Improving the Representation of Hydropower in Production Cost Models

August 2023

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About HydroWIRES

In April 2019, the U.S. Department of Energy Water Power Technologies Office launched the HydroWIRES Initiative[1] to understand, enable, and improve hydropower and pumped storage hydropower's (PSH's) contributions to reliability, resilience, and integration in the rapidly evolving U.S. electric system. The unique characteristics of hydropower, including PSH, make it well suited to provide a range of storage, generation flexibility, and other grid services to support the cost-effective integration of variable renewable resources.

The U.S. electric system is rapidly evolving, bringing both opportunities and challenges for the hydropower sector. Though increasing deployment of variable renewables such as wind and solar have enabled low-cost, clean energy in many U.S. regions, it has also created a need for resources that can store energy or quickly change their operations to ensure a reliable and resilient grid. Hydropower (including PSH) is not only a supplier of bulk, low-cost, renewable energy but also a source of large-scale flexibility and a force multiplier for other renewable power generation sources. Realizing this potential requires innovation in several areas, including understanding value drivers for hydropower under evolving system conditions, describing flexible capabilities and associated trade-offs associated with hydropower meeting system needs, optimizing hydropower operations and planning, and developing innovative technologies that enable hydropower to operate more flexibly.

HydroWIRES is distinguished in its close engagement with the DOE national laboratories. Five national laboratories—Argonne National Laboratory, Idaho National Laboratory, the National Renewable Energy Laboratory, Oak Ridge National Laboratory, and Pacific Northwest National Laboratory—work as a team to provide strategic insight and develop connections across the HydroWIRES portfolio as well as broader DOE and national laboratory efforts such as the Grid Modernization Initiative.

Research efforts under the HydroWIRES Initiative are designed to benefit hydropower owners and operators, independent system operators, regional transmission organizations, regulators, original equipment manufacturers, and environmental organizations by developing data, analysis, models, and technology research and development that can improve their capabilities and inform their decisions.

More information about HydroWIRES is available at energy.gov/hydrowires.

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[1] Hydropower and Water Innovation for a Resilient Electricity System (HydroWIRES)

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Acronyms and Abbreviations

CNRFC	California Nevada River Forecast Center
CSU	Colorado State University
DOE	U.S. Department of Energy
FLASH	Framework for the Linked Analysis of Streamflow and Hydropower
NREL	National Renewable Energy Laboratory
PCM	production cost model
PNNL	Pacific Northwest National Laboratory
RoR	run-of-river
SIIP	Scalable Integrated Infrastructure Planning
WECC	Western Electricity Coordinating Council

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1 Introduction

One of the challenges of a high-renewable, low-carbon system is that grid operators will no longer be able to count on fossil-fired generation should wind miss its forecast or modeling errors create shortage issues, and this change has operational and reliability implications that affect variable renewable energy integration. Hydropower can help in that it can provide many of the services that have been traditionally provided by fossil generation. However, getting the most from hydropower can be challenging in that its capabilities vary with time and are affected by other water users' needs, two complexities that are not well represented in most of today's production cost models (PCMs). This work is an early step in addressing these gaps and making the most of hydropower's capabilities.

Part of the reason for the lack of robust hydropower representation is that the complexities of water management have precluded the development of easily accessible depictions that characterize and accommodate hydropower subtleties (e.g., variability over time), resulting in power grid models that instead rely on simplified models that use monthly hydropower availability datasets that are too coarse to answer sub-monthly hydropower flexibility and constraints. These simplifications, while manageable in a low-renewables world, create operational challenges in a high-renewables setting where operators are counting on hydropower for providing the firm capacity and operating reserves necessary for integrating variable renewable energy. Said simply, when relying on dispatchable hydropower to fulfill flexibility and reliability needs, better hydropower representations would be helpful.

1.1 Background Information

Production cost models are widely used by the bulk power industry to answer questions ranging from "What's the most cost-effective way to meet today's customer demand?" to "How will an increase in renewables affect grid operation?" Their ease of use and flexibility have made the restructuring of power markets and the integration of increasing amounts of variable generation possible in ways that likely would have been challenging without them. However, as the amount of variable generation in models has increased, modelers are noting issues not previously observed (e.g., degeneracy and dropped load).[2] The good news is that the PCM methodology seems sound. The bad news, but also the opportunity, is that improved grid model representations appear to be needed when modeling low-carbon systems. The HydroWIRES initiative is sponsored by the U.S. Department of Energy's (DOE's) Office of Energy Efficiency and Renewable Energy Water Power Technologies Office and specifically addresses technological gaps in hydropower representations amidst technology innovation, and market and environmental changes. In 2020, two complementary projects were funded that address this hydropower representation in PCM with short-term and medium-term outcomes. The work presented here focuses on hydropower representation as an early step in this broader decarbonization effort. We start with a short introduction to production cost modeling, discuss how hydropower is typically modeled today, identify some of the benefits and challenges with such a representation, and then present the two different yet complementary approaches to improving hydropower's representation.

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[2] Both the Solar Futures and 2022 Standard Scenarios project teams encountered these issues.

PCMs are used to simulate power system operations by solving a sequence of linear, quasi-static optimal scheduling problems that balance system demands from customers with energy supply from generators, with the solution of one problem informing the initial conditions of the subsequent problem. Historically, PCM configurations have focused on day-ahead scheduling issues where each problem formulation in the sequence represents a day (plus some look-ahead period). The reason for this choice is that many of the low-cost generation technologies (e.g., coal and early combined cycle plants) were slow to start and needed lead time so that they would be available to meet power demands the following day. Although these models were originally designed for systems that relied heavily on fossil-fired generation, they also worked well for systems with small to moderate amounts of variable renewable energy[3] in that methodology and timescales align well with most grid resources (e.g., generator start times are like the time horizons in which wind and solar are predictable). However, even with the successes, there have always been known gaps, with hydropower representation being one of them. For example, in most restructured markets and even in some verticals, grid operators have little insight into hydropower capabilities beyond historical production records (self-reported monthly generation numbers) and the information that owner-operators share via the bid process. This leaves grid operators in the awkward position of not knowing the full capabilities of the hydropower fleet, which is not ideal, as hydropower is assuming more and more of the role previously handled by coal- and gas-fired generation (e.g., providing variable renewable energy operational reserves and firm capacity).

Hydropower availability depends not only on the presence of water, but also on the physical attributes of the system (e.g., hydraulic head), infrastructure capacities (reservoir capabilities), and operational constraints (rough zones), including environmental constraints (e.g., minimum flows). While these details could be represented in the PCM day-ahead problems, they are typically approximated if represented at all due to data provenance, data availability, and computational complexity issues. Consequently, most PCM hydropower representations either over-constrain operations by prescribing an hourly generation profile of hydropower facilities with little or no flexibility or under-constrain operations by only prescribing the maximum amount of energy each hydropower facility can produce over some period (e.g., typically monthly) (Oikonomou et al. 2022). The former case underrepresents hydropower capabilities, leading to suboptimal results with higher production (and likely consumer) costs and lower owner-operator revenues, while the latter case over-represents hydropower availability and flexibility and can produce results that are infeasible by suggesting that hydropower resources can generate at nameplate anytime within their budget window. Historically, the errors associated with these modeling simplifications could be mitigated with fast-start generation (e.g., gas-fired combustion turbines) that could be quickly started; however, this is becoming problematic as much of the grid's flexible generation is being retired because of carbon concerns, with the situation likely to worsen in coming years.

The work described in this report directly addresses representation-induced modeling errors. Two different yet complementary approaches for improving hydropower representation in PCMs

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[3] The amount of slow-to-start fossil-fired generation that needs to be committed in the day-ahead market can be estimated by subtracting the day-ahead variable renewable energy forecast from the day-ahead demand forecast to produce a net-load forecast. To help mitigate issues introduced by forecast error, reserves are provisioned in the day-ahead market.

are presented. The first is a statistically-based approach that improves on the current monthly observation reports by providing weekly rather than monthly hydropower availability limits by leveraging higher resolution observed flow information; the second works to improve representation by tightly coupling a physics-based river-basin operations model with a grid operations model (i.e., the PCM). Each of the new methodologies was developed for specific use cases and thus has advantages and limitations depending on the application.

2 Offline Weekly Hydropower Datasets in Support of Resource Adequacy Studies

This section describes Pacific Northwest National Laboratory's (PNNL's) approach, which focuses on updating hydropower datasets in bulk power grid models to represent both interannual variability and address submonthly water management constraints. The approach includes novel datasets complemented by an update in the hydropower dispatch to accommodate weekly rather than monthly datasets in the GridView model.

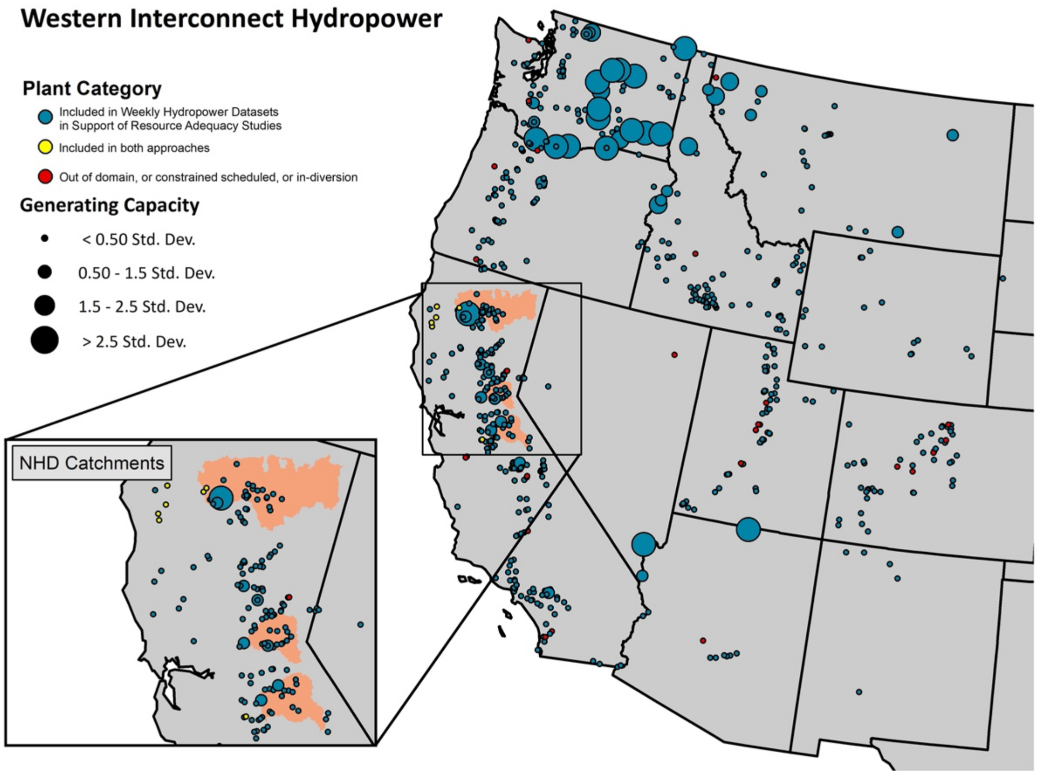

Figure 1. Western U.S. interconnect and hydropower plants contributing to the bulk power system operations. The offline monthly and weekly hydropower datasets represent all hydropower plants in the WECC conterminous United States that are dispatchable (~250). FLASH is applied to the hydropower plants in the Sacramento, Stanislaus, Trinity, Tuolumne, and Upper American river basins in the BANC balancing area (orange in the map). Source: WECC area, RTO, hydropower plants: S&P Platts 2019 https://www.spglobal.com/commodityinsights/en/products-services/oil/map-data-pro (acquired December 2020) Rivers: ESRI ArcMap Default Continental US Basemap. Software: ESRI ArcMap. Author: Nathalie Voisin

There are over 1,500 hydropower plants over the contiguous United States and 600 over the Western United States. There is a lack of information regarding the operations of those individual hydropower plants and how they contribute to bulk power system operations besides the annual and monthly EIA-923 hydropower generation data. Correspondingly, the common representation of hydropower in bulk power system models setups in the United States is a monthly representation consisting of a monthly hydropower potential (i.e., a generation target over that month), and operational constraints such as minimum and maximum hourly generation, ramping rates and mode of operations such as following load or price (Oikonomou et al. 2022). For power plants that are deemed to have no flexibility, typically run-of-the-river, daily generation schedules are provided along with hourly generation profiles and are not publicly available—rather, they are part of proprietary datasets.

