A Comparative Study of Cooling System Parameters in U.S. Thermoelectric Power Plants

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Abstract

As the importance of water use in the power generation sector increases across the nation, the ability to obtain and analyze real power plant data is pivotal in understanding the water energy nexus. The Navajo Generating Station in Arizona and the Browns Ferry Nuclear Plant in Alabama are examples of where water shortages have threatened the operation of power generators. The availability of freshwater in the United States is beginning to dictate how and where new power plants are constructed. The purpose of this study is to provide and analyze cooling system parameters using 2008 data provided by the Energy Information Administration. Additionally, the cost of water saved among different categories of power plants is calculated. In general, the conditions which cause cooling systems to withdraw less water are not necessarily the more expensive conditions, and vice versa. While not all the variability in the cost of cooling systems is being accounted for, the results from this study prove that nameplate capacity, capacity factor, age of power plant, and region affect the costs of installed cooling systems. This study also indicates that it would be most cost effective for once-through cooling systems to be replaced with recirculating- pond instead of recirculating- tower systems. The implications of this study are that as power plant owner's struggle in balancing cost with water dependence, several parameters must first be considered in the decision-making process.

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Chapter 1. INTRODUCTION

It is no surprise that power plants like the Bethlehem Energy Center in Glenmont, New York have replaced out-dated cooling systems with advanced cooling technologies (Javetski 2006). The use of such cooling technologies reduces water withdrawal which is typically massive in thermoelectric power plants. In fact, on average, more than 500 billion liters of freshwater flow through power plants in the United States per day (IEEE 2010). As areas across the nation are experiencing the effect of drought, more attention is drawn to the volumes of water on which energy generation relies. The more the relationship between water and energy (the water energy nexus) is understood, the more likely both water resources and energy production sectors can make informed decisions in planning and management. The purpose of this study is to provide updated cooling system parameters, as well as the cost of water saved in steam and combined cycle power plants using 2008 power plant data. As power plant owners struggle with being able to afford advanced cooling technologies, the intent of this research topic is to help better understand how cost changes with water withdrawal and operating conditions in power plants.

In a *New York Times* article "Water Adds New Constraints to Power," journalist Erica Gies (2010) explains how water availability is affecting proposed power plants in California. Cost and carbon emissions are not the only obstacles to solar power development; water scarcity is becoming an issue, as well. In 2003, California adopted a policy through the Integrated Energy Policy Report on water, which discourages the use of freshwater for plant cooling. This policy will affect California's power infrastructure and sources of energy. Peter Gleick (2010), president of the Pacific Institute, explains that California can no longer provide the quantities of water required by old and water-intensive cooling systems. Not only is the solar industry in the Mojave looking at ways to reduce water use, but natural gas-fired power plants, which the commission has approved, use reclaimed water instead of freshwater (Gies 2010).

In the June 2010 issue of the *Institute of Electrical and Electronics Engineers Spectrum* magazine, a special report on "Water vs. Energy" is featured. In this report, attention is drawn to the southwest region of the United States and how the declining availability of water has affected power plants. The first case is in Imperial Valley in Southern California. This area is located just above a fault line beneath the Salton Sea, indicating tremendous potential for geothermal energy generation. While there are currently 16 geothermal plants in the area, the U.S. Department of Energy's (USDOE) National Renewable Energy Laboratory predicts that the fault could supply 2,300 MW of power. Existing geothermal power plants use miles of pipes to carry water from the Colorado River, which is also being used for hydroelectric power and agriculture on which 30 million people depend (Adee 2010).

The second case study described is the Navajo Generating Station in Arizona. The Navajo is a 2.25 GW coal-fired power plant which powers cities like Tucson and Los Angeles. This power plant uses a pumping station to bring water from the bottom of Lake Powell for cooling. During Colorado's 10-year long drought, the plant operators began to worry about the availability of this cooling water. In fact, plant operators predicted that if the drought continued to the year 2005, Lake Powell would be completely dry and the power plant would have had to shut down. Fortunately, the drought did not persist so severely in the recent years. The plant did, however, have to drill through sandstone to install a new inlet 45 meters below the original inlet to provide a factor of safety (Adee 2010).

While states like California and Arizona are struggling in allocating water for power production, eastern states are struggling with water quality and fish kill issues as well as drought. Specifically, New York State has deemed the cooling system at the Indian Point nuclear power plant to be too outdated and to kill too many fish. Now the owner, Entergy Corporation, has to spend hundreds of millions of dollars to build cooling towers or be forced to shut down. The original federal licenses for the two reactors expire in 2013 and 2015. In order to obtain a 20-year renewal, a water quality certificate is required by the U.S. Nuclear Regulatory Commission. Updating Indian Point's cooling system to wet-recirculating is expected to cost $1.1 billion and would require both reactors to be shutdown for 42 weeks. The Department of Environmental Conservation claims that the power plant's water-intake system kills nearly a billion aquatic organisms a year, including an endangered species. The pressure at the water intake causes plankton, eggs, and larvae to be drawn into the plant's machinery and also causes fish to be trapped against the intake screens (Halbfinger, 2010). The Indian Point nuclear plant is an example of how power plant cooling is affected not only by water availability, but also by water quality and environmental protection. In the summer and fall of 2007, the southeastern United States suffered from a drought in which water levels in rivers, lakes, and reservoirs decreased. The decrease in water levels caused some power plants in the region to reduce production or shut down. Specifically, the Browns Ferry nuclear facility, owned by the Tennessee Valley Authority (TVA), in Alabama shut down its second reactor for one day. In this case, the reactor shut down because it was discharging cooling water back into waterways at temperatures that did not comply with the Clean Water Act's National Pollutant Discharge Elimination Systems program limits. As a result of not being able to supply the electricity demand, TVA had to purchase power at a higher cost increasing the cost of electricity for customers (Carney 2009).

While power plants across the nation are being threatened of shutting down due to water supply issues, a power plant in Nevada has already shut down due to its air emissions, coal demand, and high water demand. The Mohave Generating Station, a 1,580 MW, coal-fired power plant, shut down on December of 2005. The plant used water not only for steam cooling purposes, but also for transporting the coal to the plant in a slurry form. The owners of the power plant were faced with a similar situation as those of the Indian Point plant in which they had to pay for air pollution abatement equipment to continue operation. The owners decided to shut down the plant instead of having to pay for such expenses which is estimated to be $1.2 billion. The shutdown of the Mohave Generating Station proves that as the regulations set by the U.S. Environmental Protection Agency (EPA) for air and water quality get stricter, power plant operations have to begin complying with such regulations to remain in operation (USEIA 2009).

The purpose of this study is to provide a summary of cooling system parameters associated with different groups of power plants using 2008 data. The first objective of this study is to categorize power plants based on energy source, prime mover, type of cooling system, source of cooling water, type of cooling towers, and operating/design conditions. The result is a group of power plants divided into specific categories based on the parameters listed above. The second objective is to calculate cooling system parameters (cost of installed cooling system in $/kW, water usage in acre-feet/year, and water usage in gallons/MWh) for each category of power plants. The values of these parameters are expected to fall within the ranges of previous studies. The third objective is to calculate the annualized cost of installed cooling systems in $/year. The annualized costs for wet-recirculating cooling systems are expected to be greater than for once-through cooling systems. The fourth objective is to determine the cost of water saved, or CWS. This value expresses how much more or less expensive a cooling system is with respect to its water requirements. This value is expected to be greater than one when comparing once-through with wet-recirculating cooling systems because cost differences are expected to be greater than water savings.

Power plant operating data are obtained using EIA data files 860 and 923. The data are manipulated so that each power plant can be categorized based on primary cooling type, prime mover, energy source, region, source of cooling water, type of cooling tower and other conditions such as thermal efficiency and capacity factor. As power plants are placed in categories, one variable is chosen and the cooling system parameters are compared with one another based on the chosen variable. Additionally, calculating the CWS provides insight on how the cost of cooling system changes relative to water withdrawal rate changes. In each comparison, the cooling systems that are expected to withdraw more water and to be cheaper are in the reference group. The cooling systems expected to withdraw less water and cost more are in the target group. The hypothesis, therefore, is that for each comparison made, the CWS is a positive number proving the allocation of reference and target groups to be correct. If both the numerator and the denominator of the CWS for each category of power plants are positive numbers, the hypothesis is accepted. If both the numerator and denominator of the cost of water saved for each category are negative numbers, the hypothesis is rejected.

Previous research in water use in power plants is extensive and includes studies that analyze the determinants in water use (Yang 2007) as well as the future projections of water consumption (Elcock 2010). The studies that calculate the CWS, however, are Maulbetsch (2006) and EPRI (2004.) Both studies include the calculations of cooling system costs, operating costs, revenue, and the CWS. The differences in methodologies among different studies in calculating the CWS reveal values of different orders of magnitude.

This work is divided by chapter, two of which are complete manuscripts for submission. Chapter 2 is a literature review written for the American Society of Civil Engineer's *Journal of Energy Engineering* in which previous studies conducted in this subject matter are summarized. Chapter 3 is a manuscript written for the submission to *Journal of American Water Resources Association*. This includes introduction, methods, results and discussion, and conclusions sections. Chapter 4 contains the conclusions and recommendations for future researchers. The Appendix includes information so that this study may be repeated with the provided information. Appendix A provides an explanation of the parameters extracted from the EIA datafiles along with table number, column number, and units of each collected parameter. Appendix B provides the code for the MySQL queries performed in extracting and combining EIA data. Appendix C is a finalized list of the power plant names (in alphabetical order), corresponding utility names, and corresponding EIA-provided plant codes. Appendix D contains example calculations for two power plants so that the reader may follow the steps taken in obtaining the results used for analyses. Finally, Appendix E provides a list of power plants included in the additional dry cooling systems study.

Chapter 2. WATER USE IN U.S. THERMOELECTRIC POWER PLANTS: A LITERATURE REVIEW

Abstract

The importance of water use in thermoelectric power plants is growing across the nation. Power plants in New York and California are forced to deal with their cooling systems that pose threats to ecosystems and water availability. The purpose of this paper is to summarize, compare, and contrast previous studies in this subject matter using journal articles and government/laboratory reports. The scope of this review includes power generation in the U.S., water use in power plants, power plant cooling technologies, comparisons of cooling technologies, impact of drought on power generation, and projections of power generation and water use. While estimates of cooling system parameters are made in previous studies, few methodologies incorporate real power plant data to compare the cost of cooling technologies among different types of power plants. Furthermore, the cost of water saved for specific types of power plants that are representative of those in the nation would be beneficial in the decision-making process in both power generation and water resources sectors. Finally, an important topic in which more research should be conducted is the comparison of dry and hybrid cooling systems.

CE Database subject headings

Water management; Water use; Cooling water; Cooling towers; Energy sources; Power plants.

Introduction

On average, more than 500 billion liters of freshwater flow through power plants in the United States per day. The massive quantities of water required for the operation of power plants have been and will continue to be a major factor in water management and power plant implementation decisions. Several cases across the nation point to the increasing importance of water use in power plants. For example, in Arizona, the decreasing levels of Lake Powell almost threatened the operation of the Navajo Generating Station in 2005 (The Institute 2010). Furthermore, in California, the use of fresh surface water for power plant cooling is discouraged. Water is now dictating which sources of energy may or may not be employed in certain regions (Gies 2010). In the East, New York State has ruled that the cooling system at the Indian Point nuclear power plant is outdated and kills too many Hudson River fish. The plant owner, Entergy Corporation, must spend billions of dollars to build cooling towers or shut down the power plant (Halbfinger 2010). Additionally, in the summer and fall of 2007, the southeastern United States suffered from a serious drought in which water levels in rivers, lakes, and reservoirs decreased. The decrease in water levels caused some power plants in the region to reduce production or shut down. Specifically, the Browns Ferry nuclear facility, owned by the Tennessee Valley Authority (TVA), in Alabama had to shut down its second reactor for one day. As a result, TVA had to purchase power at higher costs which lead to increased costs of electricity for customers (Kimmel 2009).

The primary purpose of this paper is to provide background information regarding water use in power generation facilities and to summarize, compare, and contrast results of previous studies in this subject matter. Additionally, the areas which lack information and research are identified. The first objective is to summarize, compare, and contrast data for water withdrawal and consumption in thermoelectric power plants. Since water has been used for cooling in power plants for more than 70 years, it is expected that there are ample data in this subject matter. The second objective is to summarize cost comparisons between different types of power plants with different types of cooling systems. It is expected that cost data may not be as prevalent as water use data. However, due to the increasing importance of cooling systems and water conservation, it is expected to become a more popular research topic. The third objective is to summarize water demand and energy demand projections, as well as compare the results of different studies. Since the Energy Information Administration (EIA) provides annual energy demand projections, it is expected that there are a number of available studies that use EIA data to make water demand projections in the power generation sector. Because this research topic covers a wide range of disciplines, this review is divided by subject matter: power generation in the U.S., water use in thermoelectric power plants, thermoelectric power plant cooling technologies, comparisons of cooling technologies, impact of drought on power generation, and projections of power generation and water use. Within each heading, journal articles and government/laboratory reports are used to provide background information, as well as summaries of relative studies.

Power Generation in the U.S.

When generating electricity, turbines or engines convert the energy source to mechanical energy; these are prime movers. The most common types of turbines include steam turbines, internal-combustion engines, gas combustion turbines, and wind turbines. As turbines convert energy into mechanical energy, generators convert mechanical energy into electrical energy. Most of the power plants in the United States use steam turbines powered by fossil fuels and nuclear energy sources. In the case of steam turbines, fuel is burned in a boiler to produce heat and to convert water into steam. The steam is used to drive a steam turbine which, in turn, drives a generator. Other energy sources that use steam turbines are geothermal and solar (USEIA 2010b).

All sources of energy can be categorized as either nonrenewable or renewable. Nonrenewable sources are those that are not readily replenished and include petroleum, natural gas, coal, and uranium. Examples of renewable sources of energy are biomass, water, geothermal, wind, and solar. Additionally, some energy sources can be grouped as fossil fuels. These are sources that were formed millions of years ago from the decay of organic material in plants and animals. Fossil fuels include petroleum, natural gas, and coal—not uranium (USEIA 2010b). According to the EIA, 45% of the nation's generated energy in 2009 came from coal, 23% from natural gas, 20% from nuclear, and 7% from hydroelectric sources. Sixty-eight percent of the total energy generated in 2009 came from fossil fuels (USEIA 2010c).

According to the EIA, there are approximately 5,400 power plants in the United States. Each of which may have one or more generators or units. Power plants may be grouped based on the processes used in generating power. Thermoelectric power plants are those which are driven by temperature change. In steam thermoelectric plants, the steam powers a steam turbine which sends its mechanical energy to a generator. Coal, natural gas, oil, and nuclear power plants are all thermoelectric power plants while geothermal and solar energy may be thermoelectric depending on the type of generation. Examples of non-thermoelectric power generation are hydro and wind power. About 88%, a significant fraction of the total energy generated in 2009, came from thermoelectric power plants. In addition to the typical steam-driven power plants, combined cycle power plants are also prevalent (USEIA 2010c).

Combined cycle systems use gas combustion turbines as well as steam turbines to produce electricity. A combustion turbine drives a generator. The waste heat from combustion is used to produce steam, which drives the steam turbine. Combined cycle power plants are generally more efficient than conventional steam power plants because the excess heat is used to produce more electricity instead of being released as waste. Combined cycle power plants are most commonly natural gas-fired and are known as natural gas combined cycle (NGCC) power plants (EPRI 2002). Another type of combined cycle power plant is integrated gasification combined cycle (IGCC). It is similar to a natural gas combined cycle system in that heat from the gas turbine is used to produce steam and drive a second steam turbine. However, IGCC differs from NGCC in that the gas used in the combustion turbine is syngas, not natural gas. Syngas is synthesis gas produced by gasifying a carbon-based source—coal is most commonly used in IGCC systems. The coal is placed in a gasifier in which it becomes a gas that can be combusted in a combustion turbine (Power 2010). In both combined cycle systems, roughly 2/3 of the energy produced is derived from the combustion turbines while 1/3 is derived from steam turbines (EPRI 2002).

Thermoelectric power plants can also be categorized based on steam temperature and pressure conditions. The terms subcritical, supercritical, and ultra-supercritical help describe these conditions which also dictate thermal efficiency. Higher temperature and pressure conditions typically mean increased thermal efficiencies. Most power plants built prior to the fifties are subcritical meaning the steam pressures are less than 22 MPa and temperatures are typically 455 ºC; these are 35 – 37% efficient. Supercritical plants, introduced in the sixties, operate at pressures greater than 22.1 MPa and between 538 – 565 ºC and are about 46% efficient. Ultra-supercritical plants operate at even higher temperatures greater than 656 ºC. The development of ultra-supercritical conditions in power plants is becoming a topic that is widely studied as the need for efficient and cheap energy and the concern of carbon emissions increases (Viswanathan 2005).

Water Use in Thermoelectric Power Plants

Non-Cooling Water Uses

Before studying how thermoelectric power generation uses water, it is important to understand the differences between water use, water withdrawal, and water consumption. The term "water use" is broad and simply refers to the influence of humans on water, whether it be water withdrawal, delivery, consumption, discharge, and so on (Dziegielewski 2006). Water withdrawal, on the other hand, is the physical act of diverting water from its source to where it is being used; it is a parameter that can be measured. Water consumption is losing water to evaporation, transpiration, consumption by humans and livestock, or to the production of products and crops. It is the difference between the volume of water withdrawn and volume of water discharged (Yang 2007).

While the focus of this study is on water withdrawal and consumption in thermoelectric fossil-fuel power plants, it is important to note that water is used in all forms of power generation. Hydroelectric turbines rely on the constant flow of water to produce electricity, biofuels require water for irrigation, and renewable sources such as solar and geothermal rely on water for production similarly to fossil fuels. Additionally, water is used in resource extraction, refinement, and processing, as well as in the power generation, transmission, and distribution stages. The scope of this review only includes water used in the power generation stage.

Water is used for at least four general purposes in the power generation sector: drinking water supplies, general cleaning, transfer, and disposal of certain wastes, space and equipment cooling, and energy production processes. Water use in energy generation depends on the form of energy being produced and the size of the power plant. For example, fossil and nuclear generation plants use water for all the purposes listed above while hydroelectric plants do not. Other examples of water uses that are specific to the fuel include stack-gas scrubbing at some coal-fired plants, gas-turbine inlet cooling, and nitrogen oxide control at some combined cycle plants (EPRI 2004). According to a survey implemented by the Southern Illinois University research team in 2006, the largest water uses in fossil fuel power plants aside from cooling are processing and washing of cooling systems, irrigation for wet-recirculating pond systems, and scrubber dilution water and ash control for wet-recirculating cooling tower systems (Dziegielewski 2006). Other processes that demand substantial amount of water include flue gas desulfurization (FGD,) boiler feedwater make-up, and gasification process make-up water. Figure 2-1 illustrates the percentages of how much water these processes demand compared to cooling water taken from the U.S. Department of Energy (USDOE/NETL 2009b).

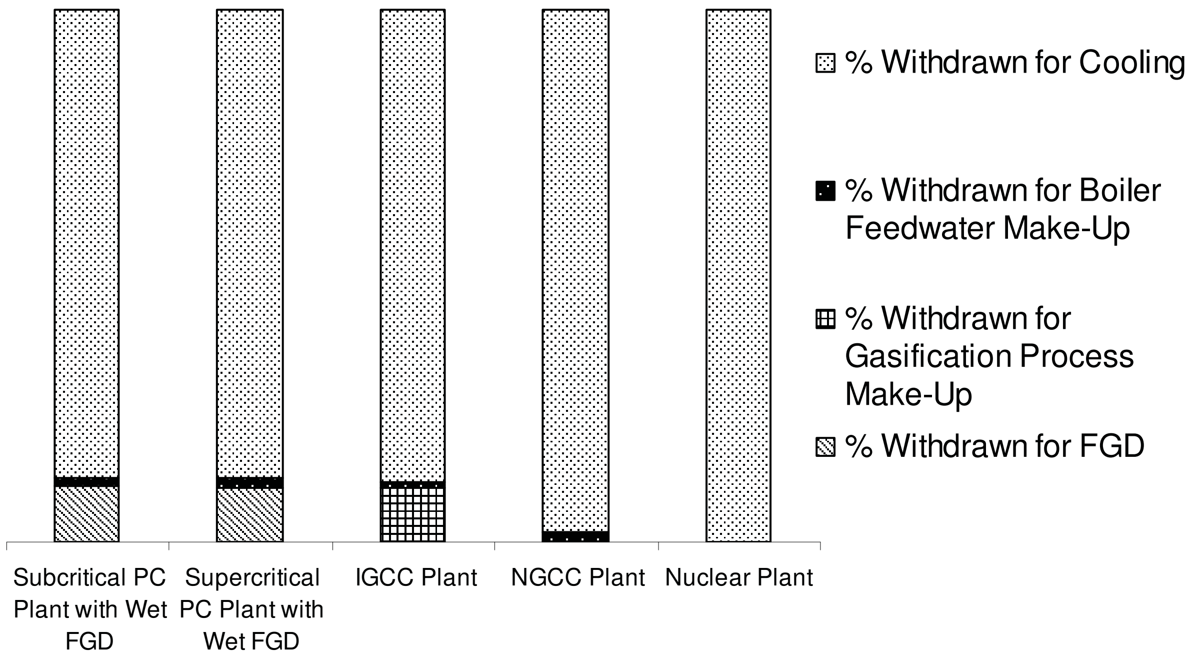

Figure 2-1. Water Use in Power Plants with Wet-recirculating Cooling Systems (USDOE/NETL 2009b)

The results indicate that cooling water makes up about 93% of total plant withdrawals as an average of all plant types. While cooling is the primary use of water in thermoelectric power plants, it is not the only one—other uses depend on the type of power plant and energy source used. (USDOE/NETL 2009b).

Cooling Water Uses

In the steam turbine segment of a thermoelectric power plant, water is used in two ways. First, water turns into steam to drive the steam turbine and produce electricity; this is known as boiler water and is recycled in a closed loop. Secondly, water is withdrawn from a cooling water source and condenses the steam back into liquid so that the water may be re-used; this is cooling water. Cooling water is typically used so that the heat from the steam is transferred to the cooling water which is then released to the environment. Figure 2-2, taken from USGAO (2009), illustrates this process (USGAO 2009).

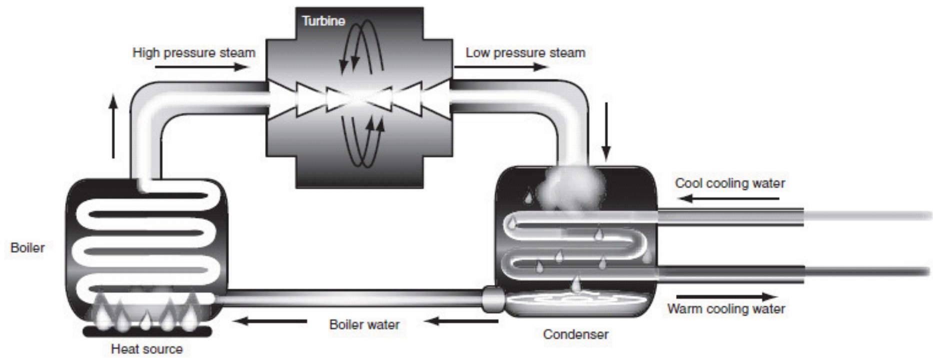

Figure 2-2. Boiler Water and Cooling Water Loops in Power Plants (USGAO 2009)

The operation and efficiency of thermoelectric power plants do not only depend on large quantities of freshwater, but also on the temperature of the influent cooling water—high temperatures of the inlet water decreases the power generation efficiency (USDOE/NETL 2009a). In addition to temperature, the amount of water a power plant withdraws is dependent on the type of power plant. For example, since only one process is thermoelectric in a natural gas combined cycle system, it uses less water for cooling than non-combined cycle plants (USGAO 2009). Since nuclear power plants operate at relatively low steam temperatures and pressures, a larger amount of steam is required to produce the same amount of electricity when compared to other plants operating at higher steam conditions (Kreis 2009). Less electricity is produced per unit of circulating steam thereby increasing the amount of water required to cool the steam on a volume per MWh basis (EPRI 2002).

Yang and Dziegielewski (2007) study the parameters that affect water use per kilowatt-hour in thermoelectric power plants. These parameters are grouped into four categories: cooling system types, fuel types, operation conditions, and water sources. In order to determine if a specific parameter has a large impact on water withdrawals, regression models are made for each of the three major types of cooling systems: once-through, wet-recirculating with cooling ponds or canals, and wet-recirculating with cooling towers. The results for a once-through cooling system indicate that operational conditions, water sources, and fuel types all have effects on the rate of water withdrawal. The operational efficiency is found to be negatively correlated with water use so that as more generation capacity is being utilized in a power plant, the less water per kWh is being withdrawn. Another determinant is the change in temperature in the cooling water. Less cooling water is required when a greater rise in temperature takes place. Thermal efficiency is another operational condition that is inversely related to water withdrawal. A high thermal efficiency indicates that more of the fuel source is being converted into electricity, thus producing less residual heat and requiring less water to produce the same amount of electricity. Other factors that are found to increase unit water withdrawals (while other factors remained the same) include older cooling system ages, use of nuclear fission, use of mixed fuels, and use of saline water. The results for a wet-recirculating system with cooling ponds or canals indicate that the average summer air temperature is the only factor with a positive coefficient, indicating a proportional relationship with water withdrawal. Similarly to the other two models, operational and thermal efficiency inversely affect unit water withdrawal in wet-recirculating cooling tower systems. Additionally, the study found that power plants with the types of cooling systems that use coal or natural gas use less water than plants of other fuels. Furthermore, using water from public supply or fresh groundwater sources result in less unit water withdrawals than plants that use other sources. Average summer temperature and cooling system age both proportionally affect unit water withdrawals. It is found that the parameters in each of the four categories account for 13% of the variability in water consumption. Therefore, these categories do not account for all the variability in power plant cooling systems (Yang 2007).

One of the environmental impacts of thermoelectric water use is the thermal pollution caused when plants discharge warmer water than was withdrawn. The Clean Water Act requires standards for the temperature of the effluent water, as well as for cooling water intake structures under § 316. It is required that plant utilities implement the best available technology in the design and construction of water intake structures. The EPA requires that all intake structure reduce the "impingement mortality of water organisms by 80 to 95 percent and in some cases must reduce the intake of small aquatic life by 60 to 90 percent" (Dziegielewski 2006). This can be achieved by decreasing the velocity of the influent water by decreasing withdrawal rates (Dziegielewski 2006). The different types of cooling technologies discussed in the following sections are the different ways in which steam can be condensed and reused in thermoelectric power plants. This review describes four different types of cooling systems: once-through, wet-recirculating, dry, and hybrid cooling systems.

Thermoelectric Power Plant Cooling Technologies

Two of the most common types of cooling systems are once-through (open loop) and wet-recirculating (closed loop). Most power plants built prior to 1970 implement once-through cooling systems in which water is withdrawn from a water source, used to condense the steam, and is then discharged back to the source. Figure 2-3 illustrates a once-through cooling system.

