NATIONAL ENERGY TECHNOLOGY LABORATORY

Estimating Freshwater Needs to Meet Future Thermoelectric Generation Requirements

2010 Update

September 30, 2010

DOE/NETL-400/2010/1339

U.S. DEPARTMENT OF ENERGY

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Executive Summary

Growing concerns about freshwater availability must be reconciled with growing demand for power if the United States is to maintain economic growth and current standards of living. Thermoelectric generating capacity is expected to increase by nearly 6% between 2010 and 2035, based on the Energy Information Administration's (EIA) *Annual Energy Outlook 2010* (AEO 2010) projections.[1] Previous water needs analyses have been conducted by the Department of Energy's National Energy Technology Laboratory (DOE/NETL); one in 2004 and annually since 2006. The 2004 report suggested that national freshwater withdrawals may increase slightly or decline depending on assumptions made, while freshwater consumption will likely increase dramatically.[2] However, regional water impacts can be significantly different than national data averages might suggest. To characterize the significance of the regional impacts on water use, the post 2004 reports compare regional electricity demand and capacity forecasts using corresponding AEO reports with representative water withdrawal and consumption estimates to identify regions where water issues could become acute.

This report is an update to the September 2009 report using projection from EIA's AEO 2010 forecast. With increased "climate change" concerns and the possible future policies regarding carbon capture and sequestration (CCS), this report also examines the impact that CCS technologies would have on water withdrawal and consumption. Future freshwater withdrawal and consumption requirements for the U.S. thermoelectric generation sector were estimated for five cases, using AEO 2010 regional projections for capacity additions and retirements:[a]

Case 1 – Additions and retirements are proportional to current water source and type of cooling system.
Case 2 – All additions use freshwater and wet recirculating cooling, while retirements are proportional to current water source and cooling system.
Case 3 – 90% of additions use freshwater and wet recirculating cooling, and 10% of additions use saline water and once-through cooling, while retirements are proportional to current water source and cooling system.
Case 4 – 25% of additions use dry cooling and 75% of additions use freshwater and wet recirculating cooling. Retirements are proportional to current water source and cooling system.
Case 5 – Additions use freshwater and wet recirculating cooling, while retirements are proportional to current water source and cooling system. Five percent of existing freshwater once-through cooling capacity is retrofitted with wet recirculating cooling every five years starting in 2015.

Summary results for the five cases, on a national basis, are presented in Table ES-1. For Cases 2 though 5, withdrawal is expected to decline and consumption for all 5 cases is expected to increase. These results are consistent with current and anticipated regulations and industry practice, which favor the use of freshwater recirculating cooling systems

[a] See Table 6 in the body of the report for a description of the rationale behind each of these cases and their assumptions.

that have lower withdrawal requirements, but higher consumption requirements, than once-through cooling systems. Case 5 provides the most extreme water consumption impacts. Converting a significant share of existing once-through freshwater power plants to recirculating freshwater plants significantly reduces water withdrawal, but significantly increases water consumption. Case 4 indicates that dry cooling could have a significant impact on water consumption; compared to Cases 1-3, which have an average consumption of 4.2 BGD.

Table ES-1 - Thermoelectric Water Impacts, National Results

		Freshwater withdrawal or consumption (BGD)					
		2010	2015	2020	2025	2030	2035
Case 1	Withdrawal	147.4	143.3	144.7	144.8	144.9	145.0
	Consumption	3.6	3.7	3.9	3.9	4.0	4.1
Case 2	Withdrawal	145.0	138.9	138.1	138.2	138.2	138.4
	Consumption	3.6	3.8	4.0	4.1	4.1	4.3
Case 3	Withdrawal	145.0	138.9	138.1	138.1	138.2	138.3
	Consumption	3.6	3.8	4.0	4.0	4.1	4.2
Case 4	Withdrawal	144.8	138.6	137.7	137.7	137.8	137.9
	Consumption	3.6	3.7	3.9	4.0	4.0	4.14
Case 5	Withdrawal	145.0	132.9	126.5	121.4	116.7	112.3
	Consumption	3.6	3.9	4.1	4.3	4.4	4.6

Each of the cases used different assumptions (see Table 6 for rationale behind each case and their assumptions). Table ES-2 was generated to show the percent change from the year 2010 to each of the future years. The negative values in Table ES-2 for withdrawal indicate decreased withdrawal while the positive consumption values indicate increasing consumption over time.

Table ES-2 – Percent Change from Year 2010, National Results

		Percent change from 2010				
		2015	2020	2025	2030	2035
Case 1	Withdrawal	-2.7	-1.8	-1.8	-1.7	-1.6
	Consumption	3.6	7.3	9.1	11.1	14.1
Case 2	Withdrawal	-4.2	-4.8	-4.7	-4.7	-4.6
	Consumption	4.9	9.7	11.6	13.9	17.8
Case 3	Withdrawal	-4.2	-4.8	-4.7	-4.7	-4.6
	Consumption	4.6	9.2	11.1	13.2	16.8
Case 4	Withdrawal	-4.3	-4.9	-4.9	-4.8	-4.8
	Consumption	4.2	8.4	10.2	12.0	15.1
Case 5	Withdrawal	-8.4	-12.8	-16.2	-19.5	-22.6
	Consumption	6.7	13.5	17.2	21.2	26.6

The regional component of the 2010 water needs analysis revealed some significant differences from the national averages. For example, consider Case 2, which represents a plausible future cooling system scenario. The national percent changes in Table ES-2 indicate that water withdrawal will fall by 22.6% and that water consumption will rise by 26.6% between 2010 and 2035. As shown in Figure ES-1 and Figure ES-2 on a regional basis, however, water withdrawal ranges from a 13% increase in the WECC/RM region to a 22% decline in ERCOT region; and while freshwater consumption increases in all regions, the biggest gains come in the Florida (53%) and New York (44%) regions.

Figure ES-1 – Average Daily Regional Freshwater Withdrawal for Thermoelectric Power Generation – Case 2

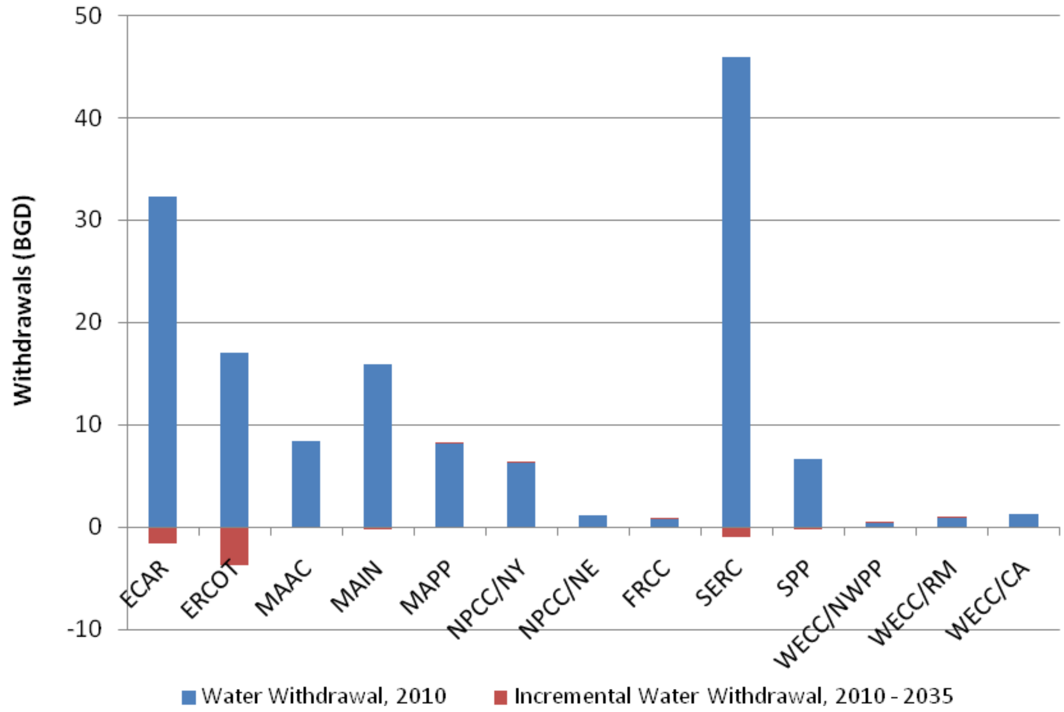
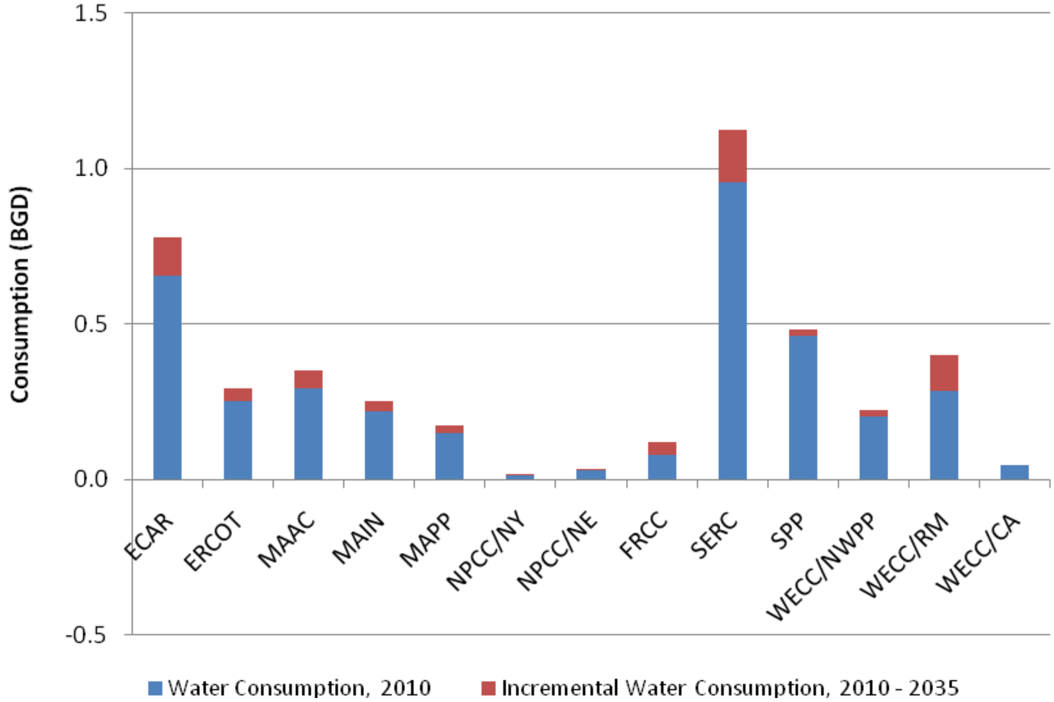


Figure ES-2 - Average Daily Regional Freshwater Consumption for Thermoelectric Power Generation – Case 2



The regional results reflect recent U.S. population shifts. Regions with strong population growth, such as the southeast and southwest, generally exhibit high growth in water consumption requirements, while regions with minimal to modest population growth, such as the Midwest and Mid-Atlantic, exhibit modest growth in water consumption requirements.

Specific to coal-fired generation, the analysis projects that by 2035, average daily national freshwater withdrawals may decrease to 76 BGD or increase to 95 BGD from an average 2010 level of 92 BGD, depending upon case assumptions. The 2010 average coal-fired plant withdrawal represents 63% of the total thermoelectric plant withdrawal. Average daily national freshwater consumption resulting from U.S. coal-fired power generation could reach 2.7 BGD to 3.0 BGD from a 2010 level of 2.3 BGD, depending upon case assumptions. The 2010 average level coal-fired plant consumption represents 64% of the total thermoelectric plant consumption. Case 2, coal-fired, regional water withdrawal and consumption are illustrated in Figures ES-3 and ES-4 respectively.

Figure ES-3 – Average Daily Regional Freshwater Withdrawal for Coal-Fired Power Generation – Case 2

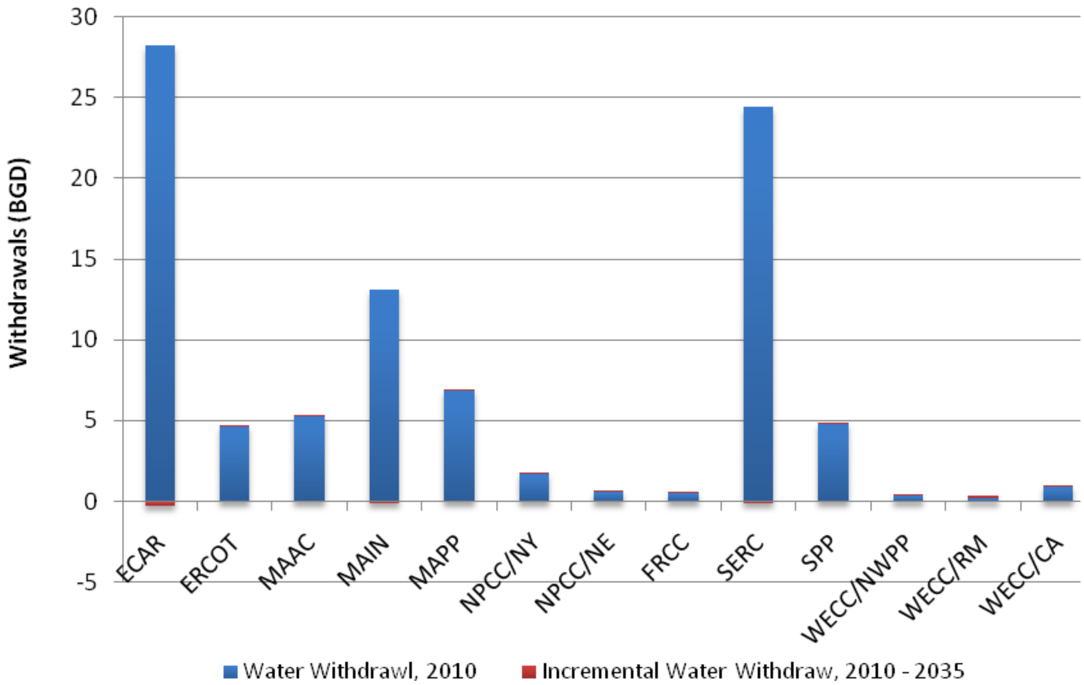
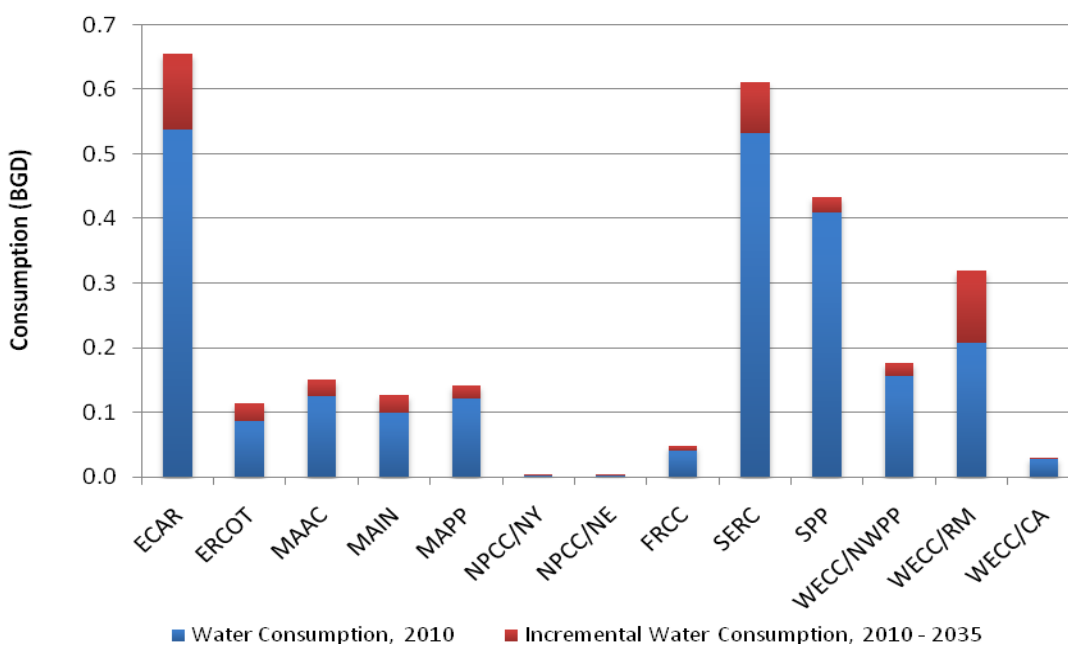


Figure ES-4 - Average Daily Regional Freshwater Consumption for Coal-Fired Power Generation – Case 2



This analysis and accompanying report were completed to estimate future freshwater needs both for coal-fired generation and for total thermoelectric generation. The results from this report will be used as a base forecast against which to compare accomplishments in freshwater withdrawal and consumption reductions. Additionally, report results will be used to better understand the regional impacts of constrained water resources.

Carbon capture technologies could increase the water demand of thermoelectric power plants. With increasing political and public interest regarding “climate change” and CO_2 mitigation, coupled with future water usage concerns, it is of interest to estimate and explore the possible effects CO_2 mitigation will have on future water demands. This analysis assumes that carbon mitigation policies will be put in place in the near future that would require all new and existing PC plants with scrubbers and IGCC plants utilize carbon capture technologies by 2035. This analysis follows the EIA AEO 2010 forecast and assumes the generation mix would not change under such a climate control scenario. This analysis provides an upper boundary of the estimated additional water usage for carbon capture.

Five scenarios regarding the additional capacity needed to make up for the “parasitic” power loss of the carbon capture retrofits were evaluated. The 5 scenarios were applied to the 5 cases. Scenario 1 only accounts for the increased water requirements for the carbon capture technologies used for the retrofits and new builds with CCS and does not account for the 67.1 GW of reduced capacity due to the retrofits. Scenario 2 builds off of Scenario 1 and assumes that the additional capacity needed to make up for the parasitic loss of the retrofits are supplemented by 67.1 GW of new IGCC plants with recirculating cooling and include carbon capture technologies. Scenario 3 is similar to Scenario 2 except instead of IGCC plants making up the parasitic loss, oxy combustion supercritical PC plants are used. Scenario 4 assumes supercritical PC plants with amine carbon capture are used to make up the parasitic loss. Scenario 5 assumes that the additional capacity needed to make up for the parasitic loss of the retrofits is supplemented by 67.1 GW of new nuclear plants with recirculating cooling.

The projected results for PC plants with scrubbers and IGCC plants with 90% CO_2 capture for the year 2035 show an increase in water withdrawal and consumption. Figure ES-5 shows the additional amount of water withdrawal for each Case and Scenario if all forecasted PC plants with scrubbers and IGCC plants were to deploy carbon capture technologies compared to no carbon capture deployment across all thermoelectric generation for the projected year 2035. For example, the bar for Case 2 in Figure ES-5 shows that in 2035, 138.4 BGD of water withdrawal is projected for all thermoelectric plants without carbon capture deployment. By deploying carbon capture technologies on the scrubbed coal-fired fleet and all new builds, an additional 1.5 BGD would be required under Scenario 1, resulting in a total of 139.9 BGD. If Scenario 2 is applied, 0.9 BGD would be added to Scenario 1, resulting in a total of 104.9 BGD. Scenario 3 would add 1.1 BGD to Scenario 1 resulting in a total of 141 BGD withdrawal. Scenario 4 would add approximately an additional 1.3 BGD to the 138.4 BGD non capture forecast and Scenario 5 would add 3.5 BGD to the 138.4 BGD base value for the additional nuclear plants to make up for the capacity lost due to the retrofitted coal plants.

Figure ES-5 - Thermoelectric Generation with Additional Water Withdrawal for PC and IGCC Carbon Capture Deployment for Year 2035

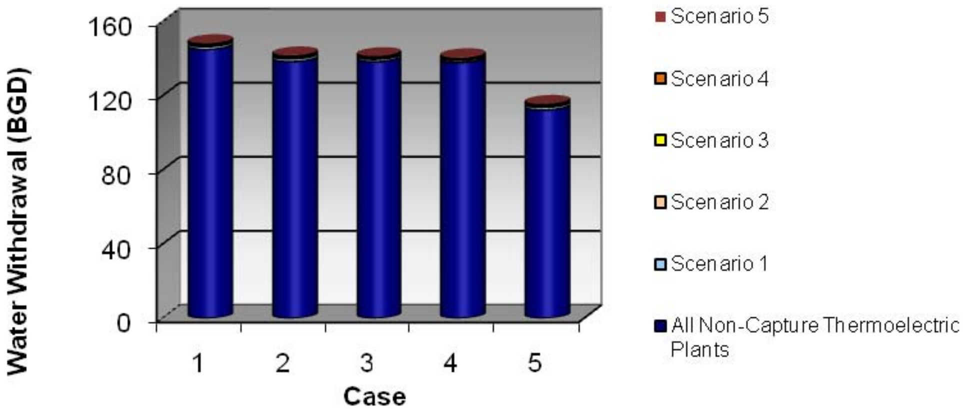
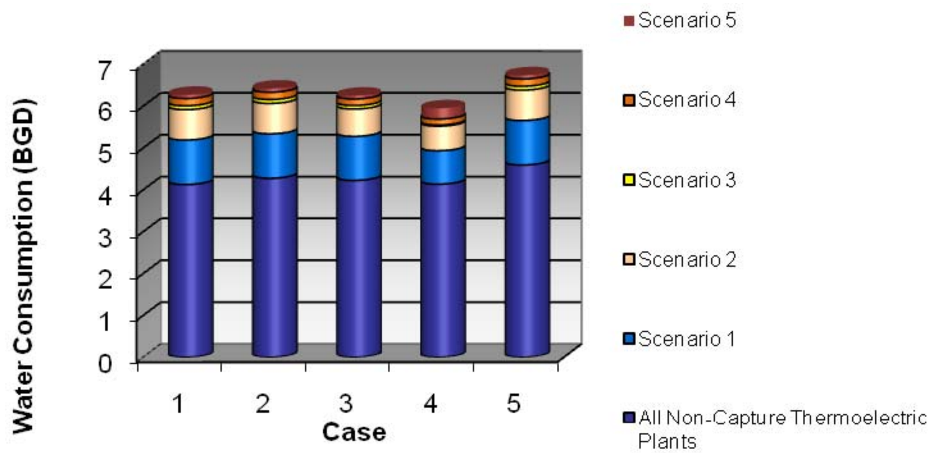


Figure ES-6 shows the additional amount of water consumption for each Case and Scenarios if all of the forecasted PC with scrubbers and IGCC plants were to deploy carbon capture technologies compared to all thermoelectric plants without carbon capture technologies. The bar for Case 2 in Figure ES-6 shows that in 2035, 4.3 BGD of water consumption is projected for all thermoelectric plants without carbon capture deployment. By deploying carbon capture technologies to the scrubbed coal-fired fleet and all new builds, an additional 1.1 BGD would be required under Scenario 1, resulting in a total of 5.3 BGD. If Scenario 2 is applied, 0.7 BGD would be added to Scenario 1, resulting in a total of 6.1 BGD. Scenario 3 would add 0.8 BGD to Scenario 1 resulting in a total water consumption of 6.2 BGD for Scenario 3. Scenario 4 would add approximately an additional 0.4 BGD to the 4.3 BGD non capture forecast, 1.1 BGD for the retrofits and new builds and 1.0 BGD for the additional supercritical/amine plants to make up for the capacity lost due to the retrofitted coal plants. Scenario 5 adds 1.1 BGD to Scenario 1 for a total of 6.4 BGD of water consumption for the additional nuclear plants to make up for the capacity lost due to the retrofitted coal plants. Since recirculating cooling systems are used in three scenarios, additional water withdrawal is lower relative to water consumption.

Figure ES-6 - Thermoelectric Generation with Additional Water Consumption for PC and IGCC Carbon Capture Deployment for Year 2035



Introduction

The purpose of this report is to estimate future freshwater needs for thermoelectric power generation. Thermoelectric power plants – coal, oil, natural gas, and nuclear fueled power generators using a steam turbine based on the Rankine thermodynamic cycle – require significant quantities of water for generating electrical energy.[b] For example, a 500 MW coal-fired power plant uses over 12 million gallons per hour of water for cooling steam turbine exhaust.[3,c] The water required for thermoelectric plants is *withdrawn* primarily from large volume sources, such as lakes, rivers, oceans, and underground aquifers. While both freshwater (approximately 70%) and saline water (approximately 30%) are currently used for thermoelectric generation, this report focuses on freshwater because freshwater sources are becoming increasingly strained.[4] *Water consumption* is used to describe the loss of that water, typically through evaporation into the air. The United States Geological Survey (USGS) estimated that thermoelectric generation accounted for approximately 41% of freshwater withdrawals, ranking only slightly ahead of agricultural irrigation as the largest source of freshwater withdrawals in the United States in 2005.[4] However, the corresponding water consumption associated with thermoelectric generation accounted for only 2.5% of total U.S. freshwater consumption in 1995.[5] As U.S. population and associated economic development continues to expand, the demand for electricity will increase. The EIA's latest forecast estimates U.S. thermoelectric generating capacity will grow from approximately 700 GW

[b] Natural gas- and oil-fired combustion turbines are not sources of thermoelectric generation.

[c] Most of today's power plants use water as the cooling medium and the amount of water required to condense the steam turbine exhaust is similar whether an open-loop or closed-loop cooling system is used depending on design conditions. Open-loop cooling systems continuously withdraw water from a local water source, and return the same quantity of water to the source. Closed-loop cooling systems circulate a similar total volume of water as open-loop systems for a given plant size, but only withdraw a limited amount of water to replace evaporative loss and blowdown. Additional information on power plant water requirements can be found in the *Water Requirements for Thermoelectric Generation* section of this report.

in 2005 to 775 GW in 2030.[6] As such, thermoelectric power plants may increasingly compete for freshwater with other sectors such as domestic, commercial, agricultural, industrial, and in-stream use – particularly in regions of the country with limited freshwater supplies. In addition, current and future water-related environmental regulations and requirements will also challenge the operation of existing power plants and the permitting of new thermoelectric generation projects.

Energy-Water Issues

At the nexus of water and energy lies a wide variety of societal issues, policy and regulatory debate, environmental questions, technological challenges, and economic concerns. Water is emerging as a significant factor in economic development activities. Planning efforts must consider the availability and quality of water resources in a given locality or region to ensure that supplies are available to accommodate existing and future water consumers over the long term. Failure to do so can result in stunted growth, economic flight, inequitable development, and even open conflict. In order for the power industry to be ecologically responsible, technologically ready, and economically stable, advanced research is imperative. Energy-water issues have become increasingly visible in recent years, with a variety of concerns on the mind of industry, regulators, Congress, DOE, and the general public. A sampling of these issues includes the passing of the Energy Policy Act of 2005; repeated introduction of the Energy-Water Efficiency and Supply Technology Bill; increasingly severe regional drought conditions across the country; additional difficulty siting new power generating facilities in arid regions; and further media attention and public concern over water availability and supply. The following is a brief summary of some of the technical, regulatory, and political issues that help explain the importance of water to thermoelectric generation. Additional background information on energy-water issues is presented in Appendix A.

Water Availability

Water shortages, potentially the greatest challenge to face all sectors of the United States in the 21st century, will be an especially difficult issue for thermoelectric generators due to the large amount of cooling water required for power generation. According to a GAO 2003 report[7], national water availability has not been comprehensively assessed in 25 years, thus water availability on a national level is ultimately unknown. However, as the report goes on to say, current trends indicate that demands on the nation's supplies are growing while the nation's capacity to store surface-water is increasingly more limited and ground-water is being depleted.

Water availability issues are intensified by the fact that population increases are occurring in water-stressed areas. Figure 1 shows the percent change in population by state from 1990 to 2000 and Figure 2 displays mean annual precipitation from 1890 to 2002. Comparison of the figures shows that areas where precipitation is low, especially in the southwest, are also areas of greatest population growth.

Figure 1 - Percent Change in Population by State: 1990 to 2000[8]

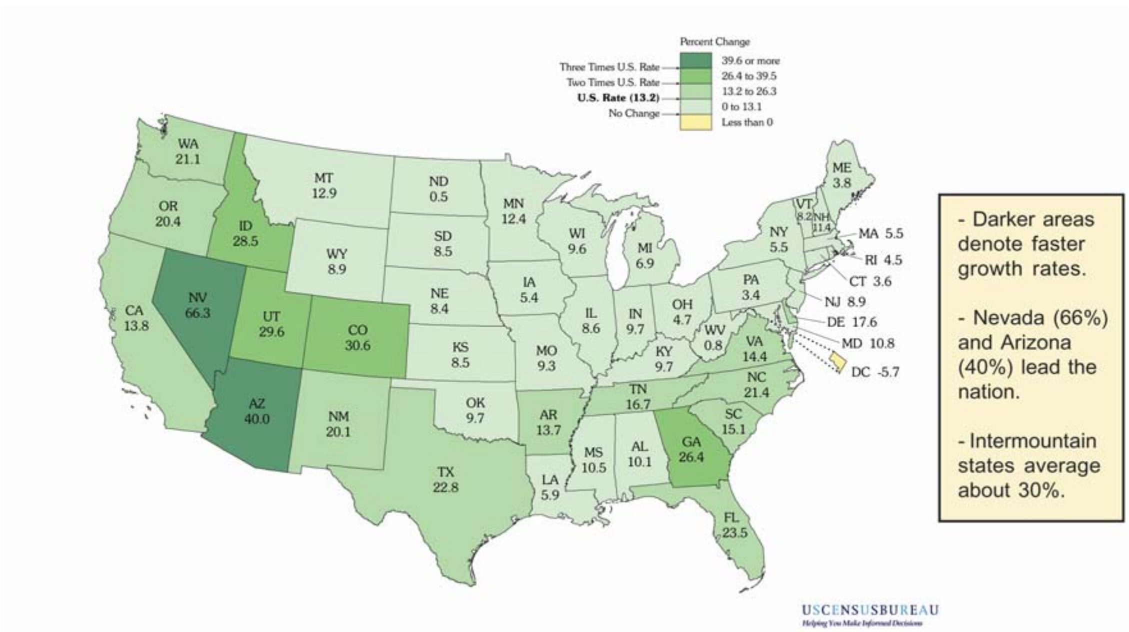
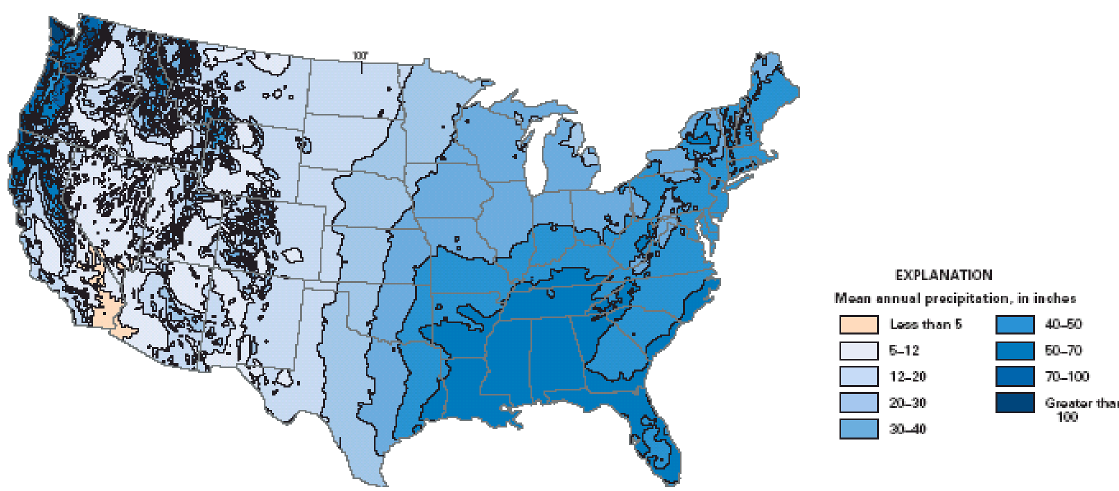


Figure 2 - Mean Annual Precipitation, 1890 to 2002[9,10]



NETL Energy-Water R&D Program

The U.S. Department of Energy, Office of Fossil Energy's National Energy Technology Laboratory (DOE/NETL) is carrying out a comprehensive, integrated research and development (R&D) effort to enhance the efficiency and environmental performance of the existing fleet of coal-fired power plants, which represent more than 300 gigawatts (GW) of generating capacity, and apply novel concepts to advanced power systems. The program goal is to ensure that technologies are available for deployment by 2015 that can reduce power plant freshwater withdrawal and consumption while minimizing the impacts of power plant operation on water quality. To achieve this goal, the energy-water interface portion of the Innovations for Existing Plants (IEP) program conducts research in four areas: Non-Traditional Sources of Process and Cooling Water; Innovative Water Reuse and Recovery; Advanced Cooling Technology; and Advanced Water Treatment and Detection Technology. The portfolio of energy-water nexus technology R&D projects encompasses laboratory studies, modeling, and pre-commercial demonstration full-scale testing. Project success is intimately tied to key collaborations and partnerships with industry, federal, state, and local agencies, and the academic and research communities. This water needs analysis was conducted in support of the IEP energy-water R&D activity.

Previous Water Needs Analysis

In 2004, NETL conducted a similar water needs analysis to estimate how thermoelectric power plants will impact national freshwater resources through 2025.[2] Using the EIA 2004 Annual Energy Outlook's (AEO) reference case forecast for electricity generating capacity, future freshwater requirements for both total and coal-based thermoelectric generation were estimated and compared to current and past water use by the power sector. In 2006, NETL developed a new water analysis which used a different methodology and different cases. The comparisons of the 2004 and 2006 studies are described in more detail in the August 2006 *Estimating Freshwater Needs to Meet Future Thermoelectric Generation Requirements* study. All post 2006 water analyses utilize the same methodology as the August 2006 report and use corresponding EIA AEO data.

Water Requirements for Thermoelectric Generation

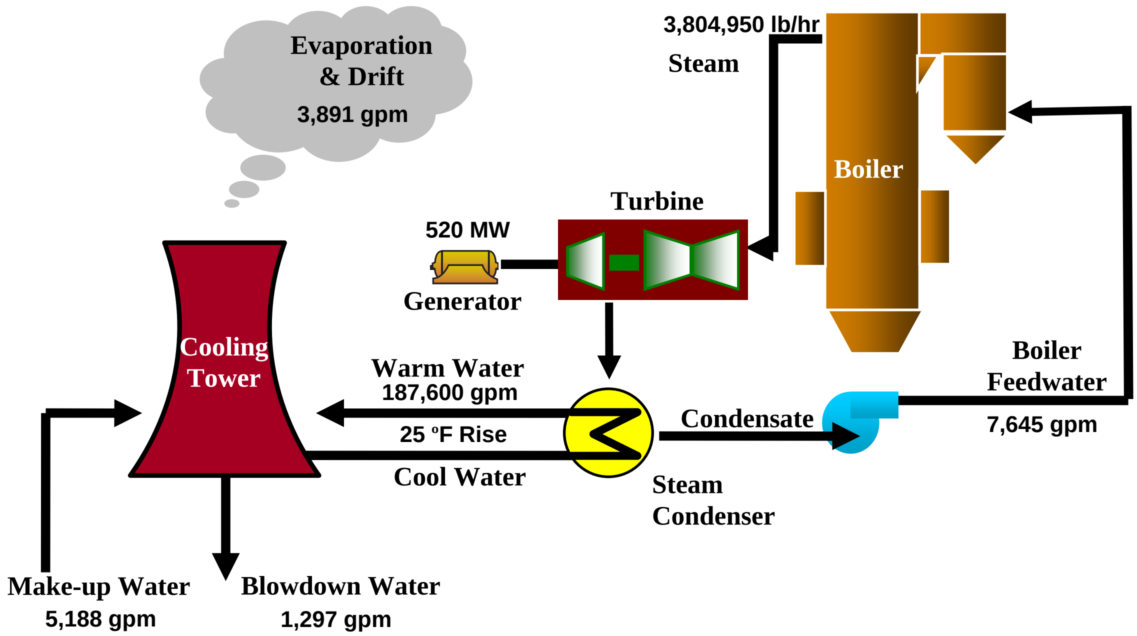
A significant quantity of water is required for thermoelectric power plants to support electricity generation. The largest demand for water in thermoelectric plants is cooling water for condensing steam. Thermoelectric generation relies on a fuel source (fossil, nuclear, or biomass) to heat water to steam that is used to drive a turbine-generator. Steam exhausted from the turbine is condensed and recycled to a steam generator or boiler. The steam condensation typically occurs in a shell-and-tube heat exchanger known as a condenser. The steam is condensed on the shell side by the flow of cooling water through tube bundles located within the condenser. Cooling water mass flow rates of greater than 50 times the steam mass flow rate are necessary depending on the allowable temperature rise of the cooling water – typically 15-25ºF. The design and operating parameters of the cooling system are critically important to overall power generation efficiency. At higher condenser cooling water inlet temperatures, the steam condensate temperature is higher and subsequently turbine backpressure is higher. The turbine backpressure is inversely related to power generation efficiency: the higher the turbine backpressure, the lower the power generation efficiency.