Over the Western United States, the water law follows first appropriation, and most substantial reservoirs are operated for flood control and water supply, taking priority over hydropower operations. The implication is that the weekly overall release pattern within a month follows storage targets determined by those water objectives and do not necessarily follow load or energy prices, as presently assumed in this common monthly representation. We hypothesized that this assumption may influence resource adequacy and reliability studies as well as misrepresent the evolving operational needs from the hydropower industry. With advances in large-scale hydrology modeling and hydrological datasets availability, we have the tools to guide this annual to monthly to weekly disaggregation representative of U.S. water operations. In this effort, PNNL developed multiyear monthly and weekly hydropower datasets for the Western interconnection.

2.1 Weekly Hydropower Datasets to Inform Reliability Studies

In this approach, weekly hydropower datasets are developed that aim to address the need to represent the coincident operations at hundreds of hydropower plants with submonthly operational constraints associated with environmental and regulatory water operations. Specifically, the datasets cover an entire power grid interconnect and are based on available observed hydropower generation and observed hydrologic conditions which address the lack of information on operations at those individual power plants. The weekly datasets span the 2001–2021 period, which address the need to better represent interannual variability for climate stress-testing power grid operations. Finally, the weekly resolution takes into account seasonal and interannual water management objectives and lets the power system dispatch process focus on weekly dispatch with water availability and water management informed by environmental and operational constraints on submonthly flexibility of scheduling. The datasets presently cover the Western Interconnection. Because the datasets are based on observed operations, they implicitly represent realistic and operational long-term water management. The datasets thus are representative of normal operations appropriate to address resources adequacy and reliability study questions at the power grid system scale.

The intended users of these datasets include bulk power system operators engaging in reliability, market, or technology integration studies for which one-to-multiple-year evaluation is necessary. Other users include utilities who can benefit from the overall PCM simulations that expand beyond their control region to understand prices and market opportunities for capital investment or rate evaluations.

While hydrologic simulations can be used to support the development of the hydropower datasets (Voisin et al. 2018), the project's industry partners first recommended that we use observations as much as possible. We therefore proceeded with leveraging 21 years of EIA-923 forms annual data that were disaggregated to a monthly resolution using observed reservoir release and downstream streamflow (Turner et al. 2022). A similar approach was used to downscale the hydropower energy target down to a weekly time step, at about 250 hydropower plants across the Western United States.

Other constraints are needed by PCMs, specifically minimum and maximum hourly generation, and daily fluctuations. The minimum hourly generation (P_{min}) typically reflects either minimum environmental flow during low-flow conditions or minimum release to meet other water objectives such as storage targets for flood control or releases for water supply. The maximum hourly generation (P_{max}) to support resource adequacy studies represents the operational capacity. Daily fluctuations provide an indication of how the hourly release space between P_{min} and P_{max} is used within a day given the weekly water conditions. Hourly hydropower generation values are not widely available, therefore we leveraged operations from 28 power plants in the Pacific Northwest to develop a set of parameterizations and imputed the parameterization to the remaining ~225 Western U.S. powerplants. See Voisin et al. 2023 for more details.

2.2 Evaluation of Weekly Sequencing

For evaluation, we used 6 years of the Western U.S. monthly and weekly datasets, all with distinct water availability conditions, for input into the ABB Hitachi GridView PCM. We leveraged the 2030 ADS Case V.2.3[4] and worked with Hitachi ABB to modify the software to accommodate the weekly dataset (GridView version 10.3.32). Specifically, the new software update skips the monthly to weekly disaggregation (formerly based on prices) and directly reads in the weekly dataset toward proceeding with the weekly to daily dispatch decisions following a combination of load and price, and then to hourly dispatch decisions that respect power system network constraints.

For an apples-to-apples evaluation of the hydropower datasets, Figure 2 shows the weekly hydropower potential aggregated over the Western Electricity Coordinating Council (WECC) scale region and the GridView simulated downscaled weekly hydropower potential. The weekly hydropower datasets reflect water management operational compliance and economic benefits, while the "monthly hydropower datasets downscaled to a weekly time scale" reflect power grid benefit without hydropower submonthly operational compliance. While results at individual power plants are more pronounced, we see differences at the WECC scale that tend to be more pronounced during average and wet years all the way from winter, largest during the spring, until early summer (2011, 2017).

Overall, we found that weekly hydropower datasets tend to increase wind and solar curtailment. Because in this experiment observed hydropower is not coincident with wind, solar, and load, curtailment is an expected result: water management is based on observations and does not have foresight of net load over the upcoming month, in contrast with the monthly representation. When coincident and based on observations, this curtailment would be realistic. A lack of foresight on temperature-sensitive load and hydro beyond 10 days is, however, realistic for operational conditions.

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[4] https://www.wecc.org/Reliability/2030ADS_PCM_ReleaseNotes_GV-V2.3_6-9-2021.pdf

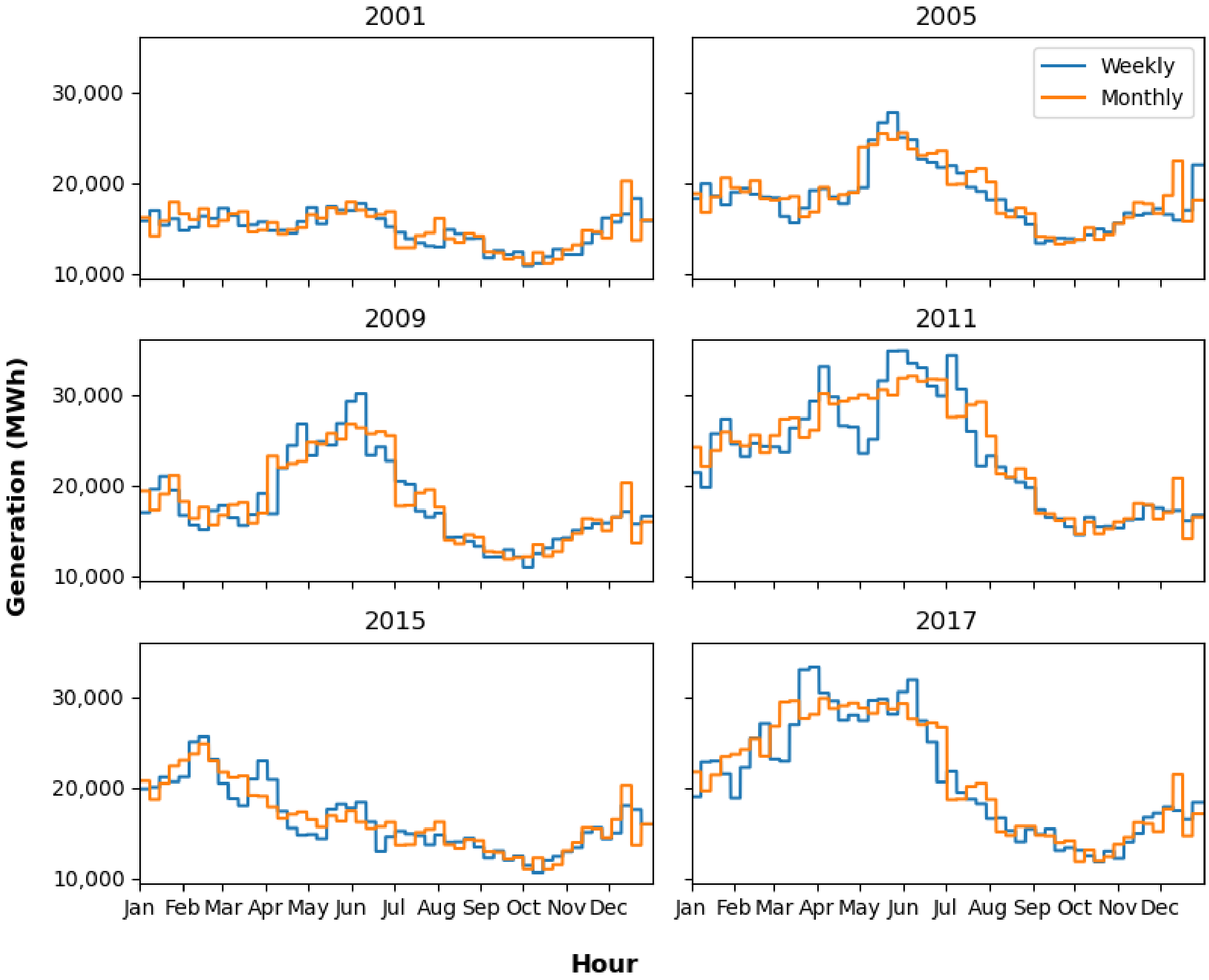

Figure 2. Weekly hydropower generation aggregated over the WECC for 6 years with distinct water conditions (dry 2001, 2015; average 2005, 2009; wet 2011, 2017). The weekly datasets are newly derived offline of the power grid model following submonthly water management while the “monthly datasets” are GridView simulations downscaling monthly to weekly following regional load conditions.

2.3 Discussion

Providing a weekly dataset directly to the bulk power system models as input enforces the weekly hydropower potentials at individual power plants, and allows updating the other hydropower operational constraints such as the minimum and maximum allowable hourly generation (P_{min} and P_{max}, respectively) to reflect the weekly hydrological conditions, and results in a consistent dataset across the Western United States. Furthermore, weekly datasets do not add additional computational burden to the PCMs.

The weekly hydropower datasets and associated PCM weekly hydro commitment updates are readily available to the industry partners. From a utility perspective, (Ploussard et al. 2022) evaluated this weekly representation with respect to an operational hourly hydropower scheduler over a handful of hydropower plants in Colorado. They concluded that there was a 3%

difference in revenues for this utility over a year with average water conditions over the Western United States. Albeit some of the hourly operations between the hydropower scheduler and the unit commitment in the PCMs did not match, but the weekly representation was deemed more realistic and closer to hydropower operations. It is important to note that the datasets represent past operations, and users are encouraged to evaluate evolving environmental conditions. For example, (Magee et al. 2022) demonstrated that the recent post-2018 environmental regulation over the Pacific Northwest is responsible for 6% of observed monthly hydropower generation being infeasible anymore in an average water year. Simulations of hydropower operations with a water management model and updated operations are needed to update the dataset as performed for the WECC ADS 2032 hydropower dataset (Voisin et al. 2022). In future work, the representation is simple enough that it could inform week-ahead and seasonal bulk power system simulations in a computational and cost-effective manner with a hydrologic data feed, regular updates of hydropower modes of operations, and understanding of planned and forced outages. More details about this summary and limitations can be found in Voisin et al. (2023).

3 Combined Grid and River Basin Operations Modeling

This section describes NREL's approach to addressing these challenges: the Framework for the Linked Analysis of Streamflow and Hydropower (FLASH). It shares some commonalities with the work presented in the last section in that it, too, relies on leveraging the capabilities of river basin operations models for improving hydropower representation. However, it differs in that the representation actively links hydrology information, river basin operations models, and a PCM, with the grid and water models directly connected by a receding horizon[5] algorithm that allows each to update the other as new grid and river information is received. This combination provides stakeholders with increased situational awareness of hydropower plant capabilities, both in terms of operations and reliability.[6] FLASH is independent of timescale[7] and can be used for retrospective, operational, and forward-looking studies.

