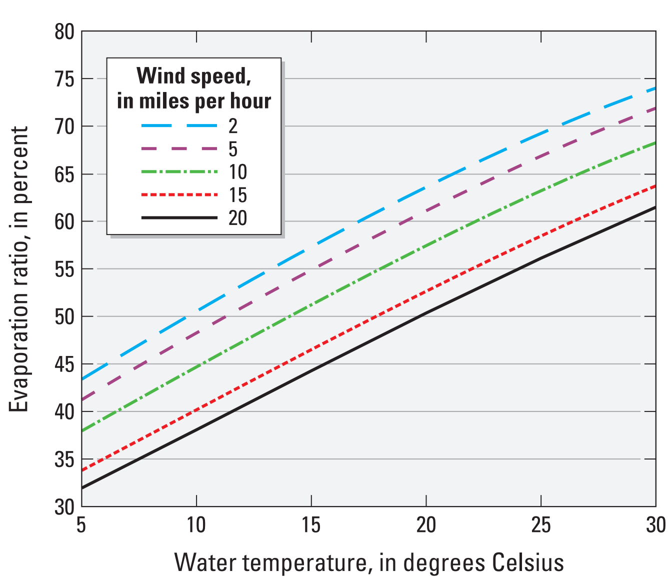


Figure 18. Evaporation ratio in relation to wind speed, estimated using Brady and others (1969) wind function.

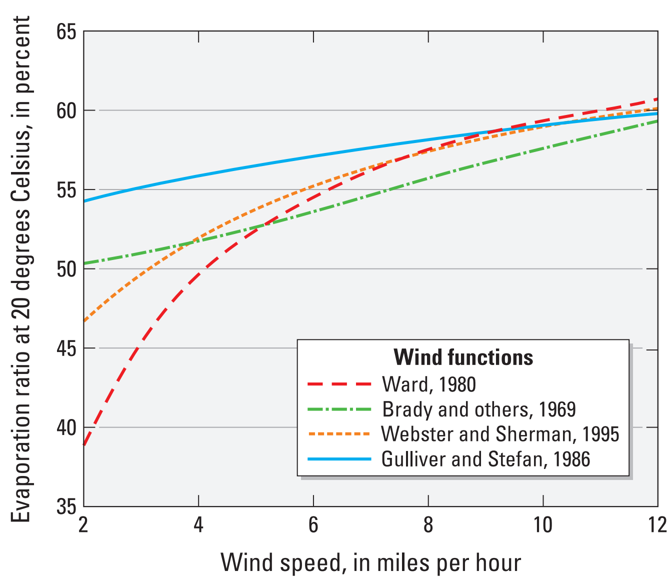


Figure 19. Evaporation ratio in relation to wind speed at 20 degrees Celsius for four selected wind functions.

reviewed by McJannet and others (2012), Majewski and Miller (1979), and Edinger and others (1974) should be checked against the original publications before being used.

Natural water temperatures in the spreadsheet were derived from measured river temperature upstream from the plant, or in nearby lakes and streams, but in principle, a natural water temperature could be derived from air temperature and wet bulb temperature. The spreadsheet solves the relevant heat-loss equations iteratively to estimate a heated water temperature that matches the heat loading, and produces monthly and annual estimates of forced evaporation.

The method implemented in this spreadsheet has four major sources of uncertainty: natural water temperature, heat loading, wind function, and error intrinsic to the model. An error in the estimated natural water temperature of 1 produces a corresponding error in estimated heated water temperature, and an error of about 1 percent in evaporation ratio (*ER*) (fig. 18). Error in estimated heat loading produces errors in the estimated *ER* that are roughly proportional to heat loading; in cold water with a low heat loading, an error of 0.1 MW/acre in heat loading produces an error in *ER* of about 1 percent (fig. 20). The range in *ER* between the largest and smallest wind function values ranges from about 3 percent for high wind speed to over 35 percent for wind speed of 1 mph; however, 90 percent of mean monthly wind speeds are greater than 4.5 mph, at which speed the range in estimated *ER* is about 12 percent between the smallest and largest wind function values. Finally, the equations for heat balance give a calculated *ER* within at most plus or minus 10 percent to 15 percent error from real heat loss (David I. Stannard, U.S. Geological Survey, written commun., 2012). Forced evaporation from dedicated cooling ponds can be measured using water budgets, and could be used to estimate the accuracy of the method.

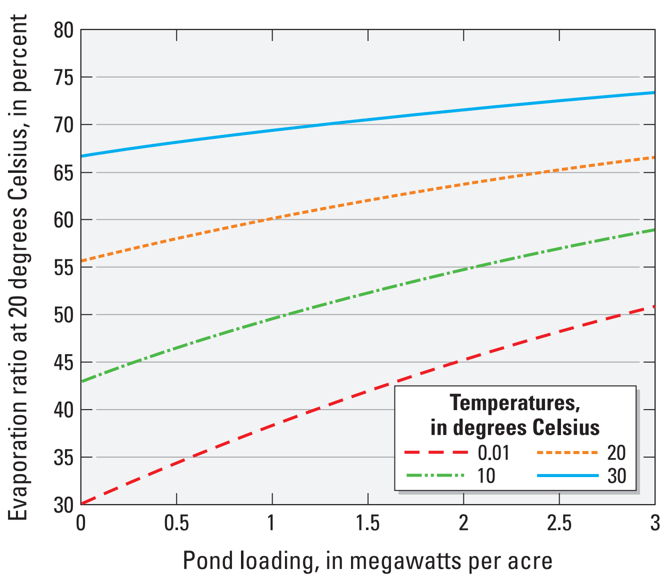


Figure 20. Effect of pond heat loading on evaporation ratio.

Error Analysis and the Prediction of Maximum and Minimum Likely Consumption

Error analysis took place in two stages—first calculating ranges of estimation error for condenser duty and evaporation ratio, and then combining these error terms by multiplication. Errors in parameter values such as boiler efficiency, auxiliary heat loss, and thermal efficiency, were assumed to be independent and normally distributed for the purposes of calculating an overall range of error. Many parameters were defined in the published literature as ranges or values of plus or minus some number. These ranges were assumed to represent the 95 percent of values within two standard deviations of a mean. Skewed distributions were ignored in analyzing error. Most parameter values were not defined by statistical analysis of measured values. Errors were not calculated for the two small generation-type categories of geothermal and solar thermoelectric. Water consumption for these generation types was estimated by simplified methods subject to undefined errors.

The maximum and minimum values of condenser duty were estimated to be the estimated value plus or minus 10 percent. For combustion steam units that reported a reasonable boiler efficiency, analysis of combined sources of error pointed to actual errors of 5 to 6 percent; 10 percent is considered to be conservative. For the 5 percent of combustion steam capacity with estimated boiler efficiency, the actual error is 7 percent to 10 percent.

Nuclear plants, despite the error introduced by estimating thermal efficiency, have low estimated error in condenser duty relative to other generation types. Calculated error is plus or minus 5 percent, but when error in estimated thermal efficiency is large, error in estimated condenser duty could approach 10 percent.

For combined-cycle plants, the critical assumption that heat loss in the exhaust gas is 20 percent is subject to an unknown degree of error. If the true range is 17 percent to 23 percent, then the error in condenser duty is close to 10 percent. If the stack losses are actually 15 percent to 25 percent, the error in condenser duty could be 15 percent or higher. This is another parameter for which errors seem likely to be greater in one direction than in the other. Since large, new plants have 20-percent stack loss, lower values for smaller and older combined-cycle plants seem unlikely, whereas higher values of stack losses are entirely plausible.

Despite the differences in calculated errors, the value of plus or minus 10 percent was chosen for the sake of simplicity in order to present a single value of uncertainty that captures typical conditions rather than produce tailored estimates for each situation. The level of uncertainty in the uncertainty analysis itself weighs against false precision in selecting a reasonable range.

The error in tower evaporation ratio was assumed to be 15 percent in addition to the full range of modeled values for the suite of 34 sets of tower-variable values. Thus, the maximum consumption was the maximum of the suite of towers plus 15 percent, and the minimum consumption was the minimum of the suite of towers minus 15 percent. When the equation of Rutberg and others (2011) yielded a higher *ER* than the maximum calculated from the suite of towers, it was substituted as the maximum *ER* value.

For evaporation ratio from water surfaces, an error of 18 percent was selected. The intrinsic error in the method of 15 percent is increased only slightly by input data uncertainty. The 18-percent error range is conservative for most plants, except for those with once-through cooling systems on the Great Lakes, where added uncertainty in the natural temperature might make plus or minus 21 percent a more appropriate value.

Multiplication of the estimated condenser duty and the estimated *ER*, including errors, resulted in a range in predicted water consumption of plus or minus 22 percent from the best estimate at plants with surface-water cooling. At plants with towers, the range in predicted water consumption is the range of results from the suite of towers plus or minus 18 percent.

Other Types of Water Consumption

Several modes of water consumption at thermoelectric plants were not amenable to modeling with heat and water budgets. These include evaporation from wet cooling towers at solar-thermal plants, flue-gas desulfurization at combustion-steam plants, and inlet cooling and nitrogen-oxides (NOx) control at combined-cycle plants.

Solar-Thermal Generation

Solar thermoelectric plants were not modeled with heat and water budgets because sufficient data are not available. Their fuel heat and generation are reported by fuel type at the plant level. However, the EIA-reported total heat use is nominal, based on an assumed 35-percent thermal efficiency, and no data on the amount of heat entering the steam turbine are available.

Parabolic-trough solar plants appear to consume 900 to 1,000 gallons per megawatt hour of net electric generation (gal/MWhe), given that wash water and cooling-tower blowdown are evaporated (Cohen and others, 1999; Kelly, 2006). Solar-power towers have consumption comparable to (Dahle, 2008) or substantially less than (U.S. Department of Energy, 2009) parabolic-trough plants. All solar thermoelectric plants in the study set had wet cooling towers, like the example plants in the studies cited.

An arbitrary consumption coefficient of 900 gal/MWhe was assigned to all solar thermoelectric plants. Solar thermoelectric plants are even smaller than geothermal plants and there are fewer of them, so use of this estimation method has little effect on regionally aggregated water consumption. Estimated water consumption at solar-thermal plants was about 0.05 percent of total thermoelectric water consumption.

Flue-Gas Desulfurization

Flue-gas desulfurization at coal- and waste-burning plants consumes water by incorporating the water into sulfur-bearing minerals and by contributing water vapor to the stack gases. Based on average differences between water consumption rates with no FGD, dry FGD, and wet FGD presented in Appendix D of U.S. Department of Energy, National Energy Technology Laboratory (2010), FGD water consumption was estimated as 64 gal/MWhe for wet FGD and 40 gal/MWhe for dry FGD. For boilers burning some fuel that does not contain sulfur (for example, natural gas), the consumption was multiplied by the ratio of heat from sulfurous fuels to total fuel heat. The water consumed by FGD was about 5 percent of total thermoelectric water consumption.

Minor Water Consumption at Combined-Cycle Plants

Minor types of water consumption at combined-cycle plants include inlet cooling and NOx control in the combustion turbine part of the plant (Texas Water Development Board, 2003; Maulbetsch and DiFilippo, 2006). Inlet cooling can consume about 20 gal/MWhe and NOx reduction can consume about 50 gal/MWhe. No publicly available data indicate whether either of these types of consumption takes place at each combustion turbine. Exclusion of these types of consumption introduces an unknown downward bias into water consumption estimates at some combined-cycle plants. Also, some combustion turbines that are not part of combined-cycle plants consume water, perhaps as much as 100 gal/MWhe (California Energy Commission, 2005), but are not included in the study set for this report.

Conclusions

The use of heat and water budgets to estimate water consumption at individual thermoelectric plants provides a useful check on other estimation approaches, and in many cases may be the most accurate method available. Constraining estimated evaporation at thermoelectric plants based on thermodynamics improves estimates of water consumption at plants where direct measurements of water use are absent or unreliable. Budgets based on heat and electric data provide an independent validation of consumption where it is measured. On a regional or national scale, budget-based consumption estimates could be used to guide policy discussions. For example, these estimates respond realistically to environmental change, increasing with temperature and wind speed.

Estimates of condenser duty vary in precision depending on what data are reported, and in what form, by the various types of thermoelectric plants. These estimates could be improved by more detailed reporting of boiler efficiency and fuel or heat use at some types of plants and could be superseded by accurately monitoring and reporting condenser duty. Nearly all fossil-fuel generation types are required to report fuel and generation data sufficient to calculate a heat budget; nuclear plant heat budgets can be constructed despite the lack of reported reactor heat data, based on maximum permitted reactor power. Geothermal and solar-thermal plants do not report enough data for a heat budget. Budgets could be improved by reporting fuel use by boiler and turbine and electricity by generator for combined-cycle plants. The quality of reported data is uneven, and quality control requires substantial effort. Some plants present ambiguities that have to be resolved by professional judgment. Additional information could be gathered at power plants that would eliminate the need for estimating condenser duty and tower evaporation with heat budgets, but not all of these data are required by plant operators.

Budget models of the evaporation process are more complex and less definitive than those that estimate condenser duty. The Leung and Moore method gives plausible estimates of the evaporation ratio for cooling towers, using available data. However, it is not definitive, and could be superseded by a better model, or, preferably, better monitoring and reporting of the elements of the water budget for cooling towers. In contrast, monitoring of evaporation from water surfaces is difficult at best, and cannot supersede modeling of the evaporation ratio for forced evaporation from water surfaces. The heat balance method presented in this report is not definitive, but it incorporates the main variables to which the evaporation ratio responds, and its output is realistically sensitive to them. This method would benefit from the development of better wind functions, and its precision would be improved by more reliable measurements of environmental variables at power plants.

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Glossary

B

boiler efficiency the ratio between the amount of heat used to generate steam and the total heat content of the fuel that is consumed.

C

combined heat and power generating systems that produce both heat and electricity from a single heat source and export waste heat to other heat-using processes.

condenser duty the amount of waste heat delivered to the cooling system through the condenser.

cooling system a system that removes waste heat from a power plant condenser and transfers it to the atmosphere.

cooling-system type the technology used to dissipate condenser duty to the atmosphere; in this report, wet cooling towers and surface-water cooling are the types considered.

D

dry cooling system a cooling system that condenses steam and transfers the waste heat to the atmosphere without the consumption of water.

E

evaporation ratio the ratio of the amount of heat transferred to the air as evaporation to the condenser duty.

exported heat the waste heat produced in electricity generation that is used in other heat-using processes, such as for a heating system.

F

forced evaporation the increase in evaporation of surface water due to the added heat of discharged cooling water.

freshwater water that contains less than 1,000 milligrams per liter (mg/L) of dissolved solids.

G

generating unit any combination of physically connected generators, reactors, boilers, combustion turbines, or other prime movers operated together to produce electric power.

generation type the type of technology used to generate electricity in a given unit or plant, including the energy source and prime mover.

