Water-CO_2 Tradeoffs in Electricity Generation Planning

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In 2011, the state of Texas experienced the lowest annual rainfall on record[1], with similar droughts affecting East Africa, China, and Australia. Climate change is expected to further increase the likelihood and severity of future droughts[2]. Simultaneously, population and industrial growth increases demand for drought-stressed water resources[3] and energy, including electricity. In the U.S., nearly half of water withdrawals are for electricity generation[4], much of which currently comes from greenhouse gas emitting fossil fuel combustion. The result is a three-way tension among efforts to meet growing energy demands while reducing greenhouse gas emissions and water withdrawals, a critical issue within the so-called water-energy nexus. We focus on this interaction within the electric sector by using a simple generation planning model to explore the tradeoffs. We show that 1) moderate restrictions in CO_2 emissions will also decrease water withdrawals, while 2) deeper cuts in CO_2 would likely increase water withdrawals for electricity generation in the absence of limits on water usage and, 3) that simultaneous restriction of CO_2 emissions and water withdrawals requires a different generation technology mix and higher costs than one would plan to reduce either CO_2 or water alone.

Previous studies have focused on various aspects of the water-energy linkage, including aggregate views across sectors[5-6], energy use in the water sector[7], and impacts of regional variation in water shortages[8] on electricity generation. Studies on the electric sector have primarily focused on the engineering design of alternative water cooling technologies for generation, their reduction in water withdrawals and consumption, and their incremental costs[3,9-12]. For example, Stillwell and Webber[8] demonstrate the economic feasibility of alternative cooling technologies using a river basin water resources model for 39 generation facilities in Texas. They found that water diversions could be reduced by 247-703 million m^3 (33-93%).

The predominant uses of water in thermoelectric generation are process steam to drive turbines and cooling. Most existing facilities in the U.S. use open-loop or once-through cooling. In this system, freshwater is removed from a source such as a river, the water is used for cooling, and then most is returned to the source at a higher temperature. To minimize environmental impacts, the temperature of the returned water is regulated and must be within established limits. This highlights a key distinction in water use for electricity generation: water withdrawal, the gross amount removed from the water source, is typically much larger than water consumption, the net difference between withdrawn and returned water from the source. However, withdrawal creates competition for water resources not completely mitigated by the fact that most is eventually returned[5].

With growing concern over water resources, several alternative cooling technologies have been developed or proposed. The least expensive is closed-loop, in which water is kept within the facility and recycled. This usually requires cooling towers to sufficiently lower the water temperature before reuse, which imposes additional capital and operating costs to the facility. Periodic withdrawals of additional water are needed to replace water lost in the cooling process, but much less water is needed than for open-loop cooling. Dry cooling, in which steam is cooled for reuse using air forced over heat exchangers, uses even less water but has higher capital and operating costs than closed-loop wet cooling. A third option of hybrid wet-dry cooling has been proposed that use a combination of cooling towers and air cooling, which would have the highest capital costs, but lower operating costs than dry cooling. The precise water requirements and costs for these cooling technologies vary with different generation technology types. The lower thermal efficiencies of nuclear and coal generation require more water for cooling than natural gas combined cycle units, while natural gas combustion turbines don't have a steam cycle and hence use effectively zero water.

Just as interactions between regional air quality and climate change have been explored under the concept of ancillary benefits, two related questions for the water-energy nexus are 1) would restricting CO_2 emissions from electricity generation reduce water intakes, and 2) would restricting water use for generation decrease CO_2 emissions? To address these questions requires a holistic assessment of a power system rather than focusing on one facility or river-basin, and requires quantitative analysis to provide more rigorous insights into the relative tradeoffs. Here we present the results of a generation capacity planning model of the Electric Reliability Council of Texas (ERCOT), which manages the power grid for the majority of the state. ERCOT is a useful region for study because it is an isolated electricity grid, and because Texas has already faced repeated droughts that will likely continue and worsen over time. We use a standard generation capacity expansion model[13−15], which solves a mixed integer linear program (MILP) to find the least-cost power system to meet demand and other constraints (including CO_2 emissions and water withdrawals). Although Texas and many other regions have deregulated the market for generation, such models are useful for investigating the system-wide minimum cost mix of generation, which then provides guidance to regulators in designing incentives for future investments by private entities. In fact, it has been shown that an ideal market based on marginal prices and the centrally planned least-cost solutions are the same[16]. The full model, including model equations and data, is provided in the supplemental material.

