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Dry cooling retrofits at existing fossil fuel-fired power plants in a water-stressed region: Tradeoffs in water savings, cost, and capacity shortfalls

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HIGHLIGHTS

- Dry cooling retrofits substantially reduce or eliminate the plant water consumption.
- Dry cooling retrofits can reduce the monthly net capacity of existing plants.
- The largest capacity losses from dry cooling deployment happen in summer months.
- The cost of water savings by dry cooling varies with plant characteristics.

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ABSTRACT

This study investigates the performance, cost, and generating capacity impacts of switching from wet cooling towers to dry cooling systems to reduce the consumptive water use at existing fossil fuel-fired power plants in a water-stressed region. Retrofit analysis of dry cooling is conducted on a unit-by-unit basis for both coal-fired and gas-fired power plants. Unit-level results are then aggregated to the regional level. Based on regional averages, retrofitting dry cooling systems in lieu of wet cooling towers decreases total annual plant water consumption at existing coal- and gas-fired power plants by 93% and 100%, respectively, while increasing the levelized cost of electricity generation by approximately 12% and 18%, respectively. Based on a nominal regional water price, this cost increase corresponds to an average cost of consumptive water savings of $2.5 and $5.9 per cubic meter of water saved at coal and gas plants, respectively, if retrofit difficulty is minimal. Over the course of a year, the change in monthly net regional generating capacity from dry cooling retrofits exhibits a seasonal pattern, with the largest shortfalls occurring in July. The average monthly reduction in net capacity is estimated at 0.7% and 1.2% of the regional nameplate capacity for coal- and gas-based plants, respectively. Dry cooling retrofits thus lead to tradeoffs in water savings, cost, and capacity shortfalls, which vary with power plant characteristics. The tradeoffs identified here can fill existing knowledge gaps to better inform electric power industry water management policies, planning, and decision-making in water-stressed regions.

1. Introduction

Operation of the thermoelectric power plants that provide most of our electricity requires a reliable supply of water, primarily for cooling. Thus, power plants are one of the largest sources of freshwater withdrawals in the U.S. [1]. They are also a major source of water consumption, as Clean Water Act regulations have led to a shift from once-through cooling systems to recirculating wet cooling towers—a shift that significantly reduced water withdrawals, but increased water consumption by evaporation in cooling towers [1,2]. In the U.S., most

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new thermal plants, and more than 61% of current thermoelectric generating capacity, now use closed-loop wet cooling systems, mainly recirculating cooling tower systems [3]. The consumptive loss of water in cooling systems is of particular concern for thermal power plants in arid regions of the country that face increasing pressure from water demands in other sectors, and the potential for climate change to exacerbate future problems. Increasing water stress already has driven some states in the western and southern U.S., such as California and Texas, to restrict freshwater use for power plant cooling, especially during dry seasons [4]. Limited water resources and drought events can significantly affect the ability to meet regional power demands, increase system-wide operation costs, and constrain future capacity expansion in the electric power sector [4–7]. This paper addresses the pressing situation of how fossil fuel power plants can continue to operate in a water-constrained region in which the cooling water supply is limited or unavailable.

This paper addresses a critical gap in current knowledge to address this problem, namely the lack of a comprehensive understanding at the regional level of the potential water savings benefits and resulting economic costs and generating capacity losses, of adopting dry cooling technology in lieu of the wet cooling systems currently in use. A quantitative understanding of the variability of these factors across a fleet of generating units is another important contribution sought in this paper.

Wet cooling towers are the largest source of water consumption at thermoelectric power plants [1]. To overcome potential water constraints on thermoelectric power generation in arid regions, air-cooled condensers (ACCs) for dry cooling can be employed to significantly reduce plant freshwater use to conserve water resources. ACCs utilize the sensible heating of air passed across finned-tube heat exchangers to reject the exhaust steam heat directly to the atmosphere, instead of to a cooling water stream [1]. Thus, dry cooling deployment in lieu of existing wet cooling towers eliminates consumptive water use for cooling. However, dry cooling systems are a capital-intensive investment compared to wet cooling towers [8]. Dry cooling may also impose a larger parasitic load than wet cooling towers [9], reducing the net capacity available to the power grid. Thus, systems research is needed to understand the tradeoffs associated with dry cooling with respect to water savings, energy penalty, and cost in order to promote efficient water use and energy production.

Past studies of the performance and cost of a dry cooling system at a new or existing thermoelectric power plant have been limited in scope and do not reflect recent technological changes that significantly affect costs. For example, one recent study (published in 2016) estimated the marginal cost of water savings from dry cooling based on technology that was in use more than a decade ago [10]; however, modern systems are significantly improved and less costly [9]. Nor have past studies considered the seasonal effects of dry cooling on power generation capacity [8,9,11]. That knowledge gap can have a significant impact on system planning and reliability, since capacity losses in the hottest summer months are likely to be much larger than the annual average. Although dry cooling systems have been included in some capacity expansion planning studies as a water reduction option, few studies have considered the associated reductions in power generating capacity [12,13]. In addition, unit commitment and dispatch modeling for power generation systems also commonly ignore such performance penalties from dry cooling deployment [14,15]. However, without careful attention to the full impact of local climate conditions and water-related technology parameters on the performance of individual power plants, including seasonal impacts and the variability of power plant characteristics, regional energy systems may be vulnerable, especially in arid regions [16,17]. This paper seeks to fill these important knowledge gaps to improve planning and policy responses in water-stressed regions.

While it is known theoretically that the effectiveness of dry cooling systems is reduced with increasing dry bulb temperature, other studies typically compare dry cooling performance to wet cooled systems only for a specific set of ambient conditions. In order to fully quantify the water-saving benefit of dry cooling relative to wet systems, one must consider how performance changes over the course of a year in response to changing ambient conditions. Although dry cooling systems eliminate water consumption, cooling effectiveness relative to wet-cooled systems will be substantially reduced during hot summer months. This results in a net reduction of megawatt-hours produced at a time when demand for electricity for air conditioning is also highest. Thus, broad deployment of dry cooling systems to reduce water consumption could inadvertently result in significant reductions in net power generation, requiring construction of new generating capacity.

This analysis, therefore, considers multiple factors associated with deployment of dry cooling systems at fossil fuel power plants, including installed cost, reduction in water consumption, and the impact that seasonal changes in ambient conditions have on power plant performance. This analysis explores these impacts via detailed case studies at 26 electric generating units (over 12 GW of fossil fuel-fired capacity) in an arid western U.S. region where dry cooling retrofits could be most needed (and where high summer temperatures could have a particularly negative performance impact). The collective performance of this dry-cooled capacity is examined over the course of a calendar year to account for seasonal changes in ambient conditions compared to the same wet-cooled capacity.

The major objectives of this study, therefore, are to (1) investigate the water-use reduction benefit of current dry cooling technology if deployed at existing fossil fuel-fired power plants using wet cooling towers, including both pulverized coal (PC) and natural gas combined cycle (NGCC) power plants; (2) evaluate the cost-effectiveness of dry cooling retrofits; and (3) quantify potential annual and seasonal shortfalls in net generating capacity from dry cooling deployment in a water-stressed region. Toward this end, case studies are conducted of dry cooling retrofits at existing electric generating units (EGUs) with wet cooling towers in a water-stressed region of the western U.S. states. The study seeks to identify the tradeoffs among multiple impacts and the implications for operating EGUs with dry cooling, especially during periods of hot weather. This new research can be used to better inform water management decisions and policies for the electric power sector in a water-stressed region.

2. Methods and materials

This study develops analytical performance and cost models of current dry cooling technology based on a recently completed study by the National Energy Technology Laboratory (NETL) (in 2018) [9]. These models have been incorporated as new options in the Integrated Environmental Control Model (IECM), a power plant modeling tool developed by Carnegie Mellon University [18].

The enhanced IECM is then applied to configure and model existing EGUs with wet cooling towers using major unit-specific attributes and local ambient air conditions. Analyses are conducted on both annual average and monthly average bases. The IECM is further applied to model the same EGUs retrofitted with dry cooling systems. In addition to plant performance and water consumption impacts, the IECM estimates the capital and operating costs of the dry cooling systems as well as the added unit-level cost of electricity generation. In this study, we assume the same capital cost for both new and retrofit applications at these western plant locations. From this baseline cost, we later estimate the impact of higher retrofit costs due to site-specific difficulties such as space constraints or other factors. The enhanced IECM can also be applied for retrofit analysis in other states or regions when unit attributes and ambient conditions are specified by location.