H

heat budget a summation of all significant flows of heat into and out of a system such as a power plant.

heat loading an estimate of the ratio of condenser duty to the area over which heat is dissipated.

heat rate the number of British thermal units (Btu) of fuel it takes to produce one kilowatt hour (kWh) of electricity.

L

linked heat and water budget a summation of all significant flows of heat and water into and out of a power plant, linked by converting energy flows embodied in water flow and evaporation into their equivalent volume flow rates of liquid water.

O

once-through cooling system a cooling system in which the water is withdrawn from a surface-water source other than a recirculating pond to condense the steam used to generate electricity and that discharges the water back to surface water at a higher temperature.

P

plant a facility that generates electricity from another source of energy such as fossil fuels, nuclear fission, geothermal energy, or solar radiation and heat.

prime mover in thermoelectric plants, the prime mover is the turbine that converts the energy in heated gases to mechanical energy.

R

recirculating cooling system a cooling system in which water is circulated through condensers, cooled, and then re-used in the same process.

S

surface-water cooling a cooling-system type that transfers heat from a condenser to the atmosphere through evaporation at the free surface of an open body of water. In addition to evaporation, some heat leaves the water surface through conduction and radiation.

T

thermal efficiency the percentage of fuel heat used to produce electricity.

thermoelectric relating to the generation of electric power from heat.

thermoelectric water consumption the water evaporated or incorporated into by-products as a result of the production of electricity from heat.

thermoelectric water withdrawal the water removed from groundwater or surface water for use in a thermoelectric power plant.

W

waste heat heat used but not converted to electricity in a thermoelectric plant.

water budget a summation of all significant flows of water into and out of a system such as a power plant.

wet cooling tower a cooling-system type that transfers heat from a condenser to the atmosphere primarily through evaporation, and to a lesser extent through conduction, in a natural-draft or mechanical-draft tower.

Appendixes 1–3

Appendix 1. The 1,284 thermoelectric plants one megawatt nameplate capacity or greater with water-cooling systems in the United States, 2010.

[EIA, U.S. Department of Energy, Energy Information Administration; MW, megawatt; initials associated with a power plant are part of the plant name, and not spelled out; --, nameplate capacity is not reported for the steam side of the combined-cycle power plant]

County	EIA plant code	Plant name	Nameplate capacity (MW)
		Alabama (24 power plants)	
Autagua	55440	Tenaska Central Alabama Generating Station	390.1
Autauga	7897	E B Harris Electric Generating Plant	564
Autauga	55271	Tenaska Lindsay Hill Generating Station	390.1
Colbert	47	Colbert	1,350
Covington	533	McWilliams	217
Etowah	7	Gadsden	138
Greene	10	Greene County	568.4
Houston	6001	Joseph M Farley	1,776.4
Jackson	50	Widows Creek	1,968.6
Jefferson	6002	James H Miller Jr	2,822
Lee	7710	H Allen Franklin Combined Cycle	777.1
Limestone	46	Browns Ferry	3,494
Lowndes	7698	General Electric Plastic	14.8
Mobile	3	Barry	2,161.1
Mobile	7721	Theodore Cogen Facility	88.4
Mobile	50407	Mobile Energy Services LLC	43.1
Mobile	55241	Hog Bayou Energy Center	80
Morgan	55292	Decatur Energy Center	171
Morgan	55293	Morgan Energy Center	270
Shelby	26	E C Gaston	2,012.8
Tallapoosa	55411	Hillabee Energy Center	306
Walker	8	Gorgas	1,416.7
Washington	56	Charles R Lowman	538
Washington	7697	Washington County Cogeneration Facility	39.9
		Alaska (5 power plants)	
Anchorage	6559	George M Sullivan Generation Plant 2	33
Denali Borough	6288	Healy	28
Fairbanks North Star	79	Aurora Energy LLC Chena	27.5
Fairbanks North Star	6285	North Pole	13
Kenai Peninsula	96	Beluga	62
		Arizona (25 power plants)	
Apache	6177	Coronado	821.8
Apache	8223	Springerville	1,749.6
Cochise	160	Apache Station	489.6
Coconino	4941	Navajo	2,409.3
Maricopa	116	Ocotillo	227.2
Maricopa	117	West Phoenix	641.6
Maricopa	141	Agua Fria	390.4
Maricopa	147	Kyrene	122

Appendix 1. The 1,284 thermoelectric plants one megawatt nameplate capacity or greater with water-cooling systems in the United States, 2010.—Continued

[EIA, U.S. Department of Energy, Energy Information Administration; MW, megawatt; initials associated with a power plant are part of the plant name, and not spelled out; --, nameplate capacity is not reported for the steam side of the combined-cycle power plant]

County	EIA plant code	Plant name	Nameplate capacity (MW)
Maricopa	6008	Palo Verde	4,209.3
Maricopa	8068	Santan	864.6
Maricopa	55282	Arlington Valley Energy Facility	317
Maricopa	55306	Gila River Power Station	1,084
Maricopa	55372	Harquahala Generating Project	480
Maricopa	55455	Red Hawk	408
Maricopa	55481	Mesquite Generating Station	642
Maricopa	57140	Maricopa Solar	--
Mohave	55124	Griffith Energy LLC	301.8
Mohave	55177	South Point Energy Center	236
Navajo	113	Cholla	1,128.8
Navajo	56616	Snowflake White Mountain Power LLC	27.2
Pima	126	H Wilson Sundt Generating Station	504.5
Pinal	118	Saguaro	250
Pinal	55129	Desert Basin	272.1
Yuma	120	Yucca	86.7
Yuma	54694	Yuma Cogeneration Associates	18.5
		Arkansas (16 power plants)	
Benton	6138	Flint Creek	558
Franklin	201	Thomas Fitzhugh	59
Hot Spring	170	Lake Catherine	552.5
Hot Spring	55418	KGen Hot Spring Generating Facility	317
Hot Spring	55714	Hot Spring Power Project	262
Independence	6641	Independence	1,700
Jefferson	6009	White Bluff	1,700
Jefferson	55075	Pine Bluff Energy Center	56
Lafayette	169	Harvey Couch	156.2
Mississippi	55340	Dell Power Station	281
Mississippi	56456	Plum Point Energy Station	720
Ouachita	203	McClellan	136
Pope	8055	Arkansas Nuclear One	1,845
Pulaski	55221	Harry L Oswald	210
Union	55380	Union Power Partners LP	1,020
Woodruff	202	Carl Bailey	120
		California (149 power plants)	
Butte	54469	Pacific Oroville Power Inc	18
Colusa	50293	Wadham Energy LP	28.6
Contra Costa	228	Contra Costa	718
Contra Costa	271	Pittsburg Power	1,403.9
Contra Costa	10342	Foster Wheeler Martinez	33.5

Appendix 1. The 1,284 thermoelectric plants one megawatt nameplate capacity or greater with water-cooling systems in the United States, 2010.—Continued

[EIA, U.S. Department of Energy, Energy Information Administration; MW, megawatt; initials associated with a power plant are part of the plant name, and not spelled out; --, nameplate capacity is not reported for the steam side of the combined-cycle power plant]

County	EIA plant code	Plant name	Nameplate capacity (MW)
Contra Costa	10367	East Third Street Power Plant	20.5
Contra Costa	10368	Loveridge Road Power Plant	20.5
Contra Costa	10369	Wilbur West Power Plant	20.5
Contra Costa	10370	Wilbur East Power Plant	20.5
Contra Costa	10371	Nichols Road Power Plant	20.5
Contra Costa	55217	Los Medanos Energy Center	280.5
Contra Costa	55333	Delta Energy Center	306
Fresno	10156	Fresno Cogen Partners	10
Fresno	10405	Kingsburg Cogen	13.1
Fresno	10767	Rio Bravo Fresno	28
Fresno	10837	Covanta Mendota	28
Fresno	57564	Algonquin Power Sanger LLC	12.5
Humboldt	10052	Fairhaven Power	18.8
Humboldt	10764	Blue Lake Power LLC	13.8
Imperial	389	El Centro	166.1
Imperial	10631	J M Leathers	49
Imperial	10632	A W Hoch	49
Imperial	10634	J J Elmore	49
Imperial	10759	Salton Sea Unit 3	53.9
Imperial	10763	Geo East Mesa III	20
Imperial	10878	Salton Sea Unit 1	10
Imperial	10879	Salton Sea Unit 2	20
Imperial	50210	Vulcan	39.6
Imperial	50762	Ormesa IH	14.4
Imperial	50764	Ormesa IE	14.4
Imperial	50766	Ormesa I	31.2
Imperial	54038	Geo East Mesa II	20
Imperial	54689	Heber Geothermal	52
Imperial	54724	Ormesa II	22.8
Imperial	54996	Salton Sea Unit 4	51
Imperial	55983	Salton Sea Unit 5	49.9
Imperial	55984	CE Turbo	11.5
Inyo	10873	Coso Finance Partners	92.2
Inyo	10874	Coso Power Developers	90
Inyo	10875	Coso Energy Developers	90
Kern	10768	Rio Bravo Jasmin	38.2
Kern	10769	Rio Bravo Poso	38.2
Kern	10840	Delano Energy	57
Kern	10850	Mojave Cogen	16
Kern	54626	Mt Poso Cogeneration	62

Appendix 1. The 1,284 thermoelectric plants one megawatt nameplate capacity or greater with water-cooling systems in the United States, 2010.—Continued

[EIA, U.S. Department of Energy, Energy Information Administration; MW, megawatt; initials associated with a power plant are part of the plant name, and not spelled out; --, nameplate capacity is not reported for the steam side of the combined-cycle power plant]

County	EIA plant code	Plant name	Nameplate capacity (MW)
Kern	55151	La Paloma Generating LLC	1,200
Kern	55182	Sunrise Power LLC	270
Kern	55400	Elk Hills Power LLC	225
Kern	55656	Pastoria Energy Facility LLC	275
Kern	56943	Ausra Kimberlina Solar Generation	5
Kings	10373	Hanford	27
Lake	510	Sonoma California Geothermal	78
Lake	902	Bottle Rock Power	55
Lake	10199	West Ford Flat Power Plant	38
Lake	10469	Bear Canyon Power Plant	24.4
Lake	50066	Calistoga Power Plant	176.4
Lassen	10777	HL Power	36.2
Lassen	50964	Amedee Geothermal Venture I	3
Lassen	54468	Mt Lassen Power	11.4
Los Angeles	315	AES Alamitos LLC	1,922
Los Angeles	330	El Segundo Power	684
Los Angeles	356	AES Redondo Beach LLC	1,316.4
Los Angeles	377	Grayson	163
Los Angeles	399	Harbor	67
Los Angeles	400	Haynes	1,410.3
Los Angeles	404	Scattergood	823.2
Los Angeles	408	Valley	311
Los Angeles	420	Broadway	75
Los Angeles	10090	Commerce Refuse-to-Energy	12
Los Angeles	10169	Carson Cogeneration	10.5
Los Angeles	10471	Spadra Landfill Gas to Energy	10.6
Los Angeles	10472	Puente Hills Energy Recovery	50
Los Angeles	10473	Palos Verdes Gas to Energy	13
Los Angeles	10478	Pitchess Cogen Station	7.4
Los Angeles	50541	Harbor Cogen	25.1
Los Angeles	50837	Southeast Resource Recovery	35.6
Los Angeles	50876	Wheelabrator Norwalk Energy	7.7
Los Angeles	54015	BKK Landfill	6.8
Los Angeles	56041	Malburg	58.8
Los Angeles	56046	Magnolia Power Project	188.7
Los Angeles	57323	Sierra SunTower Solar Generating Station	7.5
Madera	56706	Ampersand Chowchilla Biomass LLC	12.5
Merced	56707	El Nido Facility	12.5
Monterey	260	Dynegy Moss Landing Power Plant	1,870.0
Monterey	10294	King City Power Plant	42.4

Appendix 1. The 1,284 thermoelectric plants one megawatt nameplate capacity or greater with water-cooling systems in the United States, 2010.—Continued

[EIA, U.S. Department of Energy, Energy Information Administration; MW, megawatt; initials associated with a power plant are part of the plant name, and not spelled out; --, nameplate capacity is not reported for the steam side of the combined-cycle power plant]

County	EIA plant code	Plant name	Nameplate capacity (MW)
Orange	335	AES Huntington Beach LLC	888
Orange	10395	Coyote Canyon Steam Plant	20
Placer	10772	Rio Bravo Rocklin	27.9
Placer	56298	Roseville Energy Park	80
Riverside	10300	Mecca Plant	55.5
Riverside	55295	Blythe Energy LLC	227
Riverside	56356	Clearwater Power Plant	8
Riverside	57154	Imperial Valley Resource Recovery	18.1
Riverside County	55853	Inland Empire Energy Center	819
Sacramento	7527	Carson Ice-Gen Project	17.5
Sacramento	7551	SCA Cogen 2	49.8
Sacramento	7552	SPA Cogen 3	55.2
Sacramento	55970	Cosumnes	190
San Bernardino	329	Coolwater	387.3
San Bernardino	331	Etiwanda Generating Station	666
San Bernardino	358	Mountainview Power LLC	428.9
San Bernardino	10002	ACE Cogeneration Facility	108.0
San Bernardino	10437	SEGS I	13.8
San Bernardino	10438	SEGS II	30
San Bernardino	10439	SEGS III	34.2
San Bernardino	10440	SEGS IV	34.2
San Bernardino	10441	SEGS V	34.2
San Bernardino	10442	SEGS VI	35
San Bernardino	10443	SEGS VII	35
San Bernardino	10444	SEGS VIII	92
San Bernardino	10446	SEGS IX	92
San Bernardino	50850	OLS Energy Chino	7.3
San Bernardino	55518	High Desert Power Plant	333
San Diego	302	Encina	982
San Diego	310	Dynegy South Bay Power Plant	272
San Diego	360	San Onofre Nuclear Generating Station	2,254
San Diego	10810	NTC/MCRD Energy Facility	2.6
San Diego	10811	Naval Station Energy Facility	16.8
San Diego	10812	North Island Energy Facility	4
San Diego	54749	Goal Line LP	10.2
San Diego	55985	Palomar Energy	229
San Diego	57584	University of California San Diego	3
San Francisco	273	Potrero Power	226
San Joaquin	10502	Thermal Energy Dev Partnshp LP	23
San Joaquin	10640	Stockton Cogen	60

Appendix 1. The 1,284 thermoelectric plants one megawatt nameplate capacity or greater with water-cooling systems in the United States, 2010.—Continued

[EIA, U.S. Department of Energy, Energy Information Administration; MW, megawatt; initials associated with a power plant are part of the plant name, and not spelled out; --, nameplate capacity is not reported for the steam side of the combined-cycle power plant]