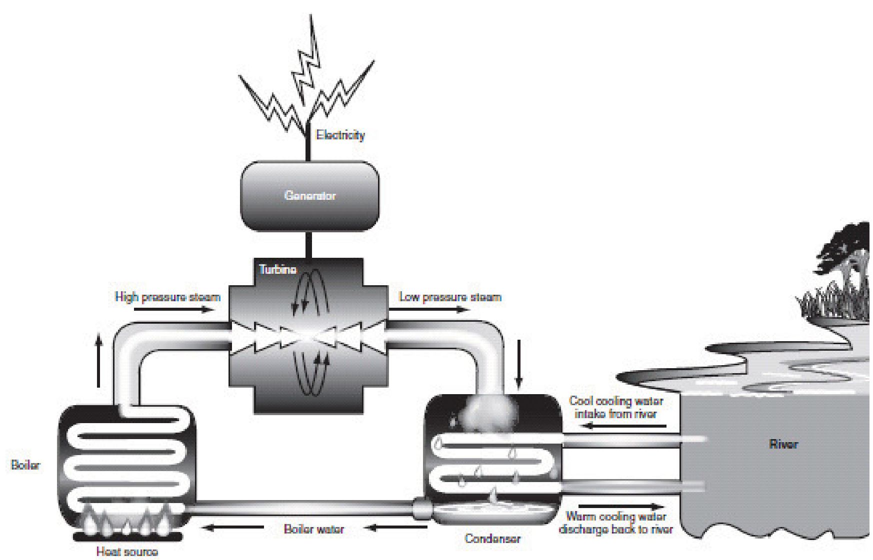

Figure 2-3. Once-Through Cooling System (USGAO 2009)

Although much of the water withdrawn from surface waters for once-through cooling is discharged, the higher temperatures of the effluent increase evaporation of water downstream. Therefore, water is indirectly consumed in the once-through cooling process. The intake screens as well as the increase in temperature in the water negatively affect the aquatic life and are major concerns in once-through cooling systems today. According to the USDOE 2009 report, about 31% of total energy generated in the U.S. came from thermoelectric plants that used open-loop cooling systems in 2006. Additionally, 42.7% of the generating capacity in the U.S. uses once-through cooling systems. However, these systems are rarely implemented in power plants being planned or built today due to the difficulty of permitting, analysis, and reporting requirements (USDOE/NETL 2009a).

A wet-recirculating cooling system is unlike the once-through system in that it reuses the cooling water. While these systems may use either cooling towers or cooling ponds, the most common recirculating systems have cooling towers to reduce the temperature of the cooling water. The warm water is pumped up to a cooling tower which provides air and evaporation to cool down. While some of the water is evaporated, most of the water is reused to condense the steam. As the cooling water evaporates after each loop, the water becomes more and more concentrated with minerals and dissolved suspended solids. A portion of the water, called blowdown liquid, is discharged and replaced with clean water. Figure 2-4 illustrates a wet-recirculating cooling system.

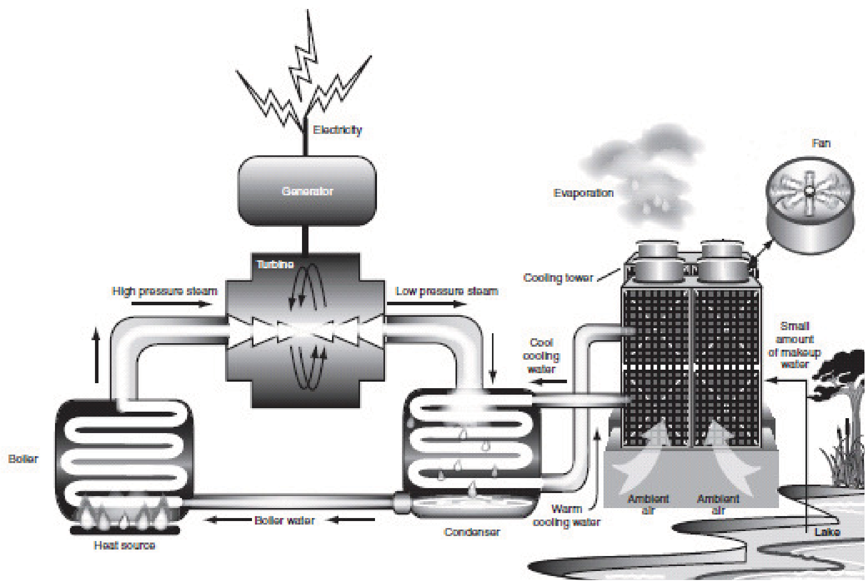

Figure 2-4. Wet-recirculating Cooling System with Cooling Tower (USGAO 2009)

An important term to know and understand when discussing recirculating cooling systems is "cycles of concentration." This is the number of times cooling water can be reused before its quality degrades so as to cause operational problems in a wet-recirculating cooling tower system. This parameter is calculated for each constituent by dividing its maximum allowable concentration by its concentration in the cooling water. The lowest cycle of concentration of all the constituents dictate how often make-up water should be added to replace the degraded cooling water. The cycle of concentration is therefore the ratio of constituent in the recirculating water to that in the makeup water. The higher the cycle of concentration, the less volumes of blowdown and makeup water is required and vice versa (Veil 2007).

Wet-recirculating towers have two basic designs: mechanical draft and natural draft. Natural draft towers use the difference in air density between the warm air in the tower and the cooler air outside the tower to move the air up through the tower either in a cross-flow or counter-flow pattern (Thomas 2005). Mechanical draft towers, on the other hand, use a fan to move ambient air through the tower either in cross-flow or counter-flow patterns. Cross- and counter- flow patterns indicate that the ambient air is flowing across, or counter to, the direction of the water flow, respectively. Mechanical draft towers may be induced or forced draft in which the primary difference is where and how the fan is used. In induced draft towers, the warm cooling water is sprayed onto baffles in the cooling tower to maximize the contact time between water and air. Fans are used to pull the warm air out of the tower to reduce the chances of recirculation. In forced draft cooling towers, the fans are located at the bottom of the towers and are used to pull cool air in. Since there is no fan pulling the hot air out, forced draft towers are more susceptible to recirculation issues (USDOE 1993). Natural draft towers typically have higher capital costs than mechanical draft towers and are usually less favorable to smaller plants for that reason (EPRI 2004).

Another example of a wet-recirculating system is one that uses a pond instead of cooling towers. As opposed to once-through cooling systems, recirculating systems withdraw less water but consume more water via evaporation and drift. About 41.9% of the generating capacity in the U.S. implements cooling towers while 14.5% uses cooling ponds. The wet-recirculating system withdraws less than 5% of the water than a once-through system. However, most of the water is lost to evaporation instead of being returned to the water source. Because of increasing regulations on discharge water quality for once-through cooling systems, it is estimated that most power plants currently planned or being built today will use wet-recirculating cooling systems. This will result in lower water withdrawals, but increased water consumption.

Dry and hybrid cooling systems are considered to be advanced cooling technologies and use significantly less amounts of water. In a dry cooling system, water is not used for cooling. Instead, fans blow air over the tubes carrying the cooling water to decrease its temperature. Dry cooling systems can either be direct or indirect air-cooled steam condensers. In direct air-cooled systems, the steam flows through air condenser tubes and is directly cooled by air that is blown across the outside surface of the tubes using fans. Direct dry cooling simply implements an air-cooled condenser (ACC) and may have natural or mechanical draft towers to move the air through the condenser. Figure 2-5 illustrates a direct dry cooling system.

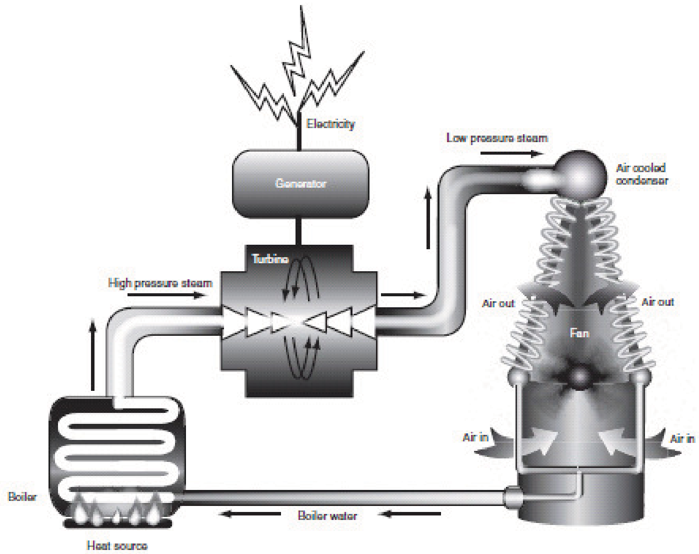

Figure 2-5. Direct Dry Cooling System (USGAO 2009)

In an indirect air-cooled system, the steam is condensed using the conventional condensers containing cooling water. The cooling water is recirculated and cooled using an air-cooled heat exchanger. A dry cooling system will generally reduce overall plant water withdrawal by 75% - 95% depending on the type of power plant (EPRI 2004). Only 0.9% of the generating capacity in the U.S. implemented dry cooling systems in 2009 (USDOE/NETL 2009a). One drawback of using dry cooling systems is that it may result in less electricity production in two ways. Firstly, energy is consumed to run the fans and pumps. Secondly, the dry cooling system performance highly depends on ambient conditions (EPRI 2004 “comparison”). Additionally, the effect that a cooling system has on power plant performance is typically correlated with increased backpressures. As long as the backpressure is maintained at or below the design value, the power plant will perform better or at design output. However, dry cooling systems operate at backpressures higher than the design value, therefore decreasing output.

In the Electric Power Research Institute’s (EPRI) 2004 report, it is stated that a 500 MW combined cycle plant located in a hot and dry location can reduce output by 2% per year when compared to wet cooling systems. During the 1,000 hottest hours of the year, a dry system can reduce electrical output by 8-25% (EPRI 2004). The first power plant to implement a dry cooling system in the United States was installed in 1968 at the Light Neil Simpson 1 station in Wyoming. The second was at the 330 MW-Wyodak plant installed in 1977. However, it was not until 1990 where the use of dry cooling systems became more prevalent. This growth initially occurred in the Northeast primarily for plume abatement before it traveled to the Southwest. According to the EPRI, the majority of the large dry cooling power plants are gas-fired combined cycle units (EPRI 2004).

A hybrid cooling system simply uses both water and air to condense the steam into liquid water. Figure 2-6 illustrates how this may work.

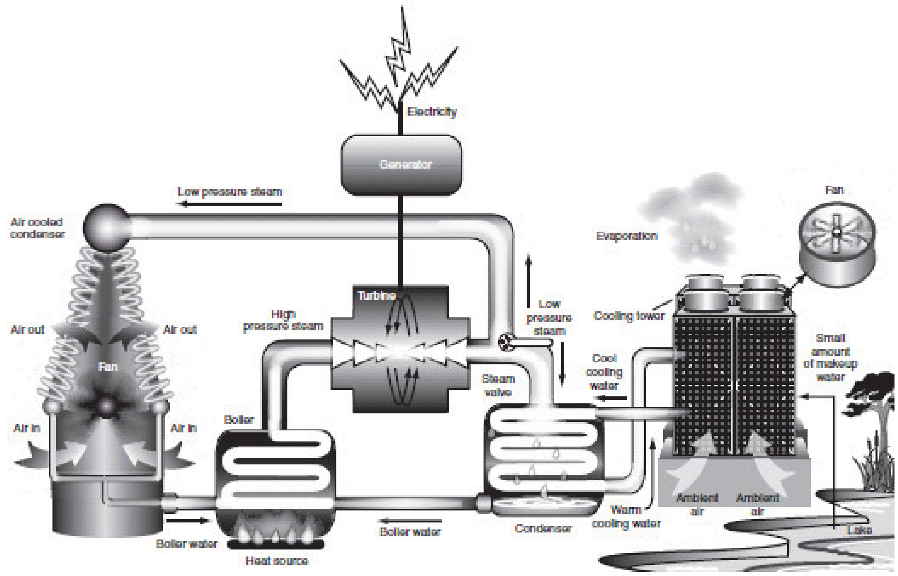

Figure 2-6. Hybrid Cooling System (USGAO 2009)

These systems may be designed for either of two specific purposes, water use reduction or plume abatement. The water reduction systems rely heavily upon dry cooling systems and incorporate wet recirculation for hot periods where dry systems may not be sufficient. These systems use about 20-80% of the water used in wet cooling systems but still achieve higher efficiency and capacity advantages during the peak loads in hot weather than dry cooling systems. In plume abatement systems, on the other hand, the primary cooling system is wet while a dry system is used for a small fraction during cold periods when plumes are likely to be visible (Maulbetsch 2006). Water reduction hybrid systems also reduce plume formation because it is not likely that wet cooling systems will be used during the colder months when plume visibility is an issue. While hybrid systems are currently rare, they are increasing in popularity despite the higher capital costs associated with them.

U.S. Water Withdrawals

In 2005 (the year for which the most recent water use data are available), the U.S. geological survey (USGS) found thermoelectric utilities to be the largest category of water use followed by irrigation. Figure 2-7 illustrates the total water, freshwater, and saline water withdrawals using USGS 2005 data.

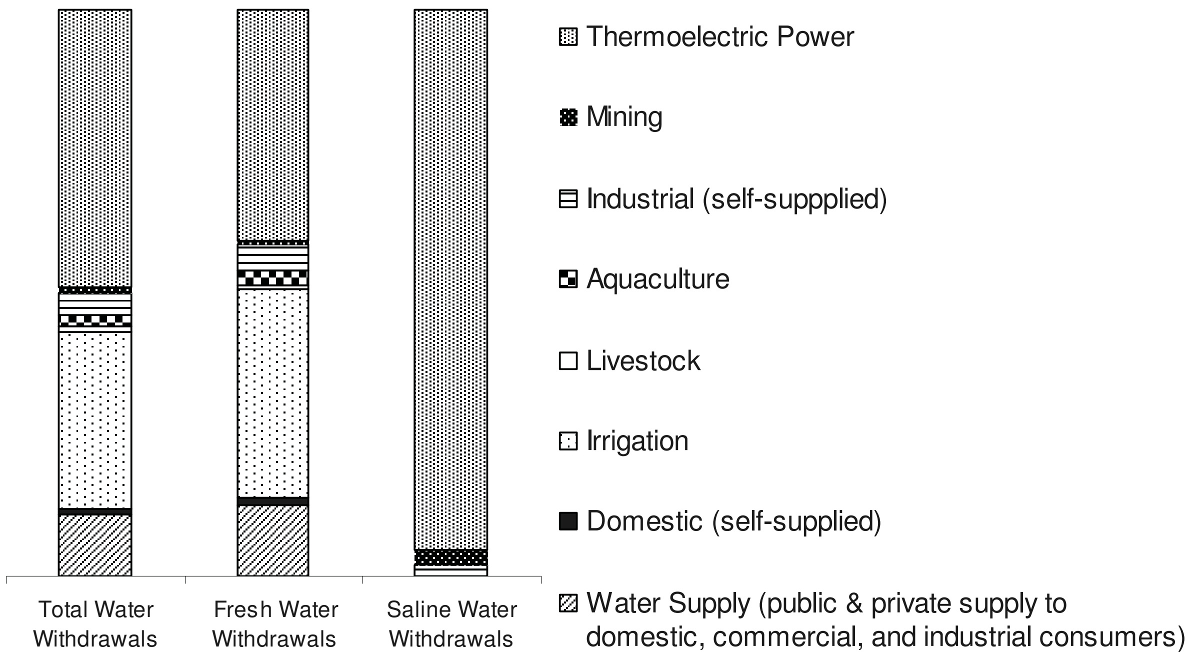

Figure 2-7. Total, Fresh, and Saline Water Withdrawals Distributions in 2005 (Kenny 2009)

While the water that is used for cooling may be withdrawn from any source and may either be fresh or saline, fresh surface water is the most widely used source of water. About 29% of the water used in thermoelectric power plants is withdrawn from oceans or brackish waters (Kenny 2009).

The USGS releases a study every 5 years called the Estimated Water Use in the United States. The most recent one is for the year 2005 and it includes the trends in water use from the year 1950 to 2005. According to the study, total withdrawals peaked in 2000 and 2005. Furthermore, the increase in total water use between 1950 and 1980 was due to the large amounts of water withdrawn for irrigation and thermoelectric power generation. The largest increase in total withdrawals from the years 1950 to 2005 occurred before 1980. Since 1965, thermoelectric power accounts for the largest amount of water withdrawals. The trends in thermoelectric power plant water withdrawal is sensitive to certain parameters such as water scarcity and regulations set forth by the Clean Water Act which is based on the Federal Water Pollution Control Amendments of 1972. This act regulates the water quality and temperature of the discharges as well as the use of best available technology to minimize environmental effects at the intakes. This explains the decrease in once-through cooling construction and increase in recirculating cooling systems during the 1970's. Figure 2-8 illustrates this trend.

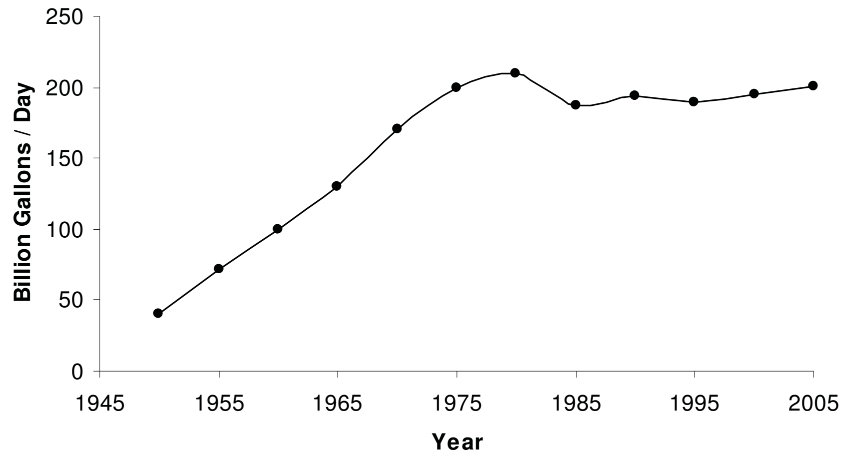

Figure 2-8. Change in Total Thermoelectric Water Withdrawals over Time (Kenny 2009)

The increase in thermoelectric total water withdrawals occurred from the years 1950 to 1980 after which it declined. This decline in 1980 can be explained by the increasing popularity in wet-recirculating cooling systems. Additionally, the recent increase in total water withdrawals can be explained by analyzing the net power generated and calculating total water withdrawals in volume / kWh. This value actually decreased from 238 L/kWh (63 gal/kWh) in 1950 to 87 L/kWh (23 gal/kWh) in 2005 indicating less water withdrawal per kWh over time (Kenny 2009).

Comparisons of Cooling Technologies

Water Use Comparisons

As previously stated, the energy source, or type of power plant, is a significant factor in determining how much water a power plant withdraws. Another factor is the type of cooling system being implemented. Table 2-1 is a collection of data from different studies of varying years.

Table 2-1. Water Use in Gallons/MWh for Varying Plant Types and Cooling Systems

Source	Data Year	Plant Type	Once-through Water Use in Gallons/MWH		Wet-recirculating with Cooling Tower Water Use in Gallons/MWh	
			Withdrawal	Consumption	Withdrawal	Consumption
USDOE 2006	1999, 2002, 2005, 2006	Fossil Fuel	20,000-50,000	300	300-600	300-480
		Coal IGCC	NA	NA	250	200
		Natural Gas CC	7,500-20,000	100	230	180
		Nuclear	25,000-60,000	400	500-1,100	400-720
EPRI 2002	2002	Fossil Fuel	20,000-50,000	300	500-600	480
		Nuclear	25,000-60,000	400	800-1,100	720
		Natural Gas/Oil CC	7,500-20,000	100	230	180
Dziegielewski 2006	1996 - 2004	Fossil Fuel	44,000	200	1000	700
		Nuclear	48,000	400	2600	800
Kenny 2009	2005	Fossil Fuel and Nuclear	50,000 - 65,000	NA	1,000 - 2,000	NA
Torcellini 2003	2003	Thermoelectric	NA	470	NA	470
Yang 2007	2007	Thermoelectric	>39,000	100	<1,320	528-793

Table 2-1 contains a summary of water use data for different types of energy sources and for different cooling systems. Data for dry cooling systems are not included in the table because the results of each study are either 0 for water withdrawal and consumption or are not available. The lower ends of the flow rates for fossil and nuclear power plants implementing the once-through cooling system correspond to a higher temperature differential. Accordingly, the higher end of water use per MWh corresponds to a lower temperature differential. For the wet-recirculating systems, on the other hand, the lower end of withdrawal flow rate corresponds to a high cycle of concentration. As can be seen in Table 2-1, the method that requires the most water to be withdrawn is the once-through cooling system for nuclear power. A wet-recirculating cooling tower system thermoelectric steam, however, consumes the most water per MWh of electricity. The value of 470 gallons / MWh (1,780 L/MWh) from Torcellini (2003) represents the water lost to evaporation in both once-through and wet-recirculating cooling systems.

Cost Comparisons

While water withdrawal and consumption among different cooling systems may be compared on a volume per MWh basis, the cost of cooling system can be represented by several different parameters such as capital cost in millions of dollars and cost per capacity in $/kW. Another parameter being calculated by both EPRI (2004) and Maulbetsch (2006) is the cost of water saved in $/volume. The tables presented in this section summarize all three parameters from three different studies. According to the DOE, wet-recirculating cooling systems are about 40% more expensive than once-through systems. Additionally, dry cooling systems are 3-4 times more expensive than wet-recirculating systems indicating that cost is a major deterrent in the installation of dry cooling systems (USDOE/NETL 2009b). The EPRI (2004) report summarizes the costs as well as the effects of implementing different cooling technologies on plant performance. The results are useful because they may be used as decision-making tools for electric utilities in comparing cooling systems in terms of performance, economic, and environmental tradeoffs. The major components of cooling systems are those that are used in the most common cooling system in the U.S. today and are: surface steam condensers, mechanical draft wet cooling towers, cooling ponds, air-cooled condensers, and water treatment equipment. For each component, the authors determine the budget price for different design conditions such as steam flow and cold water inlet temperature while specifying or assuming other conditions such as ambient wet bulb temperature, site elevation, and quality of water influent. The EPRI report also presents the different elements that make up water system costs and provide a range of water costs that can be used in comparative cost analyses.

Water system costs are divided into four categories: acquisitions costs, delivery costs, in-plant treatment costs, and discharged/disposal costs. There are two ways for power plants to acquire water, either through direct purchase or rights purchase. Power plants that use cooling water a raw surface water source, treated effluent from a wastewater treatment plant, or treated effluent from a water treatment plant are examples of direct purchases. Water rights purchases, on the other hand, occur more so in the West when the rights holder is entitled to use a specific volume of water per year. While direct purchase rights are usually in $/1,000 gallons, purchase rights are expressed in $/acre-foot. Delivery costs include the capital and operating costs for transferring the water from its source to the power plant. Capital costs include the installation of a pipeline and pumping equipment while operating costs are primarily the power costs to continually pump the water to the power plant. Power plants that use wet-recirculating cooling systems may require the treatment of water before it may be used as cooling water depending on the source of water. Suspended and dissolved solids must be kept below a certain level and the pH must be controlled as well as the concentrations of some constituents, such as ammonia.

There are four main options for the disposal of cooling water after it has been used. The first is to discharge it to surface waters under a National Pollutant Discharge Elimination System (NPDES) permit. The second is to send that water back to the wastewater treatment plant if reclaimed water was used. The third is to inject the water into groundwater reservoirs (this is not very common). Finally, the fourth is to implement a zero liquid discharge constraint using internal recycle and reuse systems. These options may require additional treatment to control the water chemistry before it can be discharged or re-used (EPRI 2004).

The EPRI report presents a method for determining the cost of water saved by comparing a wet and dry cooling system at 5 different sites: El Paso, TX, Jacksonville, FL, Bismarck, ND, Portland, OR, and Pittsburgh, PA. At each site, both a 500 MW gas-fired combined cycle power plant and a 350 MW coal-fired power plant are designed to illustrate how fuel type, capacity, and meteorological conditions may impact plant performance (EPRI 2004).

First, a dry cooling air-cooled condenser (ACC) is designed for a particular site and the initial capital cost, annualized capital cost, annual cost of the power to run the fans, cost of lost output, maintenance costs, and total annual cost of the ACC cooling system is determined. The costs correlate to different ACC sizes based in inlet temperature differences and are then summarized for each of the five sites. Next, the same analysis is done for a recirculating wet cooling tower. Finally, using the data collected in the previous chapters, the comparative costs of optimized wet and dry systems are calculated for a 500 MW combined cycle power plant. The term optimized indicates that the sum of all costs, including initial capital costs, operating and maintenance costs, plant heat rate and capacity penalties, are minimized for the life of the plant. The same analysis is repeated for a 350 MW coal-fired power plant. The results provide capital costs of the cooling systems in millions of dollars, water savings between wet and dry cooling in acre-foot/year, and cost of water saved in \$/acre-foot. The results also show that the cost of water does have an impact on the overall cost to implement wet-recirculating cooling systems. For the analyses above, a base cost of \$0.26/m^3 (\$1.00/1000 gallons) is used because it is found to be a typical average cost for industrial water. However, the authors decided to use high water costs of \$0.53/m^3 (\$2.00/1000 gallons) and \$1.06/m^3 (\$4.00/1000 gallons) to illustrate how the cost of water may impact the dry to wet cost ratios. As the water cost increases, the annual dry to wet cooling system cost ratios decrease. At a cost of \$1.06/m^3 (\$4.00/1000 gallons), the use of a dry cooling system is actually economically favored. This also suggests that the water cost at which dry and wet cooling systems break even is between \$0.53 and \$0.79/m^3 (\$2 and \$3/1000 gallons) averaged across five sites (EPRI 2004).

Maulbetsch (2006) conducted a more recent study similar to that of the EPRI. While the parameters determined in both Maulbetsch and EPRI are the same, the methodologies are different. Maulbetsch determines the optimal power plant cooling options in terms of water savings, capital and operating costs, and operational efficiency solely for gas-fired combined cycle power plants in California. Wet-recirculating cooling with a mechanical draft cooling tower is compared with a dry cooling system which uses a mechanical, forced-draft air-cooled condenser. A design for a 500 MW gas-fired combined cycle power plant with two combustion turbines and one steam turbine is used in this study; these characteristics represent typical power plants in California. Of the four different power plants selected, a variety of water sources are used which include fresh, brackish, saline, and reclaimed. The methodology for comparing water consumption, plant performance, and system cost between wet and dry cooling systems is divided into four sections: comparable plant designs, annual performance, cost elements, and water use. Under the comparable plant designs section, a plant design is made for each of the four sites. One design represents a wet cooling system while the second represents a dry cooling system. The total evaluated cost is described as the sum of the annualized capital cost and the several continuing costs of fuel, operating cost, and lost potential revenue. Water use for each site is determined, as are the calculations for water savings that could be achieved if a dry cooling were to be implemented.

The results of both these studies are summarized in Table 2-2.

Table 2-2. Summarized Cost Data for Varying Cooling Systems

Source	Capacity and Type of Plant	Type of Cooling System	Capital Cost of Cooling System in Millions of $	Water Savings Between Wet and Dry Cooling in acre-feet / year	Cost of Water Saved in $ / Acre-foot
EPRI 2004	500 MW gas-fired combined cycle	Wet-recirculating, mechanical draft cooling tower	$5.7 - $6.5	2,800	1,100 - 1,400
		Dry	$21 - $26		
	350 MW steam	Wet-recirculating, mechanical draft cooling tower	$12.9 - $14.8	6,400	
		Dry	$43 - $47		
Maulbetsch 2006	500 MW gas-fired combined cycle	Wet-recirculating, mechanical draft cooling tower	Increase of $8 to $27	2,000 – 2,500	1,100 - 1,900
		Dry			

The capital costs for a dry cooling system depend on the climate of the particular site where the cooling system is being implemented. The more hot and arid the climate, the greater the capital cost for the dry cooling system in comparison to the wet-recirculating system. Additionally, implementing a dry cooling system on a power plant reduces its overall capacity by 8-25%. Maulbetsch found that the associated costs in implementing dry cooling systems include: an increased capital cost of 5-15% of the total plant cost, 1-2% of energy reduction per year, 4-6% of capacity reduction per year, and annual revenue reduction of 1-2% of total revenue. These additional costs that arise from the use of a dry cooling system can be expressed as the effective cost of water. This is the additional cost of using a dry cooling system in order to reduce water use and consumption. Also, the cost of water saved is found to be much higher when compared to typical industrial and residential uses (Maulbetsch 2006). Table 2-3 summarizes capital cost per capacity in $/kW taken from both Maulbetsch (2006) and DOE/NETL (2009b).

