Title: The Effects of Climate Change on Interregional Electricity Market Dynamics on the U.S. West Coast

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Key Points

1. The U.S. West Coast power system is vulnerable to altered streamflow patterns and air temperature increases caused by climate change.
2. Regional power systems are most sensitive to altered streamflows in the Pacific Northwest and air temperature changes in California, respectively.
3. Results show that climate-related impacts in one regional power system can spill over to others in complex ways.

Abstract

The United States (U.S.) West Coast power system is strongly influenced by variability and extremes in air temperatures (which drive electricity demand) and streamflows (which control hydropower availability). As hydroclimate changes across the West Coast, a combination of forces may work in tandem to make its bulk power system more vulnerable to physical reliability issues and market price shocks. In particular, a warmer climate is expected to increase summer cooling (electricity) demands and shift the average timing of peak streamflow (hydropower production) away from summer to the spring and winter, depriving power systems of hydropower when it is needed the most. Here, we investigate how climate change could alter interregional electricity market dynamics on the West Coast, including the potential for hydroclimatic changes in one region (e.g. Pacific Northwest (PNW)) to "spill over" and cause price and reliability risks in another (e.g. California). We find that the most salient hydroclimatic risks for the PNW power system are changes in streamflow, while risks for the California system are driven primarily by changes in summer air temperatures, especially extreme heat events that increase peak system demand. Altered timing and amounts of hydropower production in the PNW do alter summer power deliveries into California but show relatively modest potential to impact prices and reliability there. Instead, our results suggest future extreme heat in California could exert a stronger influence on prices and reliability in the PNW, especially if California continues to rely on its northern neighbor for imported power to meet higher summer demands.

Introduction

Hydrometeorological conditions strongly influence bulk electric power systems and wholesale power markets (Kern et al., 2020; O'Connell et al., 2019; Su et al., 2020; S. W.D. Turner et al., 2019; Voisin et al., 2016). Extreme air temperatures (i.e., heat waves and cold snaps) increase electricity demands for cooling and heating, respectively, and can negatively impact the operations of power system equipment. Drought reduces the availability of water for hydropower production and cooling at thermal power plants (Bartos & Chester, 2015; Schaeffer et al., 2012; Van Vliet et al., 2012; Van Vliet, Sheffield, et al., 2016; Van Vliet et al., 2016a). These phenomena can negatively affect the physical reliability and environmental performance of power systems and cause volatility in market prices. For example, droughts tend to create scarcity on the grid, resulting in higher wholesale prices, greater greenhouse gas emissions, and lower reliability (McCall et al., 2016; Rübbelke & Vögele, 2011; Tarroja et al., 2016; Turner et al., 2017; Voisin et al., 2016, 2018).

Given the current exposure of power systems to hydrometeorological uncertainty and extremes, there is growing concern about the future impacts of climate change on power system operations (Bartos & Chester, 2015; Förster & Lilliestam, 2010; Hamlet et al., 2010; National Academies of Sciences, Engineering, and Medicine, 2017; Turner et al., 2017, 2019; Voisin et al., 2020; Zamuda et al., 2018). Previous investigations have focused on the potential impacts of climate change on streamflow dynamics and the timing and amount of hydropower production available globally (Hamududu & Killingtveit, 2012; Turner et al., 2017) and over specific regions (Bartos & Chester, 2015; Craig et al., 2020; Ganguli et al., 2017; Hamlet et al., 2010; Kao et al., 2015; Kern & Characklis, 2017; Kopytkovskiy et al., 2015; Totschnig et al., 2017, Van Vliet et al., 2016b; Voisin et al. 2020) Several studies have also investigated the impacts of higher air temperatures and altered streamflow dynamics on cooling water resources and the useable capacity of thermal power plants (Förster & Lilliestam, 2010; Koch & Vögele, 2009; Miara et al., 2018; Pechan & Eisenack, 2014; Van Vliet et al., 2016c, Voisin et al. 2020)); and many other studies have examined the potential impacts of a warming climate on electricity demand (Auffhammer et al., 2017; Dirks et al., 2015; McFarland et al., 2015; Perera et al., 2020; Ralston Fonseca et al., 2019; Van Ruijven et al., 2019), generally finding that average summer cooling demand will increase while winter heating demand decreases.

However, relatively few studies have examined the potential for climate change to impact electricity supply and demand simultaneously, especially at the more granular (daily and hourly) timescales needed to grid operations models (Ralston Fonseca et al., 2021; Turner et al., 2019). Still less attention has been paid to how projected changes in hydroclimate (precipitation, timing of streamflow, temperatures, etc.) could manifest in large interconnected power systems that span diverse climatic zones and encompass multiple regional electricity markets. Failure to consider the impacts of climate change on interregional flows of electricity may overlook the potential for hydroclimatic changes in one region to "spill over" and adversely affect the performance of other adjacent power systems and electricity markets (Voisin et al., 2020).

In the United States (U.S.), there is perhaps no system more at risk from these combined effects than the West Coast, made up of the Pacific Northwest (PNW) and California. Hydropower accounts for 54% of flexible installed capacity in the PNW (Northwest Power and Conservation Council, 2019) and 18% of installed capacity in California (California Energy Commission, 2017). There are significant interdependencies between the PNW and California regional electric grids, with California importing significant amounts of hydropower from the PNW along two critical transmission pathways (Figure 1a) to help meet the state's electricity load (Public Generating Pool, 2017; Voisin et al., 2006).

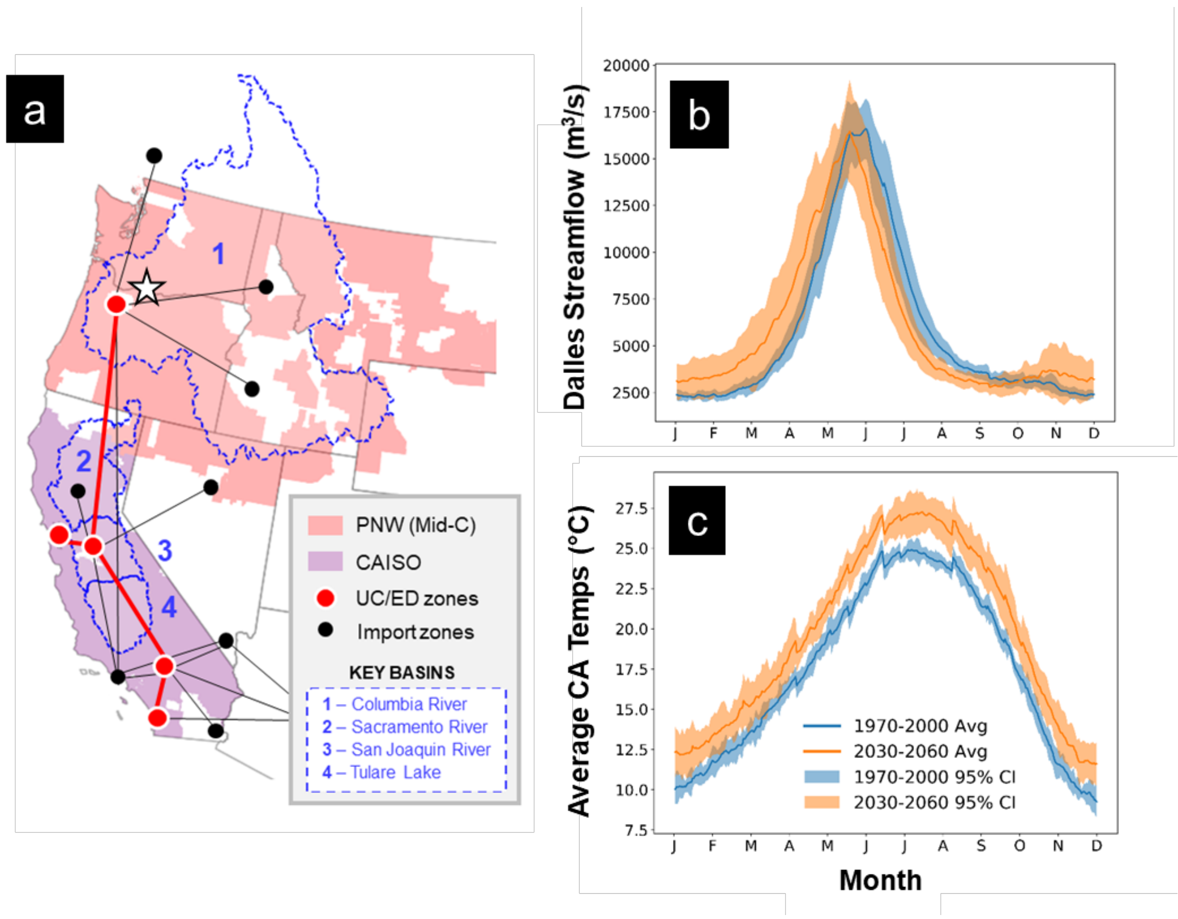

Figure 1. a) Map of study domain, including the Columbia River basin the Pacific Northwest and Sacramento River, San Joaquin River, and Tulare Lake basins in California; b) Time series of mean and 95% confidence intervals of unregulated streamflow at The Dalles, Oregon, a gauge site near the mouth of the Columbia River (indicated by a star in panel a); and c) Time series of air temperatures averaged across California. In panels b) and c), values for each time period (1970-2000 and 2030-2060) are averaged across 10 global climate models forced with the Representative Concentration Pathway (RCP) 8.5 during 2030-2060, with the 95% confidence intervals calculated from the "group" average.