County	EIA plant code	Plant name	Nameplate capacity (MW)
San Luis Obispo	259	Dynegy Morro Bay LLC	718
San Luis Obispo	6099	Diablo Canyon	2,323
Santa Clara	10034	Gilroy Power Plant	40
Santa Clara	50748	Agnews Power Plant	7.6
Santa Clara	54561	Jefferson Smurfit Santa Clara Mill	3
Santa Clara	55393	Metcalf Energy Center	235
Santa Clara	56026	Donald Von Raesfeld Power Plant	54
Shasta	7307	Redding Power	26.8
Shasta	10652	Burney Forest Products	31
Shasta	50881	Wheelabrator Shasta	62.7
Shasta	54219	Burney Mountain Power	11.4
Sonoma	286	Geysers Unit 5-20	1,163
Sonoma	7368	Geothermal 1	110
Sonoma	7369	Geothermal 2	110
Sonoma	52158	Aidlin Geothermal Power Plant	25
Stanislaus	7266	Woodland	37.7
Stanislaus	50632	Covanta Stanislaus Energy	24
Stanislaus	56078	Walnut Energy Center	110.8
Sutter	10350	Greenleaf 1 Power Plant	20
Tuolumne	50560	Pacific-Ultrapower Chinese Station	25
Ventura	345	Mandalay	436
Ventura	350	Ormond Beach	1,612
Ventura	50851	OLS Energy Camarillo	7.6
Yolo	10836	Woodland Biomass Power Ltd	28
		Colorado (25 power plants)	
Adams	469	Cherokee	801.3
Boulder	477	Valmont	191.7
Denver	465	Arapahoe	158
Denver	478	Zuni	75
Denver	55200	Arapahoe Combustion Turbine Project	51.8
El Paso	492	Martin Drake	257.0
El Paso	493	George Birdsall	59.6
El Paso	8219	Ray D Nixon	207
Fremont	462	W N Clark	43.7
Garfield	10755	Rifle Generating Station	39
Jefferson	10003	Colorado Energy Nations Company	35
Larimer	6761	Rawhide	293.6
Logan	57134	OREG 4 Peetz	--
Moffat	6021	Craig	1,427.6
Montrose	527	Nucla	113.8

Appendix 1. The 1,284 thermoelectric plants one megawatt nameplate capacity or greater with water-cooling systems in the United States, 2010.—Continued

[EIA, U.S. Department of Energy, Energy Information Administration; MW, megawatt; initials associated with a power plant are part of the plant name, and not spelled out; --, nameplate capacity is not reported for the steam side of the combined-cycle power plant]

County	EIA plant code	Plant name	Nameplate capacity (MW)
Morgan	6248	Pawnee	552.3
Morgan	10682	Brush Generation Facility	165
Prowers	508	Lamar Plant	18.5
Pueblo	460	Pueblo	22.5
Pueblo	470	Comanche	1,635.3
Routt	525	Hayden	465.4
Weld	6112	Fort St Vrain	342.6
Weld	50676	Thermo Power & Electric	16.4
Weld	50707	TCP 272	94
Weld	55835	Rocky Mountain Energy Center	334.9
		Connecticut (17 power plants)	
Fairfield	548	NRG Norwalk Harbor	326.4
Fairfield	568	Bridgeport Station	563
Fairfield	50883	Wheelabrator Bridgeport	67
Fairfield	55042	Bridgeport Energy Project	180
Hartford	10567	Algonquin Windsor Locks	16
Hartford	50648	Covanta Bristol Energy	16.3
Hartford	54945	Covanta Mid-Connecticut Energy	90
Middlesex	562	Middletown	767.9
New Haven	6156	New Haven Harbor	460
New Haven	50664	Covanta Wallingford Energy	11
New Haven	55126	Milford Power Project	578
New London	546	Montville Station	489.9
New London	566	Millstone	2,162.9
New London	10646	American Ref-Fuel of SE CT	16.9
New London	10675	AES Thames	213.9
New London	54758	Wheelabrator Lisbon	14.6
Windham	50736	Exeter Energy LP	31.3
		Delaware (5 power plants)	
Kent	599	McKee Run	151.2
Kent	10030	NRG Energy Center Dover	18
New Castle	593	Edge Moor	697.8
New Castle	7153	Hay Road	395
Sussex	594	Indian River Generating Station	782.4
		Florida (68 power plants)	
Alachua	663	Deerhaven Generating Station	325.7
Alachua	664	John R Kelly	75
Bay	643	Lansing Smith	553.3
Bay	10250	Bay Resource Management Center	13.6
Brevard	609	Cape Canaveral	804

Appendix 1. The 1,284 thermoelectric plants one megawatt nameplate capacity or greater with water-cooling systems in the United States, 2010.—Continued

[EIA, U.S. Department of Energy, Energy Information Administration; MW, megawatt; initials associated with a power plant are part of the plant name, and not spelled out; --, nameplate capacity is not reported for the steam side of the combined-cycle power plant]

County	EIA plant code	Plant name	Nameplate capacity (MW)
Brevard	55318	Indian River	609
Broward	613	Lauderdale	302.4
Broward	617	Port Everglades	1,300
Broward	50572	CSL Gas Recovery	2.2
Broward	54033	Wheelabrator North Broward	67.6
Citrus	628	Crystal River	3,333.1
Duval	207	St Johns River Power Park	1,358
Duval	667	Northside Generating Station	1,158.7
Duval	7846	Brandy Branch	228.1
Duval	10672	Cedar Bay Generating Company LP	291.6
Escambia	641	Crist	1,135.1
Hardee	7380	Midulla Generating Station	189
Hardee	50949	Hardee Power Station	95.8
Hernando	10333	Central Power & Lime	125
Hillsborough	645	Big Bend	1,822.5
Hillsborough	7873	H L Culbreath Bayside Power Station	685.1
Hillsborough	50858	Hillsborough County Resource Recovery	47
Hillsborough	50875	McKay Bay Facility	22.1
Indian River	693	Vero Beach Municipal Power Plant	117
Jackson	642	Scholz	98
Lake	50629	Covanta Lake County Energy	15.5
Lake	54423	Lake Cogen Ltd	31.1
Lee	612	Fort Myers	592.3
Lee	52010	Lee County Solid Waste Energy	59
Leon	688	Arvah B Hopkins	334.2
Liberty	50774	Telogia Power	14
Manatee	6042	Manatee	2,198.4
Martin	6043	Martin	2,823.7
Martin	50976	Indiantown Cogeneration LP	395.4
Miami-Dade	621	Turkey Point	2,796
Miami-Dade	10062	Miami Dade County Resource Recovery Fac	77
Orange	564	Stanton Energy Center	1,058.8
Orange	7294	Central Energy Plant	8.5
Orange	54466	Orlando Cogen LP	122.4
Orange	55821	Curtis H Stanton Energy Center	281.9
Osceola	672	Hansel	20
Osceola	7238	Cane Island	122.5
Palm Beach	673	Tom G Smith	36.5
Palm Beach	50071	North County Regional Resource	62.3
Palm Beach	54627	Okeelanta Cogeneration	128.9

Appendix 1. The 1,284 thermoelectric plants one megawatt nameplate capacity or greater with water-cooling systems in the United States, 2010.—Continued

[EIA, U.S. Department of Energy, Energy Information Administration; MW, megawatt; initials associated with a power plant are part of the plant name, and not spelled out; --, nameplate capacity is not reported for the steam side of the combined-cycle power plant]

County	EIA plant code	Plant name	Nameplate capacity (MW)
Palm Beach	56407	West County Energy Center	1,054
Pasco	8048	Anclote	1,112.4
Pasco	50666	Pasco Cnty Solid Waste Resource Recovery	31.2
Pasco	54424	Pasco Cogen Ltd	26.5
Pinellas	634	P L Bartow	421
Pinellas	50884	Pinellas County Resource Recovery	76.5
Polk	675	Larsen Memorial	25
Polk	676	C D McIntosh Jr	609.8
Polk	7242	Polk	133.4
Polk	7302	Hines Energy Complex	796.3
Polk	7699	Tiger Bay	82.9
Polk	54365	Orange Cogeneration Facility	28.6
Polk	54426	Mulberry Cogeneration Facility	49.5
Polk	54529	Wheelabrator Ridge Energy	45.5
Polk	54658	Auburndale Power Partners	52
Polk	55412	Osprey Energy Center	260
Putnam	136	Seminole	1,429.2
Putnam	6246	Putnam	240
St Lucie	6045	St Lucie	1,700
St Lucie	56400	Treasure Coast Energy Center	191.8
Suwannee	638	Suwannee River	147
Volusia	620	Sanford	1,028.4
Wakulla	689	S O Purdom	137
		Georgia (22 power plants)	
Appling	6051	Edwin I Hatch	1,721.8
Bartow	703	Bowen	3,498.6
Burke	649	Vogtle	2,320
Chatham	733	Kraft	333.9
Cobb	710	Jack McDonough	598.4
Coweta	728	Yates	1,487.3
Dougherty	727	Mitchell	163.2
Effingham	6124	McIntosh	177.6
Effingham	55406	Effingham County Power Project	197.8
Effingham	56150	McIntosh Combined Cycle Facility	563.8
Floyd	708	Hammond	953
Glynn	715	McManus	143.7
Heard	6052	Wansley	1,904
Heard	7917	Chattahoochee Energy Facility	187.7
Heard	7946	Wansley Unit 9	226
Heard	55965	Wansley Combined Cycle	426.6

Appendix 1. The 1,284 thermoelectric plants one megawatt nameplate capacity or greater with water-cooling systems in the United States, 2010.—Continued

[EIA, U.S. Department of Energy, Energy Information Administration; MW, megawatt; initials associated with a power plant are part of the plant name, and not spelled out; --, nameplate capacity is not reported for the steam side of the combined-cycle power plant]

County	EIA plant code	Plant name	Nameplate capacity (MW)
Houston	55040	Mid-Georgia Cogeneration Facility	110
Monroe	6257	Scherer	3,564
Murray	55382	KGen Murray I and II LLC	604
Putnam	709	Harllee Branch	1,746.2
Rabun	50201	Rabun Gap Cogen Facility	20
Worth	753	Crisp Plant	12.5
		Hawaii (12 power plants)	
Hawaii	772	W H Hill	37.1
Hawaii	6478	Shipman	15
Hawaii	52028	Puna Geothermal Venture I	35
Hawaii	55369	Hamakua Energy Plant	20
Honolulu	764	Honolulu	104.4
Honolulu	765	Kahe	609.7
Honolulu	766	Waiau	372
Honolulu	54646	Kalaeola Cogen Plant	61
Kauai	6474	Port Allen	10
Maui	6056	Kahului	34
Maui	6504	Maalaea	36
Oahu	10673	AES Hawaii	203
		Idaho (4 power plants)	
Adams	50099	Tamarack Energy Partnership	6.2
Benewah	55090	Plummer Cogen	6.2
Kootenai	55179	Rathdrum Power LLC	122.1
Minidoka	54579	Rupert Cogen Project	10.4
		Illinois (37 power plants)	
Christian	876	Kincaid Generation LLC	1,319
Cook	867	Crawford	597.4
Cook	886	Fisk Street	374
Cook	972	Winnetka	28.2
Cook	55174	Geneva Energy LLC	22
Crawford	863	Hutsonville	150
De Witt	204	Clinton Power Station	1,138.3
Douglas	55245	Tuscola Station	12
Fulton	6016	Duck Creek	441
Grundy	869	Dresden Generating Station	2,018.6
Grundy	55216	Morris Cogeneration LLC	62
Jackson	862	Grand Tower	199.3
Jasper	6017	Newton	1,234.8
Kendall	55131	Kendall County Generation Facility	536
La Salle	6026	LaSalle Generating Station	2,340

Appendix 1. The 1,284 thermoelectric plants one megawatt nameplate capacity or greater with water-cooling systems in the United States, 2010.—Continued

[EIA, U.S. Department of Energy, Energy Information Administration; MW, megawatt; initials associated with a power plant are part of the plant name, and not spelled out; --, nameplate capacity is not reported for the steam side of the combined-cycle power plant]

County	EIA plant code	Plant name	Nameplate capacity (MW)
Lake	883	Waukegan	681.7
Madison	898	Wood River	500.1
Mason	891	Havana	488
Massac	887	Joppa Steam	1,099.8
Montgomery	861	Coffeen	1,005.4
Morgan	864	Meredosia	564
Ogle	6023	Byron Generating Station	2,449.8
Peoria	856	E D Edwards	780.3
Pike	6238	Pearl Station	22
Putnam	892	Hennepin Power Station	306.3
Randolph	889	Baldwin Energy Complex	1,894.1
Rock Island	880	Quad Cities Generating Station	2,018.6
Rock Island	55188	Cordova Energy	191.2
Sangamon	963	Dallman	667.7
Shelby	55334	Holland Energy Facility	345.1
Tazewell	879	Powerton	1,785.6
Vermilion	897	Vermilion	182.3
Will	384	Joliet 29	1,320
Will	874	Joliet 9	360.4
Will	884	Will County	897.6
Will	6022	Braidwood Generation Station	2,449.8
Williamson	976	Marion	272
		Indiana (31 power plants)	
Cass	1032	Logansport	43
Dearborn	988	Tanners Creek	1,100.1
Dearborn	55502	Lawrenceburg Energy Facility	536
Dubois	6225	Jasper 2	14.5
Floyd	1008	R Gallagher	600
Gibson	6113	Gibson	3,339.5
Hamilton	1007	Noblesville	100
Jasper	6085	R M Schahfer	1,943.4
Jefferson	983	Clifty Creek	1,303.8
Knox	1004	Edwardsport	144.2
La Porte	997	Michigan City	540
Lake	981	State Line Energy	613.8
Lake	55259	Whiting Clean Energy	213
Marion	990	Harding Street	785.6
Marion	992	CC Perry K	23.4
Miami	1037	Peru	34.5
Montgomery	1024	Crawfordsville	24.1

Appendix 1. The 1,284 thermoelectric plants one megawatt nameplate capacity or greater with water-cooling systems in the United States, 2010.—Continued

[EIA, U.S. Department of Energy, Energy Information Administration; MW, megawatt; initials associated with a power plant are part of the plant name, and not spelled out; --, nameplate capacity is not reported for the steam side of the combined-cycle power plant]

