ELECTRIC POWER
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Quantifying the Value of Hydropower in the Electric Grid

Modeling Results for Future Scenarios

2012 TECHNICAL REPORT

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1023141
Final Report, December 2012

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This report describes research sponsored by EPRI and Department of Energy.

This publication is a corporate document that should be cited in the literature in the following manner:

Quantifying the Value of Hydropower in the Electric Gird: Modeling Results for Future Scenarios.
EPRI, Palo Alto, CA: 2012.
1023141.

Abstract

Work reported in this Technical Report is part of a larger study that is made up of multiple components and intends to utilize and enhance tools that can value hydropower assets in a changing electric grid. The study's main objective is to develop a methodology to facilitate improved valuation and resource planning for pumped storage and conventional hydropower projects in the future electric transmission grid.

This report covers Modeling Results for Future Electricity Market Scenarios. It describes the modeling approach and input assumptions, defines a large number of future scenarios, and provides results of electric system modeling for the Western Electricity Coordinating Council (WECC). The approach for electric system modeling first estimates the capacity expansion and generation mix and then runs a production simulation with economic dispatch. It considers details of expected demand, load profiles, commodity prices, emissions costs, available transmission and related expansion plans as well as future renewable portfolios requirements. Results include plant-by-plant energy and ancillary service contributions, unit cycling, start stops, emissions, and profitability. Sub-hourly modeling differentiates the value of generation functions and services such as energy, regulation, spinning reserve, and non-spinning reserve.

By running a large number of different future energy scenarios the effect on the value of hydro generation and pumping are shown. The hydro valuation results for different energy futures range by a factor of two when considering highest to lowest for energy plus services and overall hydropower is a valuable asset in WECC. Based on this study, in the highest value locations and scenarios improvements to existing pumped storage plants resulted in significantly increased income while building new plants did not generate enough revenue to overcome the costs. However, in order to account for the full value of building new hydro resources further modeling should be done. A key factor in the results is that in many scenarios and locations the other available dispatchable generation resources are expected to meet the majority of the system's ancillary services needs. Related to these results large differentials between daytime and nighttime electricity prices are not seen in any of the scenarios.

Keywords
Conventional hydropower
Energy and ancillary services markets
Hydropower modeling
Hydro plant optimization
Pumped storage
Renewable integration
Water flow constraints

Executive Summary

Evolving environmental regulations driven by energy security and climate change concerns are driving the development of high levels of variable renewables such as wind and solar, which increase the need for system flexibility. In the past, electric capacity expansion models and resource plans have often taken system flexibility needs and the associated ancillary services for granted tending to discount the potential value of flexible resources such as hydropower. Future generation scenarios that include high levels of wind and solar power will increase system balancing requirements that could make flexible hydropower assets more valuable. However, the actual costs and benefits from hydropower projects are not fully recognized under existing policies and market structures.

DOE-EE0002666: Quantifying the Value of Hydropower in the Electric Grid Project

Completing a cost and benefit analysis that includes all the important assumptions and variables to accurately predict the future value of hydropower plants to the transmission grid is a difficult task. In order to overcome this difficultly, EPRI assembled a unique and diverse team. The team is made up of organizations with experience in grid modeling, hydropower costs, and markets, as well as experts in hydropower operations. The two-year project scope includes the following specific tasks:

- Task 1 – Case Studies on Plant Operations and Utilization
- Task 2 - Modeling Approach and Base Case Scenario
- Task 3- Role of Hydropower in Existing Markets and Opportunities in Future Markets
- Task 4- Systemic Plant Operating Constraints
- Task 5- Plant Cost Elements
- Task 6- Modeling Results for Future Electricity Market Scenarios
- Task 7- Effects of Alternative Policy Scenarios on Value of Hydropower
- Task 8- Planning and Operating Strategies
- Task 9- Final Report

Utilities with existing or planned hydropower will gain understanding of the costs and benefits for providing ancillary services under different future scenarios including high levels of renewable integration. Results will also be useful in formulating policies and regulations, for developing fair markets, and for investing in energy and transmission infrastructure to ensure energy security and to address climate change concerns. Uses include quantifying benefits provided by existing conventional and pumped storage hydro projects to the transmission grid, validating a power and market systems model, analyzing scenarios, and examining the implications of alternative market structures.

Modeling Results for Future Electricity Market Scenarios

This report summarizes the modeling results for different energy future scenarios, describing the input assumptions, the future scenarios, and the results from modeling and simulations. The electrical system in the Western Electricity Coordinating Council region is modeled, including capacity, load and resource balance, transmission, renewable portfolios, unit cycling, commodity prices, emissions costs, expansion plans, and ancillary services. Modeling included both an estimate of electricity capacity expansion and the economic dispatch of electricity in a production simulation. The modeling and analysis considers different energy futures, polices and economics and to better understand the value of hydropower assets.

A base case, defined in the previous modeling report, was updated based on hydro industry input. It is used to run 8760-hour simulations for a range of energy future scenarios considering hydropower, wind, and other key factors that affect the generation expansion and operation of the electric power system. These scenarios were developed based on different assumptions regarding hydro conditions, technology advancements, emission allowance pricing, as well as other conditions deemed to have an impact on the value of hydropower.

This report provides insights from a detailed sub-region simulation that focuses on how key changes in available technologies, deployments such as wind energy, market structures, and other factors affect the utilization and value of hydropower. Utilities can use these results to help make investment decisions when it comes to building, upgrading and operating hydropower assets.

It should be noted that the analysis presented in this report does not consider all potential value components provided by conventional and pumped hydropower resources to the electric power system, but rather provides an assessment of the value derived from hydropower resources in the provision of the following power system services:

1. Energy to meet demand, including the ability to arbitrage energy prices by utilizing hydro resources with storage capability to store energy at low prices and deliver energy during high-price periods.
2. Regulating reserve capacity to provide frequency regulation.
3. Spinning and non-spinning reserve capacity to respond to system disturbances and restore system frequency.

Potential value components not considered include the following:

1. Efficiency of operation of other resources allowed by using hydro resources for the deployment of reserves within the hour.
2. Inertial or primary frequency response to system disturbances or reactive power support for maintaining system voltages at desired levels.
3. Capacity value that hydropower resources contribute toward long-term resource adequacy.

The fact that the analysis present here does not cover these three value components should be considered in the context that the authors believe that the primary value contributions from hydro are from the provision of energy and reserve capacity. A follow-on DOE project will develop and exercise power flow, transient stability, and long-term dynamic stability models to evaluate hydro resources contributions to the reactive power support, primary frequency response, and within-hour reserve deployment services. The results of that project will confirm whether the additional value components not studied here are substantial enough to alter the conclusions that are drawn based on the value components captured and reported here.

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Section 1: Introduction

This report presents the methodology and findings of the scenario analysis that was undertaken as a part of Task 6 of the Quantifying the Value of Hydropower in the Transmission Grid project. It should be noted that the analysis presented in this report does not consider all potential value components provided by conventional and pumped hydropower resources to the electric power system, but rather provides an assessment of the value derived from hydropower resources in the provision of the following power system services:

1. Energy to meet demand, including the ability to arbitrage energy prices by utilizing hydro resources with storage capability to store energy at low prices and deliver energy during high-price periods.
2. Regulating reserve capacity to provide frequency regulation.
3. Spinning and non-spinning reserve capacity to respond to system disturbances and restore system frequency.

The valuation of hydro's contribution to these components is determined from an hourly-resolution security-constrained unit commitment and economic dispatch model. The production cost simulations performed represent the movement of load and generation from one hour to the next by assuming average demand and supply across the hour. This means the analysis can effectively represent the value of hydro providing energy, as well as the contribution to the reserve capacity required for providing ancillary services that are needed within the hour (regulating reserve, spin/non-spin reserve). The hourly model does not, however, capture the benefits of the deployment of reserves within the hour. To the extent that the use of fast-ramping hydro units for following within-hour load movements allows other generation resources to operate at more efficient output levels, hydro resources provide value to the power system that is not captured with the hourly analysis conducted and report upon here. While we believe this within-hour "reserve deployment" value is small relative to the reserve capacity value that is captured, this work does not confirm this belief.

Similar to reserve deployment value, the analysis also does not capture the value in of hydropower providing inertial or primary frequency response to system disturbances or reactive power support for maintaining system voltages at desired levels. While conventional and pumped hydro resources are very capable of providing these services, they do not have any specific advantage relative to thermal generators in providing these services. Further, provision of these services is not presently compensated in North American power markets. If in the future these services are compensated, it is expected that competition for providing these services will be high such that prices and resulting revenues will be low.

Lastly, the analysis reported here does not consider the capacity value that hydropower resources contribute toward long-term resource adequacy. The focus of this analysis effort is the value of hydro resource in providing operational services to the power system. As such, the relative long-term capacity benefits and relative capital costs to develop hydro resources are not considered.

The fact that the analysis present here does not cover these three value components should be considered in the context that the authors believe that the primary value contributions from hydro are from the provision of energy and reserve capacity. A follow-on DOE project *Detailed Analysis to Demonstrate the Value of Advanced Pumped Storage Hydropower in the U.S.* will develop and exercise power flow, transient stability, and long-term dynamic stability models to evaluate hydro resources contributions to the reactive power support, primary frequency response, and within-hour reserve deployment services. The results of that project will confirm whether the additional value components not studied here are substantial enough to alter the conclusions that are drawn based on the value components captured and reported here.

As noted, the foundation of this analysis is the use of hourly resolution production cost simulations to determine the value of hydropower under varying system conditions in providing energy and ancillary services. The platform utilized for this analysis is LCG Consulting's UPLAN software. The Western Electric Coordinating Council (WECC) system is modeled in UPLAN for the year 2020. LCG used updated cases based on project team inputs and ran 8760-hour (8784 in 2020) simulations for a range of scenarios that addressed hydropower, wind, and other key factors that affect the generation expansion and operation of the electric power system. Scenarios for these cases have been developed based on different assumptions regarding hydro conditions, technology advancements, emission allowance pricing, as well as other conditions deemed to have an impact on the value of hydropower.

As with any future scenario production cost model based study, the modeling and data input assumptions have a significant impact on results. Many assumptions made as part of the production cost model analyses for this project significantly impact the results and conclusions presented. While all of the assumptions are discussed in detail in the report, the following most crucial assumptions provide context for the results and conclusions:

- Generation mix assumed may not include enough variable renewable. Some of the generation expansion results utilized to form the generation portfolios for 2020 scenarios include geothermal and biomass at levels that may be higher than would now be expected. The renewable resources that would likely replace these based on today's policies would be wind and solar PV, which are variable and uncertain, thereby increasing ancillary service requirements.

- Additional reserve requirements associated with variable generation. For the 2020 cases with higher levels of wind and solar PV, additional regulating, spin, and non-spin requirements were not increased for the base cases. Sensitivities were conducted where the reserve requirements are increased according to the additional variability and uncertainty expected for the wind and PV installed capacities, but the base cases do not reflect the increased reserve requirements that would result from associated levels of variable generation.
- Larger balancing areas. The base case models represent 6 large balancing areas across the WECC footprint by aggregating several of the existing 37 BAs into larger sub-regions.

Despite these assumptions, the results of the study provide insights as to the value of hydro resources in providing energy and ancillary services in the WECC system for potential 2020 scenarios. Given the assumptions and the nature of future scenario production cost modeling, the insights tend to be based more on the order of magnitude and trends between results than the absolute value of the results presented.

The report has six major sections:

- Section 1, an introduction, with background on the study;
- Section 2, a description of the modeling approach;
- Section 3, a description of study cases and assumptions;
- Section 4, an exploration of the different energy futures and scenarios; and
- Section 5: a review of the results of the simulation
- Section 6: a review of the production cost modeling validation and further scenarios

Section 2: Modeling Approach

The valuation of hydropower in this project relies heavily on the use of electric system modeling to perform simulations of the WECC system under varying conditions and operating assumptions. Principally, two models were used for this analysis: the EPRI capacity expansion and dispatch model "NESSIE" for determining the generation mix in 2020 under various energy futures; and the LCG production simulation model, UPLAN, for performing integrated generation and transmission analysis with an eye on production costs and generator revenues.

Short descriptions of these two models follow. For more information, please refer to the *Quantifying the Value of Hydropower in the Transmission Grid: Modeling Approach and Base Case Scenario*.

Future Generation Capacity Expansion

EPRI's National Electricity System Simulation Evaluator (NESSIE) is used to predict the generation capacity expansion under different energy futures. The NESSIE generation capacity and mix of technologies are an input to the UPLAN model. EPRI developed NESSIE as a capacity expansion and operations model for the U.S. electric sector. It is designed to study the sustainability of the electric system, understand the role of new, low- and non-emitting generation technologies, and analyze the profitability of existing and new generating assets under varying scenarios for the future. NESSIE incorporates sub-models to simulate bulk power markets in individual U.S. regions and to calculate prices and quantities at both regional and aggregate levels. The prices and quantities, along with the values for other parameters employed as inputs to NESSIE, provide the basis for calculating cash flows and profits for generating technologies in regional electricity markets.

NESSIE requires many input values. In general, the inputs fall into two categories. The first category covers the characteristics of generating technologies, such as fixed and variable costs, efficiency, availability, capacity factor, etc. These cost-performance characteristics and projections are generally based on historic data and expert judgments. The second category of inputs includes values determined in markets that are separate from or broader than regional electricity markets. These markets include, for example, natural gas markets (in which electricity generation is only one of many competing uses for gas) and other fuel markets, broader energy markets (in which electricity is one form of energy that competes with others to deliver services), and emission allowance markets (which, while closely related to electricity markets, are separate and extend over larger geographic regions).

Expansion Modeling and Applications

EPRI's NESSIE model was used to study and develop generation expansion plans for use as input to UPLAN. Previously, the team worked together to create a realistic WECC expansion plan for 2020. Before running the different scenario change in generation, retirements and new additions had to be interconnected to the grid in the WECC model. The energy future, or scenario, selected would lead to different capacity expansions. For example, energy futures with a carbon policy would expect less coal plants in 2020. Similarly, assumed renewable portfolio standards help to define the 2020 expected geothermal, biomass, wind, and solar plants in WECC.

EPRI's NESSIE model has been used to evaluate a broad range of electric sector issues over the past ten years. Specific applications include evaluations of the following technologies and regulatory policies:

- Low- and non-emitting generation technologies,
- Retrofits of coal plants with carbon capture and storage (CCS) equipment,
- Energy efficiency measures,
- Plug-in hybrid electric vehicles,
- Renewable Portfolio Standards (RPS),
- Greenhouse gas (GHG) regulations, including price-based policies for limiting CO_2 emissions.

NESSIE simulates the market for electric generation technologies over nine 5-year time periods from 2010 to 2050, for thirteen electric markets based on pre-2006 control regions used by the National Electric Reliability Council (NERC). The model simulates both the decisions to acquire new capacity to meet each region's peak demand and reserve requirements, and the economic dispatch of the electric system, given the mix of installed generating capacity in each time period. The NESSIE input data for forecasts of future electric loads, fuel prices, and emissions allowance prices are based on the results of the Department of Energy's National Energy Modeling System (NEMS). For each of the existing and advanced generation technology options represented in the model, the input data contain estimates of technology cost and performance, including anticipated improvements over the model time horizon.

Expansion Plan

For this project the plan reflects the market impact of current and future policies such as emission regulations, state and Federal RPS policies, technology incentives and GHG policies. It includes estimates, by region and time period, of new capacity installations, generation mix, fuel use, CO_2 and other emissions, and the future cost of electricity. Figure 2-1 shows generation capacity in the 2020 NESSIE Reference case.

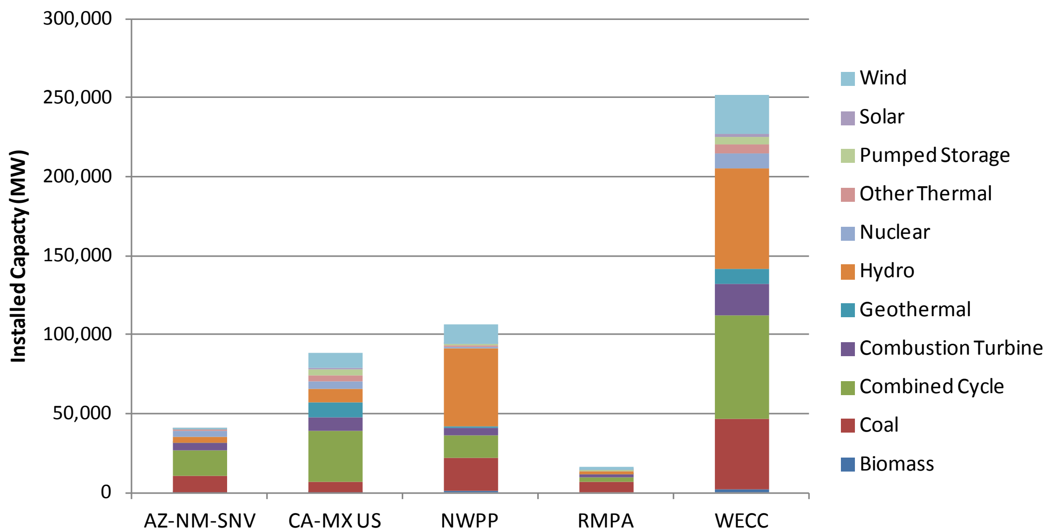


Figure 2-1
Installed Capacity in 2020 NESSIE "Base" Expansion Plan

Production Simulation and Economic Dispatch

The UPLAN Network Power Model (UPLAN-NPM) is a full network model developed to capture the commercial activities, such as bidding, trading, hedging, and contracting of all players in a restructured power market. It projects detailed physical and financial operations of electricity markets under varying conditions ranging from traditional regulation to today's post-restructuring competitive market structures.

UPLAN-NPM replicates the engineering protocols and market procedures of an operator, with a full (AC or DC) network transmission model and determines hourly Locational Market Prices (LMP). It performs coordinated marginal (opportunity) cost-based energy and ancillary service procurement, congestion management, full-fledged contingency analysis using Security-Constrained and Reliability Unit Commitment (SCUC and RUC) and Security Constrained Economic Dispatch (SCED) similar to those used by most market operators in the country.

UPLAN takes into account the physical and financial aspects of generation and transmission in WECC. The technical and commercial features of generators -- such as slow-start units, nuclear operations, pre-scheduled hydro, de-ratings, forced and planned outages, and regulatory requirements -- are all incorporated into the optimization, whose main output for each generator in each simulation hour is a production schedule that meets demand bids, clears the market, and minimizes the sum of start-up, no-load, and incremental energy bids.

All of the plant operations and economic performance presented in this report are a result of UPLAN simulations.

Modeling Generating Plants

The UPLAN generator database includes a wide range of generating technologies and variables that are salient to the diverse set of fuel type available, such as coal, gas, nuclear, wind, hydropower and other renewable resources. A variety of bidding options are available on a unit basis that incorporate block heat rates, minimum up and down times, start-up costs, etc. These variables are based on the best known available data. Bidding behavior can be adjusted over time to reflect monthly load changes, scarcity, and other factors affecting market sentiment.

Modeling Demand

The load module provides a way to create and manipulate load data. This module allows the user to add and remove a demand, manage daily load profiles, as well as monthly and annual load forecasts. Hourly demand shapes and the demand forecast comes from multiple data sources, including the FERC Form 714 (Annual Electric Control and Planning Area Report) and the WECC Loads and Resources Subcommittee (LRS) filings. The most recent electric demand growth forecasts from individual ISOs, Balancing Authorities, and FERC are consolidated to develop a forecast for 2010 through 2020. Forecasts consider various factors including population growth, economic conditions, and normalized weather. There is a relatively high, 50-percent probability of exceeding the forecast on any given hour. Peak demand forecasts are coincident sums of shaped hourly demands.

Figure 3-7 shows the forecasted electricity demand total used in the modeling and including all the balancing authorities in the WECC footprint.

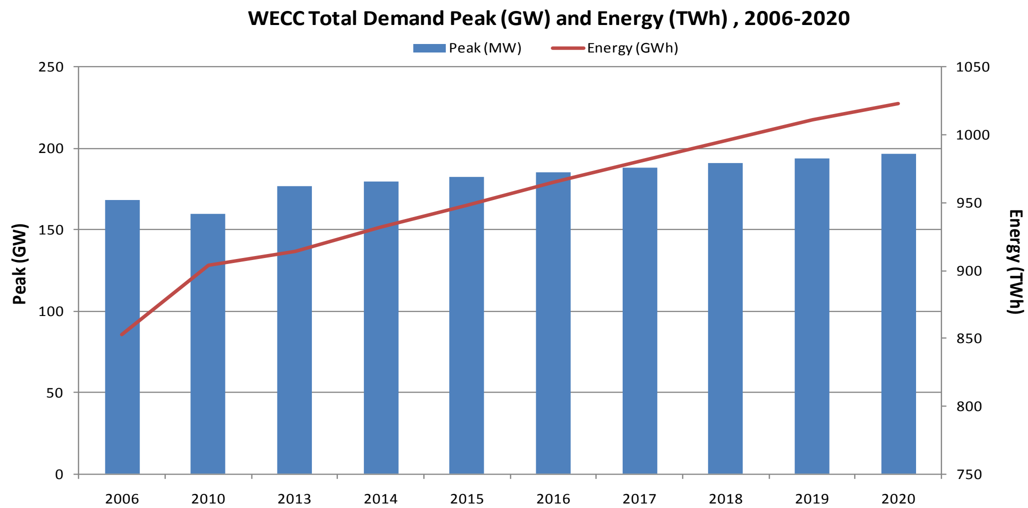


Figure 2-2
Load growth in the western interconnection

Modeling Transmission

UPLAN is a full network model and has a sophisticated built-in power flow program which optimizes power delivery twice every hour, once during unit commitment and again during dispatch. The complete representation of the transmission network allows the use of a full DC load flow for unit commitment and either DC, or AC, dispatch for every hour's simulation. In this study only the DC side was modeled. In this respect, UPLAN simulates the details of the transmission grid and the generator dispatch using data sets that describe these system components.

Modeling Conventional Hydropower

For each hydro unit, users can define the total amount of monthly energy (capacity factor) that can be dispatched by the model. This information can be obtained from plant operators' reports for the historical years and distinct hydro conditions. The available energy equivalent of the water available is scheduled as required against either the hourly demand or hourly prices as required. A portion of the monthly energy may also be reserved for daily dispatch for regulation, run of the river, and minimum river flow requirements.

Run of river energy behaves as a 'base-load' unit, with constant output throughout the month from required river run-off. Daily energy is an amount that is reserved for scheduling versus the daily load or price profile, allowing for some energy to be dedicated toward peak demand on a daily, rather than a monthly, basis.

Various hydropower settings are available in UPLAN that offer a high degree of control over how hydro energy is dispatched. For this study, initial hourly schedules were created by looking ahead one month at the load net wind and solar profiles. This determined a preliminary schedule for the hydro dispatch. The preliminary schedule was then dynamically altered on an hourly basis with a one-week look-head to optimize the total revenues of the conventional hydro plants across all products (energy, regulation up, regulation down, spin, and non-spin).

When modeling conventional hydro resources environmental constraints have a large impact on the operation and performance. In this study, an effort was made to capture these constraints but not all conventional plants were modeled according to actual operation. Instead, this modeling effort gives a clearer picture of what the possible benefits of operating conventional plants without these environmental constraints would be.

Modeling Pumped Hydro Resources

For pumped-hydro storage plants, preliminary scheduling is done at the beginning of each month and for this study the following constraints were considered:

- Monthly upper limit for the energy dispatch (GWh) of the unit if any
- Hourly maximum pumping and generating MW capacity
- Efficiency of the pumped-hydro storage unit
- Initial reservoir level
- Minimum loading level
- Ancillary Service capabilities
- Maximum storage capacity limit (GWh) in the pond

Optimization of pumped-hydro storage unit operation utilizes the nodal prices, ancillary service prices, the storage inventory, pumping and generating capacity, and the overall efficiency of the generator to set up the LP optimization program. This model maximizes the total profit from the operation of pumped-hydro storage subject to all of the constraints.

Once the preliminary schedule has been established, the pumped-hydro storage scheduling is dynamically altered to optimize its participation in the hourly security constrained unit commitment and economic dispatch processes where the pumped storage units and all other hydro and thermal units are all dispatched to meet the hourly load and ancillary service requirements subject to the network constraints. As with the conventional hydro, this process also includes a one week look-ahead.

Balancing Considerations

Sub Hourly Modeling

It is important to note that the hourly resolution production cost analysis framework does not ignore all intra-hour impacts/benefits. The potential intra-hour benefits include the following:

1. Regulating reserve held for deployment through Automatic Generation Control (AGC)
2. Secondary frequency regulation through deployment of regulating reserve on AGC
3. Inertial and primary frequency response
4. Spinning and non-spinning reserve held for deployment in the event of a contingency
5. Deployment of spinning and non-spinning reserve post-contingency

The impact/benefits that hydro has on regulating and spinning/non-spinning reserves are captured in the hourly production cost models. This is accomplished by calculating the amount of reserve which needs to be held in each hour for each category; for example regulating reserve equivalent to 2% of the load is held in every hour to be able to respond to short term variations in net load; this is discussed more in the section on Ancillary Services. The hourly regulating reserve requirement, and spinning/non-spinning reserve to cover largest realistic contingency, are added to the hourly production cost model ensuring that the intra-hour variability needs are procured on an hourly basis. This is obviously only capturing the benefits of holding the capacity needed to accommodate the within-hour variability (#1 and #4 above). The hourly resolution production cost model used in this study does not capture any of the potential impacts/benefits of hydro units moving within the hour (#2 ,#3 and #5 above), but we believe that the potential revenues that might be captured by hydro units for providing these benefits is small relative to the revenues that are potentially available from providing regulating and spinning reserves.

The amount of regulating reserve could also be calculated by conducting statistical analysis of the regulating reserve requirements for all scenarios using methods that capture the increased regulating reserve needs associated with scenarios that have higher variable generation. This statistical analysis would utilize intra-hour wind and load data to determine the amount of regulating reserve that needs to be held on an hourly basis. This method was done as a sensitivity in the study and the results of that are in section 6.

Ancillary Services

UPLAN co-optimizes the energy and ancillary service markets, producing arbitrage-free prices. To determine the economically optimal unit commitment, UPLAN realistically characterizes marginal opportunity cost-based bidding reflecting arbitrage across the different energy and ancillary service markets.

Thus, a generator's availability and willingness to sell various ancillary services depends on the resulting reduction of energy sales opportunities, and vice versa. Different A/S products (e.g., regulation, spin, non-spin, 30-minute, and reliability must-run) are integrated into UPLAN day-ahead market simulation. The ability of each generator to participate in each of the A/S markets is specified in the generator input data. Figure 2-3 shows the direct and in-direct costs of providing ancillary services. When day-ahead prices exceed variable energy costs, ancillary service prices reflect the opportunity cost of not providing in energy markets.

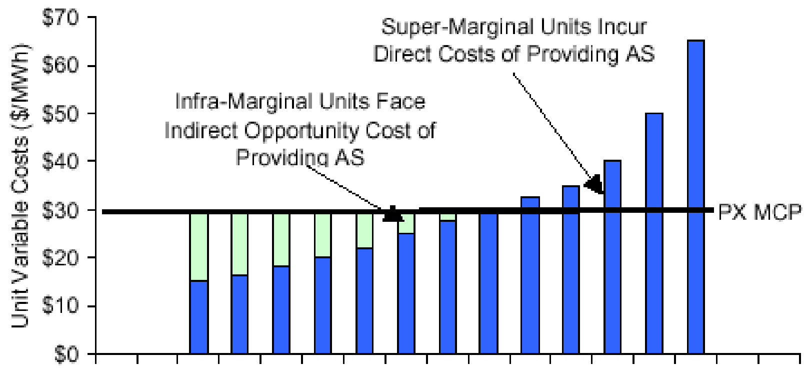


Figure 2-3
Opportunity cost-based bidding for ancillary service products

The determination of A/S requirements involves two aspects.

1. The quantity of operating reserve including regulation (i.e., Reg-Up and Reg-Down) and contingency reserve (i.e., the combination of Spin and Non-Spin) is determined according to applicable reliability standards, such as the MORC (Minimum Operating Reliability Criteria) of the WECC (Western Electricity Coordinating Council), which is a member of the NERC.

2. The locational requirements of operating reserves are not explicitly specified in the reliability standards, such as in WECC. However, the MORC of the WECC requires that "prudent operating judgment shall be exercised in distributing operating reserve, taking into account effective use of capacity in an emergency, time required to be effective, transmission limitations, and local area requirements. Spinning reserve should be distributed to maximize the effectiveness of governor action."

Minimum reserve requirements are established by the WECC MORC and are not open to interpretation or modification by individual balancing authorities. They establish a minimum standard, and the control areas can only comply by meeting or exceeding this standard. For informational purposes, the WECC MORC operating reserve requirement is currently the greater of the sum of 7% of Balancing Authority load served by thermal generation plus 5% of Balancing Authority load served by hydroelectric generation, or the Balancing Authority's most severe single contingency (MSSC). In either of these cases, half of that reserve must be synchronized to the grid, or "spinning".

Section 3: Modeling Input Assumptions

Modeling results depend on many input assumptions. Assumptions help to define the different future scenarios under varying economic conditions. As such, different assumptions and input are used for each of the scenarios that are run in the UPLAN model. All production costing simulations for Task 6 were hourly runs performed for the year 2020. Details of the differing input assumptions which were made for the various scenarios can be found in Section 5. Much of the input and assumptions, however, remain constant throughout the analysis. These inputs are detailed in the following sub sections as well as the *Quantifying the Value of Hydropower in the Transmission Grid: Modeling Approach and Base Case Scenario.*

Some principle assumptions include:

- This is a nodal analysis encompassing the entire WECC footprint with over 20,000 transmission lines modeled
- Hourly load is distributed across all buses for a peak of 249GW in 2020
- All thermal and hydro generators were represented individually
- Base case conditions for water levels, wind forecast and load profiles were taken from historical data for 2006
- Model simulations were conducted for each hour within the study year in order to accommodate ramping constraints, load movement and realistic market clearing into the solution
- Commonly traded ancillary services products and energy are all considered simultaneously
- Unit Commitment and ancillary service procurement is done at a Balancing Authority level. Ultimate dispatch and power flow is done at a WECC-wide level

Study Footprint and Scope

The study footprint includes a detailed nodal representation of the entire western interconnection. The footprint of the western interconnection includes 13 western states, portions of northern Mexico and two Canadian provinces, and 37 individual balancing authorities.

Table 3-1 Balancing Authorities and Sub-Regional Grouping in the Western Interconnection and Figure 3-1 Balancing Authorities in WECC show a list of balancing areas and the grouping for WECC balancing areas and sub-regions. Figure 3-2 shows the NERC regions in the United States and the locations within the subregions in the WECC area. The Western Interconnect is divided into several demand areas incorporating the service territories of electric utilities, power pools, independent system operators, and independent power producers. The UPLAN simulation model incorporates loads, supply resources, transmission path ratings, and operating rules for each balancing area in the Western Interconnect. In the simulation process, UPLAN will perform a unit commitment which includes ancillary service procurement at the Balancing Authority level. Subsequently, a dispatch occurs that will include a WECC-wide power flow.

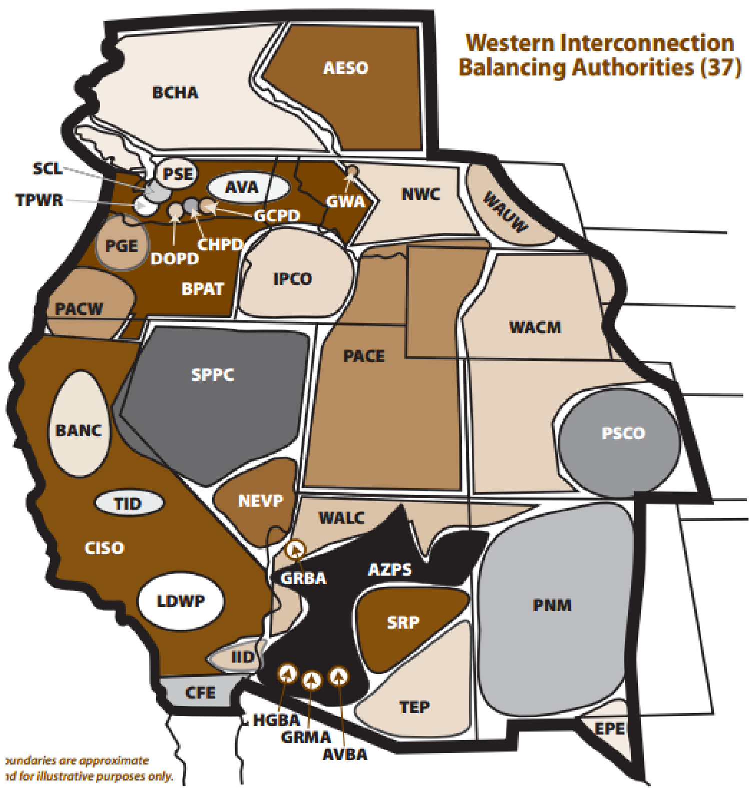


Figure 3-1
Balancing Authorities in WECC

Table 3-1
Balancing Authorities and Sub-Regional Grouping in the Western Interconnection

Acronym	Balancing Authority Name	Subregion
AESO	Alberta Electric System Operator	NWPP
AZPS	Arizona Public Service Company	AZ-NM-SNV
AVA	Avista Corporation	NWPP
BANC	Balancing Authority of Northern California	CA-MX US
BPAT	Bonneville Power Administration – Transmission	NWPP
BCHA	British Columbia Hydro Authority	NWPP
CISO	California Independent System Operator	CA-MX US
CFE	Comisión Federal de Electricidad	CA-MX US
AVBA	Arlington Valley, LLC	AZ-NM-SNV
EPE	El Paso Electric Company	AZ-NM-SNV
GRMA	Gila River Power, LP	AZ-NM-SNV
GRBA	Griffith Energy, LLC	AZ-NM-SNV
IPCO	Idaho Power Company	NWPP
PSE	Puget Sound Energy	NWPP
SRP	Salt River Project	AZ-NM-SNV
SCL	Seattle City Light	NWPP
SPPC	Sierra Pacific Power Company	NWPP
TPWR	City of Tacoma, Department of Public Utilities	NWPP
TEP	Tucson Electric Power Company	AZ-NM-SNV
TID	Turlock Irrigation District	CA-MX US
WACM	Western Area Power Administration, Colorado-Missouri Region	RMPA
WALC	Western Area Power Administration, Lower Colorado Region	AZ-NM-SNV
WAUW	Western Area Power Administration, Upper Great Plains West	NWPP
IID	Imperial Irrigation District	AZ-NM-SNV
LDWP	Los Angeles Department of Water and Power	CA-MX US
GWA	NaturEner Power Watch, LLC	NWPP
NEVP	Nevada Power Company	AZ-NM-SNV
HGBA	New Harquahala Generating Company, LLC	AZ-NM-SNV
NWC	NorthWestern Energy	NWPP
PACE	Pacifi Corp — East	NWPP

Table 3-1 (continued)
Balancing Authorities and Sub-Regional Grouping in the Western Interconnection

Acronym	Balancing Authority Name	Subregion
PACW	Pacifi Corp — West	NWPP
PGE	Portland General Electric Company	NWPP
PSCO	Public Service Company of Colorado	RMPA
PNM	Public Service Company of New Mexico	AZ-NM-SNV
CHPD	PUD No. 1 of Chelan County	NWPP
DOPD	PUD No. 1 of Douglas County	NWPP
GCPD	PUD No. 2 of Grant County	NWPP

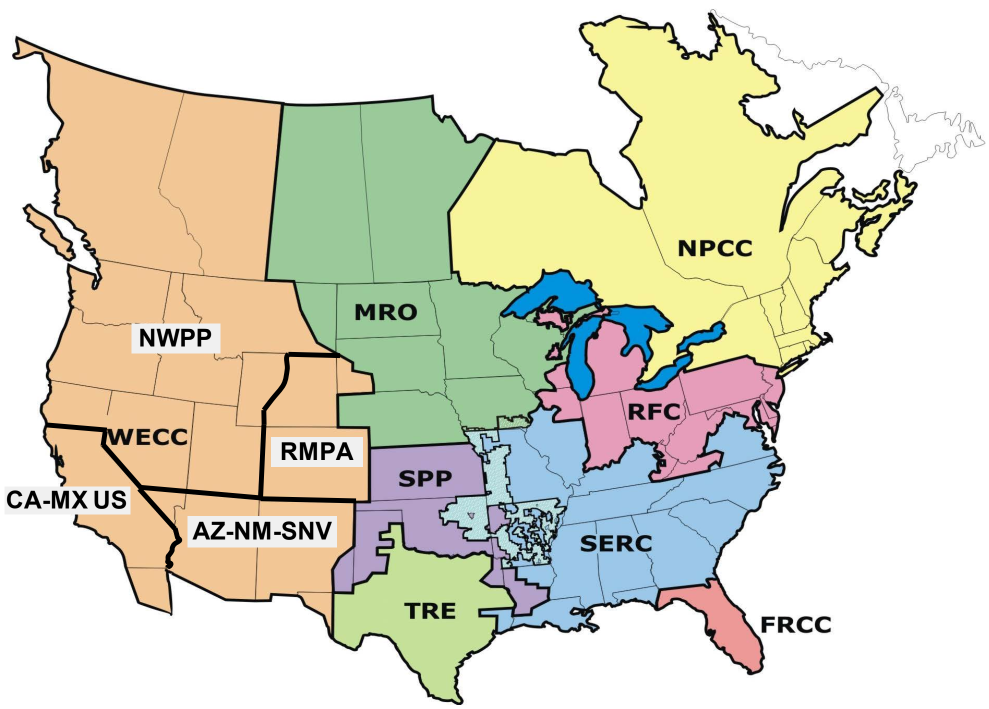


Figure 3-2
NERC Regions with WECC Subregions

Transmission Assumptions

A Western Electricity Coordinating Council (WECC) system model developed by WECC's Transmission Expansion Planning and Policy Committee (TEPPC) was used for transmission expansions of the cases studied. The specific case that was used for the analysis was *TEPPC 2019 PC1 Updated RPS Base Case*. This base case was built to produce 15 % of total electric energy from renewable resources excluding large hydropower resources while meeting renewable portfolio standards (RPS) for western interconnects' states and provinces, including a 33% RPS for California. This case was refined to include more granular information for the California portion of the grid. Nodal representation of the entire western interconnect was modeled, including a generation expansion plan for the region based on anticipated load and resource balance needs. Production cost modeling using UPLAN-NPM was used to determine energy costs, value of energy and ancillary services in future system scenarios and the performance of conventional and pumped-storage hydro assets in the western interconnect.

The resulting UPLAN WECC dataset contains 16,131 buses, 20,240 transmission lines, nearly 100 interface definitions, and transfer limits. All interfaces listed in the 2010 WECC path ratings catalog are modeled and are listed in Table 3-2 WECC Interfaces.

