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Water Use at Pulverized Coal Power Plants with Postcombustion Carbon Capture and Storage

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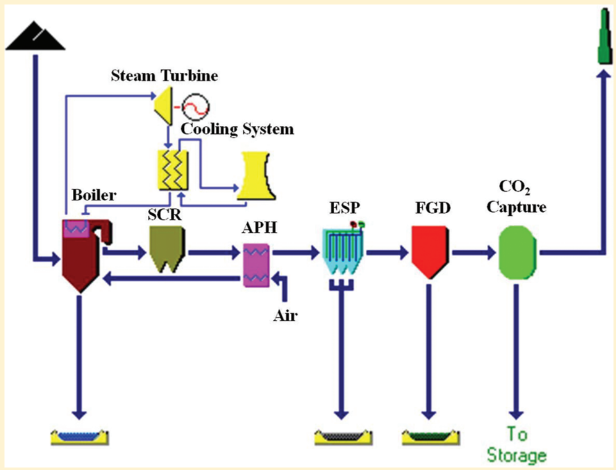
S Supporting Information

ABSTRACT: Coal-fired power plants account for nearly 50% of U.S. electricity supply and about a third of U.S. emissions of CO_2, the major greenhouse gas (GHG) associated with global climate change. Thermal power plants also account for 39% of all freshwater withdrawals in the U.S. To reduce GHG emissions from coal-fired plants, postcombustion carbon capture and storage (CCS) systems are receiving considerable attention. Current commercial amine-based capture systems require water for cooling and other operations that add to power plant water requirements. This paper characterizes and quantifies water use at coal-burning power plants with and without CCS and investigates key parameters that influence water consumption. Analytical models are presented to quantify water use for major unit operations. Case study results show that, for power plants with conventional wet cooling towers, approximately 80% of total plant water withdrawals and 86% of plant water consumption is for cooling. The addition of an amine-based CCS system would approximately double the consumptive water use of the plant. Replacing wet towers with air-cooled condensers for dry cooling would reduce plant water use by about 80% (without CCS) to about 40% (with CCS). However, the cooling system capital cost would approximately triple, although costs are highly dependent on site-specific characteristics. The potential for water use reductions with CCS is explored via sensitivity analyses of plant efficiency and other key design parameters that affect water resource management for the electric power industry.



INTRODUCTION

Coal-fired power plants currently account for nearly 50% of U.S. electricity supply, with coal-fired electricity generation nominally projected to increase by 19% over 2007 levels by 2030.[1] Significant quantities of water are needed for cooling and other purposes. The U.S. Geological Survey estimated the total quantity of water withdrawals for U.S. power plants was about 195 billion gallons per day in 2000, approximately 39% of all freshwater withdrawals, second only to agriculture.[2,3] Water use is becoming an increasingly important issue for low-carbon electricity generation. To mitigate carbon dioxide (CO_2) emissions from coal-fired power plants (which emit about a third of U.S. CO_2, the major greenhouse gas driving climate change), postcombustion carbon capture and storage (CCS) is receiving considerable attention.[4] However, in addition to the increased cost of electricity,[5−7] significant quantities of cooling water are required for current postcombustion capture systems.[8,9] Recent studies of the environmental impacts of CCS at power plants[10,11] do not include the effects on plant water use. Thus, there is a need for a more careful evaluation of water usage to better understand the impacts of carbon capture systems.

In power plants, water is used primarily for cooling and secondarily for operating environmental control systems. Wet cooling towers and once-through cooling are most widely used, accounting for 48% and 39% of cooling systems, respectively, at existing U.S coal plants.[12] The Clean Water Act (CWA) requires the use of best available technologies for new power plants to minimize the adverse environmental impacts of cooling water intake structures. This has promoted the use of closed-loop cooling systems instead of once-through systems.[13] In some areas of the U.S., limited water supplies have led to increasing deployment of new technologies such as dry cooling systems using air-cooled condensers (ACCs), the capacity of which approximately tripled between 2000 and 2004.[14]

In light of these concerns, the objectives of this paper are to (1) quantify and characterize pulverized coal (PC) power plant water use, especially in conjunction with amine-based postcombustion

