Energy 115 (2016) 1–12

Contents lists available at ScienceDirect

Energy

journal homepage: www.elsevier.com/locate/energy

Vulnerability of the US western electric grid to hydro-climatological conditions: How bad can it get?

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ARTICLE INFO

Article history:
Received 12 October 2015
Received in revised form
15 August 2016
Accepted 17 August 2016
Available online 10 September 2016

Keywords:
Electric grid
Reliability
Water-energy nexus
Inter-annual variability
Production cost model
Hydro-climatology

ABSTRACT

Large-scale assessments of the vulnerability of electric infrastructure are usually performed for a baseline water year or a specific period of drought. This approach does not provide insights into the full distribution of stress on the grid across the diversity of historic climate events. In this paper we estimate the Western US grid stress distribution as a function of inter-annual variability in regional water availability. We softly couple an integrated water model (climate, hydrology, routing, water resources management, and socioeconomic water demand models) into an electricity production cost model and simulate electricity generation and delivery of power for combinations of 30 years of historical water availability data. Results indicate a clear correlation between grid vulnerability (unmet electricity services) for the month of August, and annual water availability. There is a 21% chance of insufficient generation (system threshold) and a 3% chance that at least 6% of the electricity demand cannot be met in August. Better knowledge of the probability distribution of the risk exposure of the electricity system due to water constraints could improve power system planning. Deeper understanding of the impacts of regional variability in water availability on the reliability of the grid could help develop tradeoff strategies.

1. Introduction

1.1. Background

Water is essential in all sectors of the economy. Besides the commonly known uses in the residential, commercial, industrial, and agricultural sectors, water is critical for the generation of electricity. Water scarcity affects electricity generation in three ways: 1) it reduces the energy source of hydropower generation, thereby reducing the ability to generate electric power over a period of time; 2) it may constrain the rejection of heat from thermoelectric power plants into the river resulting in a reduction in plant capacity (derated capacity) [2]; and 3) it could also reduce the thermodynamic efficiency of power plants during conditions of low flow and high water temperature, thereby requiring more energy to reject the heat from the steam cycle in power plants. Due to recent droughts in California, Texas, and the Southeast, there are growing recognition of and attention placed on the exposure of the power grid to prolonged drought conditions, particularly in the context of climate change, because the frequency and severity of droughts are expected to increase. In this paper, we focus on the water-energy nexus from the perspective of electricity generation and power operations constrained by water availability.

1.2. Previous work on the water-energy nexus: geophysical and grid modeling approaches

As of 2010, hydropower contributes 37% to the installed electricity generation capacity in the Western United States (Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, Utah, Washington, Wyoming), while 17% of the installed capacity requires fresh surface water (i.e., no groundwater, no grey water, no ocean water) either for once-through cooling, wet recirculating, or wet cooling (large evaporative cooling towers) technologies [37]. To date, most approaches found in the literature that focus on the water-energy inter-dependencies quantification and vulnerability assessments are based either on geophysical models or on engineering models.

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http://dx.doi.org/10.1016/j.energy.2016.08.059
0360-5442/

Geophysical approaches allow analysts to explore the impacts of climate change on electricity generation capacity or potential hydropower generation. The maximum generation capacity of thermoelectric plants requiring fresh surface water has been the subject of previous assessments of vulnerability conducted under climate change conditions [3,34,35,39,40]. Potential hydropower generation has also been the subject of large-scale vulnerability assessment under climate change conditions [4,19]. Note that reasons other than low summer flow and high stream temperature could decrease capacities and/or the potential generation of water-dependent power plants—reasons like environmental flows (dissolved gas, fish migration) and changes in operations.

Some studies couple geophysical models with engineering models [33]. They comprise hydro-climate model that informs the water routing model, which in turn constrains electric power flow modeling. Vulnerability assessments under specific historical conditions such as the Dust Bowl (1934), Northwest drought (1977), and California drought (1956), using the existing and projected future grid infrastructures examined the negative impacts on these rare stress conditions [33].

Many energy-centric studies analyze data surveys, records, or models associated with a specific water-energy interdependency process [3,10]; for example, the link between thermoelectric cooling needs and water withdrawals [12,21,27,36], nuclear power plants and water withdrawals [22,34], energy needs for water supply systems [30], or bioenergy needs for electricity generation [32]. These types of water-energy dependencies can then be used to inform or constrain electricity operations models that explore the impacts on power flows through the grid. Alternatively, the projected water availability can be used to constrain an electric capacity expansion model to explore the build-out of the electric grid into the future [1,27]. These approaches assume conditions of a given water year, which neglects potential water deficits or oversupply of water from the previous year, a phenomenon that we are evaluating in this paper.

The variability of the water budget over several years needs to be considered in order to capture likely water availabilities, particularly when exploring future climate impacts on the water cycle. This paper will address this gap by studying extreme hydro-climatology factors such as drought conditions and their impacts on the operations of the electric grid. Thus, this paper provides new insights into this water-energy nexus from a risk-based hydro-climatological perspective based on coupled geophysical and engineering grid models.

1.3. Significance of this research

Previous work focused on the interactions among climate and hydrology systems, and the production and transmission of electric power; it explored various aspects for scientific reasons to gain insights into complex system phenomena, as well as to inform engineering communities about how climate via the hydrology pathway may affect current grid operation and future build-out of the power plant fleet and the transmission grid. However, only as of 2014, did the notion of grid stress testing and the development of grid stress scenarios under climate change conditions and related droughts come into being [43]. Grid planners in the Western US power grid are increasingly interested in exploring severe stress scenarios to better understand how resilient the electricity grid must become to provide reliable power services in spite of extreme natural conditions. This desire for deeper understanding is further motivated by the deployment of more variable renewable resources (such as wind and solar technologies), which reduce the level of certainty that grid operators have sufficient capacity available to meet the electric load.

To address these severe climate-hydrology conditions, this study combines the two approaches of geophysically based (usually top-down) and electric power flow modeling (usually bottom-up); it aims to investigate the impact of historical inter-annual hydro-climate variability on generation capacity and how variability further affects generation dispatch in order to look at its impact on actual grid performance. This requires a departure from the long-term resource adequacy assessment of the commonly used approach that treats water resources and extreme weather events as separate, specific, single events (e.g., average year, one extreme drought, high or low hydropower cases, etc.). Instead, the spatial and temporal variability of extreme events between regions should be considered as a portfolio of vulnerabilities. Finally, the findings will put in perspective vulnerability assessments of grid operations under climate change conditions with respect to similar assessments under historical inter-annual variability.

1.4. Specific objectives

In this paper, we estimate the impacts of water availability on electricity generation and transmission in the Western US grid for a range of historical water availability combinations, which generates a distribution function of the grid stress. We specifically address the following questions:

1. What is the relationship between water availability and the reliability (expressed as unserved electric energy without mitigating actions in operations) of the Western Interconnection (Western Electricity Coordinating Council [WECC] region)?
2. What is the value of inter-regional coordination of water-energy joint management and what regional patterns of droughts are most impactful for Western Interconnection reliability?
3. What are the grid operational risks of not addressing regional co-variability in water availability during extreme events?

To address these questions, an analytical framework is developed to explore the reliability space of the WECC region as a function of a new grid-centric drought severity metric that is specifically defined to capture and characterize the impact of water scarcity on the electric grid. The technical approach involves coupling climate, hydrology, and socioeconomic water demand models with an electricity production cost model that seeks cost-optimal electric generation dispatch within the WECC region (Fig. 1). The hydrologic regions offer a regionalization approach for analyzing the inter-regional, inter-annual and inter-seasonal availability of water-dependent energy generation. The grid simulations are performed using balancing area zones. A mechanism was developed that maps the hydrology results from the hydrologic regions to the grid balancing area zones, thus enabling the study of interactions between water availability and grid impacts (Fig. 1).