Table 2-3. Cooling System Capital Cost and Plant Capital Cost per Capacity for Varying Cooling Systems

Source	Year	Capacity and Type of Plant	Type of Cooling System	Capital Cost per Capacity in $/kW
USDOE/NETL 2009b	2005	Fossil/Biomass-Fueled Steam	Once-through	19
			Recirculating Cooling Tower	28
			Recirculating Cooling pond	27
			Other Including Dry	182
Maulbetsch 2006	2006	500 MW gas-fired combined cycle	Wet-recirculating, mechanical draft cooling tower	440
			Dry	482

The values obtained from Maulbetsch are much greater than those of the USEDOE/NETL because Maulbetsch calculates total plant capital costs while the USDOE/NETL calculates cooling system capital costs. Therefore, these values are incomparable.

The Impact of Drought

While there are three papers that discuss the impact of drought on power generation, they each differ in methodology. The National Energy Technology Laboratory (NETL) conducted two studies which explore the effects of drought on power production. The first is a study that focuses on the Western United States and discusses the impacts of water level decrease on power generation, future electricity prices, and carbon dioxide emissions (Poch 2009). Using resources such as the EIA-860, EIA-423, EIA-906, and FERC Form 714, inventory of existing and proposed power plants, historical load data, load projections, fuel price projections, and expansion candidate technology data are used to produce models. Two scenarios are compared with one another, the baseline scenario and the drought scenario. To construct the baseline scenario, data from 2006 is used to project electricity demand in 2015 and 2020. The drought scenario, on the other hand, uses compiled data from the U.S. Drought Monitor to simulate realistic drought conditions. Table 2-4 summarizes the expected increases and decreases in quantity of electricity generated within each fuel.

Table 2-4. Percent Change in Quantity of Electricity Generated in TWh from Base Scenario to Drought Scenario (Poch 2009)

Fuel	2010	2015	2020
Nuclear	0	0	0
Coal	-8	-7	-4
Natural Gas	31	30	43
Fuel Oil/Other	1	3	10
Renewable	0	0	0
Hydro	-29	-29	-29
ENS	347	109	117

Poch (2009) finds that new coal plants will be less affected by drought because of advanced cooling technologies. To compensate for the drop in electricity generation from coal and hydropower, natural gas plants face significant increases by 30.8% in 2010, 29.3% in 2015, and 43.5% in 2020. As more plants shutdown during drought conditions, natural gas plants will replace all of the generation that was lost. This is because originally, natural gas plants are not operating at maximum capacity factors, proving they have excess capacity to produce more electricity. Nuclear power plants, on the other hand, are unable to provide more electricity because they are already operating at their maximum capacity factors (as is the case with renewable sources) and also because no new nuclear power plants came online during the study period.

As droughts occur and more coal-fired plants shut down, power generation will become more dependent on natural gas as a source of energy. Also, systems that rely heavily on coal-fired plants may be beneficial in the long run because more advanced cooling technologies will be implemented within the next 10-15 years, decreasing the reliability of power generation on water. The term, ENS, is the amount of energy not served which is the amount of energy demanded by customers that the system's energy sources are unable to provide. Therefore, this ENS must be provided from another system. The energy not served more than doubles in 2015 and 2020; there is 99.9% chance that if ENS occurs, it would occur in either July or August where electricity demands are at their peaks. As the amount of electricity generated changes over time, so does the cost to produce electricity. The operating costs of natural gas power plants can be more than three times more than that of coal-fired power plants. Therefore, as natural gas generation increases, total electricity production costs increase and so will the price of natural gas. Production costs and ENS costs decrease in the long term because, as previously mentioned, coal-fired power plants will start replacing natural gas plants with more efficient water-use technology and less expensive operating costs. The authors state that they have found, using surveys, that the cost of ENS can sometimes exceed $2,000/MWh. The results from this analysis indicate not only how dependent power generation is on water, but it also provides a model that predicts how power generation will change as the United States faces more drought conditions (Poch 2009).

In addition to Poch (2009), the NETL conducts a study on how power plants may be affected by drought by considering three factors: the distance of cooling water inlet to shore, the depth of power plant intakes, and Federal/State drought programs. The scope of the NETL study includes power plants nation-wide. The database includes 422 thermoelectric power plants across 44 states that utilize fresh surface water as cooling water. Both 2005 and 2000 data from the EIA are used for fossil fuel and nuclear power plants, respectively. The data indicate that there is no change in inlet distance from the shoreline as a function of fuel type or water body type. In fact, this distance ranges from 0 ft to greater than 1 mile, with more than half of the power plants in the database having intakes greater than 50 ft from the shore. The distance from the shore is not as strong of a determining factor as intake depth is. In terms of intake depth from the surface, a large number of power plants reported 10 ft as their intake depth. This distribution is skewed with more power plants having shallow intake depths. Specifically, 65% of the power plants included in this study have intake depths at 15 ft or less, while 43% have intake depths of 10 ft or less. This suggests that during drought conditions, a large number of power plants may be at risk of shutting down due to shallow intake depths.

Kimmel also incorporates the legal issues and agreements that affect water availability to determine how the government would allocate water in drought conditions. It is found that federal, state, and local government agencies all play a role in prioritizing water users in such conditions—although the federal government plays little or no role in responding to drought when compared to state agencies. Some examples of rules that will be implemented during a drought response plan include: mandatory use restrictions, ground and surface water allocation by the DEQ, withdrawal restrictions on any withdrawer for surface or ground water. It is also found that in the past, power plants have had to shutdown during drought conditions mostly because of the high temperatures of both cooling water and receiving water (Kimmel 2009).

A third study conducted by the EPRI includes the analyses of where water shortages and increases in energy demand will take place in the U.S. This is done using a model that evaluates the impacts of water droughts on electric power generation and provides management approaches that may minimize these impacts. The approach involves two composite indices, a Water Supply Sustainability Index and a Thermoelectric Cooling Constraint Index. The former index indicates regions in the country where water sustainability will be a top priority, while the latter indicates the regions where constraints on cooling water withdrawals for power generation are expected to be significant. The Water Supply Sustainability Index, expressed in scores from 0-5, evaluates water supply constraints based on conditions such as available precipitation, groundwater availability, and projected water use. Counties that meet certain conditions may be considered somewhat susceptible, moderately susceptible, or highly susceptible to water supply constraints depending on the number of conditions met. Not only is the southwestern region (California, Nevada, Arizona, New Mexico) highly susceptible to water supply limitations, other regions such as Washington, Idaho, Texas, Alabama, Georgia, Louisiana, and Florida are as well.

The Thermoelectric Cooling Water Supply Limitation Index uses the Water Supply Sustainability Index and the percentage increase in electricity generation in 2025. An area is moderately constrained if it is considered somewhat susceptible and is expected to experience an increase greater than 50% in power generation in 2025. An area is highly constrained if it moderately susceptible and is expected to experience an increase greater than 50% in power generation in 2025. The states that were found to experience shortages in cooling water supply include all of the states by the Pacific Cost: Arizona, Utah, Texas, Louisiana, Georgia, Alabama, and Florida. The results indicate that not only the arid and semi-arid West and Southwest parts of the country are vulnerable to water shortages, but regions across the nation will face water scarcity problems as well. It is also found that in the future, thermoelectric power plants will have to evaluate the trade-offs of using less water intensive technology, especially in areas facing water shortages (Roy 2003).

Projections

Energy Demand, Electricity Generation, and Required Capacity

The EIA provides the *Annual Energy Outlook* each year which includes projections of energy supply, demand, and prices through the year 2035. These projections are based on the laws and regulations in effect on October 2009 and not those that are pending or being proposed. Just as any other projection, the EIA provides different scenarios and assumptions for each projection. The reference case is a business-as-usual scenario using the current technological and demographical trends. It is assumed, in the reference case, that these laws and regulations will not be changed throughout the years being projected. Three parameters that are important to look at are energy demand, electricity generation, and required capacity. The projected values for these parameters are summarized in Table 2-5.

Table 2-5. Energy Demand, Electricity Generation, and Required Capacity Projections (USEIA 2010a)

	Energy Demand	**Electricity Generation**	**Required Capacity**
Scenario	Reference Case	Reference Case	Reference Case
Expected Trend	Decrease	Increase	Increase
Beginning Value	310 million Btu per person	3873 billion kilowatt-hours	0 GW
Year of Beginning Value	2009	2008	2009
Ending Value	293 million Btu per person	5021 billion kilowatt-hours	250 GW
Year of Ending Value	2035	2035	2035

The EIA bases energy demand on population growth. In 2009, energy use per capita decreased during the start of the economic recession. The value of 310 million Btu per person was the lowest value since 1968. Energy use per capita is expected to slightly increase as the economy recovers. However, as population increases, total electricity generation is expected to increase by 3 % from 2008 to 2035 with an average of 1% per year. The commercial sector accounts for almost half of the increase (42%). Residential demand increased by 24% due to population growth while total industrial demand increased by 3% as a result of increased efficiency and slowed growth in industrial production. Of the 250 GW of required capacity from the years 2009 to 2035, 46% of the added capacity is expected to be in natural gas-fired power plants, 37% in renewable sources of energy, 12% in coal-fired power plants, and 3% in nuclear.

The EIA projects that the current Federal tax incentives, State energy programs, and increasing prices for fossil fuels will be incentives for renewable and nuclear energy growth while decreasing the competitiveness of coal. Additionally, the primary cause of the increase in natural gas-fired power plants is the growth in production of shale gas. There have been recent discoveries of shale gas offshore. However, uncertainties such as new regulations, fuel prices, and economic growth are among the factors that affect capacity additions and fuel sources (USEIA 2010a).

Water Use

Using available studies on projected energy demand and required capacity, the estimation of future water withdrawals and consumption may be made. This is done in four relative studies: EPRI (2002), USDOE (2009a), Elcock (2010), and Roy (2003). While the first two estimate water use in thermoelectric power plants, the third estimates future water consumption in energy generation, and the fourth estimates total water freshwater withdrawals in the year 2025.

According to the EIA's projection that about 46% of the planned added capacity in 2035 will comprise of natural gas, the EPRI predicts that freshwater use in the power industry will decrease. This is due to the fact that only one-third of the power produced in natural gas-fired combined cycle power plants relies on the steam cycle. Therefore, combined cycle systems use less water per MWh of electricity generated when compared to 100 % steam cycle systems. According to the EPRI, however, it is difficult to project the trend of water use in power plants because it depends on several factors such as which source of energy will dominate and how restrictive the environmental regulations may become. It is determined, in the EPRI (2002) technical report, that if more natural gas replaces coal and nuclear energy sources, water consumption for power generation will decrease. Additionally, if environmental regulations continue to become more and more stringent, water consumption through evaporation will increase due to replacing once-through systems with wet-recirculating systems (EPRI 2002). Another study that provides more detailed projections is the NETL's "Estimating Freshwater Needs to Meet Future Thermoelectric Generation Requirements." In the EPRI report, data from the *Annual Energy Outlook 2009* is used to summarize projections in thermoelectric capacity and generation up to the year 2030. Using energy generation and capacity predictions as well as estimated water use data from the EIA-767 database, the NETL is able to make freshwater consumption and withdrawal projections. Future freshwater withdrawal and consumption in the U.S. thermoelectric generation sector is estimated for five different cases. Table 2-6 summarizes each case as well the expected freshwater withdrawal for thermoelectric power generation in billion gallons per day.

Table 2-6. Total Annual Freshwater Withdrawal in Continental U.S. for Thermoelectric Power Generation (USDOE/NETL 2009a)

Projected Year	Case Description	Withdrawal in Billion Gallons per day
2010	Case 1: Additions and retirements proportional to current trends.	149.2
2015		145.1
2020		147.4
2025		147.6
2030		146.8
2010	Case 2: All additions use freshwater and wet-recirculating cooling, while retirements are proportional to current trends.	146.4
2015		140.5
2020		141.1
2025		141.3
2030		139.9
2010	Case 3: 90% of additions use freshwater wet-recirculating cooling, 10% of additions use saline water once-through cooling, retirements are proportional to current trends.	146.4
2015		140.5
2020		141.1
2025		141.2
2030		139.8
2010	Case 4: 25% of additions use dry cooling, 75% of additions use freshwater and wet-recirculating cooling, retirements are proportional to current trends.	146.2
2015		140.2
2020		140.7
2025		140.9
2030		139.4
2010	Case 5: Additions use freshwater wet-recirculating cooling, while retirements are proportional to current trends, 5% of existing freshwater once-through cooling capacity retrofitted with wet-recirculating cooling every 5 years starting in 2010.	140.5
2015		128.6
2020		123.9
2025		119.1
2030		113.0

For cases 2-5, water withdrawal is expected to decline, while for all five cases, consumption is expected to increase. This is consistent with the idea that power generation and industrial sectors are moving more towards recirculating cooling systems that withdraw less water but consume more water than the once-through system. Case 5 is found to be the most extreme in terms of water consumption impacts with a 28.7% increase in freshwater consumption in 2025 from 2005. The results from Case 4 indicate that dry cooling systems will provide the most percentage decline in freshwater withdrawal and one of the least percentages increase in water consumption (USDOE/NETL 2009a).

Elcock (2009) projects water consumption in the energy generation sector using EIA, as well as the U.S. Forest Service (USFS) data. Unlike USDOE/NETL (2009 a) and EPRI (2002,) it incorporates all forms of energy generation instead of only thermoelectric uses and water consumption instead of withdrawal. Elcock projects nearly a 7% increase from 2005 to 2030 in total U.S. water consumption. More than half of this increase is attributed to the energy production sector which includes oil refining, conventional gas production, coal mining, the production of fuels from coals and oil shale, and irrigation for biofuels. Irrigation for biofuels is expected to increase by almost 70% proving it to be the main reason for the increase in the energy production sector. Thermoelectric power generation is in a separate sector and is projected to increase from 6.1 billion gallons per day (BGD) to 8.2 BGD. By the end of the projection period in year 2030, thermoelectric water consumption is ranked fourth after the irrigation, energy production, and domestic and public sectors (Elcock 2009).

While it is important to know how much water thermoelectric power plants will withdraw and consume water in the future, it is just as important to test how changes in power generation may affect overall future water withdrawals. The EPRI report, "A Survey of Water Use and Sustainability in the United States with a Focus on Power Generation" contains the projection of total water demand, as opposed to thermoelectric water demand, in 2025 under different scenarios. Prior to this 2003 study, overall water demand in the U.S. had not been predicted accurately in the past. Moreover, while water demand in the past was thought to be strongly correlated with population growth, it has, more recently, been found that this is not the case. Using USGS survey data from 1955 to 1995, a decline in freshwater withdrawals occurred in 1990 during a 10% population increase. Instead of solely focusing on population growth, this study assumes that potential increases in water requirements are controlled by changing demand due to population and electricity production increases. The authors then describe two different approaches in this prediction that may be applied depending on the type of water use and the region. The first is called the "business as usual scenario" in which it is assumed that rates of water use remain at current levels even as total population or total electricity generation increases. The second method assumes that the rates of water use also incorporate trends of increasing efficiency; this is called the "improved efficiency scenario." Using both scenarios, as well as several other references for data such as the Water Resources Council and the USGS, the authors predict total annual freshwater withdrawal in the U.S. in 2025. Table 2-7 summarizes the water use projections compared to the studies of Guldin and Brown (which are provided in the same paper).

Table 2-7. Total Annual Freshwater Withdrawal in Continental U.S. (Roy 2003) Used Under the Fair Use Guidelines

Source	Year	Projected Year	Scenario	Total annual freshwater withdrawal in Continental US in Billion Gallons per day
EPRI	2003	2025	Business As Usual	451
			Improved Efficiency	330
Guldin	1989	2020	N/A	461
		2030	N/A	495
Brown	1999	2020	For middle range of population growth	349
		2030		356

The proper scenario is chosen based on the type of water used and the region. The business as usual scenario is used in areas where it is thought that the improvements in efficiency have reached a maximum and that a reduction in water use is impossible. The improved efficiency scenario, on the other hand, is used in areas where certain sectors may decrease rates of water use (Roy 2003).

Summary and Conclusions

The years in which water withdrawal and consumption data have been collected range from 1996 to 2007 with Yang (2007) being the most recent. All sources provide numbers in agreeable ranges for withdrawal and consumption in both once-through and wet-recirculating systems. Additionally, all sources agree that combined cycle, fossil fuel, and nuclear power plants withdraw water in increasing order and that wet-recirculating systems consume more water per MWh than once-through systems. The results of the first objective indicate that while water usage data for once-through and wet-recirculating cooling systems have been developed, dry and hybrid cooling system information is more difficult to obtain. Especially in the case of hybrid systems, it is beneficial to know how much less water is withdrawn or consumed as compared to conventional systems.

While the water savings and the CWS are calculated by the CEC and EPRI for 500 MW combined cycle systems and 350 MW coal systems, there are no additional reports that include the calculations of these parameters for other types of power plants. The CWS for specific types of power plants that are representative of those in the nation would be beneficial in making decisions with regards to power plant cooling systems. This is a specific area where further research is required to provide better decision-making tools. Additionally, the normalized capital cost of cooling systems provided by DOE/NETL (2009b) use actual 2005 power plant data. As expected, data regarding cost of cooling systems are not as accessible as water use data. The results of the second objective show that there are two relevant studies that determine the differences in costs of cooling systems with respect to water savings.

With respect with the third objective, while developing projections are difficult due to several uncertainties, there are, surprisingly, a number of studies available which project energy production and water use in the U.S. Thanks to the EIA's *Annual Energy Outlook*, which is updated yearly, energy supply, demand, electricity prices, and required capacity projections are available and have been used in several studies for water use projections. As energy demand per capita decreases due to increased efficiencies, total energy generated will require an additional capacity of 250 GW. Almost half of this capacity is projected to be provided by natural gas and renewable energy sources. In fact, in both Poch (2009) and USEIA (2010a,) natural gas power production is expected to increase significantly in drought conditions and in the future. While severe drought would be devastating to all sectors that rely on water, it would certainly pave the way for the development of advanced cooling technologies. This explains why coal-fired energy production may increase in 2035 due to the implementations of advanced cooling technologies. Projections for total U.S. water consumption, total U.S. freshwater withdrawals, and thermoelectric water withdrawals and consumption are also available to 2035. Results indicate that moving towards biofuels as a renewable source of energy may decrease dependence on fossil fuels, but will increase dependence on water, as well as dramatically increase water consumption. Furthermore, as more wet-recirculating systems replace once-through systems, water withdrawal will decrease as water consumption will increase by 2025. While the different studies shed light on different aspects of energy production and water use, they all indicate that the future of water availability heavily depends on the choices made regarding energy sources and cooling systems.

While there are adequate studies that provide utilities with decision-making tools in terms of cooling systems, there is a lack of information for power plants that have actually retrofitted their cooling system to ones that use less water. A review of such cases would help utilities understand the process as well as the financial and operational costs associated with retrofitting cooling systems. Additionally, more research should provide parameters that can be compared between dry and hybrid cooling systems. Examples of useful parameters are differences in cost, volumes of water saved, and costs of water saved between dry and hybrid cooling systems. For some power plants, the implementation of a hybrid system may be more appealing than a dry cooling system depending on the regional conditions. Therefore, adequate information—using recent power plant data—on hybrid cooling systems would prove useful.

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Chapter 3. A COMPARATIVE STUDY OF COOLING SYSTEM PARAMETERS IN U.S. THERMOELECTRIC POWER PLANTS

Abstract

As the importance of water use in the power generation sector increases across the nation, the ability to obtain and analyze power plant data becomes pivotal in understanding the water energy nexus. The availability of freshwater in the United States is beginning to dictate how and where new power plants are constructed. The purpose of this study is to provide and analyze cooling system parameters using 2008 data provided by the Energy Information Administration. Water use and costs of cooling systems are analyzed to provide a sense of how these parameters are related. Additionally, the cost of water saved among different categories is calculated. In general, the conditions which cause cooling systems to withdraw less water are not necessarily the more expensive conditions, and vice versa. While not all the variability in the cost of cooling systems is being accounted for, the results from this study prove that nameplate capacity, capacity factor, age of power plant, and region affect the costs of installed cooling systems. This study also indicates that it would be most cost effective for once-through cooling systems to be replaced with recirculating- pond instead of recirculating- tower systems. The implications of this study are that as power plant owners struggle in balancing cost with water dependence, several parameters must first be considered in the decision-making process.

Key Terms

Cooling systems; drought; power plants; once-through; wet-recirculating; MySQL; water conservation; planning

Introduction

On average, more than 500 billion liters of freshwater flow through power plants in the United States per day. The increasing importance of water scarcity with respect to power plants is a topic that cannot be avoided. Power plants across the nation are facing issues with their cooling systems that pose threats to ecosystems and water availability (IEEE, 2010). In a *New York Times* article "Water Adds New Constraints to Power," journalist Erica Gies (2010) explains how water availability is affecting proposed power plants in California. Awareness for water use in energy generation is growing across the state. In 2003, California adopted a policy through the Integrated Energy Policy Report on water, which discourages the use of freshwater for plant cooling. This policy will affect California's power infrastructure and sources of energy. Peter Gleick (2010), president of the Pacific Institute, explains that California can no longer support old and water-intensive cooling systems. He states that the best alternatives in terms of water use are wind and solar photovoltaic sources of energy. Not only is the solar industry in the Mojave looking at ways to reduce water use, but natural gas-fired power plants, which the commission has approved, use reclaimed water instead of freshwater (Gies, 2010).

In a June 2010 issue of the *Institute of Electrical and Electronics Engineers Spectrum* magazine, a special report on "Water vs. Energy" is featured. In this report, attention is drawn to the southwest region of the United States and how the declining availability of water has affected the construction of power plants. The first case is in Imperial Valley in Southern California. This area is located above a fault line beneath the Salton Sea, indicating tremendous potential for geothermal energy generation. While there are currently 16 geothermal plants in the area, the United States Department of Energy's (USDOE) National Renewable Energy Laboratory predicts that the fault could supply 2,300 MW of power. The existing geothermal plants use miles of pipes to carry water from the Colorado River, which is also being used for hydroelectric power, and agriculture on which 30 million people depend (Adee, 2010).

The second case study described is the Navajo Generating Station in Arizona. The Navajo is a 2.25 GW coal-fired power plant which powers cities such as Tucson and Los Angeles. This power plant uses a pumping station to bring water from the bottom of Lake Powell for cooling. During Colorado's 10-year long drought, the plant operators began to worry about the availability of this cooling water. In fact, plant operators predicted that if the drought continued to the year 2005, Lake Powell would be completely dry and the power plant would have shut down. Fortunately, the drought did not persist so severely in the recent years. The plant did, however, have to drill through sandstone to install a new inlet 45 meters below the original inlet to provide a factor of safety (Adee, 2010).

While states like California and Arizona are struggling in allocating water for power production, eastern states like New York are struggling with water quality and fish kill issues as well as drought. Specifically, New York State has ruled that the cooling system at the Indian Point nuclear power plant is too outdated and kills too many fish. Now the owner, Entergy Corporation, must spend billions of dollars to build cooling towers or shut down the power plant. The original federal licenses for the two reactors expire in 2013 and 2015. In order to obtain a 20-year renewal, a water quality certificate is required by the U.S. Nuclear Regulatory Commission. Updating Indian Point's cooling system to a wet-recirculating one is expected to cost $1.1 billion and would require both reactors to be shutdown for 42 weeks. The Department of Environmental Conservation claims that the power plant's water-intake system kills nearly a billion aquatic organisms a year, including an endangered species. The pressure at the water intake causes plankton, eggs, and larvae to be drawn into the plant's machinery and also causes fish to be trapped against the intake screens (Halbfinger, 2010). The Indian Point nuclear plant is an example of how power plant cooling is affected not only by water availability, but also by water quality and environmental protection. In the summer and fall of 2007, the southeastern United States suffered from a serious drought in which water levels in rivers, lakes, and reservoirs decreased. The decrease in water levels caused some power plants in the region to reduce production or shut down. Specifically, the Browns Ferry nuclear facility, owned by the Tennessee Valley Authority (TVA), in Alabama shut down its second reactor for one day. In this case, the reactor shut down because it was discharging cooling water back into waterways at temperatures that did not comply with the Clean Water Act National Pollutant Discharge Elimination Systems program limits. As a result of not being able to supply the electricity demand, TVA had to purchase power at a higher cost increasing the cost of electricity for customers (Carney, 2009).

According to the USDOE, about 92% of the water withdrawn in power plants is used for cooling. Therefore, addressing the cooling systems in power plants is critical in studying overall water usage in this sector. Two of the most common types of cooling systems are once-through (open loop) and wet-recirculating (closed loop.) Most power plants built before 1970 implement once-through cooling systems in which water is withdrawn from a water source, used to condense steam, and is then discharged back to the source. Although much of the water withdrawn from surface waters for once-through cooling is returned, the higher temperatures of the effluent increases evaporation of water downstream. The intake screens as well as the increase in temperature in the water negatively affect the aquatic life and are major concerns in once-through cooling systems today. About 42.7% of the U.S. generating capacity uses once-through cooling systems. However, these are rarely implemented in power plants being planned or built today due to the difficulty of permitting, analysis, and reporting requirements. A wet-recirculating, or closed loop, cooling system is unlike the once-through system in that it reuses the cooling water. The warm water is pumped up to a cooling tower, or cooling pond, and uses air and evaporation to cool down. While some of the water is evaporated, most of the water is reused to condense the steam. As the cooling water evaporates after each loop, the water becomes more and more concentrated with minerals and dissolved suspended solids. A portion of the water, called blowdown liquid, is discharged and replaced with clean water. About 41.9% of the generating capacity in the U.S. uses cooling towers while 14.5% uses cooling ponds in wet-recirculating cooling systems. The wet-recirculating system withdraws less than 5% of the water than a once-through system. However, most of the water is lost to evaporation instead of being returned to the water source (Shuster, 2009).

Dry and hybrid cooling systems are advanced cooling technologies which use significantly less amounts of water. In a dry cooling system, water is not used for cooling. Instead, fans blow air over the tubes carrying the cooling water to decrease its temperature. In direct air-cooled systems, the steam flows through air condenser tubes and is directly cooled by air that is blown across the outside surface of the tubes using fans. Direct dry cooling simply implements an air-cooled condenser (ACC) and may have natural or mechanical draft towers to move the air through the condenser. In an indirect air-cooled system, the steam is condensed using the conventional condensers containing cooling water. The cooling water is recirculated and cooled using an air-cooled heat exchanger. A dry cooling system will generally reduce overall plant water withdrawal by 75 - 95% depending on the type of power plant (Comparison, 2004). Only 0.9% of the generating capacity in the U.S. use dry cooling systems in 2009 (Shuster, 2009). A hybrid cooling system, on the other hand, uses both water and air to condense the steam into liquid water. These systems may be designed for either of two specific purposes: plume reduction or water use reduction. The water reduction systems rely heavily upon dry cooling systems and incorporate wet recirculation for the hot periods where dry systems may not be sufficient. These systems use about 20-80% of the water used in wet cooling systems but still achieve higher efficiency and capacity advantages during the peak loads in hot weather than dry cooling systems. In plume abatement systems, the primary cooling system is wet and a dry cooling system is used for a small fraction during cold periods when plumes are likely to be visible (Maulbetsch, 2006).

