Western Wind and Solar Integration Study:

Hydropower Analysis

October 2007 – October 2010

T. Acker and C. Pete
Northern Arizona University
Flagstaff, Arizona

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Subcontract Report
NREL/SR-5500-53098
March 2012

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NATIONAL RENEWABLE ENERGY LABORATORY

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NREL Technical Monitor: D. Lew
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Preface

Beginning in 2007 and extending through 2010, the National Renewable Energy Laboratory sponsored the Western Wind and Solar Integration Study (WWSIS). The study follows DOE's 20% Wind Energy by 2030 report, which did not find any technical barriers to reaching 20% wind energy in the continental United States by 2030. It was initiated to examine the operational impact of up to 35% energy penetration of wind, photovoltaics (PV), and concentrating solar power (CSP) on the power system operated by the WestConnect group of utilities in Arizona, Colorado, Nevada, New Mexico, and Wyoming. This study was set up to answer questions that utilities, public utilities commissions, developers, and regional planning organizations had about renewable energy use in the west:

- Does geographic diversity of renewable energy resource help mitigate variability?
- How do local resources compare to out-of-state resources?
- Can balancing area cooperation help mitigate variability?
- What is the role and value of energy storage?
- Should reserve requirements be modified?
- What is the benefit of forecasting?
- How can hydropower help with integration of renewables?

The goal of the WWSIS was to understand the costs and operating impacts due to the variability and uncertainty of wind, PV, and CSP on the grid, and was mainly an operations study. Using a detailed power system production simulation model, the study identified operational impacts and challenges of wind energy penetration up to 30%, and solar up to 5%.

Hydropower is an important, low cost, flexible resource in electrical system balancing. However, hydropower resources differ from other power generation resources in that scheduling and dispatch is often subservient to a number of other higher priority functions of the hydro system, as well as being dependent upon the annual precipitation. For example, the availability of hydro from a given hydropower plant may be dictated by the downstream water deliveries, flood control, and environmentally prescribed flows, significantly reducing its flexibility. These constraints, while fairly well known, are not modeled well in most production cost simulations. Stakeholders in the WWSIS process had a number of specific questions related to hydropower, thus a special effort was made, as addressed in this report, concerning issues particular to hydropower and its role in system balancing and wind/solar integration:

- How accurately were the hydro systems modeled in the WWSIS?
- What is the magnitude and character of change in generation and operations at individual hydropower and pumped storage plants when high penetration levels of variable and uncertain renewables are incorporated into the grid system?
- What is the overall value of hydropower as a balancing resource?
- What is the value to hydropower utilities from participating in wind integration?
- What is the impact and value of integrating renewables on pumped storage hydro operations?

Acknowledgements

Significant effort went into studying the interactions of hydropower related to integrating wind and solar power in NREL's Western Wind and Solar Integration Study (WWSIS) (http://www.nrel.gov/wwsis/). Thanks are due to the members and organizations that were part of the hydropower subcommittee of the WWSIS, listed below, for their time and expertise devoted to this study and report. Special thanks are due to Mr. Carson Pete, who took on this work as part of his Master's Thesis in Mechanical Engineering at Northern Arizona University, and who is the principal author of this report. The work was sponsored by NREL under subcontract XXL-7-77283-01.

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Acronyms

AGC	Automatic Generation Control
CAP	Central Arizona Project
CC	Combined Cycle units
CO2	Carbon Dioxide
CRSP	Colorado River Storage Project
CSP	Concentrating Solar Power
DOE	Department of Energy
ELCC	Effective Load Carrying Capability
EWITS	Eastern Wind Integration and Transmission Study
EXPC	Expansion Units (Combined Cycle or Gas Turbine Units)
GCDEIS	Glen Canyon Dam Environmental Impact Statement
GE	General Electric Company
GEO	Geothermal Units
GT	Simple-Cycle Gas Turbines Units
GW	Gigawatt
GWh	Gigawatt Hour
-H	Hydro Scheduled to Load Only Operations
-Hf	Flat Hydro Operations
-HH	Historical Hydro Operations
HLH	High Load Hours (6am – 10pm)
HY	Hydropower
LEAPS	Lake Elsinore Advanced Pumped Storage
LLH	Low Load Hours (10pm – 6am)
LMP	Locational Marginal Price
LNW	Load Net Wind
LO	Load Only
LUMP	Small Generic Generation Units (< 20MW) for any given area
MAPS	Multi Area Production Simulation
MLFF	Modified Low Fluctuating Flow
MOS	Model Output Statistics
MW	Megawatt
MWh	Megawatt Hour
NAU	Northern Arizona University
NERC	North American Electric Reliability Council
NOX	Nitrogen Oxides
NREL	National Renewable Energy Laboratory
NUNU	Nuclear Units
NWP	Numerical Weather Prediction
O&M	Operations and Maintenance
PSCo	Public Service Company of Colorado
PSH	Pumped Storage Hydro
PUC	Public Utility Commission
PV	Photovoltaic
RPS	Renewable Portfolio Standard

SOA	State of the Art
SOX	Sulphur Oxides
SLCA-IP	Salt Lake City Area Integrated Projects
ST-COAL	Steam Coal Units
ST	Steam Oil and Gas Units
SUNY	State University of New York
TWh	Terawatt Hour
WECC	Western Electric Coordinating Council
WRF	Weather Research and Forecasting mesoscale NWP model
WWSIS	Western Wind and Solar Integration Study

EXECUTIVE SUMMARY

Introduction

The U.S. Department of Energy's (DOE) study of 20% Wind Energy by 2030 was conducted to consider the benefits, challenges, and costs associated with sourcing 20% of U.S. energy consumption from wind power by 2030. This study found that with proactive measures, no insurmountable barriers were identified to meet the 20% goal. Following this study, DOE and the National Renewable Energy Laboratory (NREL) conducted two more studies: the Eastern Wind Integration and Transmission Study (EWITS) covering the eastern portion of the U.S., and the Western Wind and Solar Integration Study (WWSIS) covering the western portion of the United States. The WWSIS was conducted by NREL and research partner General Electric (GE) in order to provide insight into the costs, technical or physical barriers, and operational impacts caused by the variability and uncertainty of wind, photovoltaic, and concentrated solar power employed to serve up to 35% of the load energy in the WestConnect region (Arizona, Colorado, Nevada, New Mexico, and Wyoming) as shown in Figure 1. WestConnect is composed of several utility companies working collaboratively to assess stakeholder and market needs to develop cost-effective improvements to the western wholesale electricity market. Participants include the Arizona Public Service, El Paso Electric Company, NV Energy, Public Service of New Mexico, Salt River Project, Tri-State Generation and Transmission Cooperative, Tucson Electric Power, Xcel Energy and the Western Area Power Administration.

The WWSIS was conducted specifically to answer several questions that utilities, Public Utility Commissions, developers, and regional planning organizations had regarding wind and solar energy on the grid system in the West, such as:

- What is the impact on the operating system when up to 35% renewable energy penetration is employed and how can this be accommodated?
- How does geographic diversity help mitigate variability inherent in wind and solar?
- How do local resources compare to remote, higher quality resources delivered by long distance transmission?
- How does balancing area cooperation mitigate variability?
- How should reserve requirements be modified to account for variability?
- What are the benefits of integrating wind and solar forecasting into grid operations?
- How can hydro generation help with renewable integration?

In addressing these questions, the methodology described below was employed. As will be described below, the results of the WWSIS analysis led to several questions concerning the modeling of hydropower as well as its role in integrating wind and solar power, including the costs and benefits to hydropower producers.

WWSIS Background: Methodology and Assumptions

In order to accurately address the questions posed in formulating the WWSIS, it was necessary to model the power flows in and out of the WWSIS footprint correctly, and thus the entire Western

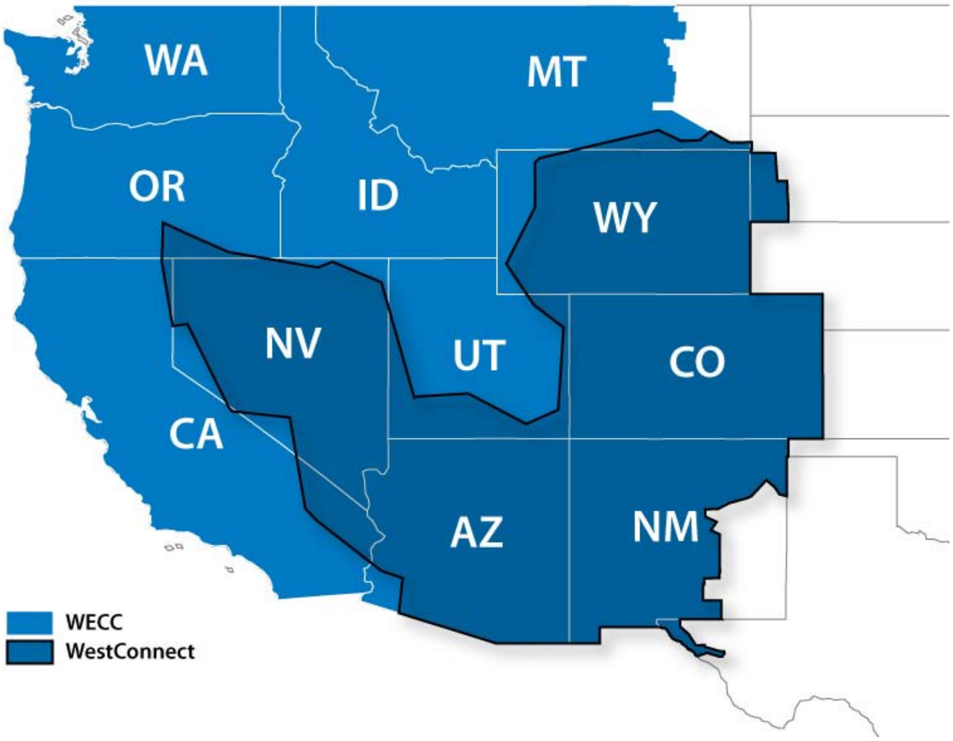

Figure 1: WestConnect study footprint area. (Source: GE Energy 2010)

Electricity Coordinating Council (WECC) region had to be modeled. The WWSIS study examined the details of system operation and dispatch through use of a transmission-constrained, hourly production cost model, GE's Multi-Area Production Simulation model (MAPS). To run MAPS, historical loads from the years 2004-2006 were employed, scaled-up to those expected in the study year 2017. Due to the lack of available wind and solar data at the spatial and temporal resolutions needed for this study, numerical weather prediction (NWP) and satellite cloud cover models were used to simulate the historical climatological conditions ultimately leading to estimates of hourly wind and solar power production time series. For this study, renewable energy forecasting company 3TIER developed the wind power dataset along with the wind and solar power forecasts, and Clean Power Research and the State University of New York at Albany developed the solar radiation dataset. In running the MAPS simulation, several key modeling assumptions were needed:

- Assumptions for fuel costs: $2/MBTU coal; $9.50/MBTU natural gas.
- Cost of carbon dioxide emissions were taken as $30/metric ton of .
- Extensive balancing area cooperation assumed between balancing areas within the WWSIS footprint.

- All units are economically committed and dispatched while respecting existing and new transmission limits, generation cycling capabilities, and minimum turndown.
- Existing available transmission capacity is accessible to renewable generation.
- Generation equivalent to 6% of load is held as contingency reserves with equal parts spinning and non-spinning.
- Renewable energy plant operations and maintenance are not included, and wind and solar generation are considered price takers.
- Increased O&M of conventional generators due to increased ramping and cycling was not included due to limited industry experience and data describing the character and magnitude of the increase.
- The balance of generation was not optimized for renewable generation but rather as a business-as-usual capacity expansion to meet the projected load growth of 2017. Renewable energy capacity was added to this mix, so the system analyzed is overbuilt by the amount of capacity value of renewable generation plants.
- Hydro generation is normally committed and dispatched to serve the daily peak net-load periods, while respecting the minimum operating points on the hydro units. With the exception of large hydropower plants (i.e. hydropower plants with a total nameplate capacity of 1,000 MW or more), hydropower units were dispatched to meet the load defined by their corresponding transmission constrained area. The larger hydro plants (though few) were dispatched to meet the entire system load.
- Hydro resource modeling did not reflect the specific climatic patterns of 2004-2006, but rather an 11-year average of monthly energy and plant capacity limits (based on data from 1996-2006). Within these defined monthly energy and capacity limits, MAPS was allowed to dispatch the hydro resources on a rational basis with the minimum generation limit of the hydro plant representing the base-load for all hours in the month. The remaining capacity and energy were scheduled in a peak-shaving mode.
- Results are presented in 2017 nominal dollars with 2% escalation per year.
- The uncertainty of the wind or solar resource is manifested in the forecast of the generation, or rather the error in the forecast, used in the day ahead commitment process as well as hour ahead. Two types of forecasts were considered in the hydro analysis: perfect (no error) and professional (state-of-the-art forecast).

Using MAPS, GE conducted hourly production simulations at four levels of renewable energy penetration as presented in Table 1. Note that "in Footprint" refers to the WestConnect region as displayed in Figure 1, and "out of Footprint" corresponds to the balance of the WECC. The penetration levels presented correspond to the percentage of the annual load energy served by either wind or solar. Of the solar power, 70% of the energy was derived from concentrated solar power (CSP) and 30% from distributed photovoltaic (PV) generation.

Table 1: Combinations of wind and solar power modeled within the WECC for various penetration levels (% of load energy) modeled in the WWSIS.

Penetration	Wind and Solar Energy (% of load)
30%	30% wind, 5% Solar in Footprint
	20% wind, 3% Solar out of Footprint
20%	20% wind, 3% Solar in Footprint
	10% wind, 1% Solar out of Footprint
20/20%	20% wind, 3% Solar in Footprint
	20% wind, 3% Solar out of Footprint
10%	10% wind, 1% Solar in Footprint
	10% wind, 1% Solar out of Footprint

At each of the penetration levels, three basic scenarios were considered. These scenarios differed in where the wind and solar power resources were presumed to be installed, founded upon a combination of constrained transmission areas and the cost trade-offs between using local and remote resources. These scenarios are described below:

- ***In-Area scenario*** – Uses local resources defined within each "transmission constrained" area within the WWSIS footprint. The installation locations were determined by selecting the best sites that corresponded to a mix of energy value, geographic diversity, and capacity factor. The transmission constrained areas correspond roughly to the state boundaries within the study footprint, with the exception of Colorado, which is split into east and west approximately along the Continental Divide.
- ***Mega-Project scenario*** – Created by trading out the lower-ranked wind power sites (ranked by capacity factor) of the In-Area scenario with higher capacity factor, remote wind resources. For example, the lowest ranked wind sites from the In-Area scenario in Arizona were traded for higher quality wind resources in Wyoming and New Mexico. However, the higher quality wind resources were further from load and across at least one transmission constrained boundary, and therefore required new high voltage transmission to be constructed in order to deliver the energy to the appropriate in-footprint load.
- ***Local Priority scenario*** – This scenario deployed what is possibly a more realistic build-out of wind sites and transmission resulting from a combination of in-area wind resources with higher quality remote resources.

Figure 2 illustrates the distribution of wind and solar resources for each of the three scenarios for the 30% wind, 5% solar case, including the conceptual interstate transmission infrastructure that would be needed to bring remote renewable resources to load. Several key assumptions were used in the scenario development:

- The specific energy target for each technology was fixed (e.g. wind sites could not be traded out for CSP sites).
- Capital cost assumptions in 2008 dollars were used in determining the geographic scenarios with: wind at $2000/kW, PV at $4000/kW, CSP with six hours of thermal storage $4000/kW, transmission at $1600/MW-mile, and transmission losses at 1% per 100 miles. No tax credits were included nor were power purchase agreements considered.

- Various interstate transmission build-outs were considered, with the eventual selections as shown in Figure 2, and these costs were included in the scenarios. No incremental intra-state transmission build-outs were specified for either the renewable generation or the new conventional generation.
- New transmission was purposely undersized: 0.7 MW of new transmission was added for each 1 MW of remote generation (this was done to account for the fact the renewable generators to not produce power all of the time, and therefore transmission equivalent to the full nameplate capacity is not necessary).

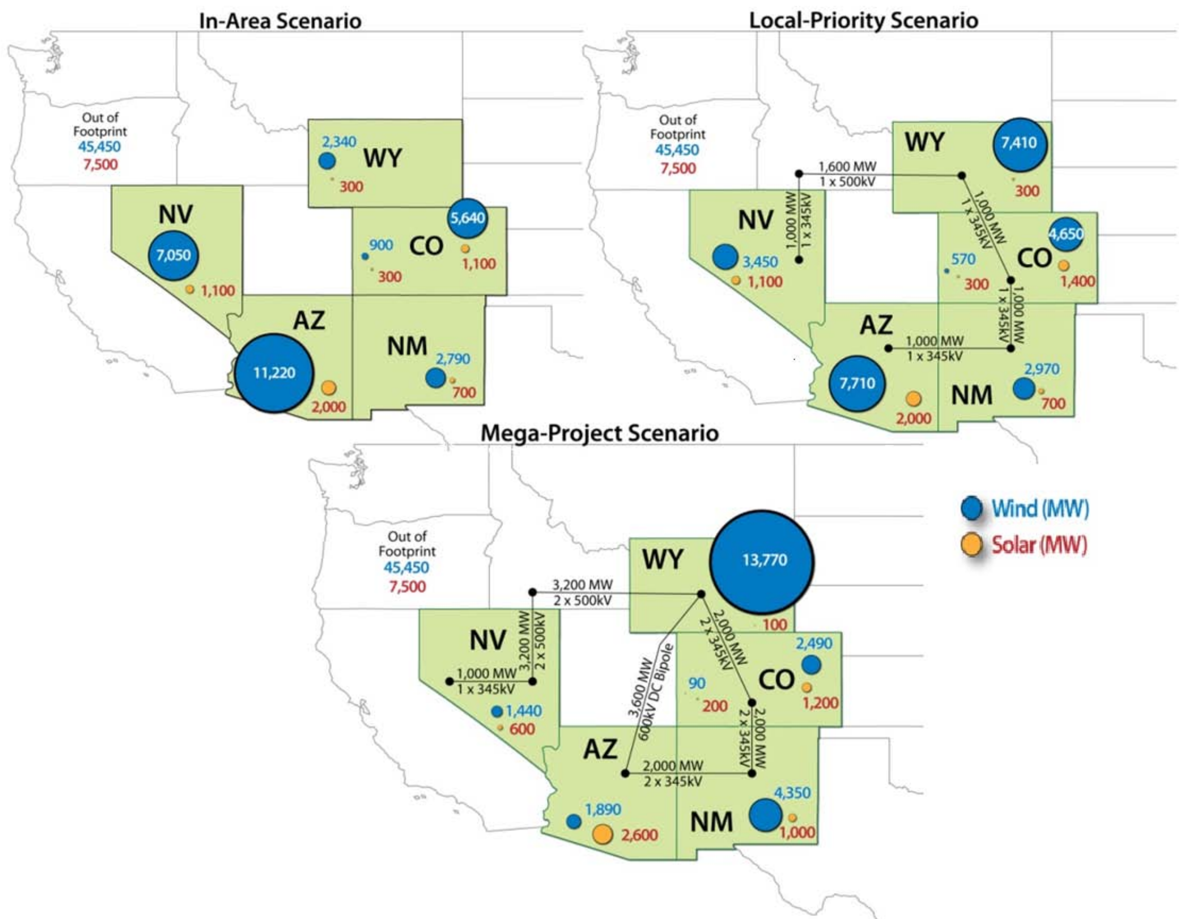

Figure 2: Three scenarios depicting wind and solar capacities for the 30% case including conceptual interstate transmission shown in black. (Source: GE Energy 2010)

The WWSIS is an operations study of the power system focusing on the variable operational costs and savings due to the fuel and emissions. In interpreting the results of the study, it is worth recognizing that the wind dataset used was conservative in terms of overestimating the actual variability found in measured wind plant output. Furthermore, the base assumption of \$9.50/MBTU for gas means that gas generation will be displaced prior to less expensive coal, thus leaving a less flexible generation fleet to accommodate the variability of the renewables. For the study year of 2017, it was assumed that both WestConnect and WECC will operate differently than today's current practices. The following operational assumptions were made:

- The current 37 regional balancing areas were pooled into five regions (Arizona-New Mexico, Rocky Mountain, Pacific Northwest, Canada, and California).
- All generation resources are shared equally and not committed to specific loads, thus allowing a least-cost economic dispatch.
- Existing available transmission capacity will be accessible to other generation on a short-term, non-firm basis.
- Pricing developed by production cost modeling can vary widely from bilateral contract prices, and was not aligned or calibrated with current bilateral contract prices. The incremental O&M costs in the report do not necessarily replicate escalated current costs in the Western Interconnection.

To analyze the performance of the system with high penetration levels of renewable generation, four primary analytical methods were used: statistical analysis, hourly production simulation analysis, sub-hourly analysis using minute-to-minute simulations, and resource adequacy analysis. Statistical analysis was used to quantify the variability due to system load, as well as renewable generation over annual, seasonal, daily, hourly, and 10-minute timeframes. The production simulation analysis was used to evaluate hourly grid operations for each scenario, renewable penetration level, and load profiles using GE's MAPS. Minute-to-minute simulation analysis was used to quantify grid performance trends and to investigate potential mitigation measures. Lastly, resource adequacy analysis with GE's Multi-Area Reliability Simulation (MARS) program was used to evaluate the loss-of-load-expectation (LOLE) calculations. As an operational study, the WWSIS *does not* cover: transmission planning, cost-benefit analysis, dynamic stability issues, the optimization of the balance between wind and solar resources or system reliability (though MAPS does include all transmission constraints when dispatching the system resources).

System Operation with 30% Wind and 5% Solar Generation: Understanding the Impacts

To understand the impact on power system operations with 35% wind and solar, two important weeks, one in July and one in April, were selected for a detailed look at load and generation. The week in July experienced the highest load while the week in April experienced the greatest variability in wind output (considered the "worst" or most challenging week in terms of operational impacts within the three years of load and renewables data analyzed). Figure 3 illustrates the load (purple line – top edge), solar generation (PV in Red and CSP in Orange), wind generation (green), and resulting net load (blue line – lower edge) that system operators must serve with generation. As shown by the week in April, the net load is substantially altered by the magnitude and variability in wind output, dropping below zero at some hours of the week during low load hours. In dealing with the net load variations for the week in April, the MAPS simulation dispatched system generation resources to meet the load as displayed in Figure 4. The stack of generation resources dispatched *with* (right plot) and *without* (left plot) 35% renewables on the system are illustrated. The plot depicting 35% renewables shows that the combined cycle gas generation has been almost completely displaced, and that the steam coal generation is significantly reduced while cycling of the units have increased. While the renewable generation did greatly alter the net load, the system is able to meet load given its resources (this is a good example where balancing area cooperation is mandatory to balance the system). Overall, it was observed that there were no significant adverse impacts up to the 20% renewables case in the WestConnect region, but system balancing does become more challenging at 35%.

Results from the production cost simulations show that increased renewable energy does present operational challenges, especially as the penetration exceeds 20%, but that wind and solar can simultaneously significantly reduce operating costs across WECC. At 30% wind for the In-Area scenario using the professional forecast, WECC operating costs result in a 40% savings due to a decrease in fuel consumption and emissions ($50 billion/yr decreasing to $30 billion/yr, depending on the scenario, or in other terms, $80/MWh of wind and solar energy produced). Additionally, CO_2 emissions were reduced by nearly 120 million tons/yr (reduction of approximately 25%), SO_x being reduced by approximately 45,000 tons/yr (~5%) and NO_x being

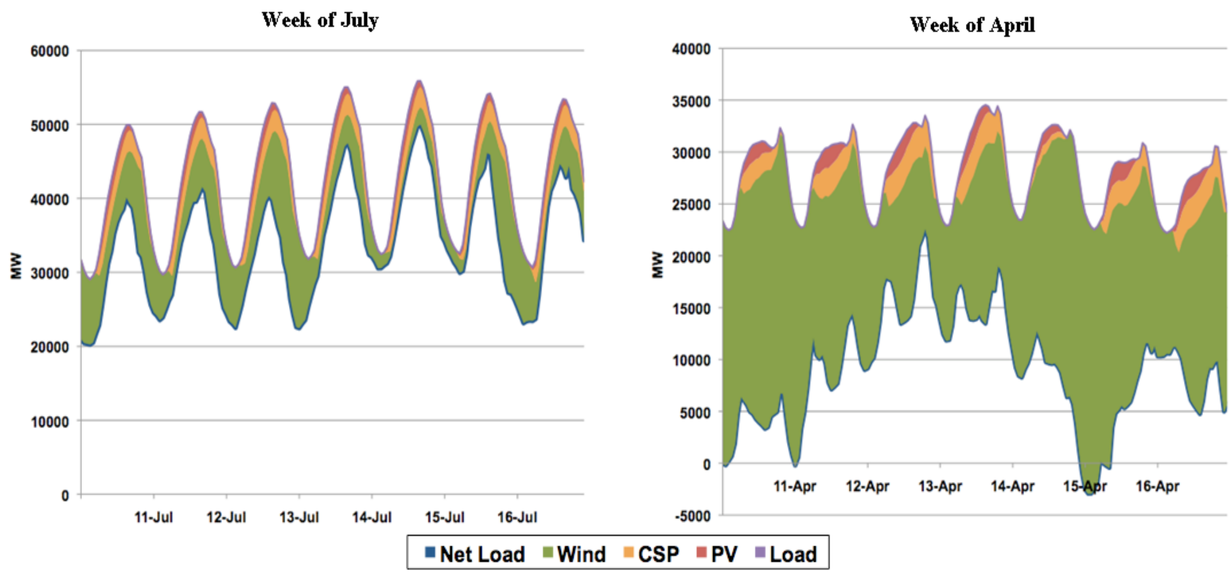

Figure 3: Net load (bottom blue line) seen during week of July and week of April. (Source: GE Energy 2010)

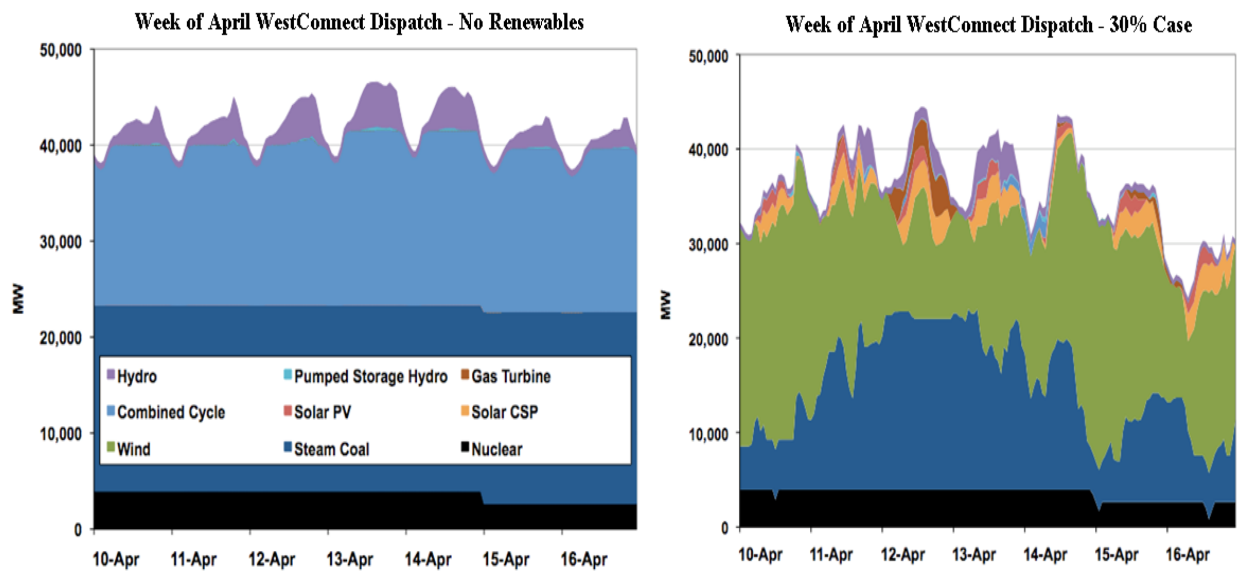

Figure 4: Impact on other generation resources as 35% wind and solar generation enters operating system. (Source: GE Energy 2010)

reduced by nearly 100,000 tons/yr (~15%).[1] These results are but a glimpse of the many results presented in the WWSIS final report, and show that system operation with 35% wind and solar energy is indeed feasible. It is therefore of interest to investigate the influence of (and on) hydropower in wind and solar integration.

Hydropower and Integration of Wind and Solar

As shown in Figure 4, when comparing the magnitude and timing of hydropower generation in the plots shown on both sides of the figure, it is evident that incorporating wind and solar does impact the hydro generation. This raised questions regarding the impact on, and interaction of, hydro generation in large-scale wind and solar integration. Results from the WWSIS addressed several key issues about the aggregate influence of wind and solar power on hydropower generation, but lacked details into the potential benefits/detriments on hydro generation, especially at the individual hydro power plant level. Thus this study follows upon the hydropower analysis conducted in the WWSIS and broadens the scope of inquiry to cover seven individual hydro facilities operated by the U.S. Bureau of Reclamation located within the study footprint, plus one pumped storage hydro facility, as shown in Table 2.

[1] For further information on the WWSIS study see http://www.nrel.gov/wind/systemsintegration/wwsis.html

Table 2: Selected hydro facilities located in WestConnect Footprint.

State	Plant Name	Nameplate Capacity
1) AZ	Hoover Dam	2,074 MW
2) AZ	Glen Canyon Dam	1,296 MW
3) AZ	Davis Dam	240 MW
4) CO	Morrow Point Dam	173.2 MW
5) CO	Blue Mesa Dam	86.4 MW
6) CO	Mt. Elbert Pumped Storage Hydro Facility	200 MW
7) AZ	Parker Dam	120 MW
8) CO	Crystal Dam	32 MW

These operations at these facilities encompass a variety of non-power regulations and constraints, and operational parameters, leading to several specific questions about issues of relevance to the hydro system. These questions can be summarized as follows:

- How accurately were the hydro systems modeled in the WWSIS?
- What impact will drought conditions in the West have on hydro's ability to meet load?
- What is the magnitude and character of change in generation and operations at individual hydropower and pumped storage plants when high penetration levels of variable and uncertain renewables are incorporated into the grid system?
- What effect does the different wind scenario build-outs studied in the WWSIS have on hydro generation dispatch?
- How does the accuracy of wind and solar forecasts impact hydro operations?
- What is the overall value of hydropower as a balancing resource?
- What is the value to hydropower utilities of participating in wind and solar integration?
- What is the effect of integrating renewables on pumped storage hydro operations?

Hydro Analysis Methodology

To answer these questions, an in-depth technical analysis was conducted using multiple approaches, based upon the output of a series of production cost simulations using GE's MAPS. Results were compared to actual production patterns, and to one another. In particular, studies were conducted to assess accuracy of the hydro modeling, the impact of renewables on hydropower operations, and the influence of hydropower on wind and solar integration. Specifically, the following were investigated:

- *MAPS Hydro Modeling Accuracy* – To ascertain the accuracy of MAPS hydro modeling capabilities, the generation output from the MAPS no-wind scenario and actual 2006 generation data at selected hydro power plants were compared against one another, noting the no-wind scenario has all renewable generation stripped from the system.

- *Drought Considerations on Hydro Operations* – A comparison was conducted between MAPS simulated "base case" operations (i.e. MAPS hydro inputs assuming 11-year average hydro energy and capacity limits) and actual 2006 historical data (i.e. hydro inputs in MAPS were adjusted to the actual energy and capacity limits during the drought year of 2006). This permitted study of the impacts of a reduction in capacity and energy limits.

- *Renewable Generation Impact on Hydro Operations* – To determine changes in use of hydro as wind and solar resources are incorporated in the bulk power system, MAPS data was statistically analyzed comparing the baseline, no-wind operations to several scenarios incorporating wind and solar generation.

- *Inter-Scenario Comparisons* – To determine differences in hydro dispatch and utilization between study scenarios, statistical analyses were conducted using MAPS simulated hydro production comparing in-area, local priority, and mega project scenarios.

- *Effect of Wind and Solar Forecasts on Hydro Usage* – To determine impacts on hydro operations as increasingly accurate wind and solar forecasts are utilized, MAPS simulated hydro production was statistically analyzed comparing state-of-the-art and perfect forecasts.

- *Value of Hydropower as a Balancing Resource* – To deduce the value of hydropower as a balancing resource, hydro capacities were reduced to an average value for each month such that the hydro facility was forced to run at a constant "flat" level for every hour during a given month, thus removing all generator flexibility and reserve capacity of the hydro system in the MAPS model. A comparison of economic parameters was conducted between this flat hydro generation and simulations where a more realistic flexibility was permitted in the hydro generators.

- *Value to Hydro Community of Participating in Wind Integration* – To answer the question about potential value to hydro utilities of participating in wind integration, an economic comparison was made between MAPS simulations where the hydro generation was scheduled to load alone versus being scheduled to load net wind and solar generation (i.e. the load less the forecasted wind and solar power).

- *Impact of Wind and Solar Integration on Pumped Storage Hydro Operations* – Concluding this study, Mt. Elbert pumped storage hydro operations were investigated comparing both economic and energy utilization factors as wind and solar generation is integrated into the system.

Hydro-Related Results and Conclusions

The WWSIS hydropower analysis revealed several significant results with regards to the use of hydropower generation in integrating renewable generation in the West. Some of the results deal solely with the usage patterns and statistics describing hydropower generation employed to meet system load, or to meet load less wind and solar power. Other results pertain to economic ramifications of hydropower in system balancing with and without renewables. Two distinct economic measures are mentioned in the summary results below: operating costs and revenue. Operating costs represent the costs incurred in generating electricity, and include fuel costs, variable operation and maintenance costs, start-up costs, and emission payments. By contrast, revenue value is calculated as the product of the generator output each hour with the corresponding Locational Marginal Price (i.e., the "spot price") as predicted by the MAPS model. Thus operating costs deal with the actual costs incurred in operating the system, while revenue pertains to the payments made for energy produced and may be more or less than the actual costs during any given hour. Both economic measures are presented in 2017 dollars. The results and concluding remarks addressing the study objectives can be summarized as follows:

- *Results of MAPS Hydro Modeling Accuracy* – In comparing the MAPS modeled hydro generation at selected hydro facilities to actual generation profiles from 2006; it was found that the MAPS modeled hydro dispatched significantly more energy and capacity. The reason for this was that MAPS assumed the entire hydro plant nameplate capacities were available for use (not accounting for water levels being less than maximum, or flow regulated at above minimum), and that eleven-year average values of the hydro energy were available on a monthly basis (corresponding to an 11-year average of the monthly water releases and reservoir levels). During 2006, the monthly hydrogenation was significantly below the 11-year average (~20% less) and the reservoir water elevations were similarly lower than their maximums, causing the available capacity at many plants to be significantly less than their nameplate capacity. This resulted in enhanced hydro generation simulated at five of the seven hydro facilities selected within the study footprint.[2]

  As for the usage pattern, the modeled hydro was dispatched primarily in a peak shaving mode where the flexibility at each hydro facility was employed during the ramps into and out of the high load hours with most hours in between staying relatively steady. Thus *less* of the generator flexibility was deployed than in the historical data. Other differences in the MAPS dispatch of the hydro were partly due to the hydro system constraints not accounted for in the model, as well as the fact that in actual practice, several utilities schedule and dispatch hydro to their balancing area loads and use the flexibility of the hydro as needed. Since the variability of each separate balancing area load is more than their aggregate variability (on a percent of load basis), more of the hydro flexibility is employed than modeled in MAPS. One challenge in modeling hydropower in any production cost model, including MAPS, is the difficulty in modeling plant-specific constraints on the hydropower that influence operations within limits of monthly energy and capacity (e.g. high priority functions, non-power constraints, and regulations imposed on each dam, such as flood control, irrigation, fishery and environmental constraints). These constraints cause MAPS modeling to deviate from actual production during certain times of the year.

  When studying the shape of the hourly time series of hydro production created by the MAPS simulation, it was evident that MAPS dispatched hydropower for peak shaving and the flexibility at each hydro facility was not used extensively to balance variability of the net load. When compared to historical generation shapes at the seven hydro plants studied in detail, MAPS compared quite favorably during those periods when the actual resource was also being utilized to meet peak demand, and less so during periods of plant specific flow constraints. Thus, in economically optimizing dispatch of system resources, MAPS utilized

[2] Blue Mesa Dam and Morrow Point Dam operations showed more flexibility and energy use than in the MAPS simulation. Further investigation revealed Morrow Point and Blue Mesa Dam have changed their hydro operations recently such that the capacity limits and monthly energies exceed those employed in the MAPS simulation.

hydropower for its value on peak, and not necessarily for its flexibility in changing generation level from hour to hour.

To reconcile the differences in hydro production and dispatch between the MAPS simulation and the actual 2006 data, an additional MAPS simulation was performed using 2006 historical hydro capacity limits and monthly energy in place of the 11-year averages. This resulted in a considerably more accurate representation of the hydro system at the selected facilities by MAPS, even without accounting for higher priority functions. Consistent with the other simulations, however, MAPS dispatched the hydro in a peak shaving mode utilizing less inter-hour load following capabilities than in the historical data. Thus, if used as a broader system resource versus serving individual balancing areas, and absent flow constraints beyond the monthly flow requirements, the rational dispatch algorithm employed in MAPS dispatches hydro more for its value on peak and less for its flexibility.

When comparing modeled pumped storage hydro (PSH) operations at the Mt. Elbert facility to actual operations, the MAPS model was found to significantly underutilize PSH resources (actual hours of operation were found to be nearly 8,000 hours while the MAPS simulation utilized approximately 2,000 hours). This discrepancy can be attributed to several factors not captured by the MAPS model such as supplemental water fed to the forebay at Mt. Elbert and the plant's ability to provide ancillary services throughout the day.

- *Results of Drought Considerations on Hydro Operations* –When comparing MAPS results of historical-hydro operations to their higher-energy-capacity counterparts of "base case" operations, WECC operating costs were found to increase by $200 million/yr or by $115/MWh of reduced hydro generation. As a reference, this difference is less than 1% of total WECC operating costs. This increase is attributed to the extra thermal resources required to balance the system load to compensate for the low-cost hydro not available due to the low water year. However, in terms of revenue value, the missing hydro capacity would cause a reduction in hydro revenue value in the footprint by nearly $200 million/yr (approximately 15% of total hydro revenues) or $105/MWh of reduced hydro energy.

- *Results of Renewable Generation Impact on Hydro Operations* – Results have shown that as renewable penetration levels increase, utilization of the hydro system in aggregate shows little change in generation pattern; however at the individual plant level, significant changes in operations were observed at some larger plants like Hoover Dam (steadily increasing change in hydro use with penetration level). Use of hydro's flexibility was found to increase during all hours of the day as the renewables penetration increased. Seasonally, the greatest differences in hydro operations occurred during spring months due to high winds occurring in the West requiring significant use of system flexibility. Other months remained very similar to the no-wind scenario. Hydro facilities were observed to back down generation during high wind periods and shift generation on a weekly, daily and hourly basis while maintaining required monthly energy generation (and therefore required water releases).

- *Results of Inter-Scenario Comparisons* – Investigating inter-scenario (In-area vs. local priority vs. mega project) differences in hydro operations revealed important changes in use of hydro flexibility. Hydro facilities located within the study footprint tended to utilize less flexibility as wind resources were transferred to more remote, higher quality resources of the mega-project scenario. This is due to the fact that hydro generation resources were assigned to meet only their corresponding net balancing area “region” loads (e.g. hydro resources located in the Arizona-New Mexico region would be dispatched based upon the AZ-NM net-loads and not net-loads of the other four regions). Thus as more wind was obtained from better wind resources of the mega-project scenario (i.e. to Wyoming and out of each designated region load area), variability in net-load experienced at the hydropower facilities decreased if the amount of wind in that region decreased.

- *Results of Effect of Wind and Solar Forecast on Hydro Usage* – When comparing the dispatch of hydro as wind and solar forecast methods become more accurate (comparing a professional forecast to a perfect forecast); results show little change in use of hydro’s flexibility throughout the year. In all cases, use of a perfect forecast led to hydro flexibility being used slightly more, enabling more expensive thermal resources to be backed down saving an additional $500 million in annual operation costs or $1-2/MWh of renewable energy. Hence, improving the wind and solar forecasts from a “professional” level of accuracy to a perfect forecast netted a relatively small savings (per MWh of renewable energy) in system operation.

- *Results of Value of Hydropower as a Balancing Resource* – The value of hydro as a balancing resource was deduced by modeling the hydro with severely restricted flexibility and reserve capabilities, essentially establishing a constant river flow and therefore generation at each hydro facility (the “flat” hydro case). The net result of running the hydro flat was increased operating costs, especially in steam oil and gas units and the small, “generic” generation fleet consisting of units less than 20 MW in capacity. WECC operating costs were modeled to increase by $35/MWh of steam oil/gas and $60/MWh of generic generation. Total WECC operating costs were predicted to increase by up to $1 billion/yr (or 2% of total operating costs in WECC). This increase in operating cost provides an indication of the value of hydropower as a system resource.

  In terms of hydro revenue value, on the footprint level, restricting flexibility would cause hydro to suffer losses totaling nearly $80 million/yr (approximately 5% of total hydro revenues for each case). The greatest impact would be felt at the two largest hydropower facilities located in the study footprint, Glen Canyon Dam at $32 million/yr and Hoover Dam at $35 million/yr. On the WECC level, total revenue gains for the generators reach $3.5 billion/yr at the lower penetration levels (due to increased use of thermal resources to balance load when the hydro is run flat), but at penetration levels exceeding 20%, wind generation is able to carry enough capacity such that there is an overall revenue loss. As a reference, the incremental impact is approximately 3% of total revenues.

- *Results of Value to Hydro Community of Participating in Wind Integration* – The MAPS simulations in the WWSIS study committed and dispatched all hydro generation to serve daily peak net-region-load (that is, load minus wind and solar in each region), while respecting the minimum and maximum operating points on hydro units. To show the value of hydropower participating in wind and solar integration, a MAPS simulation was conducted where hydropower units were dispatched to the load only and not the load minus wind and solar (the net load). Results show that changes in flexible thermal generation resource dispatch, like gas units, would result in a few $/MWh increase in total WECC operating costs throughout each penetration level. Cumulatively, at lower penetration levels, the increase in operating costs is relatively small. However, at the 30% wind level, total operating costs would increase by $200 million/yr (2% of total operating costs).

Using this same methodology, a revenue analysis of generators in the footprint revealed decreased hydro revenue across each penetration level with the greatest reduction at the 30% wind penetration level by $3/MWh, totaling $45 million/yr (11 % of total hydro revenue). Of the selected facilities, Hoover Dam and Glen Canyon Dam incurred the majority of the reduction at $18 million and $16 million, respectively. On a WECC wide basis, results showed flexible thermal generation resources (e.g. gas units) would acquire increased use at each of the penetration levels. Similarly, the impact on revenue value at lower penetration levels is relatively small, but at the 30% renewable penetration level, nearly every generation source suffers losses by a few $/MWh of generation, including renewables. This translates to over $1.3 billion in total revenue value losses at the 30% level (approximately 4% of total revenue value), with nearly $300 million due to hydro losses (approximately 3% of total hydro revenue value). These revenue losses correlate directly to the depressed LMPs due to high penetration of renewables, and a net savings to the consumer.

To summarize, participation of hydro in wind and solar integration by scheduling the hydro to the "net load" versus the load only results in an appreciable increase in hydro revenue and decrease in overall system operating costs.

- *Results of Impact of Wind and Solar Integration on Pumped Storage Hydro (PSH) Operations –*

  The PSH results led to two general conclusions:

  1) For the no wind case, MAPS predicted utilization of the PSH far less than actually occurred. During 2006, Mount Elbert was operated for 7,958 hours as compared to the1, 935 hours as simulated in MAPS. This indicates that modeling the PSH for peak shaving only, as is done in MAPS, does not adequately represent the operations of the PSH. This is likely due to the PSH being used for other purposes than peak shaving, such as energy arbitrage, ancillary services, and capacity value.
  2) When comparing the usage of PSH predicted by MAPS for the baseline, no-wind case with the highest wind and solar penetration levels, MAPS predicts a significant increase in utilization throughout the year, by nearly 30%. However, the total revenue value actually decreased in every case when compared to the baseline, no-wind case. This drop in revenue value, even with increased use, can be attributed to the depressed system spot prices. Since electricity markets throughout the West are generally not open, liquid markets, and since the system will likely not be overbuilt (with excess capacity) as modeled in MAPS, the magnitude of spot price decreases predicted by MAPS will likely not occur. While this is not an issue of importance in a relativistic operational cost study, such as that conducted for the WWSIS, it is important in an economic analysis of the value of PSH. Thus, thought the WWSIS results suggest that investment in a new 100-MW PSH does not seem economically justifiable when integrating wind and solar power, a more complete and accurate simulation is required for the purpose of valuing PSH.

The technical analysis performed in this study shows benefits of hydropower in integrating wind and solar generation in the West by helping meet changes in net load during periods of high wind generation (spring time), providing system ramping capabilities, and shifting energy production when wind generation is predominate. The inherently flexible characteristics of hydro are of greatest value to the electrical system when large amounts of variable and uncertain generation resources are producing in the power system. However, the rational (economic optimization) dispatch algorithm employed in MAPS tends to deploy the hydro for its value on peak as opposed to utilizing its ramping capabilities. Pumped storage hydro may also have opportunities in wind and solar integration, although proposed new plants will have to be justified by several potential revenue sources (like energy arbitrage, ancillary services, and capacity value) with wind integration as one component. Along with benefits and potential value of utilizing hydro more broadly to accommodate renewable generation, this study also revealed that while the hydro system can be reasonably modeled, there are several modeling limitations related to capturing non-power constraints and constraints that often govern hydro flexibility and availability. The need for production cost models to capture or incorporate these factors is apparent particularly at the individual hydro plant level and especially as wind and solar integration studies like the WWSIS become increasingly comprehensive and consider large penetrations of renewables.

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1.0 Introduction

The North American Electric Reliability Council (NERC) develops and enforces reliability standards for entities that are engaged in ownership, usage, and operation of the bulk power system. NERC is a non-profit voluntary organization whose objective is to ensure a reliable, adequate, and secure electric system. NERC is made up of eight regional reliability council members as shown in Figure 5. These members include: investor-owned utilities, federal power agencies, independent power producers, power marketers, rural electric cooperatives, and state, municipal, and provincial utilities. There are a total of 133 control areas within these regions, with 37 control areas located within the WECC. Control areas or balancing areas are defined as sub-regions of the electrical grid that are responsible for meeting the reliability standards set by NERC (balance supply and demand, maintain interchange schedules with other control areas, and contribute to the frequency regulation of the interconnection) and ensuring there is sufficient generation capacity to meet the load demand within the area. The distribution of control areas are represented by the white circles shown on the map in Figure 5.

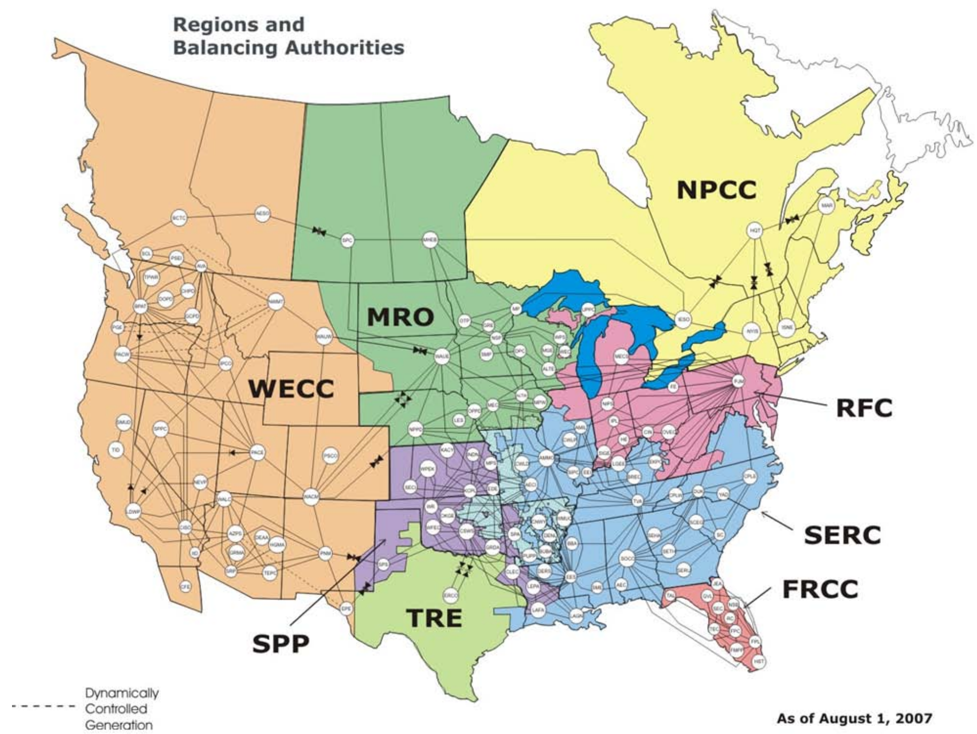

Figure 5: NERC regions and balancing authorities. (Source: http://www.nerc.com/fileUploads/File/AboutNERC/maps/NERC_Regions_BA.jpg)

A primary challenge in operating a control area is to ensure there is adequate capacity and reliability reserves to meet the daily load requirements and to ensure there is adequate flexible generation on-line that is able to cover the variation in the load that occurs on time scales from nearly instantaneous to hours ahead. The second-to-second fluctuations in load must be met by agile generators outfitted with automatic generation controls (AGC) and is frequently referred to as regulation. Gas turbines and hydropower units are capable of meeting these regulation requirements. On a longer timescale, the minute to hour variations are met by quick response units and is defined as load following. Serving the daily load demand requires scheduling units the day before operation, including both the agile generators that move with the load and the base load resources that do not vary in generation substantially, such as conventional coal or nuclear powered steam plants. The process of scheduling these units is termed unit commitment. Figure 6 illustrates the electrical system load on a varying timescale with corresponding terminology. The phrase “ancillary services” is used to describe the services (i.e. regulation, spinning, non-spinning, and placement reserves, voltage support, and black start) needed to meet these day after day fluctuations in load (Smith 2007).

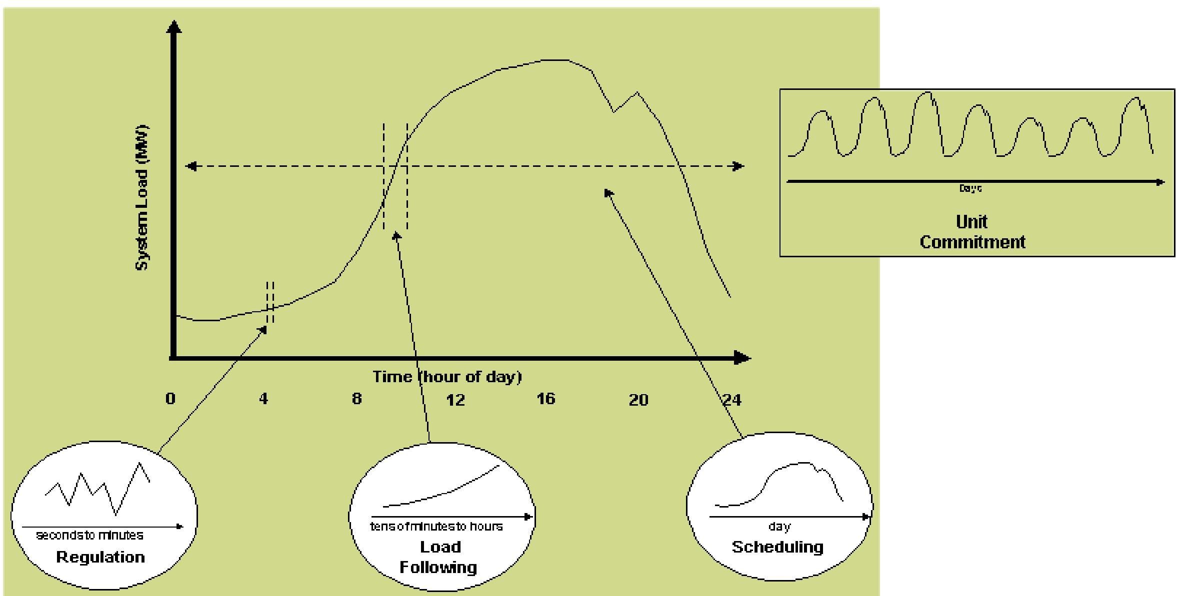

Figure 6: Terms of system load on varying timescales. (Source: National Renewable Energy Laboratory)

As the current trend in generation expansion is to meet larger amounts of the load demand with clean, reliable and affordable energy sources, renewable energy systems such as wind and solar become increasingly practical. However, these resources are inherently variable, as they are dictated by the changing state of the wind and solar resources. In the case of wind and solar photovoltaic generation, none of which have inherent storage capabilities, electricity cannot be efficiently stored on a large scale using currently available technology; it must be used as it is produced. From a system operator’s perspective, wind energy shows up like negative load, that is, the system is operated to meet the “net load”. At very small penetration levels, the variability of wind and solar energy is not noticeable. Beyond this threshold, the variability and uncertainty of wind and solar requires the grid operator to be aware of the wind and solar power forecasts, its expected accuracy, and to have a realistic understanding of the variability in its output. When a change in demand or generation occurs, such as that due to the variability in power output from a wind plant, somewhere in the interconnected power system the production or consumption of electricity should make a corresponding change. This often results in increased costs ensuing from an increased use of flexible thermal resources to maintain system reliability. Additionally, wind power contributes only a portion of its rated capacity as firm capacity (e.g. its Effective Load Carrying Capability). Despite these issues and additional costs, non-traditional, renewable energy resources can positively benefit the operating system, reducing overall system costs by displacing more expensive thermal resources.

One solution to address the lack of storage and variability issues inherent in renewable energy generation is to couple their operation with a clean, responsive generation resource such as hydropower. Hydropower, as an agile generation resource, is able to respond to rapid fluctuations in demand and due to some built-in energy storage in the form of hydro impoundment, has the ability to shift water/energy releases from hours to several months. This has long been a valued resource in electrical system balancing. Peaking or flexible hydro plants like that of Hoover Dam (located along the Colorado River System) often have significant water storage capabilities and are designed to rapidly change output levels in order to satisfy changes in demand. However, hydro facilities also serve many functions beyond power generation, and these functions typically are of higher priority such as: end water use (irrigation purposes), flood control, navigation, fish habitat, and recreation. These higher priority functions of the dam often bound the true performance potential and limit flexibility during certain times of the day. Such is the case of Glen Canyon Dam which is operated under the Glen Canyon Dam Final Environmental Impact Statement and Record of Decision (Harpman 1999). This limits the maximum and minimum generation and flow through the turbines along with limiting the up and down ramps during certain time periods.

As the price of renewable energy declines and becomes competitive with wholesale power prices, the feasibility of large-scale wind projects becomes more realistic. Thus, as larger amounts of renewables enter the electrical system, integration studies like that of the Western Wind and Solar Integration Study (WWSIS) become necessary in order to determine the operational impacts and costs associated with the variability and uncertainty inherent in wind and solar generation. With nearly 5 GW of installed hydro capacity located within the WWSIS study footprint and just over 61 GW located within the jurisdiction of the Western Electricity Coordinating Council (WECC), results from the WWSIS confirm that the agile generation resources of hydropower and pumped storage hydro play an important role in meeting variations in net-load helping to maintain system balance and provide system reserves to cover missed wind and solar forecasts. However, several in-depth questions remain unanswered in addressing MAPS modeling accuracy and capability, impact of renewable generation on individual facility operations, and the significance of hydropower and pumped storage use in the WWSIS. These questions can be summarized below:

- How well were the hydro and pumped storage systems modeled in the simulations?
- What is the magnitude and character of change in generation and operations at individual hydropower and pumped storage plants when high penetration levels of renewables are incorporated in the grid system?
- What effect do the different wind scenario build outs have on the way hydro generation is dispatched?
- How does a more accurate wind and solar forecast impact hydro operations?
- What is the overall value of hydropower as a balancing resource?
- What is the impact of a severely constrained hydro system, such as a system where constant river flow is required?

- What is the value to the hydropower community by participating in wind integration?
- What is the impact of renewables on pumped storage hydro operations?

To answer these questions, this thesis study conducts an in-depth statistical and economic analysis comparing a series of General Electric's (GE) Multi-Area Production Simulation (MAPS) data and contrasts this with actual production patterns. Seven of the largest hydropower facilities, including one pumped storage facility in the WWSIS footprint, were selected and examined covering a variety of generation capacities, constraints, and locations. Additionally, using the MAPS simulations, several different hydro schedules, forecasting methods, scenario developments, and economic parameters were used to deduce the overall value and impact of renewables on hydro operations. The methodologies used and assumptions made are discussed in further detail in the body of the report.

2.0 Background of Western Wind and Solar Integration Study

This section gives a detailed background summary of the WWSIS study. The discussions on the development of data inputs and assumptions made, design of scenarios, and key findings of the study are summarized in this section. The full report is publicly available online available at http://www.nrel.gov/docs/fy10osti/47434.pdf.

2.1 WWSIS Introduction

The National Renewable Energy Laboratory (NREL) and research partner GE carried-out the WWSIS in order to provide insight into the costs and operational impacts caused by the variability and uncertainty of wind, photovoltaic, and concentrated solar power employed to serve up to 35% of the load energy in the WestConnect region (Arizona, Colorado, Nevada, New Mexico, and Wyoming), see Figure 7 for study footprint. WestConnect is composed of several utility companies providing transmission in the Western Interconnection region. These members are working collaboratively to assess stakeholder and market needs to develop cost-effective improvements to the western wholesale electricity market. WestConnect participants include the Arizona Public Service, El Paso Electric Company, Nevada Energy, Public Service of New Mexico, Salt River Project, Tri-State Generation and Transmission Cooperative, Tucson Electric Power, Xcel Energy and the Western Area Power Administration (Western).

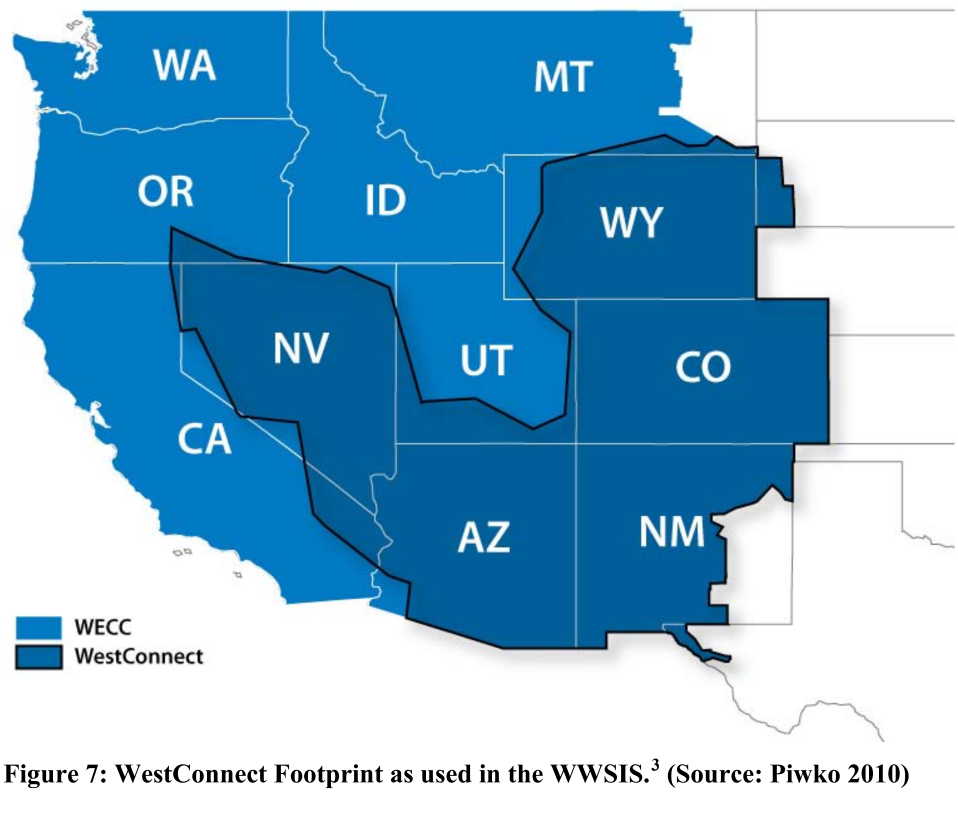

Figure 7: WestConnect Footprint as used in the WWSIS.[3] (Source: Piwko 2010)

[3] Utilities located in California were not included in the WWSIS due to the fact California had already completed a renewable integration study for the entire state.

The WECC represents one of three interconnected electrical systems in the NERC regions, and therefore it was necessary to model the entire WECC region in order to correctly model the balancing areas in the WWSIS footprint. Using historical loads and weather patterns from years 2004, 2005, and 2006, the study examined the details of system operation and dispatch through an hourly production cost model for each historical year with loads scaled to that expected in the study year of 2017 examining the inter-annual operability.[4] The load, wind power, and solar power are directly related to the weather; thus, the load, wind and solar are implicitly correlated. In order to preserve any such correlation, it is important to develop wind and solar power production estimates that are based upon the weather patterns that were present in the study years from which the load pattern was derived.

With the growing demand of clean, renewable energy driven by state Renewable Portfolio Standards (RPS) throughout the U.S., the WWSIS was conducted to specifically answer several questions that utilities, Public Utility Commissions, developers, and regional planning organizations had about wind and solar energy on the grid system in the West such as:

- What is the impact on system operations when up to 35% renewable energy penetration levels are employed and how will this be accommodated?
- How does geographic diversity help mitigate variability inherent in wind and solar?
- How do local resources compare to remote, higher quality resources delivered by long distance transmission?
- How does balancing area cooperation mitigate variability?
- How should reserve requirements be modified to account for the variability?
- What is the benefit of integrating wind and solar forecasting into grid operations?
- How can hydro generation help with renewable integration?

2.2 Wind and Solar Modeling Development used in the WWSIS

Lack of high quality wind and solar data that is synchronized with the region's electric load becomes one of the primary obstacles in conducting renewable integration studies. Time series data must be used to perform power system analysis for systems with significant amounts of wind and solar penetration levels. Data can be obtained in several ways with on-site power generation being the most desirable, but due to the fact that this data can only be obtained from a limited amount of existing projects, this restricts its use in large-scale integration projects. As a practical alternate to observed wind data, numerical weather prediction (NWP) models can be used to simulate climatological conditions over broad, selected regions. These simulations are driven by the solutions of the basic conservation equations that model the physical interactions in the atmosphere. The NWP models employ the reanalysis of wind speed datasets (spatially and temporally coarse global datasets) to determine boundary conditions for a model run, which is then downscaled using a mesoscale (i.e. regional) model that can produce a finer physical resolution, down to 1-km. Short-term observation at multiple locations can be compared to the downscaled parameters (such as wind speed) and these errors can be reduced with Model Output

[4] Though renewable energy penetration levels are not expected to reach 35% by 2017, this year, which was the WECC transmission planning year at the time, was selected in order to start with a realistic model of the transmission grid.

Statistics (MOS) equations reducing the bias (making statistical adjustments to the modeled dataset) (Potter 2008).

For the WWSIS, the renewable energy forecasting company 3TIER developed the wind dataset, hour-ahead and day-ahead wind forecasts. The wind data for the WWSIS was generated using the Weather Research and Forecasting (WRF) mesoscale NWP over the western United States at 2-km, 10-minute resolution for the consecutive years 2004-2006. Four independent domains were run in three-day blocks which were merged and smoothed at the seams (i.e. the spatial locations where the four independent domains overlapped). It was discovered that the days with seams exhibited more significant variability than the days without seams in the Arizona region. To validate the large spikes in wind speeds Northern Arizona University (NAU) selected five sites in the northern Arizona region where meteorological data is available and was compared to the NREL WWSIS data. These sites included: Gray Mountain, Anderson Canyon, Springerville, Aubrey Cliffs, and Bullhead City.[5]

To solve this modeling issue, data from every third day was eliminated. The corresponding daily energy levels were reanalyzed and determined acceptable for energy and production simulation analysis. 3TIER also developed a day-ahead wind forecast using a coarser resolution for the hourly forecast with a different input dataset (the NCEP Global Forecast System as opposed to the NCEP Global Reanalysis dataset). As a consequence, the wind forecasts were found to have a significant positive bias (total annual energy of cumulative wind plant forecasts was greater than the cumulative annual energy of the simulated power production). To remove this bias in total energy, the hourly wind forecasts were de-rated by 10% within the study footprint and by 20% for the rest of the WECC.

Solar resource data was developed by the State University of New York (SUNY) at Albany/Clean Power Research, using a satellite cloud cover model to simulate the United States at 10-km, hourly resolution. The hourly and day-ahead solar forecasts were developed by 3TIER Group. Photovoltaic (PV) was modeled as 100 MW distributed generation blocks on rooftops due to the lack of data on large, central station PV plants. Concentrating Solar Power (CSP) was modeled as 100 MW blocks of parabolic trough plants with six hours of thermal storage.

2.3 Multi-Area Production Simulation Model

The heart of the WWSIS is an hourly production cost simulation of the balancing areas in the study footprint using GE's Multi-Area Production Simulation (MAPS) Model. MAPS performs a day ahead unit commitment and an hourly dispatch recognizing transmission constraints within the system and individual unit operating characteristics using Locational Marginal Pricing (LMP). Two important economic parameters were considered, the revenue value and system operating costs. The WECC system was modeled as 106 separate load areas, each with their own load profile, generating plant portfolios, and transmission capacity with adjacent areas, while being assigned to 20 transmission zone areas with limited transfer of energy between the areas. The system was committed and dispatched in a cost-effective, rational manner recognizing transmission limits and cycling capabilities of the individual generators (GE Energy 2010). For example, units with the least amount of operating costs were commitment first (e.g. hydro)

[5] See http://wind.nau.edu/anemometer/ wind_data.shtml for more information about the site locations and data availability.

followed by base load units, and then load following units, and finally peaking units. Assumptions that were made for the production cost simulation include:

- All study results are in 2017 nominal dollars with 2% escalation per year.
- Cost for fuel was assumed to be $2/MBTU for coal and $9/MBTU for natural gas.
- Carbon dioxide costs were $30/metric ton of CO_2.
- Extensive balancing area cooperation was assumed in the WestConnect footprint.
- Generation equivalent of 6% of load is set aside as contingency reserves, split equally between spinning and non-spinning reserves.
- The sub-hourly model assumes a 5-minute economic dispatch.
- Hydro generation is normally committed and dispatched to serve the daily peak net-load periods, while respecting the minimum operating points on the hydro units. With the exception of large hydropower units (i.e. hydropower plants with a nameplate of 1,000 MW or more), hydropower units were dispatched to meet the load defined by their corresponding transmission constrained area. The larger (though few) hydro units were dispatched to meet the entire system load.

For the hydro facilities, the energy available for each month at each hydro plant was defined by a historical ten-year monthly energy average (1996-2006) along with monthly defined minimum and maximum permissible generation values. The minimum generation value or minimum capacity of the hydro plant represents the base-load for all hours in the month (i.e. the run-of-river portion of the plant). The remaining capacity and energy were scheduled in a peak-shaving or valley-filling mode over the month.

2.4 Scenario Description

Using MAPS, GE conducted hourly production simulation analysis of three base scenarios founded on the combinations of physical transmission areas and the trade-offs between using local and remote resources. Each scenario was run at three levels of wind power penetration (10%, 20%, and 30%), and three levels of solar power penetration (1%, 3% and 5%). Seventy percent of the energy from the solar power was derived from CSP and 30% from PV. Table 3 displays the combinations of wind and solar penetration levels for each study area in the WECC.

Table 3: Combinations of wind and solar power modeled within the WECC for various penetration levels (% of load energy) modeled in the WWSIS.

