EPA Public Access

Author manuscript

Environ Sci Technol. Author manuscript; available in PMC 2020 July 16.

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Published in final edited form as:

Environ Sci Technol. 2016 November 01; 50(21): 11460–11470. doi:10.1021/acs.est.6b03048.

Scenarios for Low Carbon and Low Water Electric Power Plant Operations: Implications for Upstream Water Use

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Abstract

Electric sector water use, in particular for thermoelectric operations, is a critical component of the water-energy nexus. On a life cycle basis per unit of electricity generated, operational (e.g., cooling system) water use is substantially higher than water demands for the fuel cycle (e.g., natural gas and coal) and power plant manufacturing (e.g., equipment and construction). However, could shifting toward low carbon and low water electric power operations create trade-offs across the electricity life cycle? We compare business-as-usual with scenarios of carbon reductions and water constraints using the MARKet ALlocation (MARKAL) energy system model. Our scenarios show that, for water withdrawals, the trade-offs are minimal: operational water use accounts for over 95% of life cycle withdrawals. For water consumption, however, this analysis identifies potential trade-offs under some scenarios. Nationally, water use for the fuel cycle and power plant manufacturing can reach up to 26% of the total life cycle consumption. In the western United States, nonoperational consumption can even exceed operational demands. In particular, water use for biomass feedstock irrigation and manufacturing/construction of solar power facilities could increase with high deployment. As the United States moves toward lower carbon electric power operations, consideration of shifting water demands can help avoid unintended consequences.

Graphical Abstract

Introduction

Electricity production is a highly water intensive process in terms of both withdrawals (water diverted from water bodies such as rivers, lakes, and reservoirs) and consumption (water lost to evaporation or other losses that is not returned to the original water body).(1) Operational water use in thermoelectric power plants is primarily steam-cycle cooling.(2) Cooling technologies can be once-through systems, in which large amounts of water are withdrawn and returned to the water body at higher temperatures, or closed-loop recirculating systems that reduce withdrawals but increase consumption via evaporative losses. In 2010, total withdrawals for thermoelectric power were 609 B liters (161 B gallons) per day, representing 45% of total U.S. withdrawals for all sectors.(3) Water consumption for thermoelectric power is a smaller share at 2% but is projected to increase as thermoelectric plants shift from once-through to recirculating cooling systems, driven in large part by rules under Section 316(b) of the Clean Water Act that reduce impingement and entrainment of fish and other aquatic organisms at cooling water intake structures.(4)

The operational water use for the electric power sector has been reported and calculated for individual combinations of technology/fuel and cooling type,(5-7) for current electricity generation mixes,(8, 9) and future scenarios of electric power at various scales.(10-18) Assessments of future electric sector water use commonly leverage scenarios incorporating CO₂ emissions reductions using various modeling platforms (several articles provide comprehensive reviews of these studies(19-21)). Under climate mitigation scenarios, operational withdrawals typically fall relative to the base year. Operational consumption is somewhat more variable, often falling in midyears (2030–35) and increasing in later years (2050) with growing energy demands, increases in end-use electrification, additional nuclear power generation or carbon capture and storage (CCS), and turnover to higher-consuming recirculating cooling systems.(12, 22, 23)

The studies cited above represent the “water for energy” side of the water-energy nexus.(24, 25) In addition, there is a climate linkage.(26) Climate change will affect hydrology in ways that may decrease freshwater availability, exacerbate water stress, increase ambient air and water temperatures, and increase the intensity and frequency of storm surges, extreme storm events, and flooding, creating vulnerabilities for electricity generation.(27-29) While many studies have estimated electric sector water demands for carbon reduction scenarios, (12, 13, 15-17, 22, 23, 30) fewer have assessed the impact of limiting water.(10, 18, 31) Ackerman and Fisher ran scenarios of the western U.S. that included pricing per ton of CO₂ and acre-foot of water and found small changes in response to simulated water prices.(10) Webster et al. developed an electricity generation capacity expansion model of the Electric Reliability Council of Texas (ERCOT) for the year 2050, using the model to develop an optimal generation mix for three scenarios of carbon and water reductions.(18) Their findings showed that limiting both carbon and water simultaneously would shift the generation mix. CO₂ limits spurred higher levels of nuclear and natural gas combined cycle (NGCC) plants, while water withdrawal limits shifted the mix from nuclear power to more NGCC and wind capacity. Another study of ERCOT assessed the feasibility, cost, and air quality impacts of short-term dispatching strategies that would shift electricity generation out of drought-impacted areas (focusing on the 2006 drought in Texas) to other parts of the grid.(31)

Studies have also translated electric sector withdrawals and consumption, leveraging the Regional Energy Development System (ReEDS) model, into inputs for hydrologic and water management models.(32) Recently, researchers have expanded the capability of the ReEDS model to incorporate water availability as a constraint on future capacity expansion, modeling scenarios for water access rights and available cooling technologies.(33) However, to our knowledge, Webster et al. is the only study to endogenously model future electric power generation mixes under both carbon- and water-limited scenarios for U.S. regions.