There are three general types of cooling system designs used for thermoelectric power plants: once-through, wet recirculating, and dry. In once-through systems, the cooling water is withdrawn from a local body of water such as a lake, river, or ocean and the warm cooling water is subsequently discharged back to the same water body after passing through the surface condenser. As a result, plants equipped with once-through cooling water systems have relatively high water withdrawal, but low water consumption.

There are two primary technologies used to support wet recirculating cooling systems – wet cooling towers and cooling ponds. The most common type of recirculating system uses wet cooling towers to dissipate the heat from the cooling water to the atmosphere (Figure 3). In wet recirculating systems, warm cooling water is pumped from the steam condenser to a cooling tower. The heat from the warm water is transferred to ambient air flowing through the cooling tower. In the process, a portion of the warm water evaporates from the cooling tower and forms a water vapor plume. The cooled water is then recycled back to the condenser. Because of evaporative losses, a portion of the cooling water needs to be discharged from the system – known as blowdown − to prevent the buildup of minerals and sediment in the water that could adversely affect performance. The quantity of blowdown required for a particular cooling water system is determined by a parameter known as "cycles of concentration", which is defined as the ratio of dissolved solids in the circulating water to that in the makeup water. As the cycles of concentration increases, the quantity of blowdown and makeup water decreases. For a wet recirculating system, only makeup water needs to be withdrawn from the local water body to replace water lost through evaporation and blowdown. As a result, plants equipped with wet recirculating systems have relatively low water withdrawal, but high water consumption, compared to once-through systems. Wet cooling towers are available in two basic designs – mechanical draft and natural draft. Mechanical draft towers utilize a fan to move ambient air through the tower, while natural draft towers rely on the difference in air density between the warm air in the tower and the cooler ambient air outside the tower to draw the air up through the tower. In both designs, the warm cooling water is discharged into the tower for direct contact with the ambient air. A cooling pond serves the same purpose as a wet cooling tower, but relies on natural conduction/convection heat transfer from the water to the atmosphere as well as evaporation to cool the recirculating water.

Dry cooling systems can use either a direct or indirect air cooling process. In direct dry cooling, the turbine exhaust steam flows through tubes of an air-cooled condenser (ACC) where the steam is cooled directly via conductive heat transfer using a high flow rate of ambient air that is blown by fans across the outside surface of the tubes. Therefore, cooling water is not used in the direct air-cooled system. For indirect dry cooling, a conventional water-cooled surface condenser is used to condense the turbine exhaust steam, but a dry cooling tower, similar in design to an ACC, is used to conductively transfer the heat from the water to the ambient air. As a result, there is no evaporative loss of cooling water with an indirect dry cooling system and both water withdrawal and consumption are minimal.

Figure 3 - Wet Recirculating Cooling Water System for a 520-MW Coal-Fired Boiler



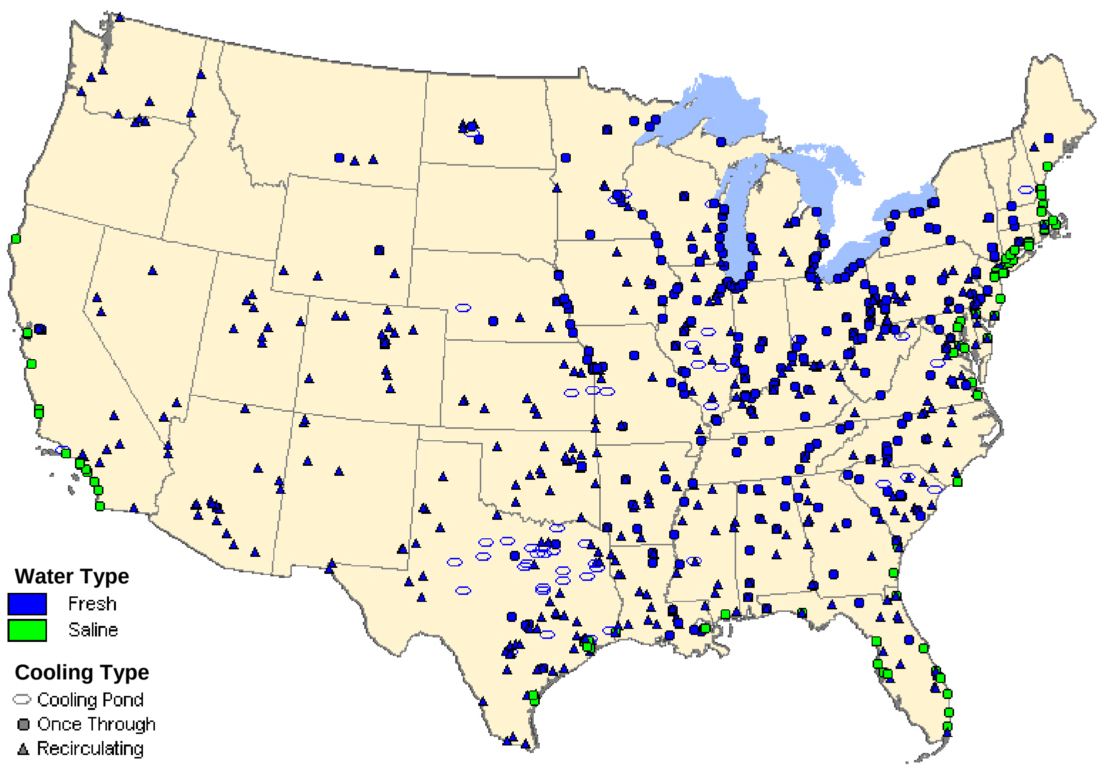
In the United States, existing thermoelectric power plants use each of these types of systems, with estimates indicating that 42.7% of generating capacity is once-through, 41.9% wet recirculating, 0.9% dry cooling, and 14.5% cooling ponds.[11] Table 1 presents a summary of the current percentage distribution of cooling technology by generation type. It should be noted that the data for combined cycle plants represents only about 7% of the total combined cycle plants currently in operation. This is because not all plants provided cooling data, so the table was created using information available at the time. If all plants reported cooling data, it is most likely that dry cooling would represent a much smaller percentage of the total combined cycle cooling. Figure 4 illustrates the location of water dependent cooling systems used for thermoelectric power generation by technology type and water source[12].

Table 1 - Cooling Technology by Generation Type

Generation Type	Percentage (%)			
	Wet Recirculating	Once-Through	Dry	Cooling Pond
Coal	48.0%	39.1%	0.2%	12.7%
Fossil Non-Coal	23.8%	59.2%	0.0%	17.1%
Combined Cycle	30.8%	8.6%	59.0%	1.7%
Nuclear	43.6%	38.1%	0.0%	18.3%
Total	**41.9%**	**42.7%**	**0.9%**	**14.5%**

Historically, the choice of cooling technology for a particular plant depended on the quantity and quality of local water sources coupled with cost and performance characteristics of the different systems. The use of closed-loop systems, however, is likely to become much more pronounced in the future due to the Clean Water Act 316(b) provisions and public pressures.[d] Although once-through cooling systems can still be legally permitted under 316(b), the complexity of the permitting, analysis and reporting requirements may discourage their use.

Figure 4- Cooling Systems by Technology and Water Source



Projections of Thermoelectric Capacity and Generation

The EIA publishes its *Annual Energy Outlook* (AEO) to provide a forecast as to where the energy sector will be in the future, including projections of thermoelectric capacity and generation. The AEO projections are based on EIA's National Energy Modeling System (NEMS), which is revised yearly to reflect technology advances, supply and demand adjustments, and other market forces. AEO 2010 projections of capacity and generation to 2035 are used in this analysis to calculate future thermoelectric generation water withdrawal and consumption. Table 2 summarizes projected changes in U.S.

[d] See Appendix A for more details on CWA 316(b).

electric power generating capacity from 2007 to 2035. Coal-fired generating capacity, including IGCC, is projected to increase by 28 GW from 2007 to 2010.

Table 2 - AEO 20010 Thermoelectric Capacity Projections – 2007 to 2035

	2007	2010	2015	2020	2025	2030	2035
Net Generating Capacity							
Coal Steam	309	317	320	320	320	323	329
Other Fossil Steam	117	114	91	87	87	87	86
Combined Cycle	183	197	201	201	207	233	244
Nuclear	101	102	105	111	111	111	113
Total Thermoelectric	**709**	**730**	**716**	**719**	**726**	**755**	**772**
Cumulative Additions (Planned and Unplanned) - 2005 Baseline							
Coal Steam	0	10	16	18	18	21	26
Other Fossil Steam	0	0	0	0	0	0	0
Combined Cycle	0	9	13	13	20	46	56
Nuclear	0	0	1	6	6	6	8
Total Thermoelectric	**0**	**18**	**30**	**37**	**44**	**73**	**91**
Cumulative Retirements - 2005 Baseline							
Coal Steam	0	0.7	4	6	6	6	6
Other Fossil Steam	0	1.5	25	29	29	29	30
Combined Cycle	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0
Total Thermoelectric	**0**	**2**	**29**	**35**	**35**	**35**	**36**

AEO 2010 also includes a breakout of thermoelectric capacity and generation by Electricity Market Module Region (EMM) using boundaries similar to the former 13 North American Electric Reliability Council (NERC) control regions, excluding Alaska and Hawaii. The Electricity Market Module Regions are shown in Figure 5 and a description of the regional abbreviations is provided in Table 3.

Figure 5 - Electricity Market Module Regions

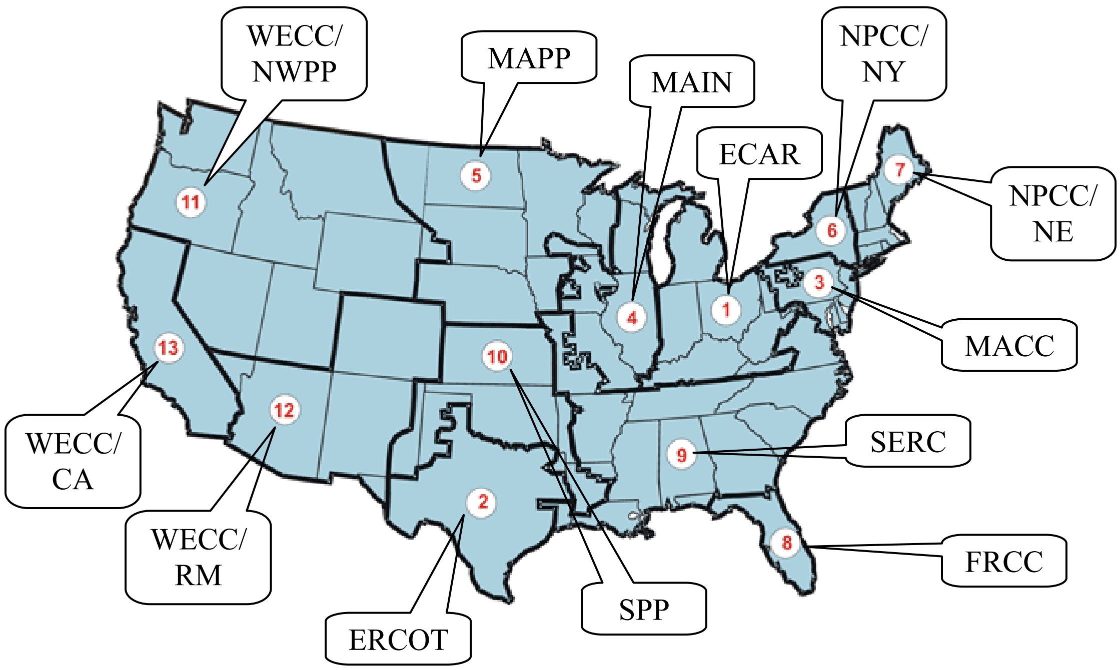


Table 3 – Description of the EMM Regions

Region Number	Abbreviation	Region
1	ECAR	East Central Area Reliability Coordination Agreement
2	ERCOT	Electric Reliability Council of Texas
3	MAAC	Mid-Atlantic Area Council
4	MAIN	Mid-America Interconnected Network
5	MAPP	Mid-Continent Area Power Pool
6	NPCC/NY	Northeast Power Coordinating Council/New York
7	NPCC/NE	Northeast Power Coordinating Council/New England
8	FRCC	Florida Reliability Coordinating Council
9	SERC	Southeastern Electric Reliability Council
10	SPP	Southwest Power Pool
11	WECC/NWPP	Western Electricity Coordinating Council/Northwest Power Pool
12	WECC/RM	Western Electricity Coordinating Council/Rocky Mountains, AZ, NM, southern NV
13	WECC/CA	Western Electricity Coordinating Council/California

Figure 6 and Figure 7 show that thermoelectric capacity (GW) will increase in most of the regions and generation (billion kWh) will increase in all regions by 2035, reflecting required generation to meet anticipated demand growth. Both capacity and generation growth are presented because the two are not necessarily directly linked. For example, if under-utilized capacity exists in a region, generation can increase without a change to capacity.

Figure 6 - Thermoelectric Capacity, 2010 vs. 2035, by Region

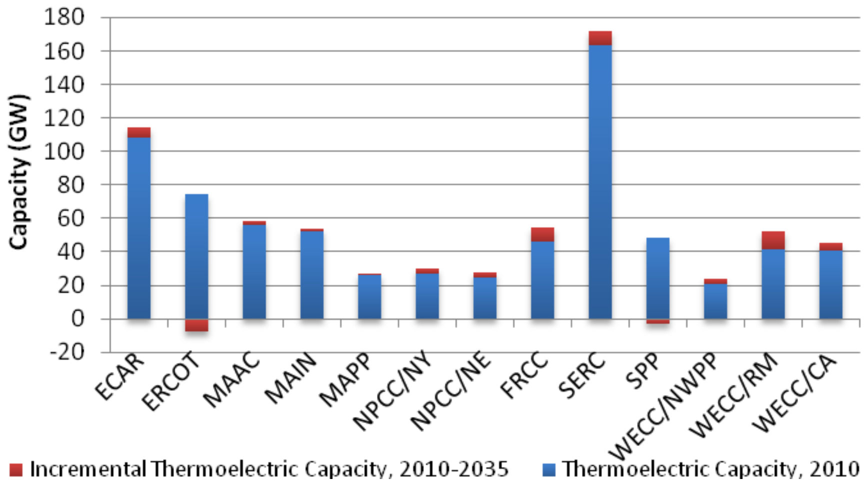


Figure 8 and Figure 9 present the same information for the portion of the total thermoelectric capacity and generation that correspond to coal-fired plants. Coal-fired capacity will also increase in most of the regions and coal-fired generation will increase in all regions by 2035.

Figure 7 - Thermoelectric Generation, 2010 vs. 2035, by Region

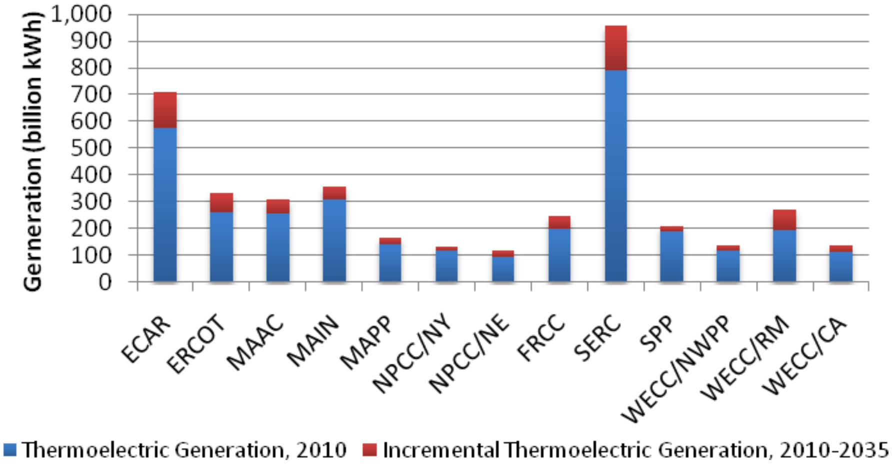


Figure 8 – Coal-Fired Capacity, 2010 vs. 2035, by Region

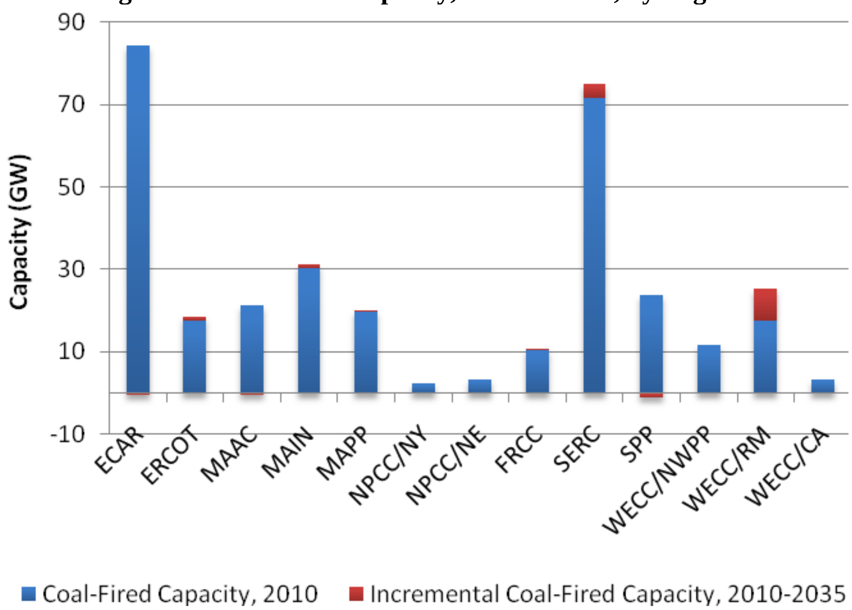
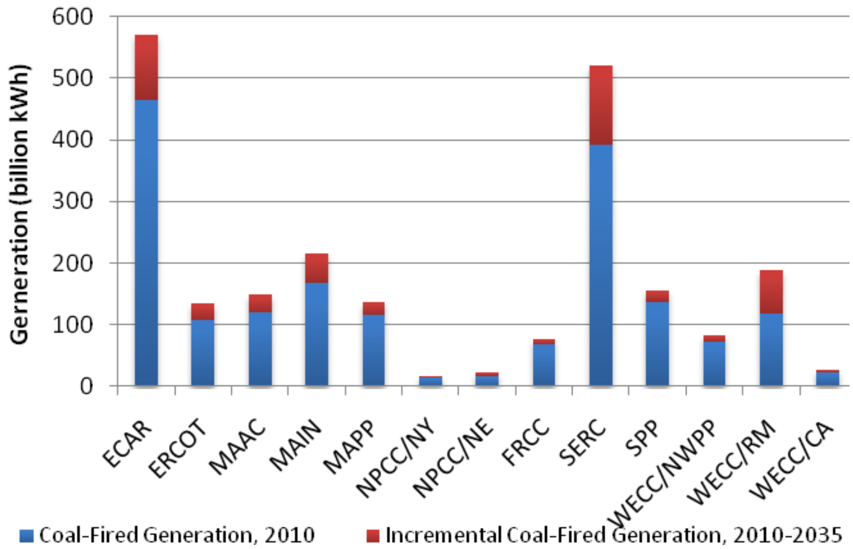


Figure 9 – Coal-Fired Generation, 2010 vs. 2035, by Region



Assumptions and Methodology

Using the electricity capacity and generation forecasts provided by AEO 2010 and the water use estimates provided by EIA-767, an estimate of freshwater consumption and withdrawal was obtained for the U.S. thermoelectric power generation industry through 2035. Table 4 lists the resources used for this analysis, and summarizes how each resource supported the analysis.

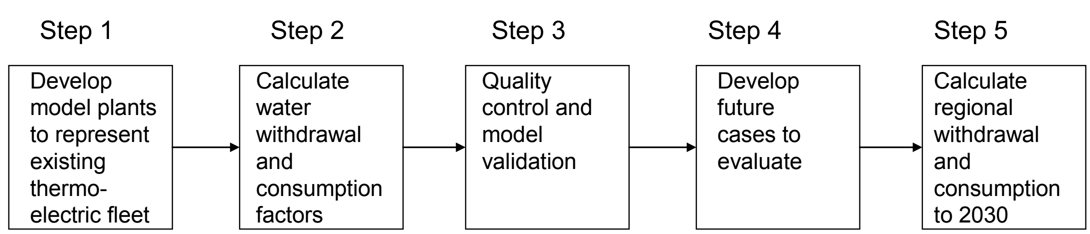
These sources provided data from which water withdrawal and consumption factors (water-use scaling factors) could be calculated for a given category of power plant in a given region. The water use scaling factors indicate average rate of water use per unit of electrical output – gallons per hour per kilowatt (gal/kWh).

Figure 10 provides a flowchart depiction of the methodology used to conduct the analysis. A brief description of each step in the process is presented below. A more detailed discussion of the methodology is provided in Appendix B.

Table 4 – Data Resources

Resource	Type of Data
EIA Annual Energy Outlook (AEO)	• Projections of capacity and generation by EMM region for coal, non-coal fossil, and nuclear plants • Coal capacity, generation, and capacity factor breakdown by four categories: existing unscrubbed, existing scrubbed, new PC (scrubbed), and IGCC
NETL 2005 Coal Power Plant Database – Including data from 2003 EIA-767	• Plant generation • Average water withdrawal and consumption • Cooling water source • Type of cooling water system • Type of boiler • Type of FGD system
EIA-860	• Plant location by EMM region • Plant summer capacity
CMU/NETL – Integrated Environmental Control Model (IECM)	• Water use factors for wet FGD and dry FGD
Power Plant Water Consumption Study, August 2005 – DOE/NETL	• Water use factors for boiler make-up
Cost and Performance Comparison Baseline for Fossil Energy Power Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity. Aug 2007, DOE/NETL.	• Water use factors for IGCC plants • Water use for PC and IGCC plants employing carbon capture technologies

Figure 10 - Methodology for the 2006 to current Water Needs Analyses



Step 1: Develop model plants

To obtain the resolution desired for this analysis, water withdrawal and consumption factors were determined for a large number of plant configurations, based on location, generation type, cooling water source, cooling system type, and where applicable, boiler type and type of FGD system. The existing thermoelectric fleet was segregated into numerous configurations, called "model plants" using data contained in several sources: the NETL Coal Plant Database, EIA-767, and EIA-860.

Fresh versus Saline Water

The analysis focuses on freshwater impacts associated with future thermoelectric power plants. It is recognized that saline water is used at a number of power plants in once-through cooling systems. However, in light of 316(b) regulations for new facilities that favor recirculating systems and siting difficulties for coastal-based power plants, the percentage of saline-based cooling systems at new plants is expected to be relatively small. Furthermore, no distinction is made between surface and groundwater; both are included as freshwater.

Step 2: Calculate water withdrawal and consumption factors

For each model plant defined in Step 1, water withdrawal and consumption factors were calculated using the data sources outlined above. For coal-fired plants, the water withdrawal and consumption factors were based on the sum of three components: 1) boiler make-up water; 2) FGD make-up water; and 3) cooling water. Average water withdrawal (gal/hr), average water consumption (gal/hr), and summer capacity were used to calculate average withdrawal and consumption scaling factors (gal/kWh) for each model plant in each of the regions. Nuclear, oil steam, gas steam, and natural gas combined-cycle plants were classified according to region, cooling water source (fresh or saline), and cooling water system (recirculating or once-through). A summary of the regional water withdrawal and consumption factors used in the analysis is included in Appendix D.

The following is a brief discussion of the more important assumptions made in calculating the water use factors.

Evaporative Loss Associated with Once-Through Cooling Systems

One important point needs to be made regarding consumption levels for once-through cooling systems. Although once-through consumption levels are extremely small at the plant boundaries, downstream consumption (evaporation) due to the elevated discharge temperature is not insignificant. An Electric Power Research Institute (EPRI) study estimated that once-through consumption levels, when including downstream evaporation, are less than, but of the same magnitude as, wet recirculating cooling system consumption levels.[13] EPRI estimated once-through fossil plant water consumption levels of 300 gal/MWh versus closed-loop water consumption levels of 480 gal/MWh. For nuclear plants, the corresponding numbers are 400 gal/MWh and 720 gal/MWh. However, since this analysis relies on the water withdrawal and consumption data reported by power plants to EIA, it does not account for this downstream evaporative loss.

Subcritical versus Supercritical Boiler for New Coal-Fired Power Plants

The analysis uses different water use scaling factors for coal-fired power plants based on boiler type. A supercritical boiler is more efficient and therefore requires less cooling water flow than a subcritical boiler for an equivalent amount of electrical generation output. Future coal-fired plant capacity is assumed to be split as 75 supercritical and 25 subcritical for the water analysis. Appendix C provides additional background information and justification for this assumption.

Flue Gas Desulfurization Systems for Retrofit and New Coal-Fired Power Plants

The FGD make-up water requirement depends on the type of FGD system – either wet or dry. Dry FGD systems require much less water than wet FGD systems, for example, so different factors were used. The FGD make-up water factors were calculated using material balance data contained in Carnegie Mellon University's Integrated Environmental Control Model (IECM).[14] The amount of existing non-scrubbed capacity projected to be retrofit with FGD was obtained from EIA based on the current AEO data. It was further assumed that all new coal-fired plants would be equipped with FGD. Since emission regulations do not dictate technology selection, the analysis apportions FGD type to retrofit and new capacity additions based on the existing split in the coal-fired power fleet (by summer capacity), which is 90% wet/10% dry.

Integrated Gasification Combined Cycle Plants

Water requirements for integrated gasification combined cycle (IGCC) plants were obtained from a baseline study conducted by DOE/NETL in 2010.[16] The average withdrawal and consumption estimates of three IGCC processes in the study were used for this analysis. The water requirements for IGCC facilities differ from those at pulverized coal facilities. While both require cooling water, IGCC requires substantially less since a large fraction of the output from an IGCC plant is produced from the combustion turbines, which require minimal water. Moreover, since IGCC relies on water for significant process (non-cooling) use, it is unlikely that a saline water source would be desirable. The model IGCC coal plant, therefore, is restricted to freshwater use.

Natural Gas Combined Cycle Plants

In calculating water withdrawal and consumption quantities for combined-cycle plants, an adjustment was made to account for the fact that the gas turbine portion of the plant does not require cooling water. The design capacity of the gas turbine portion of a combined-cycle facility is typically twice that of the steam turbine portion; in other words, two-thirds of a combined-cycle plant's total output is derived from the gas turbine(s). Therefore, only about one-third of the plant output is used for steam generation, with its associated water requirements. For this analysis, water withdrawal and consumption factors were applied to only one-third of the combined-cycle capacity. Appendix E provides additional background information and justification for this assumption.

Step 3: Quality Control and Model Validation

Step 3 represents efforts designed to ensure quality control for the analysis. The water withdrawal and consumption factors that were used in the model were obtained through a rigorous statistical evaluation of data from EIA. SPSS statistical software was utilized to generate boxplots of data that were used to identify outliers. These outliers were not considered during the calculation of water withdrawal and consumption factors. The following is a detailed description of the process used to identify outliers.

For each coal, fossil non-coal, and nuclear plant identified in EIA-767, a withdrawal usage factor (gal/MWh) was calculated. The plants were then segregated into the following groups by fuel, cooling system type, and boiler type (where applicable):

- Coal Recirculating Subcritical
- Coal Recirculating Supercritical
- Coal Once-Through Subcritical
- Coal Once-Through Supercritical
- Coal Cooling Pond Subcritical
- Coal Cooling Pond Supercritical
- Fossil Non-Coal Recirculating
- Fossil Non-Coal Once-Through
- Fossil Non-Coal Cooling Pond
- Nuclear Recirculating
- Nuclear Once-Through

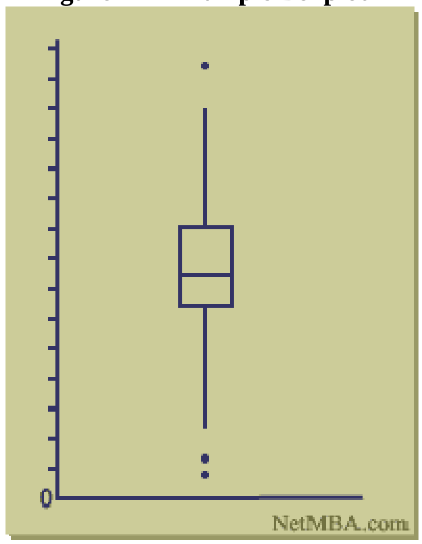
For once-through and cooling pond plants, withdrawal usage factors were multiplied by the corresponding cooling system design temperature rise to normalize the data. For recirculating plants, this step was not taken since the temperature rise would affect the size of the cooling tower, but not the amount of evaporative loss or blowdown that determine the make-up withdrawal rate.

The appropriate data (gal/MWh for recirculating plants and gal/MWh x ΔT for once-through plants) for the above categories was collected and inserted into SPSS to generate boxplots of the data in each of the above categories to identify outliers. An outlier is a data point "far away" from the rest of the data. Some of the water usage data points calculated from the EIA databases were further away from the general data population than what seems reasonable. The outliers can indicate faulty data entry, or possibly unusual operation conditions. For purposes of calculating the regional water usage factors for this study, it was decided to identify and eliminate the statistically significant outliers using the box plot technique described below.

Boxplots are a graphical tool used to identify the center, spread, extent and nature of any departure from symmetry, and outliers contained in a data set. To construct such a plot, data must be ordered in value from smallest to largest. The lower fourth and upper fourth of the data can then be identified. The lower fourth is the median of the smallest n/2 observations when n is even, and the median of the smallest (n+1)/2 observations when n is odd. The upper fourth is the median of the largest n/2 observations when n is even, and the median of the largest (n+1)/2 observations when n is odd. The fourth spread, f_s, is the difference between the upper and lower fourths. Any observation farther than $1.5f_s$ from the closest fourth is a mild outlier while those observations farther than $3f_s$ from the closest fourth are extreme outliers[26].

Figure 11 provides an example of a typical boxplot. In this plot, the upper edge of the box represents the upper fourth, while the lower edge represents the lower fourth. The horizontal line passing through the box indicates the median value of the data. The circles above and below the box indicate outliers while the vertical lines extending above and below the box represent the highest and lowest observations not considered outliers.

Figure 11 – Example Boxplot[27]



Outliers identified by SPSS boxplots were eliminated from the calculation of water usage factors. Table 5 presents the number of data points available as well as the number of outliers identified in each of the 11 categories considered.

Table 5 – Data Points and Outlier Totals for QA/QC Categories

Category	Data Points Available	Outliers Eliminated
Coal Recirculating Subcritical	199	51
Coal Recirculating Supercritical	46	7
Coal Once-Through Subcritical	400	71
Coal Once-Through Supercritical	40	3
Coal Cooling Pond Subcritical	62	0
Coal Cooling Pond Supercritical	9	4
Fossil Non-Coal Recirculating	88	34
Fossil Non-Coal Once-Through	289	55
Fossil Non-Coal Cooling Pond	6	0
Nuclear Recirculating	39	7
Nuclear Once-Through	55	9

Appendix F presents SPSS boxplots generated from the original data for each of the above categories as well as boxplots generated after outliers were eliminated from the data set.

Step 4: Develop Future Cases

Future water withdrawal and consumption for the U.S. thermoelectric generation sector are estimated for five cases – one reflecting status quo conditions, two reflecting varying levels of regulations regarding cooling water source, one incorporating dry cooling, and one reflecting regulatory pressures to convert existing once-through capacity to recirculating capacity. Table 6 presents the description and rationale for the five selected cases.

Table 6 – Case Descriptions for the Water Needs Analysis

Case Description	Rationale
Case 1: Additions and retirements proportional to current water source and type of cooling system.	Status quo scenario case. Assumes additions and retirements follow current trends.
Case 2: All additions use freshwater and wet recirculating cooling, while retirements are proportional to current water source and cooling system.	Regulatory-driven case. Assumes 316(b) and future regulations dictate the use of recirculating systems for all new capacity. Retirement decisions hinge on age and operational costs rather than water source and type of cooling system.
Case 3: 90% of additions use freshwater and wet recirculating cooling, and 10% of additions use saline water and once-through cooling, while retirements are proportional to current water source and cooling system.	Regulatory-light case. New additions favor the use of freshwater recirculating systems, but some saline capacity is permitted. Retirement decisions remain tied to age and operational costs, tracking current source withdrawals.
Case 4: 25% of additions use dry cooling and 75% of additions use freshwater and wet recirculating cooling. Retirements are proportional to current water source and cooling system.	Dry cooling case. Regulatory and public pressures result in significant market penetration of dry cooling technology. Retirement decisions remain tied to age and operational costs, tracking current source withdrawals.
Case 5: Additions use freshwater and wet recirculating cooling, while retirements are proportional to current water source and cooling system. 5% of existing freshwater once-through cooling capacity retrofitted with wet recirculating cooling every 5 years starting in 2015.	Conversion case. Same as Case 2, except regulatory and public pressures compel state agencies to dictate the conversion of a significant amount of existing freshwater once-through cooling systems to wet recirculating.

The five cases were selected to cover the range of possible design choices for new power plants including the source of water (fresh or saline) and type of cooling system (wet recirculating or dry). In addition, Case 5 assumes that 25% of existing power plants with a once-through cooling system are retrofit with a wet recirculating system. For all five cases, it is assumed that plant retirements occur proportional to current water source and cooling system type.

Step 5: Calculate regional withdrawal and consumption to 2035

Step 5 integrates the water withdrawal and consumption factors calculated in Step 2 with the various cases defined in Step 4 to assess the regional and national impacts on water withdrawal and consumption out to 2035. The *Annual Energy Outlook* provides projections of future electricity generating capacity by year, by generation type and by region. Apportioning this capacity among the chosen model plants for a given case and then applying the water withdrawal and consumption factors enabled the calculation of estimated water withdrawal and consumption trends for each of the five future cases.

Water Use for CO_2 Capture Equipped Coal-Fired Power Plants

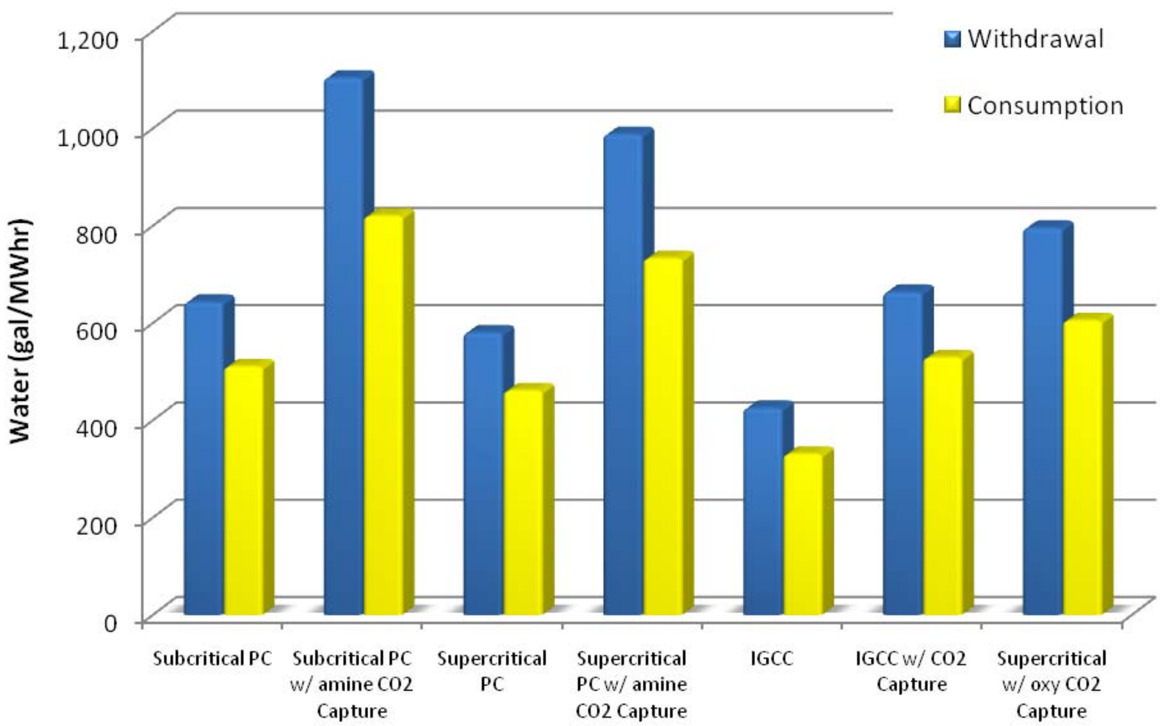
Carbon capture technologies could increase the water demand on thermoelectric power plants. With increasing political and public interest regarding "climate change" and CO_2 mitigation, coupled with future water usage concerns, it is of interest to estimate and explore the possible effects CO_2 mitigation will have on future water demands. EIA forecasts a 4.6% increase in coal-fired generation by the year 2035[1]. Current carbon capture technologies under development for coal-based power generation require large amounts of water. This analysis assumes that aggressive carbon mitigation policies will be put in place in the near future that would require all new and existing PC plants with scrubbers and IGCC plants to utilize carbon capture technologies by 2035. The deployed carbon capture technologies used in this analysis remove a nominal 90% of the CO_2 that would be generated from the fuel carbon. Carbon capture technologies are applied in the year 2020. The analysis follows the EIA AEO 2010 forecast and assumes the generation mix would not change under such a climate control scenario. This analysis provides an upper boundary of the estimated additional water usage for carbon capture. Decisions to retrofit existing plants are complicated and involve many factors such as plant age, plant size, capacity, economic viability, land restraints, and location to carbon sink and are outside of the scope of this work.