3.1 Approach

FLASH represents scheduled hydropower operations and forecasted conditions while providing opportunities to reschedule resources using its receding horizon co-simulation design as new information becomes available. This setup avoids the complexity of endogenous representation of river basin operations in the grid model yet allows the co-simulation to dynamically inform the grid model as to hydropower flexibility and firm capacity. Compared with traditional hydropower PCM representations, the FLASH Framework reduces issues associated with how quickly hydrology information deviates from historic norms. For example, precipitation patterns of the last few decades are not particularly representative of today's patterns, and if we were to rely only on historical information, our hydropower fleet representation would likely quickly deviate from actuality when used in a real-time setting. However, by periodically ingesting new information (e.g., real-time California Nevada River Forecast Center [CNRFC] streamflows and forecasts as well as monthly or seasonal reservoir operating curves), the water model and hydropower availability metrics are continually updated. This self-correcting modeling approach provides a much-improved situational awareness of the hydropower fleet's actual capability. Also beneficial is that this coupling allows each model to do what it does best. For example, the river basin model can be configured to respect water rights and environmental constraint information, something that would be difficult if not impossible to represent in a PCM alone. The framework, how the models interact, and how publicly available water information can be used to build grid model hydropower representations are described later in this chapter.

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[5] Receding horizon control (RHC), also known as model predictive control (MPC), is a general-purpose control scheme that involves repeatedly solving a constrained optimization problem, using predictions of future costs, disturbances, and constraints over a moving time horizon to choose the control action. See Mattingly J., Wang Y, and Boyd S. Receding Horizon Control: Automatic Generation of High-Speed Solvers. IEEE Control Systems Magazine, 31(3):52–65, June 2011 for more information.

[6] FLASH provides users with estimates of reservoir pool elevations and impoundment levels which helps grid operators understand each plant's capabilities throughout the year (e.g., maximum power and energy available)

[7] FLASH's resolution and time horizons are prescribed by data availability. As an example, in much of the current work we used the California and Nevada River Forecast Center's historical 15-day forecasts which had a mix of one- and there-hour resolution. In an operational setting, the historical forecasts would be replaced by live forecasts.

The FLASH framework leverages existing technology to provide a robust simulation environment based on readily available models[8], resource information, and forecasts. Specifically, it couples NREL's Scalable Integrated Infrastructure Planning (SIIP) grid operations model (grid model) with Colorado State University's (CSU's) MODSIM river basin operations model (water model) using a receding horizon/model-predictive-based approach that exchanges critical information between the grid and river basin models at regular intervals to help ensure accurate hydropower representation (each model periodically updates the other).

A typical exchange between the grid and water models in FLASH is:

- **Step 1—Grid model execution:** The grid model passes water use information to the water model regarding how much water (energy) was used at each of the hydro facilities during the previous time step and how much water (generation) is being requested for the next time step.
- **Step 2—Water model execution:** The water model simulates the river basin operations to determine the feasibility of the hydropower generation schedules requested in Step 1 and updates the hydropower availability numbers at each of the reservoirs, considering river basin system limitations, and water availability and usage data.
- **Step 3—Update:** The water model provides the grid model with updated generation limits for next simulation increment based on the following update rules:
    - **Over-generation adjustment:** If the requested amount of generation at a given hydropower plant exceeds the plant's capabilities (i.e., it is infeasible), the value is adjusted to reflect the maximum generation that is available.
    - **Feasible generation:** If the requested amount of generation at the plant is feasible, the number is returned unaltered.
- **Step 4—Increment:** The simulation increments forward one time step, and the cycle is repeated.

For the study area, the grid model is based on WECC's Anchor Data Set (WECC ADS) combined with NREL-developed wind and solar forecasts for the 2009 calendar year, providing a well-vetted platform for the grid work. The grid model uses a subset of the WECC ADS data covering the Northern California region and is described in more detail in Appendix A. Despite using data that represents electrical components in existence, the isolation of the data used in this case study from the entire WECC ADS data set invalidates the representation of the grid conditions of Northern California, which are heavily dependent on neighboring regions in the Western United States. The case study test system is only appropriate for representing

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[8] FLASH uses lightweight water models that can be readily constructed from publicly available information using RTI's WaterAlloc tool. Although the analogy is not exact, these models can be thought of as first-order models that are continually updated to ensure accurate representations of real-time river basin operating conditions.

interactions between resources within the test region, such as this case study topic—interactions between river basin systems and grid systems operating under consistent weather patterns.

To couple with the regional power system developed for this case study, the simulated water system represents hydrologic and operational water movement in five river basin systems located within California: Stanislaus, Trinity, Sacramento, Tuolumne, and the Upper American. The test system water model data is derived from the CNRFC's streamflow data and hydrologic forecasts. The water system data uses the hydrologic conditions of 2009 and the historical operations as captured in the flows and reservoir storage. The models were set up with a flexibility of 15% to deviate from the historical storage operations. The approach developed to build the water management models is described in detail in Appendix B and assumes that there are no readily available models and data to simulate detailed operations in the river basin and support the SIIP hydropower modeling. By choosing well-established models (SIIP and MODSIM) and forecasts (CNRFC), we mitigate much of the risk associated with software development and data collection and validation.

3.2 Grid and Water Model Coupling

For the case study, a set of independent river basin models were developed to represent northern California generation facilities. The individual water model reservoir and generation facilities are coupled with corresponding generation facilities in the grid model to provide refined hydropower availability information at the facilities simulated in each basin. Although not all the river basin features in these models are explicitly represented in the grid model, their operation and interaction with other facilities are included in the refined hydropower availability information provided by the water models. The case study included five river basin models. Each model consists of a network of interconnected nodes that allow the representation of the flow of water throughout the basin. The networks are a simplified representation of each river basin system using points of interest such as flow gauges, forecast points, reservoirs, and energy generation plants. The network representations for each river basin included in the case study are detailed in Appendix C.

The networks were developed with a comprehensive representation of the points of interest from the readily available data[9]. Appendix C includes tables with the interest points included in the represented river basin models. The combination of measured flow, system conditions (reservoir storage), and forecasted natural flow allows the calibration process to estimate and distribute spatially the available water and estimate water requirements between points of interest (i.e., measured flow points).

Available data at each interest point is loaded into the network model and used in a semi-automated process to simulate representative operations in the river basin and energy generated with the combination of available physical characteristics (i.e., storage capacities and dam height) and simulated flows. (Triana, Watson, and Micheletty) presents more detailed information on the water system simulation approach and the semi-automated calibration procedure developed in the WaterALLOC tool. The calibrated models allow estimation of

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[9] Available data sources include: USGS flow stations and reservoirs, the national inventory of dams, Western interconnection hydropower facilities, the California reservoir data exchange center and the CNRFC forecast points.

maximum hydropower available at each point with the combined system operations, accounting for water use/requirements and a modeler-defined flexibility band for reservoir operations deviating from operating guide curves. The hydropower availability estimate considers the detailed spatial and temporal location of the water and the reservoir operations cascading effects to produce accurate hydropower production forecasts suitable to constrain hydropower operations in the grid model.

While there were several simplifications made, a key assumption had to do with how water was treated within the day. The available water model data only supported models at the daily resolution, whereas day-ahead grid models (i.e., unit commitment models) run at hourly timescales. For the current work, daily water limits were used along with water model-passed maximum hourly limits. Within the day, the grid model was allowed to shift hydropower usage as needed within the water model-provided constraints (hourly maximum and minimum generation values).

3.3 Experimental Design and FLASH Configuration

To explore the effects of different hydropower availability data resolutions on PCM results, we set up a production cost simulation using the open-source packages PowerSystems.jl (Lara et al.) and PowerSimualtions.jl (Lara et al.), which were developed under NREL's SIIP initiative (SEAC).

The PCM configuration used for this study establishes a series of unit commitments/economic dispatches with a specified horizon and interval where the horizon defines the number of periods represented by each problem and the interval describes the time advance between each problem. For example, a typical day-ahead market simulation is configured with a 48-hour horizon and a 24-hour interval so that each problem represents 48 hours of operation and each problem starts at midnight each day. The unit conditions (status, duration on/off, and generation point) of each problem are established by the results of previous problems in the sequence. The first problem in the sequence is initialized with relaxed conditions (all units online at maximum generation, infinite duration).

The FLASH co-simulation adds a MODSIM simulation step of each river basin after each PCM problem step. The horizon of MODSIM simulation equals to the sum of PCM horizon and PCM interval, which is effectively the MODSIM simulation period. The interval of MODSIM simulation is the same as that of PCM, which defines the times that MODSIM is restarted with the simulated system conditions to estimate hydropower availability for the next PCM problem. Note that the time step used by MODSIM to simulate the operations in the river basin can be different than the interval. The FLASH setup is designed such that each new river basin model can use its own compute node (FLASH is designed to leverage parallel computing) and the results of hydropower availability in each basin are combined to solve the PCM problem. Hydro generation results from the PCM problem step are passed to MODSIM, where MODSIM will try to meet the PCM-requested generation for the interval period. In some cases, the requested generation could be infeasible due to physical or administrative constraints, which results in energy generation infeasibility. The simulated feasible system state is used in MODSIM to provide the available hydropower generation for the remaining horizon, which will serve as the upper bound for the PCM simulation in the next step. The co-simulation then advances by the interval period and repeats the process until all steps are completed. For the very first PCM problem, we obtained the initialized hydropower availability by performing a standalone MODSIM run, which simulated the river basin operations without trying to meet an energy target.