A robust forecasted hydrological response on the West Coast to future climate change is a decrease in snowpack, and several previous studies have explored the potential for changes in snow accumulation and melt regimes to affect the timing and amount of streamflow available for hydropower production (Boehlert et al., 2016; Forrest et al., 2018; S.-C. Kao et al., 2016; Turner et al., 2019; Zhou et al., 2018). Most projections show a decrease in summer water availability for hydropower and an increase over the wet season (October to May), driven by shifts in precipitation phase (snow to rain) and earlier seasonal snowmelt (Boehlert et al., 2016; Chegwidden et al., 2019; Hamlet et al., 2010;). Figure 1b illustrates this effect for The Dalles, OR (a site near the mouth of the Columbia River that is an important water management indictor for the entire basin) using simulated unregulated data from the Variable Infiltration Capacity (VIC) hydrologic model (Liang et al., 1994) averaged across 10 global climate models (GCMs) and assuming future emissions consistent with the Representative Concentration Pathway (RCP) 8.5 through the year 2060 (Chegwidden et al., 2019).

In addition to altered hydropower production, both California's and the PNW's demand for electricity (heating and cooling) are expected to change as temperatures increase (Auffhammer et al., 2017; Franco & Sanstad, 2007; Hamlet et al., 2010) (Figure 1c). Notably, the combined impacts of climate change may lead to a damaging mismatch in the timing of hydropower generation (supply) and electricity demand. Shifts in streamflow patterns across the West Coast could reduce the availability of hydropower during summer (in many places the highest demand period of the year) leaving the grid vulnerable to disruptions in reliability (North American Electric Reliability Corporation, 2020; Turner et al., 2019, Kao et al. 2016, Forrest et al. 2018).

Despite the interdependent nature of the PNW and California power grids (Penn, 2020), the potential impacts of climate change on electricity demand and hydropower production in these systems have mostly been explored in isolation and/or under a limited range of modeled climate futures. No study has leveraged the broader, multitude of global climate and hydrologic models and future climate scenarios that exist to explore impacts within (and across) these interconnected power systems. Furthermore, with few exceptions (Golombek et al., 2012; Van Vliet et al., 2013, O'Connell et al, 2019), previous studies have largely ignored effects on market prices, which apart from physical reliability, are likely to be a critical outcome with financial implications for grid participants, including consumers.

Here, we characterize the potential for hydroclimatic changes across the U.S. West Coast to impact power system operations in PNW and California, including power flows between these regions and market dynamics. We use outputs from multiple downscaled GCM runs forced with two RCPs to drive an open source power systems model (Su et al., 2020). We quantify the impacts of a changing hydroclimate in the PNW on power system operations in California (and vice versa) through a controlled experiment designed to isolate the individual and combined effects of regional climate change on these connected systems. Our results point to complex impacts from climate change on interregional market dynamics, which an array of stakeholders (independent system operators, utilities and utility commissions) will need to navigate when making long term planning and investment decisions.

Methods

2.1 Power Systems Modelling

Power system operations across the U.S. West Coast were simulated using the CAPOW model (Su et al., 2020), which represents the West Coast grid as five interconnected zones: one in the PNW, representing the informal Mid-Columbia (Mid-C) wholesale electricity market; and four across California, representing the footprint of the California Independent System Operator (CAISO), which manages the majority of California's electricity system including a wholesale market (see Figure 1a). Each zone is associated with a unique set of generation resources (hydropower, variable renewable energy, natural gas, etc.) and fluctuating electricity demands that must be met. In order to isolate the potential effects of climate change on power system outcomes, generation capacity was deliberately kept static at 2016 grid levels and no long-term changes in demand other than those caused by climate change were considered (e.g. growth in demand due to population increasing) (Iyer et al., 2019).

The CAPOW model simulates operations of the Mid-C and CAISO markets separately, as two different optimization problems, instead of a single larger problem. Daily power flows between the Mid-C and CAISO (and from other systems abutting the West Coast, including the Southwest) are not treated as decision variables. Instead, these quantities are predicted statistically using multivariate regression models fitted to historical interregional power flow time series data, with independent variables including demand, hydropower availability, and renewable energy availability in each region (Su et al., 2020) (see Supporting Information for further discussion of interregional power flow modeling). Power flows between the Mid-C and CAISO markets are then treated as exogenous time series inputs that must be upheld by power flow constraints in a dispatch model. Using two separate optimization problems to simulate the Mid-C and CAISO markets, as well as using regression models to simulate power flows between them, allows us to closely approximate observed dependencies on key hydrometeorological variables and capture how interregional exchanges of electricity could change in response to climate change. It is important to note, however, that these assumptions may bias modeled system behavior during periods of acute stress. For example, we do not allow the modeled system to evaluate in real time whether it would be more economically efficient for power generated in the PNW to serve electricity demand in the Mid-C or CAISO markets.

In the first stage of the CAPOW power simulation model, a suite of hydroclimate data (daily time series of temperatures, wind speeds, solar irradiance, and streamflow) is used to simulate time series of power system inputs across the five zones. CAPOW uses combinations of weather data as independent variables in multivariate regressions to simulate daily peak demand, and wind and solar power availability, which are then disaggregated to an hourly time step using historical profiles. When projecting potential future changes in demand, wind and solar power availability, we assume stationarity in the underlying statistical relationships between weather data and power system variables (e.g. no long-term changes in solar panel efficiency, or increased adoption of air conditioning, etc.). Similar to our exclusion of long-term population growth, this assumption helps isolate the potential impacts of climate change on power system outcomes.

Simulated daily streamflow data are used as inputs to models of hydropower production. Most hydropower capacity in the PNW is represented using a hydrologic mass balance simulation model adapted from the U.S. Army Corps of Engineers' Hydro System Seasonal Regulation (HYSSR) model of the Federal Columbia River Power System (USACE, 2008), and the U.S. Army Corps of Engineers' Hydrologic Engineering Center ResSim model of daily operations of federal dams in the Willamette River Basin (USACE, 2013). In California, where hydropower simulation models are not as readily available, hydropower generation is simulated using a rule-based approach parameterized via a differential evolution algorithm (Su et al., 2020). Table S2 in the Supporting Information shows validation information for individual models of demand, variable renewable energy generation and hydropower production in the CAPOW model. For more detailed information, see Su et al. (2020).

Hourly time series of electricity demand and variable renewable energy production, as well as daily amounts of available hydropower generation, are then passed to the second stage of CAPOW, an hourly unit commitment and economic dispatch (UC/ED) model that simulates grid and market operations in both regions. The UC/ED model is structured as an iterative, mixed integer linear program formulated to minimize the cost of meeting demand for electricity and operating reserves. More detail on the mathematical formulation of CAPOW, as well as validation of the model, can be found in a separate paper (Su et al., 2020).

2.2 Meteorological and Streamflow Data

Observed air temperature and wind speed data were collected for 17 weather stations in the Global Historical Climatological Network (GHCN; (Menne, Durre, Korzeniewski, et al., 2012; Menne, Durre, Vose, et al., 2012)), and solar irradiance data were collected for 6 sites from the National Renewable Energy Laboratory (NREL) National Solar Radiation Database (NSRDB) (Sengupta et al., 2018). These are the same observational sites used to train the regression models of electricity demand, wind and solar power production using historical data (described in the previous section). At these sites, simulated daily air temperature, wind speed, and solar irradiance were acquired for a hindcast (1970-2000) and forecast (2030-2060) period from a multi-model ensemble of statistically downscaled global climate model output consisting of 2 representative concentration pathways (RCPs) (4.5 and 8.5) x 10 global climate models (GCMs). For this study, simulated temperature and wind speed were further bias-corrected to match the statistical properties of the observed weather station data over the observational period.