Penetration	Wind and Solar Energy (% of load)
30%	30% wind, 5% Solar in Footprint 20% wind, 3% Solar out of Footprint
20%	20% wind, 3% Solar in Footprint 10% wind, 1% Solar out of Footprint
20/20%	20% wind, 3% Solar in Footprint 20% wind, 3% Solar out of Footprint
10%	10% wind, 1% Solar in Footprint 10% wind, 1% Solar out of Footprint

These penetration levels were used in investigating, among other factors, the capacity value of wind and solar power resources, the effect of balancing area cooperation, and the effectiveness of hydropower in addressing the enhanced variability and uncertainty in system operation caused by wind and solar power. In addition to these penetration levels, three basic scenarios were considered concerning where in the WWSIS footprint that the wind and solar power was assumed to be installed. These scenarios are:

- ***In-Area scenario*** – uses local resources within each "transmission constrained" area within the WWSIS footprint by selecting the best sites in correspondence to a mix of energy value, geographic diversity, and capacity factor. These transmission constrained areas correspond roughly to the state boundaries within study footprint, with the exception of Colorado, which is split into and east and west side at approximately mid-state.
- ***Mega-Project scenario*** – was created by trading out the lower ranked wind sites (ranked by capacity factor) of the In-Area scenario by higher capacity factor remote resources.
- ***Local Priority scenario*** – uses a more realistic build-out of wind sites and transmission combining both in-state and remote resources.

Figure 8 illustrates maps of the three scenarios for the 30% case including the conceptual interstate transmission infrastructure to bring renewable resources to load.

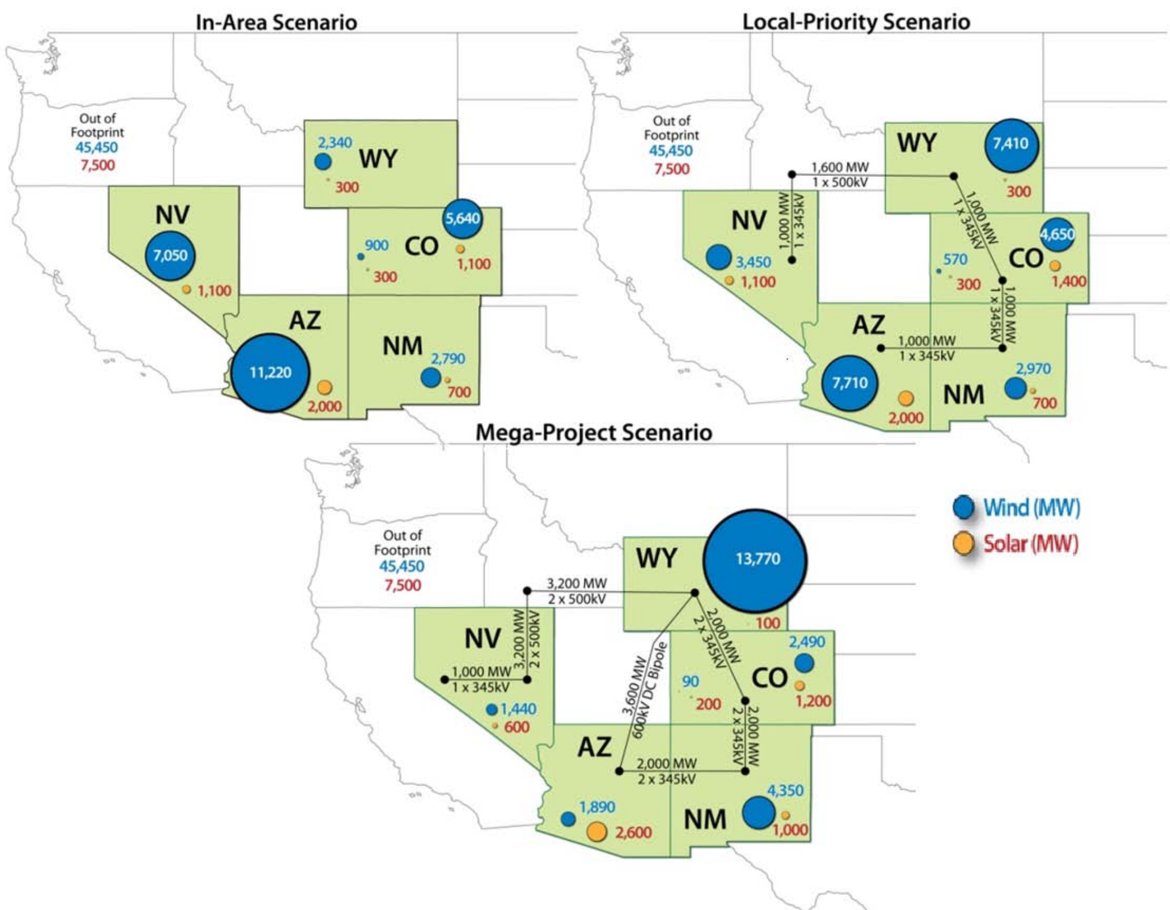

Figure 8: Three scenarios depicting wind and solar capacities for the 30% case including conceptual interstate transmission shown in black. (Source: GE Energy 2010)

Table 4: Scenario naming conventions.

Scenario	Penetration level	Forecast	Hydro Schedule
I – *In Area*	Pre – *Preselected*	P – *Perfect Forecast*	H – *Load Only*
M – *Mega Project*	10 – *10% scenario*	R – *State of the Art Forecast*	HH – *Historical Hydro*
L – *Local Priority*	20 – *20% scenario*	N – *No Forecast*	Hf – *Flat Block hydro*
	2020 – *20/20% Scenario*		
	30 – *30% scenario*		

Table 5: Aggregated wind and solar ratings by state for each scenario. (Source: GE Energy 2010)

In Area

			10%	1%	20%	3%	30%	5%
Area	Load Minimum (MW)	Load Maximum (MW)	Wind Rating (MW)	Solar Rating (MW)	Wind Rating (MW)	Solar Rating (MW)	Wind Rating (MW)	Solar Rating (MW)
Arizona	6,995	23,051	3,600	400	7,350	1,200	11,220	2,000
Colorado East	4,493	11,589	2,040	300	3,780	800	5,640	1,400
Colorado West	712	1,526	300	0	600	200	900	300
New Mexico	2,571	5,320	1,080	200	1,920	400	2,790	700
Nevada	3,863	12,584	2,340	200	4,680	700	7,050	1,100
Wyoming	2,369	4,016	930	100	1,620	100	2,340	300
In Footprint	21,249	58,087	10,290	1,200	19,950	3,400	29,940	5,800

Local Priority

			10%	1%	20%	3%	30%	5%
Area	Load Minimum (MW)	Load Maximum (MW)	Wind Rating (MW)	Solar Rating (MW)	Wind Rating (MW)	Solar Rating (MW)	Wind Rating (MW)	Solar Rating (MW)
Arizona	6,995	23,051	2,850	400	5,250	1,200	7,710	2,000
Colorado East	4,493	11,589	2,190	300	3,870	800	4,650	1,400
Colorado West	712	1,526	210	0	450	200	570	300
New Mexico	2,571	5,320	1,350	200	2,100	400	2,970	700
Nevada	3,863	12,584	1,350	200	2,490	700	3,450	1,100
Wyoming	2,369	4,016	1,650	100	4,020	100	7,410	300
In Footprint	21,249	58,087	9,600	1,200	18,180	3,400	26,760	5,800

Mega Project

			10%	1%	20%	3%	30%	5%
Area	Load Minimum (MW)	Load Maximum (MW)	Wind Rating (MW)	Solar Rating (MW)	Wind Rating (MW)	Solar Rating (MW)	Wind Rating (MW)	Solar Rating (MW)
Arizona	6,995	23,051	810	400	1,260	1,800	1,890	2,600
Colorado East	4,493	11,589	2,010	300	2,400	400	2,490	1,200
Colorado West	712	1,526	60	0	90	0	90	200
New Mexico	2,571	5,320	1,860	400	2,700	1,000	4,350	1,000
Nevada	3,863	12,584	570	100	1,020	200	1,440	600
Wyoming	2,369	4,016	3,390	0	8,790	0	13,770	100
In Footprint	21,249	58,087	8,700	1,200	16,260	3,400	24,030	5,700

			10%	1%	10%	1%	20%	3%
Out of Footprint	46,328	119,696	22,950	2,500	22,950	2,500	45,450	7,500

2.5 What the WWSIS Covers

The WWSIS is an operations study of the power system focusing on the variable operational costs and savings due to the fuel and emissions. Additionally it covers analysis on the capacity value of wind and solar.

The WWSIS does not cover: transmission planning, cost-benefit analysis, system reliability, dynamic stability issues, or optimization of the balance between wind and solar resources.

For the study year 2017, it was assumed that WestConnect and WECC will operate differently than today's operational practice. The following future operational assumptions were made: the current 37 regional balancing areas were pooled into five regions (Arizona-New Mexico, Rocky Mountain, Pacific Northwest, Canada, and California), all generation resources are shared equally and not committed to specific loads integrating the least-cost of economic dispatch, and existing available transmission capacity will be accessible to other generation on a short-term, non-firm basis.

To analyze the performance of the operating system with high penetration levels of wind and solar generation, four primary analytical methods were used including: statistical analysis, hourly production simulation analysis, sub-hourly analysis using minute-to-minute simulations, and resource adequacy analysis. Statistical analysis was used to quantify the variability due to system load, as well as renewable generation over annual, seasonal, daily, hourly, and 10-minute timeframes. Production simulation analysis was used to evaluate hourly grid operations for each scenario within each of the three selected years with several different wind, solar, and load profiles using GE's MAPS program. Minute-to-minute simulation analysis was used to quantify grid performance trends and to investigate potential mitigation measures. Lastly, resource adequacy analysis with GE's Multi-Area Reliability Simulation (MARS) program was used to evaluate the loss-of-load-expectation (LOLE) calculations.

2.6 System Operations with 35% Wind and Solar

To understand the impact on power system operations with 35% wind and solar, two important weeks were selected in July and April 2006, where July experienced the highest load and April experienced the highest variability in wind output (considered worst week in terms of operations for three years analyzed). Figure 9 illustrates the load (top edge), solar generation (PV in red and CSP in orange), wind generation (green), and resulting net load (blue line – lower edge) system operators must balance. As seen from the figure, the net load of the week in April is governed by the variability in wind output, often exceeding negative net load during several hours of the week during low load hours. The resulting net-load seen in the week of April dictates the importance of wind and solar forecasts needed in order to maintain system balance.

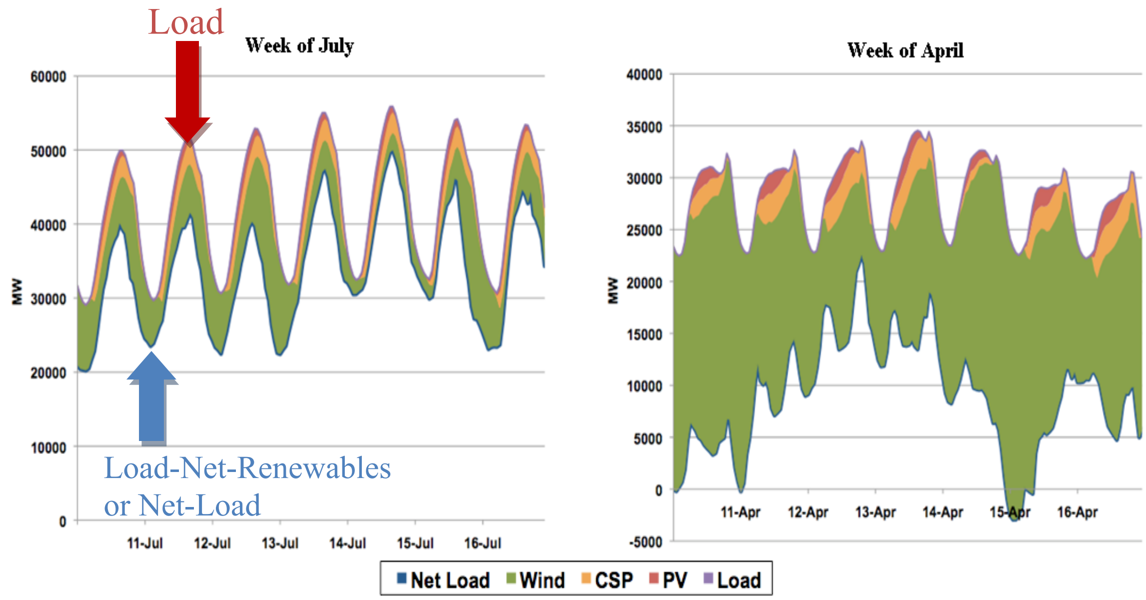

Figure 9: Net-load seen during week of July and challenging week of April. (Source: GE Energy 2010)

Analysis of the April week from Figure 9 can be seen in terms of generation impact in operations. Figure 10 illustrates the generation resources with (right plot) and without (left plot) 35% renewables on the system. As seen in the generation with renewables, the combined cycle generation has been almost completely displaced, as well as the steam coal generation being significantly reduced while cycling of the units have increased.

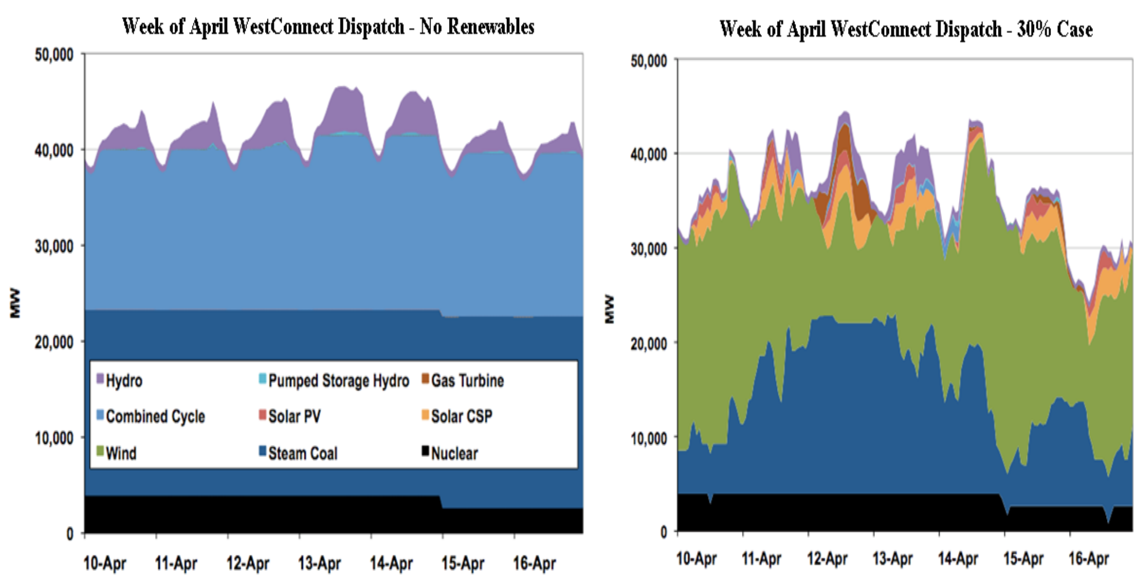

Figure 10: Impact on other generation resources as 35% wind and solar generation enters operating system. (Source: GE Energy 2010)

Though it was observed that there were no significant adverse impacts up to the 20% case in the WestConnect region (given balancing area consolidation or cooperation), further wind and solar generation led to increased stress on system operations for the rest of the WECC. In the 30%

case, operations became additionally challenging in which load and contingency reserves were only met if the renewable forecast was perfect.

Increased renewable penetration levels do present operational challenges but benefits of wind and solar significantly reduce operating costs across WECC. At the 30% case for the In-Area scenario using the professional forecast, WECC operating costs result in a 40% savings due to offset of fuel and emissions ($50 billion/yr decreasing to $30 billion/yr or in other terms, $80/MWh of wind and solar energy produced). Additionally, CO_2 emissions were reduced by nearly 120 million tons/yr (reduction of approximately 25%), SO_x being reduced by approximately 45,000 tons/yr (~5%) and NO_x being reduced by nearly 100,000 tons/yr (~15%).

2.7 Summary of Key Findings from the WWSIS

The technical analysis performed in the WWSIS shows that it is operationally feasible for the WestConnect to accommodate 30% wind and 5% solar energy penetration, assuming operating changes to current practices are gradually made. Key findings of the study can be summarized as follows:

- **Balancing area cooperation** – Effects of increased variability and corresponding operating costs are seen as penetration levels increase in small balancing areas that is running the WECC as 106 zones versus 5 large regions. Larger balancing area cooperation allows reserves to be pooled and loads distributed to others sources of generation, leading to operating costs savings. In the 10% penetration case, WECC operating costs could be reduced by $2 billion.
- **Sub-hourly scheduling** – Current practices of hourly scheduling of generation and interchanges have a significant impact on the regulation requirements. High penetration levels and large scheduled ramps can use nearly all the available regulation capability when compensating for Area Control Error (ACE) excursions, resulting in little or no regulation capability for the sub-hourly variability. Sub-hourly scheduling can substantially reduce the maneuvering on load following units. For example, in the 30% case, the fast maneuvering ability of combined cycle plants is about have of that with hourly scheduling.
- **Importance of forecasts into the unit commitment process** – Though day-ahead wind and solar forecasts utilized in the unit commitment process may sometimes result in reserve shortfalls due to missed forecasts, the benefit of having these forecasts drastically reduce the amount of reserve shortfalls as compared to no forecast. Forecasting day-ahead would reduce WECC operating costs by up to $5 billion/yr and a perfect forecast would reduce operating costs further by another $500 million/yr.
- **Demand response** – To address the problem of contingency reserve shortfalls (especially at the 30% wind penetration level using the state-of-the-art forecast), a demand response program could address shortfall hours as compared to holding additional spinning reserves for the entire year. Additional alternatives include allocating spinning reserves based on better forecasting, improving current reserve policies, and improving the prediction of shortfall occurrences.

- **Wind curtailment** – Using the SOA forecast, no curtailment of wind occurred up through the 20% penetration levels. At the 30% level, wind curtailment is expected to be on the order of 1% or less. With the perfect forecast, no curtailment occurred in any of the scenarios and even when the amount of generation exceeded the footprint load on a short timescale, WECC flexibility was able to absorb all of the generation.
- **Additional reserves** – Variability/load following reserves, which are intended to cover the 10-minute load variability 95% of the time, were found to double at 30% penetration of wind power. However, addition of wind and solar power to the system generation capacity allows thermal units to be backed down rather than be de-committed, thus providing more available up-reserves and therefore no additional reserves were required to cover the net load variability in the study footprint. Down-reserves can be addressed by curtailment of the wind.
- **Transmission additions** – The in-area scenario uses local in-state wind and solar resources, thus no additional long distance, inter-state, transmission would be needed. The local-priority and mega-project scenarios would require no or little new long distance transmission up to the 20% penetration level assuming full access to existing transmission capacity. To estimate the amount of transmission investments needed to justify new transmission at the 30% level, an assumed 15% fixed charge rate results in $2 billion for the local-priority and just over $10 billion in the mega-project scenario. This estimation implies the full-scale transmission build-out might be justified in only the 30% mega-project scenario.
- **Pumped storage** – The use of existing pumped storage hydro (PSH) was found to increase slightly with increased wind and solar penetration, but results show no additional storage was found to be necessary. In a sensitivity case analysis, a new 100 MW PSH plant was added to the system where the dispatched was optimized by giving perfect forecast of spot prices. Still at the 30% penetration level, the PSH plant had an annual operating value of $0.5 million. With the SOA forecast, spot prices are driven up by forecast error resulting in an annual value of $3.8 M. This value is still too low to economically justify additional PSH.
- **Hydro flexibility** – Sensitivity analyses were conducted to examine the effects of hydro constraints on operating costs in the WECC. Hydro schedules were adjusted to the net-load and then compared to hydro scheduled to load only. The operating costs increased slightly at the lower two penetration levels, but the 30 percent level exceeds $200M. To assess the value of hydropower as a balancing resource, all hydro plants were modeled as a flock block of energy, that is, each month the hydro system was set to a relatively constant output, removing the flexibility and any spinning reserve support. Operating cost increases ranged from $800-$1200M.

3.0 WWSIS Hydropower Analysis

Results from the hydropower analysis conducted in the WWSIS addressed the aggregate influence on hydropower generation but many in-depth questions on individual hydro facility operations remained unanswered. Hydropower is a very flexible generation resource but can be heavily constrained due to higher priority functions and non-power regulations and constraints. For this reason, hydropower can be incorrectly modeled in a production cost model such as MAPS. With respect to the WWSIS, concerns that arise related to proper modeling are the constraints and hydrological conditions (i.e. available capacity, upper and lower generation limits, flow and ramping limits due to environmental considerations), proper commitment and dispatch of the hydropower, and accuracy of the supporting hydropower data.

It is important to note, the WWSIS study assumed significant balancing area cooperation (current 37 balancing areas pooled down to five regions: Arizona-New Mexico, Rocky Mountain, Pacific Northwest, Canada, and California), and that these balancing areas would cooperate with each other in addressing system imbalances. When dispatching the hydro resources, smaller hydropower plants less than 1,000 MW in nameplate capacity were dispatched to the load of their corresponding regions. Following this logic, hydropower resources were committed and dispatched in the MAPS model for the benefit of the entire system, that is, not for the benefit of the recipients of the federal hydropower or entities that schedule them. This method allowed investigation of the full potential for meeting peak system loads and maintaining system balance with use of hydropower resources in the study footprint. Additionally, the MAPS simulation operates under a “rational” dispatch algorithm (rather than keeping track of water balances and head heights), that respects monthly minimum and maximum limits for hydro production at each hydro plant along with cumulative energy output for each month. Thus, the hydro system was allowed to shift generation schedules and daily generation profiles within defined capacity limits to best meet system needs but cumulative monthly and annual energy generation remained constant for every scenario.

One of the primary questions that need to be addressed in wind and hydropower integration is to what extent hydro systems can handle system balancing impacts caused by the variability and uncertainty of wind and solar power, given constraints on their generation. A major concern that may arise from the hydro operator’s point of view involves the change in operations and costs that ensue from increased ramping or running within “rough” zones of operation (i.e. cavitations). Ideally, hydropower would be able to provide a short- to medium-term buffer in response to the errors in forecasting wind power, and do so without interfering with its ability to meet other hydro system demands that ultimately conflict with hydropower production. Indeed, to partake in wind integration, hydropower utilities must identify and understand issues of relevance to wind integration that essentially define their generator flexibility. This study attempts to address the basic modeling concerns and additionally answer such questions as:

- What is the magnitude and character of change in generation and operations at individual hydropower and pumped storage plants when high penetration levels of renewables are incorporated in the grid system?
- How do the different wind scenario build outs effect the way hydro is being dispatched?
- How do more accurate wind and solar forecast impact hydro operations?

- What is the value of hydropower as a balancing resource?
- What is the impact of a severely constrained hydro system?
- How will hydro operations change when large amounts of renewables are integrated into the system?
- What is the economic value to the hydropower community by participating in wind integration?
- Lastly, how does renewable generation impact pumped storage hydro operations?

To answer these questions, an in-depth analysis was conducted to compare a series of MAPS simulations, and contrast the simulation data to actual production patterns. Seven of the largest hydropower facilities located along the Colorado River system, including one pumped storage hydro plant were selected and examined covering a variety of capacities, priority functions, and locations. The following chapter is divided into several sections describing the background and constraints imposed on the selected hydropower facilities, methodologies used to assess impact of renewables on hydro operations, and lastly, results to the study objectives will be presented.

3.1 Background of Selected Hydropower Plants

The following section describes the background, non-power regulations and constraints, and operational parameters defining generation flexibility for of each of the selected hydro facilities located on the upper and Lower Colorado River Basin. The ten largest hydropower facilities located within the study footprint are shown in Table 6. Though data was not available for all ten hydropower plants or for every year of the study, 2006 generation data was obtained for hydropower plants highlighted in green. Additionally, three other generation data sets were obtained located at the bottom of the table.

The United States Bureau of Reclamation (Reclamation) manages operation and power generation for all of these hydro power facilities and others located on the Colorado River system. Western Area Power Administration (Western) distributes and markets the power with public and privately owned utility groups based upon bilateral agreements. The power and water customers are governed by over 50 laws, acts, documents, regulatory agencies, and organizations overseeing the river, collectively this is known as the "Law of the River" defining the organizational and legal complexity that governs these hydro facilities along the Colorado River system (Underwood 2005).

3.1.1 Upper Colorado River Basin: Background of Blue Mesa, Morrow Point, Crystal, and Glen Canyon Dam

The Upper Colorado River Basin includes all the entire Colorado River drainage basin that occurs upstream Lee Ferry in Northern Arizona (Lee's Ferry is located several miles downstream of Glen Canyon Dam) and includes the portions of Colorado, New Mexico, Utah and Wyoming. Figure 11 illustrates the Bureau of Reclamation (Reclamation) hydropower facilities located in the state of Colorado within the Upper Colorado River Basin. Three of the four selected hydro facilities are located along the Gunnison River including: Blue Mesa, Morrow Point, and Crystal

Dam. These hydropower plants and their associated reservoirs are collectively referred to as the Aspinall Cascade.

The Aspinall Cascade is located along a 40-mile section of the Gunnison River between the towns of Gunnison and Montrose, Colorado as illustrated in Figure 12. The Aspinall Cascade is a part of the Colorado River Storage Project (CRSP). The 1956 CRSP act authorized construction and development of the water resources of the upper Colorado River basin states by providing for long-term regulatory storage of water to meet the entitlements of the Lower Colorado River Basin states. Monthly and annual release volumes for all major CRSP facilities are established by the Annual Operating Plan based on projected hydrologic conditions. Releases are then adjusted during the year to reflect actual inflow conditions. Hydropower production at

Table 6: Ten largest hydro facilities located in WestConnect Footprint (AZ, CO, NM, NV, WYO)

State	Plant Name	Nameplate Capacity (MW)	Operator
1) AZ	Hoover Dam	2,074	Reclamation
2) AZ	Glen Canyon Dam	1,320	Reclamation
3) AZ	Davis Dam	240	Reclamation
4) CO	Morrow Point Dam	173.2	Reclamation
5) CO	Flatiron Dam	94.5	Reclamation
6) CO	Blue Mesa Dam	86.4	Reclamation
7) WY	Fremont Canyon Dam	66.8	Reclamation
8) WY	Seminoe Dam	51.7	Reclamation
9) CO	Estes Dam	45	Reclamation
10) WY	Alcova Dam	41.4	Reclamation
Additional facilities selected where data was available.			
State	**Plant Name**	**Nameplate Capacity (MW)**	**Operator**
11) CO	Mt. Elbert PSH	200	Reclamation
12) AZ	Parker Dam	120	Reclamation
13) CO	Crystal Dam	32	Reclamation

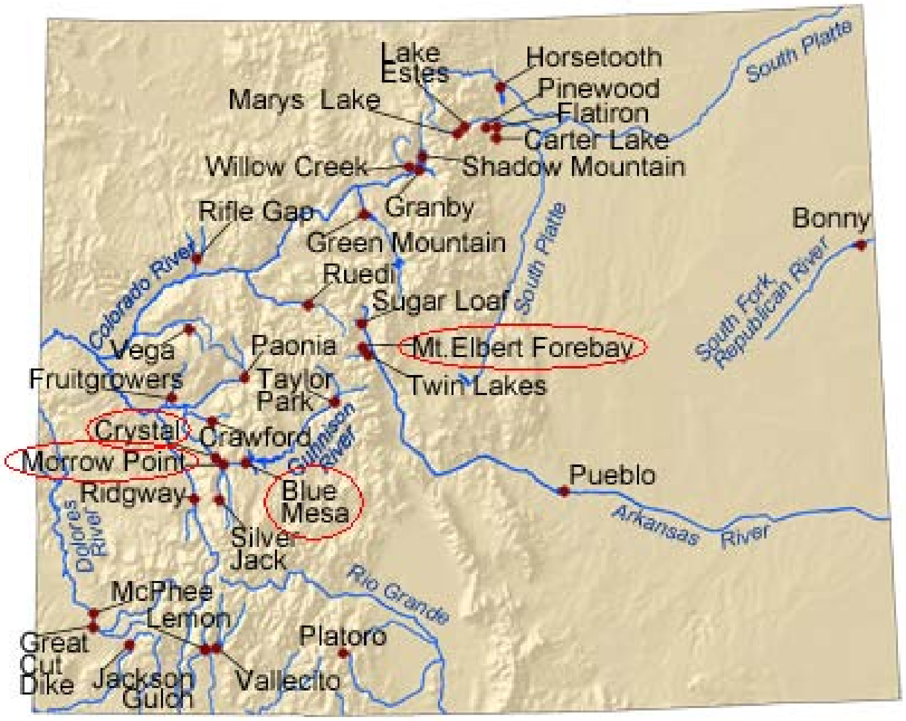

Figure 11: Reclamation hydropower facilities in Colorado located along the Upper Colorado River Basin with selected facilities highlighted in red. (Source: http://www.usbr.gov/projetcs/FacilitiesByState.jsp?StateID=CO)

CRSP facilities is secondary to all other purposes (e.g. flood control, basin storage, fish and wildlife uses, agriculture and municipal uses, and pertinent treaties) described by the Law of the River (Underwood 2005).

The Western Area Power Administration (Western) Management Center markets CRSP power resources as well as the hydroelectric power plants of the Collbran and Rio Grande projects. The energy and capacity from these projects, collectively referred to as the Salt Lake City Area Integrated Projects (SLCA/IP), are marketed to more than 140 utility customers in six western states (Arizona, Colorado, New Mexico, Nevada, Utah, and Wyoming) on both a long-term and short-term firm basis. Electricity produced by SLCA/IP resources additionally serves energy requirements for specific project uses such as irrigation while excess energy production is sold on the spot market (Reclamation 2009).

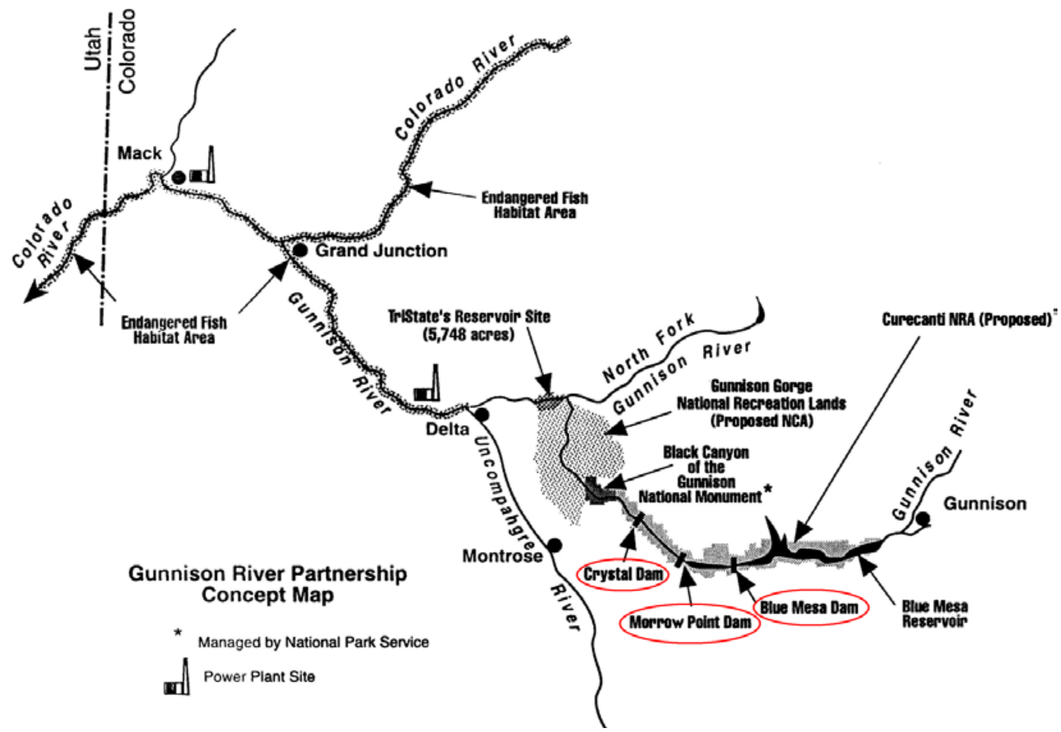

Figure 12: Enhanced view of Gunnison River with Aspinall Cascade highlighted in red. (Source Reclamation 2009)

The Aspinall Cascade is operated as a tightly-coupled multi-purpose system. Its primary purpose is to furnish the long-term regulatory storage need to states in the Upper Colorado River Basin to meet flow obligations at Lees Ferry, Arizona, as defined in the Colorado River Compact. Operations of the Aspinall Cascade consider the following priorities: power generation, projected inflows to its reservoirs, flood control needs for endangered fish and other resources, recreation, hydropower needs and other factors. Hydropower plant output levels in the cascade can be ramped up or down from zero production levels to maximum capability in a matter of minutes without adverse effects on the power equipment. This attribute makes it well suited to provide the interconnected grid with various ancillary services such as spinning and non-spinning reserves, regulation, and voltage support (Reclamation 2009). In Table 7 a summary of the Aspinall Cascade characteristics is presented.

Glen Canyon Dam is the last CRSP facility on the Upper Colorado River Basin before entering into the lower basin as shown in Figure 13. Located upstream of Grand Canyon National Park, stringent environmental regulations have been established regarding the release of flow through the dam. From 1963 through 1991, Glen Canyon Dam was operated primarily to produce power during on-peaking hours while meeting minimum flows during the remaining hours. These operations resulted in 7-12 foot fluctuations in river elevation below the dam. These historical operations have been shown to affect aquatic resources, riparian resources and the quality of recreation (Harpman 1999).

Table 7: Physical and power characteristics of Aspinall Cascade Units.[6]

Dam, Reservoir and Power Plant Characteristics	Blue Mesa	Morrow Point	Crystal [7]
Location	30 miles below Gunnison, CO	12 miles downstream of Blue Mesa	6 miles downstream of Morrow Pt.
Dam Type	Earth Filled Embankment	Double-Curvature Thin-Arch	Double-Curvature Thin-Arch
Primary Purpose	Water Storage	Power Production	Flow Regulation
Dam Height (ft)	502.0	468.0	323.0
Spillway Crest Elevation (ft)	7,487.9	7,123.0	6,756.0
Crest Elevation (ft)	7,528.0	7,165.0	6,772.0
Active Reservoir Capacity (AF)	748,500	42,120	12,891
Surface Area (acres)	9,180	817	301
Power Plant In Service Year	1967	1970	1978
Total Installed Capacity (MW)	86.4	173.3	32.0
Plant Factor (%)	31.5	19.4	61.5
Number of Turbines	2	2	1
Typical Production Mode	Peaking	Peaking	Base Load
Spinning Reserve	Yes	Yes	Yes
Non-Spinning Reserve	Yes	Yes	Yes
Replacement Reserve	Yes	Yes	Yes
Regulation/Load Following	Yes	Yes	Yes
Black Start	Yes	Yes	Yes
Voltage Support	Yes	Yes	Yes

[6] Information on these hydro facilities can be found on the Bureau of Reclamation website at: http://www.usbr.gov/projects/FacilitiesByState.jsp?StateID=CO.

[7] Note: Crystal Dam is physically capable of providing ancillary services but institutional and environmental constraints preclude Crystal power plant from operating in a mode such that these services can be sold on the market.

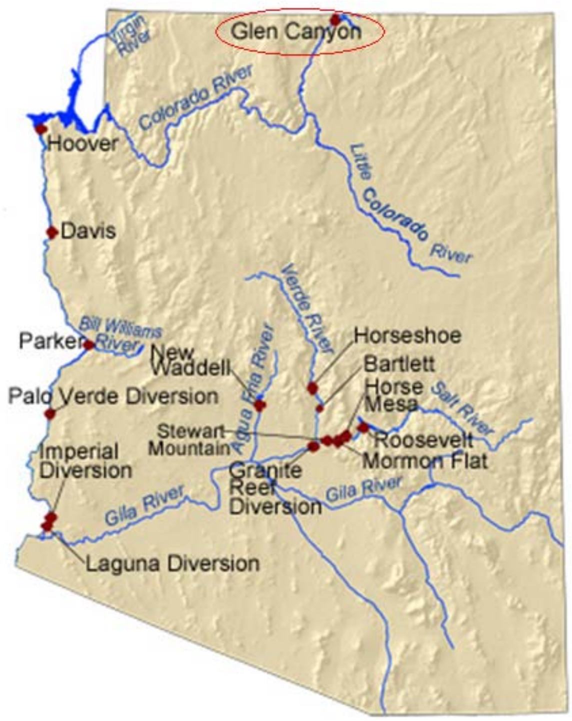

Figure 13: Glen Canyon Dam, the last hydropower facility located along the Upper Colorado River Basin. (Source: http://www.usbr.gov/projetcs/FacilitiesByState.jsp?StateID=AZ)

The Operation of the Glen Canyon Dam Environmental Impact Statement (GCDEIS) was initiated in 1989 to minimize impacts on the downstream environmental, cultural resources, and Native American interests. Moreover, in 1996, the Secretary of the Interior issued a record of decision on future operations of Glen Canyon Dam (based predominantly on the Endangered Species Act) that the facility will be operated under the Modified Low Fluctuating Flow (MLFF) (Reclamation 1994). The MLFF has set restrictions on maximum and minimum flow rates, ramp rates, and the daily change in flow as shown in
Table 8.

Table 8: Historical and modified flow operating criteria at Glen Canyon Dam. (Source: Harpman 1999)

	Historical Operations	MLFF Operations
Minimum Release (CFS)	1,000 Labor Day-Easter 3,000 Easter-Labor Day	*8,000* between 7 A.M.-7P.M. *5,000* between 7P.M.-7A.M.
Maximum Release (CFS)	31,500	25,000
Allowable Flow Fluctuations (CSF/24 hrs)	Unlimited	*5,000* – monthly release volume < 6000,000 acre-feet *6,000* – for monthly release volumes of > 600,000-800,000 acre-feet *8,000* – for monthly release volumes > 800,000 acre-feet.
Up-ramp Rate (CSF/hr)	Unlimited	*4,000*
Down-ramp Rate (CSF/hr)	Unlimited	*1,500*

This MLFF have resulted in reducing fluctuations in the river elevation to range from 1-3 feet, protecting downstream resources. These flow modifications have protected downstream environment resources, but at the cost of the dam's flexibility. Table 9 lists the physical and power characteristics of Glen Canyon Dam.

Table 9: Physical and power characteristics of Glen Canyon Dam located in along the Upper Colorado River System.

Power Plant Characteristics	Glen Canyon
Location	15 miles upstream of Lees Ferry
Dam Type	Concrete arch
Primary Purpose	Water Delivery
Dam Height (ft)	710
Spillway Crest Elevation (ft)	3,700
Crest Elevation (ft)	3,715
Active Reservoir Capacity (AF)	20,876,000
Surface Area (acres)	161,390
Power Plant In Service Year	1964
Total Installed Capacity (MW)	1,320
Plant Factor (%)	30
Number of Turbines	8
Typical Production Mode	Intermediate
Spinning Reserve	Yes
Non-Spinning Reserve	Yes
Replacement Reserve	Yes
Regulation/Load Following	Yes
Black Start	Yes
Voltage Support	Yes

3.1.2 Mount Elbert Pumped Storage Hydro

Mt. Elbert Pumped Storage Hydroelectric Project is located outside of Twin Lakes, CO, as seen in Figure 14. The plant was completed by the Reclamation as part of the Fryingpan-Arkansas Project under Public Law 87-590 (77 Stat. 393) in 1962 to provide peaking power. Twin Lakes serves as the afterbay (where the water flows into from the power plant, or is drawn from for pumping) but water is additionally supplemented to the forebay (the body of water at the top of the system that feeds water to the generators, and receives water pumped from the afterbay) from Turquoise Lake (not shown on map but is located approximately 11 miles north of twin lakes). The Fryingpan-Arkansas Project is a multi-purpose transmountain diversion development in Central Colorado enabling surplus water from the Fryingpan River and Roaring Fork River to be transferred from the western slope of the Rocky Mountains to the Arkansas River on the eastern slope.[8]

[8] Information on the Mount Elbert PSH facility can be found on the Bureau of Reclamation website at: http://www.usbr.gov/projects/Powerplant.jsp?fac_Name=Mount%20Elbert%20Powerplant.

Figure 14: Map of Mount Elbert Forebay and Twins Lakes Reservoir located in Central Colorado (source: http://grail.nau.edu/flag_rec/).

Mt. Elbert is interconnected with the Public Service Company of Colorado (PSCo) enabling Fryingpan-Arkansas Project power to be marketed to the various customers through Western Area Power Administration. Mt. Elbert PSH is used to follow daily peak power loads. This load following is accomplished by pumping water to the Mt. Elbert forebay, an 11,143 acre-foot regulating pool during off-peak hours using surplus or low cost energy.[9] Water is then returned to Twin Lakes through the turbines during peak hours. Table 10 below lists a summary of Mt. Elbert PSH characteristics.

[9] It is also noted the Mt. Elbert PSH system is not a closed water loop system in that the forebay is supplemented with water delivered from Turquoise Lake.

Table 10: Physical and power characteristics of Mt. Elbert PSH.

Dam, Reservoir and Power Plant Characteristics	Mount Elbert
Location	12 miles Southwest of Leadville, CO
Dam Type	Above Ground Pumped Storage
Primary Purpose	Peaking Power
Rated Head (ft)	448
Spillway Crest Elevation (ft)	9,590
Crest Elevation (ft)	9,652
Power Plant In Service Year	1981
Total Installed Capacity (MW)	200
Plant Factor (%)	18.1
Number of Turbines	2
Typical Production Mode	Peaking
Spinning Reserve	Yes
Non-Spinning Reserve	Yes
Replacement Reserve	Yes
Regulation/Load Following	Yes
Black Start	Yes
Voltage Support	Yes

3.1.3 Lower Colorado River Basin: Background of Hoover, Davis, and Parker Dam

The Lower Colorado River Basin begins downstream several miles from Glen Canyon Dam at the point of Lee Ferry and extends includes the river's drainage basin in Arizona, Nevada, California and Mexico. Figure 15 illustrates Reclamation hydropower facilities located in the state of Arizona and in the Lower Colorado River Basin with the three selected hydro facilities highlighted in red.

Figure 15: Reclamation hydropower facilities in Arizona located along the Lower Colorado River Basin with selected facilities highlighted in red. (Source: http://www.usbr.gov/projetcs/FacilitiesByState.jsp?StateID=AZ)

With regards to Hoover Dam, its top priority function, beyond flood control, is water delivery to downstream customers (such as irrigation districts and municipalities). Accordingly, the water orders are what primarily govern the magnitude of flow releases from Hoover, and consequently what is available for generation. Within the constraints of downstream water demands, the Hoover power customers have negotiated with Reclamation and Western Area Power Administration a cooperative agreement that assures Hoover's annual revenue is sufficient to operate, maintain, repair, and repay outstanding debt in return for each to receive a proportionate share of the hydro generation. Consequently and within these constraints, Hoover Dam is still operated as a very flexible generation resource, providing important ancillary services to the southwest. Water deliveries from Hoover are defined on a monthly basis, and these deliveries in combination with the height of the water behind the dam define the maximum generation capacity available and energy production available to the Hoover power customers each month. These customers are free to use the energy and power at their convenience. They either operate electrical control areas and use the Hoover power to their best advantage, or they contract with another organization that will serve their load and utilize the Hoover power on their behalf. In the later case, the Hoover power is typically used predominately for its flexibility and ancillary services.

The primary purpose of Davis Dam is to re-regulate Hoover Dam releases to meet downstream needs. Following Davis Dam, Parker Dam provides reservoir storage for water to be pumped into the Colorado River and Central Arizona Project Aqueducts. The Colorado River Aqueduct delivers water from Lake Havasu behind Parker Dam to the Los Angeles metropolitan area.

Hoover, Davis, and Parker Dams are operated integrally to control floods along the river and distribute hydroelectric power through Western Area Power Administration.[10] Table 11 below describes the characteristics of the selected hydro facilities located in Arizona.

As seen from the general operating characteristics and parameters that define the hydropower plant flexibility of the above selected facilities, higher priority functions of the dam will almost always supersede power generation. With respect to hydro in the United States, the most common of these priority functions can be organized in an order of priority in the following manner (though varying from country, region, and river system):

- Flood Control
- Environmental, Wildlife, Fishery Considerations
- Agriculture Demands
- Navigation Purposes
- Recreational Purposes
- Power Generation

In many cases, environmental considerations were not a top priority at the time of planning and construction of many of these facilities, but later the impacts on wildlife from the various hydro impoundments or operations became understood. The prioritization of the functions occurs under specific hydrological conditions, and these priorities define the capacity and energy available at each facility.

[10] More information on these hydro facilities can be found on the Bureau of Reclamation website at: http://www.usbr.gov/projects/FacilitiesByState.jsp?StateID=AZ.

Table 11: Physical and power characteristics of selected facilities located in along the Lower Colorado River System.

Power Plant Characteristics	Hoover	Davis	Parker
Location	Arizona-Nevada state line	67 miles downstream of Hoover	12 miles northeast of Parker, AZ
Dam Type	Concrete thick-arch	Zoned earthfill	Concrete arch
Primary Purpose	Water Delivery	Re-regulation of Hoover	Water Storage
Dam Height (ft)	726.4	200	320
Spillway Crest Elevation (ft)	1,205.4	597	NA
Crest Elevation (ft)	1,232	655	455
Active Reservoir Capacity (AF)	17,353,000	NA	NA
Surface Area (acres)	163,000	28,160	20,400
Power Plant In Service Year	1936	1951	1942
Total Installed Capacity (MW)	2,078	255	120
Plant Factor (%)	21	51.5	43.3
Number of Turbines	19	5	4
Typical Production Mode	Peaking	Base Load	Base Load
Spinning Reserve	Yes	Yes	Yes
Non-Spinning Reserve	Yes	Yes	Yes
Replacement Reserve	Yes	Yes	Yes
Regulation/Load Following	Yes	Yes	No
Black Start	Yes	Yes	No
Voltage Support	Yes	Yes	Yes

4.0 Methodologies to Assess Modeling Accuracy and Impact of Renewables on Hydropower Operation

In the first approach of this study, individual facility operations were investigated and compared to the MAPS simulated data for the no-wind scenario of the MAPS program. It is noted that in the no-wind scenario, all renewables (including existing renewables) were taken out of the system and that historical loads from 2004-2006 were scaled up to an expected level in 2017. Because current renewable penetration levels are nominal as compared to current thermal generation resources, the no-wind scenario becomes a reasonable measure to approximate the accuracy of the MAPS program in dispatching hydro generation. Using statistical measures over annual, seasonal, daily, and hourly timeframes, the modeling accuracy of individual hydro facilities in the MAPS program could be deduced. Figure 16 illustrates this comparison.

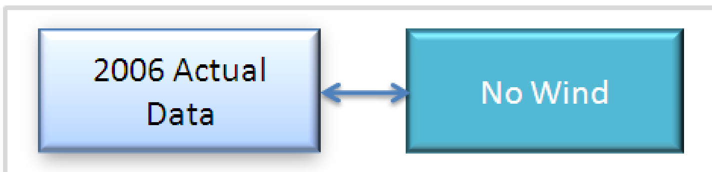

Figure 16: Comparison between 2006 actual hydro generation and MAPS no-wind hydro generation data.

One question that will not be answered in this study relates to cost allocation. For instance, the introduction of wind and solar renewable generation will result in hydropower being utilized more for its flexibility to balance the variability in generation, thus it is assumed there will be an increased maintenance and operations costs at these plants. There was no attempt made to allocate these costs within this study or to estimate the impact on the hydropower customers.

In the following sections of this report, results show that the ten-year historical averaged hydro energy inputs in MAPS often over predicts the actual hydro generation seen in 2006 due to higher monthly energy limits and more flexible capacities (higher water years). To answer the question of how well MAPS models the hydro system and the impact of renewables on historical hydro operations, a sensitivity analysis was conducted. Using 2006 historical capacity and monthly energy values as inputs into MAPS (representing current drought conditions), the true accuracy of the MAPS model could be revealed. To determine the historical monthly hydro capacity limits (maximum and minimum generation points), monthly averages of the daily limits were taken. Monthly averages had to be taken rather than monthly maximums and minimums due to other factors that could not be accounted for in the MAPS program such as varying water schedules and scheduled unit outages, both of which affect the range and variability in capacity limits throughout any given month. Figure 17 illustrates the comparison between 2006 actual generation and MAPS historical-hydro no-wind generation data.

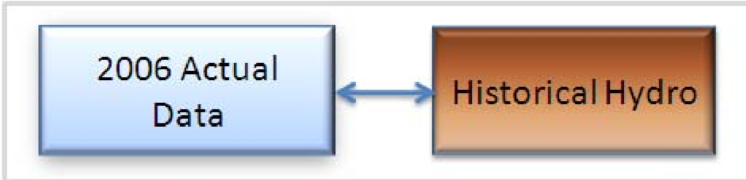

Figure 17: Comparison between 2006 actual hydro generation and MAPS Historical Hydro generation data.

The next step was to determine the impact of renewables on selected hydro facility operations (assuming water years of the study had more available energy then had been historically seen, and with little or no hydro generation restrictions). As will be shown, the difference in aggregated hydro operations between penetration levels and scenarios are relatively small, thus the L20R (i.e. local-priority scenario with 20% renewable penetration levels using a professional forecast) was chosen as a fair representation of renewable impact on hydro operations. Figure 18 shows this comparison between the two simulated hydro datasets.

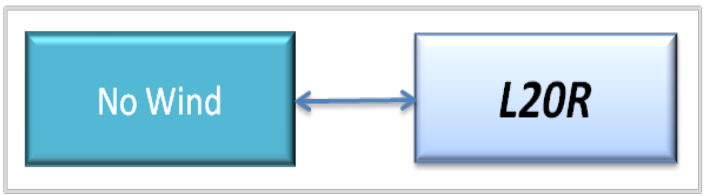

Figure 18: Comparisons to be made between the L20R case, and the no-wind hydro data.

Lastly, statistical measures are used to investigate the differences in the way hydro is dispatched and impact on operations between each scenario. The organization of these comparisons is shown in Figure 19.

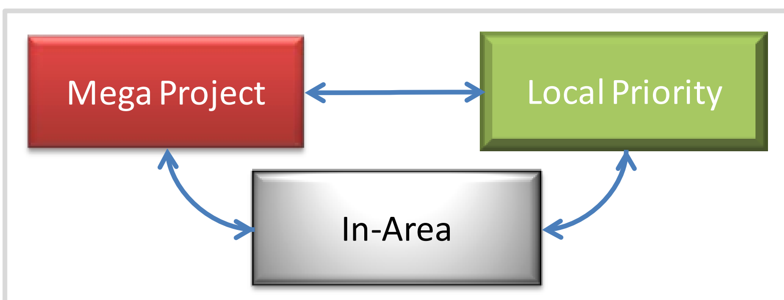

Figure 19: Comparisons to be made between hydro operations and dispatch of the three main scenarios.

4.1 Methodologies to Assess Economic Value of Hydropower Resources

To assess the economic value of hydro in the WWSIS study, several methods and sensitivity analysis were simulated using the MAPS program. MAPS, being a production cost model, is well suited to address economic issues related to system operations. Two key economic parameters were considered when analyzing the results; system operating costs and revenue value. Operating costs are categorized as fuel costs, variable operation and maintenance, start-up costs, and emission payments, these only apply to thermal based generation sources thus renewables and hydro generation sources were assumed to have no operating costs (e.g. free fuel). Operating costs can be calculated as the fuel costs multiplied by the unit heat rate with addition to any variable operations and maintenance. It is important to note all generation dispatches are made on a least-marginal-cost basis. In the MAPS simulation, the hourly marginal cost of energy or spot price is used. In a deregulated market, this is the price paid for energy each hour, but this is also useful in a regulated market as it is an hourly measure of the value of the energy. When transmission constraints are present, these values will vary across the system for any given hour, but they can be weighted by the hourly load in a given area to produce a system spot price. These spot prices were calculated chronologically for each hour of each year and for each case. Thus, revenue value is calculated as the product of the generator output each hour and the corresponding LMP price. It is also important to note, the operating costs and revenue value are two different ways of cost accounting, but are separate of each other and cannot be directly compared against one another for any given case.

In the first comparison, economic parameters are compared between the historical-hydro cases (accounting for drought conditions) and base cases (higher operating energies and more flexible capacity limits of the ten-year averaged values) at each equal counterpart (e.g. L20R was compared to the L20R-HH with "-HH" denoting historical-hydro runs). This comparison is illustrated in Figure 20.

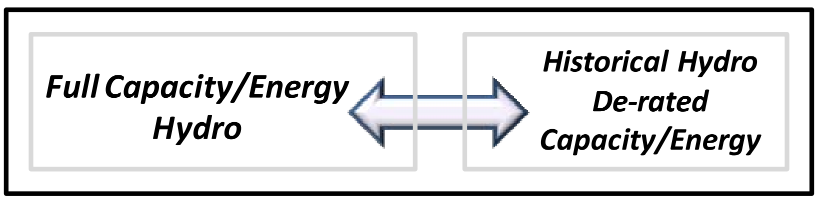

Figure 20: Economic comparison between base case and historical hydro scenarios.

To address the question of the value of hydropower's balancing capabilities when compared to other generation resources in providing the increased ancillary services required by renewable energy, hydro resources in MAPS were modeled as flat block monthly energy outputs (denoted as flat hydro or "-Hf"), thus removing all inherent flexibility and reserve capabilities of the hydro system in the MAPS model. In modeling the flat block hydro, the available generation capacities were reduced to an average value for each month such that the hydro system had to run at a fairly constant level for every hour during a given month in order to generate the required monthly energy. Again, the economic parameters were compared against their equal counterpart (e.g. I20R is compared against I20R-Hf). Figure 21 illustrates this economic comparison. Additionally, the findings from this comparison can also be interpreted as those similar to what would be found in hydro system in which higher priority functions and institutional restrictions severely restrict the hydro flexibility.

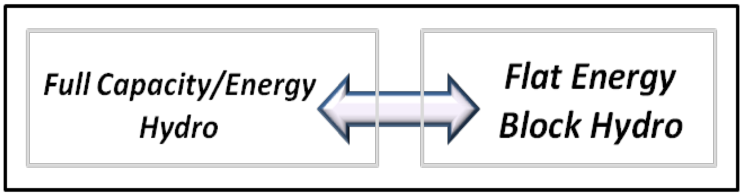

Figure 21: Economic comparison between base case and "flat hydro" scenarios.

Up to this point, all hydro analysis has been conducted on hydro that is scheduled and dispatched to the net-load or load-net-wind. To answer the question of the economic value to the hydropower community in participating in wind integration, hydro resources were scheduled to the load (denoted as "-H") before renewable generation could be accounted for, rather than after it. In this way, economic parameters could be compared to their counter parts (e.g. L20R is compared to L20R-H) to determine the value when hydro accounts for wind and solar generation. Figure 22 illustrates this comparison.

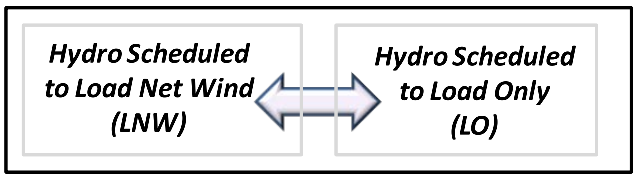

Figure 22: Economic comparison between the base cases (LNW) and hydro scheduled to the load before renewable generation could be accounted for.

5.0 Statistical Analysis of Hydro Generation

5.1 MAPS Modeling Accuracy – No-Wind versus actual Hydro Generation

In the first evaluation, aggregated actual hydropower data from the seven selected facilities was compared to that of the no-wind scenario in MAPS for 2006. The generation duration curve for each scenario at different penetration levels is illustrated in Figure 23. The fact that an eleven-year historical average (1996 – 2006) of the hydropower resources was used as energy input for hydro generation modeling is evident in this plot, as a significantly larger amount of generation occurred in the simulation than in the 2006 historical data. The actual 2006 aggregate generation from the selected facilities was 9.58 MWh, while the generation in the no-wind scenario was found to be 11.5 MWh, an increase of 20% over actual production. A closer look at this plot indicates the in-area scenario (green lines) experiences the greatest shift in generation, though modest, while the mega project (red lines) resembled the no-wind scenario the closest.

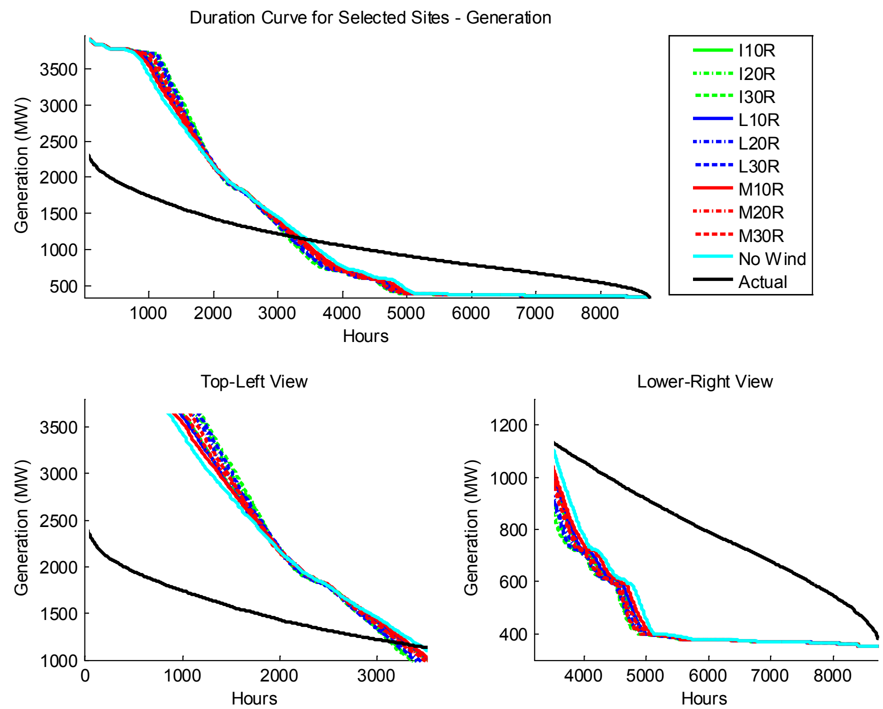

Figure 23: Duration curve showing aggregated hydropower generation from seven of the selected facilities (shown as black line) and MAPS scenario data (colored lines) in the study footprint.

5.2 MAPS no-wind versus actual Hydro Generation – Glen Canyon Dam

Focusing on one of the largest selected hydropower plants in the footprint, results from Glen Canyon Dam will be shown in further detail. It is noted that all of the hydro facilities in the Arizona region exhibited similar patterns to those seen for Glen Canyon Dam, that is, MAPS tends to over predict actual generation. In the upper Colorado region, Blue Mesa Dam and Morrow Point Dam operations were found to be the complete opposite, where actual generation tended to show more flexibility than seen in the MAPS simulation. Further investigation revealed Morrow Point and Blue Mesa Dam have recently changed their hydro operations such that the capacity limits and monthly energies allow more use of the hydro flexibility than seen in the MAPS simulation. Comparisons for the MAPS no-wind data versus actual hydro generation are shown for these and all other facilities in APPENDIX A.

Glen Canyon's limits on maximum and minimum generation/flow along with limits on up and down ramps during certain periods of the day are no more evident as in the comparison between actual and no-wind data sets illustrated in Figure 24. Looking at the actual data set, the difference in generation between the shoulder and peak production months can be observed. Higher generation occurs during the summer months to help meet cooling load demands in the region, and to move the water downstream as required by the Law of the River. On the other hand, higher generation/release occurs during the winter months to help fill water reserves downstream (i.e. Hoovers reserves) where more generation/release occurs in the spring to peak summer months, subsiding in the fall to winter months.

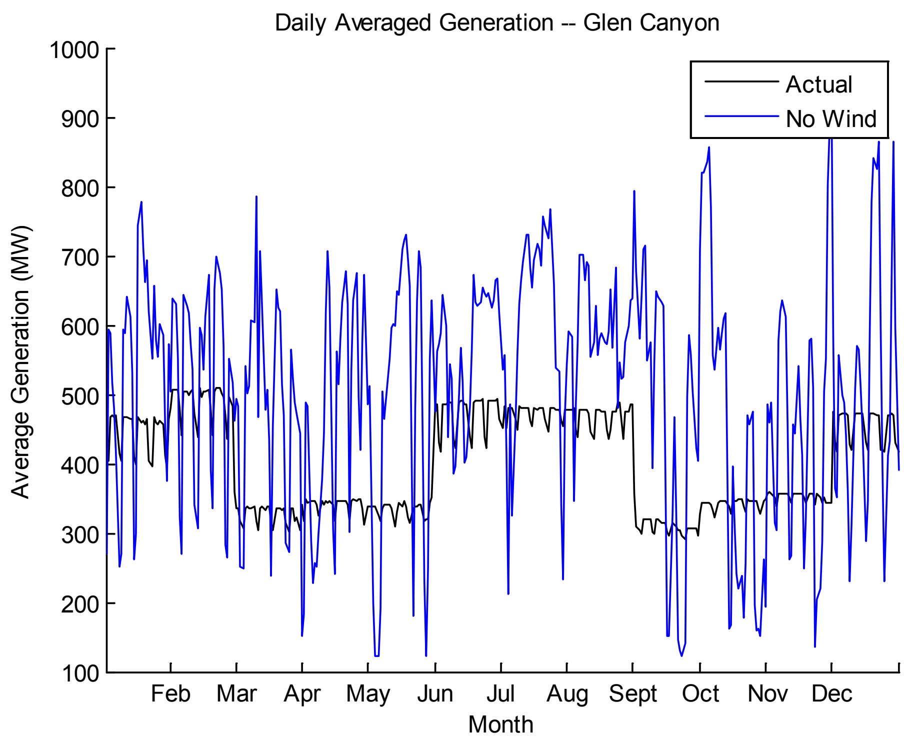

Figure 24: actual averaged daily generation at Glen Canyon Dam and as simulated in MAPS in the no-wind scenario.

To illustrate the averaged daily generation profile, monthly averaged diurnal distributions were created as shown in Figure 25. The diurnal generation patterns for the no-wind scenario generally resemble the actual generation profile throughout the months. However the magnitude of generation scales are different and the pattern from MAPS no-wind simulation shifts the majority of generation to later in the afternoon while the actual data remains fairly constant throughout the day (with exception of winter months).

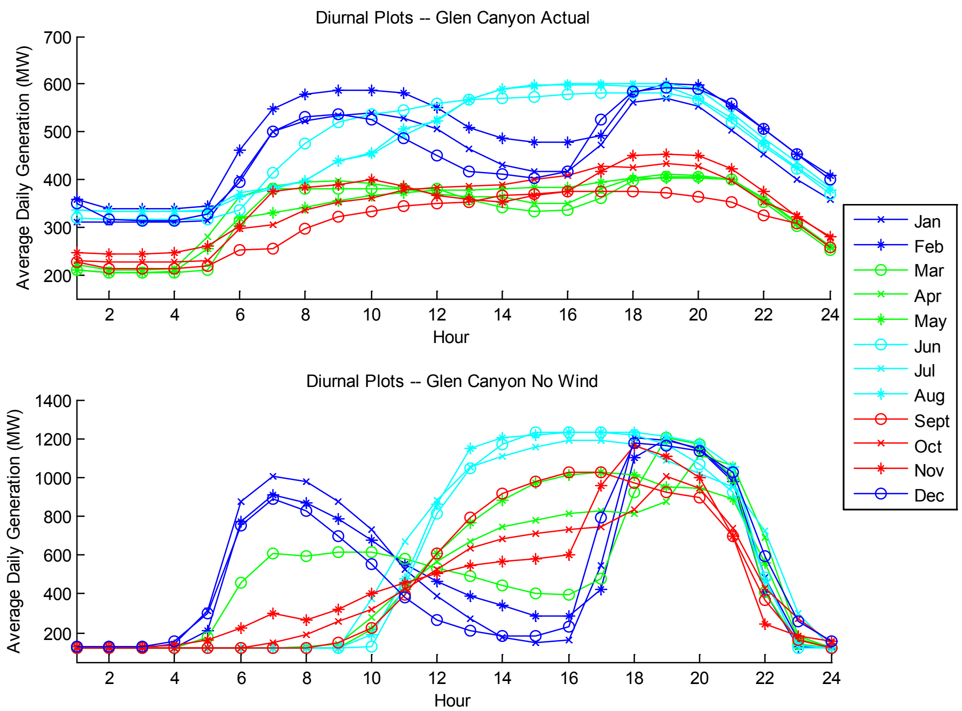

Figure 25: Monthly diurnal distributions of Glen Canyon Dam for actual data and MAPS no-wind Scenario.[11]

To examine the hour-to-hour changes in generation at Glen Canyon Dam for the actual and MAPS no-wind scenario, histograms of hourly changes in generation are illustrated in Figure 26 (note that the ordinate is scaled down to 5% allowing for the tail-ends of the histogram to be examined). In these plots, "Annual" refers to all hours of the year, "HLH" refers to high-load-hours defined as the time period between 6 am to 10 pm and "LHH" refers to low-load-hours defined as the time period between 10 pm to 6 am. It is apparent that the MAPS no-wind simulation results in more hours of little change in generation (due to peak shaving) and larger changes in generation, especially during HLH at the tail-ends, often up to nameplate capacity.

[11] Note scale shift between graphs.

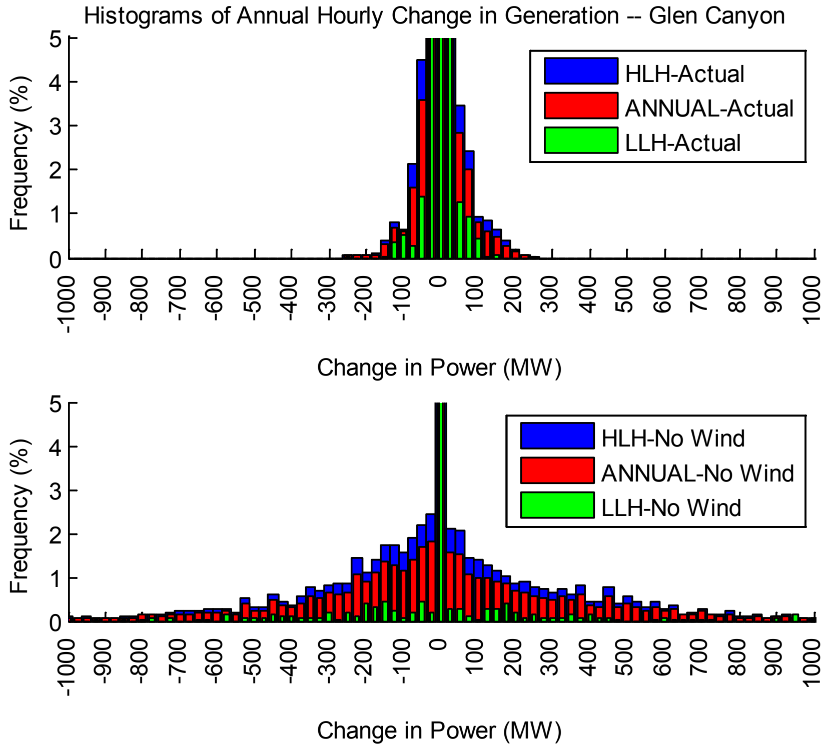

Figure 26: Histograms of hourly changes in generation for actual and no-wind at Glen Canyon Dam.

The hourly change in generation can also be viewed on a single graph representing the percent change at each power level. The percent change in hourly generation can be defined as:

(1)

Figure 27 illustrates the percent change in hourly generation where positive values indicate an increase in hourly change in generation over the actual dataset. Note, the highlighted abscissa areas in yellow indicate 100% positive change in hourly generation (due to generation limits imposed at Glen Canyon). As seen from the plot, MAPS allows more hourly changes in generation beyond the 100 MW mark, especially during HLH.