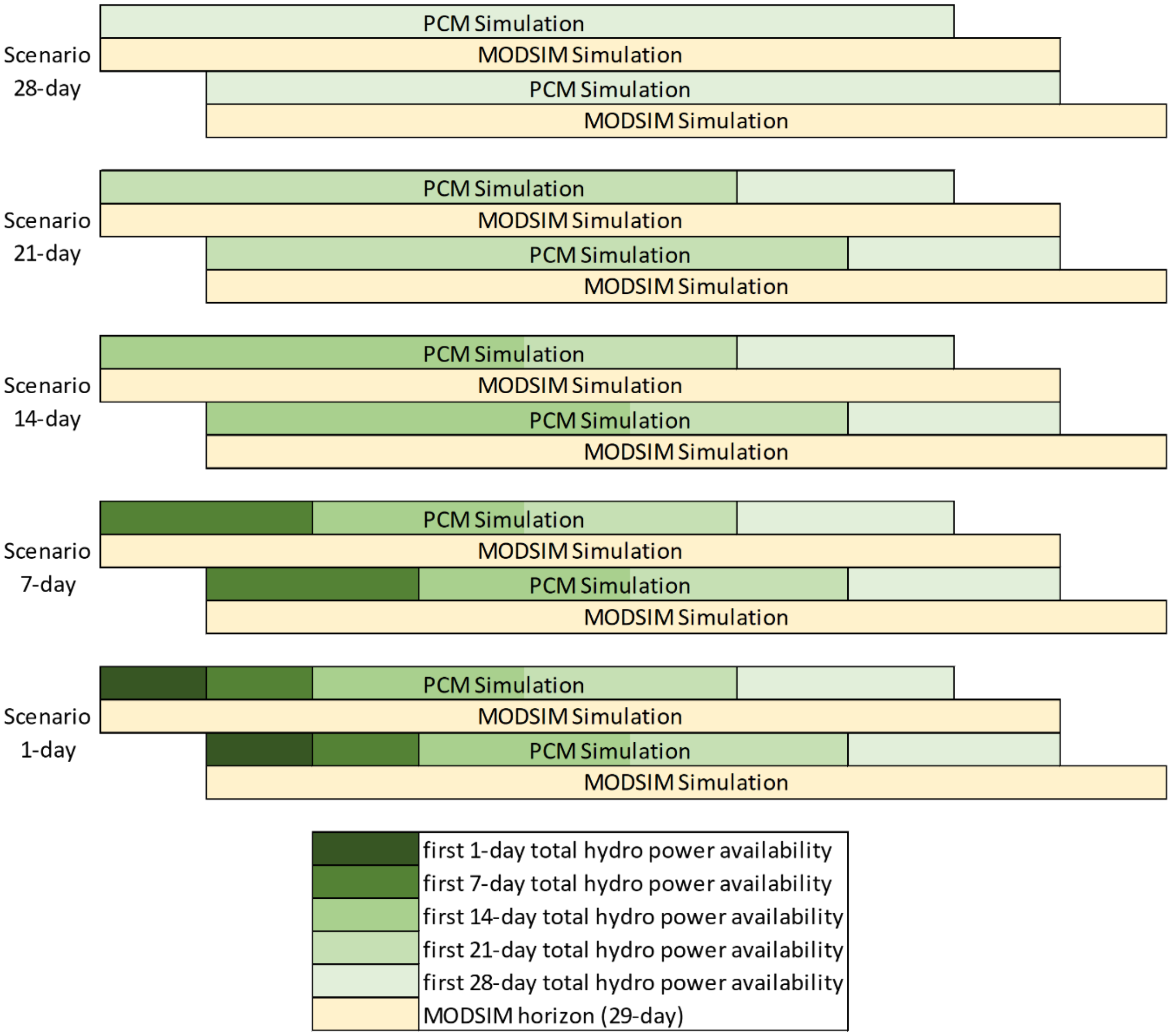

Figure 3. PCM-MODSIM co-simulation setup

Different SIIP-MODSIM co-simulation scenarios were set up with a different resolution of the hydropower availability to assess the effects of various available data resolutions of hydropower. To ensure comparability across scenarios, we used the same horizon and interval in all scenarios. Specifically, simulation horizons were set to be 28 days, which corresponded to the coarsest resolution in the scenarios we simulated, and intervals were set to be 1 day, which was the highest resolution in our simulation scenarios. This setup guaranteed that in every step of the simulation, all scenarios had the same look-ahead window. The difference between each scenario lay in the level of additional hydropower availability information. Assuming we had five scenarios with different resolutions (Scenario 28-day, 21-day, 14-day, 7-day, and 1-day), Figure 3 illustrates the simulation setups for these scenarios.

Take Scenario 28-day, for example. This scenario corresponds to the circumstance where in each step of the PCM, the optimization problem only knows the total of the hydropower available of each reservoir over the next 28-day block and uses this information as a budget to dispatch hydropower to achieve the lowest production cost based on the load schedule for the next 28 days. This 28-day total hydropower "budget" constraint is illustrated by the lightest green color in Figure 3. In this case, MODSIM runs a daily time step for 29 days (28-day horizon + 1-day interval) and the sum of the energy simulated in each reservoir over the 28 days is used as the budget for the PCM problem. For the estimate of hydropower available, the MODSIM run is set up to estimate sequentially the maximum hydropower it is possible to generate over the horizon. For scenarios with higher resolution (i.e., shorter periods of hydropower availability), we impose extra constraints to reflect the additional hydropower budget information (represented by darker green color in Figure 3). For example, Scenario 21-day is the second-coarsest resolution scenario in this case. In addition to the 28-day total hydropower availability constraint, we also impose a budget constraint restricting the first 21-day total hydropower availability. A similar construct applies to other scenarios (14-day, 7-day, and 1-day). Scenario 14-day will have budget constraints for the first 14 days, 21 days, and 28 days. Scenario 7-day will have budget constraints for the first 7 days, 14 days, 21 days, and 28 days. And Scenario 1-day will have budget constraints for the first 1 day, 7 days, 14 days, 21 days, and 28 days. These "nested" constraints reflect the fact that higher resolution scenarios have more realistic hydropower availability information, while also not overly restricting hydropower dispatch as higher resolution scenarios always have the information available in lower resolution scenarios.

To illustrate this point, compare scenario (A) total hydropower availability for the 28-day period to (B) total hydropower availability for each of the two 14-day periods. If we assume the net load is higher in the second half of the 28-day window, Scenario A will shift hydropower to the second half of the month to lower total production cost, but Scenario B will not be able to do that because of the hydro budget constraints imposed on the second 2-week period. As a comparison, our proposed nested budget constraint only applies an additional upper bound on the first 14-day period (in addition to the 28-day total budget), which will allow for shifted hydro dispatch from the first 14-day window to the second if that helps lower total production cost. On the other hand, if the net load is higher in the first half of the month, Scenario A will try to shift hydropower from the second two-week period to the first, but that hydropower is not available yet. By limiting the total hydropower availability for the first 14-day window, nested budget constraints help find a more realistic dispatch solution.

We ran 28 scenarios with an incremental resolution by a day (Scenario 1-day, 2-day, ..., 28-day). This means that for Scenario n-day, we impose hydropower budget constraints for the first n days, n+1 days, ..., 28 days. For simplicity, each scenario was run using economic dispatch formulation for thermal units; that is, we do not include unit commitment constraints in the PCM simulation. All simulations started at the beginning of the year ("2009-01-01T00:00:00") and were run for 9 months. Simulation results for selected months as well as the total simulation period are reported below.

3.4 Results

The economic dispatch and water system results are shown below.

3.4.1 Economic Dispatch Results

One of the key metrics in our evaluation is hydro operation infeasibility. Feasibility error is calculated as the positive difference between PCM hydro dispatch and MODSIM-allowed hydro releases. This metric captures the scheduled hydropower production that has been identified as infeasible by MODSIM and is evaluated daily for each reservoir.

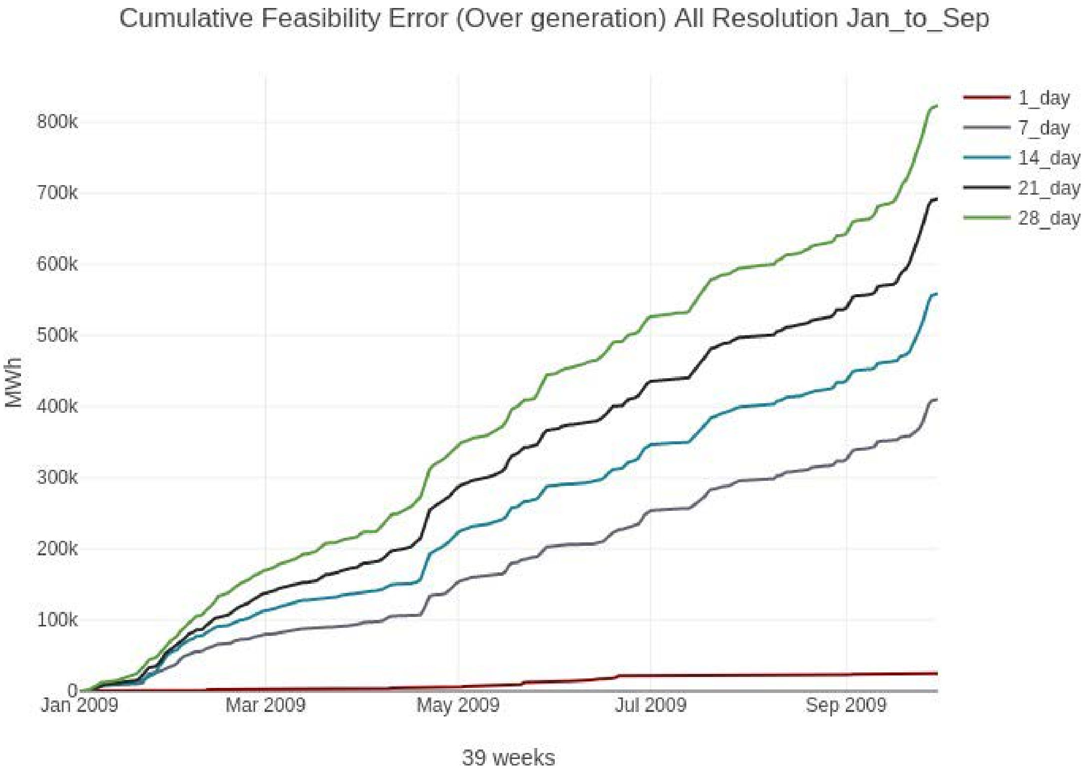

Figure 4. Cumulative feasibility error (January to September)

Table 1 summarizes the total feasibility errors by basins for Scenarios 1-day, 7-day, 14-day, 21-day, and 28-day, for period January to September. Figure 4 shows the cumulative total feasibility error for the same period.

Table 1. Cumulative Feasibility Error (PCM Overgeneration Than MODSIM Release) in MWh (January to September)

	Stanislaus	Trinity and Sacramento	Tuolumne	Upper American	Total	Approx. Error
1 day	95	8,066	11,031	5,602	24,794	0.5%
7 day	89,059	81,624	30,220	209,640	410,543	6.7%
14 day	132,242	123,812	30,267	272,567	558,887	9.1%
21 day	174,778	162,288	37,536	317,809	692,441	11.3%
28 day	200,840	208,798	42,925	371,075	823,638	13.5%

As can be seen from the table and figure, higher resolution information of hydropower availability leads to lower feasibility errors and more reliable hydro and power system operations. To put these numbers into perspective, the table also shows how large these feasibility errors are as a percentage of the total hydropower generation in the region. With commonly used methods (28-day hydropower limits), errors are approximately 13.5%. Even with 7-day limits, errors approach 7% for the 9-month study period. Although outside the scope of this study, it seems likely that such errors would lead to significant reliability concerns, especially because this is a high hydropower area.

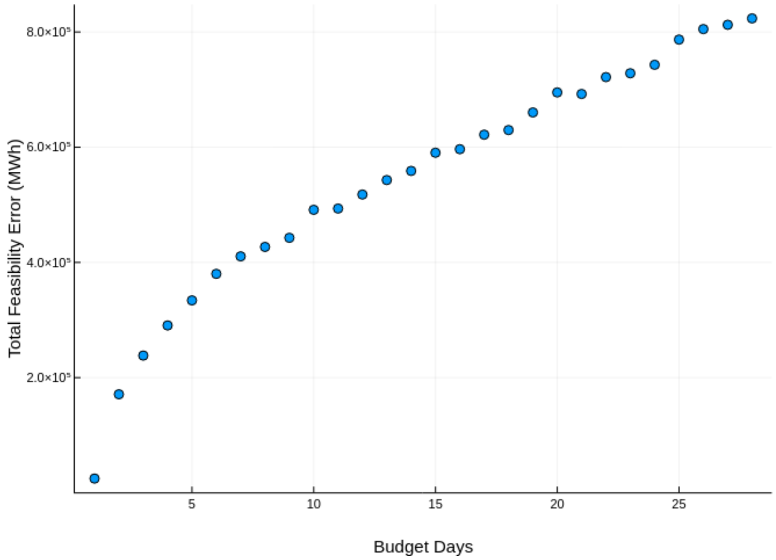

Figure 5. Feasibility error by simulation resolution (January to September)

Figure 5 plots the total feasibility error of the period January to September for the 28 scenarios (decremental resolutions). This figure also shows that total feasibility error generally increases as resolution decreases (moving to the right along the horizontal axis). However, total feasibility error may decrease with decreased resolution, such as from Scenario 20-day to Scenario 21-day. One of the reasons is because of the potential degeneracy of PCM. For example, PCM may achieve the same objective value with slightly different dispatch results: one has hydropower dispatch higher than the other on the first day. When MODSIM evaluates the feasible hydro releases for that day, higher hydropower dispatch may lead to higher feasibility errors. If the scenario with higher hydropower dispatch on the day of evaluation happens to be the scenario with higher resolution, we may see higher feasibility errors under the higher resolution scenarios.

Figure 6 shows the total feasibility error as a percentage of total PCM hydro dispatch by simulation resolution. Again, we generally observe monotonically increasing feasibility error as resolution decreases, from 0.5% in Scenario 1-day to 13.5% in Scenario 28-day.