While we acknowledge questions about the plausibility of fossil fuel emissions necessary to achieve RCP8.5 and do not treat it here as a 'business-as-usual'' scenario (e.g., Hausfather and Peters 2020), RCP8.5 may still be a very likely scenario through the year 2050 (Schwalm et al, 2020). Moreover, many different combinations of emissions scenarios can be created to achieve RCP8.5 concentrations, including scenarios that involve lower fossil fuel emissions but have large and positive carbon cycle feedbacks. Given the sizable uncertainties in the magnitude of these feedbacks, RCP8.5 scenarios are included as potentially low probability, high impact "stress tests" of the West Coast grid.

Simulated daily streamflow for the same 2 RCPs and 10 GCMs were acquired for the locations of hydropower assets in the CAPOW model. In the PNW, bias-corrected, non-regulated streamflow data were obtained for 108 streamflow gauges that directly inform the simulation of dam operations on the main stem of the Columbia River and in the Willamette River basin. Streamflows in the PNW were obtained for 4 different hydrological model parameterizations, yielding 80 scenarios (2 RCPs x 10 GCMs x 4 hydrologic models), as described in Chegwidden et al. (2019)). For California, bias-corrected, naturalized streamflow data were obtained for 20 scenarios (2 RCPs x 10 GCMs, with only one hydrological model) (U.S. Department of the Interior Bureau of Reclamation, 2014). See the Supporting Information section for details on the climate and hydrologic models, as well as meteorological and streamflow data used.

2.3 Scenario down-selection

Despite the relatively simple formulation and lower computational costs of the CAPOW model, it took approximately 8 hours to run one simulated year using eight cores and 40 GB memory. Thus, we selected a subset of 11 model configurations from the original 80 GCM-RCP-hydrologic model configurations for more detailed analysis. Prior to selection, daily "adjusted" demand in the Mid-C and CAISO markets was calculated for the forecast period (2030-2060) for every GCM-RCP-hydrologic model configuration. Adjusted demand is calculated as simulated daily electricity demand in each market minus any available hydropower, solar and/or wind power generation. It thus serves as a proxy for the need for power supply from thermal generation on a daily basis.

Table 1. Subset of 11 model configurations selected with future scenario (RCP), global atmospheric models (GCM), hydrologic models (VIC and PRMS with different parameterization) indicated. Ranking is according to initial set of 80 configurations in the PNW (with 1 being the highest and 80 lowest ranked) and 20 configurations in CA.

Modelling Configuration				PNW Adjusted Demand			CA Adjusted Demand		
RCP	GCM	Hydrologic Model (PNW)	Hydrologic Model (CA)	99th Pctile Rank	1st Pctile Rank	Median Rank	99th Pctile Rank	1st Pctile Rank	Median Rank
4.5	GFDL-ESM2M	VIC-P3	VIC	40	79	77	19	7	19
4.5	CSIRO-Mk3-6-0	PRMS-P1	VIC	72	44	55	7	5	1
4.5	CCSM4	PRMS-P1	VIC	53	66	59	15	4	11
4.5	inmcm4	VIC-P1	VIC	64	23	45	20	3	17
4.5	CNRM-CM5	VIC-P3	VIC	57	32	41	15	15	20
8.5	GFDL-ESM2M	VIC-P2	VIC	38	74	69	11	2	4
8.5	HadGEM2-CC	VIC-P2	VIC	22	5	7	8	17	10
8.5	HadGEM2-ES	VIC-P3	VIC	52	3	10	5	19	3
8.5	CSIRO-Mk3-6-0	VIC-P1	VIC	2	49	8	17	14	6
8.5	CanESM2	PRMS-P1	VIC	39	61	60	1	1	5
8.5	MIROC5	VIC-P1	VIC	43	76	72	6	13	7

Every GCM-RCP-hydrologic model configuration was evaluated in terms of its median, 99^{th} percentile and 1^{st} percentiles of daily adjusted electricity demand (see Figures S1 and S2 in the Supporting Information). Based on each configuration's ranking in terms of median, 99^{th} and 1^{st} percentiles of daily demand, 11 were selected manually (Table 1). Care was taken to include model end members (i.e. configurations ranked very high/low in terms of 99^{th} and 1^{st} demand percentiles) and to achieve a relatively balanced allocation across RCP, GCM, and hydrologic models.

2.4 Experimental Setup

For each of the 11 GCM-RCP-hydrologic model configurations selected, time series of power system inputs (hourly electricity demand, hourly variable renewable energy availability, and daily hydropower availability) were created for the hindcast (1970-2000) and forecast (2030-2060) periods. Power system operations were then simulated under 4 separate scenarios: 1) 1970-2000 data applied to both PNW and California simultaneously (a "Hindcast" scenario); 2) 1970-2000 hindcast conditions in California + 2030-2060 climate change forecasts in the PNW (referred to as "PNW only" in the remaining sections of this paper); 3) 1970-2000 hindcast conditions in PNW + 2030-2060 climate change forecasts in California ("CA only"); and 4) 2030-2060 climate change forecasts applied simultaneously in both regions (a "Combined" scenario) (Figure 2). In this manner, the individual and combined effects of regional climate change in the PNW and California on power market outcomes can be isolated, while also allowing for comparison of within and across model uncertainty. It is important to note, however, that this experimental approach may not always reproduce documented statistical dependencies between regions (e.g. covariance in annual streamflows) in the "PNW Only" and "CA Only" scenarios, because these two scenarios pair hindcast years in one region with forecast years in the other.

Another important note: the price of natural gas is held constant in each zone of the UC/ED across all scenarios tested and in each year of the hindcast and forecast simulations. Thus, with the exception of regression errors that are included in CAPOW's representation of electricity demand and variable renewable energy, the dynamics of simulated system performance can be considered purely climate and weather-based.

Performance Metrics

Grid performance is evaluated using two key metrics: reliability (measured in terms of the frequency and magnitude of hourly supply "shortfalls" in which the system is unable to meet demand for electricity and reserves) and wholesale market prices. CAPOW calculates the hourly market price (i.e. the 'shadow cost' of mathematical constraints that require that supply meets or exceeds demand) in each of the 4 zones within the CAISO territory and then determines the zonal average prices using weights fitted to historical data. In the Mid-C, there is only one zone and thus one hourly price calculated. Hours in which systems fail to meet demand for both electricity and reserves (i.e. supply shortfalls) are priced at \$1000/MWh, based on evidence in both markets of prices trading at this level, even as recently as August 2020 in CAISO and 2018 in the Mid-C (Micek, 2020; U.S. Energy Informaton Administration, 2018). This 'scarcity' price is reflective of regulatory bid caps set in these markets, in an effort to protect retail distribution companies and consumers.

Note that we do not account for the potential for adaptation to scarcity (high prices) in real-time markets using demand response, increased interregional imports, deviations from daily release schedules at dams, or allowance of lower operating reserves. Furthermore, our model does not account for sub-daily storage capacity recently added to the CAISO market and surrounding WECC areas, which would provide further adaptation potential. For each of the 11 GCM-RCP-hydrologic model configurations and 4 controlled experiment scenarios tested, we track the frequency of shortfalls greater than 100 MWh in magnitude to assess reliability risk.

