Energy 80 (2015) 239–250

Contents lists available at ScienceDirect

Energy

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

Projecting changes in annual hydropower generation using regional runoff data: An assessment of the United States federal hydropower plants

Shih-Chieh Kao [a, b, *], Michael J. Sale [c], Moetasim Ashfaq [b, d], Rocio Uria Martinez [a], Dale P. Kaiser [a, b], Yaxing Wei [a, b], Noah S. Diffenbaugh [e]

[a] Environmental Sciences Division, Oak Ridge National Laboratory, Oak Ridge, TN 37831, USA
[b] Climate Change Science Institute, Oak Ridge National Laboratory, Oak Ridge, TN 37831, USA
[c] BCS Incorporated, Wartburg, TN 37887, USA
[d] Computer Science and Mathematics Division, Oak Ridge National Laboratory, Oak Ridge, TN 37831, USA
[e] Department of Environmental Earth System Science and Woods Institute for the Environment, Stanford University, Stanford, CA 94305, USA

ARTICLE INFO

Article history:
Received 22 July 2014
Received in revised form
18 November 2014
Accepted 22 November 2014
Available online 18 December 2014

Keywords:
Climate change
Hydropower
Water availability

ABSTRACT

Federal hydropower plants account for approximately half of installed US conventional hydropower capacity, and are an important part of the national renewable energy portfolio. Utilizing the strong linear relationship between the US Geological Survey WaterWatch runoff and annual hydropower generation, a runoff-based assessment approach is introduced in this study to project changes in annual and regional hydropower generation in multiple power marketing areas. Future climate scenarios are developed with a series of global and regional climate models, and the model output is bias-corrected to be consistent with observed data for the recent past. Using this approach, the median change in annual generation at federal projects is projected to be -2 TWh, with an estimated ensemble uncertainty of ±9 TWh. Although these estimates are similar to the recently observed variability in annual hydropower generation, and may therefore appear to be manageable, significantly seasonal runoff changes are projected and it may pose significant challenges in water systems with higher limits on reservoir storage and operational flexibility. Future assessments will be improved by incorporating next-generation climate models, by closer examination of extreme events and longer-term change, and by addressing the interactions among hydropower and other water uses.

1. Introduction

In the United States, federal hydropower plants (i.e., owned and operated by federal agencies and marketed through DOE [Department of Energy] PMAs [power marketing administrations]) account for approximately half of installed US conventional hydropower capacity, and are an important part of the national renewable energy portfolio. The 132 federal hydropower projects generated an annual average of 120.6 TWh over the period from 1971 to 2008 [34], approximately 3% of the national combined total across all different sources of energy (e.g., nuclear and coal). More important, most of the hydroelectricity generated from these federal projects is sold to public bodies, such as municipalities, non-profit organizations, and other public corporations or agencies, at the lowest possible rates consistent with sound business principles, not fully for revenue [21].

Despite its higher initial capital investment, hydropower is a favored source of electricity generation owing to its operational flexibility and low maintenance costs (i.e., the “fuel” is generally free of charge, and renewable). Therefore, when conditions allow, utilities will try to optimize the usage of existing hydropower capacity before switching to other fuel-dependent energy sources to maximize revenue, especially during daily peak load periods. While hydropower operation is controlled on shorter time scales (hourly, daily, monthly) by variables such as water usage allocations, daily energy demand, pool elevation, turbine efficiency, flood protection, and other environmental constraints, on longer time scales (annual and longer) it is mainly water availability that dominates the

* Corresponding author. P.O. Box 2008 MS-6038, Oak Ridge, TN 37831-6038, USA. Tel.: +1 (865) 576 1259.
E-mail address: kaos@ornl.gov (S.-C. Kao).

http://dx.doi.org/10.1016/j.energy.2014.11.066
0360-5442/

Nomenclature

BCSD	bias-corrected and spatially downscaled
BPA	Bonneville Power Administration
CCSM3	community climate system model version 3
DJF	winter, December/January/February
DOE	Department of Energy
EBHOM	energy-based hydropower optimization model
EIA	Energy Information Administration
GCM	global climate model
HM	hydrological model
HUC8	8-digit hydrologic unit
IBWC	International Boundary Water Commission
IPCC	Intergovernmental Panel on Climate Change
JJA	summer, June/July/August
MAM	spring, March/April/May
NHAAP	National Hydropower Asset Assessment Program
NWIS	National Water Information System
ORNL	Oak Ridge National Laboratory
PMA	power marketing administration
PRISM	parameter-elevation regressions on independent slopes model
RCM	regional climate model
Reclamation	Bureau of Reclamation
RegCM3	regional climate model version 3
SEPA	Southeastern Power Administration
SON	fall, September/October/November
SWPA	Southwestern Power Administration
TVA	Tennessee Valley Authority
US	United States
USACE	United States Army Corps of Engineers
USGS	United States Geological Survey
VIC	variability infiltration capacity
WAPA	Western Power Administration

amount of hydropower generation. Therefore, high interannual streamflow variability presents challenges for business planning. For instance, the difference in total US hydropower generation between a wet year, such as 1997, and a dry year, such as 2001, can be as much as 40%, with such variation causing significant uncertainties in managing water usage, reservoir operation, and sales of power [28].

Given the direct linkage between streamflow availability and climate change, this issue may be further complicated in the future in response to continued global warming. To evaluate potential climate change impacts on hydropower, two analytical components are required: (1) a calibrated water resources relationship that can help translate streamflow into hydroelectric energy potential, and (2) future climate change scenarios, such as those that are generated from GCM (global climate model) projections. However, because US federal hydropower plants are widely distributed across the entire country, with diverse hydrologic conditions and different operational objectives, development of a uniform model to simulate their responses to climate change would require substantial resources.

Important progress has been made in assessing the potential impacts of climate change on hydropower generation on smaller spatial scales. Robinson (1997) [33] used a Reservoir Depletion Model to study how the hydropower systems of Duke Power and Virginia Power in the southeastern United States might react to a stylized 2 °C increase in temperature and 10% decrease in precipitation. Mimikou and Baltas (1997) [27] used a runoff-based water balance model with three GCM-derived future climate scenarios to study the sensitivity of annual hydroelectric energy production of a large multipurpose reservoir in northern Greece. Christensen et al. (2004) [6] analyzed the effect of climate change on the water resources of the Colorado River Basin in the United States using three downscaled climate projections generated from the Parallel Climate Model [40]. Vicuna et al. (2008) [42] used a linear programming model with four GCM-driven scenarios to investigate how climate change may impact an 11-reservoir system in the Upper American River Basin in California. Hamlet et al. (2010) [18] used two climate scenarios (constructed from projections of 20 GCMs) and a Columbia Simulation reservoir model (designed and modeled for 20 selected major reservoirs in the Columbia River Basin in Washington state in the United States; [17]) to evaluate the potential effects of climate change on the seasonality and annual amount of hydropower generation in the Pacific Northwest region. Other studies related to the assessment of climate and hydropower were reported by Refs. [1,19,35,38,43,24].

Although these studies have laid foundations for examining climate change impacts on selected hydropower plants, assessing impacts across large spatial scales remains a major challenge. For instance, it is still unclear how climate change impacts on hydropower generation at regional and national scales can be estimated (e.g., joint responses to larger-scale extremes like droughts). Given the complexity of surface water storage, management, and distribution systems, and the proprietary nature of existing hydropower models and data [22], it would likely be very costly and time-consuming to develop a large-scale energy–water model through a conventional reservoir-based approach. Even a full computational model could be built (with hundreds of hydropower plants), it will likely entail a large number of site-specific parameters that are challenging to calibrate and validate. Therefore, a simplified approach is required in the interim. An example is the EBHOM (energy-based hydropower optimization model), in which a simplified energy flow method has been used to evaluate climate change impacts on more than 135 high-elevation hydropower plants in California [22,23]. Another example is demonstrated by Markoff and Cullen (2008) [24], in which regression is used to predict the average annual streamflow and hydropower generation from the winter/summer precipitation fraction and temperature change so that the assessment can be expanded to cover more climate change models.

In the present study, a runoff-based alternative approach was developed to project the change in annual hydropower generation of the US federal hydropower plants. The assessment includes a series of hydro-climatic models and statistical techniques, including GCM projection, RCM (regional climate model) simulation, HM (hydrological modeling), historic runoff–generation relationships, and a US national hydropower data set. The methods and results are described in the following sections.