To evaluate the cost-effectiveness of dry cooling retrofits, the annual average cost of water savings is estimated based on the unit-level water consumption intensity and added cost of electricity generation. To evaluate potential plant deratings from dry cooling deployment, including seasonal variations, the enhanced IECM is used to model the changes in unit performance based on operating conditions and ambient air conditions on a monthly basis.

2.1. Power plant and climate databases

This study acquired data on the major attributes and operating conditions of existing U.S. fossil fuel-fired EGUs from several power plant databases, including ABB Ability™ Velocity Suite, the National Electric Energy Data System (NEEDS), and the Energy Information Administration (EIA) Survey Forms 860 and 923 [19–22]. NEEDS, EIA Form 860, and Velocity Suite report on plant name, identification number, location, unit type, online year, nameplate capacity, and flue gas desulfurization (FGD) type and removal efficiency, as well as environmental controls for nitrogen oxides (NOx), particulate matter, and mercury. EIA Form 923 reports the type of cooling technology. Velocity Suite also reports hourly gross and net electricity generation and fuel consumption, which were used to estimate the gross and net heat rates on monthly and annual bases. The steam cycle heat rate of existing coal-fired EGUs, which is needed to estimate the cooling duty, was further estimated based on gross heat rate and boiler efficiency [1], while the steam cycle heat rate of existing NGCC units was estimated using an adjustment function based on the net heat rate, which is discussed later. For coal-fired EGUs, boiler efficiency is calculated using existing IECM algorithms. Information on fuel properties and prices is also available from Velocity Suite, supplemented with EIA Form 923. Capacity factor was estimated based on nameplate capacity and annual electricity generation.

In addition, this study acquired hourly ambient air conditions from the National Climatic Data Center for the meteorological stations closest to each of the power plants that were modeled, or the meteorological stations referenced by power plants. Local climate data included the air dry-bulb temperature, relative humidity, and ambient air pressure [23]. Tables S1 and S2 of the Supplementary Information (SI) summarize the climate monitoring stations for the coal- and gas-fired power plants that were modeled, respectively.

2.2. Case study power plants

To assess the impacts of dry cooling retrofits on fossil fuel-fired power plants, this study analyzed 12 coal-fired EGUs at six power plants in Arizona and New Mexico, plus 14 EGUs operating at 12 NGCC power plants in Arizona, New Mexico, and Colorado. All of these units currently use wet cooling towers. The 12 coal-fired EGUs have a combined nameplate capacity of about 4700 megawatts gross (MWg), while the 14 NGCC units have a combined nameplate capacity of about 7500 MWg. Tables 1 and 2 respectively summarize the major attributes of the selected coal- and gas-fired EGUs and their ambient air conditions on an annual average basis for the year 2017. Coal properties and prices are provided in SI Table S3, while natural gas prices are provided in SI Table S4.

Table 1 shows that the unit attributes vary significantly across the 12 coal-fired units, which vary in age by up to 30 years. For the coal-fired EGUs, the nameplate capacities range from 257 to 555 MW, while the net heat rates range from 9654 to 13,215 kJ/kWh. While all coal-fired EGUs are equipped with FGD systems, eight units use wet FGD while four use dry FGD systems. This is significant because wet FGD systems are a major consumer of water while dry systems are not [1]. In terms of key climate variables, the annual average air dry-bulb temperature at the six coal-fired power plants ranges from 10.8 to 18.2 °C and the relative humidity ranges from 39 to 48%.

As shown in Table 2, the unit attributes also vary significantly across the 14 NGCC units. For the NGCC units, the nameplate capacities range from 136 to 685 MW, while the net heat rates range from 7415 to 8977 kJ/kWh. The annual average air dry-bulb temperature at the 14 gas-fired power plants ranges from 10.8 to 25.5 °C and the relative humidity ranges from 31 to 53%.

2.3. Analytical performance and cost models of dry cooling systems

The recent NETL study examined the technical and economic effects of current dry cooling systems on new fossil fuel-fired power plants under varying climate conditions based on current performance and cost estimates using data and information from vendors and users of the technology, design/build utility projects, best engineering judgment, relevant NETL studies, and published reports [9]. Based on this study, analytical models of dry cooling were derived using linear and nonlinear regressions for the design and off-design cases of coal- and gas-fired power plants in the NETL study. These models were then used to estimate capital costs and the dependency of dry cooling system performance parameters on ambient air conditions [9,24].

The resulting performance model of dry cooling systems can account for several major relationships: turbine backpressure as a function of air dry-bulb temperature; steam cycle heat rate as a function of turbine backpressure; exhaust steam temperature as a function of turbine backpressure; and dry cooling system parasitic load as a function of the initial temperature difference (ITD) between the turbine exhaust steam and ambient air. ITD is a critical parameter affecting the dry cooling system performance and cost [8].

The NETL capital cost estimates for dry cooling systems under the designated conditions were used to update the previously-developed IECM cost model, which was based on data published in 2005 [8]. The more recent NETL data indicated a significant decrease in the capital cost of dry cooling systems since the early 2000s [24]. Details of the analytical models are available in a research report [24] and are also briefly summarized in section S2 of the SI.

Table 1
Existing coal-fired EGUs with wet cooling towers.

State	New Mexico			Arizona								
Plant study ID	NM1	NM2		AZ1		AZ2	AZ3		AZ4			
Unit study ID	1	2	3	4	5	6	7	8	9	10	11	12
Online year	1984	1982	1982	1980	1981	1979	1979	1980	1985	1990	2006	2009
Nameplate capacity (MWg [a])	257	369.0	555.0	312.3	414.0	204	410.9	410.9	424.8	424.8	458.1	458.1
Capacity factor (%)	52.7	76.8	78.9	51.8	59.6	58.0	61.5	61.7	47.4	74.3	68.2	57.0
Net heat rate (kJ/kWh)	11,331	11,850	12,290	13,215	12,448	11,777	11,935	12,246	9949	9654	10,504	10,541
Net generation (billion kWh/year)	1.102	2.288	3.612	1.307	2.037	0.9637	2.085	2.093	1.662	2.607	2.578	2.156
Air dry-bulb temp. (°C)	10.8	12.1	12.1	14.8	14.8	18.2	13.7	13.7	13.7	13.7	13.7	13.7
Relative humidity (%)	47.6	46.5	46.5	39.3	39.3	39.6	41.1	41.1	41.1	41.1	41.1	41.1
Air pollution controls												
NOx (in-furnace)	√	√	√	√	√	√	√	√	√	√	√	√
NOx (post-combustion)	None	√	√	none	none	√	√	√	none	none	√	√
Mercury	√	√	√	√	√	√	√	√	none	none	√	√
Particulate matter	√	√	√	√	√	√	√	√	none	none	√	√
SO_2 (FGD)	Wet	Wet	Wet	Wet	Wet	Wet	Wet	Wet	Dry	Dry	Dry	Dry

[a] MWg represents the gross power output in megawatts.

Table 2
Existing NGCC units with wet cooling towers.

State	Arizona											New Mexico	Colorado	
Plant study ID	AZ1		AZ2	AZ3		AZ4	AZ5	AZ6	AZ7	AZ8	AZ9	NM1	CO1	CO2
Unit study ID	1	2	3	4	5	6	7	8	9	10	11	12	13	14
Online year	2001	2003	2002	2005	2006	2002	2001	2004	2002	2003	2003	2006	2015	2004
Nameplate capacity (MWg [a])	135.6	570	292	622.1	290.2	654.2	646.3	441.6	573.1	691.5	619	650.3	624.8	684.7
Capacity factor (%)	21.0	44.5	40.5	43.1	42.0	35.0	19.4	13.7	43.0	33.9	44.8	45.3	57.2	35.7
Net heat rate (kJ/kWh)	8977	8508	7821	7767	7870	7715	8465	7666	7854	7724	7485	7415	8807	8074
Net generation (billion kWh/year)	0.222	2.026	1.009	2.307	1.049	1.957	1.037	0.5196	2.079	2.015	2.388	2.536	3.08	1.996
Air dry-bulb temp. (°C)	25.5	25.5	25.5	25.5	25.5	18.1	25.5	25.5	25.5	25.5	25.5	17.5	10.8	10.8
Relative humidity (%)	31.2	31.2	31.2	31.2	31.2	33.2	31.2	31.2	31.2	31.2	31.2	41.3	52.6	52.6

[a] MWg represents the gross power output in megawatts.