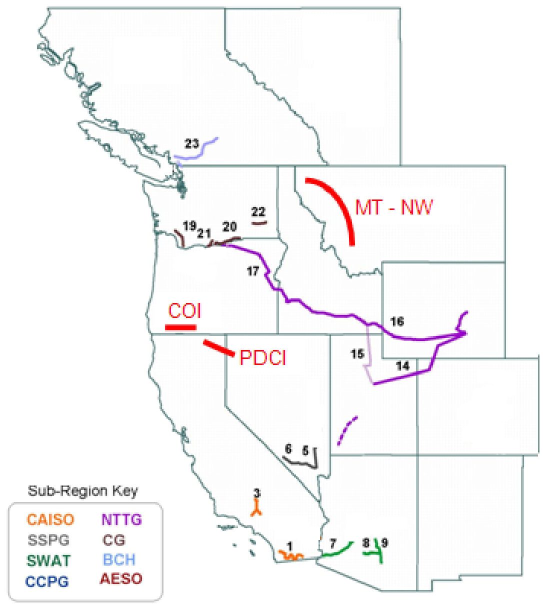
Table 3-2
WECC Interfaces

Interface Name	Path Number	Forward Rating (MW)	Reverse Rating (MW)
ALBERTA - BRITISH COLUMBIA	Path 1	1,000	1200
ALBERTA - SASKATCHEWAN	Path 2	150	150
NORTHWEST - CANADA	Path 3	2,000	3150
WEST OF CASCADES - NORTH	Path 4	10,500	10500
WEST OF CASCADES - SOUTH	Path 5	7,200	7200
WEST OF HATWAI	Path 6	4,277	9999
MONTANA - NORTHWEST	Path 8	2,950	1350
WEST OF BROADVIEW	Path 9	2,573	9999
WEST OF COLSTRIP	Path 10	2,598	9999
WEST OF CROSSOVER	Path 11	2,598	9999
IDAHO - NORTHWEST	Path 14	2,400	1200
MIDWAY - LOS BANOS	Path 15	5,400	3265
IDAHO - SIERRA	Path 16	500	360
BORAH WEST	Path 17	2,557	9999
IDAHO - MONTANA	Path 18	337	337
BRIDGER WEST	Path 19	2,200	9999
PATH C	Path 20	1,250	1600
SOUTHWEST OF FOUR CORNERS	Path 22	2,325	9999
FOUR CORNERS 345/500	Path 23	1,000	1000
PG&E - SPP	Path 24	160	150
PACIFICORP_PG&E 115 KV INTERCON.	Path 25	100	45
NORTHERN - SOUTHERN CALIFORNIA	Path 26	4,000	3000
IPP DC LINE	Path 27	2,400	1400
INTERMOUNTAIN - MONA 345 KV	Path 28	1,400	1200
INTERMOUNTAIN - GONDER 230 KV	Path 29	200	9999
TOT 1A	Path 30	800	800
TOT 2A	Path 31	690	690
PAVANT INTRMTN - GONDER 230 KV	Path 32	440	235
BONANZA WEST	Path 33	785	9999
TOT 2C	Path 35	300	300
TOT 3	Path 36	1,800	1800
TOT 4A	Path 37	937	937
TOT 4B	Path 38	680	680
TOT 5	Path 39	1,675	1675
TOT 7	Path 40	890	9999

Table 4-2 (continued)
WECC Interfaces

Interface Name	Path Number	Forward Rating (MW)	Reverse Rating (MW)
IID - SCE	Path 42	1,500	99999
NORTH OF SAN ONOFRE	Path 43	2,440	9999
SOUTH OF SAN ONOFRE	Path 44	2,500	9999
SDG&E - MEXICO (CFE)	Path 45	450	800
WEST OF COLORADO RIVER (WOR)	Path 46	11,823	9999
SOUTHERN NEW MEXICO (NM1)	Path 47	1,600	1600
NORTHERN NEW MEXICO (NM2)	Path 48	1,970	9999
EAST OF COLORADO RIVER (EOR)	Path 49	10,500	9999
CHOLLA - PINNACLE PEAK	Path 50	1,200	9999
SILVER PEAK - CONTROL 55 KV	Path 52	17	17
BROWNLEE EAST	Path 55	1,850	9999
ELDORADO - MEAD 230 KV LINES	Path 58	1,140	1140
WALC BLYTHE - SCE BLYTHE 161 KV	Path 59	218	218
LUGO - VICTORVILLE 500 KV LINE	Path 61	2,400	900
ELDORADO - MCCULLOUGH 500 KV	Path 62	2,598	2598
PACIFIC DC INTERTIE (PDCI)	Path 65	3,100	3100
COI	Path 66	4,800	3675
South of Alston	Path 71	3,430	9999
NORTH OF JOHN DAY	Path 73	8,600	8600
MIDPOINT - SUMMER LAKE	Path 75	1,500	600
ALTURAS PROJECT	Path 76	300	300
CRYSTAL - ALLEN	Path 77	950	9999
TOT 2B1	Path 78	560	600
TOT 2B2	Path 79	265	300
MONTANA SOUTHEAST	Path 80	600	600

Transmission additions required to maintain system reliability or to integrate new generation have been included in the 2020 simulations based on the work done by WECC and others in the industry. A list of new high voltage transmission projects reviewed by the Technical Advisory Subcommittee at WECC is shown in Figure 3-3 Transmission Expansion Elements for 2020 (not comprehensive).



Foundational Projects - 2020

	Project Names
1	Sunrise
3	Tehachapi Upgrade
5	TCP Harry Allen - Northwest
6	TCP Northwest - Amargosa
7	PV - NG #2
8	Pinal Central - Tortolita
9	Southeast Valley (SEV)
14	Gateway South Phase 1
15	Gateway Central Phase 1
16	Gateway West Phase 1
17	Hemingway - Boardman
19	I-5 Corridor
20	West McNary
21	Big Eddy- Knight
22	Little Goose Area Reinforcement
23	Nicola - Meridian

Figure 3-3
Transmission Expansion Elements for 2020 (not comprehensive)

Generation Assumptions

LCG utilized its proprietary PLATO-WECC database for this study. PLATO is an extensive database for generating plants, loads, fuels, and the transmission network. LCG developed this database based upon information gathered from the Energy Information Administration (EIA) of the U.S. Department of Energy (DOE), the Federal Energy Regulatory Commission (FERC), WECC, NERC, DOE, CAISO and CEC (California Energy Commission), as well as other independently verified sources. The various categories of input data required for WECC simulations are continually updated by LCG.

The supply database includes all the resources in the WECC, and consists of a wide range of generating plants using a variety of fuels, including natural gas, coal, uranium, wind, hydro, and other renewable resources.

Each generator in the database is assigned a geographically accurate injection node on the transmission network, and is individually represented in the database with over 250 parameters describing the physical and financial elements of the unit. The costs include fixed and variable O&M, fuel costs, and start-up costs. The fuel consumption is defined by heat rate curves or loading blocks from minimum to maximum capacity. Availability is specified by scheduled maintenance, monthly de-rates, forced outage rates, and maximum energy limits. Operating constraints include minimum up and down times, ramp rates, must run requirements, fuel and emission limits, and capabilities for reactive support. Each unit's ability to participate in ancillary services is also identified along with its physical location on the network grid.

LCG's team made every effort to use data that is the most up to date and accurate. With the database benchmarked to historical market performance, the model can simulate and forecast system operations using Security Constrained Unit Commitment (SCUC) and Security Constrained Economic Dispatch (SCED). In addition, utility stakeholder and the project team feedback was used to enhance the available data.

The existing resources and future generation entrants in the WECC footprint meet the NERC reserve margin targets for each balancing area. Figure 3-4 shows a snapshot of the load and resource balance of the balancing areas for the year 2010. Generator additions and retirements for the Energy Futures are determined separately and described in Section 4:.

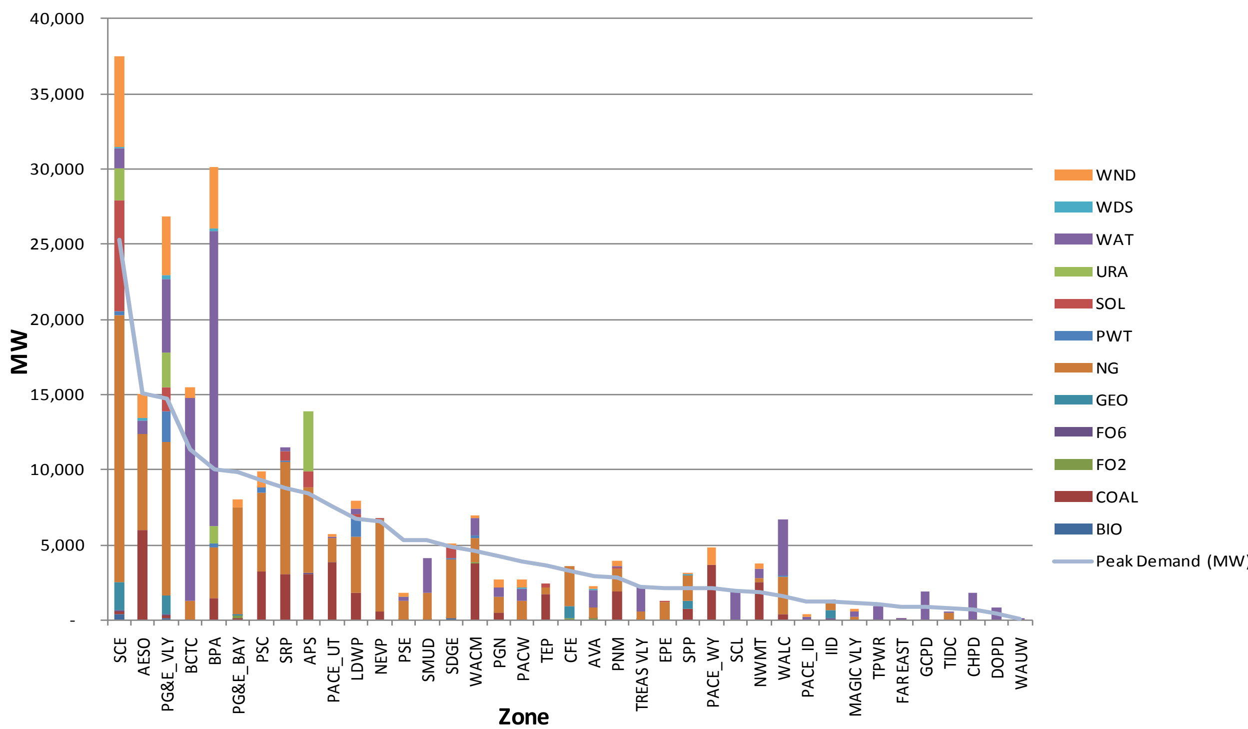


Figure 3-4
2010 Generation Capacity vs. Peak Load

In Figure 3-5 the total WECC installed capacity is shown broken down by technology. Hydro has the most capacity at 61GW, but comes in after coal and combined cycles for energy produced. Natural gas is the fuel type with the biggest installed capacity spanning combined cycle, combustion turbines and a part of the "other thermal" technologies.

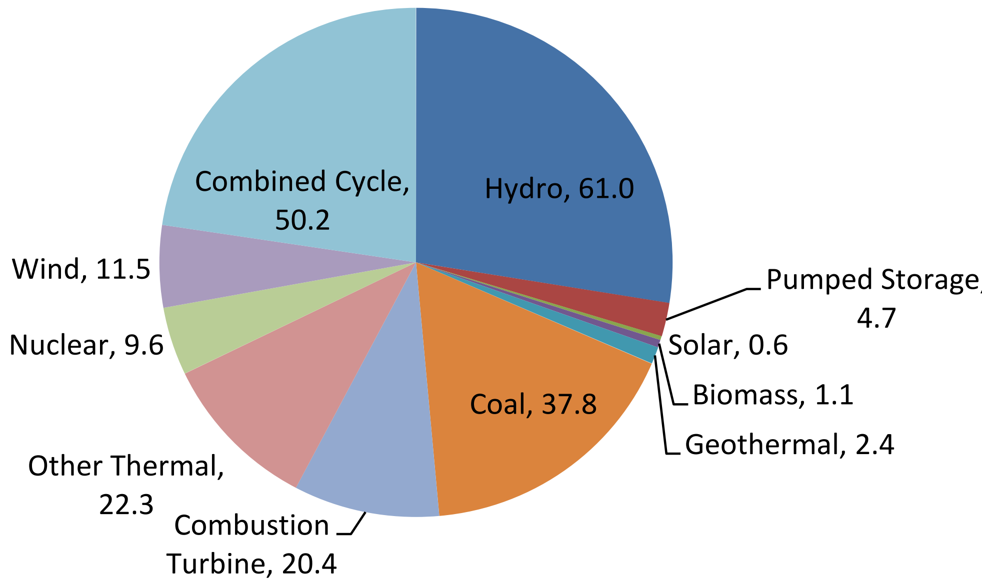


Figure 3-5
WECC Installed Capacity (GW)

Plant Parameters

The model characterizes both the conventional and pumped storage hydropower plants. Table 3-3 gives the round-trip efficiency, Pmin value, and range of operation for conventional, existing pumped storage, and new pumped storage plants. The below values were assumed for all plants unless otherwise informed by utility participants.

Table 3-3
Plant Characterization

Unit Type	Round-Trip Efficiency (%)	Pmin (%)	Range of Operation (%)
Conventional Hydro		50 - 75	25 - 50
Existing Pumped Storage	75	70	30
New Pumped Storage	80	40	60

Conventional Hydropower Plants

The US portion of Western Interconnect contains more than 200 individual hydropower facilities, totaling over 47,000 MW of generating nameplate capacity of conventional and pumped storage hydro. All individual hydropower units are modeled at their physical locations on the transmission grid along with the available unit capabilities. Median hydrological data was used for US and Canadian portions of WECC in the reference case simulations, for monthly hydro energy generation potential.

A complete list of individual hydropower units in the western interconnection was distributed to the project team for review of available data and inputs on additional operational parameters. This list contained for each unit, the unit name, generating capacity, physical injection points in the grid, balancing authority operated in, monthly energy generation based on median hydrological data and capabilities to provide regulation, spinning reserve and non-spinning reserve services. It should be noted that the project team was able to confirm from a general industry perspective on the technology capabilities of the database. To gain knowledge on specific unit capabilities to provide system reserves, LCG alongside EPRI reached out to selected conventional plant owners in WECC to receive input on the modeling assumptions, EIA data, as well as operations. LCG received feedback from the following entities: Chelan County PUD, Pacific Gas & Electric, and Idaho Power Company.

Table 3-4 contains a list of facilities operated by the US Bureau of Reclamation, along with the grid functions and services each of the facilities has been used for in the past. The information on regulation, spinning, and non-spinning capabilities of the facilities was used to determine the plant capabilities to model in the WECC system reference cases to capture the flexibility offered by the existing fleet.

This table shows the input assumptions for each plant. Similar assumptions were made for other conventional facilities. Water use constraints and environmental constraints were not considered unless noted by a utility stakeholder as data was not available.

Table 3-4
Hydropower facilities operated by US Bureau of Reclamation

Facility	State	Spinning	Non-Spinning	Replacement	Regulation/ Load Following	Black Start	Voltage Support
Alcova Power Plant	WY	Yes	Yes	Yes	Yes	No	Yes
Anderson Ranch Power Plant	ID	Yes	Yes	Yes	Yes	Yes	Yes
Big Thompson Power Plant	CO	No	No	No	No	No	No
Black Canyon Power Plant	ID	Yes	Yes	Yes	Yes	Yes	Yes
Blue Mesa Power Plant	CO	Yes	Yes	Yes	Yes	No	Yes
Boise Mesa Power Plant	ID	No	No	No	No	No	No
Boysen Power Plant	WY	No	No	No	No	No	Yes
Buffalo Bill Power Plant	WY	No	No	No	No	No	Yes
Canyon Ferry Power Plant	MO	Yes	Yes	Yes	No	Yes	Yes
Chandler Power Plant	WA	No	No	No	No	No	Yes
Crystal Power Plant	CO	Yes	Yes	Yes	Yes	Yes	Yes
Davis Power Plant	AZ	Yes	Yes	Yes	Yes	Yes	Yes
Deer Creek Power Plant	UT	No	No	No	No	Yes	Yes
Elephant Butte Power Plant	NM	No	No	No	No	Yes	Yes
Estes Power Plant	CO	Yes	Yes	No	Yes	Yes	Yes
Flaming Gorge Power Plant	UT	Yes	Yes	Yes	Yes	Yes	Yes
Flatiron Power Plant	CO	Yes	Yes	Yes	Yes	Yes	Yes
Folsom Power Plant	CA	Yes	Yes	Yes	Yes	Yes	Yes
Fonteneel Power Plant	WY	Yes	Yes	Yes	Yes	Yes	Yes
Fremont Canyon Power Plant	WY	Yes	Yes	Yes	Yes	No	Yes
Glen Canyon Power Plant	AZ	Yes	Yes	Yes	Yes	Yes	Yes
Glendo Power Plant	WY	No	No	Yes	No	No	Yes

Table 3-4 (continued)
Hydropower facilities operated by US Bureau of Reclamation

Facility	State	Spinning	Non-Spinning	Replacement	Regulation/ Load Following	Black Start	Voltage Support
Grand Coulee Power Plant	WA	Yes	Yes	Yes	Yes	Yes	Yes
Green Mountain Power Plant	CO	No	No	No	No	Yes	Yes
Green Springs Power Plant	OR	No	No	No	No	No	Yes
Guernsey Power Plant	WY	No	No	No	No	No	Yes
Heart Mountain Power Plant	WY	No	No	No	No	No	Yes
Hoover Power Plant	AZ	Yes	Yes	Yes	Yes	Yes	Yes
Hungry Horse Power Plant	MO	Yes	Yes	Yes	Yes	Yes	Yes
Judge Francis Carr Power Plant	CA	Yes	Yes	Yes	Yes	No	Yes
Keswick Power Plant	CA	No	No	No	No	Yes	Yes
Kortes Power Plant	WY	Yes	Yes	Yes	Yes	Yes	Yes
Lewiston Power Plant	CA	No	No	No	No	Yes	No
Lower Molina Power Plant	CO	No	No	No	No	Yes	Yes
Marys Lake Power Plant	CO	No	No	No	No	Yes	Yes
McPhee Power Plant	CO	No	No	No	No	Yes	Yes
Minidoka Power Plant	ID	No	No	No	No	Yes	Yes
Morrow Point Power Plant	CO	Yes	Yes	Yes	Yes	Yes	Yes
Mount Elbert Power Plant	CO	Yes	Yes	Yes	Yes	Yes	Yes
New Melones Power Plant	CA	Yes	Yes	Yes	Yes	Yes	Yes
Nimbus Power Plant	CA	No	No	No	No	No	Yes
O'Neil Power Plant	CA	No	No	No	No	No	No
Palisades Power Plant	ID	Yes	Yes	Yes	Yes	Yes	Yes
Parker Power Plant	AZ	Yes	Yes	Yes	No	No	Yes

Table 3-4 (continued)
Hydropower facilities operated by US Bureau of Reclamation

Facility	State	Spinning	Non-Spinning	Replacement	Regulation/Load Following	Black Start	Voltage Support
Pilot Butte Power Plant	WY	No	No	No	No	No	No
Pole Hill Power Plant	CO	No	No	No	No	Yes	Yes
Roza Power Plant	WA	No	No	No	No	No	Yes
San Luis- Gianelli Power Plant	CA	No	No	No	No	No	No
Seminoe Power Plant	WY	Yes	Yes	Yes	Yes	No	Yes
Shasta Power Plant	CA	Yes	Yes	Yes	Yes	Yes	Yes
Shoshone Power Plant	WY	No	No	No	No	No	No
Spirit Mount Power Plant	WY	No	No	No	No	No	No
Spring Creek Power Plant	CA	Yes	Yes	Yes	Yes	No	Yes
Stampede Power Plant	CA	No	No	No	No	No	Yes
Towaoc Power Plant	CO	No	No	No	No	Yes	Yes
Trinity Power Plant	CA	Yes	Yes	Yes	Yes	No	Yes
Upper Molina Power Plant	CO	No	No	No	No	Yes	Yes
Yellowtail Power Plant	MO	Yes	Yes	Yes	Yes	Yes	Yes

Pumped-Hydro Energy Storage

The western interconnect has 14 pumped-hydro energy storage facilities, with a total generating capacity of nearly 4,700 MW and operating ranges greater than 10 hours. A large portion of this capacity is located in California, which also has among the world's biggest pumped hydro facilities, including Castaic and Helms. Figure 3-6 below shows a map of the pumped hydro storage plants in the US.

Figure 3-6
Pumped-hydro storage facilities in the US (Source: HDR)

Inputs from other project members and tasks have shed light on the operational capabilities of pumped-hydro facilities in the US. This information was primarily used to determine grid services such as regulation up, regulation down, spinning reserve and contingency reserve that these plants can offer into the system operations. Although pumped-hydro plants can provide 10-min regulation, spinning, and non-spinning reserve services in the generating mode, existing plants are constrained, by single speed pumps, from offering regulation service in the pumping mode. Some vertically integrated utilities operate pumped plants in conjunction with conventional to have the total portfolio providing regulation, but history does not indicate that these plants have provided regulation services in the past for frequency regulation and load following alone. LCG alongside EPRI reached out to all pumped storage owners in WECC to share the assumptions being used in the model for each plant and receive input on these assumptions, EIA data, and actual operations. LCG received input from the following utilities: California Department of Water Resources, Salt River Project, Central Arizona Project, Los Angeles Department of Water and Power, Xcel Energy, and the United State Bureau of Reclamation. The input received was included.

All of the pumped storage plants that were built primarily for power supply and grid integration services have similar, and significant, incremental and decremental reserves capability. At this time, four of the 14 projects in the WECC are used primarily for power supply needs. They are:

- Pacific Gas &Electric - Helms
- Southern California Edison - Eastwood
- Public Service of Colorado - Cabin Creek
- Los Angeles Department of Water & Power - Castaic

The remaining existing ten projects' primary mission is to meet water supply commitments for irrigation and drinking water – power supply and grid needs were found to be a distant secondary usage of the projects. A detailed review of operational history confirms that these plants have not provided regulation services in the past for frequency regulation and load following. Therefore, caution is required when using historical data for these ten pumped storage projects to assess the future applicability to pumped storage.

Under Task 6, the project team will study the costs and benefits of retrofitting pumped-hydro facilities with technologies that enable regulation capability in the pumping mode as well. Table 3-5 presents a list of the pumped-hydro projects in the western interconnection.

Table 3-5
Pumped-Hydro Facilities in the Western Interconnection

Utility	Plant	State	Nameplate Capacity (MW)	Dominant Concern
Salt River Project	Horse Mesa	AZ	100	Water
Salt River Project	Mormon Flat	AZ	54	Water
Central Arizona Water Conservation District	Waddell	AZ	40	Water
City of Los Angeles	Castaic	CA	1440	Electricity
California Dept. of Water Resources	Edward C Hyatt	CA	293	Water
Pacific Gas & Electric Co.	Helms	CA	1053	Electricity
Southern California Edison Co.	J S Eastwood	CA	200	Electricity
U.S. Bureau of Reclamation	O'Neill	CA	25	Water
California Dept. of Water Resources	Thermalito	CA	83	Water
California Dept. of Water Resources	W R Gianelli	CA	424	Water
Public Service Co. of Colorado	Cabin Creek	CO	300	Electricity
U.S. Bureau of Reclamation	Faltiron	CO	9	Water
U.S. Bureau of Reclamation	Mount Elbert	CO	200	Water
U.S. Bureau of Reclamation	Grand Coulee	WA	314	Water
San Diego Water Authority	Oliven-Hodges	CA	40	Water

Capacity Expansion

The majority of the future scenarios are defined by the capacity expansion planning performed by the NESSIE model. To add new generating capacity in a given year, NESSIE first calculates the cost of delivered energy of the candidate technologies and then adds increments of new generation until demand is met by both existing and new generation resources. The capacity additions each year cover both increases in demand, as well as replacement of retired capacity. The model recognizes that intermittent technologies—such as wind and solar—are primarily fuel savers and provide only limited capacity contributions. Dispatchable generators thus meet most of the system's capacity obligations.

The NESSIE model considers three categories of duty cycle—baseload, intermediate, and peaking service. The relative economics of each technology, which depend on its cost and performance for the duty cycle, are converted into a cost per megawatt hour ($/MWh). This cost reflects the capital cost, the fixed and variable O&M, and the cost of all commodities required for operation.

The capital cost is a one-time expense. The commodities, which include fuel and emission allowances for SOX, NOX, mercury, and CO2, are streams of cost over time, present valued to plant startup. In addition to reflecting regional variations in commodity costs, NESSIE accounts for regional differences in renewable energy resources influencing the cost and performance of renewable technologies.

The cost of individual generation options may be reduced by the direct incentives provided by state and federal governments, such as the production tax credit (PTC). It also may be influenced by RPS requirements specifying that certain fractions of generation must be provided by certain renewable options. RPS mandates create a market for renewable energy credits (RECs). Each megawatt-hour of energy produced by a qualifying renewable technology also produces a REC that may be sold to entities that must meet RPS requirements. For qualifying technologies, the market value of RECs is reflected as a credit against capital, O&M, and commodity costs. For each technology, the total present value is transformed into a levelized cost of energy (LCOE) in $/MWh. The components of cost change significantly over time according to EPRI's projections. Capital cost and conversion efficiency generally improve due to development efforts (technology improvement) and cost reductions (experience-induced learning); in many cases, these advances also are reflected in reduced fuel usage and air emissions. The variable (fuel, O&M, and emission allowance) costs reflect EPRI's projections. Commodity prices reflect both the current price and movement toward a long-run forecast over time.

Once the expansion plans were defined, the results were translated into units and placed on the grid by LCG as described previously.

Hourly wind and solar shapes used to model all the wind and solar generating resources were sourced from the National Renewable Energy Laboratory (NREL). NREL derived the hourly shapes by using historical weather data from 2006 and looking at a detailed level across the United States. The hourly shapes for wind and solar generation indicate the maximum potential megawatts available at each individual site. Actual amounts of renewable installation differ by energy future and are detailed in Section 4: of this report.

Demand Assumptions

LCG developed the hourly demand shapes and the forecast from multiple data sources, including the FERC Form 714 (Annual Electric Control and Planning Area Report) and the WECC Loads and Resources Subcommittee (LRS) filings. The most recent electric demand growth forecasts from individual ISOs, Balancing Authorities, and FERC are consolidated to develop a demand forecast for 2010 through 2020. These forecasts carry a 50-percent probability of occurrence and consider various factors such as population growth, economic conditions, and normalized weather so that there is a 50-percent probability of exceeding the forecast. The internal peak demand forecasts presented here are coincident sums of shaped hourly demands.

Figure 3-7 shows the 2020 forecasted electricity demand for all the balancing authorities in the WECC footprint.

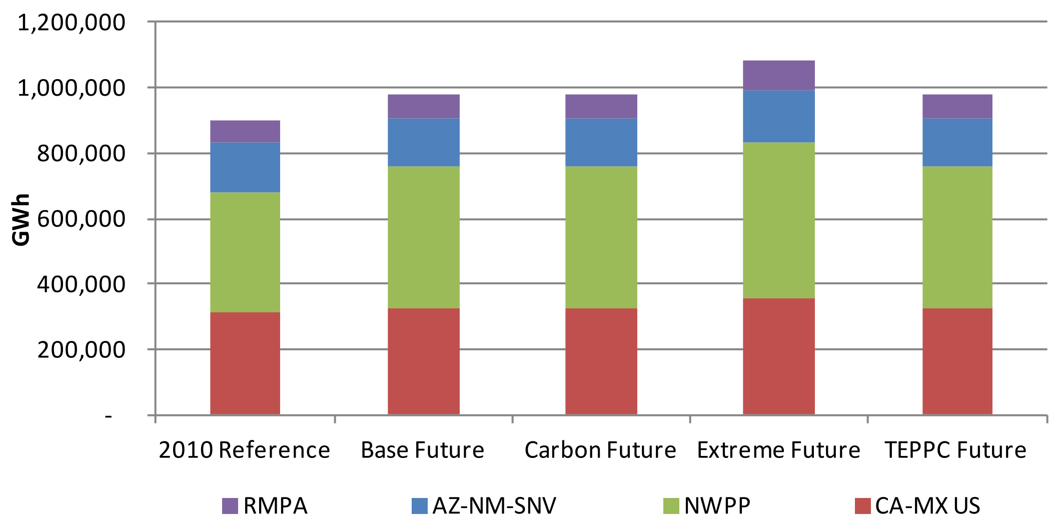


Figure 3-7
Load growth in the Western Interconnection by Energy Future

These numbers represent the load growth used for the average cases that are in place for most of the scenarios. Loads are projected to increase 14 percent from 2009 (actual) to the 2020 (1.2 percent compound annual growth rate). These projections were provided by LSEs via Balancing Authority (BA) reports to the WECC Load and Resource Subcommittee (LRS) data submittal process and adjusted by the SPSC to reflect existing Energy Efficiency (EE) and Demand Side Management (DSM) programs and policies not included in LSE projections. The population of the Western Interconnection continues to increase and is projected to grow 13 percent to 90.7 million people by 2020. The geographic location of the load has a major influence on study results. Over 53 percent of the load (by energy type) is located in coastal states and British Columbia, with 31 percent of the total being located in California. Trends in load growth rates are skewed toward interior states and Alberta. This is due to a combination of higher population growth rates, less-aggressive EE programs, and energy development (e.g., oil sands in Alberta). More information on the different energy futures developed for Task 6 along with load growth assumptions can be found in Section 4: of this report.

Section 4: Energy Future Scenarios and Sensitivity Development

In order to gain insight into the certain facets of the hydro fleet as well as the sensitivity of the results on particular fundamental drivers, simulations of the entire WECC region were conducted under varying conditions. By running many simulations the project team was able to assess the uncertainty surrounding some of the output parameters, perform "what if" analyses and quantify the value of specific system and asset changes and upgrades.

For the purposes of this discussion, each set of model inputs in conjunction with a single model run (or simulation) will be referred to as a "scenario". Many scenarios were developed for this analysis to accommodate analytical needs such as:

- Energy Futures – a set of different global energy outlooks which could, by themselves, define a scenario or could be used in combination with other parameters to develop scenarios.
- Sensitivities – sets of operating conditions or infrastructure assumptions that are designed to work in coordination with the Energy Futures to create scenarios.
- "What if" analyses – specific scenarios developed to analyze one particular facet or asset on the network.

Energy Future Scenarios

Energy Futures are used in conjunction with other sensitivity parameters to develop one of the 23 scenarios run in the model. For example, an Energy Future in combination with average hydro conditions could define a scenario.

Energy Futures do define the inputs needed beyond the parameterization of the existing infrastructure to run the NESSIE model and determine generator expansion and retirement by technology by NERC sub-region. An Energy Future can be described by the common input parameters, defined in Section 3: together with the expansion plan, fuel prices, emission prices, and load growth.

This study employs four distinct Energy Futures to address different evolutionary trajectories that the electric industry may take between the present conditions and those of the year 2020. Much effort has been placed in the development of these futures to ensure that they highlight both realistic scenarios for the future as well as give insight into future situations which may have a particularly acute effect on hydro performance. The following Table 4-1 summarizes the four Energy Futures have been developed and analyzed. Each is described in the subsequent subsections.

Table 4-1
Energy Futures

Future	CO_2 Emission Costs	Demand	Notes
Base	None	Average	NESSIE-Based Generation/Renewable Expansion
Carbon	$.02/lb	Average	NESSIE-Based Generation/Renewable Expansion
Extreme	$.02/lb	High	NESSIE-Based Generation/Renewable Expansion; High Gas Price
TEPPC	None	Average	TEPPC-Based Generation/Renewable Expansion

The generation mix present in the Base, Carbon, and Extreme Futures were developed using the NESSIE model, starting with the existing assets as of 2010 and differing assumptions regarding:

- Natural Gas Prices
- Emission Costs
- Load Growth
- Renewable Energy Policy

The starting point, with regards to generator mix, which was used as input to the NESSIE model for all NESSIE-based Energy Future Scenarios, is shown in Table 4-2. The only Energy Future Scenario which is not NESSIE-based is the TEPPC Future, which is the future as seen by the WECC's Regional Transmission Expansion Planning project and includes the generators anticipated to be in place by that group's Transmission Expansion Planning Policy Committee. Their generator expansion (and retirement) plan has the advantage of being well vetted by the industry and includes plant-level details for new builds as well as locations on the network.

Table 4-2
NESSIE 2010 Thermal Generation "Starting Point" Assumptions

Technology	AZ-NM-SNV	CA-MX US	NWPP	RMPA	WECC
Biomass	-	476	641	-	1,118
Coal	10,615	2,083	18,520	7,186	38,404
Combined Cycle	16,314	21,245	10,097	2,594	50,250
Combustion Turbine	3,570	8,034	5,415	3,333	20,353
Geothermal	-	2,578	393	-	2,972
Hydro	3,906	9,052	46,887	1,151	60,996
Nuclear	4,035	4,390	1,160	-	9,585
Other Thermal	2,422	17,271	2,230	469	22,392
Pumped Storage	198	3,639	314	560	4,711
Solar	144	413	-	8	565
Wind	394	2,530	7,356	1,224	11,503

Base Case 2020 – "Base"

The Base Future represents the most likely generator mix for WECC in 2020 as determined by the expansion modeling system, NESSIE.

The fundamental inputs to the NESSIE modeling system are the existing WECC fleet as of 2010, Table 4-2, and future conditions including load growth assumptions, emissions costs, and renewable build-out constraints.

NESSIE works in conjunction with the EIA National Energy Modeling System (NEMS). NEMS is a general equilibrium model where supply and demand are specified as functions. The input to the NEMS model consists of the Energy System in its current state as well as a fuel cost model, energy policies and load demand curves. When considering the NESSIE and NEMS systems as a single expansion planning platform, the results are not only the generation mix, but also the fuel and emission prices.

Table 4-3
Emission Prices - Base Future

Emission Costs ($/lb)	
SOX	0.01
HG	35,377
CO2	-

The resulting fuel prices are broken down by year by NERC sub-region. Based on historical trend, LCG further broke down these prices by month and by state. Figure 4-1 below shows coal and natural gas fuel prices in 2010 real U.S. dollars averaged throughout the region for 2020 for the Base Future for reference. Note that within UPLAN, each unit has a separate price based on location and fuel type.

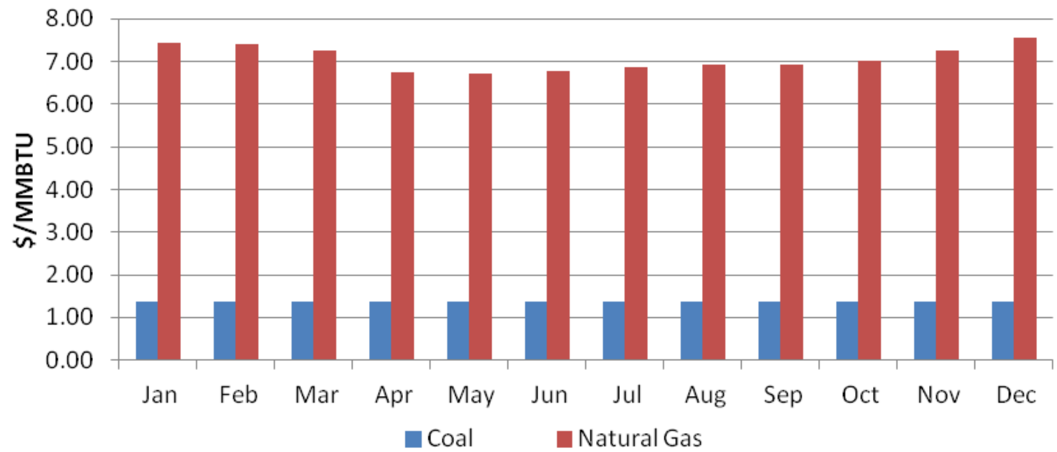


Figure 4-1
Base Future 2020 Average Fuel Prices[1]

The generator mix that is the result of the NESSIE expansion planning system is visible in Table 4-4. NESSIE determines the installed capacity of various technologies at the sub-region level. These results are then converted into actual generating units and placed onto the network by LCG and ultimately are input into the UPLAN model.

Table 4-4
Installed Capacity (MW) by Sub-Region - Base Future

Technology	AZ-NM-SNV	CA-MX US	NWPP	RMPA	WECC
Biomass	70	515	1,128	-	1,713
Coal	12,628	2,083	20,803	9,199	44,713
Combined Cycle	16,410	31,970	14,723	2,383	65,487
Combustion Turbine	4,031	9,234	4,741	2,264	20,270
Geothermal	244	8,835	645	79	9,803
Hydro	3,906	9,078	49,002	1,151	63,137
Nuclear	4,035	4,390	1,160	-	9,585
Other Thermal	600	3,969	1,173	280	6,022
Pumped Storage	198	3,639	314	560	4,711
Solar	226	1,554	75	25	1,880
Wind	832	8,708	12,689	1,997	24,225

In Figure 4-2 below, the difference in installed capacity between the Base Future and the 2010 reference is shown by NERC sub-region and then for the entire WECC. The bulk of the changes to the system occur in the Northwest and in

[1] These prices are based on the NESSIE model and a stakeholder process. It is important to note that while the natural gas prices look high given current prices, the future market is uncertain and prices could go up in the future. Using this higher future prices, gives an idea how this would affect hydro.

California where significant amounts of combined cycle are installed. Renewables including wind and geothermal experience growth, while a large quantity of older thermal units termed "other thermal" are retired. "Other thermal" is a catch-all category for the numerous smaller thermal plants around the system including fuel oil, steam plants, internal combustion, and oil combustion turbines. Note also that because the Base Future does not have emissions costs a small amount of coal capacity has been added.

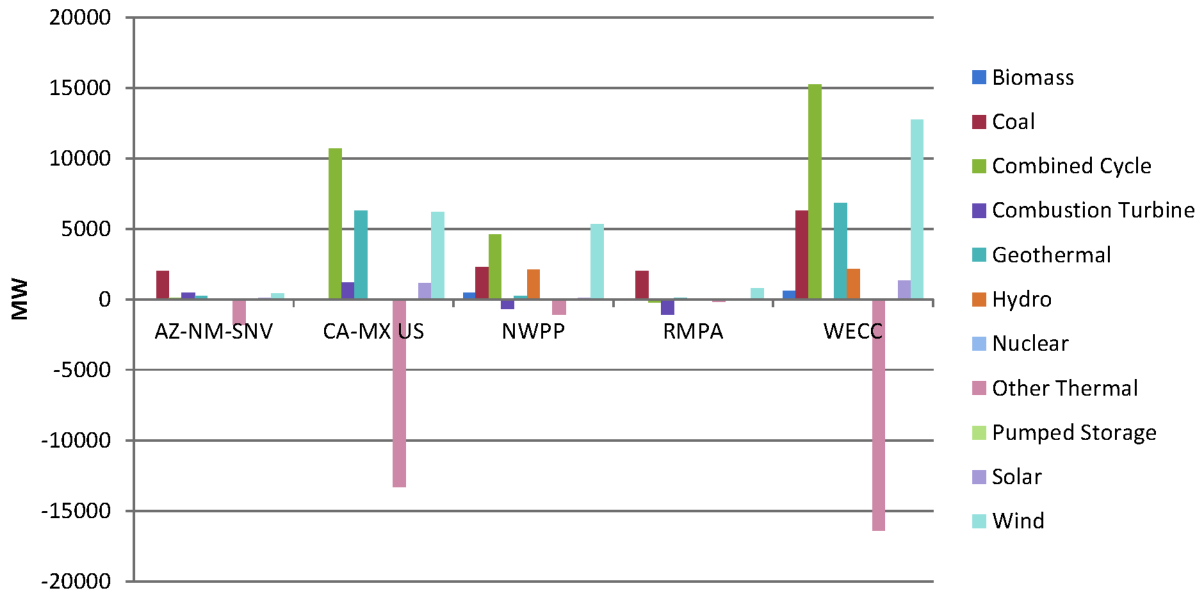


Figure 4-2
Installed Capacity – Base Future minus 2010 Reference

WECC-TEPPC 2020 – "TEPPC201D

The TEPPC Future is unique among the Energy Futures in that it relies on the expansion planning work done by another organization rather than an internal expansion modeling effort. The TEPPC group at WECC built this future with input and analysis from industry and represents their best guess at what the generation mix in WECC will look like under most likely conditions.

Loads in the TEPPC base case reflect the load forecasts of the BAs, as submitted to the WECC LRS. Energy Efficiency (EE) and Demand-side Management (DSM) assumptions are also provided by the BAs.

The generator mix was created by incorporating projects under construction, renewable resource additions that are required to meet statutory Renewable Portfolio Standards (RPS), and additional thermal generation needed to meet WECC's reserve margin targets for sub-regions of the Western Interconnection. The generation additions were selected from resources proposed in utility Integrated Resource Plans (IRP), proposed generation in BA submittals, and where the Western Renewable Energy Zones resource screening results indicated a need.

As shown in Figure 4-3, natural gas prices in this scenario are slightly higher than those found in the Base Future because they come from a different forecasting mechanism.

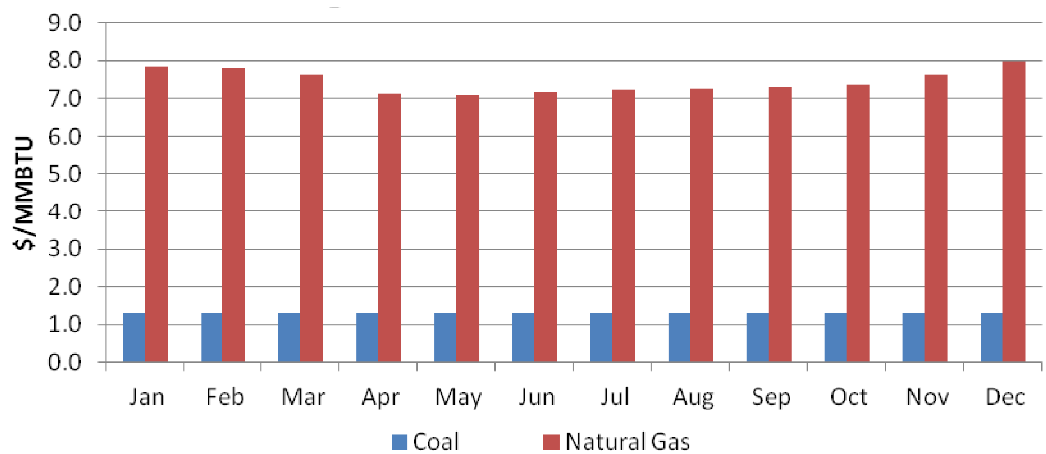


Figure 4-3
Base Future 2020 Average Fuel Prices

The installed capacity by sub region for the TEPPC Future can be seen in the table below. Hydro and nuclear capacity does not change between the various Futures, but all other technologies do experience some change.