The purpose of this study is to provide a summary of cooling system parameters associated with different groups of power plants using 2008 data. The first objective of this study is to categorize power plants based on energy source, prime mover, type of cooling system, source of cooling water, type of cooling towers, and operating/design conditions. The result is a group of power plants divided into specific categories based on the parameters listed above. The second objective is to calculate cooling system parameters (cost of installed cooling system in $/kW, water usage in acre-feet/year, and water usage in gallons/MWh) for each category of power plants. The values of these parameters are expected to fall within the ranges of previous studies. The third objective is to calculate the annualized costs of installed cooling systems in $/year. The annualized costs for wet-recirculating cooling systems are expected to be greater than for once-through cooling systems. The fourth and final objective is to determine the cost of water saved, or CWS. This value expresses how much more or less expensive a cooling system is with respect to its water requirements. This value is expected to be greater than one when comparing once-through with wet-recirculating cooling systems because cost differences are expected to be greater than water savings. As water permits are becoming more difficult for power plants to attain, this value is important because it helps in planning how much more money is necessary for the installation of upgraded, or new, cooling systems. This study is useful for power plant utilities also because it provides a means to compare cooling system parameters for cooling systems among several categories.

Methods

Database Development

In order to account for in-plant variations, power plants are categorized according to the following: region (East or West), primary cooling system, primary cooling tower, energy source, prime mover, nameplate capacity, distance of intake from shore, distance of intake from surface, source of cooling water, and operating/design conditions. The category of operating/design conditions includes capacity factor, thermal efficiency, average age of cooling systems, average age of generators, peak summer temperature, and average temperature rise of cooling water. In the paper "Water Use by Thermoelectric Power Plants in the United States" by Yang and Dziegielewski, these particular operating conditions are found to have an effect on water withdrawal and consumption per kWh of energy generated (Yang, 2007). The values and qualifiers for all 14 of the categories are obtained using the Energy Information Administration (EIA) electricity data files. The EIA collects monthly and annual electricity data via surveys; most of this data is publicly available. Specifically, data files 860 and 923 for the year 2008 are used to collect the required information. These are available for download at the EIA website (U.S. Energy Information Administration. Accessed May 8, 2010, http://www.eia.doe.gov/cneaf/electricity/page/data.html). Within each datafile, there are several tables that contain different information. Table 3-1 lists the 53 collected parameters for this study while the supplemental materials contains the data file number, table name, column letter, as well as the units and descriptions provided by the EIA for each parameter. In each table provided by the EIA, the EIA-assigned plant ID (or plant code) is provided in each row to correspond with each power plant.

Table 3-1. List of Parameters Collected

Name of Parameter Provided by the EIA		
Cooling Status	FERC_COGEN	August Quantity
Inservice_YR	Cooling System Status	September Quantity
Cooling_Type1	Annual Withdrawal Rate	October Quantity
Cooling_Type2	Annual Discharge Rate	November Quantity
Cooling Water Source	Annual Consumption Rate	December Quantity
Tower_Type1	Intake Peak Winter Temperature	January Heat Content
Cost_total	Intake Peak Summer Temperature	February Heat Content
Intake_Distance_Shore	Outlet Peak Winter Temperature	March Heat Content
UTILNAME	Outlet Peak Summer Temperature	April Heat Content
PLNTNAME	Total Annual Net Generation	May Heat Content
PRIMEMOVER	Energy Source	June Heat Content
NAMEPLATE	January Quantity	July Heat Content
STATUS	February Quantity	August Heat Content
OPERATING_YEAR	March Quantity	September Heat Content
ENERGY_SOURCE_1	April Quantity	October Heat Content
PLNTCODE	May Quantity	November Heat Content
NERC	June Quantity	December Heat Content
Primary_Purpose	July Quantity	

Combining Data

The EIA surveys are filled out at the plant level for plant information, at the generator level for generator information, at the cooling system level for cooling information, and at the boiler level for boiler information. The data required for this study listed in Table 3-1 are found in seven different tables. The EIA provides the tables in an .xls format. In order to be able to manipulate this data, the .xls documents are imported into a program called MySQL Database. This program is used to combine the required information at the generator, cooling system, and boiler level onto the plant level based on plant ID. This is done so that power plant data can be summarized in one row per power plant, instead of in several rows per power plant.

The first step in gathering the parameters is to combine all generator data from two EIA generator tables: Generator and GenY08. The data collected at the generator level from both tables include: utility name, plant name, plant code, generator status, nameplate capacity, total annual net generation, energy source, year of initial commercial operation, and prime mover. The Generator table contains total annual net generation and nameplate capacity while GenY08 contains the rest of the generator information. Nameplate capacity is the maximum amount of output, in MW, that a generator can produce according to its design. A prime mover is the type of turbine or engine used to convert the energy source to mechanical energy (U.S. Energy Information Administration, Accessed June 22, 2010, http://www.eia.doe.gov/glossary/index.cfm?id=P). While the parameter nameplate capacity is provided in both tables, it is taken from the Generator table which also contains total annual net generation. This is so that the nameplate capacity corresponds with the total annual net generation values of operating generators. Since each power plant may have several generators, certain parameters for each generator are added or averaged for each power plant. For example, the total annual net generation for each generator in each power plant is added to determine the overall annual net generation in each power plant; the same is done for nameplate capacity. The operating year of each generator, on the other hand, is averaged for each power plant and subtracted from 2010. The primary energy sources and prime movers of the first generator are taken and assumed to be the primary energy source and prime mover of the entire power plant. The written code for the calculations and for combining the two tables can be seen in the supplemental materials.

The second step is to combine cooling system information into one table. The EIA provides two tables that contain the required cooling system information: F860 Cooling System and Cooling_Operations. The data collected at the cooling system level include: cooling system status, inservice year, cooling type, installed cost of cooling system, type of cooling tower, annual withdrawal, discharge, and consumption rates, intake distance to shore, intake distance from surface, intake peak summer & winter temperatures, and outlet peak summer & winter temperatures. Both primary and secondary cooling system types are extracted for analyses. The cost and withdrawal, discharge, and consumption data are added for each cooling system while the inservice year and temperature data are averaged. The distance parameters for the first cooling system is taken and assumed to be the same for the entire power plant. The code in organizing and combining cooling system information can be seen in supplemental materials.

The data collected at the boiler level include the quantity and heat content burned in each month. These parameters are required so that thermal efficiency may be calculated. The quantity of fuel burned and the heat content of the fuel burned is used to calculate the total annual supplied heat (H) for each boiler, which is then added for each boiler within a power plant. These calculations were implemented using MySQL and its code is provided in the supplemental materials section**.**

Finally, for each power plant, the NERC region, source of cooling water, primary purpose, and cogeneration data are collected. NERC stands for North American Electric Reliability Corporation and is a system that organizes the electric grids in North America by region. NERC data is collected for each power plant to determine whether the power plants are located in the East or in the West. Figure 3-1 illustrates how East and West are identified in this project.

Figure 3-1. East and West Distributions (U.S. Energy Information Administration, North American Electric Reliability Corporation Regions. Accessed June 18, 2010, http://www.eia.doe.gov/cneaf/electricity/chg_str_fuel/html/fig02.html)

While the map includes parts of Canada, this study focuses only on the United States. The Western Electricity Coordinating Council (WECC), Texas Regional Entity (TRE), and Electric Reliability Council of Texas (ERCOT) regions are considered to be in the West. The Northeast Power Coordinating Council (NPCC), ReliabilityFirst Corporation (RFC), Southeast Electric Reliability Council (SERC), Midwest Reliability Organization (MRO), Southwest Power Pool (SPP), and Florida Reliability Coordinating Council (FRCC) are considered to be in the East. The regions in Hawaii and Alaska are labeled as External. Similarly, the name of the source of cooling water is updated so that it either says "Fresh Surface Water," "Industrial Wastewater," "Municipal," "Groundwater," or "Saline Surface Water." The term "Fresh Surface Water" indicates use of rivers, canals, aqueducts, channels, streams, creeks, bayous, lakes, and reservoirs as the source of water. "Saline Surface Water" refers to the use of oceans, seas, bays, estuaries, harbors, gulfs, and intracoastal waterways. The category "Groundwater" indicates the use of wells or aquifers to obtain cooling water, and "Municipal" represents power plants that use treated wastewater, city water, or "municipal" sources of water. The code in extracting the NERC region and source of cooling water from the table PlantY08 is found in the supplemental materials.

After the generator, cooling, boiler, and general plant information is extracted and combined so that there is only 1 row per power plant, the four different tables are combined into one useful table. The resulting table contains everything that is necessary to categorize the power plants, as well as calculate the necessary parameters. This is done using the "Join" function in which each of the four codes are combined with each other using the Plant ID as the primary link between all four tables. This code is shown in the supplemental materials. After the required data are combined into one table, the table is exported into an .xls format and opened in Microsoft Excel.

Size and Scope of Database

The EIA requires that existing electric power plants with a total nameplate capacity of equal to or greater than 1 MW fill the appropriate forms. Since this project is studying the water used for cooling, it is appropriate to limit the scope to thermoelectric power plants. Therefore, the parameters prime mover and energy source will be used in filtering the data so that the scope includes only thermoelectric power plants. Prime movers will be limited to (according to EIA categories) steam turbines, combined cycle steam parts, combined cycle combustion turbine parts, combined cycle single shafts, and combined cycle – total unit. The energy sources will be limited to the following categories provided by the EIA: anthracite coal, bituminous coal, lignite coal, sub-bituminous coal, waste/other coal, coal synfuel, distillate fuel oil, kerosene, residual fuel oil, oil-other and waste oil, petroleum coke, natural gas, blast furnace gas, other gas, propane, synthetic gas (other than coal-derived,) synthetic gas (derived from goal,) and geothermal. Nuclear sources are not included in the scope because the EIA stopped collecting cooling information from nuclear power plants since 2000.

Additionally, the scope of this study does not include cogenerator or industrial facilities. Therefore, the parameters Primary_Purpose and FERC_COGEN are used to filter out such plants. According to the EIA, a cogenerating facility is one that generates electricity as well as thermal energy in the form of heat or steam. The heat or steam is used for industrial, commercial, heating, or cooling purposes. Industrial plants are those which produce electricity primarily for manufacturing, construction, and mining agriculture (U.S. Energy Information Administration. Accessed July 1, 2010 http://www.eia.doe.gov/glossary/index.cfm?id=C). Since both cogeneration and industrial facilities operate differently than conventional power utilities, these facilities are filtered out as to prevent a skew in the data. Also, industrial and cogeneration plants may be more sensitive to economic cycles than utility plants indicating that their cost information may be skewed. It is assumed that if a power plant responds “No” to the FERC_COGEN question, which asks if the plant has Federal Energy Regulatory Commission Qualifying Facility Cogenerator Status, it is not a cogeneration facility. The primary purpose of the plant is described using the North American Industry Classification System. Electric utility plants and independent power producers are instructed to reply with a code of “22” while industrial and commercial generators are told otherwise. Therefore, only power plants that respond “No” to cogeneration and reply with a code of “22” as the primary purpose are selected and placed in the database.

The total number of power plants reported in the EIA, at the plant level, is 6,602. Table 3-2 summarizes the total number of power plants reported at the generator, cooling system, and boiler level.

Table 3-2. Number of Power Plants in EIA Data Files

<table>
<tr><th rowspan="2">Level</th><th rowspan="2">Name of Table</th><th colspan="2">Number of Power Plants</th></tr>
<tr><th>All Types of System Statuses</th><th>Operating Status Only</th></tr>
<tr><td>Plant</td><td>PlantY08</td><td>6,602</td><td>N/A</td></tr>
<tr><td rowspan="2">Generator</td><td>Geny08</td><td>5,928</td><td>5,065</td></tr>
<tr><td>Generator</td><td>1,342</td><td>N/A</td></tr>
<tr><td rowspan="2">Cooling System</td><td>f860_Cooling_System</td><td>860</td><td>731</td></tr>
<tr><td>Cooling Operations</td><td>729</td><td>688</td></tr>
<tr><td>Boiler</td><td>f860_Boiler</td><td>1,532</td><td>1,334</td></tr>
</table>

As can be seen, the number of power plants that can be included in this study is limited by the power plants in the "Cooling Operations" table because it has the least number of power plants. Additionally, only cooling systems that are operating are considered. This narrows the maximum number of power plants to 688 as can be seen in Table 3-2. Furthermore, power plants that do not provide information for total installed cooling system cost and water withdrawal information are filtered out of the dataset. After this is done, the total number of power plants included in this study is 559**.** This number represents the number of power plants that are included in the generator, boiler, and cooling tables. Although the maximum number of power plants from the cooling system data is 688, this number is decreased because some power plants are included in the cooling tables, but are not included in the generator or boiler tables. Table 3-3 lists the data filtering and additions processes, as well as the number of power plants remaining after each filter or addition is applied. The first seven filters are applied using the MySQL program, while the rest are done in Excel. The final filter is the removal of statistical outliers from the data set for the parameter water withdrawal in gallons/MWh and is done after that particular parameter is calculated. The method used in determining the outliers is the inner quartile range method in which the lower quartile is subtracted from the upper quartile. This is the inner quartile range and is multiplied by 1.5. This value is then added to the upper quartile to determine the outliers on the upper end. With this particular dataset, power plants with water withdrawal per MWh equal to or greater than 142,407 gallons/MWh are removed from the study. The same procedure is done for water consumption per MWh except that power plants are not deleted from the database. Instead, the consumption values are replaced with blank cells. The reason for which several outliers for water withdrawal and consumption are found is explained below in the "Categorizing & Cost of Water Saved" section.

Table 3-3. Database Filtering / Additions Process

Filter / Additions	Number of Power Plants Left After Filter / Additions
Select only operating generators	559
Select only operating boilers	
Select only operating cooling systems	
Select only steam & combined cycle prime movers	
Select only thermoelectric energy sources	
Select only power plants that have values for installed cost of cooling system	
Remove cogeneration and industrial facilities	
Select only power plants that have values >0 for total annual net generation	552
Select only power plants that have values for average annual withdrawal rate	507
Remove withdrawal gallons/MWh statistical outliers	458
Remove consumption gallons/MWh statistical outliers	458
Add Power Plants with dry cooling towers and with appropriate available information	460

After the outliers are removed from the dataset, 458 power plants are left in the database for this study. Since the purpose of this study is to incorporate different types of cooling systems, it is important to include dry cooling systems in the database. Additionally, a separate dry cooling system study is performed using the power plants in the EIA database that implement dry cooling technologies. According to the EPRI, there are 75 installations that implement dry cooling technologies nation-wide and 26 recent or planned installations of dry cooling systems in the United States as of 2004 (Comparison 2004). Out of the 26 recent power plants, all are included in the EIA general plant information data file, but only 4 have cooling system information in the EIA data files. These four power plants are included in the additional dry cooling system study.

The power plants that implement dry cooling systems are identified as those which have “Other” types of cooling systems. Using the additional footnotes provided by the EIA, each plant that states “Other” is confirmed to implement dry cooling systems, or an air-cooled condenser. Additionally, some power plants state that they implement a recirculating cooling type but with dry cooling towers—this is the same as a direct dry cooling system. Although recirculating cooling systems typically indicate wet cooling systems, some power plant respondents indicate the use of recirculating systems but with dry cooling towers. Therefore, power plants that implement “Other” (dry in the footnotes) cooling systems or dry or hybrid cooling towers are selected in the additional dry cooling system study. Furthermore, only those with operating cooling systems and installed costs of cooling systems information are selected to be added to the database. Since power plant respondents may have indicated use of a dry tower by mistake, it must be confirmed that all the power plants in the database that are listed as having

“Dry” cooling systems in fact use dry cooling systems. As a result, one is confirmed to implement a hybrid cooling system, and three are confirmed to implement dry cooling systems. Two additional power plants that implement dry cooling systems are added to the database resulting in 460 total power plants. Out of 460, a total of four power plants implement dry/hybrid cooling systems. The finalized list of the 460 power plants is provided in the supplemental materials. It is important to note, however, that although 460 power plants contain total annual net generation and installed cost of cooling system data, several power plants have missing parameters such as intake and outlet cooling water temperatures.

Calculating Categories and Cooling System Parameters

Microsoft Excel and MySQL are used to perform the necessary calculations in categorizing the power plants. These calculations are for determining the: capacity factor, thermal efficiency, average cooling water temperature rise, and average annual temperature of influent water for each power plant. Other parameters that are necessary to calculate include: the cost of cooling system per MWh, water withdrawal per MWh, and water consumption per MWh. Table 3-4 distinguishes the calculations made in MySQL to those made in Excel.

Table 3-4. Summary of Calculations

Calculations Done In MySQL	Sum of total annual net generation
	Sum of nameplate capacity
	Average year of operation of generators
	Average year of operation of cooling systems
	Average age of generator
	Average age of cooling system
	Sum of installed cost of cooling system
	Sum of average annual withdrawal rate
	Sum of average annual discharge rate
	Sum of average annual consumption rate
	Average temperature rise
	Total annual heat supplied to each boiler
	Sum of total annual heat supplied
Calculations Done in Excel	Capacity factor
	Thermal efficiency
	Present value of installed cost of cooling system
	Annualized installed cost of cooling system
	Total annualized cost
	Installed cost of cooling system in $MM
	Normalized installed cost of cooling system
	Water withdrawal rate
	Water withdrawal per MWh
	Cost of water saved

The capacity factor is the ratio of how much energy is generated within a period of time to the maximum amount of energy that could have been generated in the power plant within the same period of time (Yang 2007). It is calculated using the following equation:

$$CF = \frac{100 \times E}{C \times 24 \times 365} \tag{1}$$

where *CF* is the capacity factor; *E* is the total annual net generation in kWh; and *C* is the total generation capacity in kW. Thermal efficiency, on the other hand, is a measure of the efficiency in converting the energy source from heat content into useful energy (U.S. Energy Information Administration. Accessed July 06, 2010, http://www.eia.doe.gov/glossary/index.cfm?id=T.) It measures the efficiency of the fuel source as opposed to the efficiency of the power plant and is calculated using the following equation:

$$\mu_{\mathrm{TE}} = \frac{360,000 \times E}{H} \tag{2}$$

where E is the total annual net generation in kWh and *H* is the annual supplied heat in kJ. The annual supplied heat is calculated using the quantity of fuel and fuel heat content provided in the boiler fuel table:

$$H = \left(\sum Q \times HS\right) \tag{3}$$

where *Q* is fuel quantity supplied in each month in “units”; and *HS* is the average of heat content supplied for each month in 2008 in million Btu (MMBtu) per “unit.” The resulting value for H is in MMBtu and is for each boiler in each power plant. The *H* values for each boiler in each power plant must then be added up so that there is one *H* value per power plant. The units must also be converted from MMBtu to kJ. The average cooling water temperature rise is found by subtracting the average inlet peak temperatures from the average outlet peak temperatures. The average annual temperature of influent water is calculated by taking the average of the inlet winter and summer peak temperatures.

In addition to calculating parameters required for categorization, the cooling system parameters must be calculated for each power plant. However, before any calculations regarding cost can be made, the installed cost of the cooling system values must be converted so that it is in 2008 dollar values. This is done using the following equation:

$$PV = V_n \times (1 + IR_{n+1}) \times (1 + IR_{n+2}) \times \ldots (1 + IR_{2008}) \tag{4}$$

where *PV* is the present value of the installed cost of cooling system in 2008 \$1000; V_n is the value of installed cost of cooling system that began operation in year *n*; and IR_n is the inflation rate for year *n*. After the installed cost of cooling system for each power plant is converted to 2008 values, it must be annualized so that it provides the installed cost of cooling systems on a yearly basis. This is done using the following equation taken from the textbook *Principles of Engineering Economics* (Grant, 1982):

$$A = PV\left[\frac{i(1+i)^n}{(1+i)^n - 1}\right] \tag{5}$$

where A is the annualized installed cost of cooling system in 2008 \$1000 / year; PV is the installed cost of cooling system in 2008 \$1000; i is the annual interest rate; and n is the number of years. Equation 5 yields the annualized installed cost of a cooling system that a power plant would have to pay per year if it were to install a cooling system in 2008 for the next 30 years. The typical projected life time of a cooling system of 30 years is used as n, and an interest rate of 5.2% is chosen as this was the average prime rate in the year 2008 (Prime Rates, Federal Reserve Board. Accessed July 23, 2010, http://www.moneycafe.com/library/primerate.htm#graph.) After the installed cost of cooling system is brought to 2008 dollar values and annualized, the cooling system parameters may be calculated. First, the installed cost of cooling systems for each power plant is converted to \$MM by simply dividing P by 1000. Next, the normalized installed cost of cooling systems in \$/kW is calculated:

$$NC = \frac{PV \times 1000}{NC \times 1000} \tag{6}$$

where NC is the normalized installed cost of cooling system in \$/kW; PV is the installed cost of cooling system in 2008 \$1000; and NC is the nameplate capacity in MW. Furthermore, water withdrawal in acre-feet per year, denoted as WW, may also be calculated for each power plant:

$$WR = \frac{W \times OH \times 3600}{43560} \tag{7}$$

where WR is the Water withdrawal rate in 2008 in acre feet/year; W is the Annual average withdrawal rate in ft^3/s; OH is the total operating hours in 2008 in hours/year; 3600 is in s / hr; and 43,560 is in ft^3 / acre-foot. The reason for which English units are used instead of SI is that acre-feet per year and gallons per MWh are typically used in this industry. Finally, water withdrawal and consumption may be calculated in gallons/MWh.:

$$WW = \frac{W \times OH \times 3600 \times 7.48}{G} \tag{8}$$

where WW is water withdrawal in gallons / MWh; OH is the total operating hours in one year (2008) in hours/year; 3600 is in seconds/hour; 7.48 is in gallons/ft^3; and G is the total annual net generation in MWh / year. The same calculation may be made for water consumption by simply substituting the average annual withdrawal rate with average annual consumption rate in ft^3/s.

Categorizing and the Cost of Water Saved

After the above calculations for each power plant are complete, the power plants can be categorized and the cooling system parameters can be calculated and averaged for any selected category. However, before the 460 power plants can be analyzed, certain procedures must be followed to avoid obtaining errors that may have occurred among power plant respondents in the submission process. For example, thermal efficiency values greater than 60% and less than 10% are replaced with '0.' This particular range was chosen because it follows the EIA's average thermal efficiency values of about 33% for coal-fired power plants (Carbon Dioxide, 2000). Combined cycle power plants, on the other hand, may have much higher thermal efficiency values. Similarly, capacity factor values greater than 90% and less than 1% are replaced with '0'. These values are chosen for capacity factor because according to the EIA, average capacity factor for coal-fired power plants, natural gas combined cycle, and petroleum power plants are 72.2%, 40.7%, and 9.2%, respectively (Electric Power, 2010). Therefore, numbers greater than 90% and less than 1% would not be a fair representation of typical values.

One source of error in the EIA survey input method is that power plant respondents cannot insert a value of zero for water withdrawal or water consumption. As a result, power plants that do not withdraw or consume cooling water have to input a minimum value of 0.01 ft^3/sec or leave it blank. By looking at the footnotes in which power plant respondents had commented, several respondents stated to have zero water consumption. Therefore, values like "0.01" or "99,999" are used to represent a value of zero. This is taken into account when looking at the consumption data. The power plants that contain identical rates for withdrawal and discharge are given a value of zero for consumption; and power plants that contain zero for water discharge are given the identical value of water withdrawal. Another source of error, which accounts for the statistical outliers found in water withdrawal rates, is that plant respondents may be submitting values in different units than requested. In fact, according to an EIA correspondent, some power plant respondents report cooling water rates in gallons per minute or in cubic feet per 0.1 seconds instead of the requested units of cubic feet per second to the nearest tenth. The reason for statistical outliers in water consumption rates are because of units and also because of zero-discharge facilities. Several power plants are zero-discharge facilities which implement water recycling and do not discharge cooling water. The respondents at these facilities state, in the EIA data forms, that the cooling water that is not discharged is consumed. This is not necessarily the case and explains the high averages of water consumption rates especially in recirculating cooling systems. Also, since some power plant respondents provide intake temperatures without outlet temperatures, and vice versa, it is important to delete the negative values of average temperature rise as well as the values that were calculated with zero average intake temperatures. This is done to ensure that the values calculated for average temperature rise of the cooling water are not misleading. It is important to note that of the several parameters being calculated for each power plant, all but installed cost of cooling system have blank values. These cells are left blank, not zero, so that they will not affect the calculated average values.

Categorizing power plants and calculating the cooling system parameters is done using pivot tables in Microsoft Excel which are used to obtain the results in the analyses to follow. This pivot table provides a drop down menu for each category. For the categories that are identified with numbers, such as capacity factor, ranges of values will be provided from which the user may select. In order for Microsoft Excel to be able to group these values, the blank cells associated with the power plants that have missing information have to be replaced with '0'. There is also a drop down menu for Plant ID for the case in which one would like to compare individual power plants. For each drop down menu, the option 'All' is provided so that the user may compare all types of power plants in a particular category. The 'All' option also includes those power plants that are blank and have missing information in that particular category. For a group of power plants with the selected categories and operating/design conditions, the pivot table provides the seven following parameters:

1. Installed cost of cooling system in 2008 millions of U.S. dollars ($MM)
2. Normalized installed cost of cooling system in 2008 $ / kW
3. Annualized installed cost of cooling system in 2008 $1000 / year
4. Water withdrawal in gallons / MWh
5. Water consumption in gallons / MWh
6. Water withdrawal rate in 2008 in acre-feet / year
7. Count of Plant ID

Two pivot tables are created side by side so that these parameters of two groups of power plants may be compared with one another and so that the cost of water saved in $/acre-foot of water withdrawn may be determined relative to a specific group of power plants:

$$CWS = \frac{A - A_{REF}}{WR_{REF} - WR} \tag{9}$$

where *CWS* is the cost of water saved in $ / acre-foot; *A* is the annualized cost of installed cooling systems in 2008 $ / year; and *WR* is the withdrawal rate in acre-feet/year. The subscript $_{REF}$ represents the parameters of the reference group. The ability to categorize the power plants helps account for certain factors that are known to affect costs of cooling systems as well as water withdrawal rates. One pivot table contains the values for a reference power plant, or group of power plants, and the second pivot table contains the group of power plants for which CWS is being calculated. The CWS represents the extra amount of money allocated towards cooling systems for a specific category of power plants with respect to a reference category of power plants. The reference group is chosen so that its cooling system is expected to cost less and withdraw more water than the target group. The following is a list of assumptions made throughout the project.

1. Information power plants provide to the EIA is accurate
2. Projected lifetime of a typical cooling system is 30 years
3. Average interest rate of 5.2% in the year 2008 is representative of what utilities would have had in 2008
4. Data for the year 2008 are representative of previous or more recent operations in utilities
5. The year of operation of each cooling system is the same year the cooling system was installed
6. The base operating time used in the EIA data is 8,760 hrs/year (per personal communication with an EIA correspondent)

Results and Discussion

Database Analysis

According to the EIA, the total power plant population in the United States is 5,400 (U.S. Energy Information Administration, Accessed July 21, 2010, http://www.eia.doe.gov/ask/electricity_faqs.asp#coal_plants). With a sample size of 460 power plants, the data from this study represent the total U.S. power plant population with a 95% confidence level and a confidence interval of ±4.37% as determined by the z-test.

Analyses of the distributions of region, age, prime mover, and energy sources in the database are shown in Figures 3-2 to 3-6. As can be seen in Figure 3-2, the number of power plants with recirculating and dry/hybrid cooling systems is greater in the West than in the East.