Operational water use, however, is only one aspect of the full life cycle of water use for electricity generation.(34-37) Water requirements occur upstream along the fuel supply chain, including the extraction, processing, and transport of coal, natural gas, and uranium, or the allocation of irrigation water to biomass feedstocks used for electric power. Water is also used for the materials, manufacturing, and construction of electricity generation technologies, whether building a new power plant, erecting wind turbines, or deploying photovoltaic (PV) solar panels. This analysis investigates the following: How will moving to a lower carbon electricity generation mix affect water use from both an operational and a life cycle perspective? Will constraining the operational (i.e., cooling) water withdrawals or consumption affect the mix? How will the life cycle water use differ among regions under these combined low carbon and low water scenarios? Are there water trade-offs across the life cycle stages that decision makers may need to consider?

In this article, we take a combined energy system and life cycle approach to explore these potential trade-offs between climate change mitigation goals (reducing carbon emissions) and adaptation goals (reducing water requirements). We focus on reductions in operational water use, both consumption and withdrawals, for regional electricity mixes but also apply life cycle water factors. The goal is to identify potential unintended consequences or significant changes in water use for upstream fuel cycles and power plant equipment/manufacturing. To our knowledge, this represents the first analysis to assess the full life cycle water use for a range of future U.S. regional electricity portfolios.

Methods

MARKet ALlocation (MARKAL) Energy System Model

We used the MARKAL energy system model to develop a set of alternative long-range energy scenarios. A technology-rich bottom-up economic optimization model, MARKAL solves for the system-wide minimum-cost solution by determining the optimal fuel and technology mix that meets end-use demands given resource supplies and intermediate energy technology options.(38-40) The model is implemented assuming perfect foresight and utilizes a system-wide 5% discount rate. Energy resource supplies are characterized as supply curves. End-use demands are specified as energy services (e.g., vehicle miles traveled or lumens of lighting) that are met by end-use technologies (e.g., cars and trucks or lightbulbs) for transportation, residential and commercial buildings, and industrial demands. The major conversion technologies include electric power facilities and petroleum refineries, which convert primary resources into useable forms such as electricity and refined petroleum products. Technologies use input parameters including investment cost, operating costs, efficiency, and emission rates. They also include technology-specific discount or “hurdle”

rates that apply to the capital investment cost and reflect investment barriers and risk or consumer choice considerations.

The EPA's U.S. nine-region database (EPAUS9r) provides the input data for the MARKAL model at the level of the nine U.S. census divisions (see Figure S1), solving from 2005 to 2050 in 5-year time steps (see Lenox et al. 2013 for full database documentation).(41) This multidecadal time horizon allows users to model a range of scenarios, including scenarios that require more significant turnover (through retirement and new capacity expansion) of energy infrastructure and technology mixes. Recent studies using the publicly available EPAUS9r database have analyzed climate and air quality, (42-44) natural gas emissions, (45) biofuels, (46, 47) and water demands for energy. (22)

Resource supply curves, end-use demands, and technology costs are derived from the Energy Information Administration's (EIA) National Energy Modeling System (NEMS), and model inputs are taken from the EIA's Annual Energy Outlook (AEO). This analysis uses version EPAUS9r_14_v1.5 based on the EPAUS9r_14 publicly released version, which was originally calibrated to the 2014 AEO for fuel use and costs in each of the major sectors. Version 1.5 was last updated on January 19, 2016 and includes updates for wind and solar prices and availability factors (including drops in prices in 2015 as well projections of future price decreases), light and heavy duty vehicle emissions factors; methane emissions factors for natural gas extraction and coal mining, and carbon capture and storage (CCS) retrofit cost assumptions.

For the electric sector, the database includes coal, natural gas, biomass, nuclear, hydropower, geothermal, wind, concentrating solar power (CSP), solar PV, and other options. CSP refers to the use of fields of mirrors to focus sunlight to heat a working fluid that then ultimately drives a generator and produces dispatchable electricity. Distributed PV refers to smaller-scale residential and commercial solar panels, while centralized PV refers to larger solar PV arrays. There are also options for CCS for both new and existing facilities for coal, biomass, coal with co-fired biomass, and natural gas. The existing electricity generation capacity for each region is represented for 2005, allowing for capacity expansion using generation technologies already in commercial use as well as advanced technologies such as integrated gasification combined cycle with carbon capture and sequestration (IGCC-CCS) for coal, natural gas, or biomass.

Emissions include all traditional air pollutant and GHG emissions. The business-as-usual (BAU) case reflects the implementation of EPA rules and standards in place at the time of the EPAUS9r_2014 database calibration, including the Acid Rain Program (SO_2 and NO_x) requirements, Clean Air Interstate Rule, Mercury and Air Toxics Standards (MATS), regionally aggregated Renewable Portfolio Standards (RPS), Corporate Average Fuel Economy (CAFE)/Light Duty Vehicle GHG standards, Tier 3 light duty vehicle tailpipe emission standards, and heavy duty vehicle fuel and engine rules. In accordance with Section 316(b) of the Clean Water Act, all new electric generating capacity is assumed to utilize recirculating cooling systems. While not in the BAU, we also include a scenario of electric sector emissions reductions approximating targets for CO_2 reductions under the Clean Power Plan with the strong caveat that emissions reductions are implemented at the

regional level, whereas state-level plans or other multistate plans may differ significantly and will be determined by a range of additional policy, political, and other factors that cannot be modeled.