Table 4-5
Installed Capacity (MW) by SubRegion - TEPPC Future

Technology	AZ-NM-SNV	CA-MX US	NWPP	RMPA	WECC
Biomass	-	575	5,088	2,438	8,100
Coal	12,039	2,083	15,947	6,963	37,032
Combined Cycle	17,059	32,654	15,714	2,211	67,638
Combustion Turbine	3,824	8,773	4,834	2,264	19,696
Geothermal	244	7,235	775	79	8,333
Hydro	3,906	9,078	49,002	1,151	63,137
Nuclear	4,035	4,390	1,160	-	9,585
Other Thermal	430	4,284	1,046	329	6,089
Pumped Storage	198	3,639	314	560	4,711
Solar	314	2,309	123	25	2,771
Wind	1,244	8,458	12,989	2,574	25,264

When compared against the Base Future, as in Figure 4-4, it can be seen that the TEPPC group is making similar decisions with regards to overall capacity, but is more favorable to some technologies than others. TEPPC builds a lot of solar, where NESSIE views geothermal as attractive. TEPPC builds a very large number of Combustion Turbines, whereas NESSIE prefers Combined Cycles and even a little bit of coal (note that in the Base Future, Carbon emission costs are not considered). Also notable is the fact that NESSIE retires a large quantity of small and old thermal plants lumped together as "Other Thermal".

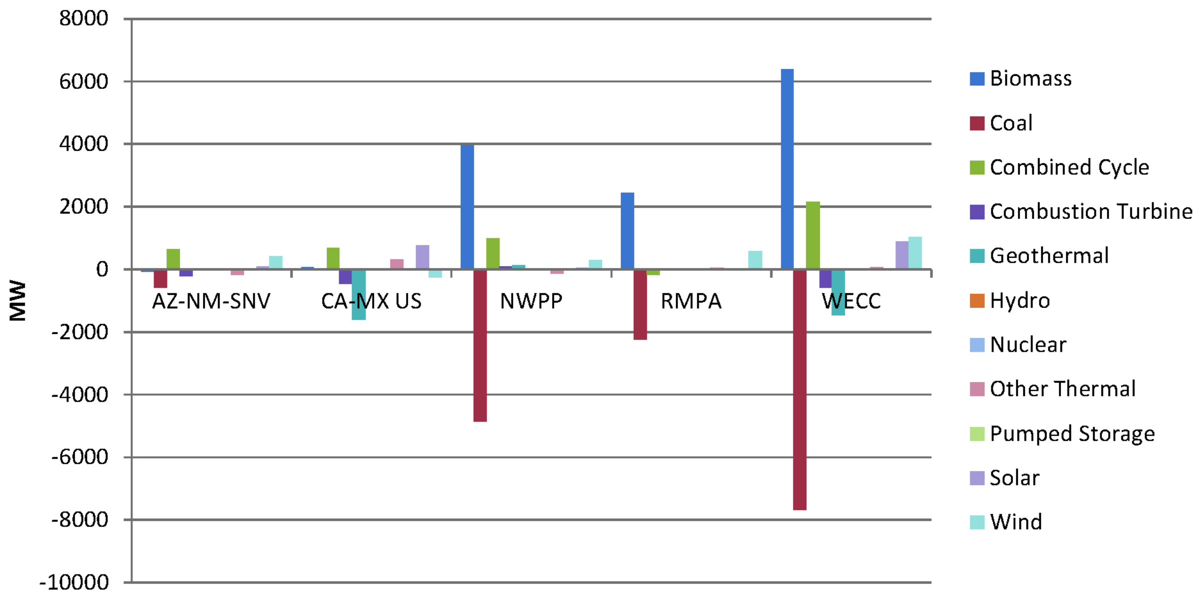


Figure 4-4
Installed Capacity – TEPPC Future minus Base Future

Carbon Policy 2020 – "CARBON"

The Carbon Future is very similar to the Base Future in terms of input assumptions, with the important exception that in the Carbon Future the assumption is made that there is a carbon policy in place which places an emission allowance cost on CO_2. All other assumptions remain the same including load growth.

Table 4-6
Emission Prices – Carbon Future

Emission Costs ($/lb)	
SOX	0.02
HG	10,138
CO2	0.02

Average real fuel prices can be seen in Figure 4-5, below. Gas prices are slightly lower than in the base case due a decrease in demand. Again, fuel prices are an outcome of the expansion planning process, not input. With CO_2 allowances in effect, less gas is utilized and that is reflected in the prices.

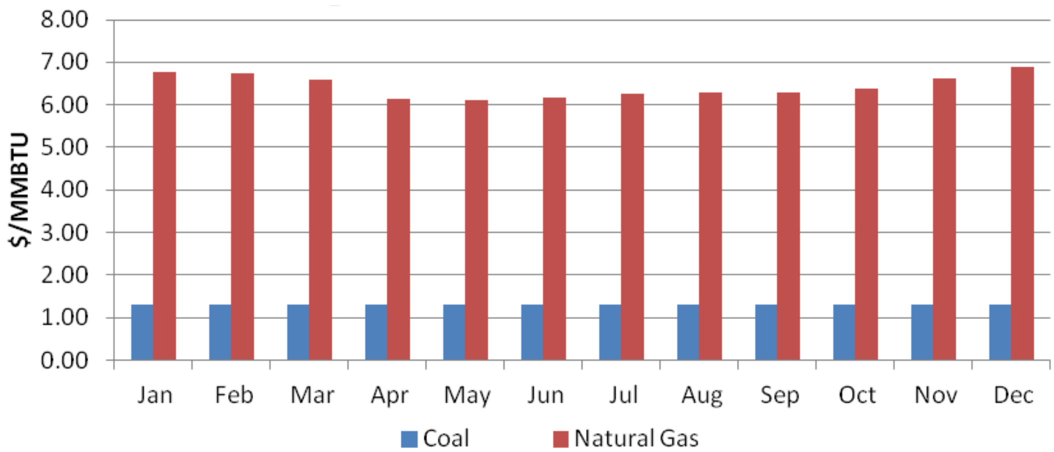


Figure 4-5
Average Fuel Prices - Carbon Future

Table 4-7
Installed Capacity (MW) by SubRegion - Carbon Future

Technology	AZ-NM-SNV	CA-MX US	NWPP	RMPA	WECC
Biomass	825	612	5,396	2,459	9,292
Coal	14,261	2,083	18,087	8,904	43,336
Combined Cycle	17,377	34,467	17,176	2,347	71,367
Combustion Turbine	4,762	11,261	6,824	2,311	25,158
Geothermal	470	9,135	1,200	460	11,265
Hydro	3,906	9,078	49,002	1,151	63,137
Nuclear	4,035	4,390	1,160	-	9,585
Other Thermal	494	3,763	1,096	363	5,716
Pumped Storage	198	3,639	314	560	4,711
Solar	496	2,384	228	25	3,133
Wind	2,407	9,458	16,101	2,677	30,642

The results of the NESSIE expansion run can be seen in Table 4-7. In this case, there is significantly less coal than in the Base Future. Biomass takes over much of the slack left by the missing coal along with lower emission Combined Cycle plants.

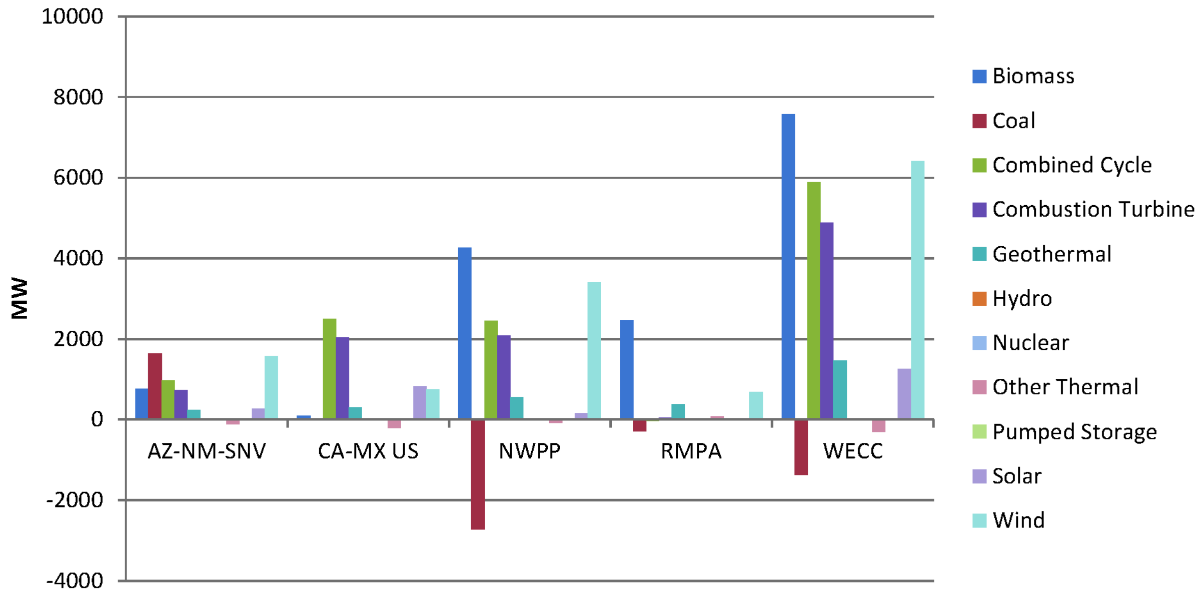


Figure 4-6
Installed Capacity – Carbon Future minus Base Future

Hydro Centric 2020 – "Extreme"

In producing the individual Energy Futures, much effort was placed into determining what would be the most likely future conditions based upon realistic and defensible assumptions concerning the condition of the network and energy policy for the year 2020. In The Extreme Future, we draw upon the main drivers of uncertainty and attempt to make assumptions which would likely be the most favorable for conventional hydro. This does not mean that the Extreme Future is unrealistic, but rather that for each of the principle assumptions that were made for the inputs to the NESSIE model, the project team attempted to select realistic values that would, at the same time, be favorable to conventional hydro.

Without running a complete production costing simulation, it is very difficult to say, definitively, whether a certain input assumption would be favorable or not to hydro, but the experience of the Team was drawn upon to develop some assumptions which were generally agreed upon. These assumptions revolved around two concepts which are generally assumed to be true:

1. Since higher energy prices typically lead to increased profit for conventional hydro, increased load growth, higher fuel prices and emission costs should all drive increased revenue.
2. Less flexible thermal generation in the future will increase the profitability of relatively unconstrained conventional and pumped-storage hydro in the realm of ancillary services.

The result of the Team's discussions and scenario planning exercises can be seen in the Table 4-8, Figure 4-7 and Table 4-9, which were the results of the NESSIE expansion planning exercise.

Table 4-8
Emission Prices – Extreme Future

Emission Costs ($/lb)	
SOX	0.03
HG	17,903
CO2	0.02

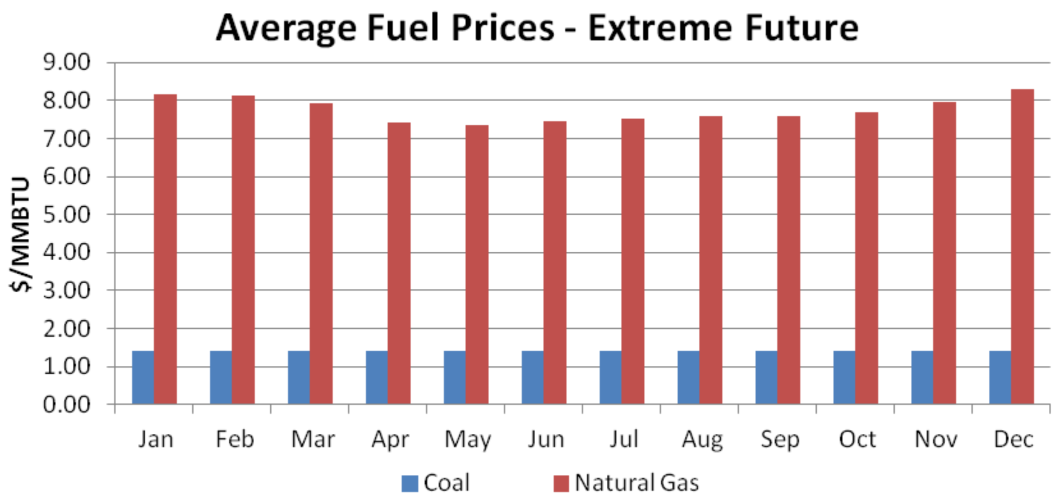


Figure 4-7
Average Fuel Prices - Extreme Future

Table 4-9
Installed Capacity by SubRegion - Extreme Future

Technology	AZ-NM-SNV	CA-MX US	NWPP	RMPA	WECC
Biomass	825	612	5,396	2,459	9,292
Coal	11,358	7,890	18,087	6,001	43,336
Combined Cycle	17,377	34,467	17,176	2,347	71,367
Combustion Turbine	4,762	11,261	6,824	2,311	25,158
Geothermal	470	9,135	1,200	460	11,265
Hydro	3,906	9,078	49,002	1,151	63,137
Nuclear	4,035	4,390	1,160	-	9,585
Other Thermal	494	3,763	1,096	363	5,716
Pumped Storage	198	3,639	314	560	4,711
Solar	496	2,384	228	25	3,133
Wind	2,407	9,458	16,101	2,677	30,642

In the Extreme Future more capacity is placed on the system across all regions simply because there is more load present. Emission Costs play a significant role and promote large investments in biomass, combined cycles, wind and to a smaller extent, solar. New-found peaks encourage the development of combustion turbines.

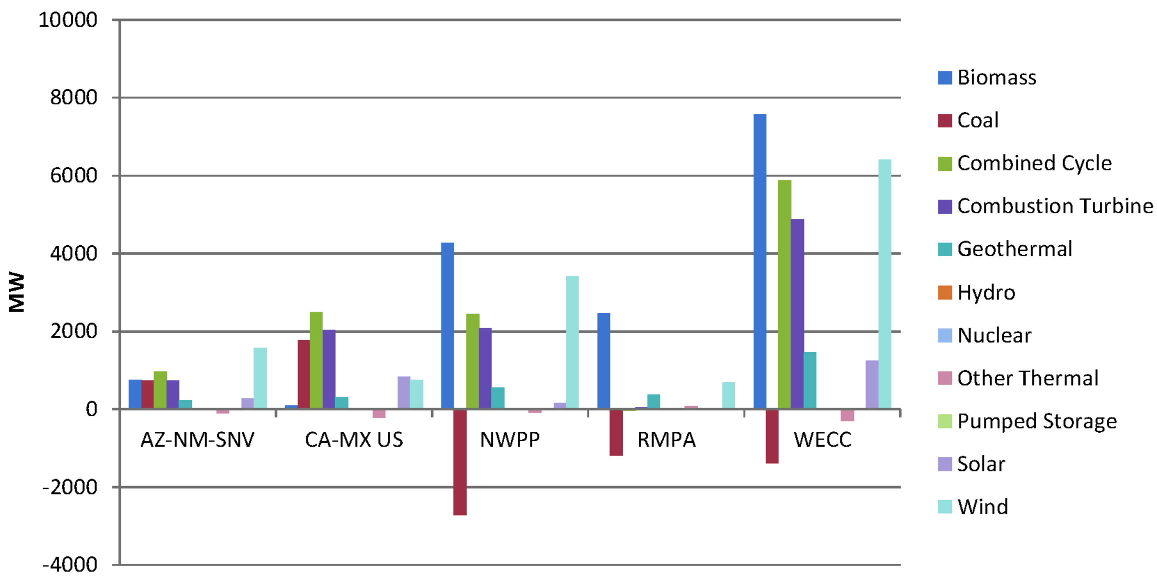


Figure 4-8
Installed Capacity – Extreme Future minus Base Future

Model Sensitivities

Once the different Energy Futures were in place, sensitivities were incorporated within the context of theses Energy Futures to define specific scenarios for simulation. The following sections describe these sensitivities and the input assumptions that define them.

Varying Hydro Conditions

The amount of hydro available in a given year is related to a number of factors including precipitation and snowpack-snowmelt timing. Since water, as a fuel, is essentially free, the amount of water available to the hydro plants has a very large impact on their revenue.

In order to capture levels of water inflow that are realistic, the Team's approach was to look at historical capacity factor data, by year, and identify two historical years: one for "low hydro" and another for "high hydro".

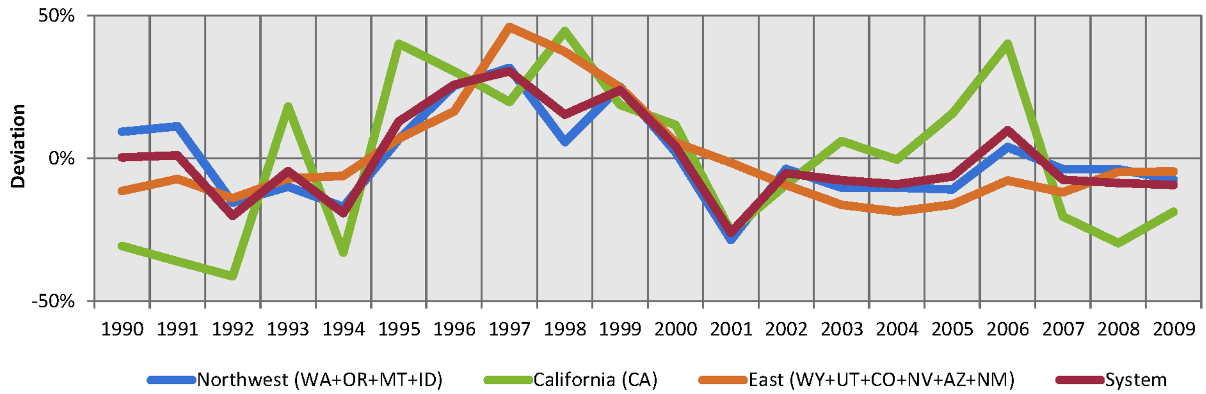


Figure 4-9
Hydroelectric Generation - Deviation from Average (Source EIA/CAISO)

As it turns out, 2011 was actually one of the wettest years in recent history for the Pacific coast states, but at the time of the analysis, there was not enough data available to use 2011 as hydro reference year. Analysis of the data led to the decision that the 2001 would be used for the Wet sensitivity and 1997 for the Dry. Note that in Figure 4-9 percentages less than 0 indicate Wet years and percentages greater than 0 indicate dry years. EIA plant data was then used to determine, plant by plant, the expected inflow on a monthly basis.

More Pumping Plants

The development of candidate sites for new pumped storage facilities was a task which involved a number of project team members as well as feedback from industry. An initial list of projects was developed by HDR Engineering Inc. as seen in Figure 4-10.

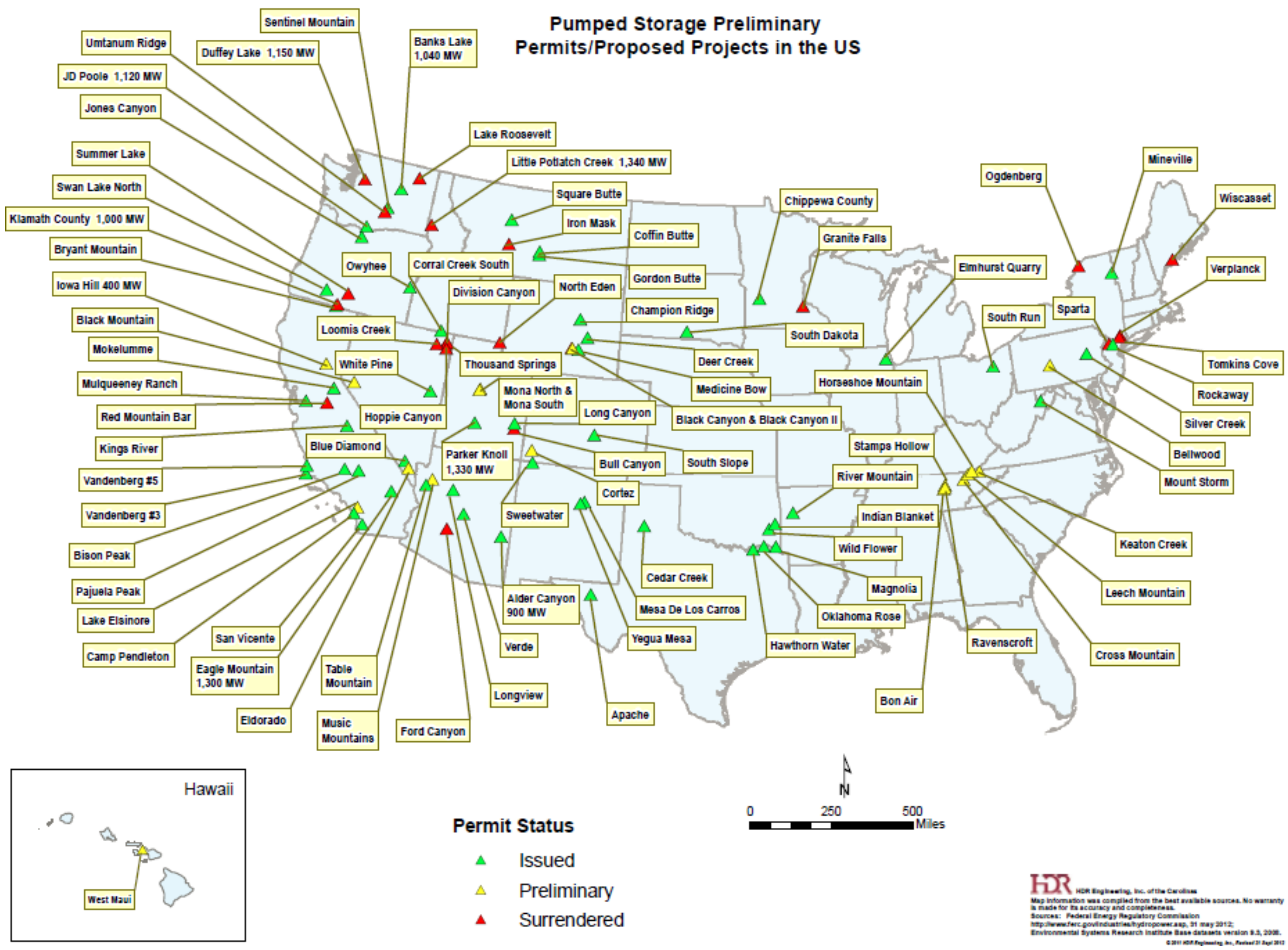


Figure 4-10
Proposed Pumped Storage Sites (Source HDR)

After presenting the initial list to stakeholders, a certain amount of discussion ensued which ultimately lead to a short list of *Top WECC pumped storage sites* as suitable representative projects for use in the UPLAN modeling can be seen in Table 4-10.

Table 4-10
Final List of Candidate Pumped Storage for Evaluation

Project	Capacity (MW)	# Units	Connection
North CA Project	400	3	Whiterock
Utah Project	1,330	10	Sigurd
South CA Project	1,300	4	Midpoint
Oregon Project	1,250	5	Malin
New Mexico Project	900	3	Shiprock

Performing simulations with these plants showed that there were some issues surrounding the installation of all five plants simultaneously. First, the plants as modeled were in competition with each other for both ancillary services and energy arbitrage opportunities. Second, there were pre-existing transmission bottlenecks which were aggravated when all of the new plants were trying to pump and generate at roughly the same time.

Since these issues were potentially reducing the profitability of the plants and it isn't likely that all of the plants will immediately and simultaneously be built, it was determined that additional scenarios would be run in order to better understand the viability of new pumped storage in the model. In one of these scenarios, transmission constraints are relaxed to show the profitability of the plants with no issues moving power. In another, only one new pumped storage plant was put online. In all of the scenarios, a 33% renewable penetration in California is applied and the transmission assumptions from the previous section are used- note these assumptions were not developed with new pumped storage in mind.

Wider Operating Range

Adjustable Speed Pumping

In these sensitivities, the intention was to investigate the change in profitability of certain plants based upon investment in upgrades. The sensitivities are designed to look at a single plant and to find the change in revenue with the improved performance that could be expected with investment in the asset. While it is beyond the scope of this study to determine capital requirements and investment criteria, this sensitivity draws upon the work done in Task 3 and Team input to give a first run at this type of valuation.

Pumped storage investments were of particular interest for this sensitivity in which more efficient variable speed pumps were employed in conjunction with state-of-the-art power electronics. From a modeling perspective, these upgrades ultimately translate into increased round trip efficiency and operating flexibility.

Additional Sensitivities

In large part, the sensitivities that were developed were created by altering fundamental inputs in conjunction with the set of Energy Futures. These changes typically consist of altering assumptions for which specific values are not known and therefore could be changed by adjusting them up or down. These consist of inputs such as fuel prices or rainfall. In addition to these types of sensitivities, however, other sensitivities were created by making more sweeping changes to the inputs or to the model settings. These sensitivities were termed "what-if" sensitivities and give additional insight into the value of hydropower.

Ancillary Service Markets

Ancillary service requirements are typically based upon a combination of forecasting and historical operating performance. NERC standards require that adequate generating capacity be available at all times to maintain scheduled frequency and avoid loss of load following contingencies. The reserves held fall into various product types including Regulating Reserve and Contingency Reserve. Actual requirements are defined by maintaining a Balancing Authority's Area Control Error (ACE) within limits established by Control Performance Standards. Contingency reserve requirements are determined by the type and size of the generators on the system and tend to remain relatively constant over the course of the day. Regulation and ramping requirements do change hourly, and the exact requirements are typically a function of the variability of the load (net of variable generation in some regions) on the system. The project team looked over the different requirements for several ISOs that publish the information. In addition, other studies including the Eastern Wind Integration and Transmission Study, Southeast Wind Integration Study and CAISO Renewable Integration Study, were referenced to get an idea of the relationship between the level of ancillary service requirements and the amount of variable energy generation on the system. To accurately predict what these requirements will be in 2020 is a large task which requires a large amount of data and analysis.

Instead, the project team looked at existing requirements and previous work done on quantifying the variability of wind to derive reasonable assumptions about the level of operating reserves that would need to be held in order to maintain the reliability of the system. The actual levels required for non-contingency (regulating) reserve are functions of the variability of the load less production from variable energy resources (e.g. wind and solar) and consider the accuracy of forecasting. With more variable energy generation, these requirements tend to increase in order to accommodate the uncertainty surrounding their availability, and their short term variability.

While there is no real consensus on exactly how to calculate the increased reserve requirements due to increased variable generation, a few different methodologies do exist. These are data intensive, statistical methods. The project team analyzed the results of these analyses and found that variable energy resources on the system seem to change the average regulation requirements by an amount somewhere between 15 MW and 20 MW per GW of installed variable generation capacity, when averaged over the entire year of study[2]. This finding allowed for the team to develop two scenarios (BaseHighRegReq and BaseLowRegReq) using ancillary service requirement levels which would represent realistic extremes. Only regulation requirements were altered by increasing or decreasing the percentage of load that needed to be covered. Therefore, regulation requirements are not directly linked to hourly load and

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[2] For example, the Eastern Wind Integration and Transmission Study (NREL February 2011, http://www.nrel.gov/wind/systemsintegration/pdfs/2010/ewits_final_report.pdf) found that integrating 225,000 MW of wind in the Eastern Interconnection would require, on average, an additional 12,000 MW of spinning reserve of which one third would be regulation.

variable generation production as in the more data intensive studies, but requirements are altered by a similar amount on average for a given installed variable generation capacity. The amount required as calculated in the more detailed studies varies by hour with both the amount of load and the level of wind generation, so the average amount reported here would not tell the full story, as there would be a higher amount needed when VG output is high. However, this simpler approach gives some insight into how hydro may operate with changing regulation requirements. In addition, spin and non-spin are not changed here; in some studies these are also increased, but it is not clear this would definitely be the case (it may be that other products are used instead).The general assumptions made for this analysis can be seen in Table 4-11.

Table 4-11
Operating Reserve Requirements 2020 as % of Load – Base

Region	Reg Up	Reg Down	Spin	Non-Spin
California	2.0%	2.0%	3.5%	3.5%
Pacific Northwest	2.0%	2.0%	3.5%	3.5%
RMPA	1.2%	1.2%	3.5%	3.5%
Canada	1.2%	1.2%	3.5%	3.5%

There were several signs that these requirements would be a natural candidate for sensitivity analysis. First, because there is some uncertainty surrounding the exact level of operating reserves required; and second, it is presumed that much of the value of hydro power will be derived from the natural flexibility of the resource. We assumed that hydro will be able to capitalize on opportunities to sell ancillary services. And, other project-specific operational constraints that may occur due to other beneficial uses such as aquatic resource protection, flood control, navigation, and recreation are not considered.

In order to get some calibration for trading off availability for services and constraints for other functions, two additional levels of requirements were established and simulated. In the first set, variability and forecast error is presumed to be extremely high and regulation requirements are set accordingly.

Table 4-12
Operating Reserve Requirements as % of Load – High Variability

Region	Reg Up	Reg Down	Spin	Non-Spin
California	3.5%	3.5%	3.5%	3.5%
Pacific Northwest	3.5%	3.5%	3.5%	3.5%
RMPA	2.0%	2.0%	3.5%	3.5%
Canada	2.0%	2.0%	3.5%	3.5%

In the second set of alternative requirements, variability and forecast error is presumed to be less than expected values.

Table 4-13
Operating Reserve Requirements as % of Load – Low Variability

Region	Reg Up	Reg Down	Spin	Non-Spin
California	1.5%	1.5%	3.5%	3.5%
Pacific Northwest	1.5%	1.5%	3.5%	3.5%
RMPA	1.2%	1.2%	3.5%	3.5%
Canada	1.2%	1.2%	3.5%	3.5%

Together these two scenarios serve to provide a floor and ceiling for the reserve requirements and opportunities for hydro. Results provide some insight into the ability of hydropower to accommodate variability and to take advantage of the economic opportunities that arise from it.

Relaxed Transmission Constraints

As described in detail in the *Quantifying the Value of Hydropower in the Electric Grid: Modeling Approach and Base Case Scenarios* report, UPLAN is a Security Constrained Unit Commitment (SCUC) and Security Constrained Economic Dispatch (SCED) simulation platform. As such, UPLAN's unit commitment and dispatch decisions are governed by the deliverability of power from the generators via the transmission grid to the loads which are located on the 16,130 buses on the system. For each hour of simulation, UPLAN ensures that all of the network constraints are respected and that power flows in a realistic manner obeying the laws of physics.

This approach ensures that the results produced are realistic for the assumed transmission system. In running the system this way, however, it was shown that some of the hydro units, in particular large pumped storage, suffered from transmission congestion on the system and were not able to operate as efficiently as they could had certain transmission constraints not been binding.

The problematic situation becomes more interesting when considering the fact that hydro can actually benefit from congestion. Since congestion tends to raise prices in some areas and reduce prices in others, conventional hydro may benefit in the case that it is situated in a high price area. Further, although it is less likely, if congestion patterns depress prices only on certain hours in a manner which would allow pumped storage to charge cheaply, but then generate later when the congestion is no longer present, a large energy arbitrage opportunity may be present. This is similar to the concept of putting batteries near wind farms which are sitting behind transmission congestion during the off-peak.

Assumptions have been made regarding transmission upgrades to the system based on work carried out by the TEPPC planning group as described previously. And, while the focus of the project was not to assess capability of the modeled transmission to deliver hydropower, it was a concern that different assumptions about transmission could greatly affect the capability of hydropower to generate revenue, in particular in the case that some actions could be taken to alleviate the congestion and thereby increase the ability of certain plants to participate more in the energy market.

These concerns lead to the development of a number of relaxed transmission scenarios in which the question transmission constraint effects was investigated and quantified. In these relaxed transmission scenarios, the physical laws are respected by power flow analysis that constrain the commitment and dispatch decisions. However, the model was set to not monitor any of the lines for thermal violations. In other words, Kirchhoff's law was still in effect and losses were still considered, but the transfer capability of the individual lines and flow gates was increased.

Scenario and Sensitivity Summary

For much of the remainder of this report, there will be discussion of the various scenarios that have been simulated. Conclusions will be drawn based on the performance of generators and the system as a whole in each of these scenarios.

With such a large number of scenarios, it can be difficult for a reader to differentiate between them all, yet this will be of utmost importance for gaining insight into the future operations of the system and into the value of hydropower. This is especially true because much of the value of hydropower is exposed by the careful selection of scenarios and comparison between their results.

Scenario names have been developed which coordinate with the underlying data and assumptions. Table 4-14 gives a complete list of scenarios and the names.

Table 4-14
Scenario List

Scenario	Hydro Conditions	CO_2 Emission Costs	Demand	Notes
Base-Wet	Wet	None	Average	NESSIE Generation, Renewable Expansion
TEPPC	Normal	None	Average	TEPPC Generation, Renewable Expansion
Base-OneNewPS	Normal	None	Average	NESSIE Generation, Renewable Expansion, one new pumped storage plant added
Base-HighRegReq	Normal	None	Average	NESSIE Generation, Renewable Expansion, increased regulation reserve requirements
Base-PumpUpgrade	Normal	None	Average	NESSIE Generation, Renewable Expansion, variable speed pump added at one plant
Base-GenUpgrade	Normal	None	Average	NESSIE Generation, Renewable Expansion, new technology at one pumped storage plant
Base	Normal	None	Average	NESSIE Generation, Renewable Expansion
Base-LowRegReq	Normal	None	Average	NESSIE Generation, Renewable Expansion, reduced regulation reserve requirements
Base-TransRelax	Normal	None	Average	NESSIE Generation, Renewable Expansion, relaxed transmission
Base-Dry	Dry	None	Average	NESSIE Generation, Renewable Expansion
Base-NoHydroAS	Normal	None	Average	NESSIE Generation, Renewable Expansion, hydro cannot supply ancillary services
Extreme-Dry	Dry	$0.02/lb	High	NESSIE Generation/Renewable Expansion
Base-FiveNewPS-TransRelax	Normal	None	Average	NESSIE Generation, Renewable Expansion, five new pumped storage plants added, relaxed transmission
Carbon-Dry	Dry	$0.02/lb	Average	NESSIE Generation, Renewable Expansion
Extreme-TransRelax	Normal	$0.02/lb	High	NESSIE Generation, Renewable Expansion, relaxed transmission
Base-FiveNewPS	Normal	None	Average	NESSIE Generation, Renewable Expansion, five new pumped storage plants added
Extreme	Normal	$0.02/lb	High	NESSIE Generation, Renewable Expansion
Extreme-OneNewPS	Normal	$0.02/lb	High	NESSIE Generation, Renewable Expansion, Iowa Hill pumped storage plant added
Carbon-OneNewPS	Normal	$0.02/lb	Average	NESSIE Generation, Renewable Expansion, one new pumped storage plant added
Carbon	Normal	$0.02/lb	Average	NESSIE Generation, Renewable Expansion
Extreme-Wet	Wet	$0.02/lb	High	NESSIE Generation, Renewable Expansion
Carbon-TransRelax	Normal	$0.02/lb	Average	NESSIE Generation, Renewable Expansion, relaxed transmission
Carbon-Wet	Wet	$0.02/lb	Average	NESSIE Generation, Renewable Expansion

Section 5: Simulation Analyses

This section provides the results of capacity expansion and production cost analysis for 2020 under the various scenarios described in Section 4: and listed in Table 4-14.

Base Case Results

The Base Scenario is designed to serve as a reference case to which other scenarios will be compared in order to glean information as to how changes in assumptions will affect the results, as a whole, and hydropower in particular. The annual hourly chronological simulation for the year 2020 has been developed using moderate, "most likely" baseline system conditions of load, hydro and other renewable energy production, etc. It deliberately avoids the use of highly speculative or unlikely energy futures. The generation plant expansion and retirement plans used for the simulation came from the Base Energy Future which was developed using the EPRI NESSIE model and the same most likely case or moderate assumptions.

The following subsections contain the results of the Base Scenario simulations and the subsequent section, Future Scenario Results, contains the results of the additional scenarios which are compared against this Base Scenario to develop the analysis and results.

Annual Generation

The energy generation summary for the Base Case is shown in Table 5-1 below. The biggest energy contributions come from coal (32%), conventional hydro (25%) and gas-fired combined cycle (19%) plants. Renewable generation, excluding hydro, accounts for 13% of the total.

In 2020 the production simulation indicates that coal generation (electric energy from coal) increases slightly over 2010 levels due to increased load and higher gas prices. Geothermal, wind and solar also show jumps in generation levels over 2010, principally due to increased generation capacity and the priority given to renewable in the dispatch stack. For a complete description of the 2010 reference case, please refer to the *Quantifying the Value of Hydropower in the Transmission Grid: Modeling Approach and Base Case Scenario.* Note that the base case results have been updated since the *Modeling Approach and Base Case Scenario* report.

Table 5-1
2020 Base Scenario Annual Generation (GWh)

Technology	AZ-NM-SNV	CA-MX US	NWPP	RMPA	WECC
Biomass	1	1,804	3,087	-	4,892
Coal	76,973	47,316	152,151	53,041	329,481
Combined Cycle	29,027	97,148	60,284	10,855	197,313
Combustion Turbine	2,864	2,496	2,297	1,277	8,934
Geothermal	1,739	53,760	4,429	506	60,435
Hydro	9,439	42,955	204,128	2,861	259,382
Nuclear	35,443	38,562	10,189	-	84,195
Other Thermal	36	1,845	4,079	19	5,979
Pumped Storage	257	3,592	390	673	4,912
Solar	582	3,744	122	55	4,502
Wind	2,446	21,603	32,754	5,915	62,719
Grand Total	158,807	314,824	473,911	75,203	1,022,745

Figure 5-1 below shows a typical week of WECC-wide dispatch in the base scenario. Nuclear, coal and geothermal dispatch results show relatively constant outputs, day and night. Hydro is a major contributor in April, day and night, and favors generation during daily peak load periods. Pumped storage generation is present only during peak hours. Wind plays a big role and can be seen to displace combined cycle generation during the off-peak periods.

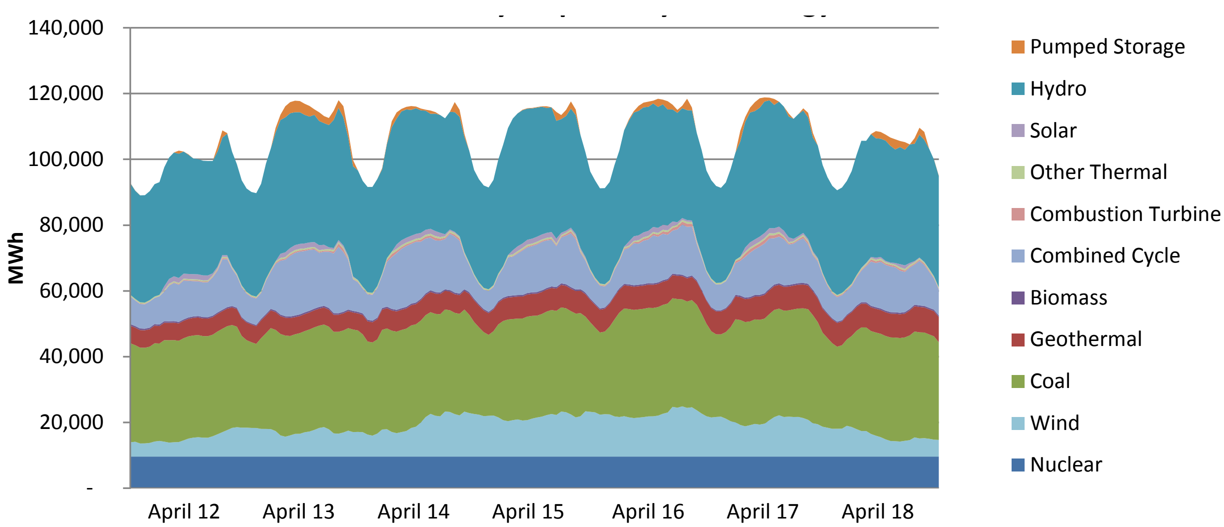


Figure 5-1
A sample weekly dispatch in WECC for April 12-18, 2020 Base Scenario

When the 2020 expected generation is compared to the 2010 Reference case, as in Figure 5-2, the 2020 Base exhibits some significant changes. Total generation is increased because of load growth over ten years. Coal production is up 55TWh due to its relatively low fuel costs (assuming no carbon tax). Also there is expected small amount of capacity expansion from; the Base Scenario as well as

6GW of new capacity (see Figure 4-2). Geothermal is also up 40.5TWh because of significant expansion in that technology in the Base Energy Future. These increases come primarily at the expense of the natural gas units which suffer from higher gas prices.