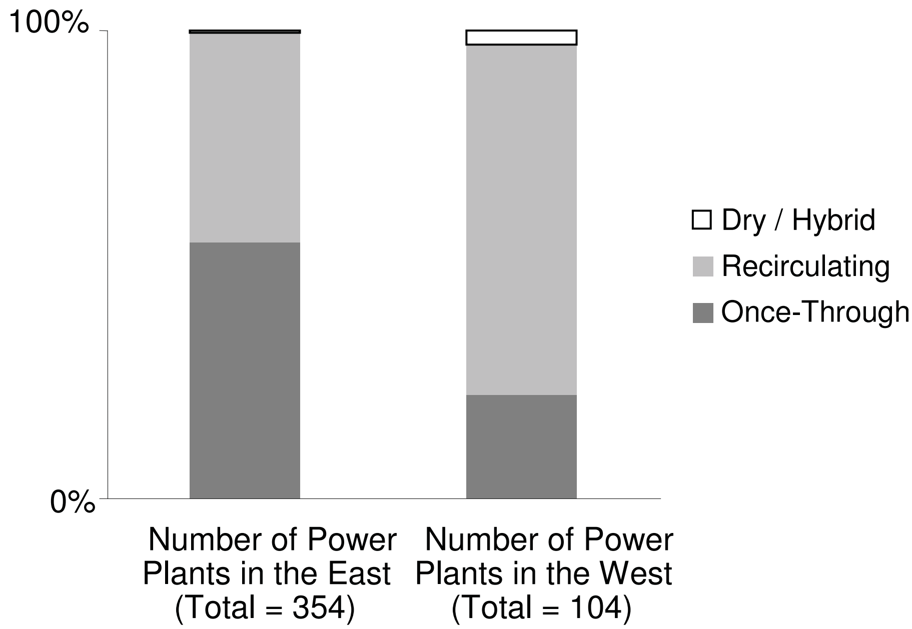

Figure 3-2. Regional Percentage Distribution of Type of Cooling System

This confirms that because water is scarce in the West, there is greater incentive to adopt low water-intensive cooling technologies. The age distribution between the East and the West shown in Figure 3-3 proves that because recirculating systems are more prevalent in the West, the cooling systems in the West are relatively newer.

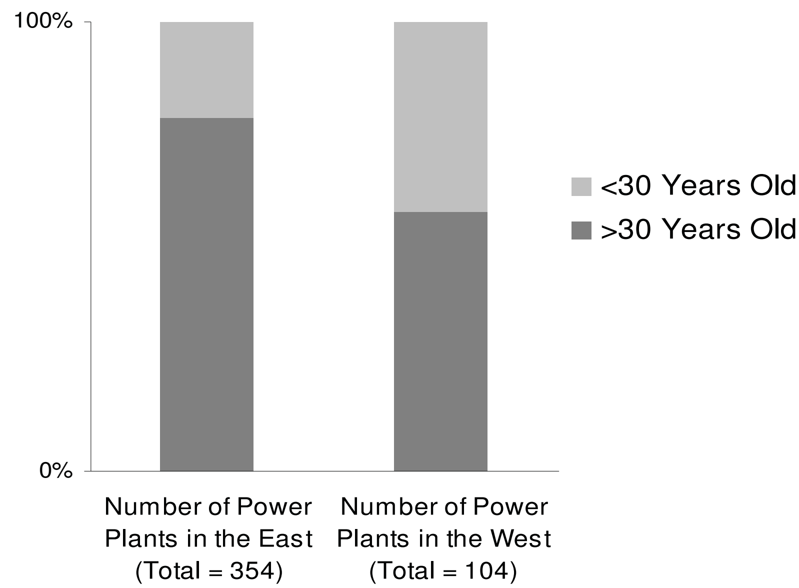

Figure 3-3. Regional Percentage Distribution of Age of Cooling System

Additionally, the sources of water in the East are different from those in the West. Figure 3-4 illustrates that fresh surface water is the most common source of cooling water in the East. While in the West, plants that use groundwater, municipal, and saline sources of water account for almost half of the population of power plants. Note that the total number of power plants in the East and West are less than in Figure 3-3 because some power plants have blank responses for source of cooling water and are, therefore, not included in the distributions.

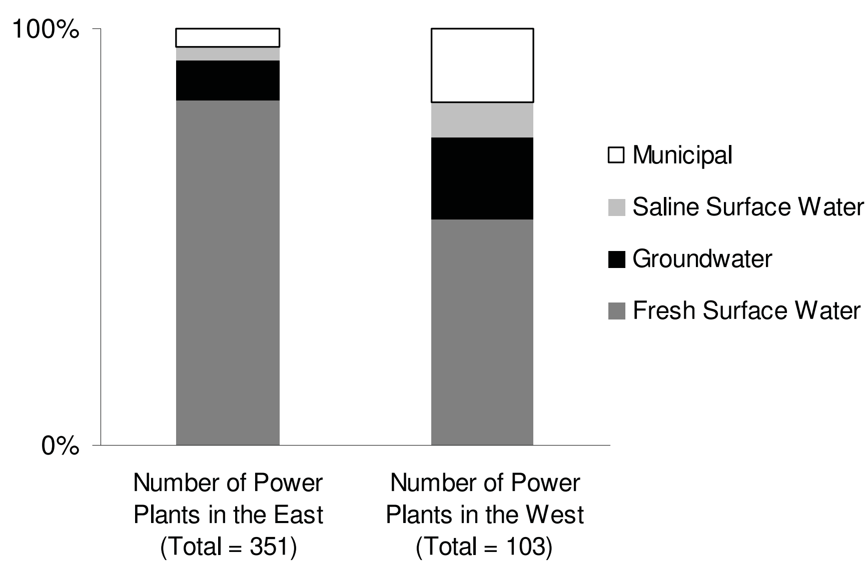

Figure 3-4. Regional Percentage Distribution of Source of Cooling Water

In terms of age distribution, it is expected that power plants of 30 years of age or less will implement wet-recirculating cooling systems, while older ones implement once-through cooling systems. Figure 3-5 illustrates that this is the case with the sample of power plants in this database.

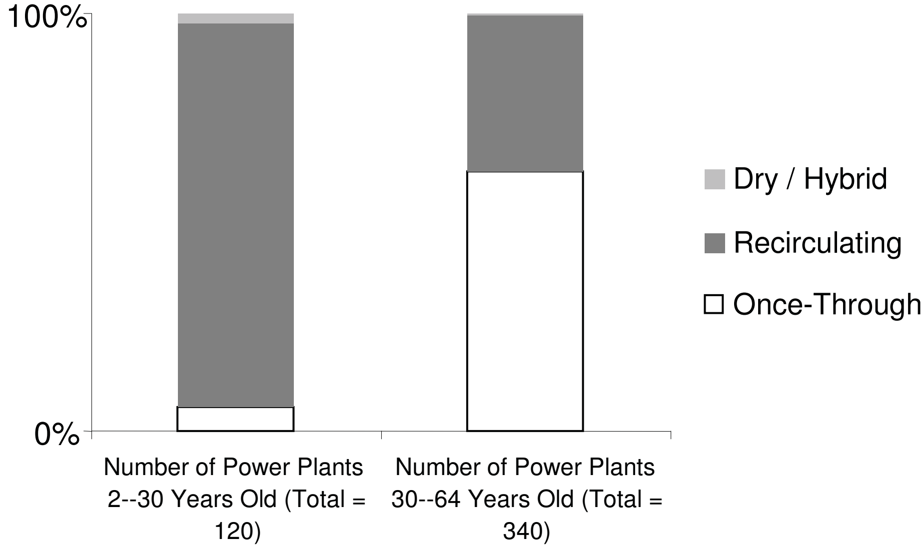

Figure 3-5. Age Percentage Distribution of Type of Cooling System

In order to gauge the variability in energy source distribution, a pie chart shown in Figure 3-6 illustrates the breakdown of coal, fuel oil, and natural gas as energy sources.

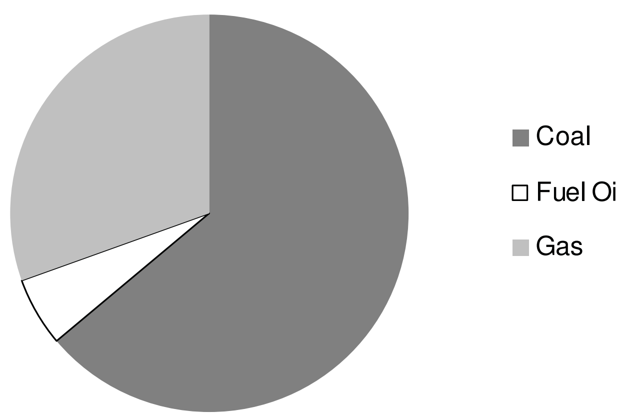

Figure 3-6. Source of Energy Percentage Distribution

The category "coal" includes anthracite coal, bituminous coal, sub-bituminous coal, and waste/other coal as provided by the EIA. The "waste/other coal" category includes fine coal, lignite waste, waste coal, and more. "Fuel oil" includes distillate fuel oil, residual fuel oil, and petroleum coke, while the category "gas" includes natural gas, blast furnace gas, and other types of gases. In the United States, coal is most prevalent fossil fuel followed by gas—primarily natural gas.

Cooling System Parameters

The average cooling system parameters, water withdrawal in gal/MWh, water consumption in gal/MWh, cost of installed cooling system in $/kW, and cost of installed cooling system in millions of dollar ($MM), are extracted from the pivot table based on prime mover and type of cooling system. Throughout this study, power plants categorized by primary cooling system are grouped so that their secondary cooling system type is left blank by the power plant respondent. This indicates that the power plant implements only one type of cooling system. This filter is applied to avoid including data for power plants that implement more than one type of cooling system. The values obtained are shown in several tables and compared with results from previous studies. Table 3-5 contains average water withdrawal and consumption, in gal/MWh, for both coal steam and combined cycle natural gas power plants. The source labeled "Badr et al." represents the data obtained from this study while the other sources are previous studies used for comparative purposes.

Table 3-5. Water Use in Gallons/MWh for Varying Plant Types and Cooling Systems

Source	Data Year	Plant Type	Once-through		Wet-recirculating with Cooling Tower		Dry Cooling	
			Withdrawal	Consumption	Withdrawal	Consumption	Withdrawal	Consumption
USDOE 2006	1999, 2002, 2005, 2006	Fossil Fuel	20,000-50,000	300	300-600	300-480	N/A	N/A
		Coal IGCC	N/A	N/A	250	200	N/A	N/A
		Natural Gas CC	7,500-20,000	100	230	180	0	0
		Nuclear	25,000-60,000	400	500-1,100	400-720	0	0
EPRI 2002	2002	Fossil Fuel	20,000-50,000	300	500-600	480	N/A	N/A
		Nuclear	25,000-60,000	400	800-1,100	720	N/A	N/A
		Natural Gas/Oil CC	7,500-20,000	100	230	180	N/A	N/A
Dziegielewski 2006	1996 - 2004	Fossil Fuel	44,000	200	1000	700	N/A	N/A
		Nuclear	48,000	400	2600	800	N/A	N/A
Kenny 2009	2005	Fossil Fuel and Nuclear	50,000 - 65,000	NA	1,000 - 2,000	NA	N/A	N/A
Torcellini 2003	2003	Thermoelectric	NA	470	NA	470	N/A	N/A
Yang 2007	2007	Thermoelectric	>39,000	100	<1,320	528-793	N/A	N/A
Badr et al. 2010	2008	Coal Steam	41,300	100	1,400	600	N/A	N/A
		Natural Gas Combined Cycle	56,500	0	5,500	700	156	0

While the withdrawal values for the coal-fired once-through power plants are within the ranges of previous studies, the combined cycle once-through power plants have higher water withdrawal rates. This is because the withdrawal and consumption values for combined cycle, once-through power plants are obtained using only two power plants. The combined cycle, wet-recirculating group, on the other hand, is represented by 59 power plants and consume more water per MWh than coal-fired power plants. This is because there are nine power plants within this group that have consumption values greater than 10,000 gal/MWh, which increases the overall average. An explanation for the high withdrawal values is that there are several combined cycle power plants that contain more steam turbines than gas combustion turbines. For example, one power plant may have one combined cycle turbine and seven steam turbines. This power plant may be labeled as "combined cycle" even through the majority of its units are steam-driven. Therefore, withdrawal rates for combined cycle power plants in Table 3-5 also represent withdrawal rates of the steam-driven units in combined cycle power plants. There is only one coal steam power plant that uses a dry cooling system and no withdrawal/consumption values were reported. Therefore, there are no withdrawal and consumption data for coal steam, dry cooling power plants. Furthermore, there are only two natural gas, combined cycle power plants in the database that implement dry cooling systems, Goldendale Generating Station and Sutter Energy Center. According to the EIA database, Sutter Energy Center withdraws, discharges, and consumes no water. Therefore, the value of 156 gal/MWh is an average value of Goldendale's 313 gal/MWh value and Sutter's 0 gal/MWh value. While it may be expected that dry cooling systems withdraw no water, this is not the case at the Goldendale Generating Station. According to the EIA, about 93% of all water withdrawn from thermoelectric power plants is used for cooling (USDOE/NETL 2009b "Water Requirements"). The remaining 7% is represented by the withdrawal rate at Goldendale Generating Station.

In order to perform any cost comparisons or analyses, the age of the power plants must be taken into consideration. Power plants built 2 years ago were not built the same as they were 40 years ago. Therefore, the installed cost of cooling for a 40 year-old plant should not be compared with that of a 10 year-old plant. While inflation is able to bring the cost of cooling systems from the year in which each cooling system was installed to 2008, it does not incorporate efficiency, technological, or industrial changes that occur over time. Figure 3-7 illustrates the variability in cost per kW with age of power plants.

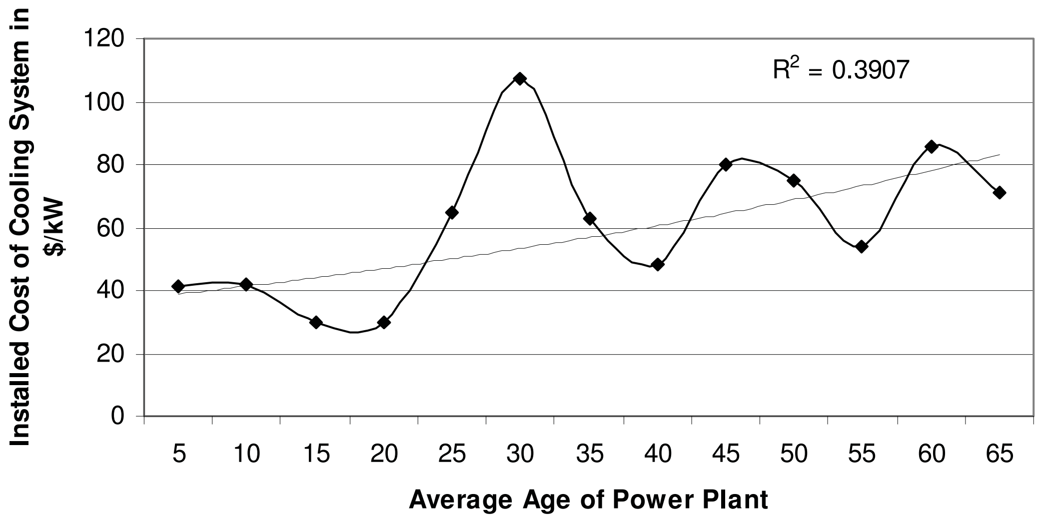

Figure 3-7. Effect of Age on Installed Cost of Cooling System

Using an exponential regression, it can be seen that the average age of power plants account for about 40% of the variability in the installed cost of cooling systems. The peak that occurs for power plants that are 25-30 years old may be explained by the increase (almost doubling) of inflation rates in the years 1979-1981 (U.S. Bureau of Labor Statistics. Accessed July 14, 2010, http://www.usinflationcalculator.com/inflation/historical-inflation-rates/.) If this peak value is removed from the data set, the R^2 value becomes 0.557 indicating a greater percent of the variability being accounted for. Therefore, in order to provide any cost parameters, the age group of power plants must be identified. In Table 3-6 the cost of the installed cooling system per kW for thermoelectric power plants of 25-30 years of age is shown along with combined cycle power plants of 5-10 years of age.

Table 3-6. Installed Cost of Cooling Systems for Varying Types of Cooling Systems

Source	Year	Capacity and Type of Plant	Type of Cooling System	Capital Cost per Capacity in $/kW
USDOE/NETL 2009b	2005	Fossil/biomass-fueled steam	Once-through	19
			Recirculating cooling tower	28
			Recirculating cooling pond	27
			Other including dry	182
Badr et al. 2010	2008	Fossil fuel steam 25--30 years old	Once-through	24
			Recirculating	48
		Combined cycle 5--10 years old	Dry	78
			Hybrid	49

The values from USDOE/NETL (2009a) are the capital costs of the cooling systems per kW. The values for installed cost of cooling systems from this study have been brought to 2008 dollar values and show that recirculating systems within a particular age group are more expensive than once-through systems. Also, while dry and hybrid systems are expected to be equally as expensive, Table 3-6 indicates that hybrid systems are cheaper. The data for the dry cooling systems are from two power plants, while there is only one hybrid power plant in the database; these are Sutter Energy Center, Goldendale Generating Station, and Bethlehem Energy Center, respectively.

The Cost of Water Saved

The cost of cooling systems for 500 MW gas-fired combined cycle plants are provided from previous studies along with water savings between wet and dry cooling and the cost of water saved. The values obtained from this study are shown in Table 3-7 where they are compared with previous studies of similar parameters but of different methods.

Table 3-7. Summarized Cost Results for Varying Cooling Systems

Source	**Capacity and Type of Plant**	**Type of Cooling System**	**Capital Cost in Million $**	**Water Savings Between Wet and Dry Cooling in Acre-foot / Year**	**Cost of Water Saved in $ / Acre-foot**
EPRI 2004	500 MW gas-fired combined cycle	Wet-recirculating, mechanical draft cooling tower	$5.7 - $6.5	2,800	1,100 - 1,400
		Dry	$21 - $26		
Maulbetsch 2006	500 MW gas-fired combined cycle	Wet-recirculating, mechanical draft cooling tower	Increase of $8 to $27	2,000 – 2,500	1,100 - 1,900
		Dry			
Badr et al. 2010	0-500 MW natural combined cycle, 5-10 Years Old, in the West	Wet-recirculating with mechanical draft cooling tower	$14	4,400	12.7
		Dry	$15		

There are 14 natural gas combined cycle power plants that are 5-10 years old, have less than 500 MW nameplate capacity, are in the West, and implement wet-recirculating systems with mechanical draft cooling towers. Furthermore, there are two power plants in the same category that implement dry cooling systems (Sutter and Goldendale). The power plants are narrowed down to these conditions to best simulate the scope of the other two studies. Using the two dry power plants, it can be seen that the installed cost of a dry cooling system is only $1MM greater than for wet-recirculating mechanical draft towers, indicating no major differences in the cost of installation between wet and dry cooling systems. The cost of water saved in EPRI (2004) and Maulbetsch (2006) are about two orders of magnitude higher than in this study. This is for several reasons pertaining to differences in methodology.

The major differences in scope, sources, and calculations in determining the cost of water saved are summarized in Table 3-8.

Table 3-8. Differences in Cost of Water Saved Studies

<table>
<tr><th>Study</th><th>Scope</th><th>Source of Plant and Cost Data</th><th>Parameters in Cost of Water Saved Calculation</th><th>Equation for Cost of Water Saved</th></tr>
<tr><td rowspan="3">EPRI 2004</td><td>500 MW combined cycle</td><td rowspan="3">Budget price data provided by major vendors of certain components</td><td rowspan="2">Savings in Cost per year by using wet-recirculating</td><td rowspan="3">= Savings in Cost per Year / Water Saved per Year</td></tr>
<tr><td>Nation-wide climatic conditions</td></tr>
<tr><td>Cost components only relate to steam part of combined cycle plants</td><td>Water Saved per year by using dry cooling</td></tr>
<tr><td rowspan="4">Maulbetsch 2006</td><td>500 MW gas-fired 2 x 1 combined cycle</td><td>Thermoflow Software Suite</td><td>Total Plant Capital Cost</td><td rowspan="4">= [[(Difference in Plant Capital Cost) x 0.075] + (Difference in Annual Revenue)] / (Difference in Annual Water Use)</td></tr>
<tr><td>California temperature conditions</td><td>Including GTPro and PEACE</td><td>Assumed recovery rate for capital cost</td></tr>
<tr><td rowspan="2">Wet mechanical draft cooling towers vs. air-cooled condenser</td><td rowspan="2">Off-design interpolation for annual performance data</td><td>Annual Revenue</td></tr>
<tr><td>Annual Water Use</td></tr>
<tr><td rowspan="2">Badr et al. 2010</td><td rowspan="2">Thermoelectric power plants in EIA database with operating generators, boilers, and cooling systems with appropriate data (460 power plants)</td><td rowspan="2">EIA 2008</td><td>Annual installed cost of cooling system</td><td rowspan="2">=(Difference in annual installed Cost of cooling system)/(Difference in annual Water withdrawal)</td></tr>
<tr><td>Annual water use</td></tr>
</table>

EPRI's methodology includes the comparison of cost and performance factors for five different sites representative of regions across the nation. Using ambient temperatures for each site, cost and performance data are produced from vendors by sizing cooling systems at each site. Parameters like water use and power generated are calculated on an hourly basis throughout the year. While calculating the cost of water saved is not the primary objective of the EPRI study, it is briefly mentioned in the "Summary and Conclusions" section. The CWS is calculated by dividing the total cost saved by implementing a wet-recirculating system instead of a dry system by the yearly volume of water saved. The cost of cooling systems is composed of the following components: surface steam condensers, mechanical draft wet cooling towers, cooling ponds, air-cooled condensers, water treatment equipment, acquisition costs, delivery costs, in-plant treatment costs, and discharge/disposal costs of cooling water. The total cooling system cost is found by summing the annualized capital cost, annual cost of fan power, cost of capacity shortfall, maintenance costs, and water costs. Therefore, the CWS does not only include the capital cost of the cooling system, but also any additional costs associated with the cooling system. Since the CWS calculated in this study only incorporates the installed cost of cooling system, it is expected to be a smaller value than that obtained in the EPRI analysis. Specifically, there are two reasons why CWS represented by the EPRI is two orders of magnitude greater than that obtained in this study. Firstly, the annual capital cost difference between wet and dry systems are found to be 3-4 million dollars while it is $56,000 in this study. This is because of the different cost components incorporated in the EPRI analysis and not in this study. Secondly, the water savings between wet and dry cooling is about half of that obtained in this study. The increase in cooling system savings and decrease in water saved both account for the difference in the values of CWS in the two studies.

The methodology of this study differs from that of Maulbetsch (2006) in that Maulbetsch uses software to develop the cost and annual performance data for power plants. Additionally, the CWS is calculated using the difference in total plant capital cost, as well as difference in annual revenue. Total plant capital cost is divided into eight categories: specialized equipment, other equipment, civil, mechanical, electrical assembly and wiring, buildings, engineering and plant startup, soft and miscellaneous costs, and labor. Since the difference in total plant cost is twenty times greater than the difference in installed cost of cooling systems obtained in this study, the cost of water saved is found to be much greater than in this study. Secondly, adding the annual revenue to the term explains why this term is larger. Annual revenue is calculated by multiplying the annual net plant output which is an assumed rate of $50/MWh. The difference in annual revenue adds about $2.9MM to the CWS. Finally, the values obtained for annual water use are lower in Maulbetsch than in this study. This is because two different sources are being used for water use data. While Maulbetsch uses plant design software to develop annual performance rates, such as water usage, this study uses real data available from power plants. Specifically, the water savings determined in Maulbetsch are half of those determined in this study.

The installed cost of cooling systems provided by the EPA includes the cost of "pumps, piping, canals, ducts, intake and outlet structures, dams and dikes, reservoirs, cooling towers, and appurtenant equipment" (U.S. Energy Information Administration, EIA-860 Forms and Instructions. Accessed May, 2010, http://www.eia.doe.gov/cneaf/electricity/2008forms/consolidate_860.html). Specifically, calculation of the CWS excludes several cost components that the EPRI includes. These are the cost of: condensers, land, labor, water, fan power, capacity loss, and operation and maintenance. While both EPRI and Maulbetsch include several factors that this study does not, the exclusion of these factors may be beneficial for this particular study. First, the "installed cost of cooling system term" can be used on a comparative basis because it has the same scope for each power plant in the EIA database. Secondly, the inclusion of items that are only directly related to the type of cooling system reduces variability among cost and other non-cooling-related factors. For example, the cost of water and land are not 100% directly related to the type of cooling system. The cost of water is dependent on location, while the cost of land is dependent on the type of cooling system but also on location. The cost of pumps, pipes, intake and outlet structures, on the other hand, are directly dependent on the type of cooling system implemented. This is the reason for not including water pollution abatement costs. Water pollution abatement costs are described as expenditures for structures, equipment, and chemicals related to the reduction of thermal pollution, coal pile runoff, and fly ash wastewater (U.S. Energy Information Administration, EIA-923 Forms and Instructions. Accessed May, 2010, http://www.eia.doe.gov/cneaf/electricity/2008forms/consolidate_923.html). Coal pile runoff and fly ash wastewater are components which are not correlated with the type of cooling system. Thirdly, the CWS calculations use real power plant data. The installed cost of cooling systems is a number that is well-known among power plant respondents, indicating low chances of error in the submission process. Furthermore, the methodology of this study enables the cost of water saved to be calculated for power plants of varying operational conditions. This tool provides interested parties to be able to compare costs of cooling systems in specific power plants with others. This tool also enables the incorporation of capacity loss and total generation when grouping power plants into certain categories.

Since the cost of water saved is calculated differently than in previous studies, it would be most beneficial to use this parameter on a comparative basis. Table 3-9 presents a broad comparison of the CWS among different types of cooling systems.

Table 3-9. Cost of Water Saved on a Comparative Level

Reference Group	Target Group	Age Group in Years	$ / Acre-foot
Once-through	Recirculating	40-45	4.8
Once-through	Recirculating	50-55	1.3
Once-through	Recirculating with cooling towers	40-45	5.6
Once-through	Recirculating with cooling ponds	40-45	0.4
Once-through with fresh surface water	Once-through with saline surface water	45-50	0.5
Recirculating with fresh surface water	Recirculating with municipal water	5-10	-110.5
Recirculating with cooling ponds	Recirculating with cooling towers	30-35	0.5
Recirculating	Dry/Hybrid	5-10	1.0

As previously mentioned, the CWS cannot be calculated for power plants of different age groups. The target power plants are picked so that their cooling systems are expected to withdraw less water and cost more than the reference power plants. Also, the age groups for each row are chosen so that the number of power plants in both the reference and target groups is maximized. As Table 3-9 indicates, the cost of water saved can range from a negative number to greater than one. There are two reasons for which the CWS saved is a negative number, if the reference group withdraws less water than the target group, or if the target group is less expensive than the reference group. The CWS can be a positive number if: the target group withdraws less water and is more expensive (the hypothesis is accepted) and if the target group withdraws more water and is cheaper than the reference group (the hypothesis is rejected). Additionally, if the CWS is between 0 and 1, the difference in water usage is greater than the difference in installed cost of cooling systems. For example, in Table 3-9, the CWS between recirculating systems with cooling ponds and once-through systems indicate that the additional installed cost of a wet cooling pond system is insignificant compared to the water savings. The same can be said when comparing once-through saline water systems and once-through freshwater systems. For groups in which the calculated cost of water saved is greater than one, the difference in installed cost of cooling system is greater than the volume of water saved. The greater the magnitude of the CWS, the more dollar value allocated towards the target group’s cooling system, relative to the volume of water saved.

The most appealing CWS values for power utilities are those which are positive and less than one. Table 3-9 indicates that the most appealing target cooling system is a cooling pond recirculating system with reference to once-through cooling systems. This is expected because the costs of cooling ponds are less than those of cooling towers. The reason that municipal water (defined as treated wastewater and city water) recirculating systems yield a negative CWS, in contrast to fresh surface water, is that the cost of installed municipal cooling systems is far cheaper. The comparison between dry/hybrid systems and recirculating systems indicate that the difference in cost is approximately equal to the difference in water savings. This particular comparison is done using two dry plants (Sutter Energy Center and Goldendale Generating Station), one hybrid plant (Bethlehem Energy Center), and 45 recirculating power plants of the same age group. Therefore, the data for the reference group are more robust than for the target (dry/hybrid) group.