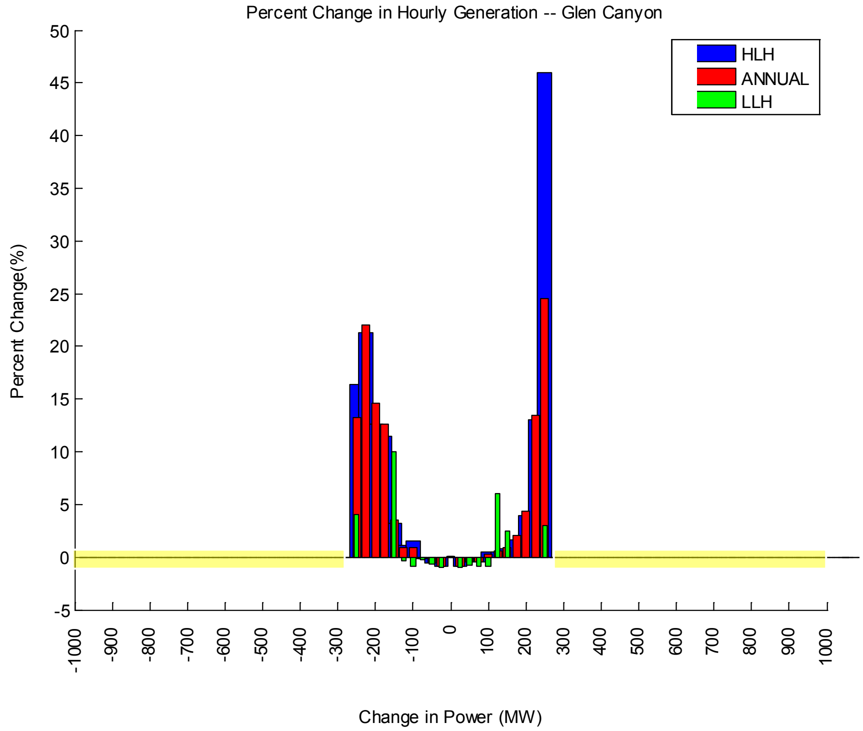

Figure 27: Percent change in hourly geneation between actual and MAPS no-wind generation.

Table 12 shows some statistics of the hourly changes in generation for the actual data and the no-wind data sets. By taking the average of the absolute value in hourly changes, the real magnitude of hourly changes in generation is exposed. Interesting, while the hourly changes during the LLH change modestly between the data sets, the difference in changes during the HLH is much more significant.

Table 12: Statistics for hourly changes in generation at Glen Canyon Dam for the actual and no-wind data sets.

Timeframe	Hourly Changes in Generation	Average (MW)	Standard Deviation (MW)	Average of the Absolute Value (MW)
Annual	actual	1.06E-2	35.9	18.5
	no-wind	8.57E-5	237	108
HLH	actual	1.49E-2	40.6	22.8
	no-wind	1.21E-4	271	142
LLH	actual	-1.69E-2	20.7	7.98
	no-wind	0.153	116	24.7

5.3 Drought and Low Water Years Considerations on Hydro Resources

As seen from the previous section, the use of an averaged, higher water year's database has resulted in MAPS simulation that utilizes more hydro capacity and energy than historically seen in 2006. Due to the occurrence of recent drought years in the southwest region of the United States, the water elevations behind many larger reservoirs have dramatically decreased.[12] The available capacity for power production at a hydro power plant is directly related to the height of the water behind the dam and total release or flow rate as shown below:

$$P = \eta \gamma Q h \qquad (2)$$

Where P is the power, η is the efficiency of the hydro turbine, γ is the specific weight of the water, Q is the flow rate of the water, and h is the height of the water level above the hydro turbine. Figure 28 illustrates the available generation capacity of Glen Canyon Dam as a function of water release and water elevation (shown in feet above sea level). As can be seen, the available generation capacity varies significantly with elevation of the water behind the dam (e.g. a drop in water elevation of only 100 feet can reduce capacity output by over 300 MW, double this and the overall generation capacity is reduced by over half).

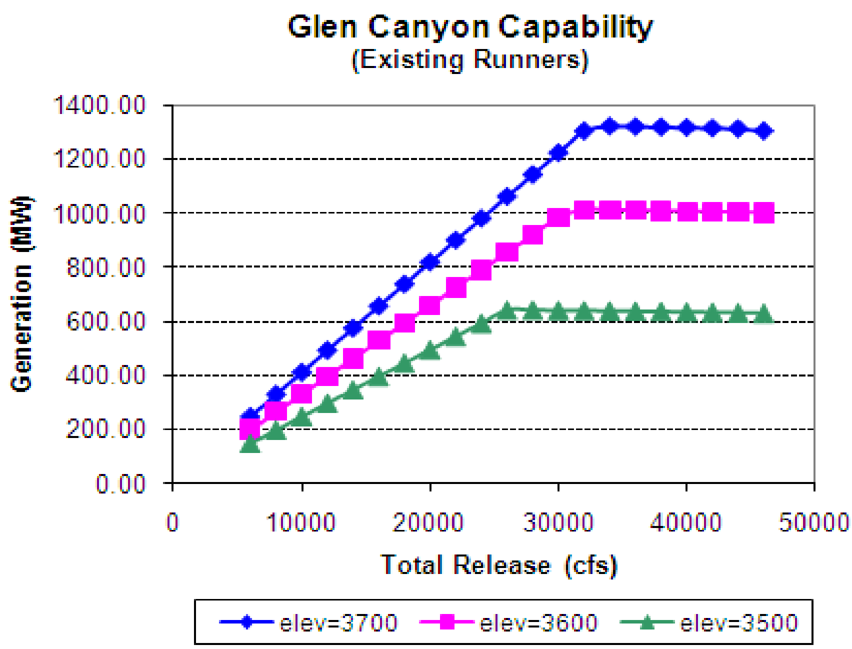

Figure 28: Glen Canyon available generation capacity as a function of water elevation and release. (Source: D. Harpman, Reclamation)

Figure 29 shows the historical water levels (dark blue line) at Lake Powell accompanied by Glen Canyon's available peak demand generation (purple *X* marks) for that year.[13] As shown, historical water elevations impounded by Glen Canyon Dam have significantly dropped from a full reservoir (pink line) in the mid-to-late nineties to just over half of the required minimum power pool (red line) in recent years. Accordingly, the available peak demand capacity has dropped by nearly 25%.

[12] Periods of drought can be considered a common occurrence in the southwest with historical records indicating this.

[13] Available peak demand hydro generation is available from FERC 714 form, the annual electric balancing authority area and planning area report.

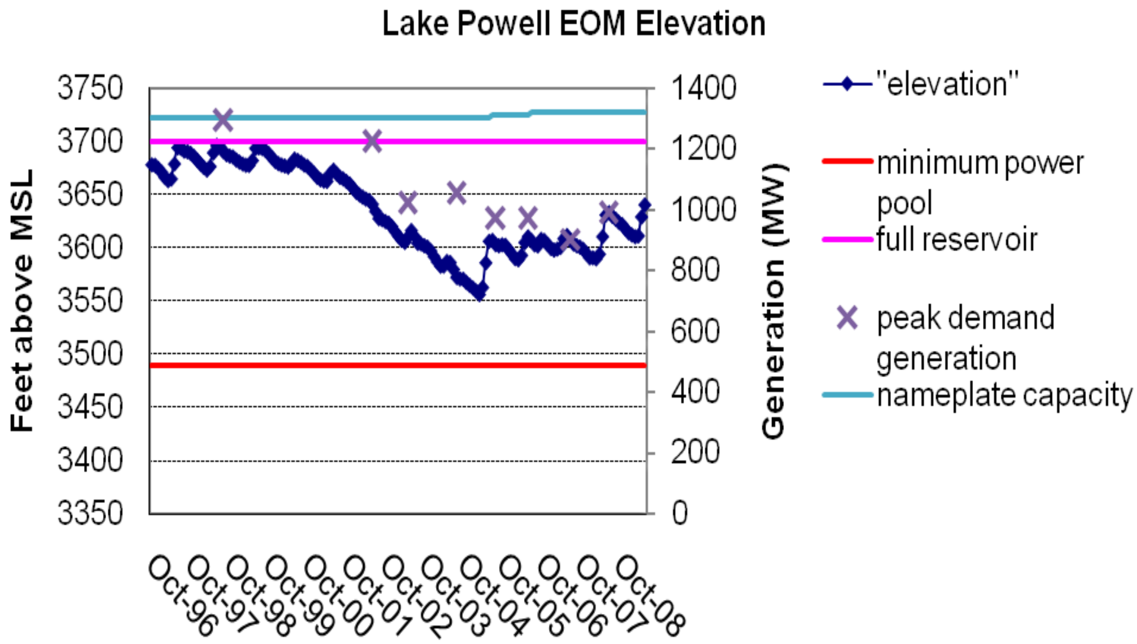

Figure 29: Historical generation capability and end-of-month (EOM) water elevations accompanied by Glen Canyon's annual peak demand generation. (Source: D. Harpman, Reclamation)

Similarly, the water elevation at many of the largest reservoirs located along the Colorado River system have decreased due to the recent extended drought, resulting in decreased available capacity. Hoover Dam's annual available capacity is shown in Figure 30 below demonstrating that the annual peak demand (green line) has steadily decreased to nearly 80% of the nameplate capacity in recent years.

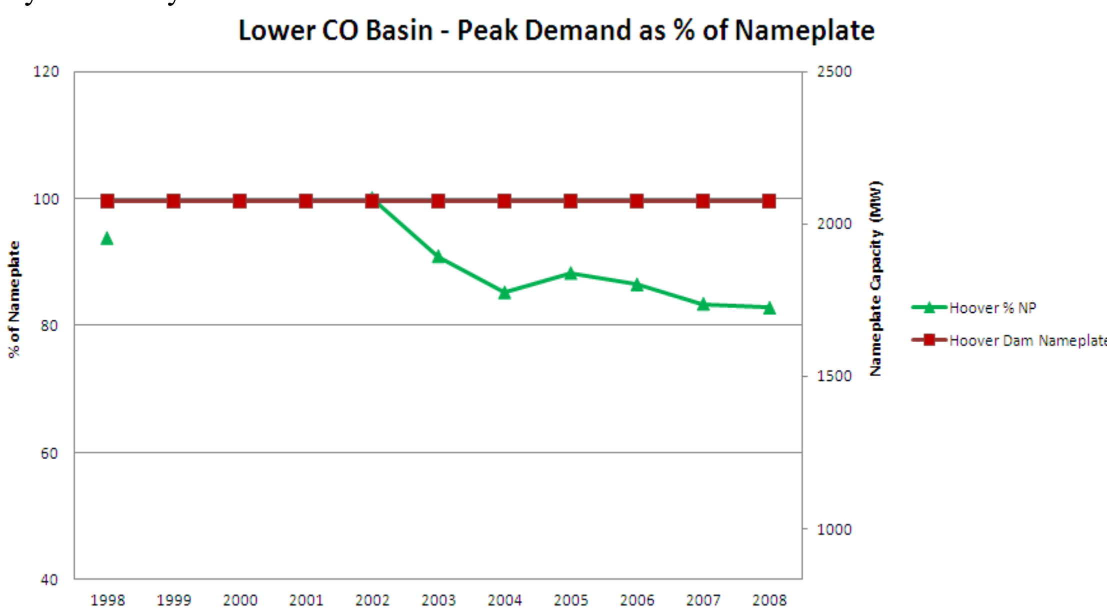

Figure 30: Hoover Dam's annual available hydro generation at peak load demand as a percentage of nameplate capacity.

Conversely, not every hydropower facility is affected by drought conditions like these seen located within the study footprint. Such as the case in the Pacific Northwest of the United States where annual water shed conditions remain fairly constant from year to year. However, due to other factors such as environmental regulations and irrigation needs, available capacity at peak demand has declined throughout the years in some instances. As an example of the decreased available capacity at peak demand of a large hydropower facility located outside of the study footprint, Grand Coulee Dam was selected and is illustrated in Figure 31.[14]

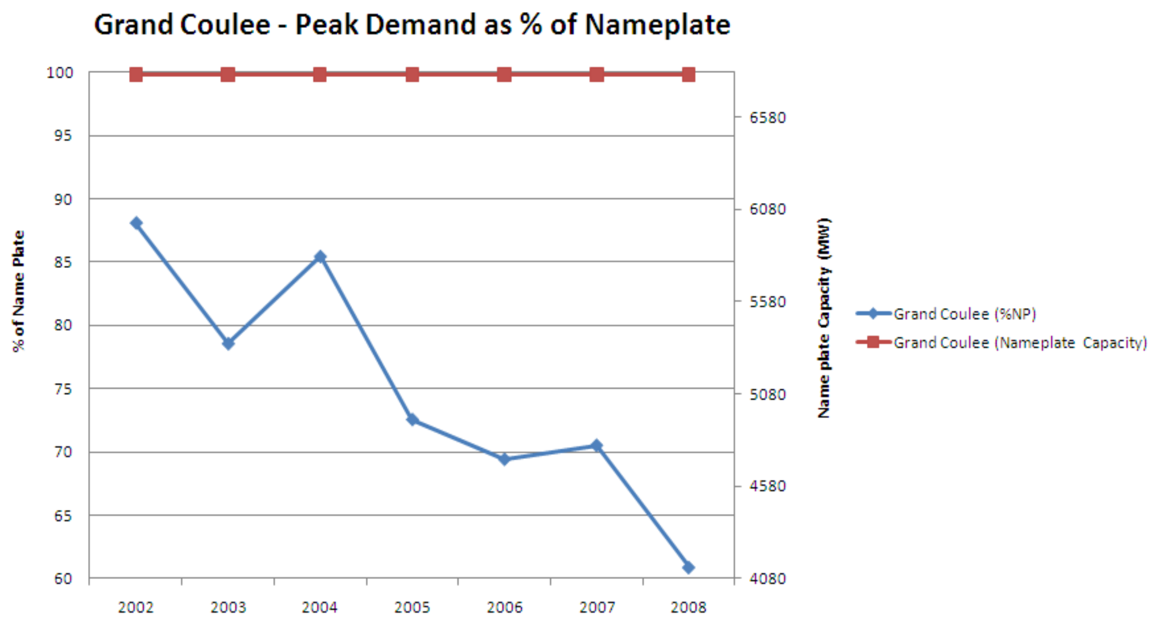

Figure 31: Grand Coulee Dam's annual available hydro generation at peak load demand as a percentage of nameplate capacity.

As shown in the illustration, the steady decline in available capacity can be attributed to several higher priority factors including strict environmental regulations restricting limits on discharge and generation during certain periods of the year (e.g. spawning periods to protect salmon populations). Figure 32 illustrates Grand Coulee's historical monthly averaged reservoir height, discharge, load and hydro energy production normalized to their historical mean value. In this figure, it can be seen that the annual peak demand that occurs during the winter months coincides with heavily restricted flow periods, resulting in a reduced available capacity to meet the load.

[14] Grand Coulee Dam with a nameplate capacity of 6,809 MW is located on the Columbia River system in the state of Washington. Operated by Reclamation, power is distributed by the Bonneville Power Administration (BPA).

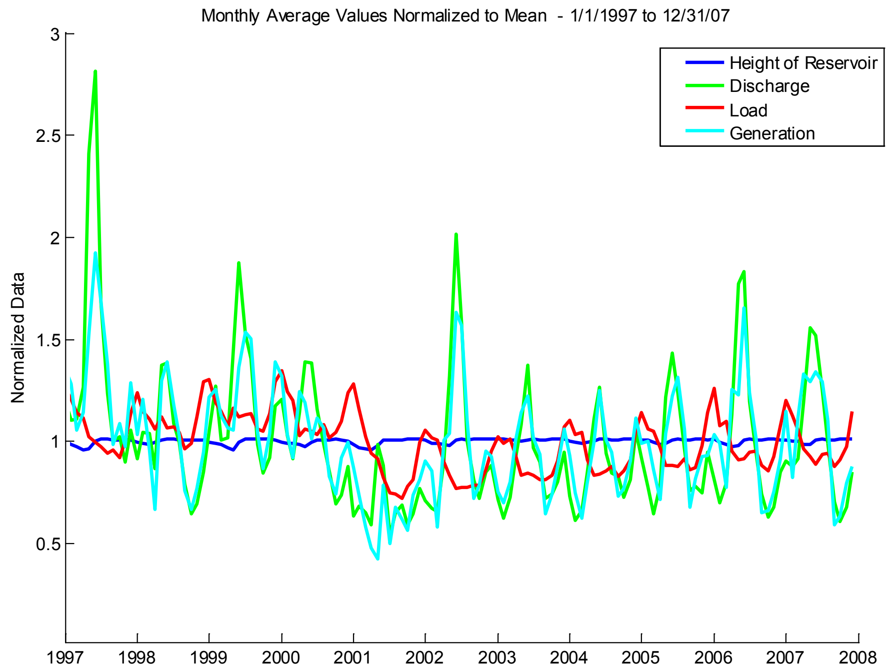

Figure 32: Grand Coulee Dam reservoir, discharge, hydro production and load normalized to respective historical means from 1997 through 2007.

5.4 MAPS Historical Hydro – Accounting for Low Water Years

Hydropower plants often have relatively low capacity factors, on the order of 25% to 45%, thus they typically have more capacity than water to run through the turbines (i.e. a capacity rich and energy poor system). From a system operation perspective, the extra capacity, though not often used, can be available as fast responding, economical reserve (spinning reserves available within less than a second, or non-spinning available within 10 minutes), in contrast, to using more expensive thermal resources (e.g. a gas turbine). It is therefore important to effectively model the reserves available at the hydro power plants in order to realistically model the integration impacts of renewable energy resources, due to the increased impact these have on ancillary services.

In order to investigate and understand the operational impacts of reducing hydro system reserves and truly representing the accuracy of MAPS capabilities in modeling the hydro system, the selected hydropower facilities were de-rated in MAPS using 2006 historical average monthly capacity limits and monthly energy values.[15] Figure 33 illustrates the duration curve of the aggregated hydropower generation from the seven selected hydro facilities accompanied by the modified historical-hydro (HH) data set. As can be seen, the historical-hydro run results in a fair representation of historical limits in generation. However, the MAPS simulation creates more

[15] Upper and lower capacity limits were averaged for the month due to several reasons including drastically changing water schedules and release changes during the month, and prolonged unit outages.

constant lines of generation (shown as steps in generation), due to more peak shaving and less load following during dispatch.

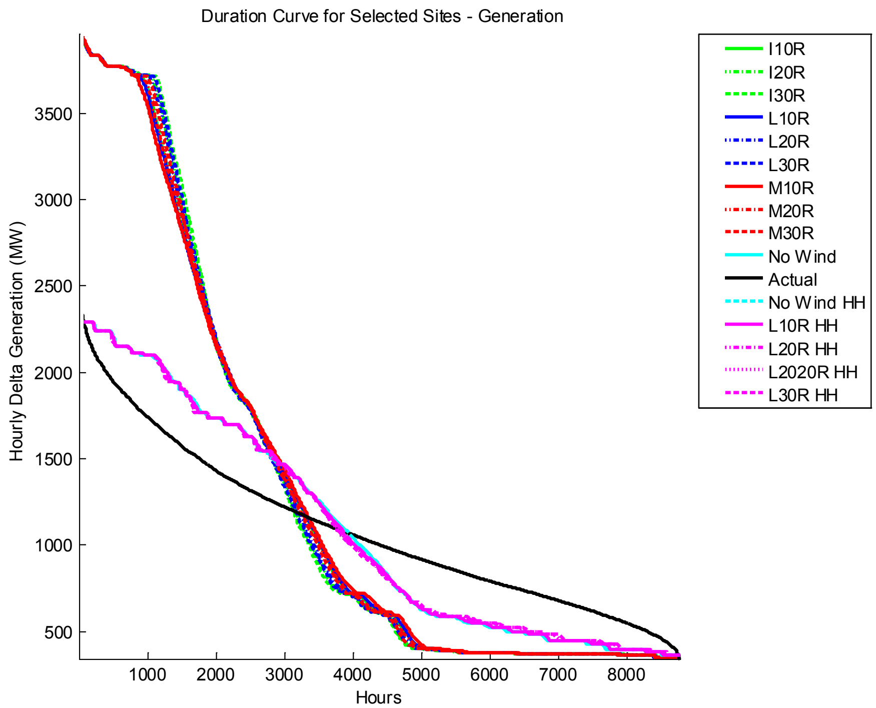

Figure 33: Duration curve showing aggregated hydropower generation from seven of the selected facilities (shown as black line), MAPS scenario data (green, blue, and red lines), and MAPS Historical Hydro data (magenta lines).

Figure 34 illustrates the duration curve of hourly change in generation (hourly delta) from selected hydropower facilities comparing MAPS historical-hydro data to actual and MAPS scenario data sets. Similarly, the historical hydro limits show reduction of hourly delta variability similar to that of the actual data set but still result in for more hours of no change due to peak shaving model used in the simulation (shown as constant line between 2500 – 6000 hrs).

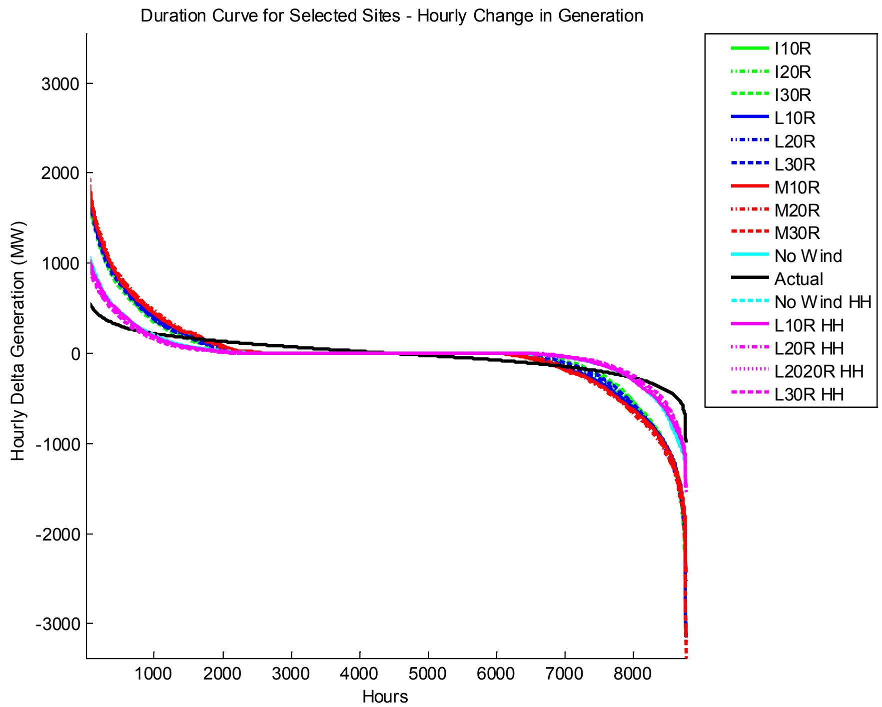

Figure 34: Duration curve of the aggregated hourly deltas from seven of the selected facilities.

The remainder of this section demonstrates the modeling accuracy of the MAPS model when 2006 historical-hydro monthly energy and capacity limits are used as inputs for Glen Canyon Dam. Similar results and patterns are illustrated for the six remaining hydropower facilities in APPENDIX B.

Figure 35 illustrates the annual hydro generation duration curve at Glen Canyon Dam for 2006 using actual and MAPS no-wind historical-hydro data. From this micro level, MAPS appears to have a better representation of the actual data set (though the peak shaving model used in MAPS tends to allow more constant periods of generation). Figure 36 shows the hourly change in hydro generation from the chronological curves, sorted and plotted as duration curves. Again it is evident that the peak shaving model results in more hours of no change in generation (shown as constant line around zero) and higher fluctuations between generation changes (greater up-ramps and down-ramps).

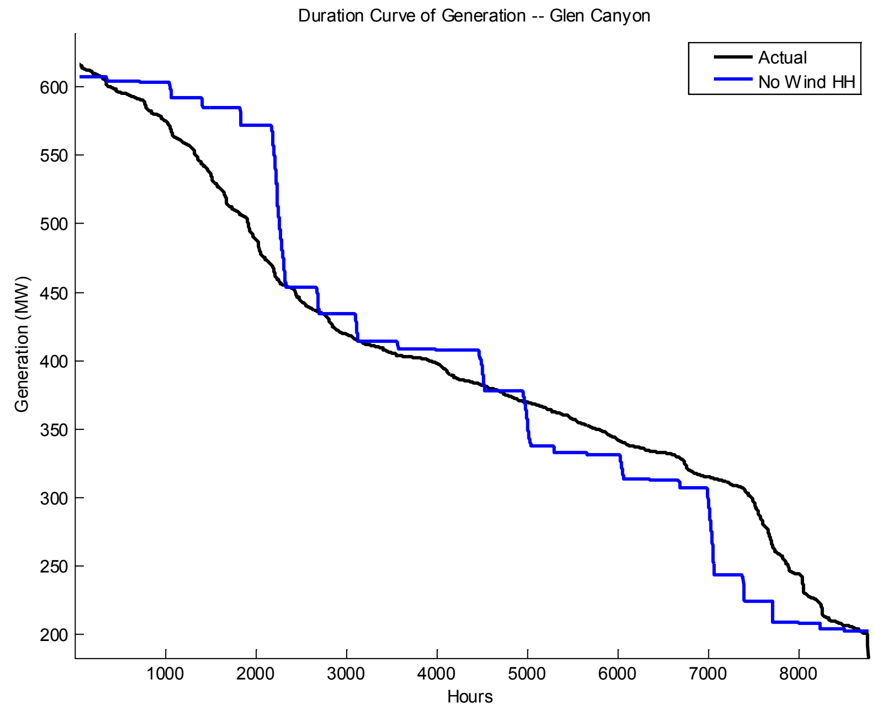

Figure 35: Generation duration curve comparing MAPS no-wind historical-hydro operations to actual generation for Glen Canyon Dam.

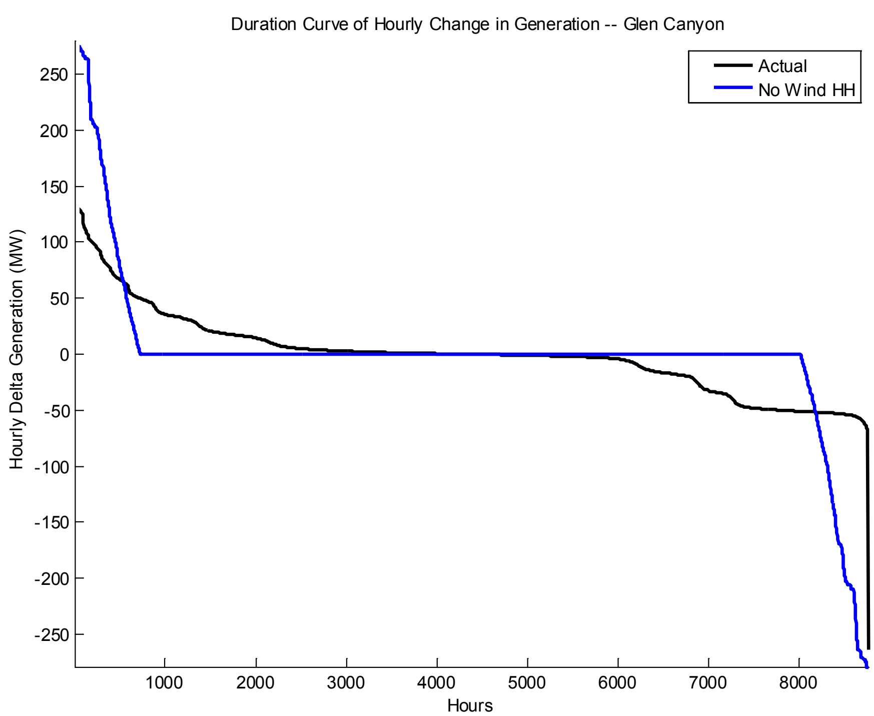

Figure 36: Hourly delta duration curve comparing MAPS no-wind historical-hydro operations to actual generation at Glen Canyon Dam.

Figure 37 illustrates the daily averaged hydro generation for actual and MAPS no-wind historical-hydro operations over the year. As can be seen, seasonal patterns that were missed using the ten-year historical database are now captured by the model. To better illustrate these patterns and capacity limits, Figure 38 plots the monthly diurnal distributions. These diurnal generation patterns for the no-wind HH scenario generally resemble the actual generation profiles throughout the months, with the slight exception of a longer duration of peak afternoon generation during the summer months.

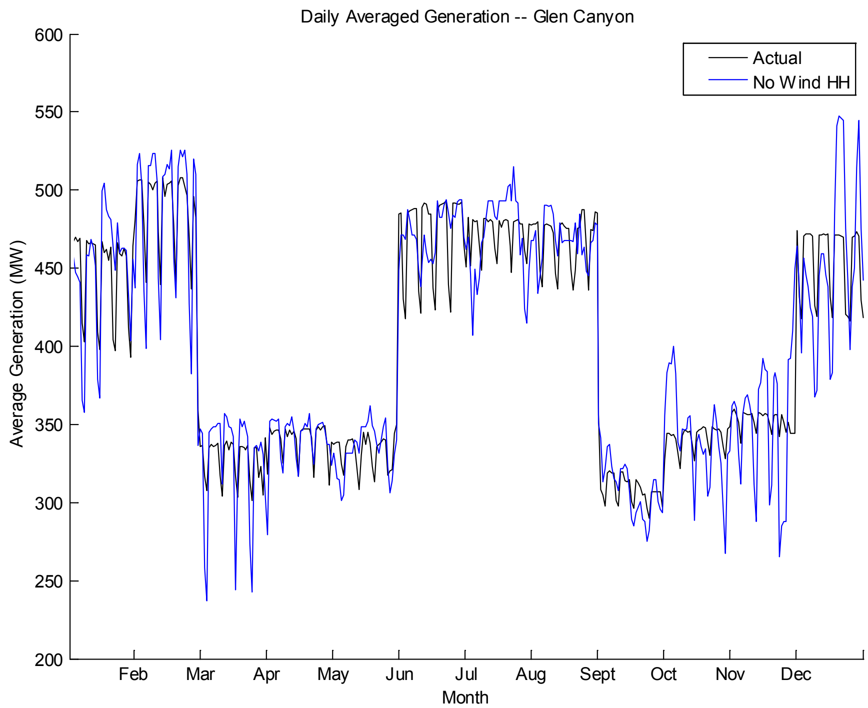

Figure 37: Daily averaged generation comparing MAPS no-wind historical-hydro operations to actual generation at Glen Canyon Dam.

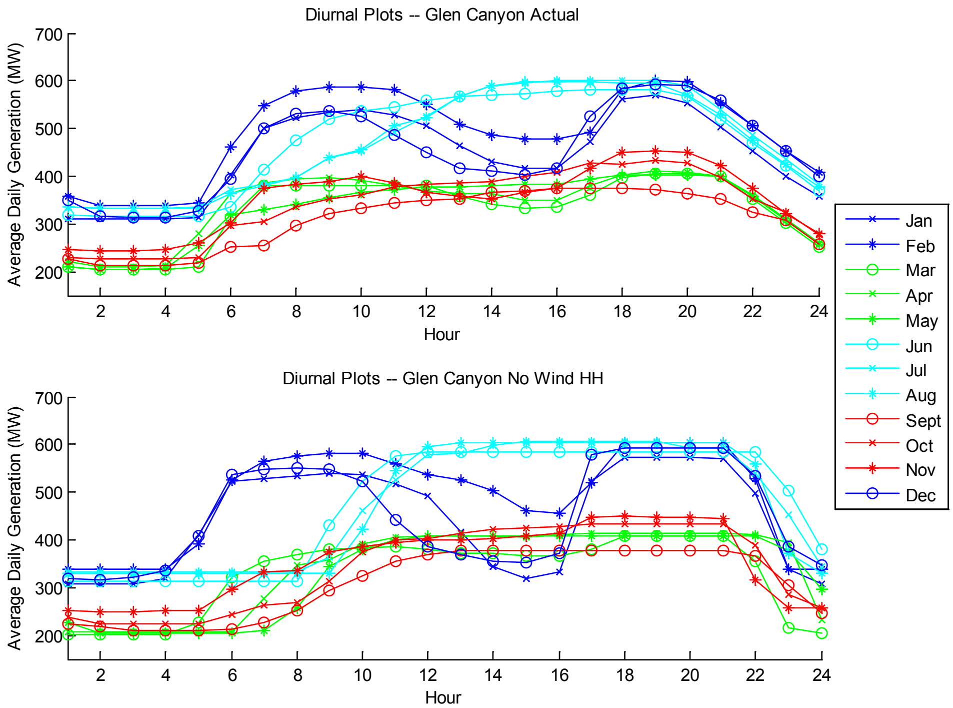

Figure 38: Monthly diurnal distributions comparing MAPS no-wind historical-hydro operations to actual generation at Glen Canyon Dam.

To demonstrate how MAPS models the double morning and afternoon peak load patterns during the winter months, Figure 39 shows the averaged weekly generation for the month of January. As can be seen, MAPS is able to capture both off-peak week days (i.e. weekends) and the on-peak week days patterns well.

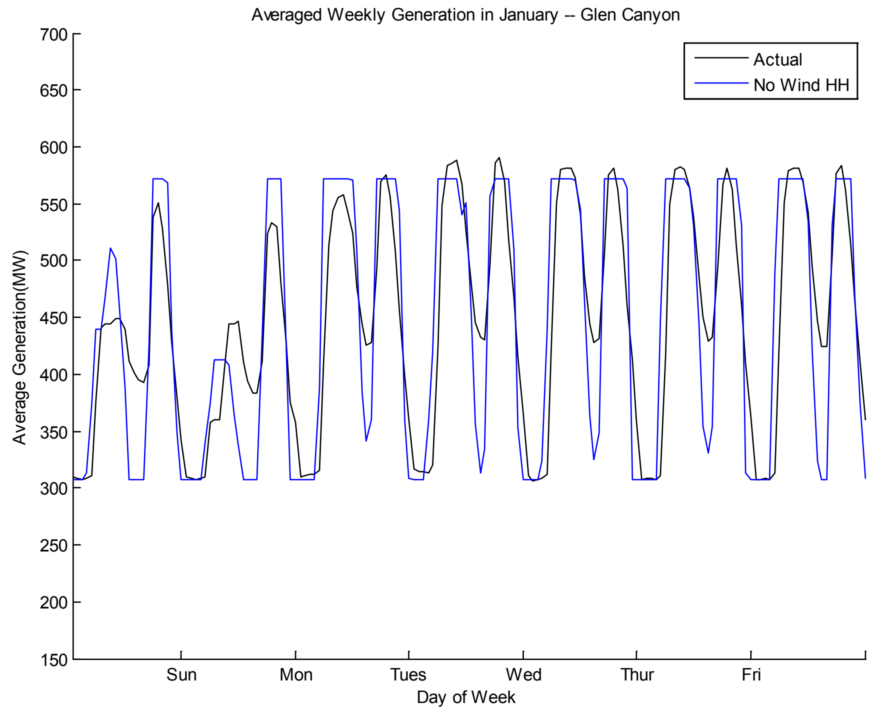

Figure 39: Weekly averaged generation comparing MAPS no-wind historical-hydro operations to actual generation in January at Glen Canyon Dam.

In order to investigate the magnitude of hourly changes in generation, histograms were created as illustrated in Figure 40 and Figure 41. Even with the use of historical-hydro limits and monthly energies, the MAPS simulation results in larger changes in generation, especially during high-load-hours and less flexibility between each hour.

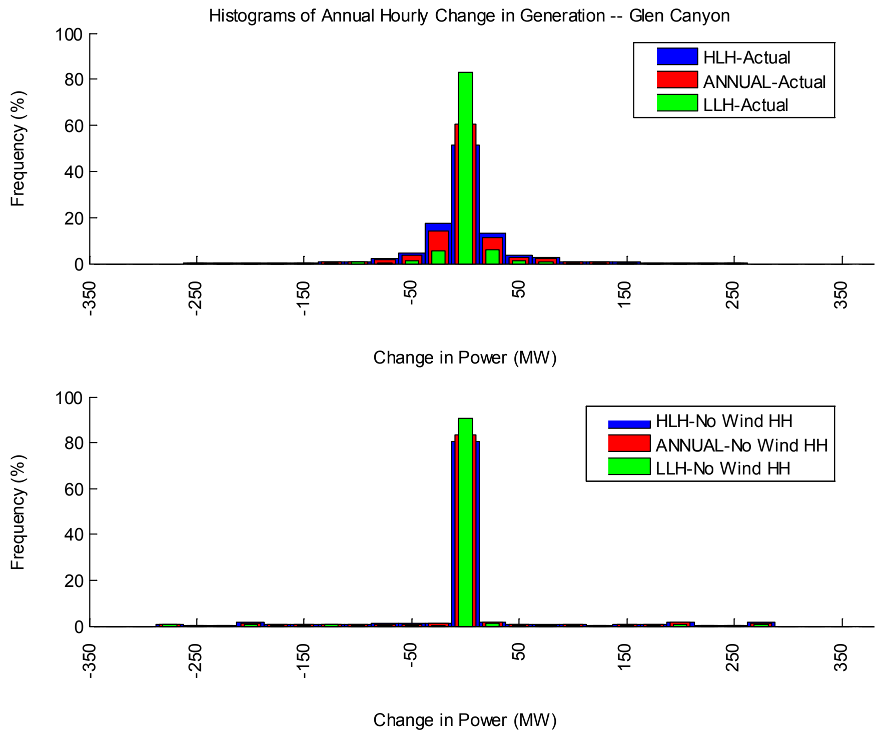

Figure 40: MAPS Historical Hydro histogram of hourly change in generation for Glen Canyon.

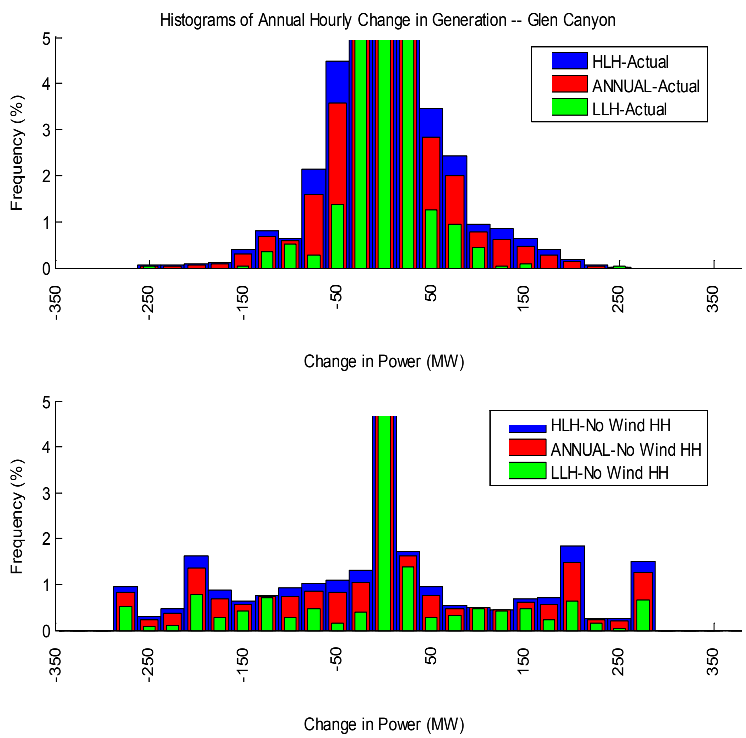

Figure 41: Enhanced view of MAPS Historical Hydro histogram comparisons for Glen Canyon.

To illustrate the difference between the no-wind historical-hydro operations and actual data sets, the percent change between the histograms is taken and is shown in Figure 42. From this plot, it is evident that the actual generation results in more flexibility at lower generation limits (noted as negative percent change), while MAPS results in more changes in generation at the extreme limits.

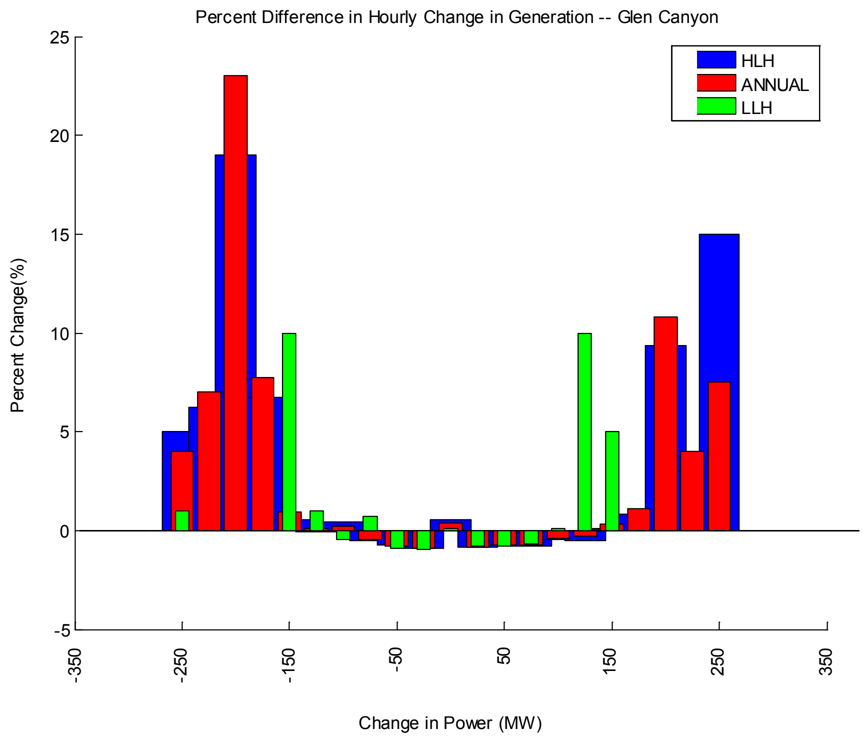

Figure 42: Percent change in hourly generation between MAPS Historical Hydro and actual data for Glen Canyon.

Table 13 lists the statistics of hourly changes in generation between MAPS historical-hydro and actual data sets for Glen Canyon Dam. The magnitude of change between the averages of the absolute value is much smaller than previously seen in Table 12, indicating more realistic modeling of Glen Canyon's hydro resources.

Table 13: Comparison of statistics of hourly changes in generation between MAPS Historical Hydro and actual data sets.

Timeframe	Hourly Changes in Generation	Average (MW)	Standard Deviation (MW)	Average of the Absolute Value (MW)
Annual	Actual	1.06E-2	35.9	18.5
	no-wind HH	3.36E-3	66.2	23.1
HLH	Actual	1.49E-2	40.6	22.8
	no-wind HH	4.74E-3	72.3	27.4
LLH	Actual	-1.69E-2	20.7	7.98
	no-wind HH	0.111	48.2	12.7

5.5 Impact of Renewables on Historical Hydro Operations

The results from the previous section in modeling the hydro system at seletced hydropower plants with historical capacity values and monthly energy inputs demonstrates the ability of a MAPS simulation to provide a fairly accurate represention of the hydro plants, even without taking priority functions and power constraints into consideration. To understand the impact of renewables on individual hydro facilities using historical-hydro limits, the no-wind simulation of hydro operations is compared with several wind and solar penetration level simulations for the local-priority scenario. Figure 43 illustrates the historical-hydro and actual generation duration curves between penetration level runs. These show little differences and minimal duration shifts occuring between each penetration level. For this reason, analysis of the 20% wind penetration case for Hoover Dam will be shown in further detailas a representative of the remaining cases.

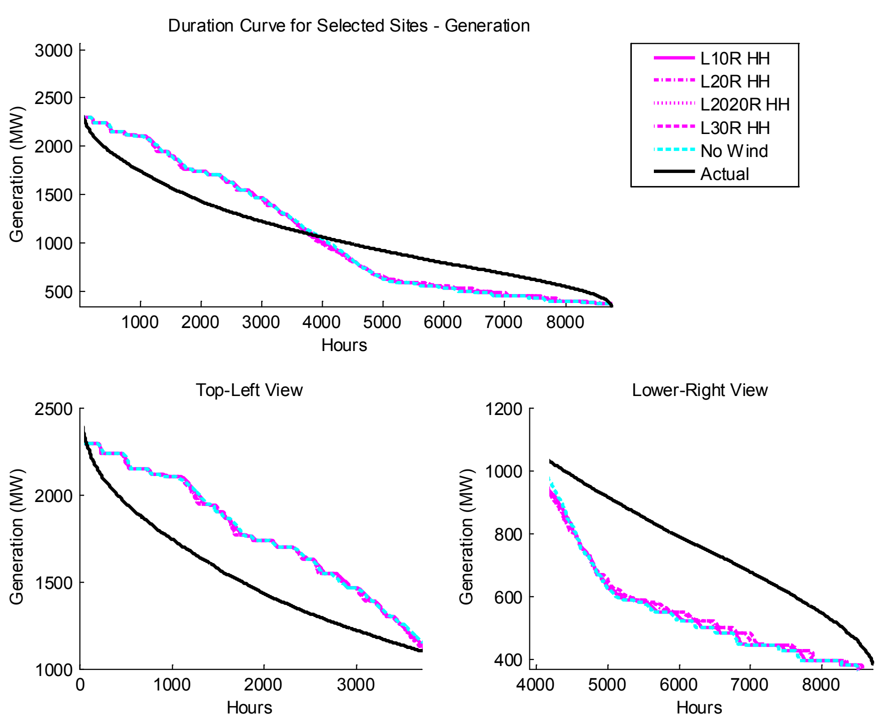

Figure 43: Duration curves of aggregated hydropower generation of the seven selected hydro facilities where actual data is depicted by black line and MAPS historical hydro data shown as cyan and magenta lines.

Figure 44 illustrates the daily averaged hydro generation using historical hydro limits comparing the baseline run to the local priority scenario with 20% wind and 3% solar. As shown in the plot, an increased use of the hydro plant's flexibility is used during the spring months (due to high winds occuring in the West), while other months remain fairly identical to the baseline scenario.

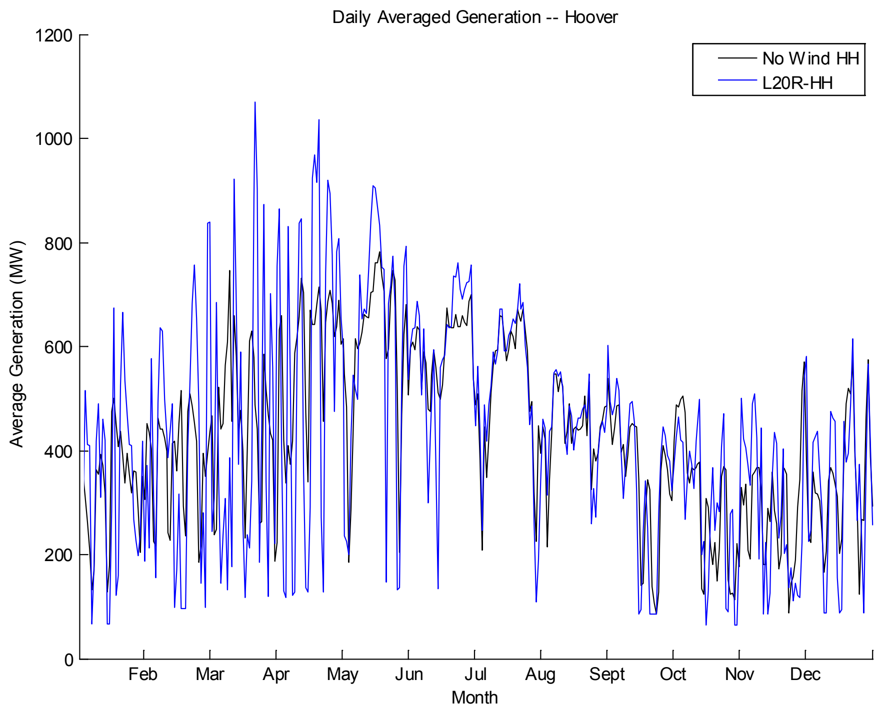

Figure 44: MAPS daily averaged Historical Hydro generation comparing the baseline (no-wind) and 20% wind and 3% solar penetration for Hoover Dam.

To understand how the hydro plant's flexibility varies throughout the year, hourly deltas were plotted chronologically over the year. For example, Figure 45 illustrates the historical-hydro L20R hourly deltas; this is accompanied by 2006 scheduled unit outages for Hoover Dam. Notice the more heavily shaded portions that occur during the late winter and summer months indicating more changes in generation throughout the day.

It is noted that only the scheduled unit outages are plotted due to the fact there were a negligible amount of forced outages observed. Additionally, the scheduled outages are shown in cumulative form (i.e. multiple units for scheduled outages on the same date are added together), and the maximum observed scheduled outage for any given unit was 744 hrs or approximately one month.

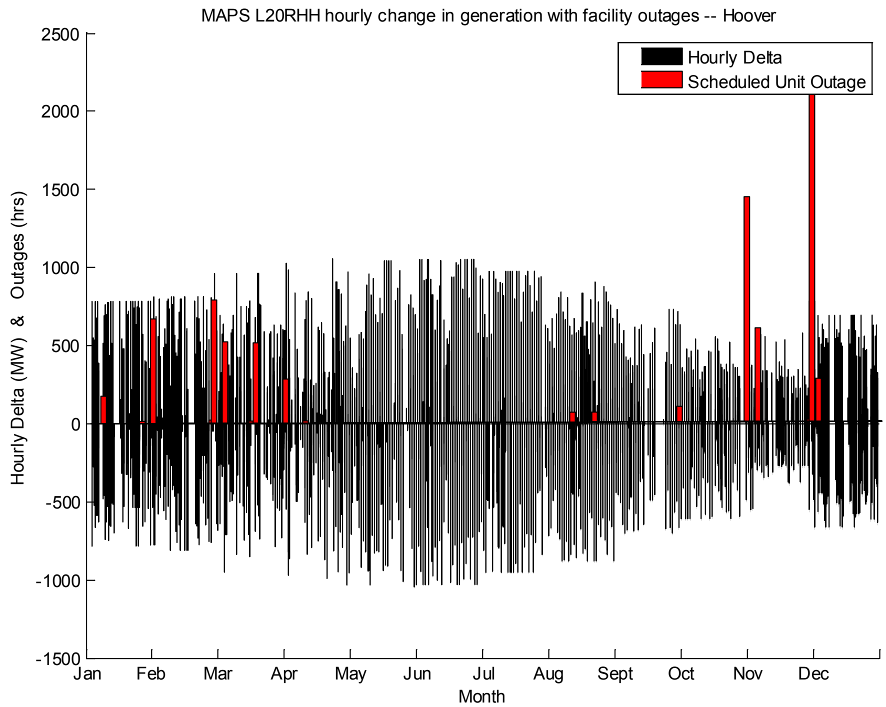

Figure 45: MAPS L20R-HH hourly delta's accompanied by scheduled unit outages for Hoover Dam.

To interpret how the change in use of the hydro plant's flexibility varies throughout the year, the percent change in hourly deltas were plotted chronologically; these were compared with chronological plots of historical unit outages occurring primarily due to operations and maintenance. Figure 46 illustrates the percent change in hourly deltas using the historical-hydro no-wind and L20R data sets, where the limit of percent change has been restricted to 200%. As shown, the highest period of increased use of flexibility occurs during the spring months.

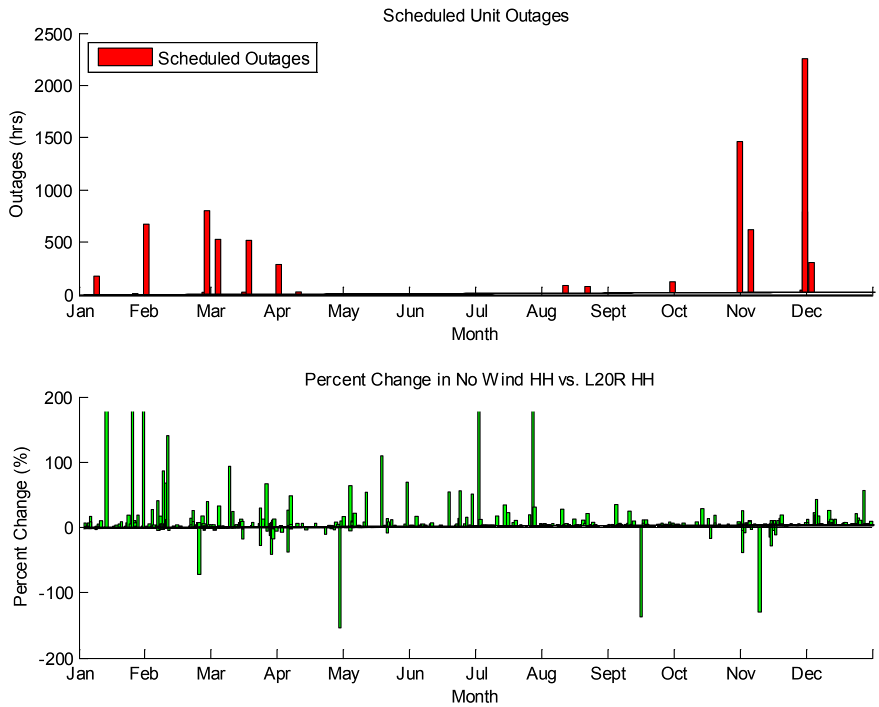

Figure 46: Percent change in hourly delta between historical-hydro, no-wind baseline versus local-priority scenario with 20% wind and 3% solar.

To understand the impact on Hoover operations with 20% wind and 3% solar, two important weeks were selected in July and April, 2006. July experienced the highest load and April experienced the highest variability in wind output (considered the worst week in terms of operations for three years analyzed). Figure 47 illustrates Hoover's hourly generation during the week of July with the red line indicating 20% penetration levels, the blue line indicating the no-wind scenario and the black line indicating actual generation. As shown, there is almost no difference between the two MAPS scenarios due to the occurrence of low winds during the summer months. Additionally, the actual generation is observed to follow load more consistently while the MAPS simulation generation results in more load factoring.

An important factor that needs to be considered when interpreting these results is that the system load was aggregated for the entire footprint (factoring in transmission constraints) in the MAPS simulation. A larger balancing area alone results in more available generation resources online to balancing the net load and less hourly fluctuations in load are seen.

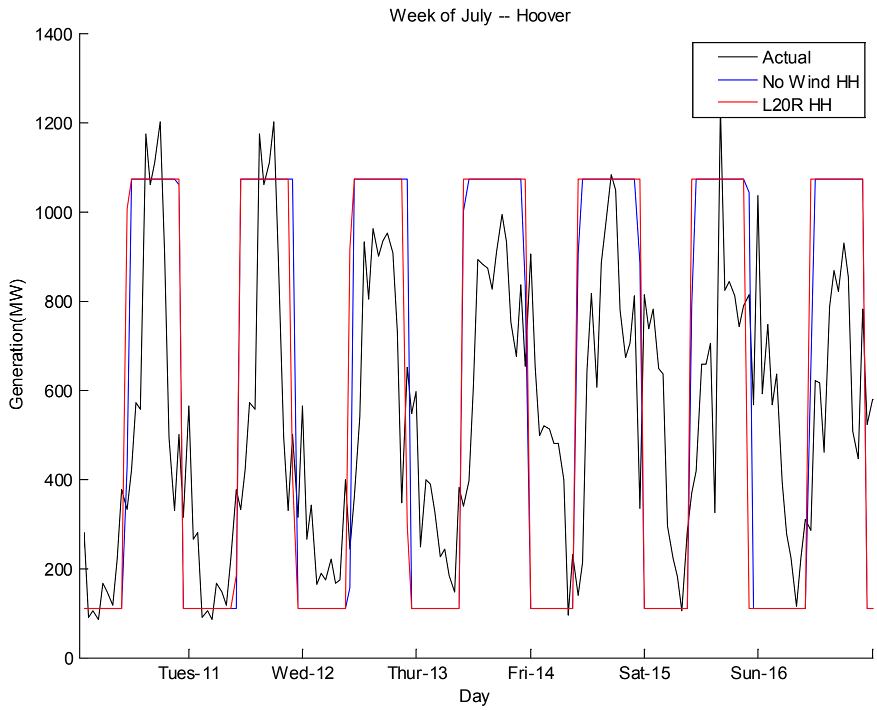

Figure 47: Hourly dispatch of power from Hoover Dam during a week of July.

Figure 48 shows the hourly production pattern as dispatched by MAPS at Hoover Dam for the week of April. From the plot, it is seen in the 20% penetration level case simulation (red line), the hydro plant accommodates the high level of wind power at times by backing down hydro generation, while other times it increases generation to meet system ramping requirements. It is noted that that while MAPS prefers to dispatch the hydro for peaking shaving, some sub-hourly regulation is need at times.

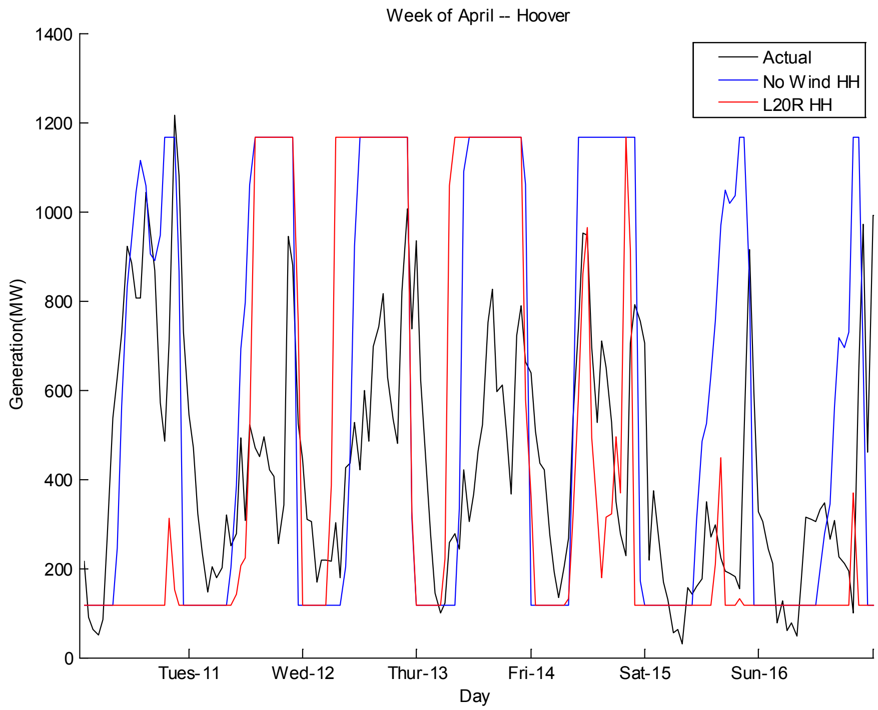

Figure 48: Hourly dispatch of power from Hoover Dam during a week of April.

To answer the question of how hydro generation resources are allocated differently between penetration levels and variance on different time scales, MAPS historical-hydro generation data was correlated to that of the baseline, no-wind HH scenario. This is shown in Figure 49. With the exception of hourly data, each timeframe was calculated upon a rolling average. As the penetration levels increase, the correlation to the baseline data tends to decrease, demonstrating greater variation in the use of hydro resources. Additionally there is a tendency for the correlation coefficients to increase as the timeframe increased (this is due to the fact historical monthly energy values were used as inputs into the model, thus monthly values were not allowed to vary), hourly generation data tended to be more highly correlated than that of the daily averaged data. From a storage standpoint, this plot also indicates the hydro plant's ability to shift water schedules on the selected time frames. For example, hydropower generation schedules were not allowed to shift on a monthly timeframe due to the defined monthly energies; however, on a weekly standpoint, hydro generation is allowed some flexibility to account for the varying wind and solar generation. On a daily and hourly timeframe, hydro is allowed more flexibility to shift hydro generation from day to day or hour to hour.

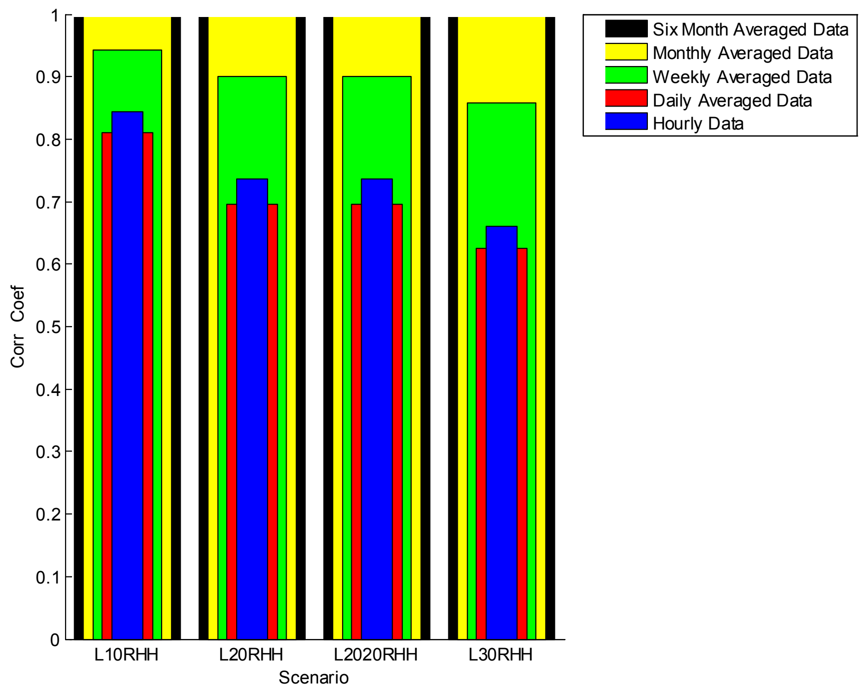

Figure 49: Correlation coefficients of Local Priority scenario using Historical Hydro limits as compared to no-wind HH case for Hoover Dam.

5.6 Impact of Renewables on Base Hydro Operations

The previous sections have shown that using historical-hydro limits/energy in the MAPS simulation results in a fair representation of actual hydro resources used in the study footprint. The remainder of this chapter analyzes the hydro production patterns using the ten year average hydro database as inputs into MAPS. Results from this analysis can be interpreted as a high water year with little or no restrictions imposed on hydro generation resources.

To analyze the impact of renewables on hydro operations when compared to the no-wind scenario, the local priority scenario and Crystal Dam is considered in this section. Crystal Dam is located along the Gunnison River below Blue Mesa and Morrow Point Dam. Figure 50 shows the daily averaged hydro generation at Crystal Dam comparing MAPS no-wind and the local-priority scenario with 20% wind and 3% solar. As shown, the 20% penetration scenario (blue line) shows several areas of increased use of hydro flexibility over the no-wind scenario during the spring and late fall months.

Figure 51 illustrates the monthly diurnal distributions between the two scenarios. As can be seen, there are several shifts in use of the Crystal Dam hydropower resources as wind and solar in incorporated in the system. In many months, the L20R simulation results in a shift of the hydropower generation to the early morning periods (i.e. low-load-hours), while afternoon generation (i.e. high-load-hours) is reduced.

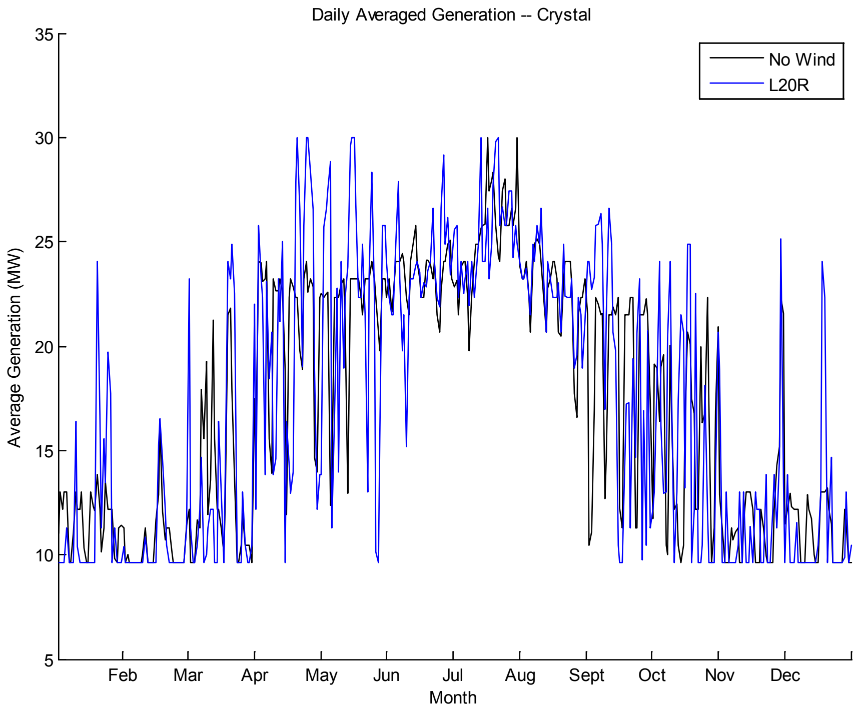

Figure 50: MAPS daily averaged hydro data comparing no-wind and L20R scenarios at Crystal Dam.

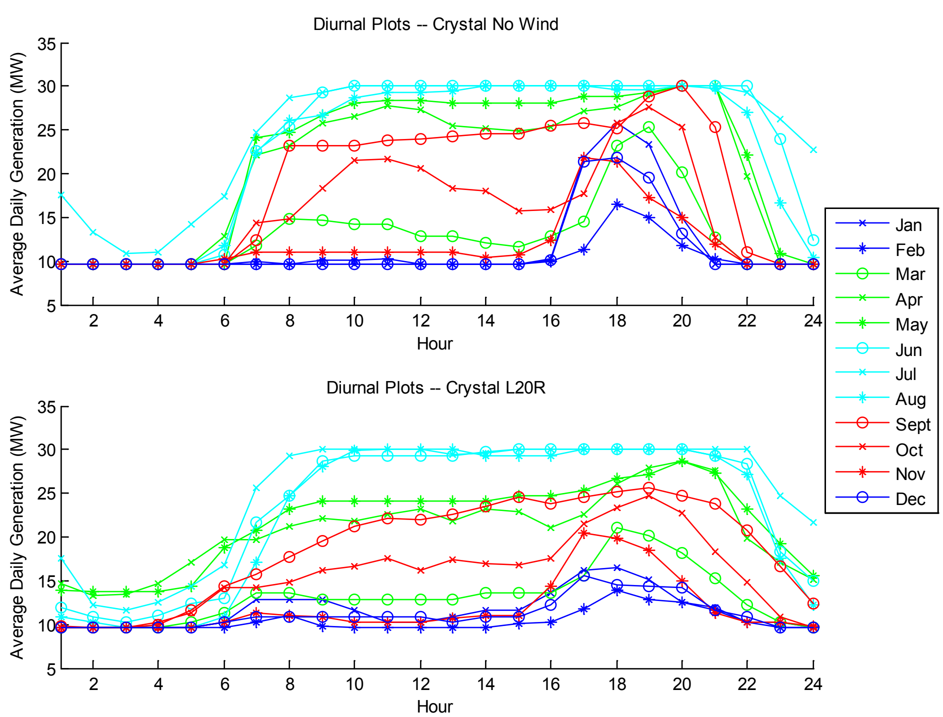

Figure 51: MAPS monthly diurnal distributions comparing no-wind and L20R scenarios at Crystal Dam.

These shifts in hydro generation can also be viewed as histograms of hourly changes in generation. Figure 52 illustrates these histograms. Figure 53 shows the percent change in use of hydro's flexibility during these certain time periods. As shown, the results confirm an increase in use during low-load-hours while overall flexibility is decreased during high-load-hours and on an annual basis.

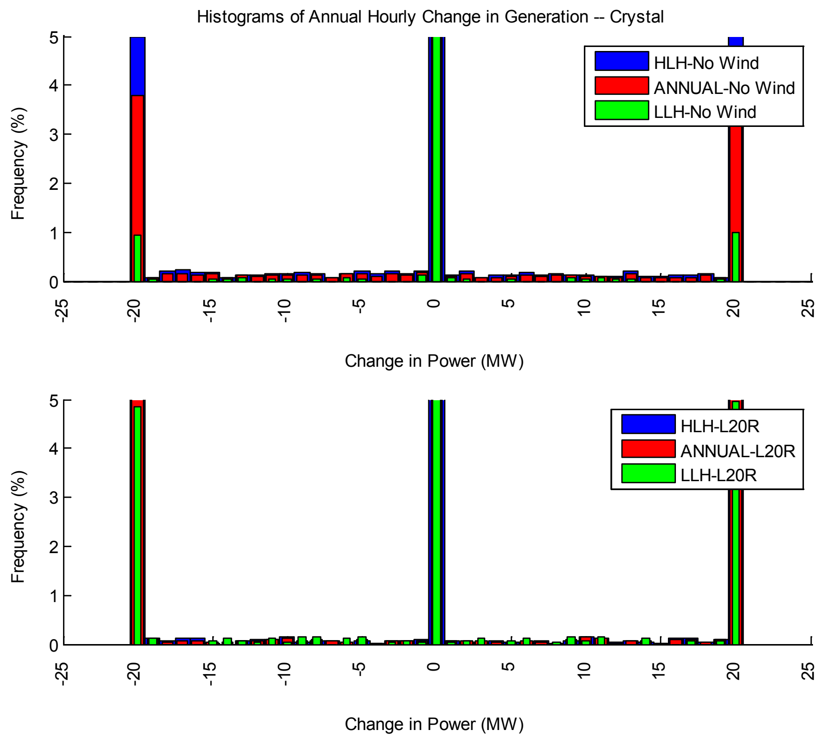

Figure 52: Histograms of hourly changes in generation comparing MAPS no-wind and L20R scenarios at Crystal Dam.