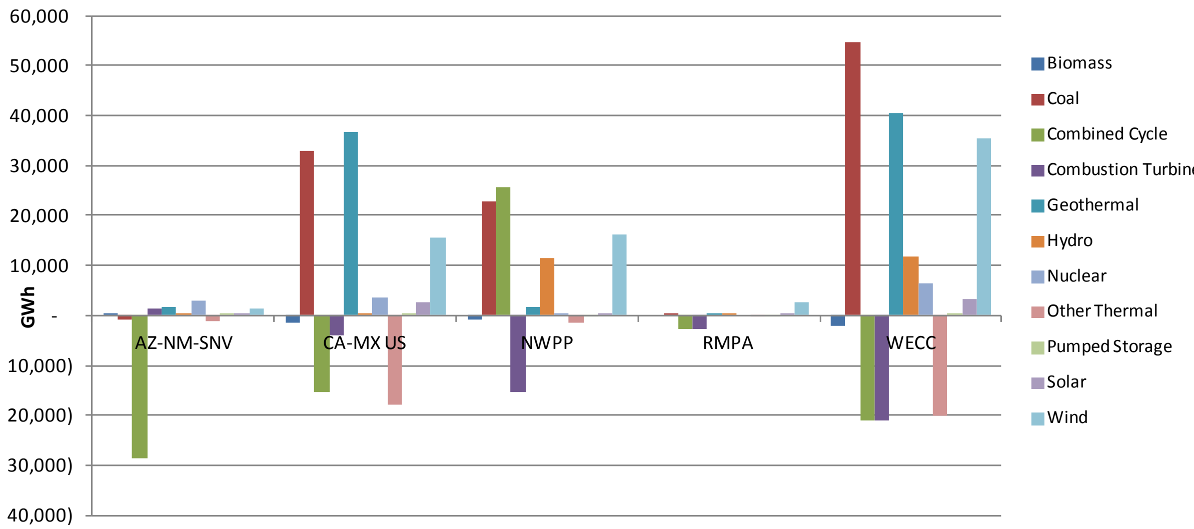


Figure 5-2
Generation by region and technology – 2020 Base Scenario minus 2010 Reference Case

Hydropower Performance

Conventional hydro generation is expected to grow only slightly in the WECC 2020 base case. Still it is expected to account for 25% of the total energy produced in the footprint. For the most part, all of this hydro is existing today, with the exception of some very small additions in California and approximately 2,100MW of new capacity in the Canadian portion of WECC.

Conventional hydro is modeled to have some degree of flexibility, but not so much that there are large swings in production. Average off-peak generation is expected to be about 70% of the average on-peak generation. See Figure 5-1 for some visual indication of this pattern. Since hydro is energy limited, the natural economic tendency would be to take advantage of higher price periods of the day to increase generation and augment its energy revenue by providing ancillary services. This does occur, but the opportunity is limited due to several non-power constraints.

Average plant revenues range from 134 to 230 $/kW when considering the base scenario for different sub-regions. RMPA and AZ-NM-SNV regions are on the low side and the NWPP and CA regions are higher. This difference is mainly due to low capacity factors, around 30%, in the eastern sub-regions and relatively high capacity factors, around 50%, in the western sub-regions of WECC.

Table 5-2 shows California prices are slightly higher than average, but generally prices are not very different among sub-regions. In U.S. RMPA prices are higher than other sub-regions due to a small amount of interface congestion particularly in the summer. In July, RMPA energy prices are about $10 higher than other sub-regions.

Table 5-2
Conventional Hydro Performance – Base Scenario

Region	Capacity (MW)	Generation (GWh)	Energy Revenue ($1000)	Ancillary Service Revenue ($1000)	Net Income ($1000)	Average Revenue ($/kW)
AZ-NM-SNV	3,906	9,439	457,617	67,053	515,231	134
CA-MX US	9,078	42,955	1,972,423	116,824	2,046,302	230
NWPP	49,002	204,128	9,854,020	153,028	9,802,920	204
RMPA	1,151	2,861	152,392	25,266	174,797	154
WECC	63,137	259,382	12,436,451	362,171	12,539,250	203

Pumped-hydro energy storage plants can be used for bulk energy arbitrage. For energy arbitrage, low cost energy is used to pump water from lower reservoir and when the prices of energy are higher the storage inventory is discharged through a turbine to generate electricity. This method of operation is profitable when the round-trip efficiency of the pumped-hydro plant ($\eta_{pump}*\eta_{gen}$) exceeds the ratio of the price for off peak pumping electricity over the price available for on peak generation, "off-peak/peak ratio" (P_{pump}/P_{gen}).

In addition to selling into the energy market, pumped-hydro can also provide ancillary services. In order to participate in the ancillary services market, the unit must be online and sufficient reserves have to be maintained in the reservoir (storage). The pumped-hydro units are well suited to provide regulation, spinning and non-spinning (quick start in 1-2 minutes) reserves where most ISOs require spinning to begin generating within 10 seconds and non-spinning within 10 minutes. Expected future ancillary service markets in WECC tend to provide considerable revenues, and improve the net income.

Pumped-hydro operations were found to be more profitable during the high wind months when wind generation tends to lower night time energy prices. In addition to energy arbitrage, pumped-hydro participates in the ancillary service markets during times when ancillary service prices are high - opportunity costs of providing an ancillary service are typically higher during summer when the energy prices are high as well.

Table 5-3
Pumped Hydro Performance – Base Scenario

Subregion	Capacity (MW)	Generation (GWh)	Energy Revenue ($1000)	Ancillary Service Revenue ($1000)	Energy Cost ($1000)
AZ-NM-SNV	198	257	14,883	5,016	12,198
CA-MX US	3,639	3,592	196,438	11,923	165,420
NWPP	314	390	22,672	4,331	17,600
[3] RMPA	560	673	41,674	1,656	32,085

Table 5-3, above, shows the performance of pumped hydro by sub-region and Table 5-4 shows the performance of each individual plant for the 2020 Base Scenario. The best performing plants are in uncongested areas. Moreover, some of the larger plants' revenue is limited because their operation causes congestion.

[3] Energy Revenue refers to the total revenue collected for power delivered; Reserve Revenue refers to the total revenue collected for the provision of ancillary services; pumping cost refers to total payments for power required to run the pumps; and Average Income is the Net Income divided by the unit size.

Table 5-4
Pumped Storage Plant Performance - Base Scenario

Plant	Number of Units Modeled	Capacity (MW)	Generation (GWh)	Energy Revenue ($1000)	Ancillary Service Revenue ($1000)	Energy Cost ($1000)	Net Income ($1000)	Average Income ($/kW)
Waddell	1	40	51	2,973	1,147	2,329	1,792	44.8
Horse Mesa	1	111	147	8,533	3,169	7,070	4,633	41.7
Grand Coulee	6	314	390	22,672	4,331	17,600	9,403	29.9
Mormon Flat	1	47	59	3,376	700	2,800	1,276	27.1
Cabin Creek	2	324	378	23,507	930	17,809	6,628	20.5
Faltiron	1	36	46	2,796	110	2,201	705	19.6
Mount Elbert	2	200	250	15,372	616	12,075	3,912	19.6
Oliven-Hodges	2	40	49	2,824	167	2,264	727	18.2
W R Gianelli	8	424	531	30,103	1,605	24,433	7,275	17.2
O'Neill	6	13	18	993	87	870	210	16.7
Edward C Hyatt	3	396	554	29,381	1,805	25,938	5,248	13.3
Castaic	6	1,275	1,484	83,287	469	67,288	16,468	12.9
J S Eastwood	1	207	275	13,506	1,400	12,631	2,275	11.0
Thermalito	3	84	50	2,658	543	2,412	803	9.5
Helms	3	1,200	630	33,687	5,848	29,585	9,950	8.3

Figure 5-3 shows the total energy dispatched by the generating turbines of the pumped hydro facilities across WECC. The energy pumped into the upper reservoir is generally higher than the energy dispatched to the grid due to round-trip efficiency loss. Historical results are shown in various shades of gray. The 2020 Base Scenario results are shown in red and exhibit an increase in the utilization of these assets. This increase is most evident during winter and spring months when the wind tends to blow the hardest. Bulk energy arbitrage income is directly related to the spread between prices during off-peak and on-peak hours. More wind at night tends to increase the spread.

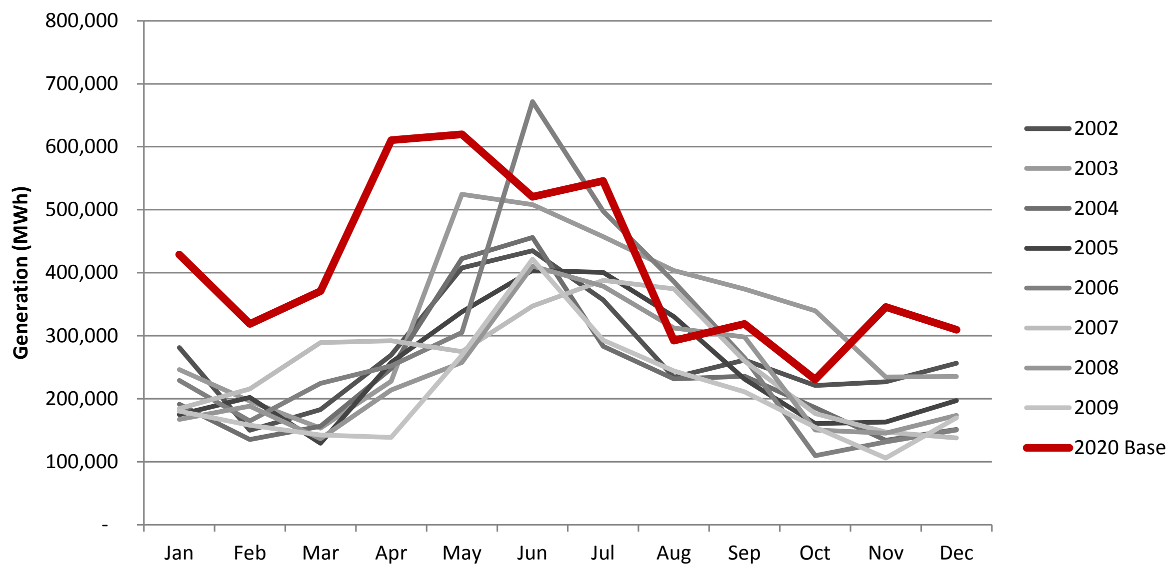


Figure 5-3
Monthly Generation for Pumped-Storage Hydro - UPLAN Future vs. Historical

Energy and Ancillary Services

This section summarizes the performance of various generation technologies in energy and ancillary services in the WECC sub-regions for the Base Scenario. UPLAN co-optimizes the energy and ancillary service products and in the process economically clears the generators offers and demand bids for each product. In addition to energy, UPLAN models five ancillary services that include regulation up, regulation down, spinning reserve, non-spinning reserve, and replacement reserve.

Table 5-5 contains a summary of the participation of various WECC generating units, aggregated by technology type. Fuel mix and the marginal fuel type play a large role in defining the market clearing prices and participation of generators in providing various ancillary services.

Table 5-5
Participation of Generators in Energy and Ancillary Services

Technology	REG DOWN Revenue ($1000)	REG DOWN Quantity (GW)	REG UP Revenue ($1000)	REG UP Quantity (GW)	SPIN Revenue ($1000)	SPIN Quantity (GW)	NON-SPIN Revenue ($1000)	NON-SPIN Quantity (GW)
Biomass							0	0
Coal	9,607	976	11,041	637	874	44	3,365	167
Combined Cycle	37,839	4,888	32,760	3,647	18,620	1,671	10,591	1,814
Combustion Turbine	115	10	16	2	255	22	4,181	1,870
Hydro	81,853	9,777	71,734	11,971	162,470	38,867	46,114	12,355
Other Thermal	189	15	585	24	207	8	1,491	305
Pumped Storage	1,354	170	4,440	619	2,035	468	15,097	13,176
Grand Total	130,957	15,836	120,575	16,900	184,461	41,080	80,840	29,687

Cascading ancillary services are considered in the model. That is, if a generating unit bids on a higher value service that is sold out than it drops down to the next most valuable service and so on until available services are exhausted or market needs satisfied. For example, generating units that are on-line and spinning receive the most revenue from the spin market, but if spinning reserves requirements are sold out than the plant can also participate in meeting non-spinning reserve requirements.

Table 5-6 below shows prices for ancillary services for the study year 2020 as a modeling result in the Base Scenario. The prices have been aggregated for WECC sub-regions based on the mapping between individual balancing authorities and the sub-regions.

Table 5-6
Regional Ancillary Service Average Prices $/MW – Base Scenario

Region	REG UP ($/MW)	REG DOWN ($/MW)	SPIN ($/MW)	NON-SPIN ($/MW)
AZNMNV	4.21	8.79	4.21	4.21
BASIN	16.4	9.54	8.02	7.62
CAISO	8.25	7.96	5.13	0.94
NWPP	3.59	7.85	3.49	3.49
RMPP	9.77	7.88	4.5	1.14

Number of Startups

Looking into the number of starts and stops gives insight into the flexibility required in the system and which technologies are providing that flexibility. At the same time some idea of which technologies are on the margin can be gleaned from this information.

Further analysis could be done to include information regarding the cost of wear and tear on the machines and potential savings that could occur. It is possible that thermal plants would be the beneficiaries of reduced cycling especially if hydro took responsibility for production swings required to integrate variable generation. Fleet benefit analysis are not performed as part of this study.

In the following tables and charts the number of starts and stops is presented along with differences in the cycling of each technology observed between various scenarios. It is possible that an additional, engineering-oriented study could use number of start-stops to quantify the costs and savings attributable to the cycling for different dispatch patterns for a fleet of plants. Hydro plants wear and tear do to start/stop should also be considered, although the affect on thermal plants are expected to be the more significant cost.

It should be noted that these transitions, from simple- to combined-cycle operation, are included when counting the starts and stops. What this means is the combined cycle is in a way over reporting the starts because of transitions. For an example, if you have a 2x1 (2 gas turbines and one steam turbine), it is possible that one gas turbine would start and then the other. Following, the second one could shut down and then turn on again later. Each of these is a "transition." However, with regard to the entire plant, there is really only one start.

Table 5-7
Number of Starts by Technology – Base Scenario

Technology	Startups	Capacity (MW)	Number of Starts per 1000 MW
Biomass	1,341	1,713	783
Coal	2,718	44,713	61
Combined Cycle	49,848	65,487	761
Combustion Turbine	17,891	20,270	883
Geothermal	1,083	9,803	110
Hydro	161	63,137	3
Other Thermal	3,839	6,022	637
Pumped Storage	23,497	4,711	4,988
Solar	8,068	1,880	4,292
Wind	18,274	24,225	754

Figure 5-4, below, shows the change in number of startups between the 2010 Reference case and the Base Scenario. The generator mix or installed capacity is different in 2010 than in the 2020 Base Scenario, so in an attempt to normalize this information, the number of starts per 1000MW of installed capacity has been calculated. This assumes that the average size of the units remains constant, which is not the case, but still gives a very good indication of the changes in cycling that might be expected. Note also that UPLAN contains very detailed information about WECC generation and therefore the starts are associated with the individual turbines or generating units, not the larger plant capacity of all units at the location.

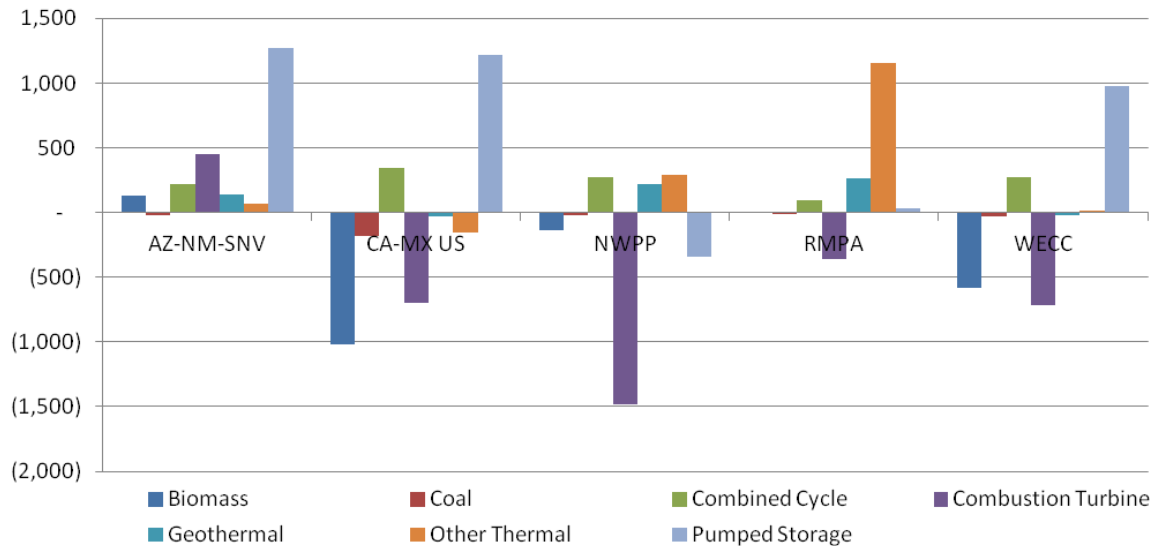


Figure 5-4
Number of Starts per 1000 MW - Base Scenario minus 2010 Reference

Conventional hydro is not shown here because those plants rarely shut down due to run of river constraints in the model designed to capture the non-power oriented constraints which guide hydro operations.

Future Scenario Results

In order to quantify the value of hydro under varying future conditions, a number of scenarios were modeled and individual simulations run to determine hourly operation and revenue information for the thousands of units on the WECC system. Presenting these results in their entirety is not feasible in a report format, nor would it be insightful. Instead, in the following sections, we present summary results for all the scenarios followed by details of only a handful of the scenarios. The project team has selected this subset of scenarios based on which ones were the most and least profitable for hydro generators and then augmenting that list with a few handpicked scenarios which give special insight into a particular facet of hydropower operations and profitability.

Pumped Storage Profitability

Average income for pumped storage is driven by the peak and off-peak price spread and the ability to avoid transmission congestion. When the price spread is low, pumped storage capacity factor[4] could be lower than 5% while in the normal case they are above 10%. Peak and off-peak price spreads are low in the Carbon and Extreme cases especially in the Wet scenarios.

Pump storage net income[5] varies significantly between the various scenarios that were run. Revenue details can be found in Table 5-8. The Average Income is a ratio of the difference in the total revenue and total cost to the total capacity. Because there are relatively few plants and, of those, some of the plants are extremely large, it is difficult to draw general conclusions. Average profitability is very much a result of local conditions surrounding the big plants, including transmission congestion. While ancillary services account for a large percentage of the overall revenues, total revenues are dictated by locational price spreads available to the plants for energy arbitrage.

Table 5-8
Pump Storage Performance by Scenario

Scenario	Capacity (MW)	Generation (GWh)	Energy Revenue ($1000)	Reserve Revenue ($1000)	Net Income ($1000)	Average Income ($/kW)
Base	4,711	4,912	275,674	22,926	71,304	15
Base-Dry	4,711	5,074	363,876	19,682	61,048	12
Base-FiveNewPS	9,890	11,504	606,408	56,705	96,572	9
Base-FiveNewPS-TransRelax	9,890	12,295	663,935	91,869	116,621	11
Base-GenUpgrade	4,711	4,955	278,066	24,459	72,898	15
Base-HighRegReq	4,711	4,917	275,399	23,995	73,116	16
Base-LowRegReq	4,711	4,905	274,691	22,264	70,177	15
Base-NoHydroAS	4,711	4,410	274,264	-	55,600	12
Base-OneNewPS	5,110	5,657	314,842	31,957	81,961	16
Base-PumpUpgrade	4,711	4,966	277,438	25,250	72,959	15
Base-TransRelax	4,711	5,588	320,546	22,317	67,132	14
Base-Wet	4,711	8,276	375,687	22,045	103,726	22
Carbon	4,711	3,437	300,063	10,693	30,258	6
Carbon-Dry	4,711	6,515	607,196	19,231	55,348	10

[4] Pumped Storage Capacity Factor = Electricity consumed (MWh)÷Plant Generating Nameplate Capacity (MW)*8760 hours

[5] Net Income is total revenue minus expenses including cost of pumping energy.

Table 5-8 (continued)
Pump Storage Performance by Scenario

Scenario	Capacity (MW)	Generation (GWh)	Energy Revenue ($1000)	Reserve Revenue ($1000)	Net Income ($1000)	Average Income ($/kW)
Carbon-OneNewPS	5,110	3,954	338,628	13,658	32,794	6
Carbon-TransRelax	4,711	3,992	337,311	12,451	27,100	5
Carbon-Wet	4,711	2,177	173,646	9,230	22,245	2
Extreme	4,711	5,032	473,743	15,949	48,322	7
Extreme-Dry	4,711	6,723	688,146	21,891	89,727	11
Extreme-OneNewPS	5,110	5,567	519,330	20,242	51,719	7
Extreme-TransRelax	4,711	5,259	498,887	17,682	48,804	10
Extreme-Wet	4,711	3,398	299,954	12,439	34,059	5
TEPPC	4,711	7,382	525,065	36,190	84,047	18

In the future there is an expectation that pumped storage plants will make a large percentage of their income from ancillary services. Simulations results show that eight of cases have greater than 40% of the 2020 revenues from AS. Regulation and spin are the most profitable services, since the clearing prices are much higher than the other services; however, the pumped units must be operating to provide that service. Furthermore, only future plants with speed control are able to provide these services while pumping. As such, pumped storage is expected to participate much more in the non-spin market.

In Table 5-9 the ancillary service revenues (not profit) for pumped storage in WECC are shown for each of the scenarios investigated. Adding PS increases the total revenues as the additional PS capacity is available for biding and dispatch. Also the model assumes that new PS is more flexible than existing systems, which enables more participation in AS markets.

Note that ancillary service revenues track energy arbitrage revenues such that scenarios with higher energy revenue tend to also have higher reserve revenue. However, ancillary service revenues from one scenario to another are expected to be much more consistent than energy revenues. With the addition of new pumped storage plants, or turbine upgrades in existing plant, ancillary service revenue will likely be less coupled to energy arbitrage.

Table 5-9
Pumped Storage Hydro Ancillary Service Revenue by Scenario

Scenario	Reg Up ($1000)	Reg Down ($1000)	Spin ($1000)	Non Spin ($1000)	Total ($1000)
Base	4,440	1,354	2,035	15,097	22,926
Base-Dry	2,982	3,316	760	12,624	19,682
Base-FiveNewPS	20,026	4,472	20,078	12,130	56,705
Base-FiveNewPS-TransRelax	23,501	1,930	39,292	17,948	82,671
Base-GenUpgrade	4,888	1,339	3,072	15,159	24,459
Base-HighRegReq	8,229	1,472	2,088	14,596	26,384
Base-LowRegReq	3,502	1,580	2,097	15,086	22,264
Base-NoHydroAS	-	-	-	-	-
Base-OneNewPS	7,319	1,455	8,193	14,989	31,957
Base-PumpUpgrade	5,176	1,325	3,631	15,118	25,250
Base-TransRelax	4,338	1,584	1,920	14,475	22,317
Base-Wet	6,028	2,789	1,908	11,320	22,045
Carbon	1,495	1,867	398	6,934	10,693
Carbon-Dry	3,782	5,384	953	9,112	19,231
Carbon-OneNewPS	2,362	2,114	2,093	7,091	13,659
Carbon-TransRelax	1,969	2,761	463	7,259	12,451
Carbon-Wet	1,101	445	480	7,204	9,230
Extreme	2,653	3,075	643	9,578	15,949
Extreme-Dry	4,889	6,464	993	9,545	21,891
Extreme-OneNewPS	3,810	3,432	2,994	10,005	20,242
Extreme-TransRelax	3,344	4,189	697	9,452	17,682
Extreme-Wet	2,061	932	823	8,623	12,439
TEPPC	9,635	6,399	2,980	17,176	36,190

The "Base Wet" scenario is defined by the Base Energy Future conditions in coordination with wet hydro conditions (i.e. 1997 levels). This scenario is of particular interest because it is the scenario that indicates pumped storage generators make the most profit. The reason is a larger difference between on- and off-peak prices in both absolute and relative terms. While prices are higher in other scenarios such as the "Dry" scenarios, it can be seen the difference in prices is larger in the Base-Wet scenario. The model indicates that an abundance of water will likely depress off-peak prices disproportionately than on-peak. In the base case, conventional hydro was already taking advantage of high prices and generating during the peak. Extra water is utilized during peak hours, but relatively more water must be shifted to the off-peak in order to minimize the risk of spillage. This condition was seen in 2011 when an abundance of water in spring and early summer led to curtailing of wind at night in the NW.

Table 5-10
Pumped Storage Performance – Base-Wet Scenario

Plant	Capacity (MW)	Generation (GWh)	Energy Revenue ($1000)	Energy Cost ($1000)	Ancillary Service Revenue ($1000)	Net Income ($1000)
Cabin Creek	324	720	39,059	28,511	899	11,448
Castaic	1,275	2,538	111,923	90,392	893	22,424
Edward C Hyatt	396	777	32,612	25,194	2,073	9,491
Faltiron	36	80	4,335	3,130	100	1,305
Grand Coulee	314	702	31,380	22,582	2,381	11,178
Helms	1,200	1,215	52,454	44,692	8,564	16,326
Horse Mesa	111	212	10,080	7,627	1,537	3,990
J S Eastwood	207	414	16,242	14,120	1,074	3,195
Mormon Flat	47	76	3,642	2,723	407	1,326
Mount Elbert	200	442	24,097	17,511	539	7,125
Oliven-Hodges	40	81	3,760	2,820	191	1,132
O'Neill	13	23	1,016	785	112	342
Thermalito	84	70	2,872	2,318	780	1,335
W R Gianelli	424	849	38,602	28,854	1,937	11,685
Waddell	40	76	3,614	2,747	557	1,425

Table 5-11
Off-Peak and Peak Prices by Scenario

Scenario	Off Peak ($/MWh)	Peak ($/MWh)	Peak - Off Peak Difference ($/MWh)	Off Peak/Peak Ratio (%)
Base	40.89	54.65	13.76	75%
Base-Dry	50.33	65.65	15.32	77%
Base-FiveNewPS	42.79	54.64	11.85	78%
Base-FiveNewPS-TransRelax	42.21	54.22	12.01	78%
Base-GenUpgrade	40.87	54.67	13.80	75%
Base-HighRegReq	40.84	54.64	13.80	75%
Base-LowRegReq	40.88	54.56	13.68	75%
Base-NoHydroAS	43.10	56.99	13.89	76%
Base-OneNewPS	41.10	54.64	13.54	75%
Base-PumpUpgrade	40.85	54.62	13.77	75%
Base-TransRelax	41.35	54.73	13.38	76%
Base-Wet	28.27	42.59	14.32	66%
Carbon	62.56	73.54	10.98	85%
Carbon-Dry	69.54	87.72	18.18	79%
Carbon-OneNewPS	62.67	73.44	10.77	85%
Carbon-TransRelax	62.78	74.03	11.25	85%
Carbon-Wet	57.15	64.64	7.49	88%
Extreme	69.12	83.14	14.02	83%
Extreme-Dry	77.35	101.64	24.29	76%
Extreme-OneNewPS	69.23	83.18	13.95	83%
Extreme-TransRelax	69.35	84.28	14.93	82%
Extreme-Wet	63.26	74.20	10.94	85%
TEPPC	52.40	67.65	15.25	77%

The impact of adding new PS plants in selected locations was found to generally increase off-peak prices relative to on-peak and therefore was not favorable for hydro profits. The scenario where pumped storage makes the least amount of profit is the "Carbon Wet" scenario. Not surprisingly, this scenario has the least difference between on- and off-peak prices.

Conventional Hydro Profitability

In 2020, there are 862 conventional hydro units available in the WECC area for a total of 63GW (includes Canada) of capacity for all scenarios modeled. Unlike other technologies, this number does not change very much with different energy futures because of the anticipated environmental limitations for adding new dams. Aside from some very small installations in U.S. portion (26MW as reported by LCG's PLATO Database), the bulk of the new capacity built between 2010 and 2020 (2,930MW) will be located in Canada or come from upgrades of existing units.

Unlike pumped storage units, conventional hydro makes almost all of its revenues from energy. Ancillary service revenues account for roughly 2 % of conventional revenues in 2010 and 3% in 2020 according to our modeling. Hydro plants in WECC are capable of providing much of the flexibility the system needs in 2010 and in 2020, but system-wide ancillary service requirements are relatively low, and the expected market prices for those products are modest.

Revenues of the conventional hydro fleet are correlated with electricity prices. The higher the prices, the more revenue the plants make. Scenarios with higher prices, such as those with carbon costs and elevated load growth, tend to favor conventional hydro profit. As can be seen in Figure 5-5, the Extreme Energy Future scenarios have much higher prices than the Base Energy Futures.

An interesting dynamic occurs with the addition of the hydro condition sensitivities. With high hydro conditions, the units have more water and can produce significantly more energy. This is essentially free fuel for the plants and is intuitively a favorable outcome for them. This can be seen in Table 5-12 where the highest revenues occur in both wet and dry years depending mostly on the price of electricity. Consequently the most profitable scenarios for conventional hydro are within the Extreme Future which does have the higher prices.

Further, the Extreme Wet scenario is the most profitable scenario because the additional water is more than sufficient to compensate for the somewhat reduced prices that are experienced throughout the system precisely because there is additional water. However, when looking to the least profitable scenario, we see that it is the Base-Wet scenario. In this scenario, the additional water puts downward influence on prices to the point that it is no longer incrementally profitable to have additional inflow. Conversely, in the Base-Dry scenario we also see low revenues directly because of scarcity of water supply. Prices in the Base-Dry scenario do not increase proportionally to the difference in water available because there are other generation fuels and options.

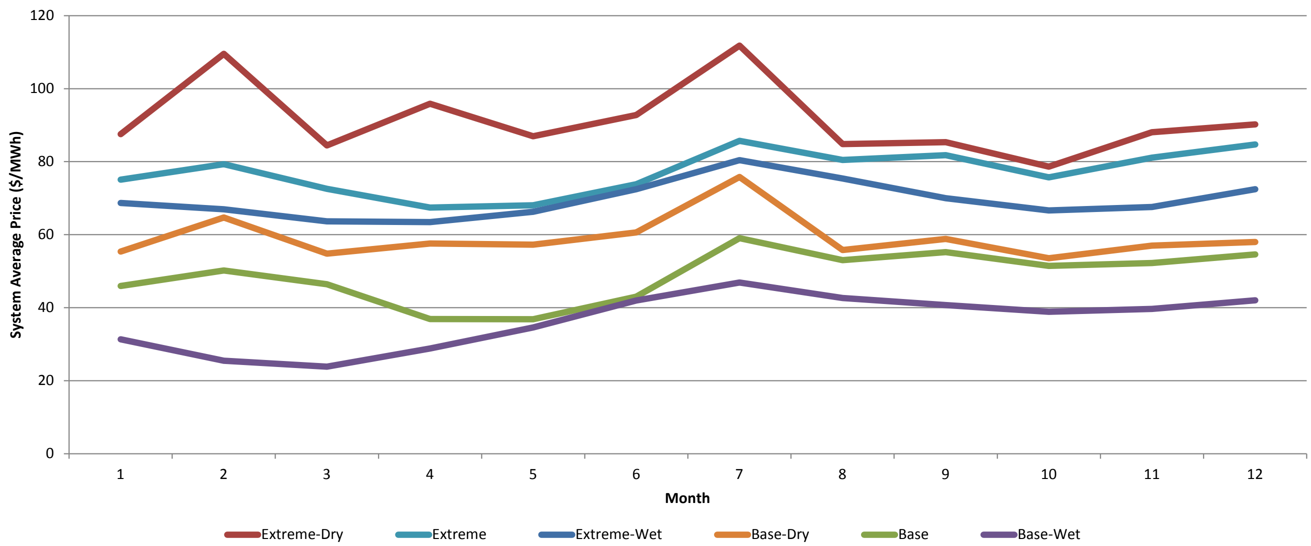


Figure 5-5
System-Wide Average Prices for Selected Scenarios

Dry Conditions

Hydro plants in WECC sub-regions operate on average at around 30% capacity factor. This is relatively low compared to Eastern US and Canada. However, it should be noted that the dry condition is indicative of the supply WECC wide, but is not plant specific. Some plants within WECC will see more water supply than others based on location. In general the capacity factors (CF) of plants in the different sub-regions are around 30%. Due to the similarity, the average revenue is driven by energy prices. Figure 5-6 shows how a dry condition affects the generation and thus the CF in the different subregions of WECC. CA and the NWPP both would experience a significant decrease in hydro generation, while the other two subregions remain relatively unchanged. The NWPP would see the driest conditions and therefore the highest energy prices making it average revenue higher.

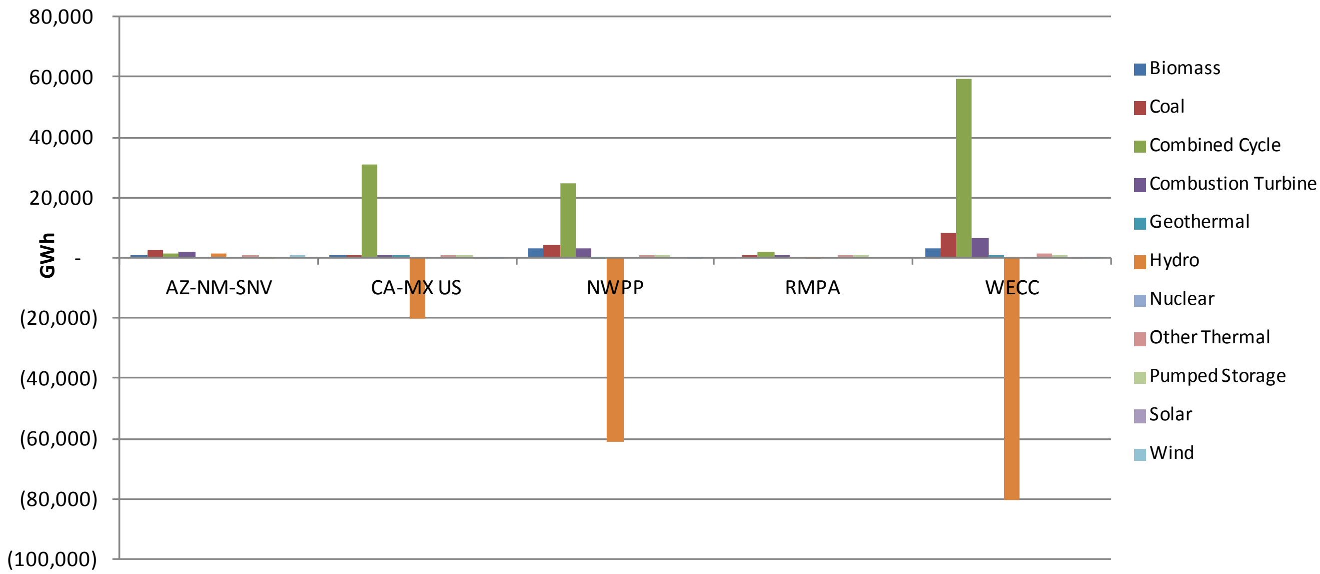
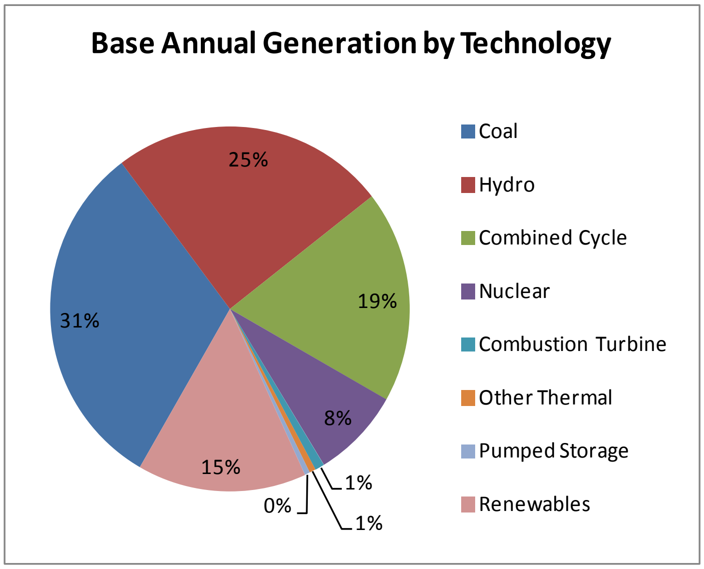


Figure 5-6
Annual Generation Comparison between Base-Dry and Base Scenarios

Figures 5-7 gives a comparison of the generation mixes under the Base and Base-Dry scenarios. The two technologies that are affected most from the dry conditions are Conventional Hydro and. With the decrease in water supply Conventional Hydro sees an 8% drop in generation, while Combined Cycle sees a 5% increase. This indicates that in a dry hydro condition, Combined Cycle units would replace the hydro generation in a typical water condition.



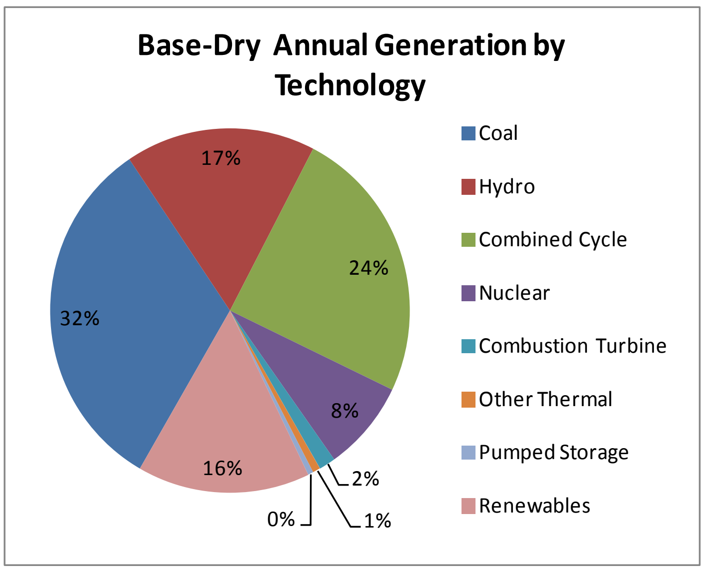


Figure 5-7
Generation Mix under Base-Dry and Base Scenarios

Wet Conditions

Similar to the dry condition, wet conditions indicate higher water supply. Note that the wet condition is indicative of the supply WECC wide, but is not plant specific. Under wet conditions, the capacity factors in different sub-regions are around 50% - 60% and average revenue is again driven by energy prices. Figure 5-8 shows how a wet condition affects the generation and thus the CF in the different subregions of WECC. Again, the NWPP would be the most affected by the wet condition seeing a significant increase in hydro generation. The AZ-NM and RMPA subregions have the highest prices due to the affects of the wet condition and therefore see the highest average revenue.