2. Methods

2.1. Scope and study area

Federal hydropower in the United States is generated from 132 plants that are owned and operated by the USACE (US Army Corps of Engineers), the Bureau of Reclamation (Reclamation), or the IBWC (International Boundary Water Commission) (Fig. 1). The

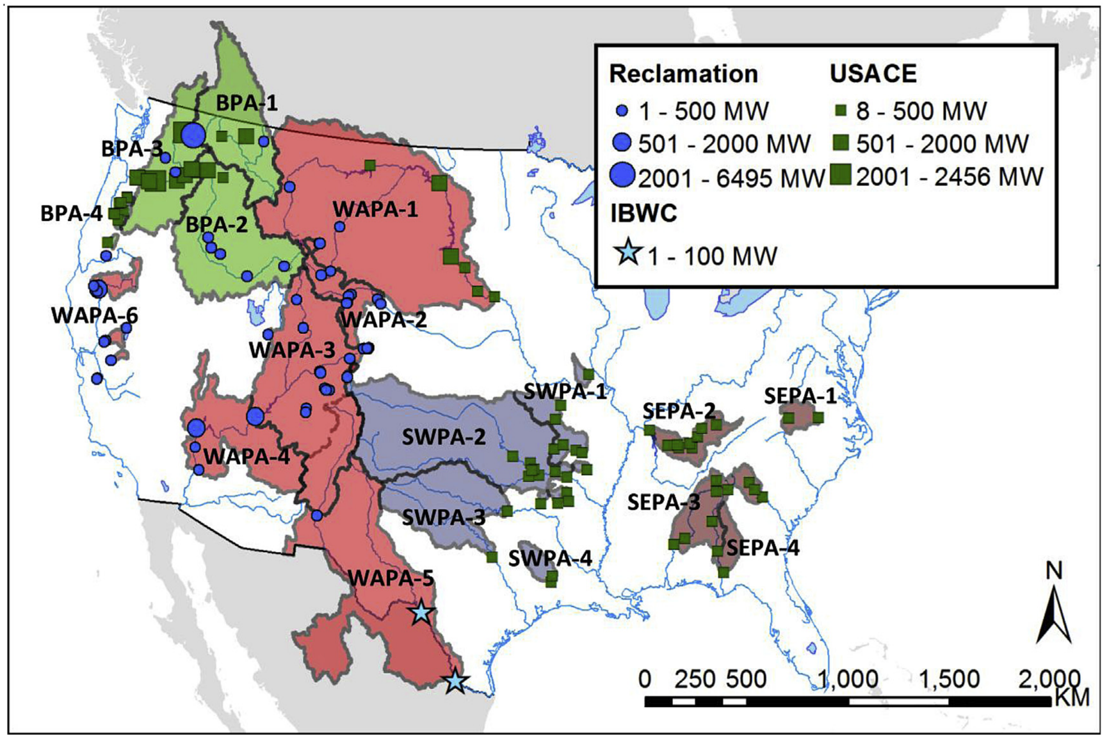

Fig. 1. The US federal hydropower plants. These 132 federal hydropower plants (owned by Reclamation, USACE, and IBWC) are divided into 18 study areas based on river basin hydrology and power systems. The colored regions are their corresponding drainage watersheds.

USACE operates 75 hydropower plants with a total rated capacity of 21.5 GW in 16 states from Washington to Georgia. In addition, there are another 90 nonfederal hydropower plants located at USACE dams with an additional 2.3 GW of capacity [39], regulated by the US Federal Energy Regulatory Commission. Reclamation owns and operates 58 power plants with a total rated capacity of 15.1 GW in 11 western states (not including those hydropower plants owned by Reclamation but operated by others through lease of power privilege). IBWC owns and operates two smaller hydropower projects (Amistad and Falson) on the Rio Grande River with a total capacity of 98 MW. The largest facility is the Reclamation Grand Coulee Dam on the Columbia River in Washington State, which is among the ten largest dams in the world and has an installed capacity in excess of 6.9 GW. The most recently commissioned facility is the USACE R. D. Willis project, which came on line in 1989. Except for some turbine replacement and expansion, overall federal hydropower capacity has varied little in the past two decades.

Hydroelectric energy generated from these federal projects is marketed through four PMAs—BPA (Bonneville Power Administration), SEPA (Southeastern Power Administration), SWPA (Southwestern Power Administration), and WAPA (Western Power Administration)—each constituting a separate assessment region in this study. By law, PMAs are to give preference in the sale of federal power to public bodies, such as electric cooperatives and municipalities (also known as preference customers). If excess power is available beyond the needs of preference customers, the PMAs may sell surpluses to non-preference entities. In practice, the cost-based rates that the PMAs charge their customers are generally lower than the profit-based rates charged by investor-owned utilities [13]. The 132 federal hydropower plants are further grouped into 18 assessment areas, labeled BPA-1, BPA-2, …, SEPA-4 in Fig. 1, based on river basin hydrology and power systems (see Ref. [34] for a detailed list of hydropower plants). Note that hydropower plants owned by the TVA (Tennessee Valley Authority) are not part of this study because the hydropower produced by TVA is not marketed through PMAs.

2.2. Data sources

The conditions of the US federal hydropower infrastructure were obtained from the ORNL (Oak Ridge National Laboratory) NHAAP (National Hydropower Asset Assessment Program) [28]. The core of NHAAP is a geospatial database that contains hydropower-related data on plant capacity, turbine types and ages, dam characteristics, and stream geography. The historic hydropower generation data were collected from the DOE EIA (Energy Information Administration) Form 923 Monthly Generation Database [14] from 1989 through 2008. When available, more accurate generation records provided by Reclamation, USACE, and the PMAs were used to update parts of the survey-based EIA plant generation data. The monthly plant generation data were then aggregated for each PMA study area for further analysis.

To summarize the historic and modeled precipitation and runoff for a hydropower plant, the contributing upstream drainage area was delineated and used to compute the spatially averaged precipitation and runoff from existing data sets. Based on the geographical coordinates of the most downstream hydropower plants in each river system in each PMA study area, the contributing watersheds were assembled by 12-digit hydrologic units from the Watershed Boundary Dataset [29], shown in Fig. 1. Parts of the contributing watersheds of BPA-1, BPA-3, WAPA-1, and WAPA-5 are located in Canada or Mexico, where the watershed boundaries were collected from the USGS (US Geological Survey) National Hydrography Dataset Plus version 1 [16].

The observed temperature and precipitation in each PMA study area were computed from the grid-based Parameter-elevation Regressions on Independent Slopes Model meteorological observation data set (PRISM [8,9]). By considering the orographic effects and some other adjustment factors, PRISM uses a knowledge-based statistical technique to assimilate grid-based precipitation and temperature from a large set of surface meteorological stations. PRISM is available monthly from 1895 to the present in 1/24° (~4 km) spatial resolution. Since PRISM is available only within the conterminous United States, the University of Delaware Air Temperature and Precipitation dataset [41] was used to provide meteorological observations for watersheds in Canada and Mexico (needed for BPA-1, BPA-3, WAPA-1, and WAPA-5). The monthly average temperature (C) and total precipitation (mm/month) from 1989 through 2008 were then summarized for each PMA study area.

Given the regionalization approach used in this study (i.e., grouping multiple hydropower plants together for analysis), spatially representative flow information is needed to study the water availability in each hydropower study area. Therefore, the USGS WaterWatch runoff [5] was used to provide observational runoff measurements. WaterWatch runoff is the assimilated monthly time series of flows per unit of area calculated for each conterminous 8-digit hydrologic unit (HUC8), derived from the comprehensive gauge observation network (thousands of gauges nationwide) that is maintained by the USGS NWIS (national water information system). For each HUC8, multiple NWIS gauge stations located within or downstream of the HUC8 are used to estimate the runoff generated locally at each HUC8, with gauge weighting factors determined by joint contributing drainage areas (both gauge-to-HUC8 and HUC8-to-gauge). This approach can effectively assimilate streamflow observations from multiple gauge stations as a consistent areal HUC8 runoff measurement that has a unit similar to that for precipitation (depth/time). WaterWatch runoff has been used and discussed in several recent hydro-climate studies, including Ashfaq et al. (2013), Beigi and Tsai (2014), and Oubeidillah et al. (2014) [3,4,30]. For upstream watersheds outside of the United States (in particular, BPA-1 and BPA-3), runoff is computed, using a similar approach, by 62 gauge stations with natural flow conditions from the HYDAT Database [15]. All contributing watersheds in Canada are treated as a whole with no further subsetting. Given the insufficient streamflow observation in the non-US portions of WAPA-1 and WAPA-5, runoff was not estimated for the non-US portion of these two study areas. The monthly areal average runoff (mm/month) time series were then computed for each PMA study area, from 1989 to 2008.

The annual total generation G (TWh), runoff Q (mm), and precipitation P (mm) are summarized in Fig. 2 for each PMA. In terms of generation, BPA is the highest, followed by WAPA, SEPA, and SWPA. As stated, the large interannual streamflow variability is a main reason for the high fluctuation in annual generation. In the worst cases, such as 2006 in the SWPA, the annual generation could be four times lower than the maximum generation in 1993. For runoff and precipitation, the highest is SEPA, followed by BPA, SWPA, and then WAPA. The different order between generation, runoff, and precipitation is due to the topography (more precisely, the different hydraulic heads in existing power plants). The correlation coefficient between annual generation–runoff (ρ_{GQ}) and generation–precipitation (ρ_{GP}) is also shown in Fig. 2. Except for WAPA, a strong correlation between the annual time series can be observed. In particular, annual runoff has a surprisingly high correlation to annual generation. These data were further analyzed to develop the statistical relationship between generation, runoff, and precipitation (shown in Section 3.1).