The following sections present: 1) description of the modeling framework, which includes the derivation and definition of WECC-based and regional water-scarcity grid impact factors; 2) experimental approach; and 3) and discussion of the role of inter-annual variability in regional water availability in the reliability of the grid. We also discuss opportunities for water-energy tradeoffs.

2. Domain and modeling tools

2.1. Western US grid and hydro-climatology

2.1.1. Western US grid and grid management regions

The Western US electric grid stretches from Western Canada south to Baja California in Mexico, and reaches eastward over the Rockies to the Great Plains (Fig. 1). It is commonly referred to as the

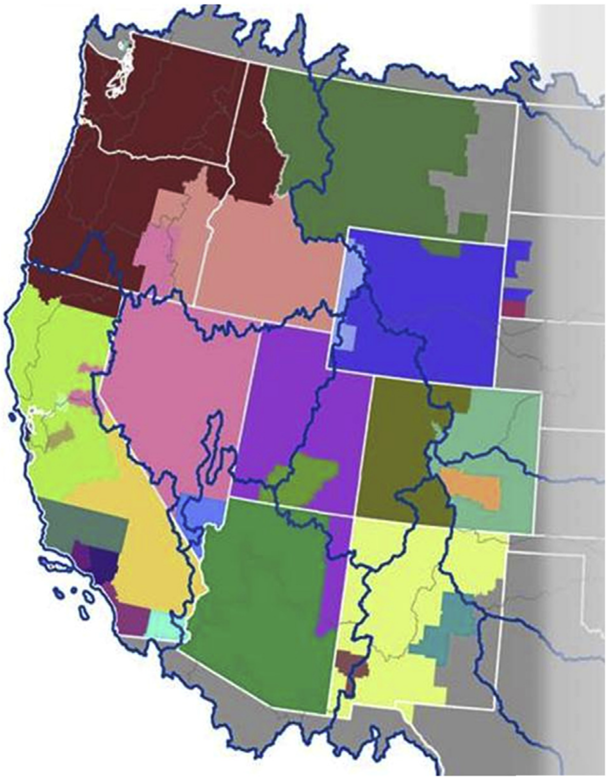

Fig. 1. Jurisdictions of decision-making for joint water-energy management over the Western Interconnection. Colors indicate the balancing authorities: the blue delineations indicate the large river basins, the grey delination indicates the subbasin for water management.

WECC region (the WECC is a council that determines and regulates grid reliability rules and regulations). The grid functions as one interconnected machine across a large transmission network. Thus, it is also referred to as the Western Interconnection. There are 38 US balancing authorities (BAs) (Fig. 1), providing electric services to 61 million people in the United Stated (Counties census 1990). Each BA is responsible for balancing loads and generation within its boundaries. The WECC annually assesses resource adequacy (i.e., is there sufficient capacity to meet the expected demand?). The assessment is commonly performed for the entire interconnection with input received from each member of the Council.

2.1.2. Hydro-climatology and water management over the western United States

Hydrologic regions, which convolute water into streams, define resources for hydropower and wet cooling of thermoelectric plants. Climate, hydrologic regions, and regional water uses (administered by states and federal agencies) affect water availability, and may restrict water-dependent electricity generation. The Western US main large river basins (or hydrologic regions) include the Columbia River Basin (Pacific Northwest), the Sacramento-San Joaquin River Basin (California region hereafter), the closed Great Basin, the Colorado River Basin, and the head waters of the Missouri River, Arkansas-Red and Rio Grande River Basins (Fig. 1). All of the Western United States is considered snowmelt-controlled in that the hydrographs of the large rivers either present one flow peak in the fall and another in the spring for snowmelt when transitional rain-snow conditions exist, or a single large flow peak in the spring for snowmelt when snowmelt-controlled conditions exist. Large reservoir storage capacity in the Western United States allows snowmelt capture for water supply over the ensuing seasons and provides stability in the timing of the release operations on an inter-annual basis, which is important for multi-objective water management and water-use opportunities, particularly during droughts. The main water withdrawals are for irrigation and need to be taken into consideration when estimating actual water availability for electricity generation. Seasonal water management in the Western United States, with decisions made in early spring, has implications for the monthly and daily operations of the energy industry over the spring and summer when the demand is the highest in the Southwestern United States and WECC region-wide.

2.2. Modeling framework

Fig. 2 describes the modeling framework and the different models involved in this integrated assessment of the water-energy nexus.

2.2.1. Integrated geophysically-based estimates of water availability

The water availability module leverages the Pacific Northwest National Laboratory (PNNL) Platform for Regional Integrated Modeling and Analysis (PRIMA) [23], specifically integrated hydrologic simulations by Ref. [18]. Details are provided in the supplementary material. Briefly, water availability over a 30-year historical period is derived using a combination of climate models (coupled Community Earth System Model and Regional Earth System Model [25]), a socioeconomic water demand model (Global Change Assessment Model–USA [[15–17]]) calibrated to U.S. Geological Survey water demand [20], a land surface-hydrology model (Community Land Model [24]) coupled to a routing model (MOSART [26]) and water resources management model [42]. Each physically based spatially distributed model is associated with numerous development and application papers, which are specified in the supplementary material (S1). The output from the water availability component includes regulated flow at a daily time step over a 1/8th degree latitude-longitude grid over the historical period (1985–2015). The annual regulated flow represents reasonably well the historical inter-annual variability. The setup allows reproduction of representative historical conditions that include the impact of multi-year water management performed during sustained droughts (see supplementary material S1 for details of setup and validation).

Conventional hydropower plants and thermoelectric units with once-through cooling and wet recirculating cooling (using fresh surface water, but no groundwater, no graywater and no ocean water) are located on the stream network that is modeled in a latitude-longitude grid (see supplementary material S2). The water availability component (Fig. 1) provides the annual regulated flow at each fresh surface-water–dependent power plant. The regional components and interdependencies are evaluated by analysing the aggregated annual impounded inflow into all power plants in order to adjust the regional analysis specifically to the energy sector. As shown in the supplementary material (S1), the main hydrologic regions (Pacific Northwest, California, and Colorado) present different inter-annual variabilities; California shows the largest range and Colorado the lowest due to the large reservoir capacities. The three regions evolve in and out of phase, which is the inter-annual variability that we aim to capture in this analysis.