County	EIA plant code	Plant name	Nameplate capacity (MW)
Morgan	991	Eagle Valley	393.6
Pike	994	AES Petersburg	2,146.7
Pike	1043	Frank E Ratts	233.2
Porter	995	Bailly	603.5
Porter	55096	Portside Energy	25.6
Posey	6137	A B Brown	530.4
Spencer	6166	Rockport	2,600
Sullivan	6213	Merom	1,080
Vermillion	1001	Cayuga	1,062
Vigo	1010	Wabash River	972.7
Vigo	55364	Sugar Creek Power	237.3
Warrick	1012	F B Culley	368.9
Warrick	6705	Warrick	777.6
Wayne	1040	Whitewater Valley	93.9
		Iowa (22 power plants)	
Allamakee	1047	Lansing	312
Black Hawk	1131	Streeter Station	51.5
Cerro Gordo	8031	Emery Station	244.6
Clay	1217	Earl F Wisdom	33
Clinton	1048	Milton L Kapp	218.4
Des Moines	1104	Burlington	212
Dubuque	1046	Dubuque	66.2
Linn	1060	Duane Arnold Energy Center	679.5
Linn	1073	Prairie Creek	221.7
Louisa	6664	Louisa	811.9
Marion	1175	Pella	38
Marshall	1077	Sutherland	119.1
Muscatine	1167	Muscatine Plant #1	293.5
Muscatine	1218	Fair Station	62.5
Polk	7985	Greater Des Moines	195.5
Pottawattamie	1082	Walter Scott Jr Energy Center	1,778.9
Scott	1081	Riverside	141
Story	1122	Ames Electric Services Power Plant	108.8
Union	1206	Summit Lake	22.5
Wapello	6254	Ottumwa	726
Woodbury	1091	George Neal North	1,046
Woodbury	7343	George Neal South	640
		Kansas (22 power plants)	
Barton	1235	Great Bend	81.6
Cherokee	1239	Riverton	87.5

Appendix 1. The 1,284 thermoelectric plants one megawatt nameplate capacity or greater with water-cooling systems in the United States, 2010.—Continued

[EIA, U.S. Department of Energy, Energy Information Administration; MW, megawatt; initials associated with a power plant are part of the plant name, and not spelled out; --, nameplate capacity is not reported for the steam side of the combined-cycle power plant]

County	EIA plant code	Plant name	Nameplate capacity (MW)
Clay	1270	Clay Center	8
Coffey	210	Wolf Creek Generating Station	1,235.7
Cowley	7013	East 12th Street	26.5
Douglas	1250	Lawrence Energy Center	566
Finney	108	Holcomb	348.7
Finney	1336	Garden City	97.9
Ford	1233	Fort Dodge	149
Labette	1243	Neosho	69
Linn	1241	La Cygne	1,578
Montgomery	1271	Coffeyville	58.7
Pottawatomie	6068	Jeffrey Energy Center	2,160
Pratt	1317	Pratt	19
Reno	1248	Hutchinson Energy Center	172
Sedgwick	1240	Gordon Evans Energy Center	526
Sedgwick	1242	Murray Gill	349
Seward	1230	Cimarron River	50
Shawnee	1252	Tecumseh Energy Center	232
Sumner	1330	Wellington 1	20
Wyandotte	1295	Quindaro	239.1
Wyandotte	6064	Nearman Creek	261
		Kentucky (20 power plants)	
Boone	6018	East Bend	669.3
Carroll	1356	Ghent	2,225.9
Clark	1385	Dale	216
Daviess	1374	Elmer Smith	445.3
Hancock	1381	Kenneth C Coleman	602
Henderson	1382	HMP&L Station Two Henderson	405
Jefferson	1363	Cane Run	644.6
Jefferson	1364	Mill Creek	1,717.2
Lawrence	1353	Big Sandy	1,096.8
Mason	6041	H L Spurlock	1,608.5
McCracken	1379	Shawnee	1,750
Mercer	1355	E W Brown	757.1
Muhlenberg	1357	Green River	188.6
Muhlenberg	1378	Paradise	2,558.2
Ohio	6823	D B Wilson	566.1
Pulaski	1384	Cooper	344
Trimble	6071	Trimble County	566.1
Webster	1383	Robert A Reid	96
Webster	6639	R D Green	586
Woodford	1361	Tyrone	75

Appendix 1. The 1,284 thermoelectric plants one megawatt nameplate capacity or greater with water-cooling systems in the United States, 2010.—Continued

[EIA, U.S. Department of Energy, Energy Information Administration; MW, megawatt; initials associated with a power plant are part of the plant name, and not spelled out; --, nameplate capacity is not reported for the steam side of the combined-cycle power plant]

County	EIA plant code	Plant name	Nameplate capacity (MW)
		Louisiana (27 power plants)	
Acadia	55173	Acadia Energy Center	528
Caddo	1416	Arsenal Hill	125
Caddo	1417	Lieberman	278
Caddo	56565	J Lamar Stall Unit	256
Calcasieu	1393	R S Nelson	1,596.8
Calcasieu	10593	Agrilectric Power Partners Ltd	12.1
De Soto	51	Dolet Hills	720.7
Evangeline	1396	Coughlin Power Station	356.7
Iberville	1394	Willow Glen	2,178
Iberville	1455	Plaquemine	44
Iberville	55404	Carville Energy LLC	196
Jefferson	1403	Nine Mile Point	2,141.5
Lafayette	1443	Louis Doc Bonin	340.9
Orleans	1409	Michoud	959.2
Ouachita	1404	Sterlington	348.7
Ouachita	55467	Ouachita	366
Ouachita	55620	Perryville Power Station	237
Pointe Coupee	1464	Big Cajun 1	227.2
Pointe Coupee	6055	Big Cajun 2	1,871
Rapides	6190	Brame Energy Center	1,707.3
St. Charles	1402	Little Gypsy	1,250.6
St. Charles	4270	Waterford 3	1,199.8
St. Charles	8056	Waterford 1 & 2	891
St. Mary	1400	Teche	427.8
St. Mary	1449	Morgan City	58.3
Terrebonne	1439	Houma	78.9
West Feliciana	6462	River Bend	1,035.9
		Maine (14 power plants)	
Androscoggin	10354	Boralex Beaver Livermore Falls	39.6
Aroostook	7513	Boralex Fort Fairfield	37.5
Aroostook	10356	Boralex Ashland	39.6
Cumberland	1507	William F Wyman	846
Cumberland	50225	Regional Waste Systems	13.3
Cumberland	55294	Westbrook Energy Center	195.5
Franklin	50650	Boralex Stratton Energy	45.7
Oxford	10495	Rumford Cogeneration	102.6
Oxford	55100	Rumford Power Associates	91.9
Penobscot	10766	Indeck West Enfield Energy Center	27.5
Penobscot	55068	Maine Independence Station	194.6

Appendix 1. The 1,284 thermoelectric plants one megawatt nameplate capacity or greater with water-cooling systems in the United States, 2010.—Continued

[EIA, U.S. Department of Energy, Energy Information Administration; MW, megawatt; initials associated with a power plant are part of the plant name, and not spelled out; --, nameplate capacity is not reported for the steam side of the combined-cycle power plant]

County	EIA plant code	Plant name	Nameplate capacity (MW)
Piscataquis	54852	Greenville Steam	15.6
Washington	10765	Indeck Jonesboro Energy Center	27.5
York	10338	Maine Energy Recovery	22
Maryland (17 power plants)			
Allegany	10678	AES Warrior Run Cogeneration Facility	229
Anne Arundel	602	Brandon Shores	1,370
Anne Arundel	1554	Herbert A Wagner	1,042.5
Baltimore	1552	C P Crane	399.8
Baltimore	1559	Riverside	72.2
Baltimore	10485	RG Steel Sparrows Point, LLC	120
Baltimore City	1553	Gould Street	103.5
Baltimore City	10629	Wheelabrator Baltimore Refuse	64.5
Calvert	6011	Calvert Cliffs Nuclear Power Plant	1,828.7
Charles	1573	Morgantown Generating Plant	1,252
Dorchester	1564	Vienna Operations	162
Montgomery	1572	Dickerson	588
Montgomery	50657	Montgomery County Resource Recovery	67.8
Prince George's	1571	Chalk Point LLC	2,046
Prince George's	54832	Panda Brandywine LP	91.4
Prince George's	56038	UMCP CHP Plant	5.4
Washington	1570	FirstEnergy R Paul Smith Power Station	109.5
Massachusetts (25 power plants)			
Barnstable	1599	Canal	1,165
Berkshire	50002	Pittsfield Generating LP	60
Bristol	1619	Brayton Point	1,124.6
Bristol	1682	Cleary Flood	123.3
Bristol	52026	Dartmouth Power Associates	32
Essex	1626	Salem Harbor	805.1
Essex	50877	Wheelabrator North Andover	40.3
Essex	50880	Wheelabrator Saugus	53.7
Hampden	1606	Mount Tom	136
Hampden	1642	NAEA Energy Massachusetts LLC	113.6
Hampden	6081	Stony Brook	105
Hampden	9864	Cabot Holyoke	20
Hampden	10726	Masspower	80.9
Hampden	50273	Pioneer Valley Resource Recovery	9.4
Hampden	55041	Berkshire Power	289
Middlesex	1588	Mystic Generating Station	1,247
Middlesex	1595	Kendall Square Station	67.4
Middlesex	10802	Lowell Cogen Plant	8.5

Appendix 1. The 1,284 thermoelectric plants one megawatt nameplate capacity or greater with water-cooling systems in the United States, 2010.—Continued

[EIA, U.S. Department of Energy, Energy Information Administration; MW, megawatt; initials associated with a power plant are part of the plant name, and not spelled out; --, nameplate capacity is not reported for the steam side of the combined-cycle power plant]

County	EIA plant code	Plant name	Nameplate capacity (MW)
Norfolk	1660	Potter Station 2	25
Norfolk	55211	ANP Bellingham Energy Project	578
Plymouth	1590	Pilgrim Nuclear Power Station	670
Worcester	50878	Wheelabrator Millbury Facility	47.6
Worcester	54805	Milford Power LP	49.1
Worcester	55079	Millennium Power	130
Worcester	55212	ANP Blackstone Energy Project	578
		Michigan (42 power plants)	
Alcona	50772	Viking Energy of Lincoln	18
Allegan	1880	Claude Vandyke	23
Baraga	1772	John H Warden	18.7
Bay	1702	Dan E Karn	1,946.3
Bay	1720	J C Weadock	312.6
Berrien	6000	Donald C Cook	2,285.3
Crawford	10822	Grayling Generating Station	38
Delta	1771	Escanaba	23
Eaton	1832	Erickson Station	154.7
Genesee	54751	Genesee Power Station LP	39.5
Hillsdale	4259	Endicott Station	55
Huron	1731	Harbor Beach	121
Ingham	1831	Eckert Station	375
Jackson	55270	Kinder Morgan Power Jackson Facility	210
Kent	10819	Ada Cogeneration LP	10.1
Manistee	50835	TES Filer City Station	70
Marquette	1769	Presque Isle	450
Marquette	1843	Shiras	65
Mason	54915	Michigan Power LP	58
Midland	10745	Midland Cogeneration Venture	423.4
Missaukee	50770	Viking Energy of McBain	18
Monroe	1723	J R Whiting	345.4
Monroe	1729	Fermi	1,217.0
Monroe	1733	Monroe	3,279.6
Montmorency	10346	Hillman Power LLC	20
Muskegon	1695	B C Cobb	312.6
Ontonagon	10148	White Pine Electric Power	40
Ottawa	1710	J H Campbell	1,585.9
Ottawa	1825	J B Sims	80
Ottawa	1830	James De Young	62.8
Ottawa	55087	Zeeland Generating Station	213.3
St. Clair	1743	St Clair	1,547

Appendix 1. The 1,284 thermoelectric plants one megawatt nameplate capacity or greater with water-cooling systems in the United States, 2010.—Continued

[EIA, U.S. Department of Energy, Energy Information Administration; MW, megawatt; initials associated with a power plant are part of the plant name, and not spelled out; --, nameplate capacity is not reported for the steam side of the combined-cycle power plant]

County	EIA plant code	Plant name	Nameplate capacity (MW)
St. Clair	6034	Belle River	1,395
St. Clair	6035	Greenwood	815.4
Van Buren	1715	Palisades	811.8
Van Buren	55297	New Covert Generating Facility	441
Washtenaw	50431	University of Michigan	37.5
Wayne	1740	River Rouge	933.2
Wayne	1745	Trenton Channel	775.5
Wayne	1866	Wyandotte	54
Wayne	55088	Dearborn Industrial Generation	250
Wexford	54415	Cadillac Renewable Energy	44
		Minnesota (32 power plants)	
Blue Earth	1934	Wilmarth	25
Blue Earth	56104	Mankato Energy Center	320
Brown	2001	New Ulm	21
Cook	10075	Taconite Harbor Energy Center	252
Dakota	1904	Black Dog	430.4
Dakota	55598	Pine Bend	6.6
Goodhue	1925	Prairie Island	1,186.2
Goodhue	1926	Red Wing	23
Hennepin	1927	Riverside	165
Hennepin	10013	Covanta Hennepin Energy	39.5
Itasca	1893	Clay Boswell	1,072.5
Itasca	10686	Rapids Energy Center	26.5
Kandiyohi	2022	Willmar	18
Martin	1888	Fox Lake	93.1
McLeod	1980	Hutchinson Plant #1	16.0
McLeod	6358	Hutchinson Plant #2	11.5
Mower	1961	Austin Northeast	31.9
Olmsted	2008	Silver Lake	99
Otter Tail	1943	Hoot Lake	129.4
Ramsey	1912	High Bridge	250
Ramsey	56643	St Paul Cogeneration	37
Rice	56164	Faribault Energy Park	122
Scott	57119	Koda Biomass Plant	23.4
Sherburne	2039	Elk River	38.8
Sherburne	6090	Sherburne County	2,430.6
St. Louis	1891	Syl Laskin	116
St. Louis	1897	M L Hibbard	72.8
St. Louis	1979	Hibbing	35.9
St. Louis	2018	Virginia	30.2

Appendix 1. The 1,284 thermoelectric plants one megawatt nameplate capacity or greater with water-cooling systems in the United States, 2010.—Continued

[EIA, U.S. Department of Energy, Energy Information Administration; MW, megawatt; initials associated with a power plant are part of the plant name, and not spelled out; --, nameplate capacity is not reported for the steam side of the combined-cycle power plant]

County	EIA plant code	Plant name	Nameplate capacity (MW)
Washington	1915	Allen S King	598.4
Washington	55010	LSP-Cottage Grove LP	106.2
Wright	1922	Monticello	631.2
		Mississippi (23 power plants)	
Attala	55220	Attala	180
Benton	55451	Magnolia Power Plant	468
Bolivar	2051	Delta	225
Choctaw	55076	Red Hills Generating Facility	513.7
Choctaw	55694	Choctaw Gas Generation Project	310.5
Claiborne	6072	Grand Gulf	1,372.5
Coahoma	2059	L L Wilkins	39
Desoto	55269	TVA Southaven Combined Cycle	366
Forrest	2046	Eaton	77.7
Harrison	2049	Jack Watson	1,173.6
Hinds	2053	Rex Brown	339.2
Hinds	55218	Hinds Energy Facility	188
Jackson	6073	Victor J Daniel Jr	1,487
Jones	2070	Moselle	177
Lamar	6061	R D Morrow	400
Lauderdale	2048	Sweatt	95
Leflore	2062	Henderson	32.6
Leflore	2063	Wright	17.5
Lowndes	55197	Caledonia	318
Panola	55063	Batesville Generation Facility	337.5
Warren	2050	Baxter Wilson	1,327.6
Washington	8054	Gerald Andrus	781.4
Yazoo	2067	Yazoo	12.6
		Missouri (25 power plants)	
Boone	2123	Columbia	73.5
Buchanan	2098	Lake Road	150.5
Callaway	6153	Callaway	1,235.8
Cass	55178	Dogwood Energy Facility	265
Clay	2171	Missouri City	46
Dunklin	7604	St Francis Energy Facility	614
Franklin	2103	Labadie	2,389.4
Greene	2161	James River Power Station	253
Greene	6195	Southwest Power Station	194
Henry	2080	Montrose	564
Jackson	2079	Hawthorn	737.1
Jackson	2094	Sibley	524