2.3. Climate projection methods

Three types of models were used to simulate future climate and hydrology—GCMs, RCMs, and HMs. The role of GCMs is to project global climate over long periods of time by simulating large-scale mass and energy exchange mechanisms between atmosphere, ocean, and land surface. Five runs of the Community Climate System Model version 3 (CCSM3 [7]) simulations were selected for this study—including the 1960–1999 baseline and 2000–2039 future periods under the IPCC (Intergovernmental Panel on Climate Change) SRES A1B moderate CO_2 emissions scenario.

An RCM is structurally similar to a GCM but focuses on specific regions. By tuning RCM parameters to reach a good agreement between GCM and RCM output on the spatial boundaries, an RCM can be used to dynamically downscale GCM variables into a finer

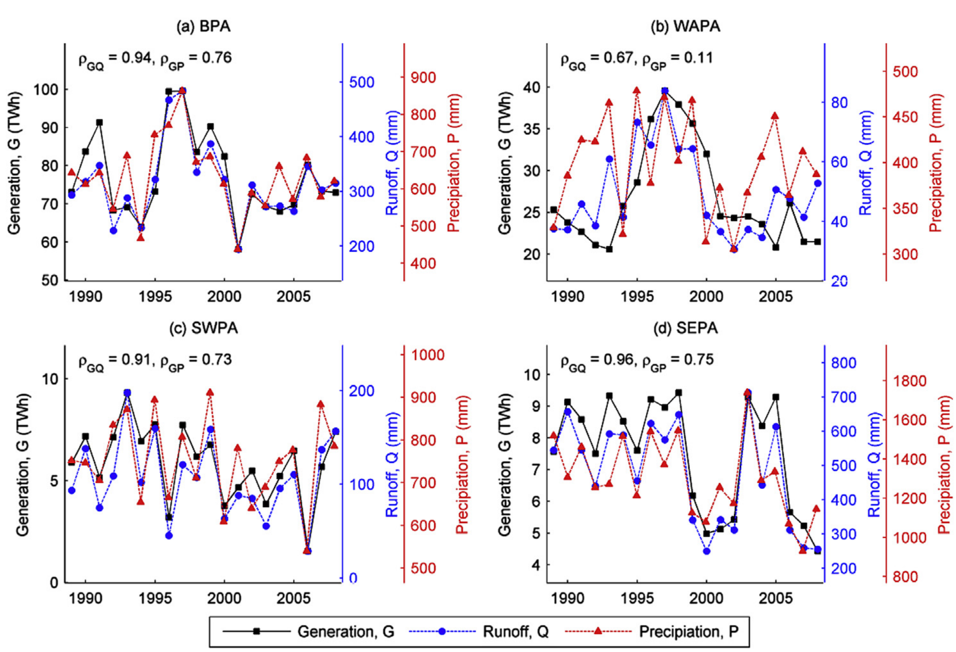

Fig. 2. The 1989–2008 annual total generation G (TWh), runoff (mm), and precipitation (mm) for each of the PMA regions. The correlation coefficient between annual generation-runoff (ρ_{GQ}) and generation-precipitation (ρ_{GP}) is also shown in each panel.

spatial resolution. In this study, the coarser-resolution CCSM3 projections (~200 km grid spacing) were downscaled by the International Centre for Theoretical Physics Regional Climate Model version 3 (RegCM3 [31]) to 25 km grid resolution [11,12], and then bias-corrected to 12 km grid resolution through a quantile-based technique [2] using 1960–1999 PRISM observations. Bias correction preserves the projected trends of climate change and can improve the performance of the subsequent hydrologic simulation [2,37].

The HM applied in this study is the widely-used Variability Infiltration Capacity model (VIC [25]) at 1/8° (~12 km) spatial resolution. VIC calculates the water budget of daily evaporation, snow pack, moisture storage, faster-response surface runoff, and slower-response baseflow at each grid cell based on inputs of daily precipitation, maximum/minimum temperature, and wind speed. Other components of the surface energy and moisture budgets, including short-wave and long-wave radiation, relative humidity, and vapor pressure, are estimated within VIC using parameterizations of maximum/minimum temperature. The water and energy balance are solved for multiple elevation bands and vegetation types, enabling the model to capture the subgrid-scale variability of these land surface features. The total runoff of VIC (surface runoff plus baseflow) has been found to be the corresponding variable of the WaterWatch runoff [30]. For each PMA study area, precipitation, temperature, and total runoff were computed for each of five climate change scenarios. Since this study focuses on runoff instead of streamflow, the additional river routing model was not required in this study. All other modeling details regarding these five CCSM3-RegCM3-VIC-A1B simulations (for short, we will use RegCM3-A1B hereafter) can be found in Ashfaq et al. (2013) [3].

To quickly visualize the projected change in the five RegCM3-A1B regional climate simulations, Fig. 3 illustrates the change of temperature (°C) and precipitation (%) from 1960–1999 to 2000–2039 in the entire United States. The 112 statistically downscaled, BCSD (bias-corrected, and spatially downscaled) monthly climate projections [32] are also plotted for comparison, with dashed lines indicating the median of the BCSD simulations. Since BCSD contains various models and three IPCC emission scenarios (B1, A1B and A2), a considerable spread was expected. The five RegCM3-A1B simulations are positioned around the center of the BCSD, with a maximum/minimum range across both sides of the BCSD medians. Therefore, the main range of mean variability should be consistent with the BCSD. Nevertheless, note that Fig. 3

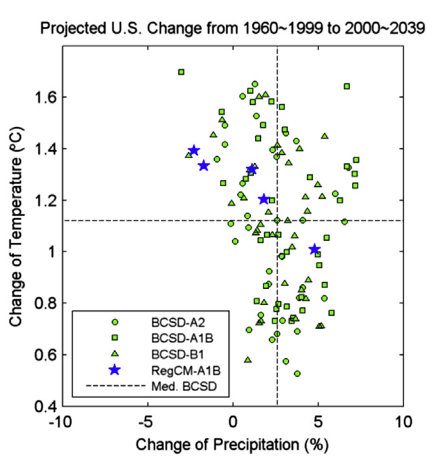

Fig. 3. The projected change of 1960–1999 to 2000–2039 average temperature (°C) and precipitation (%) across the entire United States. The stars represent the five RegCM-A1B simulations used in this study, compared with the 108 BCSD ensemble members used by Ref. [32].

serves only as a simplified comparison with the long-term national mean and has no implications for local trends and extreme events. Different patterns are expected for smaller local regions. Although dynamical downscaling can directly produce daily temperature and precipitation values that are necessary for VIC hydrologic simulation (i.e., BCSD will need extra steps to synthesize daily time series from monthly projections), each century-scale RCM realization is computationally expensive, so the number of simulations cannot easily be increased. Indeed, the climate model experiment used in this study remains one of the few transient, century-scale, multi-member high-resolution regional climate model experiments in the literature (e.g., another major dynamical downscaling effort was conducted by the North American Regional Climate Change Assessment Program [26]).

3. Results

3.1. Hydrologic sensitivity of hydropower generation

Motivated by the high correlation between WaterWatch runoff and hydropower generation (Fig. 2), we conducted a series of regression analyses based on the 1989–2008 annual time series of temperature (T), precipitation (P), runoff (Q), and hydropower generation (G) for each of the 18 study areas. Taking BPA-1 as an example, the linear regression results are shown in Fig. 4, including the best-fitted lines, 95% confidence intervals, and coefficients of determination R^2 between T–G, P–Q, and Q–G. As expected, temperature (Fig. 4a) itself cannot explain the variability of annual generation ($R^2 = 0$), since annual hydropower generation is mainly controlled by water availability rather than the total energy demand (the latter of which is more directly linked to temperature). Precipitation can only explain slightly more than over half of the variability of annual generation (Fig. 4b) in BPA-1. Surprisingly, even when using such a simplified linear model, a very strong relationship can be observed between runoff (Q) and generation (G) (Fig. 4c, $R^2 = 0.87$).

Recall that WaterWatch uses a comprehensive set of gauge stations to derive local runoff at each HUC8 unit, so the aggregated runoff time series may represent the total runoff generated from the entire study area for further surface water usage (e.g., hydropower generation). The strong linear relationship suggests that (1) the local runoff estimated by WaterWatch is somewhat reasonable, since it may explain most of the independent annual hydropower variability; and (2) the WaterWatch runoff can be a useful tool for regional hydropower evaluation. Since these patterns can also be observed in all other study areas, the WaterWatch runoff Q was selected as the main variable in the following analysis.

