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Climate change and its influence on water systems increases the cost of electricity system decarbonization

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The electric sector simultaneously faces two challenges: decarbonization to mitigate, and adaptation to manage, the impacts of climate change. In many regions, these challenges are compounded by an interdependence of electricity and water systems, with water needed for hydropower generation and electricity for water provision. Here, we couple detailed water and electricity system models to evaluate how the Western Interconnection grid can both adapt to climate change and develop carbon-free generation by 2050, while accounting for interactions and climate vulnerabilities of the water sector. We find that by 2050, due to climate change, annual regional electricity use could grow by up to 2% from cooling and water-related electricity demand, while total annual hydropower generation could decrease by up to 23%. To adapt, we show that the region may need to build up to 139 GW of additional generating capacity between 2030 and 2050, equivalent to nearly thrice California's peak demand, and could incur up to $150 billion (+7%) in extra costs.

Decarbonization of the electric sector is a critical strategy to mitigate climate change[1]. To that end, several states in the Western Interconnection grid of North America have set ambitious carbon-free generation targets[2,3]. At the same time, the electricity system of the region (also referred to as the Western Electricity Coordinating Council, or WECC) is also vulnerable to the impacts of climate change, including rising temperatures, changing precipitation patterns, declining snowpack, and more frequent extremes[4–8]. Such impacts have already caused major grid disruptions in California and in the Pacific Northwest and are projected to intensify[9–11], especially by increasing electricity demand for cooling[12,13].

Further, climate change does not affect the electricity system in isolation[14]. Electricity and water systems are already closely connected in the Western US, where hydropower comprises about 20% of annual average generation[15], and electricity use for water (including

conveyance, groundwater pumping, and drinking and wastewater treatment) comprises ~7% of electricity consumption[16]. Of primary concern in key water- and electricity-producing basins in the Southwest, climate change may decrease surface water availability[5,17–19], which stresses water supplies and lowers hydropower generation, making it more difficult to meet water demands and to reach zero emissions targets, respectively[20–22]. While more intense and frequent extreme events of increased precipitation such as atmospheric rivers are also projected[23], those storms primarily affect physical infrastructure assets in the short term, rather than the long-term water supply and demand balance and hydropower generation potential, which impacts resource planning in the region. Moreover, surface water shortages caused by climate change are also likely to coincide with increased irrigation water demand from warming, which together typically raises associated electricity use, such as for groundwater

pumping[24]. Lastly, climate adaptation measures by the water sector to augment supplies, such as with desalination or water recycling, can also be energy-intensive[25,26]. Failing to account for these changes in electricity supply and demand via the water sector may overlook cascading vulnerabilities, jeopardize electricity system climate resilience, and make decarbonization goals elusive[26–29].

Several studies have analyzed operations of the Western Interconnection or other grid regions with individual impacts of climate change either on electricity supply or on demand[22,30–32], but only a few account for the compounding impacts on multiple power system components[11,12,33,34] or consider water system interactions with a detailed water sectoral model[35,36]. Similarly, climate vulnerability studies that evaluate energy-related aspects of water systems often only focus on hydropower, which ignores related changes to the complex and energy-intensive water system[26,37], or only focus on thermal power plant cooling[32,38–41], which is mostly irrelevant for the Western Interconnection, especially with decarbonization[42–44]. Furthermore, evaluations of climate impacts on electricity systems typically hold the generation and transmission infrastructure fixed at their current levels[45]. The few electricity system planning studies[41,46–50] that include multiple impacts from climate change as constraints on new infrastructure do not typically account for the different climate vulnerabilities and resource needs (i.e., energy storage) that must also be considered when planning a fully decarbonized grid[51,52]. For example, for a grid with majority intermittent renewable generation, it is particularly important to study the technologies that can replace any losses in hydropower resources, which are a key source of flexibility to buffer against fluctuations in solar and wind[53]. Such studies also often lack the high temporal or spatial representation of the transmission network and generators to evaluate complex power system dynamics. Finally, climate projections in prior work[11,50] are often from one or two Global Circulation Models (GCM) rather than from a larger ensemble, which is considered the best practice to account for model uncertainty, the largest source of climate uncertainty in the mid-century time horizon relevant for grid planning[54,55].

Addressing these gaps, we link detailed water and electricity system models to evaluate how the Western Interconnection could proactively plan for climate change and water sector pressures, while transitioning to a carbon-free generation portfolio by 2050. Our study includes the major and often compounding climate impacts of concern to the Western Interconnection related to both electricity supply and electricity demand, and we use a large ensemble of climate models to evaluate the range of futures and uncertainty. Further, we develop a detailed water resources model that considers both changes in hydropower and water-related electricity demand in the context of the whole water sector rather than assuming that (1) hydropower operates without other, non-energy constraints or that (2) electricity use related to water stays constant at historical levels. This approach examines the challenges of adapting an electric grid to climate change while also needing to completely decarbonize the system, with the unique added complexity stemming from feedback effects from the strongly interdependent water sector on future electricity supply and demand.

To implement this approach, we first quantify the range of climate impacts that are expected to be most significant for the grid, including changes in electricity demand for cooling and heating, electricity demand related to water, and hydropower generation potential (Fig. 1). We start by constructing 15 climate scenarios from the downscaled climate projections of 15 Global Circulation Models (GCMs) at the Representative Concentration Pathways (RCP) 8.5 emissions level, and a Baseline Scenario with historical 1980 to 2010 climate[56,57]. With the Western US Water Systems Model (WWSM)[58] we then evaluate the change in hydropower generation potential and in water-related electricity use from the Western US water system (from groundwater pumping, water conveyance, domestic water heating, irrigation, drinking water distribution, and drinking and wastewater treatment) under these scenarios. Next, using load sensitivity factors[59], we estimate changes in electricity demand for building heating and cooling for each of the 50 Western Interconnection load zones for the same climate scenarios. Finally, we use a high-resolution capacity expansion model of the Western Interconnection[60], the Solar, Wind, Transmission, Conventional, and Hydroelectric generation model (SWITCH), to optimize the buildout and operations of generation and transmission and reach zero carbon emissions by 2050, subject to the estimated changes in demand and hydropower availability under the climate scenarios (Fig. 1). To characterize the adaptation strategies that may be needed by 2050, we compare the infrastructure buildout, dispatch,
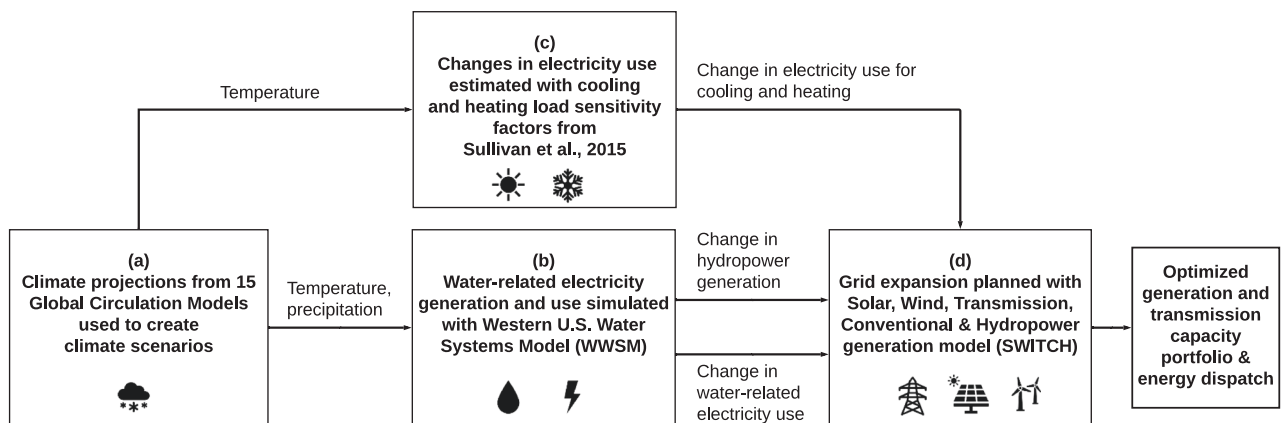

