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LETTER

Water supply as a constraint on transmission expansion planning in the Western interconnection

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Abstract

Consideration of water supply in transmission expansion planning (TEP) provides a valuable means of managing impacts of thermoelectric generation on limited water resources. Toward this opportunity, thermoelectric water intensity factors and water supply availability (fresh and non-fresh sources) were incorporated into a recent TEP exercise conducted for the electric interconnection in the Western United States. The goal was to inform the placement of new thermoelectric generation so as to minimize issues related to water availability. Although freshwater availability is limited in the West, few instances across five TEP planning scenarios were encountered where water availability impacted the development of new generation. This unexpected result was related to planning decisions that favored the development of low water use generation that was geographically dispersed across the West. These planning decisions were not made because of their favorable influence on thermoelectric water demand; rather, on the basis of assumed future fuel and technology costs, policy drivers and the topology of electricity demand. Results also projected that interconnection-wide thermoelectric water consumption would increase by 31% under the business-as-usual case, while consumption would decrease by 42% under a scenario assuming a low-carbon future. Except in a few instances, new thermoelectric water consumption could be accommodated with less than 10% of the local available water supply; however, limited freshwater supplies and state-level policies could increase use of non-fresh water sources for new thermoelectric generation. Results could have been considerably different if scenarios favoring higher-intensity water use generation technology or potential impacts of climate change had been explored. Conduct of this exercise highlighted the importance of integrating water into all phases of TEP, particularly joint management of decisions that are both directly (e.g., water availability constraint) and indirectly (technology or policy constraints) related to future thermoelectric water demand, as well as, the careful selection of scenarios that adequately bound the potential dimensions of water impact.

1. Introduction

While consumptive water use associated with thermoelectric power generation in the United States, estimated at 4836 Mm^3 (Diehl and Harris 2014), is small with respect to other water sectors (particularly irrigated agriculture), continued growth is expected for the electric sector (electricity demand to increase by 7%–23% by 2032 Energy Information Administration 2013) prompting concern over the availability of water to meet future demands (e.g., Government Accountability Office (GAO) 2012, Department of Energy (DOE) 2006). Studies attempting to project future thermoelectric water consumption have yielded results ranging from an increase of 63% to a decrease of 60% depending on the assumed mix of fuel/cooling type and emission controls (Feeley *et al* 2008, National Energy Technology Laboratory 2008, Macknick *et al* 2012). More important is how these new demands are geographically distributed and their relation to regional water resources (Sovacool and Sovacool 2009, Scott *et al* 2011, Tidwell *et al* 2012, Averyt *et al* 2013, Yates and Flores 2013). Expanded utilization of carbon capture and sequestration technology (Chandel *et al* 2011, Tidwell *et al* 2013) as well as climate change (Roy *et al* 2012, Department of Energy (DOE) 2013) have been identified as potentially important considerations relative to the thermoelectric-water nexus.

Transmission expansion planning (TEP) is a process in which the need for new electric power generation and transmission capacity is assessed for a range of assumed future conditions (e.g., Wu *et al* 2006). Beyond identifying the need for new generation, specification of power plant type (fuel and prime mover), cooling type, and location are generally made. These choices ultimately dictate changes in the thermoelectric water withdrawal and consumption profile of the TEP region. As such, consideration of available water supply (both fresh and non-fresh sources) in TEP represents an important opportunity for managing the evolving impact of thermoelectric power on water resources. While water has traditionally been an important consideration for the individual power plant (Hamilton 1979), little coordinated planning has been practiced at the utility or interconnection level. Also lacking has been engagement with local, state and federal water managers, at least until the point of permitting (Hightower and Pierce 2008). This has led to the siting of several new thermoelectric facilities being contested on the basis of water supply (e.g., Seattle Post-Intellingencer 2002, Blake 2002, Curlee and Sale 2003, Reno Gazette-Journal 2006). Other evidences include Idaho's moratorium on construction of coal-fired power plants (Idaho House Bill No. 791 2006, Adams 2010) because of potential impacts to the state's water resources, and California's policy against use of freshwater for new thermoelectric development (California Water Code, section 13552).

Here we report on efforts to explicitly integrate water supply availability (including fresh and non-fresh sources) into the Western Electricity Coordinating Council's (WECC) 20 Year Regional Transmission Expansion Planning exercise Western Electricity Coordinating Council (2013a). WECC, also known as the Western Interconnection, is a non-profit company responsible for the coordination and promotion of bulk electric system reliability in the Western United States. This effort is unique in that, to the authors' knowledge, this is the first time for water availability to be integrated into a TEP process beyond the scale of a single utility. Experience gained from this exercise provides valuable insight into the challenges with integrating available water supply into TEP; how differently thermoelectric water use (withdrawal and consumption) futures look when subjected to a range of assumptions concerning technology, fuel costs, demand growth and policy; and, how water availability can impact and be impacted by TEP. Given the breadth and complexity of the WECC TEP process, this paper limits itself to the methods and results pertaining to the integration of water. A full accounting of the WECC TEP process and results is available in a variety of reports (Western Electricity Coordinating Council 2013a, 2013b, 2013c, 2013d, 2013e, 2013f, 2013g, 2013h, 2013i).

2. Methods

The WECC TEP process endeavored to co-optimize new electric power generation and transmission capacity additions for a range of assumed future conditions considering such factors as fuel prices, technology cost, energy policy, environmental regulation and electricity demand. Because of concerns over limited water supplies in the West, there was a desire to integrate water into the TEP process. To address this concern, integration was achieved by treating water as a constraint on where a power plant might be located; specifically, water availability values estimated with the help of state water managers were used to inform the location of new thermoelectric generation. Given the size, complexity and diversity of concerns of the TEP process, the author team had little engagement with the broader TEP team beyond developing the necessary water data, assisting with its integration into the modeling process and interpreting the water related results. Accordingly, the scope of this paper is limited to the water related aspects of the WECC TEP process.

Below, the framework adopted for integrating the water supply constraint into the WECC TEP is reviewed. The discussion begins with a high-level overview of the TEP process with attention limited to those aspects influencing or influenced by water. Reviewed are the planning scenarios and transmission planning models that served as a basis for the analysis. More detailed information on the planning process is available in a variety of WECC reports (Western Electricity Coordinating Council 2013a, 2013b, 2013c, 2013d, 2013e, 2013f, 2013g, 2013h, 2013i). The discussion then turns attention to the approach to integrate water into the TEP process and evaluation of effects on water availability in the West.

2.1. Transmission expansion planning

The objective of the WECC TEP exercise was to draw clear connections between energy policy, technology costs, and environmental drivers on generation and transmission choices for the WECC service region. Recognizing the inherent uncertainty in these drivers, a series of equally likely energy futures were developed, termed scenarios, which served as the basis for planning. To support analysis of these varied scenarios, planning models were formulated.