Although annual runoff is highly correlated with annual generation overall, further modification is required for those locations with large reservoir storage. In WAPA-4, for example (Fig. 5), where multiple years of storage are located behind Hoover Dam in Lake Mead, the regression between annual runoff and annual generation is very low ($R^2 = 0.01$, Fig. 5a). When the annual runoff was replaced with 2- to 6-year running averages of runoff (Fig. 5b–f), R^2 was found to be maximized at 0.66 at the 5-year scale. Although this linear relationship is not as strong as in some other areas, such as BPA-1 (Fig. 4), considering the complexity of the entire Colorado River System, such a positive and simple relationship worked surprisingly well for the purposes of annual hydropower evaluation. The same approach was applied in other WAPA assessment areas, and it was found that both WAPA-1 and WAPA-2 are more accurately modeled by 2-year average runoff, and WAPA-3 is better modeled using 3-year runoff.

The final regression models are reported in Table 1 and illustrated in Fig. 6. To generalize the linear statistical model between

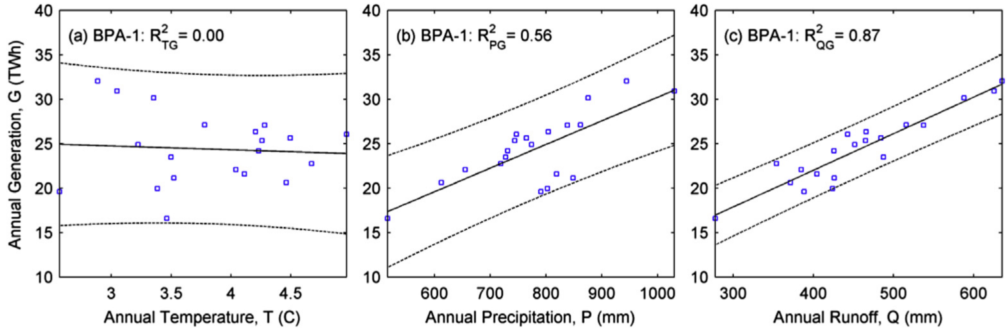

Fig. 4. Linear regression between (a) annual average temperature and generation, (b) annual total precipitation and generation, and (c) annual runoff and generation of the BPA-1 study area. The dashed lines represent the 95% confidence intervals of the regression, and R^2 values are the coefficients of determination.

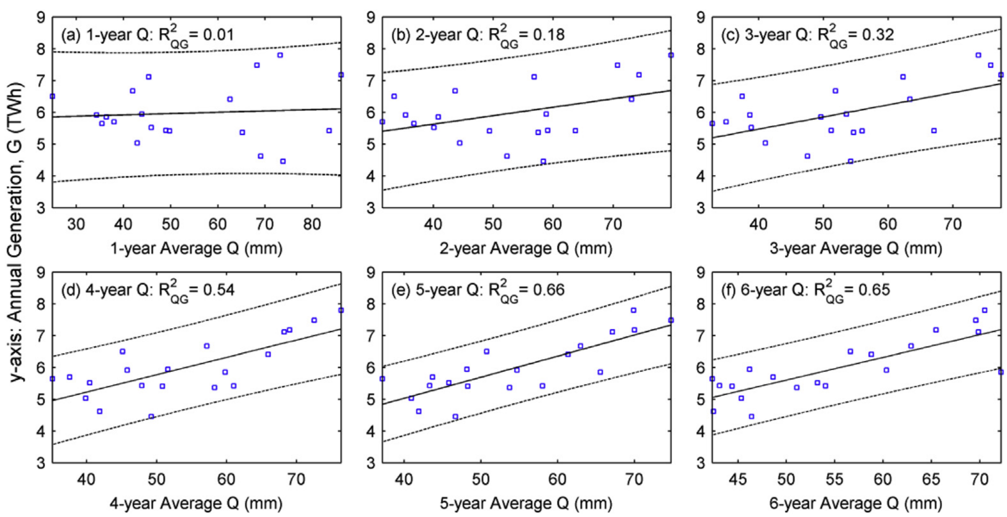

Fig. 5. Linear regression between multi-year running average runoff (from 1-year in panel a to 6-year in panel f) and annual generation of the WAPA-4 study area. The dashed lines represent the 95% confidence intervals of the regression, and R^2 values are the coefficients of determination.

regional runoff and generation, the following dimensionless formula is used in Table 1.

$$(G/G_0) = a\,(Q/Q_0) + b \quad (1)$$

Table 1
Summary of regression analysis between annual generation and runoff for each of the PMA study areas.

PMA study area	Q_0 (mm/year)	G_0 (TWh/year)	Years of average Q	Slope (a)	Intercept (b)	R^2
BPA-1	458	24.373	1	0.772	0.228	0.87
BPA-2	201	11.735	1	0.708	0.292	0.94
BPA-3	305	39.235	1	0.528	0.472	0.77
BPA-4	1146	1.761	1	0.536	0.464	0.73
WAPA-1	52	9.108	2	1.024	−0.0151	0.79
WAPA-2	88	1.380	2	0.522	0.4817	0.78
WAPA-3	67	5.558	3	0.855	0.1508	0.80
WAPA-4	53	5.972	5	0.594	0.3980	0.66
WAPA-5	16	0.179	1	0.991	0.009	0.18
WAPA-6	287	4.598	1	0.551	0.449	0.71
SWPA-1	320	2.191	1	0.851	0.149	0.86
SWPA-2	91	2.710	1	0.542	0.458	0.72
SWPA-3	53	0.794	1	0.764	0.236	0.87
SWPA-4	293	0.167	1	0.653	0.347	0.76
SEPA-1	342	0.467	1	1.062	−0.062	0.98
SEPA-2	562	3.189	1	0.742	0.258	0.83
SEPA-3	489	3.634	1	0.631	0.369	0.82
SEPA-4	424	0.199	1	0.319	0.681	0.28

In Eq. (1), G_0 is the average 1989–2008 annual generation (TWh), Q_0 is the average 1989–2008 annual runoff (mm), G is the variable of annual generation (TWh), Q is the variable of annual runoff (mm) (in some areas this is derived using a multi-year running average), and a and b are the dimensionless regression coefficients. With the exceptions of WAPA-5 (Rio Grande) and SEPA-4 (lower Apalachicola), annual G is highly correlated to observed Q. In 16 of the 18 study areas, runoff explains from 66 to 98% of the variation in annual generation. In four of the areas in the WAPA region, generation is more closely related to multi-year average runoff than single-year runoff; this relationship is due to the presence of very large surface water storage reservoirs that carry over water from one year to another.

These empirical relationships between generation and runoff are key tools because they enable projected changes in future runoff to be translated into projected changes in annual generation. This generalized approach works for US federal hydropower plants because their total installed power capacity has not changed significantly during the past 20 years. This linear relationship, while working properly between annual runoff and generation, cannot be extended to seasonal or monthly scales. To model the subannual generation in each area, the monthly reservoir storage and release should also be considered, but such storage effects may not be generalizable in a simplified equation for regional hydropower generation (i.e., a reservoir- and plant-based analysis should still be required to study the subannual generation). Although it is possible