Appendix 1. The 1,284 thermoelectric plants one megawatt nameplate capacity or greater with water-cooling systems in the United States, 2010.—Continued

[EIA, U.S. Department of Energy, Energy Information Administration; MW, megawatt; initials associated with a power plant are part of the plant name, and not spelled out; --, nameplate capacity is not reported for the steam side of the combined-cycle power plant]

County	EIA plant code	Plant name	Nameplate capacity (MW)
Jackson	2132	Blue Valley	115
Jasper	2076	Asbury	231.5
Jasper	7296	State Line Combined Cycle	206.5
Jefferson	6155	Rush Island	1,242
New Madrid	2167	New Madrid	1,200
Osage	2169	Chamois	59
Platte	6065	Iatan	1,640
Randolph	2168	Thomas Hill	1,135
Saline	2144	Marshall	22.5
Scott	6768	Sikeston Power Station	261
St. Charles	2107	Sioux	1,099.4
St. Louis	2104	Meramec	923
St. Louis	56309	Trigen St. Louis	36.8
		Montana (7 power plants)	
Big Horn	55749	Hardin Generator Project	115.7
Richland	6089	Lewis & Clark	50
Roosevelt	56833	OREG 1 Inc	--
Roosevelt	56880	OREG 2 Inc	--
Rosebud	6076	Colstrip	2,272
Rosebud	10784	Colstrip Energy LP	46.1
Yellowstone	2187	J E Corette Plant	172.8
		Nebraska (14 power plants)	
Adams	60	Whelan Energy Center	76.3
Dodge	2240	Lon Wright	130
Douglas	2291	North Omaha	644.7
Gage	8000	Beatrice	93.9
Gosper	2226	Canaday	108.8
Hall	59	Platte	109.8
Hall	2241	C W Burdick	98
Jefferson	2236	Fairbury	19
Lancaster	2277	Sheldon	228.7
Lancaster	7887	Terry Bundy Generating Station	27
Lincoln	6077	Gerald Gentleman	1,362.6
Nemaha	8036	Cooper	801
Otoe	6096	Nebraska City	1,389.6
Washington	2289	Fort Calhoun	502
		Nevada (22 power plants)	
Churchill	52015	Caithness Dixie Valley	60.5
Churchill	52174	Soda Lake Geothermal No I II	26.1
Churchill	55991	Brady	32.9

Appendix 1. The 1,284 thermoelectric plants one megawatt nameplate capacity or greater with water-cooling systems in the United States, 2010.—Continued

[EIA, U.S. Department of Energy, Energy Information Administration; MW, megawatt; initials associated with a power plant are part of the plant name, and not spelled out; --, nameplate capacity is not reported for the steam side of the combined-cycle power plant]

County	EIA plant code	Plant name	Nameplate capacity (MW)
Clark	2322	Clark	208.8
Clark	2324	Reid Gardner	636.8
Clark	2326	Sunrise	81.6
Clark	10761	Las Vegas Cogeneration LP	11.5
Clark	54271	Saguaro Power	37
Clark	54349	Nevada Cogen Associates 2 Black Mountain	29.7
Clark	54350	Nevada Cogen Assoc#1 GarnetVly	29.7
Clark	55952	Las Vegas Cogeneration II LLC	55.6
Clark	56405	Nevada Solar One	75.7
Clark	57684	Goodsprings Waste Heat Recovery	7.5
Eureka	10287	Beowawe Power	17
Eureka	56224	TS Power Plant	242
Humboldt	8224	North Valmy	567
Humboldt	50760	Empire	4.8
Lyon	2330	Fort Churchill	230
Lyon	10018	Desert Peak Power Plant	15
Lyon	55988	Wabuska	2.2
Storey	2336	Tracy	607
Washoe	50654	Steamboat Hills LP	14.6
New Hampshire (13 power plants)			
Carroll	50739	Pinetree Power Tamworth	25
Coos	10839	DG Whitefield LLC	19.9
Grafton	10290	Bridgewater Power LP	20
Grafton	50208	Pinetree Power	17.5
Merrimack	2364	Merrimack	459.2
Merrimack	50873	Wheelabrator Concord Facility	14
Rockingham	2367	Schiller	150
Rockingham	6115	Seabrook	1,242
Rockingham	8002	Newington	414
Rockingham	55170	Granite Ridge	300
Rockingham	55661	NAEA Newington Power	234.3
Sullivan	10838	Springfield Power LLC	16
Sullivan	50872	Wheelabrator Claremont Facility	4.5
New Jersey (29 power plants)			
Bergen	2398	Bergen Generating Station	545.2
Bergen	50852	Elmwood Energy Holdings LLC	24
Camden	10435	Camden Resource Recovery Facility	35
Camden	10751	Camden Plant Holding LLC	61.8
Cape May	2378	B L England	475.6
Cumberland	2434	Howard Down	25.0

Appendix 1. The 1,284 thermoelectric plants one megawatt nameplate capacity or greater with water-cooling systems in the United States, 2010.—Continued

[EIA, U.S. Department of Energy, Energy Information Administration; MW, megawatt; initials associated with a power plant are part of the plant name, and not spelled out; --, nameplate capacity is not reported for the steam side of the combined-cycle power plant]

County	EIA plant code	Plant name	Nameplate capacity (MW)
Essex	10643	Covanta Essex Company	69.8
Essex	50385	Newark Bay Cogeneration Partnership LP	40
Gloucester	10043	Logan Generating Company LP	242.3
Gloucester	50561	Eagle Point Cogeneration	45
Gloucester	50885	Wheelabrator Gloucester LP	14
Hudson	2403	PSEG Hudson Generating Station	1,114.4
Hudson	50497	Bayonne Plant Holding LLC	61.4
Hunterdon	2393	Gilbert	135
Mercer	2408	PSEG Mercer Generating Station	652.8
Middlesex	2411	PSEG Sewaren Generating Station	431
Middlesex	10308	Sayreville Cogeneration Facility	143.4
Middlesex	50799	Parlin Power Plant	48
Middlesex	55239	AES Red Oak LLC	330
Middlesex	56119	Middlesex Generating Facility	10.5
Ocean	2388	Oyster Creek	550
Salem	2384	Deepwater	73.5
Salem	2410	PSEG Salem Generating Station	2,340
Salem	6118	PSEG Hope Creek Generating Station	1,170
Salem	10099	Pedricktown Cogeneration Company LP	42.4
Salem	10566	Chambers Cogeneration LP	285
Union	2406	PSEG Linden Generating Station	542
Union	10805	Kenilworth Energy Facility	6.8
Warren	10012	Covanta Warren Energy	13.5
		New Mexico (11 power plants)	
Bernalillo	2450	Reeves	154
Dona Ana	2444	Rio Grande	266.5
Dona Ana	55210	Afton Generating Station	110
Lea	2446	Maddox	113.6
Lea	2454	Cunningham	265.4
Luna	55343	Luna Energy Facility	300
McKinley	87	Escalante	257
San Juan	2442	Four Corners	2,269.6
San Juan	2451	San Juan	1,848
San Juan	2465	Animas	15
San Juan	55977	Bluffview	27
		New York (61 power plants)	
Albany	2539	Bethlehem Energy Center	310.2
Albany	10725	Selkirk Cogen	148.4
Allegany	7784	Allegany Cogen	25
Broome	2526	AES Westover	75

Appendix 1. The 1,284 thermoelectric plants one megawatt nameplate capacity or greater with water-cooling systems in the United States, 2010.—Continued

[EIA, U.S. Department of Energy, Energy Information Administration; MW, megawatt; initials associated with a power plant are part of the plant name, and not spelled out; --, nameplate capacity is not reported for the steam side of the combined-cycle power plant]

County	EIA plant code	Plant name	Nameplate capacity (MW)
Cattaraugus	54076	Indeck Olean Energy Center	44.6
Chautauqua	2554	Dunkirk Generating Plant	627.2
Chautauqua	2682	S A Carlson	49.0
Dutchess	10305	Dutchess Cnty Resource Recovery Facility	9.2
Erie	2549	C R Huntley Generating Station	436
Erie	50451	Indeck Yerkes Energy Center	19.3
Franklin	50277	Boralex Chateaugay Power Station	19.7
Genesee	54593	Batavia Power Plant	18.5
Jefferson	10464	Black River Generation	55.5
Kings	54914	Brooklyn Navy Yard Cogeneration	80
Lewis	10617	CH Resources Beaver Falls	42.3
Lewis	54526	Lyonsdale Biomass LLC	21.1
Nassau	2511	E F Barrett	376.0
Nassau	2514	National Grid Glenwood Energy Center	228.0
Nassau	10642	Covanta Hempstead	78.6
Nassau	50292	Bethpage Power Plant	52.2
Nassau	52056	Trigen Nassau Energy	12
New York	2493	East River	716.2
Niagara	6082	AES Somerset LLC	655.1
Niagara	50202	WPS Power Niagara	56
Niagara	50472	American Ref-Fuel of Niagara	50
Niagara	54041	Lockport Energy Associates LP	75.2
Niagara	54131	Fortistar North Tonawanda	17
Oneida	50744	Sterling Power Plant	16.5
Onondaga	50651	Trigen Syracuse Energy	101.1
Onondaga	50978	Carr Street Generating Station	25
Orange	2480	Danskammer Generating Station	532
Orange	8006	Roseton Generating Station	1,242
Oswego	2589	Nine Mile Point Nuclear Station	1,901.1
Oswego	2594	Oswego Harbor Power	1,803.6
Oswego	6110	James A Fitzpatrick	882
Oswego	50450	Indeck Oswego Energy Center	16.2
Oswego	54547	Sithe Independence Station	409
Queens	2500	Ravenswood	1,907
Queens	2513	Far Rockaway	100
Queens	8906	Astoria Generating Station	1,330
Queens	54114	Kennedy International Airport Cogen	27
Rensselaer	10190	Castleton Energy Center	25
Rensselaer	54034	Rensselaer Cogen	39
Rensselaer	56259	Empire Generating Co LLC	295.7

Appendix 1. The 1,284 thermoelectric plants one megawatt nameplate capacity or greater with water-cooling systems in the United States, 2010.—Continued

[EIA, U.S. Department of Energy, Energy Information Administration; MW, megawatt; initials associated with a power plant are part of the plant name, and not spelled out; --, nameplate capacity is not reported for the steam side of the combined-cycle power plant]

County	EIA plant code	Plant name	Nameplate capacity (MW)
Richmond	2490	Arthur Kill Generating Station	911.7
Rockland	2625	Bowline Point	1,242
Saratoga	50458	Indeck Corinth Energy Center	55
St. Lawrence	54592	Massena Energy Holdings LLC	--
Suffolk	2516	Northport	1,548
Suffolk	2517	Port Jefferson	376
Suffolk	7314	Richard M Flynn	56
Suffolk	50649	Covanta Babylon Inc	17
Suffolk	56188	Pinelawn Power LLC	32
Tompkins	2535	AES Cayuga	322.5
Washington	10503	Wheelabrator Hudson Falls	14.4
Wayne	6122	R E Ginna Nuclear Power Plant	614
West Chester	8907	Indian Point 3	1,012
Westchester	2497	Indian Point 2	1,299
Westchester	50882	Wheelabrator Westchester	59.7
Wyoming	50449	Indeck Silver Springs Energy Center	17.2
Yates	2527	AES Greenidge LLC	112.5
North Carolina (29 power plants)			
Brunswick	6014	Brunswick	2,003.2
Brunswick	10378	CPI USA NC Southport	135
Buncombe	2706	Asheville	413.6
Catawba	2727	Marshall	1,996
Chatham	2708	Cape Fear	358.5
Cleveland	2721	Cliffside	780.9
Craven	10525	Craven County Wood Energy LP	50
Cumberland	1016	Butler-Warner Generation Plant	73
Duplin	10381	Coastal Carolina Clean Power	44.1
Edgecombe	10384	Edgecombe Genco LLC	114.8
Gaston	2718	G G Allen	1,155
Gaston	2732	Riverbend	466
Halifax	50555	Rosemary Power Station	54
Halifax	54035	Roanoke Valley Energy Facililty I	182.3
Halifax	54755	Roanoke Valley Energy Facility II	57.8
Mecklenburg	6038	McGuire	2,440.6
New Hanover	2713	L V Sutton	671.6
New Hanover	50271	New Hanover County WASTEC	6.3
Person	2712	Roxboro	2,558.2
Person	6250	Mayo	735.8
Person	10379	CPI USA NC Roxboro	67.5
Richmond	7805	Richmond	195.3

Appendix 1. The 1,284 thermoelectric plants one megawatt nameplate capacity or greater with water-cooling systems in the United States, 2010.—Continued

[EIA, U.S. Department of Energy, Energy Information Administration; MW, megawatt; initials associated with a power plant are part of the plant name, and not spelled out; --, nameplate capacity is not reported for the steam side of the combined-cycle power plant]

County	EIA plant code	Plant name	Nameplate capacity (MW)
Robeson	2716	W H Weatherspoon	165.5
Rockingham	2723	Dan River	290
Rowan	2720	Buck	370
Rowan	7826	Rowan	195
Stokes	8042	Belews Creek	2,160.2
Wake	6015	Harris	950.9
Wayne	2709	Lee	402.4
		North Dakota (8 power plants)	
McLean	6030	Coal Creek	1,210
Mercer	2817	Leland Olds	656
Mercer	2824	Stanton	190.2
Mercer	6469	Antelope Valley	869.8
Mercer	8222	Coyote	450
Morton	2790	R M Heskett	115
Morton	57172	Glen Ullin Station 6	5.3
Oliver	2823	Milton R Young	734
		Ohio (34 power plants)	
Adams	2850	J M Stuart	2,440.8
Adams	6031	Killen Station	660.6
Ashtabula	2835	FirstEnergy Ashtabula	256
Ashtabula	55990	Ashtabula	1.6
Belmont	2864	FirstEnergy R E Burger	103.4
Butler	2917	Hamilton	110.6
Clermont	2830	Walter C Beckjord	1,221.3
Clermont	6019	W H Zimmer	1,425.6
Coshocton	2840	Conesville	1,890.8
Cuyahoga	2838	FirstEnergy Lake Shore	256
Fulton	54974	Sauder Power Plant	7.2
Gallia	2876	Kyger Creek	1,086.5
Gallia	8102	General James M Gavin	2,600
Hamilton	2832	Miami Fort	1,278
Jefferson	2828	Cardinal	1,880.4
Jefferson	2866	FirstEnergy W H Sammis	2,455.6
Jefferson	55611	Mingo Junction Energy Center	32
Lake	2837	FirstEnergy Eastlake	1,257
Lake	2936	Painesville	38.5
Lake	6020	Perry	1,311.6
Lawrence	55736	Hanging Rock Energy Facility	634.2
Lorain	2836	Avon Lake	766
Lucas	2878	FirstEnergy Bay Shore	639.4