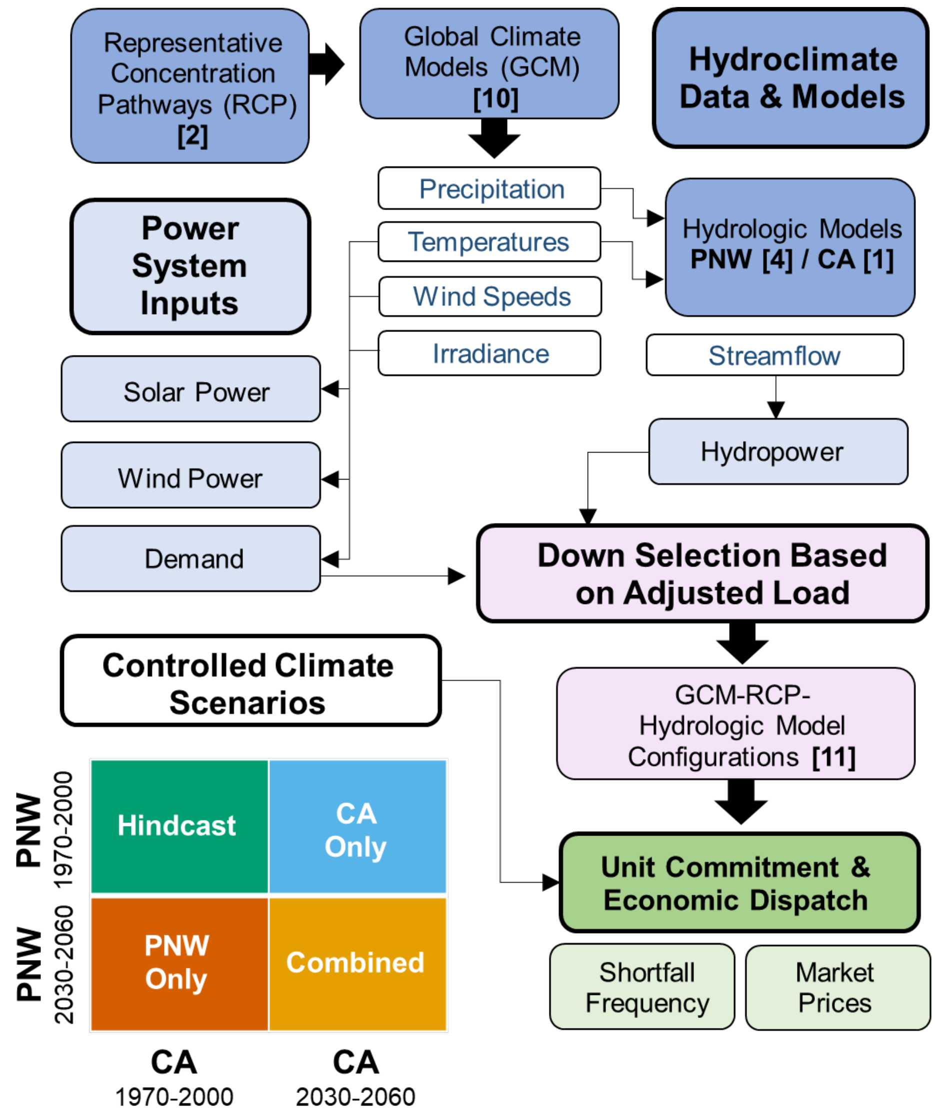

Figure 2. Modelling framework used in this work. To start, a set of ten GCMs are forced with two RCPs to produce 20 unique combinations of temperatures, wind speeds, and solar irradiance. We use four hydrologic model calibrations for the PNW streamflow sites, giving us a total of 80 independent modelling configurations (20 for California). Lists of GCMs, RCPs and hydrologic models can be found in Table S1. Hydroclimate model configurations are down-selected to an 11-member subset, which are then run through CAPOW's unit commitment/economic dispatch under four controlled experiment scenarios. Metrics tracked across all model runs include shortfall frequency and market prices.

Results and Discussion

We begin by examining illustrative examples of monthly dynamics among demand, generation, and system performance for a single representative GCM-RCP-hydrologic model configuration, and discussing the consistency of our findings across the 11 model configurations tested. We then zoom-in to a daily time step to explore specific examples of how discrete, extreme hydroclimate events in the future can cause "spill over" effects between the two power systems considered. Our discussion of results ends with an evaluation of price and reliability impacts in the Mid-C and CAISO markets across the full 31-year simulation periods.

3.1 Monthly Impacts in the Mid-C Market

Figure 3 visualizes monthly effects of climate change in the Mid-C market relative to the Hindcast scenario (1970-2000 baseline conditions in both regions) for one GCM-RCP-hydrologic model configuration, CanESM2/RCP8.5/PRMS-P1. In this configuration, the average annual temperature for the period 2030-2060 is 3.1°C higher than baseline at weather sites in the PNW, and annual streamflows at PNW hydropower sites increase by 9.5% on average. Natural streamflow decreases in summer months (the largest changes occurring in June and July, at -31.5% and -37.3%, respectively) and increases in spring (a 103% increase occurring in March on average). This causes changes in the timing of hydropower production in the PNW Only and Combined scenarios (Figure 3a).

Electricity demand in the Mid-C increases during summer months and decreases in winter (Figure 3b). Note that shifts in the timing of hydropower generation are an order of magnitude higher (in MWh) than temperature-driven impacts to system demand, despite average temperature increases as high as 4.5°C in summer. These trends are fairly consistent across the 11 model configurations tested, indicating that climate change-caused shifts in hydrology within the PNW are likely to be the most important driver of altered market dynamics in the Mid-C.

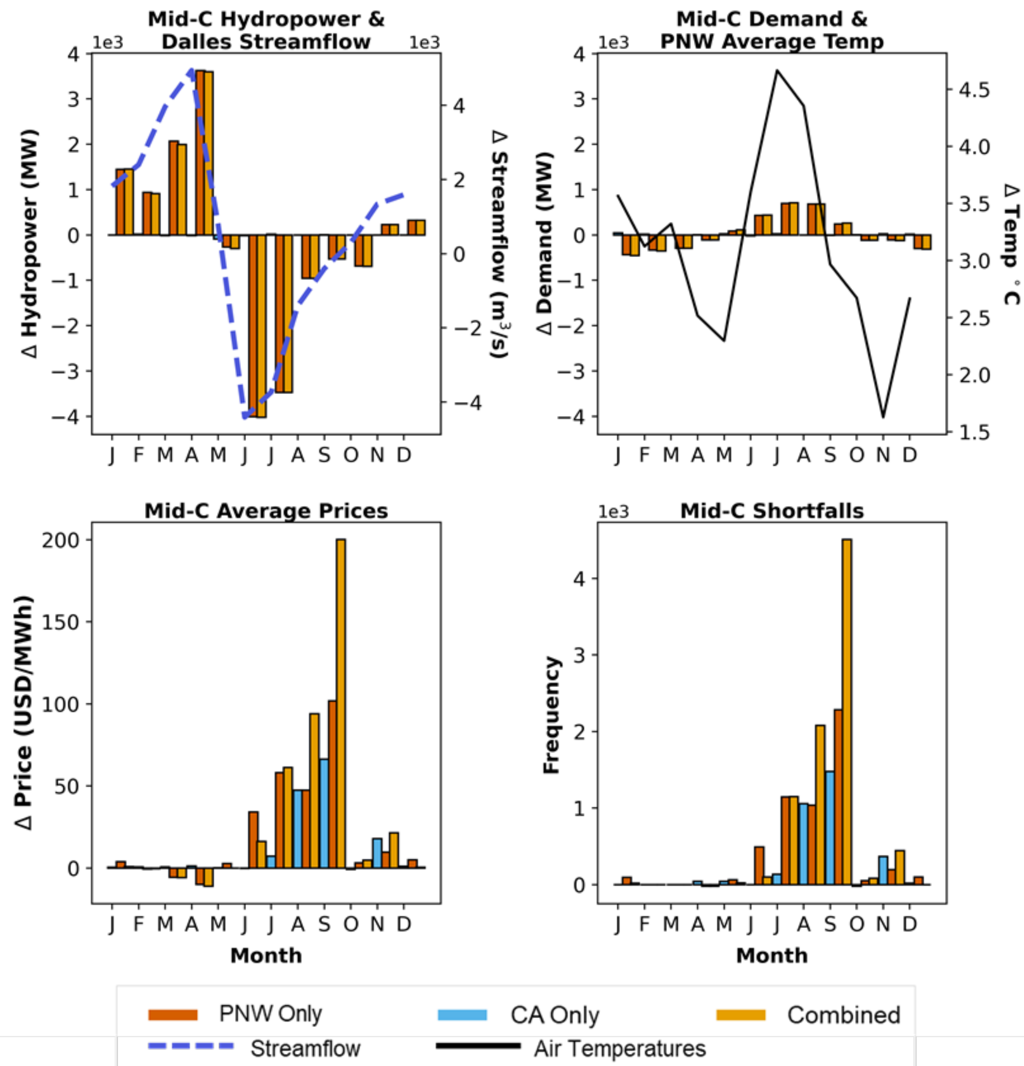

Figure 3. Changes in monthly Mid-C market conditions under the CanESM2/RCP8.5/PRMS-P1 model configuration (color coded by controlled experiment scenario), in terms of: a) hydropower generation and streamflow at the Dalles; b) Mid-C demand and average PNW temperatures; c) average Mid-C prices; and d) frequency of shortfalls in electricity and/or reserves that cause prices of $1000/MWh.