Fig. 1 | Climate-Water-Energy data and modeling framework. This schematic describes the study's integrated modeling methodology. In step (**a**), downscaled climate projections from 15 Global Circulation Models (GCMs) with Representative Concentration Pathway (RCP) 8.5 emissions are used to construct 15 climate scenarios. In step (**b**), temperature and precipitation data from the 15 climate scenarios are inputs into the Western U.S. Water Systems Model (WWSM), which simulates the monthly water supply available, the allocation of water to demands and hydropower generation, and the electricity demand related to water. In step (**c**), the changes in air-conditioning and heating electricity demand are calculated using cooling and heating sensitivities from[59] and temperature data from the 15 climate scenarios. The changes in hydropower generation and water-related electricity demand from step (**b**), and the changes in air-conditioning and heating electricity demand from step (**c**) under the climate scenarios relative to a Baseline Scenario with historical climate adjust the hydropower and electricity demand inputs of the Solar, Wind, Transmission, Conventional and Hydroelectric generation model (SWITCH). In step (**d**), SWITCH optimizes the investment and operations of generation and transmission for each of the 15 climate scenarios and the Baseline Scenario. Each SWITCH model run produces the optimal portfolio, dispatch, and cost of generation and transmission by load zone and investment period.

and cost of each climate scenario in the SWITCH model against the Baseline Scenario wherein the Western Interconnection reaches carbon-free generation but has a stationary climate.

In this work, we show that if the Western Interconnection ignores climate change impacts and associated water sector dynamics in planning a carbon-free electricity system, the grid will have insufficient resources to meet decarbonization goals and to serve the system's load. We find that due to climate change, by 2050 annual electricity use could increase by +0.5% to +2.3% because of higher cooling and water-related electricity demand, while annual hydropower generation could change by −23% to +7%. Increases in electricity demand and decreases in hydropower availability are particularly detrimental because they are both concentrated in the summer, compounding stress on the grid during peak times. To adapt to these climate impacts, we find that the region could need to build up to 139 GW (+14%) more generating capacity or up to 13 GW (+16%) more transmission capacity between 2030 and 2050, increasing the cumulative cost of complete grid decarbonization over this period by up to $150 billion (+7%).

Results

Climate change impacts on electricity supply and demand

We first evaluate the climate scenarios compared to the Baseline Scenario historical climate throughout the Western US. By 2050, across the ensemble of climate projections the annual average temperature throughout the study area increases by about 1–4 °C (Fig. 2c), while annual total precipitation changes range from about −50 km^3 to +100 km^3 across the sub-regions within the Western Interconnection (Fig. 2d), compared to historical levels. Temperatures rise especially in the Mountain region (MT; defined as Colorado, Montana, Wyoming, Idaho, and Utah), and drying is concentrated in the Southwest region (SW; defined as California, Nevada, Arizona, New Mexico), with increased precipitation in the Pacific Northwest (PacNW; defined as Oregon and Washington) in most projections (Fig. 2d and Supplementary Fig. 2). Consequently, in our water systems model WWSM we find that the majority of these climate projections produce decreasing streamflow in key basins (such as the Colorado River Basin) and increasing agricultural water demand, resulting in a substitution of surface water for groundwater use, especially in California's Central Valley[58].

Next, we decompose how these impacts of climate change may propagate and affect Western Interconnection-wide electricity demand and supply in 2050, the year targeted by many decarbonization goals. Across all climate scenarios, we find that load increases compared to the Baseline Scenario− by up to 35 TWh (+2.3% of annual load) (Fig. 2a). Load increases are predominantly driven by changes in building cooling (up to 31 TWh or 2% of total Western Interconnection load) and compounded by growing water-related electricity use (up to 6 TWh or +0.4% of total load), primarily from more groundwater pumping at greater depths. On the supply-side, total annual hydropower generation in 2050 decreases across 10 of the 15 climate scenarios, declining by as much as 56 TWh (−23% of total annual hydropower generation) from the Baseline Scenario. Even in the scenarios with wetter projected conditions (for example, CESM1-CAM5), additional hydropower generation throughout the year is insufficient to fully offset increases in load. Further, across all scenarios the load increases are concentrated in the summer (by up to +8% or +11 TWh in July), exactly during the months when hydropower generation decreases are the greatest (Fig. 2b), exacerbating grid stress during the peak season.

While these climate impacts on total Western Interconnection electricity supply and demand coincide temporally, we find that they are not uniformly spatially distributed throughout the study area because of the geographic variation both in temperature and precipitation changes and in the climate sensitivity of building, hydropower, and other water infrastructure. For example, the positive

relationship between temperature and load changes is strongest in the SW region, where about 90% of households currently use air-conditioning[61], and consequently annual electricity use could increase by up to 30 TWh from cooling loads compared to the Baseline Scenario (Fig. 2c). In the relatively temperate PacNW, where historically electric heating has been more prevalent and air-conditioning has been relatively rare, decreased electricity use for heating partially offsets increased electricity use for cooling. However, this lower net total result may underestimate future challenges if more PacNW households adopt air-conditioning to cope with warming, as has been the case since the unprecedented 2021 heat wave[62]. We do not include such technology changes, often called the extensive margin response, in the analysis[30]; therefore further study is needed to evaluate how much adaptation to extreme heat in such historically temperate areas has already changed the load-temperature sensitivity throughout the Western Interconnection.

We also find that water-related load grows under most climate projections across the MT region and SW regions, although the increases are small (up to 5 TWh) relative to cooling load changes (Fig. 2c). This water-related load is not well correlated with precipitation in the SW, likely due to offsetting factors (higher groundwater pumping loads partially offset by less conveyance pumping from decreased inter-basin water transfers under drier scenarios), while precipitation is more strongly negatively correlated with water loads in the PacNW and MT regions. As expected, hydropower generation is strongly positively correlated with precipitation levels in all regions, confirming the harmful amplifying effects of climate futures that are both drier and warmer. Overall, these spatial variations in climate impacts can affect adaptation decisions in terms of where and what type of generation and transmission capacity investments and operational adjustments may be needed.

Generation, transmission, and costs for climate adaptation

Next, we evaluate how the grid's generation and transmission infrastructure buildout and operations may adapt under the 15 climate scenarios when the climate impacts to electricity supply and demand are included in the planning process compared to the Baseline Scenario, wherein climate impacts are ignored in decarbonization planning. The Supplementary Information also includes underlying details of the online generating capacity, annual generation, and transmission capacity by investment period for these scenarios.

When optimizing the future buildout and operation of the Western Interconnection, we find that adapting to these anticipated hydropower and load changes while meeting 2050 decarbonization goals requires investing in substantially more generating capacity for all climate scenarios. Cumulatively over the five modeled investment periods (2030, 2035, 2040, 2045, and 2050), 24 GW to 139 GW (+2% to +14%) more generating capacity is built under the climate scenarios than in the Baseline Scenario (Fig. 3a). For reference, California's 2022 peak demand during a record heat wave was 52 GW[63]. Thus in the best-case, adapting to climate change would require building about half the generating capacity across the Western Interconnection as is currently needed to meet peak demand in California, and in the worst case, adapting to climate change would require building almost three times California's peak (now about a 30% share of Western Interconnection peak demand[64]) by 2050. Even in scenarios where there are increases in available hydropower generation in some periods (such as CMCC-CM in 2050, Fig. 2a), the greater increases in load still necessitate the cumulative addition of generating capacity. This is particularly the case because the highest increases in load occur in the peak summer months (Fig. 2b) when the grid is already stretched to its limit.