2.2.2. Grid operations modeling

Grid operation is commonly modeled on an hourly basis for an entire year using a Production Cost Model (PCM). A PCM optimizes the unit commitment and economic dispatch of electric energy generation resources, and power flow of the transmission system to meet hourly loads typically over a 1-year period. The optimization is subject to generation and transmission constraints, and aims to

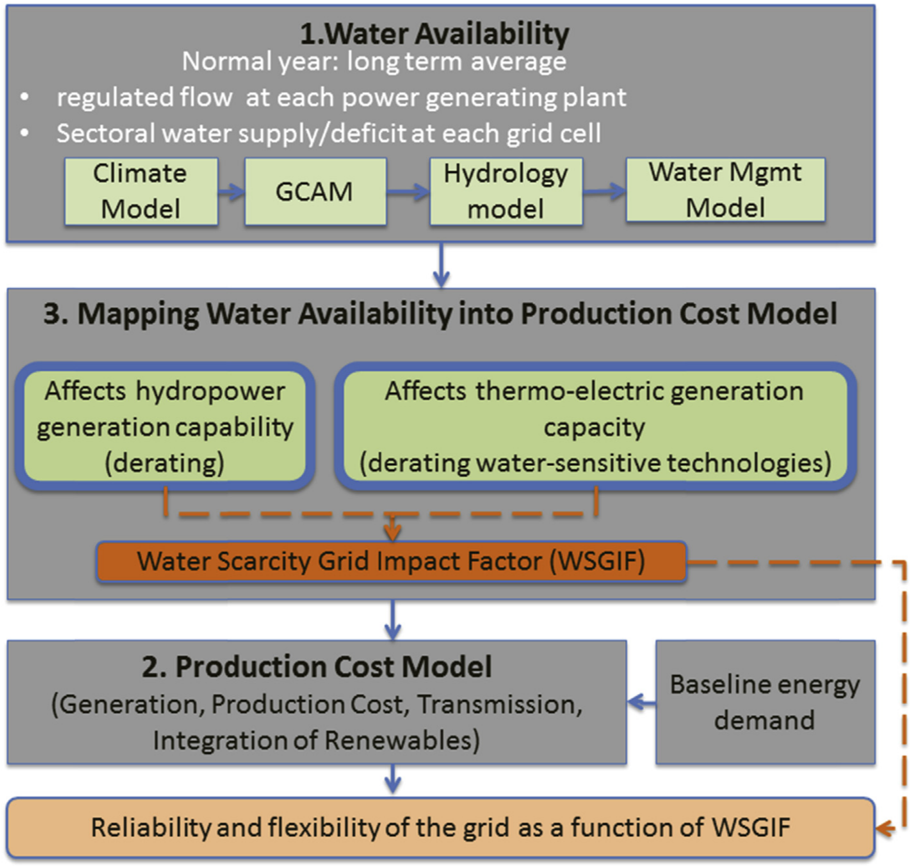

Fig. 2. Integrated modeling framework.

minimize the operating cost. The commercial production cost tool, PROMOD IV[1] from Ventyx, is used. In this study, PROMOD is run in a zonal mode, as opposed to a nodal mode, whereby generators are assigned to 22 zones and each zone can transfer power from/to other zones through the transmission network. No transmission congestions are assumed to exist within a zone (usually referred to as a copper plate assumption). Canadian provinces and Mexico's Baja California regions are simulated as part of the Western Interconnection. However, the impacts of grid operations due to drought conditions are explored by affecting power plants located in the United States and in Canadian and Mexican regions, which rely on the Columbia River Basin and California hydrologic region, respectively.

The WECC system model (database) is developed by the vendor and includes load profiles calibrated for calendar year 2010 (baseline energy demand). The other input into PROMOD includes potential monthly hydropower generation and electrothermal plant capacities (Table 1). Power plant characterization, including rated capacity, ramp rates and efficiencies, as well as transmission line capacities and transfer limits, operating costs and operating requirements (reserves), are calibrated given 2010 data. Plants in the PROMOD database include the technology type: steam turbines using natural gas, coal, solar heat, or other renewables such as biomass, geothermal resources, conventional hydropower, wind technologies, solar photovoltaics, natural gas combustion turbine, internal combustion engines, natural gas combined-cycle plants, and nuclear power, as well as pumped hydropower storage plants (Table 1). All power plants are assigned a summer and winter nameplate capacity. In addition to the summer and winter nameplate capacity, hydropower plants have an assigned monthly and annual generation constraint, which reflects the available water to be used for electricity generation within the 1-month and 1-year time frames.

Only the 2010 grid infrastructure, generation portfolio, and load level are used in this analysis, because we focus on the historical climate conditions, water availability, and 2010-level electricity infrastructure. This is explained in more details in the experimental approach below.

2.2.3. Mapping water availability into production cost modeling

Hydro-climate inputs to PROMOD consist of 1) annual potential generation of hydropower for each represented hydropower plant, and 2) maximum capacity for thermoelectric plants. Fig. 3 displays the location of the hydropower plants and fresh surface-water—dependent thermoelectric plants with the simulated long-term mean historical regulated flow on which they rely, as well as their corresponding maximum power generation capacity . Table 1 summarizes the overall capacity represented in PROMOD, as well as the water-dependent capacity by technology. Sixty-nine percent of the generation capacity installed in the Western Interconnection as of 2010 relies on fresh surface water.

A derating process (summarized here and further detailed in supplementary material S2) is applied to the baseline potential hydropower generation input data set to derive the 30 years of interannual variability over the WECC region. In brief, the derating for hydropower leverages the demonstrated relationship between

[1] PROMOD: vendor Ventyx, an ABB company. More information available at: http://www.ventyx.com.

Table 1
Installed electric generation capacity in the Western Electricity Coordinating Council (WECC) region as of 2010 represented in PROMOD. (*Surface-water–dependent plants within the contributing river basins in the conterminous USA).

	Count	Installed capacity (MW)	Percent of total capacity	Surface- water–dependent count*	Water-dependent capacity	Percent of category	Percent of total
Conventional Hydro	550	65,349	25%	462	59,728	91%	23%
Natural Gas Combined Cycle	295	52,786	20%	276	50,060	95%	19%
Steam coal	147	39,465	15%	128	32,990	84%	13%
Wind	319	23,209	9%	–	–	–	–
Natural gas combustion turbine	450	21,784	8%	–	–	–	–
Steam gas	119	20,796	8%	104	19,165	92%	7%
Nuclear	8	9571	4%	8	9571	100%	4%
Interruptible loads	35	6637	3%	–	–	–	–
Pumped storage hydro	15	4914	2%	–	–	–	–
Geothermal	238	4728	2%	231	3586	76%	1%
Internal Combustion (gas, oil, renewables)	101	3101	1%	–	–	–	–
Solar (steam and PV)	64	2864	1%	49	2425	85%	1%
Steam renewables and others	89	1748	1%	72	1311	75%	1%
Oil combustion turbine	25	868	0%	–	–	–	–
Renewable combustion turbine	11	65	0%	–	–	–	–
Total WECC	2466	257,884		1330	178,835		69%