Life Cycle Water Use

As we discuss water use, we will discuss both water consumption and withdrawals, as defined earlier. When referring to water use factors or water intensity, these terms represent volume of water per unit of energy (liters/PJ of electricity generated or liters/PJ of fuel produced/consumed). Water use or demand represents the total volume of water use and represents the water intensity multiplied by the activity. Water use is separated into three stages of the electricity life cycle: operational water use for cooling and other on-site operations; fuel cycle water use for fossil fuel and uranium extraction, processing, and transport; and manufacturing water use for power plant equipment manufacturing, construction, and decommissioning. Where necessary, factors are converted from water use per unit of electricity output to input fuel or capacity based on factors including efficiency and energy content. Water use is calculated only for the U.S. and does not include water use associated with fuel/feedstock imports or foreign manufacturing of equipment and materials for power plant construction.

The operational water factors for withdrawal and consumption (Table S1) were originally incorporated in the EPAUS9r 2012 database as documented in Cameron et al.(22) The factors from Macknick et al.(5, 6) included both withdrawals and consumption and were applied to existing and new capacity. Because EPAUS9r does not model individual facilities, we applied the median consumption and withdrawal factors from Macknick et al. according to fuel type, technology, and cooling system (e.g., coal, steam, or once-through). Because water use factors are incorporated into the EPAUS9r database, total operational water use for electric power production is a direct output of the model and can also be constrained endogenously. Expanding in scope from the Cameron et al.(22) analysis, we also exogenously calculate water use for the power plant manufacturing (equipment and construction) and the upstream fuel cycle (resource extraction, processing, and transport) for input fuels to electricity generation. To do this, we draw extensively from Meldrum et al., which is the only study to have reviewed and harmonized life cycle water use for a broad range of electricity pathways.(36)

Water use factors for the power plant manufacturing stage are applied to the electricity output results from 15 categories of electricity generation. We assume for simplicity that all manufacturing, construction, and decommissioning water use occurs in the U.S. and is located in the region where the power plant is built (refer to the Supporting Information for more discussion). For certain electricity generation categories that appear in the MARKAL generation mix, manufacturing water use was not directly estimated by Meldrum et al. In those cases, water use factors for comparable technologies are used. Although addition of CCS could increase power plant manufacturing water consumption by 23–100%, water consumption for the manufacturing stage of natural gas and coal facilities (approximately 1 M liters PJ⁻¹) is negligible in the overall life cycle.(36) For solar PV manufacturing, we use

the Meldrum et al. estimate for crystalline silicone panels (85 M liters PJ⁻¹) instead of thin films because panels have had the larger market share.

For the fuel cycle stage, we also apply the harmonized water factors from Meldrum et al.(36) We calculate the water use for all domestically produced fuels used in electricity generation. Fuels for other end-uses and export are outside the scope of the analysis. However, fuels extracted in one region may be used for electricity generation or other uses in another region. The challenge is tracking the trading of fuels between regions and allocating the water use to only the share of fuel used for electricity generation. For all fuels, we allocate the fuel cycle water use to the region in which the mining and extraction occur. For coal and natural gas, to better track fuel trading and end use, water use factors are converted from gal MWh⁻¹ of electricity output to M liters PJ⁻¹ input fuel using the same performance parameters (e.g., thermal efficiency and higher heating value) used by Meldrum et al. for their data harmonization. We summarize our approach to different fuel cycles below (detailed calculations are included in the Supporting Information).

Water use for coal is based on total modeled coal production and is then exogenously allocated by regional shares of surface and underground mining operations.(48) These shares are assumed to stay constant. Water factors for surface mining (7.9 M liters PJ⁻¹) and the more water intensive underground mining (20.2 M liters PJ⁻¹) are then applied after converting from MWh of electricity to PJ of input coal. Finally, we calculate how much of the coal production is used for electricity generation to capture only that associated water use.

Tracking regional water use for natural gas is more complex. Unlike coal (about 90% used for electricity)(49) or uranium, natural gas directly supports a wide range of end uses. For the life cycle calculations, we allocate only the water use for the natural gas that eventually is utilized in electricity generation. We attribute water use to the region of extraction. The conservative assumption is that regional shares of shale versus conventional gas production remain constant. The impact of assuming higher shares, including 100% shale gas by 2050, is explored in the Supporting Information. An additional consideration is the extensive trading of natural gas between regions. We model the regional natural gas trading flows along with their associated water intensities and also account for the final share of natural gas (traded and locally extracted) going to electricity production relative to other end uses.