AEO 2010 projects that in the year 2035, 85 MW of power will be generated from PC plants that do not have scrubbers for sulfur control. Therefore, this analysis does not include those plants for CO_2 capture. It is assumed that the PC plants without scrubbers are the oldest plants and that it is not feasible to retrofit them with CO_2 capture technologies. Therefore these plants would be subjected to carbon trading.

The carbon capture section of this analysis uses a 1st order approach derived from a recent NETL study of the cost and performance impacts associated with CCS technologies on coal-based power plants.[16] Water consumption and withdrawal factors, gallons used per energy generated on a net generation basis, from the detailed study were developed for the subcritical and supercritical plants. The water use for the carbon capture ready IGCC plants was the average of the three gasification technologies studied in the detailed report since the types of gasifiers used are not known for future generation. The water requirements, at full load, for PC and IGCC plants with and without carbon capture derived from the detail performance study and used in this analysis is shown in Figure 12. All additional cooling systems required for the retrofits and all new PC and

IGCC capture ready plants are assumed to be recirculating systems based on current regulations and concerns with once-through systems.

Figure 12 - Relative Water Usage for new PC and IGCC Plants



*** IGCC data are the averages of three different gasification technologies**

Carbon capture technologies require auxiliary power also termed "parasitic" load, which lowers the net exported power. This analysis assumes that all new additions include carbon capture technologies and that these new builds will meet the required capacity by accounting for their own parasitic load. The existing PC plants that will be retrofitted with carbon capture technologies will be de-rated due to the parasitic load. Net outputs from retrofitted PC plants are de-rated by approximately 30%[15], resulting in 67.1 GW of required replacement power. Since the EIA data did not include additions for a carbon capture case, this analysis looks at three possible scenarios to account for the capacity loss.

Scenario 1 only accounts for the increased water requirements for the carbon capture technologies used for the retrofits and new builds and does not account for the 67.1 GW of reduced capacity due to the retrofits. For this analysis, it is assumed that the reduced capacity will be replaced with some other "non-thermoelectric" generation that doesn't require cooling water. The additional water requirements, if applicable, for these other technologies are not accounted for in this scenario. This scenario is the lower estimate to serve as the lower boundary of the projections and as the initial step for the incremental water increase for scenarios 2 and 3 to build off of.

Scenario 2 builds off of scenario 1 and assumes that the additional capacity needed to make up for the parasitic loss of the retrofits is supplemented by 67.1 GW of new IGCC plants with recirculating cooling and include carbon capture technologies. Cases 3 and 4 are applicable to these new builds where 10% of the new IGCC builds us saline water (Case 3) and 25% of the new builds use dry cooling (Case 4).

Scenario 3 is similar to scenario 2 except it assumes that the additional capacity needed to make up for the parasitic loss of the retrofits is supplemented by 67.1 GW of new oxy-combustion, supercritical PC power plants with recirculating cooling and include carbon capture technologies. Cases 3 and 4 are applicable to these new builds where 10% of the new supercritical builds us saline water (Case 3) and 25% of the new builds use dry cooling (Case 4).

Scenario 4 is similar to scenario 2 except it assumes that the additional capacity needed to make up for the parasitic loss of the retrofits is supplemented by 67.1 GW of new supercritical PC with an amine (solvent based) carbon captures system power plants with recirculating cooling and include carbon capture technologies. Cases 3 and 4 are applicable to these new builds where 10% of the new supercritical builds us saline water (Case 3) and 25% of the new builds use dry cooling (Case 4).

Scenario 5 builds off of scenario 1 and assumes that the additional capacity needed to make up for the parasitic loss of the retrofits is supplemented by 67.1 GW of new nuclear plants with recirculating cooling. This scenario is only applied to Case 2 for this study.

PC and IGCC solvent carbon capture technologies increase the plants overall water use. For the PC cases with carbon capture, the increase in water consumption, compared to a plant without carbon capture, is greatly influenced by the cooling water requirements of the CO_2 capture process. The cooling water for the overall CO_2 capture process is required to reduce the flue gas temperature exiting the FGD down to below 100°F, remove heat input by the stripping steam to cool the solvent, remove heat input from the auxiliary electric loads, and remove heat in the CO_2 compressor intercoolers.[16] The increased water use for the IGCC plants in largely due to the steam used in the water gas shift reaction. More detail regarding the carbon capture technologies used for this analysis is described in Appendix G.

Results

Both national and regional water withdrawal and consumption projections for each of the five cases are presented below for total thermoelectric generation and the coal-fired generation component of thermoelectric generation. The increased water use for capturing CO_2 nationally in the year 2035 is also shown.

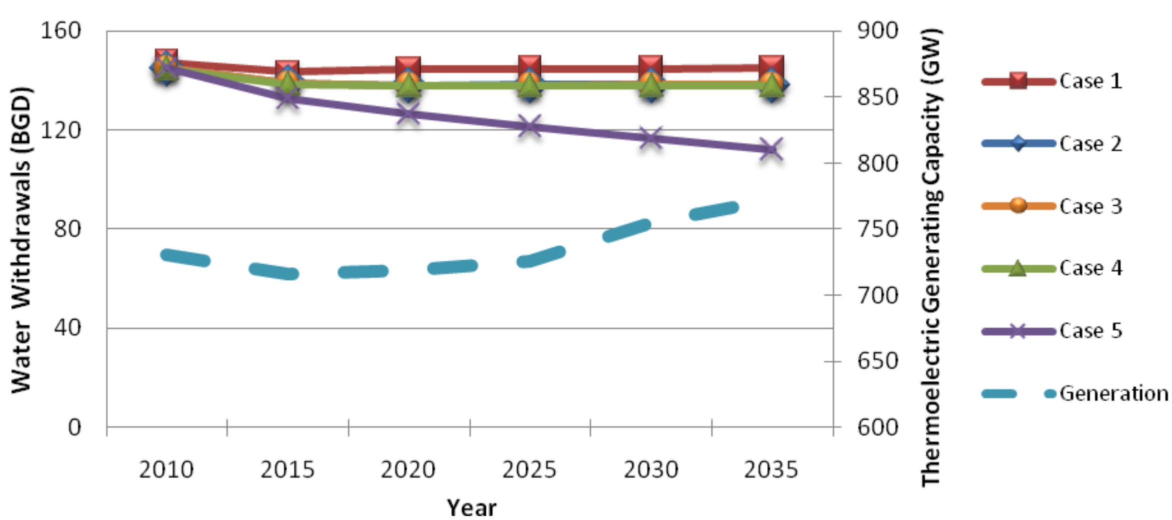
Thermoelectric Generation – National Level Summary

The analysis projects that by 2035, average daily national freshwater withdrawals required to meet the needs of U.S. thermoelectric power generation could range from 112 BGD to 145 BGD depending upon case assumptions. The 2010 average value of 145 BGD compares incrementally to the USGS estimates that thermoelectric power plants withdrew approximately 132 BGD of freshwater in 1995 and approximately 143 BGD of freshwater in 2005. Table 7 presents the range of average daily national freshwater withdrawal for each of the five cases from 2010 through 2035. This same data is presented graphically in Figure 13.

Table 7 – Average National Freshwater Withdrawal for Thermoelectric Power Generation (BGD)

	2010	2015	2020	2025	2030	2035
Case 1	147.4	143.3	144.7	144.8	144.9	145.0
Case 2	145.0	138.9	138.1	138.2	138.2	138.4
Case 3	145.0	138.9	138.1	138.1	138.2	138.3
Case 4	144.8	138.6	137.7	137.7	137.8	137.9
Case 5	145.0	132.9	126.5	121.4	116.7	112.3
Minimum	144.8	132.9	126.5	121.4	116.7	112.3
Maximum	147.4	143.3	144.7	144.8	144.9	145.0

Figure 13 – Average Daily National Freshwater Withdrawal for Thermoelectric Power Generation



The analysis projects that by 2035, average daily national freshwater consumption resulting from U.S. thermoelectric power generation could range from 4.1 BGD to 4.6

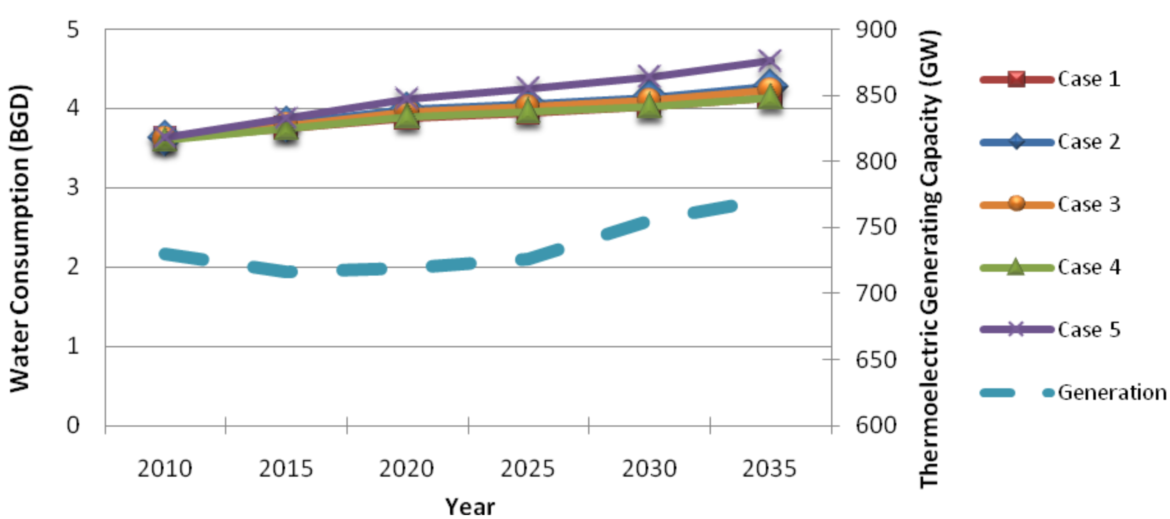
BGD depending upon case assumptions. Consumption for year 2010 is 3.6 BGD. This compares with USGS estimates that in 1995, freshwater consumption by U.S. thermoelectric power plants was approximately 3.3 BGD. Table 8 presents the range of average daily national freshwater consumption for each of the five cases from 2010 through 2035. This same data is presented graphically in Figure 14 along with the generating capacity for each of the years.

Table 8 – Average National Freshwater Consumption for Thermoelectric Power Generation (BGD)

	2010	2015	2020	2025	2030	2035
Case 1	3.6	3.7	3.9	3.9	4.0	4.1
Case 2	3.6	3.8	4.0	4.1	4.1	4.3
Case 3	3.6	3.8	4.0	4.0	4.1	4.2
Case 4	3.6	3.7	3.9	4.0	4.0	4.1
Case 5	3.6	3.9	4.1	4.3	4.4	4.6
Minimum	3.6	3.7	3.9	3.9	4.0	4.1
Maximum	3.6	3.9	4.1	4.3	4.4	4.6

Though the report primarily focuses on freshwater use, saline water usage is modeled and the results are included at the national level. Figure 15 and Figure 16 are similar to Figure 13 and Figure 14, except saline water usage is added to the graphs illustrating that nationally saline water withdrawals are approximately one-third that of freshwater withdrawals. Saline water consumption for the thermoelectric plants is negligible compared to freshwater consumption, since most plants using saline water utilize a once-through cooling system.

Figure 14 – Average Daily National Freshwater Consumption for Thermoelectric Power Generation



Thermoelectric Generation - National Level Results by Case

Case 1

Total thermoelectric generation freshwater withdrawal is projected to remain relatively constant from 2010 through 2035 for Case 1 – decreasing slightly from 147.4 BGD to 145 BGD – despite the overall 5.7% increase in generation capacity from 730 GW to 772 GW. At first glance this result seems inconsistent with the Case 1 status quo assumptions that additions and retirements are proportional to current water source and type of cooling water system. The explanation for this apparent inconsistency is that AEO 2010 projects capacity retirements primarily from the non-FGD coal and non-coal fossil generation categories, which have a relatively high proportion of once-through cooling systems, while capacity additions are primarily in the FGD coal, IGCC, and NGCC generation categories, which have a relatively high proportion of wet recirculating cooling systems. In addition, the steam cycle portion of IGCC and NGCC plants is only one-third of their total capacity. Since average freshwater withdrawal for once-through cooling is significantly higher than wet recirculating cooling – approximately 25 gal/kWh versus 0.5 gal/kWh – the net effect is no significant change in overall freshwater withdrawal over the next 25 years.

Figure 15 – Average Daily National Freshwater and Saline Withdrawals for Thermoelectric Power Generation

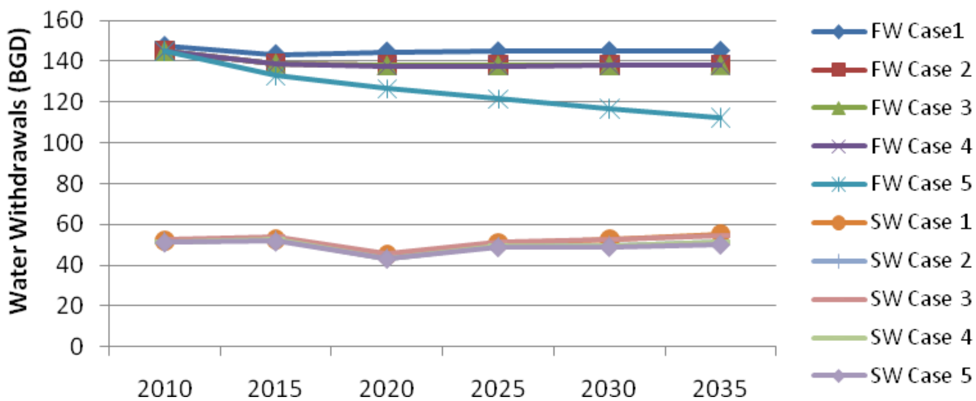
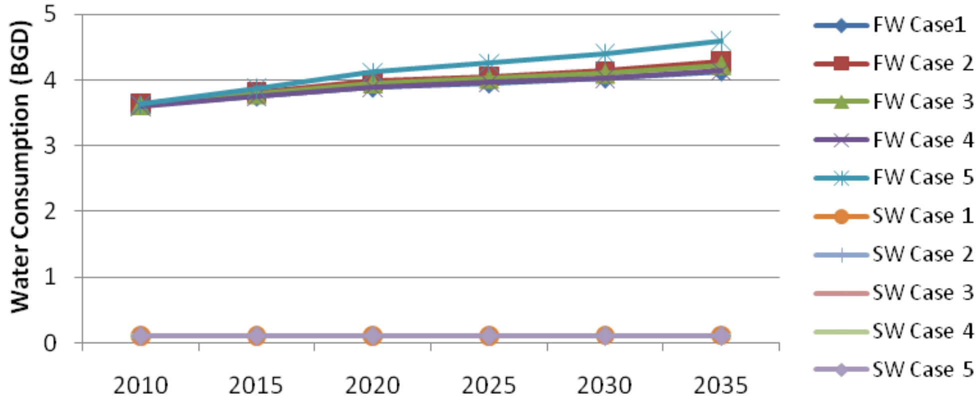


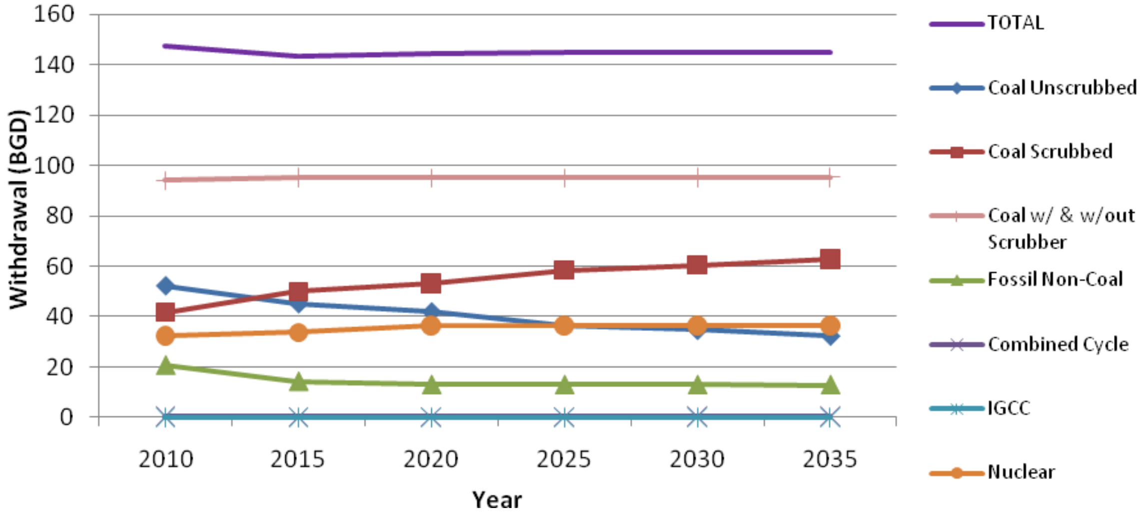
Figure 16 – Average Daily National Freshwater and Saline Consumption for Thermoelectric Power Generation



National freshwater withdrawal for each fuel type in Case 1 is presented in Figure 17. The figure shows the relatively unchanged total withdrawal, and the mirroring of scrubbed and unscrubbed coal (with scrubbed increasing over time as unscrubbed decreases). There is a decrease in fossil non-coal withdrawal and a slight increase in nuclear withdrawal.

Total thermoelectric generation freshwater consumption is projected to increase 14.1% from 2010 through 2035 for Case 1 – growing from 3.6 BGD to 4.1 BGD – consistent with the increase in generation capacity from 730 GW to 771 GW. Since once-through cooling systems have minimal water consumption, the retirement of these systems does not have the same effect on national consumption levels as they do on withdrawal levels as described above.

Figure 17 - Average Daily National Freshwater Withdrawal by Fuel for Thermoelectric Power Generation – Case 1

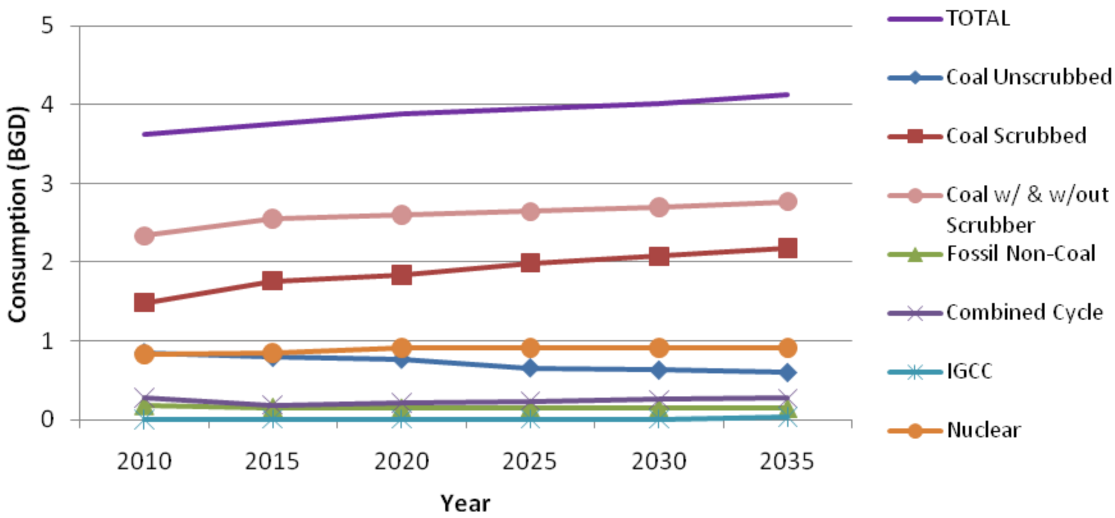


The changes in results over time reveal some interesting trends. Although total water withdrawal decreases slightly between 2010 and 2035, the increase is not uniform. There is a dip in water withdrawal in the year 2015. This dip is directly related to the dip in the total thermoelectric generation capacity where the initial decline is due to significant retirement of fossil non-coal capacity (more than 23 GW) and the subsequent increase is due to new coal and combined-cycle additions (more than 10 GW). This difference appears in the other cases as well, although to a lesser degree because of competing influences unique to each specific case.

The slow grow of IGCC technology is evident in the results over time. From a level around 500 MW in 2010, IGCC is expected to account for 4.6 GW by 2035. The water impact is small – due primarily to the assumption that all new IGCC capacity will be equipped with wet recirculating cooling. In 2035, water withdrawal for IGCC is only 0.04 BGD and water consumption is 0.03 BGD.

National freshwater consumption for each fuel type in Case 1 is presented in Figure 18. The effects of increased use of NGCC can more clearly be seen in the consumption graph than in the previous withdrawal graph. Consumption increases for each fuel type except unscrubbed coal and fossil non-coal, which decrease.

Figure 18 - Average Daily National Freshwater Consumption by Fuel for Thermoelectric Power Generation – Case 1



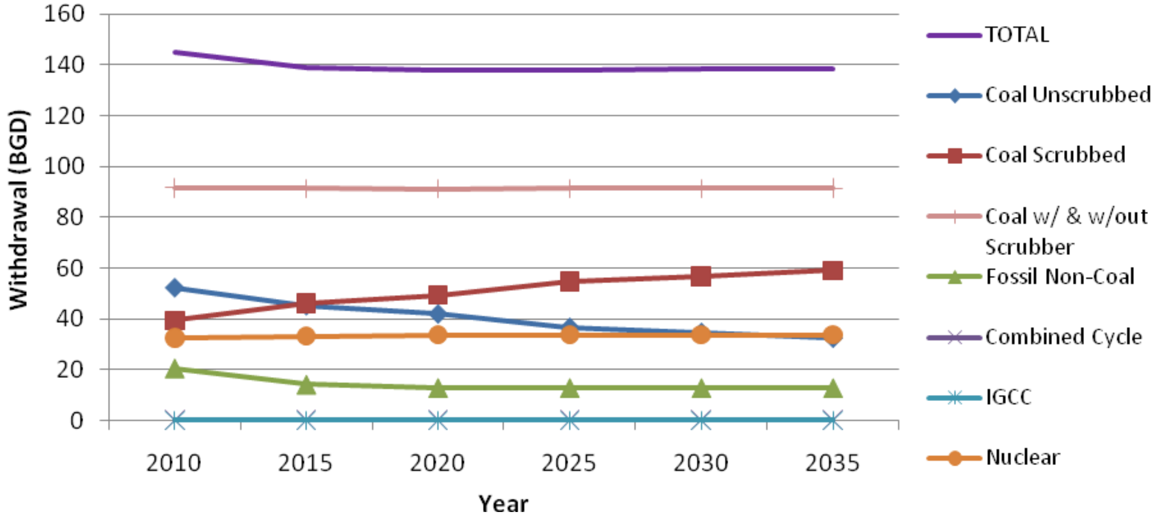
Case 2
Total thermoelectric generation freshwater withdrawal is projected to decrease approximately 5% (145 BGD to 138 BGD) from 2010 through 2035 for Case 2. This trend is consistent with the assumptions that all capacity additions use freshwater and wet recirculating cooling systems, while capacity retirements are proportional to current water source and type of cooling water system.

Figure 19 displays Case 2 national withdrawal for each fuel type. The decrease in total withdrawal can be seen along with a decrease in fossil non-coal. The line representing the combination of scrubbed and unscrubbed coal remains relatively constant. Again scrubbed coal increases, while unscrubbed decreases.

Similar to Case 1, total thermoelectric generation freshwater consumption is projected to increase – growing 18% from 3.6 BGD to 4.3 BGD between 2010 and 2035 – consistent with both the 5.7% increase in generation capacity and increased use of wet recirculating cooling water systems.

Figure 20 displays Case 2 national consumption for each fuel type. Consumption increases are seen in every fuel type except unscrubbed coal, combined cycle, and fossil non-coal, which decrease.

Figure 19 - Average Daily National Freshwater Withdrawal by Fuel for Thermoelectric Power Generation – Case 2



Case 3

The Case 3 assumptions are similar to Case 2, except that 90% of capacity additions use freshwater and wet recirculating cooling and 10% use saline water with once-through cooling. As might be expected, both thermoelectric generation freshwater withdrawal and consumption levels for Case 3 are slightly less than the respective values from Case 2. In 2035, freshwater withdrawal is 138.4 BGD in Case 2 compared to 138.3 in Case 3. Similarly, freshwater consumption in 2030 is 4.3 BGD and 4.2 BGD for Cases 2 and 3, respectively.

National freshwater withdrawal for each fuel type in Case 3 is presented in Figure 21. As the figure shows, total withdrawal decreases and then essential remains flat over time. Fossil non-coal and coal unscrubbed also display a noticeable decrease. National freshwater consumption for each fuel type in Case 3 is presented in Figure 22. Freshwater consumption is shown to increase over time. As with previous consumption cases, only coal unscrubbed and fossil non-coal consumption decreases from 2010 to 2035.

Figure 20 - Average Daily National Freshwater Consumption by Fuel for Thermoelectric Power Generation – Case 2

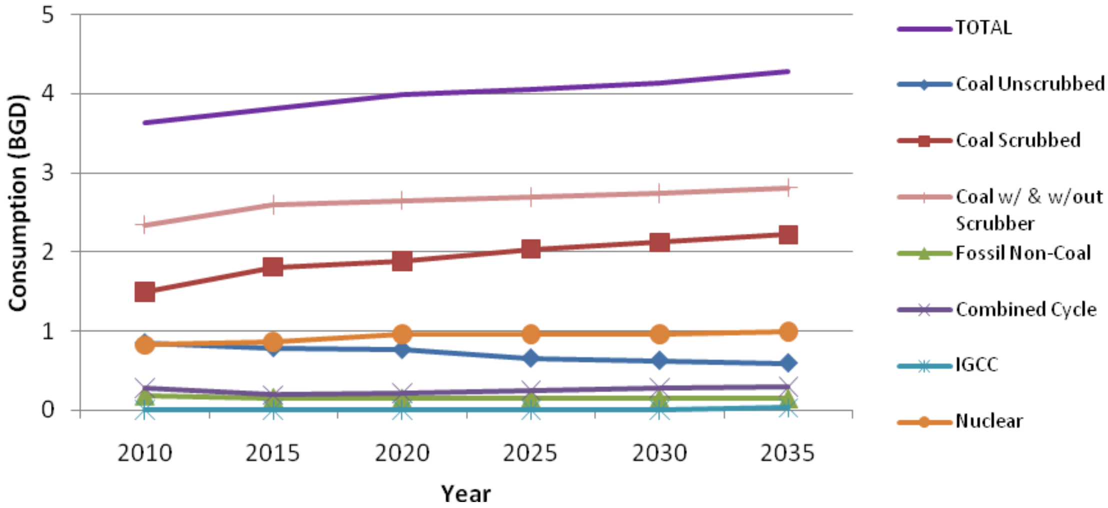


Figure 21 - Average Daily National Freshwater Withdrawal by Fuel for Thermoelectric Power Generation – Case 3

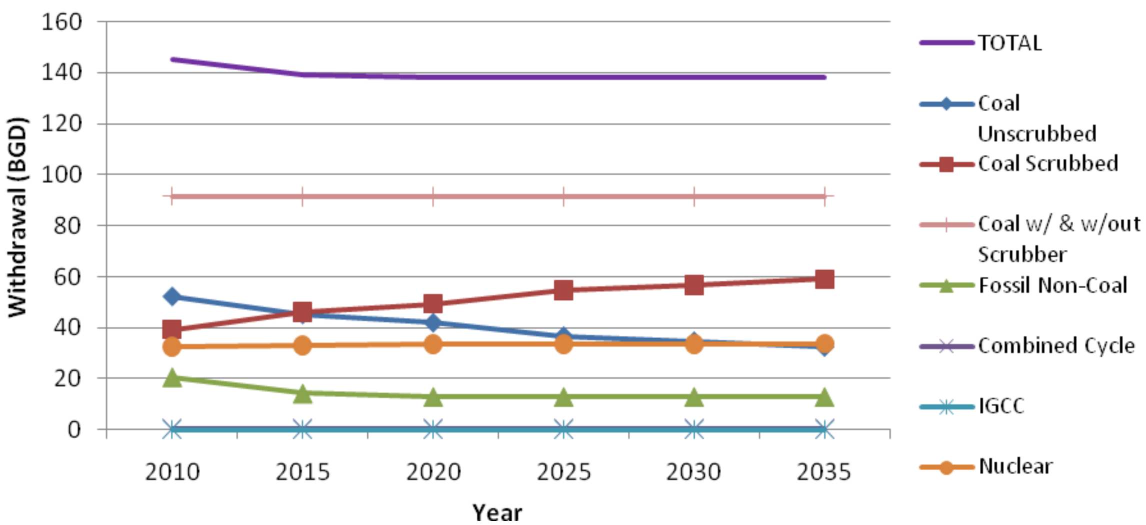
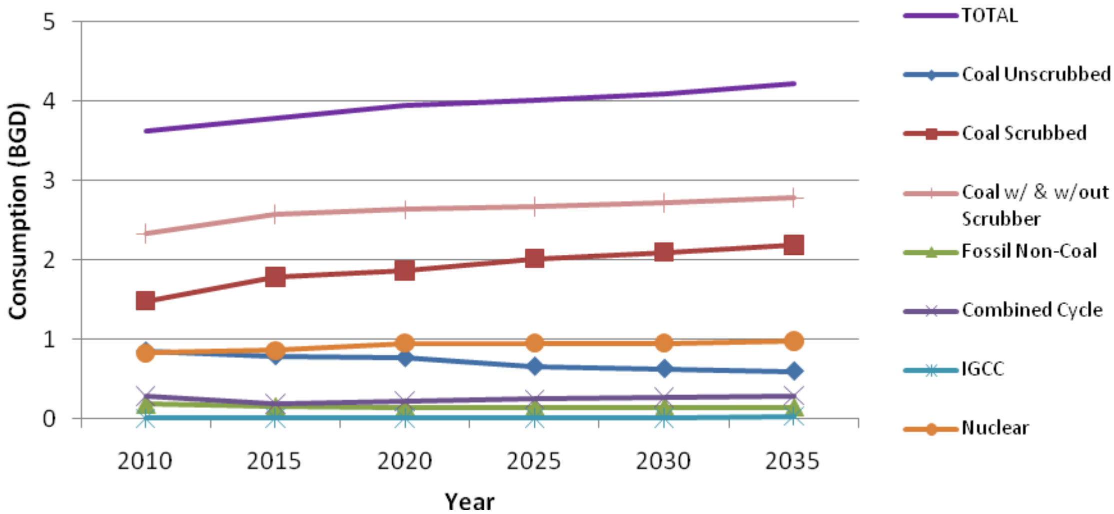


Figure 22 - Average Daily National Freshwater Consumption by Fuel for Thermoelectric Power Generation – Case 3



Case 4

The potential impact of dry cooling systems on water demand is evident in the results of Case 4, where 25% of new capacity is assumed to be equipped with dry cooling, rather than wet recirculating cooling. Thermoelectric generation freshwater withdrawal and consumption levels for Case 4 are less than the respective values from Case 2. By 2035, freshwater withdrawal is projected to be less than 1% less in Case 4 compared to Case 2 – 137.9 BGD vs. 138.4 BGD. More significantly, freshwater consumption is projected to be approximately 3.3% less – 4.1 BGD in Case 4 vs. 4.3 BGD in Case 2. The results suggest that dry cooling has the potential to play a significant role in minimizing freshwater consumption in future years if technology is developed to cost effectively build and operate dry cooling plants.

Figure 23 displays Case 4 national withdrawal for each fuel type. The total freshwater withdrawal decreases over time, as does coal unscrubbed and fossil non-coal. The line representing the combination of scrubbed and unscrubbed coal remains rather constant over the time period. Figure 24 displays Case 4 national consumption for each fuel type. Total consumption is shown to increase from 2010 to 2035, with only coal unscrubbed and fossil non-coal decreasing during that period.

Figure 23 - Average Daily National Freshwater Withdrawal by Fuel for Thermoelectric Power Generation – Case 4

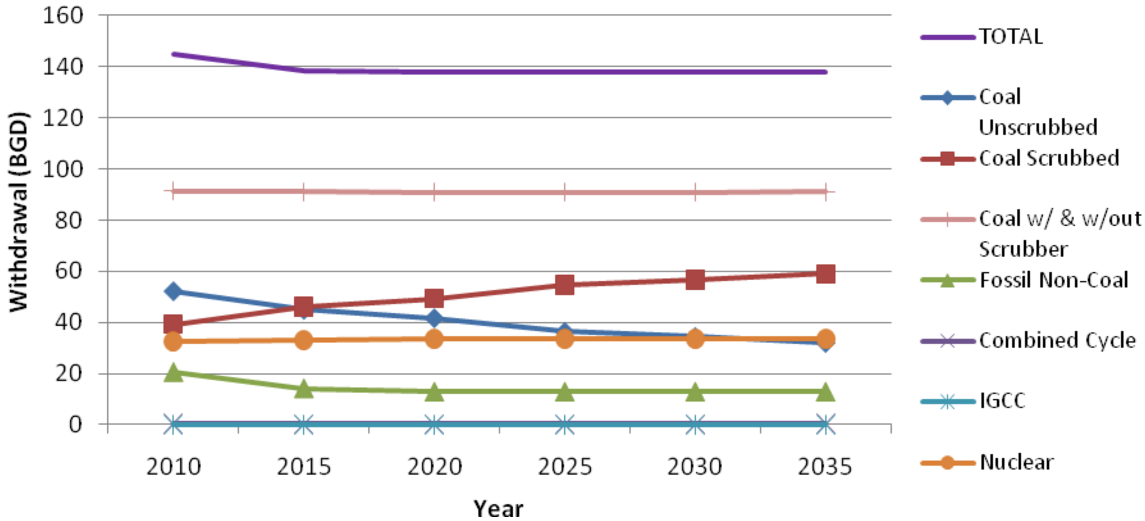
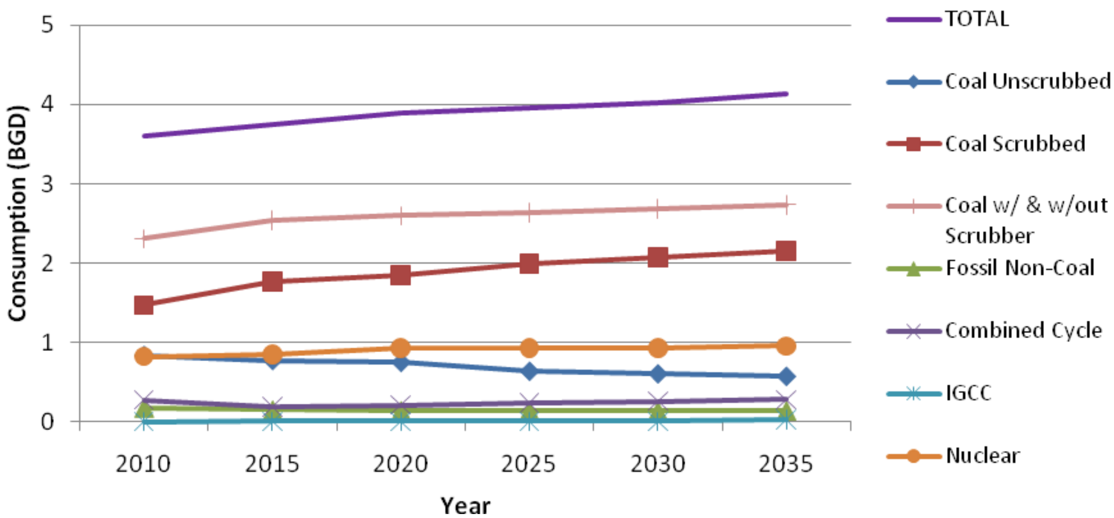


Figure 24 - Average Daily National Freshwater Consumption by Fuel for Thermoelectric Power Generation – Case 4



Case 5

The Case 5 assumptions for capacity additions and retirements are the same as Case 2. However, Case 5 also assumes that 25% of existing freshwater once-through cooling capacity is converted to wet recirculating cooling. As a result, Case 5 represents the most extreme conditions of the analysis and significantly impacts projections for both freshwater withdrawal and consumption. By 2035, total thermoelectric generation freshwater withdrawal is projected to be approximately 19% less in Case 5 compared to Case 2 – 112.3 BGD vs. 138.4 BGD – while consumption is projected to be approximately 7% more – 4.6 BGD in Case 5 vs. 4.3 BGD in Case 2.