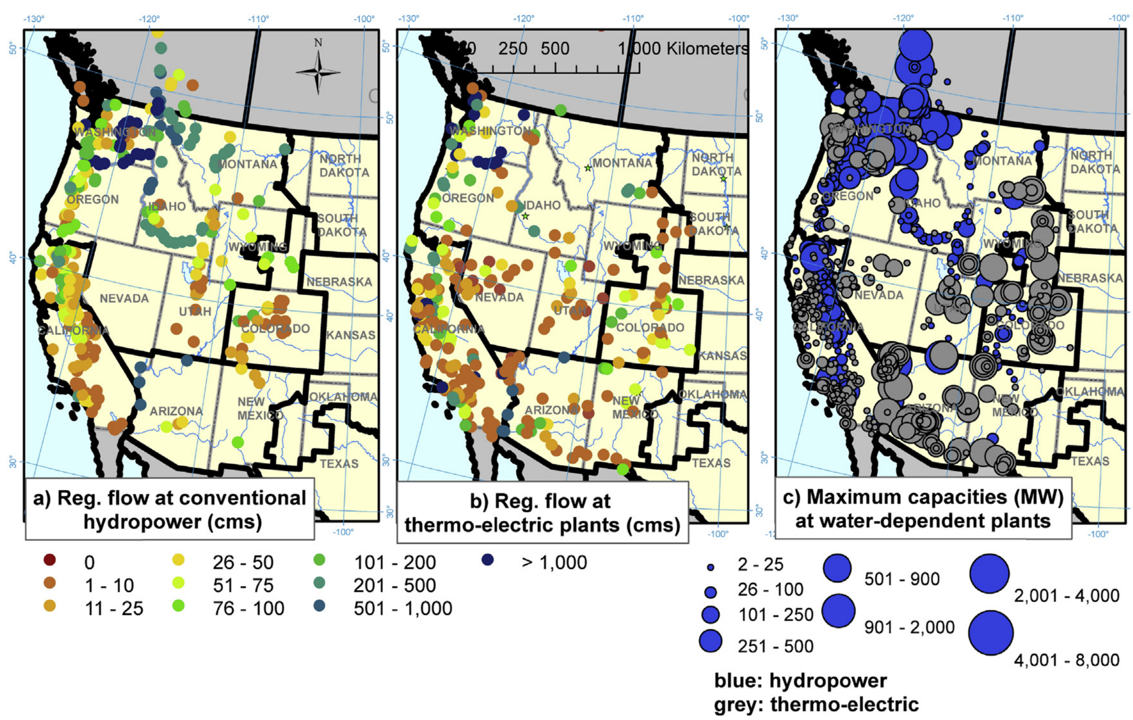

Fig. 3. Mean annual regulated flow at a) conventional hydropower plants, b) fresh surface-water–dependent thermoelectric plants, and c) their corresponding maximum generation capacity.

annual flow and annual hydropower generation [14]. For each year of the analysis, the 2010 baseline hydropower potential generation at each power plant is adjusted by the ratio of that year's simulated regional water availability over the long-term average water availability. A similar derating is performed for all fresh surface-water–dependent thermoelectric plants [14], which renders a simplified method as opposed to a full thermodynamic modeling of the entire steam cycle of a thermal power plant as water becomes scarce and as water temperatures may rise. Water temperature was not considered in the simplified derating approach. More information about the capacity constraint modeling on thermoelectric plants can be found in S2. Based on the integrated geophysically based water modeling described in Section 2.2.1, we estimate that under historical conditions inter-annual variability can drive variation in annual hydropower generation over the WECC region ranging from 68% to 136% with respect to an average water year. Similarly, fresh surface-water–dependent thermoelectric plants can lose up to 31% capacity under historical natural inter-annual variability, which is consistent with other analyses [3,14,33]. Our derating approach has the advantage of being driven by integrated water availability with a regional distribution that follows climate patterns (30 years). It therefore provides coincident derating across hydropower and thermoelectric plants and across hydrologic regions.

2.2.4. Water-scarcity grid impact factor

The motivation for defining a new indicator stems from the fact that there is no appropriate metric or indicator that represents the stress condition to a power grid as a function of water deficit or scarcity. By establishing such an indicator, we hope to succinctly capture key mechanisms that drive water stress conditions on the grid. This new indicator is called the *"water-scarcity grid impact factor"* (WSGIF). Water availability affects both hydropower and water-dependent thermoelectric plants. It is useful to combine the effects on generation capability to represent the combined effect of water availability on grid operations. Previous analyses have quantified the impact of droughts on the power system based on regional deratings for hydropower and/or thermoelectric plants [3,33]. A difference between previous analyses and ours is how we combine regional (hydrologic regions) deratings for both hydropower and thermoelectric plants into a single metric—the WSGIF, which represents the effect of regional variability in water availability on water-dependent power plants throughout the WECC region.

We define an additive relationship of hydropower impact and regional derating of thermoelectric plants in (Equation (1)). The hydropower impact (fraction of baseline potential generation) reflects the overall adjustment of potential hydropower generation, which is the sum of individual hydropower plant (i) generation adjustments (ratio of annual flow over long-term average flow) weighted by their unadjusted potential generation and normalized by the total unadjusted potential generation (Equation (1) in the Supplementary material S1 and Equation (1) below). The thermoelectric impact reflects the overall adjustment of maximum capacity. It is the sum of the individual thermoelectric plant (j) adjustment (fraction of maximum capacity) weighted by the individual unadjusted maximum capacity and normalized by the total unadjusted maximum capacity (Equations (2) and (3) in the supplementary material S1 and Equation (1) below). As seen in Table 1, hydropower has a lower capacity and lower annual generation than all thermoelectric resources. The simple addition of the hydropower and thermoelectric impact (no weights) is one possible representation of WSGIF justified by the fact that hydropower is used in priority over thermoelectric technology because of its low generation cost. An alternative would be to apply weights to each term by each share of the total installed capacity. We choose the unweighted definition for this analysis and address the alternative in the discussion section.

$$WSGIF = \frac{\sum_i H_i'}{\sum_i H_i} + \frac{\sum_j C_j'}{\sum_j C_j} \tag{1}$$

i and j are respectively individual hydropower and thermoelectric plants.

H′ is the adjusted hydropower potential for that year H is the long term mean hydropower potential.

C′ is the adjusted capacity of the thermoelectric plant j for that year.

C is the maximum capacity of the thermoelectric plant j.

WSGIF directly relates the severity of a drought to its impact on water-dependent power plant generation capacity. It can be expressed for the entire year or any duration. The indicator is dimensionless. The regional and WECC-wide WSGIFs theoretically vary from 0 (all capacity and generation cannot generate electricity) to above 3, with a median of 1.9, which represents a "normal water year" with a 50% chance of annual occurrence. The annual (rather than monthly) WSGIF is representative of the overall water availability across seasons because the western river basins are mostly snowmelt-controlled (snowpack storage) complemented by high reservoir capacities.

Fig. 4 represents the cumulative density function (CDF) of the WECC-wide and regional WSGIFs. For each large basin (Hydrologic Unit Code 2 [HUC2]) hydrologic region and the WECC region, the 30 WSGIFs corresponding to each year of the 30 regional water-year water availability data set are ranked and associated with a probability of non-exceedance following the Weibull distribution (rank divided by sample size plus one). The WECC-wide WSGIF varies from 1.32 to 2.35 and tends to have about 8 average years (plateau) over a period of 30 years with an average between ~1.8 and 1.9. The WSGIF for dry years ranges between 1.32 and 1.8, and has a larger WSGIF range than during wet years (2–2.35). The Colorado River Basin has the lowest inter-annual variability due to the multi-year storage capacity in the basin. The WSGIF in California presents the largest inter-annual variability, which is compensated at the WECC scale by the lower inter-annual variability and large fresh surface-water–dependent generation capacity in the Northwest and Colorado regions. At the WECC scale, the WSGIF takes into account the spatio-temporal patterns between regional WSGIFs.

This WSGIF CDFs are the basis of our risk-based approach for assessing the reliability of the grid. The regional WSGIF CDFs indicate a risk-based approach to link inter-annual water availability with the regional electricity generation capacity.

3. Experimental approach

In this study, we refer to "resources inadequacy" when the simulated capacity is lower than the NERC (North American Electricity Reliability Council)-prescribed 15% reference planning reserve margin. The reserve margin is defined as the percentage of generator capacity that exceeds the peak load relative to the peak load. Reserves are necessary in case a power plant fails unexpectedly.

Furthermore, we define "unserved energy" as a condition when the electric demand cannot be met, and we refer to such a condition as "inadequate generation," which represents a reliability issue. Unserved energy is an outcome of a production cost simulation. It usually is caused by insufficient generation resources in a particular load zone or inadaquate transmisssion capability to transfer power to a load zone. We use "grid stress" to represent general conditions when generation resources are in low supply relative to demand.