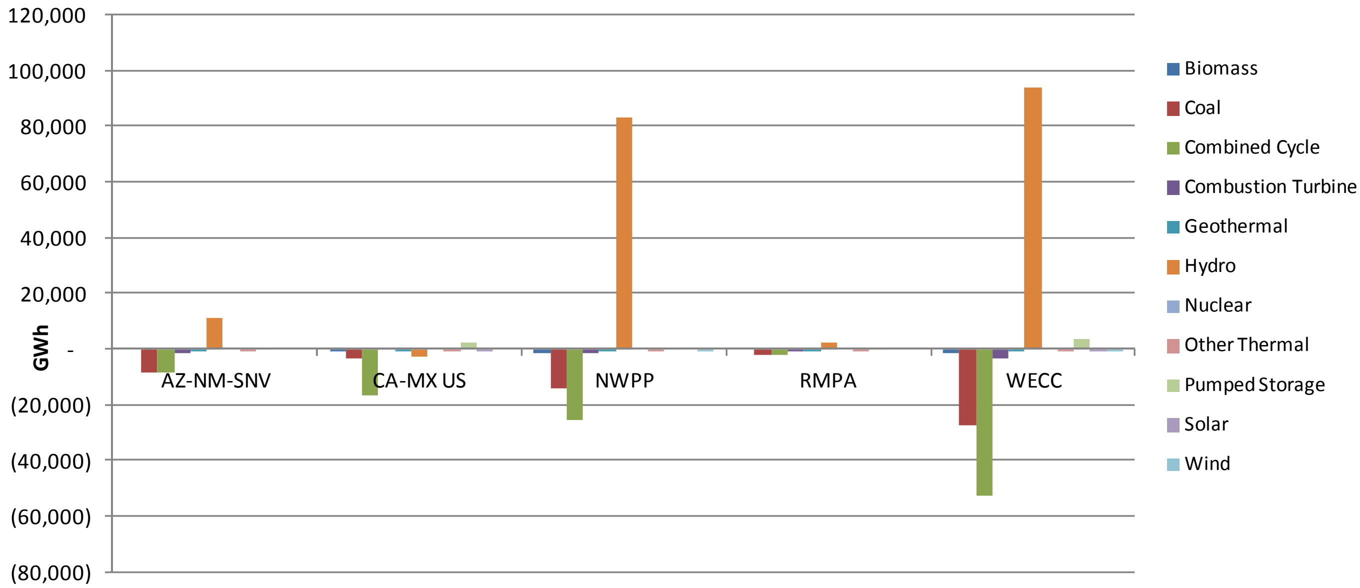
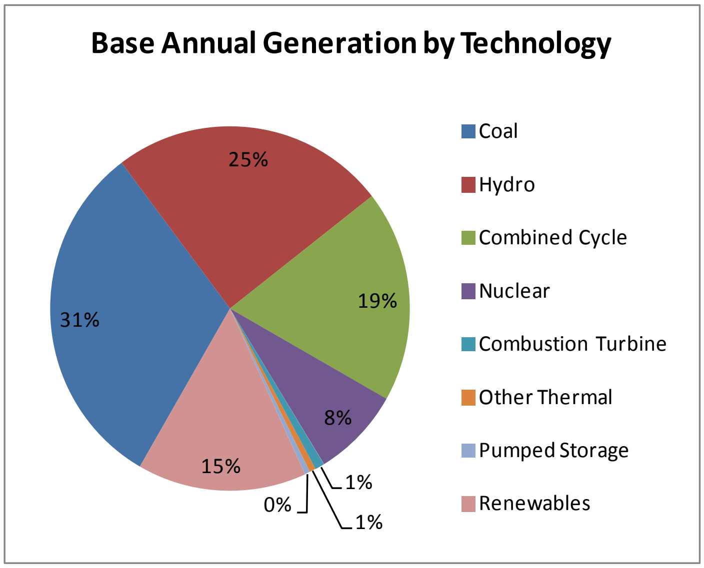


Figure 5-8
Annual Generation Comparison between Base-Wet and Base Scenarios

Figure 5-9 gives a comparison of the generation mixes under the Base and Base-Wet scenarios. Similar to the dry condition, the two technologies that are affected the most are Conventional Hydro and Combined Cycle. The Conventional Hydro sees an 8% increase with high hydro conditions, while Combined Cycle sees a 5% decrease. This again indicates that the Conventional hydro units would be replacing the use of Combined Cycle units when more water supply is available.



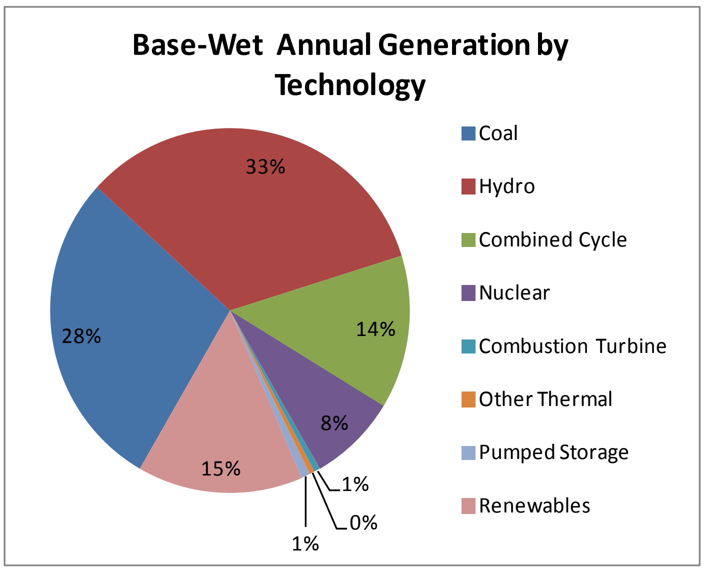


Figure 5-9
Generation Mix under Base-Wet and Base Scenarios

Table 5-12 shows the conventional hydro ancillary service revenue by scenario. Conventional hydro is able to aggressively serve the higher value requirements such as regulation and spin. In fact, conventional hydro is by far the largest supplier of spinning reserve on the system. Due to the limited energy available for hydro, it is able to capitalize on the opportunity to provide ancillary services without having to utilize extra water. In the high reserve requirement scenario, hydro is able to provide even more reserves for additional revenues, which indicates that conventional hydro could even take on more ancillary service responsibilities should the need arise. In the Extreme-Dry case, conventional hydro is able to compensate to some extent for the reduced energy revenues by participating more in the ancillary service markets.

Table 5-12
Conventional Hydro Ancillary Service Revenue by Scenario

Scenario	Reg Up ($1000)	Reg Down ($1000)	Spin ($1000)	Non Spin ($1000)	Total ($1000)
Base	71,734	81,853	162,470	46,114	362,170
Base_HighRegReq	121,330	124,457	163,658	43,834	453,279
Base-Dry	74,788	88,805	140,976	37,302	341,870
Base-FiveNewPS	59,586	65,985	121,692	26,232	273,495
Base-FiveNewPS-TransRelax	64,136	74,648	115,531	21,028	275,342
Base-GenUpgrade	71,229	82,297	162,187	45,622	361,335
Base-LowRegReq	56,858	73,978	162,755	45,900	339,491
Base-NoHydroAS	-	-	-	-	-
Base-OneNewPS	69,327	81,935	156,241	44,913	352,417
Base-PumpUpgrade	71,215	82,109	161,366	45,367	360,056
Base-TransRelax	68,800	82,455	158,335	48,149	357,739
Base-Wet	55,166	53,913	119,673	32,584	261,337
Carbon	41,058	44,000	81,374	19,250	185,682
Carbon-Dry	57,107	80,825	97,202	27,168	262,302
Carbon-OneNewPS	40,791	43,718	81,120	18,692	184,321
Carbon-TransRelax	45,567	47,296	79,516	20,524	192,903
Carbon-Wet	50,760	45,696	92,607	23,350	212,412
Extreme	53,302	61,199	111,179	30,447	256,128
Extreme-Dry	67,318	122,999	108,299	31,280	329,895
Extreme-OneNewPS	53,312	61,523	110,451	29,962	255,248
Extreme-TransRelax	55,929	67,062	111,732	30,165	264,887
Extreme-Wet	56,314	53,723	116,201	31,122	257,361
TEPPC	95,584	112,799	175,273	53,085	436,741

As seen in Table 5-13, conventional hydropower is heavily utilized and generates significant revenues in all scenarios for a range of incomes between $168/kW to $357/kW. Ancillary services account for some of these revenues, but energy is by far the most important component.

Table 5-13
Conventional Hydro Performance by Scenario

Scenario	Capacity (MW)	Generation (GWh)	Energy Revenue ($1000)	Ancillary Service Revenue ($1000)	Net Income ($1000)	Average Income ($/kW)
Base	63,137	259,382	12,436,451	362,171	12,539,250	199
Base_Dry	63,137	179,026	11,438,336	341,870	11,601,181	184
Base_FiveNewPS	63,137	259,399	13,336,764	273,495	13,350,870	212
Base_FiveNewPS_TransRelax	63,137	259,454	12,564,043	267,892	12,572,490	199
Base_GenUpgrade	63,137	259,381	12,433,724	361,334	12,535,686	199
Base_HighRegReq	63,137	259,372	12,420,522	385,875	12,547,034	199
Base_LowRegReq	63,137	259,385	12,420,569	339,491	12,500,684	198
Base_OneNewPS	63,137	259,382	12,439,863	352,417	12,532,909	199
Base_PumpUpgrade	63,137	259,379	12,426,162	360,056	12,526,849	199
Base_TransRelax	63,137	259,450	12,462,097	357,739	12,560,395	199
Base_Wet	63,137	353,447	10,716,326	261,336	10,624,236	168
Base-NoHydroAS	63,137	259,601	12,897,584	-	12,637,993	200
Carbon	63,137	259,275	17,538,827	185,682	17,465,182	277
Carbon_Dry	63,137	178,904	15,278,257	262,303	15,361,596	244
Carbon_OneNewPS	63,137	259,275	17,524,161	184,320	17,449,154	277
Carbon_TransRelax	63,137	259,287	17,763,672	192,903	17,697,236	281
Carbon_Wet	63,137	354,840	18,870,237	212,411	18,727,769	297
Extreme	63,137	259,243	19,943,714	256,128	19,940,548	316
Extreme_Dry	63,137	178,814	19,799,908	329,895	19,950,929	317
Extreme_OneNewPS	63,137	259,241	19,954,687	255,248	19,950,642	317
Extreme_TransRelax	63,137	259,286	20,313,597	264,887	20,319,147	322
Extreme_Wet	63,137	355,792	22,628,479	257,361	22,530,008	357
TEPPC	63,137	259,203	15,672,990	436,741	15,850,538	251

Marginal Units

The simulations performed are based upon the coordinated operation of the thirty nine separate Balancing Authorities in WECC sub-regions as listed in Table 1-1. In any given hour, the system as a whole will have at least one marginal unit[6]. More than one marginal unit may be present in the case of transmission constraints. Determining these units requires a complete transmission analysis including available interchange between BAs, as well as line limits, losses and other power flow parameters. Each BA will also have a marginal unit determined for each hour defined as the unit dispatched within that BA that has the highest variable cost.

The model computes both the system-wide marginal units as well as the Balancing Authority-level marginal units. To illustrate this impact of different scenarios on the dispatch, consider the BA-level marginal units of the Western Area Power Administration – Rock Mountain Region (WACM) BA. WACM is a moderately sized BA with a rich mix of generating resources, including conventional hydro, pumped storage, and a significant amount of coal to better illustrate the shifting dynamics of marginal units, see Figure 5-11.

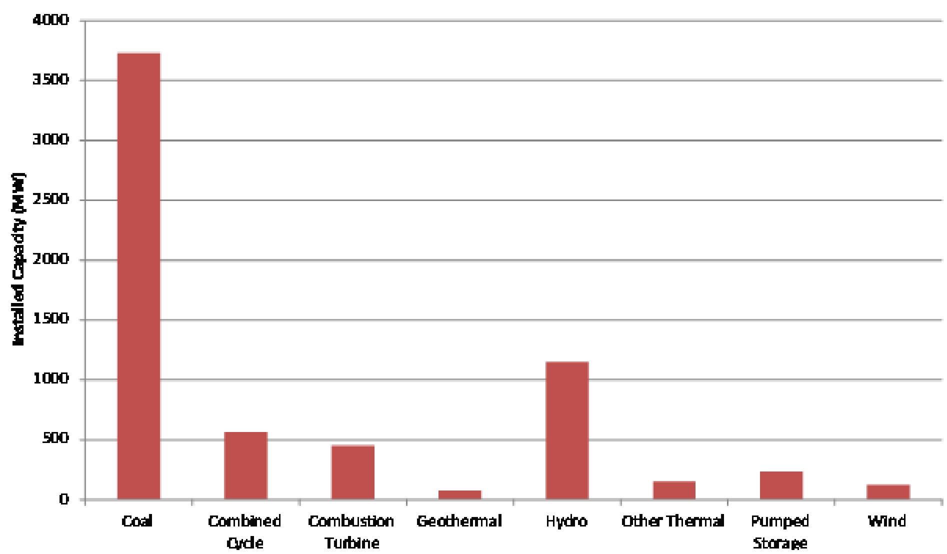


Figure 5-10
WACM - 2020 Installed Capacity (MW)

Pumped hydro value depends on having low-cost generation on the margin which in turn increases the spread and the arbitrage opportunity. In comparison conventional hydro value depends on high prices and tends to produce more profit when higher price generation is on the margin.

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[6] The marginal unit at a particular location is defined to be the unit from which an additional power will be received should an incremental amount of power be required. Note that the marginal unit will likely not be in the same location as the delivered power.

Figure 5-11 shows what technology is on the margin for each of the scenarios. The more often that lower cost coal is on the margin, the more revenues there are for pumped storage e.g. Base-Wet Scenario. The less that coal is on the margin, the more conventional hydro will profit, such as the Dry and Extreme scenarios.

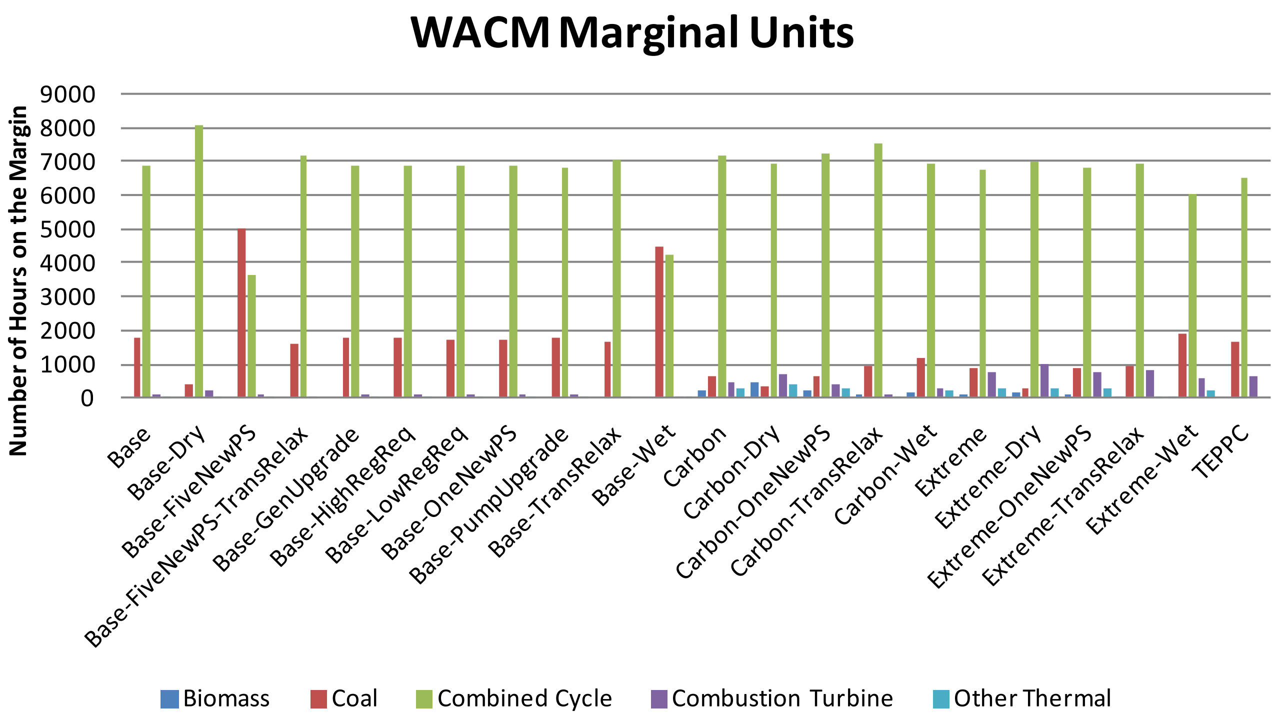

Figure 5-11
WACM Technology on the Margin by Scenario

Ancillary Services

Due to fast ramping capability and limited energy, hydro power is a natural choice for providing ancillary services. This assumes that sufficient operational flexibility is present relatively to other non-power constraints and that units are not participating in more attractive markets. Conventional hydro in WECC is expected to provide the bulk of the reserves in all scenarios. This is shown in Figure 5-12, below, showing simulation results of hourly participation of all technologies in ancillary services for the Base Scenario and by ancillary service product.

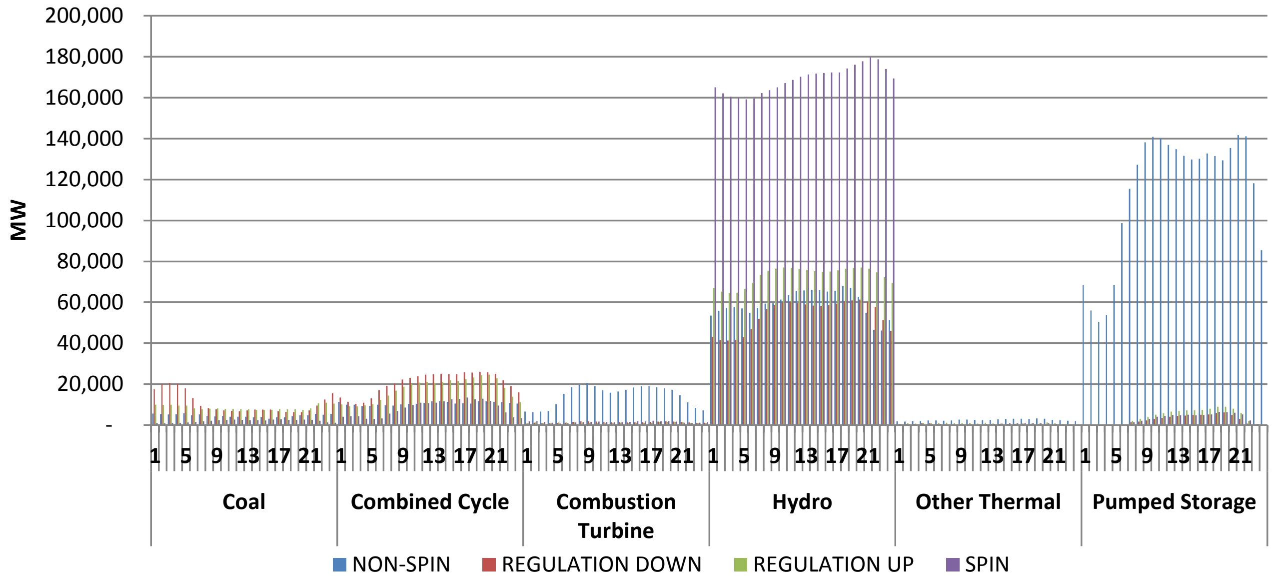

Figure 5-12
Average AS Participation by Technology - Base Scenario

Hydro is expected to provide the bulk of the spinning reserves on the system for all hours of the day. Pumped Storage is providing much of the non-spin required along with combustion turbines.

When less water is available, hydro units are expected to participate more in non-spin services as seen in Figure 5-13.

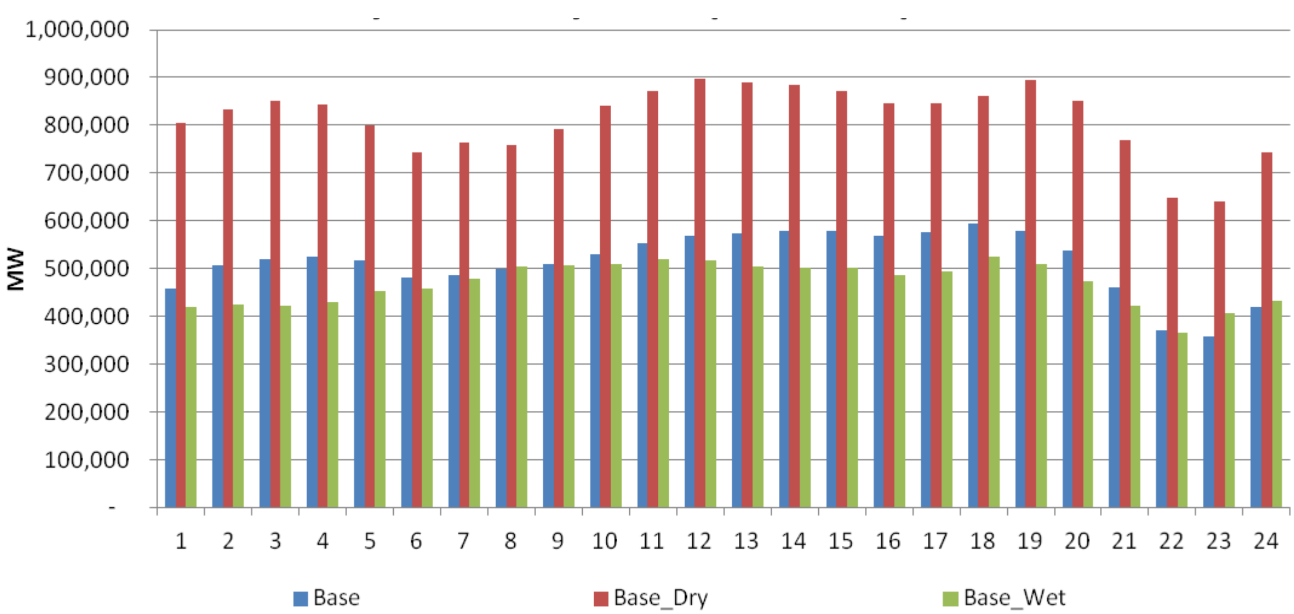

Figure 5-13
Conventional Hydro Non Spin Participation - Base Scenario

Ancillary Service Sensitivities

As described in previous sections of this document, the exact ancillary service requirements (quantities) that will need to be held in 2020 are predicted in different scenarios. These services are divided into four different categories: regulation up; regulation down; spin; and, non-spin. The expected requirements used in the 2020 modeling range from second by second regulation all the way to non-spinning reserves designed to manage contingencies. Holding these different types of ancillary services in reserve will enable Balancing Authorities to manage varying conditions as needed including load following as well as uncertainties stemming from forced outages, forecast errors. The market is designed to ensure that the generation-load balance is maintained at all times.

Contingency reserve requirements are determined by the type and size of the generators on the system and tend to remain relatively constant over the course of the day. Regulation and ramping requirements do change hourly, and the exact requirements are typically a function of the variability of the wind net load on the system. The project team looked over different requirements found today several ISOs that publish the information. In addition, other studies were referenced to get an idea of the relationship between the level of ancillary service requirements and the amount of variable energy generation on the system.

While there is no real consensus on exactly how to calculate the reserve requirements due to increased variable generation, a few different methodologies do exist. These are data intensive, statistical methods. The project team analyzed the results of these analyses and found an interesting result: variable energy resources on the system seem to change the average regulation requirements by an amount somewhere between 15 MW and 20 MW per GW of installed variable generation capacity[7]. This finding allowed for the team to develop two scenarios (BaseHighRegReq and BaseLowRegReq) using ancillary service requirement levels which would represent realistic extremes. Only regulation requirements were altered by increasing or decreasing the percentage of load that needed to be covered. Therefore, regulation requirements are not directly linked to hourly load and variable generation production as in the more data intensive studies, but requirements are altered by a similar amount on average for a given installed variable generation capacity. This gives some insight into how hydro may operate with changing regulation requirements. On the high side, 3.5% of load was used for the regulation up and regulation down requirements in the Pacific Northwest and California (where more variable energy generation is present), and 2% of the load for Canada and RMPA. For the low requirement scenario, 1.5% of the load was set as the regulation up and regulation down requirements for the Pacific Northwest and California and 1.2% was used for Canada and RMPA.

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[7] For example, the Eastern Wind Integration and Transmission Study (NREL February 2011, http://www.nrel.gov/wind/systemsintegration/pdfs/2010/ewits_final_report.pdf) found that integrating 225,000 MW of wind in the Eastern Interconnection would require, on average, an additional 12,000 MW of spinning reserve of which one third would be regulation. The amount required varies by hour with both the amount of load and the level of wind generation.

Altering the requirements in this fashion (as in Table 4-11) has a small effect on the performance of conventional hydropower. Raising the requirements increases total ancillary service revenue from $91 million to $453 million or 25%, but energy revenue hardly changes, so average income increases only $1.5/kW or 0.74%.

For more information on the setup of these cases, please refer to the section on Ancillary Service Requirements. More comprehensive results for these scenarios can be found in Table 5-8, Table 5-12 and Table 5-13.

Pumped Storage ancillary service revenues increase slightly with higher ancillary service requirements, however, overall income increases only by $0.44/kW in this example. Reducing requirements leads to a loss of $0.2/kW.

Limiting Hydro Participation

In order to better understand the value of hydro's participation in ancillary services, a sensitivity case was run in which both conventional and PS hydro units were not allowed to participate. The total production costs increase by $1.35 billion (5.87%) when hydro is not allowed to participate. Also the overall electricity prices increase by an average of 4.6%. Ancillary services, which are less than 10% of total energy prices, increase substantially. They double in British Columbia where there is a shortage of capacity, and AS prices increase by an average of 130% in the US with the biggest increases seen in NWPP and CAISO.

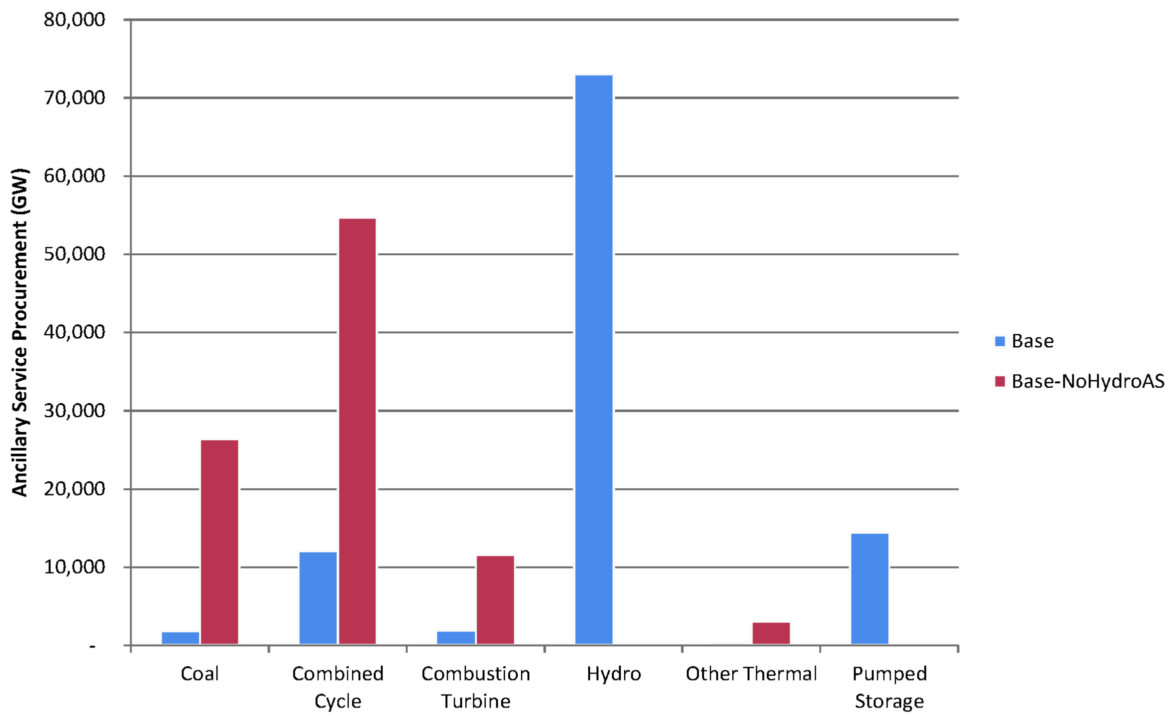

Figure 5-14
Ancillary Service Procurement with and without Hydro Participation

Pumped storage capitalizes on the increase in electricity prices to a small extent, but not enough to make up for the loss in ancillary service revenue, and pumped storage ends up with a slightly lower utilization overall. Conventional Units lose their reserve revenue as well, but make up for it because of the higher electricity prices.

Table 5-14
Revenues Base vs. Base-NoHydroAS Scenarios

Technology	Base Ancillary Service Revenue ($1000)	Base-NoHydroAS Anicillary Service Revenue ($1000)	Base Energy Revenue ($1000)	Base-NoHydroAS Energy Revenue ($1000)
Biomass	0	19	240,529	351,326
Coal	24,887	558,883	16,241,354	16,397,699
Combined Cycle	99,810	1,739,445	10,420,400	11,572,050
Combustion Turbine	4,568	255,754	560,792	811,406
Geothermal	-	-	2,828,478	2,895,733
Hydro	362,171	-	12,436,451	12,897,584
Nuclear	-	-	3,994,417	4,066,553
Other Thermal	2,472	23,851	310,716	357,787
Pumped Storage	22,926	-	275,674	274,264
Solar	-	-	230,326	239,246
Wind	-	-	2,906,436	3,007,529

Number of Starts

Table 5-15 contains a complete list of the number of startups by scenario. The metric used is startups per 1000 MW of installed capacity in order to normalize the results since the scenarios were developed using different Energy Futures which have different expansion and retirement assumptions.

Table 5-15
Number of Startups per 1000 MW by Technology by Scenario

Scenario	Biomass	Coal	Combined Cycle	Combustion Turbine	Geothermal	Other Thermal	Pumped Storage
Base	799	62	762	890	136	673	4,988
Base_Dry	1,008	58	741	1,593	140	1,077	4,860
Base_FiveNewPS	830	64	742	1,071	136	1,102	4,558
Base_FiveNewPS_TransRelax	753	60	749	751	131	600	4,213
Base_GenUpgrade	800	62	760	897	136	684	5,025
Base_HighRegReq	799	62	768	906	136	683	4,988
Base_LowRegReq	796	61	760	880	136	675	4,988
Base_OneNewPS	788	62	751	893	136	675	5,052
Base_PumpUpgrade	801	62	760	900	136	683	5,113
Base_TransRelax	763	62	744	809	131	603	5,359
Base_Wet	1,035	79	708	523	139	574	5,643
Carbon	740	69	602	1,373	157	1,158	2,677
Carbon_Dry	841	58	588	2,414	164	2,190	4,482
Carbon_OneNewPS	737	70	598	1,358	157	1,140	2,990
Carbon_TransRelax	722	71	590	1,359	156	995	3,017
Carbon_Wet	566	85	626	1,022	159	899	2,057
Extreme	758	73	569	1,539	133	1,549	3,956
Extreme_Dry	766	70	553	2,462	140	2,785	5,068
Extreme_OneNewPS	749	73	563	1,526	133	1,545	4,169
Extreme_TransRelax	710	72	540	1,449	123	1,227	3,837
Extreme_Wet	721	84	562	1,272	158	1,191	2,977
TEPPC	1,517	88	633	1,760	524	564	5,353

Figure 5-15 below shows the change in number of startups between the Carbon Scenario and the Base Scenario. Small thermal units are cycled more often as they are still needed but very costly to keep online. They also are compensating for the reduced utilization of Pumped Storage.

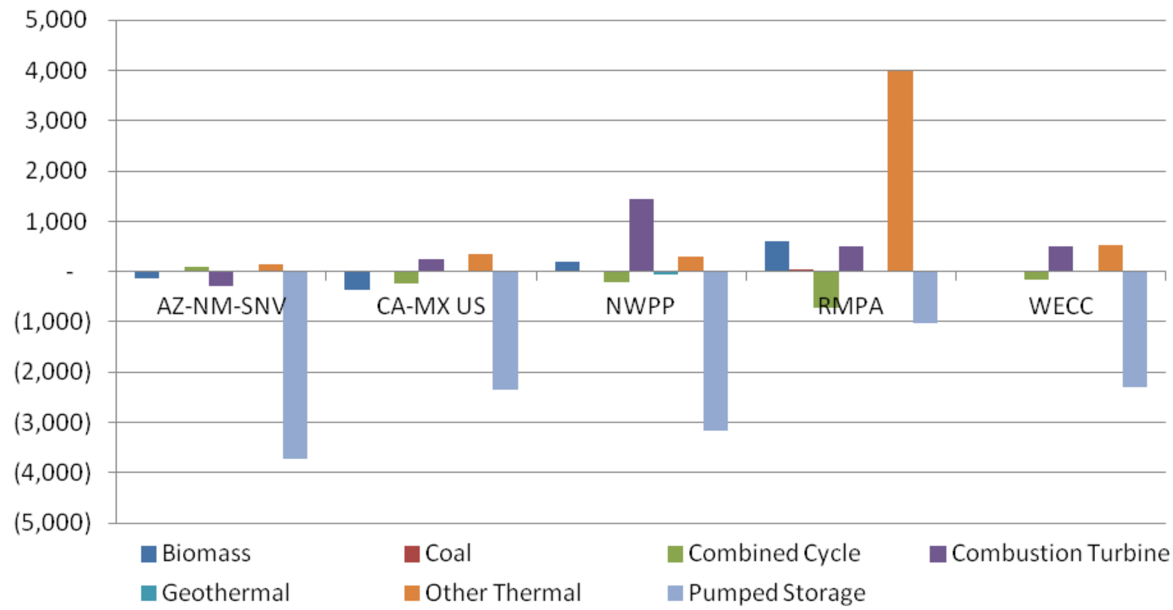

Figure 5-15
Change in Number of Startups - Carbon Scenario vs. Base Scenario

The Extreme Scenario is very much like the Carbon Scenario except there is higher load present on the system. In Figure 5-16 a similar pattern to Figure 5-15 is exposed. Small thermal units are cycled more often; Pumped Storage cycles less.

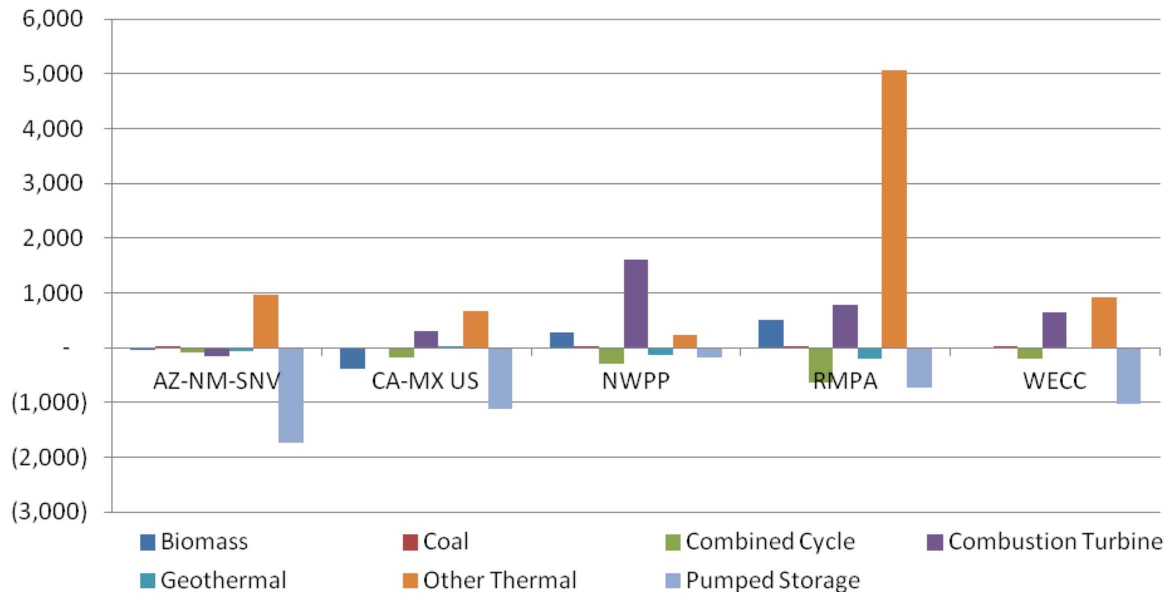

Figure 5-16
Change in Number of Startups - Extreme Scenario vs. Base Scenario

Emission Quantities

Emissions are modeled in UPLAN on a unit by unit basis and include costs based on rates correlated to the amount of fuel burned. Emission allowance prices are described in Section 4. In the Base Energy Future and the TEPPC Energy Future, which is the foundation for all of the “Base” scenarios, these costs do not enter into the decisions that the model makes. In all of the other scenarios these costs are included and significantly alter the relative costs of different technologies which ultimately lead to a different commitment and dispatch schedule.

Table 5-16
CO_2 Emissions by Scenario (Millions of Metric Tons)

Scenario	AZ-NM-SNV	CA-MX US	NWPP	RMPA	WECC
Base-Dry	110	109	214	68	500
Extreme-Dry	112	110	196	62	480
Base-HighRegReq	105	96	196	66	463
Base-OneNewPS	105	96	196	66	462
Base-PumpUpgrade	105	96	196	66	462
Base-FiveNewPS-TransRelax	106	96	194	66	462
Base	105	96	196	66	462
Base-TransRelax	105	97	195	66	462
Base-GenUpgrade	105	96	196	66	462
Base-LowRegReq	105	96	195	66	462
Base-FiveNewPS	101	99	196	65	461
Base-NoHydroAS	104	94	194	64	456
Extreme-TransRelax	109	98	172	58	437
Extreme-OneNewPS	107	97	173	59	436
Extreme	107	97	173	59	436
Base-Wet	91	87	167	63	408
Carbon-Dry	78	96	174	53	401
Extreme-Wet	93	90	140	56	380
Carbon-OneNewPS	74	81	151	49	355
Carbon	74	81	151	49	355
Carbon-TransRelax	74	82	151	48	355
Carbon-Wet	63	73	116	45	297
TEPPC	-	-	-	-	-

Carbon emissions exhibit an intuitive trend. The scenarios with the most emissions are those where there is no penalty (or cost) enforced and hydro conditions are dry, forcing more thermal generation to compensate for the lack of water available. Similarly the scenario with the least amount of CO_2 emissions is the Carbon-Wet Scenario in which this cost is present and there is increased hydropower generation.

The following tables show emissions of SOX, NOX, and Mercury, which exhibit similar patterns to CO_2, with only small deviations due to the dispatch balance between coal and natural gas units. Both technologies emit CO_2, coal at slightly more than twice the rate of gas, but coal is almost entirely responsible for the mercury and SOX emissions.

Table 5-17
SOX Emissions by Scenario (Thousands of Metric Tons)

Scenario	AZ-NM-SNV	CA-MX US	NWPP	RMPA	WECC
Base-Dry	94	33	158	54	339
Base-OneNewPS	91	32	152	54	330
Base-PumpUpgrade	91	32	152	54	329
Base-FiveNewPS-TransRelax	92	33	151	54	329
Base	91	32	152	54	329
Base-LowRegReq	91	32	152	54	329
Base-GenUpgrade	91	32	152	54	329
Base-TransRelax	91	32	152	54	329
Base-HighRegReq	91	31	153	54	329
Base-FiveNewPS	89	32	151	54	327
Base-NoHydroAS	88	26	147	52	312
Base-Wet	82	29	135	52	298
Extreme-Dry	86	32	126	47	291
Extreme-TransRelax	84	30	117	46	277
Extreme-OneNewPS	83	30	118	46	276
Extreme	83	30	118	46	276
Extreme-Wet	75	27	101	44	248
Carbon-Dry	39	30	113	38	220
Carbon-OneNewPS	37	26	102	36	201
Carbon	36	26	102	36	201
Carbon-TransRelax	36	26	102	36	200
Carbon-Wet	31	22	82	33	168
TEPPC	-	-	-	-	-

Table 5-18
NOX Emissions by Scenario (Thousands of Metric Tons)

Scenario	AZ-NM-SNV	CA-MX US	NWPP	RMPA	WECC
Base-Dry	59	32	101	35	226
Extreme-Dry	56	36	90	32	214
Base-OneNewPS	56	30	93	34	213
Base-PumpUpgrade	56	30	93	34	213
Base	56	30	93	34	213
Base-GenUpgrade	56	30	93	34	213
Base-HighRegReq	56	29	94	34	213
Base-LowRegReq	56	30	93	34	213
Base-FiveNewPS-TransRelax	57	30	92	34	213
Base-TransRelax	56	30	93	34	213
Base-FiveNewPS	54	30	93	34	212
Base-NoHydroAS	54	27	92	33	206
Extreme-TransRelax	54	33	82	30	198
Extreme-OneNewPS	54	32	82	30	198
Extreme	54	32	82	30	198
Base-Wet	50	27	80	33	190
Extreme-Wet	48	30	66	29	173
Carbon-Dry	28	32	82	27	169
Carbon-OneNewPS	26	28	71	25	150
Carbon	26	28	71	25	150
Carbon-TransRelax	26	28	71	24	149
Carbon-Wet	22	25	55	23	124
TEPPC	-	-	-	-	-

Table 5-19
Mercury Emissions by Scenario (Metric Tons)

Scenario	AZ-NM-SNV	CA-MX US	NWPP	RMPA	WECC
Base-Dry	560	237	979	332	2,108
Base-OneNewPS	546	234	949	329	2,057
Base-FiveNewPS-TransRelax	551	235	939	331	2,056
Base-PumpUpgrade	544	234	948	328	2,054
Base-GenUpgrade	546	233	946	328	2,054
Base	545	233	946	328	2,054
Base-TransRelax	547	233	945	328	2,054
Base-LowRegReq	545	234	945	328	2,053
Base-HighRegReq	544	228	953	327	2,052
Base-FiveNewPS	535	234	940	330	2,039
Base-NoHydroAS	527	198	919	315	1,960
Base-Wet	486	217	846	315	1,865
Extreme-Dry	510	237	804	279	1,830
Extreme-TransRelax	496	226	758	267	1,748
Extreme-OneNewPS	490	225	763	268	1,746
Extreme	490	224	763	268	1,745
Extreme-Wet	443	208	653	256	1,560
Carbon-Dry	249	216	735	230	1,430
Carbon-OneNewPS	233	188	679	215	1,315
Carbon-TransRelax	228	192	678	216	1,314
Carbon	232	188	679	214	1,314
Carbon-Wet	195	162	549	196	1,101
TEPPC	-	-	-	-	-

Technology Upgrades

In order to better understand how certain investments can affect the profitability of pumped hydro plants, two sensitivity cases were run. These considered technology upgrades widening the capacity range and adding adjustable speed capability during pumping. The case looked at one single pumped storage unit and compared it to the same plant without technology upgrades.