Driven by forecasted technology cost declines, across all climate scenarios we find that most of this new generating capacity comes from battery storage and solar PV (up to 110 GW and 78 GW,
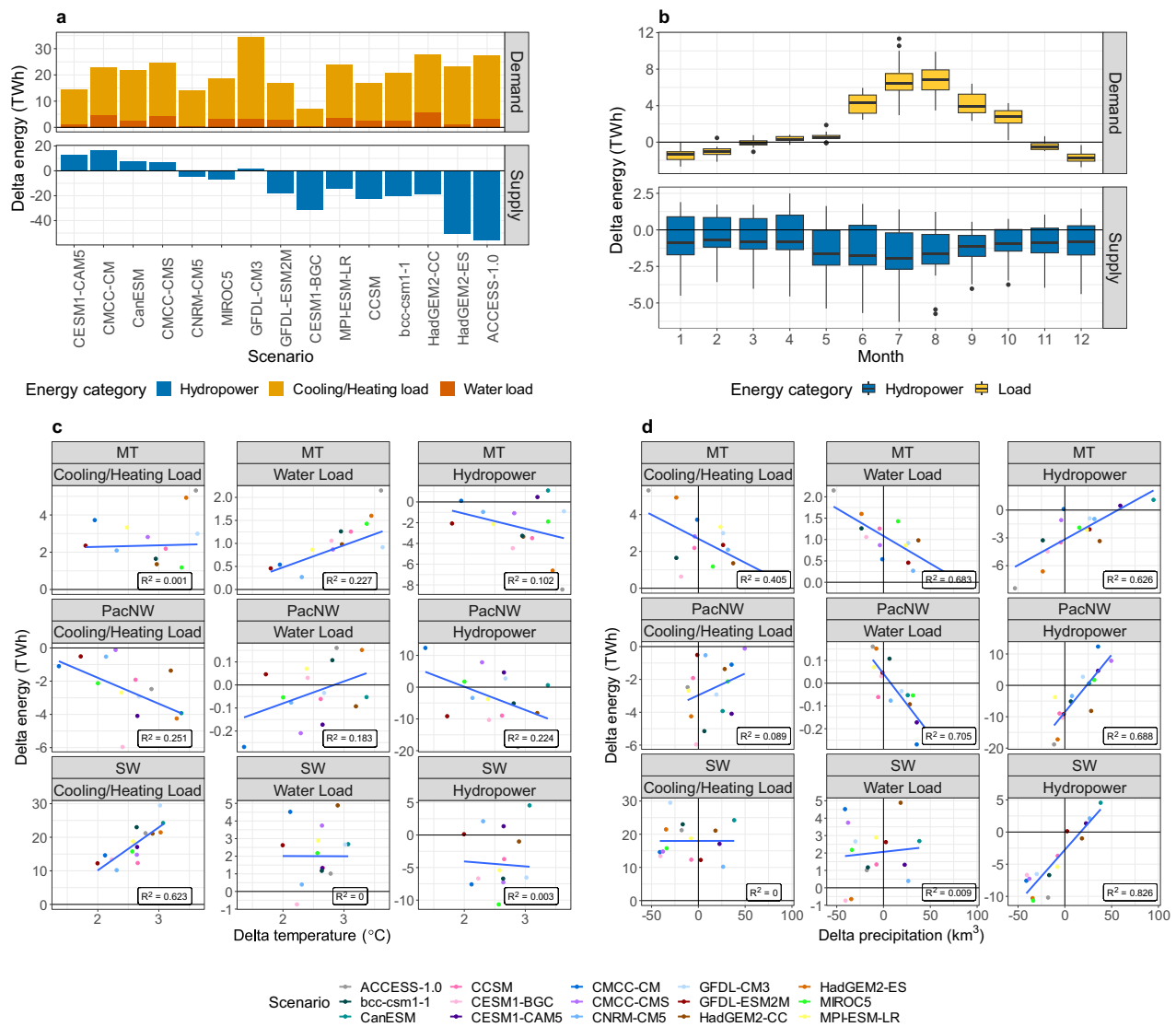
Fig. 2 | Decomposition of climate change impacts on electricity supply and demand. a Decomposition of 2050 changes in electricity supply and demand under climate scenarios compared to Baseline Scenario. The difference in 2050 total Western Interconnection demand under each climate scenario relative to under the Baseline Scenario is disaggregated by changes in load for cooling and heating and for water (such as groundwater pumping, conveyance, and water heating). The scenarios are ranked from lowest to highest total absolute energy imbalance, calculated by subtracting changes in hydropower generation from changes in load for cooling, heating, and water. Each climate scenario is named after the Global Circulation Model (GCM) from which the climate projection originates. **b** Distribution of monthly change in hydropower and electricity demand across climate scenarios in 2050 compared to Baseline Scenario. Each box plot shows the distribution of changes in electricity demand (top panel) and changes in hydropower (bottom panel) across the climate scenarios for each month in 2050.

Lines represent the median, points are outliers, and whiskers show the first and third quartiles. **c** Changes in load and hydropower vs. 2050 temperature. **d** Change in load and hydropower vs. 2050 precipitation. Each point in plots (**c**) and (**d**) is the annual change in cooling/heating loads, water-related loads, or hydropower generation in 2050 for the climate scenario relative to the Baseline Scenario plotted with annual average changes in temperature and total annual changes in precipitation, relative to the 1980–2010 average climate. Data is aggregated by region as follows: Mountain (MT, including Colorado, Montana, Wyoming, Idaho, and Utah); Pacific Northwest (PacNW, including Oregon and Washington); and the Southwest (SW, including California, Nevada, Arizona, and New Mexico). The R^2 for each figure demonstrates the goodness-of-fit. Western Interconnection regions in Canada and Mexico are omitted for visual clarity. Source data are provided as a Source Data file.

respectively; Fig. 3a). Our work also shows that the importance of flexible generation to grid operations grows when climate impacts to hydropower and load are more significant. In the climate scenarios with lower combined hydropower shortfalls and load increases (such as CanESM), most generation in 2050 tends to come from wind, and in scenarios with greater deficits, generation is primarily from solar complemented by flexible battery storage and geothermal resources (Fig. 3c). For example, GFDL-ESM2M, the scenario with the largest net increase in generation compared to the Baseline Scenario in 2050, solar generation and battery discharge increase by 16% and 22%,

respectively, and geothermal generates 5.8 TWh compared to 0 in the Baseline Scenario.