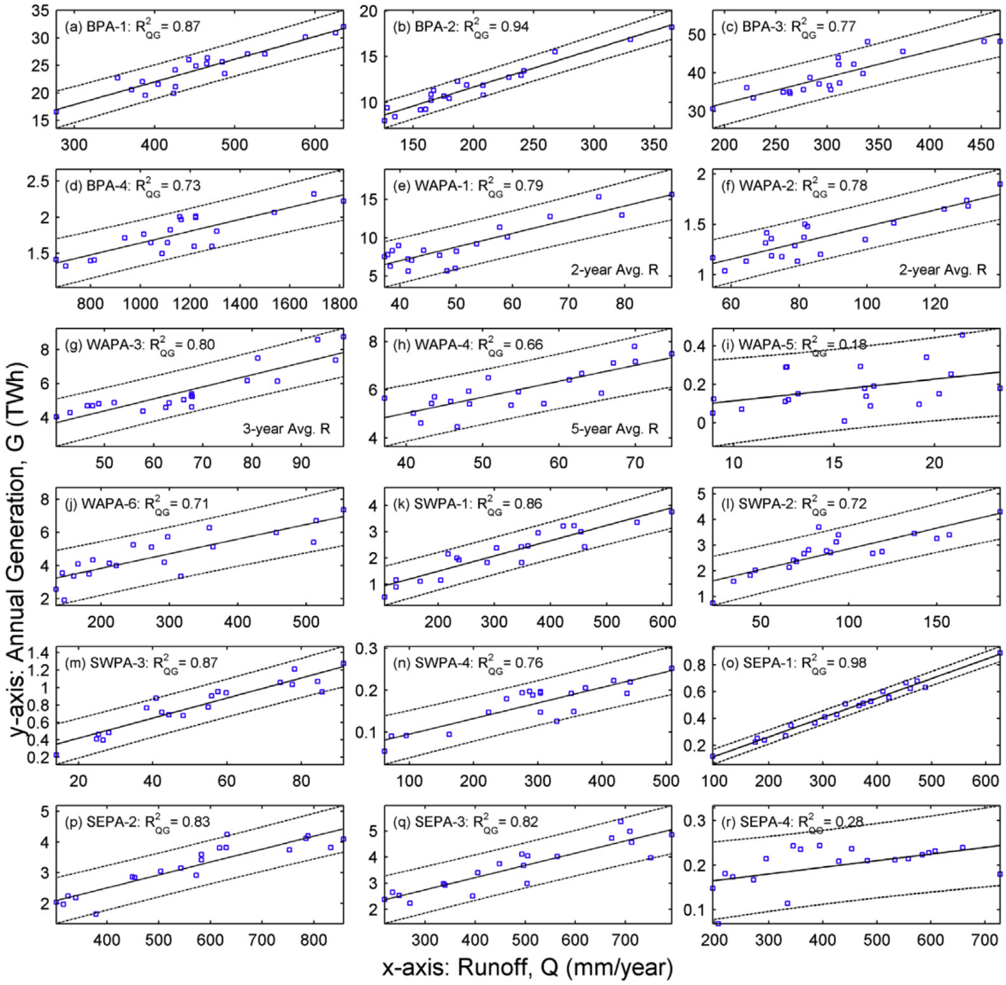

Fig. 6. Linear regression between runoff and annual generation of each PMA study area (panels a through r). Annual runoff is used in the regression, expect for 2-year runoff in WAPA-1 and WAPA-2, 3-year runoff in WAPA-3, and 5-year runoff in WAPA-4. The dashed lines represent the 95% confidence intervals of the regression, and R^2 values are the coefficients of determination.

to improve the statistical models by using multivariate or nonlinear regression methods, we opted to keep them in the simplest form. The combined climate and hydrologic modeling system was very complicated, so it would be useful if a simplified (yet justifiable) method could be used to increase the overall clarity. Through the proposed linear regression models, it may clearly be seen how the projected changes in runoff may affect regional annual hydropower generation.

3.2. Projected change of runoff

Based on a series of simulations introduced in Section 2.3, the temperature, precipitation, and runoff were projected out to 2039. Although many climate change assessments have focused on projections after 2040 or near the end of the 21st century, near-future projection is more useful for PMA operation. For instance, to help inform long-term power contracting activities (usually for a 10- to 15-year time frame), the potential climate change and variability for the following 30 years are more informative for decision making than longer-term climate projections. Therefore, we only consider near future projections (2010–2039) in this study and it is further separated into near-term (2010–2024) and mid-term (2025–2039) periods for discussion. For near future climate, the internal climate system variability has stronger influence than the long-term climate signal [10,20], so having five realizations from a single GCM would actually help better capture the influence of internal variability.

Taking 1960–1999 as the baseline period, the projected changes in annual and seasonal runoff in each PMA study area are shown in Fig. 7 (the seasons considered are spring: March/April/May; summer: June/July/August; fall: September/October/November; and winter: December/January/February). Based on the five RegCM3-A1B simulations, the circles represent the median across the five projections, while the range plotted around each circle extends from the highest to the lowest projections. The two-sample *t*-test (under a 5% significance level) is used to examine if the projected future mean runoff is statistically different than the baseline values, marked by thick lines. In addition, the spatial patterns of the projected runoff changes are shown in Fig. 8. For each grid point, the maximum change among five simulations is shown in Fig. 8a and d, the median change in Fig. 8 b and e, and the minimum in Fig. 8c and f.

Referring to the median change among the five simulations, the annual runoff values for all BPA areas are projected to decrease by 8–10% in the near-term period but then decrease by a smaller amount in the mid-term period. The statistically significant changes of annual runoff are projected in BPA-1 in the near-term and in BPA-4 in the mid-term. More important for BPA, the

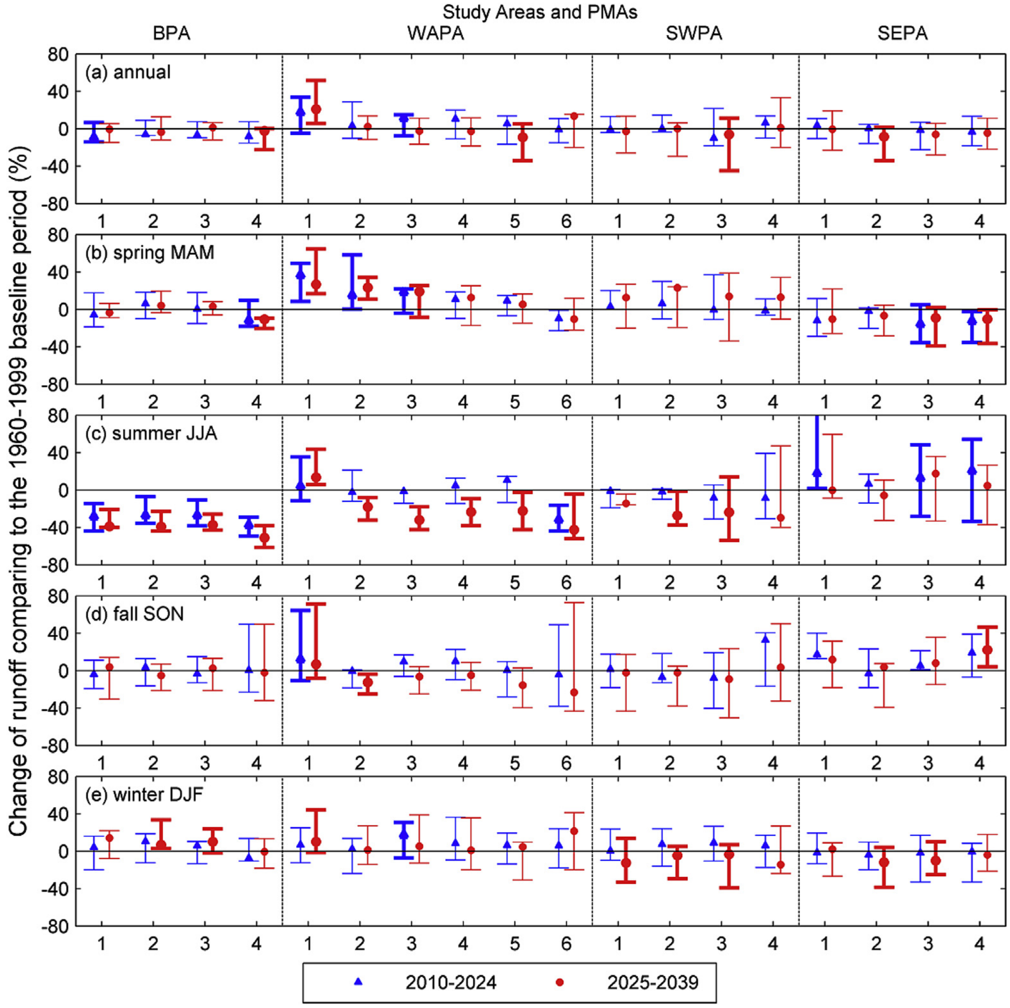

Fig. 7. Projected change of annual and seasonal runoff (panels a to e, top to bottom) of each of the 18 PMA study areas (horizontal axis). The change of runoff from baseline (1960–1999) to near-term (2010–2024) and mid-term (2025–2039) future periods is computed based on the five RegCM3-A1B simulations. Triangles and circles are the medians of the five projections in two future periods, and the range plotted around each circle extends from the highest to the lowest projections. The seasons considered are spring: March/April/May (MAM); summer: June/July/August (JJA); fall: September/October/November (SON); and winter: December/January/February (DJF). The thick lines mark the cases where the projected future mean change is statistically different than baseline under a 5% significance level.

greatest and statistically significant decrease in runoff is projected to occur in the summer season, when median changes could be as high as −40 to −50%. Such decreases in summer runoff are expected to result from earlier snowmelt triggered by increasing temperatures [3]. Although those changes are for median conditions over the 15-year time period, both high- and low-runoff years are projected to occur. In high-runoff years, the range of simulations indicates that annual runoff may be 10–20% higher than in the baseline period [34].

The greatest and statistically significant increase in runoff is projected in the Missouri River basin (WAPA-1 and, to a lesser extent, WAPA-2). In WAPA-1, the median projected change in annual runoff is +18% in the near-term (2010–2024) and +21% in the mid-term (2025–2039). Runoff is projected to consistently increase across all seasons with the largest increase in spring. The remaining WAPA areas, except for WAPA-3 in near-term and WAPA-5 in mid-term, are not projected to experience much change in annual runoff, but do show general decreases in summer runoff, especially during the mid-term period. (However, WAPA-6 shows decreasing summer runoff for both periods.) The spring runoff is projected to increase significantly in both near-term and mid-term for WAPA-1, WAPA-2, and WAPA-3, where spring runoff is dominated by snowmelt. A very large spread among the ensembles is projected in WAPA-6 during fall, but the change of overall mean is not statistically significant.