2.4. *Integrated environmental control model for assessing coal-fired EGUs*

These new analytical models of dry cooling systems have been incorporated into the IECM. The enhanced IECM provides systematic estimates of the fuel consumption, water consumption rate, net capacity, efficiency, and levelized cost of electricity generation (LCOE) of existing EGUs before and after dry cooling systems are retrofitted. The size of a dry cooling system for coal-fired EGUs is determined based on unit nameplate capacity and annual average ambient air conditions, and for NGCC units based on steam turbine capacity and annual average ambient air conditions. Analogous to the carbon dioxide avoidance cost, a widely used cost metric for evaluating carbon capture technologies [25], the cost of water savings by dry cooling at each EGU is calculated based on the annual average water consumption intensity and LCOE:

$$\mathrm{CWS} = \frac{\mathrm{LCOE_{Dry}} - \mathrm{LCOE_{Existing}}}{\mathrm{WC_{Existing}} - \mathrm{WC_{Dry}}} \tag{1}$$

where, CWS is the cost of water savings by dry cooling deployment ($\$/m^3$ of water saved); LCOE is the levelized cost of electricity generation for existing or retrofitted EGUs ($/MWh); and WC is the unit-level water consumption intensity for existing or retrofitted EGUs (m^3/MWh). The LCOE of EGUs retrofitted with dry cooling systems varies with the remaining lifetime of each unit, as well as other cost and financial parameters. Dry cooling deployment also eliminates the cost of cooling water consumption from the LCOE. The cost of water savings measures the overall expense per unit of water consumption savings, including all capital investment and operating and maintenance costs required for dry cooling systems while reducing water consumption due to evaporative losses in wet towers.

The enhanced IECM is further applied to quantify potential shortfalls in net capacity from dry cooling deployment on a monthly basis. The performance of existing EGUs with wet cooling towers is evaluated based on the monthly averages for net electricity generation, net heat rate, and ambient air conditions. To evaluate the performance of existing EGUs retrofitted with dry cooling, fuel consumption and operating hours within a month are kept constant for the pre- and post-retrofit cases. However, the monthly average heat rate is adjusted for changes in the turbine backpressure, which may be elevated by the dry cooling technology, especially in hot months [9]. As site-specific data on turbine backpressure are not reported in any available databases, an analytical model was derived from the NETL study to estimate the backpressure as a function of air dry-bulb temperature for both the wet and dry cooling systems at existing coal-fired power plants [9]. The backpressure function and the heat rate adjustment factor for dry cooling systems employed at existing coal-fired power plants are provided in SI Section S3.

For existing NGCC units, the steam cycle heat rate is a key parameter that affects the cooling duty and process design [1]. However, its value is not reported in power plant databases. Thus, it was estimated based on the net plant heat rate using a steam cycle heat rate adjustment function derived from the NETL study [9], which reports the ratio of steam cycle heat rate to net unit heat rate. This ratio is also given as a function of ambient air dry-bulb temperature, allowing the development of a model to also correct for changes in ambient air dry-bulb temperature over the year. Details of these analytical performance models are summarized in section S4 of the SI.

3. Results

This section first presents the results of a cost-effectiveness analysis of dry cooling retrofits based on annual average values. Then, the changes in net generating capacity from dry cooling retrofits are presented on a monthly basis to assess seasonal as well as annual average changes in regional generating capacity.

3.1. *Major assumptions for retrofit analysis*

To model and evaluate existing fossil fuel-fired EGUs using wet cooling systems, a number of assumptions are required. Major assumptions for this study include the following: nominal values of all plant and ambient air parameters are based on the year 2017 (the most recent year for which all required data were available); unit retirement age is assumed to be 50 years for coal-fired EGUs and 30 years for gas-fired EGUs; unit current age and remaining lifetime (in 2017 for coal-fired units and 2020 for gas-fired units) are estimated relative to the unit's online year; unit size is based on nameplate capacity; multiple units within a power plant burn the same fuel; for LCOE calculations, all existing equipment is treated as fully amortized in calculating the incremental cost of dry cooling retrofits; and, where unit-specific data are not available from the databases cited earlier, IECM default values are used (e.g., cooling water temperatures, cycles of concentration, auxiliary cooling duty).

To assess dry cooling retrofits, we make several additional assumptions: dry cooling is considered to be a mature technology with no inherent cost or technology barriers that would be considered prohibitive as a candidate for retrofit applications; for each EGU, the nameplate (gross) capacity and capacity factor are kept constant for the pre- and post-retrofit cases; the size of a dry cooling system is estimated based on annual average ambient air conditions, as noted earlier; and dry cooling system capital costs are amortized over 30 years or over the remaining life of the unit if less than 30 years (based on the assumed retirement age). In the absence of current site-specific data, the IECM default water price of $\$0.3/m^3$, which falls within the price range reported by a study on western regions [26], is used for all case studies. A sensitivity analysis later considers the impacts of alternative water prices and additional capital costs associated with site-specific retrofit factors.

3.2. *Cost-effectiveness analysis of dry cooling retrofits*

We first evaluate existing fossil fuel-fired EGUs using wet cooling towers prior to dry cooling retrofits. Fig. 1 and Fig. 2 show major performance and cost results based on IECM annual average simulations. For existing coal-fired units using wet cooling towers, the annual average water consumption intensity varies from 1.53 to 2.92 m^3/MWh-

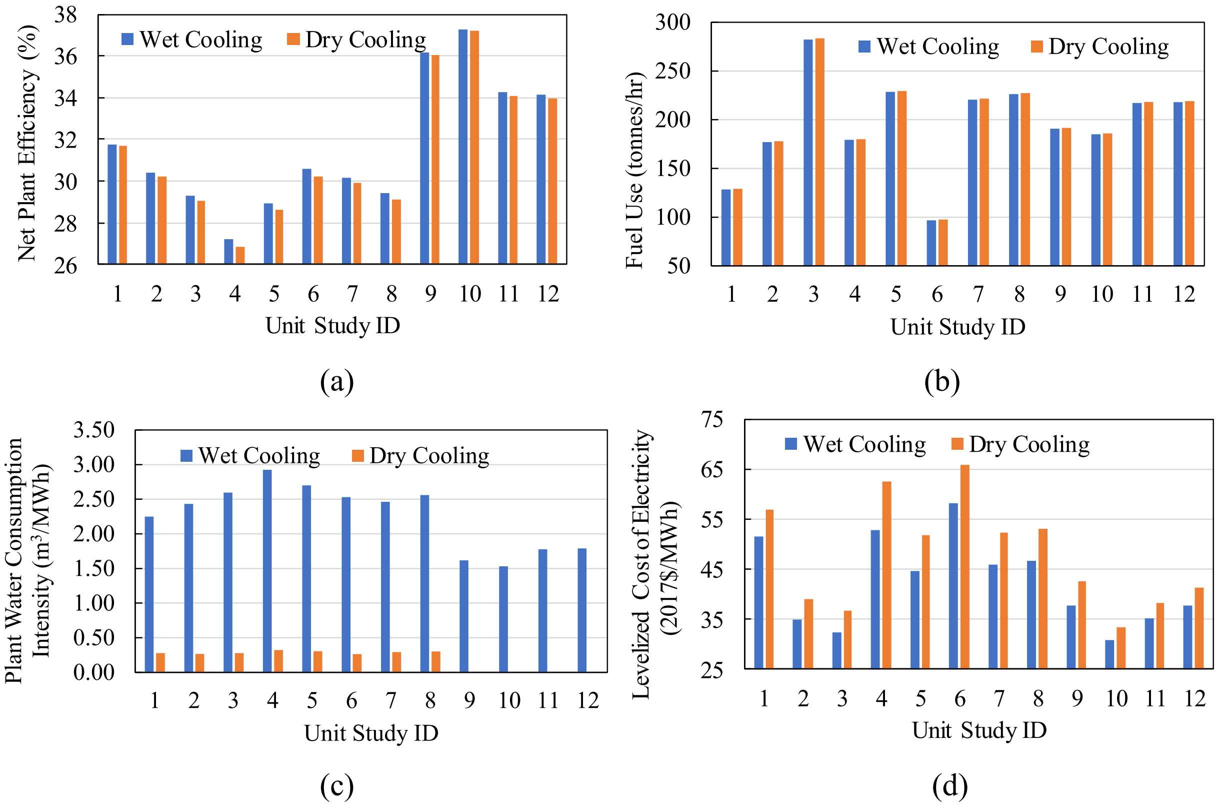


Fig. 1. Performance and cost measures for existing coal-fired EGUs with wet and dry cooling systems based on annual averages: (a) net plant efficiency, (b) fuel use, (c) plant water consumption intensity, and (d) levelized cost of electricity generation. Note that units 1–8 continue to consume water for wet FGD systems (see Table 1).

net. For existing NGCC units with wet cooling towers it varies from 0.81 to 1.35 m^3/MWh-net. The variation is due mainly to differences in unit efficiency (heat rate) and ambient air conditions, as well as FGD type (for coal plants) [1,8]. The LCOE of each unit, excluding sunk capital costs, varies from $30.1 to $58.3/MWh for coal-fired EGUs and $30.5 to $56.2/MWh for NGCC units, largely because of differences in unit capacity factors and other parameters [27]. These LCOE values, thus, reflect only the current operating and maintenance costs (including fuel cost) of each unit, assuming that all capital costs are fully amortized (which simplifies the calculation of added cost due to dry cooling retrofits, which is the main focus of this study).