The experimental approach applied in this study consists of performing multiple PCM simulations of the WECC region using water resources representative of more than 30 years of historical climate data. The results of these multiple simulations provide 1) the actual operational available generation capacity as an outcome of the water availability that then can be compared with the

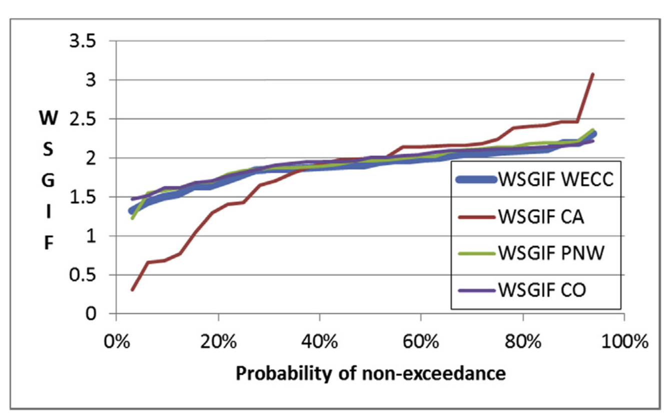

Fig. 4. Probability distribution function of the WECC and regional water-scarcity grid impact factors.

expected peak demand and NERC requirement, and 2) the distribution of grid stress for the month of August as a function of annual water availability. The reliability of the grid is evaluated for the month of August, i.e., when the flow is the second to lowest (September is the lowest), while the weather-related electricity demand is second to highest (July is the highest) over the Western United States.

The water-energy interdependencies are represented using grid performance metrics expressed in amounts of unserved energy and the total cost of production of electric energy over a month. These metrics are discussed as a function of the WSGIF. The WECC-wide WSGIF ranges from 1.32 (extreme drought) to 1.9 (baseline, average year) to wet year (2.4) with more regional variations. We establish a cumulative probability density function for the WSGIF, which serves as the basis for a risk-based estimation of grid reliability issues.

2010 is the base year set by the PROMOD database. The base year sets the capacity and load profiles, which were kept constant for all of the different water years. In other words, we varied the water availability over a 30-year period while keeping the grid infrastructure and load assumptions constant. Doing so isolated variations in the power plant fleet, the transmission system, and load conditions. For the base year 2010, we assigned the capacity and generation constraints for water-dependent plants with long-term (1985–2015) mean annual hydrological conditions and a WSGIF of 1.90, which corresponds to the median 30-year historical WECC-wide WSGIF. Thirty years are simulated using the PCM corresponding to the 30 water years of historical water availability data.

Four additional scenarios (case studies) are defined that represent bookend cases, for which we postulated worst-case scenarios. They are added to explore the maximum extent of the water dependency of the power flow simulation results. The scenarios are defined as 1) no hydropower available, 2) all vulnerable thermoelectric plants are shut off, 3) both scenarios 1 and 2 combined, and 4) a hypothetical case designed to mimic a worst-case scenario in which each BA would plan for its own worse hydrologic regional drought event, all occurring at once in the same year. For the fourth scenario, plant capacities and generation constraints are associated with the driest adjustment and no dependency in space, time, or between hydropower and thermoelectric adjustments. We refer to this case study as “All Minima”. The four hypothetical case studies are designed to bound the dependency between grid operations and water availability. Table 2 summarizes the hydropower and vulnerable thermoelectric WECC derating factors and WSGIFs for the boundary conditions, the “All Minima” case study, as well as two case studies representing the year with the most affected hydropower (largest hydropower derating of all 30 hydropower deratings and corresponding thermoelectric derating), and the year with the most affected thermoelectric derating (the largest electrothermal derating case with associated hydropower derating).

The large size of the Western Interconnection results in a range of natural, temporal, and spatial variability in water availability. There is a rich body of literature about the spatial and temporal covariabilities in climate patterns over the Western United States, and especially between California and the Pacific Northwest [7,8,28,29]. For example, the El Nino Southern Oscillation has a bimodal pattern in the Pacific Northwest and California with a moving boundary in northern California. This bipolar climate pattern has already shown the potential to improve north-south power flow during La Nina events [41].

For the inter-regional dependency analysis, we first identify the significant regions in terms of generation capabilities and transmission bottlenecks—the California, Pacific Northwest, and Colorado regions. We then identify their regional interdependence. Combinations of regional water availabilities (wet/dry combinations for all three regions) are considered to identify potential patterns where zonal generation is insufficient and transfer capabilities are limited.

4. Results and discussion

As an overview of the results, Fig. 5 demonstrates the changes in the generation mix and power transfers for the baseline case study and two drought case studies with WSGIFs of 1.5 and 1.32 presented in Table 2. The figure demonstrates the regional inter-play in the bulk power transmission system driven by droughts.

The results are organized as follows. First, we establish the relationships between WECC-wide WSGIF and 1) operational peak generation capacity and 2) grid production cost and unserved energy, using the 30-year PCM simulations. Next, we look at regional interdependencies evaluating a risk-based approach to evaluate grid reliability based on regional water availability instead of WECC-wide water availability.

4.1. Reliability of the Western Interconnection and dependence on water availability

4.1.1. Water availability and operational peak-hour generation capacity

The upper panel of Fig. 6 presents the output from PROMOD; i.e., the simulated peak-hour generation capacity for the month of August, as a function of the WECC-wide WSGIF. Each point represents the corresponding peak capacity for the baseline, 30 historical water availability case studies, and 4 hypothetical case studies. Because water availability is limited and affects water-dependent power generation (decreasing WSGIFs), the simulated capacity decreases as well and gets closer to, but not lower than, NERC's reference reserve requirement. The hypothetical scenarios (2010 baseline no hydropower, 2010 baseline no thermoelectric, 2010 baseline no hydropower and no thermoelectric, and All Minima)

Table 2
Adjustment of generation based on water availability for multiple case studies.

Name of cases	Hydropower available generation	Thermo-electric max capacity	WSGIF	Description
2010 baseline	NA	NA	1.9	Baseline
2010 baseline no hydro	0	1	1	Hypothetical – boundary condition
2010 baseline no thermal	1	0	1	Hypothetical – boundary condition
2010 baseline no hydro no thermal	0	0	0	Hypothetical – boundary condition
All Minima	0.57	0.45	1.02	Hypothetical – all regional most derated hydropower generation and thermoelectric capacity
Drought most impacting hydropower	0.67	0.83	1.50	WY w/most derated WECC hydropower generation
Drought most impacting vulnerable thermoelectric	0.71	0.61	1.32	WY w/most derated WECC thermoelectric capacity

WY = water year.

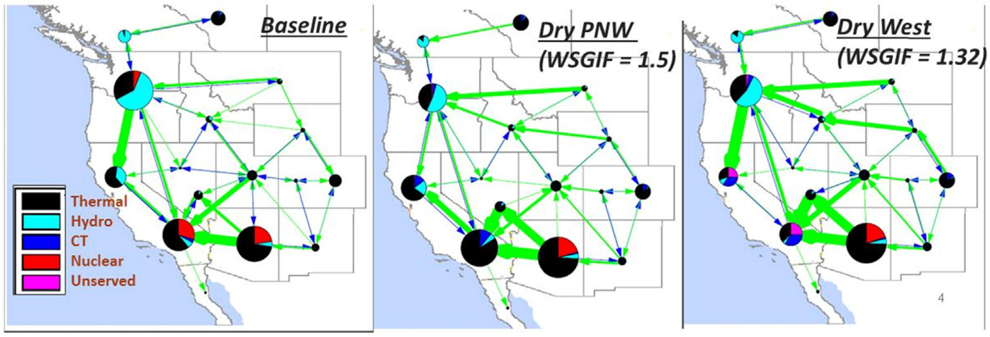

Fig. 5. Generation mix and transmission in August for the base case (left) and two drought case studies. The (WSGIF = 1.32) drought drives to a 6% unmet energy demand while the other drought (WSGIF = 1.5) does not affect the reliability of the grid. Green arrows represent the overall power transfers direction and magnitude. Blue arrows represent off-peak transfers. Pies's colors represent the generation mix and the pies' size represents the overall generation.