Given the seasonal shift in streamflow timing and hydropower production, it may seem logical to expect June and July (the months that experience the largest decrease in hydropower production) to exhibit the largest increases in wholesale prices. However, Figure 3c shows that Mid-C prices in late summer and early fall (August and September) experience the largest increase. Late summer and early fall in the PNW is already (under 1970-2000 conditions) characterized by low streamflow and hydropower availability in the Mid-C market (see Figure 1c). We find that relatively small decreases in September streamflow caused by climate change, coinciding with small increases in late summer demand, are enough to cause a significantly higher frequency of potential shortfall events (Figure 3d). Due to our valuation of shortfall events at $1000/MWh, a higher frequency of shortfall conditions directly leads to large increases in average annual prices. These results are largely consistent across all RCP8.5 model configurations (though less pronounced under RCP4.5 scenarios due to more modest impacts on air temperatures and seasonal streamflow dynamics). Overall, they suggest that even though the largest seasonal shifts in PNW hydropower may impact major snowmelt months (i.e. June and July), the most *consequential* shifts for grid reliability and power markets could be from more subtle effects that occur during late summer/early fall months when the grid is already stressed.

Figure 3 also provides evidence that the effects of climate change on California could, by themselves, impact the Mid-C market in late summer/early fall. In Figures 3c and 3d, the CA Only scenario shows increases in Mid-C prices and supply shortfalls in August and September that are roughly the same magnitude as increases observed under the PNW Only scenario. This trend is consistent across all 11 model configurations. When climate change affects both regions simultaneously (Combined scenario), the cumulative impacts of climate change in both CA and the PNW lead to much higher increases in prices and supply shortfalls in late summer and early fall.

To some degree, this observed sensitivity of the Mid-C market to climate change in California is tied to our statistical approach for simulating power flows between the Mid-C and CAISO markets. CAISO demand is an independent variable used to predict these power flows, with higher summer demand in CAISO triggering an increase is the volume of electricity exported from Mid-C to CAISO. Thus, when climate change causes higher air temperatures in California, leading to elevated summer demands in the CAISO market, the model predicts that PNW will export more power, leaving less available to meet demand in the Mid-C market. When this coincides with seasonal shifts in PNW streamflows and hydropower production in a Combined scenario, the frequency of shortfall events experienced in the Mid-C market increases.

3.2 Monthly Impacts in the CAISO Market

Figure 4 provides a similar example of monthly dynamics for the CanESM2/RCP8.5/PRMS-P1 model configuration in the CAISO market. Triggering climate change in

California (CA Only and Combined scenarios) causes a similar summer-to-spring shift in hydropower availability (Figure 4a). Nonetheless, increased demand caused by higher air temperatures is the dominant driver of increased prices observed in CAISO (Figures 4b-4c), and this trend is largely consistent across all 11 model configurations. In the CanESM2/RCP8.5/PRMS-P1 configuration, temperatures across California increase by 2.8°C on average, with the largest increases in temperature occurring in late summer. Average summer electricity demand increases by as much as 6000 MWh, which is roughly ten times the size of the loss of in-state hydropower.

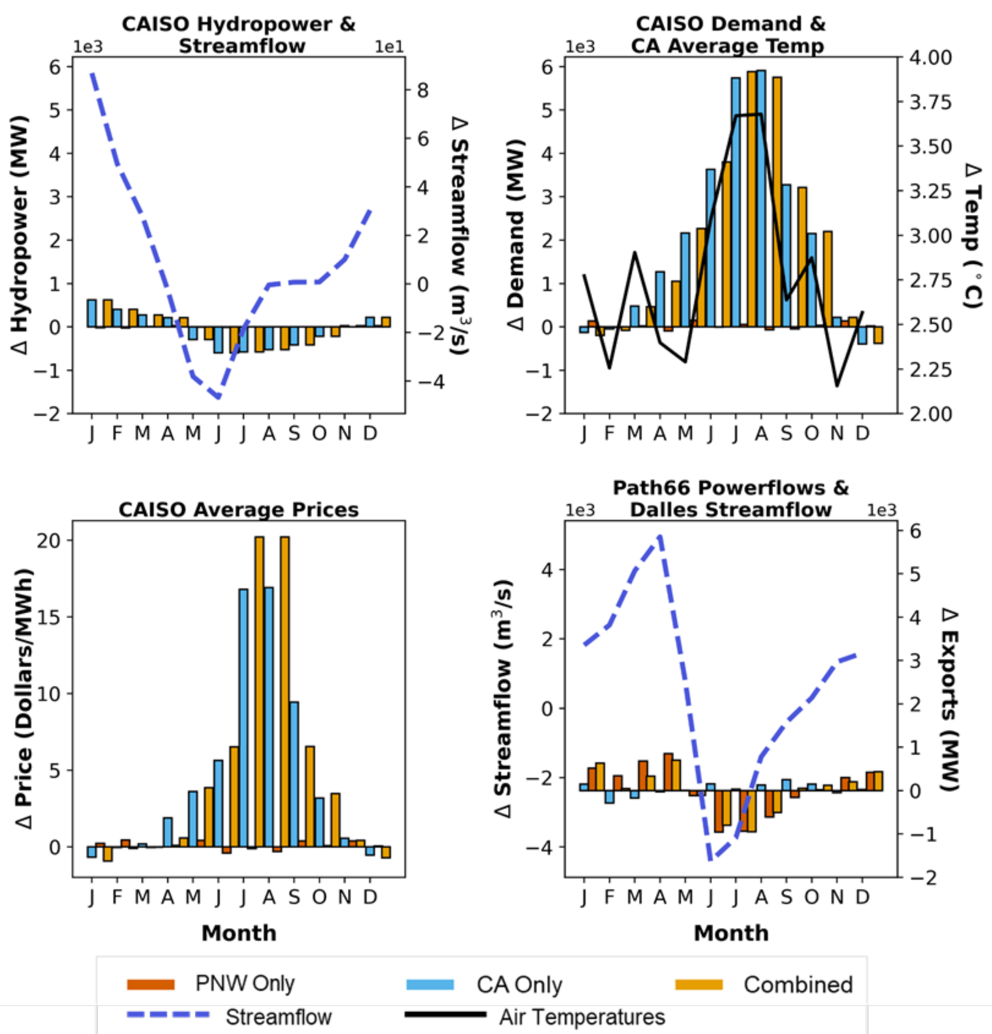

Figure 4. Changes in monthly state variables for the CanESM2/RCP8.5/PRMS-P1 model configuration, including: a) CA streamflows and in-state hydropower production; b) streamflow at the Dalles, OR and WECC Path 66 power flows from the Mid-C market to CAISO; c) average air temperatures in CA and CAISO electricity demand; d) CAISO average wholesale prices. Changes are shown for three controlled experiment scenarios relative to hindcast conditions.

An additional question concerns the role of altered hydrology in the PNW (specifically, a summer-to-spring shift in the timing of streamflow and hydropower production) on the CAISO market. Figure 4d shows that when climate change is triggered in the PNW (PNW Only and Combined scenarios), the delivery of power from the Mid-C to CAISO along the major transmission pathway known as WECC Path 66 shifts to reflect seasonal changes in streamflow and hydropower availability in the PNW.

Coincident summer decreases in CA hydropower production, reduced imports from the Mid-C market, and dramatically increased demand put significant upward pressure on market prices in CAISO during July and August (see Combined scenario in Figure 4c). This confirms the potential for an altered West Coast hydroclimate to have damaging, compounding effects on the California grid. When climate change in the PNW is triggered *in addition* to climate change in California (the Combined scenario), prices increase by 18% in CAISO during July and August, relative to a CA Only scenario. Note, however, that if climate change is triggered in the PNW alone (PNW Only scenario), the marginal impacts of altered PNW hydrology and imports from the Mid-C have minor effects on CAISO.

Recall that the effects of the CA Only scenario on the Mid-C market were generally found to be more pronounced (see Figure 3c). Figure 4d directly shows how increased summer heat in CAISO under the CA Only scenario can "pull" additional power from the Mid-C market along Path 66 in August and September (the most vulnerable period of the year in the PNW due to low streamflow). The magnitude of this increase in electricity delivered to CAISO is small compared to the reductions in June and July deliveries observed under the PNW Only and Combined scenarios (driven by shifts in PNW streamflow patterns). Yet, our results consistently suggest climate change in CA (i.e. increased summer heat) has greater potential to cause "spillover" effects on the Mid-C market than the reverse.

This may speak to the particular vulnerability of the Mid-C market to shortage during the driest months of the year. It also likely relates to our approach for modelling power flows between the Mid-C market and CAISO, which are simulated statistically and then imposed on the Mid-C as an additional source of load it must meet. In some cases, it is possible that shortfalls we observe in the Mid-C actually originate as shortfalls in CAISO, which are then masked by the Mid-C delivering power to its southern neighbor. Nonetheless, these results strongly suggest that increased summer demand in CAISO could be a significant stressor for regional power markets, with potentially important consequences for prices and reliability.