For dry cooling systems, the steam condenser operates at a higher temperature than for wet recirculating cooling tower systems as the theoretical cooling capability is constrained by the higher air dry-bulb temperature rather than the air wet-bulb temperature. The resulting increase in steam turbine exhaust temperature into the ACC increases the steam turbine backpressure, which increases the steam cycle heat rate and the plant parasitic load, especially for “off-design” ambient air conditions [8,9]. The higher exhaust steam temperature into the ACC also affects the ITD for dry cooling [8]. As discussed in Section S2 of the SI, the backpressure change with dry cooling is minor when the air dry-bulb temperature is less than about 15.6 °C [9]. SI Table S5 and Table S6, respectively, summarize the ITD design values for all the coal- and gas-based retrofit cases, which are based on annual average ambient conditions.

Fig. 1 also shows the performance and cost results for existing coal-fired EGUs after retrofit with dry cooling systems based on annual average ambient conditions. As the annual average dry-bulb air temperature adopted for designing the dry cooling systems is less than 15.6 °C for all but one EGU (where it is 18.2 °C, see Table 1), dry cooling retrofits only slightly decrease the net generating efficiency of each unit, with a corresponding small increase in coal consumption to maintain the same net electrical output as the pre-retrofit case. For the region as a whole, dry cooling deployment at all 12 coal-fired EGUs reduces total annual water consumption by 93% while increasing the unit-level LCOE by an average of $5.4/MWh (a 12% average increase based on the calculated LCOEs). We note that the capital cost of dry cooling assumes no significant site-specific difficulties that would add a premium to the cost of a new plant installation. A later sensitivity analysis shows the impact of alternative retrofit cost factor assumptions.

Fig. 2 shows similar performance and cost results for existing NGCC units based on annual average ambient conditions. For any given unit, the natural gas consumption is fixed before and after retrofitting with dry cooling. On an annual basis, dry cooling retrofits slightly decrease the net generating efficiency of each unit. As discussed later, however, the change in net efficiency or energy penalty from dry cooling deployment on existing NGCC or coal EGUs varies month to month due to seasonal changes in ambient conditions. For the region as a whole, dry cooling deployment at all 14 NGCC units eliminates freshwater consumption but increases the unit-level LCOE by $6.7/MWh (18% on average based on fully amortized plants).

In terms of the cost of water savings, the average for 12 coal-fired EGUs is found to be $2.5 per cubic meter of consumptive water saved. Fig. 3 shows the cost of consumptive water saved by dry cooling for each coal-fired EGU on an annual basis. Due to differences in unit attributes and ambient air conditions, this cost ranges from $1.6 to $3.7 per cubic meter of consumptive water saved. If the age of coal-fired EGUs were calculated as of 2020 (as assumed for gas-fired units) rather than 2017, the cost of water savings would not change in most cases because of the longer lifetime of coal units. In the worst case, the water savings cost of the oldest coal unit would increase by 16.7% due to the three-year difference in remaining life. Fig. 3 also shows the linear fit between the cost of water savings and each of six site-specific attributes as a single explanatory variable. While no single factor explains all or most of the

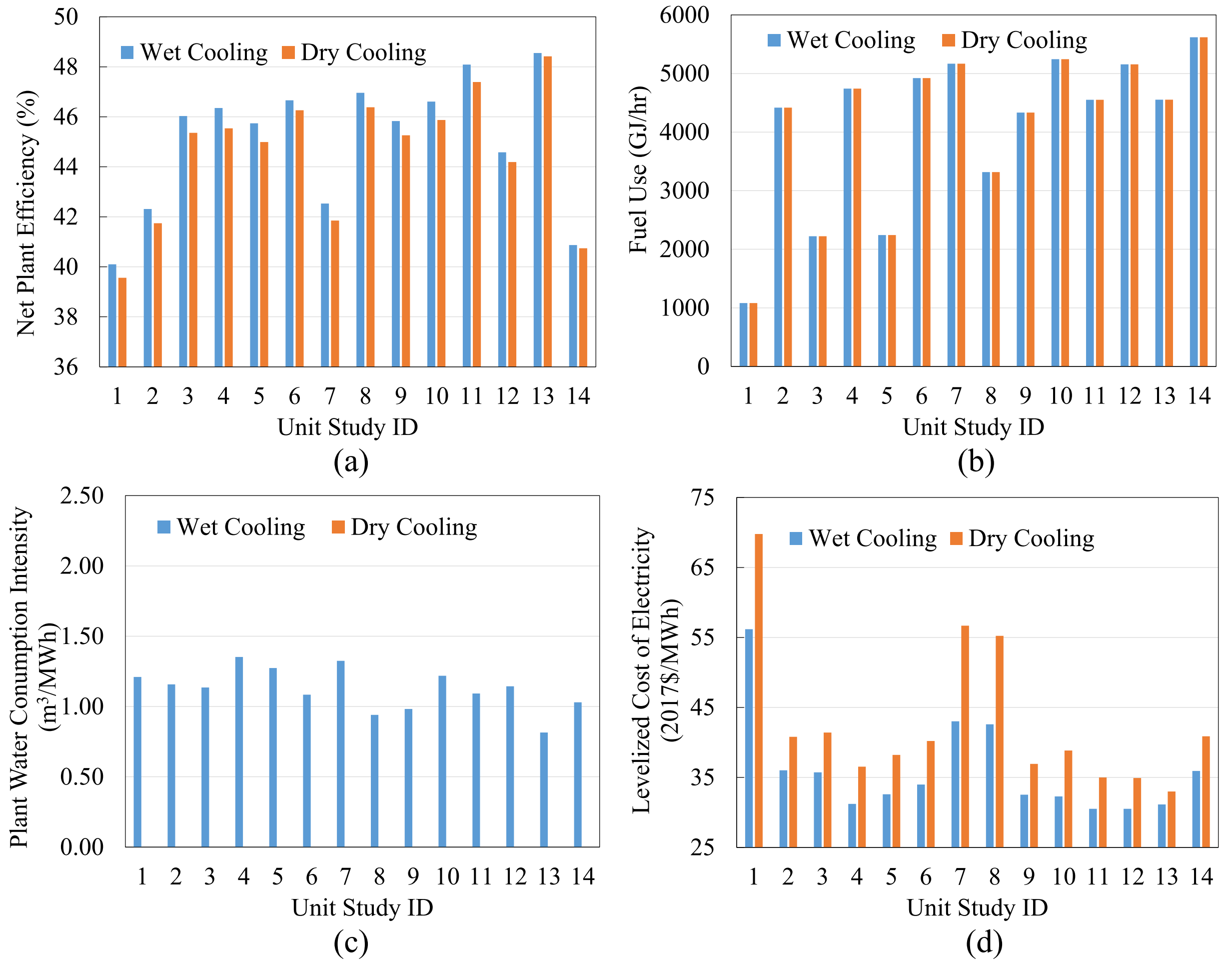


Fig. 2. Performance and cost measures for existing NGCC units with wet and dry cooling systems based on annual averages: (a) net plant efficiency, (b) fuel use, (c) plant water consumption intensity, and (d) levelized cost of electricity generation. Note: the capital cost of NGCC power plants prior to retrofits is updated in the IECM based on an NETL report published in 2018 [9], and the fuel used at NGCC units is identical for the pre- and post-retrofit cases.

variation (as indicated by the low R^2 values except for capacity factor), among the variables shown, the capacity factor has the largest impact on the cost of water saved, with higher capacity factors resulting in lower average cost as the capital investment in dry cooling is amortized over a larger number of MWh generated. The cost of water savings also is negatively correlated with increasing unit size, higher net efficiency, and higher relative humidity in ambient air, but positively correlated with increasing air dry-bulb temperature and unit age.

The cost of water savings on average for 14 NGCC units is found to be \$5.9 per cubic meter of water consumption saved. Fig. 4 shows the cost of water savings for each NGCC unit on an annual basis, which ranges from \$2.3 to \$13.4 per cubic meter of consumptive water saved. Fig. 4 also shows the linear fit between the cost of water savings and each of the site-specific attributes. Among the variables shown, the capacity factor again has the largest impact on the cost of water saved. Similar to the coal-based retrofit cases, the cost of water savings is also negatively correlated with increasing unit size, higher net efficiency, and higher relative humidity, but positively correlated with increasing air dry-bulb temperature and unit age.