In the first scenario, referred to as Base-GenUpgrade, pumping efficiency, and capability were held constant and the minimum loading point was varied. Reference data gathered by the team indicate that an average level of minimum stable loading (Pmin) is typically about 70% of the capacity, whereas new units may offer a minimum loading level closer to 40%. For the sensitivity run, a unit of capacity 132MW was upgraded to have a Pmin of 52.8MW, down from 92.4MW. For pumped units, this lower Pmin level is particularly interesting because it allows the unit to participate more in ancillary service markets.

Particularly in times when energy arbitrage opportunities are limited, pumped units may run with smaller, or even negative, profit margins for energy as long as they can compensate with higher ancillary service revenues.

In the second scenario, the turbine- generator was replaced with a state-of-the-art variable speed unit for the pumping mode. In this configuration, the plant was able to utilize two new advantages over fixed speed generating equipment. Another benefit is lower minimum loading level – in this case 40% of the capacity. Note that newly commissioned units with variable speed pumps may have Pmin as low as 25%. Further, because variable speed enables varying the amount of energy utilized while pumping, the unit could provide regulation and spinning reserve services in pumping mode.

In Figure 5-17, below, the total generation and ancillary service provision of the unit in the Base Scenario in 2020 is shown by hour of the day. Spinning reserve and regulation make up only a small portion of the total and occur only during peak hours. During the Off Peak, only non-spin reserve is provided.

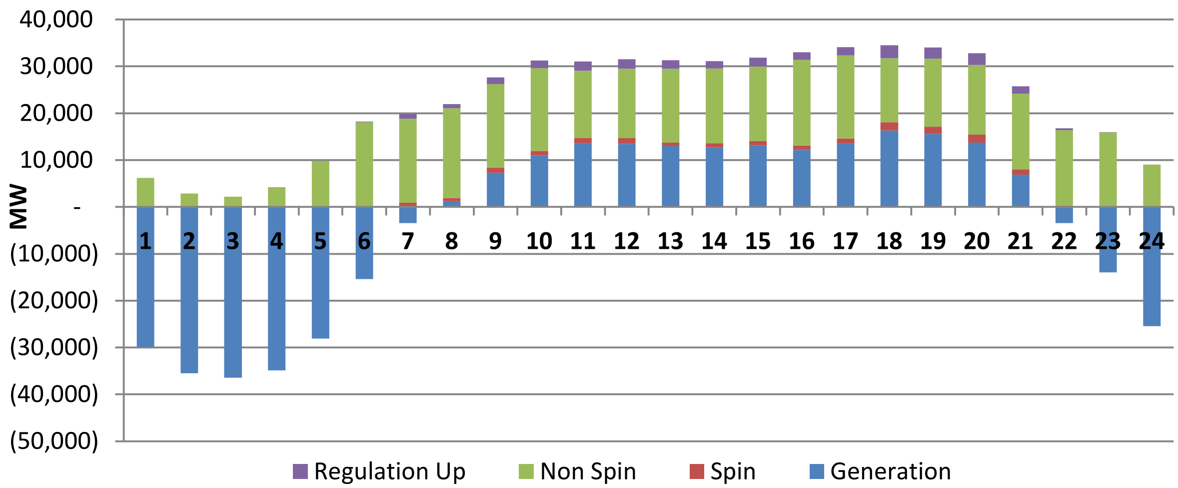

Figure 5-17
Annual Hourly Operation of 132MW Pumped Unit - Base Scenario

When the minimum loading level is allowed to drop to 40% of capacity, the unit is able to participate much more in the higher priced synchronous reserves as can be seen in Figure 5-18.

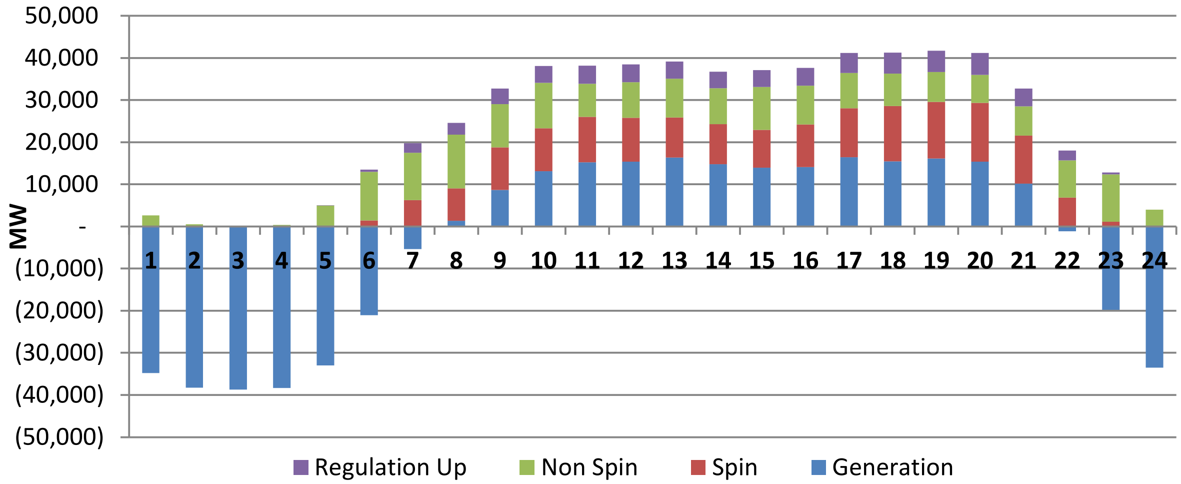

Figure 5-18
Annual Hourly Operation of 132MW Pumped Unit with Generator Upgrade

With the upgrade to a variable speed pump, the overall utilization of the unit is dramatically increased in the Off Peak hours as seen in Figure 5-19.

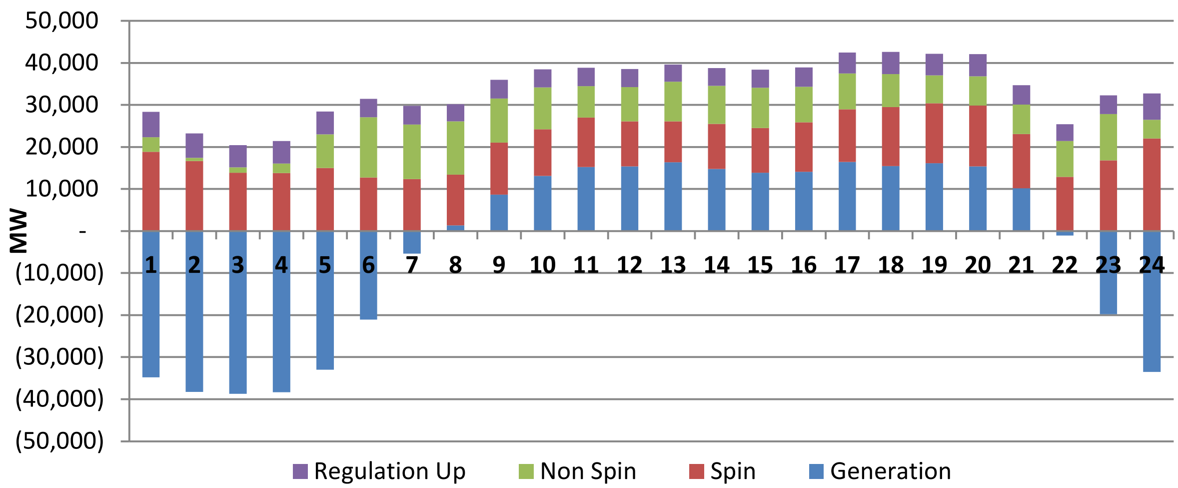

Figure 5-19
Annual Hourly Operation of 132MW Pumped Unit with Variable Speed Generator

Generator upgrades have a very large effect on the ancillary service participation of the Pumped Storage unit, but the overall generation and pumping does not exhibit such a dramatic change as can be seen in Figure 5-20.

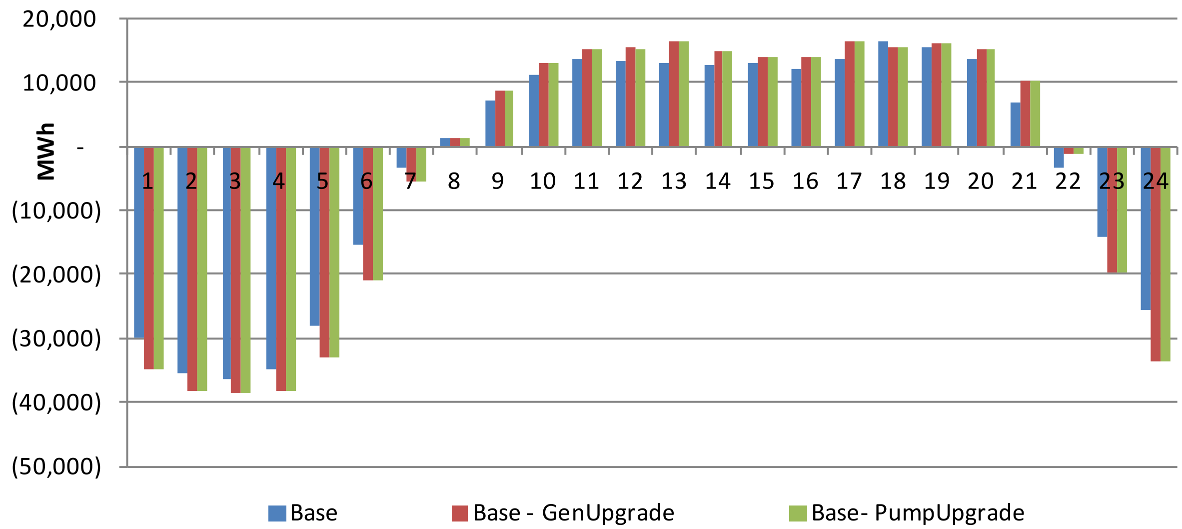

Figure 5-20
Annual Hourly Operation of 132MW Under Upgrade Scenarios

The overall performance of the unit under the various upgrade scenarios can be seen in Table 5-20. Reducing the minimum loading level of the generation side of the unit from 70% to 40% of its capacity increases the average income by 61%. Switching to variable speed increases the average income by almost 85%.

Table 5-20
Performance of Pumped Storage Units with Upgrades

Scenario	Unit Size (MW)	Capacity Factor (%)	Energy Revenue ($1000)	Ancillary Service Revenue	Fuel Cost ($1000)	Net Income ($1000)	Average Revenue ($/KW)	Average Income ($/KW)
Base	132	15.9	9,790	605	8,465	1,745	79	13
Base_GenUp	132	19.6	11,995	1,989	10,983	2,774	106	21
Base_PumpUp	132	20.5	11,988	2,863	11,483	3,131	113	24

New Pumping Plants

A number of scenarios were simulated to determine the value of new pumped storage units on the system. Five new pumped storage units were introduced into the simulations under baseline assumptions at their actual proposed locations on the network. Table 5-21 shows the performance of these plants. Generating capacity factors range from 10 to 20% which is on par for the WECC fleet. Reserve revenues are higher, however, due to the flexibility offered by newer variable speed pumps.

Table 5-21
New Pumped Storage Performance - Base-FiveNewPS Scenario

Plant	Size (MW)	Generation (GWh)	Energy Revenue ($1000)	Ancillary Service Revenue ($1000)	Total Revenue ($1000)	Net Income ($1000)
Oregon Project	1,250	2,194	133,339	9,789	143,128	17,530
South CA Project	1,300	1,146	61,641	10,535	72,176	10,879
North CA Project	399	737	45,480	7,679	53,159	9,297
Utah Project	1,330	1,438	65,656	12,866	83,591	8,828
New Mexico Project	900	1,149	29,587	2,348	31,935	7,935

Analysis of the results showed some transmission congestion relating to the operation of these new plants. Relaxing the transmission constraints, as described in Section 4, lead to increased revenues shown in Table 5-22.

Table 5-22
New Pumped Storage Performance - Base-FiveNewPSTransRelax Scenario

Plant	Size (MW)	Generation (GWh)	Energy Revenue ($1000)	Ancillary Service Revenue ($1000)	Total Revenue ($1000)	Net Income ($1000)
Oregon Project	1,250	2,076	113,184	18,561	131,745	30,349
South CA Project	1,300	1,156	58,308	15,335	73,643	16,052
North CA Project	399	707	37,307	8,337	45,644	10,574
Utah Project	1,330	1,456	74,263	14,467	90,710	17,461
New Mexico Project	900	927	49,956	13,253	63,209	18,223

A final scenario was run in which only one pumped storage plant was added in California. The results of this scenario can be seen in Table 5-23. In this scenario, the plant is able to generate more revenue than in either of the other two scenarios, which contain five plants. This is due to the fact that the five new plants are competing against each other for energy arbitrage and ancillary service opportunities.

Table 5-23
New Pumped Storage Performance

Scenario	Plant Size (MW)	Generation (GWh)	Energy Cost ($1000)	Energy Revenue ($1000)	Energy Sales - Purchase ($1000)	Ancillary Service Revenue ($1000)	Total Revenue ($1000)	Net Income ($1000)
Base-OneNewPS	399	812	39,043	43,331	4,288	9,770	53,101	14,058
Carbon-OneNewPS	399	557	41,798	42,314	516	3,125	45,438	3,640
Extreme-OneNewPS	399	598	52,460	51,369	(1,091)	4,476	55,845	3,385

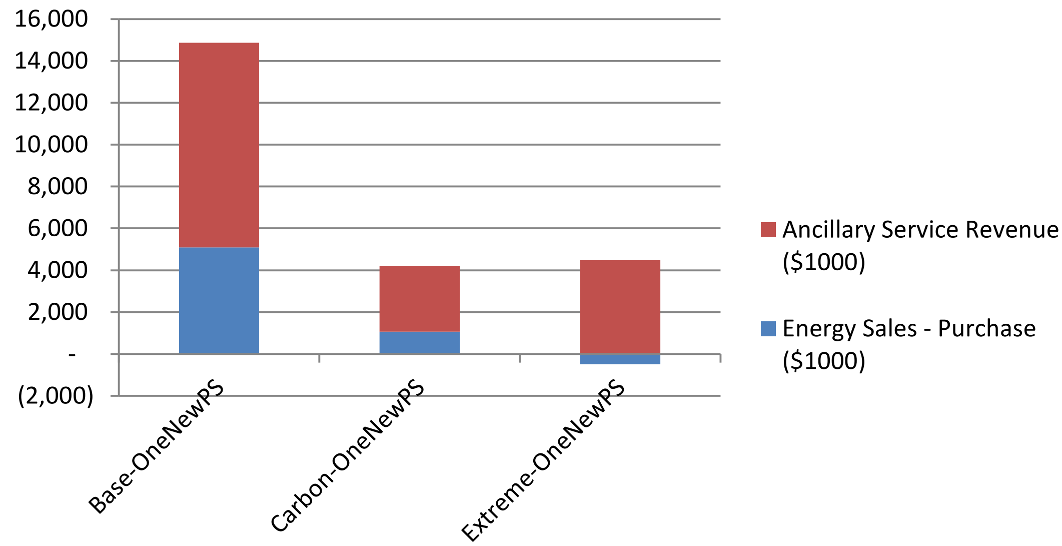

Figure 5-21
New Pumped Storage Plant Revenue by Scenario

Figure 5-21 shows the results for three different scenarios when one new pumped storage plant is added. For each scenario the net income is graphed showing the portions that is revenue from ancillary services and the portion that is attributed to energy (sales-purchases). In each scenario the ancillary services represent a greater portion of the plant revenue and the ratio or ancillary services to energy increases in the carbon and extreme future scenarios.

Discussions with manufactures revealed that new variable speed pumped storage plants could have better performance characteristics than defined in the previous scenarios. To further asses the value of these plants an additional scenario was run in which one new pumped storage plant was added to the Base Scenario. This new plant was defined to have a Pmin of 20% of the nameplate capacity, a round-trip efficiency of 80% and the ability to contribute 30% of the total capacity to regulation reserve both in pumping and generating mode. Table 5-24 shows the performance of this new plant under these conditions. As can be seen, the overall net income of the plant increases and this increase can be attributed to a higher ancillary services revenue. The energy revenue actually decreases in this scenario.

Table 5-24
New Pumped Storage Plant Performance (Pmin = 20%, 30% of Capacity Available for Regulation)

Scenario	Plant Size (MW)	Generation (GWh)	Energy Cost ($1000)	Energy Revenue ($1000)	Energy Sales - Purchase ($1000)	Ancillary Service Revenue ($1000)	Total Revenue ($1000)	Net Income ($1000)
OneNewPS: Pmin = 20	399	692	32,369	35,278	2,909	15,213	50,490	18,121

Figure 5-22 shows the distribution of revenues for the new pumped storage plant with a Pmin of 20%. In the figure, regulation reserve accounts for almost half of the revenue from the plant.

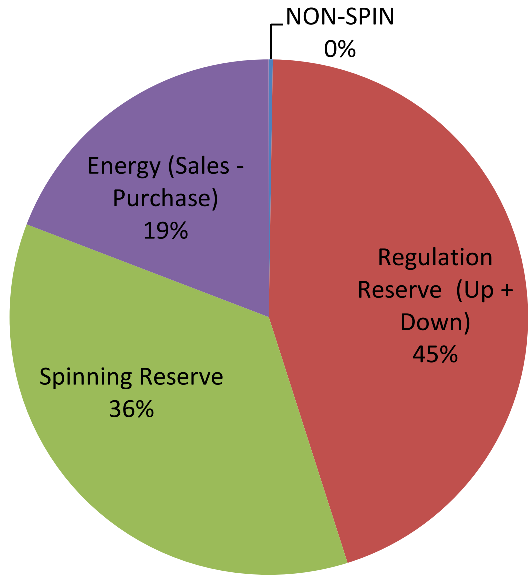

Figure 5-22
Distribution of Revenues for New Pumped Storage Plant (Pmin = 20%)

Figure 5-23 is a closer look at the ancillary services provided by the plant in this scenario. Spin accounts for just over 50% of the ancillary services provided, followed closely by regulation up. Regulation down and Non-spin account for very little of the ancillary services provided.

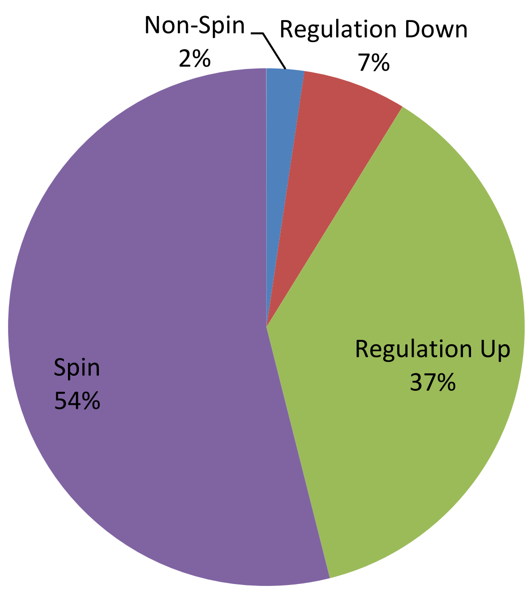

Figure 5-23
Ancillary Services Provided by New Pumped Storage Plant (Pmin = 20%)

Relaxing Transmission

In an attempt to better understand the effects of transmission congestion on the performance of hydropower, a series of scenarios was run with transmission constraints relaxed. For a description of this procedure, see Section 4.

Conventional Hydropower is well established in the WECC and transmission has been constructed to accommodate this generation. As can be seen in Table 5-13: Conventional Hydro Performance by Scenario, relaxing transmission does not actually have a big impact on conventional hydro revenues. Broadly speaking, the benefits of increased deliverability of conventional hydropower are essentially cancelled by lower prices that are also a result of relaxing transmission.

Pumped Storage revenues, however, are much more sensitive to transmission constraints. And while relaxing transmission does have the effect of depressing the energy arbitrage opportunity due to a convergence of prices, the ability of the pumped storage to pump and generate without greatly affecting local congestion ultimately benefits these plants. This is particularly true in the Base-FiveNewPS Scenario in which five new pumped storage plants are added into the system. In this scenario local congestion around the plants is present and there is a significant increase in congestion on some of the principal interfaces of the WECC system as seen in Table 5-25.

Table 5-25
Hours of Congestion for Base-FiveNewPS and Base Scenarios

Interface	Hours of Congestion: Base-FiveNewPS	Hours of Congestion: Base
IDAHO - MONTANA	117	79
IDAHO - NORTHWEST	437	185
INTERMOUNTAIN - MONA 345 KV	889	398
NORTHERN - SOUTHERN CALIFORNIA	65	10
PACIFIC DC INTERTIE (PDCI)	416	96
SOUTHERN NEW MEXICO (NM1)	32	
TOT 2C	131	62
TOT 3	25	
TOT 5	890	600

Other insights that we get from these relaxed transmission cases include:

- Even though price spreads are a little bit thinner, Pumped Storage income is increased by 45% from the Extreme Scenario to the Extreme-Relaxed Scenario. The big winner is Helms.
- Carbon Relaxed case gives lower pumped storage income mainly due to two plants, Cabin Creek and Mt. Elbert.

Section 6: Production Cost Modeling Validation and Further Sensitivity Analysis

Based on feedback received from project stakeholders at a workshop held in March 2012, one additional scenario and additional sensitivities were defined. These additional model runs were designed to validate results from the previous chapter and provide further insight into the drivers of the value of conventional and pumped hydropower. Emphasis was placed on examining in detail the likely impacts of high amounts of wind and solar and how that would relate to the value of hydro. It is expected that increased levels of wind and solar will alter reserve requirements and other drivers of pumped hydro storage revenue; these were represented in a 'business as usual' sense in the previous chapter but here additional assumptions are made about the impact of variable generation. Therefore, the impact of forecast uncertainty and additional 'flexibility reserves' was modeled.

This chapter examines the results of the additional modeling. First, the methods used to determine reserve requirements for high levels of variable wind and solar generation are shown. Then the newly defined scenario that is used as a base case for the validation sensitivities is examined, with comparisons to the TEPPC case in the previous chapter which is its closest corresponding existing case. Finally, results for multiple sensitivities are shown, to assess the impact of assumptions around both system flexibility characteristics and representation of different regions in the WECC system.

Reserve Requirements

Wind Data

The wind data used for this study was a subset of the wind data developed by the National Renewable Energy Lab (NREL) for use in the Western Wind and Solar Integration Study (WWSIS). The data was developed using numerical weather prediction models to re-create the wind at hub height in a 2 km grid across the western interconnection. The wind was calculated at 10 minute intervals for 3 years (2004, 2005 and 2006). The wind speed data was extracted from the model and used to create time series of wind plant output data at each of more than 32000 grid points. Additional corrections have been applied to compensate for a numerical problem seen in the data when the weather model was periodically restarted causing artifacts at those temporal seems.

The data that resulted from this process provides a prediction of what the wind production would actually have been at each wind plant every ten minutes over the three years. A separate day-ahead forecast dataset was also produced for each plant that is designed to behave like an actual forecast with realistic day-ahead mean-absolute-error (MAE) of 15% to 20%.

The site selection for the wind data was made based on the Western Electricity Coordinating Council (WECC) as part of their long range planning process under the Transmission Expansion Planning Policy Committee or TEPPC. The sites and wind data are based on selection done by TEPPC for its 2019 planning case 1 (2019 PC1).

Solar Data

The solar data used for this study was derived from 2 datasets developed by NREL. The data for the simulations was based on a dataset developed for the WWSIS. That dataset contained data for a number of sites across the western interconnect made up of several technologies such as photovoltaic (PV) and solar-thermal tech like concentrated solar power (CSP).

The solar data were created using irradiance models based upon satellite imaging of clouds and surface at an hourly time resolution. Ten minute data was synthesized using a statistical variability approach. The 10 minute dataset was unavailable for use in calculating reserves requirements so a new dataset from NREL was used for this purpose.

The second dataset was created using newer, more rigorous techniques and algorithms primarily for use in phase 2 of the WWSIS. This data was used exclusively for creation of statistical information that was used in combination with the earlier created data to calculate the flexibility reserve requirements. Solar site selection from done by WECC as part of TEPPC 2019 PC1.

Reserves

The increased variability and uncertainty from wind and solar power causes an increase in operating reserve requirements. Those requirements can be provided by some combination of flexible generation and responsive load. Together, these contribute to the operating reserve that is available to help manage the wind and load variability[8]. This reserve is calculated dynamically, and is a function of the

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[8] King, J.; Kirby, B.; Milligan, M.; Beuning, S. *Operating Reserve Reductions From a Proposed Energy Imbalance Market With Wind and Solar Generation in the Western Interconnection*. TP-5500-54660. Golden, CO: National Renewable Energy Laboratory, 2012. http://www.nrel.gov/docs/fy12osti/54660.pdf.

observed variability of the wind power and the load. A methodology was developed to estimate the increased requirements for reserves with wind variability in the Eastern Wind Integration and Transmission Study (EWITS)[9].

Short-term variability is challenging because it is difficult to fully anticipate the scheduling changes and fluctuations that must be covered with reserves. In a system with 10-minute or faster dispatch update cycles, a typical approach is to forecast a flat value for wind output for the next interval based on the past 10 to 20 minutes. The wind varies on that time scale, and an understanding is needed of how it will vary during the forecast interval. Figure 6-1 Forecast for 10-minute dispatch and Figure 6-2 Forecast for 1-hour dispatch made at 40 minutes prior to the beginning of the operational period illustrate how the forecast error is calculated for both 10-minute and 1-hour dispatch schedules. The forecast error is the difference between the actual data and the forecast value.

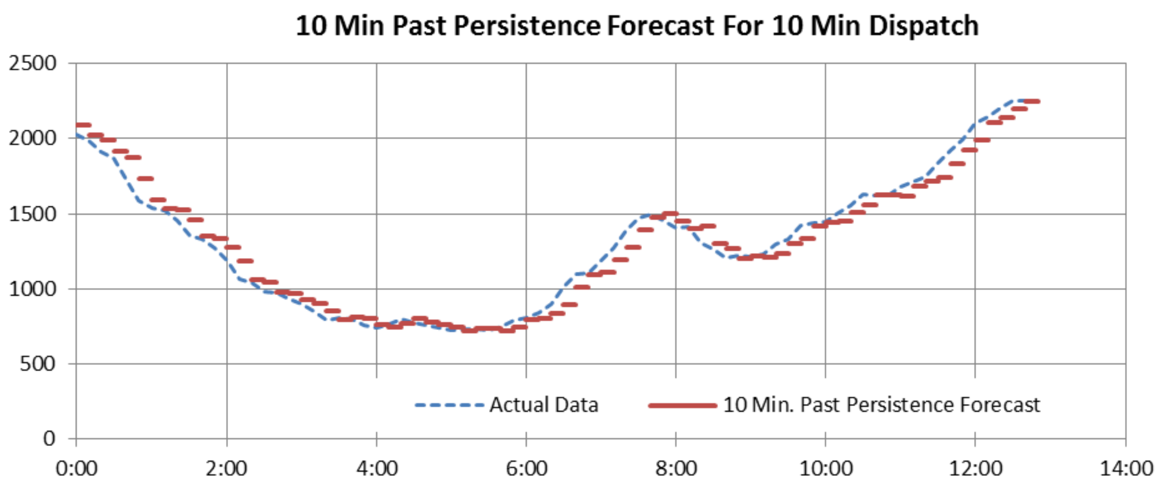

Figure 6-1
Forecast for 10-minute dispatch

[9] EnerNex Corp. *Eastern Wind Integration and Transmission Study*. NREL/SR-5500-47078. Work performed by EnerNex Corp, Knoxville, TN. Golden, CO: National Renewable Energy Laboratory, 2010. http://www.nrel.gov/wind/systemsintegration/pdfs/2010/ewits_final_report.pdf.

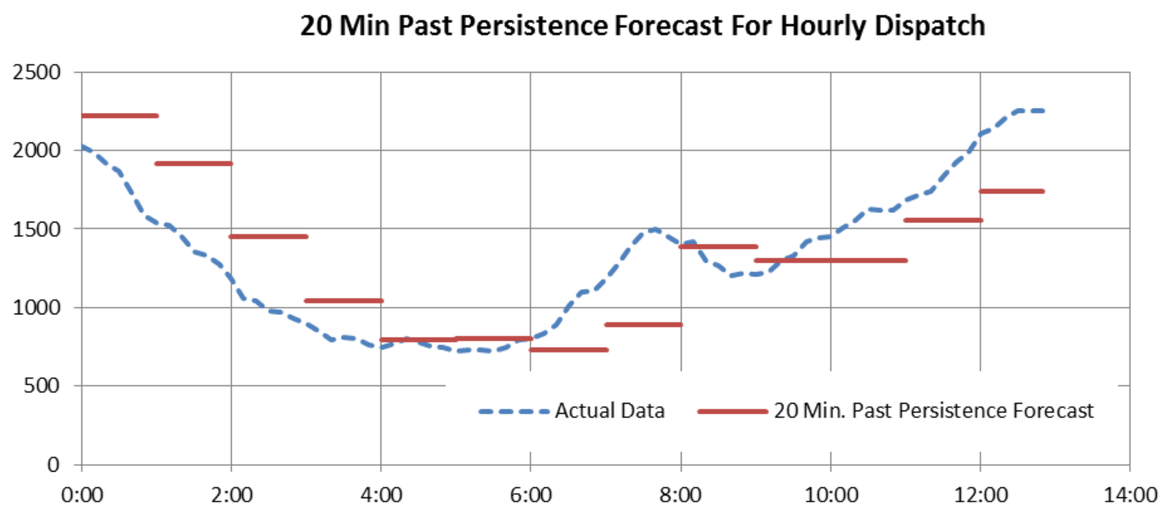

Figure 6-2
Forecast for 1-hour dispatch made at 40 minutes prior to the beginning of the operational period

An estimate of the reserve requirements can be made using a statistical approach. Based on detailed wind, solar, forecasts and optionally load, the standard deviation or other variability metric can be used to calculate this estimate.

For this study, the reserve requirements are broken down into three classes by the types of resources required to fulfill them.

Regulation is required to cover fast changes within the forecast interval. These changes can be up or down and can happen on a minute-to-minute time scale. Regulation requires resources on automatic generation control (AGC).

Spinning reserve is required to cover larger, less frequent variations that are primarily due to longer-term forecast errors. Spinning reserve is provided by resources (generation and responsive load) that are spinning and can fully respond within 10 minutes. These resources do not necessarily require AGC.

Non-spinning and supplemental reserves are used to cover large, slower-moving, infrequent events such as unforecasted ramping events. Non-spinning reserve can be made available within 30 minutes and can come from quick start resources and responsive load.

Calculation Methods

At the root of the EWITS method is the observation that the variability of wind and solar plant output is a function of its production level. Through analysis, an equation can be written for the variable generation variability as a function of VG production level. For normally distributed data this equation is in terms of standard deviation of the error by production level. Alternately, for non-normal distributions a non-parametric approach can be taken that uses confidence levels on forecast error. This analysis assumes non-normality and uses confidence level as its measure of variability.

The variability equation is derived by analyzing the wind production data over some long period of time (a year or more), sorting the data into ranges by production level and calculating the standard deviation or confidence level for the variability in various ranges of wind output. Figure 6-3 shows an example of this function.

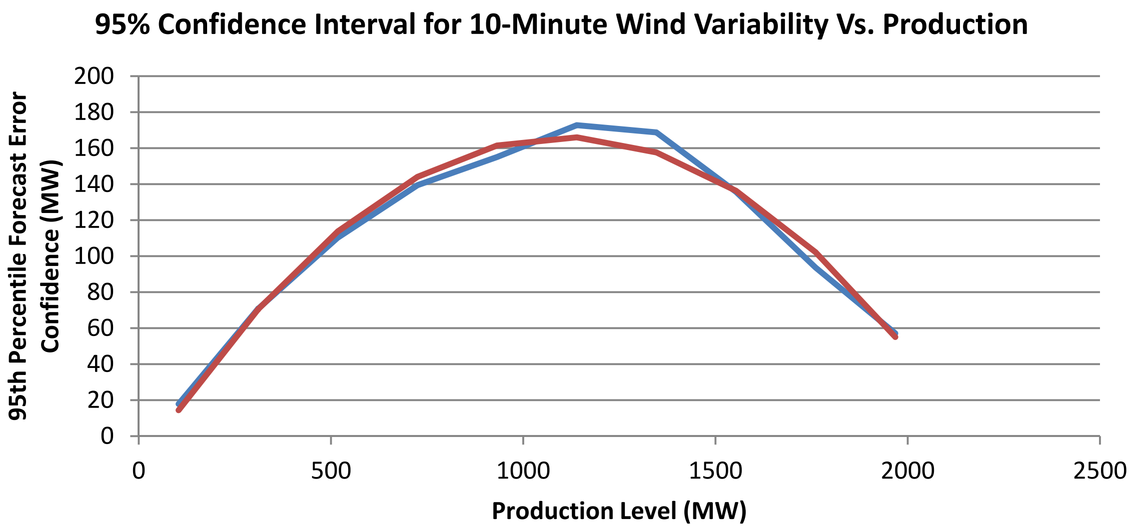

Figure 6-3
Short term forecast error statistic as a function of wind production level

The polynomial shown in Equation 1 is the curve fit shown as the smoothed line in Figure 6-3. ΘWST and ΘSST are the 95% confidence level for short term wind and solar respectively. Hourly wind is used to calculate the requirements since the production cost simulation is done at hourly time steps and the reserve resolution must align with it.

Equation 1
Sample calculation of hourly wind 95% confidence level

$$\boldsymbol{\theta_{WST}\,(Hourly\,Wind) = -.00015 \cdot (Hourly\,Wind)^2 + 0.333 \cdot (Hourly\,Wind) - 18.5}$$

The equation is used to calculate 97th percentile confidence level of the wind power for each hour. For this study, load regulation is modeled separately from the VG requirements. The same procedure is applied to the solar data yielding a similar equation for the solar variability. The wind and solar components are assumed to be uncorrelated and are combined as shown in Equation 2.

Equation 2
Calculation of intra-hour regulation requirement

$$Regulation\ Requirement\ (Wind, Solar) = \sqrt{\theta_{WST}\,(Wind)^2 + \theta_{SST}\,(Solar)^2}$$

This approach using the 95% confidence level insures that 95% of all variations will be covered by the calculated reserve requirement. This component must be covered by regulation like reserves under AGC.

An additional uncertainty component due to hour-ahead wind forecasting error was calculated as part of the EWITS method. This component is calculated in a similar manner to the short-term forecast error described above, using an equation to describe the standard deviation or confidence level of hour-ahead forecast error. Figure 6-4 shows the development of the equation for hour-ahead forecast error statistic used to estimate the flexibility reserve requirements.

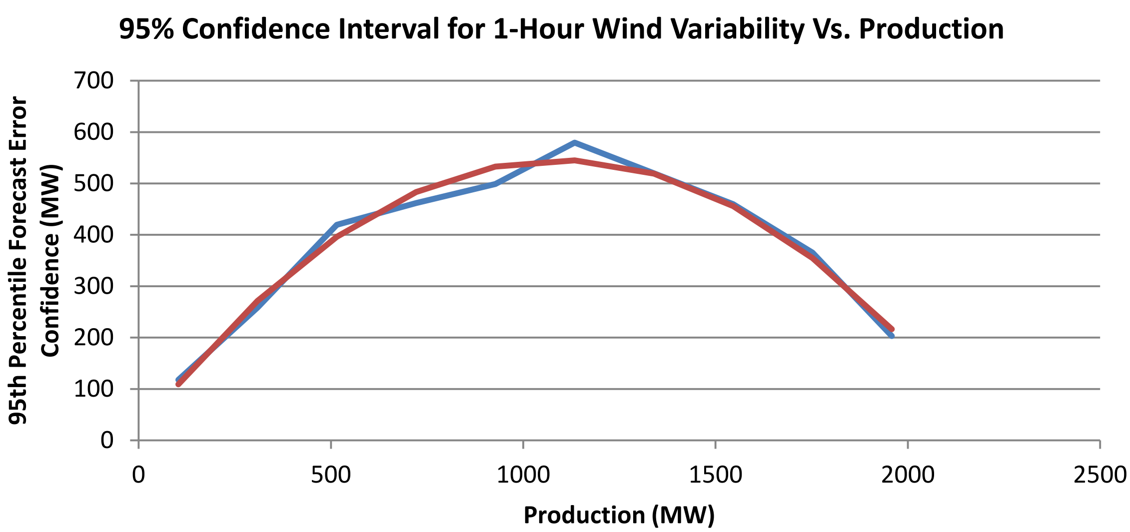

Figure 6-4
Hour-ahead forecast error statistic as a function of wind production level

The polynomial shown in Equation 3 is the curve fit shown as the smoothed line in Figure 6-4. ΘWHA and ΘSHA are the 95% confidence level for hour-ahead wind and solar respectively.

Equation 3
Sample calculation of hour-head wind 95% confidence level

$$\boldsymbol{\Theta_{WHA}(Hourly\ Wind)} = -.000443 \cdot (\boldsymbol{Hourly\ Wind})^{\mathbf{2}} + \mathbf{0}.97 \cdot (\boldsymbol{Hourly\ Wind}) + 13.8$$

With this equation, the expected 95% confidence level for the forecast error is calculated based on the previous hour's production (persistence forecast). This component helps to insure the system is positioned with enough maneuverability to cover the probable forecast error and divided as 1/3 assigned to spinning reserves and 2/3 assigned to non-spin/supplemental reserves. Equation 4 shows the function for the spinning reserves. The equation for non-spinning/supplemental reserves is the same except that 2/3 of the hour-ahead requirement is used.

Equation 4
Calculation of spinning reserves requirement

$$\boldsymbol{Flexibilty\ Spinning\ Requirement\ (Hour - ahead\ wind\ and\ solar\ forecast\ error)} = \frac{\mathbf{1}}{\mathbf{3}} \cdot \sqrt{\boldsymbol{\Theta_{WHA}(Previous\ Hour\ Wind)^{2}} + \boldsymbol{\Theta_{SHA}(Previous\ Hour\ Solar)^{2}}}$$

To calculate the total reserve requirement, each of these three components, regulation, spin and non-spin, are added arithmetically.

Results

The method described above was applied to the scenario defined for this study. In this scenario, it is assumed that each balancing area (BA) in the western interconnect is responsible for balancing its own variability for wind and solar resources assigned to it. This implies that there is a separate set of hourly reserve components (regulation, spin and non-spin) for each BA.

While there are a total of 34 load serving BAs in the western interconnect, only 20 of those contain variable resources requiring additional reserved to cover the variability. Table 6-1 Western Interconnect BAs with wind and/or solar resources shows these balancing areas with the abbreviations used later in this section. The table also includes the wind and solar capacity assigned to each of these BAs.

Table 6-1
Western Interconnect BAs with wind and/or solar resources

Abbreviation	BA Name	Solar Capacity (MW)	Wind Capacity (MW)
APS	Arizona Public Service	1070	
AVA	Avista		1563
BPA	Bonneville Power Administration		5063
CAISO	California ISO	9841	9938
EPE	El Paso Electric	195	
IPC	Idaho Power Corp		276
LDWP	LA Department of Water and Power	250	720
NEVP	Nevada Power	152	
NWMT	Northwest Energy		958
PACE	Pacificorp East		2310
PACW	Pacificorp West		583
PGN	Portland General Electric		549
PNM	Public Service of New Mexico	143	926
PSC	Public Service of Colorado	128	2084
PSE	Puget Sound Energy		279
SPP	Sierra Pacific Power		277
SRP	Salt River Project	573	
TEP	Tucson Electric Power	250	
WACM	Western Area Power Administration - Colorado Missouri Region		123
WALC	Western Area Power Administration - Lower Colorado Region	40	177

The additional regulation requirements for each BA can be found in Figure 6-5. The average value for regulation reserve is shown as the blue bar while the maximum value seen is shown by the whisker above the bar.

CAISO has been left out of the figure because its requirement of 542 MW compresses the y axis. The maximum value seen for CAISO regulation is 1540 MW. This value is dominated by the solar variability primarily surrounding sunrise and sunset.