For uranium, we applied the Meldrum et al. factors based on water use per unit of electricity output, assuming centrifugal enrichment(50) (59 M liters PJ⁻¹) for domestically enriched uranium. We also accounted for the share of domestic (8%) versus foreign-origin (92%) uranium and calculated the regional distribution of fuel cycle water use based on EIA data for facilities producing uranium concentrate (see the Supporting Information for additional discussion).(40, 41)

Calculating water use related to biomass is difficult, and even very complete life cycle assessments of electric sector water use often do not include bio-based power or water use for the biomass feedstock fuel cycle.(36) However, energy portfolios under carbon limits may include biomass as an electric sector mitigation choice via co-firing with coal or

dedicated biomass generation with and without CCS.(51, 52) EPAUS9r includes seven categories of biomass feedstocks with stepwise linear supply curves developed based on the 2011 Billion Ton Study Update.(53) We included estimates of water use utilizing the WATER model from Argonne National Laboratory,(54) which also uses feedstock production estimates developed through the Billion Ton Study Update, ensuring consistency between the feedstock categories used in EPAUS9r, their regional distribution, and the water use estimates developed by the WATER model. We report “blue water” use, which we use as a proxy for water consumption and withdrawals. The WATER model allocates a portion of the blue water from irrigation to the crop residues, such as stover and wheat straw, based on the residue to grain ratio. This approach is consistent with many studies estimating the life cycle water requirements of fuels and energy from crops and residues;(55-57) however, we will discuss the alternatives for allocating water use to residues.(58) Factors for “green water” from evapotranspiration processes and “grey water” associated with contaminants or nutrient loading are outside of the scope of this analysis.(55)

Complexities also arise with hydropower. Because of the range of estimates (up to 19 000 M liters PJ^{-1})(59) and the difficulties in correctly allocating water use for reservoirs that support multiple uses (energy, recreation, water supply, and other),(19) we omitted hydropower from the water use calculations. This approach is common among many of the analyses of electric sector water demands(16, 23) with some notable exceptions.(30) Given the potentially high consumption, future work will be needed but will require inclusion of climate change impacts on hydropower generation and evaporative losses.

Scenarios

In this study, we compare a BAU scenario and seven additional scenarios to explore a range of electric power generation mixes with different carbon and water demands. The goal is not to be predictive but rather to explore potential trade-offs between reductions in carbon and water use from electric power generation and trade-offs between operational (cooling) water use and the upstream (fuel cycle and power plant manufacturing) water use in a regional context. Other electric-sector only models, such as the ReEDS model, provide a greater level of spatial detail on the electric power mix and water resources.(33) However, a full energy system model such as MARKAL is useful for combining with life cycle water factors to better understand changes in upstream energy demands and water use resulting from electric sector trends. The goal of this effort is not to model future water scarcity impacts on electric sector capacity but rather to examine the potential for major upstream life cycle shifts in water use under low carbon and low water power operations. In particular, the scenarios can inform where emerging water demands associated with low carbon electricity pathways may warrant additional attention from decision makers.

The scenarios are summarized below:

- BAU: Business-as-usual with no limits on CO₂ emissions or water use.
- 30%: Limits to reduce regional electric sector CO₂ emissions by approximately 30% in 2030 relative to 2005 levels.

- LC (low carbon): U.S. energy system-wide limits to reduce CO₂ to 50% of 2005 levels by 2050.
- LCLW (low carbon, low withdrawals): The LC scenario plus limits to reduce regional operational (i.e., cooling system) water withdrawals, leading to a 50% reduction by 2050 relative to 2005 levels.
- LCCC (low carbon, constant consumption): The LC scenario plus limits to constrain regional operational (i.e., cooling system) water consumption to 2005 levels.
- LC-NB (low carbon, no biomass): The same as LC, excluding biomass to the electric sector via either steam, integrated gasification, dedicated biomass, or co-fired biomass.
- LCLW-NB: The same as LCLW, excluding biomass to the electric sector.
- LCCC-NB: The same as LCCC, excluding biomass to the electric sector.

The carbon limits under all LC scenarios are national and intended to represent energy system-wide reductions across all energy sectors and reductions deeper than the 30% scenario, which applies to the electric sector only. The water constraints (LW and CC) are regional and applied only to the electric sector operational (e.g., cooling system) water use (Figure S3). These operational water constraints do not directly correlate to potential water scarcity or competition in a specific region but are intended to approximate the dynamics of reduced cooling water availability (low withdrawals) or competition with other users of water resources (constant consumption). The NB scenarios are intended to force a different set of decarbonization pathways and are motivated by the high water requirements of biomass and uncertainties regarding this CO₂ mitigation option, as will be discussed later.

Results

Comparing BAU with seven scenarios of different combinations of limits on carbon, water, and biomass shows a wide range of results for each region. In many regions, the results differ markedly across scenarios in terms of total electricity demand and generation mix, total water consumption and withdrawals, and the relative contribution of each life-cycle stage to the total water demands. We will explore each aspect in turn.