The Spearman's rank correlation between the cost of consumptive water savings and the power plant characteristics, which measures monotonic linear or nonlinear relationships, was also evaluated for both coal- and gas-based retrofit cases. The coefficients given in Table 3 further indicate that capacity factor and unit age are the most important characteristics affecting the cost of water consumption savings for both coal- and gas-based retrofit cases.

3.3. Monthly change in net generating capacity with dry cooling

The magnitude of the parasitic load and heat rate penalty imposed by retrofitting dry cooling systems is sensitive to ambient air conditions, especially during hot summer months. Thus, the potential for a region-wide shortfall in net generating capacity from dry cooling deployment is evaluated based on monthly average conditions.

The change in monthly net capacity with dry cooling is calculated on a unit-by-unit basis using the IECM and then aggregated to the regional level. For this study, additional assumptions include the following: monthly fuel use and operating hours are kept constant for the pre- and post-retrofit cases; the monthly heat rate for each unit is adjusted from the current wet cooling system value based on the monthly air dry-bulb temperature; and the monthly parasitic load for dry cooling is evaluated based on the monthly air dry-bulb temperature and steam turbine exhaust temperature.

SI Fig. S1 shows the monthly variation in net heat rate of each coal-fired EGU using current wet towers, while SI Fig. S2 shows similar data for NGCC units with wet towers. The figures show no seasonal pattern or consistent behavior across units over the study year. In contrast, Fig. 5a shows a clear seasonal pattern for the monthly average air temperature at each coal plant location, with the highest levels occurring in June or July and the lowest levels in January or December. Air temperatures above 15.6 °C have a pronounced effect on the turbine backpressure, which, in turn, affects the steam turbine exhaust temperature, as noted earlier. Fig. 5b shows the monthly exhaust steam temperature by coal-

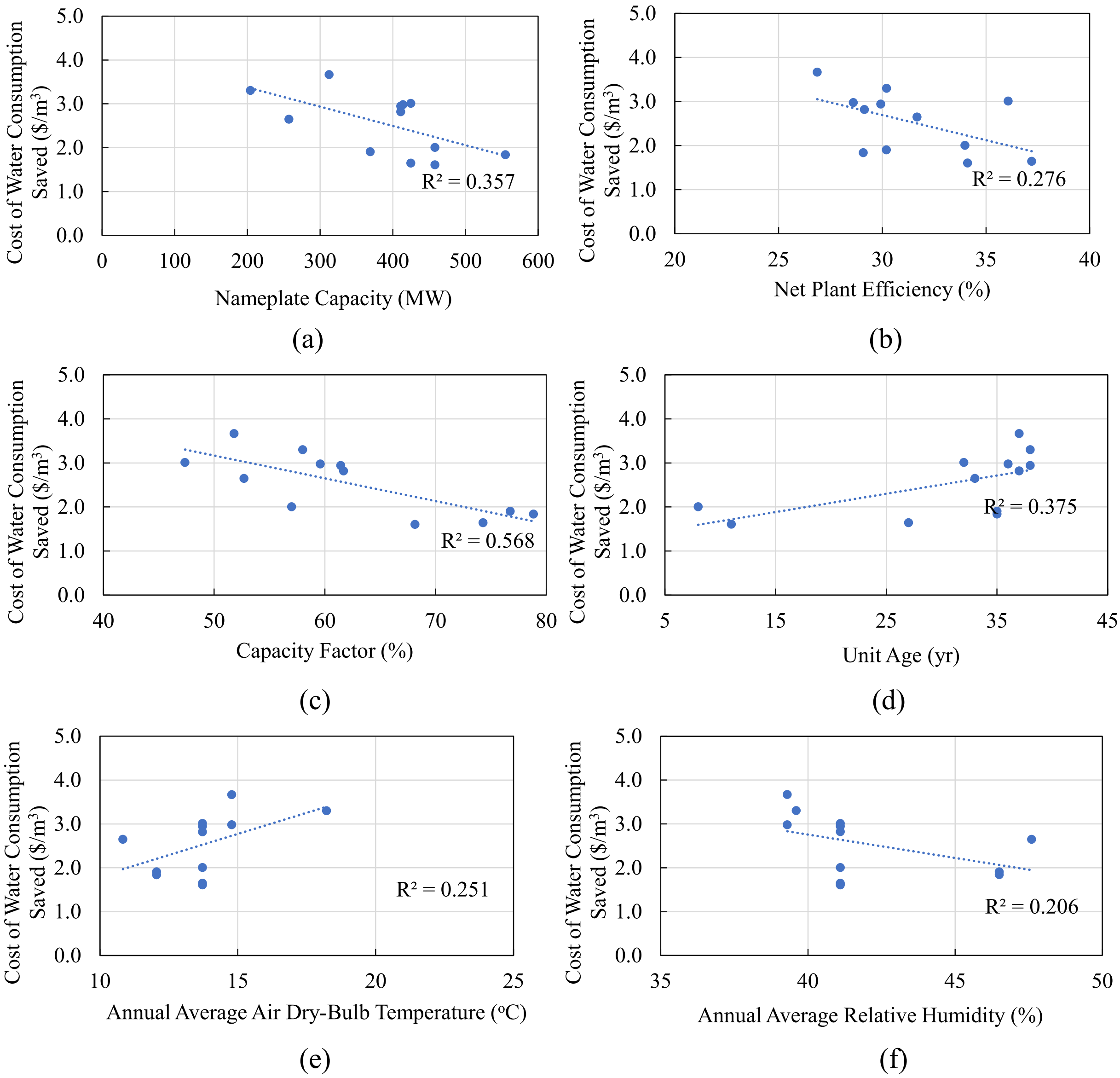


Fig. 3. Correlation of the annual average cost of water consumption saved with selected site-specific parameters of existing coal-fired EGUs: (a) nameplate capacity, (b) net plant efficiency, (c) capacity factor, (d) unit age, (e) annual average air dry-bulb temperature, and (f) annual average relative humidity.

fired power plant over the year. Here, there is a clear seasonal pattern that reaches its highest level in June or July. Recall that this steam temperature together with the ambient air temperature determines the ITD, which, in turn, governs the size and energy penalty of the dry cooling system. In general, the resulting ITDs for each EGU were found to reach their highest levels in January and December and their lowest levels in the warmer months from May to September (see SI Fig. S3). Low values of ITD incur higher energy penalties as heat transfer from exhaust steam to ambient air becomes more difficult.

Fig. 5c shows the difference between the operating and design ITD for each of the six coal-fired power plants over the year. As seen, the operating ITDs in winter are significantly higher than the design ITDs at all plants, which lowers the parasitic loads of dry cooling compared to those at the design condition. In contrast, the operating ITDs in summer months are lower than the design ITDs at four of the six coal-fired power plants, which elevates the parasitic loads of dry cooling. As shown in Fig. 6, there are similar trends in the difference between the operating and design ITDs of dry cooling systems retrofitted at existing NGCC units.

Fig. 7a and b show the resulting change in monthly net capacity after dry cooling deployment at each coal-fired EGU on an absolute and relative basis, respectively. There is a clear seasonal pattern showing slight gains in net capacity in January and December, but larger decreases from April to October, with the maximum decrease occurring in mid-summer. The magnitudes of these changes depend on how much the operating ITD differs from the design ITD. The absolute change in net capacity in Fig. 7a is also related to the unit size. On a relative basis, the largest unit-level shortfall in net capacity reaches a high of 2.7% in July (Fig. 7b). On a regional basis, the monthly change in total net capacity after dry cooling retrofits at existing coal-fired units varies from +8 MW in winter to −79 MW in summer on an absolute basis, or +0.2 to −2.0% on a relative basis, with the largest decrease occurring in July. On an annual basis, the average reduction in net regional capacity with dry cooling retrofits is estimated to be 32 MW, or 0.7% of the total regional coal-fired nameplate capacity.