We also find that there is a tradeoff between building generation capacity or transmission capacity to adapt to climate change and reach decarbonization goals. Over the 2030–2050 period, 37 GW less to 13 GW more new transmission capacity is built under the climate scenarios (a range of 47 GW to 97 GW new transmission capacity relative to 84 GW built under the Baseline Scenario; Fig. 3b). The climate scenarios with less transmission investment (for example, CMCC-CM) tend to have more renewable generation capacity investments to
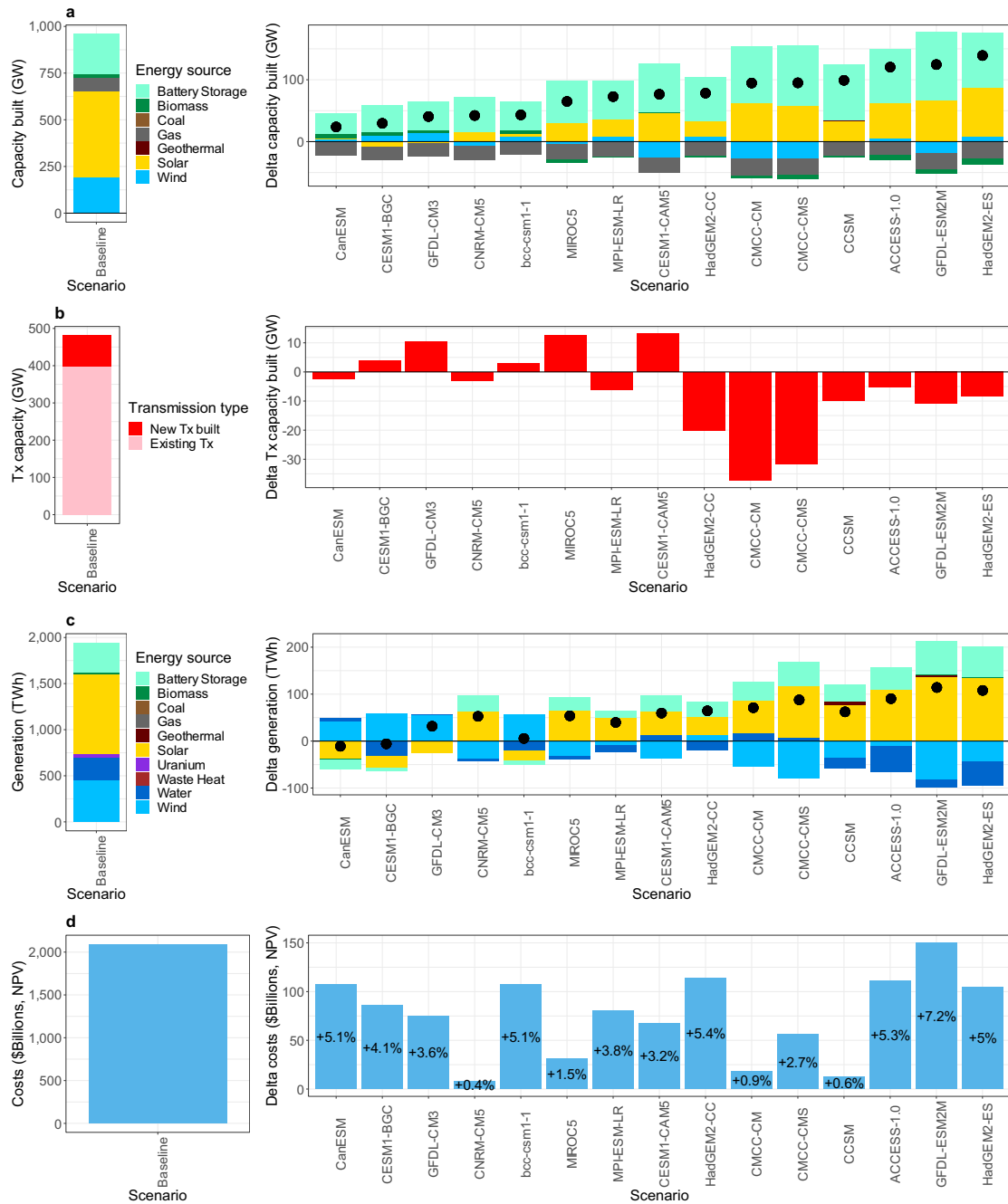
Fig. 3 | Climate impacts on generation capacity and transmission capacity built, generation, and total costs. a Baseline Scenario and cumulative change in Western Interconnection generation capacity built in 2030–2050 for climate scenarios. Black points indicate the total net change in generating capacity across all energy sources under each climate scenario relative to the Baseline Scenario. Each climate scenario is named after the Global Circulation Model (GCM) from which the climate projection originates. **b** Baseline Scenario and cumulative change in transmission capacity built in 2030–2050 for climate scenarios. The light pink bar indicates existing transmission capacity in 2030, and the red bars indicate new transmission built between 2030 and 2050. **c** Baseline Scenario and change in 2050 generation for climate scenarios relative to Baseline Scenario. Black points indicate the total net change in generation under the climate scenarios relative to the Baseline Scenario. The energy storage bars indicate discharge of battery storage (equivalent to generation). **d** Baseline Scenario and change in total system cost in 2030–2050 for climate scenarios. The Baseline and change in costs are in Net Present Value (NPV) terms using 2018 as the base year and a discount rate of 5%. The climate scenarios in plots (**b**–**d**) are sorted from lowest to highest change in cumulative generating capacity built in 2030–2050, based on the scenario ranking shown in plot (**a**). Source data are provided as a Source Data file.

compensate for the flexibility otherwise provided by the transmission network, and vice versa (for example, GFDL–CM3). We note that these transmission network buildouts and costs are an approximation based on the SWITCH model's linear and zonal representation of the transmission network; our approach models the transfer capability of the electrical network between these zones but does not directly represent

the physics of AC optimal power flow. Therefore, these results may underestimate the cost and capacity of transmission required for network reliability, especially if there are transmission constraints within individual load zones that require additional infrastructure. However, this formulation allows us to quantify and identify future electricity corridors between regions, and their associated costs and

infrastructure requirements, that would be of importance under climate change.

Overall, the additional generation, storage, and transmission capacity needed to adapt to climate change could add costs of $8 Billion to $150 Billion in Net Present Value (NPV) terms over 2030–2050 (Fig. 3d). This is a +0.4% to +7.2% increase above the Baseline cost of approximately $2000 Billion NPV of transmission and generating capacity, fuel, variable O&M, and fixed O&M costs to decarbonize the grid by 2050. The magnitude, technology, and timing of capacity investments are key cost drivers; the most expensive scenario, GFDL-ESM2M, relies on pricier geothermal generation in addition to solar and storage to balance demands. Other scenarios like CanESM and bcc-csm1-1 are also more expensive because the least-cost solution includes significant early investments in wind capacity when costs are higher relative to solar costs in later periods (results on the capacity online by investment period in Supplementary Fig. 1).

Spatial and temporal variability in capacity needed to adapt

To further explore the impacts of climate change and water system dynamics on decarbonization efforts, we analyze how variations in climate impacts over different temporal and spatial scales may affect grid investment pathways leading up to 2050, and subsequent daily operations across and between the load zones of the Western Interconnection. We illustrate these effects by focusing the remaining discussion on ACCESS-1.0, the climate scenario with the greatest 2050 combined increase in load and decrease in hydropower generation, and which represents an upper bound of climate adaptation measures in the region (Fig. 2a, full set of scenarios in Supplementary Fig. 1) compared to the Baseline Scenario.

First without consideration of climate change impacts, we note that significant investments in solar, wind, and battery storage capacity are already needed to achieve 2050 decarbonization of the Baseline Scenario, especially starting in 2040 (Fig. 4a). Adapting to temporally varying climate impacts will accelerate these investments non-linearly. Under ACCESS-1.0, additional wind resources are needed in the earlier investment periods compared to the Baseline Scenario, but as hydropower shortfalls increase and relative technology costs decline, by 2045 capacity additions shift to solar and storage (Fig. 4b).

The changing mix of resources to adapt to climate change impacts also affects the daily and seasonal patterns of dispatch under the ACCESS-1.0 scenario relative to the Baseline Scenario (Fig. 4c). Generation from solar PV is the primary energy source used to meet the summer peak and the growing fall load in 2050 under ACCESS-1.0 (Fig. 4d). However, this large investment in solar capacity comes at the cost of a substantial increase in spring curtailment (+93 GW at 11 am, i.e. +157%) when loads are not high enough to utilize all available solar generation. These results suggest that flexible demand management programs would be complementary measures to limit curtailment, and that those programs should be included in future studies of adaptation.

Finally, we find that the regional variation in climate impacts and water dynamics (Fig. 2c, d, Supplementary Fig. 2) can have substantial effects on the geographic distribution of grid expansion in the Western Interconnection. Under the Baseline Scenario in 2050, the SW region hosts the majority of both solar and battery capacity, whereas the eastern half of the Western Interconnection hosts wind capacity (Fig. 5a). The eastern half also has the majority of new investments in transmission capacity, enabling exports from the wind resource-rich areas to the western load centers. Under the ACCESS-1.0 scenario in 2050, declines in PacNW and Colorado River hydropower, and increases in electricity demand for cooling and for water in the SW (Fig. 2c, d) affect the demand for more capacity locally and in neighboring load zones. To adapt, additional capacity investments come from least-cost solar and battery resources in the regions of greatest hydropower shortfalls and load growth, notably the PacNW, British

Columbia, and the SW, and from wind capacity in the MT region (Fig. 5b–d).