The spread among the five climate projections is generally quite large in SWPA areas, especially for individual seasons. Some consistent features in Fig. 7 include negative mid-term changes in winter and summer, and positive mid-term changes in spring. The reduction in summer runoff in the mid-term compared with the near-term is fairly large. For SEPA, there are no clear trends in mean annual runoff, with the exception of SEPA-2, where there are slight decreasing trends, and the medians are less in the mid-term than in the near-term. The spread across the five simulations is especially large in summer, again indicating the strong influence of climate system variability.

3.3. Projected change of annual hydropower generation

The projected change in annual runoff can be translated into changes in annual hydropower generation by applying the statistical models reported in Table 1. To further correct some remaining VIC model bias and improve the accuracy of simulated runoff, the same bias correction approach [2] was performed for the simulated

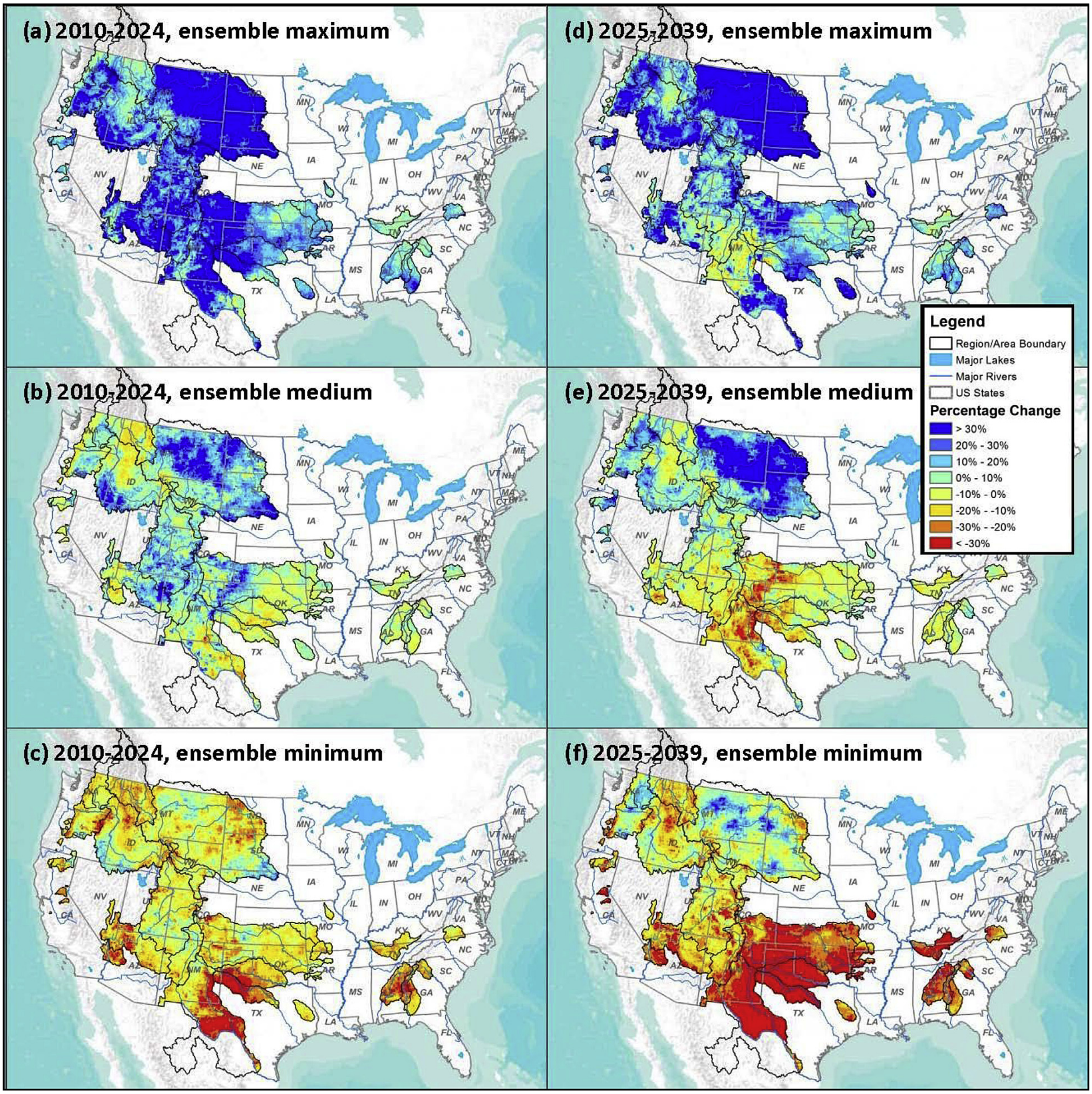

Fig. 8. The projected change of runoff over the near-term (2010–2024, left panels) and mid-term (2025–2039, right panels) future periods compared with the 1960–1999 baseline period, based on the maximum (upper panels), median (middle panels), and minimum (lower panels) of the five RegCM3-A1B simulations.

annual runoff using the 1960–1999 WaterWatch runoff records. The results are compared in Fig. 9 for three periods: 1989–2008 observation and 2010–2024 and 2025–2039 future projections. For the 1989–2008 observation period, the black line indicates the 20-year mean annual generation and the gray area defines the range from the 20-year minimum to the 20-year maximum. For both the 2010–2024 and 2025–2039 projection periods, the black line represents the mean annual generation across the five climate projections. The error bars and circles for these projection periods define the maximum, minimum, and median 15-year mean annual generation of the five ensemble members. To make them comparable to the 20-year minimum and maximum annual generation shown in the observations, the statistically equivalent 5% and 95% ensemble quantiles are shown in the two projection periods (75 years of simulated annual hydropower—five simulations multiplied by 15 years per period).

In the BPA study areas, mean annual generation is projected to increase by 1.3 TWh during 2010–2024, which is 1.7% of the 1989–2008 historical generation. In 2025–2039, the mean annual generation is projected to increase by 2.6 TWh, or 3.3% relative to 1989–2008. The range of change in annual generation among the five ensemble members is from +4 to −5 TWh. The variability in annual hydropower generation experienced in the BPA region over the past two decades is similar in magnitude to these projections of climate-related change. However, the high seasonal variability of runoff may result in operational challenges that could not be revealed through a projection of total annual generation. This should be further investigated through a reservoir-based approach for major hydropower plants in BPA.

In the WAPA region, mean annual hydropower generation is projected to increase in both the 2010–2024 and the 2025–2039 periods. This trend is due to projected increases in runoff, mostly in

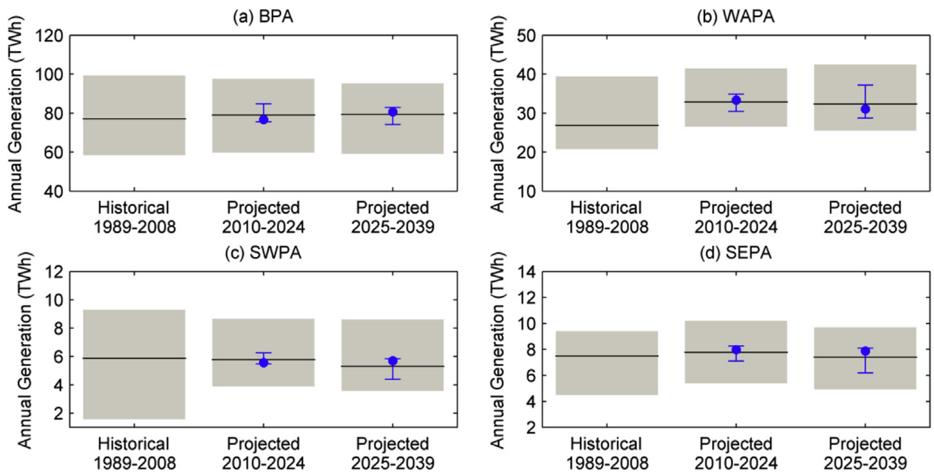

Fig. 9. Historical (1989–2008), projected near-term (2010–2024) and projected mid-term (2025–2039) annual hydropower generation of each PMA. The black line shows the overall mean over each period. The gray area shows the minimum to maximum annual generation in the 20-year historical period, or 5%–95% quantiles in the simulation periods. Circles are the 15-year average across the five RegCM3-A1B simulations, and the range plotted around each circle extends from the highest to the lowest simulations, as a measure of model uncertainty.