2.1.1. Planning scenarios

The WECC TEP process was organized according to two study timeframes looking out 10 and 20 years (to 2022 and 2032) in the future Western Electricity Coordinating Council (2013a). Division of the TEP process in this way was necessitated by differences in the character of planning across these two timeframes. Because of the long lead times required for permitting and financing large new capital projects, utilities have some idea of the generation and transmission capacity additions they will invest in over the next 10 years. So, in the initial phase of planning the focus of the TEP process was aimed at evaluating whether planned additions will meet demands projected for the next 10 years. In the second 10 year timeframe there is much more uncertainty and thus latitude as to the type, capacity and location of new additions. As such these two planning timeframes require different approaches and analysis tools.

Scenario-based planning served as the basis for managing uncertainty in the TEP process. Scenarios were developed through a deliberate stakeholder process involving facilitated workshops, an on-line database, webinars and assembly of targeted task forces which developed metrics and policy ideas for the overall project effort. The Scenario Planning Steering Group, comprised of representatives from load serving entities, transmission owner/operators, independent system operators, public utility commissions, state government, tribal government, technology advocates and environmental non-governmental organizations, took responsibility for this process.

The initial 10 year timeframe used a bottom-up process with load, resource and transmission information gathered through the aforementioned stakeholder engagement process. From this information, the '2022 common case' was created that represented an 'expected' future for the Western Interconnection based on recent trends and plans. Additional detail on the 2022 common case and related planning and analysis can be found in WECC (Western Electricity Coordinating Council 2013b).

For the second 10 year planning timeframe (2023–2032) a top-down process was used. This process started from the 2022 common case and then co-optimized the addition of resources and transmission for each of several contrasting top-down scenarios depicting the future through 2032. Unlike the initial 10 year timeframe, which looked at the performance of a specific generation and transmission infrastructure package, the second 10 year timeframe co-optimized generation and transmission expansions to meet the requirements specified by each scenario subject to a variety of planning and policy constraints.

Planning in the second 10 year timeframe used a set of scenarios based on policy, technology, environmental regulation, and other considerations—examples include renewable portfolio standards (RPSs), population growth, changes in technology, energy efficiency and demand-side management effects, regulatory policy for greenhouse gases and other environmental issues, and overall economic conditions (Western Electricity Coordinating Council 2013c). The intended outcome of the scenario development process was a set of logical, internally consistent narratives that describe what the future *might* look like without making any attempt to predict what the future *will* look like or any recommendation of what the future *should* look like. The scenarios were designed to set the context for identifying strategic resource options that had the capability to meet peak or other high-stress load conditions while minimizing the levelized (long-run) cost of energy.

Scenarios were crafted around a reference case which served as the basis for comparison and four WECC scenarios which represented four contrasting futures. The reference case represented a future trajectory based on the 2022 common case trends, or the business as usual case. The four WECC scenarios were constructed to generally represent four quadrants distinguished by low-to-high economic growth and evolutionary-to-paradigm changing technology innovation in electric supply and distribution. A thumbnail sketch of the reference case and each of the four scenarios, collectively referred to as the scenario study cases, is as follows:

- Reference case: represents the trajectory of recent WECC planning information, developments and policies extended out 20 years (Western Electricity Coordinating Council 2013d).
- Scenario one: wide-spread economic growth and evolutionary technology innovation (favoring continued trends in growing use of natural gas and renewables) (Western Electricity Coordinating Council 2013e).
- Scenario two: wide-spread economic growth and paradigm change in technology (distinct shift toward renewables, energy efficiency and significant carbon tax) (Western Electricity Coordinating Council 2013f).
- Scenario three: Slow economic growth and evolutionary technology innovation (rely on traditional technologies while simply meeting current state RPS; no carbon tax) (Western Electricity Coordinating Council 2013g).
- Scenario four: Slow economic growth and paradigm change in technology (similar technology development and policies as in scenario two except limited

by sluggish economic growth) (Western Electricity Coordinating Council 2013h).

Tables comparing key drivers, modeling parameters and policy themes across the different scenario study cases are provided in the supplemental material for this paper (tables S1 and S2).

2.1.2. Transmission expansion models

As the two 10 year planning horizons were approached in different ways, the development of unique tools, models, and datasets were required to meet the individual needs of each. Specifically, planning analyses over first 10 year timeframe (2013–2022) were performed with the aid of a production cost model (PCM), while the second 10 year timeframe (2023–2032) utilized a capital expansion model (Western Electricity Coordinating Council 2013i).

The PCM simulated the operation of the power system given a discrete set of assumed (input) load, generation and transmission characteristics. It performed a security-constrained economic dispatch (SCED) of the electric system for every hour of the study year. The SCED minimized the total operating costs of the WECC while ensuring that transmission flows and resource dispatch were within system capabilities and adhered to established reliability standards and practices, including limitations due to nomograms, path loading restrictions, and contractual obligations. Model results on operational costs, transmission utilization and congestion were used to help evaluate the electric system in the first 10 year timeframe.

Unlike the PCM, which performed a production cost simulation of a defined generation and transmission system, the long-term planning tool (LTPT) was a capital expansion planning model that co-optimized generation and transmission expansions of assets based on a set of model inputs. The LTPT was used to analyze study cases over the second 10 year timeframe. The LTPT iterated between two optimization tools in order to arrive at an optimal least-cost generation and transmission expansion solution for a given set of study assumptions.

- Scenario case development tool (SCDT)—responsible for optimizing incremental resources so that load requirements and policy goals were met via a least cost solution. The SCDT also included a catalog of candidate transmission corridors geospatially optimized to minimize environmental/cultural risks. Various transmission technology types associated with each corridor were considered for expansion by the network expansion tool (NXT). The SCDT was the first step in the iterative LTPT process.

- NXT—the NXT was run after the SCDT had developed load and generation assumptions. The NXT optimized candidate transmission to ensure that all load was served without any security violations (e.g., overloaded transmission lines) while minimizing the total capital cost of the expansions under four system conditions, which were hourly system dispatches intended to represent a variety of typical operating conditions.

The LTPT iterated between the SCDT and NXT until it converged on a feasible least-cost solution for a given energy future characterized by a set of study assumptions. For each iteration, the SCDT produced an updated optimization of generation and a corresponding study case as input to the NXT, while the NXT provided an updated optimized network expansion and allocation of grid costs to generators as inputs to the SCDT. Convergence was reached when no further updates to generation and transmission expansion were needed between iterations. The end result of this iterative process was a set of point-to-point transmission segments which, if added to the existing transmission grid, would allow the resources selected in the study case to meet the load used as an input to the study case.

Given the complexity and expanse of the Western Interconnection, the intra-regional transmission networks in the LTPT analysis were modeled as hub aggregations of generation and load. The location or geographic coordinates of these hubs were the centroids of the actual load and generation in the intra-regions weighted by generation capacities and load demands at the substations distributed throughout the sub-regions. In this way, hubs effectively represented a diffuse region around the centroid of the hub, rather than a single point in space. According to this scheme, the Western Interconnection was represented as a network of 104 interacting hubs in the LTPT model (figure 1).