Regional Electricity Generation Mix

Using the constraints on CO₂ emissions, water use, and biomass as “policy levers”, the scenarios were designed to yield a range of regional electricity portfolios. As seen in Figure 1, there are differences in total regional electricity generation and technology mixes. In 2050 for BAU, electricity generation is higher than 2015 levels due to growth in population, industrial activity, and associated electricity demands. For the 30% scenario, total generation in 2050 is higher than the 2015 levels but lower than the BAU due to slightly lower electricity demand in end-use sectors. In contrast, the LC constraint, which requires 50% system-wide reductions from all energy sectors (including buildings and transportation), leads to higher total electricity demand relative to the BAU and 30% scenario. This is

because the deeper, system-wide reductions force the model to switch end-use sectors to the low carbon electricity (e.g., vehicle electrification) and away from higher carbon fuels.

In terms of the electricity mix, the BAU and 30% scenarios show an expansion of natural gas and renewable power and a decrease in coal. The LC scenario requires a more complete shift toward nearly zero carbon electricity, mainly nuclear, wind, centralized and distributed solar, and CCS for both new natural gas facilities and coal facilities via retrofits. Interestingly, the coal facilities with CCS also utilize biomass through co-firing up to approximately 9% on an energy basis. Although the biomass contribution to total generation is small, its role in reducing the CO₂ emissions from coal-CCS with co-firing is important nonetheless. When biomass supplies are removed under the NB scenarios, the mix shifts entirely away from coal with CCS to additional nuclear, natural gas with CCS, centralized solar PV, and CSP (see Figure S4 for differences). While the NB scenarios explore one set of uncertainties, additional sensitivity analysis runs are included in the Supporting Information to highlight key uncertainties in the technology mix and their potential implications for life cycle water use.

The addition of regional water withdrawal constraints (50% lower withdrawals relative to 2005) has a relatively small effect. Because the LC scenario accelerates retirement of coal and other thermoelectric facilities with once-through cooling, withdrawals fall significantly relative to 2005 even in the absence of water constraints (Figure S6). As a result, the LC and LCLW scenarios have only marginal differences in the regional generation mix with the exception of Regions 8 and 9. Constraining regional water consumption for the operational stage to 2005 levels (e.g., limited water availability for cooling), on the other hand, shifts the generation mix substantially. Comparing the LC and LCCC scenarios in Figure 1 shows a contraction in the use of nuclear, coal with CCS, and CSP in most regions, while additional natural gas with CCS and wind comes into the mix.

The extent to which each region has to reduce its water consumption to move from the LC to LCCC scenario generally determines how much the electricity generation mix has to change. Under the combined carbon and water consumption constraints in LCCC, interregional trading and prices also become important. For example, the water consumption constraint moves Region 8 from coal with CCS and nuclear to natural gas with CCS, wind, and solar PV. Region 8 also expands electricity generation and exports to Regions 4 and 7. All regions except 6 and 9 reduce their nuclear capacity, primarily in favor of natural gas with CCS. Region 9, to move from LC to LCCC, retains and even expands its nuclear capacity, an important baseload technology, while expanding wind and solar PV. It also sharply reduced water consumption by moving away from geothermal, which is highly water intensive. In contrast, Region 2 does not have to reduce operational water consumption given its already low levels, and in this case actually increases the both total generation and its use of wind and natural gas with CCS under the LCCC scenario. It also exports electricity to Regions 1 and 3. Region 6 shows a somewhat counterintuitive result, as it did not need to make major reductions in operational water use to meet the LCCC constraints. However, it still had major shifts in the generation mix. This is due to the model's endogenous price dynamics. As other regions move toward more natural gas, the higher demand for natural gas raises prices. Region 6, now facing a higher natural gas price, opts to shift to more nuclear.

The LCCC-NB scenario is the most restrictive of all scenarios. With all three constraints applied on carbon, water, and biomass, this scenario shows the results most divergent from the BAU. The LCCC-NB results shift toward solar PV and natural gas with CCS and move away from coal-biomass with CCS and CSP.

Life Cycle Water Use Across Scenarios

Water use, for all electricity life cycle stages, is compared for 2015 and 2050 across the BAU and seven alternative scenarios.

For withdrawals, as shown in Figure 2, the operational stage (green) overwhelmingly dominates the life cycle water use. Therefore, reductions in operational water withdrawals directly translate into reductions in total life cycle water withdrawals. There are minimal increases in manufacturing (blue) or fuel cycle (yellow) water withdrawals. Relative to 2015, total life cycle withdrawals in 2050 are lower across all scenarios, including BAU.

Withdrawals decrease with more stringent CO₂ constraints: the 30% and LC scenarios have life cycle withdrawals 13 and 37 T liters yr⁻¹ below BAU. These lower withdrawals are driven by decreases in the operational water withdrawals, which are due to accelerated retirement of coal-fired facilities with once-through cooling and a shift to higher efficiency natural gas-fired power plants and more renewables. Because of the drop in water withdrawals driven by the CO₂ constraints, the addition of a low withdrawal constraint in the LCLW scenario leads to only minor changes (an additional reduction of 8 T liters yr⁻¹) at the national level, relative to the LC scenario. At a regional level (Figure S6), only Region 8 shows a significant withdrawal contribution from the nonoperational stages under some scenarios.