Figure 25 - Average Daily National Freshwater Withdrawal by Fuel for Thermoelectric Power Generation – Case 5

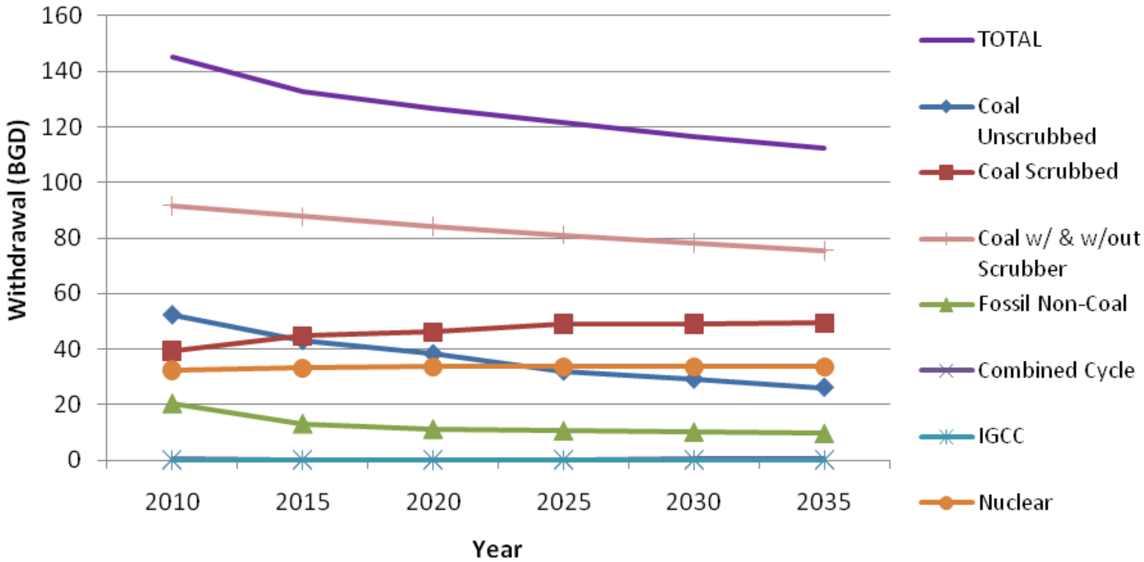
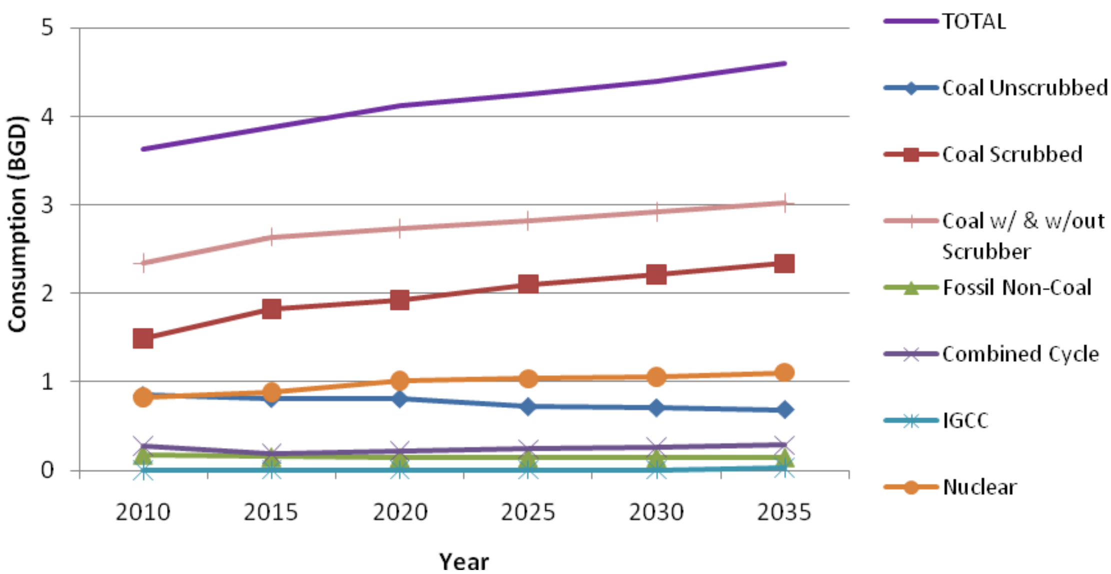


Figure 26 - Average Daily National Freshwater Consumption by Fuel for Thermoelectric Power Generation – Case 5



National freshwater withdrawal for each fuel type in Case 5 is presented in Figure 25. Total freshwater withdrawal decreases over time, as does withdrawal for all fuel types except scrubbed coal (which increases as unscrubbed coal decreases). National freshwater consumption for each fuel type in Case 5 is presented in Figure 26. As with previous consumption cases, total freshwater consumption increases and unscrubbed coal and fossil non-coal are the only fuel types shown to decrease.

Thermoelectric Generation – Regional Results

Figure 27 through Figure 31 show the results of the regional freshwater withdrawal analysis for total U.S. thermoelectric generation comparing 2010 to 2035 for each of the five cases. The graphs show the RM and NWPP region has the highest water withdrawal among the cases. The ERCOT and ECAR regions experience the largest decreases in water withdrawal in each case.
Figure 32 through Figure 36 show the results of the regional freshwater consumption analysis for total U.S. thermoelectric generation comparing 2010 to 2035 for each of the five cases. All regions, except California (cases 1, 3, and 4), show an increase in water consumption.

Case 1
As discussed previously, total thermoelectric generation freshwater withdrawal is projected to remain relatively constant from 2010 through 2035 for Case 1 – decreasing slightly from 147.4 BGD to 145.0 BGD On a regional basis, freshwater withdrawal increases in the WECC/RM, WECC/NWPP,MAAC, MAIN, MAPP, NPCC/NY, and SERC regions. The WECC/RM region shows the greatest relative water withdrawal increase, 14% by the year 2035. Decreases occurred in all other regions, with the most significant decreases in the ECAR, ERCOT, SPP, NPCC/NE, and FRCC regions (Figure 27).

Total thermoelectric generation freshwater consumption is projected to increase 14% from 2005 through 2030 for Case 1 – growing from 3.6 BGD to 4.1 BGD. Freshwater consumption increases in 11 of the 13 regions, with relatively large percentage increases occurring in the WECC/RM (42%), NPCC/NY (28%), and ECAR shows a (17%) decrease in water consumption (
Figure 32).

Figure 27 – Average Daily Regional Freshwater Withdrawal for Thermoelectric Power Generation – Case 1

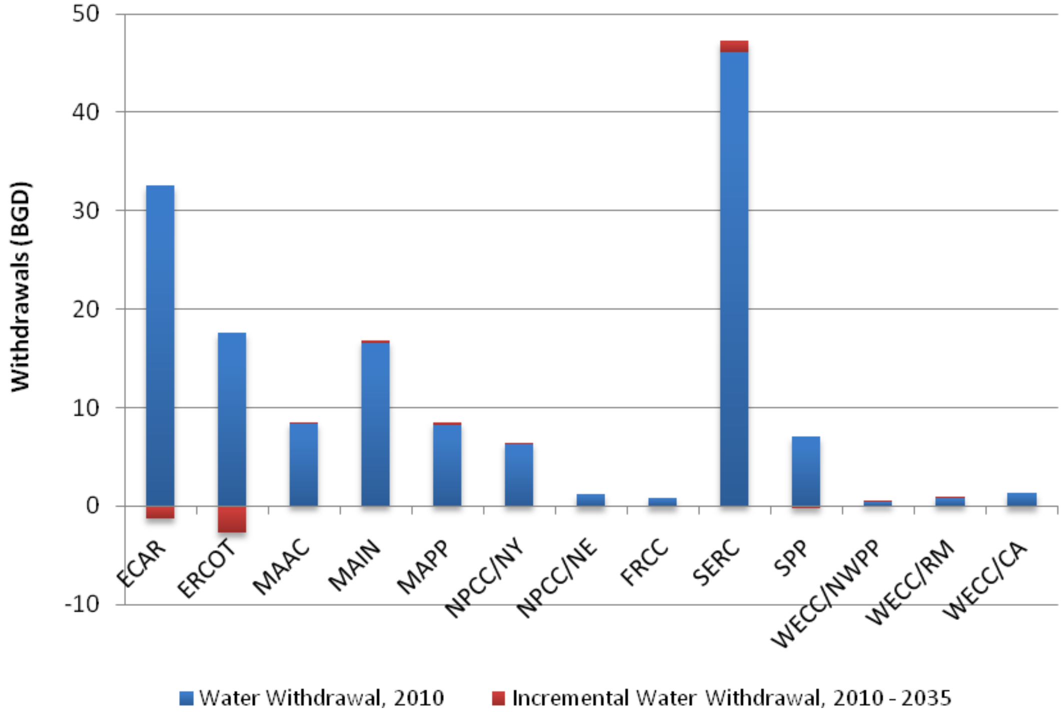


Figure 28 – Average Daily Regional Freshwater Withdrawal for Thermoelectric Power Generation – Case 2

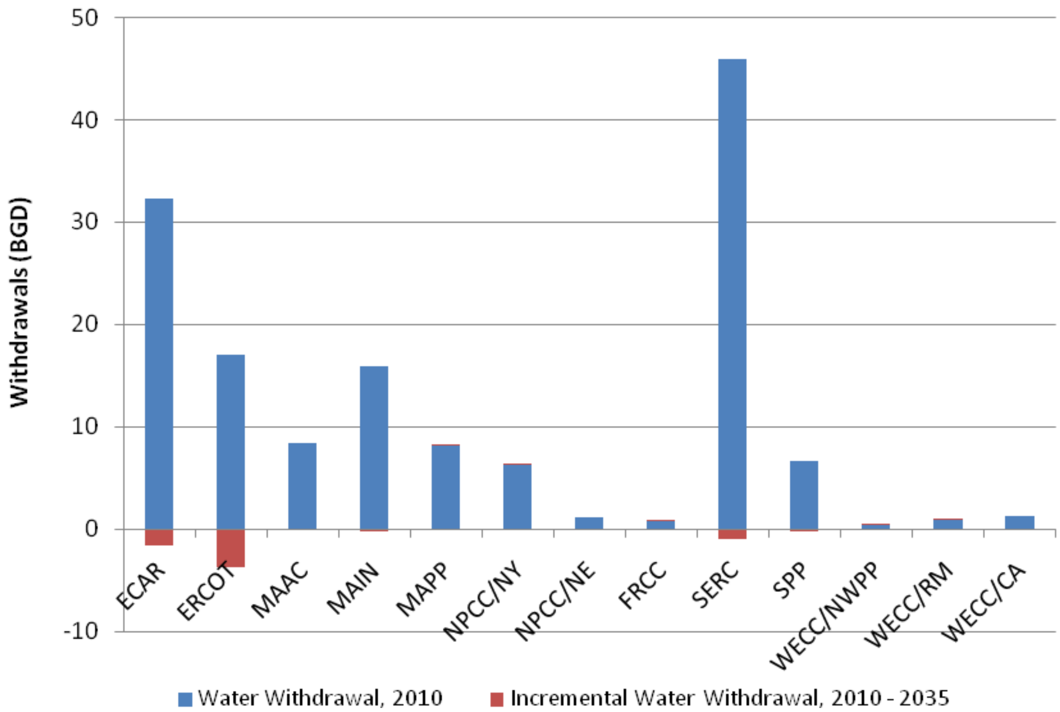


Figure 29 – Average Daily Regional Freshwater Withdrawal for Thermoelectric Power Generation – Case 3

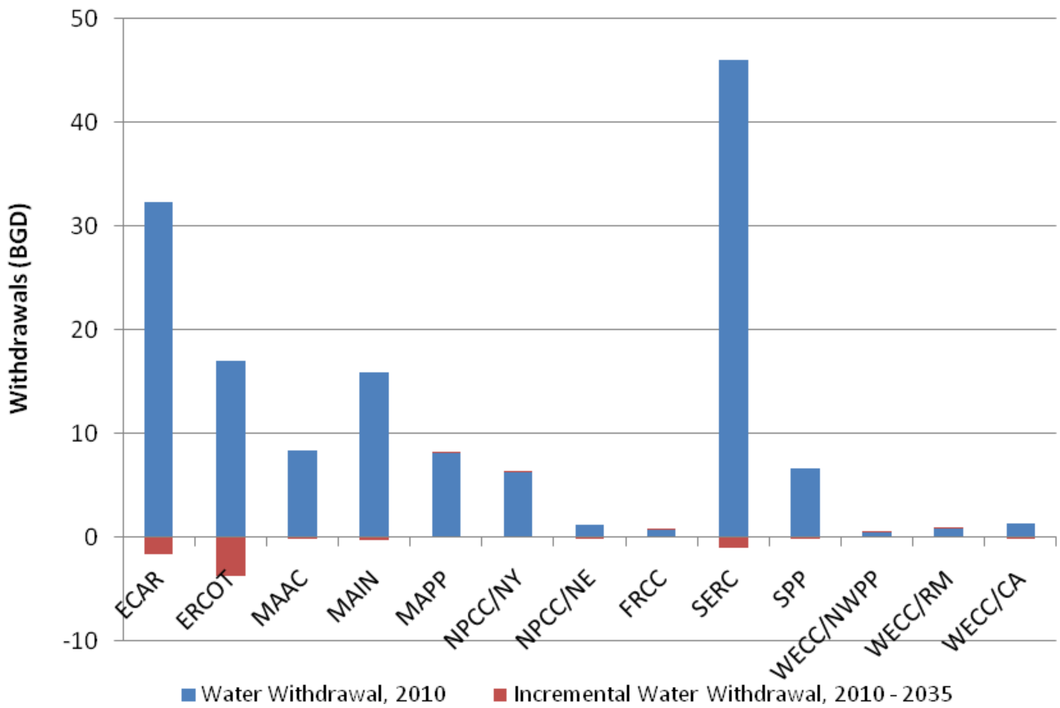


Figure 30 – Average Daily Regional Freshwater Withdrawal for Thermoelectric Power Generation – Case 4

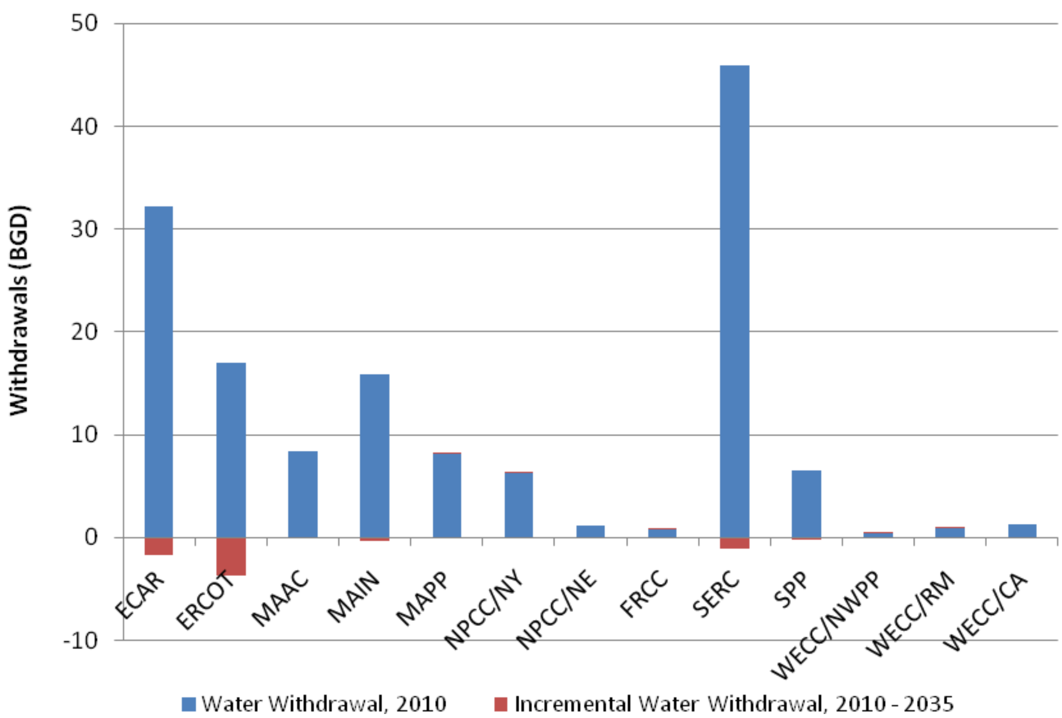


Figure 31 – Average Daily Regional Freshwater Withdrawal for Thermoelectric Power Generation – Case 5

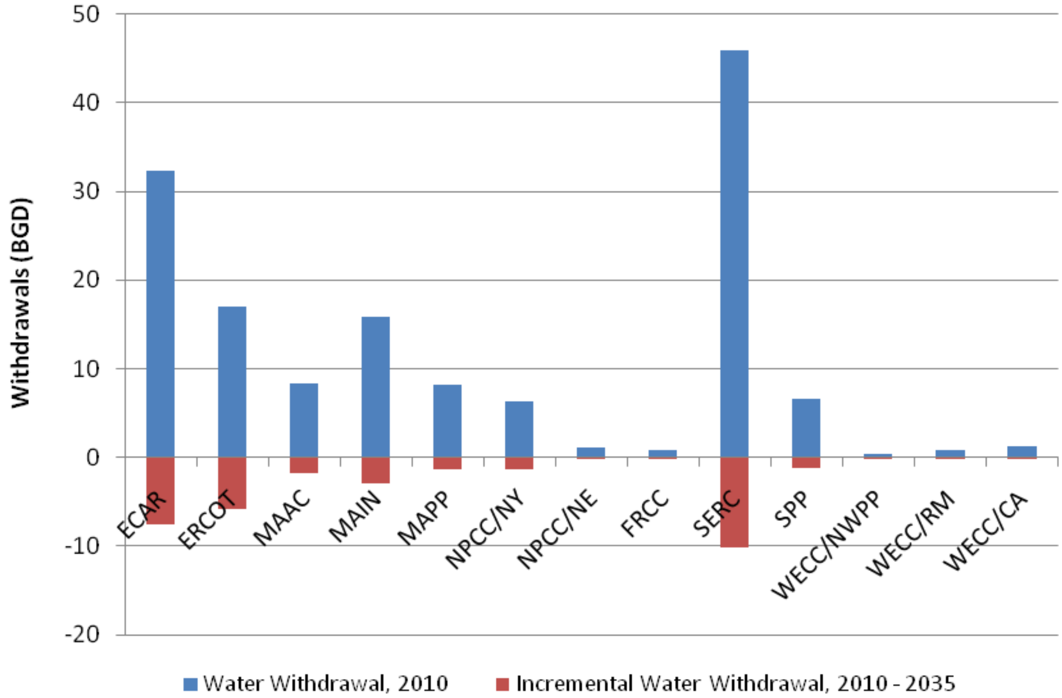


Figure 32 – Average Daily Regional Freshwater Consumption for Thermoelectric Power Generation – Case 1

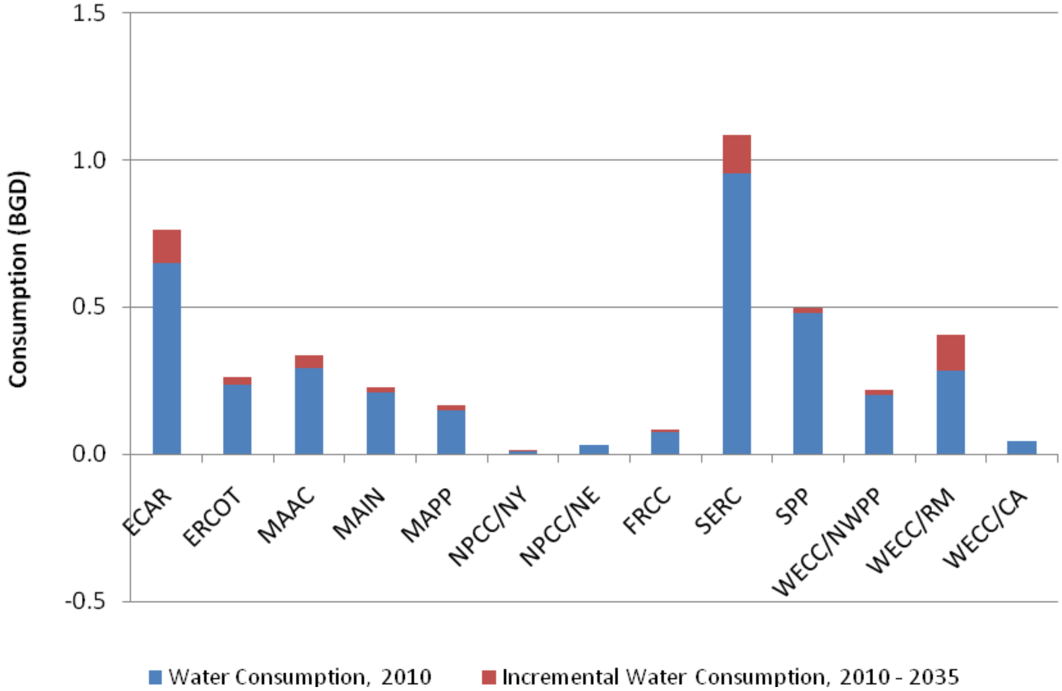


Figure 33 – Average Daily Regional Freshwater Consumption for Thermoelectric Power Generation – Case 2

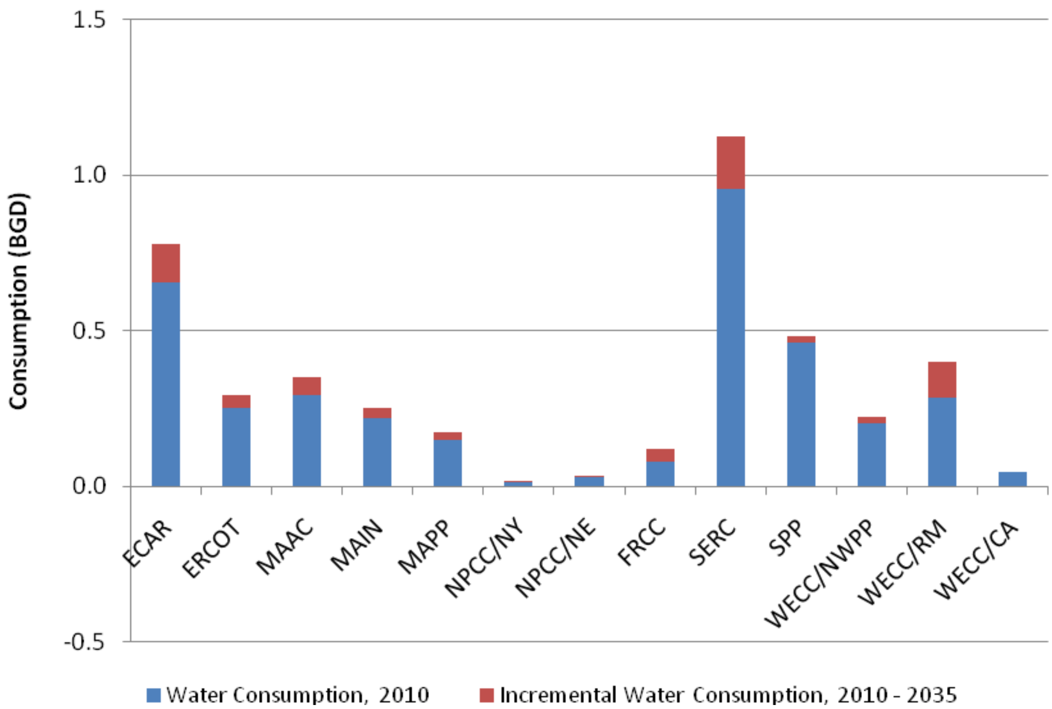


Figure 34 – Average Daily Regional Freshwater Consumption for Thermoelectric Power Generation – Case 3

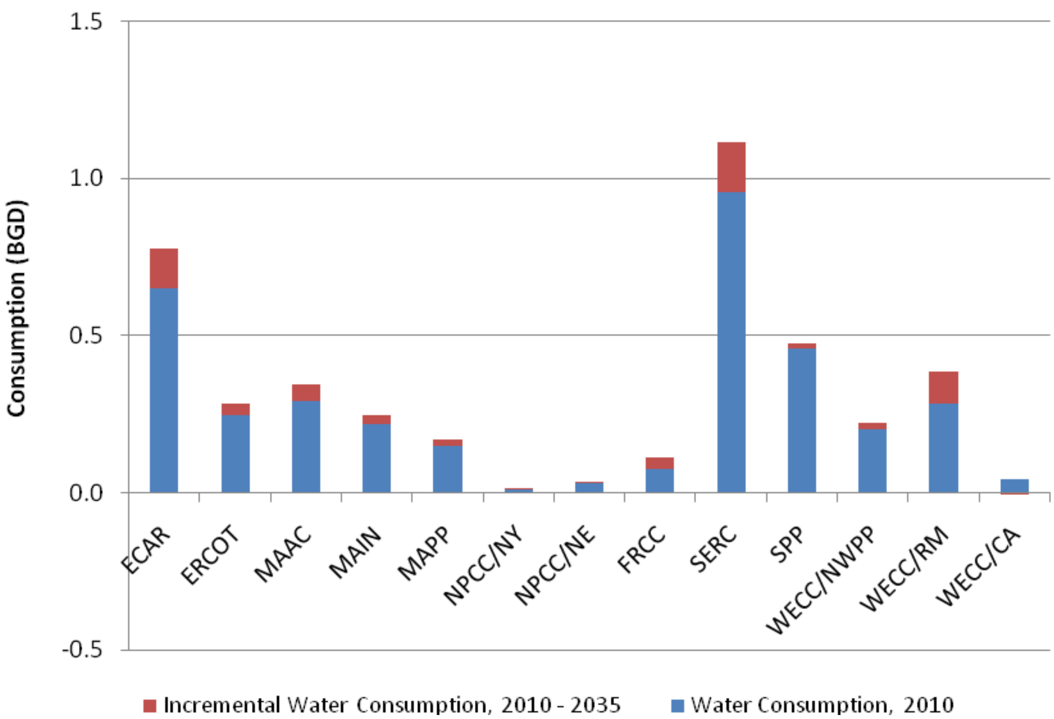


Figure 35 – Average Daily Regional Freshwater Consumption for Thermoelectric Power Generation – Case 4

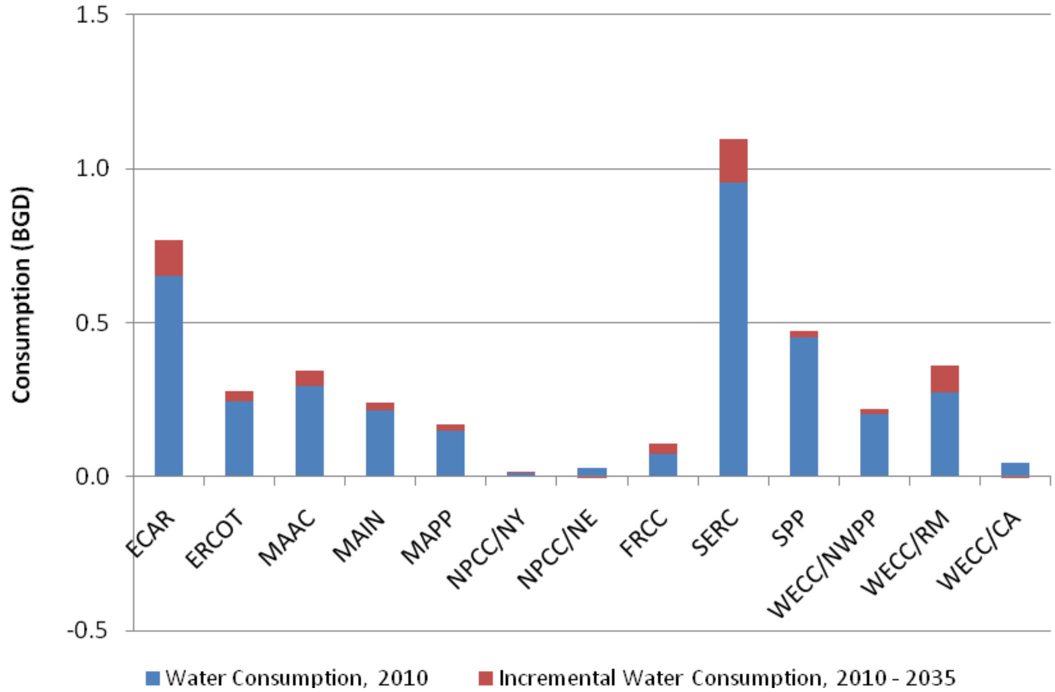
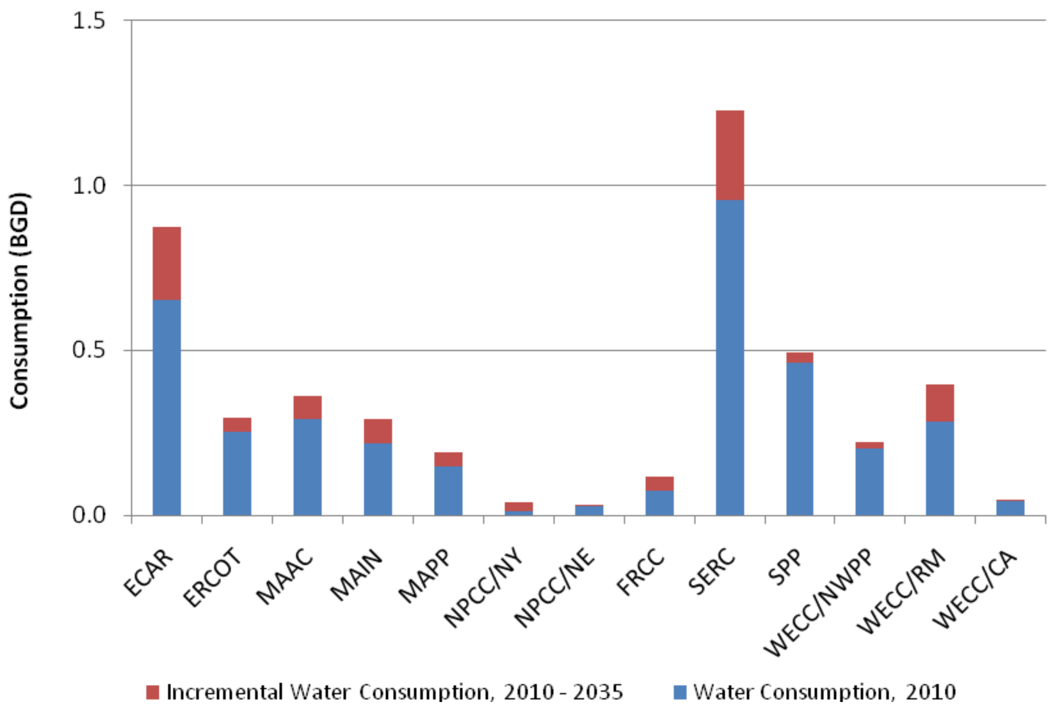


Figure 36 – Average Daily Regional Freshwater Consumption for Thermoelectric Power Generation – Case 5



Case 2
Total thermoelectric generation freshwater withdrawal is projected to decrease approximately 4% (145 BGD to 138 BGD) from 2010 through 2035 for Case 2. Similar to Case 1, total thermoelectric generation freshwater consumption is projected to increase – growing 18% from 3.6 BGD to 4.3 BGD between 2010 and 2035. On a regional basis, freshwater withdrawal increases slightly in the MAPP, NPCC/NY, FRCC, WECC/NWPP, and WECC/RM; and decreases in the ECAR, ERCOT, MAAC, MAIN, NPCC/NE, SERC, SPP, and WECC/CA regions (Figure 28). Freshwater consumption increases in all of the regions with relatively large percentage increases occurring in the FRCC (53%), NPCC/NY (44%), and WECC/RM (40%) regions (
Figure 33).

Case 3
Both thermoelectric generation freshwater withdrawal and consumption levels for Case 3 are slightly less than the respective values from Case 2. In 2035, freshwater withdrawal is 138.4 BGD in Case 2 compared to 138.3 in Case 3. Similarly, freshwater consumption in 2035 is 4.3 BGD and 4.2 BGD for Cases 2 and 3, respectively. On a regional basis, freshwater withdrawal and consumption increases and decreases are also similar to Case 2 (Figure 29 and Figure 34).

Case 4
Thermoelectric generation freshwater withdrawal and consumption levels for Case 4 are less than the respective values from Case 2. By 2035, freshwater withdrawal is projected to be approximately 1% less in Case 4 compared to Case 2 – 137.9 BGD vs. 138.4 BGD. More significantly, freshwater consumption is projected to be approximately 3.3% less – 4.1 BGD in Case 4 vs. 4.3 BGD in Case 2. On a regional basis, freshwater withdrawal and consumption increases and decreases are also similar to Case 2 (Figure 30 and Figure 35).

Case 5
The Case 5 assumptions for capacity additions and retirements are the same as Case 2, but Case 5 also assumes that 25% of existing freshwater once-through cooling capacity is converted to wet recirculating cooling. By 2035, total thermoelectric generation freshwater withdrawal is projected to be approximately 19% less in Case 5 compared to Case 2 – 112.3 BGD vs. 138.4 BGD – while consumption is projected to be approximately 7% more – 4.6 BGD in Case 5 vs. 4.3 BGD in Case 2. On a regional basis, freshwater withdrawal decreased in all regions (Figure 31). Freshwater consumption increases in all of the regions, with relatively large percentage increases occurring in the NPCC/NY (262%) and FRCC (54%) regions (Figure 36).

Saline Regional Results
Figure 37 shows the regional saline water withdrawal and Figure 38 shows the saline water consumption analyses for total U.S. thermoelectric generation comparing 2010 to 2035 for Case 3. The 2010 water analysis primarily focuses on freshwater usage. These

are the only two regional figures representing saline water use in this study. Only Case 3 was chosen to show the regional saline water uses because this case has the highest saline water withdrawal and consumption of the five cases.

On a regional basis, saline water withdrawal increases in eight regions, with relatively large percentage increases occurring in the ECAR (316%), MAPP (123%), and WECC/RM (35%), and MAIN (24%) regions; and only slightly decreases in the ERCOT, SPP, NPCC/NE, and FRCC regions (Figure 37). Saline water consumption increased in all regions except NPCC/NY (1%) and SPP (3%), with relatively large percentage increases occurring in the ECAR (42%), FRCC (37%) and WECC/RM (36%) regions (Figure 38).