WAPA-1 (upper Missouri River), a finding that is generally consistent with those of other studies (e.g., Ref. [32]). However, the projected increase in generation might not be fully realized should the amount of runoff exceed the current storage capacity of the system, or if changes in flood control operations should reduce the volume of multi-purpose reservoir storage capacity. Increasing challenges associated with flood control operations are likely to be a continuing problem in the northern WAPA areas. In other parts of WAPA, projected total changes in generation are smaller and more variable. Mean annual generation for the whole WAPA is projected to increase by 6 TWh (22%) in 2010–2024 and 5.5 TWh (20%) in 2025–2039, relative to 1989–2008.

The mean projections of SWPA annual hydropower generation indicate a 0.1 TWh (1.8%) reduction in 2010–2024 and a 0.5 TWh (7.7%) reduction in 2025–2039 relative to the historic observation from 1989–2008. The range of change among the five simulations is relatively large, so there is a potential for higher year-to-year uncertainty in hydropower operations. Over the most recent 20 years, SWPA's total annual generation has varied from a high of 9.32 TWh in 1993 to a low of 1.54 TWh in 2006, representing a range from −75% to +55% of the median generation during that time period. The 1.54 TWh in 2006 is extremely low (corresponding to a serious drought event), acting more as an outlier in the comparison shown in Fig. 9. If it is excluded, the remaining range of variability will be closer to the projections.

The mean projected change in the SEPA study area is a 0.27 TWh (3.6%) increase in 2010–2024 and essentially no change in 2025–2039 relative to the 1989–2008 period. However, as in other regions, the range between high and low ensemble members is relatively large, indicating the likelihood of extreme water years and generation outputs. In the past 20 years, total annual generation from projects in this region has ranged from a maximum of 9.44 TWh in 1993 to a minimum of 4.29 TWh in 2008. Although the projected change in generation may add to this historic variability, and more dry water years are projected for the future, the range of annual generation in the SEPA region is projected to be similar to that of the recent past.

4. Discussion and conclusions

Hydropower generation at US federal facilities varies from year to year for a number of reasons, including variations in weather and runoff, the changing condition of hydropower equipment, nonpower water uses and environmental requirements. Hydrologic variability—which is jointly influenced by precipitation, evaporation, snowfall, soil moisture, groundwater and reservoir operation—was found to be a significant factor in the annual hydropower generation. However, given the large number of federal hydropower plants and the diverse hydrologic conditions, evaluating the impacts of climate change on all federal hydropower plants through a conventional reservoir-based approach is currently not tractable in a single national-scale study. Therefore, this study used the strong linear relationship between the USGS WaterWatch runoff and annual hydropower generation to develop an alternative runoff-based approach appropriate for projecting the change in annual and regional hydropower generation in multiple power marketing areas. Linear regressions between runoff and annual generation were conducted for each study area (Table 1) using the 1989–2008 historic observation. This approach, although mathematically simple, can help examine the climate change effects on a large number of hydropower plants efficiently. Such regional hydroelectric energy projections can then be used to support energy resource planning and also to evaluate the climate-related risk for long-term power marketing activities.

While the change of energy demand would influence market price and further affect total power generation, it was not found to be a major factor for US federal hydropower plants (i.e., runoff can explain most of the annual variability). This could be attributed to the uniqueness of PMAs, for which most of the hydroelectric generation produced from these federal projects is sold to public utilities at the lowest possible rates. With the relatively cheaper cost, the hydroelectricity marketed through PMAs will continue to be more desirable to the utilities as compared to other fuel-based energy sources. For other non-federal hydropower plants that are operated under peak mode, the change of demand in the future could be another factor for consideration.

Future climate scenarios were developed using a global climate model, a nested regional climate model, and a hydrological model. Five realizations of the modeling system were generated, and the model outputs were bias-corrected for consistency with observations of the recent past. Hydro-climate variables, including temperature, precipitation, and runoff, were projected into near-term (2010–2024) and mid-term (2025–2039) periods to estimate how changes in water availability could affect hydropower generation at federal projects. The patterns of the projected changes are both spatially and temporally complex. Aggregated to a national level, the median change in federal hydropower is projected to decrease 1 to 2 TWh per year, with a model uncertainty range of ±9 TWh per year. On annual basis, this largest change is projected in the upper Missouri River Basin (WAPA-1) in the northern Great Plains, where runoff is projected to largely increase. The western slope of the Cascade Mountains is also projected to be wetter, especially in the mid-term period. Runoff and generation are projected to increase in those parts of the WAPA and BPA regions. In contrast, water availability in the southern Great Plains, Texas, and New Mexico is projected to substantially decrease in the future. Therefore, SWPA and WAPA may experience less hydropower generation in those areas, especially during the drier summer months.

The climate modeling results indicate drying trends and decadal-scale changes that are likely to have adverse impacts on federal hydropower in many regions. These trends are generally consistent with those indicated by other studies (e.g., Ref. [18]). Even against the backdrop of these projected regional drying trends, it is important to note that both wet and dry extremes will still occur in the future for all regions, although the relative frequency of these extremes is projected to change. On a longer-term basis (during the mid-21st century and beyond), climate change is likely to become even more challenging for hydropower operations if warming, drying, and seasonal shifts in hydrology continue on the projected trajectories (e.g., Ref. [32]).

Nevertheless, the regional assessment approach employed in this study cannot resolve some of the more detailed, site-specific aspects of climate and hydropower, especially at shorter time intervals (e.g., seasonal or monthly changes). For those hydropower plants with greater importance, a conventional reservoir-based evaluation will still be needed. The complexities of surface water reservoir operations are another factor limiting regional assessment capabilities. To represent monthly or shorter-term hydrology in river basins where many multiple-use reservoirs are located, such as the case in almost all federal hydropower systems, a refined regional water-balance modeling approach will eventually be needed. Future assessments can be improved by incorporating updated climate projections with enlarged ensemble members, by reducing bias of hydrologic modeling, by closer examination of extreme events and longer-term change, and by addressing the interactions among hydropower and other water uses at a more project-specific level.

Although climate change would likely influence water availability and cause direct impacts on hydropower generation, the technical assessment is challenging, especially at regional and national scale. As oppose to a reservoir-based approach, this study took an alternative top-down approach to examine the regional hydropower generation using a runoff-based approach. It is showed that, the change of annual runoff will result in a proportional change of regional hydropower generation, and hence confirms the need of more detailed studies on hydropower operation and climate change. However, given the complexity of energy-water facilities and limited information of existing hydropower data, it is unlikely to address all issues across multiple power plants and scales using a single model. Depending on the scale (e.g., national, regional, or plant-wise) and the nature of the problem (e.g., reservoir operation, risk assessment, or resource planning), one would likely need to develop different kinds of models for different challenges. This will be a continued challenge of future studies on climate change and hydropower generation.

Acknowledgments

This study was sponsored by the DOE Wind and Water Power Program. The study supported a DOE Report to Congress under Section 9505 of the SECURE Water Act of 2009 (Public Law 111-11). A second study due in 2016 under that legislation is under way. The valuable support from PMA staff, including J. Eisdorfer, B. Kuepper, E. Pytlak, L. Baker, C. Olive and T. Johnson (BPA); D. Spencer (SEPA); F. Ohlson and G. Robbins (SWPA); and M. Cowan, J. Gierard, S. Loftin, L. Cady-Hoffman, X. Gonzalez and T. Patton (SWPA), and other technical reviewers acknowledged in Ref. [34] is deeply appreciated. This paper was authored by employees of UT-Battelle, LLC, under contract DE-AC05-00OR22725 with DOE. Accordingly, the US Government retains and the publisher, by accepting the article for publication, acknowledges that the US Government retains a nonexclusive, paid-up, irrevocable, worldwide license to publish or reproduce the published form of this manuscript, or allow others to do so, for US Government purposes. NSD was supported by the US DOE Integrated Assessment Research Program, Grant No. DE-SC005171.

References

[1] AEG (Aspen Environmental Group), Cubed M. Potential changes in hydropower production from global climate change in California and the western United States. CEC-700-2005-010. Sacramento, California: California Energy Commission; 2005.

[2] Ashfaq M, Bowling LC, Cherkauer K, Pal JS, Diffenbaugh NS. Influence of climate model biases and daily-scale temperature and precipitation events on hydrological impacts assessment: a case study of the United States. J Geophys. Res 2010;115:D14116,. http://dx.doi.org/10.1029/2009JD012965.

[3] Ashfaq M, Ghosh S, Kao S-C, Bowling L, Mote P, Touma D, et al. Near-term acceleration of hydroclimatic change in the western U.S. J Geophys Res 2013;118:10676–93. http://dx.doi.org/10.1002/jgrd.50816.

[4] Beigi E, Tsai F. GIS-based water budget framework for high-resolution groundwater recharge estimation of large-scale humid regions. J Hydrol Eng 2014;19(8):05014004.

[5] Brakebill JW, Wolock DM, Terziotti SE. Digital hydrologic networks supporting applications related to spatially referenced regression modeling. J Am Water Resour As 2011;47(5):916–32. http://dx.doi.org/10.1111/j.1752-1688.2011.00578.x.