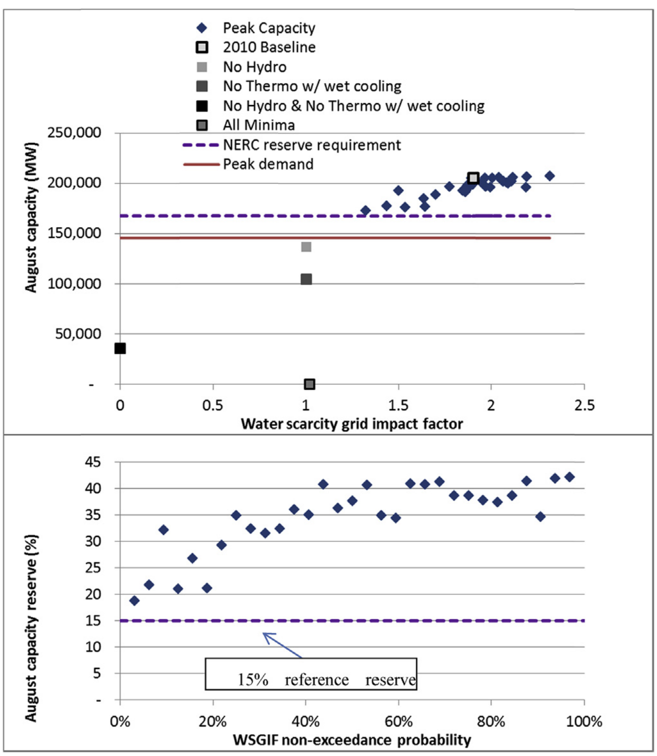

Fig. 6. Simulated operational peak-hour capacity for a range of historical water availability regional combinations.

allow further defining the limits of the observed relationship between WSGIF and the operational capacity.

The lower panel of Fig. 6 translates the resources adequacy (water-dependent grid reliability from the capacity perspective) into a grid stress function; each of the 30 WSGIF values on the x-axis is substituted for its percentile (WSGIF probability of non-exceedance) (see section 2.2.4). Hypothetical scenarios do not have a probability of occurrence and are not represented in this lower panel. Each dot represents the chance (x-axis) that the amount of unserved energy (y-axis) can be exceeded. The lower panel highlights the inter-annual variability in simulated operational maximum capacity and a risk-based estimate of the grid's vulnerability to meet NERC's requirement. The threshold of 15% brings one of the drought case studies very close to the system performance threshold, while this same drought is driving to a 6% unserved energy overall as seen later. The next section addresses a similar assessment of vulnerability based on the ability to meet the overall demand rather than peak demand.

4.1.2. Water availability and reliability of the grid

Fig. 7 represents another output from PROMOD; i.e., August unserved energy or unmet demand as a function of the WECC-wide WSGIFs (upper panel) and the August fractional unserved energy as

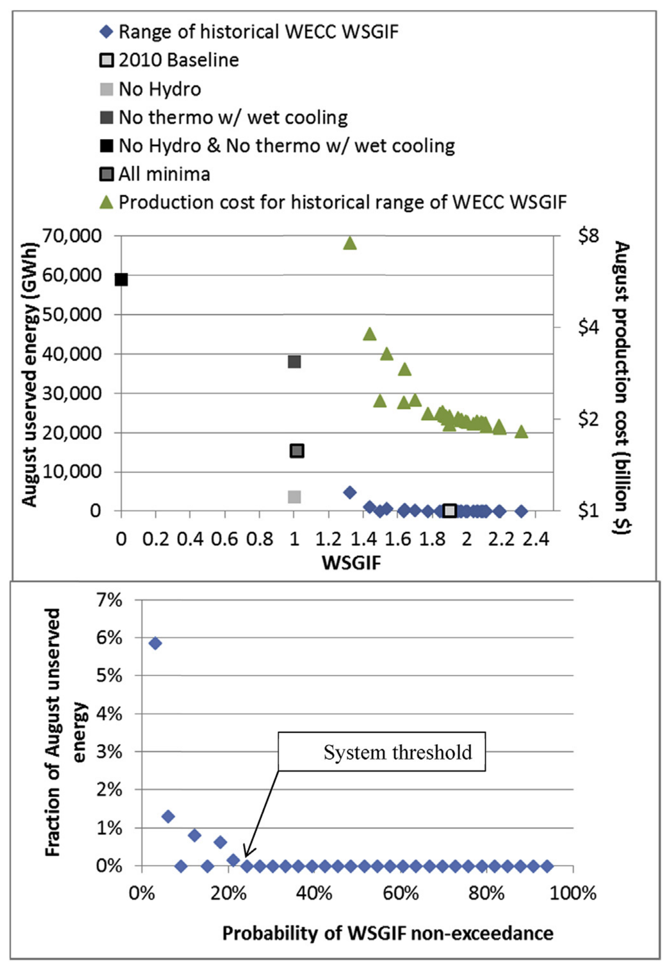

Fig. 7. (Top) August unserved Energy (GWh) for a historical range of water availability (diamond) as measured by the water-scarcity grid impact factor (WSGIF), and (bottom) fractional unserved energy as a function of WSGIF probability of non-exceedance.

a function of non-exceedance probability for WSGIFs. The upper panel of Fig. 7 indicates that under historical inter-annual variability, the grid is reliable (no unserved energy) up to a specific threshold in water-scarcity level beyond which the grid cannot meet the energy demand anymore. The hypothetical cases highlight the threshold in water-scarcity impact on the capacity (coincidently around 1) beyond which the reliability of the system becomes significantly compromised. The polynomial front between unserved energy and WSGIF demonstrates a direct relationship (87% variance, 0.93 correlation) between the reliability (unserved energy) of the Western Interconnection and water availability. It means that with given WSGIF information, we have 87% of the information to perfectly predict the unserved energy. A similar relationship is demonstrated between production cost and water availability. The variance in the simulated production cost is statistically explained at 49% by the WECC-wide WSGIF (0.7 correlation, Table 2).

The lower panel of Fig. 7 presents the grid stress distribution. Based on historical inter-annual variability in regional water availability (30 years of historical integrated assessment of water availability impact on the generation), there is a 21% chance of having a water availability (drought) that will cause some failure in meeting the overall demand (i.e., the onset of unserved energy) and a 3% chance (x-axis) that the Western Interconnection could not serve 6% or more (y-axis) of the August demand.

For the most severe case with 6% unserved energy, most of the unserved energy is located in California, bringing the California unmet energy close to 15%. Even though the water availability case is realistic, the grid operations driving such a significant unserved energy is likely unrealistic. Focusing on California, the overall adjusted generation capacity is 56% of the baseline. Specifically by water-dependent technology, the potential hydropower generation is derated to 18% of the baseline, and the combined cycle capacity is derated to 49% for that case study, while combined cycle represents 22% of the overall California generation capacity (as of 2010 PROMOD database). The current analysis does not consider any contingency plans such as shifting the source of water supply for wet cooling technologies or associated transfer of water rights. The derating of the thermoelectric plants is likely overestimated without the contingency plans. However, the analysis quantifies the vulnerability of the grid without the contingency plans and highlights the historical effectiveness of contingency plans to mitigate this vulnerability.