2.2. Integrating water into the TEP process

As analyses using the PCM and LTPT operated in a very different manner, so too was the way in which water was handled. With the PCM (first 10 year timeframe) the type, capacity and location of new thermoelectric generation was largely known and, as such, new thermoelectric demands for water (withdrawal and consumption) were simply calculated. Alternatively, the LTPT (second 10 year timeframe) co-optimized the placement of new generation subject to differing assumptions and constraints in the five scenario study cases. In this second 10 year timeframe available water supply was treated as a constraint such that placement of new generation was allowed as long as there was an available supply of water sufficient to meet the consumptive demand of the proposed thermoelectric power plant (consumptive water use was adopted as it is the basis on which water rights/permits are issued and any difference between

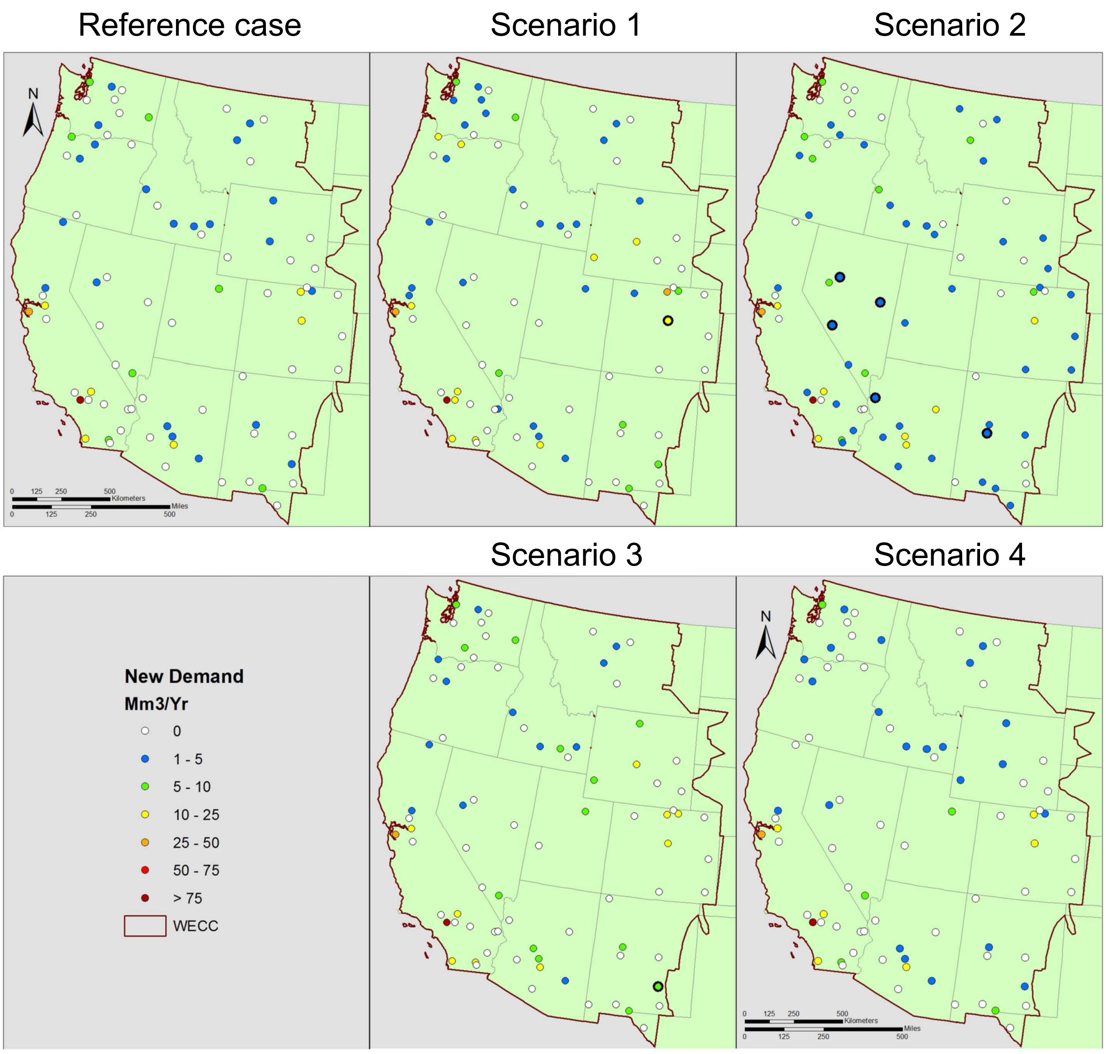

Figure 1. Map of WECC area (U.S. region only) including transmission planning hubs. The color of the hub icon distinguishes the projected new consumptive water demand for thermoelectric development. Hubs outlined in black designate locations where limited water availability constrained thermoelectric development. Individual maps are given for the reference case and each of the four scenarios.

withdrawal and consumption would be returned to the initial water source for use by others). Integration of water into the TEP process required estimates of thermoelectric water withdrawal and consumption (both timeframes) as well as estimates of available water supply to constrain placement of new generation (second 10 year timeframe). Additionally, there was the need to formulate the water supply constraint based on the water availability data.

2.2.1. Power plant water use estimates

Power plant water use estimates, including water withdrawal and consumption, were required for both the existing fleet of power plants as well as that associated with any new thermoelectric generation. Estimates for existing plants were needed to address reductions in thermoelectric water use due to the retirement or displacement (where production is limited by high cost of operation) of current generation. Estimates of water withdrawal and consumption for WECC's current fleet of thermoelectric power plants were taken from the Union of Concerned Scientists (2012), while withdrawal and consumption factors (m^3/MWh) for future power plants, distinguished by power plant type, fuel type, cooling type, emission controls and geographic location were taken from Woldeyesus *et al* (2016) (see table S3 in the supplemental material for average water intensity factors by plant/cooling type). It was further assumed that all new development would adopt closed loop cooling systems (40 CFR Parts 122 and 125). Air-cooling was considered within the LTPT analysis but never emerged as a preferred alternative.

2.2.2. Water availability estimates

Water availability data used in the TEP process were taken from Tidwell *et al* (2014). Estimates were carefully formulated for the specific needs of TEP. Here the concern was availability of water on an average annual basis for new power plant additions. As any new thermoelectric power plant would have to obtain a water right or permit, water availability values were estimated as the amount of water a state considers available for appropriation; that is, the total amount of additional water demand that a basin can support above current use. Given the relatively coarse spatial resolution of the LTPT analysis (104 hubs spread across the Western US), water availability estimates were not collected with the intent to support the placement of a power plant at a particular location; rather, their purpose was to provide a consistent and comparable measure of the relative difficulty to develop the water resources in a given basin. The goal was to inform the TEP process so as to direct new thermoelectric development toward locations where water resources were more abundant and away from water limited basins.