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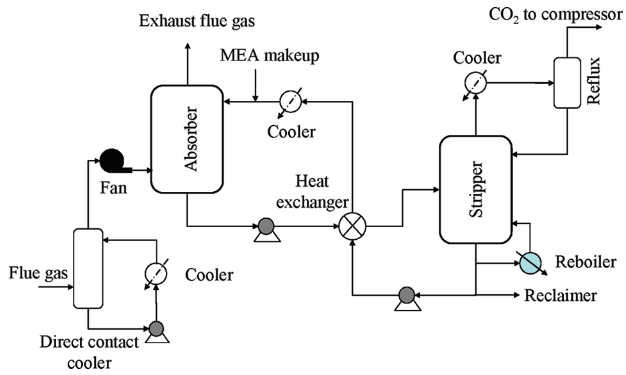

Figure 1. Schematic of an amine-based carbon capture system. Reprinted from ref 17. Copyright 2002 American Chemical Society.

carbon capture and (2) identify the effects of key factors on water use at PC power plants with CCS. The term *water use* in this paper includes both water withdrawals and water consumption. Water withdrawal refers to the total makeup of water taken from a source while consumption refers to the loss of water that is not returned to the source (mainly evaporation losses).[15] Total plant water account includes the requirements for the plant cooling system, steam cycle, and traditional environmental control systems as well as a CCS system.

OVERVIEW OF POSTCOMBUSTION CARBON CAPTURE

Amine-based postcombustion carbon capture is the leading commercial CO_2 removal system for PC power plants [16] and is typically designed to capture 75 to 90% of the flue gas CO_2.[17] As shown in Figure 1,[17] the flue gas first passes through a direct contact cooler (DCC). A lean amine-based solvent then absorbs CO_2 from the flue gas, which is then cleaned with a water wash to remove any residual ammonia. The CO_2-rich solvent is then pumped to a stripper where the CO_2 is separated by the application of heat. The concentrated CO_2 gas stream is then compressed and transported to a storage site while the solvent is returned to the absorber. Low-quality steam extracted from the steam turbine provides the heat for separating the CO_2 in the stripper, which incurs an energy penalty (efficiency loss) in the steam cycle. Cooling water is required to support the operations of the DCC, the CO_2 absorber and stripper, and the CO_2 product compression.[17−20]

WATER SYSTEM MODELS

Water system models were developed based on fundamental mass and energy balances for a PC power plant. Further details are provided in the Supporting Information and in the references cited. Here, we highlight the nature of these models.

Figure 2 illustrates the configuration and major water flows of a PC power plant with CCS. Major water-consuming units for electricity generation include the boiler, steam turbine, condenser, and wet cooling tower while major environmental control systems include the selective catalytic reduction (SCR), electrostatic precipitator (ESP), wet (limestone) flue gas desulfurization (FGD), and amine-based carbon capture systems for removing nitrogen oxides (NO_x), flyash, sulfur dioxide (SO_2), and CO_2, respectively, from the flue gas. Cooling water for the carbon capture system is provided by the primary plant cooling system unless otherwise noted.

Steam Cycle Water Use Model. In a Rankine cycle, steam produced in a boiler flows through a steam turbine driving an electric generator. Exhaust steam from the turbine condenses to liquid water in a condenser, transferring heat to the cooling water, and then is pumped back to the boiler as feedwater. To maintain boiler operations, a blowdown stream is necessary to remove dissolved salts and suspended solids that accumulate.

Water is required to make up blowdown and miscellaneous losses. The blowdown rate depends on water quality and is estimated empirically as a percent of the boiler feedwater.[21−23] Boiler makeup water is typically treated by a demineralizer to improve water quality. Makeup water requirements for the demineralizer are estimated in terms of the required boiler makeup water and the fraction of water lost in demineralizer waste.[21] The boiler feedwater flow, cooling duty, and other key parameters depend on the steam cycle efficiency, commonly expressed as a heat rate (thermal energy input per unit of electricity generated) for a given steam cycle design.