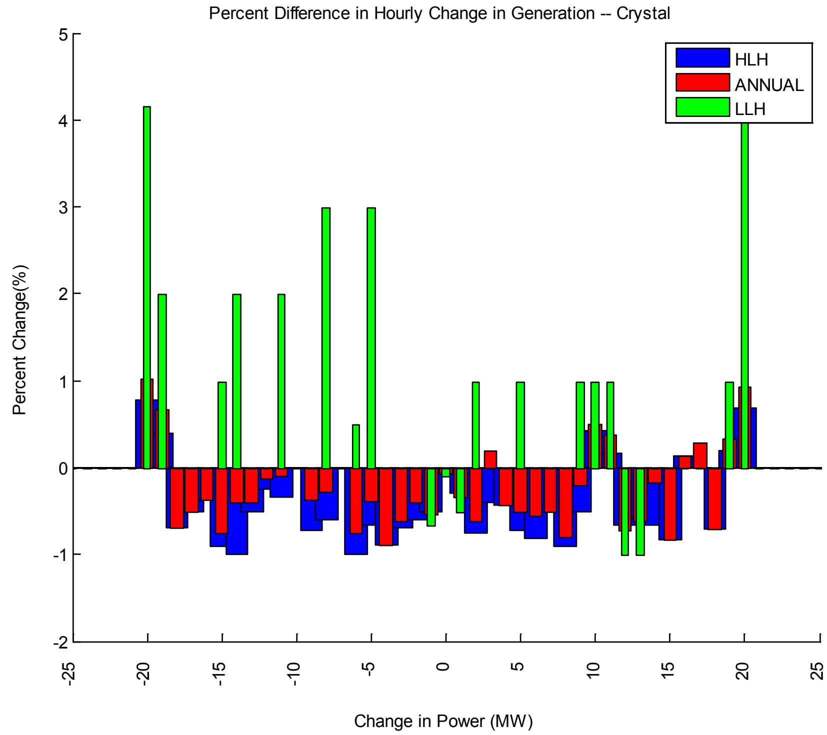

Figure 53: Percent difference between MAPS no-wind and L20R scenarios at Crystal Dam.

5.7 In-Area, Local Priority, and Mega Project Results

This section analyzes the differences between the three main scenarios considered in the WWSIS and their impact on hydro operations. When interpreting these results it is important to note that the majority of hydro generation resources were dispatched to their corresponding balancing area regions load (e.g. dams located in the Arizona-New Mexico balancing area region would be dispatched to meet only the AZ-NM loads and not the loads of the other four regions). Thus as more wind generation is obtained from better wind resources (i.e. Wyoming in the mega-project scenario) the net-regional-load will change correspondingly.

Figure 54 illustrates an annual duration curve (left graph) and hourly delta duration curve (right graph) for the selected hydro facilities located within the study footprint. Looking at the generation duration curve, it appears the in-area scenario (green lines) experienced the greatest shift in generation, though modest, while the mega-project (red lines) resembles the no-wind scenario the closest. Again, looking at the hourly delta duration curves (right graph), the wind appears to have some effect on the in-area and local-priority scenarios, shifting the furthest way from the no-wind scenario.

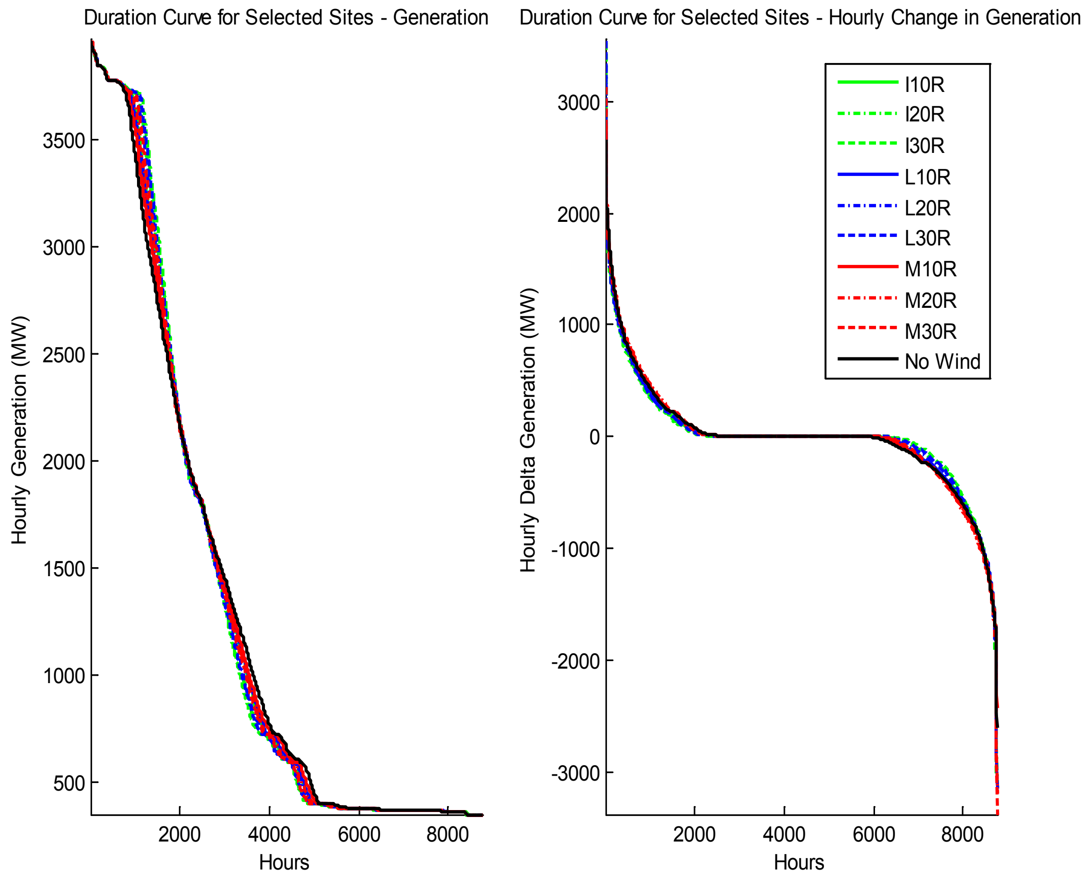

Figure 54: Duration curves of MAPS hourly generation (left) and hourly deltas (right) for selected hydro facilities located within footprint.

To further interpret these results, hydro generation from the selected sites of each scenario are correlated to the no-wind scenario generation on different time scales as shown in Figure 55. This is a perfect example of how dispatching the hydro generation for each scenario correlates to the amount of wind generation located within their defined balancing area. As shown, the in-area scenario (uses local resources within each transmission constrained area within the study footprint) has the lowest correlation coefficients between the scenarios indicating that hydro flexibility and balancing resources are utilized more. As more wind generation is gradually transferred from local resources to higher quality wind resources of the local-priority and mega-project scenarios, less variability in net-load is seen at the hydro facilities located within the study footprint. Accordingly, the hydro plant's flexibility is used less, corresponding to a higher correlation to the baseline, no-wind scenario. Looking at the intra-scenario differences, the correlation tends to drop as renewable penetration level increases. Again, as renewable penetration levels increase, the variability in net-region-load increases, resulting in more use of hydro flexibility.

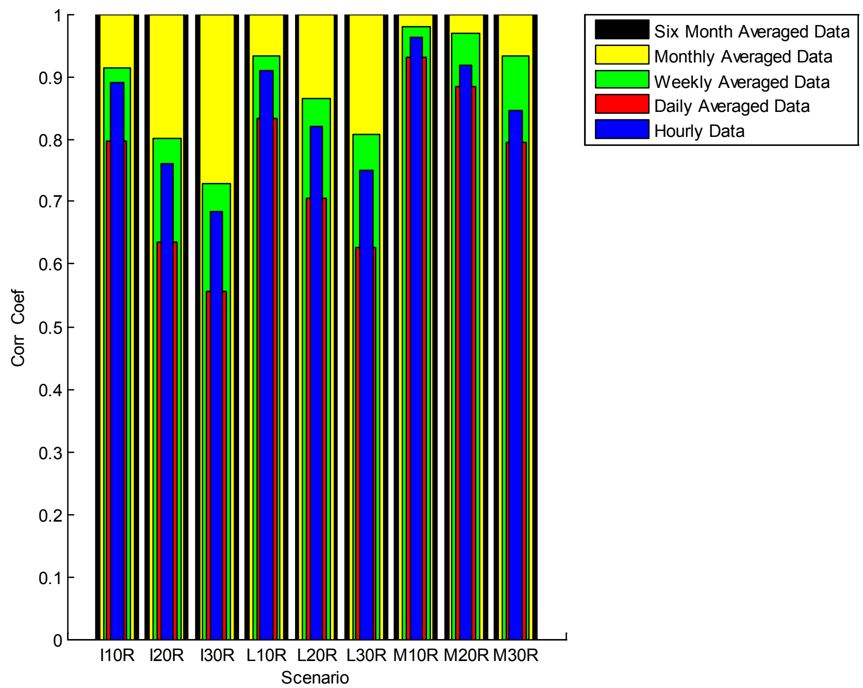

Figure 55: Correlation coefficients of three main scenarios as compared to no-wind case for selected hydro facilities located in the study footprint.

To illustrate these changes in generation patterns at the micro level (i.e. a weekly timeframe), hourly hydro generation at Glen Canyon Dam for the week of April is plotted for each scenario using 20% wind and 3% solar in Figure 56. As can be seen, the different scenario build-outs and corresponding wind resources have severe affects on the way hydro is being dispatched to the net-load.

For this week, hydro generation of the in-area scenario is dictated by the occurrence of high wind generation resulting in the reduction of hydro generation on many occasions. In contrast, the utilization of Glen Canyon's hydropower resource in the mega-project scenario, which uses remote, higher quality wind resources outside of the net-load region, result in a smaller impact on net-region-load, thus differed only slightly from the no-wind scenario generation set.

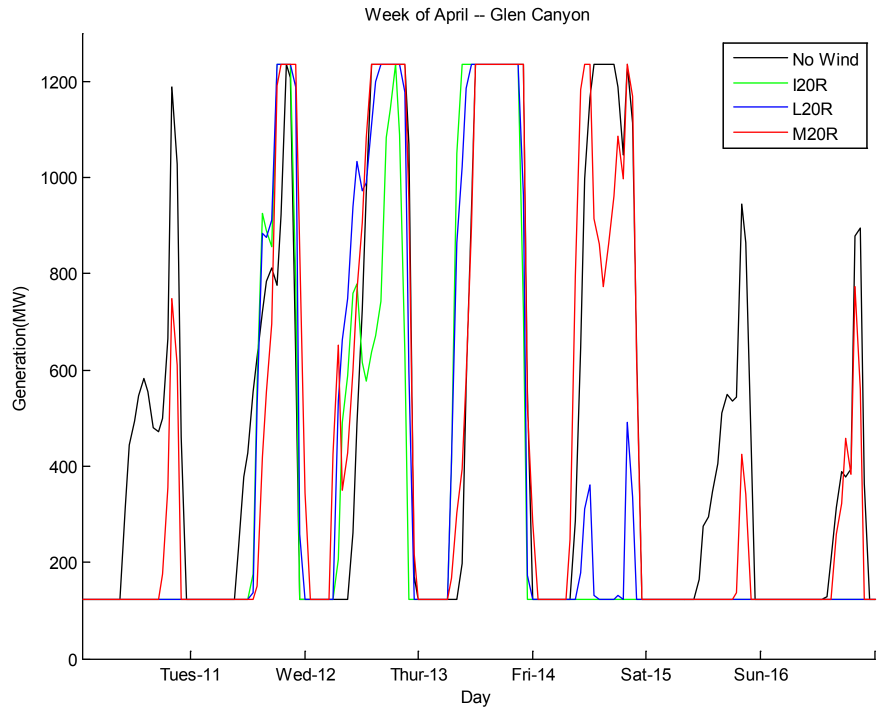

Figure 56: Hourly dispatch of power from Glen Canyon Dam during a week of April.

5.8 Impact of Perfect Forecast on Hydro Resources

Up to this point, analysis has only been conducted on scenarios run using a professional or State-of-Art forecast to predict wind and solar output on an hourly and daily basis. Using these forecasts, generation units could be dispatched based on the predicted renewable generation. To answer the question of how hydro resources are dispatched as the forecast methods becomes more proficient, hydro schedules were compared using the professional and perfect forecast (best-case scenario where renewable generation output predictions are perfect). Figure 57 illustrates histograms of hourly changes in generation for the local priority 20% penetration level for Blue Mesa Dam.[16] At this level, there appears to be little difference in the hydrogenation use between forecasting method simulations.

Figure 58 shows the percent change between the two histograms. As can be seen, results show a modest change in use between the two simulated data sets, with almost no change occurring during low-load-hours. In all cases, any change that does occur is directed to more utilization of hydro flexibility. This is due to the fact that the perfect forecast would enable hydro flexibility to be used to the fullest extent, reducing more expensive thermal generation resources and saving an additional $500 million in annual operating costs ($1-2 per MWh of renewable generation).

[16] Blue Mesa Dam was chosen as an example for the comparison of different forecasting methods, but other selected facilities showed similar patterns in change of use.

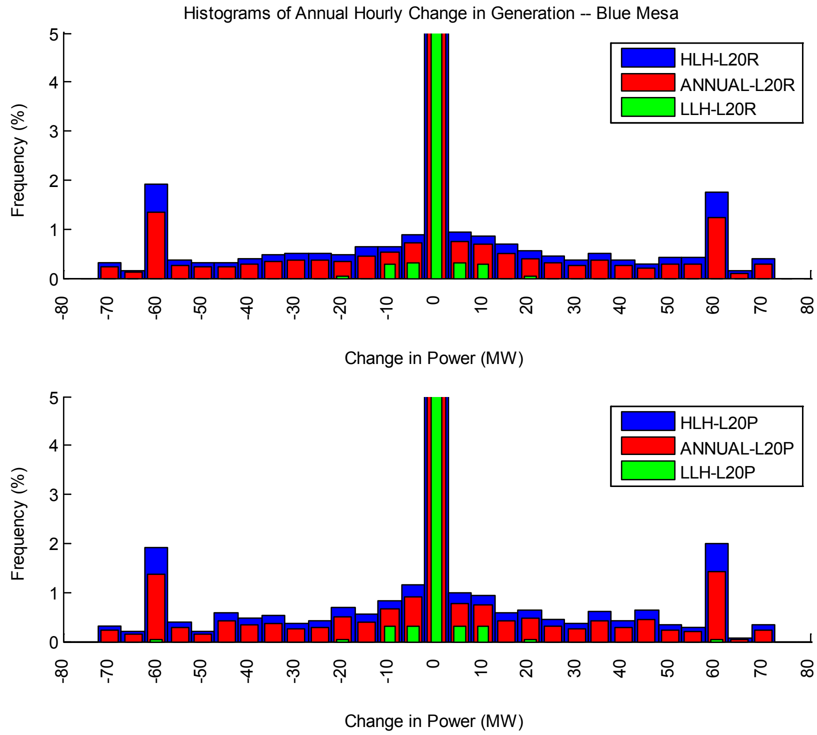

Figure 57: Enhanced view of MAPS local priority Professional Forecast vs. Perfect histogram of hourly changes comparison for Blue Mesa Dam.

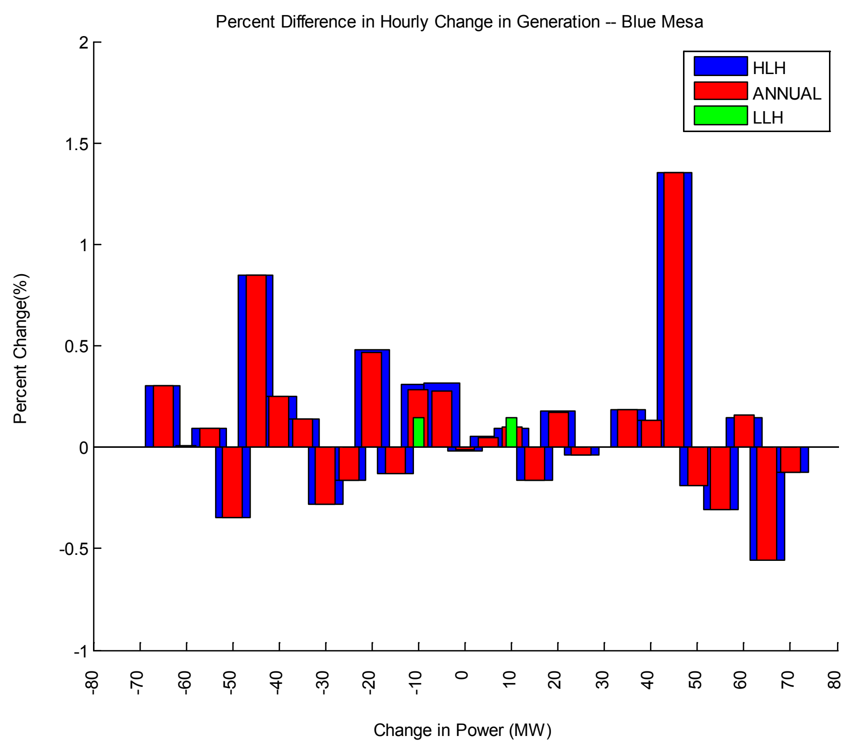

Figure 58: Percent change in hourly generation between MAPS local priority using professional and perfect forecast for Blue Mesa Dam.

Figure 59 illustrates how each scenario is correlated to their corresponding counterpart (e.g. L20R is correlated to L20P). From these results, it becomes apparent that the hourly data between the two forecasting methods is highly correlated, but less so as wind penetration levels increase. At longer timeframes of comparison, the data is nearly the same between forecast scenarios at all wind penetration levels.

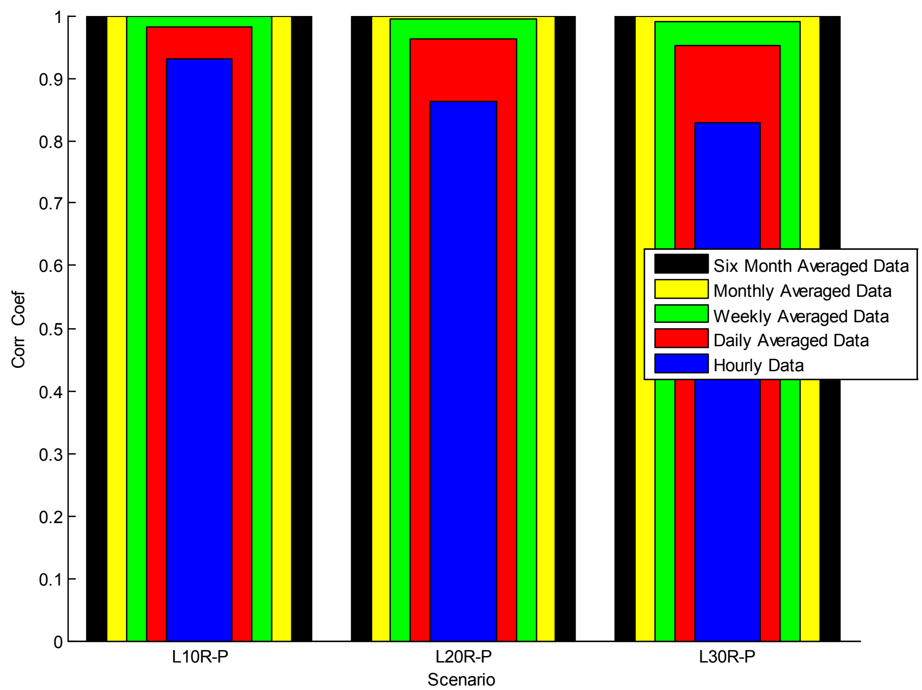

Figure 59: Correlation coefficients of local priority scenario comparing forecast methods for Blue Mesa Dam.

6.0 Aggregate Hydro Operations with Wind and Solar

This section examines the aggregate operations of hydro power in the WECC using the in-area scenario. This section is based on the findings from the WWSIS and results show the overall impact on hydropower operations with the introduction of wind and solar generation. Figure 60 shows the aggregate hourly operation of the WECC hydro plants for the week of April 10th as a function of renewable penetration. As shown, each case had a slightly different generation pattern throughout this week, especially at the 30% penetration level, but there did not appear to be any major changes to occur. A similar comparison and results are shown in Figure 61, for the week of July 10th.

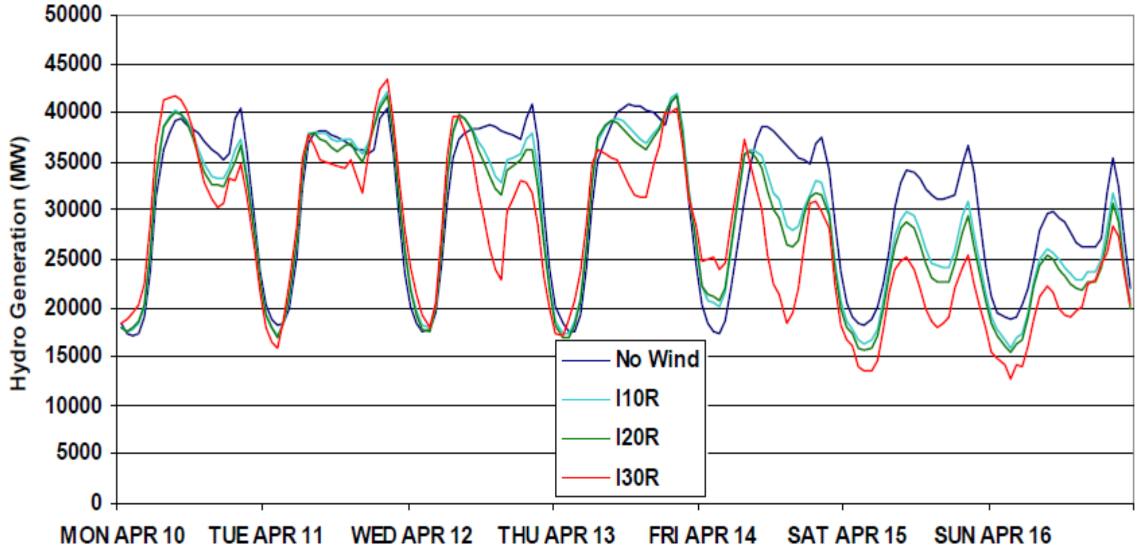

Figure 60: WECC hydro operation for week of April. (Source: GE Energy 2010)

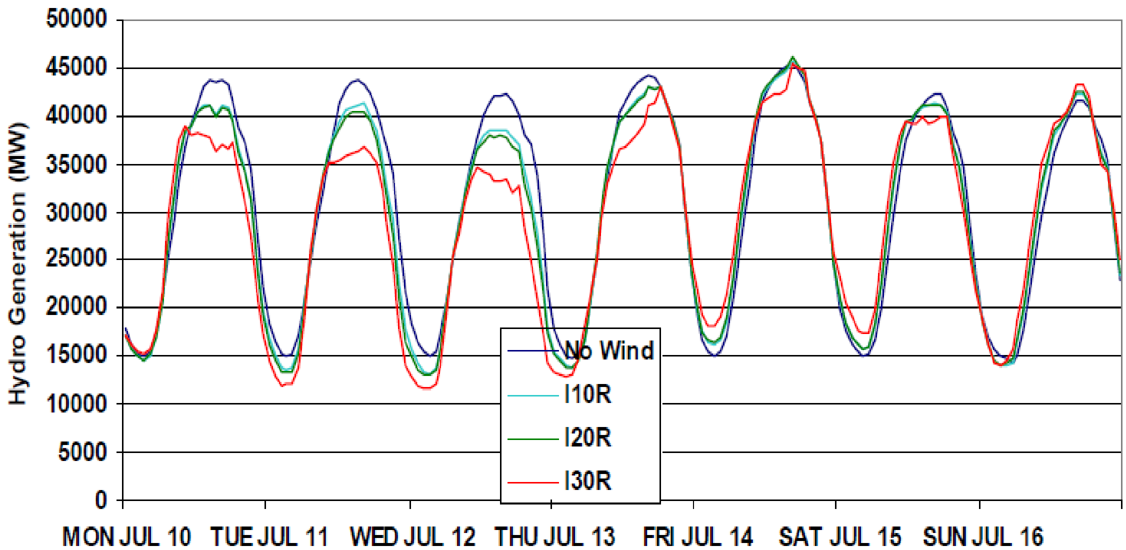

Figure 61: WECC hydro operation for week of July. (Source: GE Energy 2010)

Figure 62 shows the annual duration curve for the WECC hydro operation for the same set of cases. Again, from this macro level, there does not appear to be any significant shifts in hydropower operation. Similarly, the hourly delta for the hydropower generation from the chronologically curves were sorted, and plotted as duration curves as shown in Figure 63. As shown, it did not appear the wind and solar generation had any major affects on significant up or down ramps in aggregate hydro operation that were different from the baseline, no-wind case.

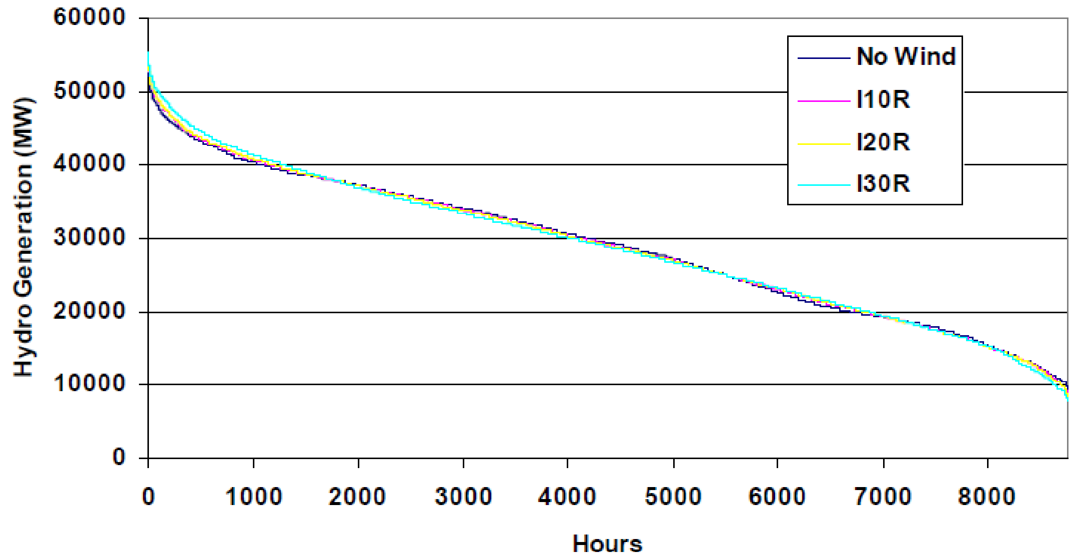

Figure 62: WECC annual hydro generation duration curve. (Source: GE Energy 2010)

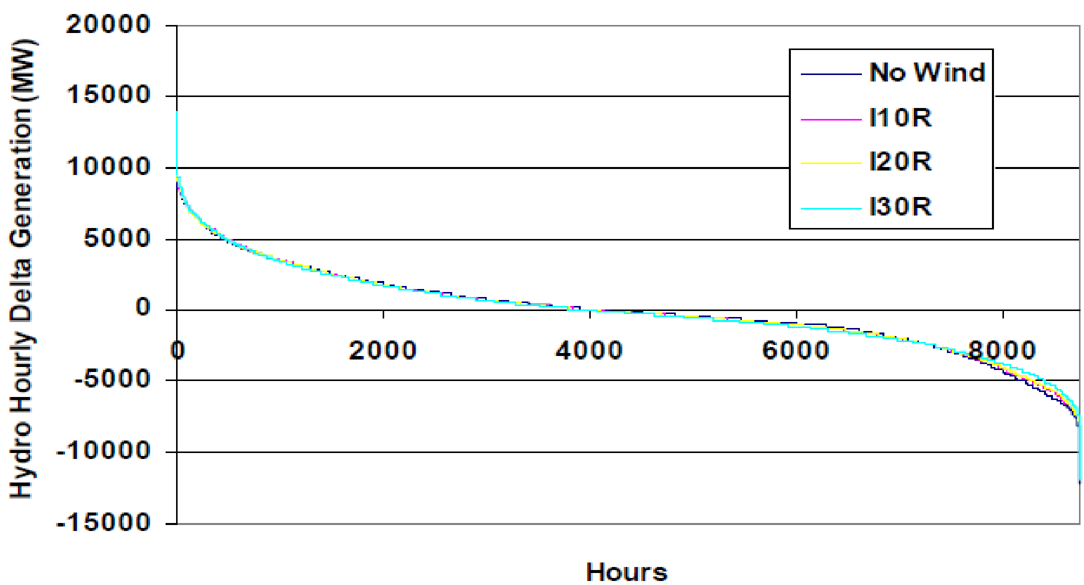

Figure 63: WECC annual hydro hourly delta duration curve. (Source: GE Energy 2010)

7.0 Economic Impact of Renewables on Hydropower Operations

This chapter addresses the economic impact of hydropower use in the WWSIS. MAPS, being a production cost model, is well suited to address economic issues related to system operations. Several scenarios were analyzed to deduce the economic value of hydropower as a balancing resource, determine the impact of adjusting both hydro capacity limits and available monthly energy, and the value of integrating wind and solar forecasts into the hydro dispatch schedule. Results are highlighted for both the study footprint area and the WECC.

When interpreting the economic results presented in this section, it is important to note all generation dispatches are made on a least-marginal-cost basis. In the MAPS simulation, the hourly marginal cost of energy or spot prices is used. In a deregulated market, this is the price paid for energy each hour, but this is also useful in a regulated market as it is an hourly measure of the value of the energy. When transmission constraints are present, these values will vary across the system for any given hour, but they can be weighted by the hourly load in a given area to produce a system spot price. These spot prices were calculated chronologically for each hour of each year and for each case.

There are two important economic measures that will be presented; these are the system operating costs reductions and revenue value or spot price. Operating costs can be categorized as fuel costs, variable operation and maintenance, start-up costs, and emission payments. For example, operating costs can be calculated as fuel costs multiplied by the unit heat rate and addition to any variable operations and maintenance costs. Additionally, it is noted that renewable and hydro generation resources were assumed to have no operating costs (i.e. fuel has no cost). Operating cost reductions can be viewed as the actual cost savings because these represent the actual reductions in cost. Revenue value is calculated as the product of the generator output each hour and the corresponding Locational Marginal Price.[17] It is also noted the operating costs and revenue value are two different ways of cost accounting, but are separate of each other and cannot be directly compared against one another for any given case. Lastly, all economic values are presented in 2017 dollar values.

7.1 Economic Impact of Historical Hydro Operations

As seen in the previous sections, the use of historical hydro limits as inputs into the MAPS simulation produced a fair representation of selected hydro plants without accounting for priority functions, or power constraints. This section examines the operating cost and revenue value impacts of using the historical-hydro operations for the local-priority scenario where both monthly energy values and capacity limits were adjusted in the MAPS model (translating to a reduction of 1,880 GWh in hydro generation). This is compared to the ten-year higher energy hydro operations.

[17] The "revenue value" is not to be confused with the actual revenue as used in the electrical power industry which is a financial construct and has a much different connotation. Typically, revenue is a function of the rate charged and the energy that is produced. In the case of the Federal Power System, actual revenue would not vary, if at all, as new renewable sources are added to the system, the rate would be simply be adjusted to ensure project repayments are met.

7.1.1 Historical Hydro Operations – Operating Cost Analysis

Figure 64 illustrates the total WECC operating costs per MWh of hydro generation between the two scenarios. From this level, there appears to be almost no difference between each case. By taking the difference between the cases (i.e. historical-hydro – base cases), the magnitude of historical-hydro operations is revealed.

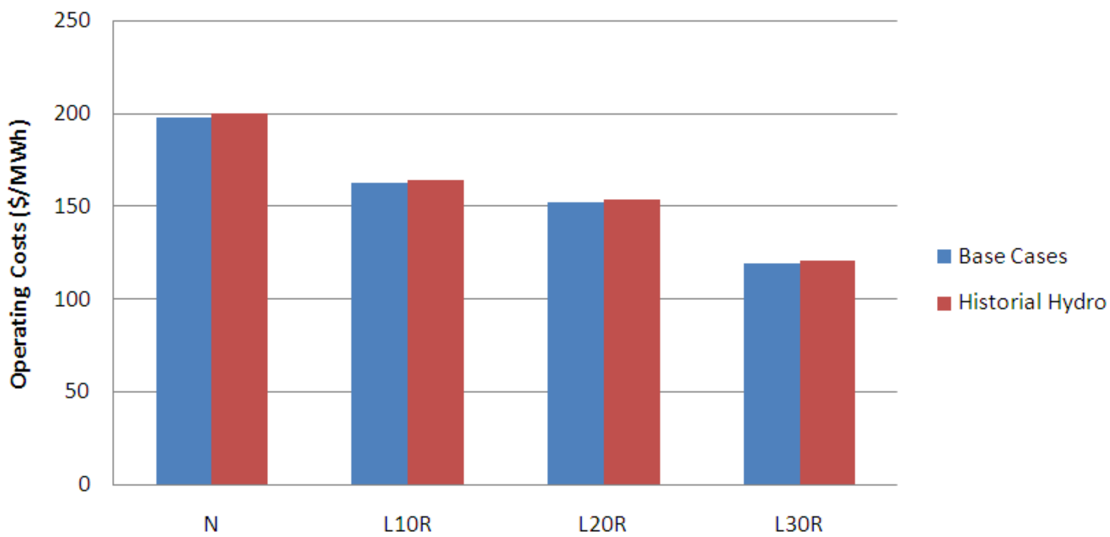

Figure 64: Operating costs per MWh of hydro generation between base cases and historical hydro operation, WECC.

Figure 65 shows the operating cost increase per MWh of reduced hydro energy capacity. For example, in the no-wind case, WECC operating costs would increase by $115/MWh of reduced hydro capacity and energy. These values can be transformed into total operating costs as seen in Figure 66. Interesting enough, these values exceed $175 million for every case, with the no-wind case exceeding $200M. As a reference of scale, this difference is less than 1% of total WECC operating costs.

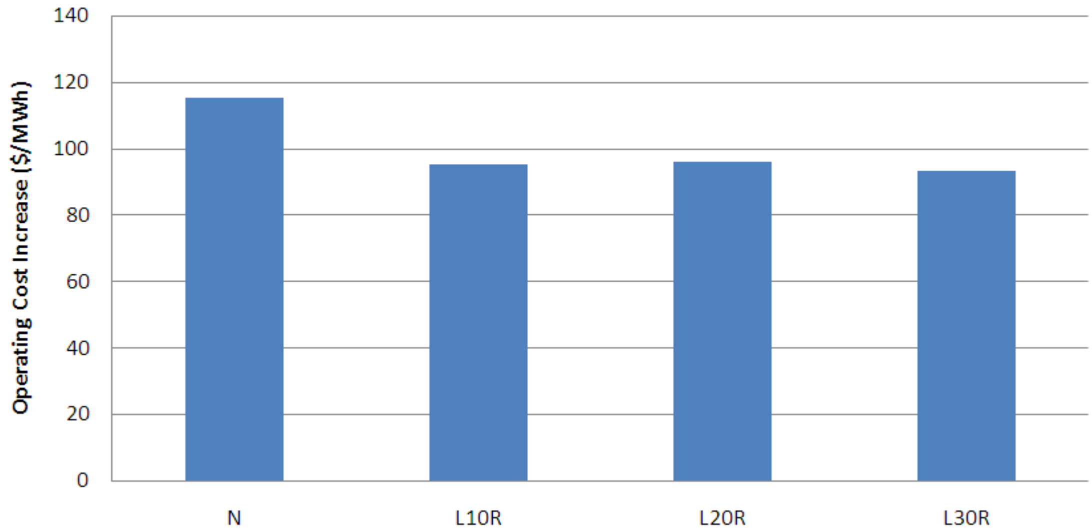

Figure 65: Operating cost increase per MWh of reduced hydro energy, WECC.

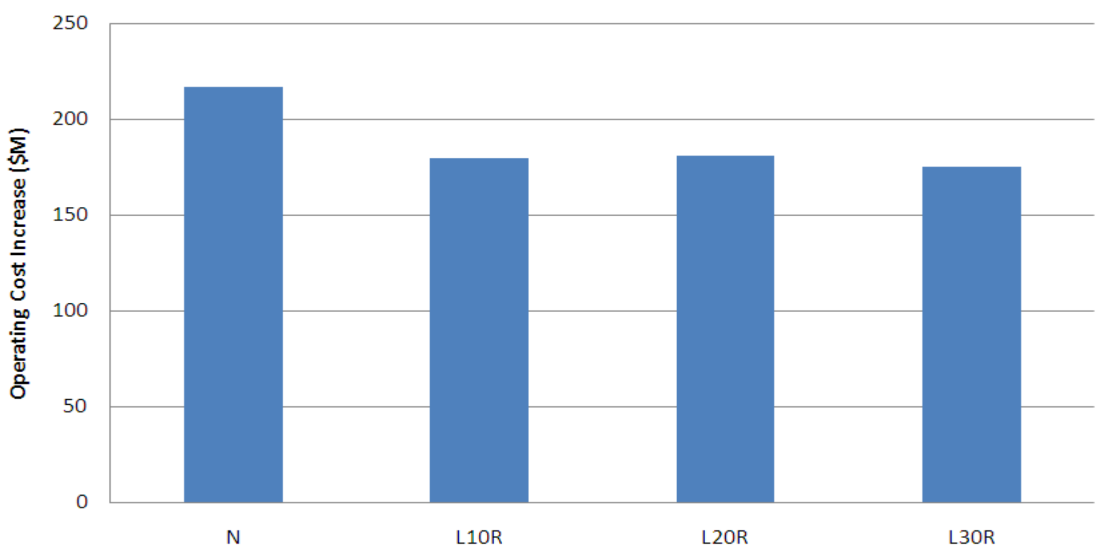

Figure 66: Total operating cost increase due to de-rated historical hydro operation, WECC.

7.1.2 Historical Hydro Operations – Revenue Value Analysis

Another result of using de-rated hydro capacities and monthly energies of historical-hydro operations is that hydropower revenue value will be reduced. Making a similar comparison as prior shown, the revenue value between the base-case operations and historical-hydro operations is compared. This is shown in Figure 67. As a point of reference, there is 12,185 GWh of hydro generation produced in the historical-hydro cases while the base-cases produced 14,065 GWh of hydro generation. Again, the delta is taken between the two cases (i.e. base cases – historical-hydro). Figure 68 shows the hydro revenue value losses associated with historical-hydro operations. De-rating the hydro system at selected hydropower plants reduces hydro revenue value located within the study footprint by $200-$150 million (approximately 15% of total hydro revenues) or $105-$80 per MWh of reduced hydro generation.

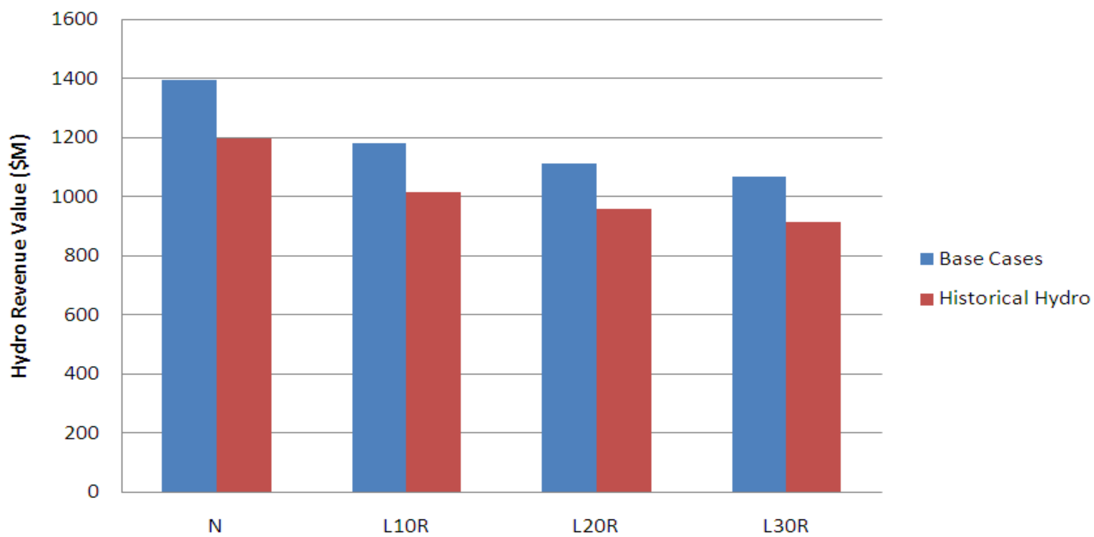

Figure 67: Hydro revenue across base cases and historical hydro operation, Footprint.

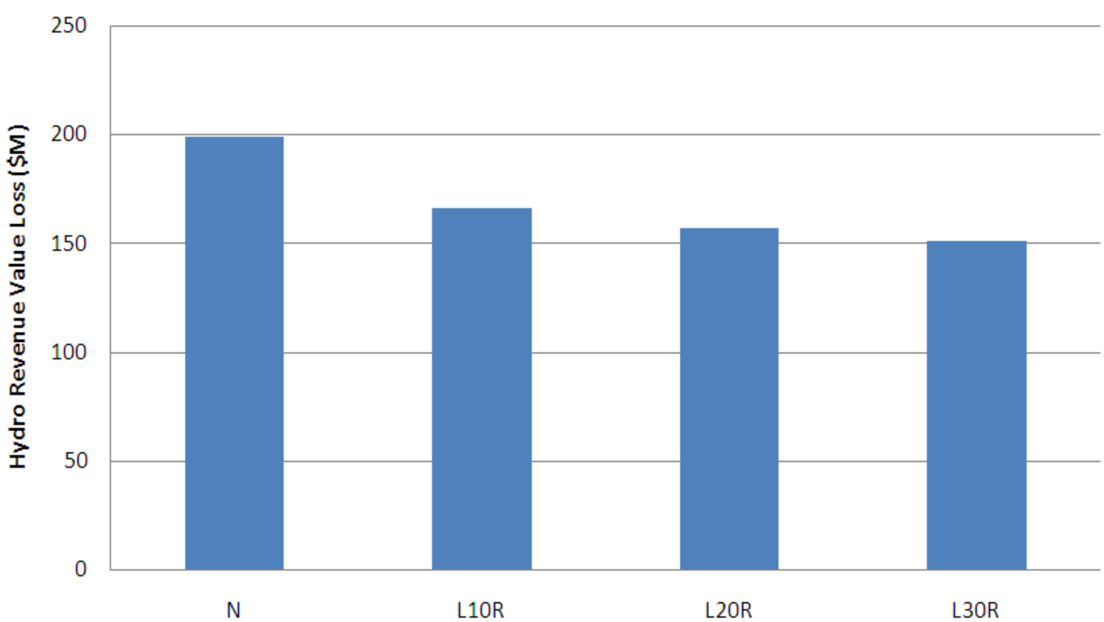

Figure 68: Incremental hydro revenue loss impact of historical hydro operation, Footprint.

7.2 Economic Impact of Flat Hydro Operations

One of the positive effects of using hydropower to meet the increased reserves and flexibility requirements caused by integrating large amounts of wind power is reducing overall system operating costs. This is due to hydropower having a very low cost compared to other flexible generation resources such as combustion turbines. To the extent that there are cost savings, this represents an opportunity for those that possess hydro generation to benefit economically. To address the question of the value of hydropower's balancing capabilities when compared to other generation resources in providing the increased ancillary services required by renewable energy, hydropower resources in MAPS were modeled as flat-block monthly outputs (denoted as flat-hydro or "–Hf"), removing all inherent flexibility and reserve capabilities of hydro in the MAPS model. In modeling the flat-block hydro, the available generation capacities were reduced to an average value for each month such that the hydro plant was not able to provide any sufficient reserves or storage capabilities. Figure 69 shows the difference in hydro generation using flat-hydro limits and the base-case limits at Hoover Dam for the local-priority scenario with 20% penetration levels. As shown the hydro system was forced to run at a fairly constant level for every hour during a given month in order to generate the required monthly energy. The results from this analysis may also be interpreted as having a severely constrained hydropower system in which high priority functions and generation restrictions restrict hydro flexibility to a "run-of-river" type operation.

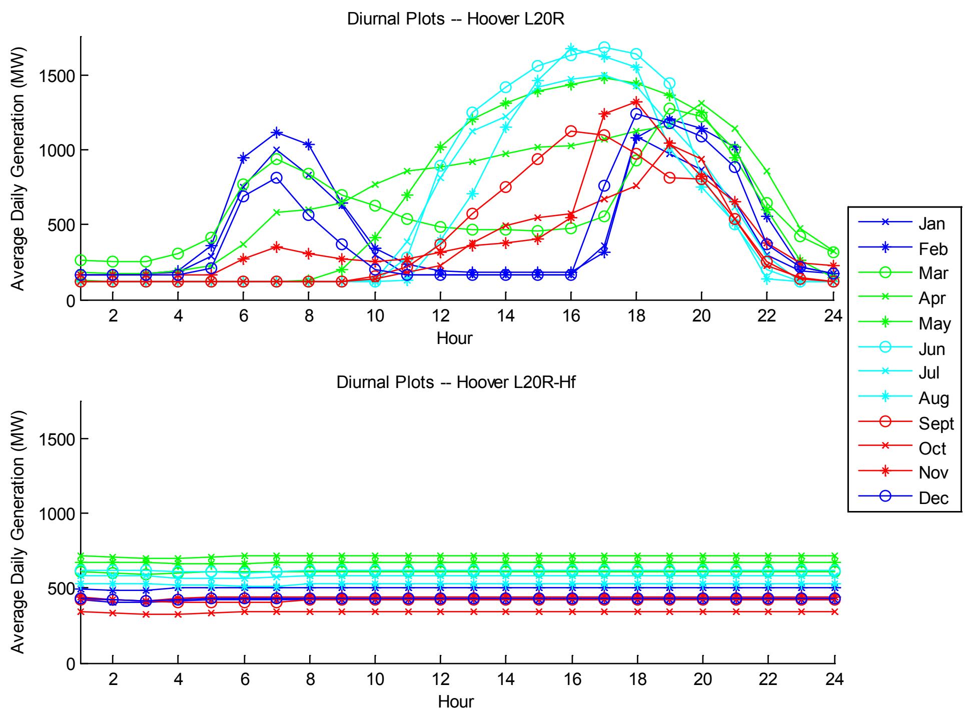

Figure 69: MAPS monthly diurnal plots illustrating the flat-hydro output at Hoover Dam.

7.2.1 Flat Hydro Operations – Operating Cost Analysis

Figure 70 shows the WECC operating costs per MWh of generation by source for the base-cases. Similar results were produced for the flat-hydro operating costs, though not shown. Figure 71 illustrates the delta impact on WECC operating costs per MWh of generation (i.e. flat-hydro – base-cases) by generation source. As shown, a reduction in hydropower's flexibility results in a dramatic increase in operating costs for the steam turbine and LUMP (small generic resources < 20 MW) generation fleet.

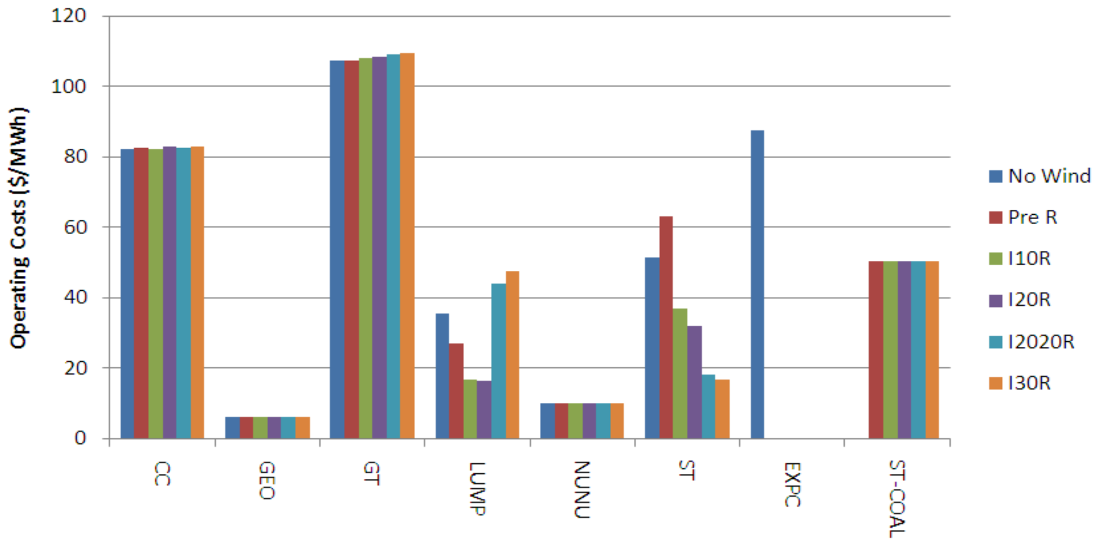

Figure 70: Base case operating costs per MWh of generation by source, WECC.

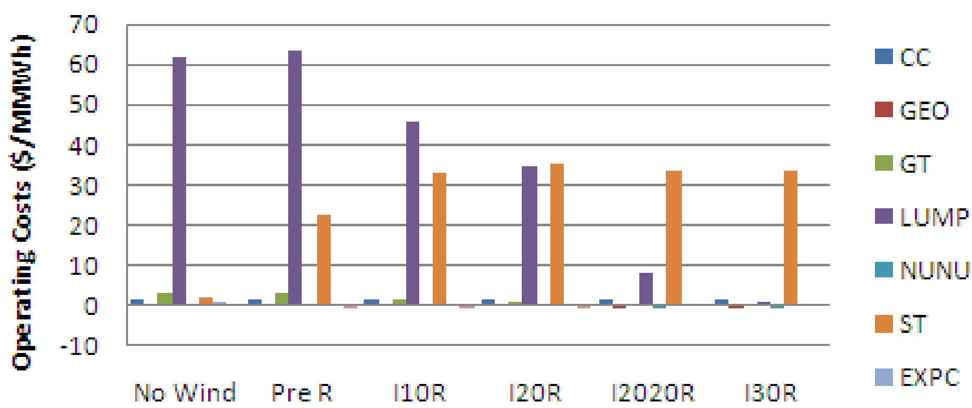

Figure 71: Incremental operating cost impact per MWh of generation of flat-hydro operations by generation source, WECC.

Figure 71 can be converted to show the net impact on WECC operating costs. This is shown in Figure 67. The results displayed essentially show a "bookend" of the value of the hydro flexibility and reserves, and that it varies from $860M to $1180M (2% of total operating costs in

WECC) in reducing overall system operating costs, or $10.00 to $4.00 per MWh of wind generation.

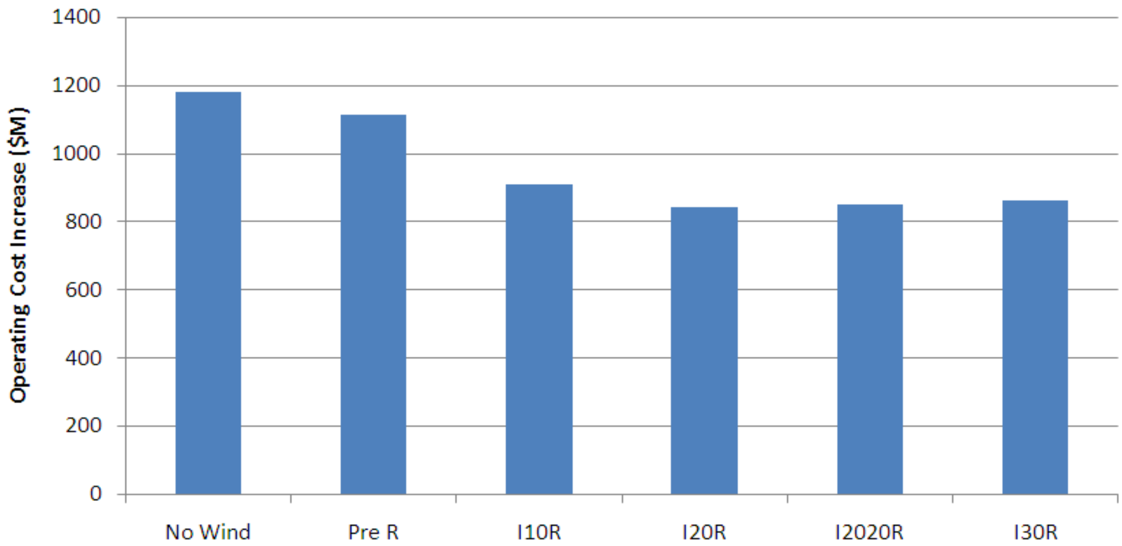

Figure 72: Total incremental operating cost impact of flat-hydro operations at various wind penetrations, WECC.

7.2.2 Flat Hydro Operations – Revenue Analysis

Figure 73 illustrates the footprint hydro revenue value between the base-cases and flat-hydro operations. As a point of reference there is 14,065 GWh of hydro generation produced within the footprint for each case. Figure 74 shows the delta in revenue between each case (i.e. base-cases – flat-hydro), as a reference, this is approximately 5% of total hydro revenues for each case. As expected, hydro acquires revenue value loss across each penetration level with the least amount of loss occurring at the 20% level due to the fact gas turbine and combine-cycle units are continuously on the margin.

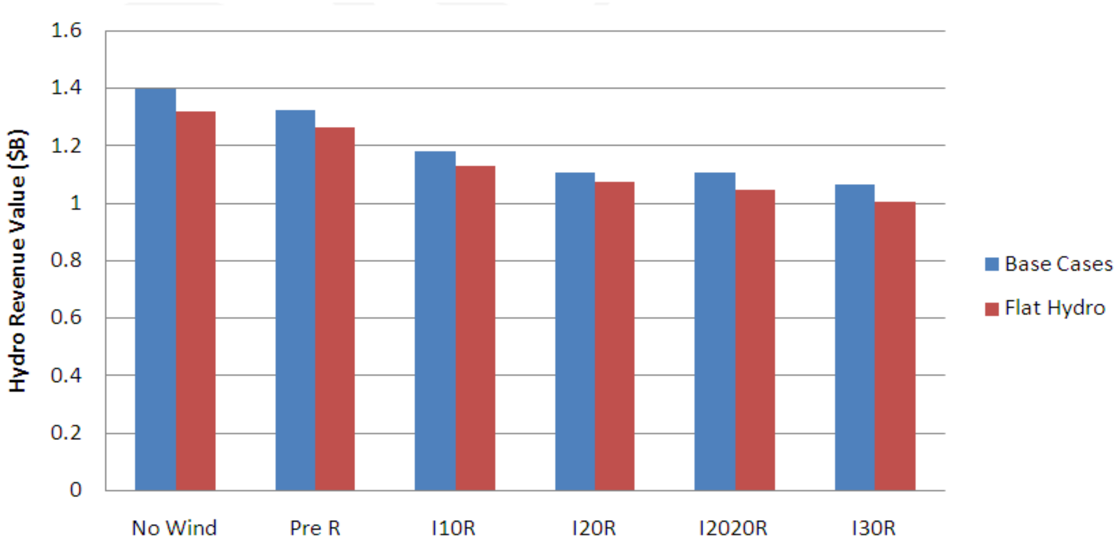

Figure 73: Hydro revenue value between base-cases and flat-hydro operations, Footprint.

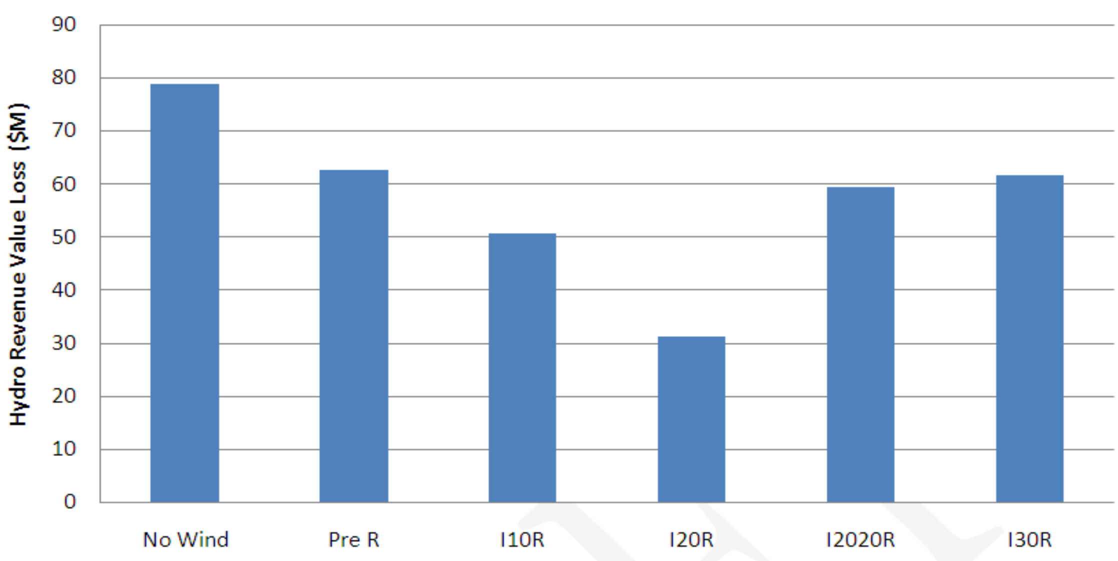

Figure 74: Incremental hydro revenue loss of flat hydro operations at various wind penetrations, Footprint.

Similarly, the revenue value impact of flat-hydro operations can be observed at the selected hydro plants located within the study footprint as shown in Figure 75. As can be seen, flat-hydro operations have almost no impact on smaller hydro facilities, though a more noticeable impact is seen on larger hydro plants.

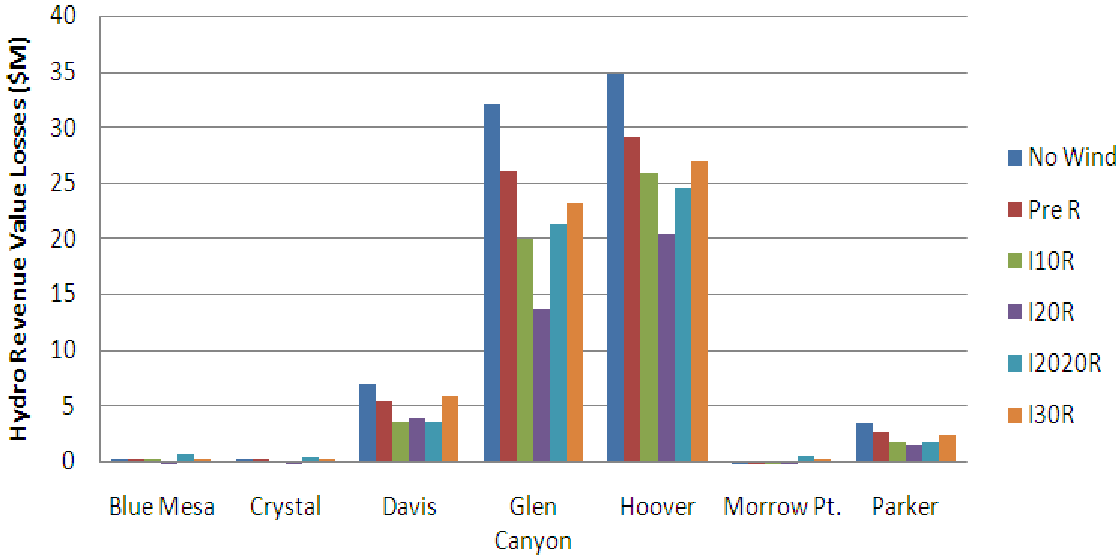

Figure 75: Incremental revenue value losses of flat-hydro operations at selected hydro facilities located within the Footprint.

The remainder of this section highlights results found from a similar analysis conducted for flat-hydro operations in the WECC. Figure 76 shows the delta (i.e. flat-hydro – base-cases) in WECC revenue value per MWh of generation by source at various wind penetration levels. From this macro level, there appears to be several generation sources incurring revenue loss at penetration levels beyond 20% including: geothermal, nuclear, steam-coal, wind, and hydropower. Remarkably, at the higher penetration levels beyond the 20% case, flat-hydro operations actually decreases the value of wind by a few $/MWh. Overall, flat-hydro operations increase the value of renewables by a few $/MWh, this is due to the fact that flat-hydro operations alleviates the use of peaking units, especially in the no-wind case where peaking units experience shortages. Wind and solar generation alleviate these shortages.

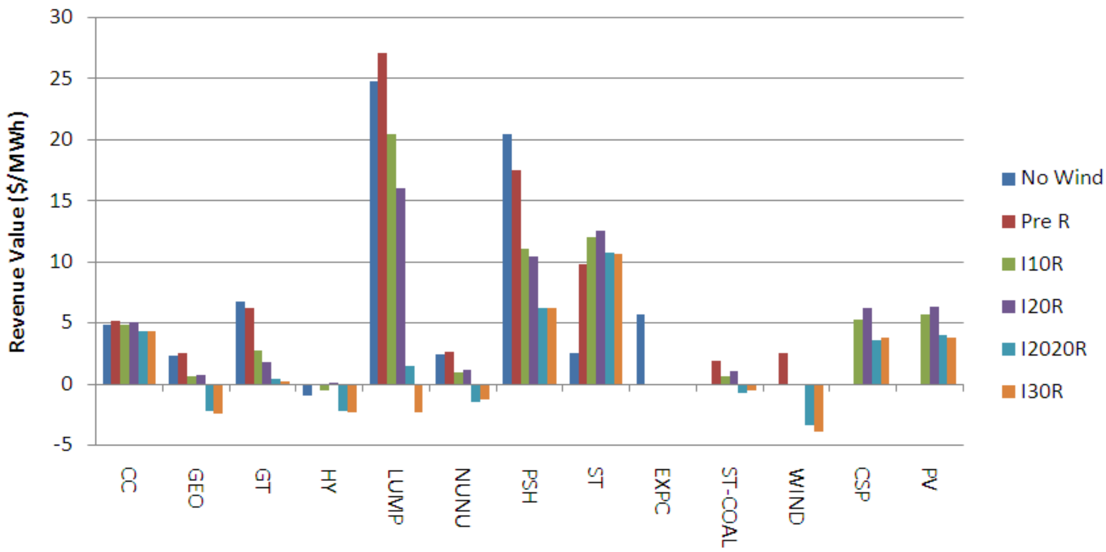

Figure 76: Incremental revenue per MWh of generation of flat hydro operations by generation source at various wind penetrations, WECC.

A better representation of the revenue values is shown in Figure 77 where the revenue values are taken as a product of each generation source for each penetration level (i.e. flat-hydro-base-cases). As a reference, this total incremental revenue impact is approximately 3% of total revenues. As shown, flat-hydro operations actually decrease overall WECC revenue value at penetration levels beyond 20%, that is, wind power is at the point where it carries enough capacity such that hydro's flexibility is less valued in the system.

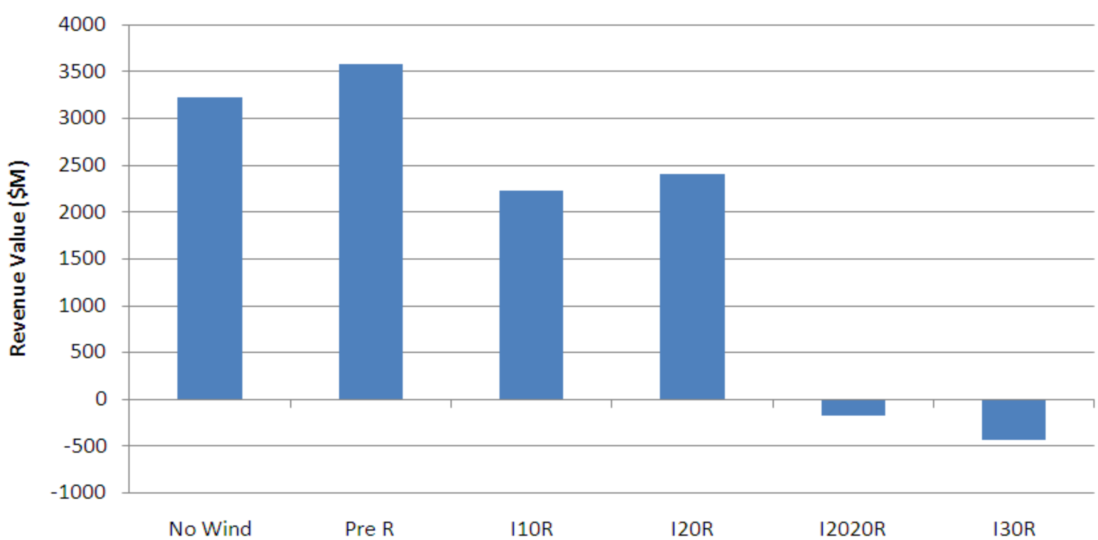

Figure 77: Total incremental revenue impact of flat hydro operations at various wind penetrations, WECC.

7.3 Economic Impact of Load Only Operations

Hydropower has several inherent characteristics that make integrating wind power beneficial to the electrical power system. Hydropower has the ability to meet rapid changes in net load, shift energy generation around times of increased wind production, and supply fast responding spinning and non-spinning reserves. Additionally hydropower has the ability to provide voltage support to wind systems by supplying reactive power. All of these are of great importance to a power system that incorporates high levels of variable and uncertain generation resources. By providing these services, there exists opportunity for hydropower producers to benefit economically. Up to this point, all hydro analysis has been conducted on hydro that is scheduled and dispatched to the net-load. This section examines the economic benefits of hydropower participating in wind integration. To deduce this value, hydro was schedule to the load before renewable generation (i.e. hydro scheduled to load-only, noted has "–H") rather than after it (i.e. hydro scheduled to net-load). Figure 78 shows MAPS daily averaged hydro generation for Glen Canyon for the L20R case with the blue line indicating hydro dispatched to load-only and black line indicating hydro dispatched to the net-load. As can be seen, the hydro generation dispatched to the net-load (black line) uses considerably more hydro flexibility, especially during the windy months of the year (i.e. spring months).

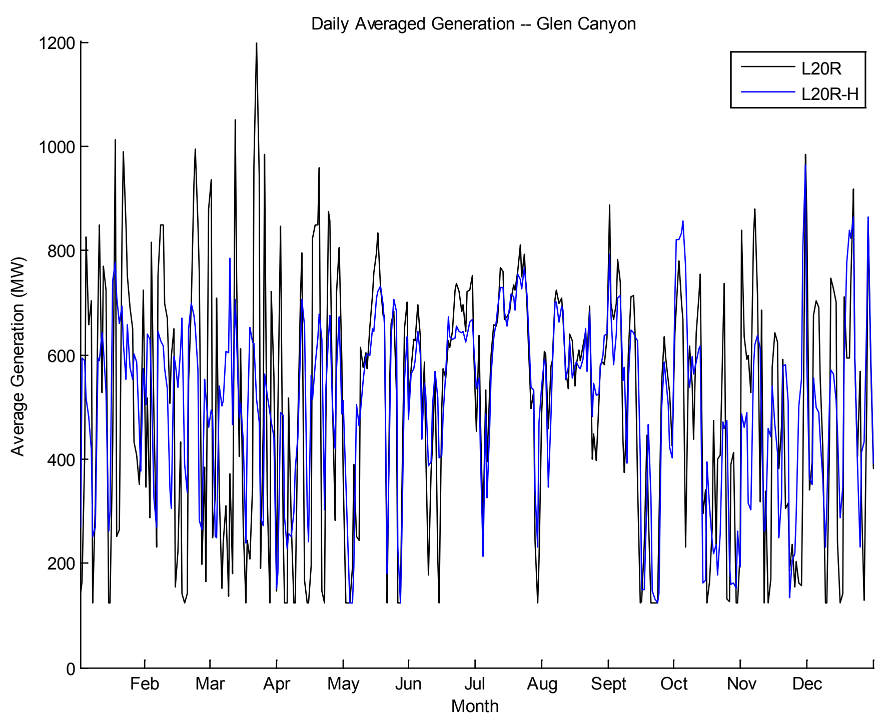

Figure 78: MAPS daily averaged hydro generation for 20% penetration levels denoting load-only ("-H") hydro generation by blue line for Glen Canyon.