Water consumption presents a more complex picture of trade-offs across life cycle stages. For all scenarios, 2050 life cycle water consumption is higher than 2015 levels. Most of the consumption still comes from operational water use for cooling. This operational water consumption growth is driven by growth in electricity demand by 2050, with new demands met predominantly by generation technologies using recirculating cooling. For 2050, the 30% scenario represents the lowest operational and full life cycle water use. Relative to BAU, the fuel cycle and manufacturing water use is higher in the 30% scenario but not enough to offset the lower operational water consumption. In contrast, the deeper CO₂ reductions in the LC scenario lead to increases in life cycle water consumption by nearly twice the levels of the 30% scenario and reflect additional nuclear and higher total electricity demand (as shown in Figure 1) needed to meet system-wide carbon constraints that force a certain degree of additional electrification of end-use demands.

While the nonoperational (fuel cycle and manufacturing) stages make a negligible contribution to water withdrawals, these stages become increasingly important for water consumption. Nonoperational (fuel cycle and manufacturing) water consumption grows from a 7% share in 2015 to a 24, 25, and 26% share in the LC, LCLW, and LCCC scenarios, respectively, at the national levels. This is primarily due to the use of biomass co-fired with coal for electricity with CCS retrofits. For this reason, biomass fuel cycle water use is shown separately (hatched yellow) in the regional graphs in Figure 3. In particular, Regions 4, 5, and 7 show the highest levels of water use associated with biomass. This model solution for

the electric sector leads to use of feedstocks such as corn stover (e.g., in Region 4), wheat straw, and other agricultural residues (e.g., in Region 8) to which a portion of the total crop irrigation water use is allocated.

In these scenarios, the high total water consumption is due not to large quantities of biomass used, given that biomass is only co-fired with coal at about 9% blend, but rather to the extremely high water intensity of the biomass feedstock. These results, therefore, are highly sensitive to the decisions regarding how to calculate water intensity as well as how to allocate water use for residues versus crops, which could include zero allocation, allocation based on economic value, to mass-based allocation. A dry ton of corn stover feedstock from rain-fed production in Iowa requires roughly 760 L (200 gallons) compared to irrigated acres in Kansas or Nebraska that may require over 189 000 L (50 000 gallons).(54) The data from the WATER model are also sensitive to the year of crop, irrigation data, and climate assumptions. Clearly, under a future climate of higher evapotranspiration, there would be higher irrigation rates or expansion of irrigated acreage, which would further intensify the water use, while more efficient irrigation practices, higher yields, or drought resistant crops could lower water use.

As discussed earlier, an operational water consumption constraint (i.e., restricting cooling water use) shifts regional electricity generation mixes. In terms of water trade-offs across the life cycle (e.g., nonoperational water use going up when operational water use is restricted), the regional results are mixed. We compare the shift from LC to LCCC. In Regions 1, 7, 8, and 9, lowering operational water consumption also reduced water consumption for biomass and fossil fuel cycles as well as manufacturing water use. Region 4 has slightly more biomass-related water use on top of its already high levels in the LC scenario. With a 56% share of total life cycle water consumption, Region 4's biomass-related water use surpasses even operational water consumption in the LCCC scenario. However, while the share changes, the absolute water consumption for biomass in the LCCC differs only marginally from the biomass water consumption in the LC scenario.

Given the sensitivity of the results to biomass utilization, we ran NB scenarios with no biomass for either co-firing with coal or dedicated biomass steam or IGCC. There is still a trade-off among stages of the life cycle, albeit of a different type. When removing the use of biomass for electricity under the constant water consumption scenario (e.g., comparing the LC and LC-NB scenario), the manufacturing stage increased and became the major nonoperational water use as the regions shift away from biomass as a low carbon option and toward a greater use of nuclear, solar PV, CSP, and natural gas with CCS (Figure S5). In the no-biomass scenarios, the nonoperational water use falls to between 8 and 10% of life cycle water use at the national level. However, it also shifts to more water consumption for the manufacturing stage for solar PV and CSP technologies.

Contribution of Nonoperational Water Use

As shown in Figure 3, fuel cycle water use increases sharply for the regions where biomass formed a key carbon reduction strategy. The majority of these increases are a result of biomass co-fired with coal with CCS in the LC, LCLW, and LCCC scenarios. Figure 4 highlights the scale of the differences. Water consumption for irrigation of biomass

feedstocks is an order of magnitude higher than that of the other fuel cycles in the LC scenario and is particularly high in Regions 4, 7, and 8. For nonbiomass fuel cycle water consumption, however, the trend is generally decreasing for all regions. In 2015, the fuel cycle water use is highest for coal, followed by natural gas and uranium, and is generally concentrated in the more resource-rich regions, for example, Region 8 for coal and uranium and Region 7 for natural gas. When 2050 to 2015 levels are compared across all scenarios, the fuel cycle water use for coal falls, whereas natural gas cycle water use varies across scenarios (Figure S7), increasing in some regions in the BAU, 30%, LCCC, and LCCC-NB scenarios, but generally falling in other scenarios. Looking at the most water intensive region in terms of fossil fuel cycle water use, Region 8, the shift from coal to biomass co-firing and nuclear in the LC scenario lowers coal-related water use but with increases in biomass water use and nearly doubling of uranium water use.