Cooling Water Requirement. Cooling water requirements are affected by the plant size, steam cycle heat rate, and cooling water temperature drop across the tower.[24] When CO_2 is captured, the heat rejected around the primary condenser does not include the steam extracted for CO_2 regeneration. The additional cooling water for the CO_2 capture system also must be taken into account. The total amount of recirculation cooling water for the PC power plant with CCS is then estimated as

$$\dot{m}_c = \frac{(Hr - 3600)\cdot MWg \cdot 1000 \cdot (1 + \eta_{aux}) - q_r^{CCS}}{c_p \cdot \Delta T_w \cdot 1000} + \dot{m}_c^{CCS} \tag{1}$$

where Hr = steam cycle heat rate (kJ/kWh) (3600 = units conversion factor), $\dot{m}_c$ = total recirculation cooling water (tonnes/h), $\dot{m}_c^{CCS}$ = cooling water used for supporting the capture system (tonnes/h), MWg = plant gross size (MWe), q_r^{CCS} = extracted steam heat for CO_2 regeneration in the reboiler (kJ/h), ΔT_w = cooling water temperature drop range (°C), η_{aux} = auxiliary cooling load (%), and c_p = water specific heat capacity (4.2 kJ/kg·°C).

Makeup Water Requirements for Wet Cooling System. In a wet cooling tower system, the condenser cooling water is cooled by contact with ambient air and then recirculated back to the condenser to cool the steam turbine exhaust. The wet tower relies mainly on the latent heat of water evaporation for transferring heat to the atmosphere. Water is used to make up evaporation, drift, and blowdown losses.[25] On the basis of the mass balances of water and impurities dissolved in the cooling water, makeup water and water losses for wet cooling systems are calculated as

$$\dot{m}_{makeup} = \dot{m}_{evap} + \dot{m}_{drift} + \dot{m}_{bd} \tag{2}$$

$$\dot{m}_{evap} = \dot{m}_a (W_2 - W_1) \tag{3}$$

$$\dot{m}_{drift} = f \cdot \dot{m}_c \tag{4}$$

$$\dot{m}_{bd} = \frac{\dot{m}_{evap}}{CC - 1} - \dot{m}_{drift} \tag{5}$$

where CC = cycles of concentration (ratio), f = fraction of cooling water lost as drift, $\dot{m}_a$ = air flow rate (tonnes/h), $\dot{m}_{makeup}$ = makeup water rate for the wet cooling system (tonnes/h),

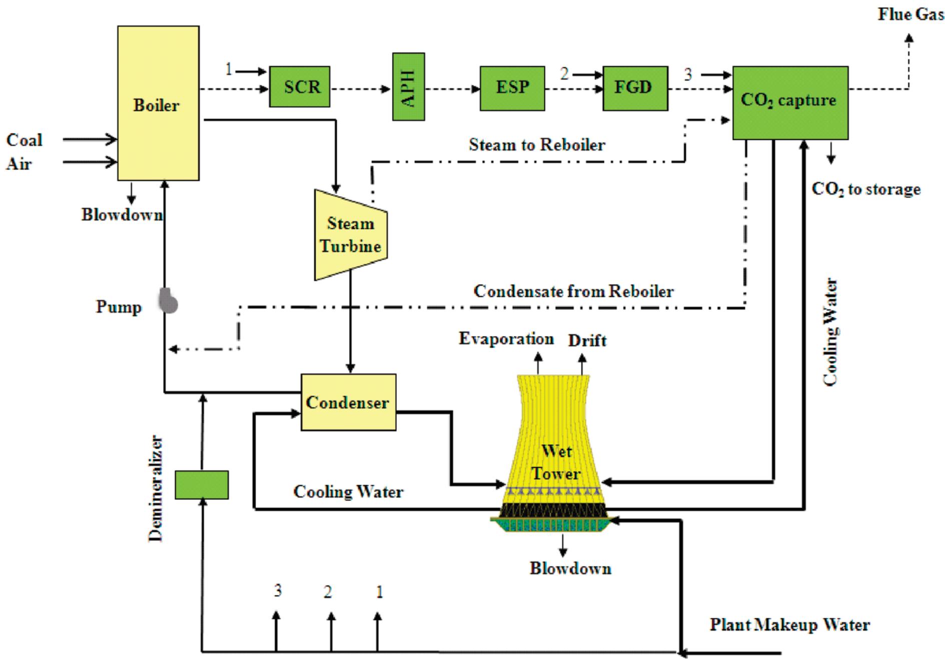

Figure 2. Schematic of an illustrative pulverized coal power plant with carbon capture (SCR = selective catalytic reduction; APH = air preheater; ESP = electrostatic precipitator device; and FGD = flue gas desulfurization). The figure shows only the major plant water and flue gas streams discussed in this paper. For simplicity, it does not show other streams such as the cooling tower air flow or solid waste streams, nor the additional fans, pumps, compressors, and other plant equipment whose energy requirements are incorporated in the power plant simulation model described in this paper. Such details can be found in the Supporting Information and in the IECM documentation.[26] See Table 4 for numerical values for the overall plant water balance.