Figure 37 – Average Daily Regional Saline Water Withdrawal for Thermoelectric Power Generation – Case 3

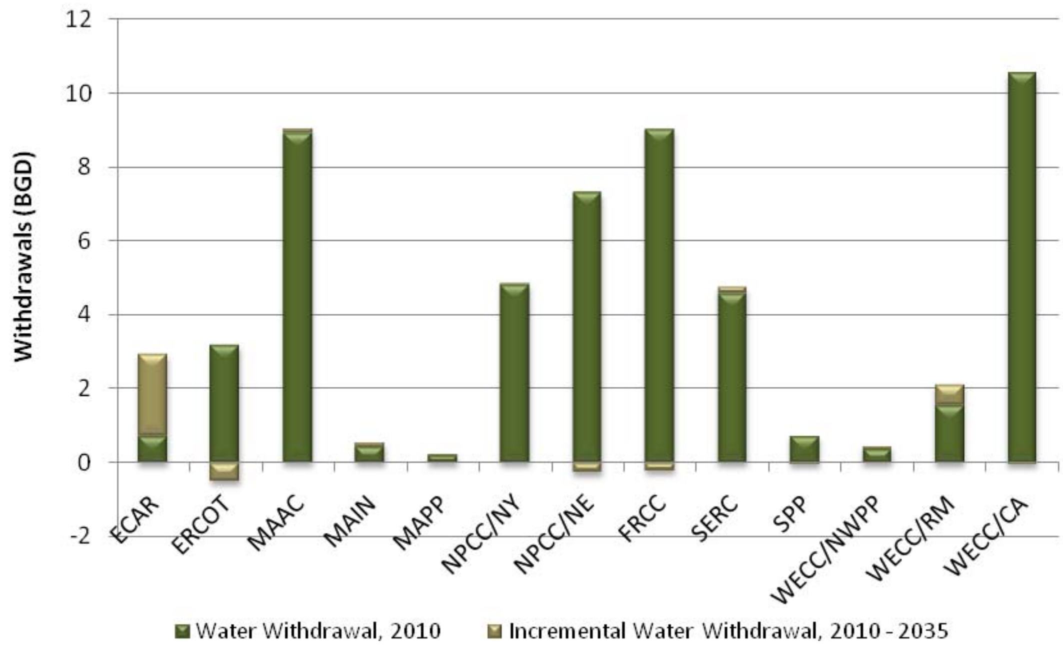
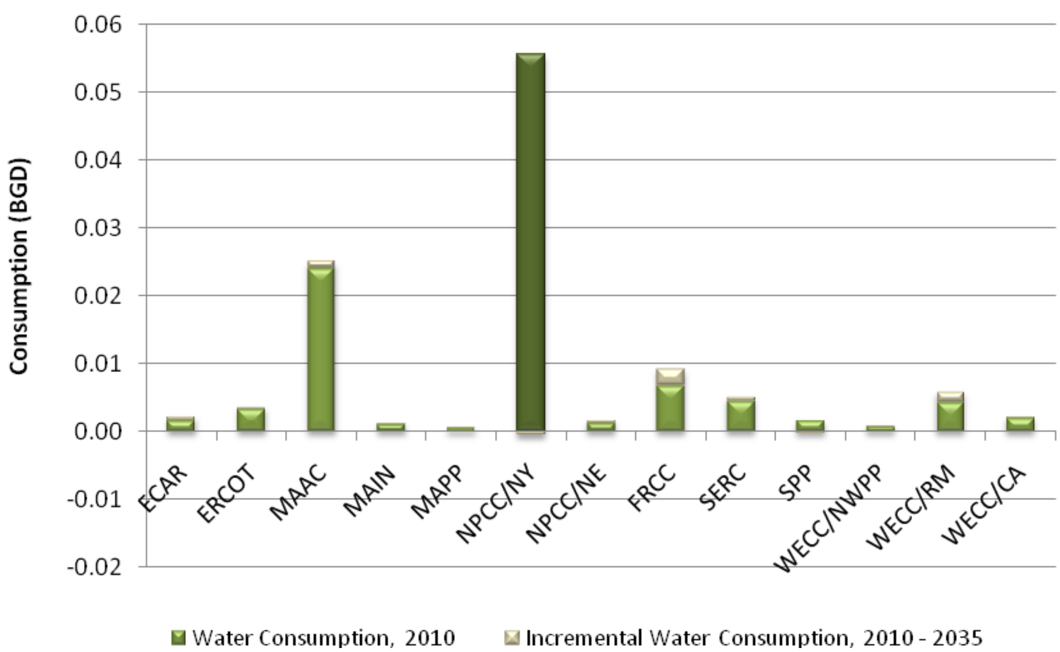


Figure 38 – Average Daily Regional Saline Water Consumption for Thermoelectric Power Generation – Case 3



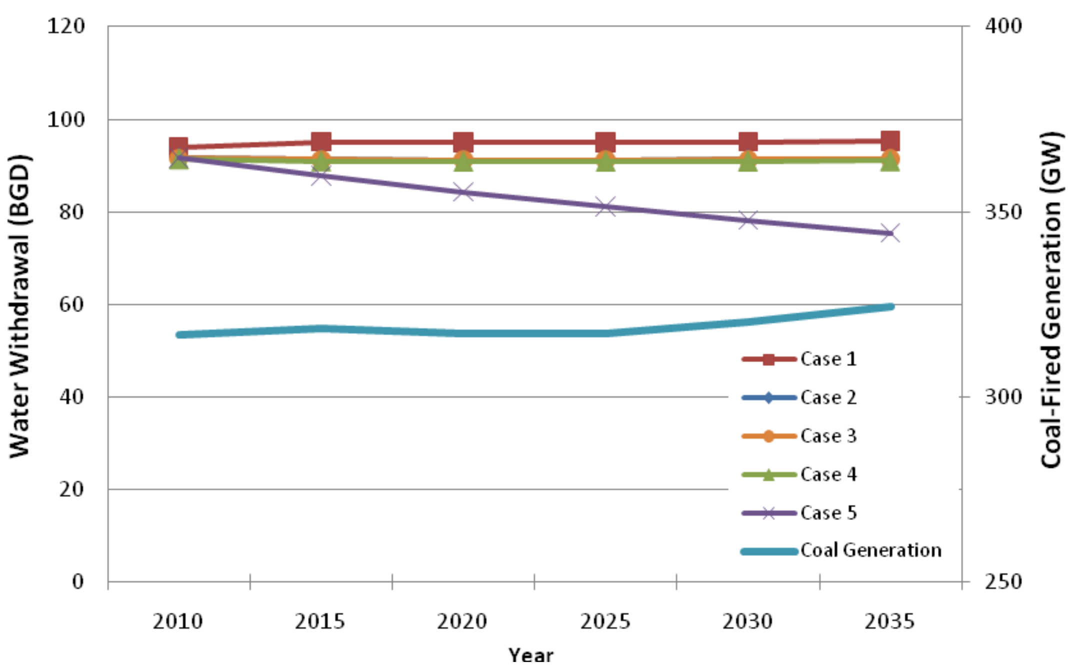
Conventional Coal-Fired Generation – National Level Summary

Conventional coal-fired (not including IGCC) generating capacity is projected to increase by 7.5 GW from 2010 to 2035. The analysis projects that by 2035, average daily national freshwater withdrawals required to meet the needs of the U.S. coal-fired generation component of thermoelectric generation may decrease to 75.5 BGD (17%) or increase to 95.3 BGD (1%) depending upon case assumptions. Table 9 presents the range of average daily national freshwater withdrawal for each of the five cases from 2010 through 2035. This same data is presented graphically in Figure 39.

Table 9 –Average National Freshwater Withdrawal for Conventional Coal Power Generation (BGD)

	2010	2015	2020	2025	2030	2035
Case 1	94.0	95.2	95.0	95.1	95.1	95.3
Case 2	91.6	91.3	91.3	91.3	91.3	91.42
Case 3	91.6	91.3	91.2	91.3	91.3	91.38
Case 4	91.4	91.0	90.9	90.9	91.0	91.0
Case 5	91.6	87.8	84.3	81.2	78.2	75.5
Maximum	94.0	95.2	95.0	95.1	95.1	95.3
Minimum	91.4	87.8	84.3	81.2	78.2	75.5

Figure 39 –Average Daily National Freshwater Withdrawal for Conventional Coal Power Generation

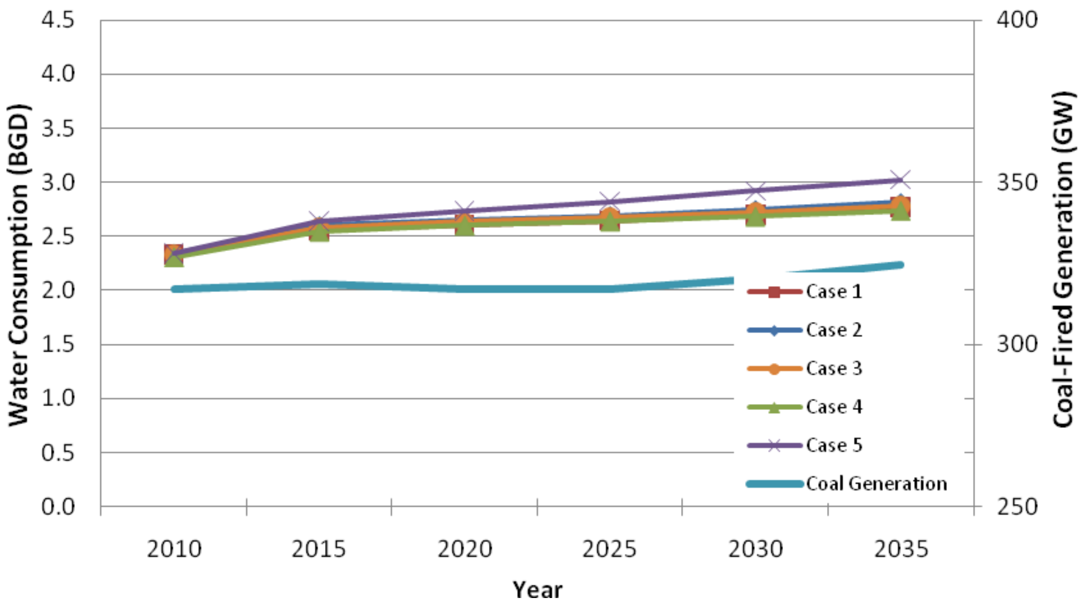


The analysis projects that by 2035, average daily national freshwater consumption resulting from U.S. coal-fired power generation could range from 2.7 BGD to 3.0 BGD depending upon case assumptions. This represents an increase of 19% and 29% respectively. Table 10 presents the range of average daily national freshwater consumption for each of the five cases from 2010 through 2035. This same data is presented graphically in Figure 40.

Table 10 – Average National Freshwater Consumption for Conventional Coal Power Generation (BGD)

	2010	2015	2020	2025	2030	2035
Case 1	2.3	2.6	2.6	2.6	2.7	2.8
Case 2	2.3	2.6	2.7	2.7	2.7	2.8
Case 3	2.3	2.6	2.6	2.7	2.7	2.8
Case 4	2.3	2.5	2.6	2.6	2.7	2.7
Case 5	2.3	2.6	2.7	2.8	2.9	3.0
Maximum	2.3	2.6	2.7	2.8	2.9	3.0
Minimum	2.3	2.5	2.6	2.6	2.7	2.7

Figure 40 – Average Daily National Freshwater Consumption for Conventional Coal Power Generation



Conventional Coal-Fired Generation - National Level Results by Case

Case 1

The conventional coal portion of thermoelectric generation freshwater withdrawal is projected to increase approximately 1.3% from 2010 through 2035 for Case 1 – from 94.0 BGD to 95.3 BGD – consistent with the overall 2% increase in generation capacity from 317 GW to 324 GW and roughly equal distribution of once-through and wet recirculating cooling water systems. More significantly, conventional coal generation freshwater consumption is projected to increase 19% from 2010 through 2035 for Case 1 – growing from 2.3 BGD to 2.8 BGD. See Figure 17 and Figure 18 for plots of coal withdrawal and consumption from 2010-2035.

Case 2

Conventional coal generation freshwater withdrawal is projected to slightly increase by 1.4% (91.6 BGD to 91.4 BGD) from 2010 through 2035 for Case 2. This trend is consistent with the assumptions that all capacity additions use freshwater and wet recirculating cooling systems, while capacity retirements are proportional to current water source and type of cooling water system.

Similar to Case 1, conventional coal generation freshwater consumption is projected to increase in Case 2 – growing 20% from 2.3 BGD to 2.8 BGD between 2010 and 2035 – consistent with both the 2% increase in generation capacity and increased use of wet recirculating cooling water systems. See Figure 19 and Figure 20 for plots of coal withdrawal and consumption from 2010-2035.

Case 3

The Case 3 assumptions are similar to Case 2, except that 90% of capacity additions use freshwater and wet recirculating cooling and 10% use saline water with once-through cooling. As might be expected, both conventional coal generation freshwater withdrawal and consumption levels for Case 3 are the same as Case 2. In 2035, freshwater withdrawal is 91.4 BGD in Case 2 compared to 91.4 in Case 3. Similarly, freshwater consumption in 2030 is 2.8 for Cases 2 and 3, respectively. See Figure 21 and Figure 22 for plots of coal withdrawal and consumption from 2010-2035.

Figure 21

Case 4

The potential impact of dry cooling systems on water demand is evident in the results of Case 4, where 25% of new conventional coal capacity is assumed to be equipped with dry cooling, rather than wet recirculating cooling. Conventional coal generation freshwater withdrawal and consumption levels for Case 4 are less than the respective values from Case 2. By 2035, freshwater withdrawal is projected to be slightly less in Case 4 – 91.0 BGD compared to Case 2 – 91.4 BGD. Freshwater consumption is projected to be approximately 3% less – 2.7 BGD in Case 4 vs. 2.8 BGD in Case 2. See Figure 23 and Figure 24 for plots of coal withdrawal and consumption from 2010-2035.

Case 5

The Case 5 assumptions for conventional coal capacity additions and retirements are the same as Case 2. However, Case 5 also assumes that 25% of existing freshwater once-through cooling capacity is converted to wet recirculating cooling. As a result, Case 5 represents the most extreme conditions of the analysis and significantly impacts projections for both freshwater withdrawal and consumption. By 2035, total conventional coal generation freshwater withdrawal is projected to be approximately 17%

less in Case 5 compared to Case 2 – 75.5 BGD vs. 91 BGD – while consumption is projected to be approximately 7% more – 3.0 BGD in Case 5 vs. 2.8 BGD in Case 2. See Figure 25 and Figure 25 for plots of coal withdrawal and consumption from 2010-2035.

Conventional Coal-Fired Generation – Regional Results

Figure 41 through Figure 45 shows the results of the regional water withdrawal analysis for total U.S. coal-fired generation comparing 2010 to 2035 for each of the five cases. With each successive case, the water withdrawal of the regions displays greater decreases, with Case 5 showing the largest overall decrease in water withdrawal.

Figure 46 through

Figure 50 show the results of the regional water consumption analysis for total U.S. coal-fired generation comparing 2010 to 2035 for each of the five cases. Aside from Case 5, where water consumption increases more than other cases, the water consumption regionally stays rather consistent.

Case 1

Conventional coal generation freshwater withdrawal is projected to increase approximately 1% from 2010 through 2035 for Case 1 – from 94.9 BGD to 95.3 BGD. Conventional coal freshwater consumption is projected to increase 18% from 2010 through 2035 for Case 1 – growing from 2.3 BGD to 2.8 BGD. On a regional basis, freshwater withdrawal increases in all regions with the largest increase in the WECC/RM (57%) region (Figure 41). Freshwater consumption increases in all of the regions with relatively large percentage increases occurring in the WECC/RM (57%) and NPCC/NY (25%) regions (

Figure 46).

Case 2

Conventional coal generation freshwater withdrawal is projected to decrease less than 1% (91.6 BGD to 91.4 BGD) from 2010 through 2035 for Case 2. Similar to Case 1, conventional coal generation freshwater consumption is projected to increase in Case 2 – growing 20% from 2.3 BGD to 2.8 BGD between 2010 and 2035. On a regional basis, freshwater withdrawal increases in all regions except for MAIN, and ECAR (Figure 42). Similar to Case 1, freshwater consumption increases in all of the regions, with relatively large percentage increases occurring in the WECC/RM (154%) and ERCOT (31%) regions (Figure 47).

Case 3

Both conventional coal generation freshwater withdrawal and consumption levels for Case 3 are relatively the same as Case 2. In 2035, freshwater withdrawal is 91.4 BGD in for Case 2 and Case 3 (Figure 43). Similarly, freshwater consumption in 2035 is 2.8 BGD for Cases 2 and 3 (

Figure 48). On a regional basis, freshwater withdrawal and consumption increases and decreases are also similar to Case 2.

Figure 41 – Average Daily Regional Freshwater Withdrawal for Coal-Fired Power Generation – Case 1

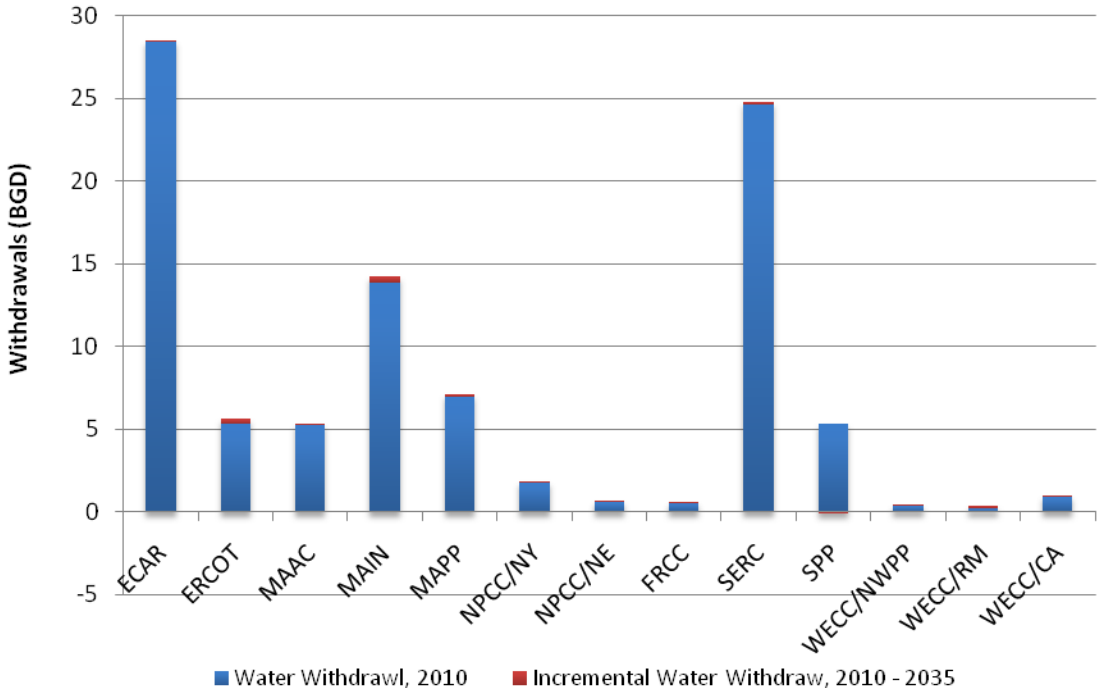


Figure 42 – Average Daily Regional Freshwater Withdrawal for Coal-Fired Power Generation – Case 2

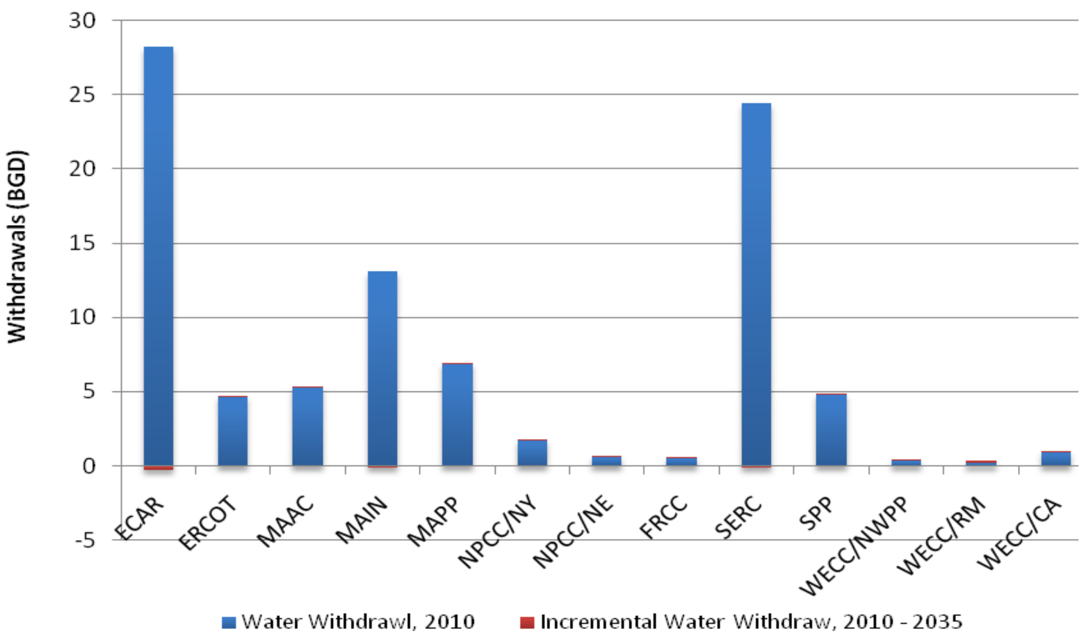


Figure 43 – Average Daily Regional Freshwater Withdrawal for Coal-Fired Power Generation – Case 3

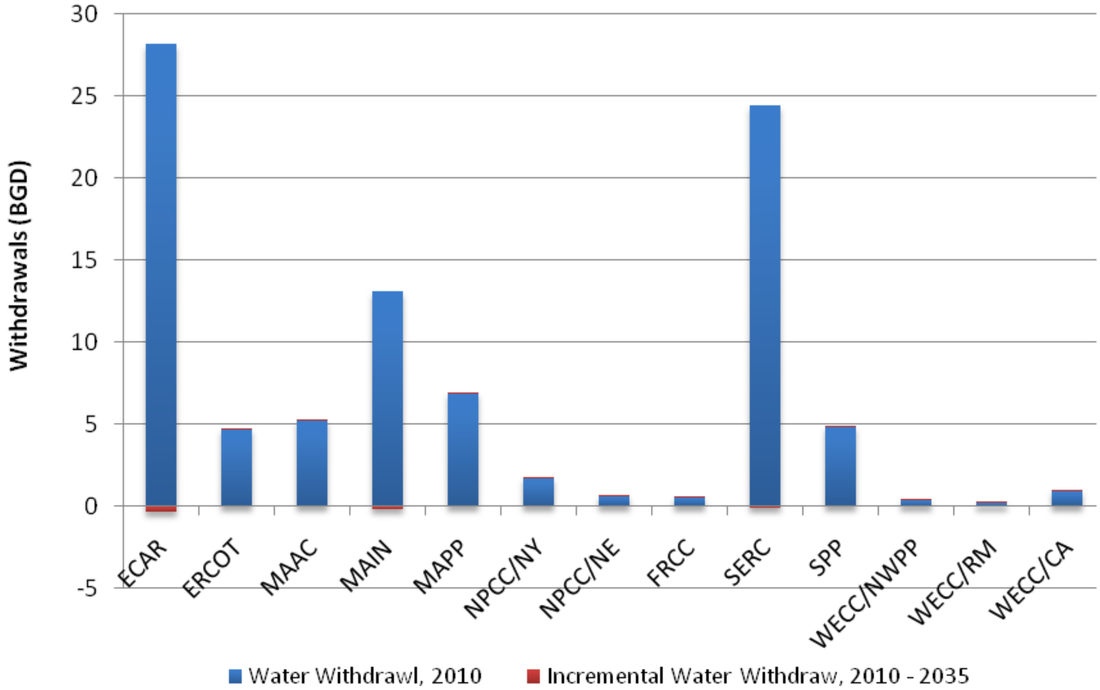


Figure 44 – Average Daily Regional Freshwater Withdrawal for Coal-Fired Power Generation – Case 4

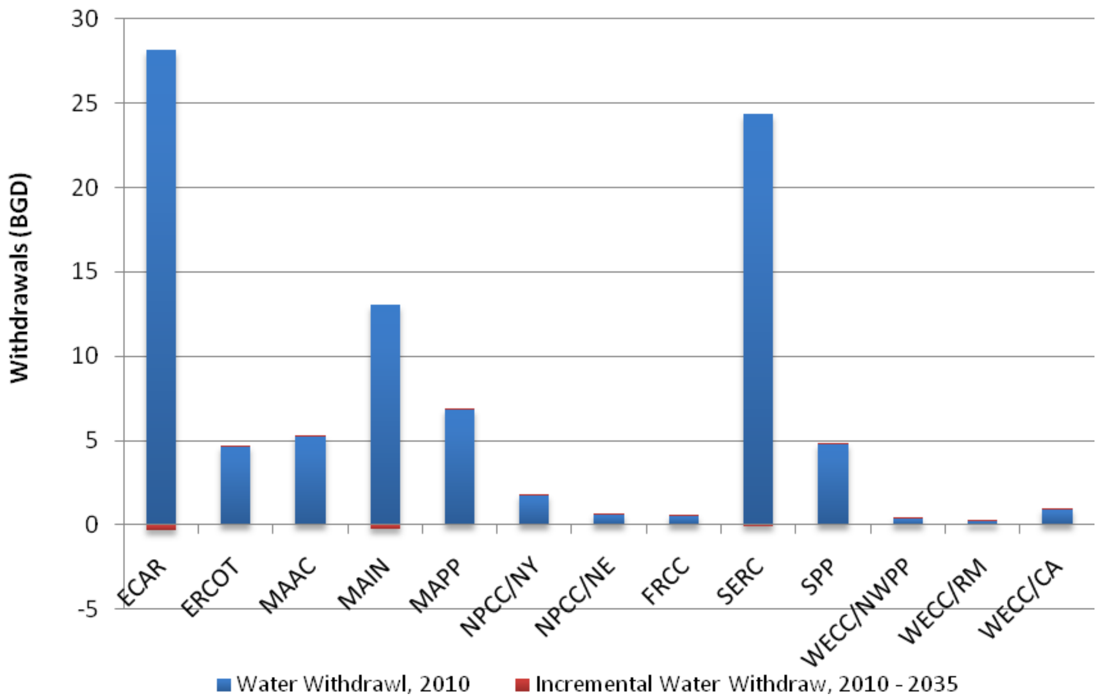


Figure 45 – Average Daily Regional Freshwater Withdrawal for Coal-Fired Power Generation – Case 5

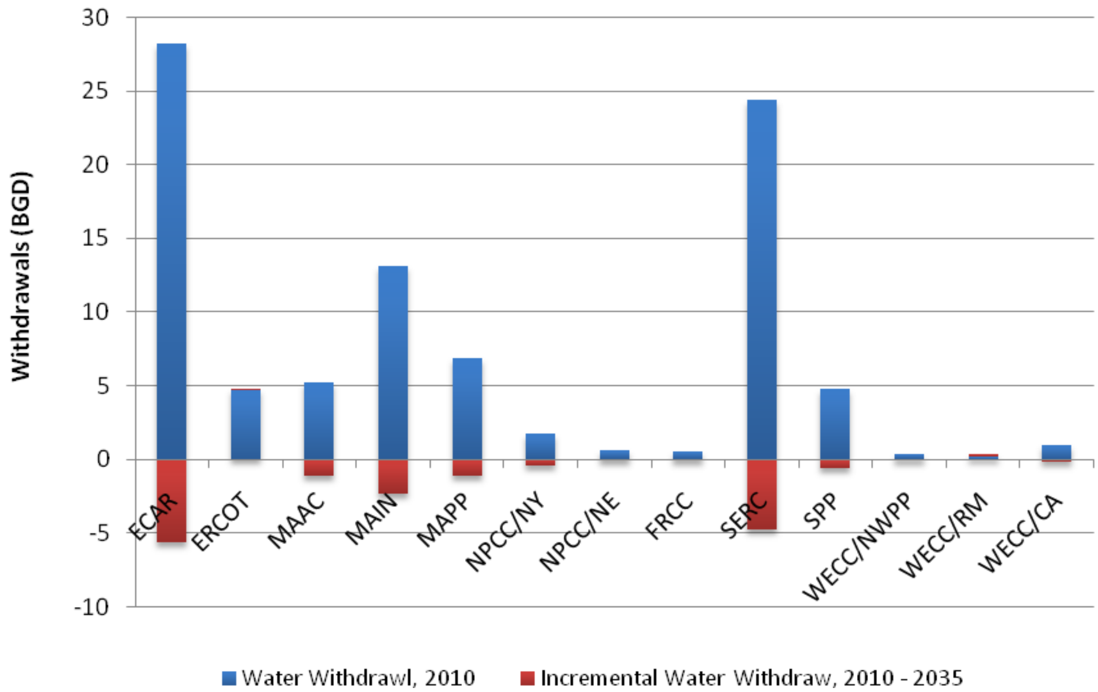


Figure 46 – Average Daily Regional Freshwater Consumption for Coal-Fired Power Generation – Case 1

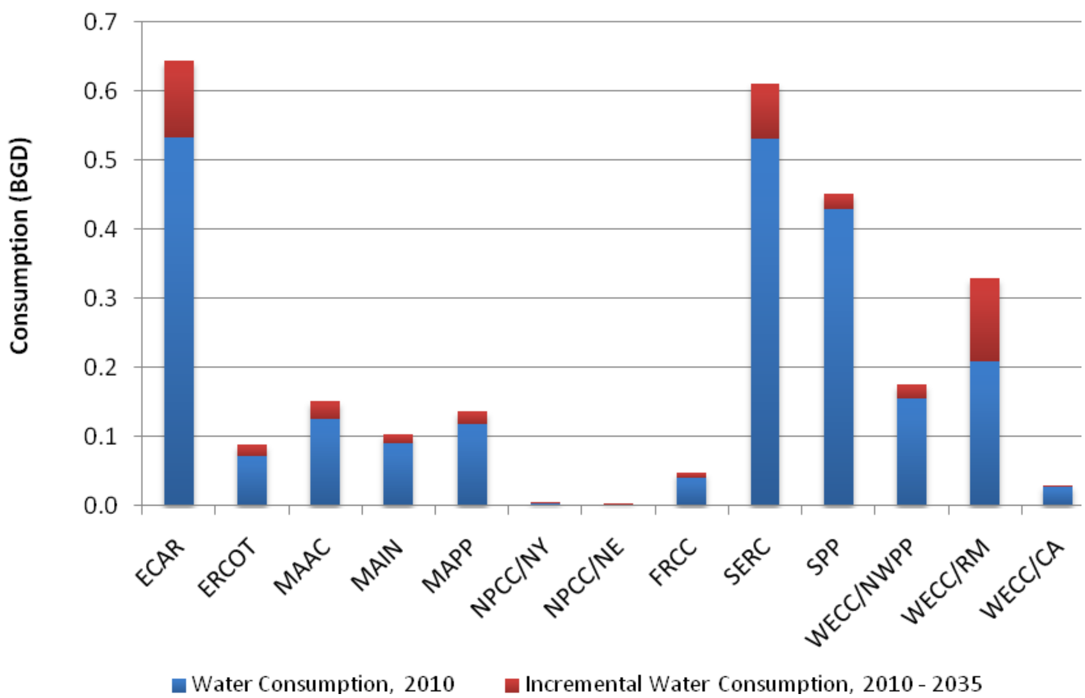


Figure 47 – Average Daily Regional Freshwater Consumption for Coal-Fired Power Generation – Case 2

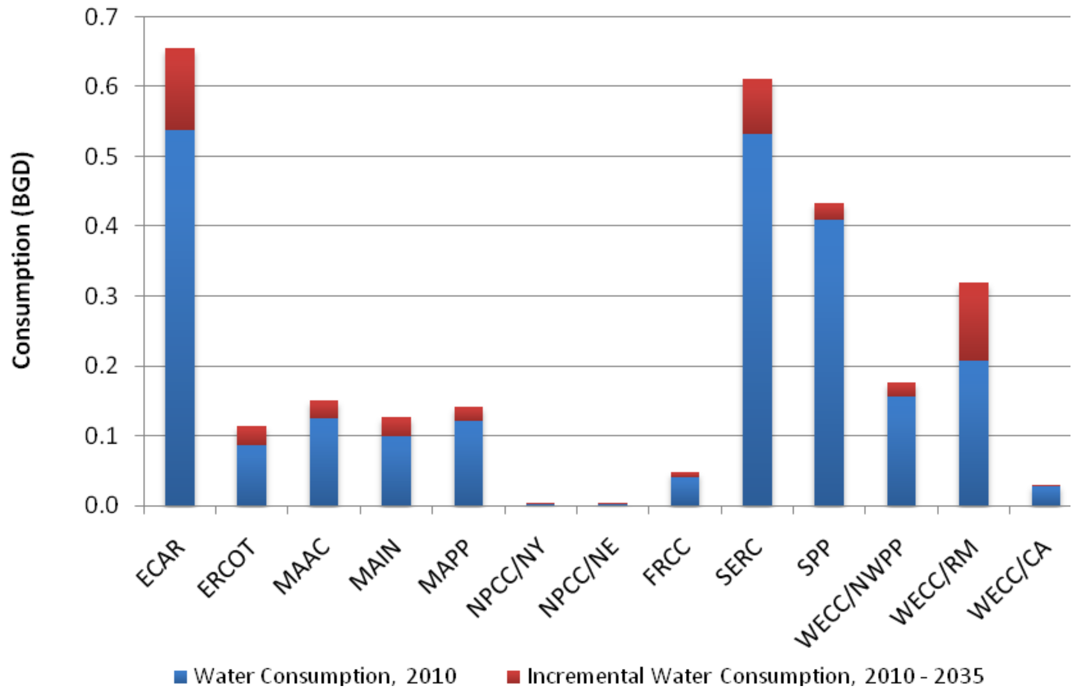


Figure 48 – Average Daily Regional Freshwater Consumption for Coal-Fired Power Generation – Case 3

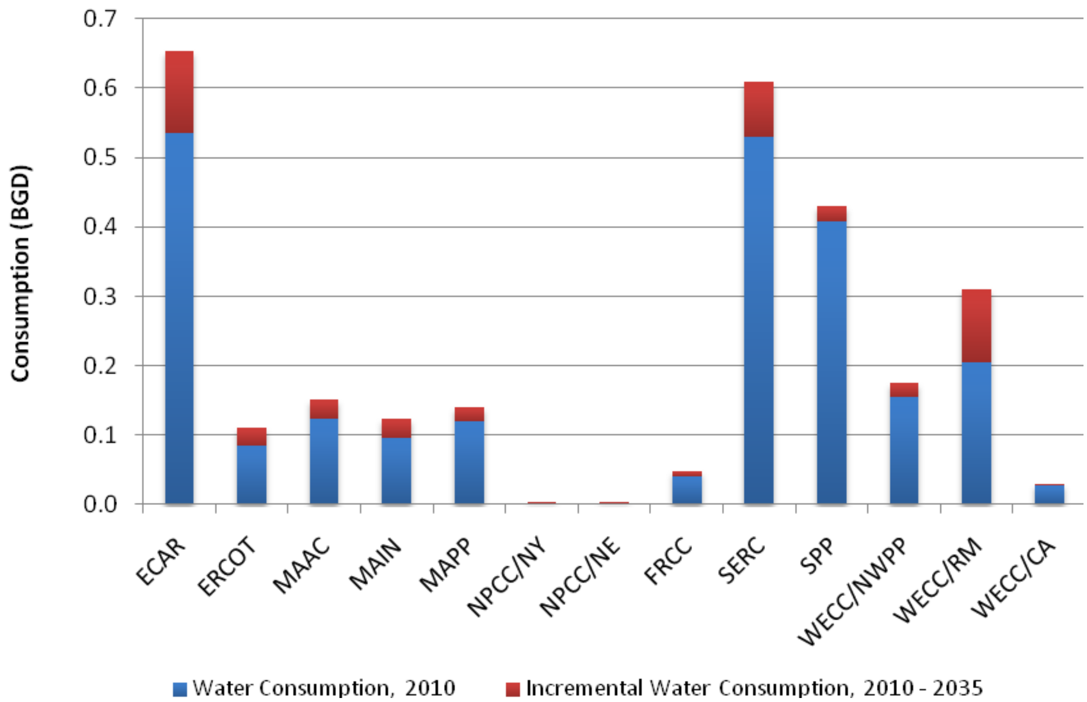


Figure 49 – Average Daily Regional Freshwater Consumption for Coal-Fired Power Generation – Case 4

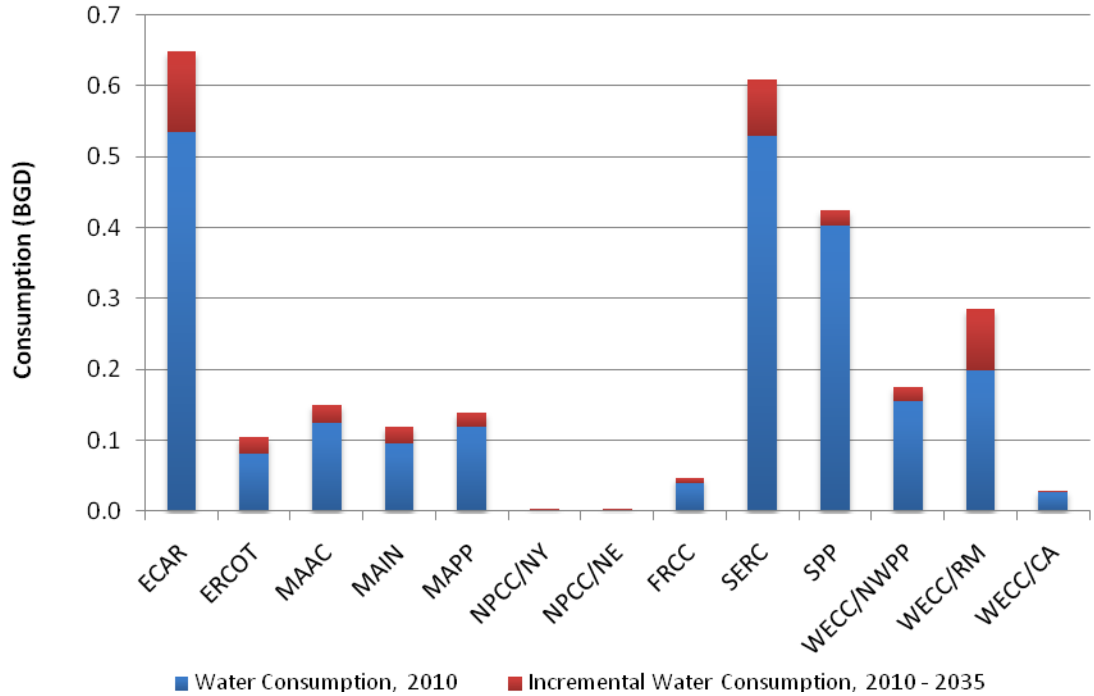
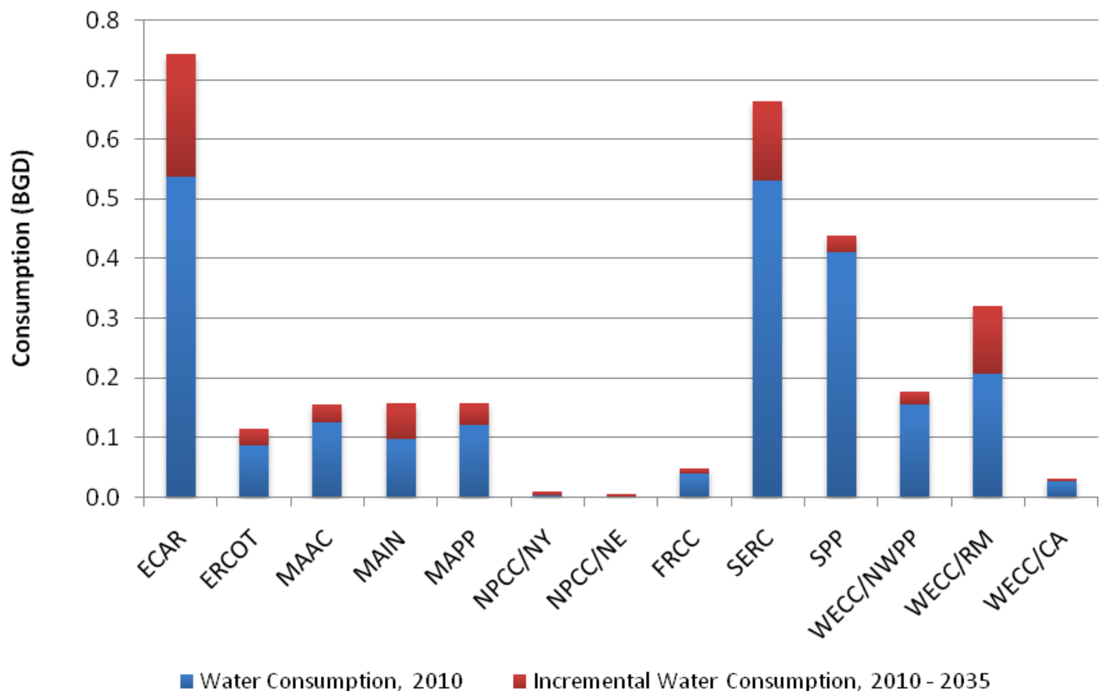


Figure 50 – Average Daily Regional Freshwater Consumption for Coal-Fired Power Generation – Case 5



Case 4
Conventional coal generation freshwater withdrawal and consumption levels for Case 4 are less than the respective values from Case 2. By 2035, freshwater withdrawal is projected to be slightly less in Case 4 compared to Case 2 – 91 BGD vs. 91.4.0 BGD (Figure 44). Freshwater consumption is projected to be approximately 3% less – 2.7 BGD in Case 4 vs. 2.8 BGD in Case 2 (Figure 49). On a regional basis, freshwater withdrawal and consumption increases and decreases are also similar to Case 2.