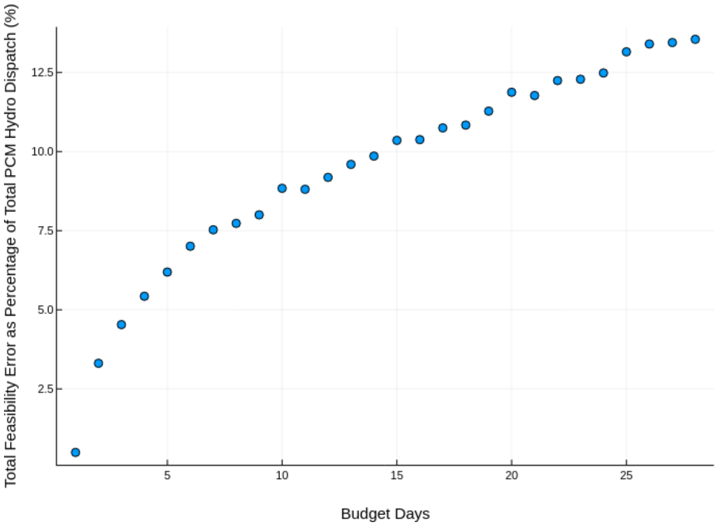

Figure 6. Total feasibility error as percentage of PCM hydro dispatch by simulation resolution (January to September)

Figure 7 shows the marginal feasibility error improvement percentage for each scenario (resolution). Each point in the plot represents the total feasibility error difference between two adjacent resolution scenarios, divided by the total feasibility error of the lower resolution scenario. Because the feasibility evaluation is on a daily basis, it is not surprising that Scenario 1-day sees the largest feasibility improvement.

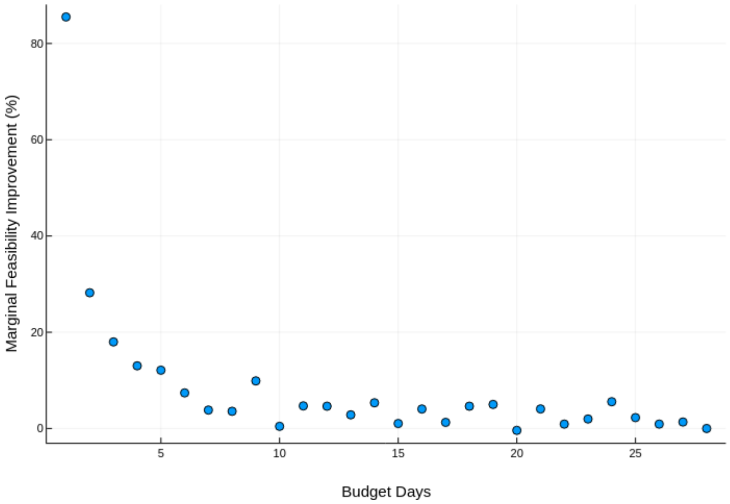

Figure 7. Marginal feasibility error improvement by simulation resolution (January to September)

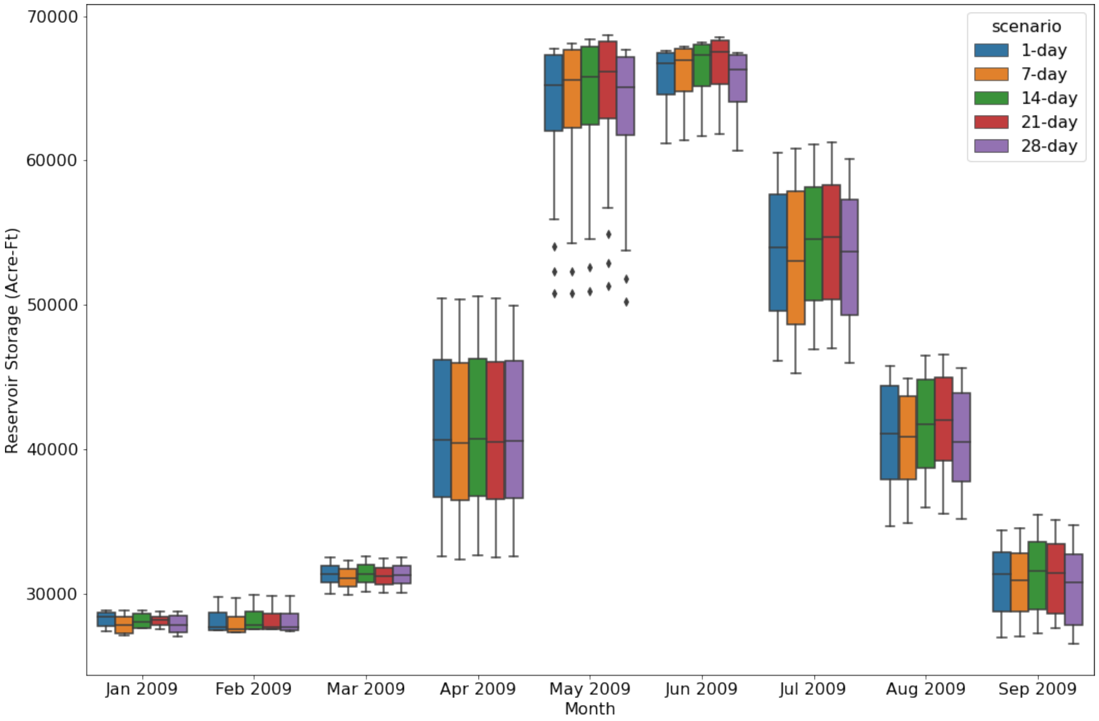

Figure 8. Average daily reservoir storage levels across the Upper American basin per month by scenario resolution

3.4.2 Water System Operations

In this experiment, MODSIM is used to simulate water system operations in the river basins and inform the PCM hydro dispatch model on the total hydropower available based on the scenario resolution. To better understand the feasibility error discussed in the previous section, results from the simulated the water system are explored.

Figure 8 shows a box plot of the daily variability in reservoir storage per month for the Upper American basin, compared across the five different resolution scenarios (i.e., 1-day, 7-day, 14-day, 21-day, and 28-day). This figure displays a few key results. The first is the general shape of the storage throughout the year. As described previously, the shape of the simulated reservoir storage curve is due to the guide curve storage bands that are in place to represent historical operations. The shape of the curves is relatively typical of snowmelt-dominated basins where storage is low in the winter months due to minimal inflows and high in spring where the reservoirs can fill when snowmelt runoff is highest. The summer months typically show a reduction in storage because of water demand use. The figure also shows that daily variability in storage is greatest in the spring months when the inflows are higher and the reservoirs are filling, or in the summer months when the reservoirs are releasing. Lastly, the storage across all scenarios is relatively uniform. The Upper American is shown in this example because the simulated overall storage is significantly higher in this basin, but the overall trends in the data are the same across all basins.

The results in Figure 8 support that the constraints in the MODSIM model are working to model reservoir storage operations. However, in this experiment, the water system model is being used to produce a maximum limit in the PCM scheduling problem. Because the water system is being driven by maximizing hydropower, each simulation appears to reach an "equilibrium" where the maximum allowable power is being produced within the constraints of the model for each scenario. Therefore, the storage is uniform between the different scenarios because the simulations are hitting the lower constraints of the model. Table 2 supports this by showing similar MODSIM simulated (feasible) total energy across all scenarios. Therefore, the feasibility errors are not being driven by differences in the long-term simulated water system operations between the scenarios.

Table 2. Simulated Total Feasible Energy in MWh (January to September)

Limit Period	Stanislaus	Trinity and Sacramento	Tuolumne	Upper American
1 day	18,355	38,511	18,036	66,024
7 day	18,055	38,548	17,834	66,187
14 day	18,411	38,654	17,856	67,000
21 day	18,585	38,869	18,114	67,170
28 day	18,265	38,388	17,604	67,088

The infeasibility that is being shown in the previous section is mainly due to daily misalignment of water release timing. In each scenario, the PCM hydro dispatch model is using a single budget for the available energy over a long period of time but scheduling the hydro production for each day. However, the PCM problem has no additional information about when in the period the power is available from the water simulation. For example, it is possible that only certain days within the 28-day budget can produce power due to the water system state at each time step (i.e., current storage level, available inflows, releases from upstream reservoirs, losses in the system, etc.). So, the daily schedule from the PCM model for the longer resolution scenarios have increasingly less information about timing from the water system, and that tends to accumulate larger infeasibilities over time.

4 Summary

In this report, we presented two methods of improving hydropower representation within PCMs. The two approaches share several similarities. Both leveraged the additional information that can be provided by river basin operations models and demonstrated that it is possible to reduce the hydropower infeasibilities by reducing the timescale of the hydropower limits (e.g., shortening the hydropower limits used in the modeling process from monthly to weekly). Also, each advances the science of production cost modeling in useful and unique ways.

The first provides users with weekly hydropower datasets that should be straightforward to implement in existing PCMs, allowing users to improve their current models with only minor configuration changes on their part. PNNL is further working with PLEXOS to implement the datasets and derived hydrologic and river operations variables. The datasets are also used with the PNNL-North Carolina State University open-source grid operations model (GO) (Akdemir et al. 2023) as part of other HydroWIRES projects exploring the value of flow forecast to power system analytics as well as in the Office of Science funded Integrated Multi Scale Multi Sector Modeling project (https://im3.pnnl.gov/model?model=GOWEST). The datasets provided the opportunity to enhance resource adequacy and reliability studies in the Western United States. Similar datasets are being developed for the other interconnects.

The second provides a prototype for a next-generation PCM. We were able to show that by coupling river basin models that were constructed from commonly available information (e.g., publicly available information from the CNRFC) to grid operations models that we were able to reduce hydropower dispatch feasibility errors from 13.5% to 0.5%. Note that the WaterALLOC tool that we used for building grid-modeling-appropriate river basin models as well as the source code for the receding horizon algorithm that we used for coupling the grid and water models will be released in a future publication.

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Appendix A Regional Test Grid System

For this case study, a subsection of the Western Interconnection (see Figure A-1)was selected to demonstrate the power system scheduling implications of different hydropower generation fleet representations. All unselected Western Interconnection elements were simply deleted from the dataset to separate the selected subnetwork from the remainder of the Western Interconnection. This separation process fundamentally changes the interactions of network components, the resulting power flow, and the relative costs of generators. Therefore, the results produced in this case study are not intended to reflect the behavior of any specific regional power system. Rather, the test network results are only appropriate for drawing general conclusions about power system phenomena.