$\dot{m}_{bd}$ = tower water blowdown rate (tonnes/h), $\dot{m}_{drift}$ = tower water drift loss rate (tonnes/h), $\dot{m}_{evap}$ = tower water evaporation rate (tonnes/h), and W_1,W_2 = absolute humidity of moist air before and after passing through the tower (grams of water vapor per gram of dry air).

The cycles of concentration reflect the allowable buildup of trace contaminants in the recirculating cooling water as water is evaporated and, thus, depend on the cooling system water quality.[25,26] The tower evaporation loss is affected by cooling water requirements and ambient air conditions.

The air thermal state change across the wet tower is modeled based on steady-state energy and mass balances for the counterflow cooling tower. The thermal state of the moist air passing through the tower is described in eq 6,[27−29] which is used to determine W_2, the air humidity exiting the tower (see Supporting Information for details):

$$\frac{dh}{dW} = Le\frac{(h_{s,w} - h)}{(W_{s,w} - W)} + (h_{g,w} - 456Le) \qquad (6)$$

where h = enthalpy of moist air (kJ/kg), $h_{s,w}$ = enthalpy of saturated moist air at the temperature of water (kJ/kg), $h_{g,w}$ = specific enthalpy of saturated water vapor at the temperature of water (kJ/kg), Le = Lewis number (dimensionless), W = humidity of moist air (grams of water vapor per gram of dry air), and $W_{s,w}$ = humidity of saturated moist air at water temperature (grams of water vapor per gram of dry air).

Dry Cooling System Model. Dry cooling systems employing ACCs utilize the sensible heating of atmospheric air passed across finned-tube heat exchangers to reject waste heat.[30] ACCs condense exhaust steam from the steam turbine and return condensate to the boiler as feedwater. There is no cooling water required for dry cooling systems. Detailed performance models and evaluation for dry cooling systems are presented in the Supporting Information.

Air Pollution Control System Water Use Model. Water is also used in major air pollution control systems. Bottom ash from the boiler is disposed in an ash pond with an overflow that is recirculated to sluice ash.[21] Flyash from the ESP is separately disposed using a dry system. Blowdown from a wet tower is assumed to be recycled and used as makeup water for ash sluicing.[21] Thus, no fresh makeup water is used for sluicing ash. When an SCR system is used, ash and other deposits are periodically removed by water washing.[21,24]

In a wet FGD system, makeup water is required primarily to offset evaporative losses in the scrubber.[24] These losses are estimated from an energy balance in which the sensible energy released by the flue gas entering the scrubber equals the energy needed to evaporate the water.[24]

When an amine-based CO_2 capture system is added, water is required to make up process losses.[31] Makeup water due to evaporation losses is also estimated based on an energy balance as above. Makeup water requirements for flue gas washing after the absorber are empirically estimated as a percent of flue gases entering the absorber.[19,20] There are additional water requirements for the capture process, such as for sorbent dilution.[31] The detailed performance models for each environmental control system discussed in this paper are available elsewhere.[17,21,24,26,31,32]

INTEGRATED ENVIRONMENTAL CONTROL MODEL FRAMEWORK

The water system models outlined above have been embedded in the Integrated Environmental Control Model (IECM) developed by Carnegie Mellon University for the U.S. Department

Table 1. Design Assumptions and Parameters for Baseline Power Plants and Associated Environmental Controls