Discussion

In the Western Interconnection, where the fate of the water and electricity systems are already closely tied, climate change impacts mediated through the water system, and their associated adaptation considerations, have substantial consequences for the planning of a carbon-free grid. While the range of projected changes in temperature and precipitation does make a difference in both the qualitative and quantitative nature of adaptations required, there are commonalities in the nature of the buildout of the scenarios despite the uncertainty in future climate. We find that by 2050, cooling and water-related loads increase in all climate scenarios, which is compounded in the majority of cases by decreases in hydropower generation, and made worse by their coincidence during the peak summer months. When these climate impacts are less severe, the system relies more on wind and transmission buildout, and when the impacts are greater (higher load increases and less hydropower), large increases in solar capacity alongside flexible resources, including battery storage and geothermal, take on a larger role in serving load. This suggests that the robust adaptation strategy is to pursue diversified capacity investments to maintain flexibility and enable a dynamic adaptive policy pathways[65] approach, while continuously monitoring the way the climate changes, updating expectations, and reevaluating which climate trajectory appears to be more likely to come to fruition.

Our findings also point to several areas of further research to better understand the opportunities and constraints for decarbonizing the electricity grid while simultaneously adapting to climate change. For example, it would be important for future analyses to evaluate how demand response and other flexible demand programs may reduce the capacity and transmission expansion needed to address resource shortfalls from climate warming[46]. Further, this study calculates the optimal buildout for the region, but in practice competitive electricity markets that do not necessarily incentivize coordination may lead to higher investment and different operational strategies for individual load zones than what we calculate as optimal for the Western Interconnection as a whole. Additional analysis is thus needed to understand how more coordinated planning and operations for climate adaptation, such as through the Western Energy Imbalance market[66], may converge adaptation actions closer to the global optimum. Additionally, it is important to test how parallel transitions in the electricity sector, such as increased adoption of air-conditioning, widespread electrification of transportation and buildings, and availability of long-duration energy storage resources and hydrogen, may reinforce or ameliorate the challenges of climate change and water sector dependencies for the grid. To date, there has been no consensus on the extent of climate change impacts on solar and wind generating potential[67,68], but with the emergence of new methods and data[69], future capacity expansion analyses could also consider any such effects. Future study may also be warranted to understand and overcome the significant political and environmental barriers to transmission expansion, which may make capacity additions difficult to achieve in practice. Finally, more analysis is needed of how climate extremes, such as extended and more intense droughts, could compound water and electricity systems.

Overall, these results underscore the importance of incorporating water sector interactions and climate projections into grid expansion models to help ensure a climate-resilient and zero-emissions grid of the future. Without explicitly quantifying how climate change and water interdependencies may together affect future electricity supply and demand, grid planners may mal-adapt[70] by significantly underestimating the magnitude, and mis-calculating the type, location, and cost, of generation and transmission resources needed to achieve decarbonization goals and serve load at all times.
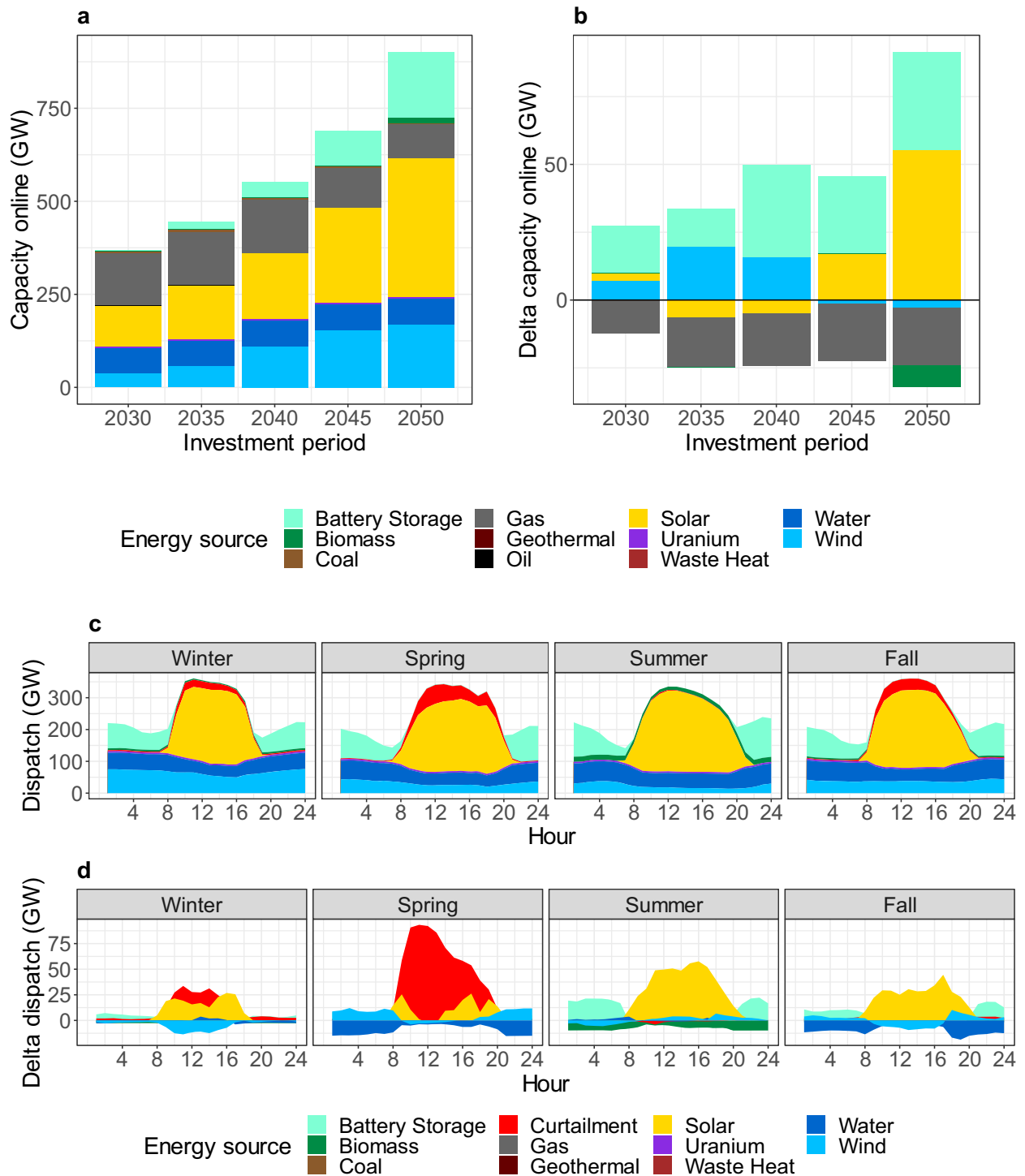
Fig. 4 | Temporal patterns of capacity expansion and dispatch across the Baseline and ACCESS-1.0 Scenarios. a Online generating capacity under Baseline Scenario. **b** Difference in online generating capacity by investment period for ACCESS-1.0 Scenario relative to Baseline Scenario. The ACCESS-1.0 Scenario is named for the ACCESS-1.0 Global Circulation Model (GCM) from which the climate projection originates. **c** Western Interconnection 2050 seasonal average peak-day dispatch under Baseline Scenario. **d** Difference in 2050 seasonal average peak day dispatch for ACCESS-1.0 Scenario relative to Baseline Scenario. Dispatch is averaged for the hours in each season. Winter includes December, January, and February; Spring includes March, April, and May; Summer includes June, July, and August; and Fall includes September, October, and November. Source data are provided as a Source Data file.