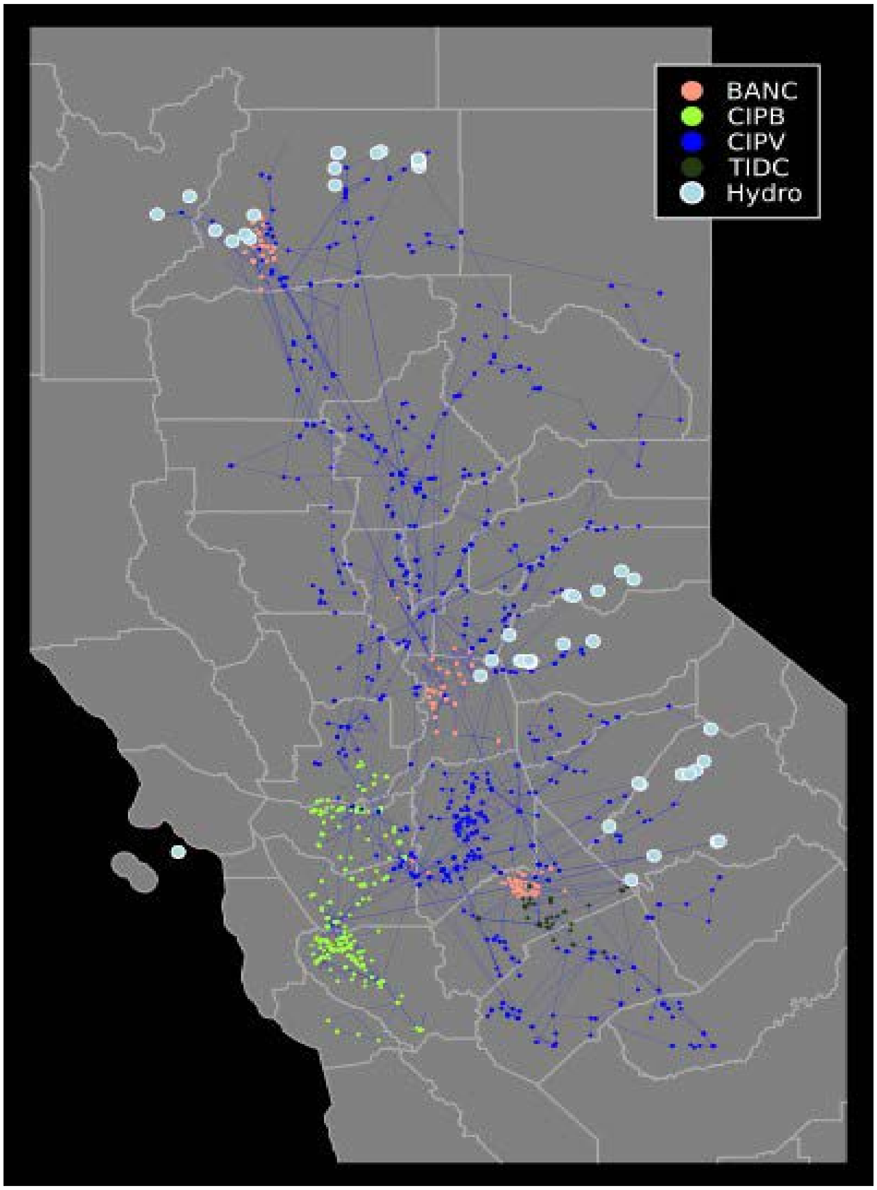

Figure A-1. Regional test system network

Table A-1. Regional Test System Generation Capacity Summary

Category	Prime Mover	Fuel	MW	Count
Hydro	HY		4,705	48
Thermal	CT	Natural gas	2,717	70
Thermal	ST	Agri byproducts	540	29
Thermal	CC	Natural gas	7,270	23
Thermal	CT	Biogas	32	9
Thermal	ST	Nuclear	2,400	2
Thermal	CT	Distillate and fuel oil	124	2
Renewable	PV		4,227	23
Renewable	WT		1,629	36

The regional test system, shown in Figure A-1, has 1,964 buses, 2,187 branches, and 449 generators, with a total installed capacity of 23,648 MW and a total peak load of 14,007 MW. The generation capacity is summarized by generator type in Table A-1.

Weather-dependent resources are all spatially and temporally consistent based on hourly realized weather patterns in 2009. The generation capabilities of wind and solar resources are defined with upper limit values according to data from NREL's WIND toolkit and National Solar Radiation Database data sets. The active power demand time series is defined by the balancing authority represented in the WECC ADS 2028 case and scaled to represent the demand at each remaining node in each balancing region in the test system.

Nominally, hydropower resource generation capabilities are represented with time series derived from historical 2009 operations. However, in this case study, hydropower production capabilities are represented directly by the MODSIM water system management model (see Figure A-1). Specifically, the FLASH co-simulation allows for a bidirectional exchange of information between SIIP and MODSIM to improve the accuracy of hydropower scheduling. In this study, the hydropower facilities are represented in the PCM using a "budget" formulation that restricts the maximum total energy production of each hydropower facility to a budget over a specified time window in addition to the capacity limits of each facility applied in each time period. This allows for the PCM to optimize the timing of hydropower production, but also presents opportunities to create unrealistic and infeasible schedules when budgets are applied over long time windows without more temporal detail on water availability. Budget values are passed from a MODSIM simulation informed by hydropower dispatch results of the previous PCM step.

Aside from hydropower, which is represented with co-simulated hydrologic conditions, the power system representations follow standard PCM practice. Specifically, all generation offers represent the full range of unit capabilities and are offered at the unit operating cost (without strategic behavior). To focus on the effects of enhanced hydropower representations, the results presented here focus only on energy scheduling (active power production) and omit any representations of ancillary services. These results also ignore the effects of the transmission by using a "copper plate" transmission representation.

Appendix B Development of MODSIM-Based Water System Models

MODSIM is a generalized river basin operations model that uses optimization algorithms with sequential approximations to efficiently simulate water allocation and movement. MODSIM, developed by CSU, is publicly available at no cost and is currently maintained by RTI International in collaboration with CSU. MODSIM features out-of-the-box functionality to simulate the elements described in the previous section and is being coupled with NREL's SIIP modeling framework. This section describes the approach to building MODSIM-based water management models that can provide an initial approximation of the river basin operations to support the hydropower representation in SIIP simulations. The MODSIM network comprises "nodes" and "links," which represent components of the hydrologic and water management system. Nodes are characterized as non-storage (i.e., confluences, divergences), storage nodes (i.e., reservoirs), and fully or partially consumptive nodes (i.e., demands and sinks). The nodes are interconnected via links (i.e., stream reaches, canals, pipelines, etc.). The first step is to construct the network topology to represent the physical connectivity of the hydrologic system and water management system. Then, parameterizing the MODSIM objects is required to simulate water allocation and operations in the river basin.

WaterALLOC is a modeling framework developed by RTI International to support efficient modeling, analysis, and management of river basins around the world. WaterALLOC includes a module to support MODSIM-based simulations, including a geo-referenced graphical user interface that allows the user to build MODSIM networks using geospatial data and interact with MODSIM objects in the geo-referenced interface. The benefits of this functionality are that: (1) it offers custom tools that allow for MODSIM network nodes (i.e., inflows, reservoir, and demands) and links to be generated automatically from GIS layers such as the national hydrologic dataset; (2) it provides a tool for manual creation of MODSIM nodes and/or links; and (3) the final MODSIM network is aligned with the geography of the system. In this case study, the use of WaterALLOC allows for a semi-automated approach to developing a MODSIM network that is easily reproducible, using a methodology that is easily transferrable to other locations.

We consider this data-driven approach to be a new contribution to water resources system modeling that is applicable to large-scale systems and scalable while meeting the goal of improving the reality in representation of hydropower availability. By developing tools that automatically utilize and disaggregate available parameters and data, we provide an entirely new philosophy for developing models to support hydropower availability estimation. Typically, water operations modeling consists of converting river and operational water movement characteristics manually into a collection of model features, informed by conducting research into river operations through interviewing water managers directly, reviewing river and reservoir operational manuals, and conducting historical data analysis to understand and write explicit rules to mimic water management operations. Through our semi-automated, data-driven approach, we provide a rich understanding of basin water movement/availability and management more efficiently and quickly than traditional modeling methods.

The approach builds the topology of the models with GIS data that can be compiled from data sets widely available beyond the selected study area. The models implement "calibration structures" that use available measured flows and historical forecast data to allow automation of the model calibration, which are combined with reservoir historical storage for capturing the overarching results of detailed operations without extensive data collection and processing. The calibration process calculates gains and losses that represent operations not explicitly included in the model simulated inflows and outflows by applying water balance between the measured and historical forecast flows throughout the basin. The calibration structures provide the basis for simulating operations that deviate from historical operations for hydropower generation while maintaining the operational constraints/drivers in the historical context. Estimates of naturalized flows in the forecast data sets allow the models to estimate natural contributions to the gains (and losses) and provide the framework to analyze operations with different realizations of natural flows (i.e., different forecasts) while maintaining the historical-based operational drivers. This feature allows evaluating the uncertainty with forecasted inflows in the system response as well as informing SIIP of hydropower generation uncertainty to support decision-making. The initial model generated through this process is a functional representation of the water system for the SIIP co-simulation and could be refined over time based on the availability of water use and operations data. The incremental benefit of the water system models refinement is to be evaluated in future studies.

Appendix C Case Study Water Model Detail

Upper American River Basin

The river network representation for the Upper American River Basin is shown in Figure C-1. Table C-1 shows the energy generation facilities in the Upper American river basin with the corresponding capacity and associated storage capacity.

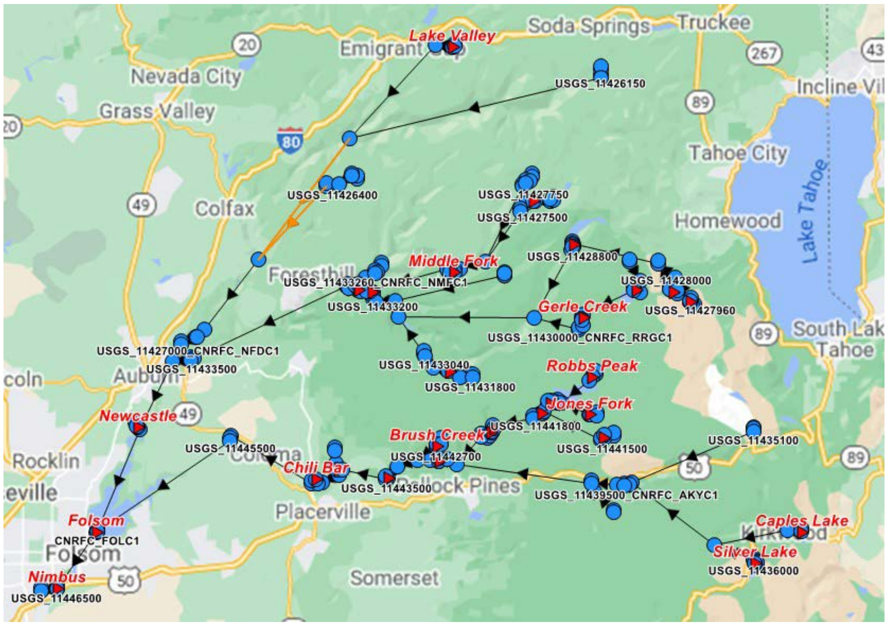

Figure C-1. MODSIM network for the Upper American River basin

Upper Sacramento River Basin and Trinity River Basin Model

Figure C-2 shows the MODSIM network created to simulate the hydropower availability in the Sacramento and Trinity river basins, and the list of facilities and reservoirs for this basin is shown in Table C-3.

Stanislaus River Basin Model

The MODSIM network for the Stanislaus river basin is shown in Figure C-3. The facilities in this river basin are summarized in Table C-5. The calibration points for this basin are listed in Table C-6.

Tuolumne River Basin Model

Table C-1. Regional Test System Generation Capacity Summary for the Upper American River Basin

Name	Max Storage Capacity [AF]	Max Power Capacity [MW]	BANC
Brush Creek	1,350	N/A	
Buck Island	1,070	N/A	
Camino	543	150	Y
Caples Lake	22,338	N/A	
Chili Bar	3,140	7	
El Dorado	0 (RoR)	21	
Folsom	1,002,000	207	Y
French Meadows	134,000	18.5	
Gerle Creek	831	N/A	
Hell Hole	207,000	0.5	
Ice House	43,496	N/A	
Jaybird	0 (RoR)	154	Y
Jones Fork	0 (RoR)	9.5	Y
Junction	3,000	N/A	
Lake Valley	7,964	N/A	
Loon Lake	69,309	77	Y
Mark Edson	20,000	N/A	
Middle Fork	155	123.5	
Newcastle	0 (RoR)	12	
Nimbus	8,800	17	Y
Oxbow	2,780	6	
Ralston	0 (RoR)	89.5	
Robbs Peak	0 (RoR)	24.5	Y
Rock Creek LP	0 (RoR)	113.9	
Rubicon Lake	1,439	N/A	
Silver Lake	8,951	N/A	
Union Valley	266,369	46	Y
White Rock	16,000	235	Y

Notes: Facilities without storage capacities are run-of-river (RoR) generation stations. Facilities without power capacities are non-power storage reservoirs.