We solve our model of the ERCOT region for the future year of 2050, for a capacity of 152GW[17] (see SOM). We assume no existing generation, since the vast majority of current units will likely retire by 2050. The set of generation technologies considered includes nuclear, supercritical pulverized coal (Coal), natural gas combined-cycle (NG CCGT), natural gas combustion turbine (NG CT), wind, and options for the coal and CCGT to have carbon capture and sequestration (CCS). Each of these technologies, with the exception of gas CT and wind, have three different cooling types: wet (we assume closed-loop), hybrid, and dry. We first solve a reference case in which there are no limits on either CO_2 emissions or water withdrawals. We then solve for the least-cost generation mix for 11 additional scenarios that pair a water limit (50% of reference, 75%, or no limit) with a CO_2 limit (25% of reference, 50%, 75%, or no limit). We use generation cost and efficiency assumptions from the U.S. Energy Information Administration (EIA)[18], and water requirements and incremental costs of cooling from National Energy Technology Laboratory (NETL)[11].

In the ERCOT results, CO_2 emissions are impacted primarily by the CO_2 caps (Fig. 1). If water withdrawal limits also drove CO_2 emissions, we would expect noticeable changes in emissions for different water limits when combined with unconstrained CO_2. In contrast, Fig. 2 shows important impacts of CO_2 caps on water withdrawals. For moderate emissions reductions (50% or 75%), water withdrawals also decrease even in the absence of water limits. However, a more stringent reduction of CO_2 to 25% of the reference scenario results in greater water withdrawal than the reference case. This effect can be dampened or eliminated by simultaneously enforcing water withdrawal limits.

These water withdrawal impacts can be understood by examining differences in the generation mix (Fig. 3). Comparing the four scenarios with no water limits (four leftmost stacks in the figure), decreasing the CO_2 emissions (moving from left to right) induces a shift away from coal generation to natural gas, mainly combined-cycle units. This is consistent with the findings of other studies of the effects of CO_2 caps on generation technology choice[19−20]. However, a cap of 25% of reference

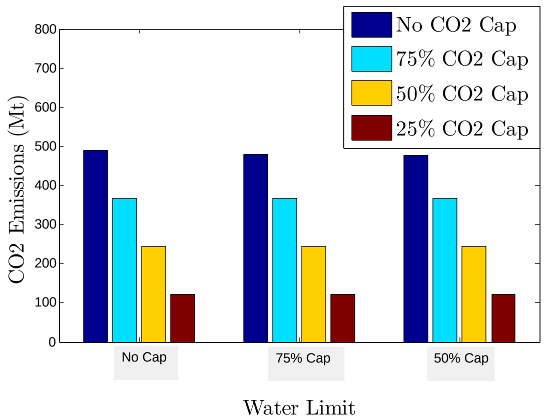

Figure 1: Annual carbon dioxide emissions as a function of water and carbon limits.

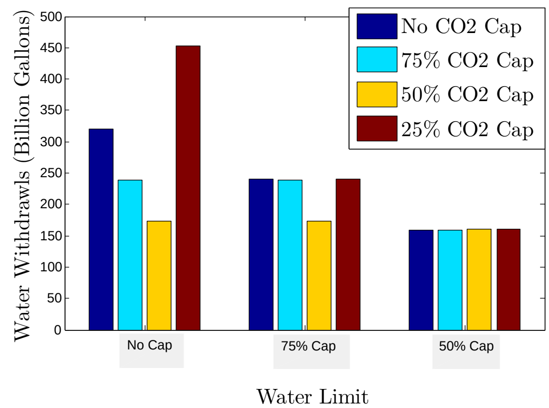

Figure 2: Annual water withdrawals for generation as a function of water and carbon limits.

Table 1: Increase in Electricity Generation Costs above No Limits Case

Water Limit	CO_2 Emissions Limit	Cost Relative to Reference (%)
No Water Cap	No CO_2 Cap	0
	75% CO_2 Cap	1%
	50% CO_2 Cap	3%
	25% CO_2 Cap	19%
75% Water Cap	No CO_2 Cap	0%
	75% CO_2 Cap	1%
	50% CO_2 Cap	3%
	25% CO_2 Cap	21%
50% Water Cap	No CO_2 Cap	1%
	75% CO_2 Cap	2%
	50% CO_2 Cap	3%
	25% CO_2 Cap	39%

CO_2 emissions cannot be achieved by traditional natural gas generation. Some form of even lower- or non-carbon emitting generation is needed. Candidate technologies include renewable generation such as wind, carbon capture and sequestration applied to coal or natural gas, or nuclear. The water usage implications of each of these are quite different. Using reference capital, operating, and fuel costs, the nuclear generation option is least cost. But the lower thermal efficiency of nuclear requires higher water usage (even assuming a closed-loop design), increasing the total water withdrawals.