Methods

In this analysis, we (1) quantify the climate impacts on hydropower availability, electricity demand for water, and cooling demand in the Western US under a range of potential climate futures; and (2) evaluate the optimal Western Interconnection electricity grid buildout and operations both to meet decarbonization targets and to anticipate and adapt to these projected climate impacts (Fig. 1). We evaluate these connected models with the downscaled climate projections for
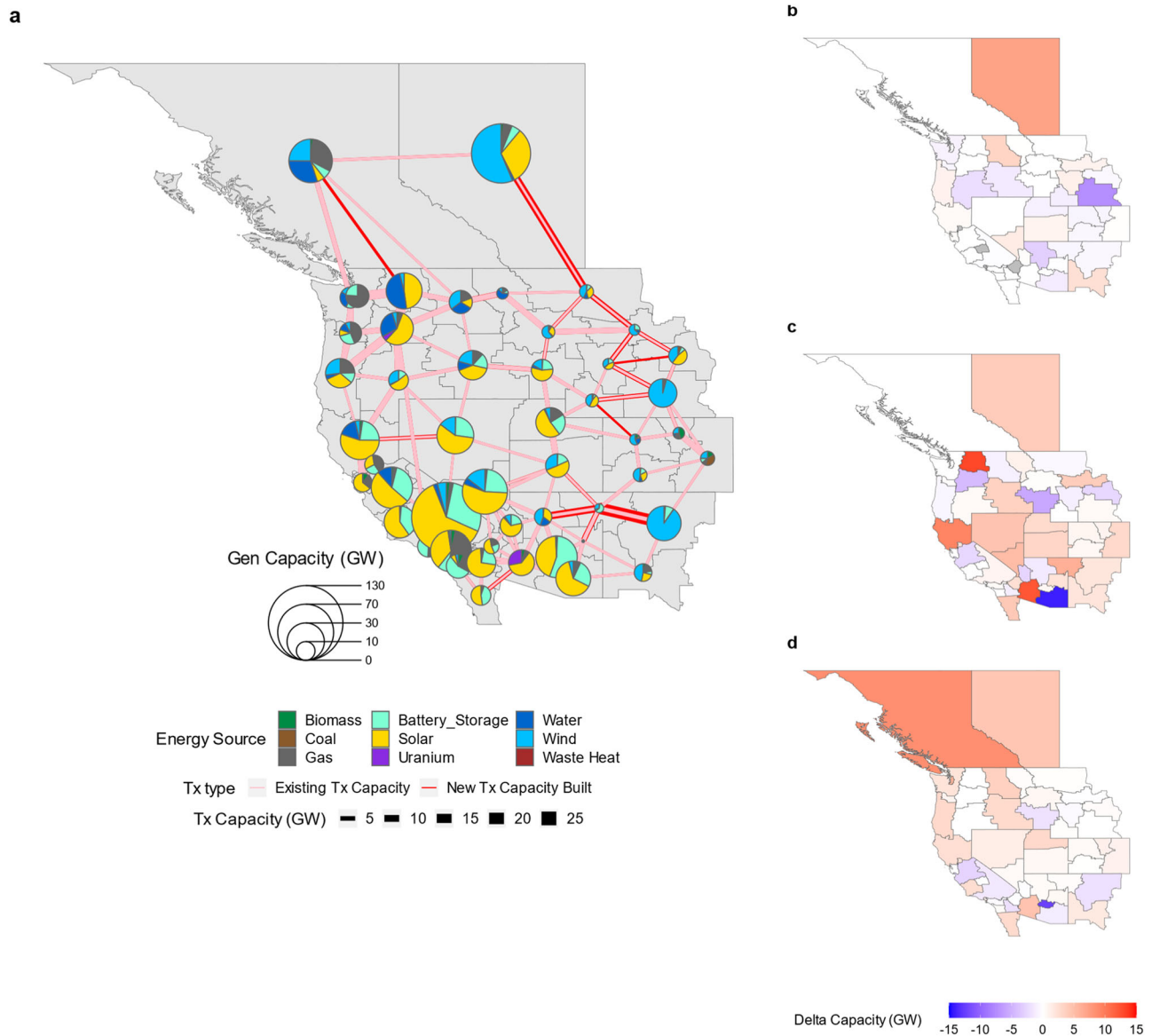
Fig. 5 | Spatial patterns of 2050 capacity expansion. a Baseline Scenario generation and transmission (Tx) capacity online in 2050. Generating capacity online in 2050 by energy source is shown for each of the 50 utility load zones, and transmission capacity connecting utility load zones is distinguished between existing (before 2030) and new transmission capacity (cumulative total transmission built between 2030 and 2050). **b** Change in wind capacity online with ACCESS-1.0 Scenario compared to Baseline Scenario in 2050. **c** Change in solar PV capacity online with ACCESS-1.0 Scenario compared to Baseline Scenario in 2050. **d** Change in battery storage capacity online with ACCESS-1.0 Scenario compared to Baseline Scenario in 2050. Source data are provided as a Source Data file.

2030–2050 from an ensemble of 15 Global Circulation Models (GCM) that have been selected for skill in characterizing the regionally relevant hydroclimatic phenomenon, with the Representative Concentration Pathways (RCP) 8.5 emissions scenario, compared to a Baseline Scenario with historical climate from 1980 to 2010[56,57]. We start with the water resources model, Western US Water Systems Model (WWSM)[58] to evaluate the change in hydropower generation potential for almost 200 individual generators and water-related electric energy use from the Western US water system (including from groundwater pumping, water conveyance, domestic water heating, irrigation, water treatment and distribution, and wastewater treatment), under the climate projections relative to historical climate. The same GCM temperature projections are also used with load sensitivity factors to estimate changes in electricity demand for heating and cooling for each of 50 utility load zones[59]. These hydropower and electricity demand changes adjust the inputs of the Solar, Wind, Transmission,

Conventional and Hydroelectric generation model (SWITCH), which optimizes investment in generation and transmission in the Western Interconnection at five-year time steps from 2030 to 2050, co-optimized with hourly operations for a sample of representative days for each of the investment years. Each step of this analysis is summarized below and detailed in the Supplementary Information.

Baseline scenario

We evaluate each of the climate scenarios relative to a Baseline Scenario in our water and electricity system models, consisting of a stationary climate and a set of assumptions regarding future population growth and decarbonization policy targets. For example, in the WWSM Baseline Scenario, our water system model assumes a 1% annual population growth rate throughout the study area, no change in the current configuration of hydropower and water conveyance infrastructure, and a continuation of current water allocation policies[58]. For

the SWITCH Baseline Scenario, we assume in our electricity model that the Western Interconnection reaches 0 carbon emissions by 2050 with a linear declining trajectory between 2030 to 2050, and that future demand changes with projected population growth, electrification, and energy efficiency, according to state projections and existing policy goals (see Supplementary Information). Importantly, the Baseline Scenario across both the water and electricity models assumes no future changes in climate. By contrast, the climate change scenarios follow the same assumptions as the Baseline Scenario in every regard, including the Western Interconnection-wide 0 carbon emissions target by 2050, with the additional effect of climate change as described further below. This allows us to isolate the effect of climate change and its associated adaptation costs on the optimal grid configuration.

Climate projections

During our study's near-term, mid-century time horizon the majority of climate uncertainty and differences in modeling results comes from differences in GCMs, rather than from the relatively similar emissions scenarios (such as RCP 8.5 compared to RCP 4.5)[55]. Therefore, to encompass the range of plausible futures we construct climate change scenarios with temperature [°C] and precipitation [mm] variables from projections of 15 GCMs from the Coupled Model Intercomparison Project 5 (CMIP5) ensemble for 2015 – 2055, which was the ensemble with the most complete set of bias-corrected and statistically downscaled data available for the Western Interconnection at the time of the analysis. The 15 GCMs (ACCESS-1.0, CCSM, CESM-BGC, CMCC-CMS, CMCC-CM, CESM-CAM5, CNRM-CM5, CanESM, GFDL-CM3, GFDL-ESM2M, HadGEM2-CC, HadGEM2-ES, MIROC5, MPI-ESM-LR, and bcc-csm1-1) are chosen as the most credible for our specific study area based on a model selection analysis[56] evaluating their performance at the global scale (such as for longwave and shortwave radiation, winds, precipitation, and temperature)[71], for the Southwest and Northwest region (such as for seasonal temperatures and variability of precipitation)[72], and for the state of California (such as for dry and wet extremes)[56]. The GCM projections have been statistically downscaled based on the Localized Constructed Analog (LOCA) method and all use the RCP 8.5 emissions scenario, because of the similarity between emissions scenarios within our 2030−2050 planning horizon and study region. These climate projections are compared to the Baseline Scenario, which is based on historical 1980–2010 climate data[57].