Parameter	Value
Technical parameters	
Net plant output (MW)	550.0
Boiler type	Supercritical[a]
Steam cycle heat rate (w/o CCS) (kJ/kWh)	7764[a]
Ambient air pressure (kPa)	101.35
Ambient air temperature (°C)	15
Ambient relative humidity (%)	50
Coal type	Illinois #6
Boiler blowdown rate (% of feedwater)[b]	6.0
Miscellaneous steam losses (% of steam)[c]	0.4
Demineralizer underflow (% of input water)[c]	8.5
Cooling system	
Cooling technology	Wet tower, forced draft[d]
Cooling water temperature drop range (°C)	11.1
Cycle of concentration[e]	4
Drift loss (% of cooling water)[f]	0.001
Auxiliary cooling duty (% of primary cooling)[c]	1.4
Environmental controls[g]	
NO_x control	SCR
Particulates control	ESP
SO_2 control	Wet FGD
CO_2 capture (if applicable)	Econamine FG+
Economic/financial parameters	
Cost year	2009
Plant capacity factor (%)	75
Fixed charge factor	0.15
Plant lifetime (years)	30
Labor cost ($/h)	33.0
Water cost ($/m^3)	0.26
Coal cost ($/tonne) (as-fired)	46.3

[a] Steam conditions are 24.1 MPa/593 °C/593 °C for the throttle pressure/throttle temperature/reheat outlet temperature.[9] [b] The boiler blowdown rate typically ranges from 4% to 8% of boiler feedwater but can be as high as 10% or even more.[22,23] [c] Source of data: ref 21. [d] Cooling system power requirement is approximately 7.4 MW without carbon capture and storage (CCS) and 19.2 MW with CCS. See refs 25, 26, and 33 for further details of the cooling system design. [e] Cycles of concentration are defined as the concentration ratio of pollutants dissolved in the recirculating cooling water versus makeup water.[25,26] [f] The drift loss is a relatively small amount of entrained water lost as fine droplets in the air discharge from a tower.[25] [g] Detailed performance parameters are presented in the Supporting Information section. SCR = selective catalytic reduction; ESP = electrostatic precipitator device; and FGD = flue gas desulfurization.

Table 2. Detailed Performance Parameters of Amine-based Capture System

Parameter	Value
Amine-based capture system type	Econamine FG+
CO_2 removal efficiency (%)	90.0
Sorbent concentration (wt, %)	30.0
Temperature exiting direct contact cooler (°C)	45
Maximum train CO_2 capacity (tonnes/h)	209
Max CO_2 compressor capacity (tonnes/h)	299
Lean CO_2 loading (mol CO_2/mol sorbent)	0.19
Nominal sorbent loss (kg/tonne CO_2)	0.30
Liquid-to-gas ratio	3.0
Ammonia generation (mol NH_3/mol sorbent)	1.0
Gas phase pressure drop (kPa)	6.9
Solvent pumping head (kPa)	206.8
Pump efficiency (%)	75
Heat-to-electricity efficiency (%)	22
Makeup water for washing (% of flue gases)	0.8 [a]
Regeneration heat requirement (kJ/kg CO_2)	3517
Capture system cooling duty (tonnes H_2O/tonne CO_2)	91.2[a]

[a] The makeup wash water and cooling duty factor for the capture process are estimated on the basis of the detailed process simulation results.[19,20] On the basis of an energy balance, the cooling duty factor was adjusted from the reported water temperature of seawater cooling (for the case study plant in the data source) to the temperature for freshwater cooling assumed in this study.

Table 3. Performance and Cost Results of Supercritical Power Plants With and Without Carbon Capture

Performance and cost measure	Carbon capture without	Carbon capture with
Gross power output (MW)	590	685
Net plant efficiency, HHV (%)	38.3	26.4
Net plant heat rate, HHV (kJ/kWh)	9410	13650
Coal flow rate (tonnes/h)	190.7	276.6
NO_x flue gas into SCR (tonnes/h)	0.96	1.39
SO_2 flue gas into FGD (tonnes/h)	9.2	13.2
CO_2 flue gas out of FGD (tonnes/h)	450.9	655
CO_2 captured product (tonnes/h)	n/a	590
Monoethanolamine (MEA) sorbent makeup (kg/h)	n/a	59.8
Cooling water requirement (tonnes/h)	53530	100200
Plant water withdrawals (tonnes/h)[a,b]	1318	2405
Plant water consumption (tonnes/h)[a,b]	925	1694
Plant total capital requirement (2009 US $/kWnet)	1846	3244
Plant revenue required (2009 US $/MWh)	69.3	121.2

[a] This includes the amount of water used for the cooling system, steam cycle, and traditional environmental controls, as well as the CO_2 capture system. [b] The difference between water withdrawal and consumption is the blowdown and other wastewater streams that are discharged back to the source after treatment.

of Energy's National Energy Technology Laboratory (USDOE/NETL). The IECM is a publicly available model that provides systematic estimates of performance, emissions, cost, and uncertainty for the preliminary design of fossil-fueled power plants with and without CCS.[26] To account for many factors that affect power plant water requirements, the 2010 release of IECM (Version 6.2.4) was employed for this paper.