Figure 79 shows the spot price duration curves for the various penetration levels for the hydro scheduled to net-load and when the hydro is scheduled on load alone. In the hydro dispatched to load-only, the hourly hydro generation remains unchanged between each case where as hydro dispatched to net-load is allowed to follow the load within the defined monthly energy and capacity limits defined for each facility. As shown, there is not much shift in spot price between any pair of cases at the same penetration with the exception of the 30% penetration level where spot prices are lowered modestly for the load-only scenario. To further investigate the impact on revenue and associated system operating costs with scheduling the hydro to load-only, an in-depth analysis was conducted on footprint and WECC operations. These results are shown in the following sections.

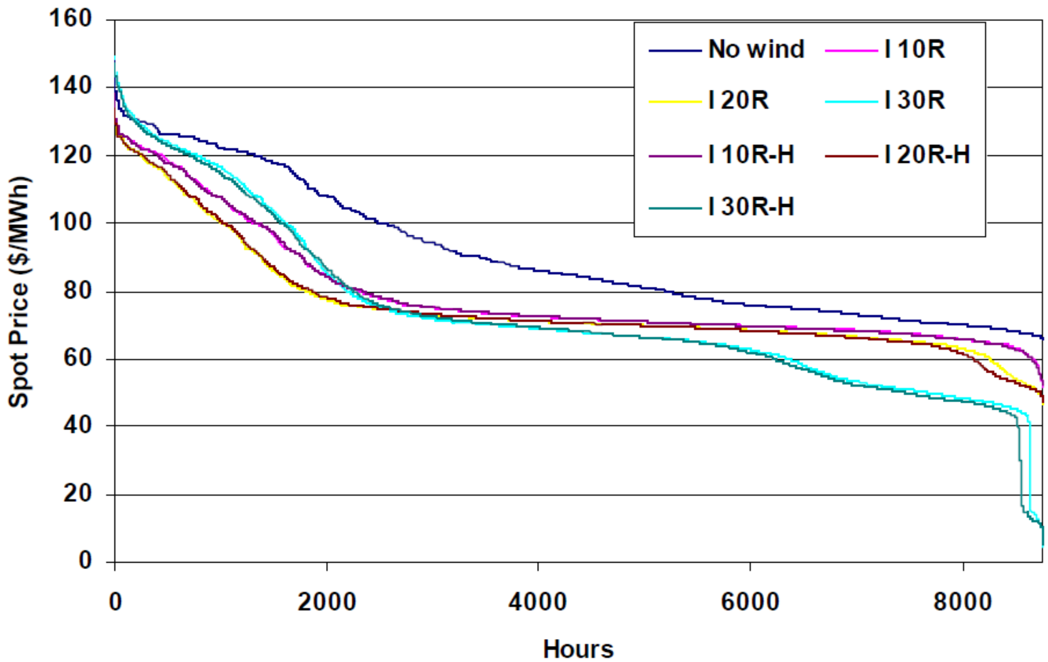

Figure 79: System spot price impact of hydro scheduled to load-only vs. hydro scheduled to net-load, WECC. (Source: GE Energy 2010)

7.3.1 Load Only Operations – Operating Cost Analysis

Figure 80 shows the operating costs per MWh of generation by source for the hydro scheduled to load-only case. The base-case operating costs are not shown, but have a similar magnitude and shape. Figure 81 shows the delta impact (i.e. load-only – base-cases) of load-only operations on operating costs per MWh of generation by source. As shown, several generation sources have a slight increase in operating costs due to load-only operations like that of the steam oil and gas units.

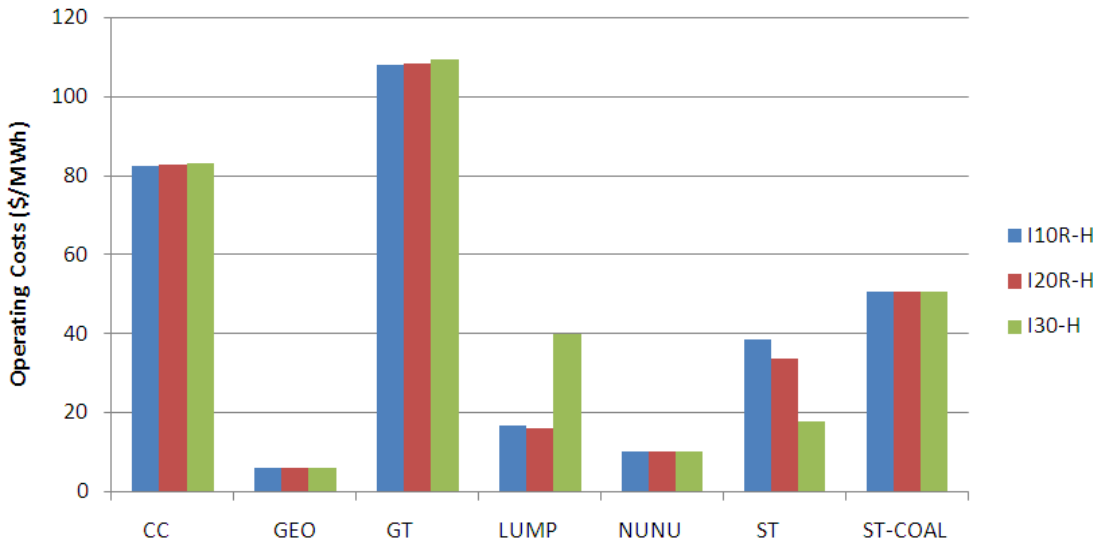

Figure 80: Load-only operating costs per MWh of generation by source for in-area scenario, WECC.

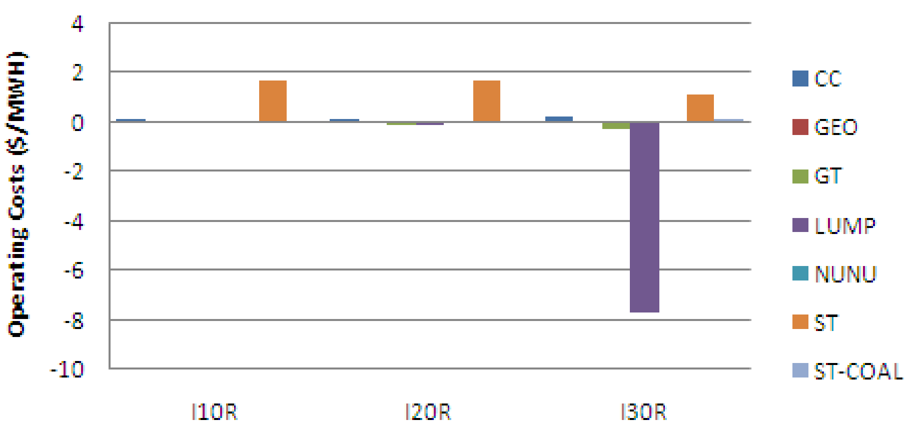

Figure 81: Hydro scheduled to load-only impact on operating costs per MWh of generation, WECC.

Figure 82 shows the delta in total WECC operating costs between the base-cases and hydro scheduled to load-only. Although the operating cost increase is relatively small for low renewable penetrations, they exceed $200M for the 30% case (2% of total operating costs).

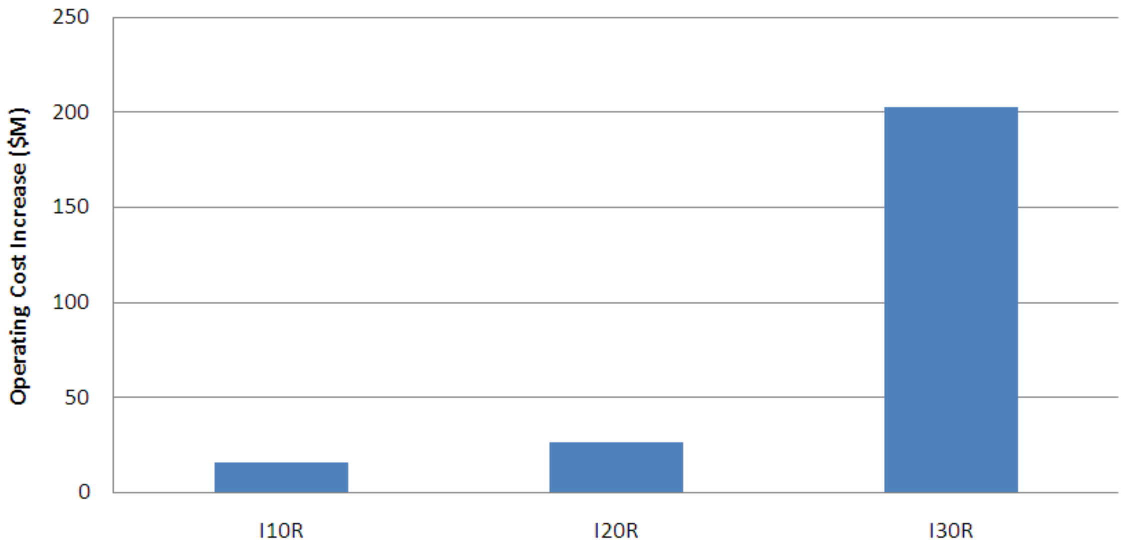

Figure 82: Total operating cost increase for load-only operations, WECC.

7.3.2 Load Only Operations – Revenue Value Analysis

A similar analysis was conducted for revenue value rather than operating costs for the study footprint and WECC. Figure 83 shows the hydro revenue value losses over the varying penetration levels. Hydropower revenue value losses are relatively small for low penetration levels but exceeded $45M or $3/MWh of hydro generation for the 30% case (11 % of total hydro revenue value).

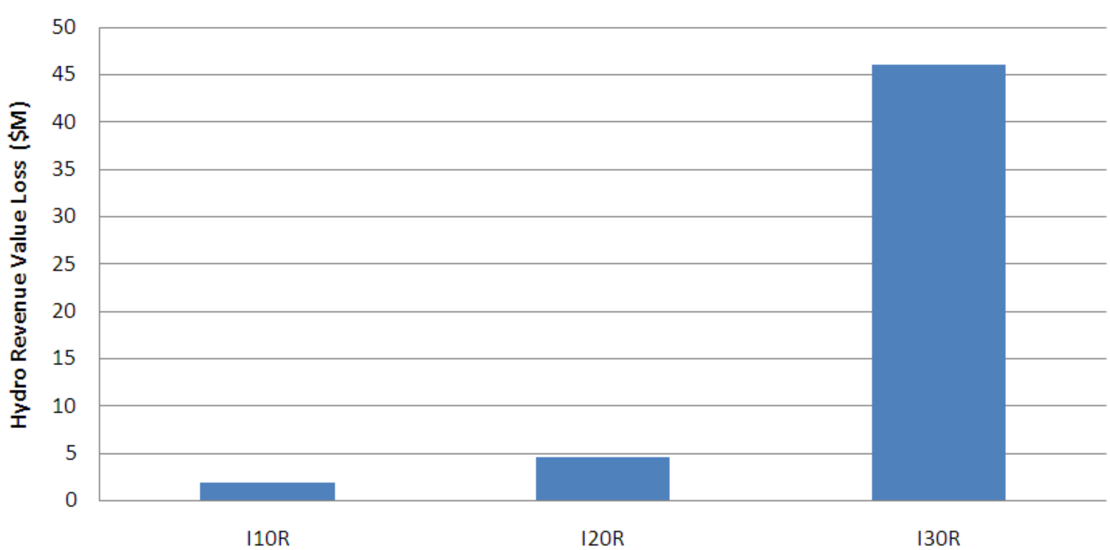

Figure 83: Hydro revenue value loss for dispatching hydro on load alone vs. hydro schedule to net load, Footprint.

Figure 84 shows the annual footprint revenue value losses at selected hydro facilities due to load-only operations. Again, at the lower penetration levels, there is a small change in revenue values, especially at the smaller hydro facilities. At the 30% penetration level, revenue value loss is dramatically increased with the majority of losses occurring at Hoover Dam ($18M) and Glen Canyon Dam ($16M).

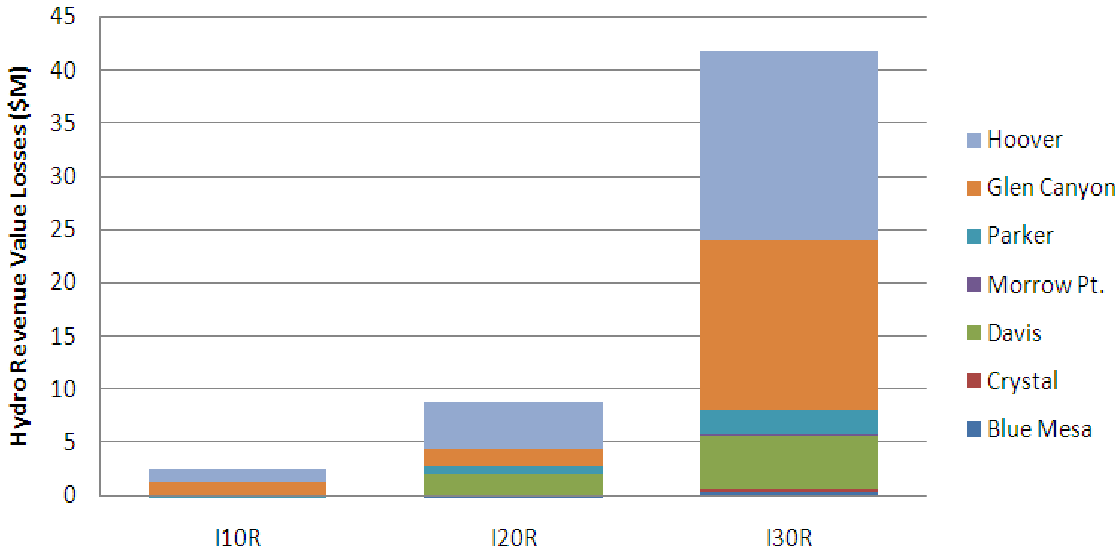

Figure 84: Revenue value loss for load-only operations at selected facilities located within the footprint. Losses

The remainder of this section examines the WECC revenue value impact of hydro scheduled to load-only when compared to base-case operations. Figure 85 illustrates the WECC revenue value spot prices by source for load-only operations. Base-case operations results in a similar plot, but is not shown. As can be seen, there are modest differences in revenue value between generation sources with the exception of the steam oil and gas units where a higher use occurs due to the increased need of flexible generation resources.

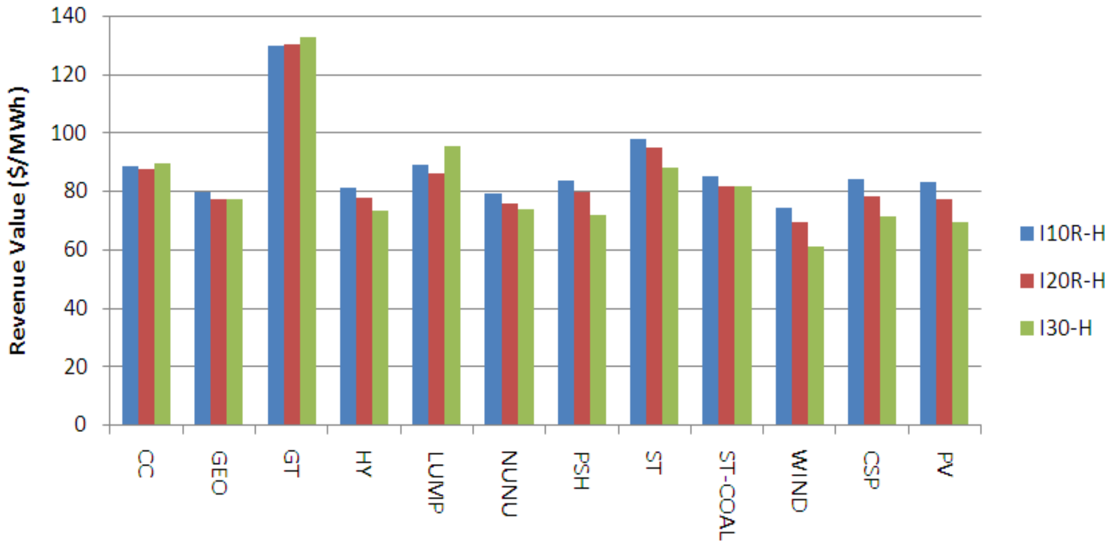

Figure 85: Revenue value per MWh of generation by source for hydro scheduled to load only case, WECC.

Figure 86 shows the incremental WECC revenue value impact of load-only operations by generation source. As shown, the lower penetration levels have a modest revenue impact. At the 30% level, nearly every generation sector has a decrease in value with renewables decreasing in value by nearly $4/MWh.

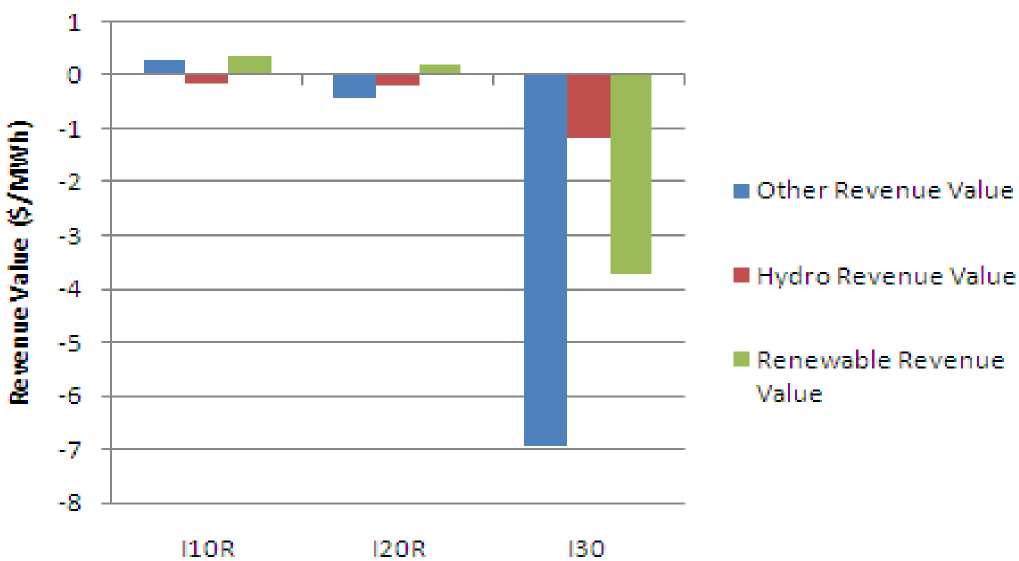

Figure 86: Revenue value per MWh of generation impact for load-only operations, WECC.

Figure 87 and Figure 88 converts' revenue values from the above graph to total hydro revenue value losses and total WECC revenue value losses, respectively. Again, revenue value losses are modest at the lower penetrations for each case, but exceed $290M in hydro revenue losses (approximately 3% of total hydro revenue value) and over $1 billion on a WECC wide basis at the 30% penetration level (approximately 4% of total revenue value).

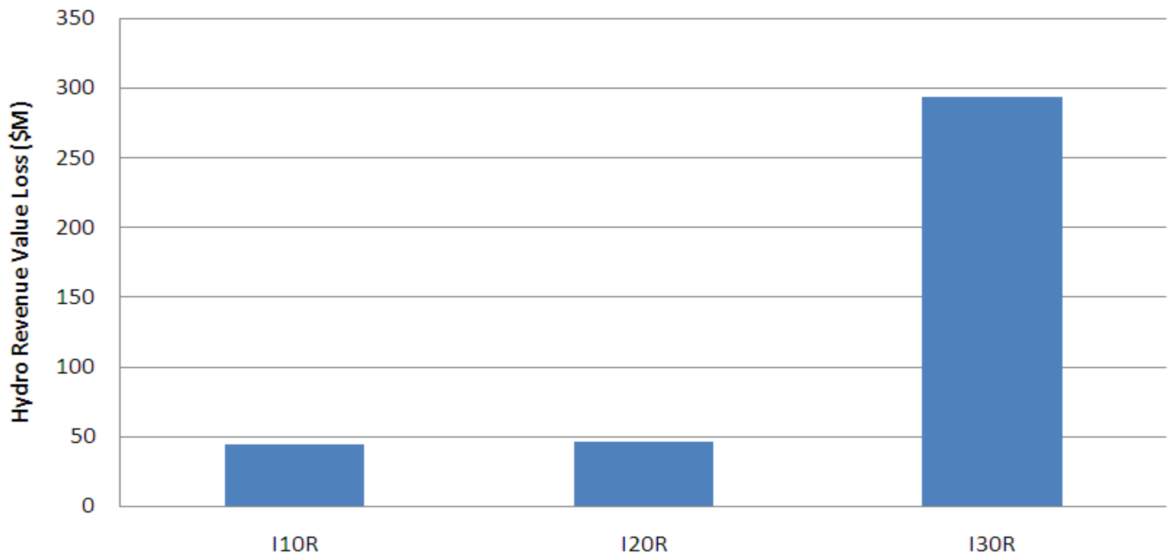

Figure 87: Total hydro revenue loss for load-only operations, WECC.

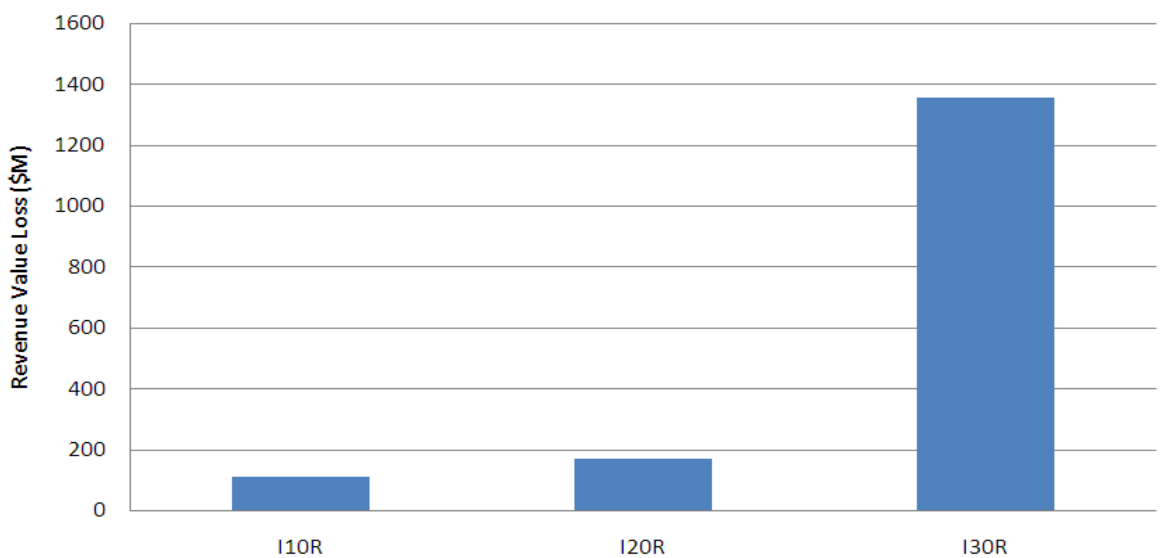

Figure 88: Total revenue value loss for load-only operations, WECC.

8.0 Analysis of Pumped Storage Hydro

Up to this point, analysis has been conducted on both selected hydro facilities and aggregated hydropower use located within the study footprint and on a WECC basis. This chapter investigates the application of energy storage in the form of pumped storage hydro (PSH). Along with a brief description into PSH basics, this chapter is divided into three main topics. The first section highlights the results found from the WWSIS. Secondly, using actual hourly pumping and generation data from the Mount Elbert PSH plant (located within the study footprint), operations are examined and compared to MAPS simulated data over a range of renewable penetrations. Lastly, an economic analysis will show the impact of renewables on PSH operations and most importantly, the implications of renewable generation on spot prices and how this affects PSH operations.

8.1 PSH Introduction

Pumped storage hydro relies on the basic principle of "load factoring". The process of load factoring relies on the price differential between high-demand periods (price of electricity is high) and low-demand periods (price of electricity is low). During high-demand periods, water is released from an upper reservoir via pipes which are connected to turbines located at the lower reservoir. Pumping of water to replenish reserves occurs during low-demand periods. Generally speaking, roundtrip electrical efficiencies of PSH can reach levels of 70% to 80% (Tester 2005). As used in the WWSIS, pumped storage was assumed to have a round trip efficiency of 75%, thus the minimum price differential between the peak and off-peak periods required to break even is 1.33; that is, on-peak market prices would have to be 33% higher than off-peak pumping prices. If overall roundtrip electrical efficiencies increase, this percentage is reduced (e.g. 80% efficiency would result in a price differential of 1.25).

Pumped hydropower storage plants are primarily valued due to their ability to provide up-regulation, down-regulation, spinning reserve, non-spinning reserve, frequency control and other ancillary services, as well as their ability to load factor. For example, PSH can provide ancillary services required due to wind's variability and uncertainty. PSH also has the ability to provide some storage in the form of the upper reservoir in which it can be used to compensate for wind forecast uncertainty and thereby allow wind to bid into the day-ahead markets for commitment. However, there are certain limitations associated with any system modeling effort, and in the case of the production cost modeling performed here, the economic aspect of PSH that was evaluated was that related to load factoring; in particular, how will price the on-peak/off-peak price differential be effected by large-scale renewable energy penetration, and what effect will that have on PSH. Other economic factors (i.e., frequency control) were not evaluated in the WWSIS or this study. As will be presented below, results from the WWSIS indicate that it may make more economic sense, from a system standpoint, to commit the other (non-PSH) fast-responding system generation (e.g. natural gas turbines) based on State-of-the-Art wind and solar forecasts, and to cover the errors in these forecasts with operating reserves, quick-start generation and demand response.

8.2 PSH Results from WWSIS

This section is broken into two main topics covered by the WWSIS. First, the base-case assumption of PSH schedules are based on the assumed cost of pumping versus the assumed value of the generation it displaces is investigated. Secondly, a sensitivity analysis was conducted to estimate the economic feasibility of a new PSH facility.

8.2.1 Baseline PSH Operations

Figure 89 shows the annual duration curves for the WECC PSH units over a range of renewable penetrations for the in-area scenario using the professional forecast. As can be seen, as renewable penetration levels increase, the utilization of PSH increases slightly but does not push the usage to a point where more storage would seem required as would be indicated by flat portions at either extreme of the curve (i.e. indicating saturation). Similar results were found for PSH within the study footprint.

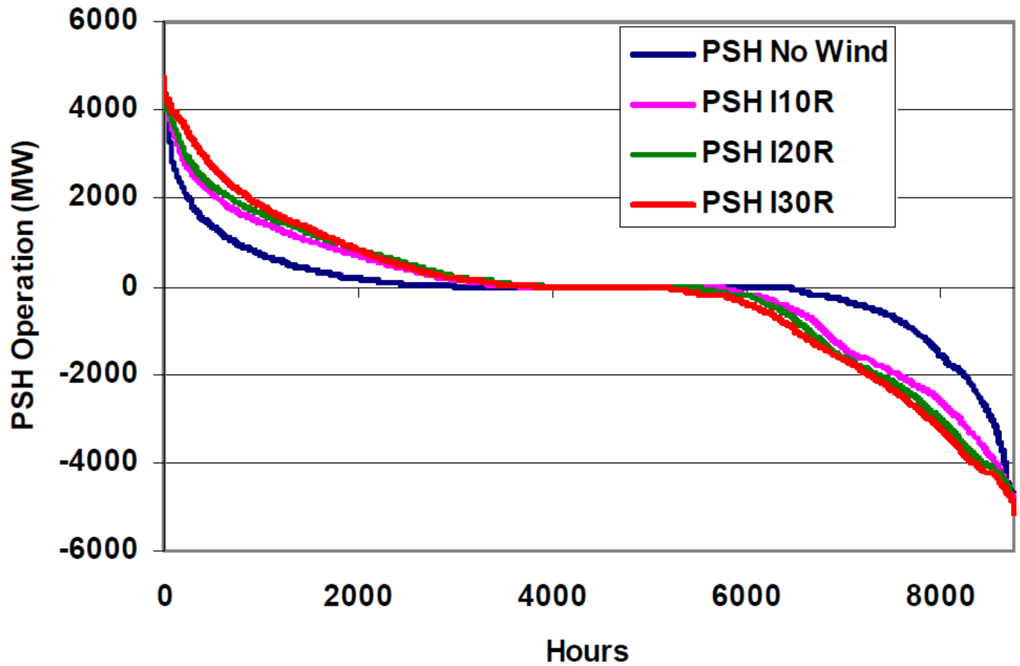

Figure 89: PSH annual duration curve, WECC. (Source: GE Energy 2010)

It is noted that PSH storage schedules are planned based on the assumed cost of pumping versus the assumed value of the displaced generation for the coming day and week. In order to validate these baseline assumptions not being overly conservative, the simulations were re-run using a pumping cost discount multiplier by either 0.75 or 0.50 before being compared to generation savings (e.g. if the pumping energy costs was $600, then the 0.75 discount would make the effective pumping cost to only be $450, thus making the PSH more economical and would be assumed to be utilized more). These “discount factors” were only used for PSH decision purposes and do not affect the actual costs of operation. Figure 90 shows the PSH utilization results of discounting the pumping costs. As shown, there is an increased use of PSH operation as the assumed cost of pumping decreases.

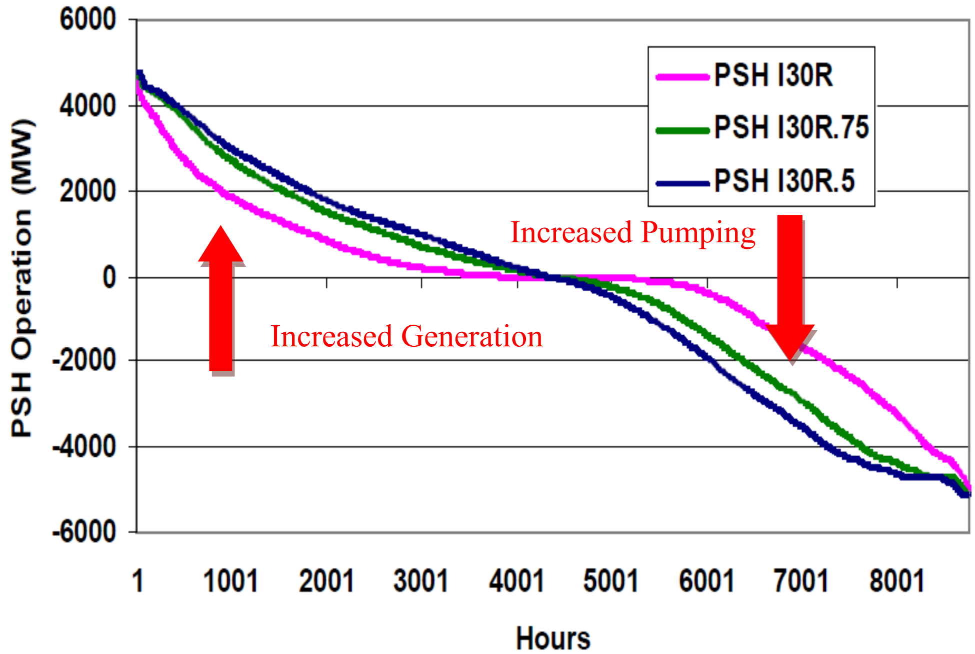

Figure 90: PSH annual duration curve with discounted pumping costs, WECC. (Source: GE Energy 2010)

Figure 91 shows the impact on WECC operating costs with discounting PSH pumping costs. As can be seen, discounting the pumping costs of PSH actually increased the annual total cost of operations by $60M – $120M. Thus the model was forced to operate PSH more than necessary (i.e. increased operating costs) confirming the base-case assumptions were valid.

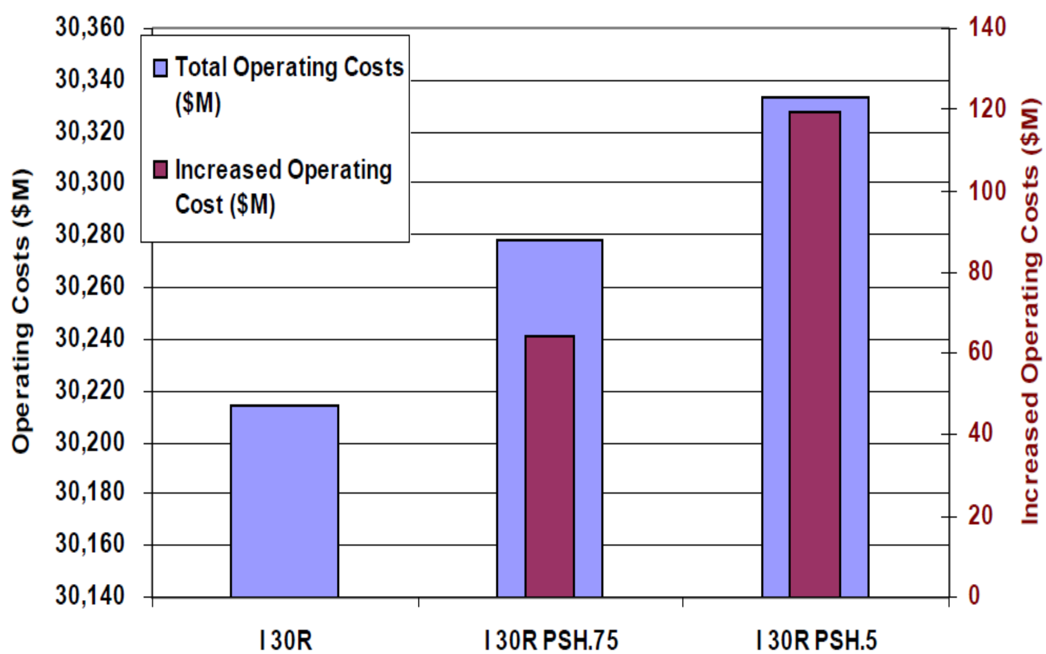

Figure 91: Operational cost impact of discounting PSH operation, WECC. (Source: GE Energy 2010)

8.2.2 PSH Optimization

To investigate the optimization of pumped storage, a new 100-MW PSH plant was added to the Arizona/New Mexico system. In this best-case scenario, the new PSH plant was given perfect foresight of spot prices so that it could best be dispatched to optimize revenue. The results from this best-case scenario are shown in Figure 92 with number of operating hours (left-side of graph) and the operating value resulting from this simulation (right-side of graph). With no renewables, the new PSH plant would run about 2,200 hours (both pumping and generating time) and have an operating value of about \$2.6M for the year. With a 10% fixed charge rate this would result in a capitalized value of roughly \$260/kW. Even with full capacity credits of \$600-\$1,000/kW there still presents a short fall to the estimated cost for a new PSH facility (e.g. \$2,500/kW for LEAPS project, a 500 MW PSH plant in California).[18] With the perfect forecast, the value of the PSH decreased with increased penetration levels due to the spot price being depressed by high levels of wind. With 30% penetration, the 100-MW PSH plant only had an annual operating value of \$0.5M which would only yield a capitalized value of about \$50/kW.

With a State-of-the-Art forecast, initial values decreased slightly but not as much as with the perfect forecast. At the 30% penetration level, the value increases significantly to \$3.8M of annual operating value. This is due to the higher spot prices resulting for increased forecast error. However, this translates to roughly \$380/kW which is far less than would be required to recover the costs of a new PSH plant. Even with perfect foreknowledge of when spot prices will spike and fall does not seem to provide sufficient value to justify adding any new PSH facilities.

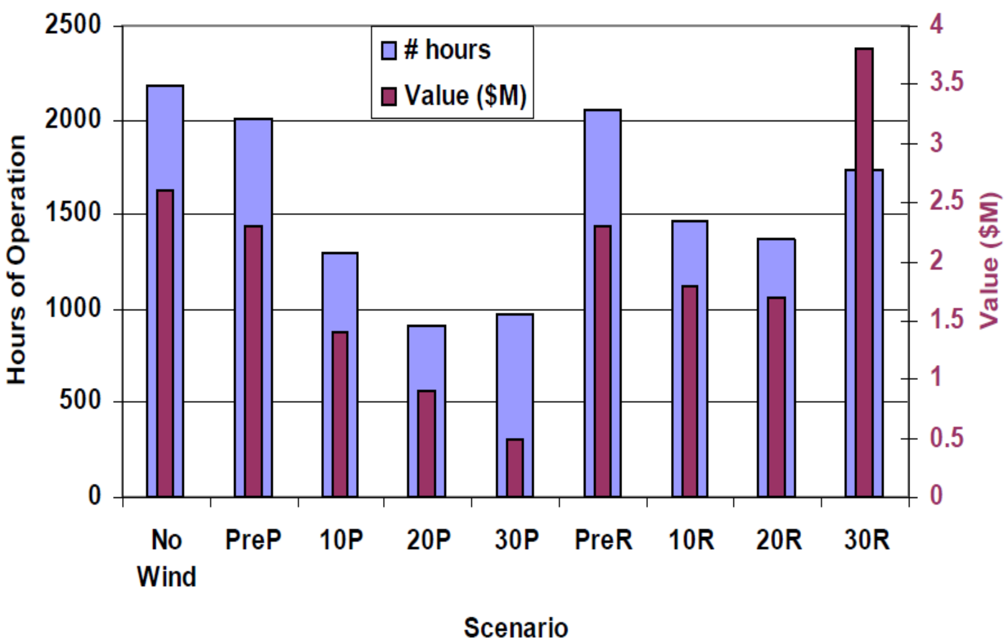

Figure 92: Incremental value of a new 100-MW PSH plant. (Source: GE Energy 2010)

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[18] If one would to assume \$1,200-\$2,000/kW capital cost and a fixed charge rate of 15% for a new PSH facility, \$18-\$20M would be needed to recover capital costs.

8.3 Mount Elbert PSH Operations Analysis

In this section, analysis of Mt. Elbert PSH operations is separated into two parts; the first section compares actual operation patterns from Mt. Elbert PSH to that of MAPS baseline, no-wind scenario (all renewables are taken out of the system). Secondly, Mt. Elbert PSH operations are analyzed as renewables are introduced.

It is noted that in the MAPS simulation, monthly energy inputs and capacity limits defined by the ten-year averaged database were used for PSH operations. PSH plants were allowed to operate within these defined limits but not forced to run if the economic factors or load factoring deemed unfavorable, thus PSH plant operations and resulting energy outputs may vary between the scenarios.

8.3.1 Mount Elbert PSH actual Operations versus MAPS no-wind Operations

In the first evaluation, actual PSH operations are compared to the MAPS no-wind simulation for Mt. Elbert PSH plant. Figure 93 shows the annual generation duration curve between the two data sets. As shown, there is a significant difference in flexibility used and lower pumping limits between the simulated and actual profiles. For this case, actual generation was found to be 326 GWh while the MAPS simulation generated only 98 GWh, a 70% decrease in production. Additionally, actual hours of operation were found to be 7,958 hrs at 5,083 hrs generation and 2,875 hrs of pumping. The no-wind scenario was only 1,935 hrs at 851 hrs of generation and 1,084 hrs of pumping.

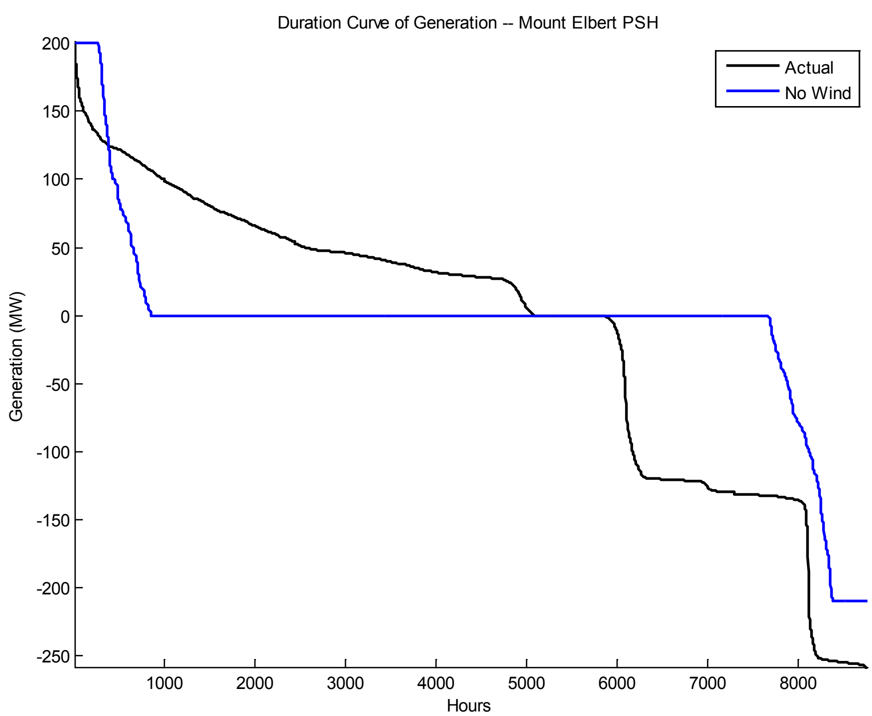

Figure 93: Annual Duration curve comparing actual and no-wind PSH generation at Mt. Elbert.

Figure 94 shows the monthly averaged diurnal distributions comparing actual (top graph) and no-wind (bottom graph) PSH operations at Mt. Elbert. As can be seen, actual generation profiles show increased use throughout the months during high-load-hours where MAPS opts to commit the majority its generation resources during the peak afternoon-evening load periods. Furthermore, the MAPS simulation has several months where little generation occurs (e.g. spring and fall months).

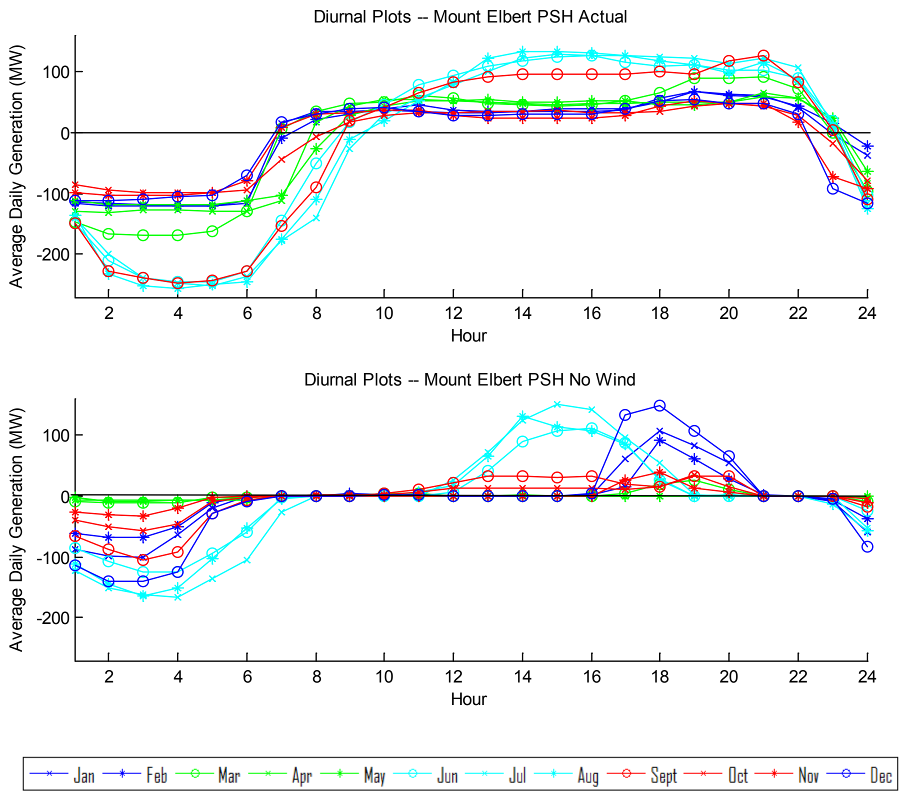

Figure 94: Monthly diurnal distributions of Mt. Elbert PSH plant for actual and MAPS no-wind data sets.

There are two explanations for the dramatic change in operations between actual operational profiles and the MAPS simulation, both of which are not accounted for in the MAPS simulation. As prior mentioned, the forebay of the Mt. Elbert PSH station receives the majority of water via pumping from the afterbay (i.e. tailbay) of Twin Lakes. The forebay is also supplemented from Turquoise Lake, thus reducing the amount of pumping time required to fill the forebay to adequate levels. For example on July 4, 2004, the plant pumped a total of 10 hours at 1,458MWh and generated for 13 hours for 1,502MWh. A second consideration that was not accounted for in the MAPS programs is Mt. Elbert's ability to provide ancillary services (e.g. regulation, spinning and non-spinning reserves, frequency control, voltage support, and other ancillary services that would cause units to run at a more constant rate of generation throughout the day). Together, supplemental forebay feed coupled with the capacity to provide ancillary services, Mt. Elbert PSH actual generation profiles differ greatly from the typical load factoring profiles of the MAPS simulation.

8.4 Mount Elbert PSH Economic Analysis

As prior shown, the investment of a new 100 MW PSH plant did not seem economically plausible. One of the effects of using wind power in a de-regulated market is that spot prices will ultimately be driven down as penetration levels increase. Additionally system spot prices often fluctuate heavily throughout the day, thus making it more difficult for new generation resources like PSH to recover initial capital costs. This section investigates the economic impact of wind energy on spot prices seen at Mt. Elbert PSH plant. In MAPS, all PSH plants assume a closed-water-loop system and typical load factoring capabilities. Figure 95 illustrates the hourly spot price duration curves seen at Mt. Elbert PSH plant for the local-priority and no-wind scenarios. As can be seen, as renewable penetration levels increase, spot prices are decreased.

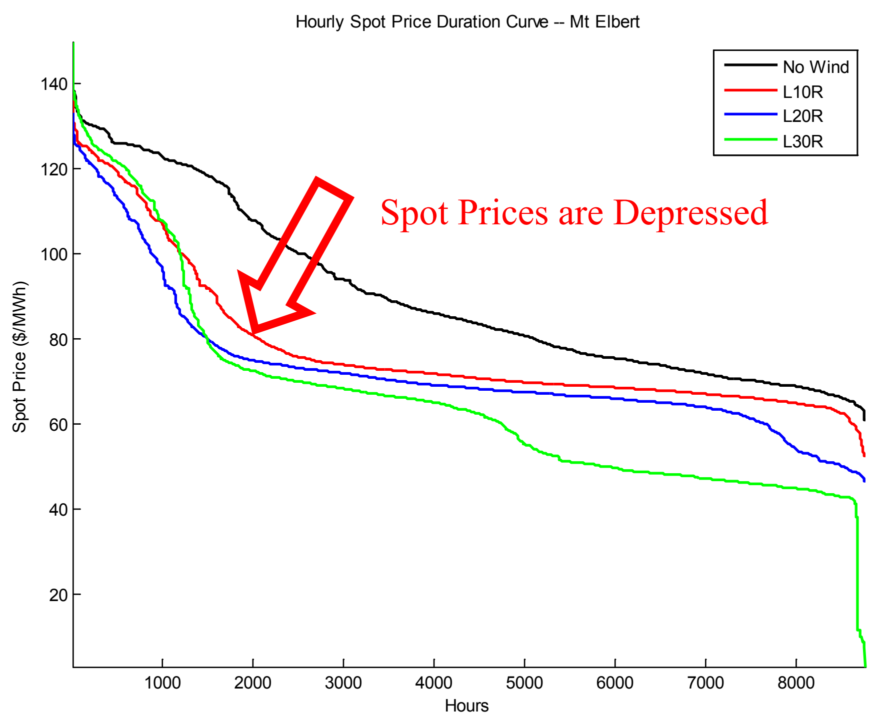

Figure 95: Hourly spot price duration curves for Mt. Elbert PSH as seen in MAPS simulation.

To better understand the impact of renewables on spot prices during different demand periods, spot prices were separated between high-load-hours and low-low-hours. These values were then averaged on a daily basis. Figure 96 shows this relationship accompanied by the daily difference in spot prices (lower line of each plot). As can be seen in the top graph (no-wind scenario), there is a noticeable difference between each demand period, especially during peak summer months (i.e. allowing better economics for utilization of PSH). The bottom graph (L30R case) depicts how the varying wind energy dramatically changes the spot prices seen during peak and low demand periods with negative spot prices differences occurring throughout the year. To combat the varying spot system prices and give a more accurate approximation of PSH usage (e.g. not accounting for providing ancillary services), PSH systems in MAPS were given perfect foresight of spot prices thus enabling PSH to optimize revenue.[19]

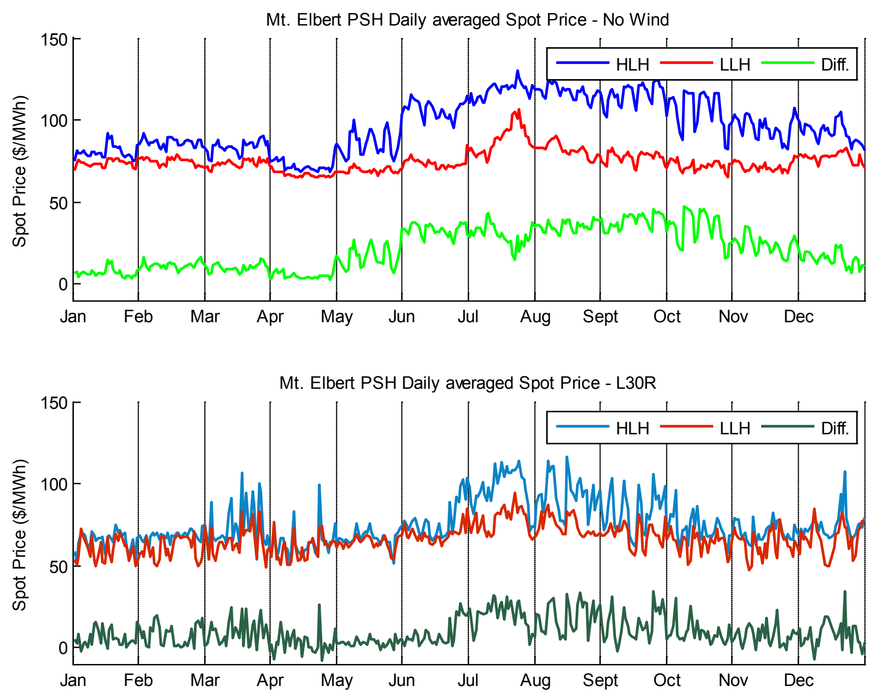

Figure 96: Spot Prices during critical time periods use to determine economic dispatch in MAPS model for baseline scenario (top-graph) and 30% penetration levels (bottom-graph) at Mt. Elbert PSH plant.

To illustrate Mt. Elbert's PSH annual change in use, a PSH "Utilization Factor" was created as shown in Equation 3. The PSH utilization factor or capacity factor assumes a "Full Energy Capacity" accounting for a maximum pumping time of 8 hours at 210 MW (during low-load-hours and not accounting for any renewables on the system) and assuming 8 hours of generation would be recovered at 200 MW.[20] "Total Energy for Day" accounts for the actual generation and pumping seen for each day. Arbitrarily

(3)

Figure 97 illustrates the utilization factor (shown as blue shaded area) between the no-wind scenario (top graph) and the L30R case (bottom graph) at Mt. Elbert PSH. As can be seen, the

[19] Perfect foresight spot prices are not shown and should not be confused with the "difference in spot price" illustration for the PSH system incorporating renewable energy. The no-wind scenario does not account for any renewables (e.g. very little fluctuation in spot prices during demand periods) thus giving an accurate approximation of what the PSH plant would see given a perfect foresight in spot prices.

[20] Capacity limits were defined as maximum pumping and generation values used in MAPS simulation at Mt. Elbert PSH plant. The amount of pumped time was arbitrarily chosen as eight hours, the typical amount of time seen during LLH.

30% penetration level dramatically increases the utilization of PSH use throughout the year to balance the variability in net-load. Additionally a few occurrences the of utilization factor greater than 1 occur during the month of January as a direct result of changing spot prices during the different demand periods (i.e. economically allowing more pumping greater than 8 hours to occur). It is also noted the “difference in spot price” is not shown for the L30R case as Mt. Elbert PSH plant operations were based on the assumed perfect foresight knowledge of spot prices.

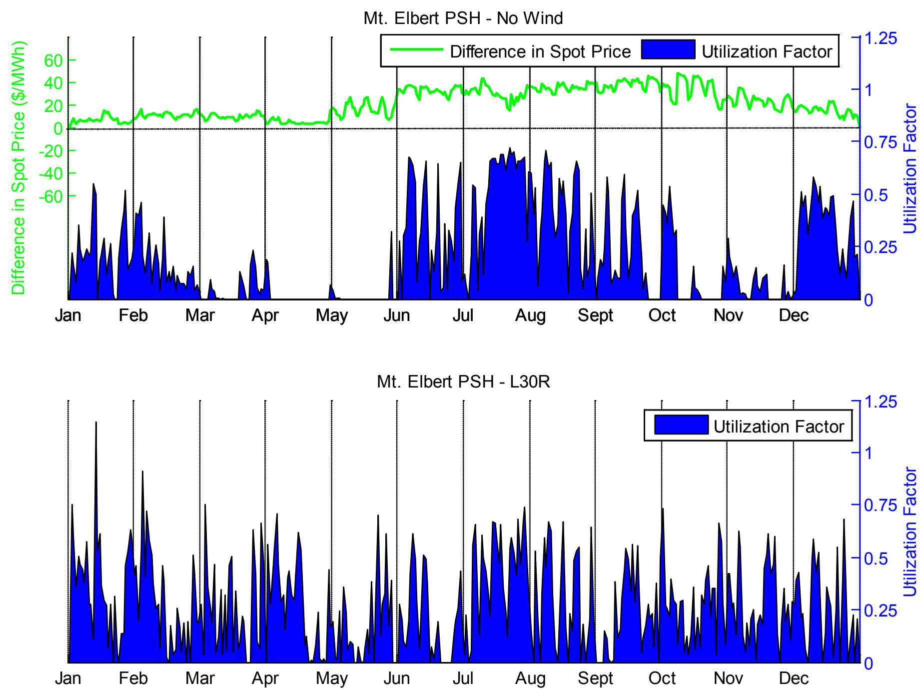

Figure 97: Differences in load factoring spot prices (top-graph) accompanied with daily utilization factor (blue area) at Mt. Elbert PSH plant between baseline (top-graph) and 30% penetration levels (bottom-graph).

Summarizing these findings, Figure 98 shows the differences in revenue value and energy usage (accounting for both pumping and generation) for the no-wind and local-priority scenario at the Mt. Elbert PSH plant. As can be seen, PSH use increases at the penetration levels above 20%. Interesting enough, even with increased energy usage of nearly 30% for the 20% penetration case (over no-wind case), revenue value does not surpass that of the no-wind case. This can be attributed to the reduced system spot prices created by wind and solar generation.

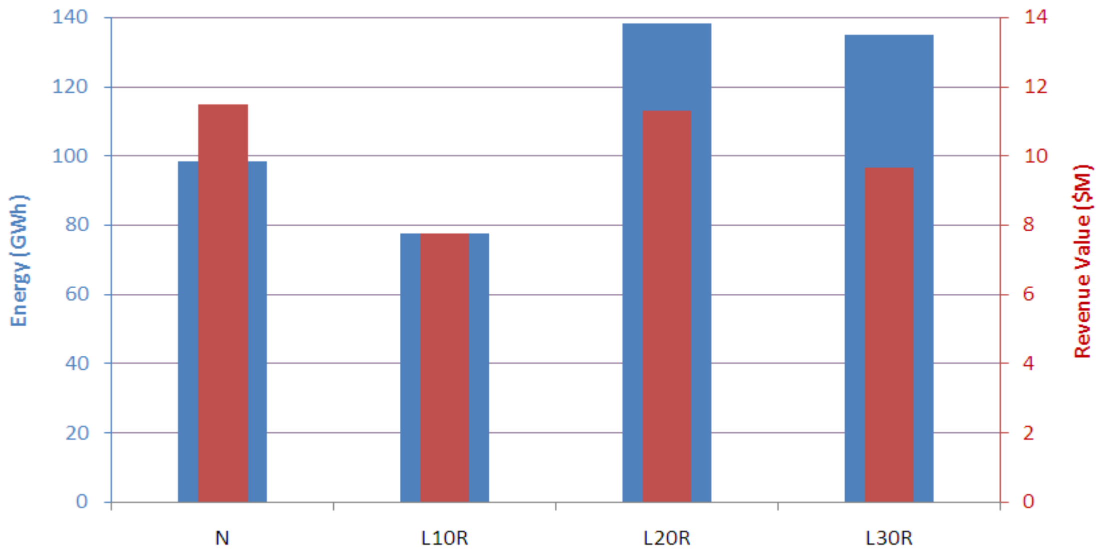

Figure 98: Revenue value and corresponding energy usage at Mt Elbert PSH plant for local-priority scenario.

9.0 Conclusions and Key Findings

This study follows upon the hydropower analysis conducted in the WWSIS and broadens the scope to cover selected individual hydro facility operations located within the study footprint in order to answer several specific questions. These questions can be summarized as follows:

- How well was the hydro and PSH system modeled?
- What affects do drought conditions in the West have on hydro ability to meet load?
- What impact does renewable generation have on individual hydro operations?
- How effect does the different wind scenario build outs have on the way hydro generation is dispatched?
- How does a more proficient wind and solar forecast impact hydro operations?
- What is the value of hydropower as a balancing resource?
- What is the value of the hydropower community in participating in wind integration?
- Lastly, how does wind and solar generation impact PSH operations?

The results and answers to these questions are listed below and were derived from the technical analysis performed in chapters 5 through 8.

9.1 MAPS Modeling Accuracy of Base-Case Scenarios.

In comparing the MAPS modeled hydro generation at selected hydro facilities to actual generation profiles from 2006 (sections 5.1 and 5.2), it was found that the MAPS modeled hydro dispatched significantly more energy and capacity. The reason for this was that MAPS assumed the entire hydro plant nameplate capacities were available for use (not accounting for water levels being less than maximum, or flow regulated at above minimum), and that eleven-year average values of the hydro energy were available on a monthly basis (corresponding to an 11-year average of the monthly water releases and reservoir levels). During 2006, the monthly hydrogenation was significantly below the 11-year average (~20% less) and the reservoir water elevations were similarly lower than their maximums, causing the available capacity at many plants to be significantly less than their nameplate capacity. This resulted in enhanced hydro generation simulated at five of the seven hydro facilities selected within the study footprint.[21]

As for the usage pattern, the modeled hydro was dispatched primarily in a peak shaving mode where the flexibility at each hydro facility was employed during the ramps into and out of the high load hours with most hours in between staying relatively steady. Thus *less* of the generator flexibility was deployed than in the historical data. Other differences in the MAPS dispatch of the hydro were partly due to the hydro system constraints not accounted for in the model, as well as the fact that in actual practice, several utilities schedule and dispatch hydro to their balancing area loads and use the flexibility of the hydro as needed. Since the variability of each separate balancing area load is more than their aggregate variability (on a percent of load basis), more of

[21] Blue Mesa Dam and Morrow Point Dam operations showed more flexibility and energy use than in the MAPS simulation. Further investigation revealed Morrow Point and Blue Mesa Dam have changed their hydro operations recently such that the capacity limits and monthly energies exceed those employed in the MAPS simulation.

the hydro flexibility is employed than modeled in MAPS. One challenge in modeling hydropower in any production cost model, including MAPS, is the difficulty in modeling plant-specific constraints on the hydropower that influence operations within limits of monthly energy and capacity (e.g. high priority functions, non-power constraints, and regulations imposed on each dam, such as flood control, irrigation, fishery and environmental constraints). These constraints cause MAPS modeling to deviate from actual production during certain times of the year.

When studying the shape of the hourly time series of hydro production created by the MAPS simulation, it was evident that MAPS dispatched hydropower for peak shaving and the flexibility at each hydro facility was not used extensively to balance variability of the net load. When compared to historical generation shapes at the seven hydro plants studied in detail, MAPS compared quite favorably during those periods when the actual resource was also being utilized to meet peak demand, and less so during periods of plant specific flow constraints. Thus, in economically optimizing dispatch of system resources, MAPS utilized hydropower for its value on peak, and not necessarily for its flexibility in changing generation level from hour to hour.

To reconcile the differences in hydro production and dispatch between the MAPS simulation and the actual 2006 data, an additional MAPS simulation was performed using 2006 historical hydro capacity limits and monthly energy in place of the 11-year averages. This resulted in a considerably more accurate representation of the hydro system at the selected facilities by MAPS, even without accounting for higher priority functions (section 5.4). Consistent with the other simulations, however, MAPS dispatched the hydro in a peak shaving mode utilizing less inter-hour load following capabilities than in the historical data. Thus, if used as a broader system resource versus serving individual balancing areas, and absent flow constraints beyond the monthly flow requirements, the rational dispatch algorithm employed in MAPS dispatches hydro more for its value on peak and less for its flexibility.

When comparing modeled pumped storage hydro (PSH) operations at the Mt. Elbert facility to actual operations, the MAPS model was found to significantly underutilize PSH resources (actual hours of operation were found to be nearly 8,000 hours while the MAPS simulation utilized approximately 2,000 hours, refer to (section 8.3.1). This discrepancy can be attributed to several factors not captured by the MAPS model such as supplemental water fed to the forebay at Mt. Elbert and the plant's ability to provide ancillary services throughout the day.

9.2 Drought Considerations on Hydropower Plants located within the Study Footprint

When comparing MAPS results of historical-hydro operations to their higher-energy-capacity counterparts of "base case" operations, WECC operating costs were found to increase by $200 million/yr or by $115/MWh of reduced hydro generation (section 7.1.1). As a reference, this difference is less than 1% of total WECC operating costs. This increase is attributed to the extra thermal resources required to balance the system load to compensate for the low-cost hydro not available due to the low water year. However, in terms of revenue value, the missing hydro capacity would cause a reduction in hydro revenue value in the footprint by nearly $200 million/yr (approximately 15% of total hydro revenues) or $105/MWh of reduced hydro energy (section 7.1.2).

9.3 Renewable Generation Impact on Hydro Operations

Results have shown that as renewable penetration levels increase, utilization of the hydro system in aggregate shows little change in generation pattern; however at the individual plant level, significant changes in operations were observed at some larger plants like Hoover Dam (steadily increasing change in hydro use with penetration level). Use of hydro's flexibility was found to increase during all hours of the day as the renewables penetration increased. Seasonally, the greatest differences in hydro operations occurred during spring months due to high winds occurring in the West requiring significant use of system flexibility. Other months remained very similar to the no-wind scenario. Hydro facilities were observed to back down generation during high wind periods and shift generation on a weekly, daily and hourly basis while maintaining required monthly energy generation (sections 5.5 and 5.6).

9.4 Inter-Scenario differences in Hydro Operations

Investigating inter-scenario (In-area vs. local priority vs. mega project) differences in hydro operations revealed important changes in use of hydro flexibility. Hydro facilities located within the study footprint tended to utilize less flexibility as wind resources were transferred to more remote, higher quality resources of the mega-project scenario. This is due to the fact that hydro generation resources were assigned to meet only their corresponding net balancing area "region" loads (e.g. hydro resources located in the Arizona-New Mexico region would be dispatched based upon the AZ-NM net-loads and not net-loads of the other four regions). Thus as more wind was obtained from better wind resources of the mega-project scenario (i.e. to Wyoming and out of each designated region load area), variability in net-load experienced at the hydropower facilities decreased if the amount of wind in that region decreased (section 5.7).

9.5 Forecasting Methods Impact on Hydro Operation

When comparing the dispatch of hydro as wind and solar forecast methods become more accurate (comparing a professional forecast to a perfect forecast); results show little change in use of hydro's flexibility throughout the year. In all cases, use of a perfect forecast led to hydro flexibility being used slightly more, enabling more expensive thermal resources to be backed down saving an additional $500 million in annual operation costs or $1-2/MWh of renewable energy (section 5.8). Hence, improving the wind and solar forecasts from a "professional" level of accuracy to a perfect forecast netted a relatively small savings (per MWh of renewable energy) in system operation.

9.6 Value of Hydropower as a Balancing Resource

The value of hydro as a balancing resource was deduced by modeling the hydro with severely restricted flexibility and reserve capabilities, essentially establishing a constant river flow and therefore generation at each hydro facility (the "flat" hydro case). The net result of running the hydro flat was increased operating costs, especially in steam oil and gas units and the small, "generic" generation fleet consisting of units less than 20 MW in capacity. WECC operating costs were modeled to increase by $35/MWh of steam oil/gas and $60/MWh of generic generation. Total WECC operating costs were predicted to increase by up to $1 billion/yr (or 2%

of total operating costs in WECC; section 7.2.1). This increase in operating cost provides an indication of the value of hydropower as a system resource.

In terms of hydro revenue value, on the footprint level, restricting flexibility would cause hydro to suffer losses totaling nearly $80 million/yr (approximately 5% of total hydro revenues for each case). The greatest impact would be felt at the two largest hydropower facilities located in the study footprint, Glen Canyon Dam at $32 million/yr and Hoover Dam at $35 million/yr. On the WECC level, total revenue gains for the generators reach $3.5 billion/yr at the lower penetration levels (due to increased use of thermal resources to balance load when the hydro is run flat), but at penetration levels exceeding 20%, wind generation is able to carry enough capacity such that there is an overall revenue loss. As a reference, the incremental impact is approximately 3% of total revenues (section 7.2.2).

9.7 Value to Hydro Community of Participating in Wind Integration

The MAPS simulations in the WWSIS study committed and dispatched all hydro generation to serve daily peak net-region-load (that is, load minus wind and solar in each region), while respecting the minimum and maximum operating points on hydro units. To show the value of hydropower participating in wind and solar integration, a MAPS simulation was conducted where hydropower units were dispatched to the load only and not the load minus wind and solar (the net load). Results show that changes in flexible thermal generation resource dispatch, like gas units, would result in a few $/MWh increase in total WECC operating costs throughout each penetration level. Cumulatively, at lower penetration levels, the increase in operating costs is relatively small. However, at the 30% wind level, total operating costs would increase by $200 million/yr (2% of total operating costs; section 7.3.1).

Using this same methodology, a revenue analysis of generators in the footprint revealed decreased hydro revenue across each penetration level with the greatest reduction at the 30% wind penetration level by $3/MWh, totaling $45 million/yr (11 % of total hydro revenue). Of the selected facilities, Hoover Dam and Glen Canyon Dam incurred the majority of the reduction at $18 million and $16 million, respectively. On a WECC wide basis, results showed flexible thermal generation resources (e.g. gas units) would acquire increased use at each of the penetration levels. Similarly, the impact on revenue value at lower penetration levels is relatively small, but at the 30% renewable penetration level, nearly every generation source suffers losses by a few $/MWh of generation, including renewables. This translates to over $1.3 billion in total revenue value losses at the 30% level (approximately 4% of total revenue value), with nearly $300 million due to hydro losses (approximately 3% of total hydro revenue value). These revenue losses correlate directly to the depressed LMPs due to high penetration of renewables, and a net savings to the consumer (section 7.3.2).

To summarize, participation of hydro in wind and solar integration by scheduling the hydro to the “net load” versus the load only results in an appreciable increase in hydro revenue and decrease in overall system operating costs.