Modeling hydropower and electricity related to water

The climate projections are inputs into WWSM to calculate the changes in hydropower generation potential and electricity use related to water. WWSM is developed using the WEAP water resources management and watershed hydrology modeling platform[58,73], which has been used in numerous studies to assess climate impacts on energy-water linkages[44,74,75]. WWSM covers the US portion of the Western Interconnection with 147 rivers and 311 catchments (including the Columbia River, Snake River, Missouri River, Colorado River, Platte River, Salt River, Sacramento River, Feather River, and San Joaquin River, among many others), long-distance and energy-intensive conveyance for inter-basin water transfers (including the State Water Project of California, the Central Valley Project of California, Colorado River Aqueduct from Arizona to California, and the Central Arizona Project), 50 urban water demand nodes, 133 major reservoirs (which together provide 280 Billion m^3 of available storage capacity), and about 200 individual hydropower generators (about 48 GW of total generating capacity). WWSM also includes one desalination plant in Carlsbad, California[76] and non-potable reuse to supply urban outdoor demand from up to 5% of the urban indoor return flows in the drier Southwest states (California, Arizona, and Nevada).

Climate impacts on hydropower generation potential and electricity use for water are directly related to streamflow and reservoir

storage; therefore the monthly and annual streamflow and reservoir inflows at key points of the study area are calibrated in WWSM to observational US Geological Survey (USGS) gauge data based on goodness-of-fit metrics for the historical period of 1980–2010[77]. Water demands and electricity demands related to water are also calibrated and validated against available data across all the states in the water model in the Western Interconnection region. Hydropower generators are parameterized based on hydraulic head, tailwater elevation, and max turbine flow based on publicly available data[78–81] and WWSM represents the behavior of run-of-river and reservoir-based hydropower generators differently. For example, reservoir-based generators have monthly electricity targets but also have a constraint to prioritize water storage to retain water supplies throughout the year. Evaporative losses are also included for reservoirs using the temperature input data from the climate projections. The WWSM hydropower generation potential in the Baseline Scenario is calibrated to match as closely as possible the historical monthly and annual generation patterns of individual generators from EIA Form 923 data per generator[79]. Pumped storage generators are not modeled in WWSM because of limited available data for calibration.

In the capacity expansion model SWITCH, hydropower generation in the Baseline Scenario is modeled such that the average power across all the time points (hours) of a day must match historical average power of that month[79], and exceed the minimum power of that month (to represent minimum flow constraints for generators). For the climate scenarios, the changes in hydropower generation potential from WWSM relative to a historical Baseline Scenario are coupled with SWITCH to represent how generation levels may change under different climate futures. For each climate projection and for each generator we calculate the monthly average WWSM generation potential for a rolling 10-year window to smooth inter-annual variability, centered on the investment years modeled in SWITCH (2030, 2035, 2040, 2045, and 2050). Then we calculate the Delta ratio by dividing these monthly average generation levels for each decade by the monthly average Baseline generation for each generator. We multiply these monthly Delta ratios for each decade from WWSM with the SWITCH Baseline Scenario monthly average power and minimum power parameters by generator. For generators that are not modeled in WWSM (<30 MW), we use the average Delta ratios for each generator in that SWITCH load zone. If there are load zones in SWITCH with no hydropower generators included in WWSM, we use the average load zone Delta fractions from the nearest neighboring load zone. We also adjust the reserve capacity value that each hydropower generator can provide by calculating the new capacity factor (monthly average power/ max capacity limit) with the Delta ratio-adjusted monthly average power values. As a simplification, all hydropower generators in SWITCH are treated as dispatchable within the average and minimum power limits set by the water systems model (i.e. they are all treated as reservoir-based hydropower).

WWSM also tracks the embedded electricity along parts of the water system—including groundwater pumping, conveyance, treatment, water heating and irrigation, wastewater treatment, reuse, and desalination—by multiplying energy intensity values (electricity use per unit of water, kWh/m^3) with the monthly water volumes calculated in WWSM throughout the stages of this managed water cycle. Energy intensity values are either derived with first principles from endogenous model data (i.e. groundwater pumping based on water depth and flow, and conveyance electricity based on flow and height water is lifted), exogenous calculations (distribution electricity, water heating electricity, agricultural electricity), or averages across literature (desalination, treatment, wastewater treatment, reuse).

For each climate projection, we couple these changes in electricity use related to water relative to the Baseline Scenario from WWSM with the total electricity demand by load zone in SWITCH. We first sum up the monthly electricity use in WWSM by category (water
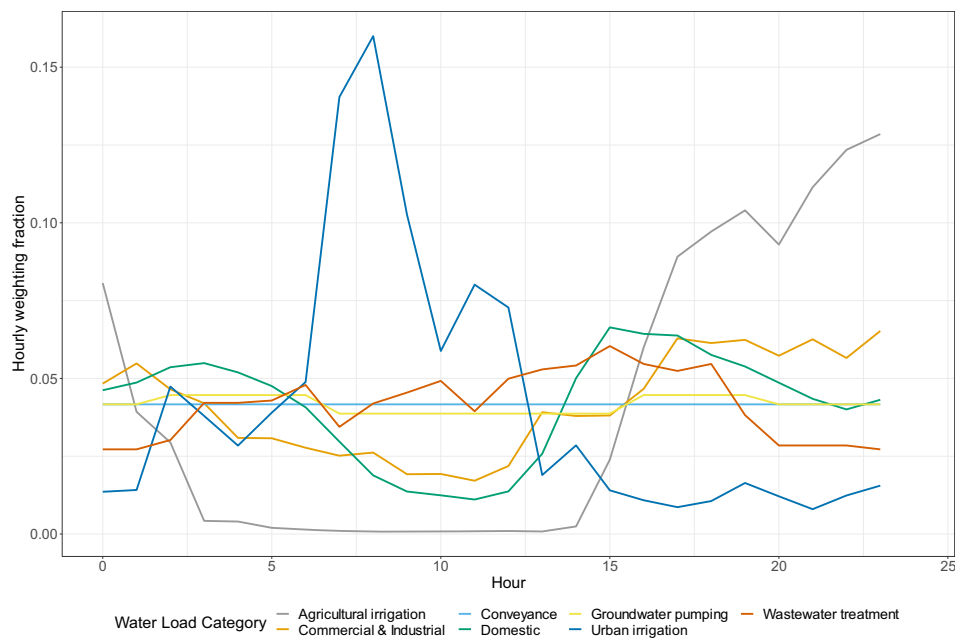
Fig. 6 | Daily load shapes of water load energy categories. The fractions are used to allocate the monthly changes in electricity use for each water load category from Western U.S. Water Systems Model (WWSM) to hourly changes in load for the Solar, Wind, Transmission, Conventional, and Hydroelectric generation model (SWITCH). Source data are provided as a Source Data file.

heating, treatment, distribution, groundwater pumping, irrigation, conveyance, wastewater treatment, reuse, and desalination) and by load zone. To smooth out inter-annual variability, we calculate the rolling-window decadal average monthly electricity use for each energy category under the WWSM Baseline Scenario and under each climate projection. For each energy category and load zone, we calculate the absolute monthly delta for each decade as the difference between WWSM electricity use under the climate projection and under the Baseline Scenario. Next, we allocate the monthly deltas by energy category and load zone to corresponding hourly deltas to match the temporal resolution of load data in SWITCH. We assign each energy category a daily load shape, which determines the share of a day's total electricity that is used in each hour, based on a study of 24-hour patterns of water use of different water sector components[82] (Fig. 6), and a mapping of water sectors and processes included in the WWSM model. For this calculation, we make a simplifying assumption that the electricity use associated with each water sector category follows the same 24-hour pattern as that of the corresponding water use (i.e. there is no time lag between the water use and its associated electricity use). We sum the resulting hourly deltas across all energy categories for each load zone and add those to the Baseline SWITCH hourly load to calculate the new total hourly load under each climate projection in SWITCH. Because of limited available data, climate impacts on electricity use related to water are only calculated for the US portion of the Western Interconnection; load zones in Canada and Mexico are excluded.