Case 5
By 2035, total conventional coal generation freshwater withdrawal is projected to be approximately 18% less in Case 5 compared to Case 2 – 75.5 BGD vs. 91.4 BGD – while consumption is projected to be approximately 7% more – 3.0 BGD in Case 5 vs. 2.8 BGD in Case 2. On a regional basis, freshwater withdrawal decreased an all regions except WECC/RM (51%) and ERCOT (1%). Significant increases were in the NPCC/NY (40%), ECAR (19%), and MAAC (21%) regions (Figure 45). Freshwater consumption increases in all of the regions, with relatively large percentage increases occurring in the NPCC/NY (273%), NPCC/NE (136%), MAIN (61%), and WECC/RM (54%) regions (
Figure 50).

Carbon Capture Deployment Analysis

The carbon capture deployment analysis uses the same five cases for the types of cooling systems for the new plant additions. All water withdrawal and consumption results in this analysis are for freshwater. The analysis also assumes four aggressive scenarios for the additions required to supplement the decrease in capacity for the PC plants retrofitted with carbon capture technologies as described in the *Assumptions and Methodology* section of this report. The projected results of all of the scenarios for PC plants with scrubbers and IGCC plants with 90% CO_2 capture, for the year 2035, show an increase in water withdrawal and consumption over the non-capture scenario. Figure 51 and Figure 53 show the results for the five cases and four scenarios with respect to all thermoelectric generation.

Figure 51 shows the additional amount of water withdrawal if all of the forecasted PC plants with scrubbers and IGCC plants were to deploy carbon capture technologies, compared to all thermoelectric plants without carbon capture technologies for the projected year 2035. The Case 2 column in Figure 51 shows that in 2035, 138.4 BGD of water withdrawal is projected for all thermoelectric plants without carbon capture deployment. Scenario 1 shows by retrofitting carbon capture technologies to the existing scrubbed coal-fired fleet and deploying capture ready technologies to all new additions, an additional 1.5 BGD would be required, resulting in a total of 139.9 BGD. If Scenario 2 is applied, building all IGCC plants for the replacement power lost to the retrofits, 0.9 BGD would be added to Scenario 1, resulting in a total of 140.9 BGD. Scenario 3, building all PC oxy combustion, supercritical plants for the replacement power, would add 1.1 BGD to Scenario 1 resulting in a total of a 141 BGD withdrawal. Scenario 4, building all PC supercritical, amine based plants for the replacement power, would add 1.3 BGD to Scenario 1 resulting in a total of a 141.3 BGD withdrawal. Scenario 5 withdrawals the most water of the four scenarios, adding 2.0 BGD to Scenario 1 and resulting in a total of 141.9 BGD withdrawal. Since recirculating cooling systems are used in all scenarios, water withdrawal is low relative to water consumption.

Figure 51 - Thermoelectric Generation with Additional Water Withdrawal for PC and IGCC Carbon Capture Deployment for Year 2035

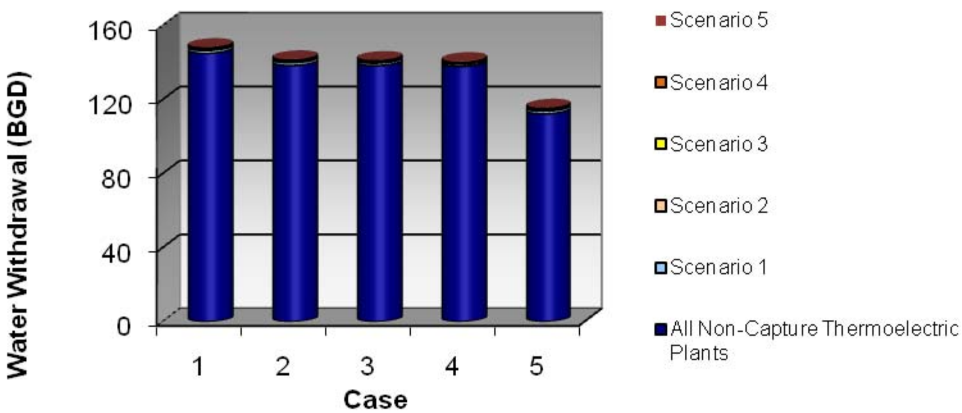


Figure 52 illustrates the breakdown of Scenario 1, a closer look at scenarios 2 through 5 as applied to Case 2. The bottom section of the blue bars represents the additional water withdrawal required for the existing PC retrofits, 1.4 BGD. The top section of the blue bars represent the additional water withdrawal required for the carbon capture technologies of the new PC and IGCC capacity, 0.2 BGD. Therefore, Scenario 1 would require a total of 1.6 BGD. Scenario 2 would include the 1.6 BGD plus an additional 0.9 BGD of water withdrawal for the new IGCC plants built to replace the power lost to the retrofits for a total 2.5 BGD. Scenario 3 is similar to Scenario 2 except instead of IGCC plants built to make up the power loss, oxy combustion supercritical PC plants would be built. These oxy combustion supercritical PC plants would require 1.3 BGD water withdrawal and combined with the Scenario 1 demand, would require a total 2.9 BGD. Scenario 5, additional nuclear plants built to replace the power lost to the retrofits, would add 2.0 BGD to scenario1 for a total water withdrawal of 43.5 BGD.

Figure 52 – Additional Water Withdrawal of CO_2 Capture Scenarios – Case 2

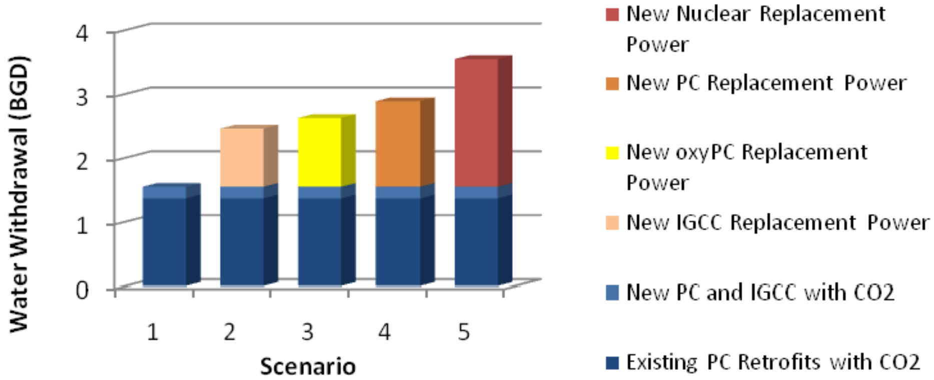


Figure 53 shows the additional amount of water consumption if all of the forecasted PC with scrubbers and IGCC plants were to deploy carbon capture technologies compared to all thermoelectric plants without carbon capture technologies. The Case 2 data in Figure 53 shows that in 2035, 4.3 BGD of water consumption is projected for all thermoelectric plants without carbon capture deployment. Scenario 1 shows by deploying carbon capture technologies to the scrubbed coal-fired fleet, an additional 1.1 BGD would be required, resulting in a total of 5.4 BGD. If Scenario 2 is applied, 0.7 BGD would be added to Scenario 1, resulting in a total of 6.1 BGD. Scenario 3 would add 0.8 BGD to Scenario 1 resulting in a total water consumption of 6.2 BGD for Scenario 3. Scenario 4 adds 0.2 BGD to Scenario 1 and results in a total of 6.3 BGD consumed. Scenario 5 adds 0.1 BGD to Scenario 1 and results in a total of 6.4 BGD consumed.

Figure 53 - Thermoelectric Generation with Additional Water Consumption for PC and IGCC Carbon Capture Deployment for Year 2035

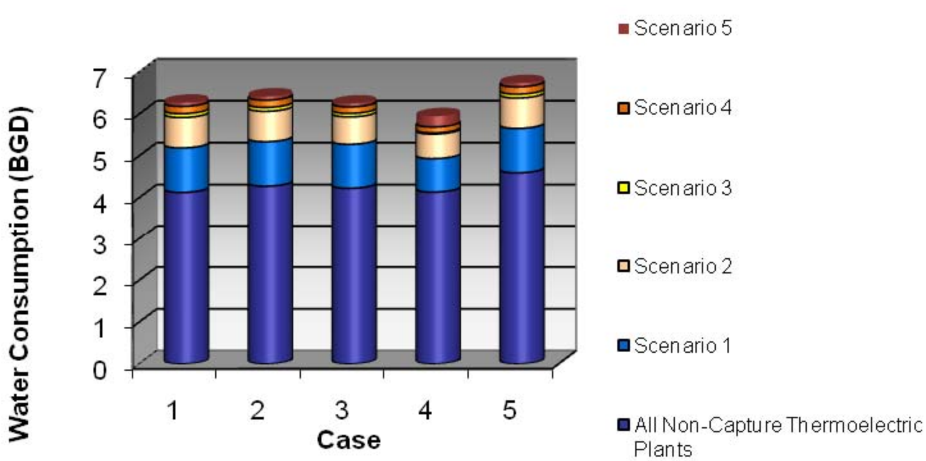


Figure 54 illustrates the breakdown of Scenario 1 and a closer look at the other scenarios for Case 2. The bottom section of the blue bars are the additional water consumption required for the existing PC retrofits, 0.9 BGD. The top section of the blue bars is the additional water consumption required for the carbon capture technologies of the new PC and IGCC capacity, 0.1 BGD. Therefore, Scenario 1 would require at total of 1.1 BGD. Scenario 2 would include the 1.1 BGD plus an additional 0.7 BGD of water consumption for the new IGCC plants built to replace the power lost to the retrofits for a total 1.8 BGD. Scenario 3 is similar to Scenario 2 except instead of IGCC plants built to make up the power loss, oxy combustion, supercritical PC plants would be built. These supercritical PC plants would require 0.1 BGD water consumption and combined with the Scenario 1 demand, would require a total 1.9 BGD. Scenario 4 adds 0.2 BGD to Scenario 1 and results in a total of 2.0 BGD consumed. Scenario 4, additional nuclear plants built to replace the power lost to the retrofits, would add 0.1 BGD to Scenario1 for a total water consumption of 2.2 BGD.

Figure 54 - Additional Water Consumption of CO_2 Capture Scenarios – Case 2

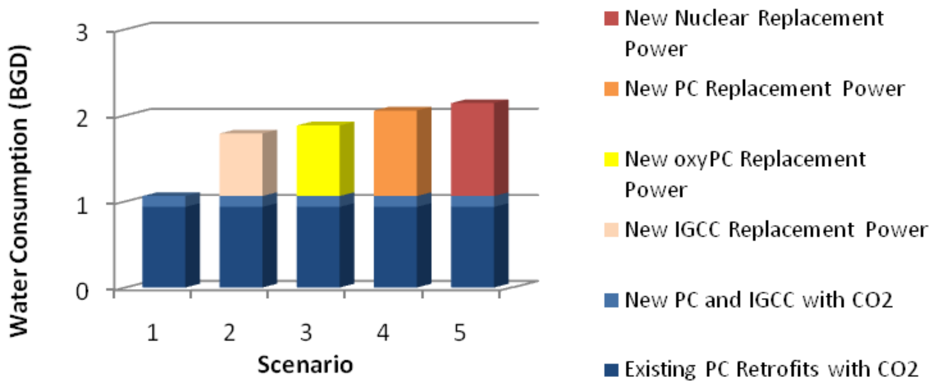


Figure 55 and Figure 56 show the water withdrawal and consumption for the five cases and four coal-fired scenarios with respect to just the coal-fired fleet.

Figure 55 - PC and IGCC Generation with Additional Water Withdrawal for PC and IGCC Carbon Capture Deployment for Year 2035

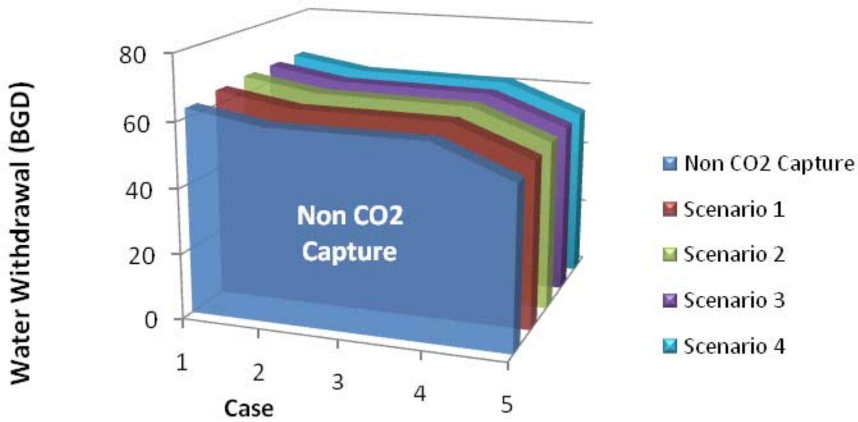
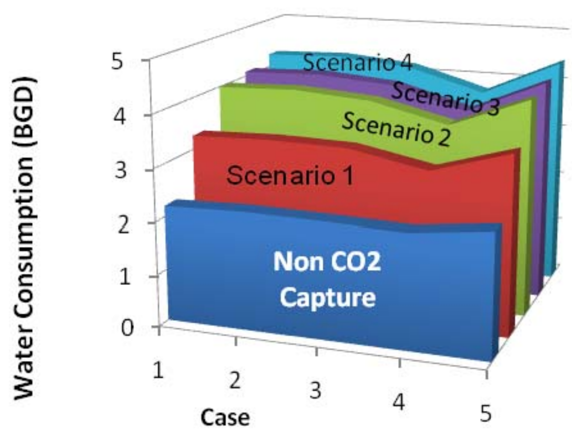


Figure 56 - PC and IGCC Generation with Additional Water Consumption for PC and IGCC Carbon Capture Deployment for Year 2035



The results for the three scenarios for total water withdrawal and consumption for PC plants with scrubbers and IGCC plants with carbon capture technologies are presented in Table 11 and Table 12 respectively. The baseline values listed in the tables are used as a reference for non-capture PC plants with scrubbers and IGCC plants.

Table 11 – Scenarios for Year 2035 Total Water Withdrawal for Scrubbed PC and IGCC with CO_2 Capture and No Capture Baseline Reference

Scenario	Water Withdrawal (BGD)				
	Case 1	Case 2	Case 3	Case 4	Case 5
No CO_2 Capture Baseline	62.9	59.1	59.0	59.0	49.4
1. No Water Based Generation *Retrofit load not accounted for using water intensive generation types*	64.5	60.6	60.4	60.2	50.9
2. IGCC Recirculating Additions *Fixed Additions accounts for retrofit load*	65.4	61.5	61.3	60.9	51.8
3. Supercritical Recirculating (oxy) Additions *Fixed Additions accounts for retrofit load*	65.6	61.7	61.4	61.0	52.0
4. Supercritical Recirculating (amine) Additions *Fixed Additions accounts for retrofit load*	65.8	62.0	61.6	61.2	52.2
5. Nuclear Recirculating Additions *Fixed Additions accounts for retrofit load*	66.5	62.6	62.2	62.0	52.9

Table 12 – Scenarios for Year 2030 Total Water Consumption for Scrubbed PC and IGCC with CO_2 Capture and No Capture Baseline Reference

Scenario	Water Consumption (BGD)				
	Case 1	Case 2	Case 3	Case 4	Case 5
No CO_2 Capture Baseline	2.2	2.2	2.2	2.2	2.4
1. No Water Based Generation *Retrofit load not accounted for using water intensive generation types*	3.3	3.3	3.3	3.0	3.4
2. IGCC Recirculating Additions *Fixed Additions accounts for retrofit load*	4.0	4.0	3.9	3.6	4.2
3. Supercritical Recirculating (oxy) Additions *Fixed Additions accounts for retrofit load*	4.1	4.1	4.0	3.6	4.3
4. Supercritical Recirculating (amine) Additions *Fixed Additions accounts for retrofit load*	4.3	4.3	4.2	3.7	4.4
5. Nuclear Recirculating Additions *Fixed Additions accounts for retrofit load*	4.3	4.4	4.2	4.0	4.5

Depending on the cases and scenarios for plant additions, deploying carbon capture technologies in PC plants with scrubbers and IGCC plants in the year 2035 would increase water withdrawal anywhere from 1.2 BGD to 3.5 BGD where the average increased water withdrawal for all scenarios and cases is 4%. The increase in water consumption could range from 0.8 BGD to 2.1 BGD and the average increased water consumption for all scenarios and cases is 75%.

Comparison of 2010 & 2009 Study Projections

The 2010 and 2009 water needs analyses evaluated the same five cases. In general, the 2010 analysis shows lower water consumption for all years and all five cases and lower water withdrawal (except for case 5) compared to the 2009 analysis. Table 13 presents the differences in water withdrawal and consumption for the 2010 update compared to the 2009 report at the national level. Table 14 shows the percent changes from the 2009 results.

Table 13

Overall, there are many parameters that affected the results. The largest factor to account for the increase in overall thermoelectric water withdrawal and decreased consumption this year compared to the 2009 study is EIA's decrease in thermoelectric retirements for all years and a large decrease in new builds for the later years. Therefore the existing once through systems are not be retired and new builds with recirculating systems are not going in at the capacity of the 2009 report. The EIA's AEO 2010 forecast estimates U.S. thermoelectric generating capacity will only grow from approximately 730 GW in 2010 to 755 MW in 2030 and to 772 MW in 2035, compared to the AEO 2009 forecast which was 735 GW in 2010 to 776 GW in 2030[17]. The 2010 AEO forecasts less coal and nuclear additions but more natural gas combined cycle plants than the 2009 AEO. Overall thermoelectric capacity has decreased.

The 2010 report presented a slightly lower amount of makeup power for the parasitic loss due to the carbon capture retrofits (67.1 GW) compared to the 2009 report (66.8 GW). This is due to EIA's lower forecast of new coal-fired and IGCC additions. This affect reduced the amount of water withdrawal and consumed compared to the 2009 report.

Table 13 - Results Comparison, Difference from 2010 vs. 2009 Water Needs Analysis

		Difference Between 2010 and 2009 Results (BGD)				
		2010	**2015**	**2020**	**2025**	**2030**
Case 1	Withdrawal	-1.8	-1.8	-2.8	-2.8	-2.0
	Consumption	-0.1	-0.1	-0.1	-0.1	-0.1
Case 2	Withdrawal	-1.45	-1.6	-3.0	-3.1	-1.7
	Consumption	-0.1	-0.1	-0.1	-0.1	-0.2
Case 3	Withdrawal	-1.44	-1.6	-3.0	-3.1	-1.6
	Consumption	-0.1	-0.1	-0.1	-0.1	-0.2
Case 4	Withdrawal	-1.4	-1.6	-3.0	-3.2	-1.6
	Consumption	-0.1	-0.1	-0.1	-0.1	-0.2
Case 5	Withdrawal	4.5	4.3	2.6	2.3	3.7
	Consumption	-0.2	-0.1	-0.2	-0.18	-0.3

The 2010 analysis show the same general trends among the 5 cases as seen in the 2008 analysis. For cases 2 though 5, withdrawal is expected to decline, and consumption for all 5 cases is expected to increase. These results are consistent with current and anticipated regulations and industry practice, which favor the use of freshwater recirculating cooling systems that have lower withdrawal requirements, but higher consumption requirements, than once-through cooling systems. Case 5 provides the most extreme water consumption impacts. Converting a significant share of existing once-through freshwater power plants to recirculating freshwater plants reduces water withdrawal, but increases water consumption. Case 4 indicates that dry cooling could have a significant impact on water consumption; compared to Cases 1-3, which have an average consumption of 5 BGD, Case 4.2 results in an almost 2% decline, equivalent to more than 27 billion gallons per year.

Table 14 - Results Comparison, Percent Changes from 2010 Water Needs Analysis

		Percent Change from 2009 Results				
		2010	**2015**	**2020**	**2025**	**2030**
Case 1	Withdrawal	-1.2%	-1.2%	-1.9%	-1.9%	-1.3%
	Consumption	-3.0%	-1.6%	-2.1%	-2.3%	-3.2%
Case 2	Withdrawal	-1.0%	-1.1%	-2.1%	-2.2%	-1.2%
	Consumption	-3.3%	-1.8%	-2.5%	-2.8%	-5.1%
Case 3	Withdrawal	-1.0%	-1.1%	-2.1%	-2.2%	-1.2%
	Consumption	-3.2%	-1.8%	-2.4%	-2.7%	-4.8%
Case 4	Withdrawal	-1.0%	-1.1%	-2.2%	-2.3%	-1.2%
	Consumption	-3.2%	-1.7%	-2.3%	-2.5%	-4.3%
Case 5	Withdrawal	3.2%	3.3%	2.1%	1.9%	3.3%
	Consumption	-5.0%	-3.5%	-4.0%	-4.0%	-6.1%

Conclusions

Population shifts, increasing power demand, and greater competition for water resources has heightened interest in the link between energy and water. The EIA projects about a 5.7% increase in total generating capacity by 2035 compared to 2010. Of the 177 GW of new capacity projected to come on-line by 2035, more than 78 GW will be thermoelectric generation. Compared to previous year reports, the forecast for increased thermoelectric generation has decreased, mainly due to the decrease in increased coal-fired generation.

On a national basis, this analysis indicates that the potential impacts on future freshwater withdrawals to meet forecasted increases in electricity generating capacity would be relatively low, with most cases exhibiting a decrease in daily withdrawals.

To operate the 63 GW of additional thermoelectric generating capacity in 2035, excluding Case 1:

- Freshwater withdrawal requirements will decrease by 4.6% to 23% compared to freshwater withdrawals in 2010
- Freshwater consumption in 2035 will increase by 15% to as much as 27% compared to 2010

Similar trends in freshwater withdrawal and consumption are projected for the additional coal-based generating capacity that will come on line by 2035:

- Freshwater withdrawal requirements will range from a 17% decrease to an 1% increase
- Freshwater consumption requirements will increase ranging from 18% to a 29%

While thermoelectric water consumption could increase by as much as 27%, it is still relatively small compared to other sectors, specifically irrigation/agriculture as seen in Appendix A.

The regional component of the 2010 water needs analysis revealed some significant differences from the national averages, reflecting recent U.S. population shifts. Regions with strong population growth, such as the southeast and southwest, exhibit high growth in water consumption requirements, while regions with minimal to modest population growth, such as the midwest and mid-Atlantic, exhibit modest growth in water consumption requirements. EIA projects an 81% increase in thermoelectric capacity by 2030 for the western United States and an 8% increase in the southeast compared to the 6% increase nationally. These increases in projected capacity will occur in regions of the United States that are challenged in terms of both current and future availability of freshwater. For example, consider Case 2, a plausible future cooling system scenario that assumes all capacity additions use freshwater and wet recirculating cooling.

National percent changes indicate between 2010 and 2035 (Case 2)

- water withdrawal will fall by 4.6%
- water consumption will rise by 17.8%

Regional percent changes indicate between 2010 and 2035 (Case 2)

- Water withdrawal ranges from a 13% increase in the WECC/RM region to a 22% decline in Texas
- Water consumption increases ranges from a near zero in California to a 44% decline in New York

The thermoelectric power generation sector will remain a considerable water consumer for the foreseeable future. While national water withdrawals are projected to decline slightly over the 25-year time period evaluated in this analysis, the amount of water withdrawal is huge, on the order of 112 to 145 billion gallons per day. On a consumption basis, although the magnitude is much less than that for withdrawal, the trend is steadily upward, regardless of the case considered. National water consumption is expected to grow from 3.6 billion gallons per day in 2010 to between 4.21 and 4.6 billion gallons per day by 2035. In the face of growing competition for water resources – particularly in the arid West and Southwest, and in the expanding Southeast – regional and national efforts to reduce water withdrawal and consumption for thermoelectric power plants are expected to intensify.

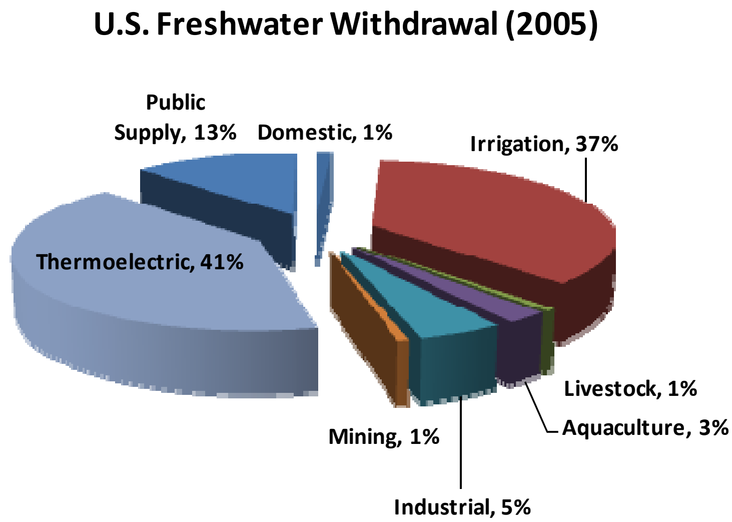
Assuming current carbon capture technologies are implemented at coal-fired PC plants in the future, an increased amount of water usage will to be required. EIA's current forecasts show that the existing coal-fired generation will continue to play a large part in our Nation's electric generation portfolio. The water use for the carbon capture section of this analysis is a 1st order view to get a general idea of how the implementation of these technologies will affect the water withdrawal and consumption. Depending on the cases and scenarios for plant additions, deploying carbon capture technologies in PC plants with scrubbers and IGCC plants in the year 2035 would increase water withdrawal anywhere from 1.5 BGD to 3.5 BGD where the average increased water withdrawal for the coal fleet for all scenarios and cases is 4%. The increase in water consumption could range from 1 BGD to 2.1 BGD and the average increased water consumption for the coal fleet for all scenarios and cases is 795%. As seen in the past with other emission control technologies, R&D efforts will promote improved efficiencies with current technologies and develop new emerging technologies, therefore lowering the water demands.

Appendix A
Energy-Water Issues
Supplemental Information

Competing Water Uses

Concerns over limited water quantities are not restricted to thermoelectric generation. According to USGS, 349 *billion* gallons of freshwater were withdrawn *per day* in the United States in the year 2005.[4] The largest use, thermoelectric, accounted for 41% of freshwater withdrawn at 143 billion gallons per day (BGD) (see Figure A-1).

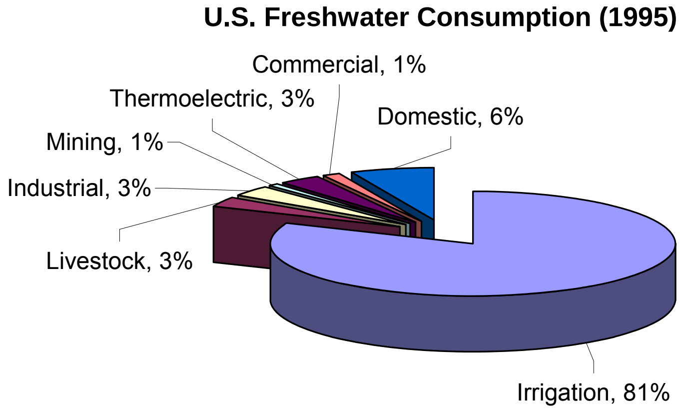
Figure A-1 - Percent of freshwater withdrawal by use category



The second largest use, irrigation, withdrew 128 billion gallons per day (BGD), followed by public supply, industrial uses, aquaculture, domestic use, mining, and livestock. Similarly, thermoelectric generation withdrew the largest amount of saline water, 58 BGD (95% of all saline withdrawn). Withdrawal of saline water (and other non-traditional waters) reduces the strain on freshwater supplies and is one research area facilitated by the IEP program.

USGS estimates for freshwater consumption for the year 1995 (the most recent year for which this data is available) is presented in Figure A-2.[5] Freshwater consumption for thermoelectric purposes appears low (only 3%) when compared to other use categories (irrigation was responsible for 81% of water consumed). However, even at 3% consumption, over 3 BGD were consumed. As a result of growing public pressures to withdraw less water, coupled with requirements under Section 316(b) of the Clean Water Act, consumption will likely increase significantly due to greater use of closed-loop cooling systems that consumes far more water than once-through cooling systems due to evaporation losses.

Figure A-2 - Percent of freshwater consumption by use category



In addition to the water uses described above, increased value is being placed on in-stream freshwater uses, consisting mainly of habitat/species protection and recreational uses. In-stream uses will require a minimum flow rate or depth to be maintained in water bodies.

Because freshwater supply is limited, choices will have to be made regarding withdrawal and consumption of this natural resource. Water availability and its withdrawal and consumption are top priorities on the public agenda in many nations throughout the world. It is likely that the issue will also filter to the top of the U.S. public agenda in the near future. In water-stressed areas of the country, power plants will increasingly compete with other water users. Agriculture and public supply will most likely be the greatest competitors due to their large water withdrawal. As with all resources, tradeoffs will occur, and concerns will increasingly be raised over which use is more important: water for drinking and personal use, growing food, or energy production.

Regulatory Impacts on Water Withdrawal and Consumption

The power industry must comply with a variety of local, state and federal regulations pertaining to water acquisition, use, and quality. In considering long-term water withdrawal and consumption patterns in the power sector, the cooling water intake structure regulations established under the Clean Water Act, Section 316(b) will likely have the greatest impact. Designed to protect aquatic life from inadvertently being killed by intake structures at power stations and certain manufacturing facilities, Section 316(b) requires EPA to ensure that the "location, design, construction and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact."

EPA divided its 316(b) rulemaking into three phases: Phase I, completed in late 2001, applies to new facilities; Phase II, completed in early 2004, applies to large existing power facilities; and Phase III, due to be finalized in 2006, applies to existing manufacturing facilities. The regulations establish performance standards for cooling water intake structures based on impingement mortality and entrainment (IM&E) impacts. A minimum level of IM&E reduction is required based on the type of water body a given facility accesses for cooling water. Compliance with 316(b) is coordinated through the individual states' NPDES (National Pollutant Discharge Elimination System) permitting program.

The largest design impact of 316(b) compliance is that most new power plants will have to use closed-loop, recirculating cooling systems or dry (air-cooled) systems. Open-loop systems are strongly discouraged unless the permit applicant can demonstrate that alternative IM&E measures can provide a reduction level comparable to that achieved through closed-loop cooling or that the compliance costs, air quality impacts, and/or energy generation impacts would outweigh the IM&E benefits and justify an open-loop system. Because 316(b) portends a greater reliance on closed-loop cooling systems, water withdrawal and consumption patterns for the thermoelectric power sector are destined to change over time. Even accounting for significant thermoelectric capacity additions, water withdrawal levels will likely remain relatively constant. Water consumption, on the other hand, is expected to increase substantially since closed-loop cooling systems consume more water, due to evaporation, than open-loop systems.

Existing and future air quality regulations will also affect water withdrawal and consumption patterns, although to a lesser extent than cooling water regulations. Tighter emission levels for sulfur dioxide, for example, have sparked a mini-boom in the flue gas desulfurization (FGD) market. The size of the U.S. FGD market is expected to increase by more than 100,000 megawatts (MW) over the next 10 years. Although FGD water requirements are a fraction of those required for cooling purposes, FGD units require a significant amount of water to produce and handle the various process streams (limestone slurry, scrubber sludge, etc.). Makeup water requirements for the FGD island at a nominal 550 MW subcritical coal-fired power plant are about 570 gpm, versus about 9,500 gpm for cooling water makeup.[18] Nonetheless, the additional FGD systems coming online within the next decade will place a greater strain on water supplies. Notably, semi-dry flue gas desulfurization systems are available that substantially reduce water requirements for SO_2 control, and these systems are in commercial application at numerous plants, many in arid environments.

Several other regulatory actions warrant attention because of their potential impact on water withdrawal and consumption. Under section 303(d) of the 1972 Clean Water Act, states, territories, and authorized tribes are required to develop a list of impaired waters not meeting water quality standards and then establish total maximum daily loads (TMDL) for these waters. A TMDL specifies the maximum amount of a pollutant that a waterbody can receive and still meet water quality standards, and allocates pollutant loadings among point and nonpoint pollutant sources. TMDL requirements could potentially constrain a power plant's ability to discharge cooling water, as well as trace metals and other pollutants from flue-gas cleanup byproducts, into a water body if the water body is impaired. The power plant may then be required to seek an alternate water source or install additional water treatment equipment.

The current debate over global climate change and carbon dioxide (CO_2) emissions could also potentially impact the water resource situation. If power plants are ultimately required to implement carbon separation and sequestration technologies to comply with future regulations, additional water may be needed for certain process steps and groundwater could be impacted by CO_2 sequestration (in a manner similar to produced water from oil and gas recovery applications). On the other hand, water could potentially be recovered from the CO_2 stream prior to dry pumping for sequestration or reclaimed from produced waters due to underground displacement. A detailed analysis would be required to delineate the net water withdrawal and consumption associated with CO_2 separation and sequestration and is outside the scope of this study.

Legislative Activities

The Energy Policy Act of 2005 (Title IX, Subtitle G − Science, Section 979) directs the DOE to address energy-water nexus issues and assess the effectiveness of existing Federal programs to address energy-water related issues. The direction is for a program of research, development, demonstration, and commercial application to: 1) address energy-related issues associated with provision of adequate management, and efficient use of water; 2) address water-related issues associated with the provision of adequate supplies, optimal management, and efficient use of energy; and 3) assess the effectiveness of existing programs within the Department and other Federal agencies to address these energy and water related issues.