Fig. 8a and Fig. 8b show similar results for NGCC units. The change in monthly net capacity after dry cooling retrofits also shows a seasonal pattern similar to that at coal-fired units. The estimated monthly shortfall in total net regional capacity due to dry cooling varies from 23 to 167 MW on an absolute basis, or 0.3 to 2.2% on a relative basis. Again,

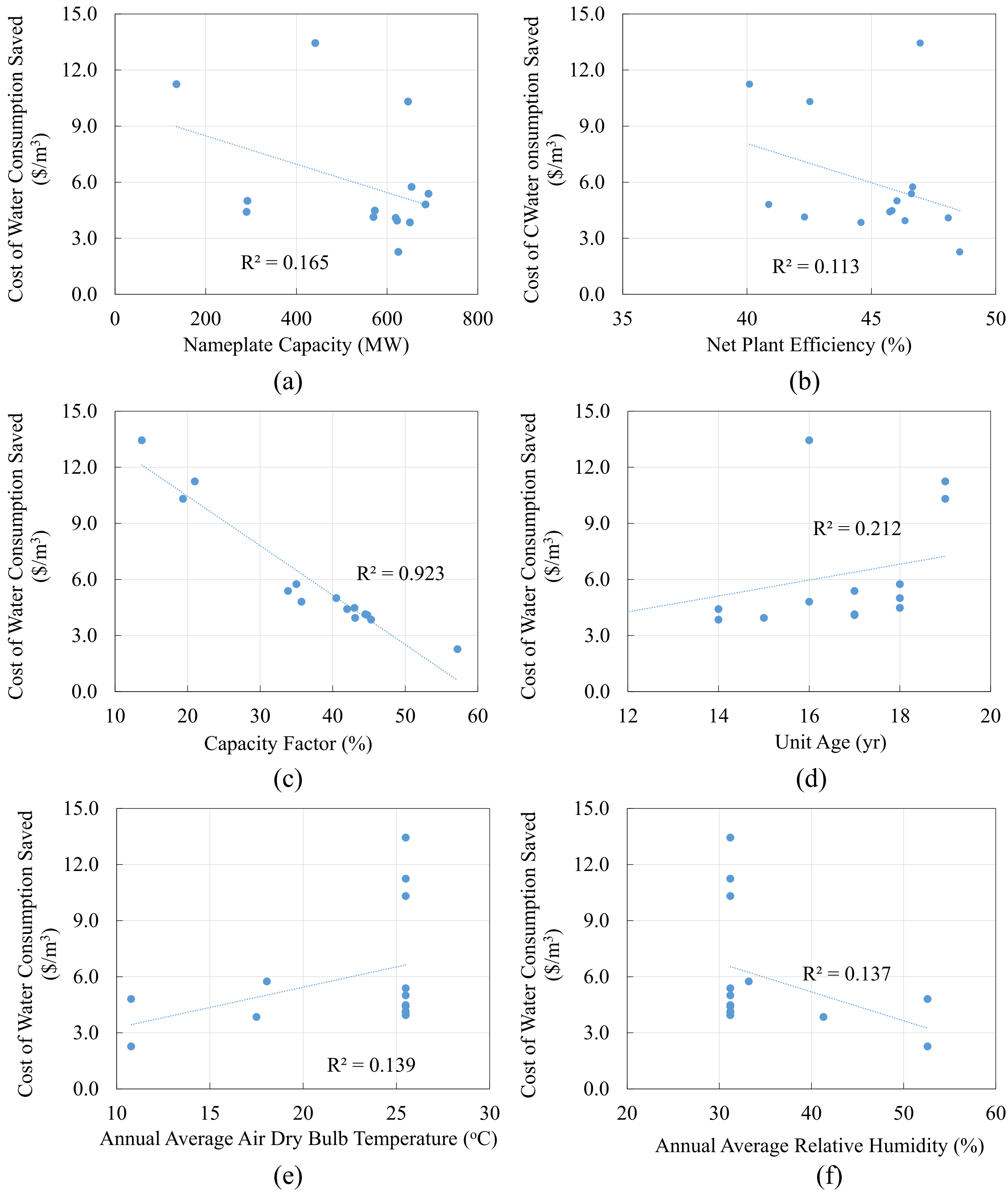


Fig. 4. Correlation of the annual average cost of water consumption saved with selected site-specific parameters of existing NGCC units: (a) nameplate capacity, (b) net plant efficiency, (c) capacity factor, (d) unit age, (e) annual average air dry-bulb temperature, and (f) annual average relative humidity.

the largest decreases in regional water consumption and net regional capacity occur in June and July. Over the year, the average reduction in monthly regional capacity of NGCC units is estimated at 86 MW, or 1.2% of total regional gas-fired nameplate capacity, which is slightly higher than the annual average decrease on a percentage basis for coal-fired EGUs in the region, due mainly to the higher steam cycle heat rate of NGCC units.

4. Discussion

This study investigated the performance and cost impacts of switching from wet cooling to dry cooling at existing fossil fuel-fired power plants in order to reduce water consumption in dry or arid regions. Case studies for power plants in three western U.S. states evaluated the cost and cost-effectiveness of retrofitting current dry cooling technology and the associated reduction in water consumption. For the region as a whole, a 93% reduction in annual power plant water consumption at existing coal-fired units was achieved at an average increase

Table 3
Spearman's rank correlation coefficients of water consumption savings cost with power plant characteristics.

Power Plant Characteristics	Coal-Based Retrofit	Gas-Based Retrofit
Nameplate capacity	−0.601	−0.147
Net plant efficiency	−0.434	−0.204
Capacity factor	−0.734	−0.969
Unit age	0.650	0.681
Annual average air dry-bulb temperature	0.626	0.356
Annual average relative humidity	−0.618	−0.356

of \$5.4/MWh (approximately 12%) in the LCOE. This corresponds to an average cost of \$2.5 per cubic meter of consumptive water saved. For existing NGCC units with wet cooling, retrofits of dry cooling increase the LCOE by \$6.7/MWh (approximately 18%) while fully eliminating water consumption at an average cost of \$5.9 per cubic meter of water saved. As shown in Fig. 1a and Fig. 2a, retrofitting dry cooling systems at existing EGUs would not significantly decrease their net plant efficiency on an annual basis. Thus, it would not significantly increase the annual CO_2 emission intensity.

Across the existing units modeled in this study, the cost and cost-effectiveness of water savings by dry cooling retrofits was found to vary by roughly a factor of two for coal-fired EGUs and a factor of five for NGCC units due to differences in plant attributes and ambient air conditions. In general, improvements in plant efficiency and increases in capacity factor were most influential in lowering the cost of water savings.

As noted earlier, the cost of water savings by dry cooling is also affected by two parameters whose site-specific values were unavailable: the unit price of water and the "retrofit factor" for dry cooling system capital cost. Increased water prices tend to enhance the economic viability of dry cooling retrofits in water-stressed regions [28]. For example, a sensitivity analysis for one coal-fired EGU in this study (unit Study ID 3) shows that when the water price is varied from 0 (free water) to \$0.7/m^3, the cost of consumptive water saved by dry cooling decreases by 39% from \$2.1 to \$1.3/m^3 (see SI Fig. S5). In addition, other studies suggest that if rights to the water saved by dry cooling deployment could be transferred or leased to other users in western states, the revenue could offset the cost of retrofit to some extent, which may change with location as water rights vary by state [28].

In contrast, the cost of dry cooling retrofits is adversely affected if site-specific factors such as space limitations and/or the need for modifications to the steam turbine or other plant equipment resulted in substantially higher capital costs relative to the cost of a new greenfield installation. Such added costs are commonly represented by a "retrofit factor" multiplier applied to the nominal cost for new plant. For example, a dry cooling system retrofit factor of 1.5 means a capital cost increase of 50 percent over the nominal dry system cost. The average cost of water saved would then increase roughly in proportion since capital cost dominates the economics of dry cooling. In this study, a retrofit factor of 1.25 (similar to average factor for flue gas desulfurization system retrofits at U.S. power plants [29]) would increase the average cost of water saved by about 23% from \$2.5 to \$3.1/m^3 for existing coal-fired EGUs, and from \$5.9 to \$7.3/m^3 for existing NGCC units. Quantifying such retrofit factors, however, would require a detailed engineering assessment of each power plant site and cooling system modeled, which is beyond the scope of this study; nor were site-specific retrofit studies available in the literature. Therefore, pending further study of individual plant sites to determine a degree of retrofit difficulty (if any), the costs and sensitivity results reported here serve as a foundation for future refinements.