As the states have ultimate authority over water appropriation decisions within their borders, we engaged directly with each western state water manager to frame, identify and vet water availability values (see supplemental material table S4). Through this process water availability estimates were informed both by the physical supply of water as well as the institutional controls (e.g., water right administration, administrative control areas, interstate compacts, groundwater depletion rules, limits on water rights transfers, Native American Water Rights) unique to each state. Both factors result in noticeable differences in water availabilities across the states; specifically, physical supply is seen to have a geographical influence as evidence by limited freshwater availability in the south, while distinct difference in water availability are evident at state boundaries owing to differences in the way the state's administer water (see Tidwell *et al* 2014, also see the data portal and water availability maps produced through ArcGIS at http://energy.sandia.gov/?page_id=1741).

Water supply for power plant operations can come from a variety of sources. As such, water availability was mapped for five unique sources, including:

- Unappropriated surface water, streamflow (fresh) available for beneficial use through application with the appropriate state water management agency (i.e., permit or water right).
- Unappropriated groundwater, fresh groundwater available for beneficial use through application with the appropriate state water management agency.
- Appropriated surface/groundwater, water that could be made available for new development by abandonment and transfer of the water right from its prior use. Such transfers have traditionally involved sales of water rights from irrigated farm land to urban uses.
- Municipal wastewater, and
- Brackish groundwater.

Water availability metrics were formulated so as to estimate the available water rights or permitable water in a basin. Such rights/permits are granted for a specified amount of water use each year; that is, the right or permitted value does not vary by season or water year (in times of drought). In fact, a water right or permit does not guarantee water in times of drought (where demand exceeds supply), rather a system of priority dictates which users have seniority (generally only an issue for unappropriated and appropriated fresh surface water). In this context, water availability is related to the consumptive demand associated with new development (that portion of water not available downstream to other users). Water availability values for unappropriated surface and groundwater were adopted from state estimates where they existed. Where these estimates were lacking and for the other three water sources a West-wide consistent set of metrics were developed with help from the Western Governors' Association, Western States Water Council, US Geological Survey, and individual state water management agencies. Details concerning the five water availability metrics and associated data sources is reproduced from Tidwell *et al* (2014) in the supplemental material. Maps of water availability by source can be found in Tidwell *et al* (2014) and through the project data portal at http://energy.sandia.gov/?page_id=1741.

Water supply availability was mapped for the 13 states in the WECC service region (Tidwell *et al* 2014). Mapping was performed according to the 8-digit Hydrologic Unit Code (HUC) watershed classification (e.g., Seaber *et al* 1987), which resolved the 13 western states into over 960 unique hydrologic units. The 8-digit HUC was selected as it provided a physically meaningful unit relative to water supply/use and provided the highest level of detail that could be justified with the data consistently available across all 13 western states. Because of limitations in access and availability to comparable water data in Mexico and Canada, mapping efforts were not pursued outside the US.

Water source selection for new thermoelectric development is strongly influenced by cost and as such comparative costs for the different sources of water were developed (Tidwell *et al* 2014). Originally, the LTPT analysis was to consider both water supply and cost unique to each of the five sources of water. However, limited resources and the difficulty of integrating a full supply curve (pairing of quantity and cost for each of the five sources of water) into the LTPT analysis precluded consideration of cost. Thus total water availability was set as the constraint for the TEP analysis, calculated on a per watershed basis as the sum of the five individual sources of water less projected growth in water consumption over the next 20 years (including thermoelectric power plant additions projected in the 2022 common case).

2.2.3. Water supply constraint

Formulating the water supply constraint for the LTPT analyses in the second 10 year timeframe of the TEP process faced two challenges. First, the 104 LTPT hubs were on a very different spatial reference system than the 960 watersheds on which the water availability data were estimated (see map in supplemental material). Mapping hubs to watersheds proved difficult because the transmission network associated with the hubs varied in size and shape and even overlapped in many cases. Second, there was the question concerning how much of the available supply of water was appropriate to allocate to new thermoelectric development relative to other competing demands.

As the water supply constraint was required early in the modeling process and with little experience on which to rely, a simple approach was adopted. The water available for thermoelectric use was assigned to each hub according to the watershed in which the hub's centroid was located. This approach had the advantage of intensifying the water constraint, as the limit was established by the total water availability for a single watershed (sum of the five sources of water less projected growth) rather than the multiple watersheds each hub encompassed.

2.3. Assessing impacts to western water resources

Also of interest to this study was understanding how changes in water consumption for thermoelectric generation might impact water availability in the West. This required mapping the new and displaced thermoelectric generation to the 960 watersheds (8-digit HUC) in the WECC region. Mapping retired and displaced generation was straight forward as the locations of these assets were known (existing plants). The locations of new additions associated with the 2022 common case were also assumed as siting had already been initiated for these assets. This left the need to map thermoelectric generation added in the second 10 year timeframe associated with the five scenario study cases, which were located according to the 104 LTPT hubs.

Unfortunately the mapping used to formulate the water supply constraint (see section 2.2.3) was of no value here as that approach used the centroid of the hubs. Fortunately, as the program evolved we were provided with a mapping of 2012 thermoelectric generation to the 104 LTPT hubs, which was then used to map new (2023–2032) generation to watersheds. This approach assumed that future resource expansion will follow a similar configuration to current development largely guided by the need to utilize existing transmission, fuel supply and other enabling infrastructure. Specifically, capacity additions scheduled for a given hub were distributed to all associated watersheds where power plants with the same fuel type and belonging to the same balancing authority were currently operating. Among these watersheds, capacity was distributed according to the relative water availability associated with each.

To satisfy projected new thermoelectric water demands (consumption), sources beyond traditional freshwater supplies were often required. Here we assumed that new thermoelectric demands were met first with any water freed up by retired/displaced thermoelectric generation; otherwise, new demands were met using the traditionally least expensive source of water available while working to the more expensive water (following the progression of unappropriated surface water, appropriated water, unappropriated groundwater, wastewater and finally brackish groundwater) (see Tidwell *et al* 2014).

3. Results

Results from the integration of water into the WECC TEP exercise are provided and discussed. First, the influence of the water availability constraint on power plant placement is reviewed. Next, thermoelectric water use (withdrawal and consumption) implications associated with the 2022 common case and five scenario study cases are explored for the WECC region. Finally, water consumption projections are extended to the watershed level to explore implications for water resources in the West. Note that results are limited to the US portion of the WECC service region due to the absence of water availability and future use data for Canada and Mexico.

3.1. Water availability constraint

Of primary interest to this effort was the extent to which water availability constrained the location of new generation in the capital expansion modeling (second 10 year timeframe). Originally there was concern that the constraint would be too restrictive as the available water assigned to a hub was limited to that associated with the watershed at the centroid of the hub rather than the aggregate of available water across all watersheds associated with the hub. Regardless, the constraint had relatively limited effect, as there were very few cases where the location of new generation was rejected on the basis of limited water availability. In only seven instances was the water availability constraint reached, one hub in scenario 1, five hubs in scenario 2, and one hub in scenario 3 (figure 1).

It is interesting that the scenario study case with the fewest new thermoelectric additions (scenario 2) was the case with the most hubs that reached the water availability constraint. It is also interesting that only three scenarios registered hubs with constraint issues and that no hub reached its constraint in more than one scenario. The only factor in common across the seven hubs is limited water availability as all seven hubs had total water availability below 0.01 $Mm^3 d^{-1}$.