In order to study how cooling system parameters change with certain conditions, specific categories of power plants are chosen so that there is one variable between two groups of power plants. The results are found in Table 3-10.

Table 3-10. Cost of Water Saved for Power Plant Categories

Age Group	Category	Sub-Category	Sub-Category	Number of Power Plants in Category	Cost of Installed Cooling System in $/kW	Average Water Withdrawal in Gallon/MWh	Average Water Withdrawal in Acre-feet/Year	Average Annualized Cost of Installed Cooling System in 2008 $1000 / Year	Cost of Water Saved in $/Acre-foot
35-40	Once-through	Nameplate Capacity 1000-2000	Avg Intake Pk Summer 57-114 F	8	69	42,733	506,533	7,913	-133
			Avg Intake Pk Summer 0-57 F	5	48	36,202	481,409	4,560	
		Nameplate Capacity 1000-2000	Avg Temp Rise 0-15 F	7	91	46,217	439,096	10,181	62
			Avg Temp Rise > 15 F	6	26	33,225	564,272	2,474	
		Nameplate Capacity 1000-2000	Capacity Factor 0-60	6	38	60,060	355,335	3,700	-20
			Capacity Factor >60	7	81	23,216	618,185	9,070	
		Nameplate Capacity 1000-2000	Thermal Efficiency 0-35	6	90	22,169	411,539	10,381	44
			Thermal Efficiency >35	7	36	55,694	570,010	3,403	
		Nameplate Capacity 1000-2000	Distance Shore > 10 ft	9	74	47,964	506,149	8,081	-157
			Distance Shore < 10 ft	4	32	22,801	475,990	3,345	
		Nameplate Capacity 1000-2000	Distance Surface < 15 ft	5	100	16,113	497,423	11,941	-9,606
			Distance Surface > 15 ft	8	36	55,289	496,524	3,300	
		Fresh Surface Water	Nameplate Capacity 0-1500 MW	12	33	46,547	344,168	1,981	-13
			Nameplate Capacity >1500 MW	10	65	24,072	898,769	8,897	
35-40	Recirculating	Nameplate Capacity 0-1000	Avg Intake Pk Summer 57-114 F	8	59	5,753	4,760	1,721	45
			Avg Intake Pk Summer 0-57 F	6	47	2,054	9,013	1,529	
		Nameplate Capacity 0-1000	Avg Temp Rise 0-15 F	9	52	1,597	8,712	2,097	-215
			Avg Temp Rise > 15 F	5	58	8,796	2,751	814	
		Nameplate Capacity 0-1000	Capacity Factor 0-60	8	43	6,886	6,588	1,328	59,972
			Capacity Factor >60	6	68	544	6,576	2,052	

Table 3-10 Continued

Age Group	Category	Sub-Category	Sub-Category	Number of Power Plants in Category	Cost of Installed Cooling System in $/kW	Average Water Withdrawal in Gallon/MWh	Average Water Withdrawal in Acre-feet/Year	Average Annualized Cost of Installed Cooling System in 2008 $1000 / Year	Cost of Water Saved in $/Acre-foot
		Nameplate Capacity 0-1000	Thermal Efficiency 0-35	10	67	1,610	7,942	1,955	-233
			Thermal Efficiency >35	4	21	10,564	3,185	847	
		Nameplate Capacity 0-1000	Distance Shore > 10 ft	3	44	13,832	5,309	1,519	-94
			Distance Shore <10 ft	11	56	1,533	6,930	1,671	
		Nameplate Capacity 1000-2000	Distance Surface < 15 ft	5	46	457	13,973	5,023	70
			Distance Surface > 15 ft	3	23	1,913	48,240	2,632	
		Fresh Surface Water	Nameplate Capacity 0-1500 MW	10	51	4,421	4,684	1,798	-138
			Nameplate Capacity >1500 MW	13	43	934	33,069	5,712	
35-40	Fresh Surface Water	Once-through	East	19	52	35,632	646,499	5,730	-12
			West	3	23	40,759	278,076	1,290	
30-35		Recirculating	East	12	34	6,264	230,143	3,416	-6
			West	7	28	4,871	81,477	2,556	
5-10	West	Recirculating	Fresh Surface Water	4	132	2,605	5,937	2,023	70
			Municipal	7	25	3,208	27,045	554	

The more subcategories chosen for a group of power plants, the less variability is expected in the cooling system parameters, and the less number of power plants in each category. Using Table 3-10, water withdrawal per year and per MWh, annualized installed cost of cooling system, and cost in $/kW can be compared for groups of power plants of different categories. Additionally, using suspected reference and target groups, the CWS is estimated. These values provide insight on how certain operating and design conditions affect installed costs of cooling system and water withdrawals, as well as the magnitude of their effects. For the categories of once-through and recirculating fresh surface water power plants, power plants of similar conditions are grouped together. The ranges for each operational condition are determined based on average values of the entire data set. Using the cooling system parameters and the cost of water saved, the results can be grouped into four categories. The first is the case where the hypothesis is accepted. This occurs for only one category. This is the recirculating category with varying capacity factors. The cost of water saved for varying capacity factors is a very large value indicating a greater difference in cost relative to water withdrawal. While power plants with less capacity factors withdraw more volume of water per year, it is apparent that water withdrawal in gallons/MWh is greater. This indicates that, as expected, power plants with high capacity factors withdraw less water per MWh than those with lower capacity factors.

The second category of results is where the reference group withdraws more water, but is more expensive to construct. This is the largest category of results shown by Table 3-10, indicating that the predictions made relative to water use are more accurate than those relative to cost. For example, it is expected that power plants of higher cooling water-intake during peak summer temperatures require greater amounts of water than plants of lower temperatures; Table 3-10 shows that this is the case on a per MWh basis. However, increased cooling water temperature does not mean increased cost of cooling systems, which is why the cost of water saved is negative for once-through systems. Other cases where the same concept is applied is for once-through systems with varying distances of water intake from the shore and recirculating systems with varying temperature rise and thermal efficiencies. When comparing power plants in the East with those in the West, it is found that those in the East withdraw more water, but are more expensive to construct (for both once-through and recirculating cooling systems).

The third category of results are those in which the reference group is cheaper to install, but withdraws less water. For example, it is suspected that power plants with greater capacity factors withdraw less water than those of less capacity factors. While this is proven true by the gallon/MWh values, the parameter that is incorporated in the cost of water saved is the volume of water withdrawn per year. This indicates that, in general, power plants with greater capacity factors withdraw less water per MWh, but withdraw more volume per year. This is because most plants with large capacity factors are larger than those with small capacity factors. The same concept is shown by comparing power plants of different nameplate capacities. Those with larger capacities are more efficient in terms of water use per MWh, but are more costly to install. This is an important observation because the same is seen for both once-through and recirculating cooling systems. Other results in this category are recirculating fresh water systems of varying distances from inlet to the shore.

The fourth category of results is for where both water withdrawal and cost negate the hypothesis. While once-through power plants of greater temperature rise withdraw less water per MWh, more volume of water is withdrawn per year. Additionally, it is cheaper to construct those which withdraw less water per year in this particular category. The same concept applies for thermal efficiencies in the once-through fresh water category and for intake peak summer temperatures in recirculating systems, and when comparing fresh surface water sources to municipal water sources. It is found that recirculating systems which rely on municipal water sources withdraw more water per year and per MWh and are much cheaper to construct. This may be because no inlets or outlets structures are required for municipal cooling systems. Finally, it is expected that cooling systems with deeper intake structures withdraw less water due to seasonal stratification (the cooler the water, the less volume of water needed for cooling). However, in both once-through and recirculating systems, Table 3-10 indicates no such correlation.

Dry & Non-Operating Cooling Systems Analyses

The first of two additional analyses conducted is a distribution study of where all the advanced cooling technologies are currently operating or are being implemented. Table 3-11 summarizes the percent of power plants with dry cooling technologies, including cogeneration plants, in certain categories.

Table 3-11. Cooling Systems Distributions

Category	Percent of Power Plants in Category
East	32
West	68
Operating	47
Planned	26
Under Construction	21
Standby	5
Fresh Surface Water	16
Groundwater	53
Municipal	21

Four of the power plants listed in Table 11 are included in the list of recent U.S. plants implementing air-cooled condensers in EPRI (2004). This analysis shows that the majority of the dry cooling systems in the EIA are combined cycle natural gas systems, located in the West, and use non-fresh surface water sources. Additionally, almost 50% of them are being planned or are under construction, while 5% are on standby. The term “standby” is applied for units that are not normally used but are available for service. This term may be synonymously used with “inactive reserve”.

The second additional analysis is of cooling systems that are either planned, operating under test conditions, or are new units under construction. Figure 3-8 illustrates that cooling system distribution of such units in the East and in the West.

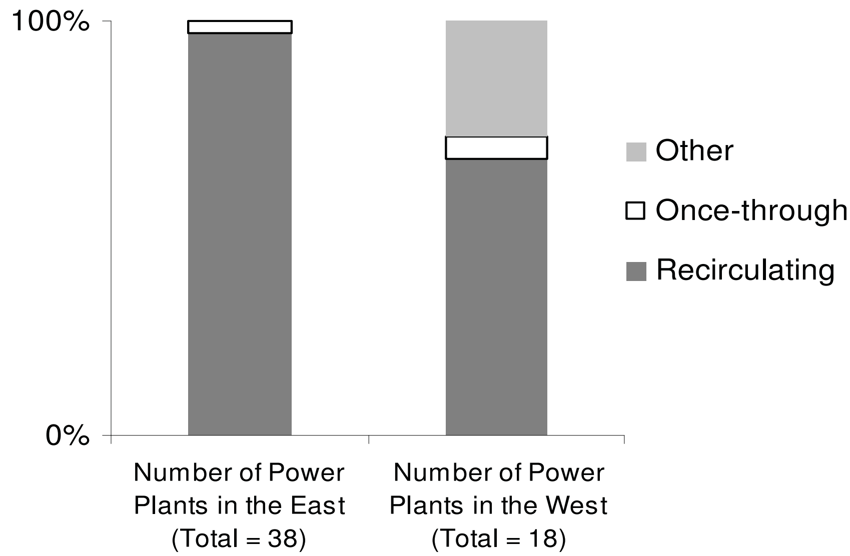

Figure 3-8. Planned, Operating Under Test Conditions, and New Units Under Construction Cooling Systems

This additional analysis illustrates where this industry is headed in terms of cooling technologies. Figure 3-8 illustrates two major points. First, once-through cooling systems are out-dated and are of the past. Power plants today are facing difficulties in obtaining permits for once-through cooling systems and, as a result, are leaning more towards recirculating systems. Secondly, as previous graphs displayed, the use of advanced cooling technologies is growing faster in the West than in the East. This proves that in areas where water availability is already a primary concern, power plants have incentives to adopt low water-intensive technologies. Therefore, as the East begins to face water scarcity issues as in the West, the interest in dry and hybrid cooling technologies will increase.

Shortcomings

While this study provides a tool in which cooling system costs and water withdrawal may be compared between different categories of power plants, there are three major shortcomings. The first is that as power plant categories become more and more specific, the less number of power plants are available to represent the categories. Secondly, the inclusion of operation and maintenance costs for cooling systems would further strengthen this analysis and illustrate how such costs vary with types of cooling systems. However, the EIA does not provide operation and maintenance costs for cooling systems. Finally, the installed costs of cooling systems provided by the EIA purposely exclude the cost of condensers. This is a shortcoming because this excludes the cost of air-cooled condensers for dry cooling systems. This may explain the unexpected low costs of dry cooling systems in this study.

Summary and Conclusions

The results of the first objective can be seen in Table 3-10 where power plants are categorized based on certain characteristics as well as operating and design conditions. Tables 3-5 and 3-6 support the hypothesis of the second objective that the cooling system parameters calculated fall within the ranges of previous studies. The cases where certain values are not as expected can be explained using the methodology or data source. Additionally, the hypothesis of the third objective is also accepted: annualized costs of installed cooling systems for once-through cooling systems are less than for wet-recirculating cooling systems. However, this is true only when power plants of similar ages are compared. This is because once-through systems are much older than wet-recirculating cooling systems. Therefore, when the installed costs of cooling systems are brought to 2008 dollar values, the incorporation of inflation increases the cost of installed cooling systems for once-through cooling systems more than for wet-recirculating cooling systems. Therefore, the age of the power plant must be considered when comparing cost data.

The results of this study support previously sought information, as well as introduce some observations in this field. The first observation is that, in general, it used to be more expensive to install cooling systems than it is today. Secondly, because there are a large number of combined cycle power plants that implement recirculating cooling systems, as opposed to once-through cooling systems, combined cycle power plants are most likely to implement wet-recirculating (or dry) cooling systems. Additionally, Table 3-9 indicates that it is 93% cheaper for power plants to switch to a recirculating cooling pond than to a recirculating cooling tower system, with respect to volume of water saved. Table 3-10 helps clarify which operating and design conditions affect cooling system operations and how. While capacity factor is inversely related to water withdrawal in gal/MWh, thermal efficiency is not. Power plants of greater capacity factors withdraw 61% and 92% less water per MWh in once-through and wet-recirculating cooling systems, respectively. However, power plants of greater capacity factors withdraw 74% more volume of water per year than those with less capacity factors for once-through cooling systems. The cooling systems that correspond with power plants with capacity factors greater than 60 are typically more expensive (ranging from 50 to greater than 100%) than for those with capacity factors less than 60. Additionally, as the cooling water average intake peak water temperatures increase, water withdrawal per MWh increases by 18 to 180%. Also, power plants with greater nameplate capacities can be 96% more efficient in water use, but since they are larger, they are also more expensive and withdraw more volumes of water per year. Generally, about 35% of the results in Table 3-10 indicate that a cooling system that withdraws less water per year is not necessarily a more expensive cooling system. Additionally, Table 3-10 points out that cooling systems built at shallow depths are 90-200% more expensive. The comparison of power plants in the East and West indicate that power plants in the East withdraw greater than 100% more water per year, but are 34 to 300% more expensive to construct for both once-through and recirculating cooling systems. Finally, as categories and sub-categories are selected to produce Table 3-10, it is found that there are more once-through cooling systems in the 1000-2000 MW nameplate capacity category while most of the recirculating systems are in the less than 1000 MW nameplate capacity category. This indicates that either recirculating cooling systems are usually implemented in small power plants, or that the most recent power plants are smaller in nameplate capacity than older power plants.

The results of the fourth objective, the calculation of the CWS, are values that are lower than expected, indicating tremendous water savings with small differences in installed costs of cooling systems. However, the hypothesis that the CWS is greater than one when comparing once-through with wet-recirculating systems is supported by Table 3-9. The CWS can range from 0.4 to almost 60,000 $/acre-foot, indicating the magnitude that certain conditions have on water withdrawal and cost of cooling systems. In general, the conditions which cause cooling system to withdraw less water are not necessarily the more expensive conditions, and vice versa. While Yang (2007) concludes that operating conditions do not account for all the variability in water withdrawal and consumption in power plants, the same can be said for installed costs of cooling systems. While there are several factors that may affect the costs of cooling systems and are not incorporated in this study, the results from this study provide a basis from which cost estimations can be made for thermoelectric power plants. Furthermore, for a power plant of specific operating and design conditions, the cooling system parameters calculated in this study may be used to estimate the water withdrawal and costs of future power plants.

Recommendations

To refine the analyses presented in this study, operation and maintenance costs should be incorporated into the cost of water saved, if and when such data become available to the public. This would account for the cases where the installation of a particular cooling system is inexpensive but the operation and maintenance is relatively high (and vice versa). Additionally, the inclusion of a larger number of power plants that implement dry and hybrid cooling technologies is recommended so that the cost and water withdrawal data for these categories are more robust. As more recent data become available, this study can be repeated for the years 2009 and 2010 so that the changes over the years may be analyzed. Perhaps the economic downturn of 2008 affected the number of planned dry cooling systems as well as the cost to install such systems. Performing such a study would shed light on the variability in water withdrawal from year to year.

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Chapter 4. CONCLUSIONS AND RECOMMENDATIONS

The results of the first objective can be seen in Table 3-10 where power plants are categorized based on certain characteristics as well as operating and design conditions. Tables 3-5 and 3-6 support the hypothesis of the second objective that the cooling system parameters calculated fall within the ranges of previous studies. The cases where certain values are not as expected can be explained using the methodology or data source. Additionally, the hypothesis of the third objective is also accepted: annualized costs of installed cooling systems for once-through cooling systems are less than for wet-recirculating cooling systems. However, this is true only when power plants of similar ages are compared. This is because once-through systems are much older than wet-recirculating cooling systems. Therefore, when the installed costs of cooling systems are brought to 2008 dollar values, the incorporation of inflation increases the cost of installed cooling systems for once-through cooling systems more than for wet-recirculating cooling systems. Therefore, the age of the power plant must be considered when comparing cost data.

The results of this study support previously sought information, as well as introduce some observations in this field. The first observation is that, in general, it used to be more expensive to install cooling systems than it is today. Secondly, because there are a large number of combined cycle power plants that implement recirculating cooling systems, as opposed to once-through cooling systems, combined cycle power plants are most likely to implement wet-recirculating (or dry) cooling systems. Additionally, Table 3-9 indicates that it is 93% cheaper for power plants to switch to a recirculating cooling pond than to a recirculating cooling tower system, with respect to volume of water saved. Table 3-10 helps clarify which operating and design conditions affect cooling system operations and how. While capacity factor is inversely related to water withdrawal in gal/MWh, thermal efficiency is not. Power plants of greater capacity factors withdraw 61% and 92% less water per MWh in once-through and wet-recirculating cooling systems, respectively. However, power plants of greater capacity factors withdraw 74% more volume of water per year than those with less capacity factors for once-through cooling systems. The cooling systems that correspond with power plants with capacity factors greater than 60 are typically more expensive (ranging from 50 to greater than 100%) than for those with capacity factors less than 60. Additionally, as the cooling water average intake peak water temperatures increase, water withdrawal per MWh increases by 18 to 180%. Also, power plants with greater nameplate capacities can be 96% more efficient in water use, but since they are larger, they are also more expensive and withdraw more volumes of water per year. Generally, about 35% of the results in Table 3-10 indicate that a cooling system that withdraws less water per year is not necessarily a more expensive cooling system. Additionally, Table 3-10 points out that cooling systems built at shallow depths are 90-200% more expensive. The comparison of power plants in the East and West indicate that power plants in the East withdraw greater than 100% more water per year, but are 34 to 300% more expensive to construct for both once-through and recirculating cooling systems. Finally, as categories and sub-categories are selected to produce Table 3-10, it is found that there are more once-through cooling systems in the 1000-2000 MW nameplate capacity category while most of the recirculating systems are in the less than 1000 MW nameplate capacity category. This indicates that either recirculating cooling systems are usually implemented in small power plants, or that the most recent power plants are smaller in nameplate capacity than older power plants.

The results of the fourth objective, the calculation of the CWS, are values that are lower than expected, indicating tremendous water savings with small differences in installed costs of cooling systems. However, the hypothesis that the CWS is greater than one when comparing once-through with wet-recirculating systems is supported by Table 3-9. The CWS can range from 0.4 to almost 60,000 $/acre-foot, indicating the magnitude that certain conditions have on water withdrawal and cost of cooling systems. In general, the conditions which cause cooling system to withdraw less water are not necessarily the more expensive conditions, and vice versa. While Yang (2007) concludes that operating conditions do not account for all the variability in water withdrawal and consumption in power plants, the same can be said for installed costs of cooling systems. While there are several factors that may affect the costs of cooling systems and are not incorporated in this study, the results from this study provide a basis from which cost estimations can be made for thermoelectric power plants. Furthermore, for a power plant of specific operating and design conditions, the cooling system parameters calculated in this study may be used to estimate the water withdrawal and costs of future power plants.

To refine the analyses presented in this study, operation and maintenance costs should be incorporated into the cost of water saved, if and when such data become available to the public. This would account for the cases where the installation of a particular cooling system is inexpensive but the operation and maintenance is relatively high (and vice versa). Additionally, the inclusion of a larger number of power plants that implement dry and hybrid cooling technologies is recommended so that the cost and water withdrawal data for these categories are more robust. As more recent data become available, this study can be repeated for the years 2009 and 2010 so that the changes over the years may be analyzed. Perhaps the economic downturn of 2008 affected the number of planned dry cooling systems as well as the cost to install such systems. Performing such a study would shed light on the variability in water withdrawal from year to year.

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Appendix A. EIA Parameters & Codes

Table A-1. EIA Parameters, Locations, and Descriptions

Parameter Name (as given by the EIA)	Data file	Table Name	Sheet Name	Column	Units	Description
Plant_Code	EIA-860 2008	F860_Schedule_6_Y08	F860 Cooling System	C	EIA-given Code	Plant Code
Cooling Status				E	Code 1	Cooling System Status
Inservice_YR				G	Year	Cooling System Actual or Projected Inservice Year
Cooling_Type1				H	Code 2	Type of Cooling System (1^{st})
Cooling_Type2				I		Type of Cooling System (2^{nd})
Cooling Water Source				L	Name of Source	Source of Cooling Water
Tower_Type1				V	Code 3	Cooling Towers - Type of Towers (1st)
Cost_total				Z	$1,000.00	Installed cost of cooling system
Cost_Ponds				AA	$1,000.00	Installed cost of cooling ponds
Cost_Towers				AB	$1,000.00	Installed cost of cooling towers
Intake_Distance_Shore				AD	feet	Maximum Distance from Shore – Inlet
Intake_Distance_Surface				AF	feet	Average Distance Below Water Surface – Inlet
UTILNAME		GenY08	NA	A	name	Company Name
PLNTNAME				B	name	Plant Name
PLNTCODE				E	EIA-given Code	Plant Code
PRIMEMOVER				G	Code 4	Generator Unit Type
STATUS				O	Code 5	Status of Generator
OPERATING_YEAR				R	Year	Year of Initial Commercial Operation
PLNTCODE		PlantY08	NA	B	EIA-given Code	Plant Code
NERC				J	NERC Code	NERC Region
Primary_Purpose				K	North American Industry Classification System	Primary Purpose of Plant

Parameter Name (as given by the EIA)	Data file	Table Name	Sheet Name	Column	Units	Description
FERC_COGEN				P	Y = Yes, N = No	FERC Qualifying Facility Cogenerator Status
Plant ID	EIA 923 2008	SCHEDULE 3A 5A 8A 8B 8C 8D 8E 8F 2008	Cooling Operations	B	EIA-given Code	Plant Code
Annual Withdrawal Rate				F	ft^3/sec	Average Rate of Cooling Water
Annual Discharge Rate				G	ft^3/sec	Average Rate of Cooling Water
Annual Consumption Rate				H	ft^3/sec	Average Rate of Cooling Water
Intake Peak Winter Temperature				I	Degrees F	Maximum cooling water temperature intake
Intake Peak Summer Temperature				J	Degrees F	Maximum cooling water temperature intake
Outlet Peak Winter Temperature				K	Degrees F	Maximum cooling water temperature at outlet
Outlet Peak Summer Temperature				L	Degrees F	Maximum cooling water temperature at outlet
Plant ID			Generator	A	EIA-given Code	Plant Code
Nameplate Capacity				F	MW	Nameplate Capacity for Generator
Total Annual Net Generation				S	MWh	Total Annual Net Generation
Plant ID			Boiler Fuel	B	EIA-given Code	Plant Code
Energy Source				E	Code 6	Energy Source Code
January Quantity				F	Code 7	Total quantity of fuel burn in month
February Quantity				G		Total quantity of fuel burn in month
March Quantity				H		Total quantity of fuel burn in month
April Quantity				I		Total quantity of fuel burn in month
May Quantity				J		Total quantity of fuel burn in month
June Quantity				K		Total quantity of fuel burn in month
July Quantity				L		Total quantity of fuel burn in month
August Quantity				M		Total quantity of fuel burn in month
September Quantity				N		Total quantity of fuel burn in month
October Quantity				O		Total quantity of fuel burn in month
November Quantity				P		Total quantity of fuel burn in month
December Quantity				Q		Total quantity of fuel burn in month
January Heat Content				R	MMBtu/unit	Average Heat Content as Burned
February Heat Content				S		Average Heat Content as Burned
March Heat Content				T		Average Heat Content as Burned

Parameter Name (as given by the EIA)	Data file	Table Name	Sheet Name	Column	Units	Description
April Heat Content				U		Average Heat Content as Burned
May Heat Content				V		Average Heat Content as Burned
June Heat Content				W		Average Heat Content as Burned
July Heat Content				X		Average Heat Content as Burned
August Heat Content				Y		Average Heat Content as Burned
September Heat Content				Z		Average Heat Content as Burned
October Heat Content				AA		Average Heat Content as Burned
November Heat Content				AB		Average Heat Content as Burned
December Heat Content				AC		Average Heat Content as Burned
Water Pollution Abatement Collection O&M Expense			ByProduct Expenses and Revenues	F	$1,000	Operation and Maintenance (O&M) Expenditures During Year (1000 Dollars)
Water Pollution Abatement Disposal O&M Expense				L	$1,000	
Water Pollution Abatement Other O&M Expense				R	$1,000	
Water Pollution Abatement Capital Expenditures				V	$1,000	Capital Expenditures for New Structures and Equipment

Table A-2. EIA Unit Codes

Code 1 – Cooling System Status Codes	
CN	Canceled (previously reported as "planned")
CO	New unit under construction
OP	Operating (in commercial service or out of service less than 365 days)
OS	Out of service (365 days or longer)
PL	Planned (on order and expected to go into commercial service within 5 years)
RE	Retired (no longer in service and not expected to be returned to service)
SB	Standby (or inactive reserve); i.e., not normally used, but available for service)
SC	Cold Standby (Reserve); deactivated (usually requires 3 to 6 months to reactivate)
TS	Operating under test conditions (not in commercial service)

Code 2 – Type of Cooling System	
OC	Once-through with cooling pond(s) or canal(s)
OF	Once-through, fresh water
OS	Once-through, saline water
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)
OT	Other (specify in a footnote on SCHEDULE 7)

Code 3 – Type of Towers	
MD	Mechanical draft, dry process
MW	Mechanical draft, wet process
ND	Natural draft, dry process
NW	Natural draft, wet process
WD	Combination wet and dry processes

Code 4 – Prime Mover	
ST	Steam Turbine, including nuclear, geothermal and solar steam (does not include combined cycle)
GT	Combustion (Gas) Turbine (includes jet engine design)
IC	Internal Combustion Engine (diesel, piston)
CA	Combined Cycle Steam Part
CT	Combined Cycle Combustion Turbine Part
CS	Combined Cycle Single Shaft (combustion turbine and steam turbine share a single generator)
CC	Combined Cycle - Total Unit

HY	Hydraulic Turbine (includes turbines associated with delivery of water by pipeline)
PS	Hydraulic Turbine – Reversible (pumped storage)
BT	Turbines used in a binary cycle such as geothermal
PV	Photovoltaic
WT	Wind Turbine
CE	Compressed Air Energy Storage
FC	Fuel Cell
OT	Other
NA	Unknown at this time (use only for plants/generators in planning stage)

Code 5 – Status of Generator	
OP	Operating - in service (commercial operation) and producing some electricity. Includes peaking units that are run on an as-needed (intermittent or seasonal) basis.
SB	Standby/Backup - available for service but not normally used (has little or no generation during the year).
OA	Out of Service - was not used for some or all of the reporting period but was either returned to service on December 31 or will be returned to service in the next calendar year.
OS	Out of Service - was not used for some or all of the reporting period and is not expected to be returned to service in the next calendar year.
RE	Retired - no longer in service and not expected to be returned to service.