[6] Christensen NS, Wood AW, Voisin N, Lettenmaier DP, Palmer RN. The effects of climate change on the hydrology and water resources of the Colorado River Basin. Clim Change 2004;62(1–3):337–63. http://dx.doi.org/10.1023/B:CLIM.0000013684. 13621.1f.

[7] Collins WD, Blackmon M, Bitz C, Bonan G, Bretherton CS, Carton JA, et al. The community climate system model version 3 (CCSM3). J Clim 2006;19(11):2122–43. http://dx.doi.org/10.1175/JCLI3761.1.

[8] Daly C, Gibson WP, Taylor GH, Johnson GL, Pasteris P. A knowledge-based approach to the statistical mapping of climate. Clim Res 2002;22:99–113. http://dx.doi.org/10.3354/cr022099.

[9] Daly C, Halbleib M, Smith JI, Gibson WP, Doggett MK, Taylor GH, et al. Physiographically sensitive mapping of climatological temperature and precipitation across the conterminous United States. Int J Climatol 2008;28:2031–64. http://dx.doi.org/10.1002/joc.1688.

[10] Deser C, Knutti R, Solomon S, Phillips AS. Communication of the role of natural variability in future North American climate. Nat Clim Change 2012;2:775–9. http://dx.doi.org/10.1038/nclimate1562.

[11] Diffenbaugh NS, Ashfaq M. Intensification of hot extremes in the United States. Geophys Res Lett 2010;37:L15701,. http://dx.doi.org/10.1029/2010GL043888.

[12] Diffenbaugh NS, Pal JS, Trapp RJ, Giorgi F. Fine-scale processes regulate the response of extreme events to global climate change. Proc Natl Acad Sci U S A 2005;102(44):15774–15778,. http://dx.doi.org/10.1073/pnas.0506042102.

[13] EIA (Energy Information Administration). Federal electricity programs. Report#:SR/OIAF/2000-02. 1999. Available at:, http://www.eia.doe.gov/oiaf/servicerpt/subsidy1/electricity.html [accessed in December, 2010].

[14] EIA. (Energy Information Administration). From EIA-923 databases, http://www.eia.gov/electricity/data/eia923/index.html. 2010 [accessed in December, 2010].

[15] Environment Canada. HYDAT Database. http://www.ec.gc.ca/rhc-wsc/default.asp?lang=En&n=9018B5EC-1. 2011 [accessed January 2011].

[16] EPA (Environmental Protection Agency), USGS (US Geological Survey). NHDPlus user guide. Environmental Protection Agency; 2010. Available at: ftp://ftp.horizon-systems.com/NHDPlus/NHDPlusV1/documentation/NHDPLUSV1_UserGuide.pdf [accessed in July 2013].

[17] Hamlet AF, Lettenmaier DP. Effects of climate change on hydrology and water resources in the Columbia River Basin. J Am Water Resour As 1999;35(6):1597–623. http://dx.doi.org/10.1111/j.1752-1688.1999.tb04240.x.

[18] Hamlet AF, Lee S-Y, Mickelson KEB, Elsner MM. Effects of projected climate change on energy supply and demand in the Pacific Northwest and Washington State. Clim Change 2010;102:103–28. http://dx.doi.org/10.1007/s10584-010-9857-y.

[19] Harrison G, Whittington HW. Susceptibility of the Batoka Gorge Hydroelectric Scheme to climate change. J Hydrol 2002;264(1–4):230–41. http://dx.doi.org/10.1016/S0022-1694(02)00096-3.

[20] Hawkins E, Sutton R. Time of emergence of climate signals. Geophys Res Lett 2012;39:L01702. http://dx.doi.org/10.1029/2011GL050087.

[21] Lane N. Power marketing administrations: background and current issues. Order Code RS22564. Washington, D.C: Congressional Research Service; 2007.

[22] Madani K, Lund JR. Modeling California's high-elevation hydropower systems in energy units. Water Resour Res 2009;45:W09413. http://dx.doi.org/10.1029/2008WR007206.

[23] Madani K, Lund JR. Estimated impacts of climate warming on California's high-elevation hydropower. Clim Change 2010;102(3–4):521–38. http://dx.doi.org/10.1007/s10584-009-9750-8.

[24] Markoff MS, Cullen AC. Impact of climate change on Pacific Northwest hydropower. Clim Change 2008;87(3–4):451–69. http://dx.doi.org/10.1007/s10584-007-9306-8.

[25] Maurer EP, Wood AW, Adam JC, Lettenmaier DP. A long-term hydrologically based dataset of land surface fluxes and states for the conterminous United States. J Clim 2002;15(22):3237–51. http://dx.doi.org/10.1175/1520-0442(2002)015. <3237:ALTHBD>2.0.CO;2.

[26] Mearns LO, Gutowski W, Jones R, Leung R, McGinnis S, Nunes A, et al. A regional climate change assessment program for North America. Eos Trans AGU 2009;90(36). http://dx.doi.org/10.1029/2009EO360002. 311–311.

[27] Mimikou MA, Baltas EA. Climate change impacts on the reliability of hydroelectric energy production. Hydrol Sci J 1997;42(5):661–78. http://dx.doi.org/10.1080/02626669709492065.

[28] NHAAP (National Hydropower Asset Assessment Program). Existing hydropower assets assessment. 2014 [accessed June 2014], http://nhaap.ornl.gov/.

[29] NRCS (National Resources Conservation Service). Watershed boundary dataset. 2011 [accessed January 2011], http://www.ncgc.nrcs.usda.gov/products/datasets/watershed/.

[30] Oubeidillah AA, Kao S-C, Ashfaq M, Naz BS, Tootle G. A large-scale, high-resolution hydrological model parameter data set for climate change impact assessment for the conterminous US. Hydrol Earth Syst Sci 2014;18:67–84. http://dx.doi.org/10.5194/hess-18-67-2014.

[31] Pal JS, Giorgi F, Bi X, Elguindi N, Solmon F, Gao X, et al. Regional climate modeling for the developing world: the ICTP RegCM3 and RegCNET. B Am Meteorol Soc 2007;88(9):1395–409. http://dx.doi.org/10.1175/BAMS-88-9-1395.

[32] Reclamation (Bureau of Reclamation). West-wide climate risk assessments: BCSD surface water projections. Technical Memorandum No. 86-68210–2011-01. US Department of Interior, Bureau of Reclamation; 2011.

[33] Robinson PJ. Climate change and hydropower generation. Int J Climatol 1997;17(9):983–96. http://dx.doi.org/10.1002/(SICI)1097-0088(199707)17. 9<983::AID-JOC174> 3.0.CO;2-I.

[34] Sale MJ, Kao S-C, Ashfaq M, Kaiser DP, Martinez R, Webb C, et al. Assessment of the effects of climate change on federal hydropower. Technical Manual 2011/251. Oak Ridge, TN: Oak Ridge National Laboratory; 2012.

[35] Schaefli B, Hingray B, Musy A. Climate change and hydropower production in the Swiss Alps: quantification of potential impacts and related modelling uncertainties. Hydrol Earth Syst Sci 2007;11:1191–205. http://dx.doi.org/10.5194/hess-11-1191-2007.

[37] Sharma M, Coulibaly P, Dibike YB. Assessing the need for downscaling RCM data for hydrologic impact study. J Hydrol Eng 2011;16(6):534–9. http://dx.doi.org/10.1061/(ASCE)HE.1943-5584.0000349.

[38] Tanaka SK, Zhu T, Lund JR, Howitt RE, Jenkins MW, Pulido MA, et al. Climate warming and water management adaptation for California. Clim Change 2006;76(3–4):361–87. http://dx.doi.org/10.1007/s10584-006-9079-5.

[39] USACE (US Army Corps of Engineers). U.S. army corps of engineers civil works program five-year development plan, fiscal year 2009–2013. Washington, D.C: Department of the Army; 2009.

[40] Washington WM, Weatherly JW, Meehl GA, Semtner Jr AJ, Bettge TW, Craig AP, et al. Parallel climate model (PCM) control and transient simulations. Clim Dyn 2000;16(10/11):755–74. http://dx.doi.org/10.1007/s003820000079.

[41] Willmott CJ, Matsuura K. Smart interpolation of annually averaged air temperature in the United States. J Appl Meteorol 1995;34:2577–86. http://dx.doi.org/10.1175/1520-0450(1995)034. <2577:SIOAAA>2.0.CO;2.

[42] Vicuna S, Leonardson R, Hanemann MW, Dale LL, Dracup JA. Climate change impacts on high elevation hydropower generation in California's Sierra Nevada: a case study in the Upper American River. Clim Change 2008;87(1):123–37. http://dx.doi.org/10.1007/s10584-007-9365-x.

[43] Yao H, Georgakakos A. Assessment of Folsom Lake response to historical and potential future climate scenarios: 2. Reservoir management. J Hydrol 2001;249:176–96. http://dx.doi.org/10.1016/S0022-1694(01)00418-8.