Turning to water use for power plant manufacturing, Figure 4 shows the relative contribution of the different electricity generation technologies for the LC scenario. Solar power, in particular CSP, entered the electricity mix because of the CO₂ limits and had a substantial impact on the manufacturing stage of life cycle water use. Although the life cycle water factors developed by Meldrum et al. (36) highlighted the high water intensity of CSP for both the manufacturing phase as well as the operational phase, the extent to which that affected the overall water footprint for the regional electricity mix in certain regions was surprising. This high water intensity of the CSP power plant and equipment manufacturing (168 M liters PJ⁻¹) is due to the requirement of the specialty chemicals (i.e., mined and synthetic nitrate salts). The lower availability of both solar PV and CSP due to intermittency (nighttime or cloudy days) also means lower lifetime electricity output for a facility, driving a higher water use per unit of output. Looking at the manufacturing water consumption for all technologies excluding CSP and PV (the left side of Figure 4b), the next largest contributor is wind, followed by nuclear and natural gas.

Discussion

A range of studies(19, 20) using electric sector or energy system modeling tools have estimated total operational water consumption and withdrawal for future electricity mixes under different scenarios. Although life cycle water use has been estimated for selected electricity generation technologies and total operational water use has been estimated for different electricity mixes, this is the first time that the full life cycle water use has been estimated for regional electricity mixes in the U.S. In terms of water withdrawals, the operational water use remains the major driver. As stricter carbon limits are put in place, withdrawals at the national level and in most regions decline. Constraints on operational water use change operational water demands, but there are no major trade-offs in the form of increased withdrawals from the fuel cycle or manufacturing stages of the electricity life cycle. Water consumption is more complex, with increased life cycle water consumption for all scenarios relative to 2015 as well as a number of regional trade-offs in the form of reductions in operational consumption, often leading to higher fuel cycle and manufacturing consumption. The results highlight the potential upstream water use impacts of emerging low carbon electricity pathways such as biomass-based mitigation options (affecting the fuel cycle water use) and CSP (affecting the power plant manufacturing water use).

In terms of methodological challenges, allocating the fuel cycle and power plant manufacturing water use to the appropriate region is difficult because of interregional fuel trading and uncertainties regarding where future resource extraction and manufacturing of power plant equipment may occur. However, the results provide insights regarding the regional-scale drivers of water use as well as the uncertainties in the data regarding water factors and in the assumptions required to regionally allocate the water use for different life cycle stages. Clearly, biomass water use was critical and orders of magnitude different than fossil fuels and uranium. Water use associated with coal mining and processing is significant relative to other nonbiomass fuel cycles but is generally declining in the scenarios.

The water consumption associated with the natural gas fuel supply chain is of high interest due to recent expansion of natural gas extraction and related water quality concerns.⁽⁶⁰⁾ However, natural gas water consumption is generally on the same scale as that of coal extraction and processing based on this analysis. Looking ahead, there are many uncertainties related to natural gas production: future growth in domestic supplies, its role in climate mitigation, potential LNG exports, and uncertainties regarding the water intensity of production methods.⁽⁶¹⁻⁶³⁾ New data continue to emerge regarding the heterogeneity of water use both between and within different shale plays, meaning more spatially detailed analysis is needed.⁽⁶⁴⁾

The nuclear fuel cycle (milling, conversion, enrichment, etc.) is highly water intensive, ranging from 59 to 92 M liters per PJ electricity output depending on the enrichment process. This water intensity is higher than that of shale gas and underground coal mining when normalized to units of electricity generated from those fuels.⁽³⁶⁾ However, the total U.S. water use (in liters) calculated here for the nuclear fuel cycle (uranium recovery, milling, conversion, and enrichment) is low considering the large share of U.S. nuclear power production in the mix. This is because of the large amount of imported uranium (approximately 92% in 2013), the water use for which was excluded from the calculations when looking at water demands in the U.S. (see the Supporting Information for additional discussion).