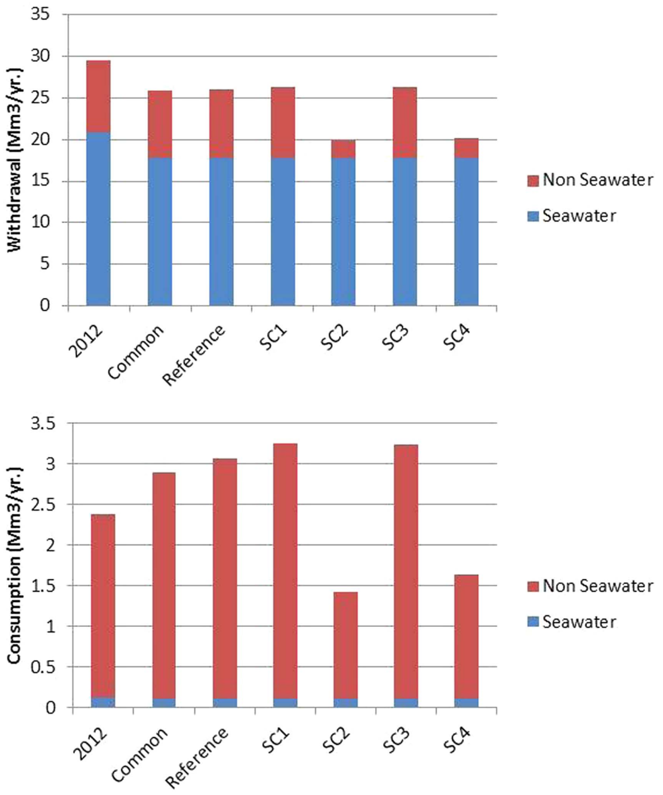

Figure 2. Thermoelectric water use by the WECC region in 2012, the 2022 common case and for each five scenario study cases. The top graph shows water withdrawals, while the bottom provides water consumption. Values include the US region only.

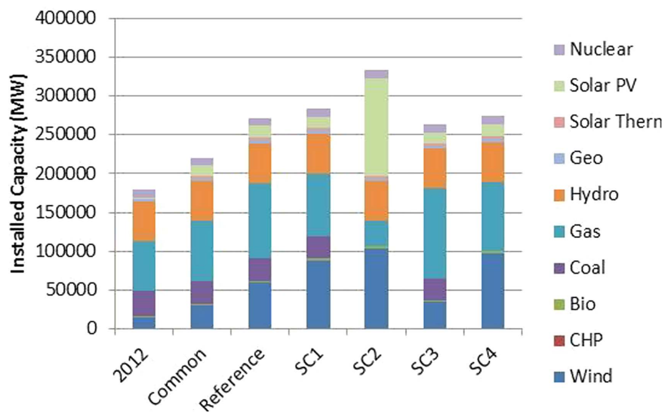

Figure 3. Installed capacity and fuel mix for the WECC region in 2012, for the 2022 common case and for each of the five scenario study cases (WECC 2013c). Reported capacities include the US region only.

3.2. Thermoelectric water use

Big differences in thermoelectric withdrawal and consumption are projected between current use (2012), the 2022 common case, and each of the five scenario study cases (figure 2 and table S5 in supplemental material). These differences are the result of changes to the portfolio of thermoelectric generation (both capacity and mix of technology) realized through the construction of new power plants as well as the retirement or displacement of existing capacity, where displaced capacity refers to plants which are rarely operated due to their profitability. Ultimately, the differing mix of generation unique to each TEP timeframe and scenario study case reflect the underlying assumptions concerning evolving electricity demand, policy, and technology costs (figure 3, table S6 included in supplemental material).

In 2012, the base year for the planning exercise, the thermoelectric generation portfolio included 65 000 MW of natural gas-fired capacity, 31 900 MW of coal, 9990 MW of nuclear, 2780 MW of geothermal, 1190 MW of biopower, and 460 MW of solar thermal (Western Electricity Coordinating Council 2013c). Associated fresh water consumption was estimated to be

2.25 $Mm^3\ d^{-1}$ with accompanying withdrawals of 8.58 $Mm^3\ d^{-1}$. Sourced water included fresh surface water, fresh groundwater and recycled municipal wastewater.

The 2022 common case projected changes in power generation over the first 10 year timeframe, 2013–2022, based on additions and retirements that were already at some level of planning throughout the WECC. Projected changes included the retirement of 2800 MW of coal-fired generation and 2500 MW of natural gas, while new thermoelectric additions included 11 000 MW of natural gas combined cycle generation, 2600 MW of solar thermal, 1330 MW of geothermal and 570 MW of biopower. An additional 39 190 MW of simple cycle natural-gas and renewables were added to the grid. Accompanying these changes was an increase in water consumption of 0.53 $Mm^3\ d^{-1}$ (24%) while withdrawals decreased by 0.54 $Mm^3\ d^{-1}$ (−6%). This decrease in withdrawals reflects the retirement of coal-fired generation that used open-loop cooling which was replaced with other thermoelectric generation employing closed-loop cooling (withdrawals between the open and closed-loop differ by roughly two orders of magnitude (see Woldeyesus *et al* 2016).

Over the second 10 year timeframe there was much more uncertainty concerning the future mix of thermoelectric power generation. As such, five different scenario study cases based on different assumptions were developed. One of these scenarios was the reference case which followed a business as usual trajectory, extending the basic trends found in the 2022 common case. Projected changes included new thermoelectric builds of 7300 MW of natural gas combined cycle with no displacement of 2022 common case generation capacity. An additional 44 600 MW of simple cycle natural-gas and renewables were added to the grid. Consumptive water use increased by 0.18 $Mm^3\ d^{-1}$ (6%) and withdrawals by 0.21 $Mm^3\ d^{-1}$ (3%) over this second 10 year timeframe and by 0.71 $Mm^3\ d^{-1}$ (31%) and −0.33 $Mm^3\ d^{-1}$ (−4%), respectively since 2012. The reference case and 2022 common case resulted in very similar trajectories, as would be expected, except in the move from thermoelectric renewables (e.g., solar thermal) to non-thermoelectric renewables which explains the lower growth in consumptive water use.

Scenario 1 assumed high energy demand, high natural gas prices and low solar technology costs relative to the other scenarios (see tables S1 and S2 in the supplemental material). This resulted in new thermoelectric additions of 3200 MW of natural gas steam generation and 1000 MW of combined heat and power, with no displacement of 2022 common case generation capacity. An additional 59 100 MW of non-thermoelectric renewables (wind and solar) were added to the grid. Consumptive water use increased by 0.36 $Mm^3\ d^{-1}$ (13%) and withdrawals by 0.43 $Mm^3\ d^{-1}$ (5%) over this second 10 year timeframe and by 0.89 $Mm^3\ d^{-1}$ (39%) and −0.11 $Mm^3\ d^{-1}$ (−1%), respectively since 2012. The driver of increased water use over the reference case is the choice of natural gas steam over combined cycle (table S3 in the supplemental material).