Imposing water limits along with carbon caps induces further changes in the generation mix. With a 75% water cap and 25% CO_2 cap, nuclear switches from wet to hybrid cooling technologies, and almost half of the NG CCGT units use dry cooling. A tighter 50% water cap and 25% CO_2 cap result in less hybrid-cooled nuclear, dry-cooling for all the NG CCGTs, and nearly 20% of the total capacity is from wind generation. Because wind generation has a lower capacity factor (30%) the total capacity is higher when significant amounts of wind are built. Other generation/cooling technology pairs not shown in the figure have zero capacity in the figure because they were not cost-effective in any of the scenarios.

In addition, the electricity generation costs increase sharply with greater reductions in CO_2 or water use (Table 1). This non-linearity of abatement costs is well-known to environmental economists[21] and is expected. The comparable effect on costs of tighter limits on water is not seen except in the

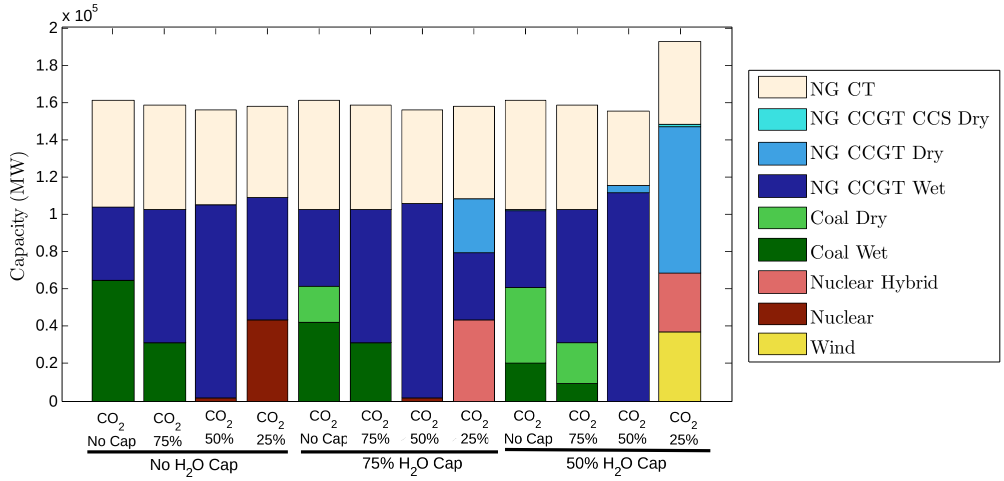

Figure 3: Capacity mix of electricity generation as a function of water and carbon limits. Technologies with zero capacity built not listed.

25% CO_2 cap cases, where it nearly doubles the cost relative to the same CO_2 cap with no limit on water. Note that these costs are simply the modeled increase in capital, operating, and fuel costs of electricity generation for the ERCOT system, and they are not a true measure of the economic welfare costs of these hypothetical regulations, nor an estimate of how electricity prices would change. Quantities such as the welfare loss to consumers or electricity price require economic models of the entire economy[22] or electricity market models that represent different actors in the electricity market and the regulatory structure[23]. Here we provide sectoral costs to illustrate the relative effects of water and CO_2 limits and their interaction.

The results presented above are based on the assumption that nuclear generation costs less than coal with CCS. However, proponents argue that coal-CCS could be a critical part of the low carbon technology portfolio for numerous reasons, including the abundance of coal and concerns over the safety or political acceptance of nuclear power[24]. Coal-CCS is important in water-energy interactions because its lower thermal efficiency, relative to that of traditional coal[25], requires more water for cooling. To explore this issue, we perform a sensitivity analysis in which we assume that the capital cost of coal-CCS is reduced by 50% by some combination of technological progress and government subsidy. For simplicity, we assume no change in operating cost or efficiency. Fig. 4 compares the effect of the lower coal-CCS capital costs for four of the previous scenarios: reference (no limits), a 25% CO_2 cap with no water cap, a 75% water cap, and 50% water cap. With a strict CO_2 cap but no water use restriction, the lower capital costs favor coal-CCS over nuclear. However, if water use must simultaneously be reduced to 75% or 50% of the reference, coal-CCS cannot replace nuclear even at lower costs because of the greater water requirements, and generation mix is the same as for reference CCS costs.