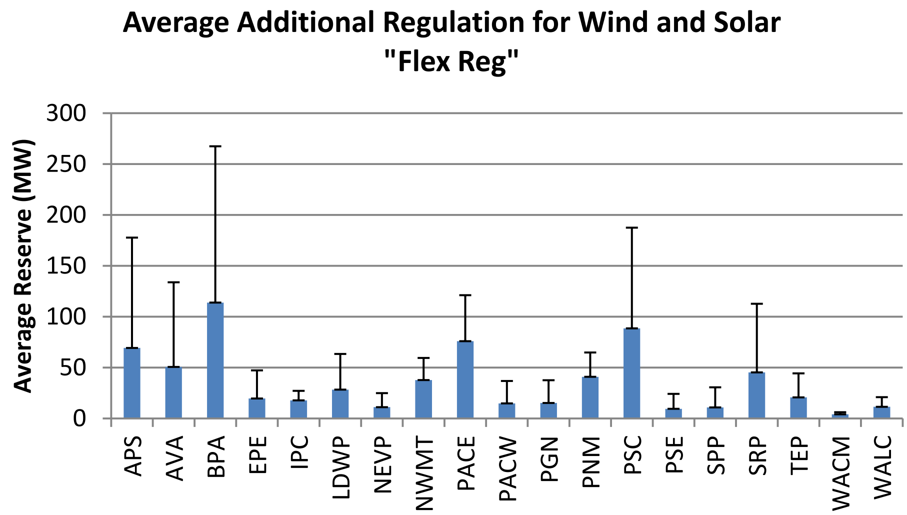

Figure 6-5
Average additional regulation requirement

Figure 6-6 shows the additional spinning reserve requirements for the BAs with wind and solar resources. The requirements for CAISO are an average 808 MW and maximum of 1984 MW.

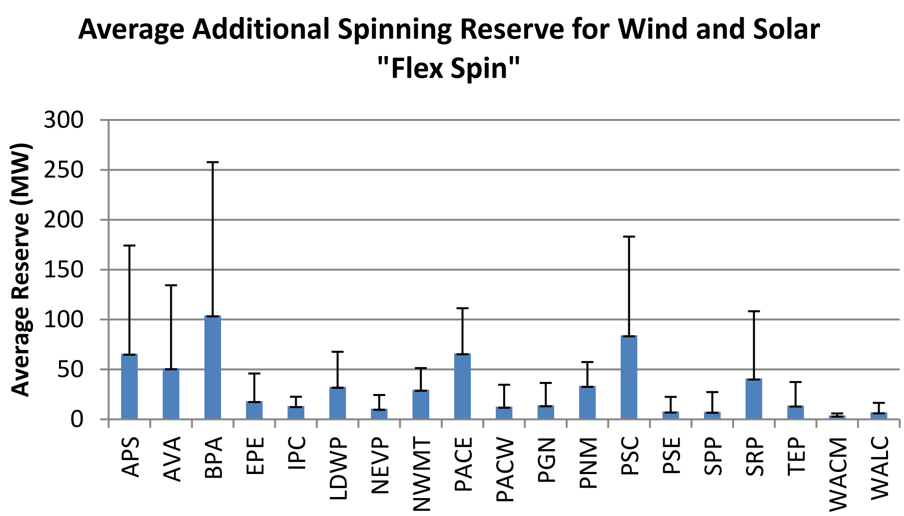

Figure 6-6
Average addition spin requirement

Figure 6-7 shows the additional non-spinning reserve requirements for each BA with wind and solar resources. The non-spin requirement for CAISO are an average value of 1617 MW and maximum of 3967 MW.

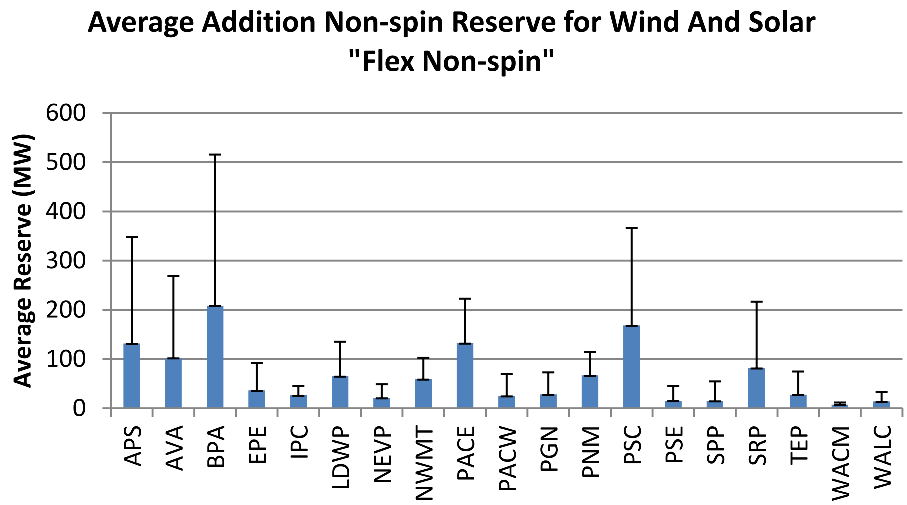

Figure 6-7
Average additional non-spin requirement

Figure 6-8 shows the same information for total flexibility reserve requirements. The total flexibility requirement is defined as sum of the regulation, spin and non-spin components of the additional reserves calculated to cover variability of wind and solar resources. For CAISO, the average value of total reserves is 2966 MW with a maximum of 4525 MW.

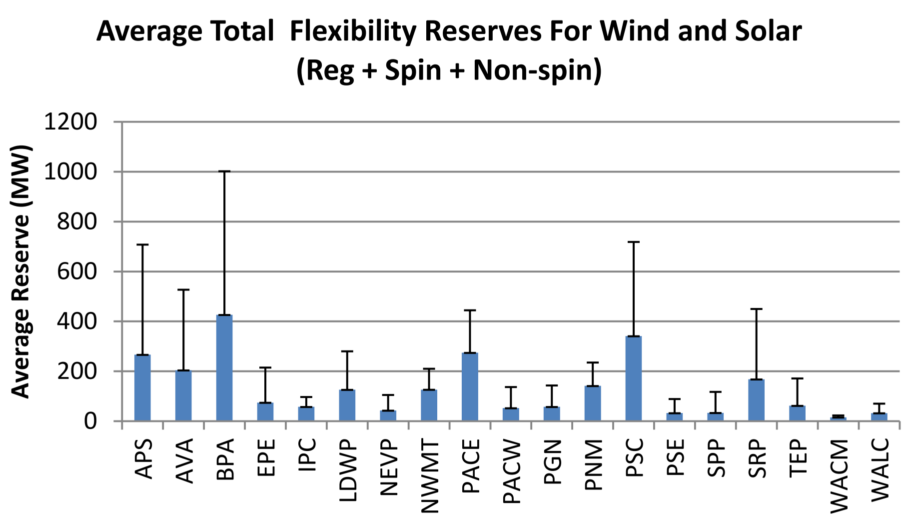

Figure 6-8
Average total flexibility reserves for wind and solar

Flexible Reserves Base Case Results

Definition of New Base Case and High Level Results

For the purposes of this chapter, a new base case has been defined based on the TEPPC case from the previous chapter, with four significant changes:

- A new reserve category, flexible reserves, has been defined as described in the previous section. This increases spinning, non-spinning, and regulation reserves.
- These runs all include a forecast for wind and PV in the day ahead commitment stage and a different realized value in the real time economic dispatch stage. Data is taken from the same place as the wind and load, i.e. WECC TEPPC data. Forecasts are based in current state-of the art performance, and are simulated to result in an error approximately equal to that which would currently be seen in day ahead forecasts.
- Subsequent to the runs done in the previous chapter, data for Combined Cycle units has been updated. This results in a less flexible operation of combined cycle units and their ability to provide reserves. This is based on feedback from stakeholders.
- New wind and solar data was made available; this updates the time series profiles for wind and solar based on newer information.

Here, we first examine results for this case and compare to the previously seen results and then analyze the impacts and implications of the changes made for pumped and conventional hydropower.

The new base case has 5 regions. These are used in the day ahead commitment, whereby each region has to satisfy energy and ancillary service requirements using resources in the region. Economic dispatch is then simulated across the entire WECC footprint. Generation by unit type and region is given in Table 6-2.

Table 6-2
2020 Flexible Reserves Base Case Scenario Annual Generation (GWh)

Technology	AZ-NM-SNV	CA-MX US	NWPP	RMPA	WECC
Biomass	-	8,071	4,563	-	12,634
Coal	77,583	14,694	134,783	51,459	278,519
Combined Cycle	36,166	94,727	63,014	14,220	208,127
Combustion Turbine	6,130	4,866	15,773	4,123	30,892
Geothermal	-	32,691	4,871	-	37,562
Hydro	9,439	42,955	203,789	2,861	259,044
Nuclear	35,443	38,562	10,189	-	84,195
Other Thermal	473	7,815	1,998	87	10,373
Pumped Storage	356	5,783	598	1,116	7,854
Solar	6,529	20,006	-	319	26,854
Wind	3,323	26,813	36,498	6,597	73,231
Grand Total	175,443	296,982	476,077	80,782	1,029,284

Comparing this to generation in the TEPPC case from the previous chapter as shown in Table 6-3 with the difference between the two cases shown in Figure 6-9, the increased reserves and forecast error being included in the model have the result of increasing combined cycle usage and units in the other thermal category slightly, increasing pumped hydro usage by approximately 6% and reducing solar output due to curtailment. Generation in the Arizona-New Mexico- South Nevada region goes up, mainly due to an increase in combined cycle usage there, while generation in all other regions goes down, particularly California, with a decrease in combined cycle and solar resulting in a slightly increased generation level system wide (due to increased usage of pumped storage). As combined cycles are often used to carry reserves, and there is an increase in reserves in certain hours when wind and solar are high in the Flexible Reserves base case, an increase in combined cycle usage would be expected. Similarly, much of the solar resource is located in the desert southwest, so combined cycles in that region are on more often to provide reserve and ramping to make up for forecast error.

Table 6-3
2020 TEPPC Scenario Annual Generation (GWh)

Technology	AZ-NM-SNV	CA-MX US	NWPP	RMPA	WECC
Biomass	-	8,103	4,557	-	12,660
Coal	77,495	14,738	134,764	51,735	278,732
Combined Cycle	30,787	96,813	63,560	14,652	205,812
Combustion Turbine	6,116	4,903	15,860	4,043	30,923
Geothermal	-	33,088	4,871	-	37,959
Hydro	9,439	42,955	203,948	2,861	259,203
Nuclear	35,443	38,562	10,189	-	84,195
Other Thermal	352	6,803	2,101	75	9,331
Pumped Storage	328	5,434	562	1,059	7,382
Solar	6,594	22,568	-	420	29,582
Wind	3,257	26,286	36,573	6,551	72,667
Grand Total	169,811	300,251	476,988	81,395	1,028,445

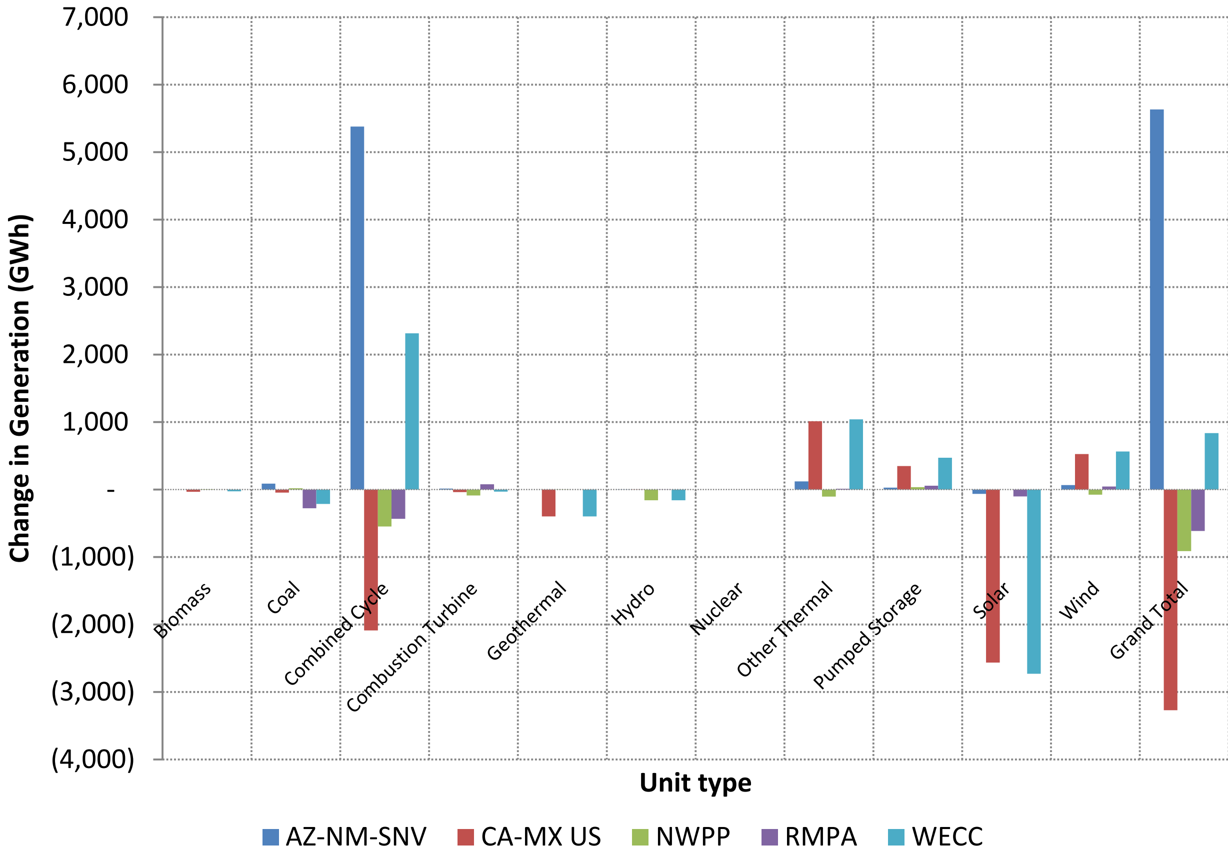

Figure 6-9
Change in Generation by Unit Type and Area from TEPPC scenario to Flexible Reserves base Scenario

Conventional and Pumped Hydro Performance

In this new base case, conventional hydro performs as shown in Table 6-4. It can be seen that most of the generation in is the northwest area.

Table 6-4
Conventional Hydro Performance - Flexible Reserves base case

Region	Capacity (MW)	Generation (GWh)	Energy Revenue ($1000)	Ancillary Service Revenue ($1000)	Net Income ($1000)	Average Income ($/kW)
AZ-NM-SNV	3,906	9,439	563,610	128,874	683,045	175
CA-MX US	9,078	42,955	2,414,816	271,617	2,643,488	291
NWPP	49,002	203,789	12,367,189	181,457	12,344,857	252
RMPA	1,151	2,861	171,813	42,136	211,088	183
WECC	63,137	259,044	15,517,428	624,084	15,882,478	252

As can be seen, conventional hydro in California is the most profitable. Comparing this to results for the TEPPC case in Table 5-13 the previous chapter (the case closest to this new Flexible Reserves base case, with changes as identified earlier in chapter), it can be seen that total average income across WECC is approximately the same per kW installed. Ancillary Service revenue is increased versus the previous results, due to flexibility reserve requirements and forecast error. This can be seen in Figure 6-10 – while revenue for certain regions change significantly between this new case with flexibility reserves and forecast error, total revenue for conventional hydro remains approximately the same (only $1/kW more), with more A/S revenue offset by a reduction in energy revenue.

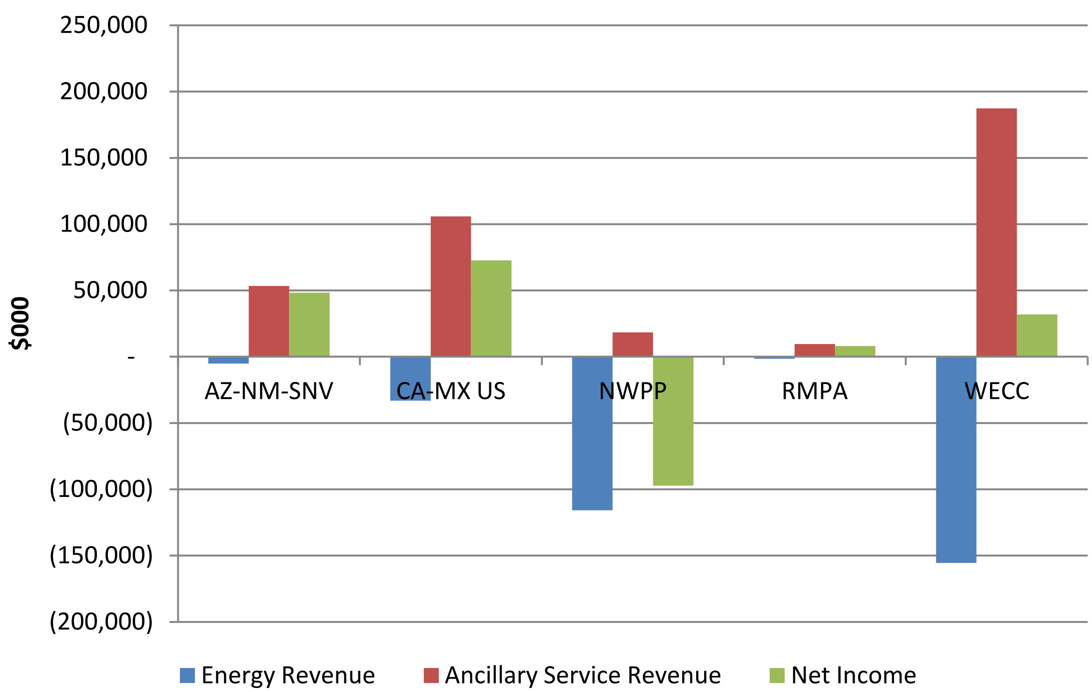

Figure 6-10
Change in Revenues for Conventional Hydro by region. Difference is new Flexible Reserves base case minus previous TEPPC case

In the new cases with additional flexibility reserves and representation of forecast uncertainty, it would be expected that pumped hydro revenues would increase. This is shown to be the case in Table 6-5.

Table 6-5
Pumped Hydro Storage Performance by Region – Flexible Reserves Base Scenario

Region	Capacity (MW)	Generation (GWh)	Energy Revenue ($1000)	Reserve Revenue ($1000)	Net Income ($1000)	Average Income ($/kW)
AZ-NM-SNV	198	356	26,821	5,226	9,464	48
CA-MX US	3,639	5,783	413,929	47,652	80,255	22
NWPP	314	598	44,519	3,815	11,251	36
RMPA	560	1,116	84,294	8,510	19,315	34
WECC	4,711	7,854	569,563	65,202	120,284	26

Comparing this to Table 5-8, average income per kW across the entire WECC footprint has increased from $18/kW to $26/kW when comparing the new Flexible Reserves base case with its closest comparison point in the previous chapter, the TEPPC scenario. This is due to all the changes listed above – flexibility reserves, new wind and PV data, forecast error being considered in the model and possibly due in part to changed flexibility parameters for the combined cycle units. This is shown in Figure 6-11. Compared to the situation where adding flexibility reserves and forecast error did not significantly impact total revenue for conventional hydropower, for pumped hydro storage, there is a significant increase. The increase in revenue of $35k corresponds to approximately $8/kW installed, an increase of over 40%.

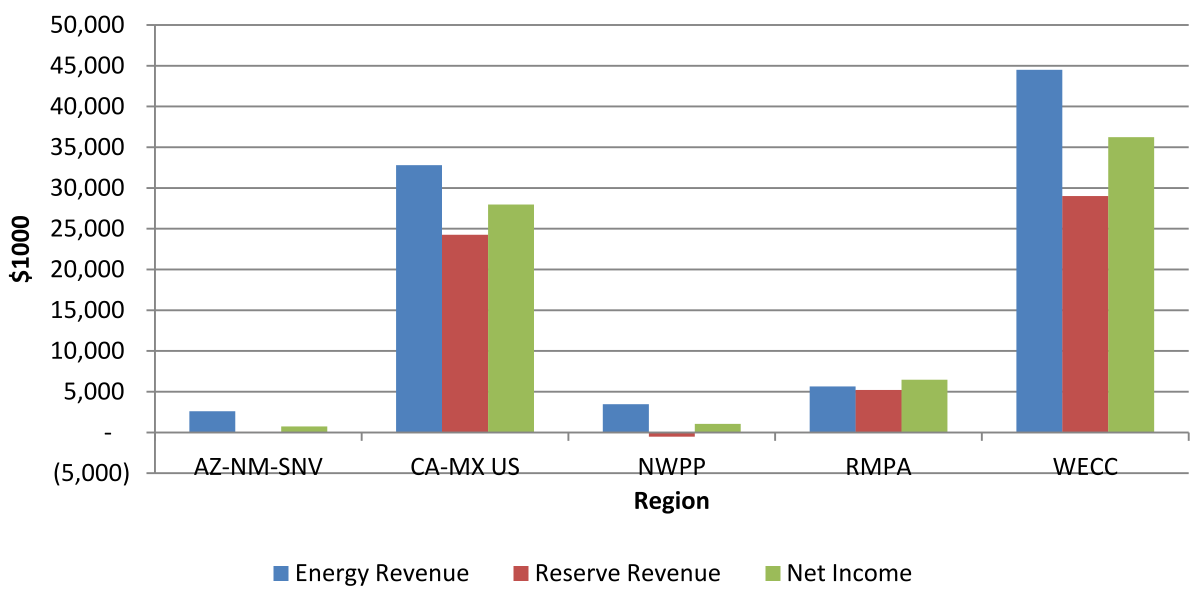

Figure 6-11
Change in Revenues for Pumped Hydro Storage by region. Difference is new Flexible Reserves base case minus previous TEPPC case

Looking at individual regions and comparing to Table 6-4, pumped hydro in California is not the most profitable location for pumped hydro, in comparison to conventional hydro. In this case, Arizona-New Mexico-South Nevada is the most profitable region for pumped hydro; this would be expected as this also makes up the largest part of generation. In addition, a large portion of the total pumped storage revenue in that region is made up of ancillary services payments, indicating that these are significant, possibly due to large amount of solar PV in this region, which needs increased short term flexibility reserves. To examine these results in more detail, performance of pumped hydro by unit is given in Table 6-6.

Table 6-6
Pumped Hydro Storage Plant Performance - Flexible Reserves Base Scenario

Plant	Number of Units Modeled	Capacity (MW)	Generation (GWh)	Energy Revenue ($1000)	Ancillary Service Revenue ($1000)	Energy Cost ($1000)	Net Income ($1000)	Average Income ($/kW)
Waddell	1	40	75	5,645	1,172	4,797	2,020	50
Horse Mesa	1	111	210	15,788	3,221	13,426	5,583	50
Mormon Flat	1	47	71	5,389	833	4,361	1,861	40
Grand Coulee	6	314	598	44,519	3,815	37,083	11,251	36
ONeill	6	13	18	1,303	231	1,087	448	36
Cabin Creek	2	324	647	48,831	4,960	42,544	11,247	35
Hodges-Olivenhain	2	40	78	5,644	679	4,940	1,383	35
Mount Elbert	2	200	397	30,034	3,010	26,206	6,837	34
Flatiron	1	36	72	5,429	540	4,739	1,230	34
WR Gianelli	8	424	809	59,087	7,065	52,130	14,022	33
Edward Hyatt	3	396	730	51,143	6,719	46,375	11,488	29
Thermalito	3	84	88	6,082	1,941	5,882	2,141	26
Helms	3	1,200	1,157	82,570	24,999	81,561	26,008	22
Castaic	6	1,275	2,508	183,083	2,472	164,155	21,400	17
JS Eastwoood	1	207	396	25,015	3,545	25,196	3,365	16

It can be seen in Table 6-6 that there is once again a wide range of revenue, due to both location of the pumped storage plant (congestion, market conditions in the region will impact revenue) and the characteristics of the plant itself (efficiency, minimum generation levels, contribution to Ancillary Services). The two largest units make the least profit, due to congestion and the markets they are participating in. This is consistent with results shown in Table 5-4; however now the numbers are significantly higher for all plants. Whereas previously, the highest income was in the region of $45/kW and lowest was $8/kW, the range is now $16 /kW to $50/kW.

The change in revenue expressed as $/kW for each plant when compared to the TEPPC case in the previous chapter shows an increased revenue when considering forecast uncertainty and a new flexibility reserve product. This is shown in Figure 6-12. Adding these features can be seen to increase revenue in all pumped hydro storage plants, but there is a large range in the value of the increase. As shown in Figure 6-11, this mainly occurs in the California plants.

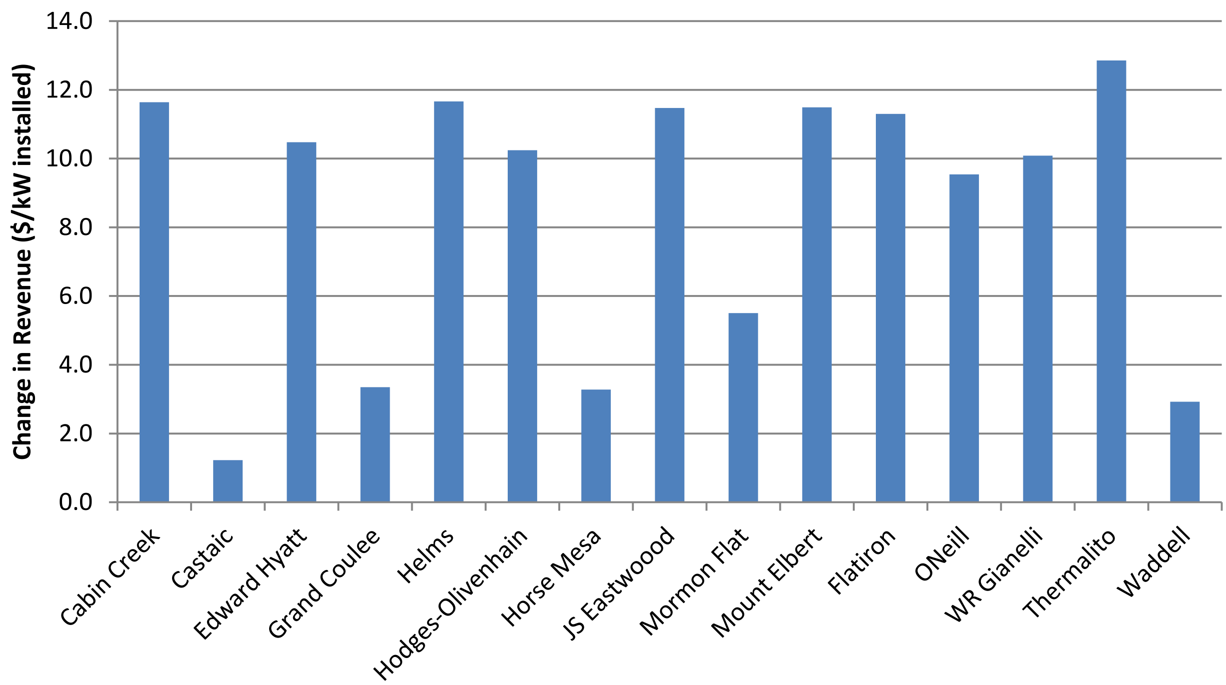

Figure 6-12
Increase in revenue for pumped hydro plants in new Flexible Reserves Base Case versus corresponding TEPPC case

This indicated that the results in the chapter 5 are on the low end of possible future value of pumped storage. The previous chapter uses 'business as usual type' values and policies for reserves and doesn't explicitly consider forecast uncertainty that may be used in the future to operate the system.. The flexibility reserves and other operational assumptions made in this chapter represent a possible method of dealing with increased variability and uncertainty from wind and solar power.

While they are not considered to be the exact way a system might operate in the future, they do give some indication of how the system may operate under these conditions, and thus issues relating to variable generation integration can be examined in the context of their impact on conventional and pumped hydro.

The results above show that increased penetrations of wind and solar could affect the value of pumped hydro more than was shown in the 'business as usual' case. This indicates that different methods for calculating reserve requirements will likely affect the value of pumped storage. The results here and in Chapter 5 show the results of various methods that could be used in the future by utilities/ISOs. The approach in Chapter 5 may not be optimal but may be something utilities/ISOs decide to do. Likewise, better forecasting methods, stochastic optimization, dynamic reserve determination, etc., could all affect the value of pumped hydro storage as seen either in this chapter or Chapter 5.

System Wide Detailed Results for Flexible Reserves Base Case

This section aims to put the value of conventional and pumped hydropower in a system wide context by examining system level results for all generation in more detail. To understand the operation of the Flexible Reserves base scenario and show the model produces accurate dispatches, 2 weeks of operation are examined, one high and one low wind. WECC-wide, the lowest wind penetration was in the week of July 12, when wind and solar provided approximately 5% of total energy over the week, including some less than 1% of energy requirements being instantaneously met by wind and solar. Production by unit type is shown in Figure 6-13 this week. Also shown on the secondary axis is pumped hydro generation – it follows a daily pattern of generation, beginning at morning load rise and going through the evening peak; the actual generation from pumped storage varies based on, among other things, wind and solar generation. As expected for a low variability week, coal remains constant during this week; hydro is also fairly constant with some peaking during the day, with the majority of cycling being done by hydro and combined cycle generation.

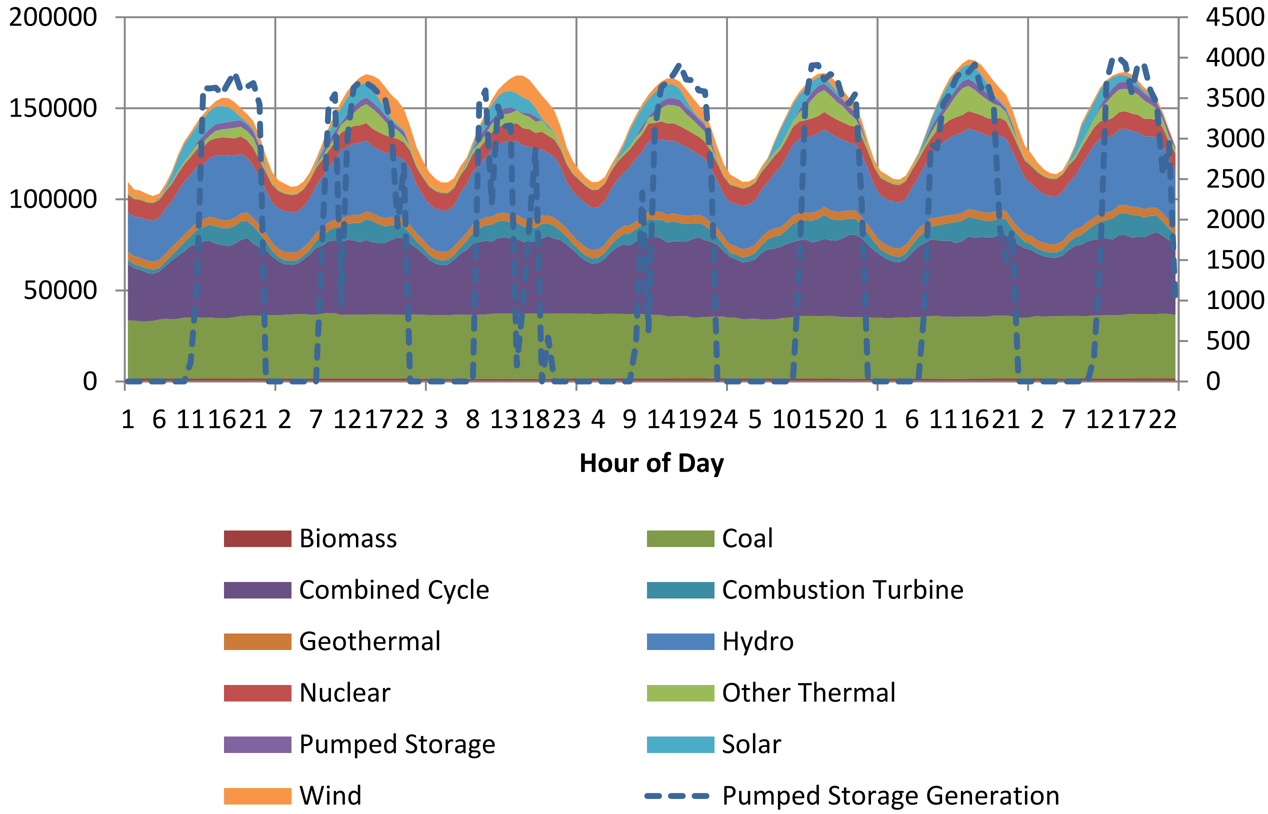

Figure 6-13
Generation by unit type in WECC for week with lowest wind penetration, Flexible Reserves Base Scenario

The highest wind penetration was in the week of January 26, when wind and solar provided approximately 14% of total energy over the week, including more than 20% of energy requirements being instantaneously met by wind and solar. Production by unit type is shown in Figure 6-14 this week. Also shown on the secondary axis is pumped hydro generation – it follows a twice-daily pattern of generation, first at morning load rise and then at the evening peak; the actual generation from pumped storage again varies based on, among other things, wind and solar generation. As expected for a high variability week, coal cycles a little more during the week; hydro cycles more with some relationship to wind and solar, with the majority of cycling being done by hydro and combined cycle generation.

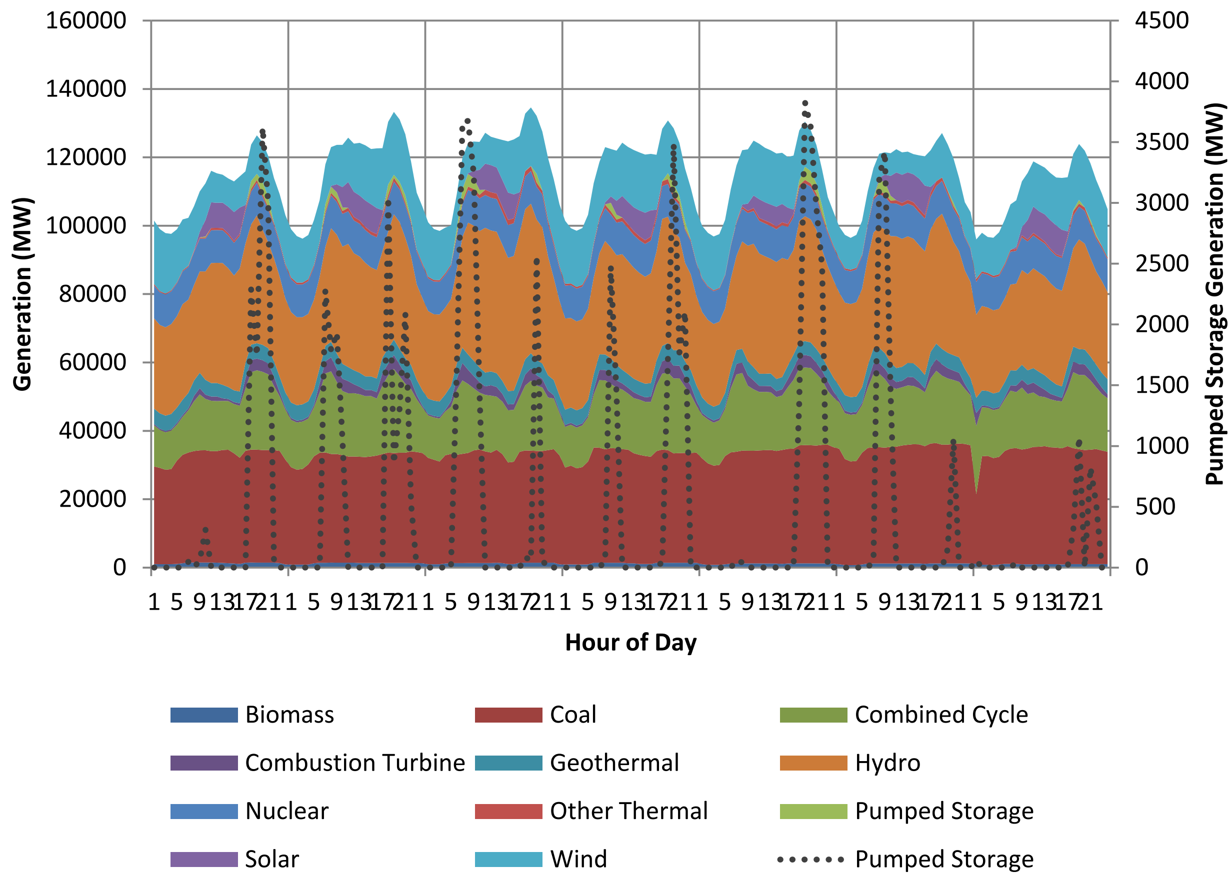

Figure 6-14
Generation by unit type in WECC for week with highest wind penetration, Flexible Reserves Base Scenario

To better understand how this looks in a smaller region, the generation for only the SMUD region (Balancing Authority North California) is also examined, taken from the WECC wide results. This is shown in Figure 6-15 for the week of July 12; note that wind and hydro, while contracted to SMUD may not show up in the BA. It can be seen that in a low wind case, storage follows the same daily pattern. Combined cycles do much of the cycling, with hydro also being used. The SMUD area imports more energy during the night.

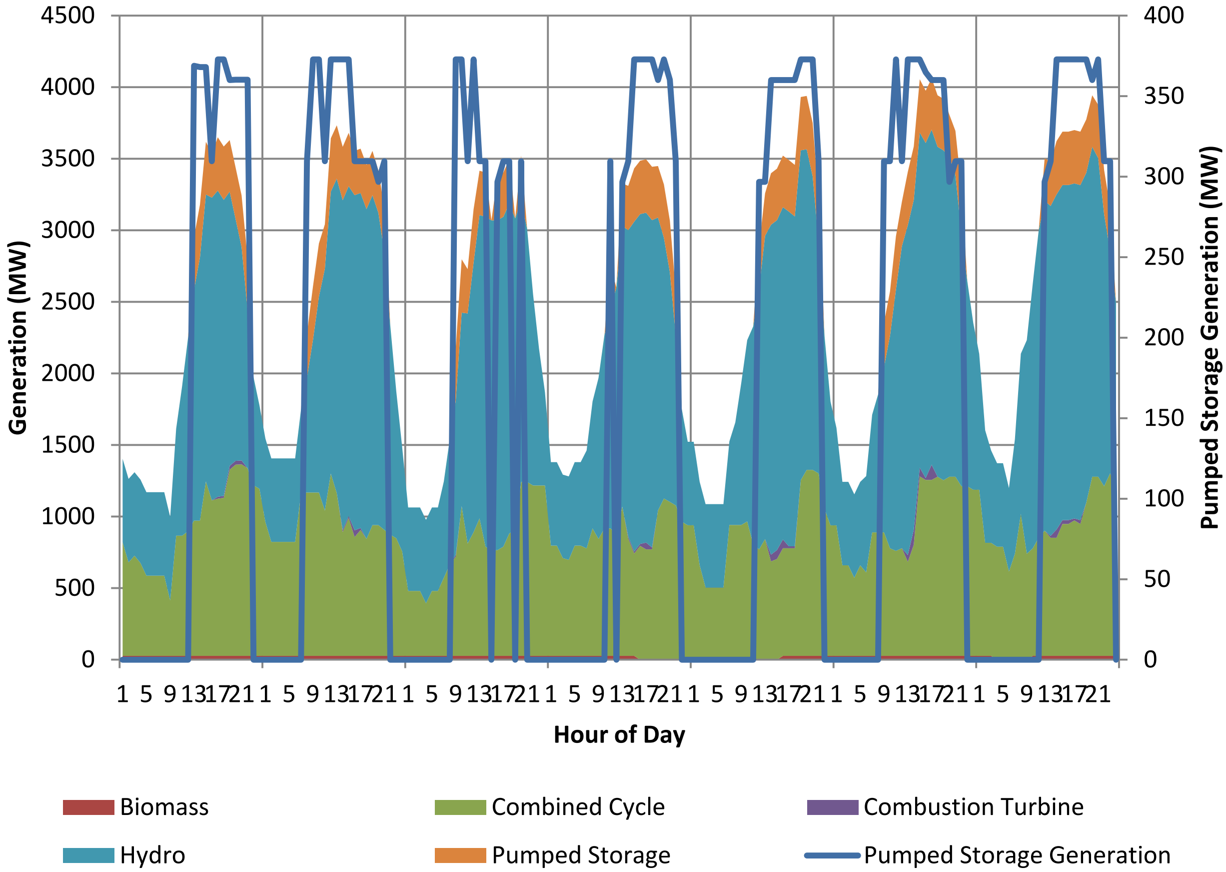

Figure 6-15
Generation in the SMUD BA, low wind week, Flexible Reserves Base Scenario

Figure 6-16 shows the SMUD BA for the same high wind week as earlier. Again, generators are cycled more, with all combined cycles being switched off at various times. Pumped storage is again utilized less in the SMUD region. With wind and solar resources freeing up other plants, SMUD imports even more during this high wind and solar week. As in the WECC-wide results, the pumped storage operates twice a day for shorter intervals. The wind and solar, while utilizing pumped storage flexibility, may also free up other resources to provide energy at low cost during peak times. This effect increases the need for storage as a flexible resource, but possibly reduces its effectiveness to arbitrage between cheap night time and expensive day time generation.