Code 6 – Energy Source	
BIT	(Anthracite Coal, Bituminous Coal)
LIG	Lignite Coal
SUB	Sub-bituminous Coal
WC	Waste/Other Coal (Anthracite Culm, Bituminous Gob, Fine Coal, Lignite Waste, Waste Coal)
SC	Coal Synfuel. Coal-based solid fuel that has been processed by a coal synfuel plant, and coal-based fuels such as briquettes, pellets, or extrusions, which are formed from fresh or recycled coal and binding materials.
DFO	Distillate Fuel Oil (includes all Diesel and No. 1, No. 2, and No. 4 Fuel Oils)
JF	Jet Fuel
KER	Kerosene
RFO	Residual Fuel Oil (includes No. 5 and No. 6 Fuel Oils and Bunker C Fuel Oil)
WO	Oil-Other and Waste Oil (Butane (Liquid), Crude Oil, Liquid Byproducts, Oil Waste, Propane (Liquid), Re-refined
PC	Petroleum Coke

NG	Natural Gas
BFG	Blast Furnace Gas
OG	Other Gas (Butane, Coal Processes, Coke-Oven, Refinery, and other processes)
PG	Propane
SG	Synthetic Gas, other than coal-derived
SGC	Synthetic gas, derived from coal
NUC	Nuclear (Uranium, Plutonium, Thorium)
AB	Agriculture Crop Byproducts/Straw/Energy Crops
BLQ	Black Liquor
GEO	Geothermal
LFG	Landfill Gas
MSW	Municipal Solid Waste
OBS	Other Biomass Solid (Animal Manure and Waste, Solid Byproducts, and other solid biomass not specified)
OBL	Other Biomass Liquid (Ethanol, Fish Oil, Liquid Acetonitrile Waste, Medical Waste, Tall Oil, Waste Alcohol, and other Biomass not specified)
OBG	Other Biomass Gases (Digester Gas, Methane, and other biomass gases)
OTH	Other (Batteries, Chemicals, Coke Breeze, Hydrogen, Pitch, Sulfur, Tar Coal, and miscellaneous technologies)
PUR	Purchased Steam
SLW	Sludge Waste
SUN	Solar (Photovoltaic, Thermal)
TDF	Tires
WAT	Water (Conventional, Pumped Storage)
WDS	Wood/Wood Waste Solids (Paper Pellets, Railroad Ties, Utility Poles, Wood Chips, and other wood solids)
WDL	Wood Waste Liquids (Red Liquor, Sludge Wood, Spent Sulfite Liquor, and other wood related liquids not
WND	Wind
NA	Not Available

Code 7 – Unit for Energy Source	
BIT	tons
LIG	tons
SC	tons
SUB	tons
WC	tons
DFO	barrels
JF	barrels
KER	barrels
PC	tons
RFO	barrels

WO	barrels
BFG	Mcf
OG	Mcf
NG	Mcf
PG	Mcf
SG	Mcf
SGC	Mcf
AB	tons
MSB	tons
MSN	tons
OBS	tons
WDS	tons
OBL	barrels
SLW	tons
BLQ	tons
WDL	barrels
LFG	Mcf
OBG	Mcf

Appendix B. MySQL Queries

Query 1: Combining Generator Information

```
Select table1.UTILNAME, table1.PLNTNAME, table1.plntcode,
table1.PRIMEMOVER, table1.ENERGY_SOURCE_1, table1.`Sum of
Nameplate Capacity`, table1.`Sum of Total Annual Net Generation`,
2010-table1.`Avg of Operating Year` as `Avg Age of Generators`

from
(Select geny08.UTILNAME, geny08.PLNTNAME,
geny08.plntcode,
geny08.PRIMEMOVER,
geny08.ENERGY_SOURCE_1,
sum(geny08.NAMEPLATE) as `Sum of Nameplate Capacity`,
sum(generator.`Total Annual Net Generation`) as `Sum of Total
Annual Net Generation`,
avg(geny08.OPERATING_YEAR) as `Avg of Operating Year`
from geny08 inner join generator on geny08.PLNTCODE =
generator.`Plant ID` and geny08.GENCODE=generator.`Generator ID`

where geny08.`STATUS`='OP' and geny08.ENERGY_SOURCE_1='BIT' or
geny08.ENERGY_SOURCE_1='LIG' or geny08.ENERGY_SOURCE_1='SUB'
or geny08.ENERGY_SOURCE_1='WC' or geny08.ENERGY_SOURCE_1='SC' or
geny08.ENERGY_SOURCE_1='DFO' or geny08.ENERGY_SOURCE_1='KER'
or geny08.ENERGY_SOURCE_1='RFO' or geny08.ENERGY_SOURCE_1='WO' or
geny08.ENERGY_SOURCE_1='PC' or geny08.ENERGY_SOURCE_1='NG'
or geny08.ENERGY_SOURCE_1='BFG' or geny08.ENERGY_SOURCE_1='OG' or
geny08.ENERGY_SOURCE_1='PG' or geny08.ENERGY_SOURCE_1='SG'
or geny08.ENERGY_SOURCE_1='SGC'


group by geny08.PLNTCODE) as table1
```

Query 2: Combining Cooling System Information

```
select table2.PLANT_CODE,table2.COOLING_TYPE1, table2.COOLING_TYPE2,
table2.TOWER_TYPE1,table2.`Sum Cost Total`, table2.`Sum Cost Ponds`,
table2.`Sum Cost Towers`, table2.`Sum Cost Chlorine`,
table2.`Total W Rate`, table2.`Total D Rate`, table2.`Total C Rate`,
table2.`Avg Age of Cooling System`, table2.`Avg Dist Shore`,
table2.`Avf Dist Surface`, table2.`Avg Intake Pk Summer`, table2.`Avg Intake
Pk Winter`,
table2.`Avg Outlet Pk Summer`, table2.`Avg Outlet Pk Winter`,
(table2.`Avg Intake Pk Summer`+ table2.`Avg Intake Pk Winter`) / 2 as `Avg
Intake Temperature`,
((table2.`Avg Outlet Pk Summer` - table2.`Avg Intake Pk Summer`) +
(table2.`Avg Outlet Pk Winter` - table2.`Avg Intake Pk Winter`)) / 2 as `Avg
Temperature Rise`

from
(select table1.PLANT_CODE,table1.COOLING_TYPE1, table1.COOLING_TYPE2,
table1.TOWER_TYPE1,table1.`Sum Cost Total`, table1.`Sum Cost Ponds`,
table1.`Sum Cost Towers`, table1.`Sum Cost Chlorine`,
table1.`Total W Rate`, table1.`Total D Rate`, table1.`Total C Rate`, 2010-
table1.`Avg Inservice Yr` as `Avg Age of Cooling System`, table1.`Avg Dist
Shore`,
table1.`Avf Dist Surface`, table1.`Avg Intake Pk Summer`, table1.`Avg Intake
Pk Winter`, table1.`Avg Outlet Pk Summer`, table1.`Avg Outlet Pk Winter`

from
(select f860_cooling_system.PLANT_CODE,
f860_cooling_system.COOLING_TYPE1, f860_cooling_system.COOLING_TYPE2,
f860_cooling_system.TOWER_TYPE1,

sum(f860_cooling_system.COST_TOTAL) as `Sum Cost Total`,
sum(f860_cooling_system.COST_PONDS) as `Sum Cost Ponds`,
sum(f860_cooling_system.COST_TOWERS) as `Sum Cost Towers`,
sum(f860_cooling_system.COST_CHLORINE_EQUIPMENT) as `Sum Cost Chlorine`,
sum(`cooling operations`.`Annual Withdrawal Rate`) as `Total W Rate`,
sum(`cooling operations`.`Annual Discharge Rate`) as `Total D Rate`,
sum(`cooling operations`.`Annual Consumption Rate`) as `Total C Rate`,
avg(f860_cooling_system.INSERVICE_YR) as `Avg Inservice Yr`,
avg(f860_cooling_system.INTAKE_DISTANCE_SHORE) as `Avg Dist Shore`,
avg(f860_cooling_system.INTAKE_DISTANCE_SURFACE) as `Avf Dist Surface`,
avg(`cooling operations`.`Intake Peak Summer Temperature`) as `Avg Intake Pk
Summer`, avg(`cooling operations`.`Intake Peak Winter Temperature`) as `Avg
Intake Pk Winter`,
avg(`cooling operations`.`Outlet Peak Summer Temperature`) as `Avg Outlet Pk
Summer`, avg(`cooling operations`.`Outlet Peak Winter Temperature`) as `Avg
Outlet Pk Winter`
from f860_cooling_system inner join `cooling operations` on
f860_cooling_system.PLANT_CODE=`cooling operations`.`Plant ID` and
f860_cooling_system.COOLING_ID=`cooling operations`.`Cooling System ID`
where f860_cooling_system.COOLING_STATUS='OP'
-- and f860_cooling_system.PLANT_CODE='3935'
group by f860_cooling_system.PLANT_CODE) as table1)

as table2
where table2.`Sum Cost Total` != '0'
```

Query 3: Combining Boiler Information

```
select table3.`Plant ID`,sum(table3.H) as `Total Annual Supplied Heat`


from
(select table2.`Plant ID`, `Average Heat Content` * `Total Quantity` as
`H`

from
(select table1.`Plant ID`, table1.`Boiler ID`, table1.`Energy Source`,
table1.PRIMARY_FUEL1, table1.`Total Heat Content`, `Total Heat Content`
/ 12 as `Average Heat Content`,table1.`Total Quantity`

from
(select DISTINCT boiler_fuel.`Plant ID`, boiler_fuel.`Boiler ID`,
boiler_fuel.`Energy Source`, boiler_fuel.`January Quantity`,
boiler_fuel.`February Quantity`, boiler_fuel.`March Quantity`,
boiler_fuel.`April Quantity`, boiler_fuel.`May Quantity`,
boiler_fuel.`June Quantity`,boiler_fuel.`July Quantity`,
boiler_fuel.`August Quantity`,
boiler_fuel.`September Quantity`, boiler_fuel.`October Quantity`,
boiler_fuel.`November Quantity`, boiler_fuel.`December Quantity`,
boiler_fuel.`January Heat Content`, boiler_fuel.`February Heat Content`,
boiler_fuel.`March Heat Content`, boiler_fuel.`April Heat Content`,
boiler_fuel.`May Heat Content`, boiler_fuel.`June Heat Content`,
boiler_fuel.`July Heat Content`, boiler_fuel.`August Heat Content`,
boiler_fuel.`September Heat Content`, boiler_fuel.`October Heat
Content`, boiler_fuel.`November Heat Content`, boiler_fuel.`December
Heat Content`,
f860_boiler.PLANT_CODE, f860_boiler.BOILER_ID,
f860_boiler.PRIMARY_FUEL1,
`January Quantity` + `February Quantity` + `March Quantity` + `April
Quantity` + `May Quantity` + `June Quantity` + `July Quantity` + `August
Quantity` + `September Quantity` + `October Quantity` + `November
Quantity` + `December Quantity` as `Total Quantity`,
`January Heat Content`+`February Heat Content`+`March Heat
Content`+`April Heat Content`+`May Heat Content`+`June Heat
Content`+`July Heat Content`+`August Heat Content`+`September Heat
Content`+`October Heat Content`+`November Heat Content`+`December Heat
Content`as `Total Heat Content`
from boiler_fuel inner join f860_boiler on boiler_fuel.`Plant
ID`=f860_boiler.PLANT_CODE and boiler_fuel.`Boiler
ID`=f860_boiler.BOILER_ID
where f860_boiler.BOILER_STATUS='OP') as table1) as table2) as table3
-- where table3.`Plant ID`='3935'

group by table3.`Plant ID`
```

Query 4: Combining Plant Information

```
select planty08.PLNTCODE, NERC, NAME_OF_WATER_SOURCE

from planty08

WHERE
FERC_COGEN = 'N' AND PRIMARY_PURPOSE = 22
```

Query 5: Merging All Four Tables Into One

```
SELECT
      everything.`Plant ID`,
      PLNTNAME AS `Plant Name`,
      UTILNAME AS `Utility Name`,
      ENERGY_SOURCE_1 AS `Primary Energy Source`,
      PRIMEMOVER AS `Prime Mover`,
      NERC AS `Reigon`,
      COOLING_TYPE1 AS `Primary Cooling Type`,
      COOLING_TYPE2 AS `Secondary Cooling Type`,
      TOWER_TYPE1 AS `Primary Tower Type`,
      `Total Annual Supplied Heat`,
      `Sum of Nameplate Capacity`,
      `Sum of Total Annual Net Generation`,
      `Avg Age of Generators`,
      NAME_OF_WATER_SOURCE AS `Name of Water Source`,
      `Sum Cost Total` AS `Total Cost`,
      `Sum Cost Ponds` AS `Total Cost of Ponds`,
      `Sum Cost Chlorine` AS `Total Cost of Chlorine`,
      `Total W Rate`,
      `Total D Rate`,
      `Total C Rate`,
      `Avg Age of Cooling System`,
      `Avg Dist Shore`,
      `Avf Dist Surface` AS `Average Distance Surface`,
      `Avg Intake Pk Summer`,
      -- `Avg Intake Pk Winter`,
      -- `Avg Outlet Pk Summer`,
      -- `Avg outlet Pk Winter`,
      `Avg Intake Temperature`,
      `Avg Temperature Rise`,
      byproductexpensesandrevenues.`Water Abatement Collection O&M
Expense`,
      byproductexpensesandrevenues.`Water Abatement Disposal O&M
Expense`,
      byproductexpensesandrevenues.`Water Abatement Other O&M
Expense`,
      byproductexpensesandrevenues.`Water Abatement Capital
Expenditures`
FROM

(
Select
*
```

Query 5 Continued

```
From
(SELECT*
FROM(
SELECT*
FROM
(
(SELECT
table3.`Plant ID`,
sum(table3.H)AS `Total Annual Supplied Heat`
FROM(
SELECT
table2.`Plant ID`,
`Average Heat Content` * `Total Quantity` AS `H`
FROM(
SELECT
table1.`Plant ID`,
table1.`Boiler ID`,
table1.`Energy Source`,
table1.PRIMARY_FUEL1,
table1.`Total Heat Content`,
`Total Heat Content` / 12 AS `Average Heat Content`,
table1.`Total Quantity`
FROM(
SELECT DISTINCT
boiler_fuel.`Plant ID`,
boiler_fuel.`Boiler ID`,
boiler_fuel.`Energy Source`,
boiler_fuel.`January Quantity`,
boiler_fuel.`February Quantity`,
boiler_fuel.`March Quantity`,
boiler_fuel.`April Quantity`,
boiler_fuel.`May Quantity`,
boiler_fuel.`June Quantity`,
boiler_fuel.`July Quantity`,
boiler_fuel.`August Quantity`,
boiler_fuel.`September Quantity`,
boiler_fuel.`October Quantity`,
boiler_fuel.`November Quantity`,
boiler_fuel.`December Quantity`,
boiler_fuel.`January Heat Content`,
boiler_fuel.`February Heat Content`,
boiler_fuel.`March Heat Content`,
boiler_fuel.`April Heat Content`,
boiler_fuel.`May Heat Content`,
boiler_fuel.`June Heat Content`,
boiler_fuel.`July Heat Content`,
boiler_fuel.`August Heat Content`,
boiler_fuel.`September Heat Content`,
boiler_fuel.`October Heat Content`,
boiler_fuel.`November Heat Content`,
boiler_fuel.`December Heat Content`,
```

Query 5 Continued

```
f860_boiler.PLANT_CODE,
f860_boiler.BOILER_ID,
f860_boiler.PRIMARY_FUEL1,
`January Quantity` + `February Quantity` + `March Quantity` + `April
Quantity` + `May Quantity` + `June Quantity` + `July Quantity` + `August
Quantity` + `September Quantity` + `October Quantity` + `November
Quantity` + `December Quantity` AS `Total Quantity`,
`January Heat Content` + `February Heat Content` + `March Heat Content`
+ `April Heat Content` + `May Heat Content` + `June Heat Content` +
`July Heat Content` + `August Heat Content` + `September Heat Content` +
`October Heat Content` + `November Heat Content` + `December Heat
Content` AS `Total Heat Content`
FROM
boiler_fuel
INNER JOIN f860_boiler ON boiler_fuel.`Plant ID` =
f860_boiler.PLANT_CODE
AND boiler_fuel.`Boiler ID` = f860_boiler.BOILER_ID
WHERE
f860_boiler.BOILER_STATUS = 'OP'
)AS table1
)AS table2
)AS table3
GROUP BY
table3.`Plant ID`
)AS boiler
JOIN(
SELECT
table1.UTILNAME,
table1.PLNTNAME,
table1.plntcode,
table1.PRIMEMOVER,
table1.ENERGY_SOURCE_1,
table1.`Sum of Nameplate Capacity`,
table1.`Sum of Total Annual Net Generation`,
2010 - table1.`Avg of Operating Year` AS `Avg Age of Generators`
FROM
(
SELECT
geny08.UTILNAME,
geny08.PLNTNAME,
geny08.plntcode,
geny08.PRIMEMOVER,
geny08.ENERGY_SOURCE_1,
sum(geny08.NAMEPLATE)AS `Sum of Nameplate Capacity`,
sum(generator.`Total Annual Net Generation`)AS `Sum of Total Annual Net
Generation`,
avg(geny08.OPERATING_YEAR)AS `Avg of Operating Year`
FROM
geny08
INNER JOIN generator ON geny08.PLNTCODE = generator.`Plant ID`
AND geny08.GENCODE = generator.`Generator ID`
WHERE
```

Query 5 Continued

```
geny08.`STATUS` = 'OP'
AND geny08.ENERGY_SOURCE_1 = 'BIT'
OR geny08.ENERGY_SOURCE_1 = 'LIG'
OR geny08.ENERGY_SOURCE_1 = 'SUB'
OR geny08.ENERGY_SOURCE_1 = 'WC'
OR geny08.ENERGY_SOURCE_1 = 'SC'
OR geny08.ENERGY_SOURCE_1 = 'DFO'
OR geny08.ENERGY_SOURCE_1 = 'KER'
OR geny08.ENERGY_SOURCE_1 = 'RFO'
OR geny08.ENERGY_SOURCE_1 = 'WO'
OR geny08.ENERGY_SOURCE_1 = 'PC'
OR geny08.ENERGY_SOURCE_1 = 'NG'
OR geny08.ENERGY_SOURCE_1 = 'BFG'
OR geny08.ENERGY_SOURCE_1 = 'OG'
OR geny08.ENERGY_SOURCE_1 = 'PG'
OR geny08.ENERGY_SOURCE_1 = 'SG'
OR geny08.ENERGY_SOURCE_1 = 'SGC'
GROUP BY
      geny08.PLNTCODE)AS table1
)AS generator2 ON boiler.`Plant ID` = generator2.plntcode
))AS boilerGenerator
JOIN(
SELECT
planty08.PLNTCODE AS `PLANT_CODE`,NERC,NAME_OF_WATER_SOURCE
FROM planty08
WHERE
FERC_COGEN = 'N' AND PRIMARY_PURPOSE = 22
)AS waterSrce ON boilerGenerator.plntcode = waterSrce.PLANT_CODE
)AS boilerGeneratorWater
JOIN(
SELECT
            table2.PLANT_CODE as `plant Code`,
            table2.COOLING_TYPE1,
            table2.COOLING_TYPE2,
            table2.TOWER_TYPE1,
            table2.`Sum Cost Total`,
            table2.`Sum Cost Ponds`,
            table2.`Sum Cost Towers`,
            table2.`Sum Cost Chlorine`,
            table2.`Total W Rate`,
            table2.`Total D Rate`,
            table2.`Total C Rate`,
            table2.`Avg Age of Cooling System`,
            table2.`Avg Dist Shore`,
            table2.`Avf Dist Surface`,
            table2.`Avg Intake Pk Summer`,
            table2.`Avg Intake Pk Winter`,
            table2.`Avg Outlet Pk Summer`,
            table2.`Avg Outlet Pk Winter`,
(table2.`Avg Intake Pk Summer` + table2.`Avg Intake Pk Winter`)/ 2 AS
`Avg Intake Temperature`,(
(table2.`Avg Outlet Pk Summer` - table2.`Avg Intake Pk
Summer`)+(table2.`Avg Outlet Pk Winter` - table2.`Avg Intake Pk
Winter`))/ 2 AS `Avg Temperature Rise`
```

Query 5 Continued

```
FROM(SELECT
       table1.PLANT_CODE,
       table1.COOLING_TYPE1,
       table1.COOLING_TYPE2,
       table1.TOWER_TYPE1,
       table1.`Sum Cost Total`,
       table1.`Sum Cost Ponds`,
       table1.`Sum Cost Towers`,
       table1.`Sum Cost Chlorine`,
       table1.`Total W Rate`,
       table1.`Total D Rate`,
       table1.`Total C Rate`,
       2010 - table1.`Avg Inservice Yr` AS `Avg Age of Cooling System`,
       table1.`Avg Dist Shore`,
       table1.`Avf Dist Surface`,
       table1.`Avg Intake Pk Summer`,
       table1.`Avg Intake Pk Winter`,
       table1.`Avg Outlet Pk Summer`,
       table1.`Avg Outlet Pk Winter`
FROM(SELECT
       f860_cooling_system.PLANT_CODE,
       f860_cooling_system.COOLING_TYPE1,
       f860_cooling_system.COOLING_TYPE2,
       f860_cooling_system.TOWER_TYPE1,
       sum(f860_cooling_system.COST_TOTAL)AS `Sum Cost Total`,
       sum(f860_cooling_system.COST_PONDS)AS `Sum Cost Ponds`,
       sum(f860_cooling_system.COST_TOWERS)AS `Sum Cost Towers`,
       sum(f860_cooling_system.COST_CHLORINE_EQUIPMENT)AS `Sum Cost Chlorine`,
       sum(`cooling operations`.`Annual Withdrawal Rate`)AS `Total W Rate`,
       sum(`cooling operations`.`Annual Discharge Rate`)AS `Total D Rate`,
       sum(`cooling operations`.`Annual Consumption Rate`)AS `Total C Rate`,
       avg(f860_cooling_system.INSERVICE_YR)AS `Avg Inservice Yr`,
       avg(f860_cooling_system.INTAKE_DISTANCE_SHORE)AS `Avg Dist Shore`,
       avg(f860_cooling_system.INTAKE_DISTANCE_SURFACE)AS `Avf Dist Surface`,
       avg(`cooling operations`.`Intake Peak Summer Temperature`)AS `Avg Intake
Pk Summer`,
       avg(`cooling operations`.`Intake Peak Winter Temperature`)AS `Avg Intake
Pk Winter`,
       avg(`cooling operations`.`Outlet Peak Summer Temperature`)AS `Avg Outlet
Pk Summer`,
       avg(`cooling operations`.`Outlet Peak Winter Temperature`)AS `Avg Outlet
Pk Winter`
FROM
f860_cooling_system
INNER JOIN `cooling operations` ON f860_cooling_system.PLANT_CODE = `cooling
operations`.`Plant ID`
AND f860_cooling_system.COOLING_ID = `cooling operations`.`Cooling System ID`
WHERE
f860_cooling_system.COOLING_STATUS = 'OP' -- and
f860_cooling_system.PLANT_CODE='3935'
GROUP BY
f860_cooling_system.PLANT_CODE
                          )AS table1
             )AS table2
WHERE
table2.`Sum Cost Total` != '0')AS coolingData ON boilerGeneratorWater.plntcode
=coolingData.`plant Code`
) AS everything
LEFT JOIN
(select * from `byproduct expenses and revenues`
) AS `byproductexpensesandrevenues` on byproductexpensesandrevenues.`Plant ID` =
everything.PLANT_CODE
```

Appendix C. Power Plants Included in Database

Table C-1. List of Power Plants in Study

Plant ID	Plant Name	Utility Name
55173	Acadia Energy Center	Acadia Power Partners
2535	AES Cayuga	AES Cayuga LLC
10670	AES Deepwater	AES Deepwater Inc
2527	AES Greenidge LLC	AES Greenidge
335	AES Huntington Beach LLC	AES Huntington Beach LLC
994	AES Petersburg	Indianapolis Power & Light Co
356	AES Redondo Beach LLC	AES Redondo Beach LLC
6082	AES Somerset LLC	AES Somerset LLC
2526	AES Westover	AES Westover LLC
141	Agua Fria	Salt River Project
1915	Allen S King	Northern States Power Co
4140	Alma	Dairyland Power Coop
8048	Anclote	Progress Energy Florida Inc
6469	Antelope Valley	Basin Electric Power Coop
160	Apache Station	Arizona Electric Power Coop Inc
465	Arapahoe	Public Service Co of Colorado
3178	Armstrong Power Station	Allegheny Energy Supply Co LLC
7512	Arthur Von Rosenberg	San Antonio City of
688	Arvah B Hopkins	City of Tallahassee
2076	Asbury	Empire District Electric Co
2706	Asheville	Progress Energy Carolinas Inc
2835	Ashtabula	FirstEnergy Generation Corp
2836	Avon Lake	Orion Power Midwest LP
2378	B L England	RC Cape May Holdings LLC
995	Bailly	Northern Indiana Pub Serv Co
889	Baldwin Energy Complex	Dynegy Midwest Generation Inc
4939	Barney M Davis	Topaz Power Group LLC
3	Barry	Alabama Power Co
55063	Batesville Generation Facility	LSP Energy Ltd Partnership
2050	Baxter Wilson	Entergy Mississippi Inc
2878	Bay Shore	FirstEnergy Generation Corp
8042	Belews Creek	Duke Energy Carolinas, LLC
603	Benning	Potomac Power Resources
2398	Bergen Generating Station	PSEG Fossil LLC
2539	Bethlehem Energy Center	PSEG Power New York Inc
645	Big Bend	Tampa Electric Co
3497	Big Brown	TXU Generation Co LP
6055	Big Cajun 2	Louisiana Generating LLC
1353	Big Sandy	Kentucky Power Co
6098	Big Stone	Otter Tail Power Co
1904	Black Dog	Northern States Power Co

Plant ID	Plant Name	Utility Name
3992	Blount Street	Madison Gas & Electric Co
6106	Boardman	Portland General Electric Co
7790	Bonanza	Deseret Generation & Tran Coop
703	Bowen	Georgia Power Co
602	Brandon Shores	Constellation Power Source Gen
7846	Brandy Branch	JEA
1619	Brayton Point	Dominion Energy New England, LLC
55357	Brazos Valley Generating Facility	Brazos Valley Energy
3796	Bremo Bluff	Virginia Electric & Power Co
6094	Bruce Mansfield	FirstEnergy Generation Corp
2720	Buck	Duke Energy Carolinas, LLC
1104	Burlington	Interstate Power and Light Co
1552	C P Crane	Constellation Power Source Gen
2549	C R Huntley Generating Station	NRG Huntley Operations Inc
55197	Caledonia	Tennessee Valley Authority
1599	Canal	Mirant Canal LLC
1363	Cane Run	Louisville Gas & Electric Co
609	Cape Canaveral	Florida Power & Light Co
2708	Cape Fear	Progress Energy Carolinas Inc
3644	Carbon	PacifiCorp
2828	Cardinal	Cardinal Operating Co
1001	Cayuga	Duke Energy Indiana Inc
167	Cecil Lynch	Entergy Arkansas Inc
1571	Chalk Point LLC	Mirant Chalk Point LLC
56	Charles R Lowman	PowerSouth Energy Cooperative
7917	Chattahoochee Energy Facility	Oglethorpe Power Corporation
469	Cherokee	Public Service Co of Colorado
3803	Chesapeake	Virginia Electric & Power Co
3797	Chesterfield	Virginia Electric & Power Co
113	Cholla	Arizona Public Service Co
1893	Clay Boswell	Minnesota Power Inc
2721	Cliffside	Duke Energy Carolinas, LLC
983	Clifty Creek	Indiana-Kentucky Electric Corp
3775	Clinch River	Appalachian Power Co
7213	Clover	Virginia Electric & Power Co
6030	Coal Creek	Great River Energy
861	Coffeen	Ameren Energy Generating Co
10071	Cogentrix Virginia Leasing Corporation	Portsmouth Operating Services LLC
47	Colbert	Tennessee Valley Authority
6178	Coleto Creek	ANP-Coleto Creek
10682	Colorado Power Partners	Colorado Energy Management
6076	Colstrip	PPL Montana LLC