Table C-2. Gage and CNRFC Hindcast and Forecast Points Modeled Within the Upper American River Basin

Name	USGS Station Name	Measure Point	Hindcast Point	Forecast Point
CNRFC_FMDC1			Y	Y
CNRFC_FOLC1			Y	Y
CNRFC_HLLC1			Y	Y
CNRFC_ICHC1			Y	Y
CNRFC_LNLC1				Y
CNRFC_RBBC1				Y
CNRFC_RUFC1				Y
CNRFC_UNVC1			Y	Y
USGS_11426150	ONION C NR SODA SPRINGS CA	Y		
USGS_11426200	NF FORBES C NR DUTCH FLAT CA	Y		
USGS_11426400	N SHIRTTAIL C NR DUTCH FLAT CA	Y		
USGS_11427000_CNRFC_NFDC1	NF AMERICAN R A NORTH FORK DAM CA	Y		Y
USGS_11427500	MF AMERICAN R A FRENCH MEADOWS CA	Y		
USGS_11427700	DUNCAN CYN C NR FRENCH MEADOWS CA	Y		
USGS_11427750	DUNCAN CYN C BL DIV DAM NR FRENCH MEADOWS CA	Y		
USGS_11427760_CNRFC_MFPC1	MF AMERICAN R AB MF PH NR FORESTHILL CA	Y		Y
USGS_11427770	MF AMERICAN R BL INTERBAY DAM NR FORESTHILL CA	Y		
USGS_11427960	RUBICON R BL RUBICON LK CA	Y		
USGS_11428000	RUBICON R A RUBICON SPRINGS NR MEEKS BAY CA	Y		
USGS_11428400	L RUBICON R BL BUCK ISLAND DAM CA	Y		

Name	USGS Station Name	Measure Point	Hindcast Point	Forecast Point
USGS_11428800	RUBICON R BL HELL HOLE DAM CA	Y		
USGS_11429500	GERLE C BL LOON LK NR MEEKS BAY CA	Y		
USGS_11430000_CNRFC_RRGC1	SF RUBICON R BL GERLE C NR GEORGETOWN CA	Y		Y
USGS_11431800	PILOT C AB STUMPY MEADOWS RES CA	Y		
USGS_11433040	PILOT C BL MUTTON CANYON NR GEORGETOWN CA	Y		
USGS_11433100	LONG CANYON C NR FRENCH MEADOWS CA	Y		
USGS_11433200	RUBICON R NR FORESTHILL CA	Y		
USGS_11433260_CNRFC_NMFC1	NF OF MF AMERICAN R NR, FORESTHILL CA	Y		Y
USGS_11433300_CNRFC_MFAC1	MF AMERICAN R NR FORESTHILL CA	Y		Y
USGS_11433500	MF AMERICAN R NR AUBURN CA	Y		
USGS_11435100	PYRAMID C A TWIN BRIDGES CA	Y		
USGS_11436000	SILVER LK OUTLET NR KIRKWOOD CA	Y		
USGS_11439500_CNRFC_AKYC1	SF AMERICAN R NR KYBURZ (RIVER ONLY) CA	Y		Y
USGS_11440000	ALDER C NR WHITEHALL TOTAL FLOW CA	Y		
USGS_11441002	UNION VALLEY PH NR PACIFIC CA	Y		
USGS_11441500	SF SILVER C NR ICE HOUSE CA	Y		
USGS_11441800	SILVER C BL JUNCTION DAM NR POLLOCK PINES CA	Y		

Name	USGS Station Name	Measure Point	Hindcast Point	Forecast Point
USGS_11441900_CNRFC_SVCC1	SILVER C BL CAMINO DIV DAM CA	Y		Y
USGS_11442500	SF AMERICAN R BL SILVER C NR POLLOCK PINES CA	Y		
USGS_11442700	BRUSH C BL BRUSH CREEK DAM NR POLLOCK PINES CA	Y		
USGS_11443500	SF AMERICAN R NR CAMINO CA	Y		
USGS_11444201	ROCK C NR PLACERVILLE CA	Y		
USGS_11444500_CNRFC_CBAC1	SF AMERICAN R NR PLACERVILLE CA	Y		Y
USGS_11445500	SF AMERICAN R NR LOTUS CA	Y		
USGS_11446500	AMERICAN R A FAIR OAKS CA	Y		

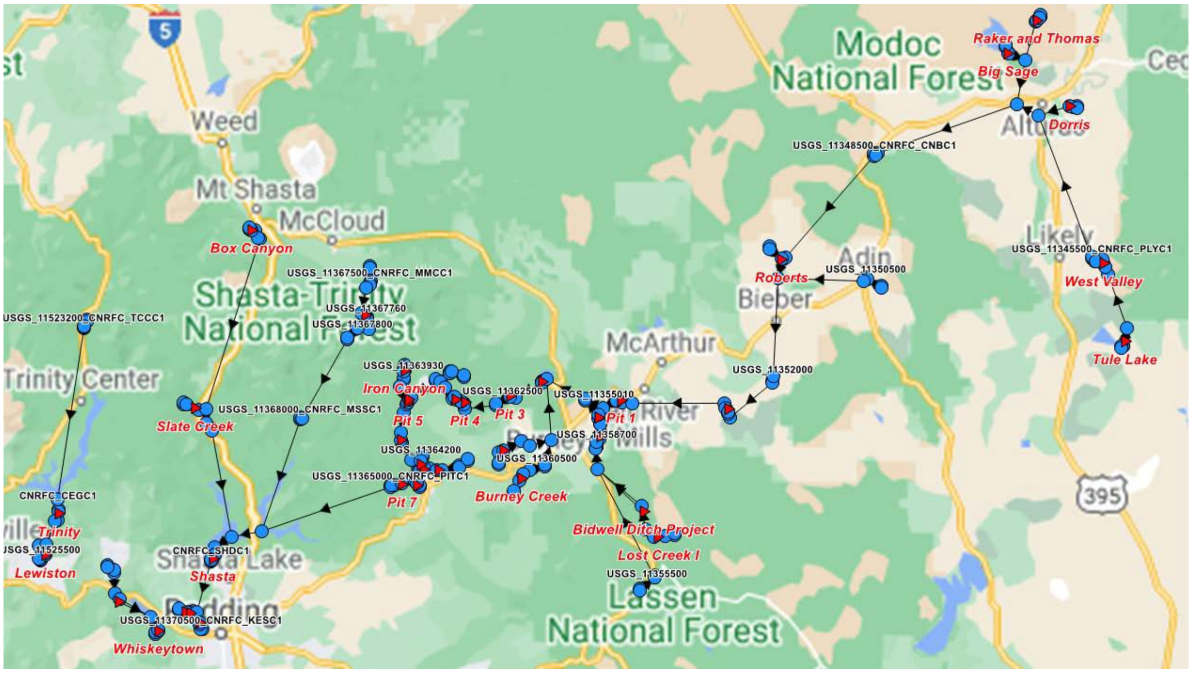

Figure C-2. MODSIM network for the Upper Sacramento River basin and Trinity River basin

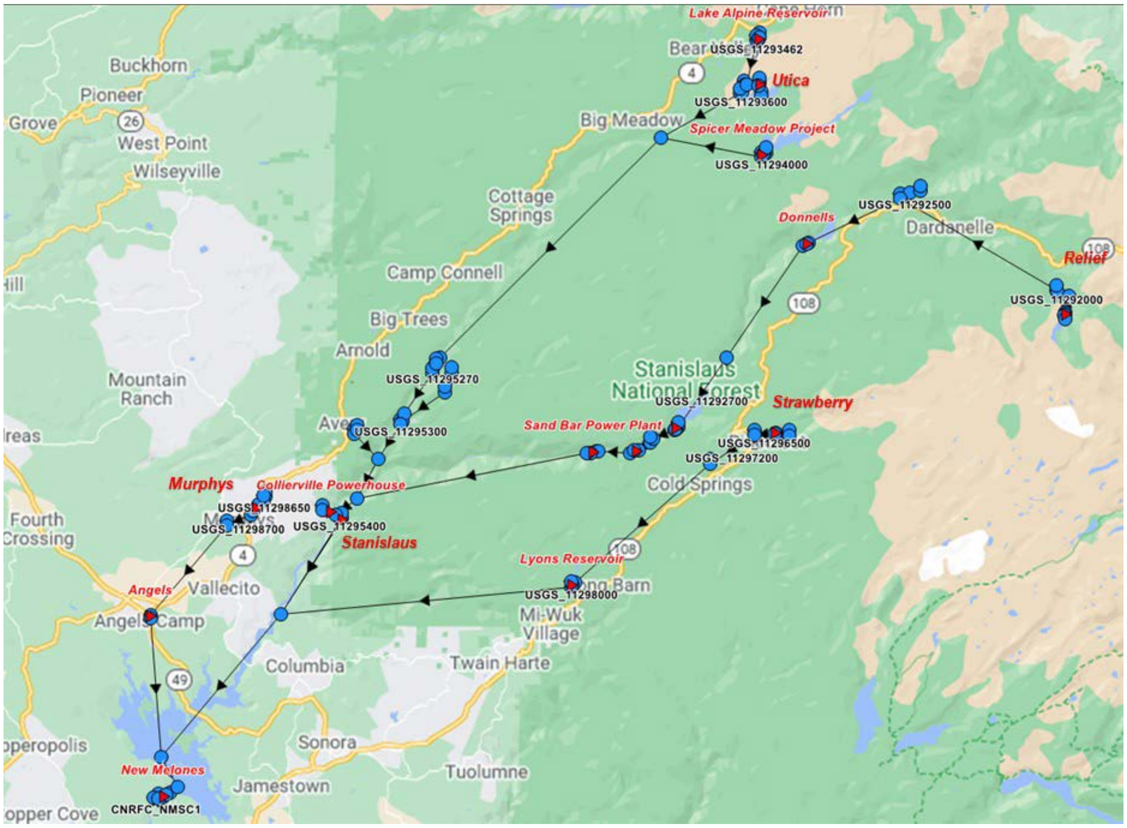

Figure C-3. MODSIM network for the Stanislaus River basin

Table C-3. Facilities/Reservoirs Modeled Within the Upper Sacramento River Basin and Trinity River Basin

Name	Max Storage Capacity [AF]	Max Power Capacity [MW]	BANC
Bidwell Ditch Project	0 (RoR)	1.8	
Big Sage	77,000	N/A	
Box Canyon	26,000	84.8	
Burney Creek	0 (RoR)	3	
Cove Hydroelectric	0 (RoR)	5	
Dorris	20,690	N/A	
Hat Creek 1	0 (RoR)	8	
Hat Creek 2	629	8	
Hatchet Creek Project	0 (RoR)	6.8	
Haynes	5,870	N/A	
Iron Canyon	24,241	N/A	
James B Black	0 (RoR)	169	
Judge F Carr	0 (RoR)	172	Y
Keswick	25,132	75	Y
Lake Britton	41,907	N/A	
Lake McCloud	35,234	N/A	
Lewiston	14,660	0	
Lost Creek I	0 (RoR)	49	
Montgomery Creek Hydro	0 (RoR)	2.6	
Muck Valley Hydroelectric	0 (RoR)	32.5	
Nelson Creek	0 (RoR)	1.2	
Pit 1	0 (RoR)	64	
Pit 3	0 (RoR)	80	
Pit 4	0 (RoR)	103.4	
Pit 5	0 (RoR)	164	
Pit 6	15,900	79	
Pit 7	34,100	110.3	
Raker and Thomas	6,530	N/A	
Roaring Creek Water Power	0 (RoR)	2	Y
Roberts	5,500	N/A	
Shasta	4,661,860	710	Y
Slate Creek	0 (RoR)	3.4	
Spring Creek	0 (RoR)	192	Y
Spring Creek Reservoir	7,286	N/A	
Trinity	2,760,870	140	Y
Tule Lake	39,500	N/A	
West Valley	23,000	N/A	
Whiskeytown	276,117	5	

Table C-4. Gage and CNRFC Hindcast and Forecast Points Modeled Within the Upper Sacramento River and Trinity River basins.