An amendment to the Energy Policy Act, the Energy-Water Efficiency and Supply Technology Bill, was originally introduced in 2004 and has gone through two revisions. The current version of the bill would allocate $5 million for the first year and "such sums as are necessary for each fiscal year thereafter." The bill would instruct the Secretary of Energy to "establish a national program for the research, development, demonstration, and commercial application of economically viable and cost-effective water supply technologies."

Drought Conditions

A Government Accountability Office (GAO) report[19] prepared in 2003 addressed the issue of freshwater supply at the state level. The report indicated that under normal rainfall conditions, state water managers in 36 states anticipated shortages in localities, regions, or even statewide in the next 10 years (2003 – 2013). The report goes on to say that "drought conditions will exacerbate shortage impacts."

During the summer of 2005, a joint effort between the Department of the Interior (DOI) and the Department of Agriculture (USDA) created Interagency Drought Action Teams to coordinate relief efforts in communities in western states facing droughts. A DOI report[20] about the action teams quotes Secretary (of the Interior) Norton, "Much of the Pacific Northwest has been hard hit by drought this year."

Power Generation Facility Siting

Concern about water supply, expressed by state regulators, local decision-makers, and the general public, is already impacting power projects across the United States. For example, in March 2006, an Idaho state House committee unanimously approved a two-year moratorium on construction of coal-fired power plants in the state based on environmental and water supply concerns.[21] Arizona rejected permitting for a proposed power plant because of concerns about how much water it would withdraw from a local aquifer.[22] In early 2005, Governor Mike Rounds of South Dakota called for a summit to discuss drought-induced low flows on the Missouri River and the impacts on irrigation, drinking-water systems, and power plants.[23] A coal-fired power plant to be built in Wisconsin on Lake Michigan has been under attack from environmental groups because of potential effects of the facility's cooling-water-intake structures on aquatic life.[24] In February 2006, Diné Power Authority reached an agreement with the Navajo Nation to pay $1,000 per acre foot and a guaranteed minimum total of $3 million for water for its proposed Desert Rock Energy Project.[25] In an article discussing a 1,200 MW proposed plant in Nevada, opposition to the plant stated, "There's no way Washoe County has the luxury anymore to have a fossil-fuel plant site in the county with the water issues we now have. It's too important for the county's economic health to allow water to be blown up in the air in a cooling tower."[26]

Appendix B
Water Needs Analysis Methodology

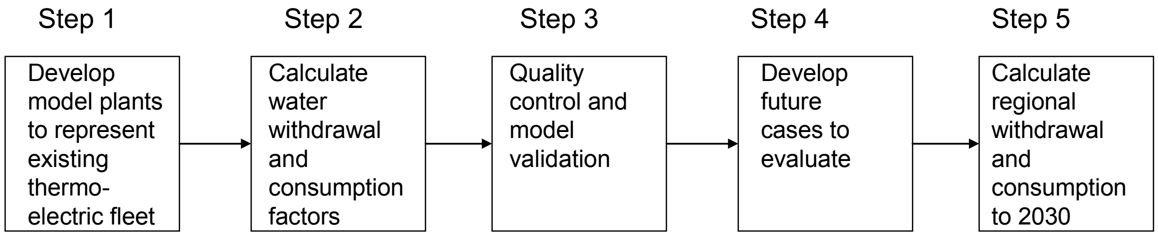
The purpose of this analysis is to update a 2004 National Energy Technology Laboratory (NETL) study to estimate freshwater needs to meet future year thermoelectric generation capacity requirements. The 2006 and 2007 analyses use a more detailed analytical approach and incorporate data and projections from the Energy Information Administration's *Annual Energy Outlook* yearly publications. Table B-1 summarizes the specific items that are updated in the 2006/2007 Water Needs Analyses. The additional level of detail and resolution included in the 2006/2007 analyses required a modified methodology from that used in the 2004 analysis.

Table B-1 - U.S. Power Generation Industry Water Withdrawal and Use Analysis – Comparison of Assumptions and Methodologies

Item	2004 Analysis	2006/2007 Analysis
Capacity/Generation Projections	AEO 2004	AEO 2006/2007
Geographical Breakdown	National	National and NERC region
Cooling Water Source Breakdown	Freshwater and Saline	Freshwater and Saline
Cooling Water System Type	Once-through and wet recirculating	Once-through and recirculating (dry, wet, and cooling pond)
Generation Type Breakdown	Total thermoelectric and coal	Total thermoelectric and coal, nuclear, non-coal steam, and natural gas combined cycle
Final Year of Projection	2025	2030
Cases	Six cases representing upper and lower bounds	Five cases with conservative assumptions
Water Use Scaling Factors – Geographic Coverage	National	NERC region with adjustment for capacity factor increase
Water Use Scaling Factors – Coal Plant Design	Not included	Boiler type – subcritical or supercritical FGD type – wet, dry, or none
Additional Water Uses for CO_2 Capture Plants	Not included	2006 Analysis – Not included 2007 Analysis – Included for PC and IGCC Plants

Figure B-1 provides a flowchart depiction of the methodology used to conduct the analysis. The five-step approach represents a refined and more robust methodology than that used in the 2004 Water Needs Analysis. Each step in the process is described below.

Figure B-1 - Methodology for the 2006/2007 Water Needs Analysis



Step 1: Develop model plants

To obtain the resolution desired for this analysis, water withdrawal and consumption factors were determined for a large number of plant configurations, based on location, generation type, cooling water source, cooling system type, and where applicable, boiler type and type of flue gas desulfurization (FGD) system. The existing thermoelectric fleet was segregated into numerous configurations, called "model plants" using data contained in several sources: the NETL Coal Plant Database, EIA-767, and EIA-860. Water withdrawal and consumption factors were calculated for each model plant using the available data and then used in conjunction with projections from AEO 2006/2007 to provide an estimate of future water withdrawal and consumption for various cases.

The model plant derivation process is detailed below.

NERC Regions

Cooling water needs will vary by region due to climatic variations and availability of cooling water. Performing the water needs analysis on a regional level, therefore, provides a more accurate estimate of cooling water trends than a higher-level analysis. To accomplish this, the 13 NERC regions (excluding Alaska and Hawaii) were integrated into the *NETL Coal Plant Database* from the EIA-860 database.

Thermoelectric Generation Type

Water withdrawal and consumption factors were determined for thermoelectric power plants: coal, nuclear, oil, natural gas and the steam portion of gas-fired combined cycles. However, more detailed effort was expended in determining water factors for coal-fired power plants. The analysis doe not include non-thermoelectric plants such as combustion turbines, renewable generations, etc.

Individual water use estimates were developed for the following thermoelectric generation types:

i. Coal
ii. Nuclear
iii. Non-Coal Fossil
iv. Combined Cycle

Model plants for coal in each NERC region were developed using the following hierarchy:

Cooling Water Type (Freshwater/Saline)

↓

Cooling Water System Type (Once-Through, Wet Recirculating, Dry Recirculating, Cooling Ponds)

↓

Boiler Type (Subcritical, Supercritical)

↓

FGD Type (Wet, Dry, None)

Using this hierarchy, a total of 30 model plants are possible for coal in each region[e]:

1. Freshwater, once-through, subcritical, wet FGD
2. Freshwater, once-through, subcritical, dry FGD
3. Freshwater, once-through, subcritical, no FGD
4. Freshwater, once-through, supercritical, wet FGD
5. Freshwater, once-through, supercritical, dry FGD
6. Freshwater, once-through, supercritical, no FGD
7. Freshwater, recirculating, subcritical, wet FGD
8. Freshwater, recirculating, subcritical, dry FGD
9. Freshwater, recirculating, subcritical, no FGD
10. Freshwater, recirculating, supercritical, wet FGD
11. Freshwater, recirculating, supercritical, dry FGD
12. Freshwater, recirculating, supercritical, no FGD
13. Freshwater, cooling pond, subcritical, wet FGD
14. Freshwater, cooling pond, subcritical, dry FGD
15. Freshwater, cooling pond, subcritical, no FGD
16. Freshwater, cooling pond, supercritical, wet FGD
17. Freshwater, cooling pond, supercritical, dry FGD
18. Freshwater, cooling pond, supercritical, no FGD
19. Saline, once-through, subcritical, wet FGD
20. Saline, once-through, subcritical, dry FGD

[e] According to the hierarchy presented, 36 model plant combinations are possible. Six of these combinations would be configured with saline cooling ponds. Such a cooling water source is technically impractical and, therefore, not included in this analysis.

21. Saline, once-through, subcritical, no FGD
22. Saline, once-through, supercritical, wet FGD
23. Saline, once-through, supercritical, dry FGD
24. Saline, once-through, supercritical, no FGD
25. Saline, recirculating, subcritical, wet FGD
26. Saline, recirculating, subcritical, dry FGD
27. Saline, recirculating, subcritical, no FGD
28. Saline, recirculating, supercritical, wet FGD
29. Saline, recirculating, supercritical, dry FGD
30. Saline, recirculating, supercritical, no FGD

Similar model plants were developed for nuclear, non-coal fossil, and combined cycle, but only broken down by cooling water type (freshwater vs. saline) and cooling water system type (once-through, recirculating, cooling pond).

Step 2: Calculate water withdrawal and consumption factors

For each model plant defined in Step 1, water withdrawal and consumption factors were calculated using the data sources outlined above.

<u>Coal</u>

For coal, the water withdrawal and consumption factors were based on the sum of three components: 1) boiler make-up water; 2) FGD make-up water; and 3) cooling water.

The boiler make-up water component at a coal plant depends on the type of boiler – either subcritical or supercritical. The boiler make-up water factors were calculated using water balance data contained in Parsons' "Power Plant Water Consumption Study" conducted for NETL in August 2005. Separate values were determined for subcritical and supercritical plant configurations, but the values were fixed for all regions, water source, cooling type, and FGD type.

The FGD make-up water component depends on the type of FGD system – either wet or dry. Dry FGD systems require much less water than wet FGD systems, for example, so different factors must be used. The FGD make-up water factors were calculated using material balance data contained in Carnegie Mellon University's Integrated Environmental Control Model (IECM). Separate values were determined for subcritical and supercritical plant configurations, but the values were fixed for all regions, water source, and cooling type.

The cooling water component for each model plant was calculated by compiling data from the *NETL Coal Power Plant Database* and EIA-860 for water withdrawal, water consumption, and summer capacity. Average water withdrawal (gal/hr), average water consumption (gal/hr), and summer capacity were used to calculate average withdrawal and consumption scaling factors (gal/kWh) for each model plant in each of the NERC regions. The power plant capacity data contained in the NETL database consists of nameplate MW capacity taken from the EIA-767 report. However, the AEO projections are based on summer capacity. Therefore, summer capacity (MW) data was obtained from the EIA-860 report to calculate the scaling factors. The following methodology was used to calculate the average cooling water withdrawal and consumption factors for each type of cooling water system:

- *Once-through systems:* To maximize plant efficiency during partial load operation, power plant operators normally maintain cooling water flow through the condenser at full load design rates. Therefore, the cooling water withdrawal rate for a once-through cooling water system is dependent on plant capacity (kW) and independent of plant electrical generation (kWh). For this reason, the water usage factors for once-through systems were determined by dividing the sum of the average withdrawal or consumption rate by the sum of the generator summer capacity.

  Withdrawal Factor (gal/kWh) = ΣAverage Withdrawal (gal/h) / ΣCapacity (kW) (1a)

  Consumption Factor (gal/kWh) = ΣAverage Consumption (gal/h) / ΣCapacity (kW) (1b)

- *Wet Recirculating Systems:* Similar to once-through systems, to maximize plant efficiency during partial load operation, power plant operators normally maintain cooling water flow through the condenser and across the cooling tower at full load design rates. However, as more power is produced, the heat load to the cooling tower increases, resulting in greater evaporative losses and blowdown and consequently, higher water withdrawal requirements. Therefore, water withdrawal and consumption are independent of plant capacity (kW) and dependent on plant electrical generation (kWh) in wet recirculating systems. For this reason, the water usage factors for wet recirculating cooling systems were adjusted for each year of the analysis by applying a capacity factor ratio, F, to account for the growth in generation.

  Withdrawal Factor (gal/kWh) = F x ΣAverage Withdrawal (gal/h) / ΣCapacity (kW) (2a)

  Consumption Factor (gal/kWh) = F x ΣAverage Consumption (gal/h) / ΣCapacity (kW) (2b)

  Where:

  F = Ratio of capacity factor in year X to capacity factor in baseline year 2003

- *Cooling Ponds*: EIA-767 considers cooling ponds to be a type of wet recirculating cooling system since heat loss occurs through evaporative loss. However, cooling water flow rates for a cooling pond are more similar to once-through than wet recirculating systems. Therefore, for this study, water usage factors were calculated using the same formula as for once-through systems.

- *Dry Recirculating Systems*: For dry recirculating systems, the cooling water withdrawal and consumption factors are both assumed to be zero.

Non-Coal Plants

Nuclear, oil steam, gas steam, and natural gas combined-cycle plants were classified according to NERC region, cooling water source (fresh or saline), and cooling water system (recirculating or once-through). Water usage factors for each plant classification were determined using equations 1a, 1b, 2a, and 2b, depending on type of cooling water system.

In calculating water withdrawal and consumption quantities for combined-cycle plants, an adjustment was made to account for the fact that the gas turbine portion of the plant does not require cooling water. The design capacity of the gas turbine portion of a combined-cycle facility is typically twice that of the steam turbine portion; in other words, two-thirds of a combined-cycle plant's total output is derived from the gas turbine(s). Therefore, only about one-third of the plant output is used for steam generation, with its associated water requirements. For this analysis, water withdrawal and consumption factors were applied to only one-third of the combined-cycle capacity.

Step 3: Quality Control and Model Validation

Step 3 represents just one of several efforts designed to ensure quality control for the analysis. Because models, by definition, are simplified representations of reality, absolute model accuracy is impossible to guarantee in any situation. It is important, however, to have procedures in place to ensure that output from a given analysis is consistent with reality and reasonable expectations. Several steps were taken for the water needs analysis to achieve this objective.

The water withdrawal and consumption factors that were used in the model were obtained through a rigorous evaluation of data collected by the Energy Information Administration, primarily forms EIA-767 and EIA-860. Data presented on these forms is assumed to accurately represent conditions at a particular power plant. A variety of reasons, however, could account for errors and discrepancies in the data: lack of understanding of the form's directions, data entered in the wrong places, inaccurate data entry, improperly aggregated data, and others.

The calculated water withdrawal and consumption factors for a given categorical breakdown (e.g., NERC region) should fall within a limited range based on generation type and cooling type. If the dataset in that categorical breakdown was too small, data outliers could have disproportionately impacted the results. While it is impossible to eliminate all such errors, the data was carefully vetted to ensure quality data points were used. Certain entries were modified or discarded based on accompanying information and engineering judgment. For example, if a power plant was designated as a once-through facility, but reported cooling water withdrawal and consumption quantities that clearly identify it as a recirculating facility, the plant was re-classified as a recirculating facility.

To ensure that the estimates generated by the water needs analysis model were reasonable, power generation data from 1995 was obtained and inserted into the model. The calculated water withdrawal and consumption values for thermoelectric generation were then compared with U.S. Geologic Service estimates for water withdrawal and consumption for 1995.

Step 4: Develop Future Cases

Table B-2 summarizes the cases evaluated in the original 2004 analysis and the 2006/2007 analysis. The effects of emerging issues, particularly the impact of the Clean Water Act 316(b) regulations,[f] were incorporated into the selection of the 2006/2007 cases. Comments are provided with each of the cases to assess their likelihood and justify the chosen cases. Five cases were included in the 2006/2007 Water Needs Analysis, one reflecting status quo conditions, two reflecting varying levels of regulations regarding cooling water source, one incorporating dry cooling, and one reflecting regulatory pressures to convert existing once-through capacity to recirculating capacity.

To determine total water withdrawal and consumption requirements for thermoelectric generation in future years, new capacity additions and existing capacity retirements were factored into the analysis. As noted in the table, retirements were modeled based on current source withdrawals; in other words, freshwater and saline units were retired from service in proportion to their current contributions to total installed capacity, which is thought to more accurately reflect industry behavior. Units recently retired and/or placed in cold reserve have been removed from service due to age and operational cost constraints; cooling water source has played a minimal or nonexistent role. Future capacity retirement decisions, therefore, will likely remain more dependent on age and operational costs than cooling water source, and should reflect current proportions of freshwater and saline water facilities.

Retired capacity in a given NERC region was broken down by generation type, water source, cooling type, and, where applicable, boiler and FGD type, based on the current proportion of capacity for each specific combination. The corresponding water withdrawal and consumption factors were then applied to the retired capacity to determine how much water must be deducted from the withdrawal and consumption totals.

In modeling capacity additions, it was necessary to consider the different thermoelectric generation types. A variety of model plants were added based on the case assumptions. Expected capacity additions in a given region in a given year, as projected by AEO 2006/2007, were apportioned into these model plant categories. Each model plant will

[f] The Clean Water Act's 316(b) regulations require the U.S. Environmental Protection Agency to ensure that cooling water intake structures at power plants and other manufacturing facilities reflect the best technology available for minimizing adverse environmental impact. The practical impact of these regulations is that most new power plants will have to incorporate closed-loop, recirculating cooling systems, which overwhelmingly rely on freshwater.

have an associated water withdrawal and consumption factor. The corresponding capacity (kW) for each model plant category was used with the withdrawal and consumption factors to calculate incremental water withdrawal and consumption.

The model plants for the five cases are listed in Table B-3. Because of the resolution provided in this analysis for coal-fired power plants, more model plants were developed for coal than for the other generation types. Several notes are in order regarding the coal model plants:

- For pulverized coal plants, new additions are expected to favor supercritical boiler technology. Nationwide, the current split between subcritical and supercritical boiler technology capacity is 73% subcritical/27% supercritical, reflecting greater industry experience and familiarity with subcritical technology. Pressure from several sources – environmental entities, state utility commissions, the threat of CO_2 regulations – is increasing utility interest in supercritical boiler technology. A majority of the coal-fired power plants currently under construction or planned will rely on supercritical boiler technology. In selecting model coal plants for new additions, therefore, a 75% supercritical/25% subcritical split was employed. See Appendix B for further information.
- For coal-fired power plants equipped with flue gas desulfurization equipment, water withdrawal and consumption rates can exhibit relatively significant differences based on whether the FGD is a wet or dry system. Since all new pulverized coal-fired power plants will need FGD systems to comply with emission regulations, future capacity additions must be apportioned by FGD type. Since emission regulations do not dictate technology selection, the analysis apportions FGD type to new capacity additions based on the existing split in the coal-fired power fleet (by summer capacity), which is 90% wet/10% dry.
- The *Annual Energy Outlook* assumes that a portion of new coal-fired capacity will utilize integrated gasification combined-cycle (IGCC) technology. The water requirements for IGCC facilities differ from those at pulverized coal facilities. While both require cooling water, IGCC requires substantially less since a large fraction of the output from an IGCC plant is produced from the combustion turbines, which require minimal water. Moreover, since IGCC relies on water for significant process (non-cooling) use, it is unlikely that a saline water source would be desirable. The model IGCC coal plant, therefore, is restricted to freshwater use.

As discussed above, model plants for the non-coal thermoelectric generation capacity – nuclear, oil steam, gas steam, and natural gas combined cycle – were broken down by water source (fresh or saline) and cooling water type (once-through or wet recirculating) based on data from the EIA-767 and EIA-860 databases. Two model plants account for all likely new non-coal thermoelectric additions: a plant using a freshwater recirculating system and a plant using a saline once-through system. For Case 4, an additional model plant with dry cooling is included for both coal and non-coal generation types.

Table B-2 - Case Selection, 2004 vs. 2006/2007

2004 Water Needs Analysis	
Case description	Comments
Case 1: All additions and retirements occur at facilities using freshwater.	Reasonable. While the vast majority of new additions will use freshwater due to 316(b) regulations, it is unlikely that the majority of retirements will be from freshwater facilities. Retirement decisions will depend more on age and operational costs than on cooling water source.
Case 2: Additions and retirements are proportional to current source withdrawals (70% freshwater/30% saline).	Reasonable. As discussed for Case 1, retirement decisions will depend on age and operational costs, which will likely mirror the proportional split between freshwater and saline. For additions, however, 316(b) regulations will likely lead to a higher proportion of freshwater facilities since saline water is incompatible with wet recirculation systems.
Case 3: All additions and retirements occur at facilities using saline water.	Unlikely. Due to 316(b) regulations, saline water will likely account for a significantly smaller percentage of new additions. Retirements may slightly favor saline, but decision will depend more on age and operational costs.
Case 4: Additions occur at freshwater facilities, while retirements occur at saline facilities.	Reasonable. Although retirements are likely to be more proportional to current source withdrawals, as discussed above.
Case 5: Additions occur at saline facilities, while retirements occur at freshwater facilities.	Extremely unlikely. 316(b) regulations will make saline a difficult choice for additions. No regulatory or operational trends indicate that retirements would favor freshwater.
Case 6: All retired coal units use once-through cooling and are repowered using the existing once-through system. Additions reduced by the repowered units.	Unlikely. Via repowering, units would be subject to new source regulations, which favor recirculating systems and the use of freshwater.
2006/2007 Water Needs Analysis	
Case Description	**Rationale**
Case 1: Additions and retirements proportional to current water source and type of cooling system.	Status quo scenario case. Assumes additions and retirements follow current trends.
Case 2: All additions use freshwater and wet recirculating cooling, while retirements are proportional to current water source and cooling system.	Regulatory-driven case. Assumes 316(b) and future regulations dictate the use of recirculating systems for all new capacity. Retirement decisions hinge on age and operational costs rather than water source and type of cooling system.
Case 3: 90% of additions use freshwater and wet recirculating cooling, and 10% of additions use saline water and once-through cooling, while retirements are proportional to current water source and cooling system.	Regulatory-light case. New additions favor the use of freshwater recirculating systems, but some saline capacity is permitted. Retirement decisions remain tied to age and operational costs, tracking current source withdrawals.
Case 4: 25% of additions use dry cooling and 75% of additions use freshwater and wet recirculating cooling. Retirements are proportional to current water source and cooling system.	Dry cooling case. Regulatory and public pressures result in significant market penetration of dry cooling technology. Retirement decisions remain tied to age and operational costs, tracking current source withdrawals.
Case 5: Additions use freshwater and wet recirculating cooling, while	Conversion case. Same as Case 2, except regulatory and public pressures compel state agencies to dictate the conversion of a

retirements are proportional to current water source and cooling system. 5% of existing freshwater once-through cooling capacity retrofitted with wet recirculating cooling every 5 years starting in 2010.	significant amount of existing freshwater once-through cooling systems to wet recirculating.

Table B-3 - Model Plants for New Capacity Additions

Case 1	

Coal	• Pulverized coal, freshwater, recirculating cooling system
	  o 75% supercritical/25% subcritical
	  o Wet FGD/dry FGD based on existing split
	• Pulverized coal, saline water, once-through cooling system
	  o 75% supercritical/25% subcritical
	  o Wet FGD/dry FGD based on existing split
	• Integrated gasification combined-cycle, freshwater, recirculating

Nuclear	• Freshwater, recirculating cooling system • Saline water, once-through cooling system
Non-coal fossil	• Freshwater, recirculating cooling system • Saline water, once-through cooling system
Case 2	

Coal	• Pulverized coal, freshwater, recirculating cooling system
	  o 75% supercritical/25% subcritical
	  o Wet FGD/dry FGD based on existing split
	• Integrated gasification combined-cycle, freshwater, recirculating

Nuclear	• Freshwater, recirculating cooling system
Non-coal fossil	• Freshwater, recirculating cooling system
Case 3	

Coal	• Pulverized coal, freshwater, recirculating cooling system
	  o 75% supercritical/25% subcritical
	  o Wet FGD/dry FGD based on existing split
	• Pulverized coal, saline water, once-through cooling system
	  o 75% supercritical/25% subcritical
	  o Wet FGD/dry FGD based on existing split
	• Integrated gasification combined-cycle, freshwater, recirculating

Nuclear	• Freshwater, recirculating cooling system • Saline water, once-through cooling system
Non-coal fossil	• Freshwater, recirculating cooling system • Saline water, once-through cooling system
Case 4	

Coal	• Pulverized coal, freshwater, recirculating cooling system
	  o 75% supercritical/25% subcritical
	  o Wet FGD/dry FGD based on existing split
	• Pulverized coal, freshwater, dry cooling system
	  o 75% supercritical/25% subcritical
	  o Wet FGD/dry FGD based on existing split
	• Integrated gasification combined-cycle, freshwater, recirculating
	• Integrated gasification combined-cycle, dry cooling system

Nuclear	• Freshwater, recirculating cooling system • Dry cooling system

Non-coal fossil	• Freshwater, recirculating cooling system • Dry cooling system
Case 5	

Coal	• Pulverized coal, freshwater, recirculating cooling system
	    o 75% supercritical/25% subcritical
	    o Wet FGD/dry FGD based on existing split
	• Integrated gasification combined-cycle, freshwater, recirculating

Nuclear	• Freshwater, recirculating cooling system
Non-coal fossil	• Freshwater, recirculating cooling system

Step 5: Calculate regional withdrawal and consumption to 2030

Step 5 integrates the water withdrawal and consumption factors calculated in Step 2 with the various cases defined in Step 4 to assess the regional and national impacts on water withdrawal and consumption out to 2030.

The *Annual Energy Outlook* provides projections of future electricity generating capacity by year, by generation type and by NERC region. Apportioning this capacity among the chosen model plants for a given case and then applying the water withdrawal and consumption factors enables one to estimate water withdrawal and consumption trends.

For a given case in a given region, the capacity additions and retirements projected by AEO 2006/2007 were first divided between freshwater and saline water based on the source withdrawal split for each technology type (coal, nuclear, non-coal fossil), as determined using existing fleet data. The additions and retirements were further apportioned among cooling water system type (once-through, recirculating), again using existing fleet splits. For nuclear and non-coal fossil, the water withdrawal and consumption factors determined in Step 2 were then applied to the resulting capacity amounts to calculate water withdrawal and consumption totals.

For coal, further segregation was necessary before performing the calculations. The additions and retirements were further apportioned by technology type (supercritical and subcritical boilers). Retirements were divided based on the existing fleet split between supercritical and subcritical technology. Additions were divided between supercritical and subcritical boilers at a 75/25 ratio to reflect a growing preference for supercritical technology, as described above in Step 4 and in Appendix C. The additions also must accommodate new IGCC plants; AEO projections for IGCC were used to apportion capacity amounts by region. Finally, coal retirements and additions were apportioned by FGD type (wet, dry, none) using existing fleet data. The water withdrawal and consumption values determined in Step 2 were applied to the segregated capacity quantities determined in Step 5 to calculate water withdrawal and consumption totals.

The calculations were a result of summing the results for each model plant in each region. The following is an example formula to calculate water withdrawal that was used for a model plant:

$$\text{Water Withdrawal (gal/hr)} = A \times B \times C \quad (3)$$

Where:
A = Total regional capacity, kW
B = Proportion of capacity assigned to model plant, %/100
C = Capacity factor-weighted water use scaling factor for model plant, gal/kWh

Appendix C
Future Coal-Fired Power Plant Boiler Type
Supercritical versus Subcritical

The water analysis uses different water use scaling factors for coal-fired power plants based on boiler type. A supercritical boiler – operating at steam conditions above the critical point – is more efficient and therefore requires less cooling water flow than a subcritical boiler for an equivalent amount of electrical generation output. The critical point represents the highest temperature and pressure at which a substance can exist as a vapor and liquid in equilibrium. The critical point for water is 3200 psia and 705°F. Today's supercritical boilers operate at steam conditions of approximately 3500 psia and 1000°F compared to subcritical boilers that operate at approximately 2400 psia or less and 1000°F.

Table C-1 presents a summary of the breakdown by boiler type for currently operating U.S. coal-fired power plants according to data taken from Platt's UDI Power Plant Database. The current boiler type breakdown by MW capacity is 27% supercritical and 73% subcritical. It should also be noted that supercritical boilers tend to be significantly larger in capacity. The average size of supercritical boilers is 743 MW compared to 234 MW for subcritical boilers.

Table C-1 – Boiler Type for Existing Plants

Operating Plants	Total	Super-critical	Sub-critical
No. Units	1,136	117	1,019
Total Capacity, MW	325,651	86,903	238,748
Average Unit Capacity, MW	287	743	234
% Total Capacity	Base	27%	73%

Table C-2 presents a similar summary by boiler type for coal-fired power plants either under construction or planned also taken from Platt's UDI Power Plant Database. However, not all of the plants reported boiler type. For those plants that boiler type is reported, the breakdown by capacity is 55% supercritical and 45% subcritical. Similar to the currently operating plants, the average size of supercritical plants is 719 MW compared to 312 MW for subcritical plants. Since it appears that plant capacity correlates fairly well with boiler type, the unreported plants are segregated into two plant sizes – greater than or equal to 500 MW (87%) and less than 500 MW (13%).

Table C-2 – Boiler Type for Future Plants – As Reported

Plants Under Construction or Planned	Total	Boiler Type Reported			Boiler Type Not Reported		
		Total	Super-critical	Sub-critical	Total	≥ 500 MW	< 500 MW
No. Units	86	49	17	32	37	26	11
Total Capacity, MW	42,835	22,203	12,225	9,978	20,632	17,887	2,745
Average Capacity, MW	498	453	719	312	558	688	250
% Total Capacity			55%	45%		87%	13%

Based on the boiler type data in Table C-1 and reported boiler type data in Table C-2, it is apparent that plant capacity correlates fairly well with boiler type. As a result, the unreported plants in Table C-2 that were segregated by plant capacity can also be categorized by boiler type. Plants with a capacity greater than or equal to 500 MW are assumed to be supercritical and those with a capacity less than 500 MW are assumed to be subcritical. Table C-3 presents the result of this categorization by combining the reported and unreported plant data from Table C-2. Therefore, future coal-fired plant capacity is assumed to be split as 75% supercritical and 25% subcritical for the water analysis.

Table C-3 – Boiler Type for Future Plants - Combined

Plants Under Construction or Planned	Total	Super-critical	Sub-critical
No. Units	86	43	43
Total Capacity, MW	42,835	30,112	12,723
Average Capacity, MW	498	700	296
% Total Capacity		70%	30%

Appendix D
Water Withdrawal and Consumption Factors

The bulk of the data in the following tables (except for the IGCC model plant) is derived from actual data that was reported to the EIA from U.S. power plants. Outliers were removed and the values were averaged for each model plant. Some values may appear inconsistent with conventional thought; however this is the data that was reported. Cooling pond data had the largest spread and showed the most variation.

Table D-1 – National Average Withdrawal and Consumption Factors for Model Coal Plants

Model Plant	Withdrawal Factor (gal/kWh)	Consumption Factor (gal/kWh)
Freshwater, Once-Through, Subcritical, Wet FGD	27.113	0.138
Freshwater, Once-Through, Subcritical, Dry FGD	27.088	0.113
Freshwater, Once-Through, Subcritical, No FGD	27.046	0.071
Freshwater, Once-Through, Supercritical, Wet FGD	22.611	0.124
Freshwater, Once-Through, Supercritical, Dry FGD	22.590	0.103
Freshwater, Once-Through, Supercritical, No FGD	22.551	0.064
Freshwater, Recirculating, Subcritical, Wet FGD	0.531	0.462
Freshwater, Recirculating, Subcritical, Dry FGD	0.506	0.437
Freshwater, Recirculating, Subcritical, No FGD	0.463	0.394
Freshwater, Recirculating, Supercritical, Wet FGD	0.669	0.518
Freshwater, Recirculating, Supercritical, Dry FGD	0.648	0.496
Freshwater, Recirculating, Supercritical, No FGD	0.609	0.458
Freshwater, Cooling Pond, Subcritical, Wet FGD	17.927	0.804
Freshwater, Cooling Pond, Subcritical, Dry FGD	17.902	0.779
Freshwater, Cooling Pond, Subcritical, No FGD	17.859	0.737
Freshwater, Cooling Pond, Supercritical, Wet FGD	15.057	0.064
Freshwater, Cooling Pond, Supercritical, Dry FGD	15.035	0.042
Freshwater, Cooling Pond, Supercritical, No FGD	14.996	0.004

Table D-2 – National Average Withdrawal and Consumption Factors for Model Nuclear Plants

Model Plant	Withdrawal Factor (gal/kWh)	Consumption Factor (gal/kWh)
Freshwater, Once-Through	31.497	0.137
Freshwater, Recirculating	1.101	0.624

Table D-3 – National Average Withdrawal and Consumption Factors for Model Fossil Non-Coal Plants

Model Plant	Withdrawal Factor (gal/kWh)	Consumption Factor (gal/kWh)
Freshwater, Once-Through	22.74	0.09
Freshwater, Recirculating	0.25	0.16
Freshwater, Cooling Pond	7.89	0.11

Table D-4 – National Average Withdrawal and Consumption Factors for Model IGCC/NGCC Plants

Model Plant	Withdrawal Factor (gal/kWh)	Consumption Factor (gal/kWh)
NGCC, Freshwater, Once-Through	9.01	0.02
NGCC, Freshwater, Recirculating	0.15	0.13
NGCC, Freshwater, Cooling Pond	5.95	0.24
NGCC Air Cooled	0.004	0.004
IGCC, Freshwater, Recirculating	0.425	0.331

Appendix E
Combined-Cycle Power Plants: Relative Contributions from Gas and Steam Turbines

Combined-cycle power plants integrate the power generating capabilities of gas turbines and steam turbines in a highly efficient manner. The waste heat generated by fuel combustion in the gas turbine is recovered in a heat recovery steam generator, producing steam that is then used to generate additional power in the steam turbine. A common rule of thumb for combined-cycle design is that the gas turbine capacity is about twice that of the steam turbine (i.e., steam turbine output represents about one-third of total plant output).

The water needs analysis incorporates this rule of thumb by applying the water withdrawal and consumption factors to only one-third of the combined-cycle capacity. To justify this assumption, the Platts *World Electric Power Plants Database* was analyzed. For those plants reporting gas turbine and steam turbine capacity in a combined-cycle configuration, the database produced the numbers shown in the table below.

Table E-1 - Gas and Steam Turbine Contribution

	Capacity (MW)	Percentage	Number of units	Percentage
Gas turbines in combined-cycle configuration	93,526	62.1%	846	63.2%
Steam turbines in combined-cycle configuration	57,068	37.9%	493	36.8%
Total	150,594	100.0%	1339	100.0%

Steam turbine capacity represents about 38% of total combined-cycle capacity. While the data do not precisely equal the 2:1 ratio posited by the rule of thumb, the agreement is fairly close. Industry product evolution and individual plant design data also support the 2:1 ratio. Siemens Power Generation recently expanded its product portfolio with the SGT5-8000H gas turbine, featuring advanced H-class efficiency.[27] This turbine will be capable of producing about 340 MW in simple-cycle configuration, and about 530 MW in combined-cycle configuration, resulting in a steam turbine percentage of 35.8%. In the forthcoming NETL report, "2006 Cost and Performance Comparison of Fossil Energy Power Plants," the steam turbine in the natural gas-fired combined-cycle design represents 29.2% of total plant output.[28]

Based on this information, assuming that the water scaling factors should only be applied to one-third of the generating capacity for combined-cycle plants appears quite reasonable.