■ CASE STUDY RESULTS

Case studies were conducted for illustrative supercritical PC plants (typical of new construction) with and without CCS. Table 1 gives the plant configuration and key design, economic, and financial assumptions. Performance parameters of the amine-based capture system are given in Table 2. The parameter values in Tables 1 and 2, together with calculated IECM results (for quantities such as the steam requirement for sorbent

Table 4. Water Use and Distribution at Supercritical Power Plants With and Without Carbon Capture

	Without carbon capture				With carbon capture			
	Water withdrawals		Water consumption		Water withdrawals		Water consumption	
Operation Unit	(Liters/MWh)	(%)	(Liters/MWh)	(%)	(Liters/MWh)	(%)	(Liters/MWh)	(%)
Boiler	230.9	9.6	0	0.0	333.1	7.6	0	0.0
SCR	3.8	0.1	0	0.0	3.8	0.1	0	0.0
FGD	234.7	9.8	234.7	14.0	340.7	7.8	340.7	11.1
Carbon capture system	0	0.0	0	0.0	83.3	1.9	30.3	0.9
Cooling system[a]								
steam cycle cooling	1930.6	80.5	1449.8	86.0	1676.9	38.3	1260.5	40.9
carbon capture cooling	0	0.0	0	0.0	1938.1	44.3	1453.5	47.1
Total plant water use	2400.0	100.0	1684.5[b]	100.0	4379.9	100.0	3085.0[b]	100.0

[a] The cooling system provides cooling water for the steam cycle and the amine-based capture system at the plant with carbon capture. [b] The difference between this value and the total withdrawal represents the total plant discharge back to the water source. Numerically, it is the sum of the difference between withdrawal and consumption for each of the listed Operation Units.

regeneration in the capture system reboiler), provide all required input parameter values for the water system model summarized in eqs 1−6. All cases are evaluated on a basis of 550 MW net power output. All costs are in constant 2009 US dollars.

Effect of CCS on Plant Performance. We first use the IECM to model a baseline plant without carbon capture and then a plant with CCS. Table 3 summarizes key plant performance and cost results for both cases. The baseline plant has a gross power output of 590 MW and a levelized cost of electricity (LCOE) of \$69.3/MWh (based on net power output). For the case with CCS, the gross plant size required to produce 550 MW net is 16% larger than the base case. The captured CO_2 rate is 590 tonnes per hour, and the solvent regeneration heat required from the steam turbine is approximately 3500 kJ/kg CO_2 product. This increases the steam cycle heat rate by 25% compared to the baseline plant. As a result of the sizable energy requirements for CO_2 capture (i.e., steam extraction from the power cycle for sorbent regeneration, plus electricity to power fans, pumps, and compressors), the addition of an amine-based CCS system decreases the net plant efficiency from 38.3% to 26.4% (based on higher heating value, HHV) and increases the LCOE by 75%.

Effect of CCS on Plant Water Use. Table 4 summarizes results for plant water use. The total water withdrawals and consumption for the baseline plant without CCS are 2400 and 1685 L/MWh, respectively. Most water is for the cooling system, which accounts for approximately 80% of total water withdrawals and 86% of total water consumption. Makeup for the wet cooling tower is found to be 2% of the recirculation cooling water for the given ambient air conditions. Evaporation accounts for 75% of tower losses, blowdown for 25%, and drift losses for less than 1% of total tower losses.

On the basis of IECM parameters, the boiler and FGD system each account for approximately 10% of total water withdrawals. The wet FGD system also accounts for approximately 14% of total water consumption due to evaporation losses. Wash water for the SCR system is less than 1% of the total.

As also seen in Table 4, total plant water use increases by more than 80% when the amine-based capture system is added. The capture system requires 91.2 tonnes of cooling water per tonne of CO_2 product, accounting for 54% of total cooling water in the plant with CCS. Other capture system water use adds approximately 2% to total water withdrawals and 1% to total consumption. Addition of the capture system also increases water requirements for boiler water makeup and air pollution control systems to maintain net plant output at reduced efficiency.