Appendix 1. The 1,284 thermoelectric plants one megawatt nameplate capacity or greater with water-cooling systems in the United States, 2010.—Continued

[EIA, U.S. Department of Energy, Energy Information Administration; MW, megawatt; initials associated with a power plant are part of the plant name, and not spelled out; --, nameplate capacity is not reported for the steam side of the combined-cycle power plant]

County	EIA plant code	Plant name	Nameplate capacity (MW)
Montgomery	2848	O H Hutchings	414
Ottawa	6149	Davis Besse	925.2
Pickaway	2843	Picway	106.2
Richland	2943	Shelby Municipal Light Plant	32
Scioto	56848	Haverhill North Cogeneration Facility	67
Trumbull	2861	Niles	265.6
Tuscarawas	2914	Dover	19.5
Washington	2872	Muskingum River	1,529.4
Washington	55397	Washington Energy Facility	317.1
Washington	55503	AEP Waterford Facility	399
Wayne	2935	Orrville	72
		Oklahoma (24 power plants)	
Caddo	2964	Southwestern	483
Caddo	3006	Anadarko Plant	315.3
Canadian	2953	Mustang	531
Choctaw	6772	Hugo	446
Comanche	8059	Comanche	120
Kay	7546	Ponca City	19.8
Leflore	10671	AES Shady Point LLC	350
Mayes	165	GRDA	1,010
Mayes	7757	Chouteau	181.9
McClain	55457	McClain Energy Facility	168.3
Muskogee	2952	Muskogee	1,716
Noble	6095	Sooner	1,138
Oklahoma	2951	Horseshoe Lake	826
Oklahoma	50558	PowerSmith Cogeneration Project	49.9
Oklahoma	55463	Redbud Power Plant	638
Payne	3000	Boomer Lake Station	22.7
Pittsburg	55501	Kiamichi Energy Facility	634.4
Rogers	2963	Northeastern	1,589
Seminole	2956	Seminole	1,701
Tulsa	2965	Tulsa	340
Tulsa	4940	Riverside	946
Tulsa	55146	Green Country Energy LLC	366
Wagoner	55225	Calpine Oneta Power LLC	510
Woodward	3008	Mooreland	305
		Oregon (12 power plants)	
Columbia	8073	Beaver	176.4
Columbia	56227	Port Westward	171
Douglas	50993	Co-Gen II LLC	7.5

Appendix 1. The 1,284 thermoelectric plants one megawatt nameplate capacity or greater with water-cooling systems in the United States, 2010.—Continued

[EIA, U.S. Department of Energy, Energy Information Administration; MW, megawatt; initials associated with a power plant are part of the plant name, and not spelled out; --, nameplate capacity is not reported for the steam side of the combined-cycle power plant]

County	EIA plant code	Plant name	Nameplate capacity (MW)
Grant	50921	Co-Gen LLC	7.5
Jackson	10869	Biomass One LP	30
Klamath	55103	Klamath Cogeneration Plant	178.5
Marion	50630	Covanta Marion Inc	13.1
Morrow	6106	Boardman	601
Morrow	7350	Coyote Springs	80.6
Morrow	7931	Coyote Springs II	117
Umatilla	54761	Hermiston Generating Plant	212.2
Umatilla	55328	Hermiston Power Partnership	264.4
Pennsylvania (60 power plants)			
Allegheny	3096	Brunot Island	144
Allegheny	8226	Cheswick Power Plant	637
Armstrong	3136	Keystone	1,872
Armstrong	3178	FirstEnergy Armstrong Power Station	326.4
Beaver	6040	Beaver Valley	1,846.8
Beaver	6094	FirstEnergy Bruce Mansfield	2,741.1
Beaver	10676	AES Beaver Valley Partners Beaver Valley	149
Berks	3115	Titus	225
Berks	55193	Ontelaunee Energy Center	228
Bucks	7701	Fairless Hills	60
Bucks	54746	Wheelabrator Falls	53.3
Bucks	55298	Fairless Energy Center	542.4
Cambria	10143	Colver Power Project	118
Cambria	10603	Ebensburg Power	57.6
Cambria	10641	Cambria Cogen	98
Carbon	50776	Panther Creek Energy Facility	94
Chester	3159	Cromby Generating Station	417.5
Clarion	54144	Piney Creek Project	36.2
Clearfield	3131	Shawville	626
Dauphin	8011	Three Mile Island	975.6
Dauphin	10118	Harrisburg Facility	24.1
Delaware	3161	Eddystone Generating Station	1,489.2
Delaware	10746	American Ref-Fuel of Delaware Valley	90
Delaware	55231	Liberty Electric Power Plant	242
Delaware	55801	FPL Energy Marcus Hook LP	271.5
Fayette	55516	Fayette Energy Facility	317.1
Greene	3179	Hatfields Ferry Power Station	1,728
Indiana	3118	Conemaugh	1,872
Indiana	3122	Homer City Station	2,012
Indiana	3130	Seward	585

Appendix 1. The 1,284 thermoelectric plants one megawatt nameplate capacity or greater with water-cooling systems in the United States, 2010.—Continued

[EIA, U.S. Department of Energy, Energy Information Administration; MW, megawatt; initials associated with a power plant are part of the plant name, and not spelled out; --, nameplate capacity is not reported for the steam side of the combined-cycle power plant]

County	EIA plant code	Plant name	Nameplate capacity (MW)
Lackawanna	50279	Archbald Power Station	23.2
Lancaster	50859	Lancaster County Resource Recovery	35.7
Lawrence	3138	New Castle Plant	348
Lebanon	55337	AES Ironwood LLC	259.2
Luzerne	6103	PPL Susquehanna	2,596
Lycoming	10731	Koppers Susquehanna Plant	12.5
Montgomery	6105	Limerick	2,277
Montour	3149	PPL Montour	1,641.7
Northampton	3113	Portland	427.0
Northampton	3148	PPL Martins Creek	1,701.0
Northampton	50888	Northampton Generating Company LP	114.1
Northampton	55690	Bethlehem Power Plant	460
Northampton	55667	Lower Mount Bethel Energy	232
Northumberland	10343	Foster Wheeler Mt Carmel Cogen	47.3
Northumberland	50771	Viking Energy of Northumberland	18
Philadelphia	3169	Schuylkill Generating Station	190.4
Philadelphia	54785	Grays Ferry Cogeneration	57.6
Schuylkill	10113	John B Rich Memorial Power Station	88.4
Schuylkill	50611	WPS Westwood Generation LLC	36
Schuylkill	50879	Wheelabrator Frackville Energy	48
Schuylkill	54634	St Nicholas Cogen Project	99.2
Snyder	3152	Sunbury Generation LP	437.9
Venango	50974	Scrubgrass Generating Company LP	94.7
Washington	3098	Elrama Power Plant	510
Washington	3181	FirstEnergy Mitchell Power Station	373.9
Washington	55710	Allegheny Energy Units 3 4 & 5	188
York	3140	PPL Brunner Island	1,558.7
York	3166	Peach Bottom	2,319.4
York	50215	York County Resource Recovery	36.5
York	54693	York Generation Company LLC	19
		Rhode Island (6 power plants)	
Newport	55048	Tiverton Power Plant	93.2
Providence	3236	Manchester Street	140.0
Providence	51030	Ocean State Power	88.6
Providence	54056	Pawtucket Power Associates	27
Providence	54324	Ocean State Power II	88.6
Providence	55107	Rhode Island State Energy Partners	204
		South Carolina (21 power plants)	
Aiken	3295	Urquhart	250
Aiken	7652	US DOE Savannah River Site (D Area)	78.2

Appendix 1. The 1,284 thermoelectric plants one megawatt nameplate capacity or greater with water-cooling systems in the United States, 2010.—Continued

[EIA, U.S. Department of Energy, Energy Information Administration; MW, megawatt; initials associated with a power plant are part of the plant name, and not spelled out; --, nameplate capacity is not reported for the steam side of the combined-cycle power plant]

County	EIA plant code	Plant name	Nameplate capacity (MW)
Anderson	3264	W S Lee	355
Anderson	7834	John S Rainey	190
Berkeley	130	Cross	2,390.1
Berkeley	3298	Williams	632.7
Berkeley	3319	Jefferies	445.6
Calhoun	55386	Columbia Energy Center	274.5
Charleston	7737	Cogen South	99.2
Cherokee	55043	Cherokee County Cogen	41.2
Colleton	3280	Canadys Steam	489.6
Darlington	3251	H B Robinson	975.2
Fairfield	6127	V C Summer	1,029.6
Georgetown	6249	Winyah	1,260
Horry	3317	Dolphus M Grainger	163.2
Jasper	55927	Jasper	405
Lexington	3287	McMeekin	293.6
Oconee	3265	Oconee	2,666.7
Orangeburg	7210	Cope	417.3
Richland	3297	Wateree	771.8
York	6036	Catawba	2,410.2
		South Dakota (2 power plants)	
Grant	6098	Big Stone	456
Pennington	3325	Ben French	25
		Tennessee (10 power plants)	
Anderson	3396	Bull Run	950
Hamilton	6152	Sequoyah	2,441
Hawkins	3405	John Sevier	800
Haywood	7845	Lagoon Creek	257.6
Humphreys	3406	Johnsonville	1,485.2
Rhea	7722	Watts Bar Nuclear Plant	1,269.9
Roane	3407	Kingston	1,700
Shelby	3393	Allen Steam Plant	990
Stewart	3399	Cumberland	2,600
Sumner	3403	Gallatin	1,255.2
		Texas (111 power plants)	
Atascosa	6183	San Miguel	410
Bastrop	3601	Sim Gideon	639
Bastrop	55154	Lost Pines 1 Power Project	204
Bastrop	55168	Bastrop Energy Center	285
Bexar	3609	Leon Creek	188.7
Bexar	3611	O W Sommers	892

Appendix 1. The 1,284 thermoelectric plants one megawatt nameplate capacity or greater with water-cooling systems in the United States, 2010.—Continued

[EIA, U.S. Department of Energy, Energy Information Administration; MW, megawatt; initials associated with a power plant are part of the plant name, and not spelled out; --, nameplate capacity is not reported for the steam side of the combined-cycle power plant]

County	EIA plant code	Plant name	Nameplate capacity (MW)
Bexar	3612	V H Braunig	894
Bexar	6181	J T Deely	932
Bexar	7097	J K Spruce	1,444
Bexar	7512	Arthur Von Rosenberg	200
Bosque	55172	Bosque County Peaking	345
Brazoria	54676	Oyster Creek Unit VIII	200.9
Brazos	6243	Dansby	105
Cameron	3559	Silas Ray	27
Chambers	3460	Cedar Bayou	1,530
Chambers	55327	Baytown Energy Center LLC	275
Chambers	56806	Cedar Bayou 4	178.5
Cherokee	3504	Stryker Creek	703.4
Collin	3576	Ray Olinger	345
Dallas	3452	Lake Hubbard	927.5
Dallas	3453	Mountain Creek	852.2
Denton	4266	Spencer	126.5
Ector	55215	Odessa Ector Generating Station	448.4
Ector	56349	Quail Run Energy Center	250
El Paso	3456	Newman	405
Ellis	55091	Midlothian Energy Facility	1,734
Ellis	55223	Ennis Power Company LLC	133
Fannin	3508	Valley NG Power Company LLC	594.9
Fayette	6179	Fayette Power Project	1,690
Fort Bend	3470	W A Parish	3,992.1
Fort Bend	55357	Brazos Valley Generating Facility	275.6
Freestone	3497	Big Brown Power Company LLC	1,186.8
Freestone	55226	Freestone Power Generation LLC	369.2
Frio	3630	Pearsall	66
Galveston	52088	Texas City Cogeneration LLC	141
Goliad	6178	Coleto Creek	622.4
Gregg	3476	Knox Lee	501
Grimes	6136	Gibbons Creek	453.5
Grimes	55062	Tenaska Frontier Generation Station	390.1
Guadalupe	55137	Rio Nogales Power Project	373.2
Guadalupe	55153	Guadalupe Generating Station	403.8
Harris	3464	Greens Bayou	446.4
Harris	3468	Sam Bertron	826.2
Harris	3469	T H Wharton	226.2
Harris	10670	AES Deepwater	184
Harris	10741	Clear Lake Cogeneration Ltd	78.2

Appendix 1. The 1,284 thermoelectric plants one megawatt nameplate capacity or greater with water-cooling systems in the United States, 2010.—Continued

[EIA, U.S. Department of Energy, Energy Information Administration; MW, megawatt; initials associated with a power plant are part of the plant name, and not spelled out; --, nameplate capacity is not reported for the steam side of the combined-cycle power plant]

County	EIA plant code	Plant name	Nameplate capacity (MW)
Harris	50815	Optim Energy Altura Cogen LLC	129.2
Harris	55047	Pasadena Cogeneration	270
Harris	55187	Channelview Cogeneration Plant	149.9
Harris	55299	Channel Energy Center LLC	285
Harris	55464	Deer Park Energy Center	276
Harrison	7902	Pirkey	721
Harrison	55176	Eastman Cogeneration Facility	127.7
Harrison	55664	Harrison County Power Project	230
Hays	55144	Hays Energy Project	989
Henderson	3507	Trinidad	239.3
Hidalgo	55098	Frontera Energy Center	185
Hidalgo	55123	Magic Valley Generating Station	267
Hidalgo	55545	Hidalgo Energy Center	198.1
Hood	55139	Wolf Hollow I LP	280
Howard	52176	C R Wing Cogen Plant	75
Hunt	4195	Powerlane Plant	84.7
Johnson	54817	Johnson County	104.4
Kaufman	55480	Forney Energy Center	765
Lamar	50109	Paris Energy Center	90
Lamar	55097	Lamar Power Project	404
Lamb	3485	Plant X	434.4
Lamb	6194	Tolk	1,136
Limestone	298	Limestone	1,867.2
Llano	4937	Thomas C Ferguson	446
Lubbock	3482	Jones	496
Lubbock	3602	Ty Cooke	97.6
Lubbock	3604	J Robert Massengale	44
Marion	3478	Wilkes	882
Matagorda	6251	South Texas Project	2,708.6
Milam	6648	Sandow No 4	590.6
Montgomery	3457	Lewis Creek	542.8
Moore	3483	Moore County	49
Morris	3477	Lone Star	40
Newton	55358	Cottonwood Energy Project	624
Nueces	3441	Nueces Bay	351
Nueces	4939	Barney M Davis	703
Nueces	55206	Corpus Christi Cogeneration LLC	195.5
Orange	3459	Sabine	2,051.2
Orange	55104	Sabine Cogen	27
Orange	55120	SRW Cogen LP	145