Appendix F
Results from Statistical Analysis of Water Usage Factor Data

Figure F-1 – Boxplot for All Water Usage Factor Data for Coal Recirculating Subcritical Category

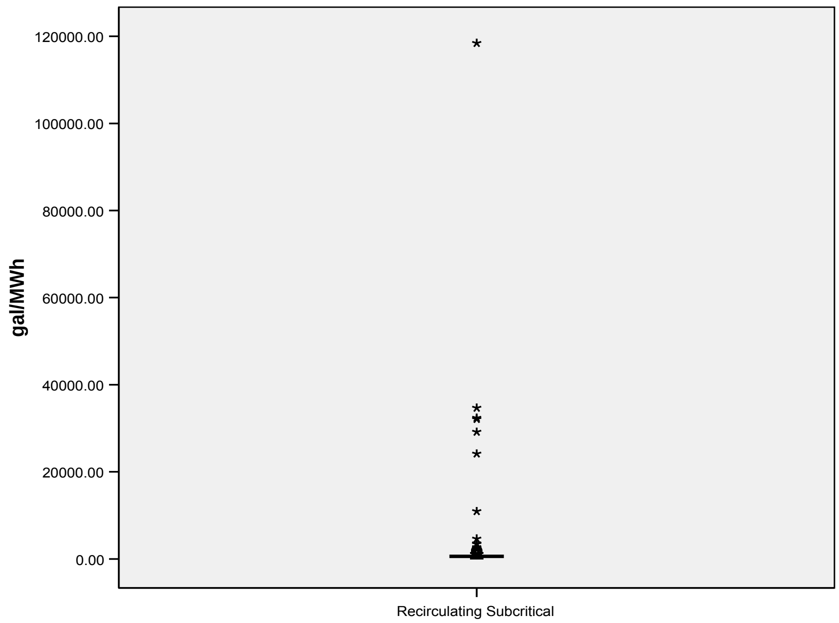


Figure F-2 - Boxplot for Water Usage Factor Data for Coal Recirculating Subcritical Category with Outliers Eliminated

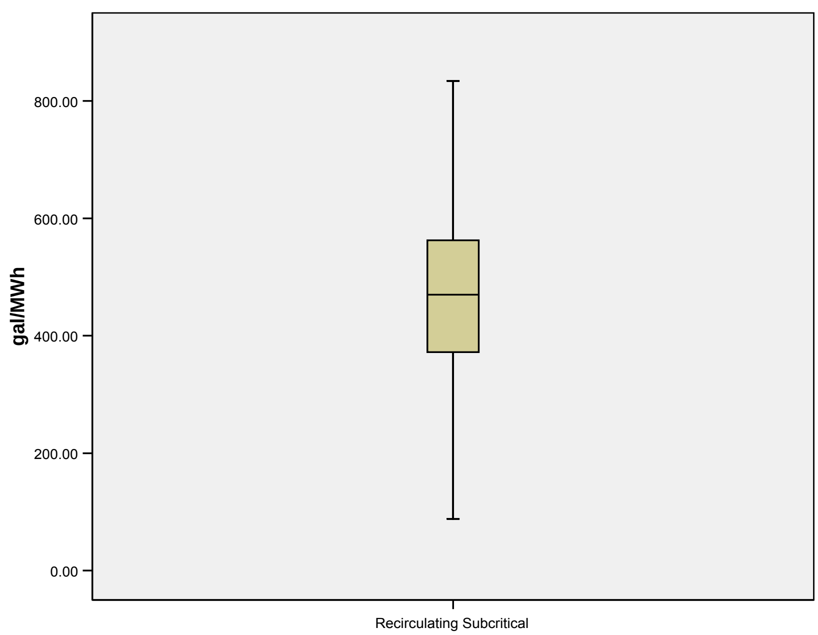


Figure F-3 – Boxplot for All Water Usage Factor Data for Coal Recirculating Supercritical Category

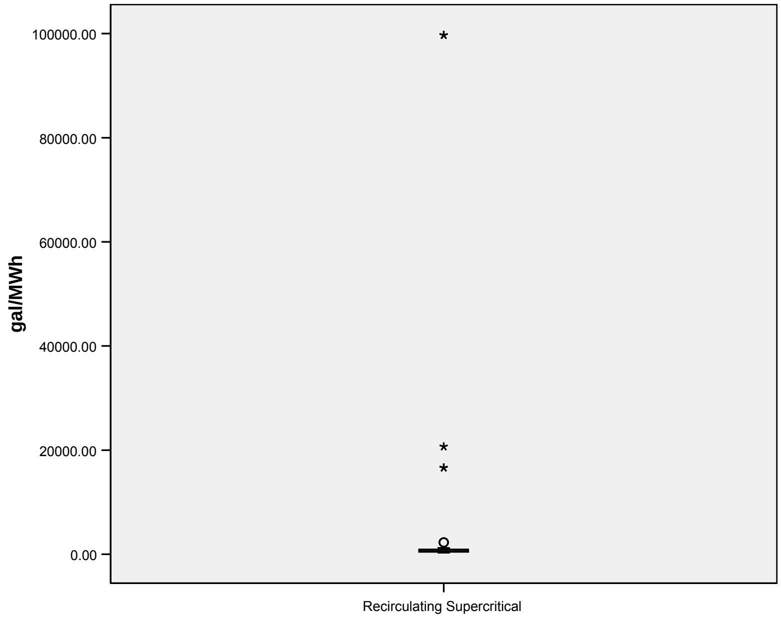


Figure F-4 - Boxplot for Water Usage Factor Data for Coal Recirculating Supercritical Category with Outliers Eliminated

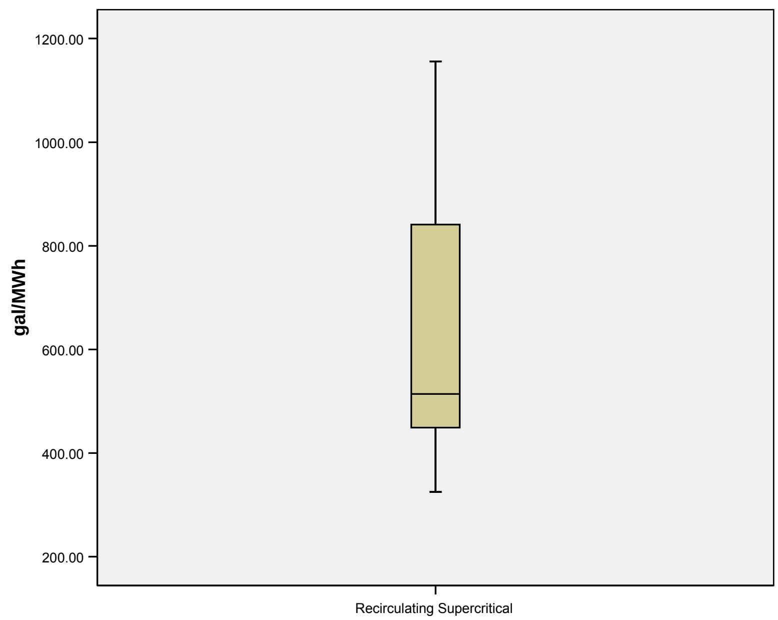


Figure F-5 – Boxplot for All Water Usage Factor Data for Coal Once-Through Subcritical Category

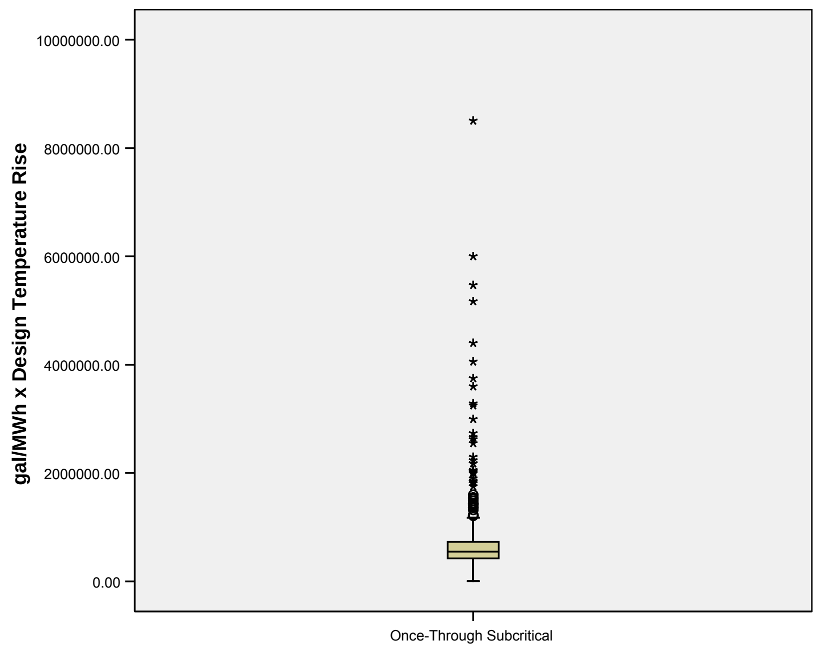


Figure F-6 - Boxplot for Water Usage Factor Data for Coal Once-Through Subcritical Category with Outliers Eliminated

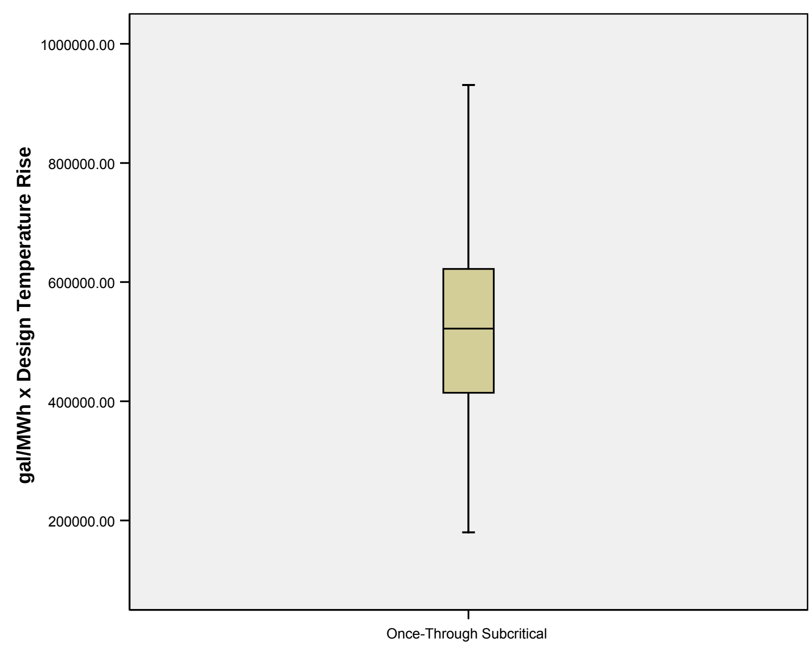


Figure F-7 – Boxplot for All Water Usage Factor Data for Coal Once-Through Supercritical Category

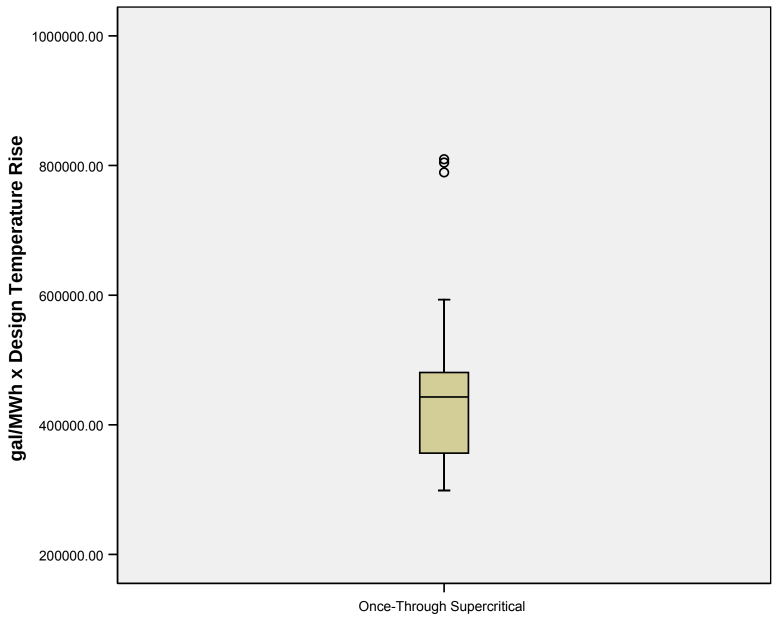


Figure F-8 - Boxplot for Water Usage Factor Data for Coal Once-Through Supercritical Category with Outliers Eliminated

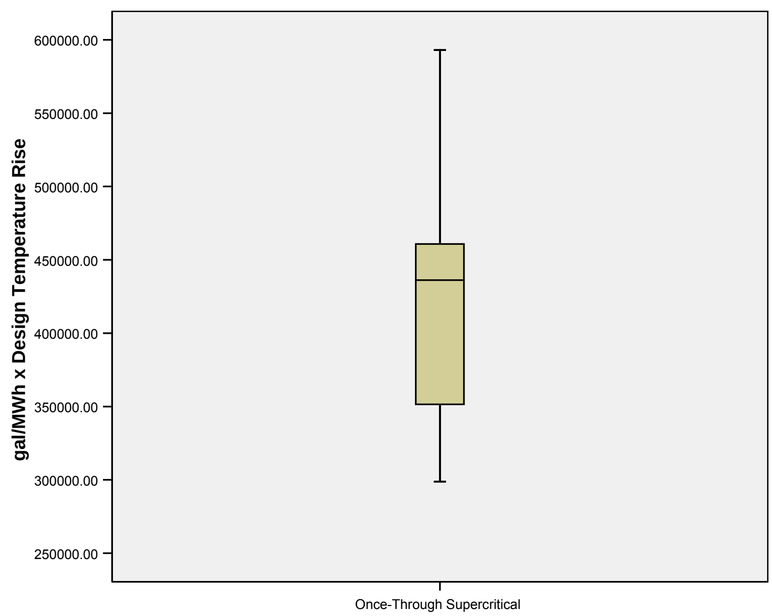


Figure F-9 – Boxplot for All Water Usage Factor Data for Coal Cooling Pond Subcritical Category

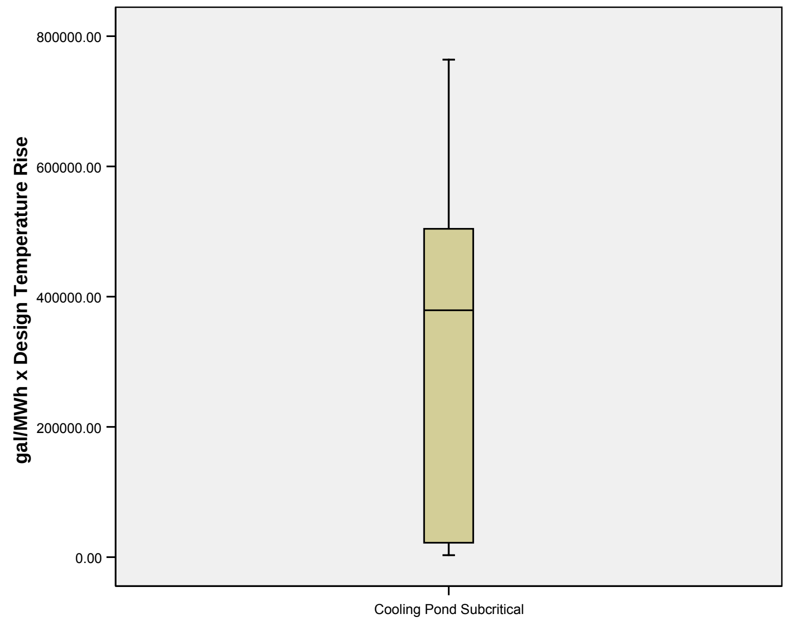


Figure F-10 – Boxplot for All Water Usage Factor Data for Coal Cooling Pond Supercritical Category

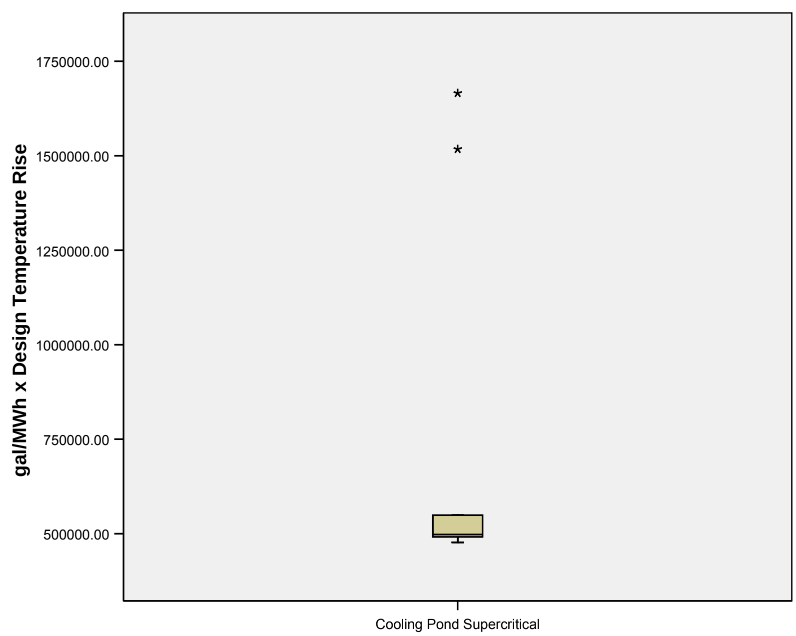


Figure F-11 - Boxplot for Water Usage Factor Data for Coal Cooling Pond Supercritical Category with Outliers Eliminated

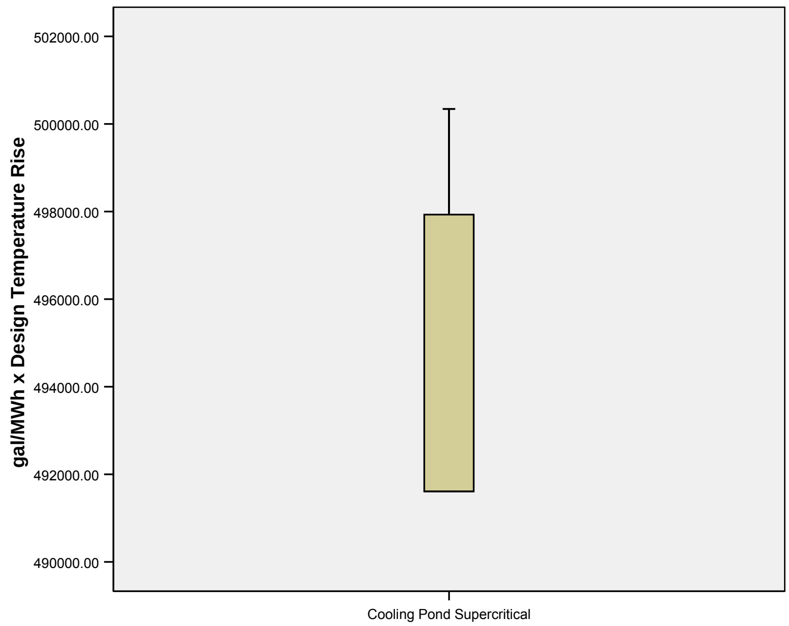


Figure F-12 – Boxplot for All Water Usage Factor Data for Fossil Non-Coal Recirculating Category

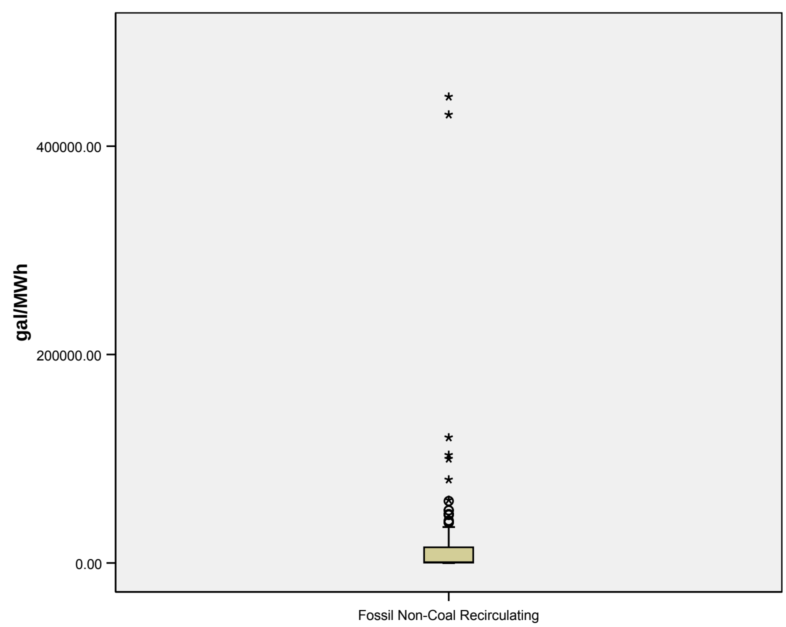


Figure F-13 - Boxplot for Water Usage Factor Data for Fossil Non-Coal Recirculating Category with Outliers Eliminated

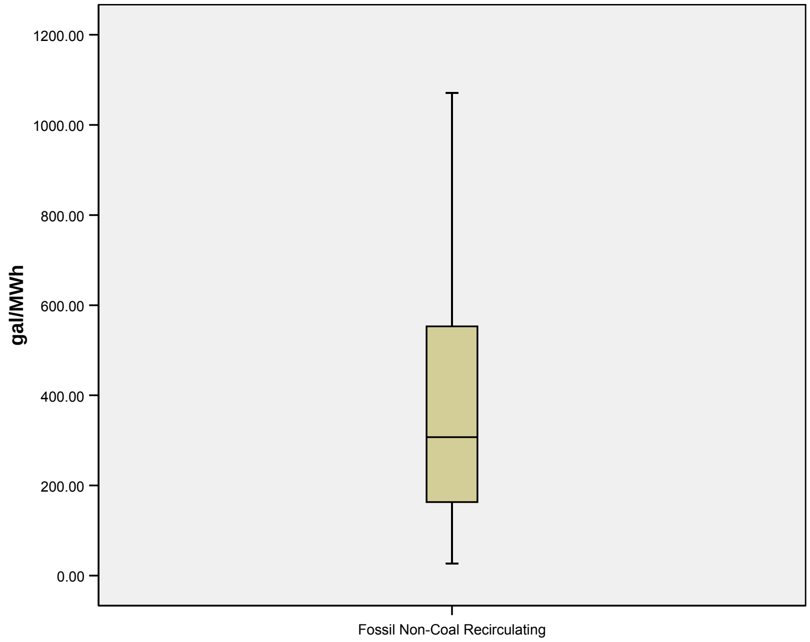


Figure F-14 – Boxplot for All Water Usage Factor Data for Fossil Non-Coal Once-Through Category

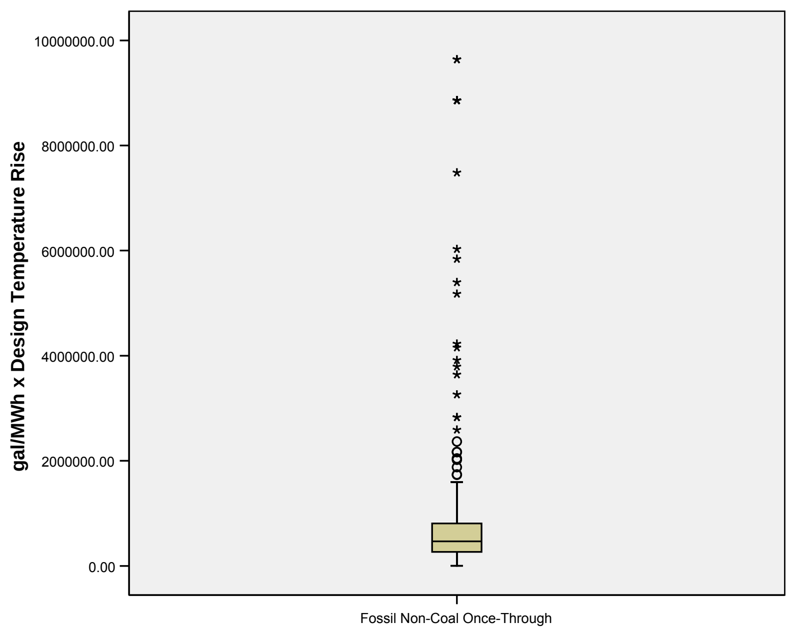


Figure F-15 - Boxplot for Water Usage Factor Data for Fossil Non-Coal Once-Through Category with Outliers Eliminated

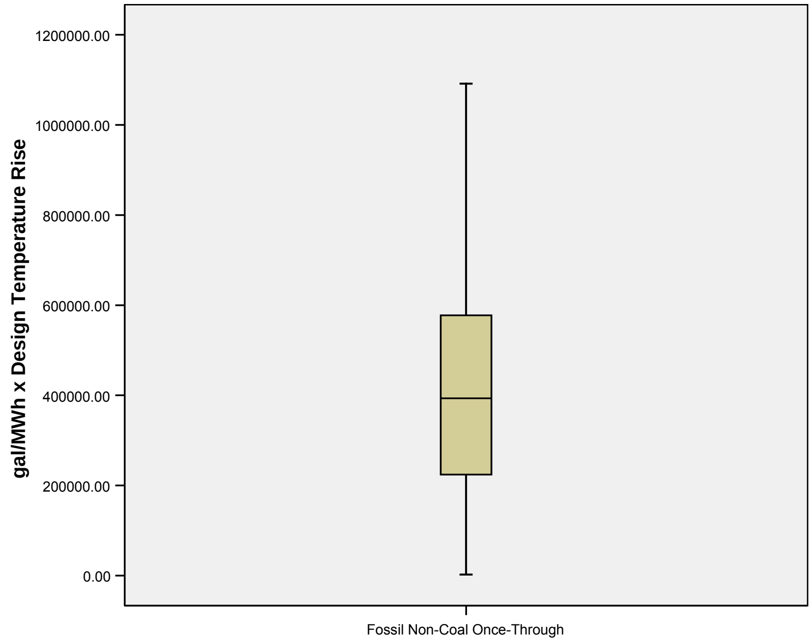


Figure F-16 – Boxplot for All Water Usage Factor Data for Fossil Non-Coal Cooling Pond Category

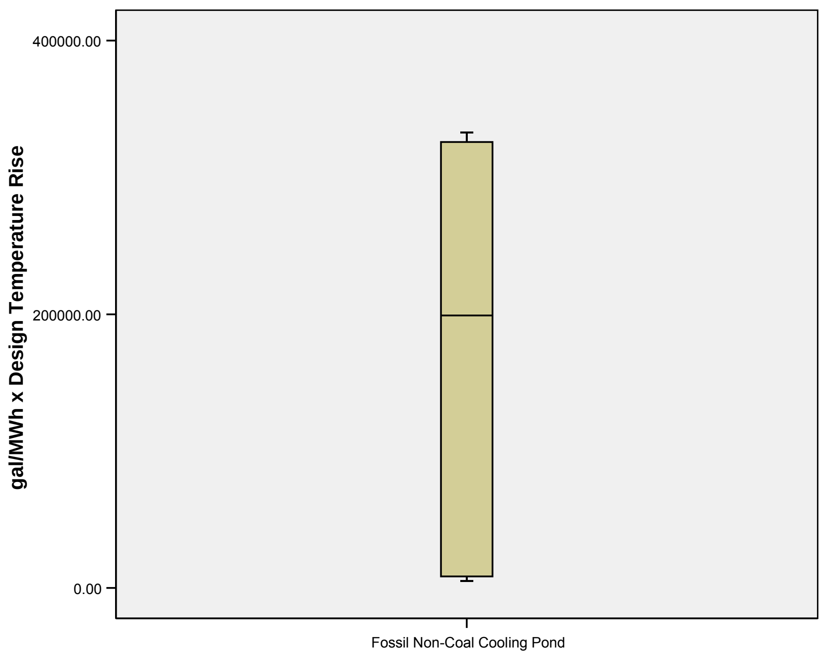


Figure F-17 – Boxplot for All Water Usage Factor Data for Nuclear Recirculating Category

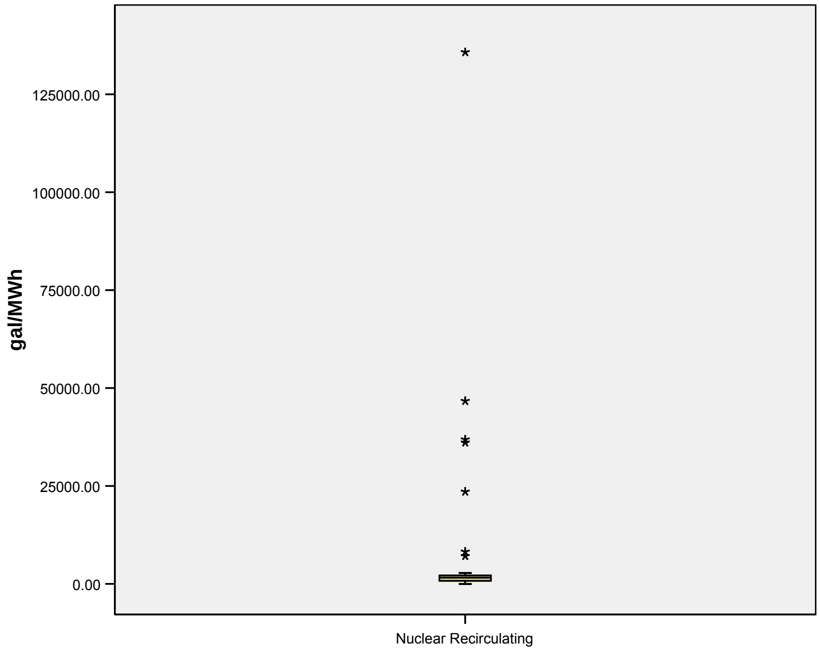


Figure F-18 - Boxplot for Water Usage Factor Data for Nuclear Recirculating Category with Outliers Eliminated

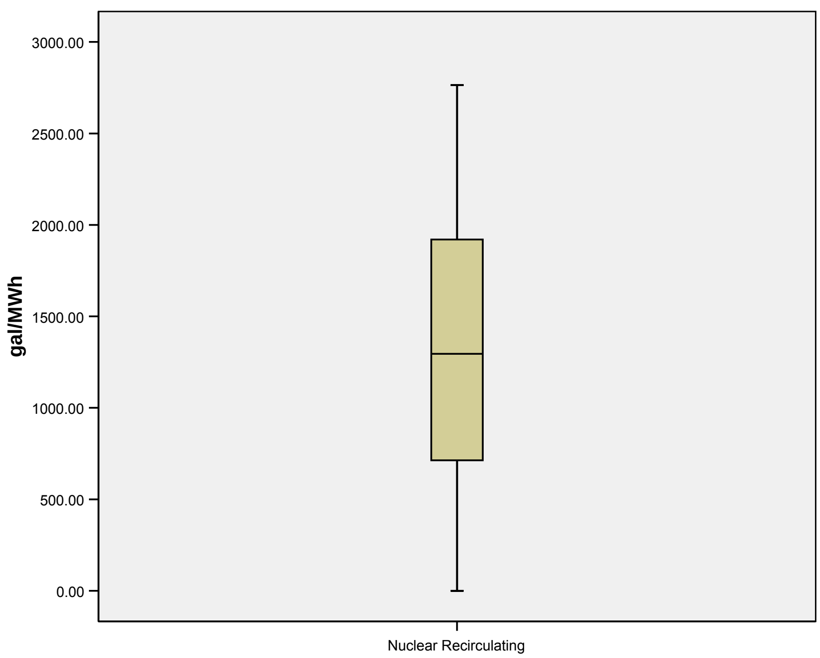


Figure F-19 – Boxplot for All Water Usage Factor Data for Nuclear Once-Through Category

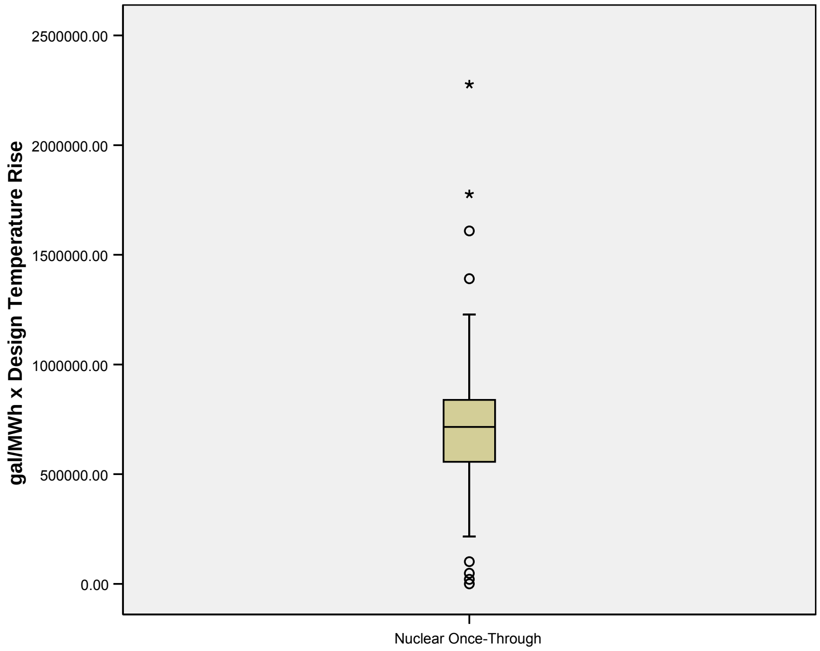
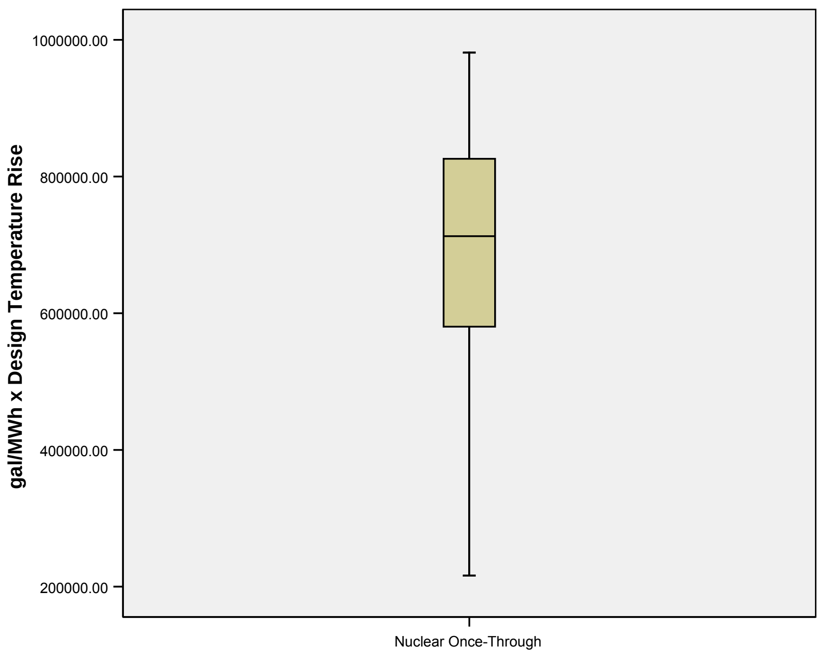


Figure F-20 - Boxplot for Water Usage Factor Data for Nuclear Once-Through Category with Outliers Eliminated



Appendix G
Carbon Capture Technologies

This appendix briefly describes the carbon capture technologies used for this analysis. Though other pre- and post-combustion carbon capture systems could be applied, such as other solvent based systems, sorbents, and membranes, the systems described below were selected because of the available data and that they are further developed compared to some of the emerging technologies. For all retrofit, new PC and new IGCC plants, a nominal 90% CO_2 capture rate is used. The captured CO_2 is dried and compressed to 2,200 psig.

PC Retrofits and New Builds with Carbon Capture

All retrofitted and new PC plants are assumed to use monoethanolamine (MEA) solvent based absorption systems to remove the CO_2 from the flue gas. This solvent based process is designed to recover high-purity CO_2 from low-pressure streams that contain oxygen. The process uses a stripping tower to recover the CO_2 from the solvent.

The additional water required for both PC retrofits and new PC plant with the solvent based carbon capture technologies is largely due to the additional cooling water requirements used for these systems. Cooling water is indirectly used to lower the temperature of the flue gas down to approximately 100°F. The water in the flue gas is condensed out and internally used within the plant. The compression and dehydration of the CO_2 is the other process that increases cooling water use. As the CO_2 is compressed, heat is generated. Intercoolers are used between compression stages to cool the CO_2 fluid. Additional cooling water within the CO_2 capture system is also used for water wash cooling, absorber intercooling, reflux condenser, reclaimer cooling, and lean solvent cooler.[16]

For the PC retrofits, it is assumed that the sulfur levels in the flue gas are acceptable for the carbon capture system. All additional cooling systems required for the retrofits will be recirculating. Makeup water for the amine system is drawn from the recycled water that is condensed from the flue gas.

New PC Builds to Make Up for Parasitic Losses (Scenario 3)

Scenario 3 introduces supercritical, pulverized coal (PC) oxy-combustion plants. The concept of PC oxy-combustion involves the combustion of coal in an enriched oxygen environment using pure oxygen diluted with recycled flue gas. In this manner, the flue gas is composed primarily of CO2 and H2O, so that a concentrated stream of CO2 is produced by simply condensing the water in the exhaust stream. An advantage of oxy-combustion over air-fired combustion is that it provides a high potential for a step-change reduction in both CO2 separation and capture costs because virtually all of the exhaust effluents can be captured and sequestered (co-sequestration).

New IGCC Plants with Carbon Capture

For this analysis, all IGCC plants with carbon capture technologies utilize a two-staged Selexol process. Untreated syngas enters the first of two absorbers where H_2S is preferentially removed using loaded solvent form the CO_2 absorber. The gas exiting the first absorber passes through the second absorber where the CO_2 is removed. Additional water used for the capture technologies is due to the increased cooling load required to further cool the syngas before entering the Selexol process and steam for the water gas shift (WGS) reactor. The WGS reactors are located before the Selexol unit and convert the carbon monoxide (CO) to CO_2. Water is required for this reaction:

$$CO + H_2O \leftrightarrow CO_2 + H_2$$

Products from the gasifier are humidified with steam or water and contain a portion of the water vapor necessary to meet the water-to-gas criteria at the reactor inlet.

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