To illustrate the effects of uncertainty or variability in key parameters associated with plant water use, an uncertainty analysis also was conducted for the plant with CCS using the probabilistic capability of the IECM. Details of the assumed uncertainty distributions and the probabilistic results for total water use are given in the Supporting Information. The resulting distributions for total water use have a 95-percentile confidence range of 2120−3100 tonnes/h for plant water withdrawals and 1528−2230 tonnes/h for plant water consumption. The variability in capture system water requirements was the dominant factor in this analysis.

EFFECTS OF ALTERNATIVE PLANT TYPES

Analyses also were conducted to investigate the effects of two major plant design factors: the PC boiler type and the cooling system technology, specifically, wet versus dry cooling for the primary steam condenser. In each case, other factors were kept at the base case values in Table 1 unless otherwise noted.

Effects of Boiler and Steam Cycle Design. Our base case plant employed a supercritical boiler since such systems are typically less costly than subcritical boilers when CCS is employed.[4] Nonetheless, subcritical units are the dominant power plant technology today. Thus, the effects on water use were evaluated for subcritical units with CCS as well as for ultrasupercritical (USC) plants whose efficiency exceeds that of our base case plant. The net plant efficiencies with CCS are 24.0% and 30.3% (HHV) for the subcritical and USC plants, respectively, compared to 26.4% for the base case plant. For the same net power output, the subcritical and USC plants have 14% higher and 19% lower cooling duty, respectively, than the base case plant due to differences in net efficiency. Figure 3 shows the pronounced effects on total water use with CCS. Compared to the base case, the subcritical and USC plants require 13% more and 18% less total makeup water, respectively. Put another way, relevant to prevailing subcritical designs, supercritical and USC designs with CCS reduce total water use by 12% and 28%, respectively. Note that improvements in net plant efficiency achieved through reductions in the CCS energy requirements also will result in reduced water consumption.

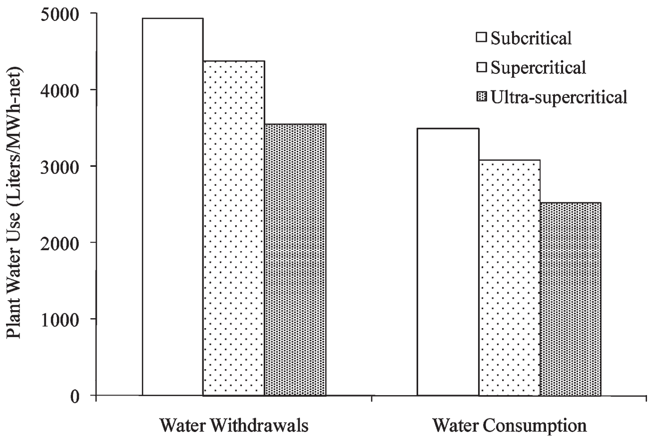

Figure 3. Effects of boiler type on total plant water use at the pulverized coal power plants with carbon capture and storage.

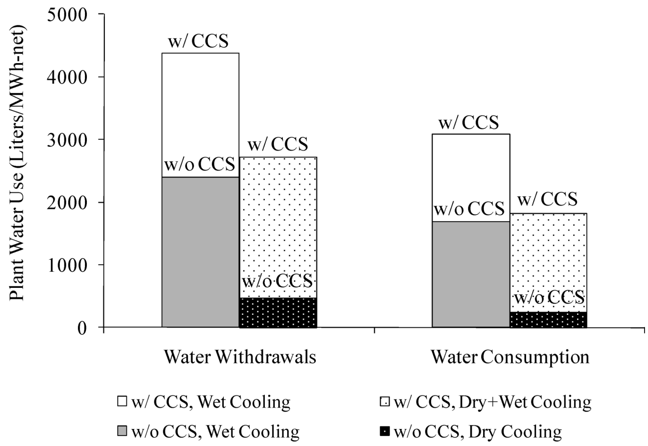

Figure 4. Effects of primary cooling technology on plant water use at the supercritical pulverized coal power plants with and without carbon capture and storage (CCS). (It is assumed that a wet tower is used as the auxiliary cooling for supporting the capture process when the primary cooling system at the plant with carbon capture uses air-cooled condensers for dry cooling. The steam turbine backpressure is two inches mercury when the dry cooling system is used.)