To further illustrate the variability in site-specific cost and water consumption savings of dry cooling, Fig. 9a and b exhibit two "supply curves" for the 12 modeled coal-fired EGUs and 14 NGCC units. The cost

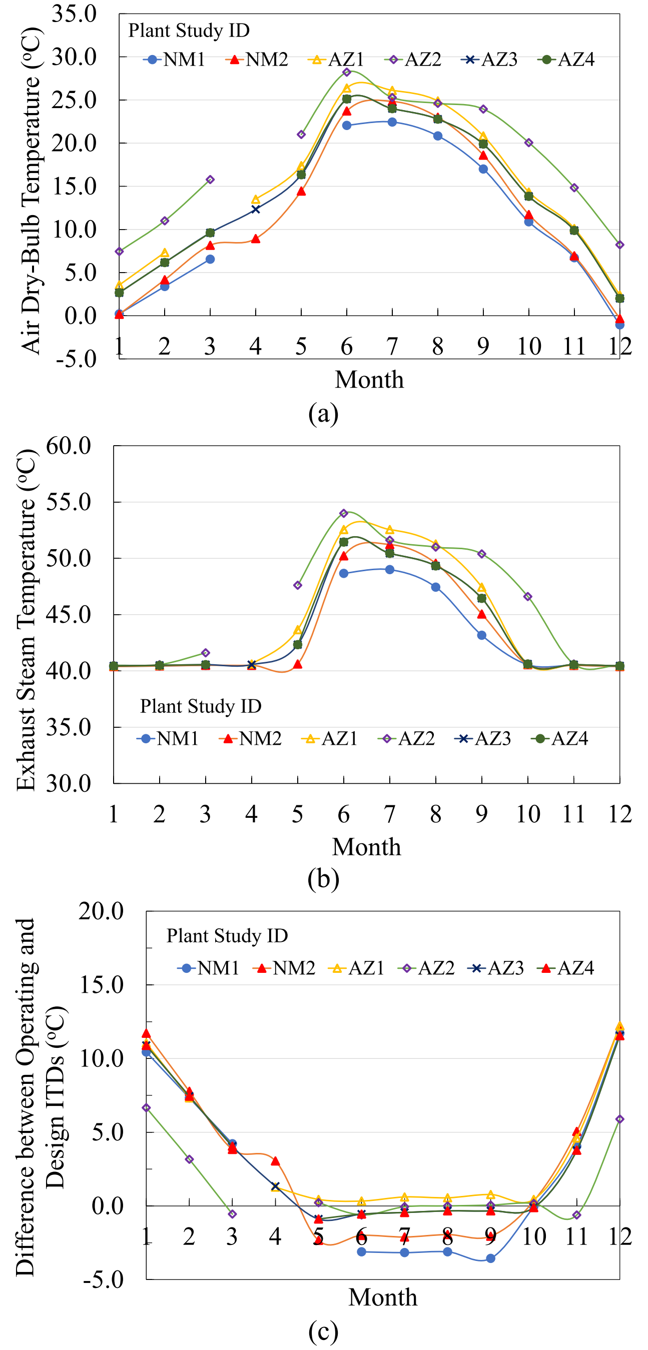


Fig. 5. Monthly operating conditions of existing coal-fired EGUs: (a) air dry-bulb air temperature, (b) exhaust steam temperature (out of turbine), (c) difference between operating and design ITDs. Note: This figure shows the plant-level operating conditions. Missing points on a curve indicate that the power plant had no units in operation in those months.

of water savings increases nonlinearly with cumulative annual water savings (Fig. 9a) as well as with cumulative gross generating capacity (Fig. 9b). These results show that 54% (2522 MWg) of the coal-fired regional gross capacity has a cost of water savings of less than \$2.6/m^3, corresponding to a 51% reduction in regional water consumption by these plants. Furthermore, 90% of the coal-fired capacity has a cost of less than \$3.2/m^3, corresponding to an 82% reduction in regional water consumption. For NGCC plants with wet cooling towers, about 75% of the gross capacity has a water savings cost of less than \$5.3/m^3, corresponding to an 80% reduction in regional water consumption by those plants. In comparison between coal- and gas-fired power plants, the unit

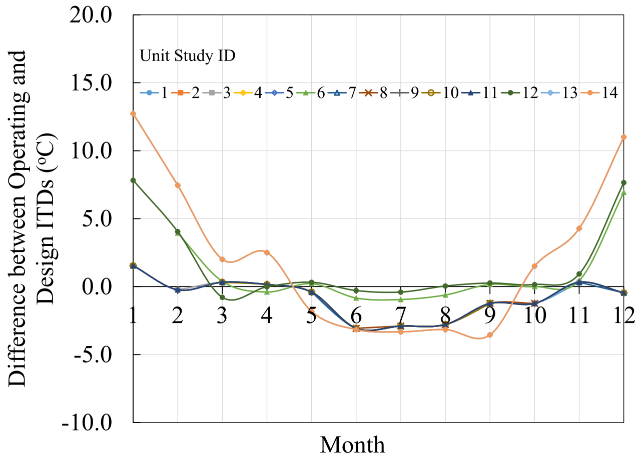
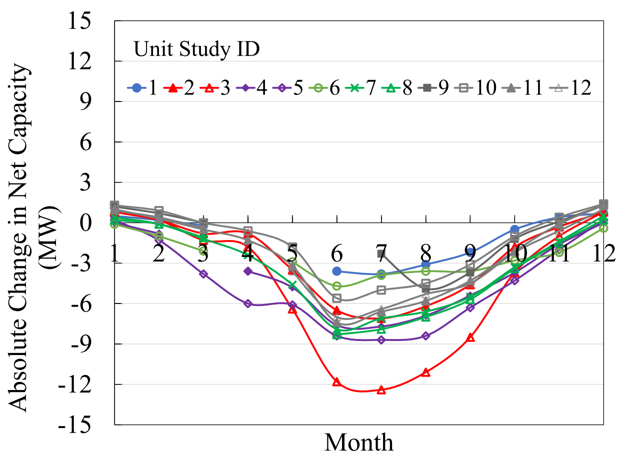
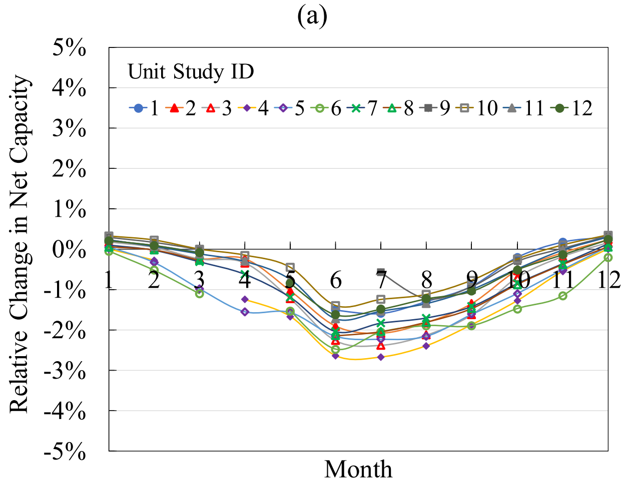


Fig. 6. Difference between operating and design ITDs of dry cooling systems retrofitted at existing NGCC units. Note: This figure shows the unit-level results. Missing points on a curve indicate that the EGU was not in operation in those months.

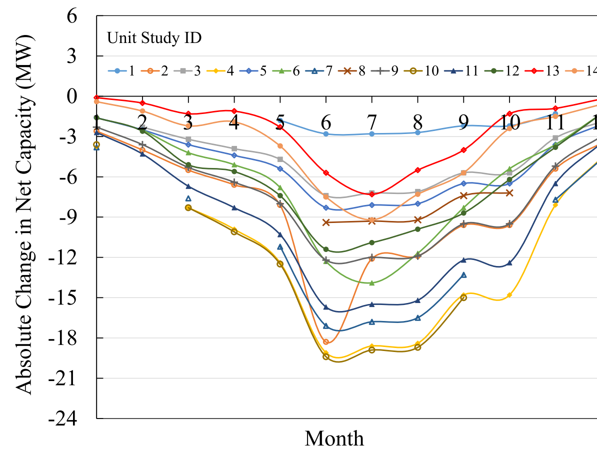


(a)

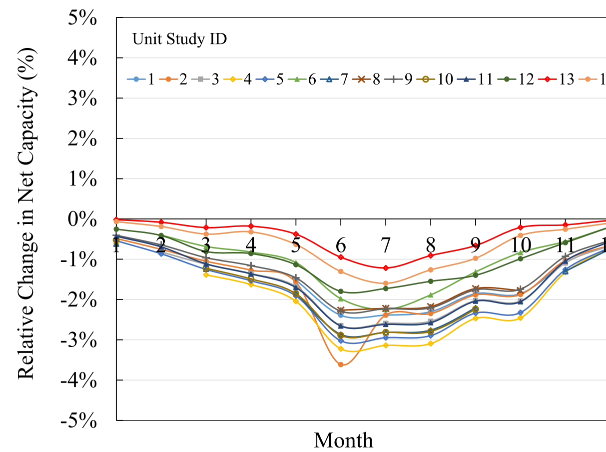


(b)

Fig. 7. Monthly change in net capacity from dry cooling deployment on existing coal-fired EGUs: (a) absolute change in net capacity, (b) relative change in net capacity. Note: This figure shows the unit-level results. Missing points on a curve indicate that the EGU was not in operation in those months.