Scenario 2, assumed high growth in electricity demand, a high carbon tax and significant reductions in the cost of all renewables relative to the other scenarios. This resulted in big changes to the generation portfolio; specifically, all existing coal and much of the natural gas (45 600 MW) generation were displaced. To compensate 188 000 MW of new generation was added, including significant quantities of solar PV and wind. Of the added generation, only 1500 MW was thermoelectric (biopower). Big decreases in water use were realized. Consumptive water use decreased by −1.47 $Mm^3\ d^{-1}$ (−53%) and withdrawals by −5.99 $Mm^3\ d^{-1}$ (−74%) over this second 10 year timeframe and by −0.94 $Mm^3\ d^{-1}$ (−42%) and −6.5 $Mm^3\ d^{-1}$ (−76%), respectively since 2012. The substantial changes in water use were the result of the displacement of the coal and natural gas steam generation, which was replaced largely by wind and PV.

Scenario 3 assumed lower electricity demand growth, low natural gas prices and relatively little improvement in the cost of renewables. To take advantage of low fuel prices, 17 000 MW of natural gas combined cycle was added while 1000 MW of thermoelectric biopower was displaced. An additional 26 900 MW of non-thermoelectric natural-gas and renewables were added. Consumptive water use increased by 0.34 $Mm^3\ d^{-1}$ (12%) and withdrawals by 0.4 $Mm^3\ d^{-1}$ (5%) over this second 10 year timeframe and by 0.87 $Mm^3\ d^{-1}$ (39%) and −0.14 $Mm^3\ d^{-1}$ (−2%), respectively since 2012. Low growth and use of natural gas combined cycle generation (relatively low water use) kept water demands manageable in this case.

Scenario 4, assumed slower growth in electricity demand than scenarios 1 and 2, with a high carbon tax and reduced cost of renewables (not as aggressive as scenario 2). As in scenario 2 all coal capacity along with 1000 MW of natural gas were displaced, while 84 000 MW of generation was added, primarily wind and natural gas. Of these additions only 6000 MW were thermoelectric (natural gas combined cycle). Again, consumptive water use decreased by −1.25 $Mm^3\ d^{-1}$ (−45%) and withdrawals by −5.63 $Mm^3\ d^{-1}$ (−70%) over this second 10 year timeframe and by −0.72 $Mm^3\ d^{-1}$ (−32%) and −6.17 $Mm^3\ d^{-1}$ (−72%), respectively since 2012. As with scenario 2 the substantial reduction in water use was caused by the displacement of coal and natural gas generation that was replaced largely by wind.

Beyond the freshwater and recycled wastewater use noted above, seawater is also used for thermoelectric power generation in the WECC. In 2012 thermoelectric generation consumed 0.13 $Mm^3\ d^{-1}$ and withdrew 20.9 $Mm^3\ d^{-1}$, or 5.5% and 71%, respectively of total thermoelectric water use (figure 2). The

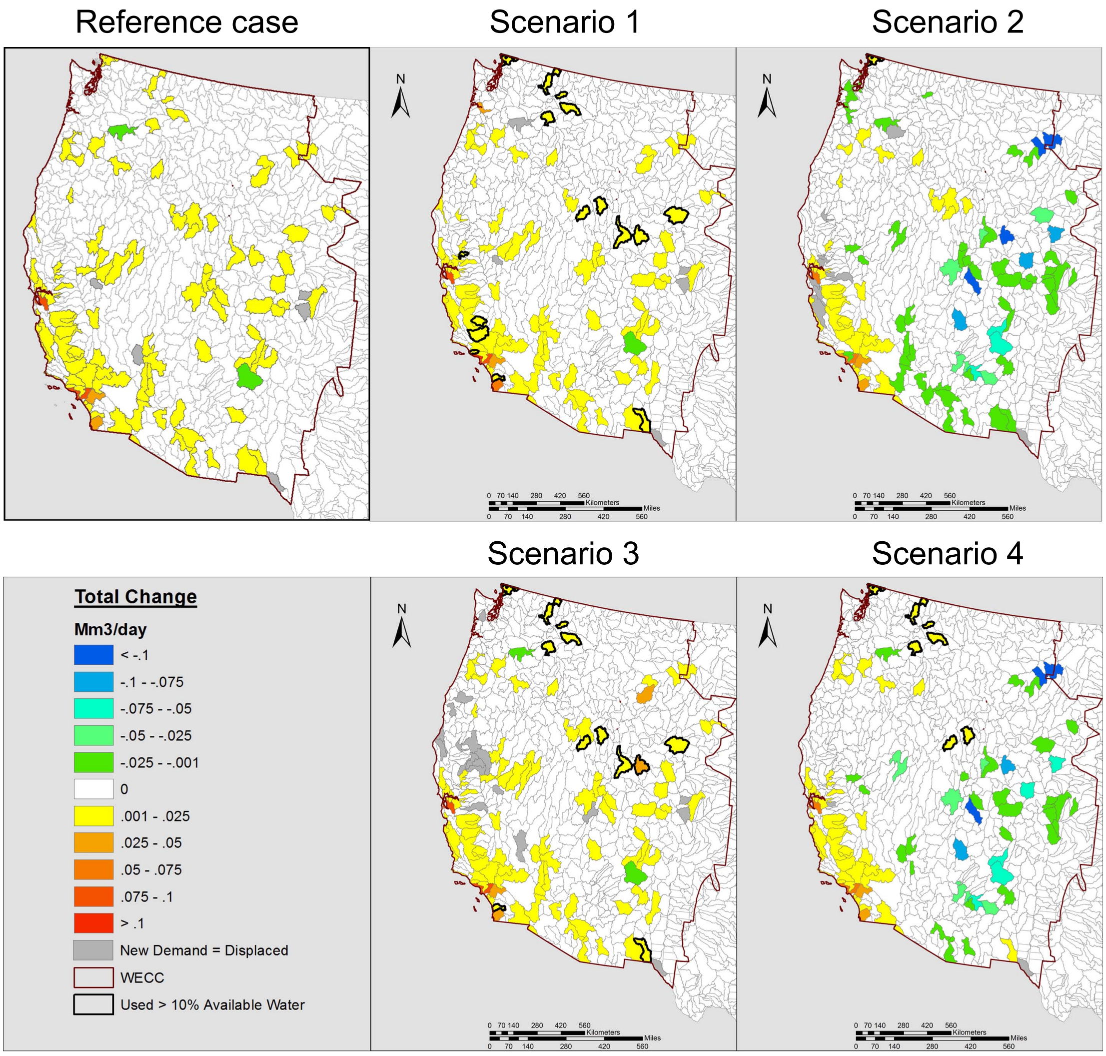

Figure 4. Projected change in thermoelectric water consumption by watershed in the WECC region. Warm colors indicate an increase in water consumption while cool colors indicate a net decrease. Outlined watersheds indicate locations where future thermoelectric consumption exceeds 10% of the available water supply. Individual maps are given for the reference case and each of the four scenarios.

only changes projected for seawater cooled generation occurred in the 2022 common case where 8490 MW of natural gas steam generation concentrated along the California coast was retired (largely related to changes necessary to achieve compliance with California's policy on 'Use of Coastal and Estuarine Waters for Power Plant Cooling'). This resulted in decreased consumption of seawater by -0.02 Mm^3 d^{-1} (-15%) and withdrawals by -3.1 Mm^3 d^{-1} (-15%). Capital cost expansion modeling did not identify existing seawater using plants for displacement nor new additions that would utilize seawater.