Returning to the issue of biomass, there are unique challenges here. Using the MARKAL scenarios and applying consumptive water use on a state level according to the types of feedstock allows for estimates of scenario-specific water use for the biomass fuel cycle. However, the results are highly sensitive to those scenarios. Scenarios using more no irrigated energy crops would have a very low consumptive water use, whereas agricultural residues such as corn stover have a very high consumptive use in some regions. We allocated biomass feedback water use using the assumptions from the WATER model, which allocates water use based on the mass ratio of residue to grain. Other approaches to allocation could include zero allocation to the residue or allocation based on economic value. Geography also matters because irrigation rates vary widely. Finally, there are critical technical, scientific, and policy questions regarding long-range feasibility of biomass-based electricity with CCS (either through co-firing or dedicated biomass). Techno-economic questions include: biomass availability, cost and logistics for delivery to the power plants, ability to achieve economies of scale due to limited biomass supplies, and technical barriers related to the handling and gasification of biomass and incorporation of CCS. A key science and policy

issue is the role of biomass as a carbon mitigation strategy and approaches to biogenic carbon accounting.(65)

In addition to the power plant manufacturing water use, the CSP operational cooling water use also becomes a relatively significant source of water use for the regional electric power mix, particularly in those regions with a high penetration of CSP. Under the constrained consumption (LCCC) scenario, CSP use decreases, leaving solar PV as the major manufacturing water consumer. A key uncertainty is the estimate of CSP power plant equipment and manufacturing water use, where design alternatives can have a major impact on both CO₂ emissions and water consumption.(66) Other uncertainties include (a) geographic allocation of the water use for the power plant manufacturing stage, which may or may not be in the region where the CSP power plant will be installed, and (b) temporal allocation of the water use, which is amortized over the life of the power plant for the life cycle water use factors, but in reality would occur in a more limited time window.

With very low operational water use and no fuel cycle water use, the water footprint of wind power was low across all scenarios. The only water impact from wind is the water associated with the power plant manufacturing stage, which was minimal even under scenarios with very high deployment of wind power. Regional results showed lower consumption and withdrawals when scenarios had high levels of wind power, which reduced water use across all life cycle stages.

Looking at another renewable power source, hydropower, analysis of its water consumption was outside of the scope of this analysis. However, as discussed earlier, future assessments should explore the role of hydropower and evaporative losses, including potential climate-change driven impacts.

Coupling energy system scenarios with water use factors for upstream fuel cycle and power plant manufacturing allows for a broader life cycle assessment of the water demands of regional electricity portfolios under different scenarios. There are key uncertainties in the assumptions that affect the projected technology mix and the water factors that are applied for all life cycle stages. These are further explored and discussed in the Supporting Information, which includes five additional sensitivity runs. However, we can draw insights from these scenarios. For water withdrawals, the trade-offs appear to be minimal: operational water accounts for over 95% of total life cycle withdrawals across all regions in all scenarios. For water consumption, this analysis identifies some potential trade-offs that decision makers may see as unintended consequences. Moving toward a lower carbon energy system and less water intensive electric sector (in terms of consumption) can lead to significant increases in the water consumption in the upstream stages of the life cycle (e.g., biomass feedstock production and manufacturing of CSP and PV). We caution that upstream impacts are highly region and scenario specific but suggest that they merit additional exploration, including more extensive sensitivity analysis on the technology mix and water intensity of key technologies.

Supplementary Material

Refer to Web version on PubMed Central for supplementary material.

Acknowledgment

The authors would like to acknowledge Carol Lenox, Ozge Kaplan, and Dan Loughlin of the EPA's Energy and Climate Assessment Team, which is responsible for developing and maintaining the EPAU9r MARKAL database. We also thank Ozge Kaplan and Wes Ingwersen for feedback on earlier drafts. The views expressed in this article are those of the authors and do not necessarily reflect the views or policies of the U.S. Environmental Protection Agency.

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Figure 1.

Electricity generation mix (PJ) by major fuel/technology type in 2015 and 2050 for BAU and seven scenarios: 30% reduction (30%), low carbon (LC), low carbon and low withdrawals (LCLW), low carbon and constant consumption (LCCC), and the same carbon and water constrained scenarios without biomass (LC-NB, LCLW-NB, and LCCC-NB). Results are shown at the nine-region (Census Divisions) and national level.

Figure 2.

(a) National water withdrawals (T liters yr⁻¹) by life cycle stage in 2015 and 2050 for the BAU and seven scenarios. The dashed boxes show the 2050 water withdrawal reductions relative to BAU. (b) National water consumption (B liters yr⁻¹) by life cycle stage in 2015 and 2050 for the BAU and seven scenarios.

Figure 3.

Regional water consumption (B liters yr⁻¹) by life cycle stage in 2015 and in 2050 for the BAU and seven scenarios. The fuel cycle water use (yellow) is divided into biomass water use and other fuel cycle (coal, natural gas, and uranium) water use. The markers show operational (i.e., cooling system) consumption in 2005 for each region. For the LCCC and LCCC-NB scenarios, the operational stage is constrained to meet those levels out to 2050. If the green bar for the operational water use for the LC scenario is above those regional operational water constraint markers, it means that the region has to make cuts in operational stage water use under the LCCC scenario.

Figure 4.

Regional water consumption (B liters yr⁻¹) under the LC scenario in 2015 and 2050 for (a) the fuel cycle stage and (b) the power plant manufacturing stage. For the fuel cycle stage, biomass is shown on a separate scale; for the power plant manufacturing stage, solar PV and CSP are shown on a separate scale, as these are orders of magnitude higher