The key point of this analysis is that the resulting mix depends critically on the interactions of the generation technologies with each other, and that considering water limits along with CO_2 limits could dramatically change the configuration of the electric sector from what is typically predicted from energy-climate models that do not consider water.

A future where large reductions in greenhouse gases are desirable is likely to be one in which water resources are even more constrained than they are today. Although the electricity sector is only one part of the energy-water nexus, it is a critical one. Assumptions about the future technology mix in a low-carbon world typically have not considered simultaneous water use reductions. To the extent

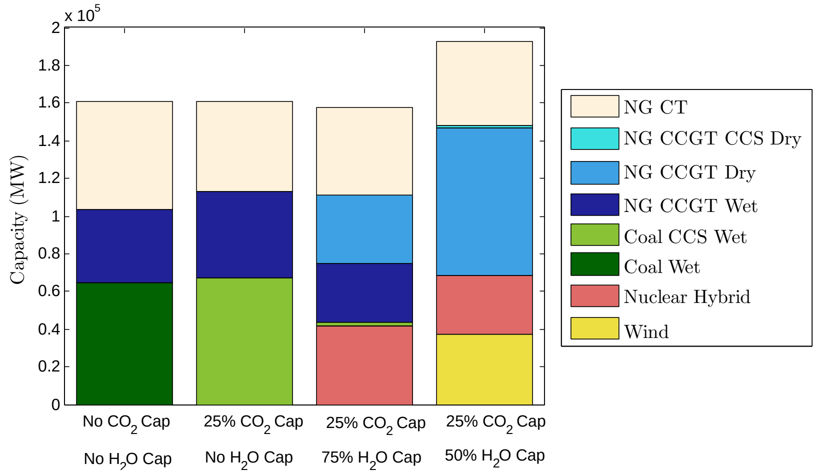

Figure 4: Capacity mix of electricity generation when carbon capture capital costs reduced by 50%.

that these technology portfolios are used for guidance to policymakers considering future regulatory designs or R&D investments, neglecting water in the models that produce these portfolios could lead to biased results and incorrect inferences.

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Supplemental Material

Model Formulation

We use a standard static generation capacity planning model, with simplified operations performing economic dispatch for an 8760 hour load duration curve. Below, we list the equations of the model and give the data assumptions in tables. The model is written in the GAMS programming language as a Mixed Integer Linear Programming (MILP) problem and solved using the commercial solver CPLEX 12.2. We use MILP to enforce that the number of generators of each type must be integer, where each generator technology type has a standard unit size. The model minimizes total system cost Z (A.1) subject to constraints(A.2)-(A.9) specified below.

$$\max_{n_g, e_{g,d}} Z = C^F_{OM} + C^V_{OM} + C^V_{FC} + C^F_I. \tag{A.1}$$

The control variables are the number of generation units n_g to build of each technology type g, and the energy generated $e_{g,d}$ by each unit of type g for demand time block d. The total cost is the sum of the fixed O&M costs C^F_{OM}, the variable O&M costs C^V_{OM}, the fuel costs C^V_{FC}, and the investment cost to build the capacity C^F_I. We constrain the power output in each time block to be equal to the total demand for that block,

$$\sum_g [e_{g,d}] = D_d \ \forall d. \tag{A.2}$$

Total emissions of CO_2 over the year must be below the cap E_{lim} if one is set,

$$\sum_d \sum_g [e_{g,d} * HR_g * E_g] \leq E_{lim}. \tag{A.3}$$

The total emissions are the sum over all demand blocks and all generation technologies of the product of the power output, the heat rate of the technology HR_g (the inverse of the efficiency), and the carbon content of the fuel E_g. Similarly, total water withdrawals must be below the cap W_{lim} if one is set,

$$\sum_d \sum_g [e_{g,d} * HR_g * W_g] \leq W_{lim}, \tag{A.4}$$

where W_g is the water withdrawal rate for technology t. The remaining constraints (A.5)-(A.9) define intermediate variables in terms of the underlying data. The capacity in MW of each technology is equal to the number of units built multiplied by the standard unit size,

$$CAP_g = n_g * SIZE_g. \tag{A.5}$$

Capital costs are defined as the capacity built multiplied by the annualized cost of capital, using a capital recovery factor

$$C^F_I = \sum_g CAP_g * CRF. \tag{A.6}$$

Total fixed O&M costs are the sum over technology types of fixed O&M costs multiplied by the capacity of that technology.