Name	USGS Station Name	Measure Point	Hindcast Point	Forecast Point
CNRFC_LEWC1				
CNRFC_CEGC1			Y	Y
CNRFC_SHDC1			Y	Y
CNRFC_WHSC1				Y
USGS_11341400	SACRAMENTO R NR MT SHASTA CA			
USGS_11342000_-	SACRAMENTO R A DELTA CA	Y		Y
CNRFC_DLTC1				
USGS_11345500_-	SF PIT R NR LIKELY CA	Y	Y	
CNRFC_PLYC1				
USGS_11348500_-	PIT R NR CANBY CA	Y	Y	
CNRFC_CNBC1				
USGS_11350500	ASH C A ADIN CA	Y		
USGS_11352000	PIT R NR BIEBER CA	Y		
USGS_11355010	PIT R BL PIT NO 1 PH NR FALL RIVER MILLS CA	Y		
USGS_11355500	HAT C NR HAT CREEK CA	Y		
USGS_11358700	HAT C BL HAT NO 1 DIV DAM NR BURNEY CA	Y		
USGS_11360500	BURNEY C A PARK AVENUE NR BURNEY CA	Y		
USGS_11362500	PIT R BL PIT NO 4 DAM CA	Y		
USGS_11362950	EF NELSON C BL DIV TO NELSON C PP	Y		
	NR BIG BEND CA			
USGS_11363000	PIT R A BIG BEND CA	Y		
USGS_11363930	IRON CANYON C BL IRON CANYON	Y		
	DAM NR BIG BEND CA			
USGS_11364200	ROARING C BLW DIV TO ROARING C PP	Y		
	NR MONTGMRY C CA			

Name	USGS Station Name	Measure Point	Hindcast Point	Forecast Point
USGS_11364300	HATCHET C BL DIV TO HATCHET C PP	Y		
	NR MNTGMRY C CA			
USGS_11365000_-	PIT R NR MONTGOMERY CREEK CA	Y	Y	
CNRFC_PITC1				
USGS_11367500_-	MCCLOUD R NR MCCLOUD CA	Y	Y	
CNRFC_MMCC1				
USGS_11367760	MCCLOUD R BL MCCLOUD DAM NR	Y		
	MCCLOUD CA			
USGS_11367800	MCCLOUD R A AH-DI-NA NR MCCLOUD CA	Y		
USGS_11368000_-	MCCLOUD R AB SHASTA LK CA	Y	Y	
CNRFC_MSSC1				
USGS_11370500_-	SACRAMENTO R A KESWICK CA	Y		
CNRFC_KESC1				
USGS_11371000	CLEAR C A FRENCH GULCH CA	Y		
USGS_11523200_-	TRINITY R AB COFFEE C NR TRINITY	Y	Y	
CNRFC_TCCC1	CTR CA			
USGS_11525500	TRINITY R A LEWISTON CA	Y		

Notes: Hindcast and forecast data are provided by the CNRFC. Hindcasts are available for a subset of forecast points for 1985–2010, and archived operational forecasts are available for all forecast points for 2013–present. The river basin model includes hindcast points for the 2009 demo year.

Table C-5. Facilities/Reservoirs Modeled Within the Stanislaus River Basin

Name	Max Storage Capacity [AF]	Max Power Capacity [MW]	BANC
Angels	0 (RoR)	1.4	
Beardsley	97,800	11	
Collierville Powerhouse	0 (RoR)	243	
Donnells	65,000	72	
Lake Alpine Reservoir	4,300	N/A	
Lyons Reservoir	6,228	N/A	
Murphys	0 (RoR)	3.6	
New Melones	2,870,000	333.4	Y
Relief	15,600	N/A	
Sand Bar Power Plant	0 (RoR)	15	
Spicer Meadow Project	193,000	6.6	
Spring Gap	0 (RoR)	7	
Stanislaus	320	91	
Strawberry	19,000	N/A	
Utica Reservoir	2,500	N/A	

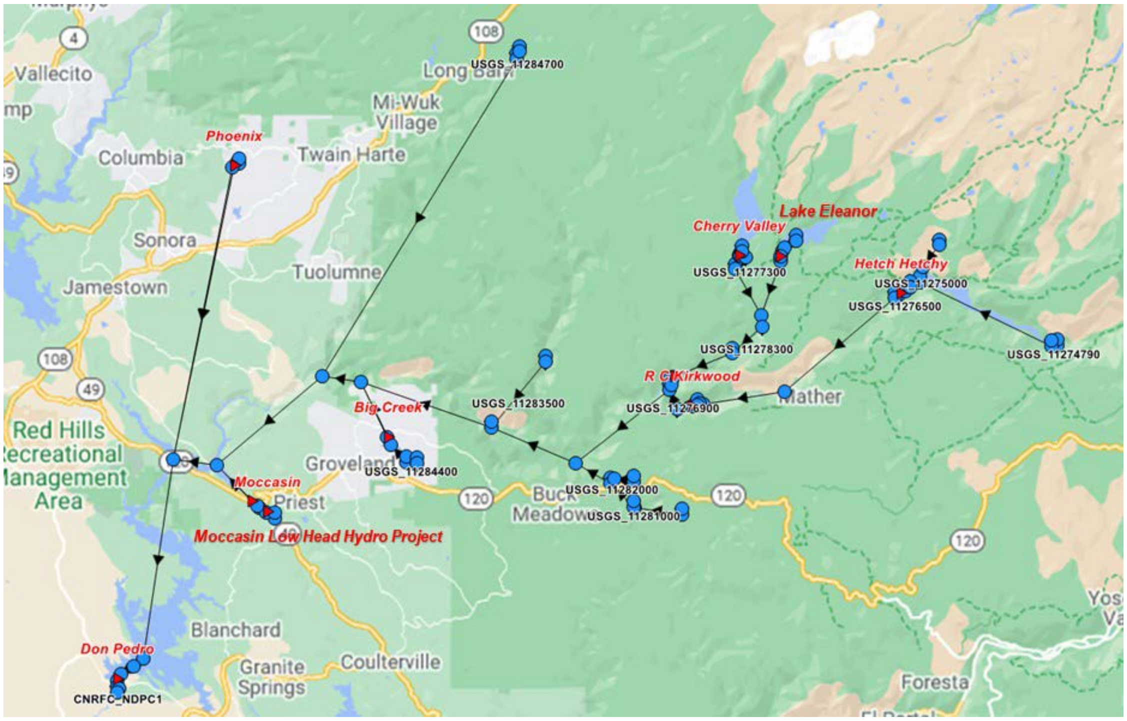

Figure C-4. MODSIM network for the Tuolumne River basin

Table C-6. Gage and CNRFC Hindcast and Forecast Points Modeled Within the Stanislaus River Basin

Name	USGS Station Name	Measure Point	Hindcast Point	Forecast Point
USGS_11299200	NEW MELONES PP BL NEW MELONES DAM NR SONORA CA	Y		
USGS_11298700	ANGELS C BL UTICA D DIV DAM NR MURPHYS CA	Y		
USGS_11298650	ANGELS C BL MURPHYS AFTERBAY NR MURPHYS CA	Y		
USGS_11298000	SF STANISLAUS R NR LONG BARN CA	Y		
USGS_11297200	SF STANISLAUS R NR STRAWBERRY CA	Y		
USGS_11296500	SF STANISLAUS R A STRAWBERRY CA	Y		
USGS_11295400	STANISLAUS R NR HATHAWAY PINES CA	Y		
USGS_11295340	MILL C BL HUNTER RES A HATHAWAY PINES CA	Y		
USGS_11295300	NF STANISLAUS R BL BEAVER C NR HATHAWAY PINES CA	Y		
USGS_11295270	NF STANISLAUS R BL MCKAYS POINT DAM NR AVERY CA	Y		
USGS_11295230	BEAVER CR BEL DIV DAM NR ARNOLD CA	Y		
USGS_11294500_-CNRFC_AVYC1	NF STANISLAUS R NR AVERY CA	Y		Y
USGS_11294000	HIGHLAND C BL SPICER MEADOWS RES CA	Y		

Name	USGS Station Name	Measure Point	Hindcast Point	Forecast Point
USGS_11293600	NF STANISLAUS R BL DIV DAM NR BIG MDW CA	Y		
USGS_11293500	NF STANISLAUS R BL SILVER C CA	Y		
USGS_11293462	SILVER C BL LK ALPINE NR BEAR VALLEY CA	Y		
USGS_11293372	NF STANISLAUS R BL UTICA RES NR BEAR VALLEY CA	Y		
USGS_11292900	MF STANISLAUS R BL BEARDSLEY DAM CA	Y		
USGS_11292700	MF STANISLAUS R A HELLS HALF ACRE BRIDGE CA	Y		
USGS_11292500	CLARK FORK STANISLAUS R NR DARDANELLE CA	Y		
USGS_11292000	MF STANISLAUS R AT KENNEDY MDWS NR DARDANELLE CA	Y		
CNRFC_NSWC1				Y
CNRFC_NMSC1			Y	Y
CNRFC_NDVC1				Y

Notes: Hindcast and forecast data are provided by the CNRFC. Hindcasts are available for a subset of forecast points for 1985–2010, and archived operational forecasts are available for all forecast points for 2013–present. The river basin model includes hindcast points for the 2009 demo year.

Table C-7. Facilities/Reservoirs Modeled Within the Tuolumne River Basin

Name	Max Storage Capacity [AF]	Max Power Capacity [MW]	BANC
Big Creek	7,650	N/A	
Cherry Valley	274,433	N/A	
Dion R Holm	0 (RoR)	156.8	
Don Pedro	2,300,000	203.2	Y
Hetch Hetchy	361,944	N/A	
Lake Eleanor	28,600	N/A	
Moccasin	0 (RoR)	115	
Moccasin Low Head Hydro Project	554	115	
Phoenix	0 (RoR)	1.9	
R C Kirkwood	0 (RoR)	129.4	

Table C-8. Gage and CNRFC Hindcast and Forecast Points Modeled Within the Tuolumne River Basin

Name	USGS Station Name	Measure Point	Hindcast Point	Forecast Point
CNRFC_CHVC1				Y
CNRFC_HETC1			Y	Y
CNRFC_LNRC1				Y
CNRFC_NDPC1			Y	Y
USGS_11274790	TUOLUMNE R A GRAND CYN OF TUOLUMNE AB HETCH HETCHY	Y		
USGS_11275000	FALLS C NR HETCH HETCHY CA	Y		
USGS_11276500	TUOLUMNE R NR HETCH HETCHY CA	Y		
USGS_11276600	TUOLUMNE R AB EARLY INTAKE NR MATHER CA	Y		
USGS_11276900	TUOLUMNE R BL EARLY INTAKE NR MATHER CA	Y		
USGS_11277300	CHERRY C BL VALLEY DAM NR HETCH HETCHY CA	Y		
USGS_11278000	ELEANOR C NR HETCH HETCHY CA	Y		
USGS_11278300	CHERRY C NR EARLY INTAKE CA	Y		
USGS_11278400	CHERRY C BL DION R HOLM PH, NR MATHER CA	Y		
USGS_11281000	SF TUOLUMNE R NR OAKLAND RECREATION CAMP CA	Y		
USGS_11282000	M TUOLUMNE R A OAKLAND RECREATION CAMP CA	Y		
USGS_11283500	CLAVEY R NR BUCK MEADOWS CA	Y		
USGS_11284400	BIG C AB WHITES GULCH NR GROVELAND CA	Y		
USGS_11284700	NF TUOLUMNE R NR LONG BARN CA	Y		
USGS_11288000	TUOLUMNE R AB LA GRANGE DAM NR LA GRANGE CA			

Notes: Hindcast and forecast data are provided by the CNRFC. Hindcasts are available for a subset of forecast points for 1985–2010, and archived operational forecasts are available for all forecast points for 2013–present. The river basin model includes hindcast points for the 2009 demo year.

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