3.3. Implications of future thermoelectric water use

Figure 4 provides maps of the projected net change in thermoelectric water consumption at the watershed level for each of the five scenario study cases. These maps were developed by adding the projected net changes in water consumption associated with the 2022 common case to each of the five scenario study cases. In this way, results capture the total projected change over the full 20 year planning horizon. Seawater was not included in these calculations, as its use is equal across all five scenario study cases. In the maps the net change in water consumption is given such that hot colors designate increasing water consumption while cool colors represent cases where water consumption was reduced relative to initial 2012 conditions. For reference, individual maps of displaced water and thermoelectric water consumption for new construction (raw data that was aggregated to produce the projected net change in thermoelectric water consumption given in figure 4) for each of the five scenario study cases are provided in the supplemental material (figures S1 and S2).

Three important implications for future water availability in the West were gleaned from the projected changes in thermoelectric water consumption. First, changes in consumptive water use for thermoelectric generation tended to be broadly distributed

Table 1. Characteristics of new thermoelectric consumptive water use across the 960 HUC-8 watersheds in the WECC region.

Scenario	Watersheds[a] (#)	Watersheds[b] (#)	Surface water (%)	Ground water (%)	Approp. water (%)	Waste water (%)	Brackish ground water (%)
Reference case	125	12	11	6	12	37	34
Scenario 1	123	12	16	6	10	35	33
Scenario 2	141	3	1	5	4	51	39
Scenario 3	123	12	16	7	12	31	34
Scenario 4	84	9	2	2	5	52	39

[a] Watersheds with some change in thermoelectric water use.

[b] Watersheds where new thermoelectric water consumption exceeds 10% of available water.

across the West (table 1). While this result is biased by our assumed mapping from hub to watershed, the distribution of new generation by hub is also dispersed (figure 1). Regardless of scenario assumptions, the very process of balancing load, transmission, policy and regulation favors distributed generation. The advantage is that in only a limited number of cases does the new thermoelectric consumptive water use require more than 10% of the available water supply in a given watershed; specifically, 12 watersheds in the reference case, scenarios 1 and scenario 3; 9 watersheds in scenario 4; and 3 watersheds in scenario 2 (figure 4 and table 1). Although arbitrary, the 10% limit represents a natural break in the data.

The second important implication, is that under certain conditions water from retired/displaced thermoelectric generation could represent an important source for future thermoelectric and other water demands. Under scenarios 2 and 4, which assumed a significant carbon tax, all coal-fired generation and some natural gas steam were displaced. When this generation was replaced with low water use natural gas combined cycle and renewables (e.g., wind and PV solar), the water from the displaced generation often exceeded that needed to meet the projected growth in thermoelectric water consumption (figure 4). This feature also has important regional implications, as this 'extra' water was concentrated in the Mountain West where the majority of coal-fired generation was located.

The third implication is that non-fresh water sources (e.g., municipal wastewater and brackish groundwater) will likely be required to satisfy new thermoelectric water demands. Table 1 provides the mix of water sources required to meet projected growth in thermoelectric consumptive water demand for each of the five scenario study cases. All five cases required 65% or more non-fresh water to meet future thermoelectric demands. This percentage jumped up to 90% or more for scenarios 2 and 4. There were two reasons for the high dependence on non-fresh sources. First, freshwater supplies were limited in the Western US (Tidwell *et al* 2014). Second, the State of California has policies in place that essentially prohibit new thermoelectric development from using fresh-water sources (California Water Code, section 13552) and California alone accounted for between 48% and 61% of total new thermoelectric water demands. This policy was the reason the percentage of non-fresh water use jumps in scenarios 2 and 4 (table 1), as most new water demands not covered by displaced water were located in California.

4. Discussion and summary

This paper describes an approach and results aimed at integrating water into a long-term TEP exercise conducted by the Western Electricity Coordinating Council, a non-profit responsible for bulk electric system reliability in the Western US. Unique to this effort was the use of water availability data, collected with the help of state water managers, to constrain regional TEP for a variety of stakeholder-vetted energy futures. Experience gained from this exercise provides valuable insight into the challenges with integrating available water supply into TEP; how significantly thermoelectric water use (withdrawal and consumption) projections can vary when subjected to a range of assumed energy futures; and how water availability can impact and be impacted by TEP.

4.1. Water availability estimates

Water availability estimates played a central role in formulating the water constraint in the LTPT model as well as in evaluating how future thermoelectric water use could impact Western water resources. As such, the results presented are sensitive to these estimated water availability values, which are not without their limitations. As the resolution of the TEP process was relatively coarse (104 hubs scattered across the West) detailed hydrology at a particular location (annual/seasonal variability, water operations constraints, local physiographic challenges to water access) was of little importance. Rather, the interest was simply to direct power plant placement away from areas with limited supply. In this way the water availability estimates resolved at the 8-digit HUC watershed level provide a relative measure of where water is limited versus abundant and where future development would be most disruptive to the basin's water resources. These estimates of water availability carry additional credibility as they were made with the help of the state water managers who will ultimately be making decision on new water appropriations.

4.2. Water constraint

Important lessons were learned concerning the approach taken to integrating water into TEP. As limited water supply is a concern in the West, water availability was set as a constraint on the placement of new thermoelectric generation. Surprisingly, there were few instances where water availability restricted generation expansion at a particular hub. Out of the 104 hubs and five scenario study cases, only seven instances were identified where more generation would have been added to a hub if additional water were available. From this result it could easily be assumed that water was not important to the planning process. This was not the case; rather, the resulting pattern of thermoelectric water use was determined by planning constraints that were not directly related to water. Specifically, all five scenario study cases favored construction of low to zero water use generation (natural gas combined cycle, PV solar and wind). This choice was driven primarily by cost (assumptions related to future fuel and technology costs) and policy constraints (renewable portfolio standards) (Western Electricity Coordinating Council 2013d, 2013e, 2013f, 2013g, 2013h). Additionally, scenarios 2 and 4 favored displacement of significant coal and to lesser extent natural gas capacity, again not for water savings but to meet policy constraints associated with emission standards. Each of the five scenario study cases also favored broad geographic dissemination of new thermoelectric generation (generally distributed among 25 or more hubs in each scenario) (Western Electricity Coordinating Council 2013d, 2013e, 2013f, 2013g, 2013h). This was driven largely by economic, reliability and utilization constraints applied to the interplay between demand topology, existing transmission capacity and new transmission additions. Combined, these policy, economic, demand and transmission decisions dictated the dispersed and limited growth in thermoelectric water demand resulting in few instances where the water constraint was reached.