Future research is planned to evaluate how changes in water sector policies and climate adaptation measures could affect grid buildout. For example, because of stressed groundwater resources, water managers may need to replace declining surface water with alternative supplies to maintain reliable deliveries[83–85]. There are limited remaining low-energy-intensive water supplies[86], therefore, many water adaptation strategies (including desalination and water recycling)[87–89] may also add to electricity capacity needs[88,90]. Additional study is also planned to evaluate scenarios with different 24-hour patterns of electricity use related to water, especially for conveyance pumping during off-peak hours.

Modeling electricity use for space heating and cooling
One of the major impacts of climate change on the electricity system is the increased electricity use for air-conditioning and decreased use for heating[91]. We estimate these electricity demand changes using heating and cooling load sensitivity factors in mega-watt (MW) per degree-day change that have been calculated for the entire United States in a National Renewable Energy Laboratory analysis for their Regional Energy Deployment System (ReEDS) model's zones[59]. Degree days are the difference in mean daily temperature and a threshold temperature, above which cooling is typically needed (cooling degree day or CDD), and below which heating is typically needed (heating degree day or HDD)[92].

To couple the changes in load with the SWITCH model, we first interpolate these CDD and HDD load sensitivity factors from the ReEDS model's zones to the SWITCH load zones by population weighting. For each of the 15 climate projections, using the same GCM input data as for WWSM, we then calculate the daily CDD and HDD from daily maximum and minimum temperatures at the population-weighted centroid of each SWITCH load zone using a threshold temperature of 18.3 °C (65 °F). To smooth out the inter-annual variability we calculate the change between the 10-year rolling average daily CDD and HDD and the historical daily average. We then calculate the change in electricity demand as the product of the delta CDD or HDD and the load sensitivity factor for each load zone, and sum these changes with the Baseline Scenario SWITCH electricity demand in each hour. Only changes in US electricity use are included in the analysis because of lack of available data for Canadian and Mexican load zones of the Western Interconnection.

Modeling capacity expansion for the Western Interconnection
To optimize long-term electricity system buildout under climate projections and given water sector adaptations, we use the capacity expansion model SWITCH. SWITCH is an open-source framework that can be configured with high spatial and temporal resolution capable of modeling systems with high levels of renewable resources[60], and has been used to evaluate system expansion in several WECC or Western Interconnection case studies[50,93–95]. We build on the SWITCH 2.0

(Python) version[60], and the academic license of the Gurobi solver[96], to evaluate the optimal generation and transmission capacity expansion and operations decisions for the Western Interconnection out to 2050. For computational tractability, we used a zonal representation of the Western Interconnection with 50 balancing areas or zones that model the existing transmission topology, and a simplified linear, transport formulation of transmission that assumes unconstrained, well-connected transmission within zones and only represents connections between zones. The size of the lines between zones and the flow along them are decision variables of the model, and linear line losses are included in energy balance constraints. The objective function minimizes the expected value of the total net present value of generation and transmission operations and investment, with a discount rate of 5%.

The key decision variables (and results) include investment in generation and transmission capacity (MW of capacity built of each generator and transmission line for each investment period among the set of available transmission lines and about 7000 candidate generators), and dispatch for a sample of hours (hourly generation and transmission line flows for each generator and transmission line online in that period). The investment decisions are optimized for five, 5-year investment periods (2030, covering 2028–2032; 2035, covering 2033–2037; 2040, covering 2038–2042; 2045, covering 2043–2047; and 2050, covering 2048–2052). For computational tractability, hourly dispatch is modeled for 24 hours of the peak and median day of each month of the investment year; in total 2880 hours are sampled (24 hours * 2 days * 12 months * 5 investment years) and the dispatch decisions are scaled with hourly weights to represent the annual generation. A sensitivity analysis of the sampling strategy is included in the Supplementary Information. In this time sampling sensitivity analysis we demonstrate only nominal differences from a higher time sampling resolution in terms of overall capacity built, annual generation, and curtailment, with the results being qualitatively very similar. The sensitivity analysis also shows our sampling strategy of 24 h of each month's peak and median day can represent diurnal storage patterns, which is important for such a decarbonization study.

The SWITCH optimization is subject to a number of constraints, including technology operational constraints, limits on capacity investments in both generation and transmission, energy balance requirements for hourly load in each zone to equal generation and net imported electricity transmitted into and out of the zone, the dispatch of generation and transmission flows limited to available capacity and line limits net of outages or derating factors, and dispatch constraints specific to variable generators (solar and wind), hydropower, and battery storage[60]. There are also planning reserve constraints, which require the total available capacity of generators and imports meet or exceed a percentage (15%) above peak annual load (a reserve margin) in each reserves area. In addition to the above operational and investment constraints, we include two main policy constraints on the model for each investment period: a renewable portfolio standard requiring a percentage of annual load to come from renewable sources (wherever applicable according to current policies)[3], and a cap on Western Interconnection total carbon emissions from generation which decreases to 0 from 2030 to 2050. The data, assumptions, objective function, and key constraints are described in more detail in the Supplementary Information.

Data availability
The WWSM input data, including the climate projections data used in this study, have been deposited in the WWSM-WEAP-SWITCH repository[97] under accession code (https://github.com/jszinai/WWSM-WEAP-SWITCH and available with the identifier https://doi.org/10.5281/zenodo.7145298). The data on existing generators used in the SWITCH model was downloaded from the public Energy Information administration (EIA) database from EIA form 860 and EIA 923[78,79], using the code available on Github: https://github.com/RAEL-Berkeley/eia_scrape. Data on the technology characteristics and costs of candidate generators was obtained from the publicly available National Renewable Energy Laboratory (NREL) 2020 Annual Technology Baseline[98]: https://atb-archive.nrel.gov/electricity/2020/data.php. The processed input and output result data from the SWITCH model generated in this study are available in the Code Ocean code capsule provided with this paper: https://codeocean.com/capsule/7256902/tree. Source data for the figures are are provided with this paper.

Code availability
The WWSM model (version 1.0.0), related code, and the water systems files referenced in this paper are available for download from a public WWSM-WEAP-SWITCH repository[97] published on GitHub (https://github.com/jszinai/WWSM-WEAP-SWITCH, and available with the identifier doi: 10.5281/zenodo.7145298. The WWSM was developed within the WEAP software version 2022.0002[99], which is developed and maintained by the Stockholm Environmental Institute (SEI). An evaluation version of the WEAP software, which allows users to open and view WWSM's saved results, is available for free without a license purchase from SEI. To open and view the WWSM, you must first register on the WEAP website and download and install WEAP software from https://www.weap21.org/. A free tutorial on using the WEAP software is available on the WEAP website. The data and the WWSM model code are described in a published paper[58] and its supplementary information files. The code used to couple the results from the WWSM model, and the changes in load for heating and cooling with the inputs of the SWITCH-WECC model is published on GitHub (https://github.com/jszinai/SWITCH-Water-Climate). The SWITCH-WECC model (version v2.0.0) code is open source and published on GitHub (https://github.com/REAM-lab/switch). The SWITCH model is described in a published paper[60]. The SWITCH input and output data and code used for analysis and the creation of figures are available in the reproducible Code Ocean code capsule provided with this paper (https://codeocean.com/capsule/7256902/tree).

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Author contributions

J.K.S. conceived and designed the experiments, curated the data, performed the analysis, wrote the original draft, and reviewed and edited the paper. D.Y. contributed to the methodology and software development, curated the data, and performed the analysis. P.A.S-P. contributed to the methodology and software development, and analyzed the data. M.S. contributed to the methodology and software development and provided paper edits. D.M.K contributed materials/tools to software development. A.D.J. conceived and designed the experiments, contributed the methodology, edited the paper, acquired funding for the work, and supervised the work. P.H-G. conceived and designed the experiments, analyzed the data, contributed to the methodology and software development, edited the paper, acquired funding for the work, and supervised the work. J.K.S., P.A.S-P., M.S., D.M.K., and P.H-G. contributed to the development and analysis of the SWITCH electricity system model. J.K.S., D.Y., and A.D.J. contributed to the development and analysis of the WEAP water system model.

Competing interests

The authors declare no competing interests.

Additional information