9.8 Impact of Wind and Solar Integration on PSH Operations

WWSIS results show that investment in a new 100-MW PSH plant does not seem economically justifiable if based on its use for balancing wind and solar integration. This is due largely to the fact that large penetrations of wind generation in an open, liquid market will ultimately cause spot prices to decrease with increased renewable penetration. On behalf of the consumers, this becomes very appealing as electricity prices of drop; on the other hand, a newly built PSH may not be able to recover the initial capital costs based upon revenue generated due to its increased use. Results from the MAPS simulation of Mount Elbert PSH plant showed a dramatic increase of utilization throughout the year, by nearly 30% at the higher wind and solar penetration levels as compared to baseline operations. However, the total revenue value actually decreased in every case when compared to the baseline, no-wind case. This drop in revenue value (even with increased use) can be attributed to the depressed system spot prices. Since electricity markets throughout the West are generally not open, liquid markets, the magnitudes of spot price decreases predicted by MAPS will likely not occur. While this is not an issue of importance in a relativistic operational cost study such as that conducted for the WWSIS, it is important in an economic analysis of the value of PSH. Thus, a more complete and accurate simulation is required for the purpose of valuing PSH.

9.9 Closing Remarks

The technical analysis performed in this study shows benefits of hydropower in integrating wind and solar generation in the West by helping meet changes in net load during periods of high wind generation (spring time), providing system ramping capabilities, and shifting energy production when wind generation is predominate. The inherently flexible characteristics of hydro are of greatest value to the electrical system when large amounts of variable and uncertain generation resources are producing in the power system. However, the rational (economic optimization) dispatch algorithm employed in MAPS tends to deploy the hydro for its value on peak as opposed to utilizing its ramping capabilities. Pumped storage hydro may also have opportunities in wind and solar integration, although proposed new plants will have to be justified by several potential revenue sources (like energy arbitrage, ancillary services, and capacity value) with wind integration as one component. Along with benefits and potential value of utilizing hydro more broadly to accommodate renewable generation, this study also revealed that while the hydro system can be reasonably modeled, there are several modeling limitations related to capturing non-power regulations and constraints that often govern hydro flexibility and availability. The need for production cost models to capture or incorporate these factors is apparent particularly at the individual hydro plant level and especially as wind and solar integration studies like the WWSIS become increasingly comprehensive and consider large penetrations of renewables.

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APPENDIX A. MAPS Simulated no-wind versus actual Hydro Generation Plots

A.1 Hoover dam – MAPS no-wind versus actual Hydro Generation

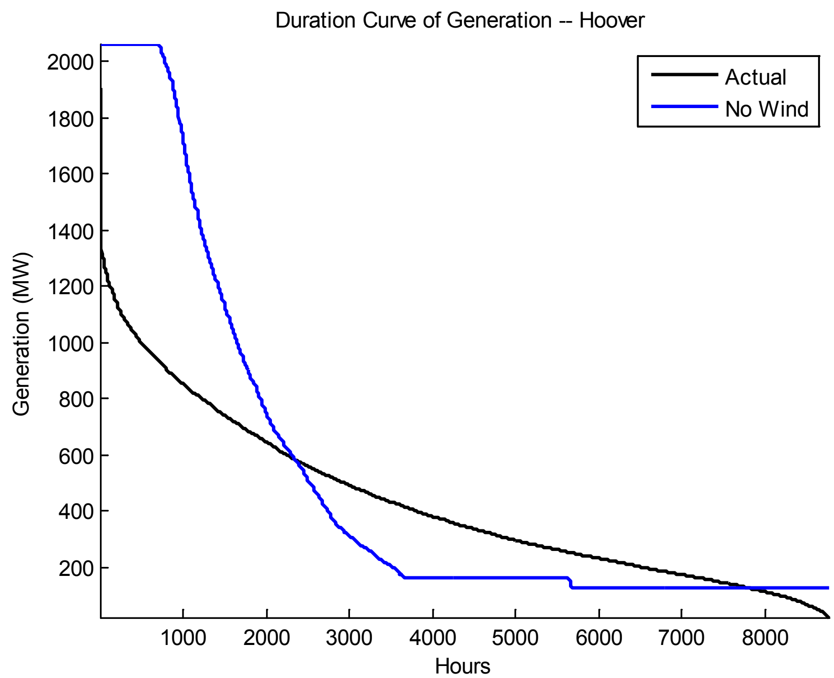

Figure 99: Generation duration curve of MAPS no-wind versus actual hydro generation, Hoover dam.

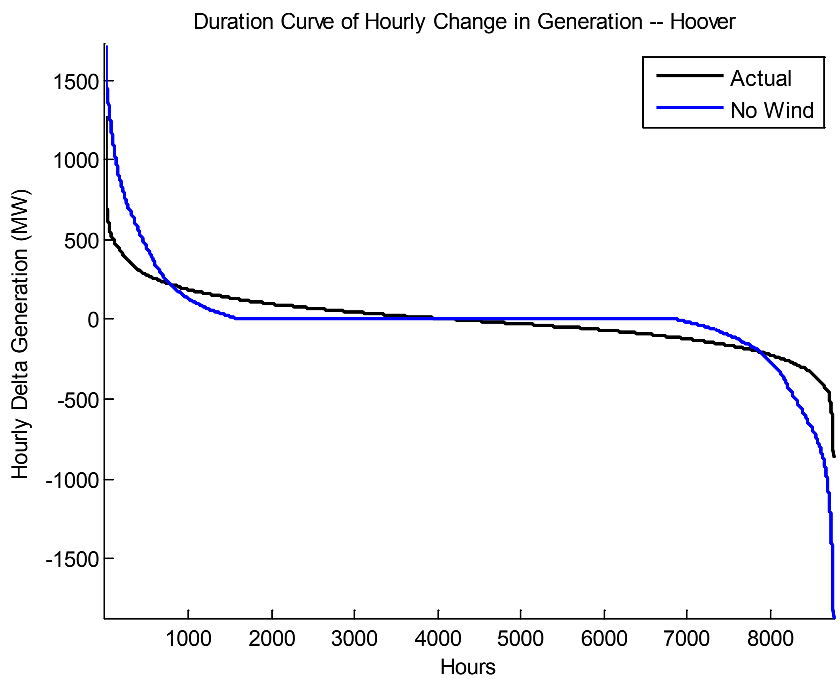

Figure 100: Hourly delta duration curves of MAPS no-wind versus actual hydro generation, Hoover dam.

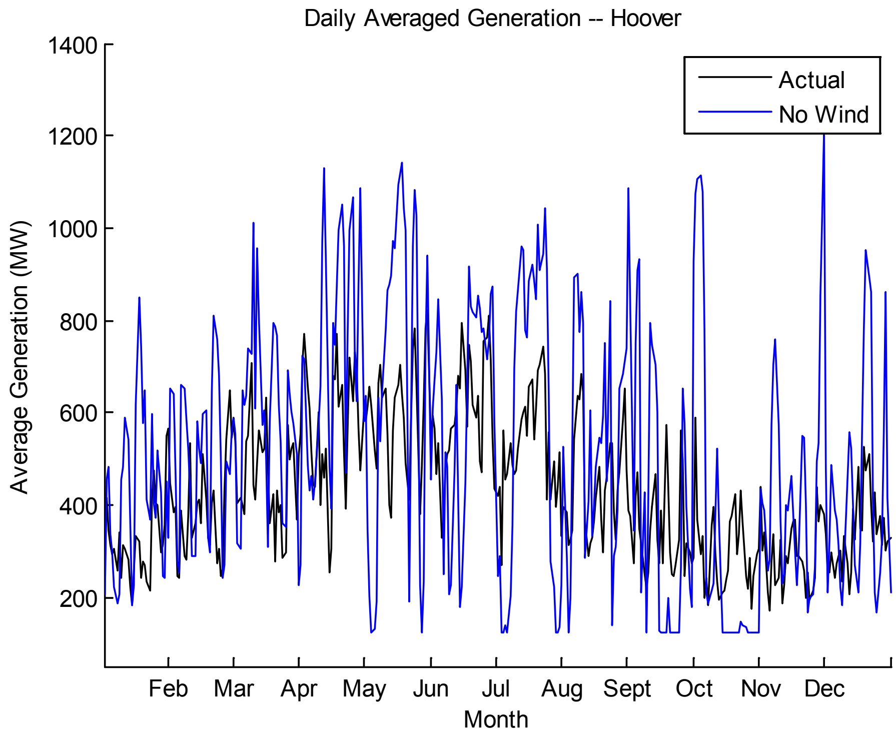

Figure 101: Daily averaged hydro generation of MAPS no-wind versus actual hydro generation, Hoover dam.

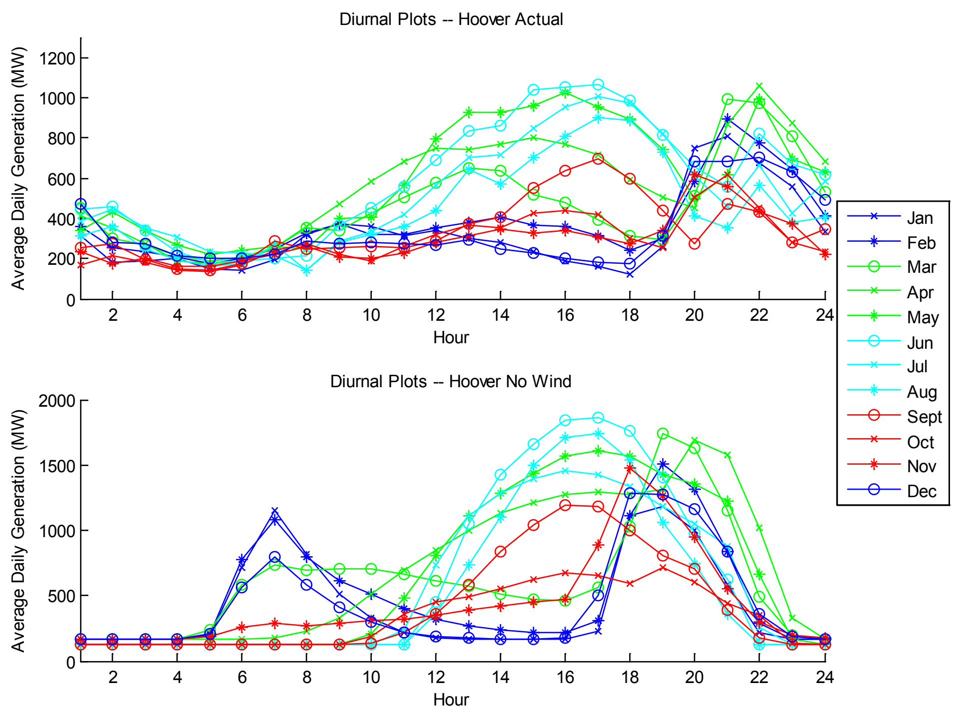

Figure 102: Monthly averaged diurnal plots of MAPS no-wind versus actual hydro generation, Hoover dam.

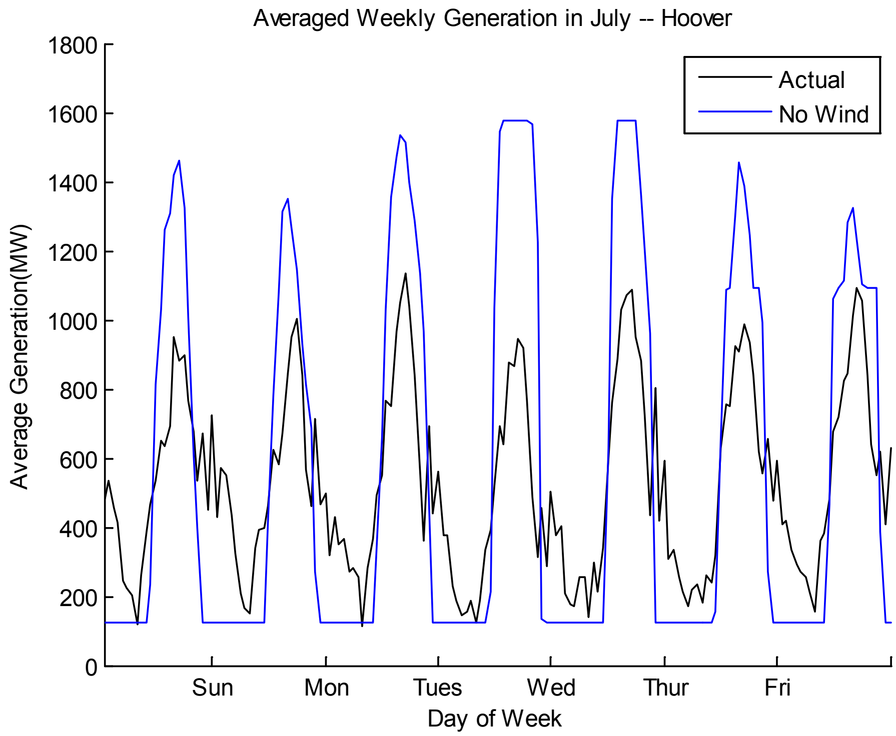

Figure 103: Averaged weekly generation in July, MAPS no-wind versus actual hydro generation, Hoover dam.

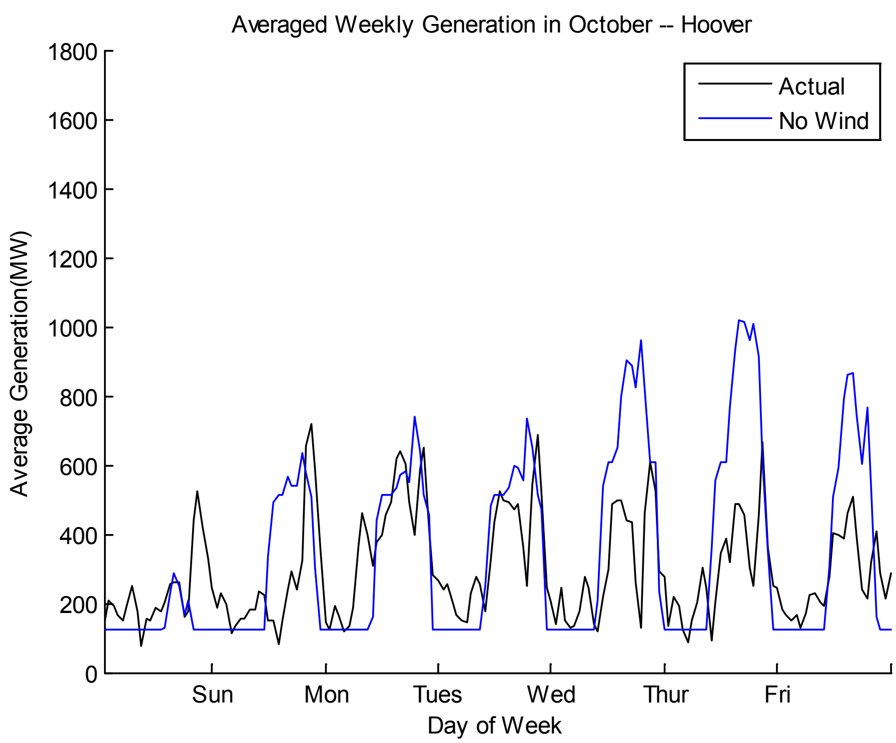

Figure 104: Averaged weekly generation in October, MAPS no-wind versus actual hydro generation, Hoover dam.

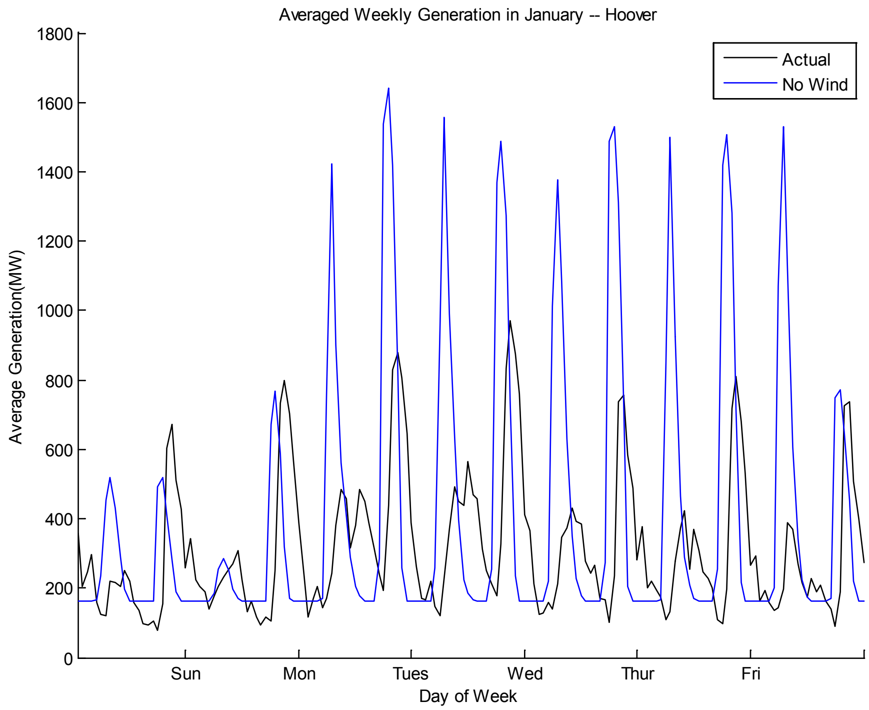

Figure 105: Averaged weekly generation in January, MAPS no-wind versus actual hydro generation, Hoover dam.

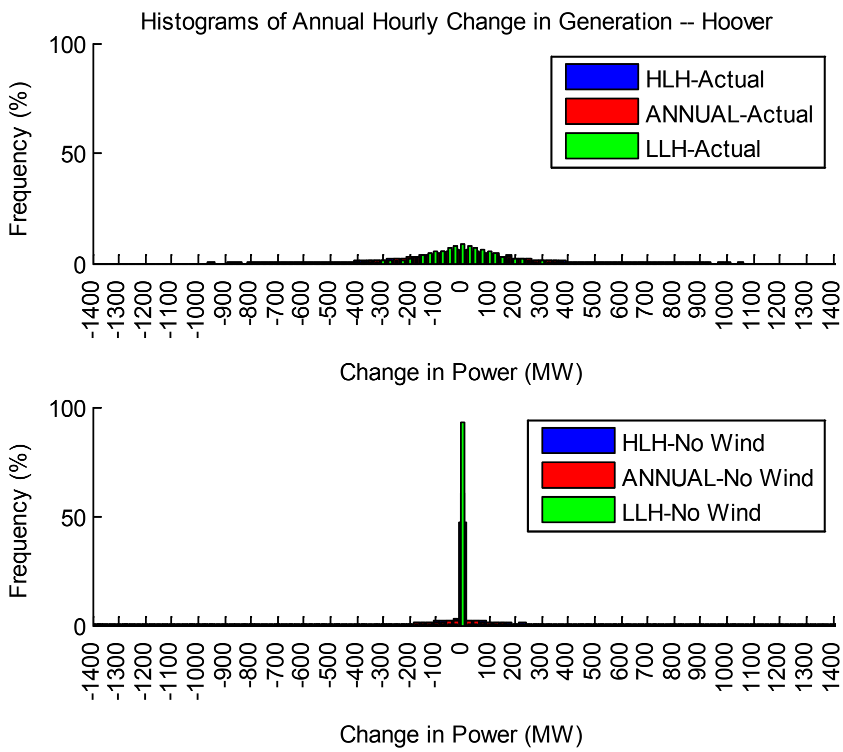

Figure 106: Histograms of hourly change in generation between MAPS no-wind versus actual hydro generation, Hoover dam.

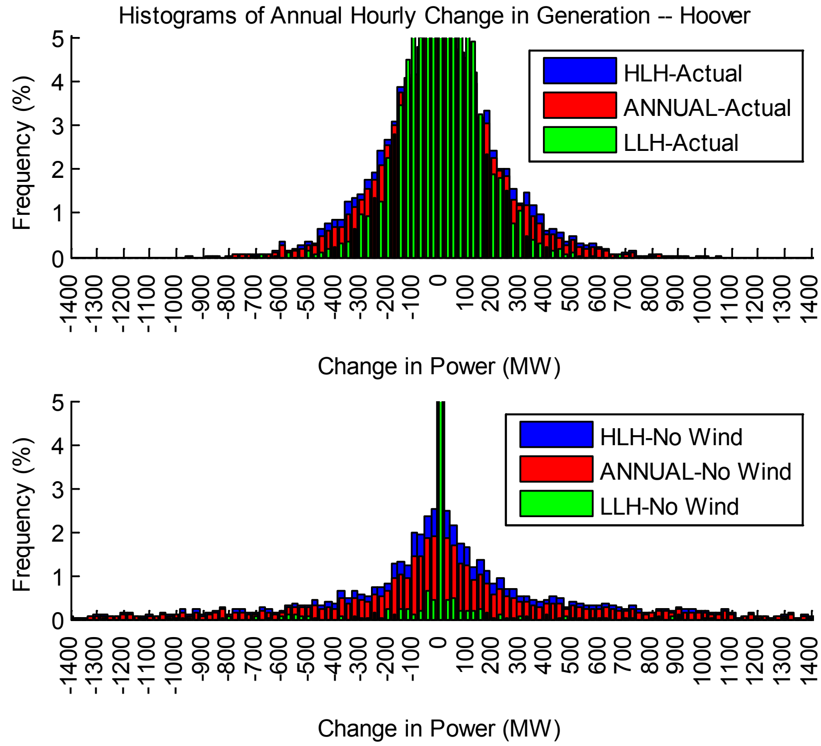

Figure 107: Enhanced view of histograms between MAPS no-wind versus actual hydro generation, Hoover dam.

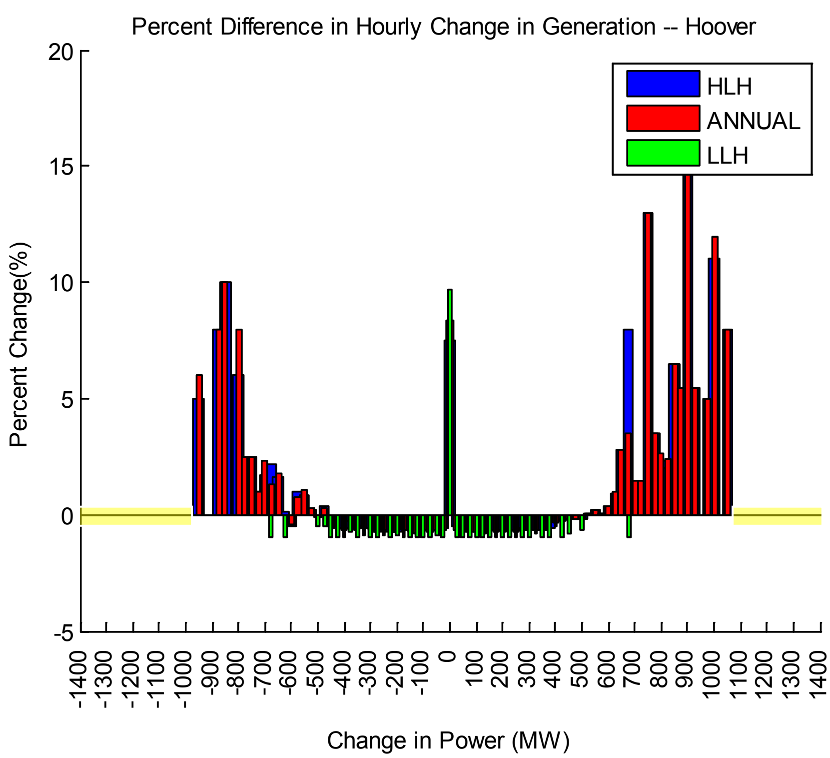

Figure 108: Percent difference in hourly change in generation between MAPS no-wind versus actual hydro generation, Hoover dam.

Table 14: Statistics of hourly changes in generation between MAPS no-wind versus actual hydro generation, Hoover dam.

Timeframe	Hourly Changes in Generation	Average (MW)	Standard Deviation (MW)	Average of the Absolute Value (MW)
Annual	actual	-5.48e-3	209	155
	no-wind	0.0	370	157
HLH	actual	3.82e-2	229	173
	no-wind	0.0	431	212
LLH	actual	-7.624e-2	149	112
	no-wind	4.70e-3	133	23.2

A.2 Parker dam – MAPS no-wind versus actual Hydro Generation

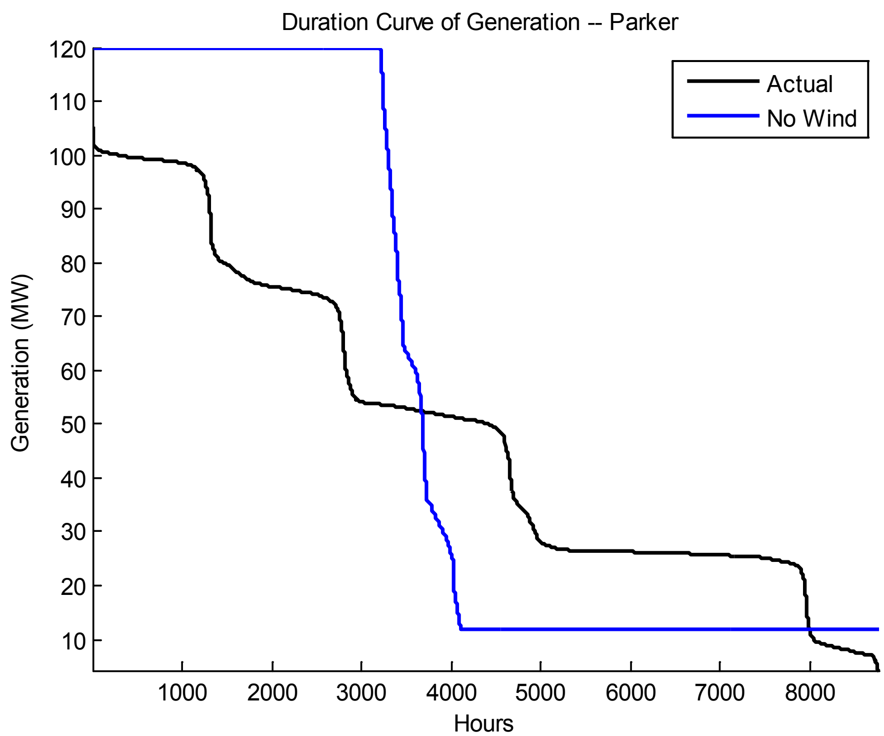

Figure 109: Generation duration curve of MAPS no-wind versus actual hydro generation, Parker dam.

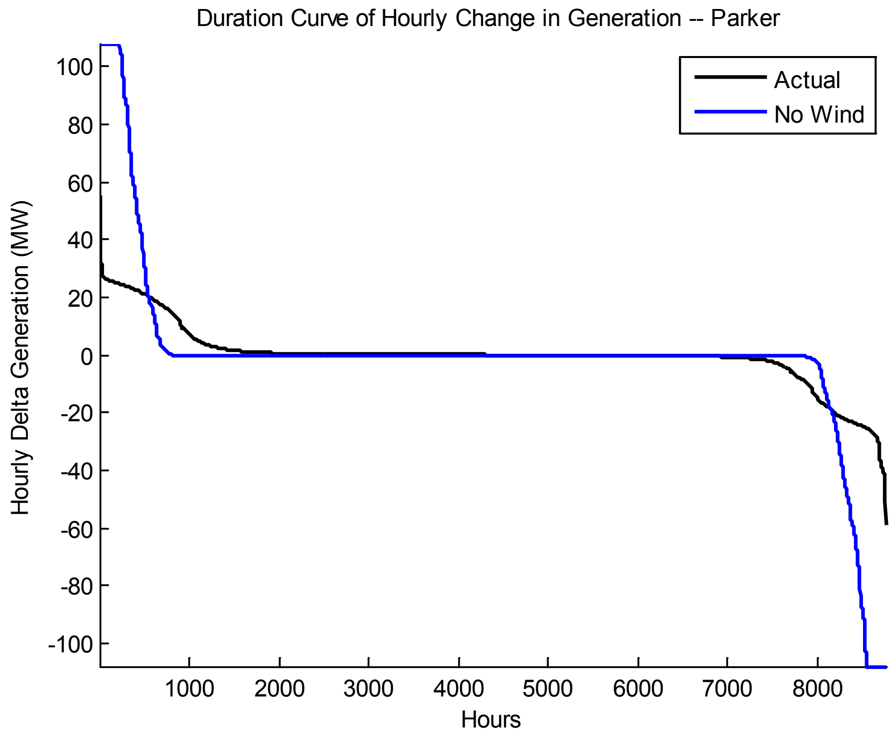

Figure 110: Hourly delta duration curves of MAPS no-wind versus actual hydro generation, Parker dam.

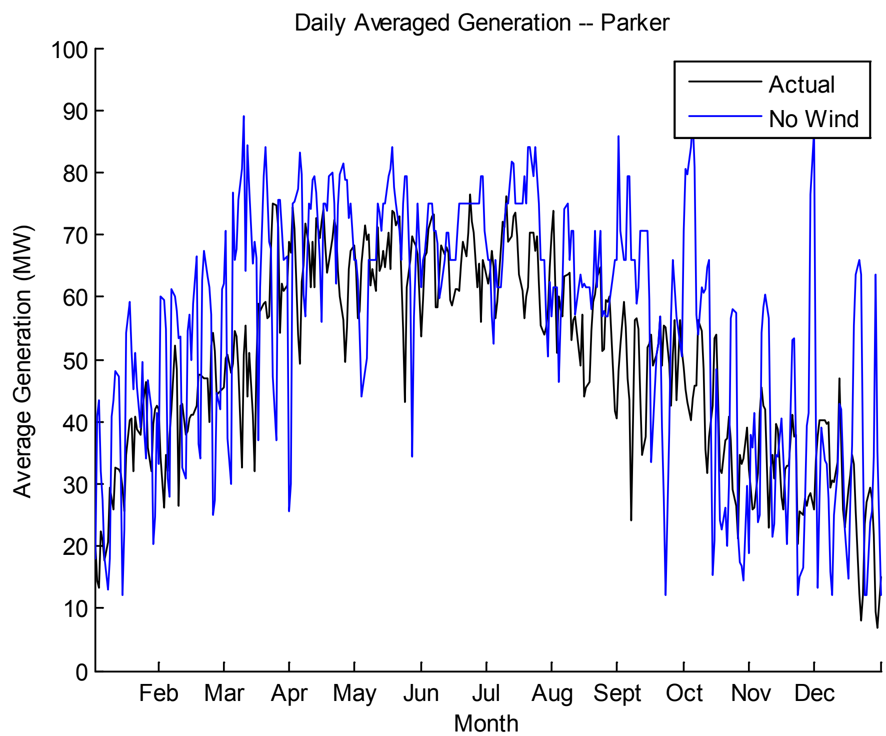

Figure 111: Daily averaged hydro generation of MAPS no-wind versus actual hydro generation, Parker dam.

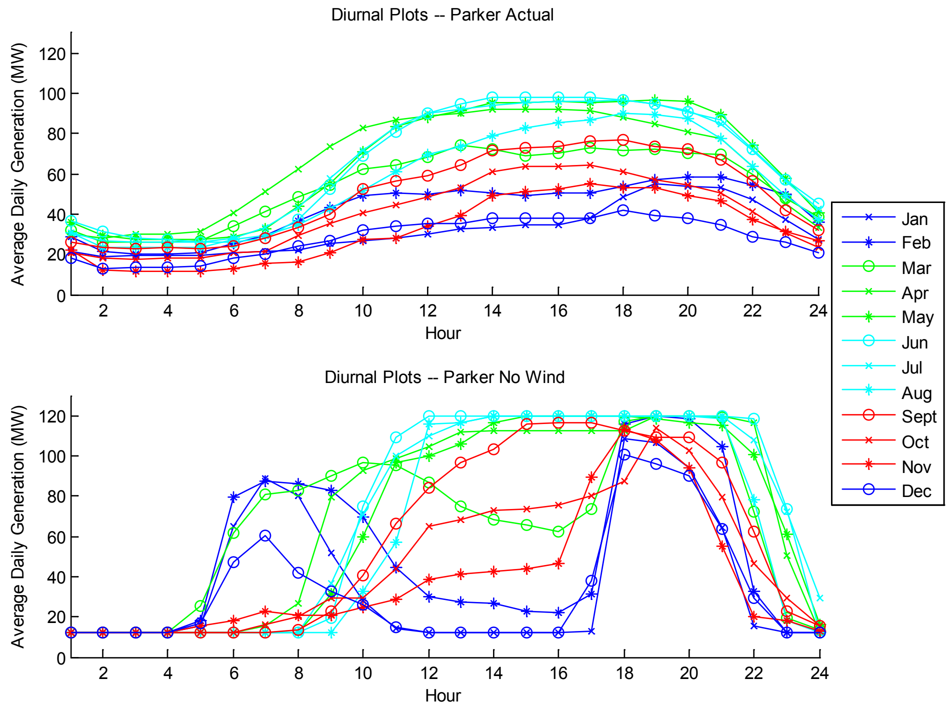

Figure 112: Monthly averaged diurnal plots of MAPS no-wind versus actual hydro generation, Parker dam.

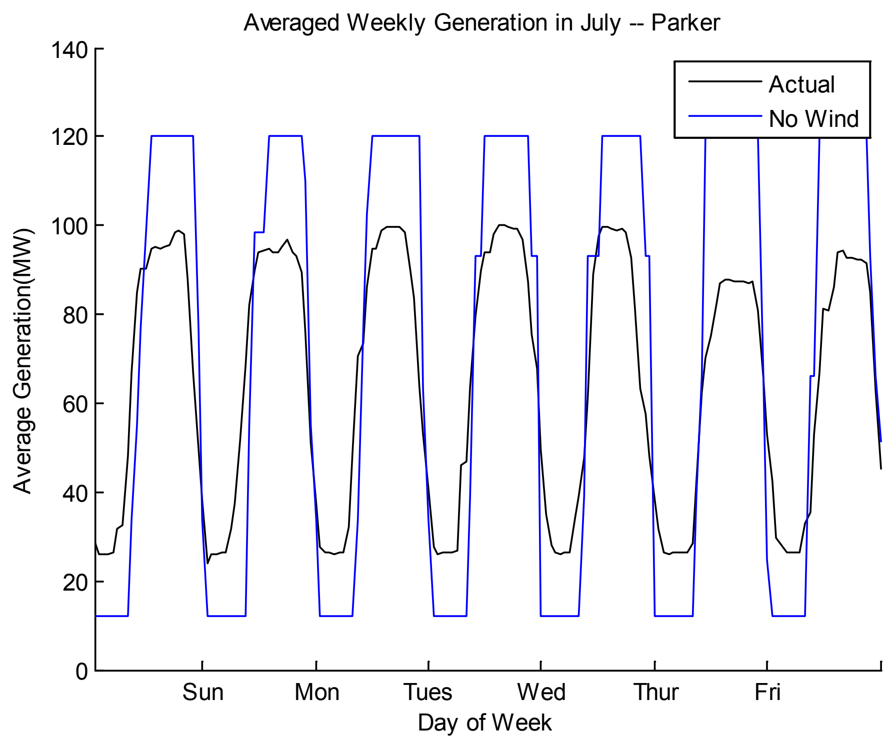

Figure 113: Averaged weekly generation in July, MAPS no-wind versus actual hydro generation, Parker dam.

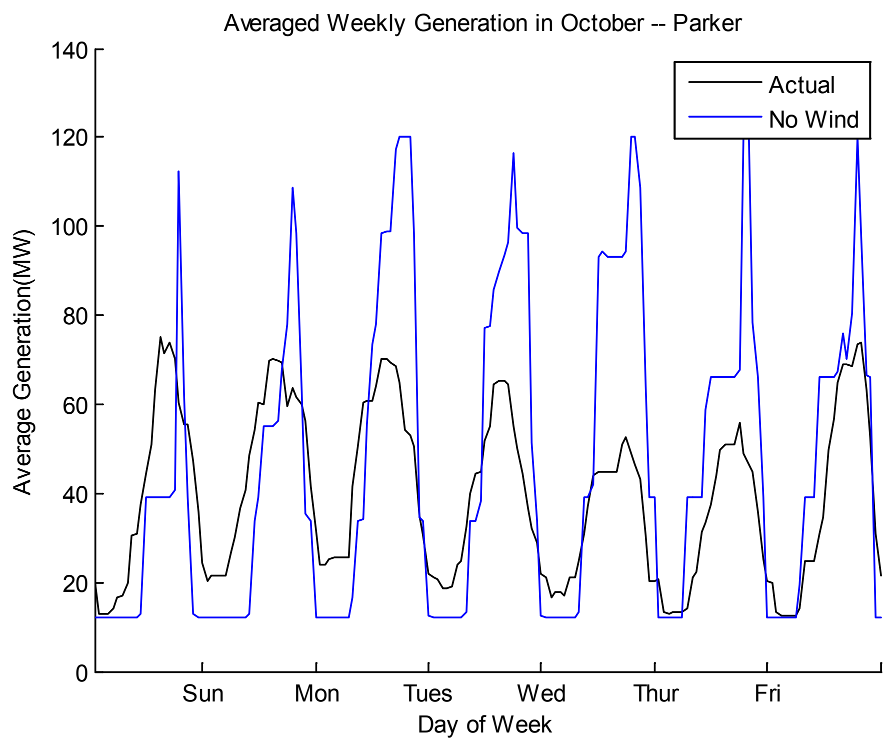

Figure 114: Averaged weekly generation in October, MAPS no-wind versus actual hydro generation, Parker dam.

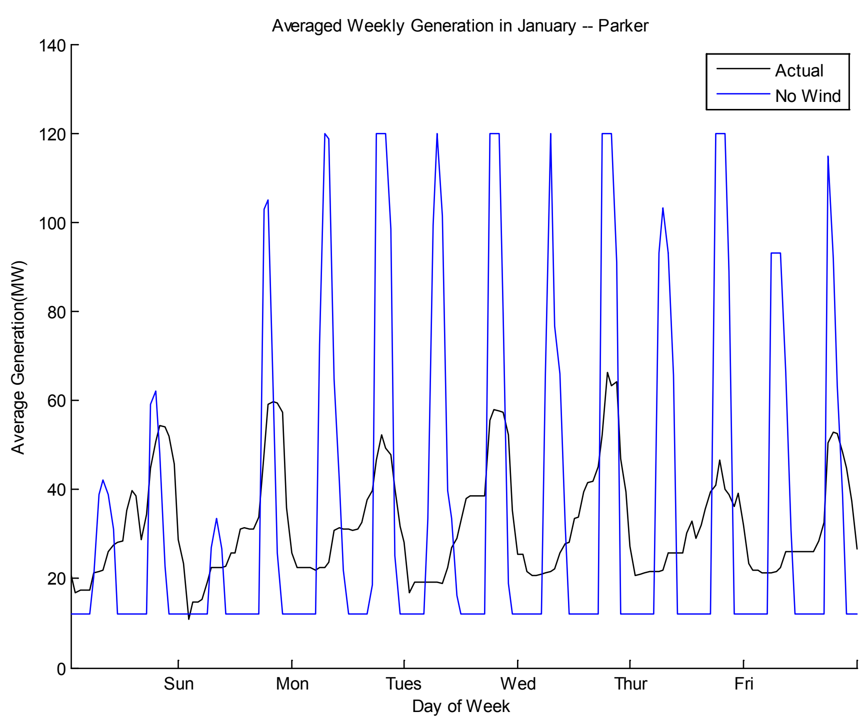

Figure 115: Averaged weekly generation in January, MAPS no-wind versus actual hydro generation, Parker dam.

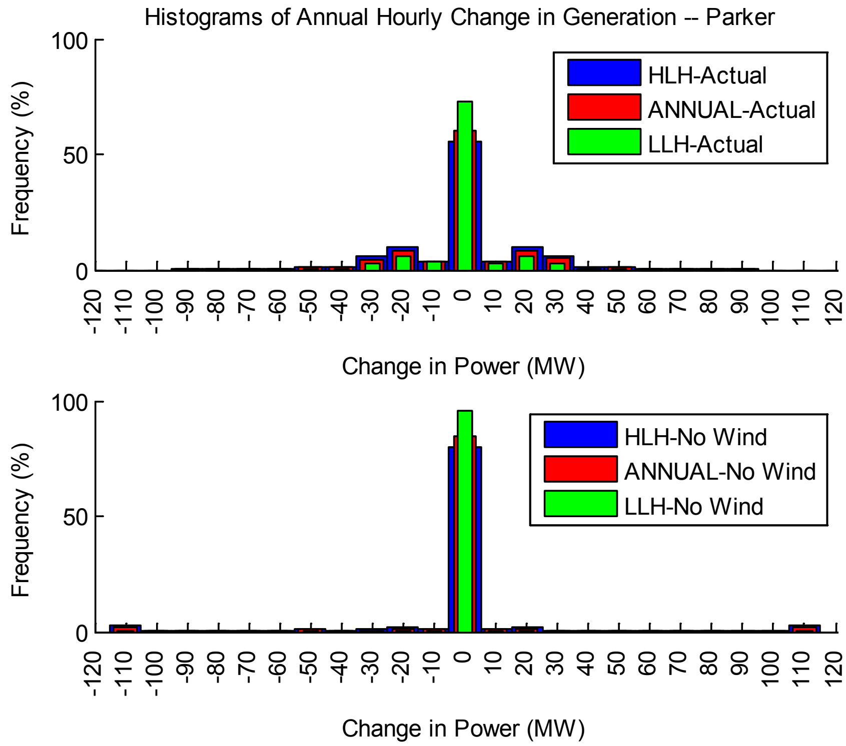

Figure 116: Histograms of hourly change in generation between MAPS no-wind versus actual hydro generation, Parker dam.

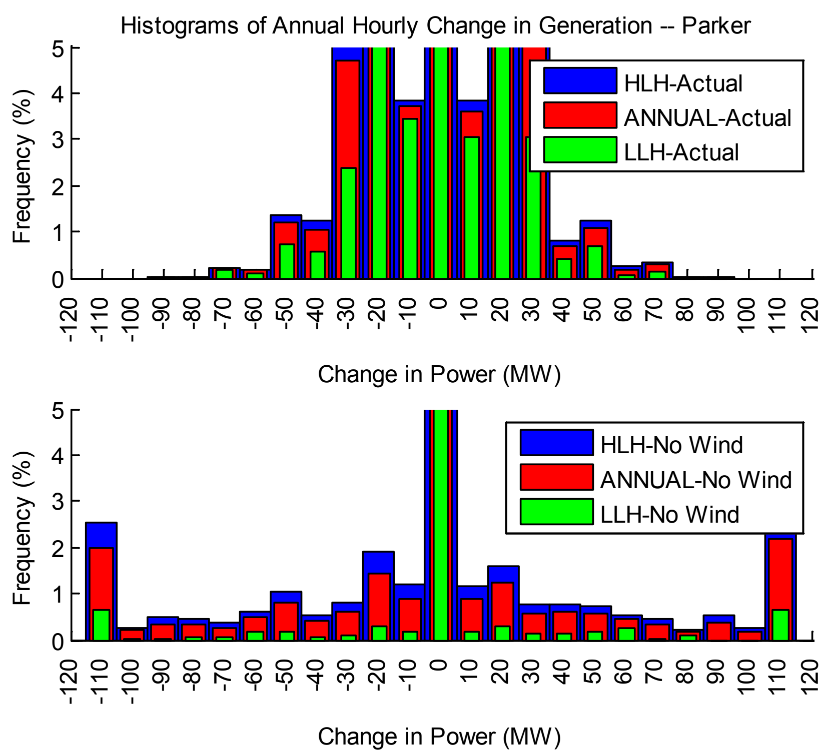

Figure 117: Enhanced view of histograms between MAPS no-wind versus actual hydro generation, Parker dam.

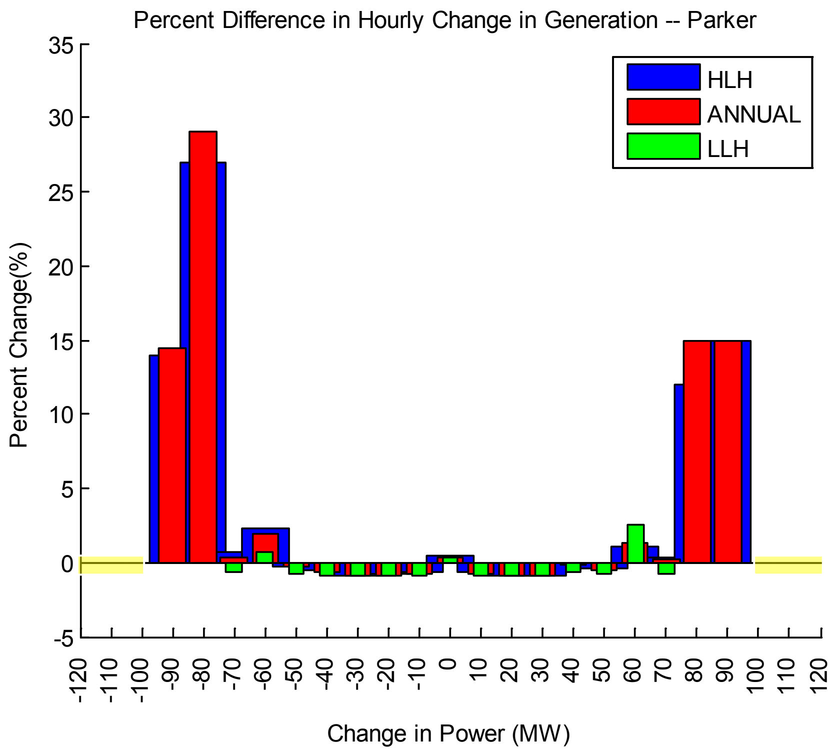

Figure 118: Percent difference in hourly change in generation between MAPS no-wind versus actual hydro generation, Parker dam.

Table 15: Statistics of hourly changes in generation between MAPS no-wind versus actual hydro generation, Parker dam.

Timeframe	Hourly Changes in Generation	Average (MW)	Standard Deviation (MW)	Average of the Absolute Value (MW)
Annual	actual	1.02e-4	16.9	10.0
	no-wind	0.0	27.5	9.17
HLH	actual	2.91e-3	18.2	11.4
	no-wind	0.0	31.3	11.9
LLH	actual	-6.98e-3	13.1	6.54
	no-wind	0.0	14.7	2.56

A.3 Davis dam – MAPS no-wind versus actual Hydro Generation

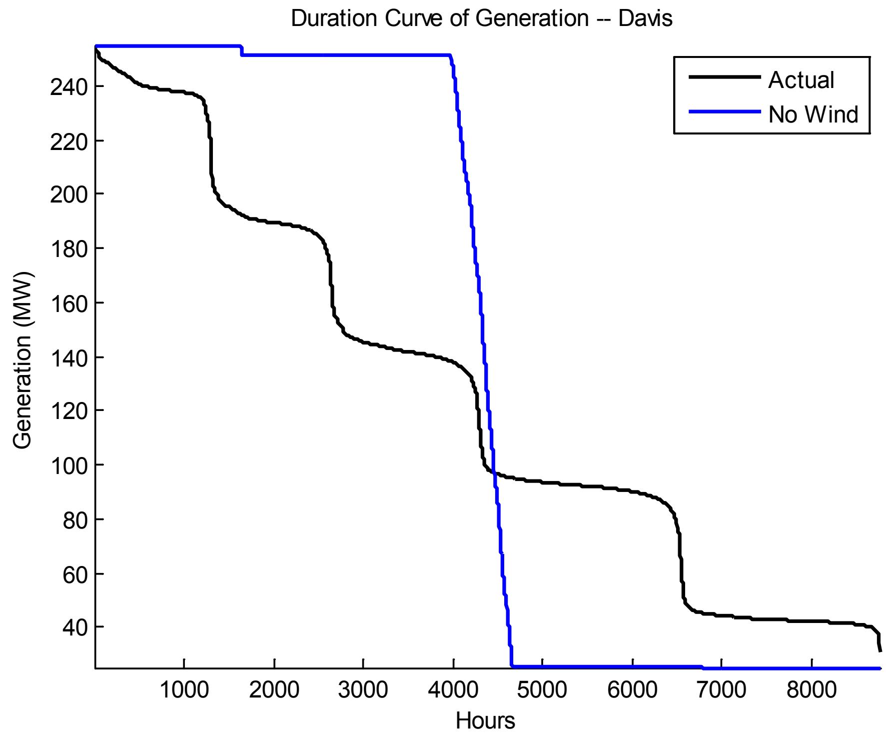

Figure 119: Generation duration curve of MAPS no-wind versus actual hydro generation, Davis dam.

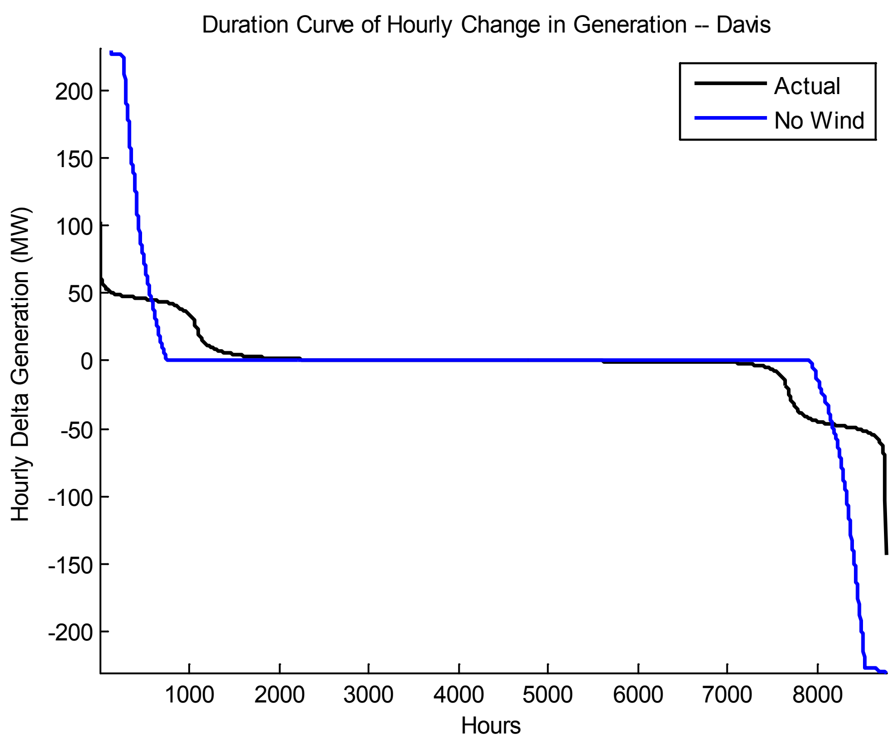

Figure 120: Hourly delta duration curves of MAPS no-wind versus actual hydro generation, Davis dam.

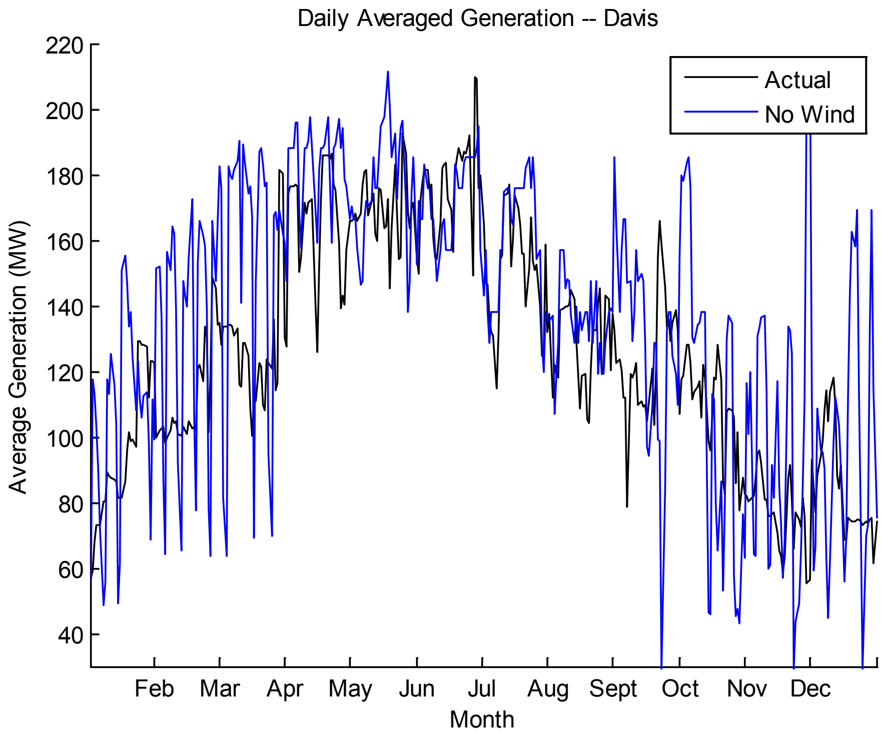

Figure 121: Daily averaged hydro generation of MAPS no-wind versus actual hydro generation, Davis dam.

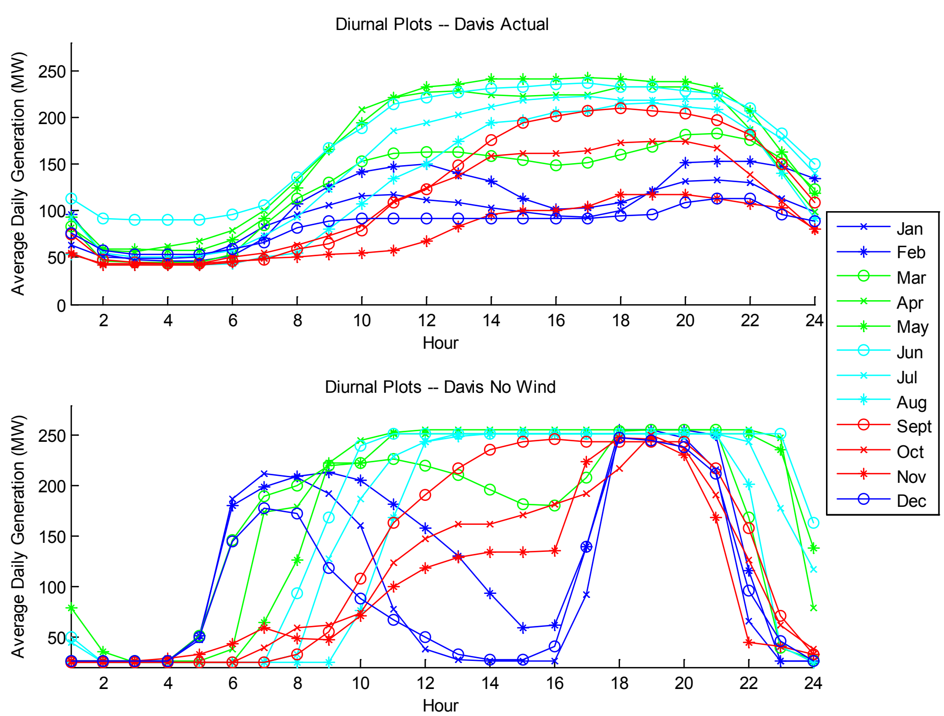

Figure 122: Monthly averaged diurnal plots of MAPS no-wind versus actual hydro generation, Davis dam.

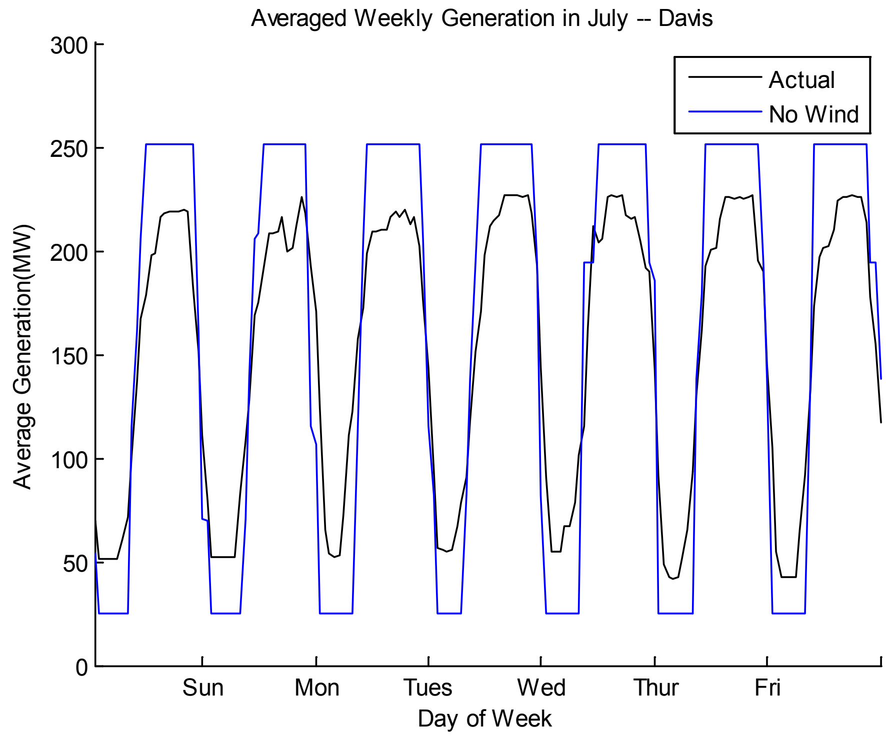

Figure 123: Averaged weekly generation in July, MAPS no-wind versus actual hydro generation, Davis dam.

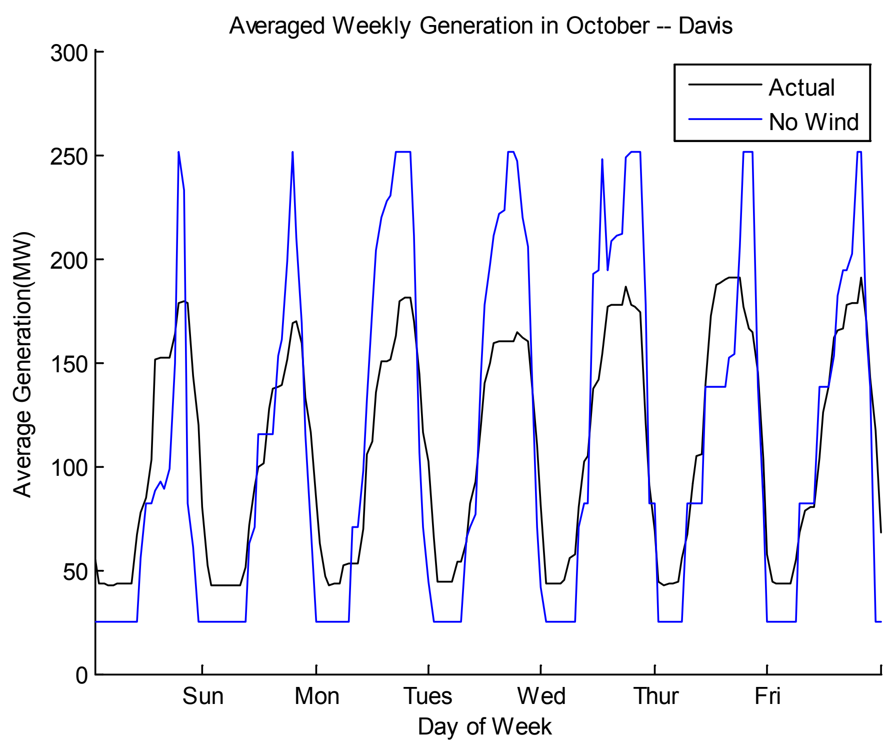

Figure 124: Averaged weekly generation in October, MAPS no-wind versus actual hydro generation, Davis dam.

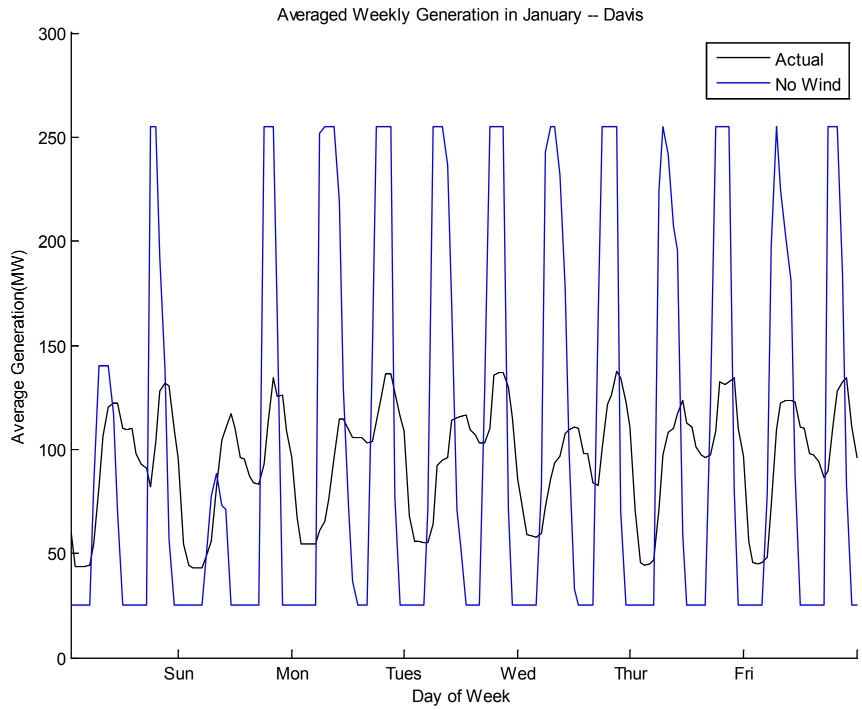

Figure 125: Averaged weekly generation in January, MAPS no-wind versus actual hydro generation, Davis dam.

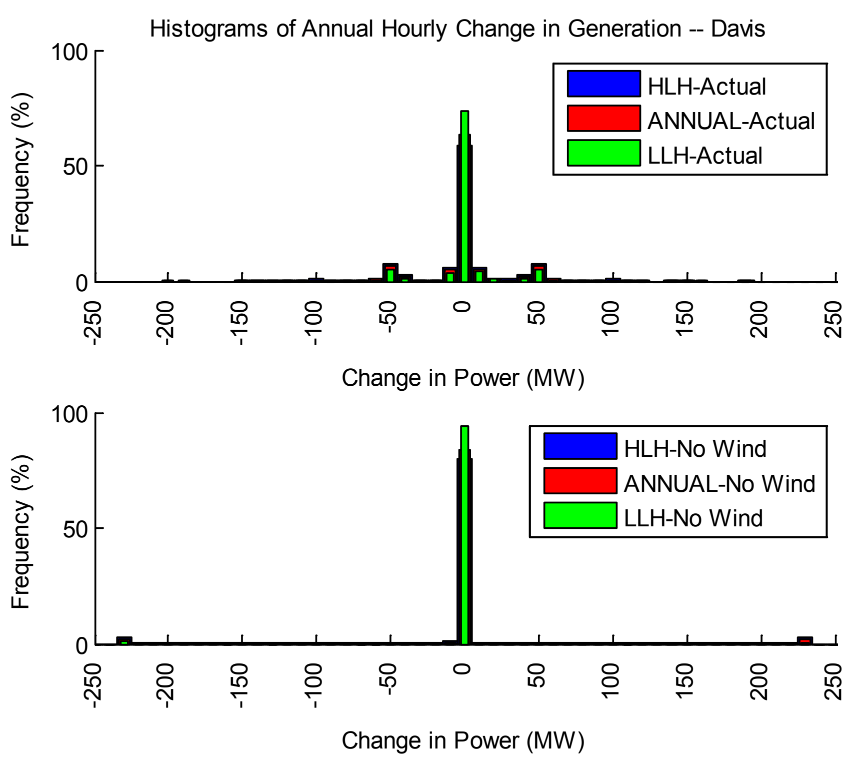

Figure 126: Histograms of hourly change in generation between MAPS no-wind versus actual hydro generation, Davis dam.

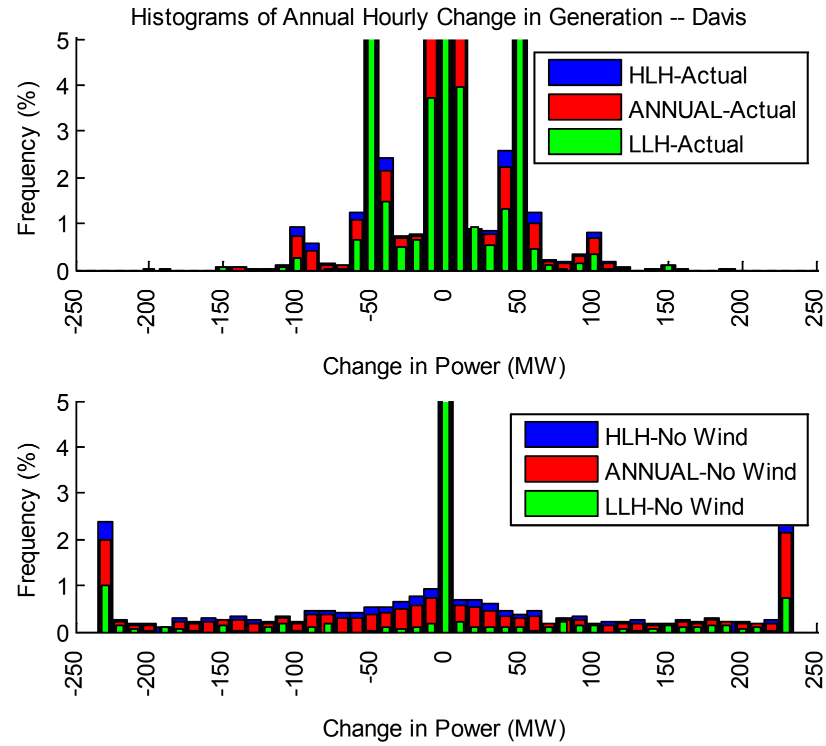

Figure 127: Enhanced view of histograms between MAPS no-wind versus actual hydro generation, Davis dam.

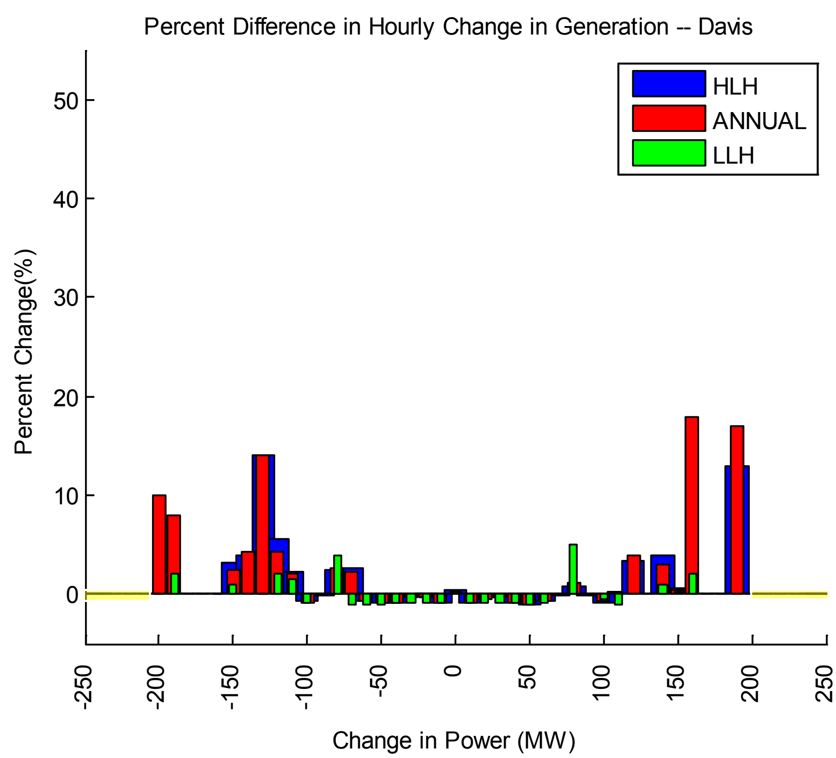

Figure 128: Percent difference in hourly change in generation between MAPS no-wind versus actual hydro generation, Davis dam.

Table 16: Statistics of hourly changes in generation between MAPS no-wind versus actual hydro generation, Davis dam.