Note the degree of uncertainty for WSGIF cases with non-exceedance probabilities between 12 and 21% where there are two cases that have no unserved energy. One can consider the 21% as a system performance threshold for not being able to meet all of the energy demand reliably given the generation and transmission infrastructure as of 2010. The two instances for which the grid is meeting the demand despite a low WSGIF have to do with the regions affected by the droughts and the transmission capacity. The regional interdependencies and the isolation of the regional patterns leading to reliability issues are addressed in the next section.

We anticipate that the vertical trajectory in Fig. 7 between the WSGIF of 1.0 and 1.2 (we call it "wall") in the top panel, and the system performance threshold in the lower panel, will shift toward a higher chance of vulnerability (shift upward and to the right) as the energy demand increases during a heat wave, for example.

4.2. Inter-regional dependencies

Table 3 presents the correlation between the WECC, Pacific Northwest, California, and Colorado annual hydrologic regions' regulated flows with the WECC-wide WSGIF time series. The high correlations indicate the strength of the interdependency between water availability and potential impacts on water-dependent energy generation; i.e., they indicate the contributions of regions to the potential vulnerability of the grid.

Table 3
Correlation between annual regional (WECC, California, Pacific Northwest, and Colorado) regulated flow anomalies and production cost anomaly with the WECC water scarcity grid impact factor.

Independent variable	Correlation coefficient with WECC-wide WSGIF
WECC flow	0.85
WECC Production Cost	−0.70
PNW flow	0.70
CA flow	0.78
CO flow	0.29

WECC-wide WSGIF is correlated at 85% with the WECC regulated flow. The California region flow has the largest inter-annual variabilities along with a considerable and predictable effect on its regional WSGIF with a 78% correlation. The Pacific Northwest region is the largest hydropower producer and its flow is correlated at 70% to the WSGIF. Colorado River flow has a lower influence with only a 29% correlation. The Colorado hydrologic region has a large hydropower capacity used for peaking hours, as well as large electrothermal capacity, but mostly in the lower river basin. The multi-year storage capacity in the lower basin reduces the inter-annual variability in regulated flow, and decreases the correlation between regulated flow and unserved energy (grid reliability). The large Colorado River Basin storage capacity provides flexibility (and reliability) to the grid. It results in considering the Colorado River Basin as a "player" in the regional interdependencies toward reliability, and not as a "driver" toward vulnerability under historical conditions (i.e., as long as the level of the storage level does not go below the reservoir power pool). Droughts in the California and Pacific Northwest regions seem to drive the water-dependent vulnerability of the WECC.

Fig. 8 shows the equivalent of Fig. 7 but with the added information about regional capacities affected by water availability (regional WSGIFs) with respect to WECC-wide August unserved energy. The regional WSGIFs differ from the WECC-wide WSGIFs because they include only the effect of the regional water availability on the associated regional generation capacity. The 30 case studies are represented in the figure by a common WECC-wide unserved energy with 4 indicators of the regional water availability for that event: WECC-wide, California, Pacific Northwest (PNW), and Colorado hydrologic regions. The upper panel of Fig. 8 shows the California WSGIF's wider range (large inter-annual variability). Lower values indicate more severe local drought conditions. The WECC case studies with the highest unserved energy (>100 GWh in August) all have low California WSGIFs (lower than the 1.96 median, i.e. drought) and seem to be mitigated by high PNW and Colorado WSGIFs (wet years).

The lower panel of Fig. 8 is of interest for planning purposes. The BAs plan for their seasonal operations based on the seasonal forecast of water availability, i.e., April snowpack status [9]. BAs can evaluate the projected effect on the generation capacity of their load region. However, more uncertainty is associated with the availability of power transfer ability from adjacent regions. For instance, the Northwest Power Council uses the driest year on record for Northwest plants, and an average year in adjacent regions in planning scenarios [31]. The regional combination of WSGIFs can further inform the decision-making at it indicates the expected performance of the grid. The lowest panel of Fig. 8 shows that for the largest unserved energy event for the grid (6% unserved energy), the California region had its lowest WSGIF on record, the Pacific Northwest region had a very low WSGIF as well, but

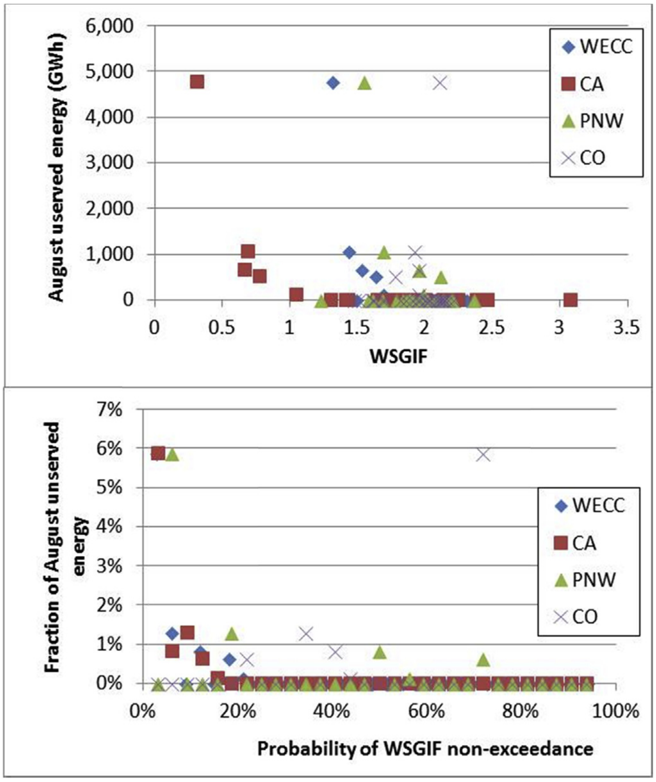

Fig. 8. WECC-wide unserved energy as a function of WECC and hydrologic region water scarcity grid impact factors. The lower panel shows the WECC fractional unserved energy as a function of regional WSGIF non-exceedance probabilities. Each event (specific unserved energy) is associated with four WSGIFs—those of the WECC, California, Pacific Northwest, and Colorado regions—in order to look at the regional distribution of water-dependent impact on generation capacity onto the WECC grid performance.

Colorado River Basin was wet (70% chance of not exceeding that WSGIF). Other significant unserved energy events for the grid all had California's WSGIF percentiles in their lowest 20th percentiles but tended to be mitigated by the Pacific Northwest and Colorado regions' generation and transmission capacities. Fig. 8 suggests that available information about WSGIF in adjacent regions could be used to enhance the reliability of the grid.

The experiment has demonstrated a clear relationship between water availability and power flow system vulnerability (reliability and financial sustainability) over the Western Interconnection. Below is some discussion about assumptions made.

4.3. Discussion on reliability space as a function of water availability

Using the PCM, the 30 historical condition case studies delineate a space of feasible operating conditions with sufficient generation adequacy (called reliability space). The reliability space defines the water availability conditions for which the grid has sufficient generation capacity to meet the baseline load and NERC's requirement. Hypothetical case studies help further define the reliability space limits. This reliability space is defined for historical variability in hydro-climate conditions, water demand and water management, and for a 2010-level of electricity demand and 2010-specified generation portfolio. Given a WSGIF, the grid reliability space can indicate the reliability of the system—answering whether the grid will have adequate resources to meet the energy demand and NERC's requirement, and quantifying the expected margin or deficit. Fig. 9 uses results from Fig. 8 and represents the reliability space, at the WECC scale, for August. The boundary between unreliable and reliable domains corresponds to the performance threshold (here unmet electricity demand) under multiple combinations of hydro-climate conditions. The reliability space is of interest because it allows for the assessment of grid reliability as a function of the water availability, and it provides information for operations (contingency plans) and tradeoffs in units of water.