The manner with which the water availability constraint was structured also contributed to its limited role in the TEP exercise. Improvements could have been achieved by developing a mapping that relates the heterogeneous distribution of water availability over the LTPT hub region to the heterogeneous placement criteria for new thermoelectric generation (e.g., access to transmission, fuel supply). The constraint would also have benefitted from state and local dialog as to how the available supply of water should be allocated across different water use sectors. Although such improvements are unlikely to have made a significant difference here, the structure would matter for scenarios where coal or nuclear generation were favored as the plants tend to be large (gigawatt or more) and have higher water intensities (see table S3 in the supplemental material).

Other factors beyond water availability could also have been integrated into the water constraint. Water quality, in particular water temperature, could be important where open-loop cooling is being considered (not the case here). Integration of water cost could have helped the water constraint play a more relevant role in this TEP exercise, in particular the variability in cost across the different sources of water. If water prices are high enough, low water intensity generation will be favored or the thermoelectric generation moved to a watershed with lower water costs. Although initial plans called for cost to be part of the analysis, time, resources and priorities prevented its implementation.

4.3. Scenario analysis

Different energy futures gave rise to very different projected thermoelectric water use profiles. Energy futures, termed scenarios were developed to capture uncertainty concerning future RPSs, population growth, changes in technology costs, energy efficiency and demand-side management effects, regulatory policy for greenhouse gases and other environmental issues, and overall economic conditions. In total, changes in thermoelectric water consumption over the full 20 year planning horizon increased by as much as 31% for the business-as-usual case while decreased by as much as 42% under a low carbon future. Interestingly, consumptive water use associated with the construction of new generation was relatively uniform among the five scenario study cases (including the 2022 common case), projected between 0.83 and 1.01 $Mm^3\ d^{-1}$. This narrow range largely reflected the consistent preference for natural gas combined cycle, solar PV, and wind generation—all of which have the advantage of relatively low water use. In contrast large differences in displaced generation were noted, with an associated change in water consumption ranging from 0.23 to 1.89 $Mm^3\ d^{-1}$. All scenarios shared a small level of expected retirements; however, significant displacement of existing power generation was projected for the two scenarios assuming a high carbon tax (scenarios 2 and 4). Uncertain is the extent to which this displaced water would be available for other uses. Clarity on this issue depends both on how the utility decides to manage their water rights and generation assets (e.g., continue to maintain the facility and its water rights but operate it sparingly, retire the plant and sell off the water rights, retire the plant and lease the water rights), as well as the intricacies of state water policy that constrain the sale, lease or use of water from the displaced power generation.

While considerable differences in thermoelectric water consumption were realized across the five scenario study cases, other factors not considered in this analysis could have led to even larger differences. The WECC TEP scenarios focused on the stakeholder's best guess at what the future might look like rather than attempting to bracket the full spectrum of technology and policy evolution. No consideration was given to a future that favored expanded coal or nuclear generation which would result in significantly higher thermoelectric water use. Also lacking was the treatment of climate change and with it the higher electricity demands, water demands for power plant cooling and competition over water. Each of these assumptions would have resulted in increased thermoelectric water use, possibly causing the water constraint to play a more significant role. Had water costs been integrated into the TEP exercise, assumed costs for dry cooling or treatment of brackish or municipal wastewater could have important implications on freshwater use as well as where the new thermoelectric generation was located.

4.4. Impacts on water availability

Projected changes in thermoelectric water use will influence future water availability in the West. Across the five scenario study cases (including the 2022 common case) new thermoelectric consumption accounted for less than 10% of the available water supply in almost 90% of the watersheds seeing some change in thermoelectric use or 99% of all watersheds (figure 4 and table 1). This implies that the projected growth in thermoelectric generation is manageable from a water availability (e.g., competition with other water use sectors) perspective. In fact, for scenarios resulting in displacement of coal generation, the thermoelectric sector could become a source of water for development in other water use sectors. However, the new thermoelectric generation will rely more on non-fresh sources of water as all five scenario study cases required 65% or more non-fresh water to meet future thermoelectric demand. This reflects both the limited availability of fresh water and state level policies promoting use of non-fresh water sources for new thermoelectric development (California Water Code, section 13552).

These results are subject to the assumed study case scenarios. A scenario favoring coal or nuclear generation would have greater impact on water availability. Results are also subject to the approach used to map new thermoelectric generation from the LTPT hubs to watersheds. It was assumed that new generation would be distributed in a manner similar to existing generation so as to take advantage of supporting infrastructure (transmission, fuel and water). Consideration of the cost of water would also influence the pattern with which the new generation is located as well the sourcing of water. That is, if the cost constraint was active, some construction may have been moved to other locations where less expensive freshwater was available. However, the availability of unappropriated surface and groundwater is very limited in the West (Tidwell *et al* 2014) and targeting these dispersed 'islands of supply' would likely require some additional transmission capacity that in most cases would be more expensive than utilizing a non-fresh source of water.

4.5. Lessons learned

Throughout the conduct of this project several lessons were learned that should be of use in other TEP exercises. First, and foremost, broader engagement was needed to more fully integrate water into TEP. Because this was such a large and complicated planning process features outside the primary focus of transmission planning were largely compartmentalized and isolated from the broader process. Rather, planning decisions would have benefited from joint management of decisions that both directly (i.e., formulation of the water constraint) and indirectly (i.e., assumptions that effect the mix and distribution of generation technology) influence thermoelectric water use. Although the water availability constraint did not factor largely in this case study, the situation could have been much different if higher water intensity scenarios (other generation technologies, climate change or drought) had been considered, thus requiring much more attention to water. Broader engagement would also have provided the opportunity to elevate appreciation for potential impacts of thermoelectric water use on future transmission expansion plans. Failure to achieve such appreciation resulted in water cost being excluded from the LTPT modeling when the schedule and budget were pinched. Likewise the five scenario study cases failed to reflect water related drivers as neither drought nor climate change were included. Toward this need a culture of iterative planning is encouraged. Iteration allows needed time to build shared appreciation while implementing: improvements over past integration efforts (e.g., better hub to watershed mapping), ideas that were not prioritized at early stages of engagement (e.g., incorporation of water cost), and a broader range of scenario study cases (e.g., climate change and drought).

In retrospect, insufficient time was spent at the onset of the project to jointly identify an appropriate mapping between the two disparate reference systems (hubs and watersheds). Proactively addressing this issue, which will be common in any effort to integrate energy and water, would have saved the project considerable time, effort and frustration.

On a positive note, a simple and compact means of representing the complexity of water resources focused on the issues pertinent to transmission planning was identified. Here we were able to collapse much of the complexity of water supply, water use, water rights, etc into simple water availability metrics which could easily be integrated into the TEP process. This could be directly expanded to include consideration of water costs represented by a simple supply curve.

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