Timeframe	Hourly Changes in Generation	Average (MW)	Standard Deviation (MW)	Average of the Absolute Value (MW)
Annual	actual	1.55e-2	29.2	15.7
	no-wind	0.0	60.3	20.3
HLH	actual	2.20e-2	31.1	17.5
	no-wind	0.0	66.8	25.0
LLH	actual	-5.01e-4	23.9	11.1
	no-wind	0.0	40.5	8.84

A.4 Crystal dam – MAPS no-wind versus actual Hydro Generation

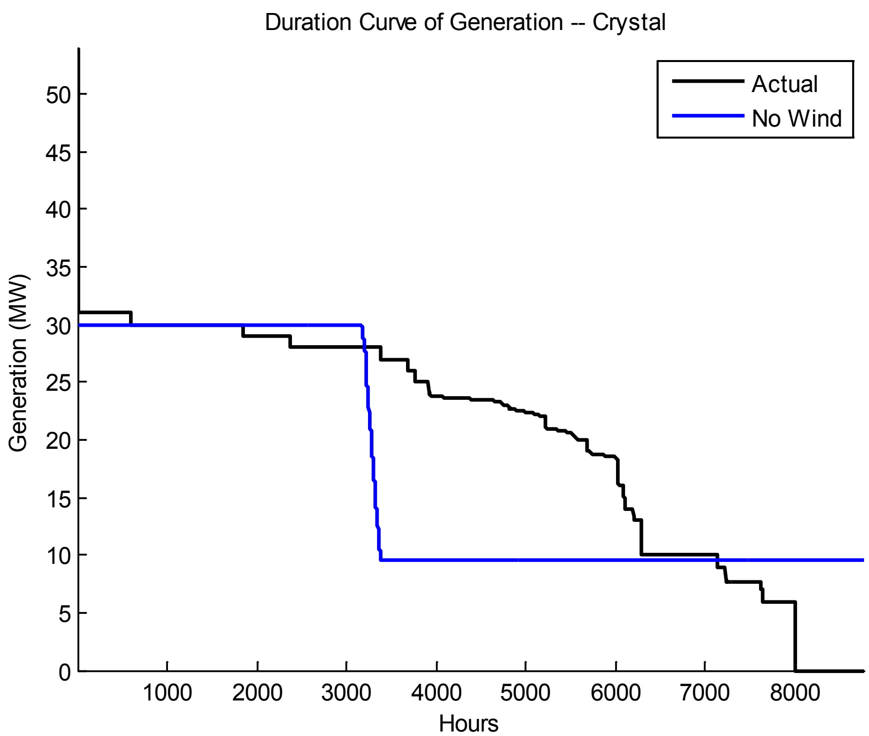

Figure 129: Generation duration curve of MAPS no-wind versus actual hydro generation, Crystal dam.

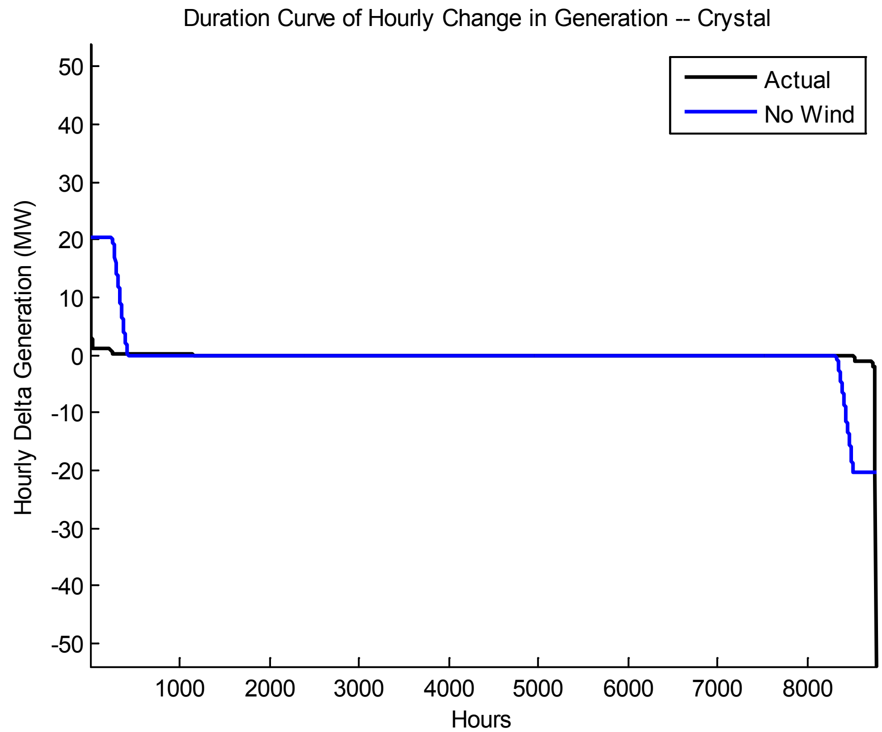

Figure 130: Hourly delta duration curves of MAPS no-wind versus actual hydro generation, Crystal dam.

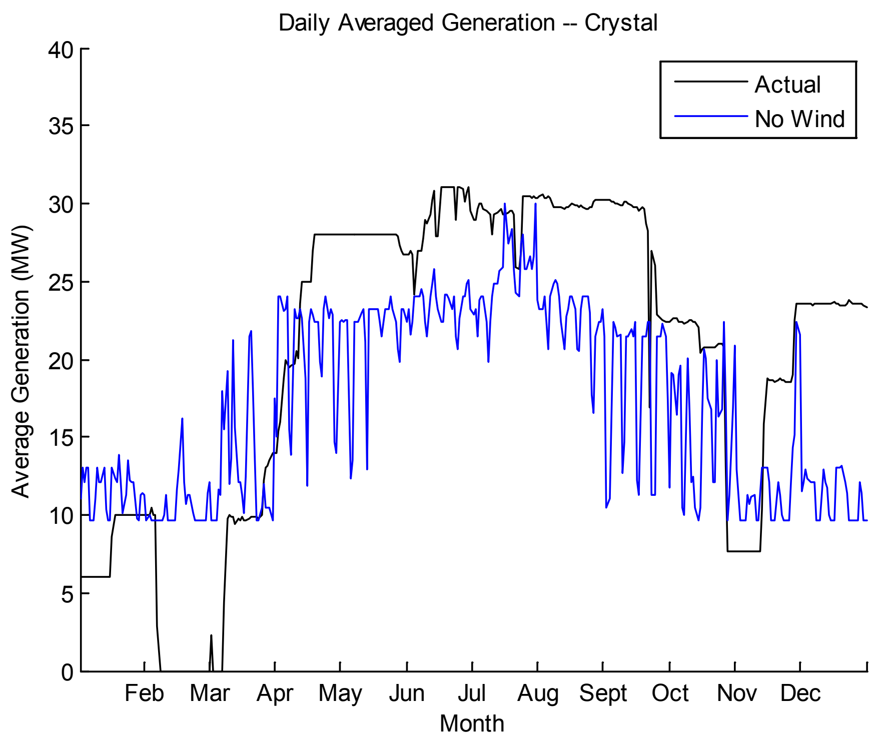

Figure 131: Daily averaged hydro generation of MAPS no-wind versus actual hydro generation, Crystal dam.

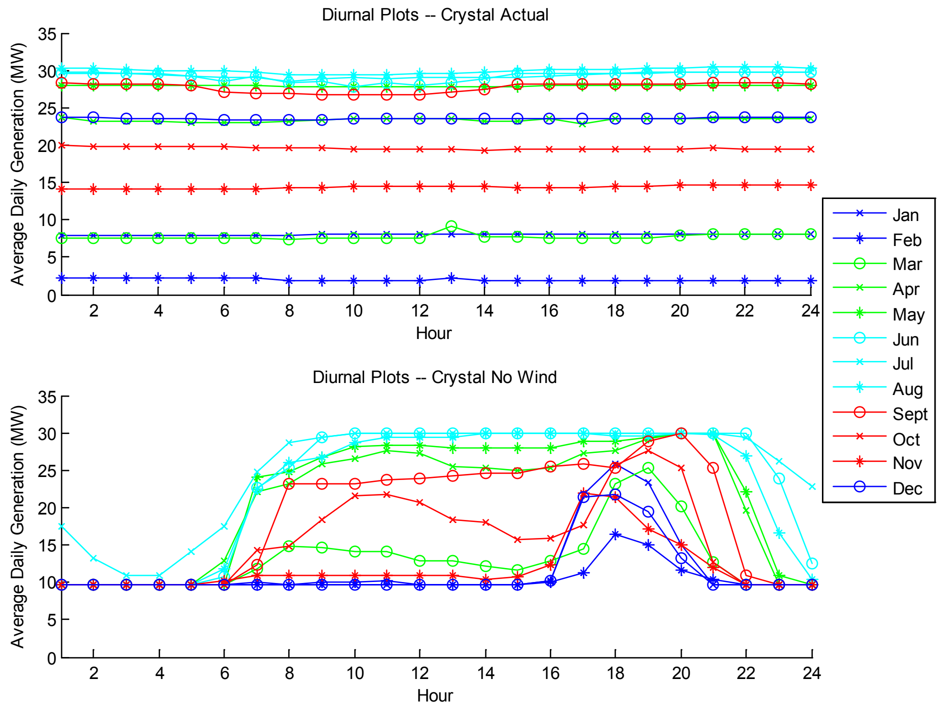

Figure 132: Monthly averaged diurnal plots of MAPS no-wind versus actual hydro generation, Crystal dam.

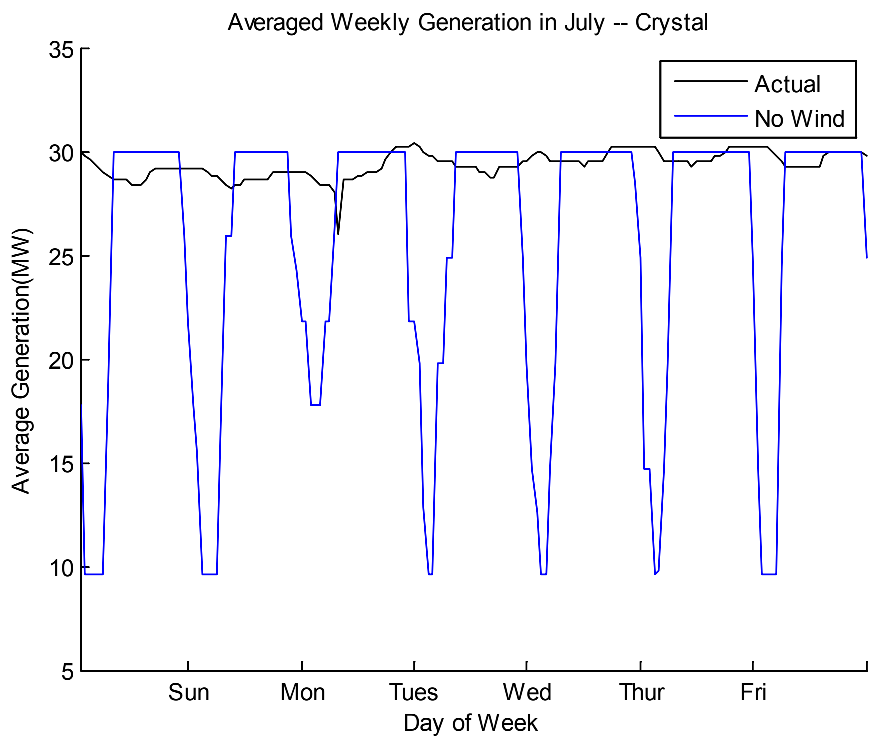

Figure 133: Averaged weekly generation in July, MAPS no-wind versus actual hydro generation, Crystal dam.

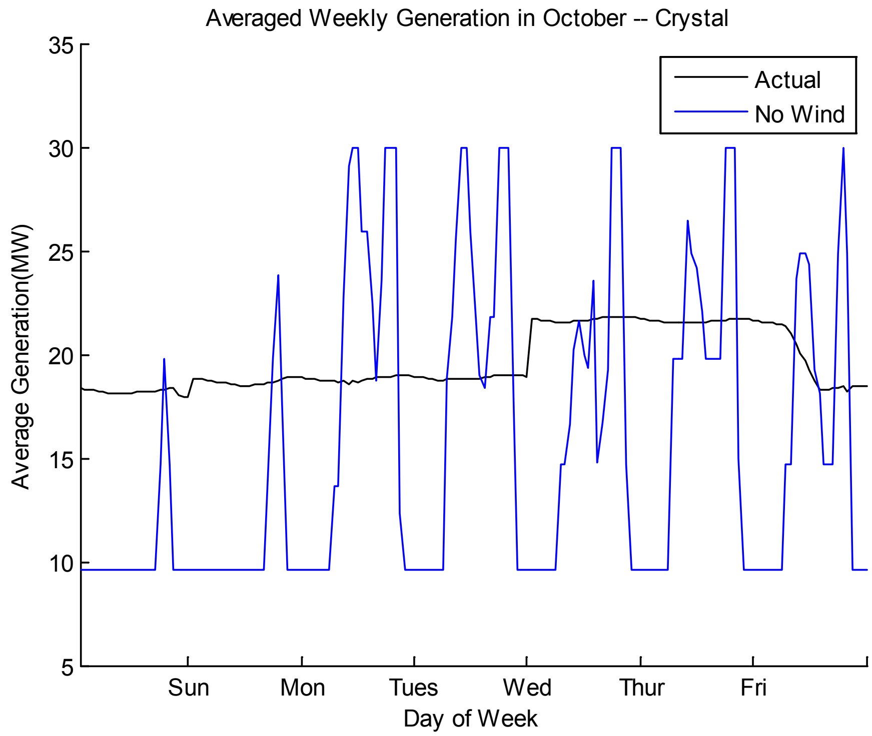

Figure 134: Averaged weekly generation in October, MAPS no-wind versus actual hydro generation, Crystal dam.

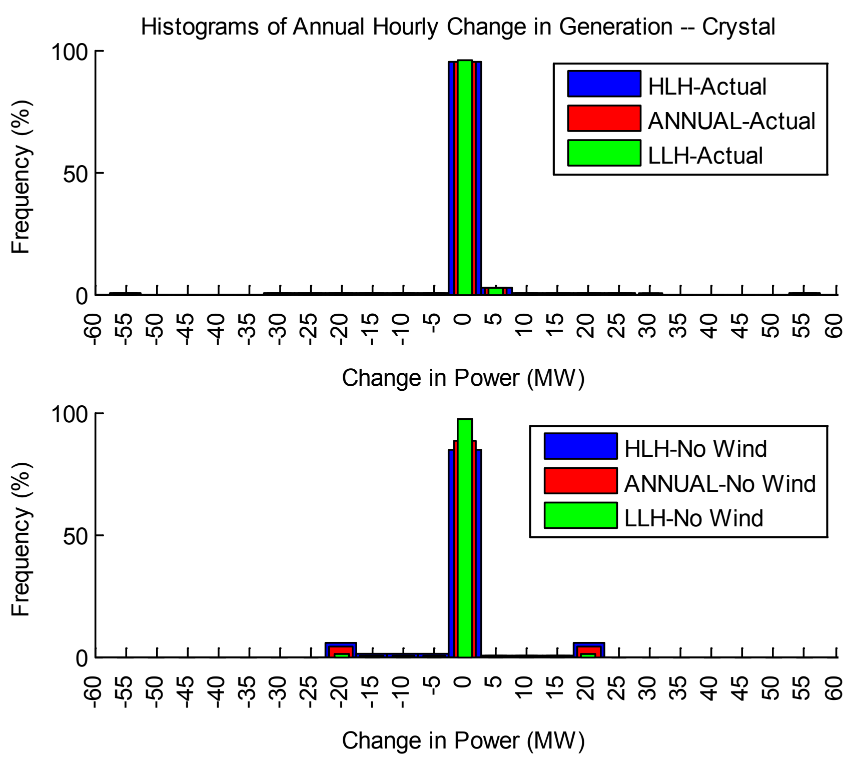

Figure 135: Histograms of hourly change in generation between MAPS no-wind versus actual hydro generation, Crystal dam.

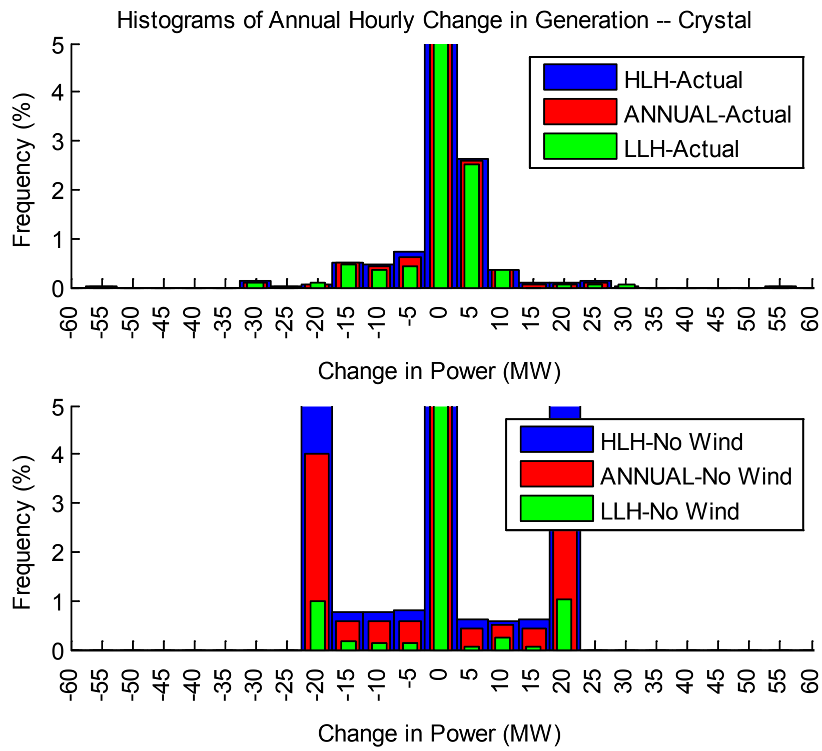

Figure 136: Enhanced view of histograms between MAPS no-wind versus actual hydro generation, Crystal dam.

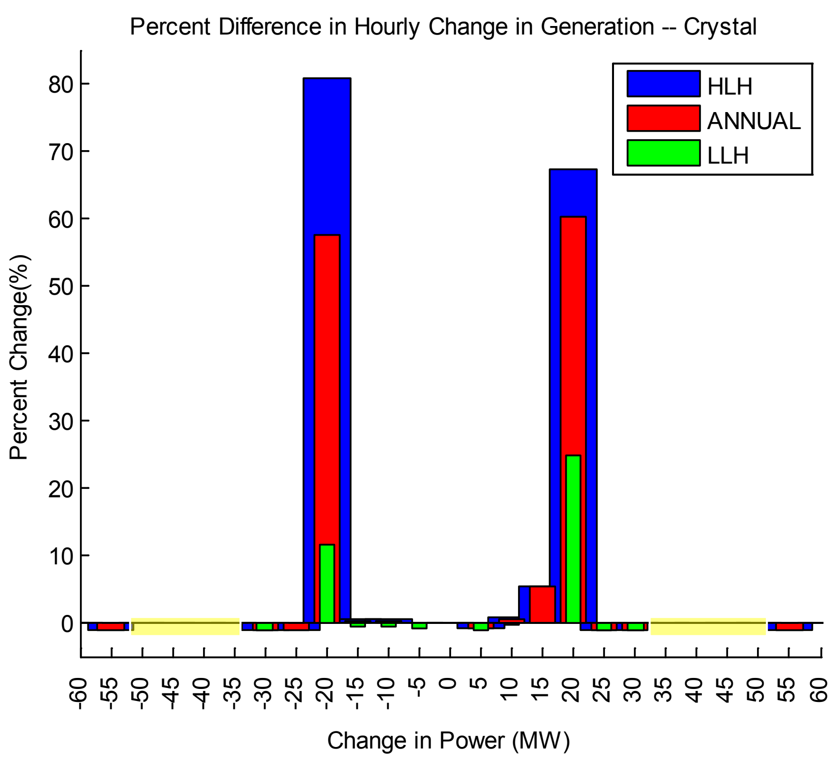

Figure 137: Percent difference in hourly change in generation between MAPS no-wind versus actual hydro generation, Crystal dam.

Table 17: Statistics of hourly changes in generation between MAPS no-wind versus actual hydro generation, Crystal dam.

Timeframe	Hourly Changes in Generation	Average (MW)	Standard Deviation (MW)	Average of the Absolute Value (MW)
Annual	actual	2.0e-3	2.41	0.519
	no-wind	0.0	6.13	1.99
HLH	actual	2.82e-3	2.53	0.553
	no-wind	0.0	7.02	2.61
LLH	actual	6.75e-3	2.04	0.431
	no-wind	0.0	3.0	0.479

A.5 Morrow Point dam – MAPS no-wind versus actual Hydro Generation

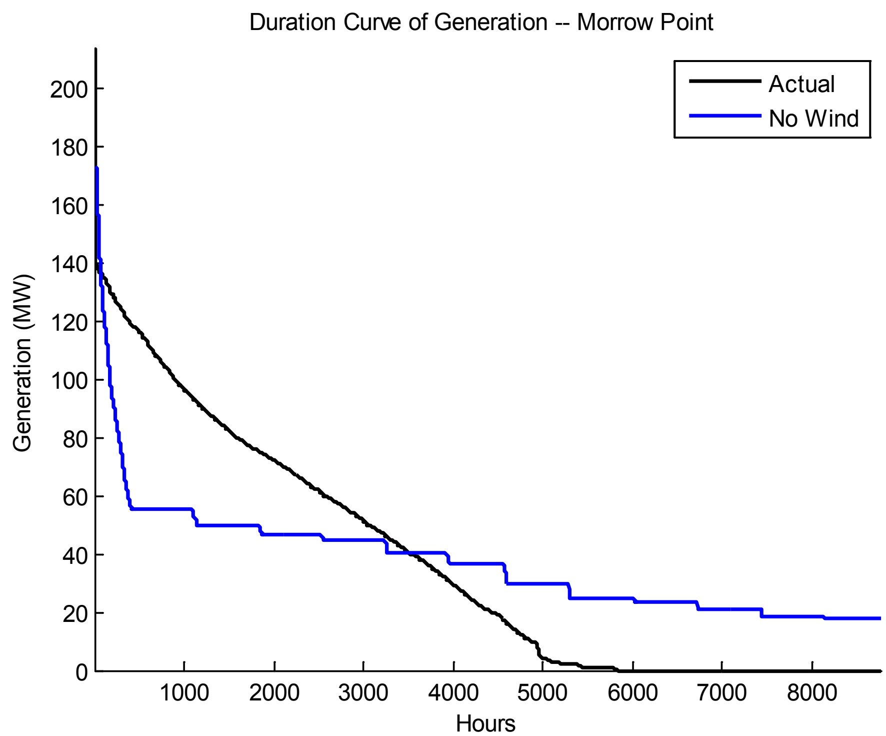

Figure 138: Generation duration curve of MAPS no-wind versus actual hydro generation, Morrow Point dam.

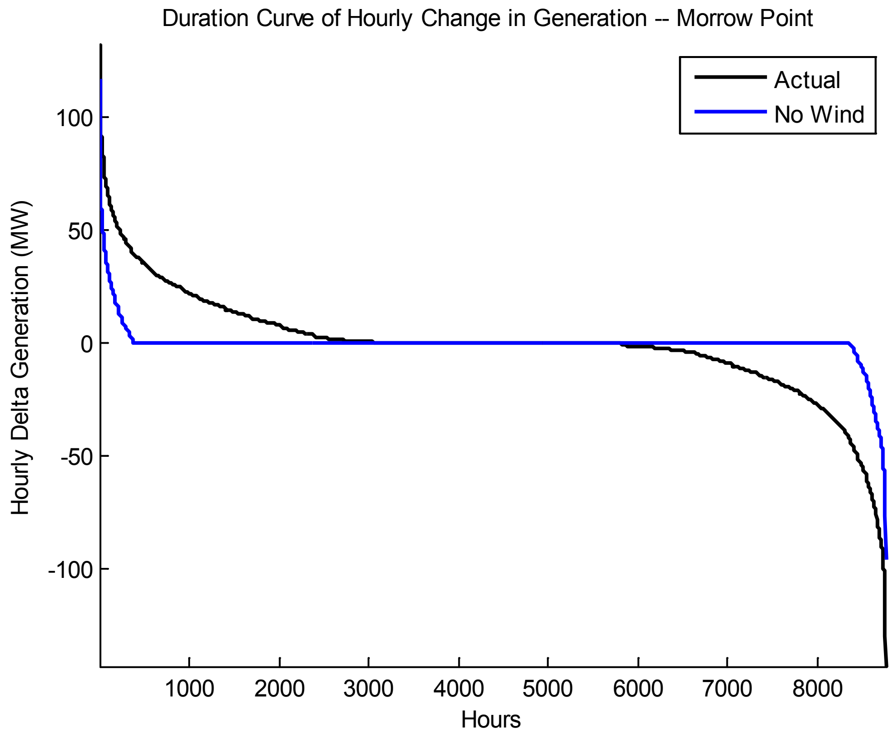

Figure 139: Hourly delta duration curves of MAPS no-wind versus actual hydro generation, Morrow Point dam.

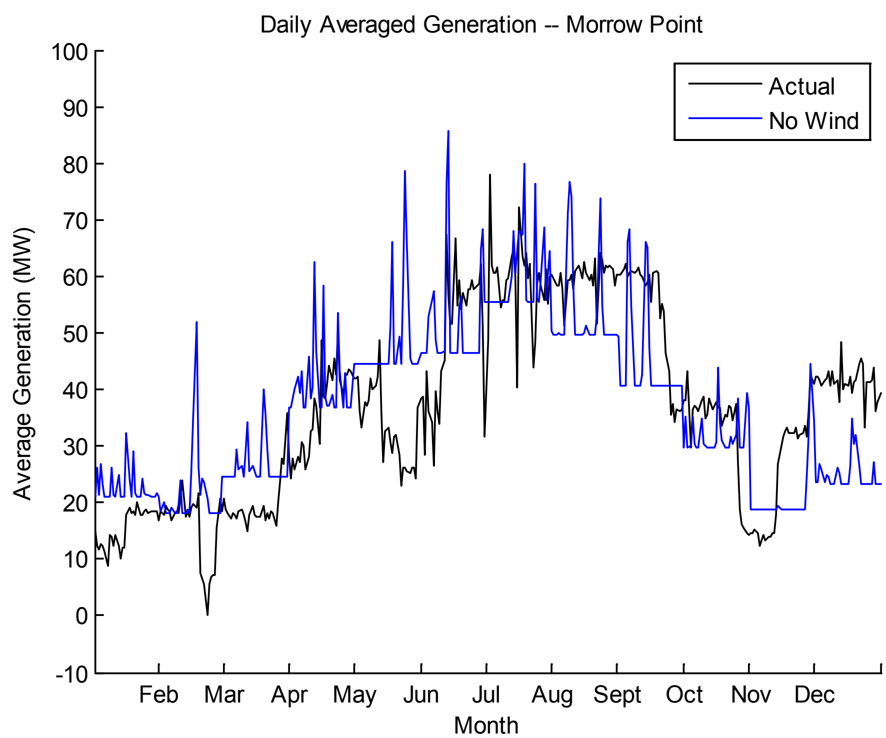

Figure 140: Daily averaged hydro generation of MAPS no-wind versus actual hydro generation, Morrow Point dam.

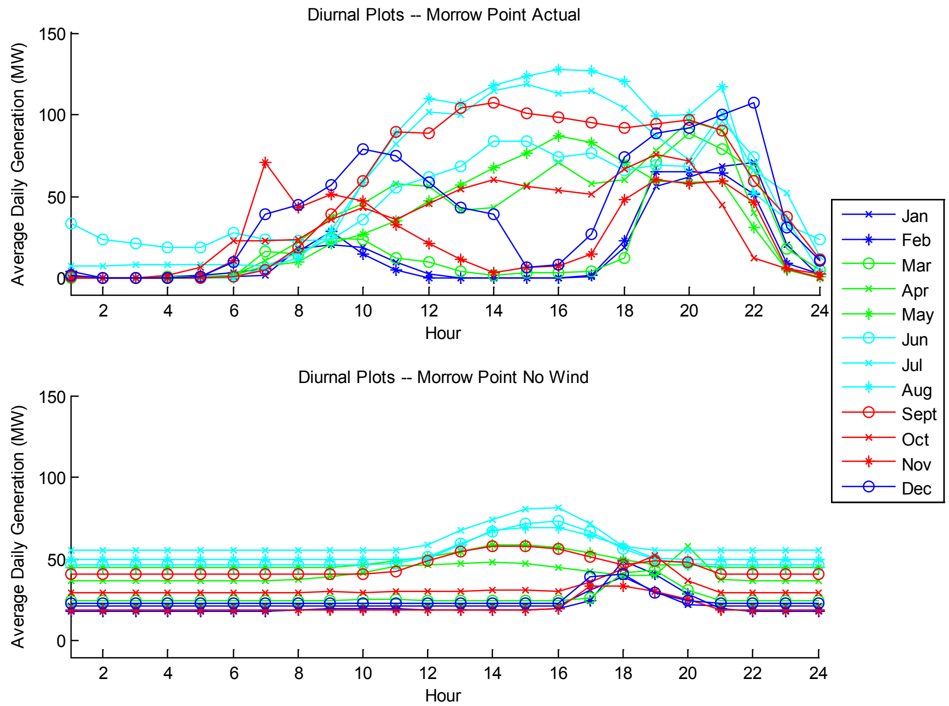

Figure 141: Monthly averaged diurnal plots of MAPS no-wind versus actual hydro generation, Morrow Point dam.

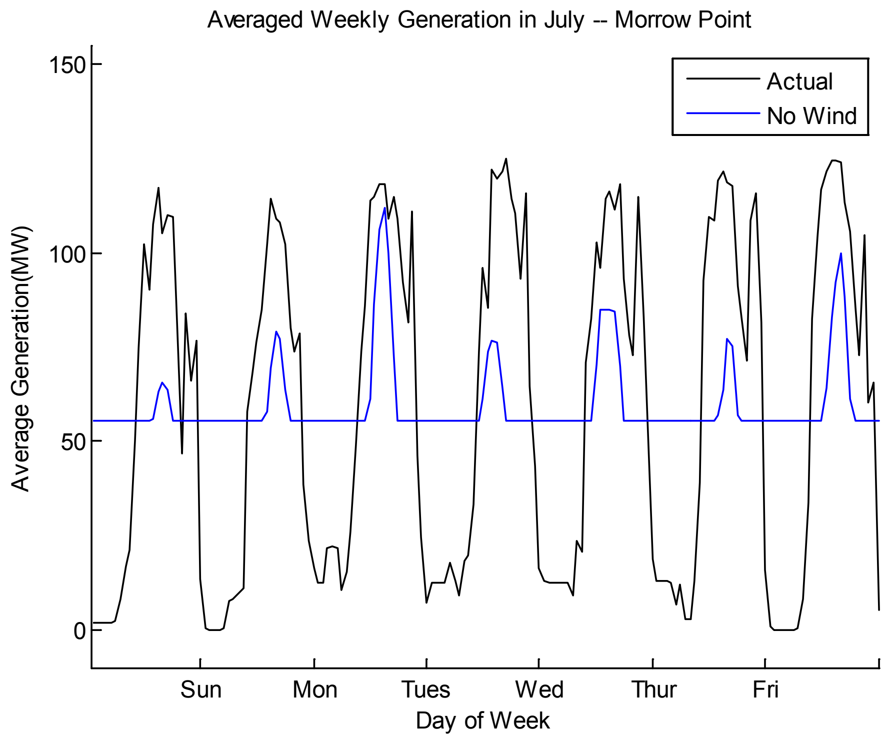

Figure 142: Averaged weekly generation in July, MAPS no-wind versus actual hydro generation, Morrow Point dam.

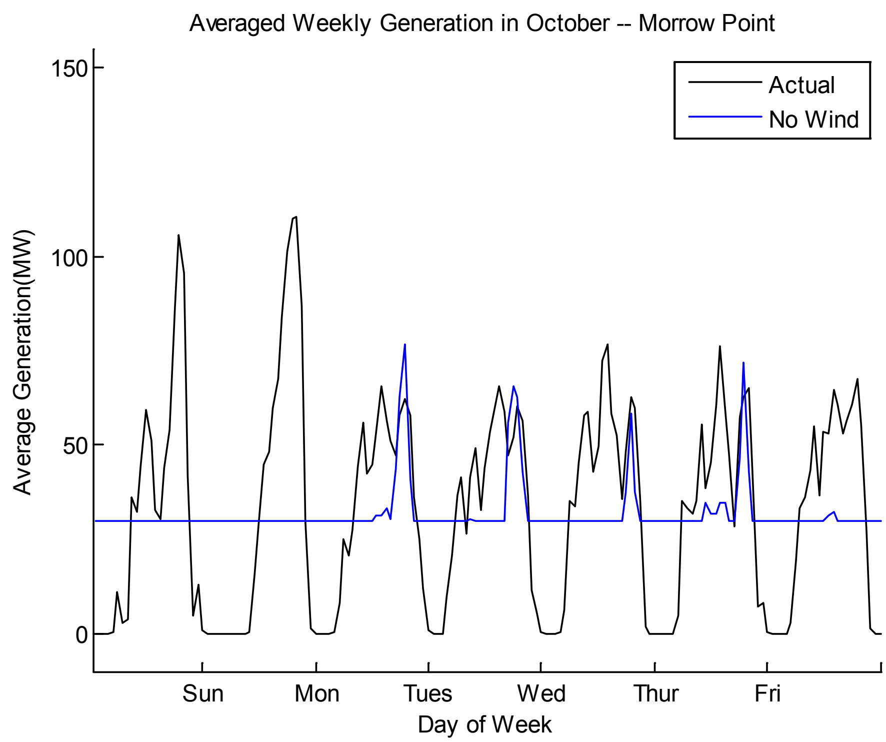

Figure 143: Averaged weekly generation in October, MAPS no-wind versus actual hydro generation, Morrow Point dam.

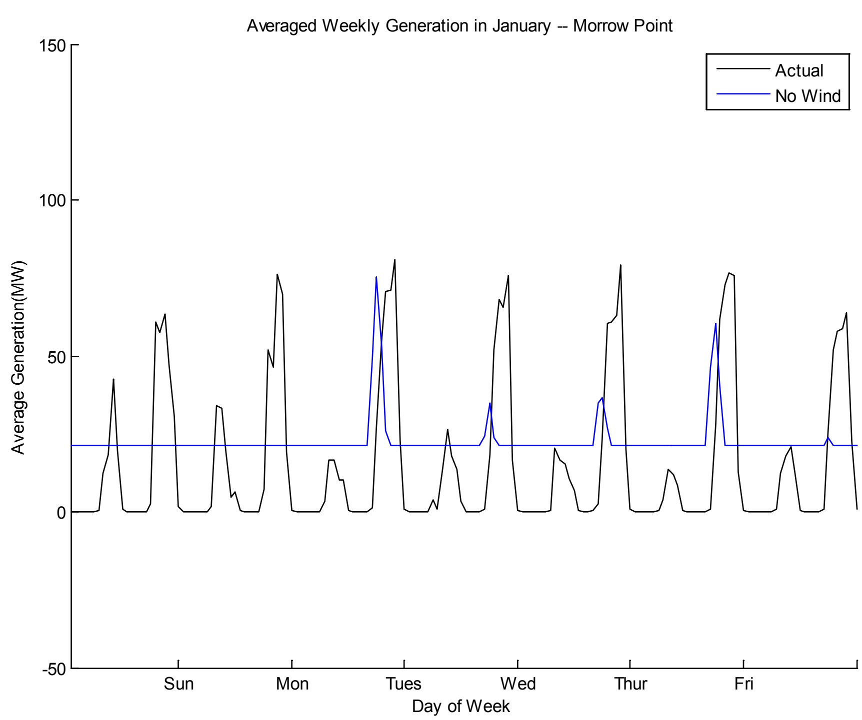

Figure 144: Averaged weekly generation in January, MAPS no-wind versus actual hydro generation, Morrow Point dam.

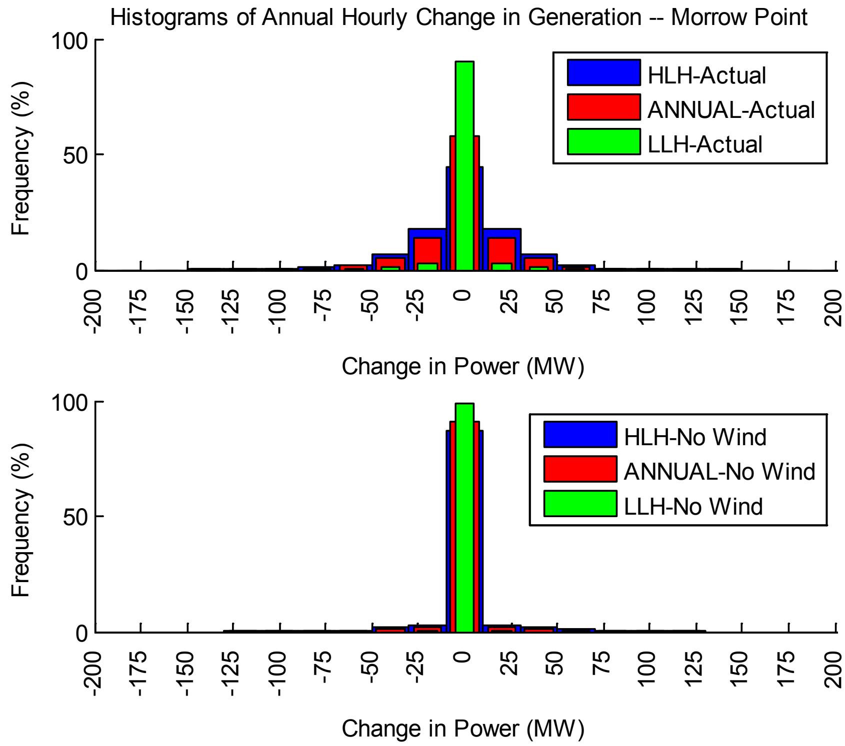

Figure 145: Histograms of hourly change in generation between MAPS no-wind versus actual hydro generation, Morrow Point dam.

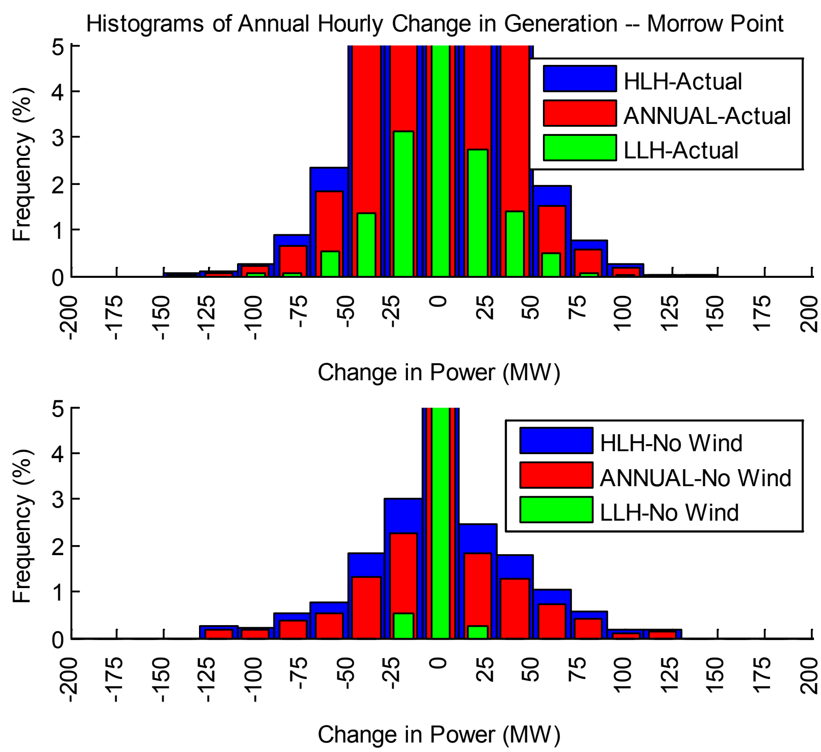

Figure 146: Enhanced view of histograms between MAPS no-wind versus actual hydro generation, Morrow Point dam.

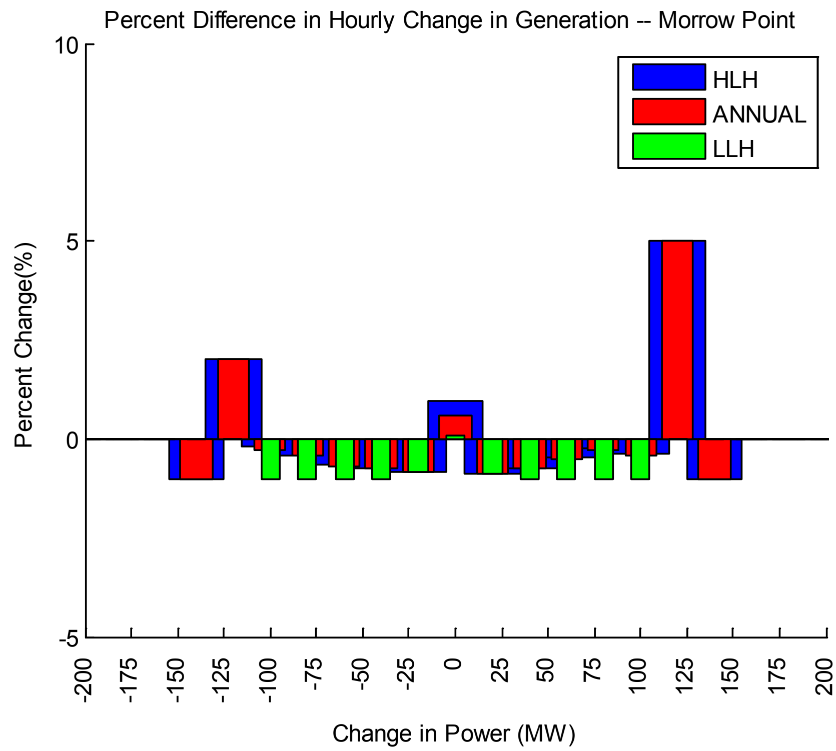

Figure 147: Percent difference in hourly change in generation between MAPS no-wind versus actual hydro generation, Morrow Point dam.

Table 18: Statistics of hourly changes in generation between MAPS no-wind versus actual hydro generation, Morrow Point dam.

Timeframe	Hourly Changes in Generation	Average (MW)	Standard Deviation (MW)	Average of the Absolute Value (MW)
Annual	actual	4.10e-3	22.7	13.5
	no-wind	2.39e-4	14.9	3.97
HLH	actual	5.62e-3	25.9	17.6
	no-wind	3.37e-4	17.7	5.51
LLH	actual	1.28e-3	11.1	3.47
	no-wind	8.18e-4	1.41	0.229

A.6 Blue Mesa dam – MAPS no-wind versus actual Generation

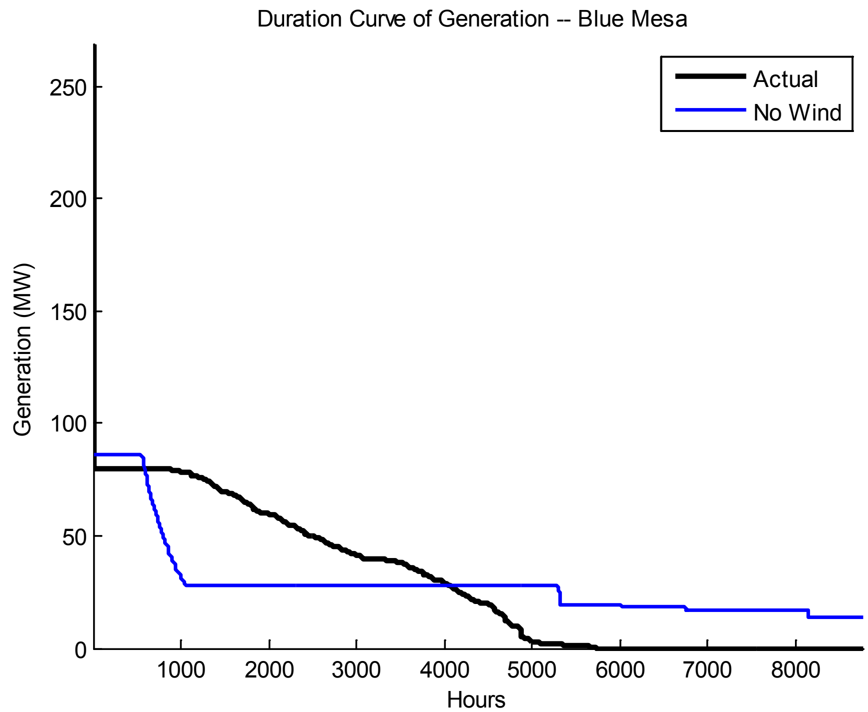

Figure 148: Generation duration curve of MAPS no-wind versus actual hydro generation, Blue Mesa dam.

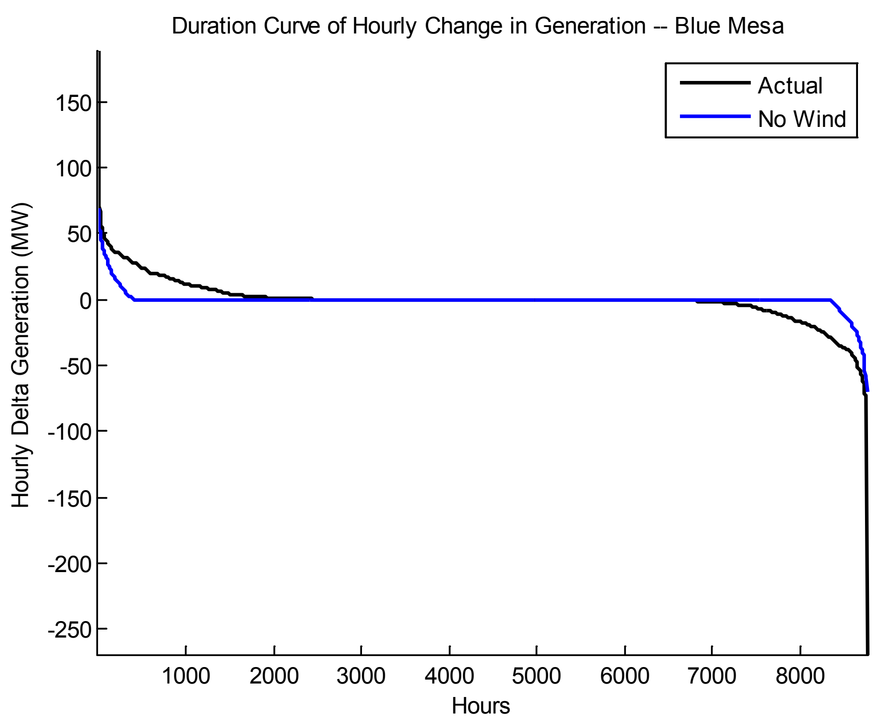

Figure 149: Hourly delta duration curves of MAPS no-wind versus actual hydro generation, Blue Mesa dam.

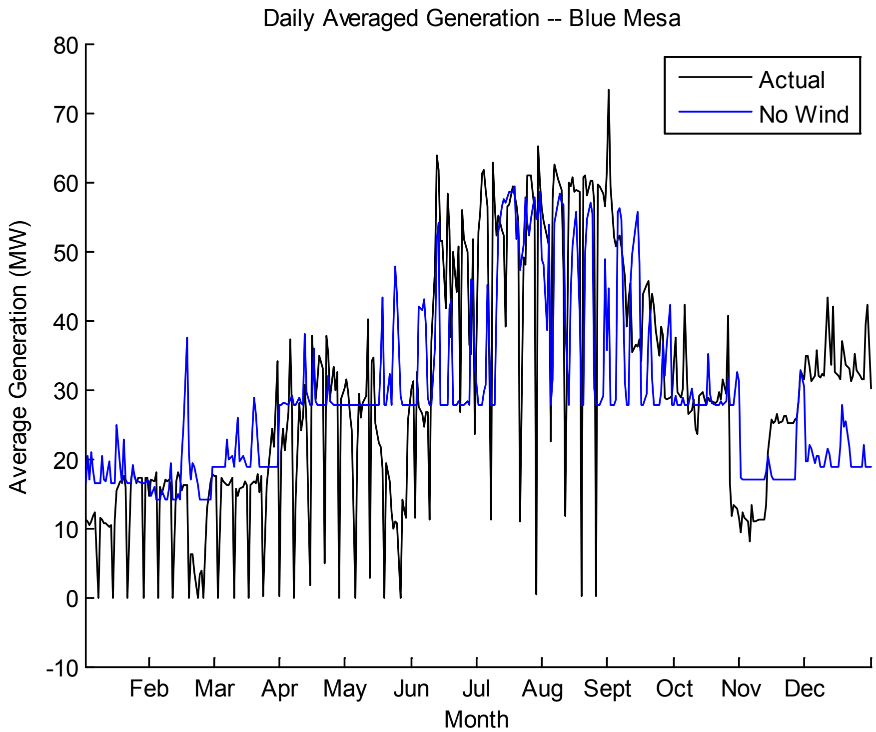

Figure 150: Daily averaged hydro generation of MAPS no-wind versus actual hydro generation, Blue Mesa dam.

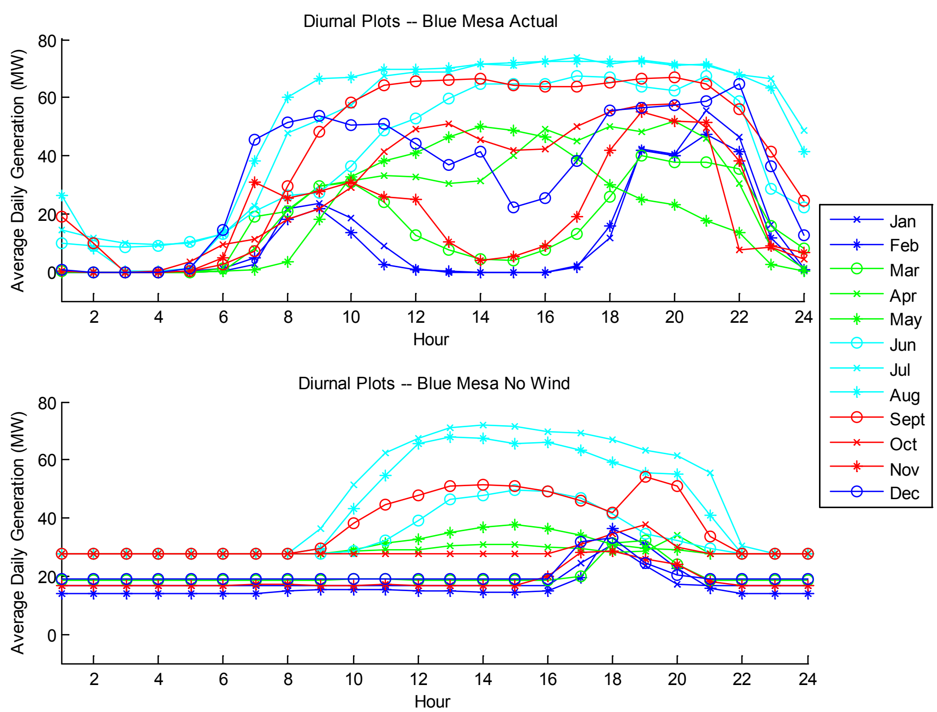

Figure 151: Monthly averaged diurnal plots of MAPS no-wind versus actual hydro generation, Blue Mesa dam.

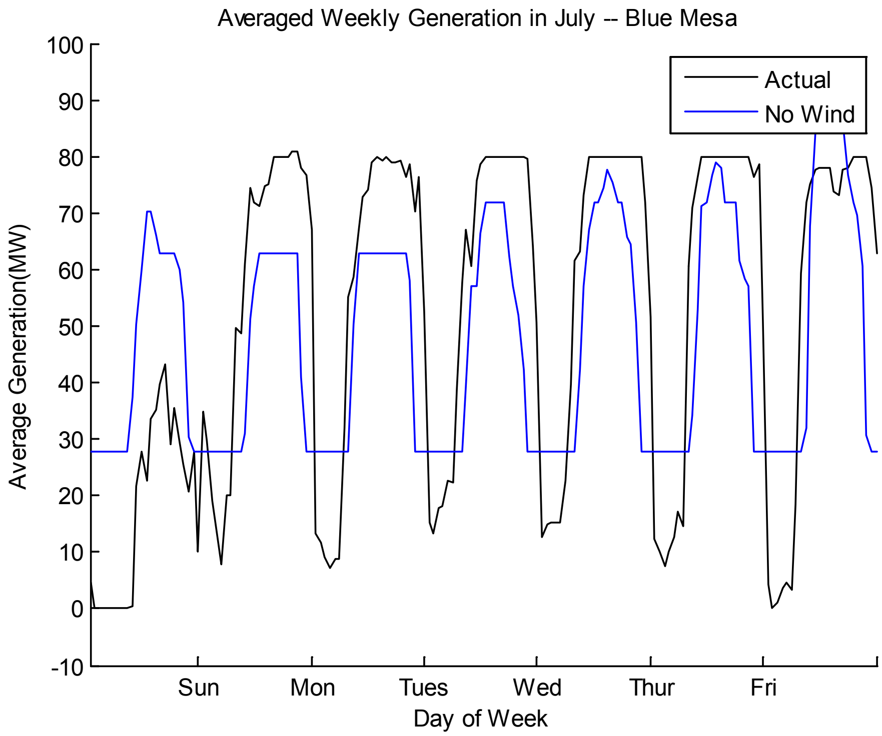

Figure 152: Averaged weekly generation in July, MAPS no-wind versus actual hydro generation, Blue Mesa dam.

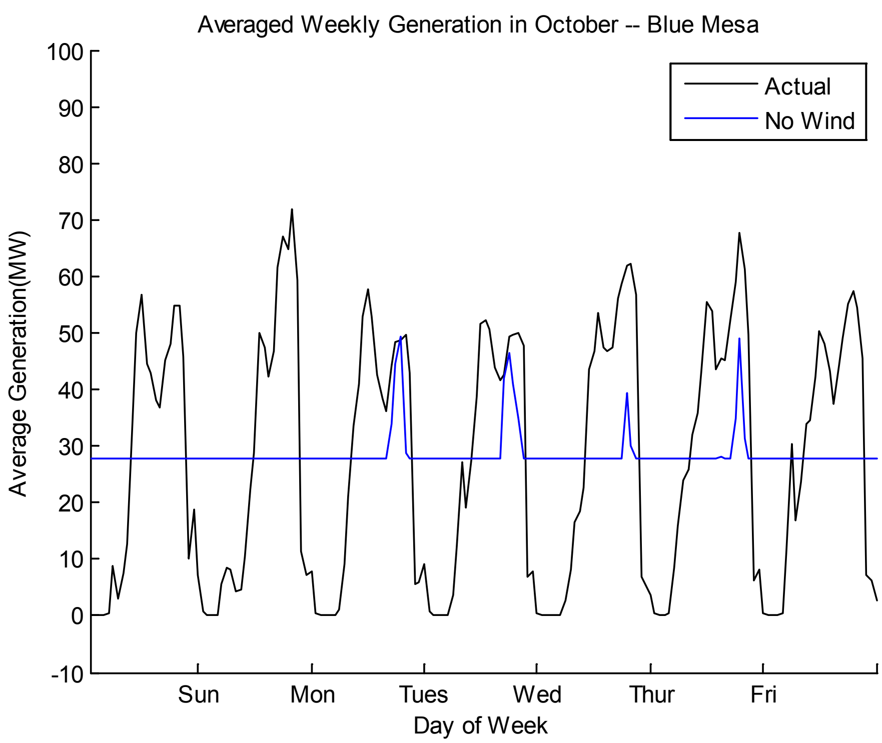

Figure 153: Averaged weekly generation in October, MAPS no-wind versus actual hydro generation, Blue Mesa dam.

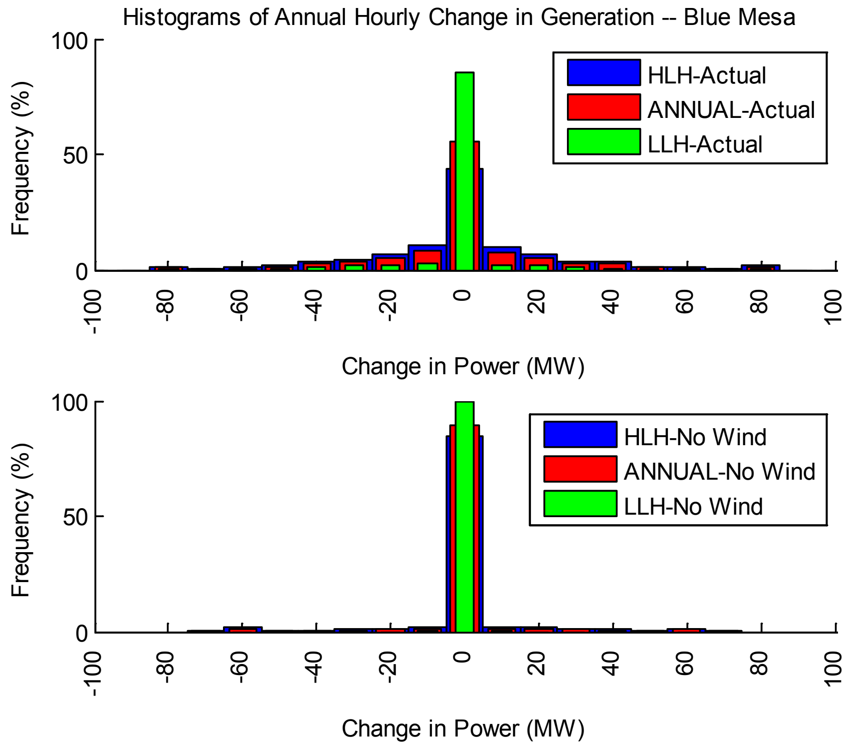

Figure 154: Histograms of hourly change in generation between MAPS no-wind versus actual hydro generation, Blue Mesa dam.

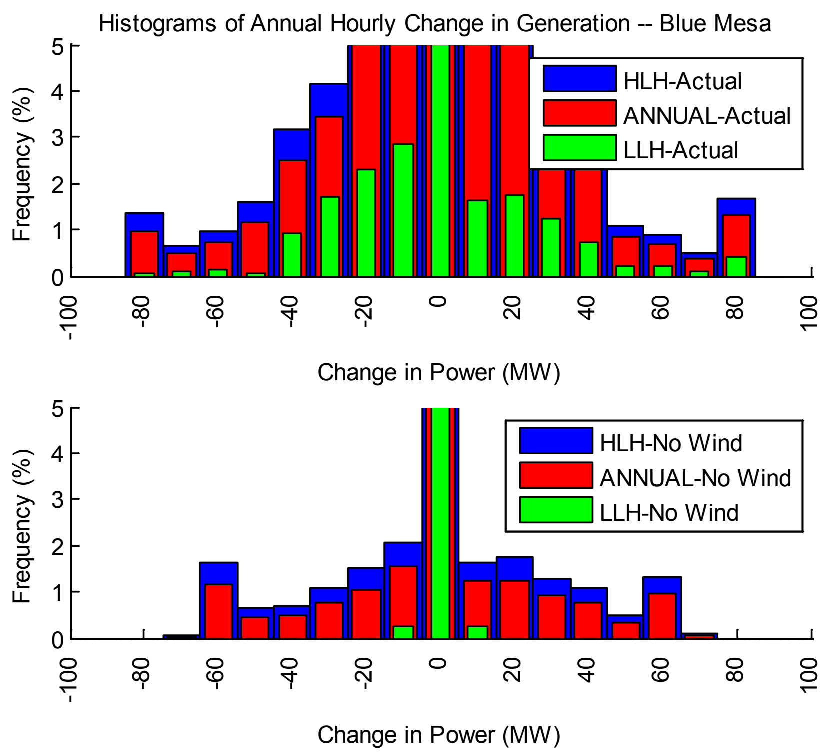

Figure 155: Enhanced view of histograms between MAPS no-wind versus actual hydro generation, Blue Mesa dam.

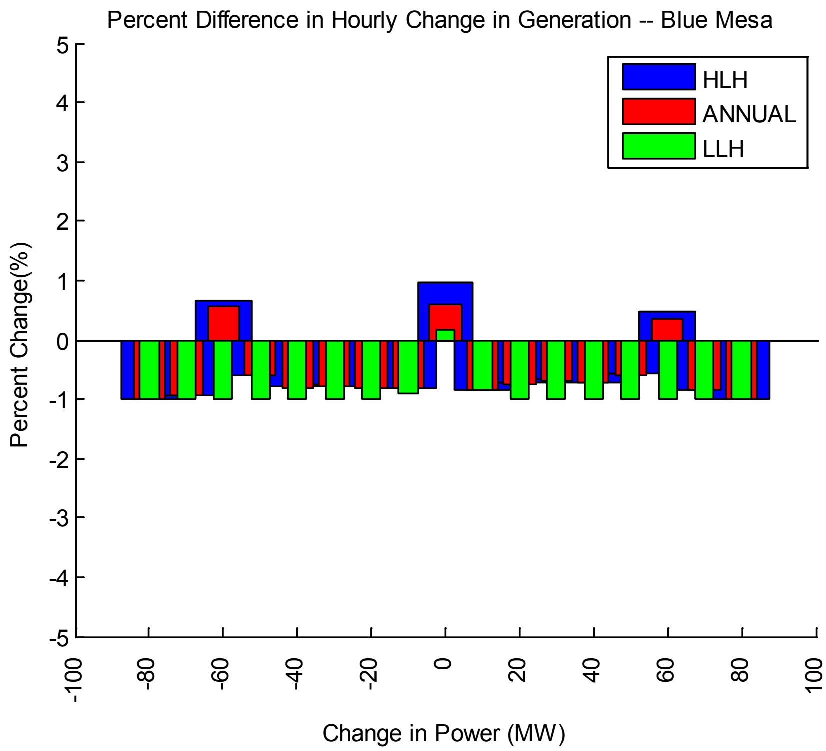

Figure 156: Percent difference in hourly change in generation between MAPS no-wind versus actual hydro generation, Blue Mesa dam.

Table 19: Statistics of hourly changes in generation between MAPS no-wind versus actual hydro generation, Blue Mesa dam.

Timeframe	Hourly Changes in Generation	Average (MW)	Standard Deviation (MW)	Average of the Absolute Value (MW)
Annual	actual	5.43e-3	22.4	12.3
	no-wind	2.74e-4	12.0	3.51
HLH	actual	7.66e-3	25.0	15.6
	no-wind	3.87e-4	14.3	4.92
LLH	actual	1.27e-2	13.9	4.18
	no-wind	9.40e-4	0.803	8.55e-2

APPENDIX B. Historical Hydro Operations

B.1 Hoover dam – MAPS Historical Hydro versus actual Hydro Generation

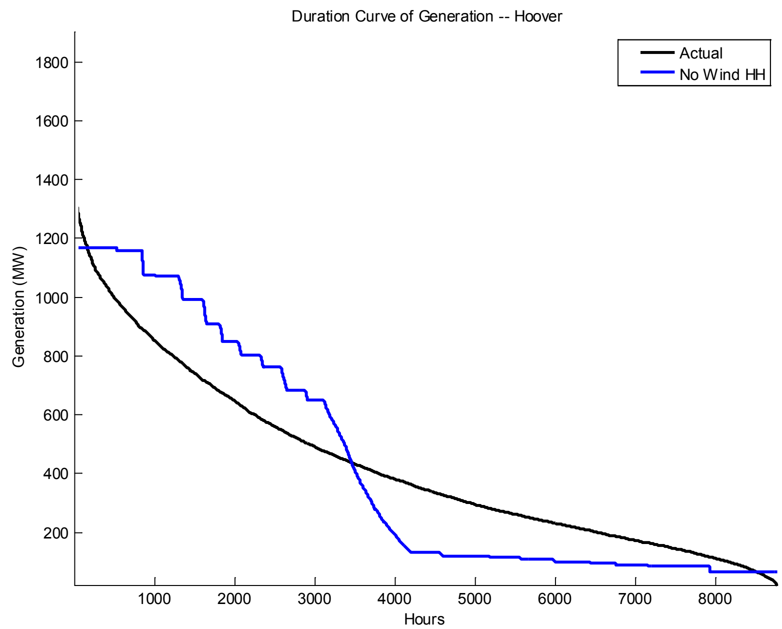

Figure 157: Generation duration curve of MAPS no-wind historical hydro operations versus actual hydro generation, Hoover dam.

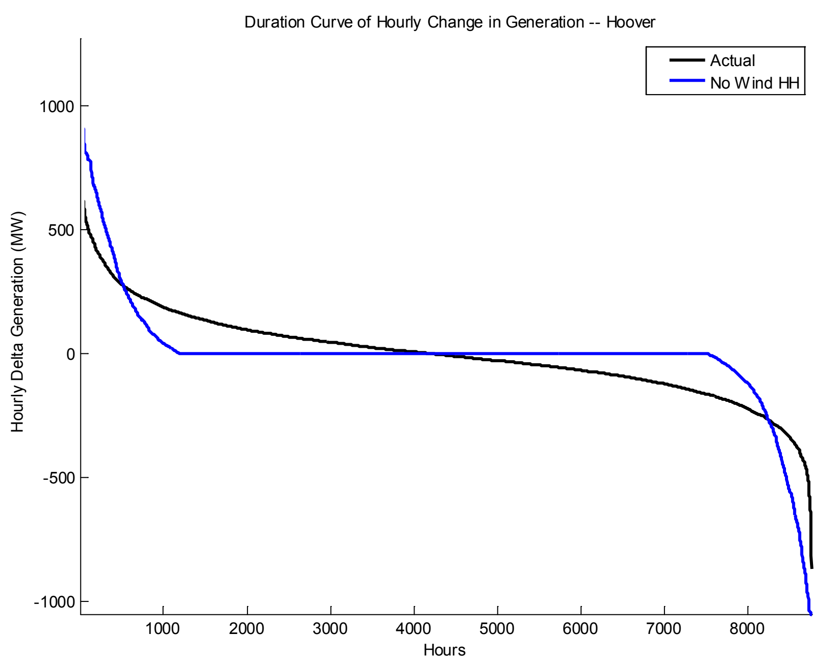

Figure 158: Hourly delta duration curves of MAPS no-wind historical hydro operations versus actual hydro generation, Hoover dam.

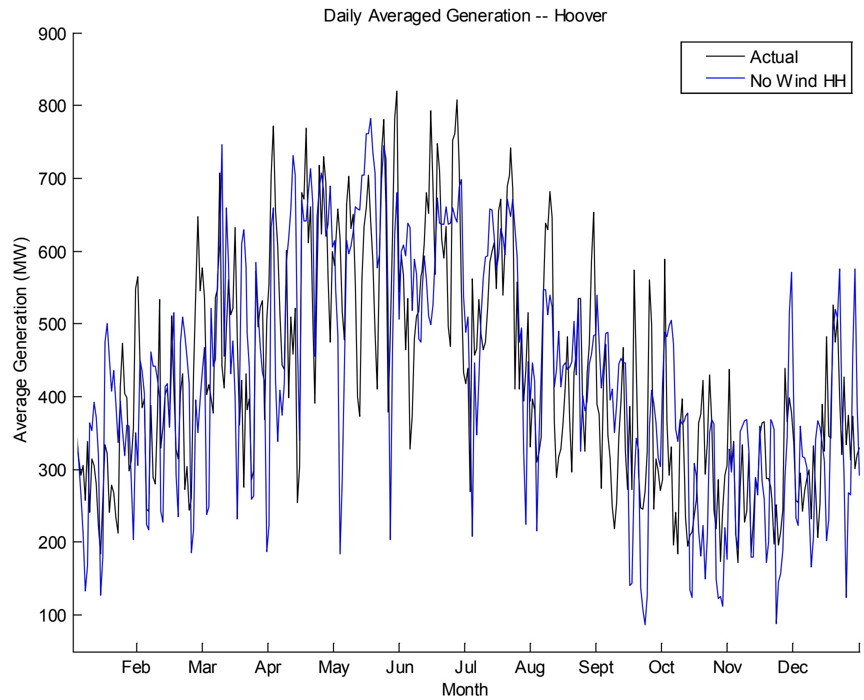

Figure 159: Daily averaged hydro generation of MAPS no-wind historical hydro operations versus actual hydro generation, Hoover dam.