3.3 Daily cross-regional dynamics

The impacts of climate change on interregional market dynamics can be further explored by zooming in to individual modelling years and discrete events. Figure 5 shows one year of daily generation in the Mid-C and CAISO markets for the HadGEM2-CC/RCP8.5/VIC-P2 model configuration. In the Mid-C market, this particular configuration has the lowest overall forecasted hydropower generation, and it produces some of most severe vulnerabilities to supply shortfalls.

Figure 5a shows the daily generation mix in the Mid-C market under a PNW Only scenario (i.e. climate change conditions are applied in the PNW, while hindcast conditions are applied in California). The average daily price is \$69.51/MWh, with prices over the summer months (June, July, August and September (JJAS)) reaching an average of \$140.70/MWh. These prices are close to the average experienced over 2030-2060 for the PNW Only scenario under this model configuration.

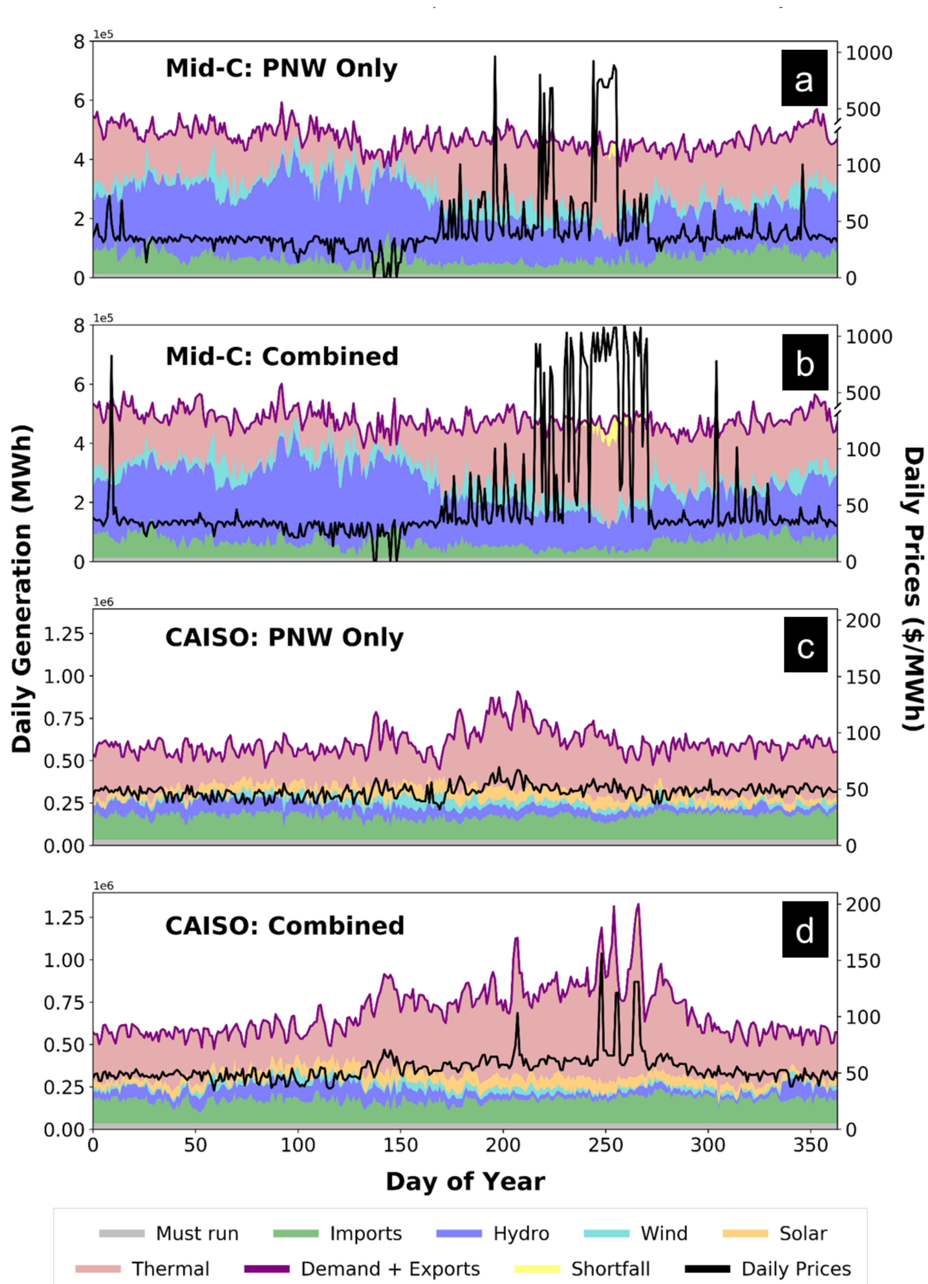

Figure 5. One year of daily generation and prices for the Mid-C and CAISO markets for two controlled climate experiment scenarios: PNW Only and Combined, simulated under the HadGEM2-CC RCP8.5 VIC-P2 model configuration. Note: In order to better visualize daily prices, the second y-axis in panels a-b

are broken above \$100/MWh.

Figure 5b shows the generation mix in the Mid-C under the Combined scenario (climate change triggered simultaneously in both California and the PNW). Average prices increase to \$120.51 and the average JJAS price increases to \$280.35/MWh. This additional stress in the Mid-C market is caused by the impacts of climate change in California. Figures 5c and 5d show the same two controlled experiment scenarios (PNW Only and Combined) for the same year in the CAISO market. Figure 5d shows a significant increase in late summer demand in California relative to Figure 5c (annual average temperature for this example year is +2.9°C compared to the 2030-2060 average for HadGEM2-CC/RCP8.5/VIC-P2, and +5.8°C compared to average hindcast conditions). The higher CAISO load that is caused by excessive heat in California leads to an increase in Mid-C exports during JJAS in Figure 5b (+16.9% compared to the PNW Only scenario in Figure 5a) and a higher frequency and magnitude of \$1000/MWh shortfall events in the Mid-C market. Considering that this model configuration exhibits the largest declines in summer PNW hydropower under forecasted climate conditions, it is noteworthy that increased summer demand in CAISO pulls extra electricity from the Mid-C, even during a period of grid stress in the PNW. This example is illustrative of our broader finding that future extreme summer temperatures in California show the potential to negatively influence outcomes on the PNW grid, although this finding is linked our statistical modeling of power flows between the Mid-C and CAISO.

3.4 Impacts to Prices and Reliability on an Annual Timescale

Figure 6 shows distributions of average annual wholesale prices in the Mid-C market for all 11 GCM-RCP-hydrologic model configurations examined. The highest prices tend to occur under RCP8.5 with climate change triggered for both regions simultaneously (Combined scenarios). These simulations experience the largest decline in summer hydropower, and the largest increase in summer demand. This results in more frequent shortfall events priced at \$1000/MWh, especially during (already vulnerable) late summer months. Especially under RCP8.5 conditions, we also find that climate change significantly increases interannual variability in prices, representing a growing source of risk for market participants. We also track the frequency and magnitude of shortfall events in the Mid-C market under each model configuration (see Figure S5 in the Supporting Information). In general, the model configurations/controlled experiment scenarios that exhibit the greatest price increases in Figure 6 tend to experience the most frequent and severe reliability issues, again due to the valuation of supply shortfalls at \$1000/MWh.

For 7 out of 11 model configurations tested, the three climate change scenarios (CA Only, PNW Only, and the Combined scenario) result in increases in median and interquartile prices in the Mid-C, relative to Hindcast conditions. In most cases, prices in the Mid-C market show more sensitivity to a PNW Only scenario than a CA Only scenario, due to the significant effects of the former on seasonal streamflow patterns and hydropower availability. However, it is clear that climate change in California has a significant impact on prices in the Mid-C, as evidenced by the CA Only and Combined scenarios. In fact, for 4 out of 11 model configurations, triggering climate change in California alone (CA Only scenario) causes a greater increase in Mid-C prices than PNW Only conditions.