Appendix 1. The 1,284 thermoelectric plants one megawatt nameplate capacity or greater with water-cooling systems in the United States, 2010.—Continued

[EIA, U.S. Department of Energy, Energy Information Administration; MW, megawatt; initials associated with a power plant are part of the plant name, and not spelled out; --, nameplate capacity is not reported for the steam side of the combined-cycle power plant]

County	EIA plant code	Plant name	Nameplate capacity (MW)
Palo Pinto	3628	R W Miller	366
Potter	3484	Nichols	474.7
Potter	6193	Harrington	1,080
Robertson	6180	Oak Grove	916.8
Robertson	7030	Twin Oaks Power One	349.2
Rusk	6146	Martin Lake	2,379.6
Rusk	55132	Tenaska Gateway Generating Station	390
San Patricio	55086	Gregory Power Facility	100
Somervell	6145	Comanche Peak	2,430
Tarrant	3491	Handley	1,314.8
Tarrant	55309	Air Products Port Arthur	23.5
Titus	6139	Welsh	1,674
Titus	6147	Monticello	1,980
Travis	3548	Decker Creek	726
Travis	7900	Sand Hill	190
Victoria	3443	Victoria	180
Victoria	3631	Sam Rayburn	67
Ward	3494	Permian Basin	535.5
Wharton	56350	Colorado Bend Energy Center	220.1
Wichita	50127	Signal Hill Wichita Falls Power LP	20
Wilbarger	127	Oklaunion	720
Wise	55230	Jack County	300
Wise	55320	Wise County Power LLC	262
Yoakum	55065	Mustang Station	172.6
Young	3490	Graham	634.7
		Utah (11 power plants)	
Beaver	299	Blundell	38.1
Carbon	3644	Carbon	188.6
Carbon	50951	Sunnyside Cogen Associates	58.1
Davis	55302	Wasatch Energy Systems Energy Recovery	1.6
Emery	6165	Hunter	1,472.2
Emery	8069	Huntington	996
Millard	6481	Intermountain Power Project	1,640
Salt Lake	3648	Gadsby	251.6
Uintah	7790	Bonanza	499.5
Utah	56177	Nebo Power Station	75
Utah	56237	Lake Side Power Plant	225.9
		Vermont (3 power plants)	
Caledonia	51026	Ryegate Power Station	21.5
Chittenden	589	J C McNeil	59.5
Windham	3751	Vermont Yankee	563.4

Appendix 1. The 1,284 thermoelectric plants one megawatt nameplate capacity or greater with water-cooling systems in the United States, 2010.—Continued

[EIA, U.S. Department of Energy, Energy Information Administration; MW, megawatt; initials associated with a power plant are part of the plant name, and not spelled out; --, nameplate capacity is not reported for the steam side of the combined-cycle power plant]

County	EIA plant code	Plant name	Nameplate capacity (MW)
		Virginia (25 power plants)	
Alexandria	3788	Potomac River	514
Campbell	10773	Altavista Power Station	71.1
Chesapeake	3803	Chesapeake	649.5
Chesterfield	3797	Chesterfield	1,506.5
City of Richmond	54081	Spruance Genco LLC	229.6
Fairfax	50658	Covanta Fairfax Energy	124
Fluvanna	3796	Bremo Bluff	254.2
Fluvanna	55439	Tenaska Virginia Generating Station	396.2
Giles	3776	Glen Lyn	337.5
Halifax	7213	Clover	848
Harrisonburg City	56006	Harrisonburg Power Plant	2.5
Hopewell City	10377	James River Genco LLC	114.8
Hopewell City	10771	Hopewell Power Station	71.1
King George	54304	Birchwood Power	258.3
Louisa	6168	North Anna	1,959.4
Mecklenburg	52007	Mecklenburg Power Station	139.8
Pittsylvania	52118	Multitrade of Pittsylvania LP	90
Portsmouth City	10071	Portsmouth Genco LLC	114.8
Prince George	10633	Hopewell Cogeneration	96
Prince William	3804	Possum Point	1,499.9
Richmond	50966	Bellmeade Power Station	110
Russell	3775	Clinch River	712.5
Southampton	10774	Southampton Power Station	71.1
Surry	3806	Surry	1,695
York	3809	Yorktown	1,257
		Washington (13 power plants)	
Benton	371	Columbia Generating Station	1,200
Cowlitz	55700	Mint Farm Generating Station	133
Grays Harbor	7999	Grays Harbor Energy Facility	300
Klickitat	55482	Goldendale Generating Station	114.3
Lewis	3845	Transalta Centralia Generation	1,539.8
Pierce	55818	Frederickson Power LP	126.3
Skagit	54268	March Point Cogeneration	27
Snohomish	7627	Everett Cogen	42
Spokane	50886	Wheelabrator Spokane	26
Stevens	550	Kettle Falls Generating Station	50.7
Whatcom	7870	Encogen	58.2
Whatcom	54476	Sumas Power Plant	37.7
Whatcom	54537	Tenaska Ferndale Cogeneration Station	71.8

Appendix 1. The 1,284 thermoelectric plants one megawatt nameplate capacity or greater with water-cooling systems in the United States, 2010.—Continued

[EIA, U.S. Department of Energy, Energy Information Administration; MW, megawatt; initials associated with a power plant are part of the plant name, and not spelled out; --, nameplate capacity is not reported for the steam side of the combined-cycle power plant]

County	EIA plant code	Plant name	Nameplate capacity (MW)
		West Virginia (15 power plants)	
Grant	3954	Mt Storm	1,662.4
Harrison	3944	FirstEnergy Harrison Power Station	2,052
Kanawha	3936	Kanawha River	439.2
Marion	3945	FirstEnergy Rivesville	109.7
Marion	10151	Grant Town Power Plant	95.7
Marshall	3947	Kammer	712.5
Marshall	3948	Mitchell	1,632.6
Mason	3938	Philip Sporn	1,105.5
Mason	6264	Mountaineer	1,300
Monongalia	3943	FirstEnergy Fort Martin Power Station	1,152
Monongalia	10743	Morgantown Energy Facility	68.9
Pleasants	3946	FirstEnergy Willow Island	213.2
Pleasants	6004	FirstEnergy Pleasants Power Station	1,368
Preston	3942	FirstEnergy Albright	278.2
Putnam	3935	John E Amos	2,932.6
		Wisconsin (26 power plants)	
Ashland	3982	Bay Front	67.2
Brown	4072	Pulliam	350.2
Buffalo	4140	Alma	181
Buffalo	4271	John P Madgett	387
Columbia	8023	Columbia	1,023
Dane	3992	Blount Street	177.5
Dane	7991	West Campus Cogeneration Facility	61.3
Grant	4054	Nelson Dewey	200
Grant	4146	E J Stoneman Station	53

Appendix 1. The 1,284 thermoelectric plants one megawatt nameplate capacity or greater with water-cooling systems in the United States, 2010.—Continued

[EIA, U.S. Department of Energy, Energy Information Administration; MW, megawatt; initials associated with a power plant are part of the plant name, and not spelled out; --, nameplate capacity is not reported for the steam side of the combined-cycle power plant]

County	EIA plant code	Plant name	Nameplate capacity (MW)
Jefferson	55011	LSP-Whitewater LP	106.2
Kenosha	6170	Pleasant Prairie	1,233
Kewaunee	8024	Kewaunee	560.1
La Crosse	4005	French Island	30.4
Manitowoc	4046	Point Beach Nuclear Plant	1,047.6
Manitowoc	4125	Manitowoc	127.4
Marathon	4078	Weston	1,087.1
Milwaukee	4041	South Oak Creek	1,191.6
Milwaukee	4042	Valley	272
Milwaukee	7549	Milwaukee County	11
Milwaukee	56068	Elm Road Generating Station	701.3
Outagamie	56031	Fox Energy Center	250
Ozaukee	4040	Port Washington Generating Station	538
Rock	55641	Riverside Energy Center	299.7
Sheboygan	4050	Edgewater	770
Vernon	4143	Genoa	345.6
Winnebago	4127	Menasha	28
		Wyoming (8 power plants)	
Albany	6204	Laramie River Station	1,710
Campbell	4150	Neil Simpson	21.7
Campbell	7504	Neil Simpson II	80
Campbell	56319	Wygen 2	95
Campbell	56596	Wygen III	116.2
Converse	4158	Dave Johnston	816.7
Lincoln	4162	Naughton	707.2
Sweetwater	8066	Jim Bridger	2,317.7

Appendix 2. Guide to data contained in the U.S. Department of Energy, Energy Information Administration (EIA) 2010 Annual Electric Generator Data, Form-860, and the 2010 Power Plant Operations Report, Form EIA-923, used for the classification of thermoelectric plants and consumption estimation model input.

Evaporation at thermoelectric plants depends on the method by which electricity is generated (generation type) and the method by which waste heat is transferred to the atmosphere (cooling-system type). Because generation type and cooling-system type vary independently of one another and represent two distinct stages in the overall process of thermoelectric water consumption, it is useful to consider them separately. Such consideration leads to a two-tiered classification of thermoelectric plants that provides the analytical framework for the estimation methods presented in this report.

Appendix 2, table 1 shows the data fields used in the classification scheme and consumption estimation model from the *2010 Annual Electric Generator Data* database, which is the repository for data from Form EIA-860, and the *2010 Power Plant Operations Report*, which is the repository for data from Form EIA-923. The *Description* column describes the corresponding field name in *Field Name*; *Form*, data field source, either Form EIA-860 or Form EIA-923; *File*, database spreadsheet name, see file names below; *Tab*, spreadsheet tab associated with a corresponding spreadsheet file; *Field Name*, field name descriptor. Accessed on August 7, 2013 at *http://www.eia.gov/electricity/data/eia860/index.html* and *http://www.eia.gov/electricity/data/eia923/*.

Survey Form EIA-860 collects generator-level specific information about existing and planned generators and associated environmental equipment at electric power plants with one megawatt or greater of combined nameplate capacity. Survey Form EIA-923 collects detailed electric power data—monthly and annually—on electricity generation, fuel consumption, fossil fuel stocks, and receipts at the power plant and prime mover level. Data fields shown in Appendix 2, table 1 are grouped by power plant technology type—generator, boiler, flue gas desulfurization, and cooling system—and by plant characteristics and boiler-unit associations.

Selected Form EIA-860 survey files and tabs:

- **LayoutY2010**—Provides a directory of all (published) data elements collected on the Form EIA-860 together with the related description, specific file location(s), and, where appropriate, an explanation of codes (Appendix 2, tables 1–4).
- **GeneratorY2010**—Contains generator-level data for the surveyed generators, split into three tabs. The Exist tab includes those generators that are currently operating, out of service, or on standby.
- **PlantY2010**—Contains plant-level data for the generators surveyed in all available years.
- **EnviroAssocY2010**—Contains boiler association data for the environmental equipment data collected on the Form EIA-860. The Boiler_Gen identifies which boilers are associated with each generator; the Boiler_Cool tab shows which cooling systems are associated with each boiler.
- **EnviroEquipY2010**—Contains environmental equipment data for the surveyed generators. The Boiler tab collects boiler data as collected on Schedule 6, Parts B, and C of the Form EIA-860; the Cooling tab collects cooling system data as collected on Schedule 6, Part F; the FGD tab collects FGD data as collected on Schedule 6, Part H.

Specific Form EIA-923 survey files and tabs:

- **EIA923 SCHEDULES 2_3_4_5 Final 2010**—contains monthly and annual operational data as collected on Schedules 2, 3, 4, and 5. Tab Page 1 Generation and Fuel Data contains the quantity of fuel consumed, the heat content of fuels, and the net generation of electricity data as collected on Schedules 3 and 5, parts A. Tab Page 3 Boiler Fuel Data contains the quantity of fuel consumed in the boiler and the heat, sulfur, and ash content of the fuels for steam-electric, organic-fueled electric power plants as collected on Schedule 3, Part A.
- **EIA923 SCHEDULE 3A 5A 8A 8B 8C 8D 8E 8F 2010 on NOV 30 2011**—contains monthly and annual operational data as collected on Schedules 3, 5, and 8. Tab Cooling Operations contains monthly cooling water data that includes diversion, withdrawal, discharge, and consumption rates as well as water temperature data as collected on Schedule 8, Part D. Tab FGD Operations contains annual FGD data as collected on Schedule 8, Part F.

Appendix 2, tables 2, 3, and 4 detail the codes and descriptions of the specific prime mover technologies and energy sources by generator type, and the cooling-system types contained in the files and tabs outlined in Appendix 2, table 1.

Appendix 2. Table 1. Data used in the two-tiered classification system for thermoelectric plants and heat and water budget models to estimate water consumption from the 2010 Annual Electric Generator Data, EIA Form-860 and 2010 Power Plant Operations Report, Form EIA-923.