(a)



(b)

Fig. 8. Monthly change in net capacity from dry cooling deployment on existing NGCC units: (a) absolute change in net capacity, (b) relative change in net capacity. Note: This figure shows the unit-level results. Missing points on a curve indicate that the EGU was not in operation in those months.

cost of water saved at NGCC plants is higher than for PC plants, mainly because of their lower capacity factors and shorter lifetime for amortizing the dry cooling system capital cost. Differences in cooling duty and other site-specific factors also contribute to higher costs at NGCC units.

While dry cooling deployment would alleviate power plant vulnerabilities to water shortage [11], it would also reduce regional net generating capacity over most of the year. Results for the study region indicate the largest monthly shortfall would occur in July, with a reduction of nearly 2% of the current (pre-retrofit) coal-fired gross capacity and 2.2% of the current gas-fired gross capacity. Fig. 9c also shows the regional supply curve for the worst-case (July) reduction in *net* summer capacity versus cumulative annual water savings for both coal and gas plant retrofit cases. Although the shortfall in monthly net capacity at the unit level is less than 3% for the coal-based plants and less than 4% for the gas-based plants, note that while net plant capacity with dry cooling is reduced with increasing ambient air temperature, the gross plant capacity remains constant over the year (by definition).

The electricity demand varies with season and typically reaches peak levels in summer [30]. High air temperatures can increase both the electricity demand [30] and the generating capacity derating from dry cooling deployment on the supply side, thus imposing pressure on the electricity demand-supply balance during the hottest periods. We also note that in the western United States, the daily maximum temperatures

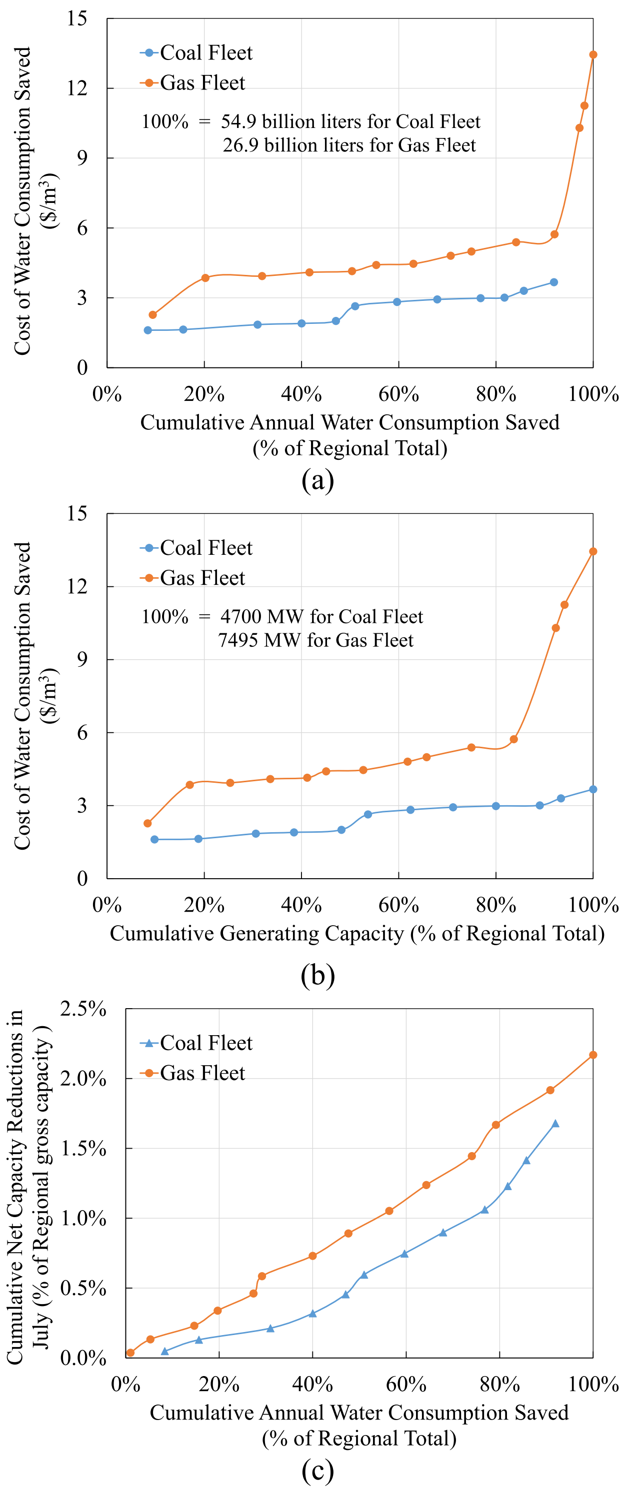


Fig. 9. Supply curves for dry cooling retrofits: (a) cost of water consumption saved vs. cumulative annual water consumption saved, (b) cost of water consumption saved vs. cumulative (regional nameplate) generating capacity, (c) cumulative net capacity reductions in July vs. cumulative annual water consumption saved.

in summer are often higher than 37.8 °C, which is above the monthly average temperatures shown in Fig. 5a. Thus, the shortfall in net capacity during the hottest hours of the year could be larger than the monthly average shortfall, with possible effects on short-term unit commitments and dispatch [31]. A derating analysis on a daily or even hourly basis is, thus, recommended for a future study to quantify such short-term shortfalls in net capacity. Such an analysis, however, would require short-term (daily or hourly) unit-level data, which are not currently available in utility databases such as those used for this study.

5. Conclusions

Motivated by increasing concerns about the availability of fresh water in dry or arid regions, this study investigated the technical, economic, and water savings impacts of retrofitting dry cooling systems in lieu of wet cooling towers at existing fossil fuel-fired power plants in a three-state region of the western U.S. The analysis of 12 coal-fired units and 14 gas-fired units quantified tradeoffs among water savings, cost increases, and reductions in net plant capacity, which were found to vary with generating unit characteristics, especially fuel price, net efficiency, and capacity factor. Retrofits of dry cooling systems in lieu of wet cooling towers were found to reduce regional water consumption by 93% for coal-fired plants and 100% for gas-fired combined cycle plants, but increased the LCOE by an average of 12% ($5.4/MWh) and 18% ($6.7/MWh) for PC and NGCC units, respectively. This translates to a regional average cost of consumptive water savings estimated at $2.5 and $5.9 per cubic meter of water saved at existing coal- and gas-fired units, respectively. This cost may increase with a more detailed analysis of site-specific retrofit difficulty. Over a calendar year, the monthly change in net regional generating capacity after dry cooling retrofits exhibits a clear seasonal pattern, with the largest capacity shortfalls occurring in hot summer months. This monthly average reduction in net regional capacity is estimated to be 0.7% and 1.2% of the regional nameplate (gross) capacity for coal- and gas-based units, respectively. The shortfall in net capacity during the hottest days or hours, however, could be much larger than the monthly shortfall. A derating analysis on a daily basis is recommended to quantify such short-term shortfalls in net capacity, although this would require daily or hourly data that are not currently available.

Correlations between the cost of water consumption savings and the selected power plant characteristics indicate that the most promising candidates for dry cooling retrofits are coal- and gas-fired EGUs that are large and relatively new, with high net efficiency and high capacity factors. Where the cost of water saved exceeds the current cost of water consumed, policies regarding water pricing, water use, water rights transfers, or other measures would be needed to enhance the viability and use of dry cooling retrofits in water-stressed regions.

In summary, limited freshwater supplies in dry or arid regions has prompted increased interest in advanced cooling systems for thermoelectric power plants. However, the retrofit of dry cooling systems in lieu of current wet systems produces tradeoffs in water consumption reduction, net capacity reduction, and economic cost, all of which vary with unit attributes and ambient air conditions. To make both water consumption and energy production more efficient and sustainable, utility decision-makers and other stakeholders must understand and quantify these tradeoffs in technical, environmental, and economic impacts. To achieve the best outcomes, such tradeoffs for alternative cooling options should be incorporated into a multi-criteria decision-making framework using analysis results of the type illustrated in this study.

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Haibo Zhai: Conceptualization, Methodology, Formal analysis, Investigation, Writing – original draft, Writing – review & editing, Supervision, Project administration. **Edward S. Rubin:** Conceptualization, Methodology, Formal analysis, Investigation, Writing – review & editing, Supervision, Project administration. **Eric J. Grol:** Conceptualization, Methodology, Investigation, Writing – review & editing. **Andrew C. O'Connell:** Methodology, Writing – review & editing. **Zitao Wu:** Formal analysis, Investigation. **Eric G. Lewis:** Methodology, Writing – review & editing.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Appendix A. Supplementary material

Supplementary data to this article can be found online at https://doi.org/10.1016/j.apenergy.2021.117997.

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