Plant ID	Plant Name	Utility Name
8023	Columbia	Wisconsin Power & Light Co
10143	Colver Power Project	Inter-Power/AhlCon Partners, L.P.
470	Comanche	Public Service Co of Colorado
8059	Comanche	Public Service Co of Oklahoma
3118	Conemaugh	Reliant Engy NE Management Co
2840	Conesville	Columbus Southern Power Co
228	Contra Costa	Mirant Delta LLC
6177	Coronado	Salt River Project
8222	Coyote	Otter Tail Power Co
7931	Coyote Springs II	Avista Corp
6021	Craig	Tri-State G & T Assn, Inc
867	Crawford	Midwest Generations EME LLC
641	Crist	Gulf Power Co
3159	Cromby Generating Station	Exelon Power
130	Cross	South Carolina Pub Serv Auth
628	Crystal River	Progress Energy Florida Inc
2454	Cunningham	Southwestern Public Service Co
6823	D B Wilson	Western Kentucky Energy Corp
1702	Dan E Karn	Consumers Energy Co
2723	Dan River	Duke Energy Carolinas, LLC
2480	Danskammer Generating Station	Dynegy Northeast Gen Inc
4158	Dave Johnston	PacifiCorp
663	Deerhaven Generating Station	Gainesville Regional Utilities
1572	Dickerson	Mirant Mid-Atlantic LLC
51	Dolet Hills	Cleco Power LLC
3317	Dolphus M Grainger	South Carolina Pub Serv Auth
2554	Dunkirk Generating Plant	Dunkirk Power LLC
259	Dynegy Morro Bay LLC	Dynegy Morro Bay LLC
260	Dynegy Moss Landing Power Plant	Dynegy -Moss Landing LLC
310	Dynegy South Bay Power Plant	Dynegy South Bay LLC
55282	Dynergy Arlington Valley Energy Facility	Dynegy - Arlington LLC
7897	E B Harris Electric Generating Plant	Southern Power Co
26	E C Gaston	Alabama Power Co
856	E D Edwards	Ameren Energy Resources Generating Co.
2511	E F Barrett	KeySpan Generation LLC
1355	E W Brown	Kentucky Utilities Co
991	Eagle Valley	Indianapolis Power & Light Co
6018	East Bend	Duke Energy Kentucky Inc
2493	East River	Consolidated Edison Co-NY Inc
2837	Eastlake	FirstEnergy Generation Corp

Plant ID	Plant Name	Utility Name
1831	Eckert Station	Lansing Board of Water and Light
593	Edge Moor	Conectiv Delmarva Gen Inc
4050	Edgewater	Wisconsin Power & Light Co
389	El Centro	Imperial Irrigation District
55400	Elk Hills Power LLC	Elk Hills Power LLC
1374	Elmer Smith	City of Owensboro
1832	Erickson Station	Lansing Board of Water and Light
1012	F B Culley	Southern Indiana Gas & Elec Co
56164	Fairbault Energy Park	Minnesota Municipal Power Agny
55298	Fairless Energy Center	Fairless Energy LLC
2513	Far Rockaway	KeySpan Generation LLC
55516	Fayette Energy Facility	Duke Energy Ohio Inc
6179	Fayette Power Project	Lower Colorado River Authority
886	Fisk Street	Midwest Generations EME LLC
6138	Flint Creek	Southwestern Electric Power Co
55480	Forney Energy Center	FPLE Forney LP
2330	Fort Churchill	Sierra Pacific Power Co
1233	Fort Dodge	Sunflower Electric Power Corp
3943	Fort Martin Power Station	Monongahela Power Co
6112	Fort St Vrain	Public Service Co of Colorado
2442	Four Corners	Arizona Public Service Co
55818	Frederickson Power LP	Frederickson Project Operations Inc.
2718	G G Allen	Duke Energy Carolinas, LLC
3648	Gadsby	PacifiCorp
7	Gadsden	Alabama Power Co
3403	Gallatin	Tennessee Valley Authority
1336	Garden City	Sunflower Electric Power Corp
8102	General James M Gavin	Ohio Power Co
4143	Genoa	Dairyland Power Coop
1091	George Neal North	MidAmerican Energy Co
7343	George Neal South	MidAmerican Energy Co
6077	Gerald Gentleman	Nebraska Public Power District
1356	Ghent	Kentucky Utilities Co
6136	Gibbons Creek	Texas Municipal Power Agency
6113	Gibson	Duke Energy Indiana Inc
55482	Goldendale Generating Station	Puget Sound Energy Inc
1240	Gordon Evans Energy Center	Kansas Gas & Electric Co
8	Gorgas	Alabama Power Co
3490	Graham	Luminant Generation Company LLC
377	Grayson	City of Glendale
165	GRDA	Grand River Dam Authority
55146	Green Country Energy LLC	Green Country OP Services LLC
1357	Green River	Kentucky Utilities Co

Plant ID	Plant Name	Utility Name
10	Greene County	Alabama Power Co
7710	H Allen Franklin Combined Cycle	Southern Power Co
3251	H B Robinson	Progress Energy Carolinas Inc
6041	H L Spurlock	East Kentucky Power Coop, Inc
2917	Hamilton	City of Hamilton
55749	Hardin Generator Project	Rocky Mountain Power Inc
990	Harding Street	Indianapolis Power & Light Co
709	Harllee Branch	Georgia Power Co
6193	Harrington	Southwestern Public Service Co
3944	Harrison Power Station	Allegheny Energy Supply Co LLC
169	Harvey Couch	Entergy Arkansas Inc
3179	Hatfields Ferry Power Station	Allegheny Energy Supply Co LLC
891	Havana	Dynegy Midwest Generation Inc
2079	Hawthorn	Kansas City Power & Light Co
525	Hayden	Public Service Co of Colorado
400	Haynes	Los Angeles City of
892	Hennepin Power Station	Dynegy Midwest Generation Inc
1554	Herbert A Wagner	Constellation Power Source Gen
55518	High Desert Power Plant	Tenaska Frontier Partners Ltd
1382	HMP&L Station Two Henderson	Western Kentucky Energy Corp
108	Holcomb	Sunflower Electric Power Corp
55334	Holland Energy Facility	Tenaska Frontier Partners Ltd
3122	Homer City Station	Midwest Generations EME LLC
2951	Horseshoe Lake	Oklahoma Gas & Electric Co
55714	Hot Spring Power Project	Hot Spring Power Co LLC
6772	Hugo	Western Farmers Elec Coop, Inc
6165	Hunter	PacifiCorp
8069	Huntington	PacifiCorp
1248	Hutchinson Energy Center	Westar Energy Inc
863	Hutsonville	Ameren Energy Generating Co
6065	Iatan	Kansas City Power & Light Co
6641	Independence	Entergy Arkansas Inc
594	Indian River Generating Station	Indian River Operations Inc
6481	Intermountain Power Project	Los Angeles City of
2187	J E Corette Plant	PPL Montana LLC
7097	J K Spruce	San Antonio City of
2850	J M Stuart	Dayton Power & Light Co
6181	J T Deely	San Antonio City of
710	Jack McDonough	Georgia Power Co
2049	Jack Watson	Mississippi Power Co
6002	James H Miller Jr	Alabama Power Co
2161	James River Power Station	City Utilities of Springfield
3319	Jefferies	South Carolina Pub Serv Auth

Plant ID	Plant Name	Utility Name
6068	Jeffrey Energy Center	Westar Energy Inc
8066	Jim Bridger	PacifiCorp
3935	John E Amos	Appalachian Power Co
4271	John P Madgett	Dairyland Power Coop
3405	John Sevier	Tennessee Valley Authority
3406	Johnsonville	Tennessee Valley Authority
384	Joliet 29	Midwest Generations EME LLC
874	Joliet 9	Midwest Generations EME LLC
3482	Jones	Southwestern Public Service Co
887	Joppa Steam	Electric Energy Inc
765	Kahe	Hawaiian Electric Co Inc
1381	Kenneth C Coleman	Western Kentucky Energy Corp
3136	Keystone	Reliant Engy NE Management Co
55418	KGen Hot Spring LLC	Cinergy Solutions O&M LLC
55382	KGen Murray I and II LLC	Duke Energy Generation Services
55501	Kiamichi Energy Facility	Kiowa Power Partners LLC
6031	Killen Station	Dayton Power & Light Co
876	Kincaid Generation LLC	Dominion Energy Services Co
55270	Kinder Morgan Power Jackson Facility	Kinder Morgan Power Co
3407	Kingston	Tennessee Valley Authority
733	Kraft	Georgia Power Co
2876	Kyger Creek	Ohio Valley Electric Corp
2713	L V Sutton	Progress Energy Carolinas Inc
1241	La Cygne	Kansas City Power & Light Co
2103	Labadie	Union Electric Co
2098	Lake Road	KCP&L Greater Missouri Operations Co
55097	Lamar Power Project	Lamar Power Partners LP
1047	Lansing	Interstate Power and Light Co
643	Lansing Smith	Gulf Power Co
6204	Laramie River Station	Basin Electric Power Coop
1250	Lawrence Energy Center	Westar Energy Inc
55502	Lawrenceburg Energy Facility	AEP Generating Company
2709	Lee	Progress Energy Carolinas Inc
2817	Leland Olds	Basin Electric Power Coop
3457	Lewis Creek	Entergy Texas Inc.
298	Limestone	NRG Texas Power LLC
1402	Little Gypsy	Entergy Louisiana Inc
2240	Lon Wright	Fremont City of
1443	Louis Doc Bonin	Lafayette Utilities System
6664	Louisa	MidAmerican Energy Co
55343	Luna Energy Facility	Public Service Co of NM

Plant ID	Plant Name	Utility Name
2446	Maddox	Southwestern Public Service Co
55123	Magic Valley Generating Station	Calpine Corp-Magic Valley
976	Marion	Southern Illinois Power Coop
2727	Marshall	Duke Energy Carolinas, LLC
492	Martin Drake	Colorado Springs City of
6146	Martin Lake	TXU Generation Co LP
6250	Mayo	Progress Energy Carolinas Inc
6124	McIntosh	Georgia Power Co
599	McKee Run	NAES Corporation
3287	McMeekin	South Carolina Electric&Gas Co
52007	Mecklenburg Power Station	Virginia Electric & Power Co
2104	Meramec	Union Electric Co
864	Meredosia	Ameren Energy Generating Co
6213	Merom	Hoosier Energy R E C, Inc
2364	Merrimack	Public Service Co of NH
2832	Miami Fort	Duke Energy Ohio Inc
997	Michigan City	Northern Indiana Pub Serv Co
1409	Michoud	Entergy New Orleans Inc
1364	Mill Creek	Louisville Gas & Electric Co
2823	Milton R Young	Minnkota Power Coop, Inc
727	Mitchell	Georgia Power Co
3948	Mitchell	Ohio Power Co
3181	Mitchell Power Station	Allegheny Energy Supply Co LLC
1733	Monroe	Detroit Edison Co
6147	Monticello	TXU Generation Co LP
2080	Montrose	Kansas City Power & Light Co
3008	Mooreland	Western Farmers Elec Coop, Inc
1573	Morgantown Generating Plant	Mirant Mid-Atlantic LLC
2070	Moselle	South Mississippi El Pwr Assn
1606	Mount Tom	FirstLight Power Resources Services LLC
3453	Mountain Creek	Exelon Power
3954	Mt Storm	Virginia Electric & Power Co
1242	Murray Gill	Kansas Gas & Electric Co
1167	Muscatine Plant #1	Board of Water Electric & Communications
2872	Muskingum River	Ohio Power Co
2952	Muskogee	Oklahoma Gas & Electric Co
2953	Mustang	Oklahoma Gas & Electric Co
55065	Mustang Station	Denver City Energy Assoc LP
1588	Mystic Generating Station	Boston Generating LLC
4162	Naughton	PacifiCorp
4941	Navajo	Salt River Project

Plant ID	Plant Name	Utility Name
6064	Nearman Creek	Kansas City City of
6096	Nebraska City	Omaha Public Power District
4054	Nelson Dewey	Wisconsin Power & Light Co
3138	New Castle Plant	Orion Power Midwest LP
2167	New Madrid	Associated Electric Coop, Inc
8002	Newington	Public Service Co of NH
3456	Newman	El Paso Electric Co
6017	Newton	Ameren Energy Generating Co
3484	Nichols	Southwestern Public Service Co
2861	Niles	Orion Power Midwest LP
1403	Nine Mile Point	Entergy Louisiana Inc
2291	North Omaha	Omaha Public Power District
8224	North Valmy	Sierra Pacific Power Co
50888	Northampton Generating Company LP	US Operating Services Company
2963	Northeastern	Public Service Co of Oklahoma
2516	Northport	KeySpan Generation LLC
548	NRG Norwalk Harbor	Norwalk Power LLC
2848	O H Hutchings	Dayton Power & Light Co
3611	O W Sommers	San Antonio City of
116	Ocotillo	Arizona Public Service Co
127	Oklaunion	Public Service Co of Oklahoma
6013	Olive	City of Burbank Water and Power
350	Ormond Beach	Reliant Energy Ormond Bch LLC
55412	Osprey Energy Center	Calpine Operating Services Company Inc
2594	Oswego Harbor Power	NRG Oswego Harbor Power Operations Inc
6254	Ottumwa	Interstate Power and Light Co
55467	Ouachita	Entergy Louisiana Inc
634	P L Bartow	Progress Energy Florida Inc
55985	Palomar Energy	San Diego Gas & Electric Co
1378	Paradise	Tennessee Valley Authority
6248	Pawnee	Public Service Co of Colorado
3494	Permian Basin	Luminant Generation Company LLC
55620	Perryville Power Station	Entergy Louisiana Inc
7902	Pirkey	Southwestern Electric Power Co
271	Pittsburg Power	Mirant Delta LLC
3485	Plant X	Southwestern Public Service Co
59	Platte	Grand Island City of
6170	Pleasant Prairie	Wisconsin Electric Power Co
617	Port Everglades	Florida Power & Light Co
2517	Port Jefferson	KeySpan Generation LLC

Plant ID	Plant Name	Utility Name
56227	Port Westward	Portland General Electric Co
3113	Portland	Reliant Energy Mid-Atlantic PH LLC
3804	Possum Point	Virginia Electric & Power Co
3788	Potomac River	Mirant Potomac River LLC
273	Potrero Power	Mirant Potrero LLC
879	Powerton	Midwest Generations EME LLC
3140	PPL Brunner Island	PPL Brunner Island LLC
3148	PPL Martins Creek	PPL Martins Creek LLC
3149	PPL Montour	PPL Montour LLC
1073	Prairie Creek	Interstate Power and Light Co
1769	Presque Isle	Wisconsin Electric Power Co
2403	PSEG Hudson Generating Station	PSEG Fossil LLC
2406	PSEG Linden Generating Station	PSEG Fossil LLC
2408	PSEG Mercer Generating Station	PSEG Fossil LLC
4072	Pulliam	Wisconsin Public Service Corp
56349	Quail Run Energy Center	Navasota Odessa Energy Partners LP
1295	Quindaro	Kansas City City of
6639	R D Green	Western Kentucky Energy Corp
6061	R D Morrow	South Mississippi El Pwr Assn
1008	R Gallagher	Duke Energy Indiana Inc
2790	R M Heskett	Montana-Dakota Utilities Co
1570	R Paul Smith Power Station	Allegheny Energy Supply Co LLC
55179	Rathdrum Power LLC	Rathdrum Operating Services Co., Inc.
6761	Rawhide	Platte River Power Authority
8219	Ray D Nixon	Colorado Springs City of
3576	Ray Olinger	City of Garland
55455	Red Hawk	Arizona Public Service Co
55076	Red Hills Generating Facility	Choctaw Generating LP
2450	Reeves	Public Service Co of NM
2324	Reid Gardner	Nevada Power Co
2444	Rio Grande	El Paso Electric Co
2732	Riverbend	Duke Energy Carolinas, LLC
1081	Riverside	MidAmerican Energy Co
1927	Riverside	Northern States Power Co
4940	Riverside	Public Service Co of Oklahoma
55641	Riverside Energy Center	Rock River Energy LLC
619	Riviera	Florida Power & Light Co
6166	Rockport	Indiana Michigan Power Co
2712	Roxboro	Progress Energy Carolinas Inc
6155	Rush Island	Union Electric Co
3459	Sabine	Entergy Texas Inc.
118	Saguaro	Arizona Public Service Co

Plant ID	Plant Name	Utility Name
1626	Salem Harbor	Dominion Energy New England, LLC
2451	San Juan	Public Service Co of NM
6183	San Miguel	San Miguel Electric Coop, Inc
7900	Sand Hill	Austin Energy
8068	Santan	Salt River Project
6257	Scherer	Georgia Power Co
2367	Schiller	Public Service Co of NH
136	Seminole	Seminole Electric Cooperative Inc
2956	Seminole	Oklahoma Gas & Electric Co
3130	Seward	Reliant Energy Wholesale Generation LLC
1379	Shawnee	Tennessee Valley Authority
3131	Shawville	Reliant Energy Mid-Atlantic PH LLC
6090	Sherburne County	Northern States Power Co
2094	Sibley	KCP&L Greater Missouri Operations Co
6768	Sikeston Power Station	City of Sikeston
2107	Sioux	Union Electric Co
1613	Somerset Station	Somerset Power LLC
6095	Sooner	Oklahoma Gas & Electric Co
4041	South Oak Creek	Wisconsin Electric Power Co
55177	South Point Energy Center	Calpine Operating Services Company Inc
6195	Southwest Power Station	City Utilities of Springfield
2964	Southwestern	Public Service Co of Oklahoma
4266	Spencer	City of Garland
1743	St Clair	Detroit Edison Co
207	St Johns River Power Park	JEA
2824	Stanton	Great River Energy
564	Stanton Energy Center	Orlando Utilities Comm
7296	State Line Combined Cycle	Empire District Electric Co
981	State Line Energy	State Line Energy LLC
55364	Sugar Creek Power	Northern Indiana Pub Serv Co
3152	Sunbury Generation LP	Sunbury Generation LP
55182	Sunrise Power LLC	Sunrise Power Co LLC
1077	Sutherland	Interstate Power and Light Co
55112	Sutter Energy Center	Calpine Corp-Sutter
1891	Syl Laskin	Minnesota Power Inc
10075	Taconite Harbor Energy Center	Minnesota Power Inc
1252	Tecumseh Energy Center	Westar Energy Inc
4937	Thomas C Ferguson	Lower Colorado River Authority
2168	Thomas Hill	Associated Electric Coop, Inc
3115	Titus	Reliant Energy Mid-Atlantic PH LLC

Plant ID	Plant Name	Utility Name
6194	Tolk	Southwestern Public Service Co
2336	Tracy	Sierra Pacific Power Co
3845	Transalta Centralia Generation	TransAlta Centralia Gen LLC
1745	Trenton Channel	Detroit Edison Co
6071	Trimble County	Louisville Gas & Electric Co
56224	TS Power Plant	Newmont Nevada Energy Investment, LLC
2965	Tulsa	Public Service Co of Oklahoma
55269	TVA Southaven Combined Cycle	Tennessee Valley Authority
55380	Union Power Partners LP	Union Power Partners LP
3295	Urquhart	South Carolina Electric&Gas Co
3612	V H Braunig	San Antonio City of
4042	Valley	Wisconsin Electric Power Co
477	Valmont	Public Service Co of Colorado
897	Vermilion	Dynegy Midwest Generation Inc
6073	Victor J Daniel Jr	Mississippi Power Co
1564	Vienna Operations	NRG Vienna Operations Inc
3613	W B Tuttle	San Antonio City of
2866	W H Sammis	FirstEnergy Generation Corp
2716	W H Weatherspoon	Progress Energy Carolinas Inc
6019	W H Zimmer	Duke Energy Ohio Inc
3264	W S Lee	Duke Energy Carolinas, LLC
1010	Wabash River	Duke Energy Indiana Inc
766	Waiau	Hawaiian Electric Co Inc
2830	Walter C Beckjord	Duke Energy Ohio Inc
1082	Walter Scott Jr Energy Center	MidAmerican Energy Co
6052	Wansley	Georgia Power Co
55965	Wansley Combined Cycle	Southern Power Co
7946	Wansley Unit 9	Municipal Electric Authority
3297	Wateree	South Carolina Electric&Gas Co
883	Waukegan	Midwest Generations EME LLC
6139	Welsh	Southwestern Electric Power Co
117	West Phoenix	Arizona Public Service Co
4078	Weston	Wisconsin Public Service Corp
6009	White Bluff	Entergy Arkansas Inc
55259	Whiting Clean Energy	BP Alternative Energy
50	Widows Creek	Tennessee Valley Authority
3478	Wilkes	Southwestern Electric Power Co
884	Will County	Midwest Generations EME LLC
1507	William F Wyman	FPL Energy Wyman LLC
3298	Williams	South Carolina Genertg Co, Inc
3946	Willow Island	Monongahela Power Co
6249	Winyah	South Carolina Pub Serv Auth

Plant ID	Plant Name	Utility Name
55139	Wolf Hollow I, L.P.	Wolf Hollow I L P
898	Wood River	Dynegy Midwest Generation Inc
6101	Wyodak	PacifiCorp
728	Yates	Georgia Power Co
55087	Zeeland Generating Station	Consumers Energy Co

Appendix D. Example Calculations

Table D-1. Parameters Collected for Two Example Power Plants

Plant ID	593	6664
Plant Name	Edge Moor	Louisa
Utility Name	Conectiv Delmarva Gen Inc	MidAmerican Energy Co
Primary Energy Source	Coal	Coal
Prime Mover	Steam	Steam
Region	East	East
Primary Cooling Type	Once-through	Recirculating
Secondary Cooling Type	Once-through	
Primary Tower Type		Mechanical Draft Wet Process
Total Annual Supplied Heat in kJ	1.6E+13	5.4E+13
Nameplate Capacity in MW	697.8	811.9
Total Annual Net Generation in MWh	1,471,104	4,919,163
Average Age of Generators	46	27
Average Age of Cooling system	46	27
Source of Cooling Water	Fresh Surface Water	Groundwater
Total Withdrawal Rate in cfs	400.3	11.1
Total Discharge Rate in cfs	398.7	0.5
Total Consumption Rate in cfs	1.7	10.6
Average Distance Shore in ft	3	0
Average Distance Surface in ft	14	0.0
Average Intake Peak Summer in F	83	55
Average Intake Temperature in F	66	55
Average Temperature Rise in F	19	33
Total Installed Cost of Cooling System in $1000	1,978	18,103

Table D-2. Parameters Calculated and Equations Used

Calculations Made			**Equation Used**
Plant Name	Edge Moor	Louisa	
Capacity Factor	24	69	(100 x total annual net generation in MWh) / (nameplate capacity in MW x 24 x 365)
Thermal Efficiency	34	33	(360,000 x total annual net generation in kWh) / annual supplied heat in kJ
Installed Cost of Cooling System in 2008 $1000	13,740	39,135	original installed cost of cooling system x (1+inflation rate)installation year plus 1 x (1 + inflation rate) x …. (1+ inflation rate)2008
Cost in 2008 $ / kW	20	48	(installed cost of cooling system in 2008 $1000 x 1000) / (nameplate capacity in MW x 1000)
Water Withdrawal in Gallons / MWh	64,187	532	(water withdrawal in cfs x 8760 x 7.48) / annual supplied heat in MWh
Water Withdrawal in Acre-feet / Year	289,804	8,036	(water withdrawal in cfs x 8760 x 3600) / 43540
Annuity Factor for 5.2% Interest Rate and 30 years	15.03	15.03	(1-(1/(1.052)^30))/0.052
Annualized Installed Cost of Cooling System in 2008 $ / year	914,171	2,603,792	(installed cost of cooling system in 2008 $1000 / annuity factor) x 1000
Cost of Water Saved in $ / acre-foot	6		(difference in annualized installed cost of cooing system in 2008 $ / year) / (difference in water withdrawal in acre-feet per year)

Table D-3. Annual Inflation Rates (Bureau Labor of Statistics)

Year	Annual Inflation Rate
1914	1
1915	1
1916	7.9
1917	17.4
1918	18
1919	14.6
1920	15.6
1921	-10.5
1922	-6.1
1923	1.8
1924	0
1925	2.3
1926	1.1
1927	-1.7
1928	-1.7
1929	0
1930	-2.3
1931	-9
1932	-9.9
1933	-5.1
1934	3.1
1935	2.2
1936	1.5
1937	3.6
1938	-2.1
1939	-1.4
1940	0.7
1941	5
1942	10.9
1943	6.1
1944	1.7
1945	2.3
1946	8.3
1947	14.4
1948	8.1
1949	-1.2
1950	1.3
1951	7.9
1952	1.9
1953	0.8
1954	0.7
1955	-0.4

Year	Annual Inflation Rate
1956	1.5
1957	3.3
1958	2.8
1959	0.7
1960	1.7
1961	1
1962	1
1963	1.3
1964	1.3
1965	1.6
1966	2.9
1967	3.1
1968	4.2
1969	5.5
1970	5.7
1971	4.4
1972	3.2
1973	6.2
1974	11
1975	9.1
1976	5.8
1977	6.5
1978	7.6
1979	11.3
1980	13.5
1981	10.3
1982	6.2
1983	3.2
1984	4.3
1985	3.6
1986	1.9
1987	3.6
1988	4.1
1989	4.8
1990	5.4
1991	4.2
1992	3
1993	3
1994	2.6
1995	2.8
1996	3
1997	2.3
1998	1.6
1999	2.2

Year	Annual Inflation Rate
2000	3.4
2001	2.8
2002	1.6
2003	2.3
2004	2.7
2005	3.4
2006	3.2
2007	2.8
2008	3.8

Appendix E. List of Power Plants Included in Additional Dry Cooling Systems Study

Plant Name	Inservice Year	Cooling Status	Prime Mover	Energy Source	Region	Water Source	Cost of Installed Cooling System in $1000
Afton Generating Station	2007	Operating	Combined cycle	Natural gas	West	Groundwater	9700
Ashdown	1985	Operating	Steam	Black liquor	East	Fresh Surface Water	
Astoria Energy	2011	Under construction	Combined cycle	Natural gas	East	Municipal	
Colusa Generating Station	2010	Under construction			West	Fresh Surface Water	
Crockett Cogen Project	1995	Operating	Combined cycle	Natural gas	West		
Currant Creek	2006	Operating	Combined cycle	Natural gas	West	Groundwater	
Deer Creek Station	2012	Planned			East	Groundwater	18000
Dry Fork Station	2011	Under construction			West	Groundwater	
Gateway Generating Station	2009	Under construction			West	Municipal	
Goldendale Generating Station	2004	Operating	Combined cycle	Natural gas	West	Municipal	4200
Hobbs Generating Station	2008	Operating	Combined cycle	Natural gas	East	Groundwater	9600
Hunterstown	2003	Operating	Combined cycle	Natural gas	East		
Ivanpah 1	2010	Planned			West	Groundwater	
Ivanpah 2	2011	Planned			West	Groundwater	
Ivanpah 3	2012	Planned			West	Groundwater	
Mystic Generating Station	2003	Standby	Steam & combined cycle	Natural gas	East	Fresh Surface Water	60000
Sutter Energy Center	2001	Operating	Combined cycle	Natural gas	West	Groundwater	20000
Two Elk Generating Station	2012	Planned			West	Groundwater	
Wyodak	1978	Operating	Steam	Coal	West	Municipal	20158