[EIA, U.S. Department of Energy, Energy Information Administration; FERC, Federal Energy Regulatory Commission; Btu, British thermal unit; blue highlighted field name detailed in Appendix 2, tables 2, 3, and 4]

Description	Form	File	Tab	Field name
Plant descriptors				
EIA-assigned plant code	860 and 923	All files	All tabs	PLANT_CODE
Name of plant	860 and 923	All files	All tabs	PLANT_NAME
State location of plant	860 and 923	All files	All tabs	STATE
Combined heat and power system status of the generator	860	GeneratorY2010	Exist	COGENERATOR
FERC-qualifying cogenerator status of the plant	860	PlantY2010		FERC_COGEN
North American Industry Classification System (NAICS) code indicating the primary purpose of the reporting plant	860	PlantY2010		PRIMARY_PURPOSE
Plant-level sector name and number, designated by the plant's NAICS code, regulatory status and FERC-cogen status	860	PlantY2010		SECTOR_NAME and SECTOR_NUMBER
Generator technology				
Generator identification code	860	GeneratorY2010	Exist	GENERATOR_ID
Operating status of the generator	860	GeneratorY2010	Exist	STATUS
Prime mover code (turbine that converts the energy in heated gases to mechanical energy)	860	GeneratorY2010	Exist	PRIME_MOVER
The generator nameplate capacity in megawatts	860	GeneratorY2010	Exist	NAMEPLATE
Fuels used to power the generator	860	GeneratorY2010	Exist	ENERGY_SOURCE
Net generation of electricity in megawatt hours (MWh) per month and for the year. Note: This is total electrical output net of station service. In the case of combined heat and power plants, this value is intended to include internal consumption of electricity for the purposes of a production process, as well as power put on the grid.	923	EIA923 SCHEDULES 2_3_4_5 Final 2010	Page 1 Generation and Fuel Data	Electricity Net Generation
Boiler Technology				
Boiler identification code	860	EnviroEquipY2010	Boiler	BOILER_ID
Operating status of the boiler	860	EnviroEquipY2010	Boiler	BOILER_STATUS
Fuels used to power the boiler	860	EnviroEquipY2010	Boiler	PRIMARY_FUEL
Boiler efficiency when burning at 100 percent load (nearest 0.1 percent)	860	EnviroEquipY2010	Boiler	EFFICIENCY_100_PCT_LOAD
Boiler efficiency when burning at 50 percent load (nearest 0.1 percent)	860	EnviroEquipY2010	Boiler	EFFICIENCY_50_PCT_LOAD

Appendix 2. Table 1. Data used in the two-tiered classification system for thermoelectric plants and heat and water budget models to estimate water consumption from the 2010 Annual Electric Generator Data, EIA Form-860 and 2010 Power Plant Operations Report, Form EIA-923.—Continued

[EIA, U.S. Department of Energy, Energy Information Administration; FERC, Federal Energy Regulatory Commission; Btu, British thermal unit; blue highlighted field name detailed in Appendix 2, tables 2, 3, and 4]

Description	Form	File	Tab	Field name
Total consumption of the fuel, in millions of Btus, per month and for the year. Note: this is the total quantity consumed for both electricity and, in the case of combined heat and power plants, process steam production (nominal for nuclear, geothermal, and solar plants).	923	EIA923 SCHEDULES 2_3_4_5 Final 2010	Page 1 Generation and Fuel Data	Total Fuel Consumed
Consumption of fuel in millions of Btus for the purpose of generating electricity, per month and for the year. Note: These data are relevant to combined heat and power plants.	923	EIA923 SCHEDULES 2_3_4_5 Final 2010	Page 1 Generation and Fuel Data	Quantity Consumed for Electricity
Cooling system technology				
Cooling system identification code	860	EnviroEquipY2010	Cooling	COOLING_ID
Operating status of the cooling system	860	EnviroEquipY2010	Cooling	COOLING_STATUS
Cooling system code for the type of cooling system(s) at the plant (multiple codes for primary, secondary, and tertiary cooling systems)	860	EnviroEquipY2010	Cooling	COOLING_TYPE
Name of the principal source from which cooling water is directly obtained.	860	EnviroEquipY2010	Cooling	COOLING_WATER_SOURCE
Cooling water flow rate at 100 percent load at intake (cubic feet per second)	860	EnviroEquipY2010	Cooling	INTAKE_RATE_AT_100_PCT
Total surface area of cooling pond (in acres)	860	EnviroEquipY2010	Cooling	POND_SURFACE_AREA
The hours that the cooling system operated in the month.	923	SCHEDULE 3A 5A 8A 8B 8C 8D 8E 8F 2010 on NOV 30 2011	Cooling Operations	Hours in Service
Average rate of diversion, withdrawal, discharge, and consumption of cooling water per cooling unit each month (0.1 cubic feet per second)	923		Cooling Operations	Diversion Rate
	923		Cooling Operations	Withdrawal Rate
	923		Cooling Operations	Discharge Rate
	923		Cooling Operations	Consumption Rate
Method used to measure or estimate flow rates	923		Cooling Operations	Method for Flow Rates
Cooling water average and maximum temperature at cooling-water intake and discharge outlet (Fahrenheit to the nearest whole number)	923	SCHEDULE 3A 5A 8A 8B 8C 8D 8E 8F 2010 on NOV 30 2011	Cooling Operations	Intake AverageTemperature
	923		Cooling Operations	Intake Maximum Temperature
	923		Cooling Operations	Discharge Average Temperature
	923		Cooling Operations	Discharge Maximum Temperature
Method used to measure or estimate water temperatures	923		Cooling Operations	Method for Temperatures

Appendix 2. Table 1. Data used in the two-tiered classification system for thermoelectric plants and heat and water budget models to estimate water consumption from the 2010 Annual Electric Generator Data, EIA Form-860 and 2010 Power Plant Operations Report, Form EIA-923.—Continued

[EIA, U.S. Department of Energy, Energy Information Administration; FERC, Federal Energy Regulatory Commission; Btu, British thermal unit; blue highlighted field name detailed in Appendix 2, tables 2, 3, and 4]

Description	Form	File	Tab	Field name
Flue gas desulfurization (FGD) technology				
Flue gas desulfurization (FGD) unit identification code	923	SCHEDULE 3A 5A 8A 8B 8C 8D 8E 8F 2010 on NOV 30 2011	FGD Operations	FGD ID
Operating status of the FGD unit	923		FGD Operations	FGD Unit Status
FGD unit code for the type of FGD unit used	860	EnviroEquipY2010	FGD	FGD_TYPE
Type of fuel used for generation. Only certain fuels are associated with FGD systems.	923	EIA923 SCHEDULES 2_3_4_5 Final 2010	Page 3 Boiler Fuel Data	Reported Fuel Type Code
Boiler unit associations				
EIA-assigned plant code	860	EnviroAssocY2010	Boiler_Gen; and, Boiler_Cool	PLANT_CODE
Boiler identification code; this database provides tables that associate plant boiler units with their paired generator and cooling system units.	860	EnviroAssocY2010	Boiler_Gen; and, Boiler_Cool	BOILER_ID
Generator identification code	860	EnviroAssocY2010	Boiler_Gen	GENERATOR_ID
Code indicating whether the boiler and generator associations during the year were actual (A) or theoretical (T).	860	EnviroAssocY2010	Boiler_Gen	GENERATOR_ASSOCIATION
Cooling system identification code	860	EnviroAssocY2010	Boiler_Cool	COOLING_ID

Appendix 2. Table 2. Prime mover types used to classify plants according to generation type [U.S. Department of Energy, Energy Information Administration (EIA), 2010 Annual Electric Generator Report, LayoutY2010. See Appendix 2, table 1, Generator Technology, PRIME_MOVER].

[Prime mover is the turbine that converts the energy in heated gases to mechanical energy.]

EIA prime mover code	Generation type
	Prime mover description
Combustion steam, nuclear, geothermal, solar thermal	
ST	Steam turbine
Combined cycle	
CA	Combined cycle steam part
CS	Combined cycle single shaft (combustion turbine and steam turbine share a single generator.)
CT	Combined cycle combustion turbine part
Geothermal	
BT	Turbines used in a binary cycle

Appendix 2. Table 3. Energy sources used to classify plants by generation type [U.S. Department of Energy, Energy Information Administration (EIA), 2010 Annual Electric Generator Report, LayoutY2010. See Appendix 2, table 1, Generator Technology, ENERGY_SOURCE].

EIA energy source code	Generation type Energy source description
	Combustion steam
AB	Agriculture crop by-products/straw/energy crops
BFG	Blast-furnace gas
BIT	Bituminous coal
BLQ	Black liquor
DFO	Distillate fuel oil (all diesel, and no. 1, no. 2, and no. 4 fuel oils)
LFG	Landfill gas
LIG	Lignite
MSB	Municipal solid waste - biogenic
NG	Natural gas
OBS	Other biomass solids (animal manure and waste, solid by-products, and other solid biomass not specified)
OG	Other gas (coke-oven, coal processes, butane, refinery, other process)
PC	Petroleum coke
RFO	Residual fuel oil (includes no. 5, and no. 6 fuel oil, and bunker C fuel oil)
SUB	Subbituminous coal
TDF	Tires
WC	Waste/other coal (culm, gob, coke, and breeze)
WDS	Wood/wood waste solids (paper pellets, railroad ties, utility poles, wood chips, and other wood solids)
	Combined cycle
BFG	Blast-furnace gas
BIT	Bituminous coal
DFO	Distillate fuel oil (all diesel, and no. 1, no. 2, and no. 4 fuel oils)
JF	Jet fuel
KER	Kerosene
LFG	Landfill gas
NG	Natural gas
OG	Other gas (coke-oven, coal processes, butane, refinery, other process)
OTH	Other (batteries, chemicals, hydrogen, pitch, sulfur, miscellaneous technologies)
RFO	Residual fuel oil (includes no. 5, and no. 6 fuel oil, and bunker C fuel oil)
WH	Waste heat
WO	Oil—other, and waste oil (butane, liquid), crude oil, liquid by-products, propane (liquid), oil waste, re-refined motor oil, sludge oil, tar oil)
	Nuclear
NUC	Nuclear (uranium, plutonium, thorium)
	Geothermal
GEO	Geothermal
	Solar thermal
SUN	Solar (thermal)

Appendix 2. Table 4. Cooling-sytem types used to classify plants by cooling system technology [U.S. Department of Energy, Energy Information Administration (EIA), 2010 Annual Electric Generator Report, LayoutY2010. See Appendix 2, table 1, Cooling System Technology, COOLING_TYPE].

EIA cooling type code	Cooling-system type
	Cooling type description
Dry (air) cooling system	
DC	Air cooling systems
Hybrid cooling systems	
HRC	Hybrid: recirculating cooling pond(s) or canal(s) with dry cooling
HRF	Hybrid: recirculating with forced draft cooling tower(s) with dry cooling
HRI	Hybrid: recirculating with induced draft cooling tower(s) with dry cooling
Once-through cooling systems	
OC	Once through with cooling pond(s) or canal(s)
OF	Once through, freshwater
OS	Once through, saline water
Recirculating cooling systems	
RC	Recirculating with cooling pond(s) or canal(s)
RF	Recirculating with forced draft cooling tower(s)
RI	Recirculating with induced draft cooling tower(s)
RN	Recirculating with natural draft cooling tower(s)
Other cooling system	
OT	Other

Appendix 3. Databases accessed for thermoelectric plant classification and modeling data.

ECHO is the U.S. Environmental Protection Agency's Enforcement & Compliance History Online database. ECHO contains location latitude/longitude coordinates in decimal degrees for power plants with regulated water discharge data. ECHO database water data come from two data sets: the Permit Compliance System (PCS) for Clean Water Act permitted dischargers (under the National Pollutant Discharge Elimination System, or NPDES), and the Integrated Compliance Information System (ICIS) for Clean Water Act permitted dischargers (under the NPDES). Accessed January 22, 2013 at *http://www.epa-echo.gov/echo*.

eGRID is the U.S. Environmental Protection Agency's Emissions & Generation Resource Integrated Database. The eGRID database provides data on electric generation and air emissions of U.S. power plants and includes plant locations in latitude/longitude decimal degrees. Accessed January 22, 2013 at *http://www.epa.gov/cleanenergy/energy-resources/egrid/index.html#download*.

Form EIA-860 is the Department of Energy's Energy Information Administration electricity database for the Annual Electric Generator Report. The database provides generator-level information on existing and proposed generators and includes design parameter data on associated environmental equipment. Accessed January 29, 2013 at *http://www.eia.gov/electricity/data/eia860/index.html*.

Form EIA-923 is the Department of Energy's Energy Information Administration electricity database for the Power Plant Operations Report. The database provides monthly and annual operational data on electricity generation, fuel consumption, and environmental equipment. Accessed January 29, 2013 at *http://www.eia.gov/electricity/data/eia923/*.

GLSEA2 is the National Oceanic and Atmospheric Administration's Great Lakes Surface Environmental Analysis, which is a daily digitial map of lake surface temperatures and ice cover that is produced by the Great Lakes Environmental Research Laboratory. Accessed March 8, 2013, at *http://coastwatch.glerl.noaa.gov/glsea/doc/*.

HSIP Gold is the Department of Homeland Security's Homeland Security Infrastructure Program database. The HSIP provides power plant information from several databases including latitude and longitude coordinates. Accessed January 24, 2013 at *https://www.hifldwg.org/public/HSIP%20Gold%20Freedom%20One%20Pager_July%202012.pdf*.

NEEDS is the National Electric Energy Data System database, and it contains the generation unit records used to construct the "model" plants that represent existing and planned/committed units in USEPA modeling applications of the Integrated Planning Model (IPM). NEEDS includes basic geographic, operating, air emissions, and other data on these generating units. NEEDS was completely updated for Base Case v.4.10. For a description of the sources used in preparing NEEDS v.4.10, see Base Case v.4.10 Documentation, Chapter 4: Generating Resources. Accessed August 1, 2013 at *http://www.epa.gov/airmarkt/progsregs/epa-ipm/BaseCasev410.html#needs.*

NETL-CPPDB is the Department of Energy's National Energy Technology Laboratory, Coal Power Plant Database. NETL's CPPDB provides electric generation and emissions information for all coal power plants in the U.S. and includes locations in latitude/longitude decimal degrees. Accessed January 13, 2013 at *http://www.netl.doe.gov/energy-analyses/hold/technology.html*.

NHDPlus is an integrated suite of application-ready geospatial data products, incorporating many of the best features of the National Hydrography Dataset (NHD), the National Elevation Dataset (NED), and the National Watershed Boundary Dataset (WBD). NHDPlus includes a stream network based on the medium resolution NHD (1:100,000 scale), improved networking, feature naming, and "value-added attributes" (VAA). NHDPlus also includes elevation-derived catchments produced using a drainage enforcement technique. This technique involves enforcing the 1:100,000-scale NHD drainage network by modifying the NED elevations to fit with the network via trenching and using the WBD, where certified WBD is available, to enforce hydrologic divides. The resulting modified digital elevation model (DEM) was used to produce hydrologic derivatives that closely agree with the NHD and WBD. An interdisciplinary team from the U.S. Geological Survey (USGS) and the U.S. Environmental Protection Agency (USEPA) found this method to produce the best-quality agreement among the ingredient datasets among the various methods tested. Accessed January 29, 2013 at *http://www.horizon-systems.com/NHDPlus/NHDPlusV2_home.php*.

NWIS is the U.S. Geological Survey's National Water Information System database. NWIS provides surface-water and ground-water resource data collected at streamgaging stations throughout the United States. It includes current and historical daily mean surface water temperature data. Accessed March 8, 2013, at *http://waterdata.usgs.gov/nwis/sw*.

QCLCD is the National Oceanic and Atmospheric Administration National Climatic Data Center, Quality Controlled Local Climatological Data database, and it consists of hourly, daily, and monthly summaries of meteorological observations. Accessed March 8, 2013, at *http://www.ncdc.noaa.gov/land-based-station-data/quality-controlled-local-climatological-data-qclcd*. QCLCD documentation accessed March 8, 2013, at *http://cdo.ncdc.noaa.gov/qclcd/qclcddocumentation.pdf*.

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