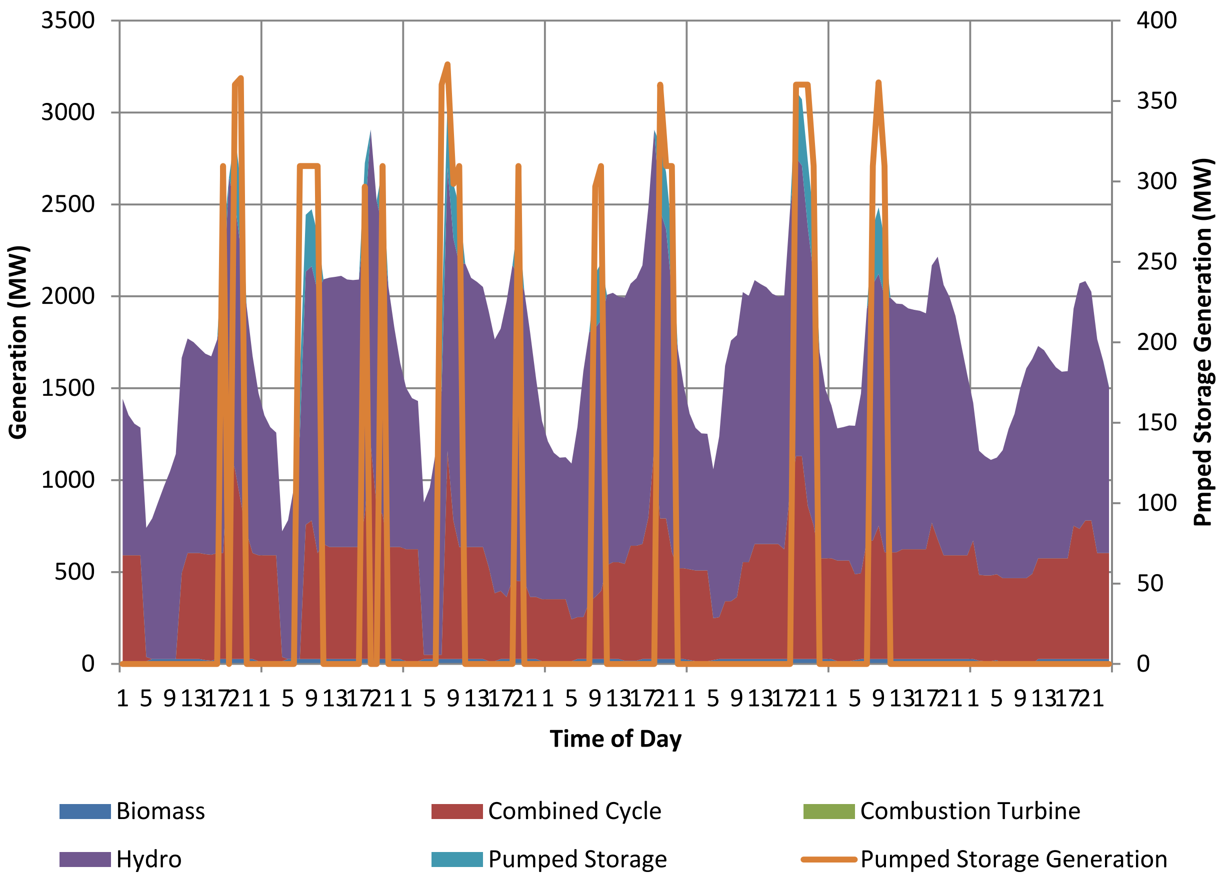

Figure 6-16
Generation in the SMUD BA, high wind week, Flexible Reserves Base Scenario

To examine how the changes made to reserve requirements and forecast error affect the price of A/S, Table 6-7 and Figure 6-17 show the A/S prices and the difference in A/S prices versus the TEPPC case from Chapter 5 respectively.

Table 6-7
Average of hourly Ancillary Service prices for new Flexible Reserves Base Case

Region	REG DOWN ($/MW)	REG UP ($/MW)	SPIN ($/MW)	NON-SPIN ($/MW)
AZNMNV	9.4	6.3	5.5	5. 5
BASIN	19.3	26.0	11.5	10.6
CAISO	9.2	17.2	12.6	3.6
NWPP	11.4	2.9	2.8	2.8
RMPP	16.7	14.3	5.1	2.9

As expected, in general A/S prices increase in most cases, with the exception of regulation down in California and some other prices in the northwest. Spin in California in particular is seen to increase by over $6/MW. This is one of the reasons pumped hydro storage can make more money in this case.

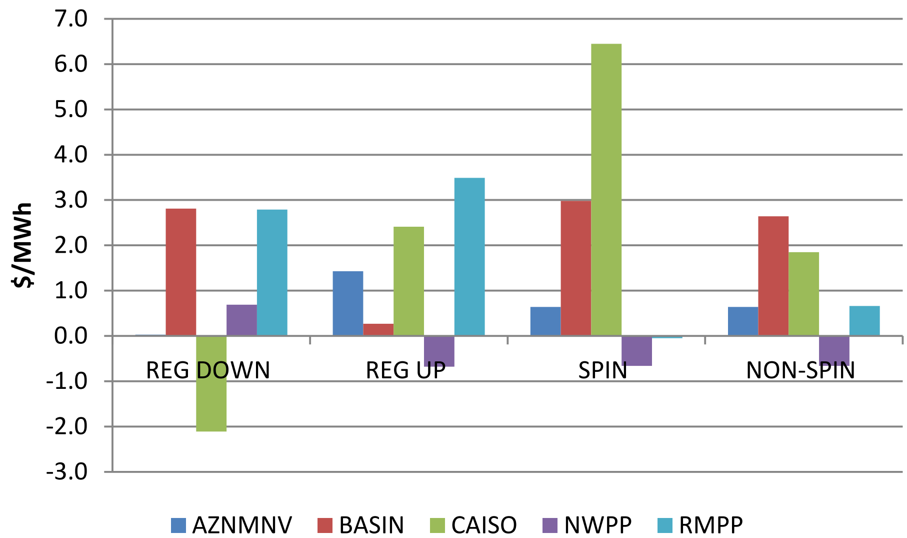

Figure 6-17
Change in average of hourly Ancillary Services prices for new Base case versus old TEPPC scenario

The change in A/S prices is driven by both an increase in requirements and the fact that there is a forecast error which has to be catered for. Figure 6-18 shows the change in revenue from A/S due to the inclusion of these aspects of a high wind and solar future. As expected, revenue for all generation increases; A/S revenues were already shown to increase for conventional and pumped hydro power were shown to increase in Table 6-4 and Table 6-5 earlier. Combined cycles also see a large increase in revenue. Combustion Turbines, used offline to provide non-spin and online to provide spin also increase revenue from A/S. This shows that, while earlier results indicate there is increased value for pumped hydro due to flexibility reserve requirements and forecast error, there is also increased value to fossil plant.

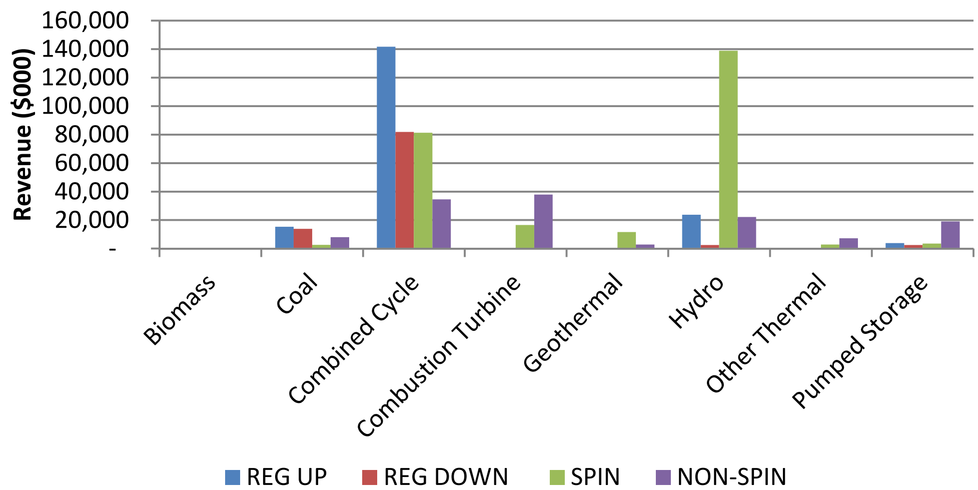

Figure 6-18
Change in annual A/S revenue in new Flexible Reserves base case versus TEPPC case

To get a better picture of how A/S prices are impacted by reserve requirements, 2 separate weeks of data are examined; the same 2 weeks as used in Figure 6-13 and Figure 6-14 are given for California ISO A/S prices in Figure 6-19 and Figure 6-20.

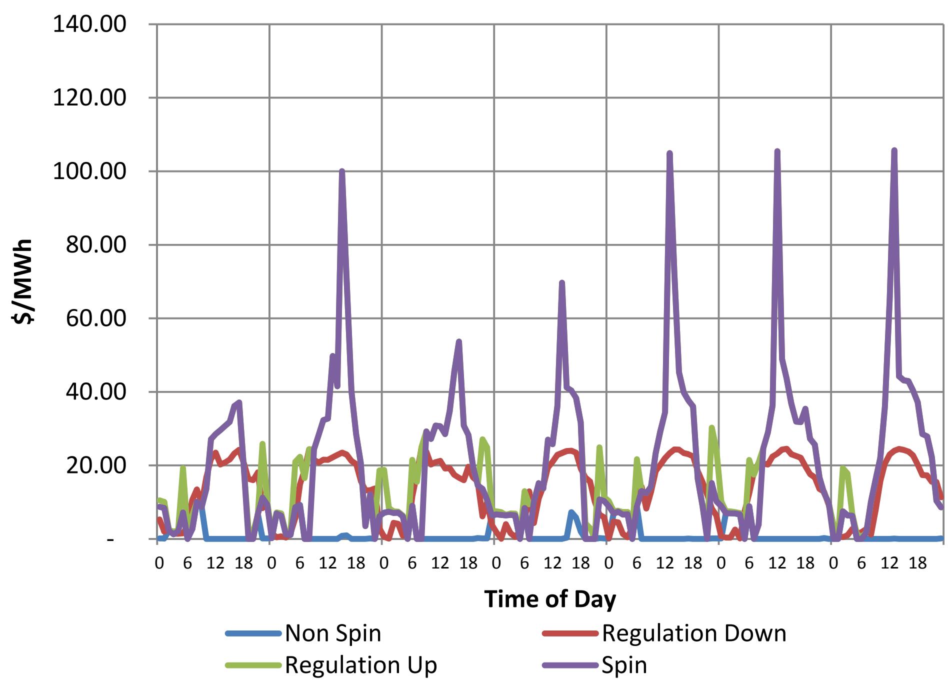

Figure 6-19
Ancillary service prices ($/MW) for CAISO for low wind week

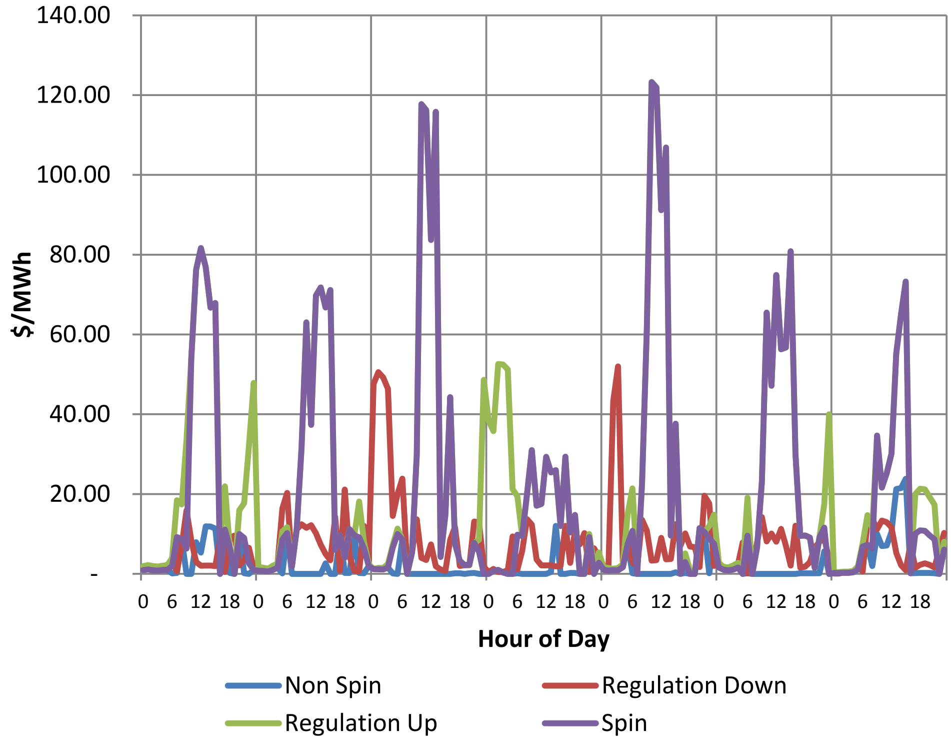

Figure 6-20
Ancillary service prices ($/MW) for CAISO for high wind week

As shown in these figures, A/S prices are particularly 'spiky' for those weeks with very high or very low wind and solar output. In the low wind case, up regulation is a little higher in shoulder periods, but is equal to spin in peak periods; in the high wind case, regulation up is significantly higher in some periods versus spin. The increased reserve requirements also lead to higher overall prices in the high wind and solar case. Regulation down can be seen to be lower in general in the high wind and solar week, with some large spikes in places as units are backed off as much as possible implying a low amount of down capacity available. In general then it can be seen that prices are spikier in the high wind and solar week.

The final result needed to get a better picture of the impact of the new operating assumptions in this chapter is the change in starts. This shows the increase in fossil plants being asked to cycle on and off, which increases damage to the plant, reducing lifetime and increasing outages. The number of starts is shown in Table 6-8.

Table 6-8
Startup data for new Flexible Reserves base scenario

Technology	Startups	Capacity (MW)	Number of Starts per 1000 MW	Increase in Number of Starts per 1000 MW versus TEPPC case
Biomass	3,079	1,796	1,714	197
Coal	3,476	38,360	91	3
Combined Cycle	46,539	58,642	794	161
Combustion Turbine	49,671	25,819	1,924	164
Geothermal	2,882	5,211	553	29
Other Thermal	14,480	20,573	704	140

As expected from previous results, starts are shown to increase, by approximately 5% to 20%, depending on technology. This is due to increased need to start plants due to forecast error, and increased reserve requirements.

Conclusions on New Base Case

This section showed that adding additional modeling assumptions related to reserves and wind and solar forecast error can increase the value of hydropower, particularly pumped hydro, which increases revenues by over $70M across all pumped hydro resources versus previously modeled results ($8/kW or over 40%). It also increases A/S prices, conventional A/S revenue, starts etc due to increased flexibility requirements. It was shown that the system will now face very different conditions when comparing high wind and solar weeks to low wind and solar weeks; this will mean the value of the different hydro technologies will vary over the course of a year far more than at present.

This section also examined the implications on individual units, showing that some pumped hydro units are more affected by an increase in flexibility requirements than others. A final result to note is that total WECC-wide production costs (fuel and start up costs) were shown to increase by $550M, or just above 2%, when adding the additional operational assumptions to the model. From earlier, pumped hydro captures an additional $70M, a substantial piece of this increased cost, in increased revenue.

Further Validation and Exploration of Future Scenarios

Having examined the impact of possible changes to operating paradigms in the previous section, mainly caused by high wind and solar penetration, this section examines the impacts of several scenarios identified by project stakeholders as being important to further understanding the value of hydro power. These use the new scenario defined above as a base case against which to compare. These can broadly be divided into two types of scenario analyses, which are examined separately in the remainder of this chapter:

- Flexibility analysis, examining issues around how conventional and pumped hydro and other generation can contribute to system flexibility requirements
- Increased representation of the number of regions in WECC, to analyze the impact that modeling fewer larger BAs has in the other results shown.

Flexibility Sensitivities for Hydro and Fossil Plant

This section examines the impact of different scenarios which examine flexibility issues for the Flexible Reserves base case system defined in the previous section. The following sensitivities are examined:

- **Fewer PHS providing AS**: Stakeholder feedback indicated that not all pumped hydro storage can provide ancillary services. Therefore, this scenario reduced to 4 the number of pumped hydro generators which could provide A/S.
- **Helms Pmin reduced:** This scenario reduced the minimum stable level of the three Helms pumped storage units to 83 MW (instead of 280 MW), with regulation able to offer the full range from 83 MW to 400 MW. This was based on stakeholder feedback.
- **No CC AS:** Here, combined cycles are not allowed to provide any ancillary services; this is very unlikely but does allow examination of the value of the ancillary services from hydro (conventional and pumped) in an extreme case.
- **No Conventional Hydro AS:** In this scenario, conventional hydro power cannot provide ancillary services – this will show the benefits of being able to use conventional hydro providing such services, particularly in cases with increase A/S requirements for wind and solar.

The first result to examine is the change in conventional hydropower revenue due to these scenarios. These are shown, together with the TEPPC case from before and the newly defined Flexible Reserves base case, in Table 6-9.

Table 6-9
Conventional Hydropower Performance by Flexibility Scenario

Scenario	Capacity (MW)	Generation (GWh)	Energy Revenue ($1000)	Ancillary Service Revenue ($1000)	Average Income ($/kW)
TEPPC	63,137	259,203	15,672,990	436,741	251
NewBaseCase	63,137	259,044	15,517,428	624,084	252
Fewer PHS providing AS	63,137	259,042	15,536,631	631,418	252
Helms Pmin Reduced	63,137	259,053	15,522,785	604,603	251
No CC AS	63,137	259,200	13,257,276	3,949,931	268
No Conv Hydro AS	63,137	259,330	15,989,797	-	249

As shown, most results do not change significantly. Changing pumped hydro storage characteristics does not have a noticeable impact on conventional hydropower plants. Not allowing combined cycles units to provide A/S clearly provides conventional hydropower with more opportunity due to relative scarcity in the A/S market. A/S revenue increase by $4M (somewhat offset by a reduction in energy revenue of $2.3M, due to more generation being online to provide A/S). On the other hand, conventional hydro revenue falls as expected when it is not allowed to provide A/S. Energy does increase a little, but not significantly.

The next result to examine is pumped hydro storage, as given in Table 6-10. This can be seen to be affected more, which would be expected as pumped hydro operates on the margins, and thus small changes in assumptions can make a big difference in results. While total generation is impacted, the results are clearer in the revenue and income areas.

Table 6-10
Pumped Storage Hydropower Performance by Flexibility Scenario

Scenario	Capacity (MW)	Generation (GWh)	Energy Revenue ($1000)	Reserve Revenue ($1000)	Net Income ($1000)	Average Income ($/kW)
TEPPC	4,711	7,382	525,065	36,190	84,047	18
NewBaseCase	4,711	7,854	569,563	65,202	120,284	26
Fewer PHS providing AS	4,711	7,781	565,500	47,120	102,394	22
Helms Pmin Reduced	4,711	7,871	565,136	105,150	147,744	31
No CC AS	4,711	7,863	449,215	397,981	375,887	80
No Conv Hydro AS	4,711	7,851	577,230	86,884	123,320	26

Clearly, average pumped hydro storage revenue decreases when some PHS is not allowed provide A/S. It can be seen that by reducing the minimum stable level of one pumped hydro plant, total revenue across all is increased. Additionally, it can be seen that not allowing combined cycle units to provide A/S greatly increases the value of pumped hydro. An interesting result is the fact that income does not significantly increase when conventional hydropower is not allowed to provide A/S. This is surprising as all other scenarios indicate that the more flexibility pumped hydro has (or the less other generators have or the more the system needs) the more profitable it becomes. What seems to be happening here is that, although pumped hydro makes an increased amount from A/S (and indeed energy), this is almost completely offset by the fact that the pumped storage units also need to pay more to fill their reservoirs, as hydro is now more likely to be used to provide energy during the day at a higher price and thus will increase prices of energy during the night. On the other hand, this does not seem to happen with combined cycle units not being allowed to provide A/S, possibly due to the timing of when combined cycles usually provide A/S and the fact that withdrawing these from providing A/S increases the prices to such an extent that even increasing pumping costs does not impact significantly overall.

Looking at individual units, it can again be seen that each unit will behave differently due to its own circumstances; while there are some definite trends, there is not one simple explanation covering all pumped storage. This is shown in Figure 6-21. Clearly, the case with no A/S being allowed from combined cycles is most lucrative for nearly all. The 4 pumped hydro units allowed to provide A/S in the "Fewer PHS providing A/S" scenario are Cabin Creek, Helms, Eastwood, and Castaic. These all perform at least as well in this scenario, while all others perform worse, again indicating that reducing total system flexibility increases value for pumped hydro storage if it is a flexible resource itself. When the minimum output on Helms is reduced, it is not the only generator to increase its income versus the Flexible Reserves base case; some others can also be seen to increase revenue. This may be due to the fact that increased flexibility in Helms allows additional fossil plant to be kept at more efficient points and thus arbitrage opportunities increase. It may also be that Helms is now providing more reserves, allowing these other plants to make increased revenue from energy while still reducing total system costs.

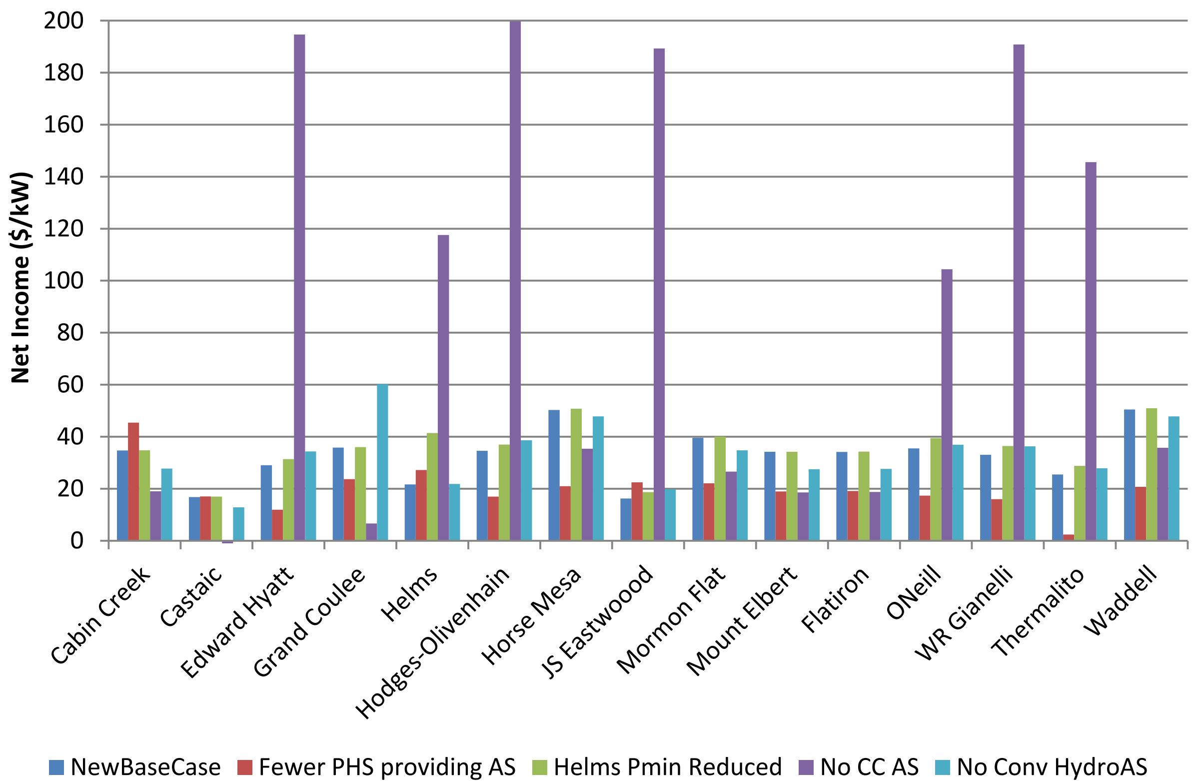

Figure 6-21
Average Income per kW for pumped storage plants for different flexibility related scenarios

These sensitivities therefore show how pumped hydro storage value can be increased due to system conditions. Clearly the scenario with combined cycles not providing A/S is too extreme; however it may be the case that the assumptions made here allow combined cycles to provide too much A/S; in the future this may be limited – while this result is not realistic it does show a maximum upper bound if no combined cycles provided A/S in WECC.

Final results to be examined for the sensitivity cases will look at system wide results to see how much prices and costs change due to the sensitivities here. Table 6-11 shows peak and off-peak prices by scenario. It can be seen that prices decrease in the case where combined cycles cannot provide A/S (they now provide energy and less expensive generators provide A/S instead of energy); however, the arbitrage opportunity decreases, as shown in reduced energy revenues in Table 6-10. In the case where conventional hydro cannot provide A/S, peak and off peak prices both increase by the same amount, thus keeping arbitrage values the same. For all other cases, prices versus the NewBaseCase (Flexible Reserves base case) change very little, showing that it is those plants producing large amounts of energy (hydro, combined cycles) that set energy prices in general, while pumped hydro changes mainly affect smaller aspects of system operation.

Table 6-11
Average of hourly peak and off-peak energy prices by scenario

Scenario	Off Peak ($/MWh)	Peak ($/MWh)	Peak - Off Peak Difference ($/MWh)	Off Peak/Peak Ratio (%)
NewBaseCase	52.5	66.7	14.3	79%
Fewer PHS providing AS	52.5	66.8	14.3	79%
Helms Pmin Reduced	52.6	66.6	14.0	79%
No CC AS	46.0	55.8	9.8	82%
No Conv Hydro AS	54.8	69.3	14.5	79%

The final system result to consider is the total production costs for each scenario. This is given in Table 6-12. Again, the pumped hydro flexibility scenarios do not significantly alter total costs (although as seen earlier they do alter profits of pumped hydro); both other scenarios related to flexibility increase total costs. From previous results which show a greater impact on profit of pumped hydro due to combined cycles not providing A/S, it is somewhat surprising that the case with no conventional hydropower providing A/S is the more significant. This case increases costs more as hydropower provides a bigger overall portion of the A/S. It doesn't increase pumped hydro profits more as in this case combined cycles (due to high efficiency) take much of the A/S duty from pumped hydro. In the case of combined cycles not providing A/S, conventional hydro is already close to maximum and cannot take over as much of the A/S duties previously performed by combined cycles, and pumped hydro takes over this provision, increasing its revenues substantially. These results give another example of the complex way in which various factors interact, particularly around how pumped storage revenues can be increased.

Table 6-12
Total System Production Costs (fuel and starts) by Scenario

Scenario	Total Cost (M$)	% Reduction vs Flexible Reserves Case
NewBaseCase	25,504	0%
Fewer PHS providing AS	25,533	0%
Helms Pmin Reduced	25,487	0%
No CC AS	26,745	-5%
No Conv HydroAS	27,623	-8%

Increased Number of Balancing Authorities Represented in the Model

The model results to date assume that there are only 5 Balancing Authorities (BAs), instead of the 30-plus seen in reality today; this greatly reduces model complexity and allows more runs to be examined. As the purpose of this work is to do significant scenario analysis to identify drivers of hydropower value, 7 BAs was deemed appropriate. This scenario aims to examine the impact of this assumption by modeling an increased number of BAs having to meet their energy and reserve targets in the day-ahead commitment stage. The data used in this study indicates a significant number of BAs do not have sufficient capability to meet peak demand and ancillary service requirements. In reality, this would not be relevant due to the fact that BAs will have contracted reserves or energy from outside their region to meet demand in their region, such that they can be counted towards targets. However, in this modeling exercise such arrangements are not known in advance, so each region defined in the model has to meet its own demand. There are a number of methods to get around this – if contract details were known then certain resources could be assigned to meet demand in another region; other modeling approaches may also work but do not offer the optimized unit commitment and economic dispatch used here. It was instead decided to reduce the number of BAs by consolidation until the largest possible number which can meet demand is achieved. Based on this dataset, the threshold was 18 different BAs. While this is not entirely realistic, looking at the trends between these results and the Flexible Reserves Case results will at least give trends as the importance of many smaller BAs being considered versus a few large BAs. Some of the more interesting results are picked out here to show how this issue impacts results.

Firstly, the impact on conventional hydropower is given in Table 6-13. Here, it is shown that revenue actually decreases. While more BAs should mean that there is less flexibility available across the region and every BA has to meet its own targets, which would be expected to increase value of a flexible unit, at the same time there is also less opportunity for those conventional hydro plants in resource rich regions to sell to resource poor regions and increase revenue.

Table 6-13
Value of conventional hydropower with 7 versus 18 BAs

Scenario	Capacity (MW)	Generation (GWh)	Energy Revenue ($1000)	Ancillary Service Revenue ($1000)	Average Income ($/kW)
NewBaseCase	63,137	259,044	15,517,428	624,084	252
NewBaseCase _18BA	63,137	258,917	14,962,309	464,220	240

Less expected is that the value of pumped hydro storage also goes down when the number of BAs is reduced as seen in Table 6-14. While this may seem counterintuitive, what can be seen is that, to meet their own demand in the day ahead commitment stage, regions are turning on more generators, thus reducing the arbitrage possibilities for storage.

Table 6-14
Value of pumped hydro storage with 7 versus 18 BAs

Scenario	Capacity (MW)	Generation (GWh)	Energy Revenue ($1000)	Reserve Revenue ($1000)	Net Income ($1000)	Average Income ($/kW)
NewBaseCase	4,711	7,854	569,563	65,202	120,284	26
NewBaseCase _18BA	4,711	7,841	543,878	62,028	113,497	24

Table 6-15
Pumped Storage Revenue for Case with 18 BAs

Plant	Generation (GWh)	Energy Revenue ($1000)	Ancillary Service Revenue ($1000)	Energy Cost ($1000)	Net Income ($1000)	Average Income ($/kW)
Cabin Creek	640	47,107	5,396	41,181	11,321	34.9
Castaic	2,505	173,842	2,433	156,156	20,119	15.8
Edward Hyatt	732	48,934	8,291	44,424	12,801	32.3
Grand Coulee	597	42,514	2,661	35,510	9,665	30.8
Helms	1,160	79,189	28,779	78,568	29,400	24.5
Hodges-Olivenhain	78	5,390	827	4,723	1,494	37.3
Horse Mesa	211	15,248	3,591	12,884	5,956	53.7
JS Eastwoood	397	23,789	4,332	24,130	3,992	19.3
Mormon Flat	71	5,154	997	4,139	2,012	42.8
Mount Elbert	392	28,943	904	25,324	4,522	22.6
Flatiron	71	5,236	161	4,586	811	22.5
ONeill	18	1,239	279	1,031	487	38.7
WR Gianelli	804	56,046	811	49,506	7,350	17.3
Thermalito	88	5,837	2,332	5,671	2,499	29.7
Waddell	75	5,411	234	4,576	1,069	26.7

Examining the change in revenue for the individual pumped hydro storage plants shows that increasing the number of BAs can provide more revenue for some and less for others; this is given for the 18 BA case in Table 6-15, and shows the change in total revenue by pumped hydro generator, comparing these results with Table 6-5.

As this figure shows, the revenue is increased slightly for quite a few pumped hydro storage units, indicating that for many having less BAs and subsequently less flexibility available to each BA increases profit; however this is more than offset by a few pumped hydro storage units who, due to their location in a far less lucrative smaller BA now reduce their profit. This shows that each pumped hydro unit and its value needs to be considered differently – the value of one may increase if it is in a smaller area, but the value of another increases in a larger area, depending on the fuel mix, wind and solar etc in the area in question.

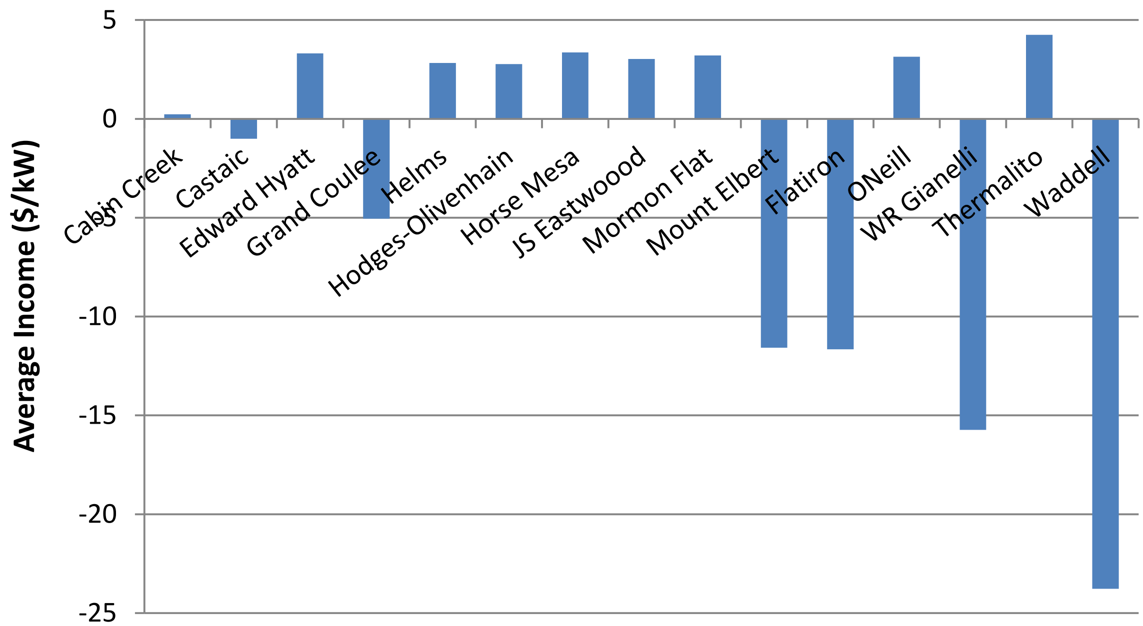

Figure 6-22
Change in average income per kW when modeling 18 instead of 7 BAs in WECC

From this section, it can thus be seen that increasing the number of BAs considered to more realistic levels does not automatically result in increased value for hydro generation. More detailed modeling changes, examining actual business processes (which are likely not known for 2020 at this time) will need to be examined to fully capture the impact of an increased number of smaller BAs. However, results here do indicate that simply reducing the size of BA that a hydro generator is located in does not result in increased value for that generator.

Lessons Learned from Additional Scenarios

This chapter examines the impact of certain modeling assumptions based on stakeholder feedback. These are kept separate from previous results as the assumptions used in the modeling are very different in terms of reserve requirements and representation of wind and load uncertainty. This chapter examines what a future with increased flexibility reserve requirements could do to the value of conventional and pumped storage. It is shown that conventional hydropower is not affected significantly in the base case; this is expected as conventional hydropower is still likely to make money mainly on energy and be based around meeting demand, even in high wind and solar scenarios. However, pumped hydro storage can be seen to increase in value substantially when wind and solar increase reserve requirements. This is expected as pumped hydro storage is a very flexible resource. Sensitivities show that flexibility of pumped hydro plants can greatly impact pumped hydro storage revenues, but does not significantly impact system prices or results. On the other hand, restrictions on flexibility from conventional hydropower or combined cycle units providing ancillary services can impact total production costs or prices significantly; in the case of combined cycles not providing A/S, pumped hydro revenues can more than double. It is also shown that simply increasing the number of BAs modeled does not necessarily increase the profits of conventional or pumped hydro. Additional modeling beyond the scope of this work would be required to represent market behavior, bilateral contracts etc.

Section 7: Conclusions and Future Research Recommendations

This report provides insights from a detailed sub-regional simulation that focuses on how key changes in available technologies, deployments such as variable renewable resources (wind and solar), market structures, and other factors affect the utilization and value of hydropower in the future. The analysis presented in this report does not consider all potential value components provided by conventional and pumped hydropower resources to the electric power system, but rather provides an assessment of the value derived from hydropower resources in the provision of the following power system services:

1. Energy to meet demand, including the ability to arbitrage energy prices by utilizing hydro resources with storage capability to store energy at low prices and deliver energy during high-price periods.
2. Regulating reserve capacity to provide frequency regulation.
3. Spinning and non-spinning reserve capacity to respond to system disturbances and restore system frequency.

The results showed that overall hydropower is a valuable asset in WECC. Based on the modeling done here, improvements to existing pumped storage plants resulted in significantly increased income while building new plants did not generate enough revenue to overcome the costs. However, in order to account for the full value of building new hydro resources further modeling should be done to consider the contributions not investigated here.

This study did not consider several potential value components that may have an impact of the value of hydropower resources to the grid. While the authors believe that energy and reserve capacity are the primary value contributions for hydropower, in order to capture the full value more work needs to be done in the following areas:

1. Operation efficiency of other resources allowed by using hydro resources for the deployment of reserves within the hour.
2. Inertial or primary frequency response to system disturbances or reactive power support for maintaining system voltages at desired levels.
3. Capacity value that hydropower resources contribute toward long-term resource adequacy.

To quantify the first two items in the list above a follow-on DOE project *Detailed Analysis to Demonstrate the Value of Advanced Pumped Storage Hydropower in the U.S.* will develop and exercise power flow, transient stability, and long-term dynamic stability models to evaluate hydro resources contributions to the reactive power support, primary frequency response, and within-hour reserve deployment services. The results of that project will confirm whether the additional value components not studied here are substantial enough to alter the conclusions that are drawn based on the value components captured and reported in this study.

In addition this study does not capture the capacity related benefits of hydro power. These benefits are related to ensuring long term adequacy and the ability of a resource to meet peak demand. There are two related pieces to long term capacity as it relates to conventional and pumped hydro power – resource adequacy, which ensures reliability, and capacity markets, which aim ensure resource adequacy in deregulated systems by ensuring long term revenue streams for resources. At present, pumped hydro in particular is not well rewarded in such markets.

Resource adequacy ensures there are sufficient installed resources on a given power system to meet peak demand based on a desired reliability level. This desired level is defined by NERC as an adequate level of installed capacity such that there is a Loss of Load Expectation (LOLE) of one day in ten years. This number is calculated based on probability of outages of each generator on the system. For a given system, depending on its plant mix, this will result in a planning reserve margin usually somewhere between 15% and 20% of peak demand, i.e. it must have installed capacity of 15% greater than peak. The calculations are usually carried out for future years, anywhere from the following year to 10 years out. These resource adequacy requirements are maintained in both market and non-market regions; NERC ensures each region has sufficient resources to maintain an adequate level of reliability.

Storage could contribute to resource adequacy in a similar way to conventional generation, particularly if the ratio of energy to capacity (i.e. how many hours of energy can be stored) is high. Therefore, building storage can reduce the need for the building of other conventional plant, as storage has a capacity credit, which is based on its expected ability to provide energy on peak. This could be calculated similar to conventional generation, based on outage rates and expected maintenance. Storage would have the additional complication of the amount of hours energy it can provide, but in most cases with pumped storage this is high enough that storage can count as a conventional plant. This study doesn't look at this type of time horizon; instead plant build outs are assumed and the system operation for one year is examined. Therefore the capital cost savings due to storage reducing the need for other plants is not captured, and is an additional value of storage. It should be noted that building storage purely for peaking capacity would not seem to be realistic, as other peaking capacity (e.g. combustion turbines) provide peaking capacity at lower cost; however, if the storage can be shown to improve other system economics, then the capacity value should also be considered as an additional source of value to the system.

Resource adequacy is ensured through different mechanisms. Since deregulation, areas with an ISO/RTO have adopted multiple methods to ensure capacity adequacy. Capacity markets currently exist in the Northeast of the country (PJM, ISO New England, and New York ISO are the only capacity markets in the United States) to procure sufficient resources into the future to meet projected peak demand. California ISO, which is the ISO most relevant to this study, has a capacity requirement which it imposes on the individual Load Serving Entities, but no capacity market. Therefore, the value of a resource in capacity markets will depend on the region it is built. For those regions with capacity markets, hydro generation and pumped hydro storage can bid into forward capacity markets (which can be anywhere from months to 3 years ahead), and could be cleared depending on the bids of other resources in the system. This means plants get a capacity payment to ensure they are available to provide energy and ancillary services at a specified time. Capacity prices can range significantly. For example, PJM's 2015/2016 Reliability Pricing Model cleared at $136/MW-day for most of the RTO region. California's capacity procurement mechanism charge is $55/kW-yr since 2010. This does not imply that hydro generation would definitely benefit, only the price the market cleared at. As can be seen the range between different markets is significant; therefore examining the capacity value of hydro generation would require a follow on study to the work begun here.

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