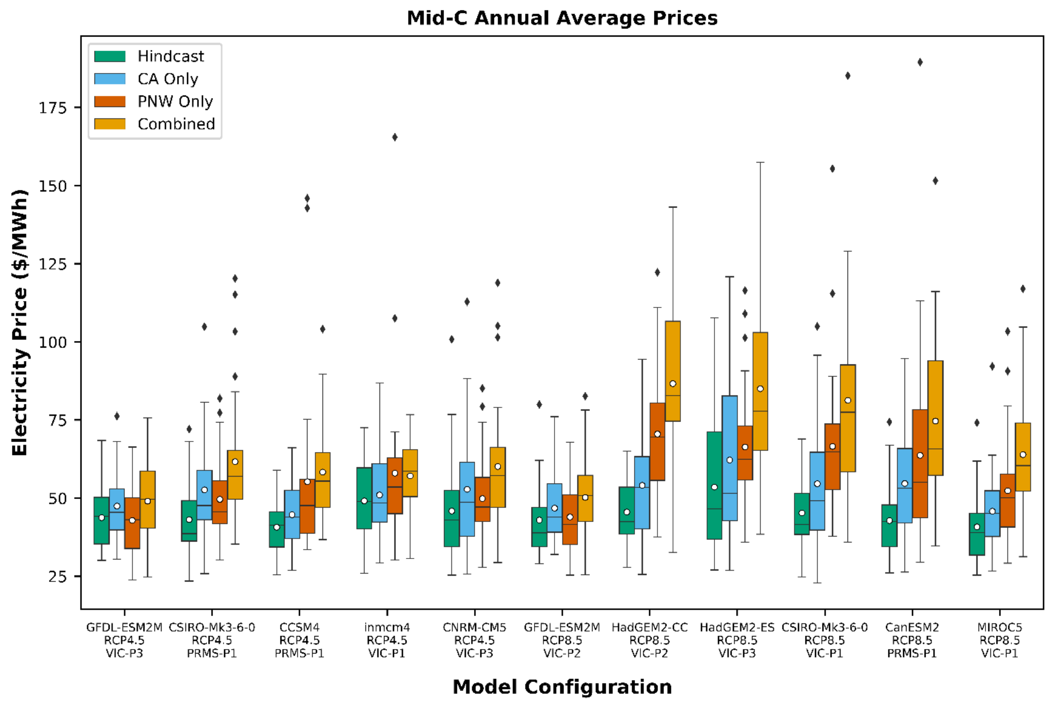

Figure 6. Distributions of annual wholesale prices in the Mid-C market across 11 GCM-RCP-hydrologic model configurations and four controlled experiment scenarios. Each boxplot describes the distribution of average annual prices across 31 modeling years, with white circles indicating mean values.

In the Mid-C system, the month with the highest frequency of \$1000/MWh shortfall events is September (when streamflows and storage are at a minimum and dams in the Columbia River Basin produce less hydropower). The four GCM-RCP-hydrologic model configurations (GFDL-ESM2M/RCP4.5/VIC-P2, CSIRO-Mk3/RCP4.5/PRMS-P1, CNRM-CM5/RCP4.5/VIC-P3, and GFDL-ESM2M/RCP8.5/VIC-P3) that exhibit muted effects on prices under the PNW Only scenario compared to CA Only exhibit relatively high September streamflows (Figure S5), translating to a greater availability of hydropower and an enhanced ability to meet demand for electricity during a critical dry month. This result again supports our finding that, even though the largest hydrologic shifts associated with climate change in the PNW occur in traditional snowmelt months (i.e. June and July), smaller differences in late summer/early summer low flows could prove critical to power system performance.

Figure 7 shows distributions of average annual prices in the CAISO market for the 11 GCM-RCP-hydrologic model configurations and 4 controlled experiment scenarios. These results again confirm that the effects of climate change in the PNW appear to have a more modest impact on the distribution of market prices in CAISO. This is clear from the similarities between the distributions of prices under the PNW Only and Hindcast scenarios, as well as similarities between the CA Only and Combined scenarios. Like the Mid-C market, we find that the highest and most variable prices tend to occur in CAISO under RCP8.5 model configurations. These scenarios experience the largest increases in summer demand from excessive heat in California, which lead to more frequent shortfall events priced at $1000/MWh (see also Figure S6 in the Supporting Information).

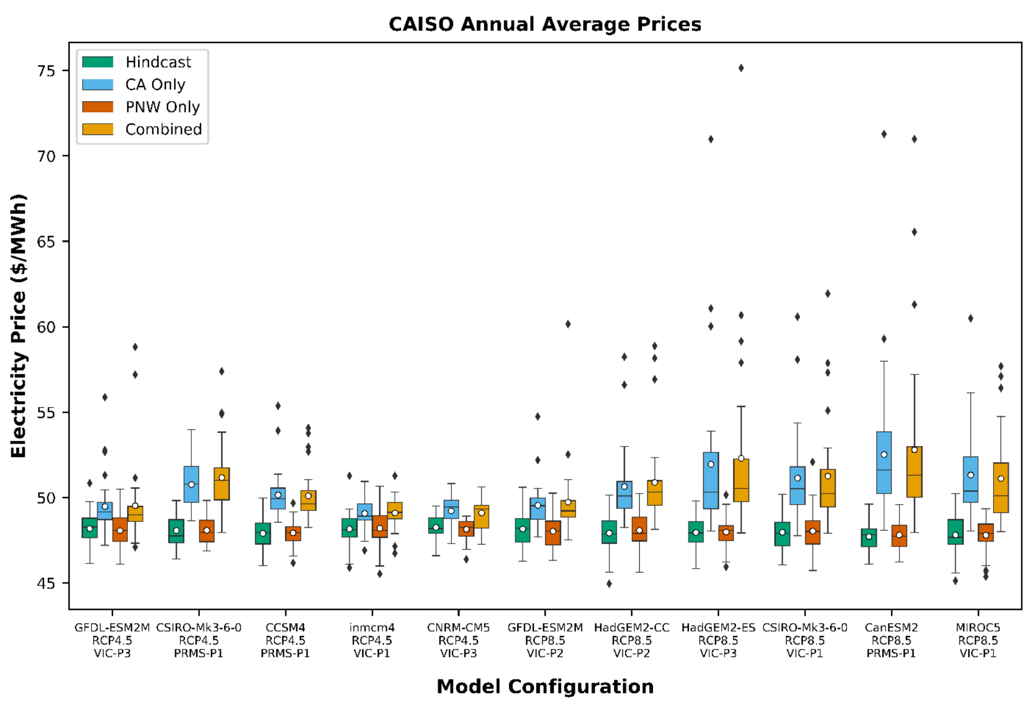

Figure 7. Distributions of CAISO average annual wholesale prices across 11 GCM-RCP-hydrologic configurations and 4 controlled experiment scenarios. Each boxplot describes the distribution of average daily prices across 31 modeling years, with white circles indicating mean values.

Our modeling approach, which involves simulation of the Mid-C and CAISO markets using separate optimization problems with power flows between the two markets modeled statistically, may underestimate the ability of both markets to jointly manage periods of grid stress through coordinated operations, and/or strategically purchasing electricity from adjacent regions. Thus, in an effort to understand the frequency of reliability issues that could be persistent under alternative model assumption, we also analyze the frequency of "coincident" shortfalls across the West Coast grid (i.e. hours in which both the Mid-C and CAISO markets fail to meet demand with existing generation resources (Table 2)). Coincident shortfall events are potentially more damaging than shortfall events in one market alone, because neither system would be able to rely on the other for electricity imports and would be forced to reduce demand across both markets or buy from other regions. Under Hindcast conditions, there are no instances of coincident shortfalls under any GCM-RCP-hydrologic model configuration. The PNW Only climate change scenario triggers a small number of coincident shortfalls across model configurations, while the CA Only and Combined climate change scenarios contribute significantly more. Even so, these remain relatively rare events. Even under the most severe case (the HadGEM2-ES model, run under RCP8.5 conditions using the VIC-P3 hydrologic model calibration) the maximum number of coincident shortfalls is 72 hourly occurrences over 31 modeling years for the Combined scenario. The timing of these potential coincident blackout events is shown in Figure 8, which displays a histogram of day-of-year for these events. Most potential coincident blackouts occur in late summer/early fall, when seasonal hydropower production in both zones is typically at a minimum (regardless of hydrologic year and model configuration). This suggests that these combined shortfall events are caused by the incidence of heat waves during periods of the year that are already associated with very low streamflows (as opposed to major shifts in the timing of spring snowmelt). This also explains the significant increase in coincident shortfalls under RCP8.5 configurations in Table 2, in which projected temperature increases are much greater and consistent.

Table 2. Frequency of hours in 31 years experiencing potential coincident physical shortfall events across Mid-C and CAISO markets under 11 GCM-RCP-hydrologic model configurations and three controlled experiment scenarios. No coincident shortfalls occur in the Hindcast scenario.