$$C^F_{OM} = \sum_g [CAP_g * C^F_{OM,t}]. \tag{A.7}$$

Total variable O&M costs are the sum over all demand blocks and all technology types of the variable O&M costs.

$$C^V_{OM} = \sum_d \sum_g [e_{g,d} * C^V_{OM,t}]. \tag{A.8}$$

Finally, the capital recover factor CRF is defined in terms of the weighted average cost of capital ($WACC$) and the economic lifetime of the unit L.

$$CRF = \frac{WACC}{1 - \frac{1}{(1+WACC)^L}}. \tag{A.9}$$

Table A.1: Generation Data Assumptions

Technology	Var. O&M [$ /MWh]	Fixed O&M [$/kW-yr]	Capital Cost [$/kW]	Heat Rate [MMBTU/MWh]	Plant Size [MW]	Water With. Rate [gal/MMBTU]
Nuclear Wet	2	89	5335	10.4	1350	105.9
Nuclear Hybrid	2	89	5558	10.4	1350	60.5
Nuclear Dry	2	89	5808	10.4	1350	15.1
Coal Wet	4.25	30	2844	9	600	65.3
Coal Hybrid	4.25	30	2945	9	600	37.3
Coal Dry	4.25	30	3059	9	600	9.3
Coal CCS Wet	9	63	4579	11.88	600	92.4
Coal CCS Hybrid	9	63	4807	11.88	600	76.3
Coal CCS Dry	9	63	5063	11.88	600	60.1
Gas CCGT Wet	3	15	1003	6.93	400	37.2
Gas CCGT Hybrid	3	15	1093	6.93	400	19
Gas CCGT Dry	3	15	1211	6.93	400	0.9
Gas CCGT CCS Wet	6.5	30	2060	9.15	400	55.1
Gas CCGT CCS Hybrid	6.5	30	2206	9.15	400	47.9
Gas CCGT CCS Dry	6.5	30	2396	9.15	400	40
Gas CT	10	7	665	11.87	230	0
Wind	0	28	2438	1	50	0

Table A.2: Fuel Cost and Carbon Content

Fuel	Price ($/MMBTU)	CO_2 (t/MMBTU)
Uranium-235	0.766	0
Coal	1.98	0.0965
Natural Gas	6.42	0.0531
Wind	0	0

We assume a weighted average cost of capital of 8%, and a 30yr lifetime for all generation technologies, except for wind with a 20 year life.

Data and Assumptions

Key assumptions about generation costs, efficiency, standard unit size, and water withdrawal rates are given in Table A.1. Capital costs, fixed and variable operations and maintenance (O&M) costs, the heat rate are based on the Energy Information Administration (EIA)[17]. The heat rate is the inverse of the efficiency, in units of MMBTU / MWh, and is used to compute the fuel usage for a given amount of generation output. Capital costs are based on building two co-located units. The water withdrawal rates are taken from a report of the National Energy Technology Laboratory (NETL)[10]. The unit sizes are an assumption based on commonly observed generation unit sizes of each type, in order to simulate the building of discrete units. These sizes are also based on EIA [17]

Fuel-related assumptions are given in Table A.2. The cost of fuel is based on projections to 2030 by the EIA[A.1], except for uranium-235, which is based on a study by the Royal Academy of Engineering[A.2]. The carbon content of fuels is based on data from the EIA program on voluntary reporting of greenhouse gas emissions[A.3].

The demand is based on 2009 ERCOT demand. We scale the 8760 hour demand data for ERCOT

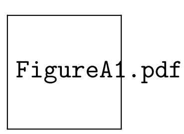

Figure A.1: Projected Load Duration Curve for ERCOT Demand in 2050.

by a factor of 2.15 (Figure A.1), based on an extrapolation of the trends in the ERCOT demand forecast[17].

Additional References

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