Effects of Wet versus Dry Cooling Technology. We also investigated the water use impact of a dry cooling system using ACCs. A key performance parameter for ACCs is the initial temperature difference (ITD) between the inlet condensing exhaust steam and the ambient air temperature,[14,18,33] assumed here to be 22.8 °C. Figure 4 shows the resulting plant water use for the base case supercritical plants with and without CCS. Without CCS, replacing wet cooling towers with ACCs decreases total plant water withdrawals by 80% and total plant consumption by 86% since no cooling water is needed. However, the capital cost of the dry cooling system is approximately three times that of the wet tower system. This cost is sensitive to the ITD, which strongly affects the ACC size and hence the capital cost of the dry system [18] (see Supporting Information for details).

When a CO_2 capture system is added to a plant with ACCs, there is no longer cooling water available from the primary (dry) cooling system. Here, we assume that a wet cooling tower system is used to meet the capture unit cooling demands. Figure 4 shows that this hybrid (dry plus wet) system reduces plant water withdrawals by 38% and plant water consumption by 41%, relative to the PC-CCS plant with all wet cooling.

On an absolute basis, Figure 4 shows that total plant water use for the CCS plant with a hybrid dry—wet cooling system is comparable to that of the base case plant without carbon capture (using a wet tower system). Thus, to further reduce water use, an alternative cooling system that does not require water is needed for the CCS technology.

■ DISCUSSION

The addition of a commercially available amine-based CCS system to a PC power plant has profound effects not only on plant performance and cost but also on plant water use. Power plants already are the second largest source of freshwater withdrawals in the United States and widespread adoption of current CCS technologies could further exacerbate that problem.

The largest source of water loss at power plants is the evaporation loss from wet cooling towers employed in cooling the steam used for power generation. The addition of an amine-based carbon capture system approximately doubles the cooling water requirements and losses using a wet tower system. Consumptive water use varies by location and season due to changes in ambient temperature and other factors. For example, makeup water requirements for wet cooling tower systems increase by more than ten percent when the ambient temperature changes from 15 to 25 °C.[18]

The choice of cooling system technology can significantly affect power plant water use. Dry cooling systems such as the ACCs now used in some locations can significantly reduce water use at PC power plants, albeit at a much higher cost. For a power plant with dry cooling, the addition of CCS could require a large-scale auxiliary wet cooling system to support the carbon capture unit. Alternatively, other types of cooling or refrigeration systems that do not require water would have to be designed for postcombustion CCS applications to reduce pressure on water resources.[18]

Currently, compliance with the Clean Water Act promotes the use of wet cooling towers at new power plants. The growth of low-carbon electricity generation with amine-based capture systems would accelerate consumptive water use by power plants. Thus, there is a need for careful coordination of energy, climate change, and water resource policies. In this content, it is important to improve water use efficiency and reduce the water footprint of power plants with and without CCS.

The strategies we recommend include improving overall plant thermal efficiency, especially at new plants, through use of supercritical boilers; recycling or reusing plant water; promoting the deployment of advanced cooling technologies; and seeking alternative water sources. Improved water management also includes improving makeup water quality to reduce boiler and cooling tower blowdown losses. For example, increasing the cooling tower cycles of concentration from four to five in the case study plant decreases blowdown by 25%. Improved energy integration of process streams also can reduce cooling water requirements and use, such as by better integration of the steam cycle and CO_2 capture system. Recovering heat from the heated cooling water in wet cooling systems also would reduce tower evaporation losses and decrease water use. More generally, lowering plant water use needs to be explicitly considered in R&D programs for advanced carbon capture technologies for PC power plants.

■ ASSOCIATED CONTENT

S Supporting Information. Texts, tables, and figures regarding current plant water use; steam flow and boiler makeup water estimation; model formulation of thermal state of air through wet cooling tower; coal properties; performance parameters of traditional environmental control systems; uncertainty analysis of plant water use; cost estimates of wet cooling towers; and performance and cost of air-cooled condensers. This material is available free of charge via the Internet at http://pubs.acs.org.

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