Model Configuration	CA Only	PNW Only	Combined
GFDL-ESM2M / RCP4.5 / VIC-P2	5	0	13
CSIRO-Mk3-6-0 / RCP4.5 / PRMS-P1	3	0	0
CCSM4 / RCP4.5 / PRMS-P1	2	6	3
inmcm4 / RCP4.5 / VIC-P1	1	0	6
CNRM-CM5 / RCP4.5 / VIC-P3	4	0	8
GFDL-ESM2M / RCP8.5 / VIC-P3	0	0	25
HadGEM2-CC / RCP8.5 / VIC-P2	17	2	29
HadGEM2-ES / RCP8.5 / VIC-P3	46	0	72
CSIRO-Mk3-6-0 / RCP8.5 / VIC-P3	18	0	29
CanESM2 / RCP8.5 / PRMS-P1	20	1	69
MIROC5 / RCP8.5 / VIC-P1	15	1	48

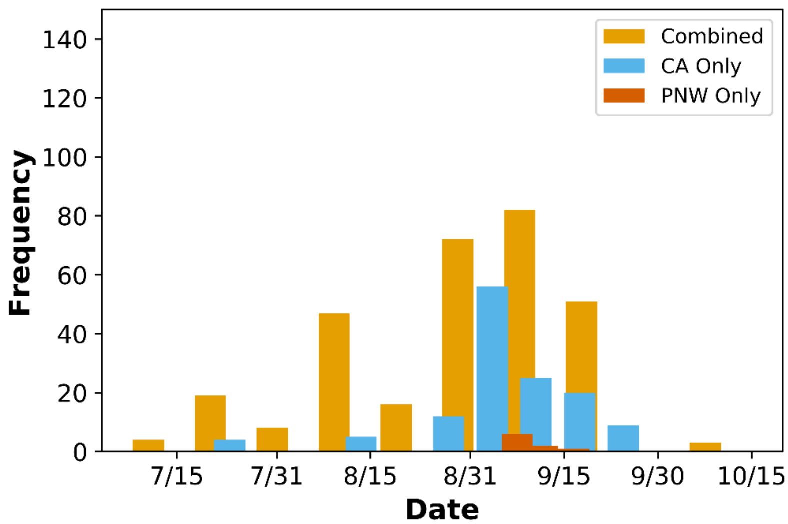

Figure 8. Timing of potential coincident shortfall events across both the Mid-C and CAISO systems across all 11 GCM-RCP-hydrologic model configurations and the four controlled experiment scenarios. There are no coincident shortfalls under hindcast climate conditions.

4 Study limitations and future work

Our findings should be considered in the context of a number of model limitations and assumptions. First, all results reflect the impact of projected future climate change on the circa 2016 grid in both the Mid-C and CAISO markets—meaning, even as load in both markets increases due to higher air temperatures, no additional generation capacity is added. Therefore, this work is not meant to serve as predictor of future market prices, per se, but rather an exploration of the impacts of climate change *in isolation* on existing power system reliability and prices. This research is meant to help inform longer term grid planning and investment strategies by providing insights into how climate change, manifesting as altered intra- and inter-regional supply and demand dynamics, could propagate through the power grid and markets in complex ways (Fiedler et al., 2021).

An important assumption in CAPOW is that power flows between the Mid-C and CAISO markets are modeled statistically and then treated as operational constraints (an additional source of dynamic demand that must be met). As a result, in many cases we find that even in times of stress in the Mid-C market, power producers in the PNW continue to export electricity into California. Ultimately, these power flow dynamics would depend on established regulatory frameworks and wholesale power trading agreements, many of which may change in the future. Our results point to the need for future studies of Western grid operations to consider altered regional power flow dynamics, including altered trading structures and constraints, as both a byproduct of and strategy for managing climate change.

Furthermore, our model does not price shortfall events according to the magnitude of an event (i.e. not meeting demand by 100 MW or 10000 MW results in the same hourly price). This influences our general finding that August and September are the most “at risk” months, because they experience the highest frequency of shortfall events; but the highest magnitude shortfalls generally occur in June and July, when temperatures are highest across both systems. In reality, system planners and investors consider the magnitude of potential shortfall events to be just as (if not more) important than the frequency, since the magnitude of shortfall events would directly inform capacity expansion decision.

An additional assumption within this work is the price of natural gas is held constant across the entire modelling horizon, to limit additional confounding factors on system and price dynamics. While this assumption certainly has an impact on prices, given that natural gas generators are usually the marginal unit (set the hourly price), this assumption would not change findings related to the frequency and volume of shortfall events.

Another key assumption that may bias our findings is our treatment of hydropower in the CAPOW model. Daily hydropower production at dams is simulated either through the use of mechanistic hydrologic-mass balance models or statistically, based on current operating guidelines, and then defined as an exogenous input to CAPOW’s dual UC/ED problems for each market. The UC/ED optimally schedules this generation on an hourly basis, 24-hours at a time, but cannot move hydropower production from one day to another. In reality, it is likely that operators have considerable leeway to deviate from normal operating rules to avoid costly reliability shortfalls, and storage dams in particular may shift their seasonal operations in the future to accommodate altered hydrology.

5.Conclusions

In this work we examine the impacts of climate change on interconnected, hydropower-dependent power markets on the U.S. West Coast. Changes in system reliability (the ability to meet hourly demand) and wholesale market prices are analyzed for both the Mid-C and CAISO markets using an open-source power simulation software, CAPOW. The CAPOW model is forced with a wide set of model configurations; from 80 configurations (10 GCMs x 2 RCPs x 4 hydrologic model calibrations), we use adjusted daily demand statistics to select a subset of 11 configurations to run through dual UC/ED optimization problems that separately represent each market. We compare performance under hindcast (1970-2000) conditions to future scenarios (2030-2060) in which climate change is triggered in the PNW, California, and both regions simultaneously. We are thus able to gain insights about the impacts of climate change in one region on grid dynamics in the other.

We find that without significant capacity expansion or demand-side management, both the Mid-Columbia and CAISO systems are vulnerable to an increased frequency of potential supply shortfalls (reliability failures) under forecasted climate conditions, even under RCP4.5 forcings. We also find that the risk of shortfalls occurring simultaneously in both systems could increase, especially under an RCP8.5 future, but these remain relatively rare events. Wholesale electricity prices in each market show considerable sensitivity to the combined effects of altered hydrology and higher air temperatures, and especially the increased incidence of supply shortfalls, which are valued at $1000/MWh.

In the PNW, altered seasonal streamflow dynamics cause major summer-to-spring shifts in the timing of hydropower production, which combined with increased summer electricity demand cause high prices in the Mid-C market. However, we find evidence that more subtle shifts in late summer streamflows (typically the driest period of the year) may pose greater reliability risks for the PNW grid than the large expected reductions in June and July hydropower production. In the CAISO system, we find changes in summer demand (driven by excessive heat) to be a larger influence on market prices and reliability than shifting hydrology and altered California hydropower production.

A key question we sought to answer was whether the combined effects of shifting hydrology in the PNW (i.e. reduced summer deliveries of hydropower from the Mid-C market region to CAISO) and excessive heat in California could combine to create supply shortfalls and market price shocks in California. While our results confirm some potential for this to occur, we generally find a modest effect of altered PNW hydrology on the CAISO market. Instead, we find that the potential for "spillover" effects may be greater in the opposite direction. The projected climate change-caused increase in summer CAISO demand is so large that it can "pull" additional power from the Mid-C market, even during periods when the PNW grid is experiencing extreme scarcity. We consistently find that this is a dynamic that could significantly disrupt market prices and reliability in the Mid-C market.

The results of this study point to several new insights about how projected climate change conditions may impact the reliability and market price dynamics of interconnected power systems in the U.S. Although our work does not consider capacity expansion, i.e. the exercise of expanding the generating infrastructure in order to maintain the shortfall risk under a certain level, these findings can be used as a tool to inform long-term system planning. Policymakers, utilities, power producers and other important stakeholders should consider the implications of climate-driven changes to not only system performance metrics such as shortfall frequency but also market dynamics, and expand their perspective beyond their respective markets and regions, to include possible additional vulnerabilities due to climate impacts in other regions.

Data Availability

A stable version of the CAPOW model is available through Zenodo (Kern, 2021a). All data and code used to make figures are also available through Zenodo (Hill et al., 2021).

Downscaled GCM data is available through

http://thredds.northwestknowledge.net:8080/thredds/nw.csc.climate-macav2livneh.aggregated.html. An archive of streamflow data for the PNW can be found in (Chegwidden, et al., 2017). An archive of streamflow data for California from downscaled CMIP3 and CMIP5 climate and hydrology projections are available at: http://gdo-dcp.ucllnl.org/downscaled_cmip_projections/. Observed air temperature and wind speed were collected for 17 weather stations in the Global Historical Climatological Network (GHCN; (Menne, Durre, Korzeniewski, et al., 2012; Menne, Durre, Vose, et al., 2012)), and solar irradiance data were collected for 6 sites from the National Renewable Energy Laboratory (NREL) National Solar Radiation Database (NSRDB) (Sengupta et al., 2018).

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