The WSGIF information combined with the definition of the reliability space can be used first to assess risk, and then to assess inter-regional and inter- water-uses flexibility as discussed below. The inter-regional and inter-use flexibilities present opportunities for tradeoff and therefore enable cooperative and potentially comprehensive risk management.

4.4. Current assumptions and ongoing progress

The concept of the water-dependent electric grid reliability space has been explored and characterized at some level, but certainly needs to be refined. The definition of the WSGIF could be modified for individual regions or when combining the hydropower and thermoelectric derating factors to customize the analysis for individual BAs. An alternative definition used at the WECC scale weighted the derating of hydropower and thermoelectric capacity based on the maximum capacity for each resource. The two WSGIFs were found to be closely related (linear) and did not lead to any difference in the results. The WSGIF concept is opening perspectives on grid-centric indices to the level used by other drought monitors for recovery and resilience.

A planned improvement in the current modeling framework is the changes in water operations during droughts. The current approach is derating the annual hydropower potential and thermoelectric capacity based on annual regulated flow only. However, the distribution of the annual potential hydropower generation into monthly values is maintained. This monthly disaggregation is a current area of research for application of this proof of concept for single-year and multi-year droughts (reservoir storage carry-over) under current climate conditions, demand, and infrastructure (generation mix policy, generation and transmission assets portfolios). The definition of the reliability space will be fine-tuned but not fundamentally changed. The changes in operations could lead to less variability in the overall grid performance, but it could also lead to higher failures if it does fail to meet the energy demand. Under climate change conditions (earlier snowmelt, lighter snowpack and lower summer flows, increased flood control pool), similar investigations of changes in reservoir operations during

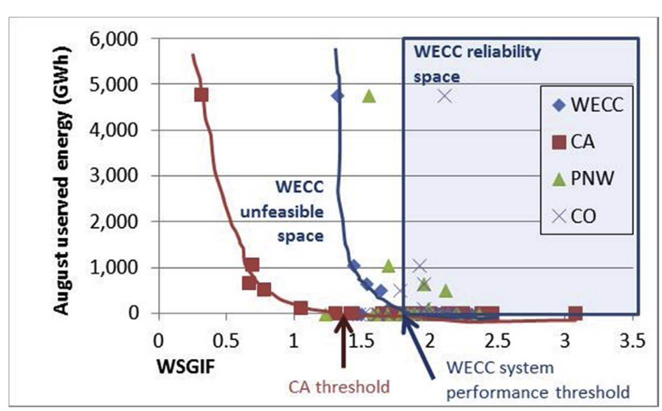

Fig. 9. WECC and California regional grid reliability spaces based on the impact of water availability on generation.

droughts would be required and associated with projected generation and transmission assets portfolios and generation mix policy.

The derating of thermoelectric plants could be further refined using stream temperature modeling. The large reservoir capacity over the Western Interconnection offers opportunities to release water from different reservoir pools to manage stream temperature for joint grid-water optimum management, which would also need to be taken into consideration. The Eastern Interconnection will be more sensitive to derating linked to stream temperature constraints.

The definition of the reliability space is informative and can be improved by following the suggestions just mentioned, as well as by using another flexibility metric that considers the congestion in the transmission system.

Remaining challenges for decision-making and tradeoff analyses include the multitude of jurisdictions (load regions, hydrologic regions, states, counties). The results presented here would need to be further scaled to the different sector specific decision-making jurisdiction for this next step [5].

The developed approach for deriving the risk distribution of grid performance as a function of integrated water availability is transferrable to other regions where the same or equivalent models or observations are available. The insights based on regional drought patterns affecting the grid performance will vary depending on 1) the diversity in hydro-climate over the domain covered by the electrical grid, 2) the spatial distribution of grid, and 3) how the electric grid is managed; for example, market-driven management can affect the sensitivity of grid performance to water availability.

5. Conclusions

5.1. Summary

Our study combines the effects on both hydropower and vulnerable thermoelectric plants to represent the combined effect of water availability on grid operations. Based on integrated geophysically based water modeling, we estimate that under historical conditions inter-annual variability can drive variation in annual hydropower generation over the WECC region ranging from 68% to 136% with respect to an average water year. Similarly, fresh surface-water–dependent thermoelectric plants can lose up to 31% capacity under historical natural inter-annual variability, which is consistent with other analyses. The water scarcity grid impact factor (WSGIF) was developed and corresponds to existing drought severity indices but with a grid-centric focus; it reflects the impact of the water availability specifically on the electricity grid generation capacity.

Using an integrated modeling approach that combines geophysical and grid modeling, we force a production cost model with 30 years of this integrated water availability. The simulated grid performance allows us to develop a non-linear distribution of the interdependency of the performance of the western electricity grid with inter-annual water availability as represented by the WSGIF, with insight into the role of regional distribution of water and regional drought patterns in leading to higher stress on the grid. The distribution quantifies the water-energy interdependencies for a portfolio of water conditions.

5.2. Impactful results

Because no contingency plans are used in this current climate and current infrastructure analysis, the derived risk distribution quantifies the vulnerability of the grid to water availability, and associated risk, that needs to be mitigated by contingency plans and other flexible water-energy management. The risk distribution highlights the effectiveness of contingency plans so far to mitigate this vulnerability. Within historical inter-annual variability in the grid-centric drought monitor (WSGIF), the operational peak capacity meets NERC's WECC-wide requirement. However, there is a 3% chance that, under historical inter-annual climate variability, the grid as of 2010 would not be able to meet 6% or more of its August energy demand. We also determined the water-energy system performance threshold to be at 21%; i.e., there is a 21% or more chance that August energy demand will not be met. The system performance threshold indicates a level of grid operational flexibility beyond which contingency plans need to be designed and used.

5.3. Conclusion and future work

The findings lead to the conclusion that reliability assessment may not fully account for drought conditions, and the planning for expansion of transmission and infrastructure is suboptimal if the range of inter-annual and inter-regional variability is not well represented in the analyses.

The concept of the grid level and regional reliability spaces as a function of hydro-climate–dependent indices is opening opportunities to develop more informed joint water-energy management in terms of flexibility across regions and also across water uses for a more resilient, reliable and sustainable grid and hydro system. Energy management will likely turn toward inter-hydrologic-region water-energy tradeoffs for adapting to future conditions. The potential for inter-regional water-energy tradeoffs will require increasing levels of planning and management sophistication for entities responsible for management of individual hydrologic regions.

Acknowledgements

This work was supported by the Office of Science of the U.S. Department of Energy, Office of Biological and Environmental Research as part of the Integrated Assessment Research Program. Initial model development and data analyses were supported by the Laboratory Directed Research and Development Program at Pacific Northwest National Laboratory, a multiprogram national laboratory operated by Battelle for the US Department of Energy under Contract DE-AC05-76RL01830. Authors wish to thank anonymous reviewers who helped improve the manuscript, as well as Landis Kannberg and Nader Samaan (PNNL) for constructive feedbacks on an earlier version of this manuscript.

Appendix A. Supplementary data

Supplementary data related to this article can be found at http://dx.doi.org/10.1016/j.energy.2016.08.059.

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