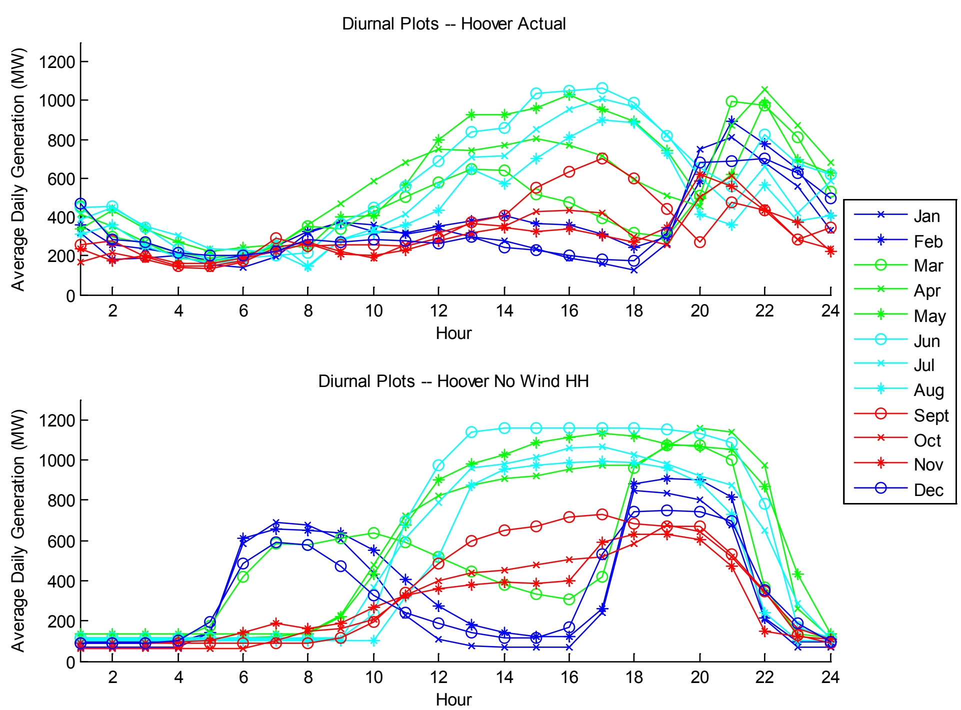

Figure 160: Monthly averaged diurnal plots of MAPS no-wind historical hydro operations versus actual hydro generation, Hoover dam.

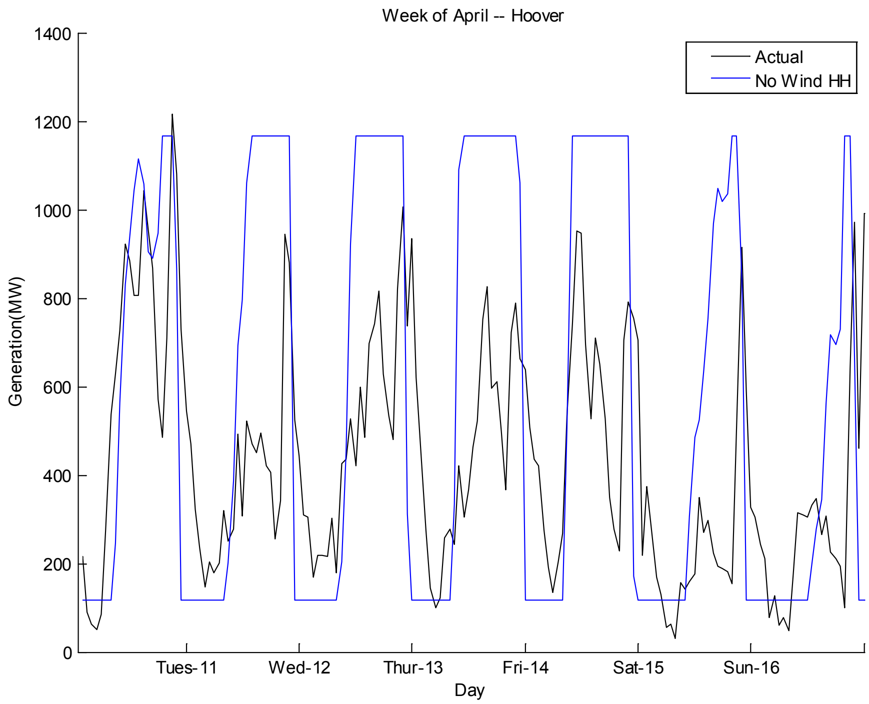

Figure 161: Hourly generation for week of April between MAPS no-wind historical hydro operations versus actual hydro generation, Hoover dam.

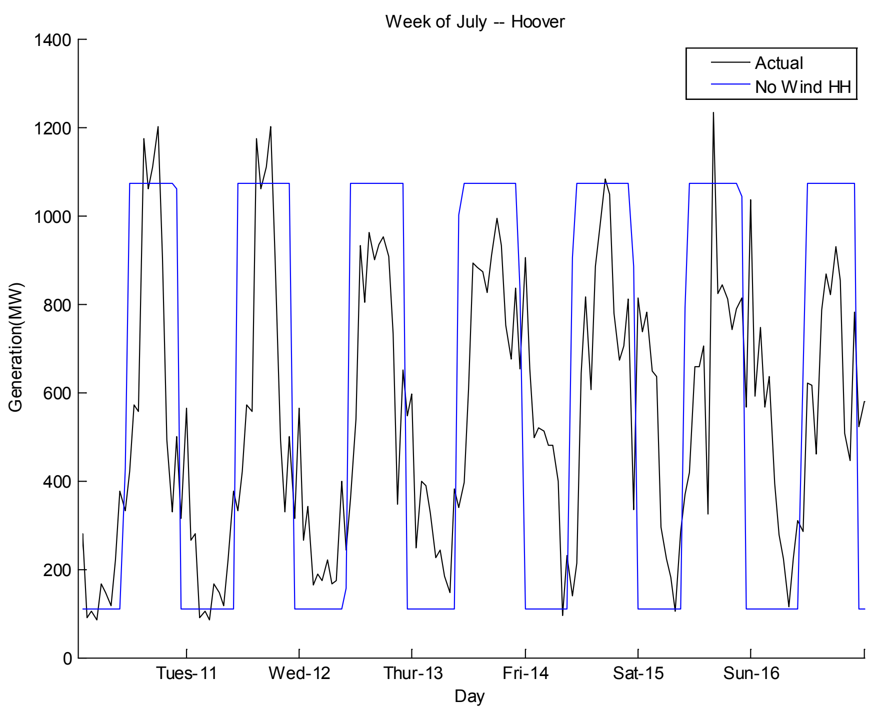

Figure 162: Hourly generation for week of April between MAPS no-wind historical hydro operations versus actual hydro generation, Hoover dam.

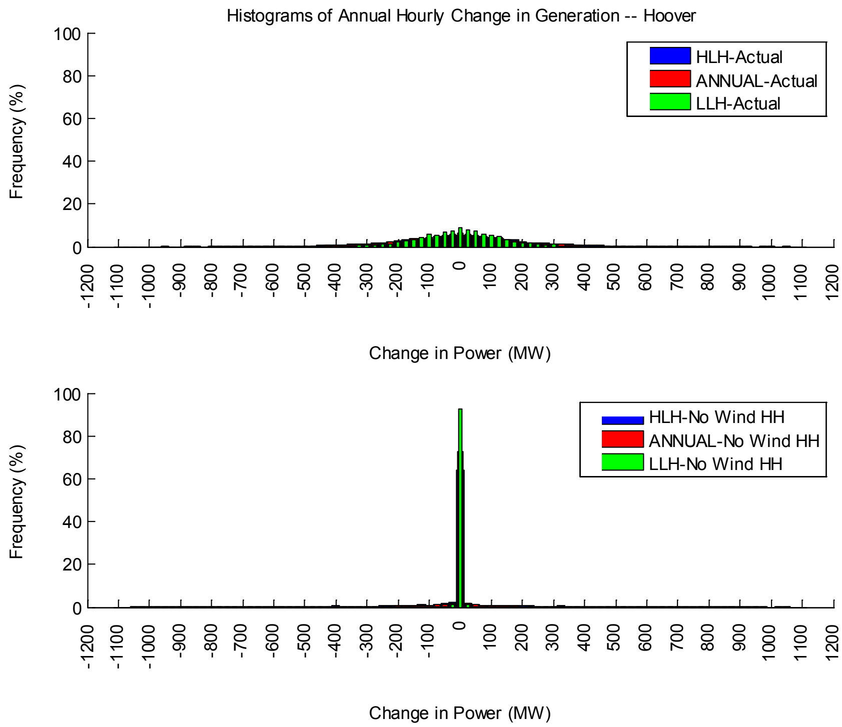

Figure 163: Histograms of hourly change in generation between MAPS no-wind historical hydro operations versus actual hydro generation, Hoover dam.

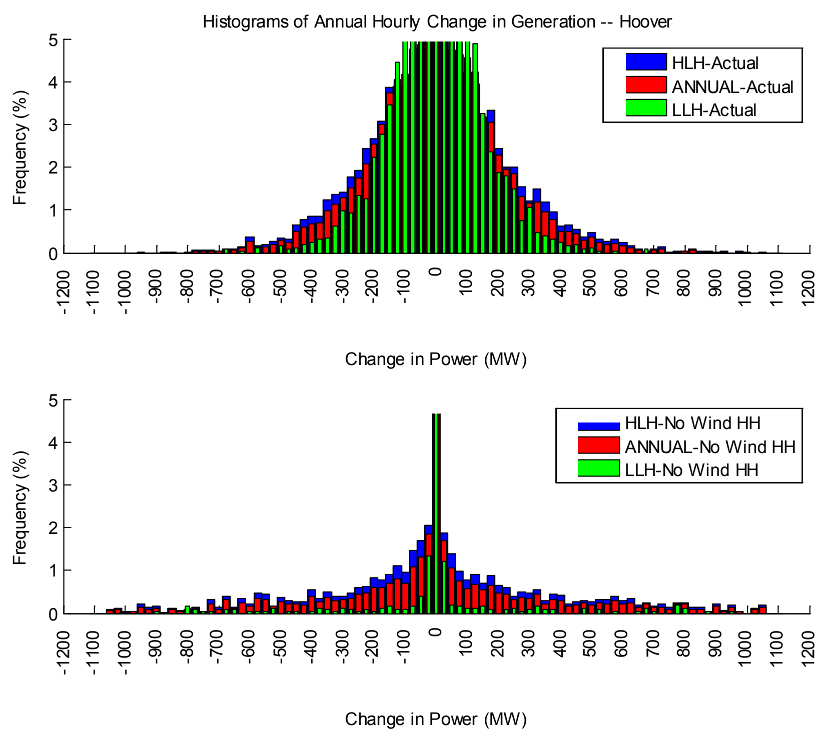

Figure 164: Enhanced view of histograms between MAPS no-wind historical hydro operations versus actual hydro generation, Hoover dam.

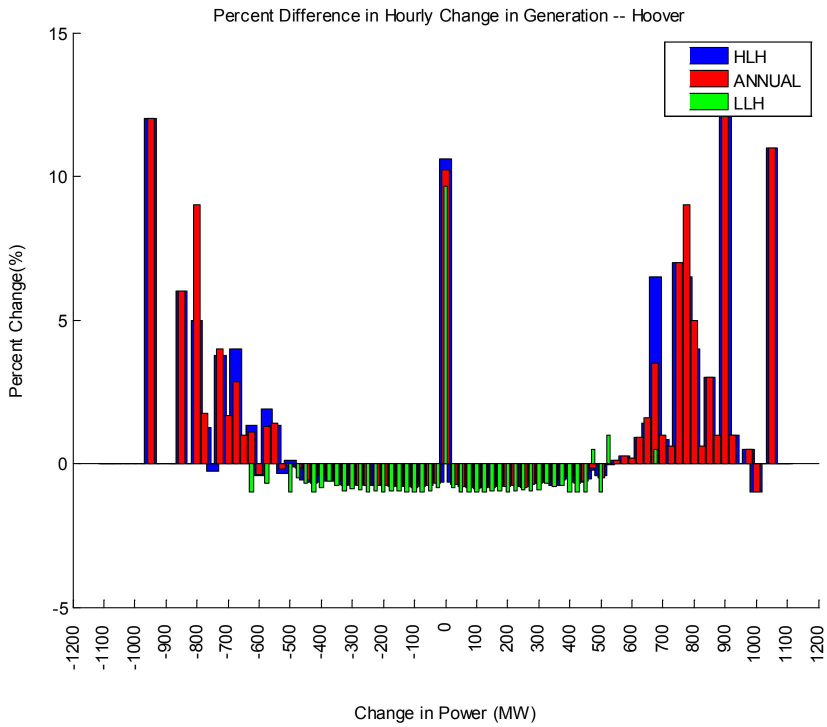

Figure 165: Percent difference in hourly change in generation between MAPS no-wind historical hydro operations versus actual hydro generation, Hoover dam.

Table 20: Statistics of hourly changes in generation between MAPS no-wind historical hydro operations versus actual hydro generation, Hoover dam.

Timeframe	Hourly Changes in Generation	Average (MW)	Standard Deviation (MW)	Average of the Absolute Value (MW)
Annual	actual	-5.48e-3	209	155
	no-wind	2.42e-3	210	82.1
HLH	actual	3.82e-2	229	173
	no-wind	3.42e-2	241	109
LLH	actual	-7.63e-2	149	112
	no-wind	6.28e-2	96.8	17.4

B.2 Parker dam – MAPS Historical Hydro versus actual Hydro Generation

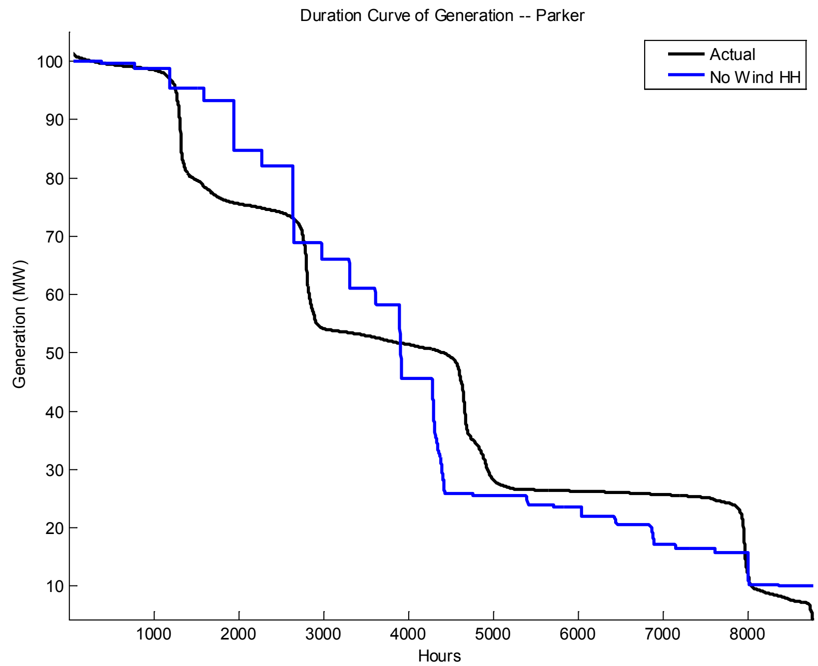

Figure 166: Generation duration curve of MAPS no-wind historical hydro operations versus actual hydro generation, Parker dam.

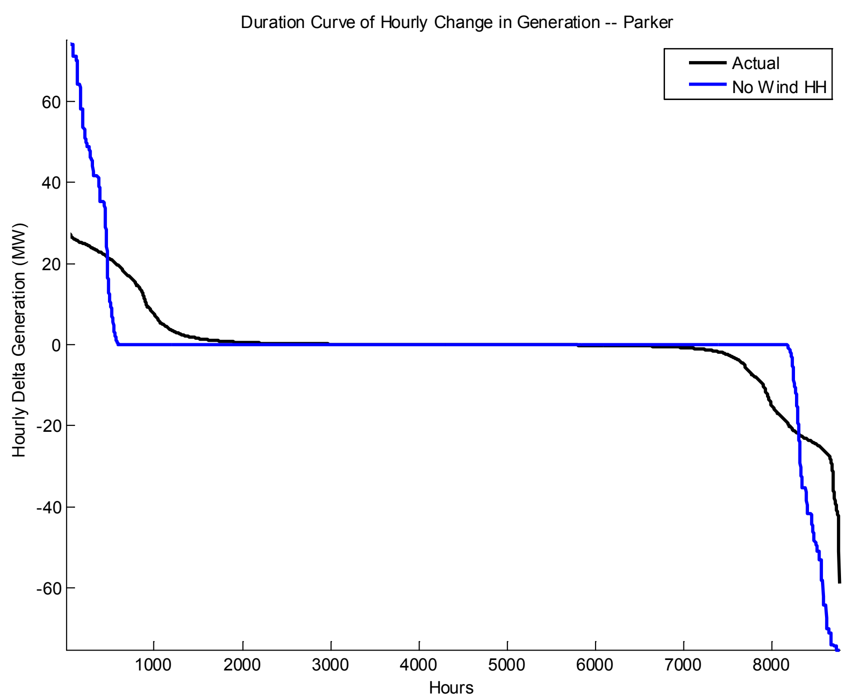

Figure 167: Hourly delta duration curves of MAPS no-wind historical hydro operations versus actual hydro generation, Parker dam.

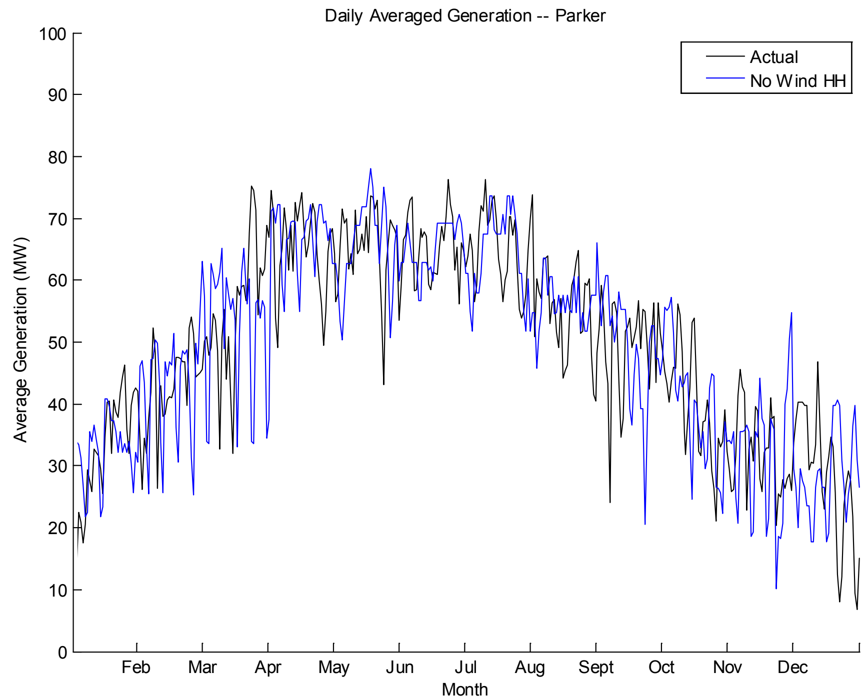

Figure 168: Daily averaged hydro generation of MAPS no-wind historical hydro operations versus actual hydro generation, Parker dam.

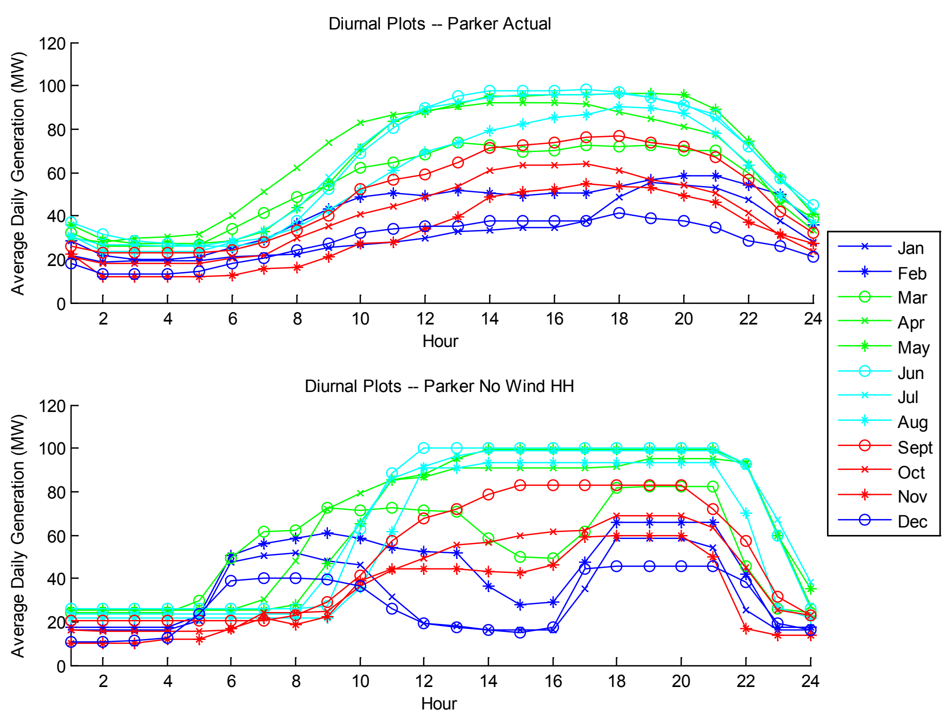

Figure 169: Monthly averaged diurnal plots of MAPS no-wind historical hydro operations versus actual hydro generation, Parker dam.

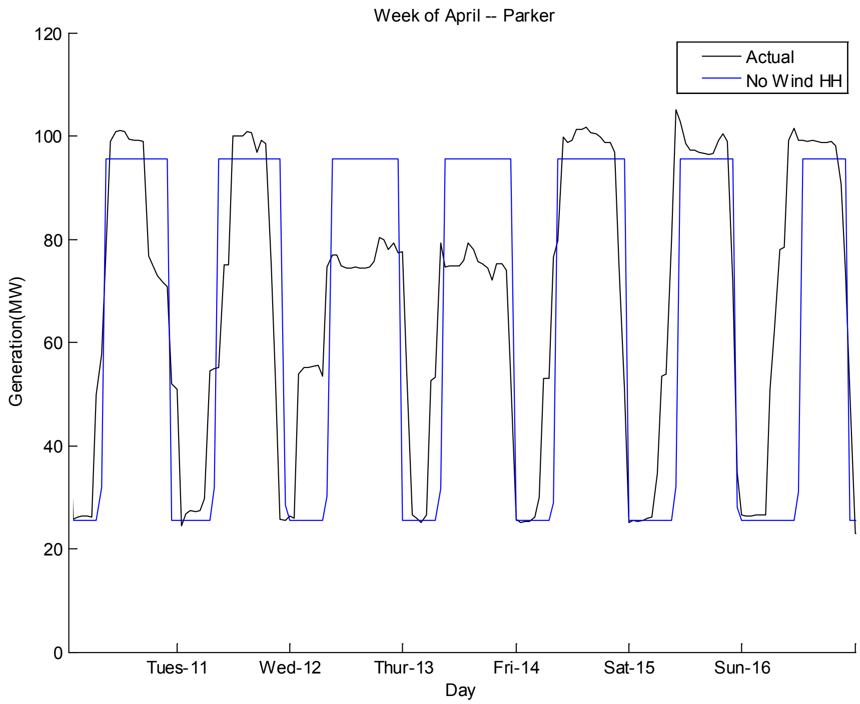

Figure 170: Hourly generation for week of April between MAPS no-wind historical hydro operations versus actual hydro generation, Parker dam.

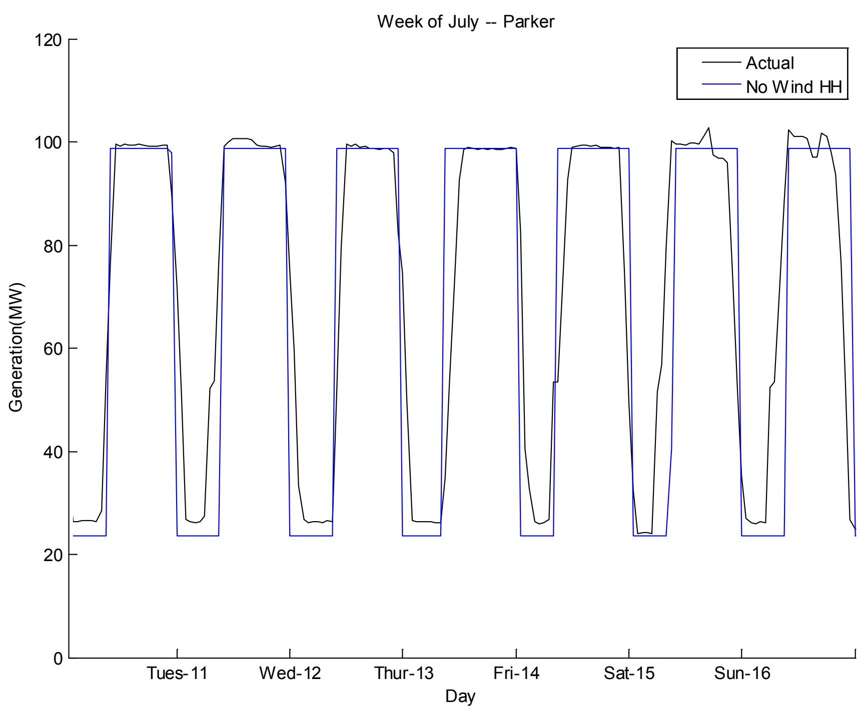

Figure 171: Hourly generation for week of April between MAPS no-wind historical hydro operations versus actual hydro generation, Parker dam.

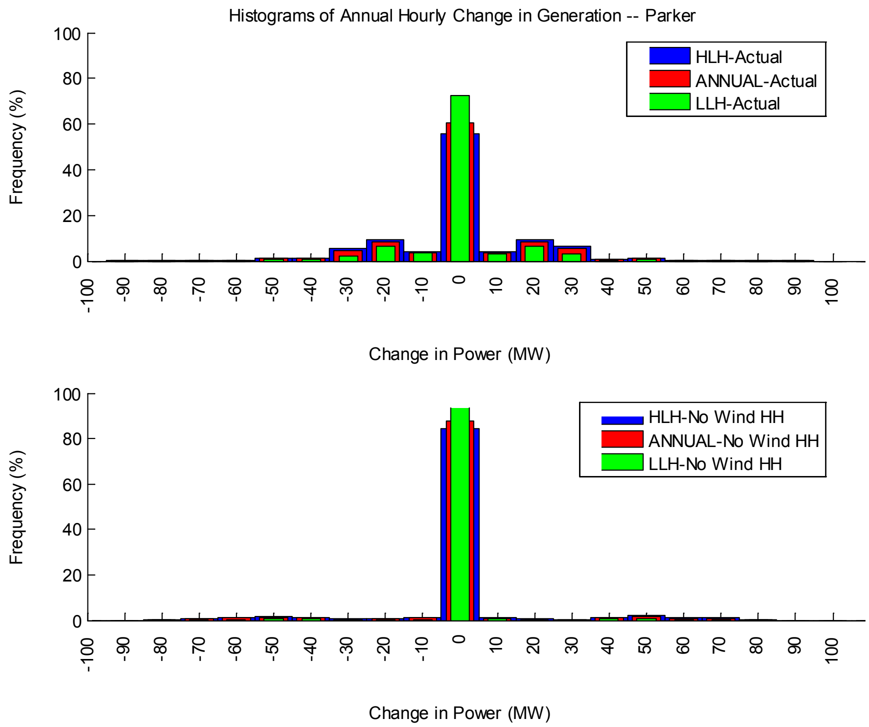

Figure 172: Histograms of hourly change in generation between MAPS no-wind historical hydro operations versus actual hydro generation, Parker dam.

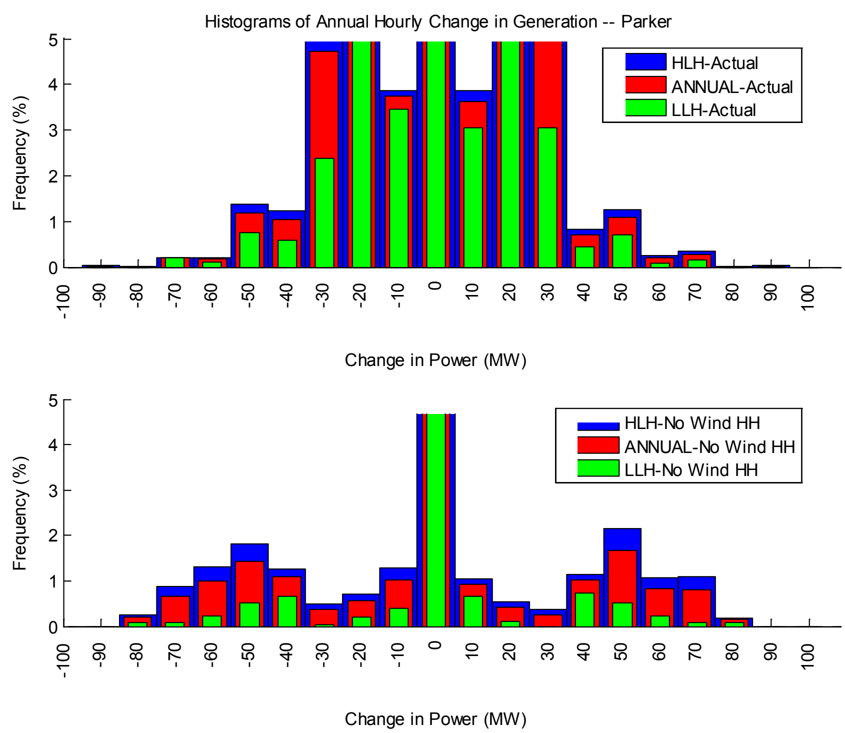

Figure 173: Enhanced view of histograms between MAPS no-wind historical hydro operations versus actual hydro generation, Parker dam.

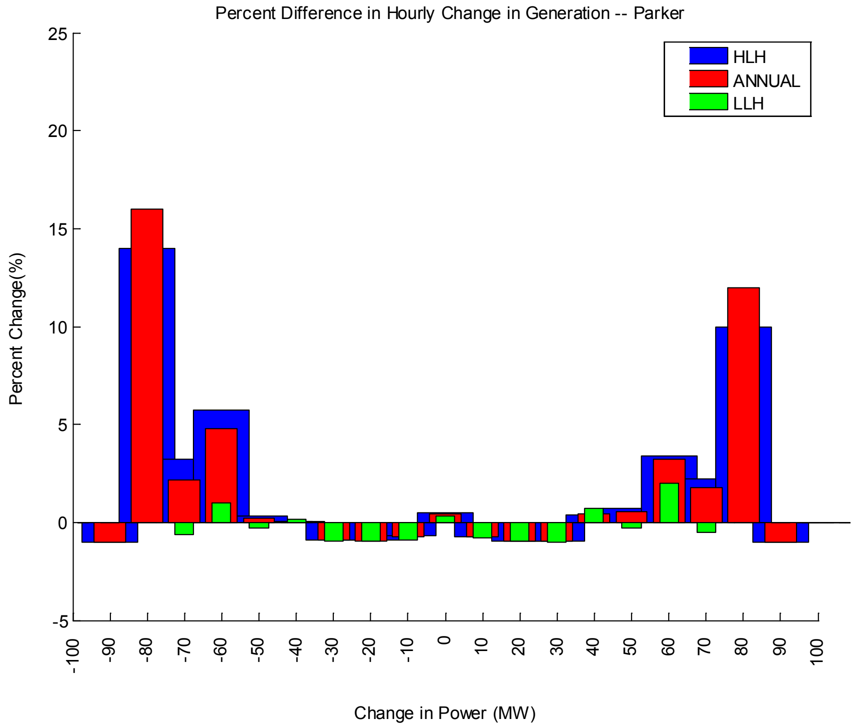

Figure 174: Percent difference in hourly change in generation between MAPS no-wind historical hydro operations versus actual hydro generation, Parker dam.

Table 21: Statistics of hourly changes in generation between MAPS no-wind historical hydro operations versus actual hydro generation, Parker dam.

Timeframe	Hourly Changes in Generation	Average (MW)	Standard Deviation (MW)	Average of the Absolute Value (MW)
Annual	actual	1.02e-4	16.9	10.0
	no-wind	.708e-4	16.8	5.36
HLH	actual	2.91e-3	18.2	11.4
	no-wind	-9.99e-4	19.1	6.86
LLH	actual	-6.98e-3	13.1	6.54
	no-wind	1.14e-2	8.98	1.73

B.3 Davis dam – MAPS Historical Hydro versus actual Hydro Generation

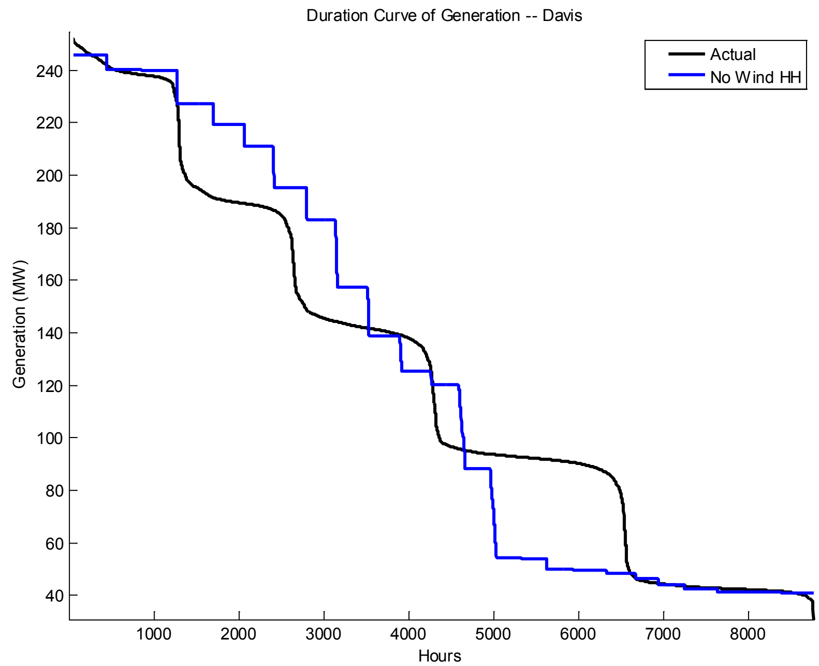

Figure 175: Generation duration curve of MAPS no-wind historical hydro operations versus actual hydro generation, Davis dam.

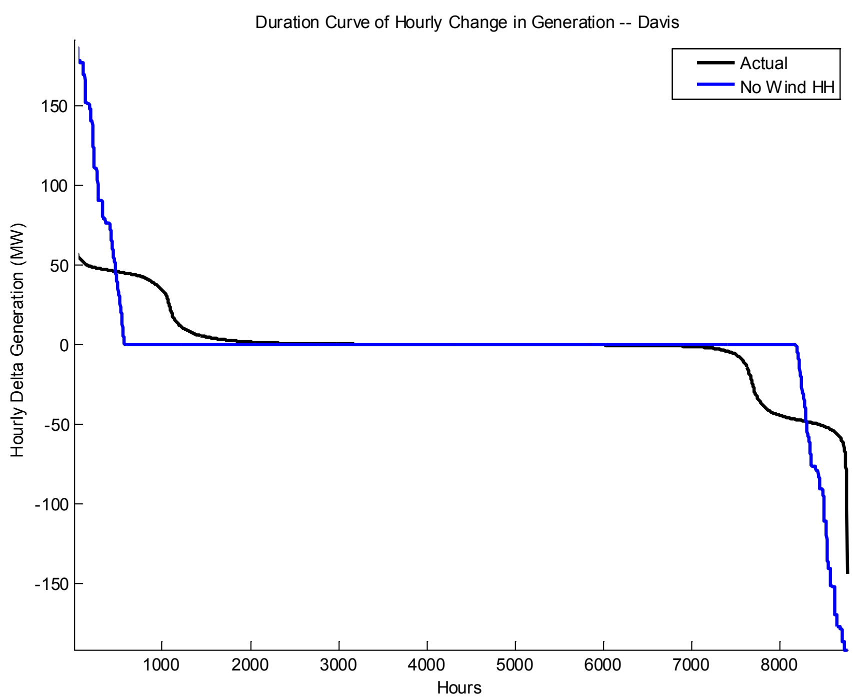

Figure 176: Hourly delta duration curves of MAPS no-wind historical hydro operations versus actual hydro generation, Davis dam.

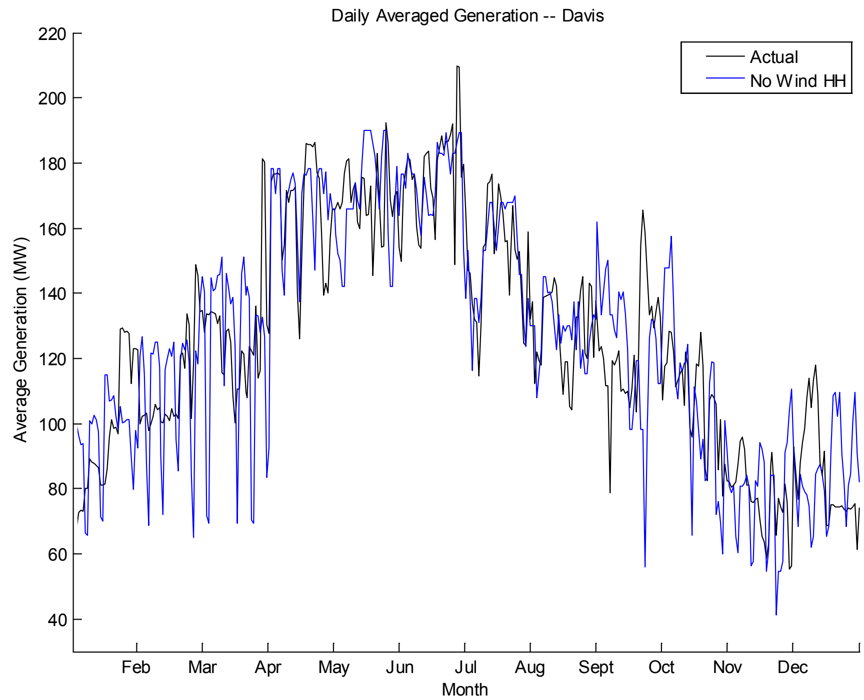

Figure 177: Daily averaged hydro generation of MAPS no-wind historical hydro operations versus actual hydro generation, Davis dam.

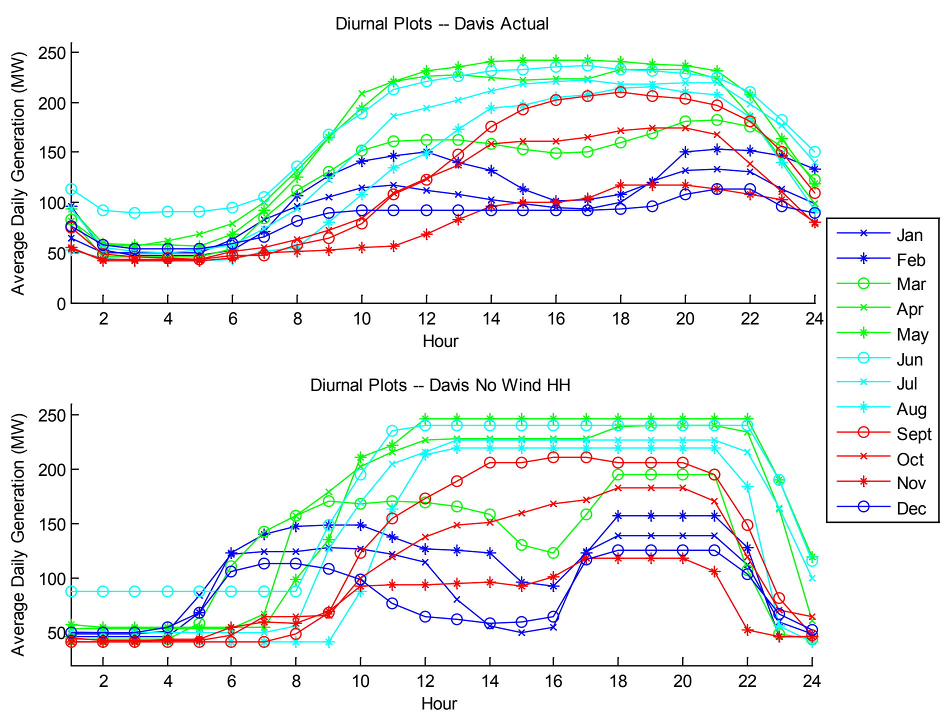

Figure 178: Monthly averaged diurnal plots of MAPS no-wind historical hydro operations versus actual hydro generation, Davis dam.

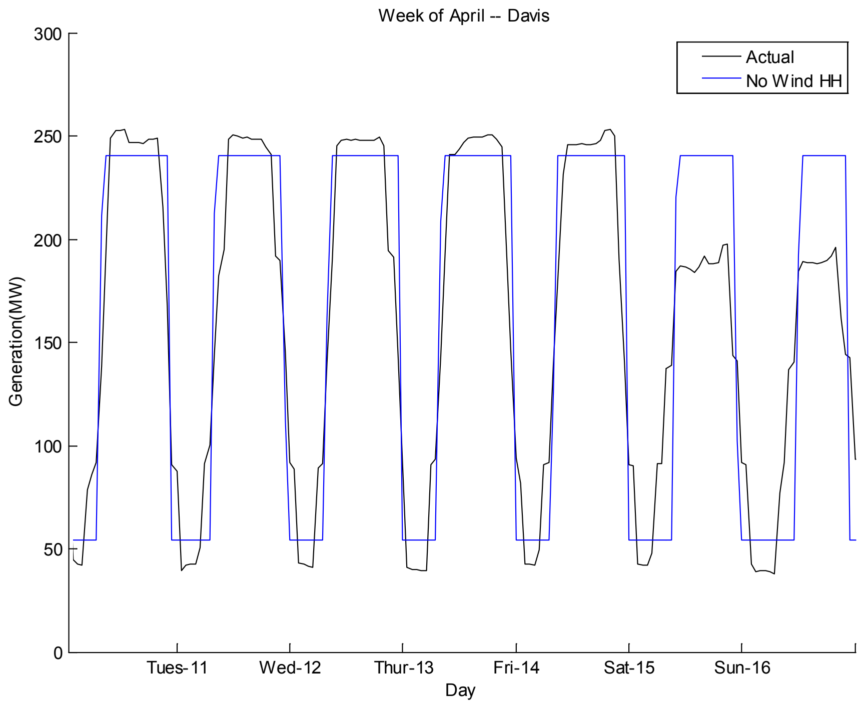

Figure 179: Hourly generation for week of April between MAPS no-wind historical hydro operations versus actual hydro generation, Davis dam.

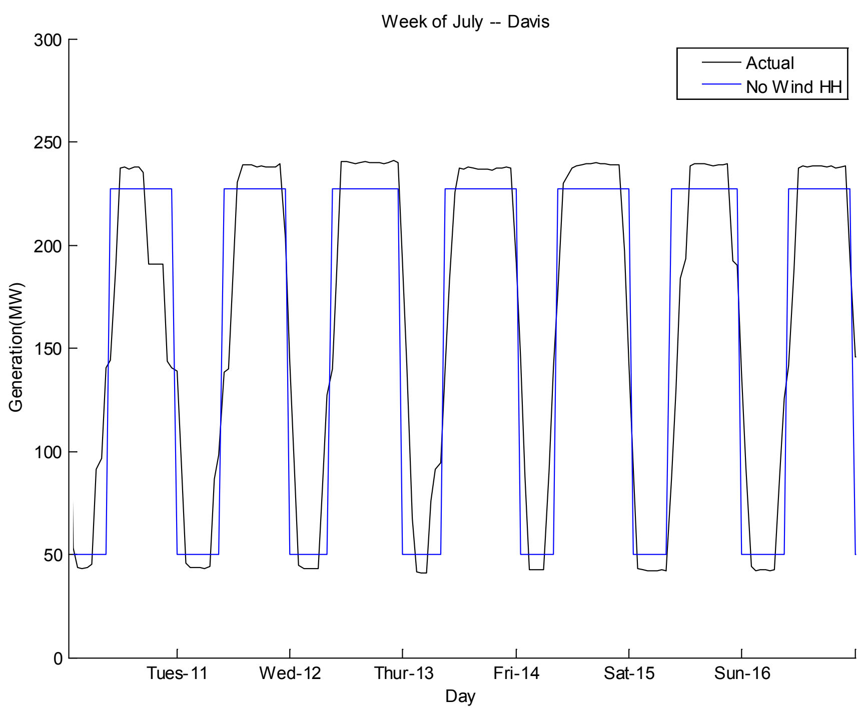

Figure 180: Hourly generation for week of April between MAPS no-wind historical hydro operations versus actual hydro generation, Davis dam.

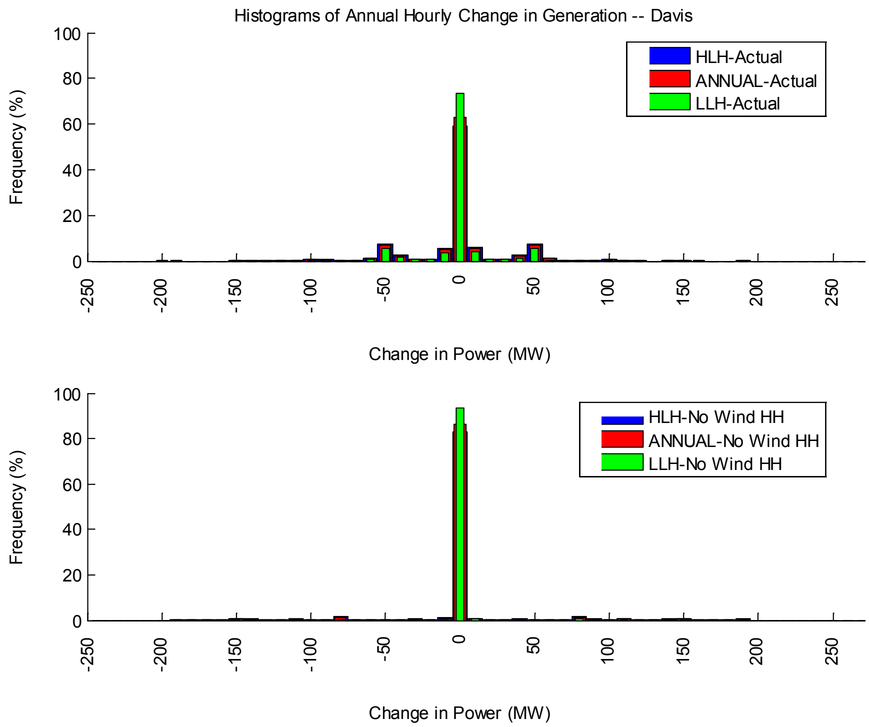

Figure 181: Histograms of hourly change in generation between MAPS no-wind historical hydro operations versus actual hydro generation, Davis dam.

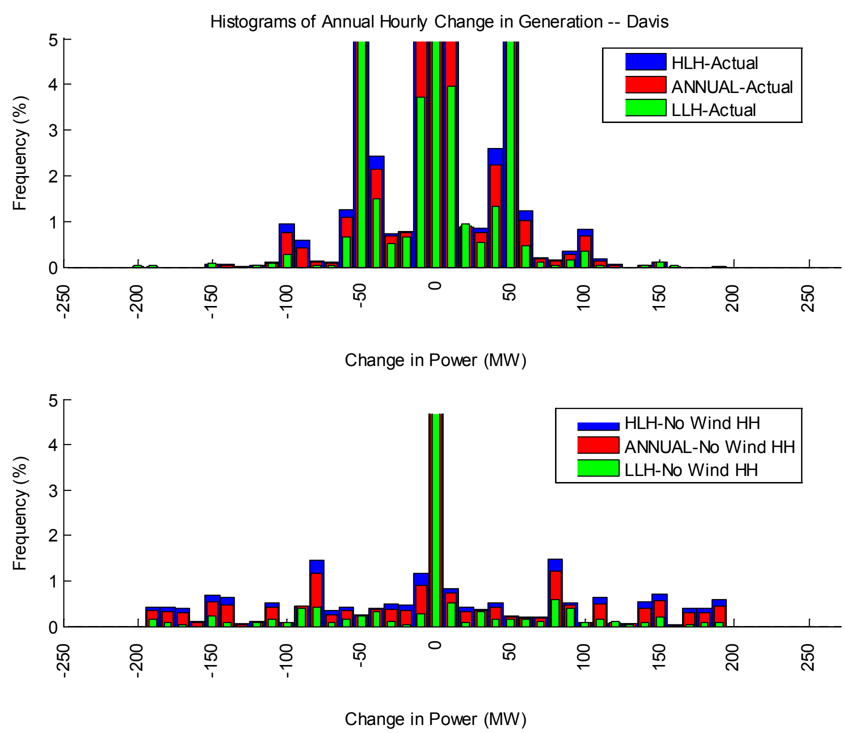

Figure 182: Enhanced view of histograms between MAPS no-wind historical hydro operations versus actual hydro generation, Davis dam.

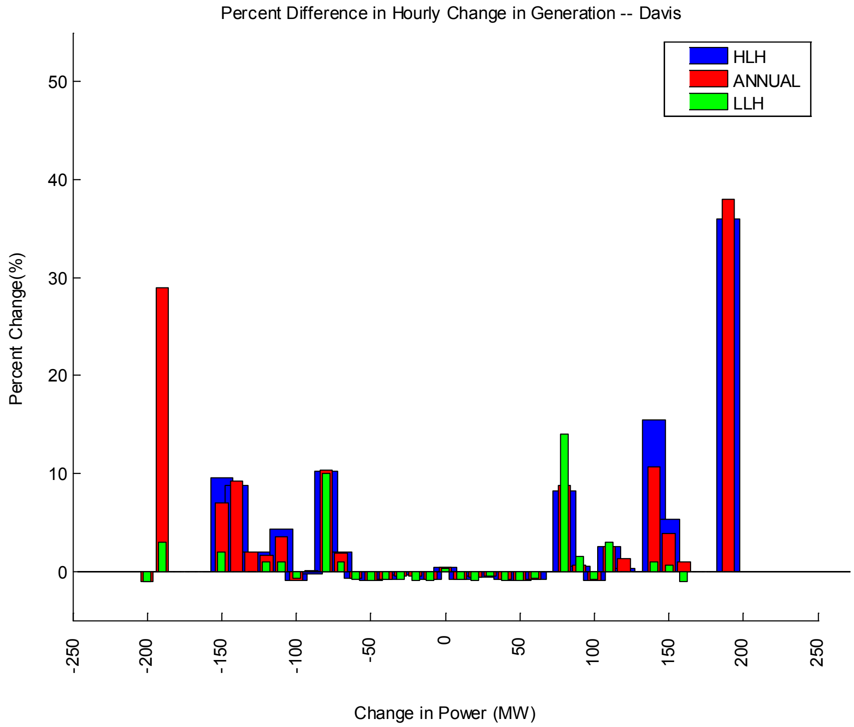

Figure 183: Percent difference in hourly change in generation between MAPS no-wind historical hydro operations versus actual hydro generation, Davis dam.

Table 22: Statistics of hourly changes in generation between MAPS no-wind historical hydro operations versus actual hydro generation, Davis dam.

Timeframe	Hourly Changes in Generation	Average (MW)	Standard Deviation (MW)	Average of the Absolute Value (MW)
Annual	actual	1.55e-2	29.2	15.7
	no-wind	1.37e-4	39.5	12.5
HLH	actual	2.20e-2	31.1	17.5
	no-wind	1.93e-4	44.5	15.6
LLH	actual	-5.01e-4	23.9	11.1
	no-wind	3.02e-2	23.3	4.99

B.4 Crystal dam – MAPS Historical Hydro versus actual Hydro Generation

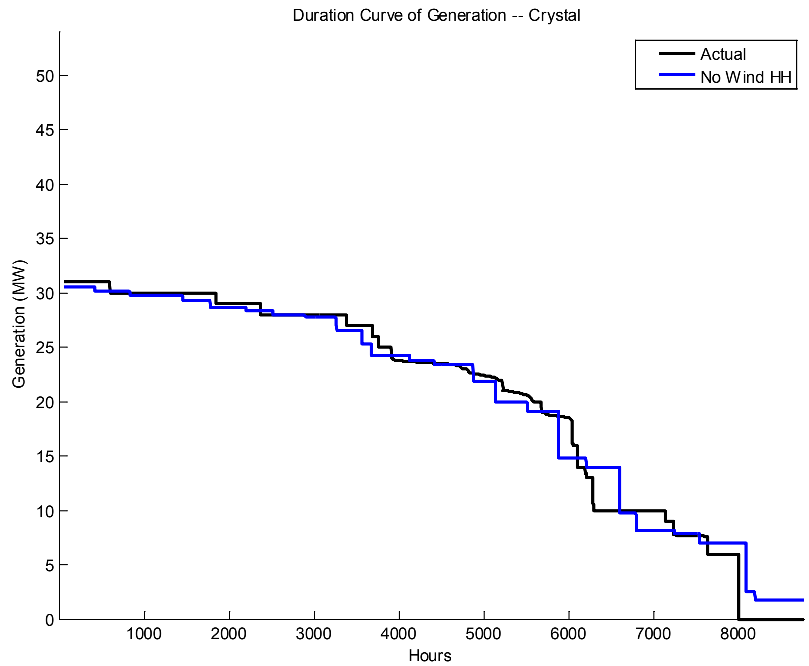

Figure 184: Generation duration curve of MAPS no-wind historical hydro operations versus actual hydro generation, Crystal dam.

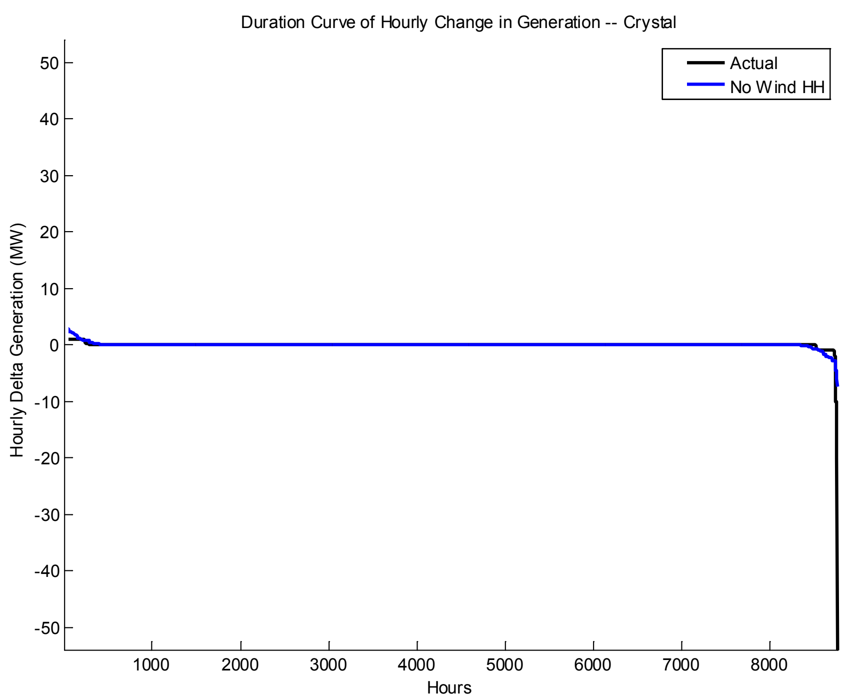

Figure 185: Hourly delta duration curves of MAPS no-wind historical hydro operations versus actual hydro generation, Crystal dam.

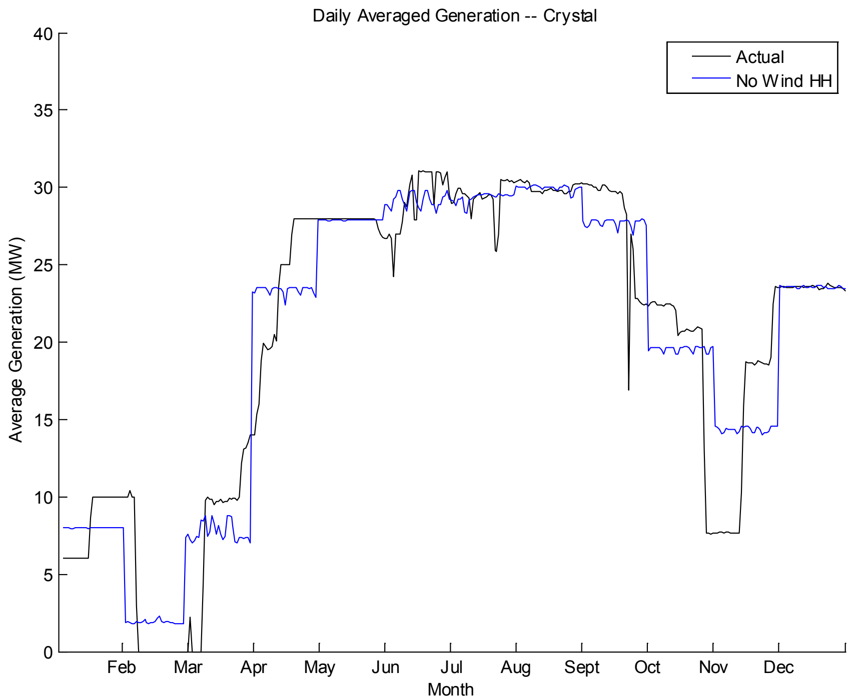

Figure 186: Daily averaged hydro generation of MAPS no-wind historical hydro operations versus actual hydro generation, Crystal dam.

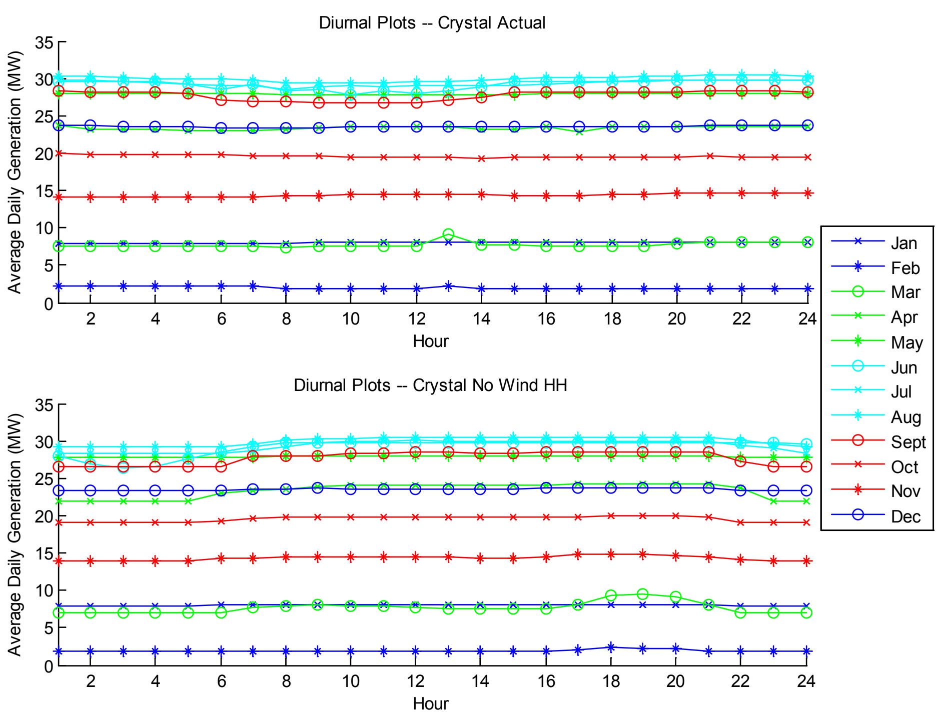

Figure 187: Monthly averaged diurnal plots of MAPS no-wind historical hydro operations versus actual hydro generation, Crystal dam.

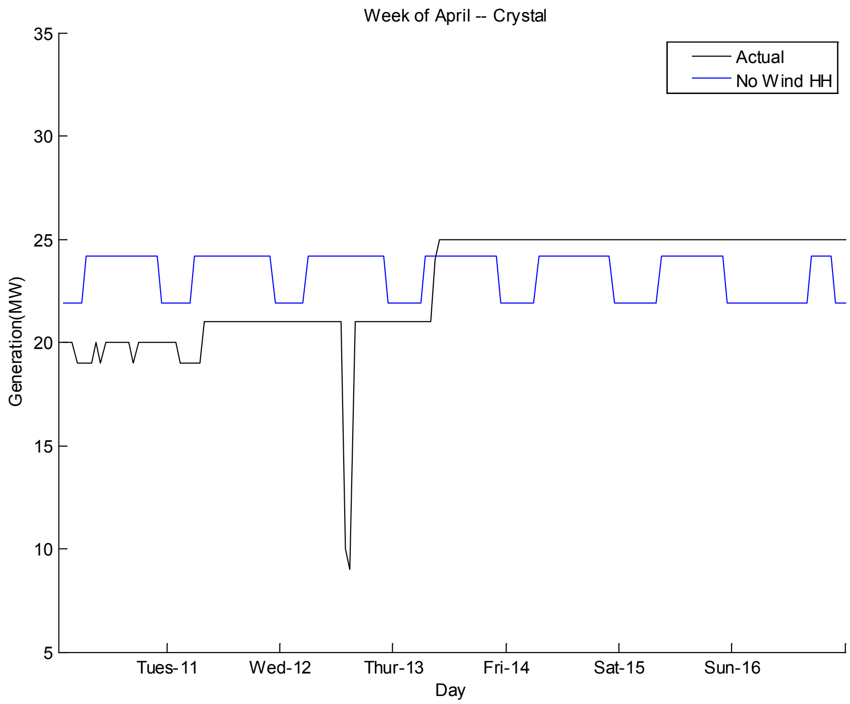

Figure 188: Hourly generation for week of April between MAPS no-wind historical hydro operations versus actual hydro generation, Crystal dam.

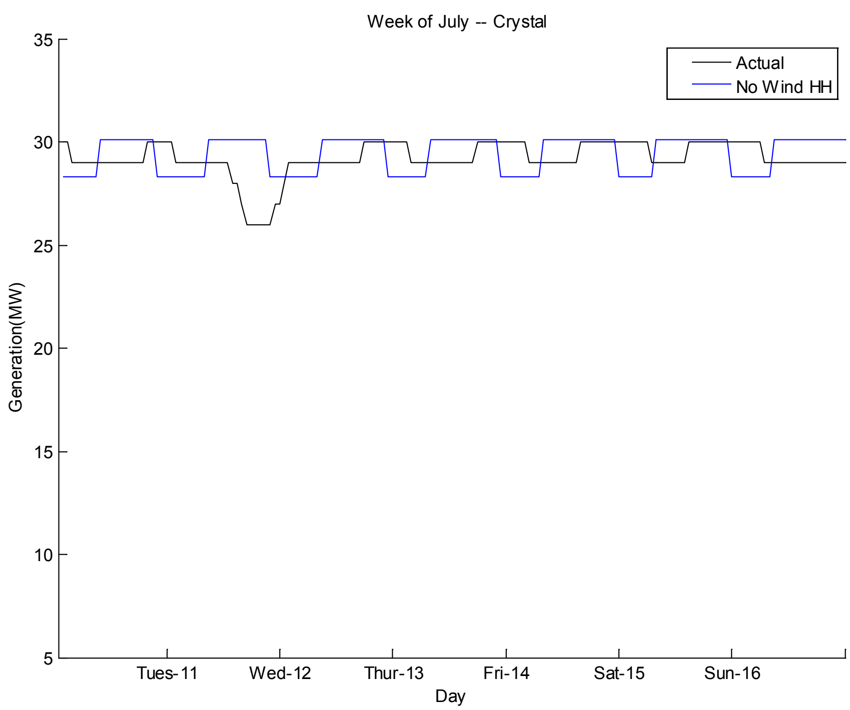

Figure 189: Hourly generation for week of April between MAPS no-wind historical hydro operations versus actual hydro generation, Crystal dam.

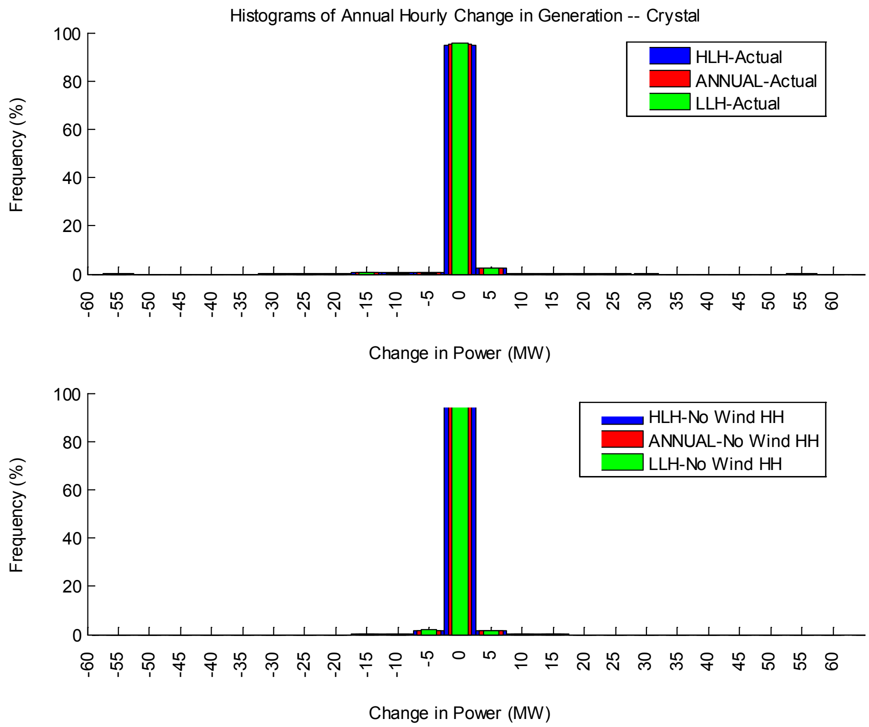

Figure 190: Histograms of hourly change in generation between MAPS no-wind historical hydro operations versus actual hydro generation, Crystal dam.

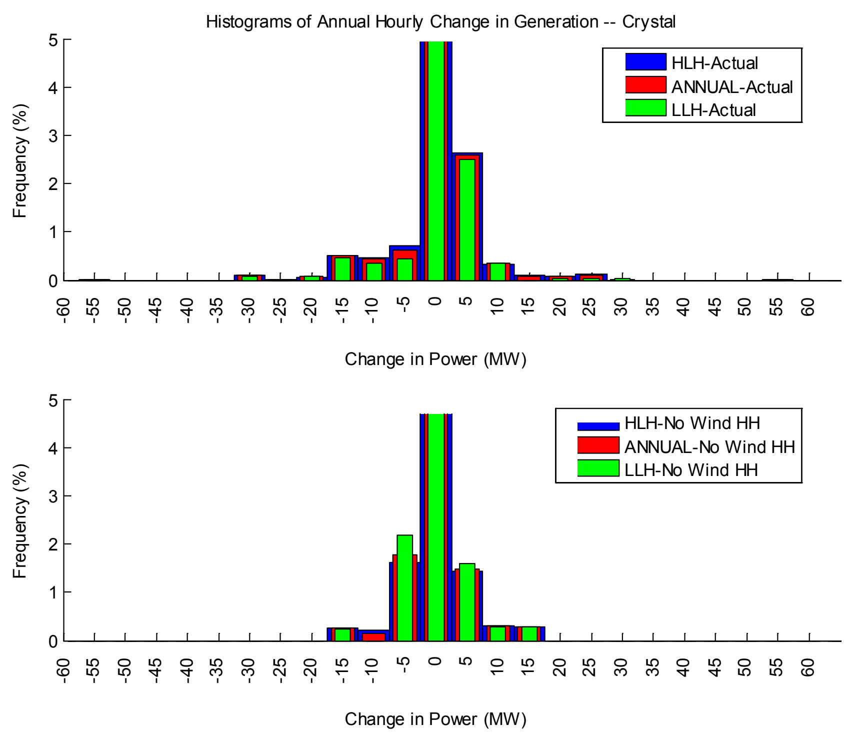

Figure 191: Enhanced view of histograms between MAPS no-wind historical hydro operations versus actual hydro generation, Crystal dam.

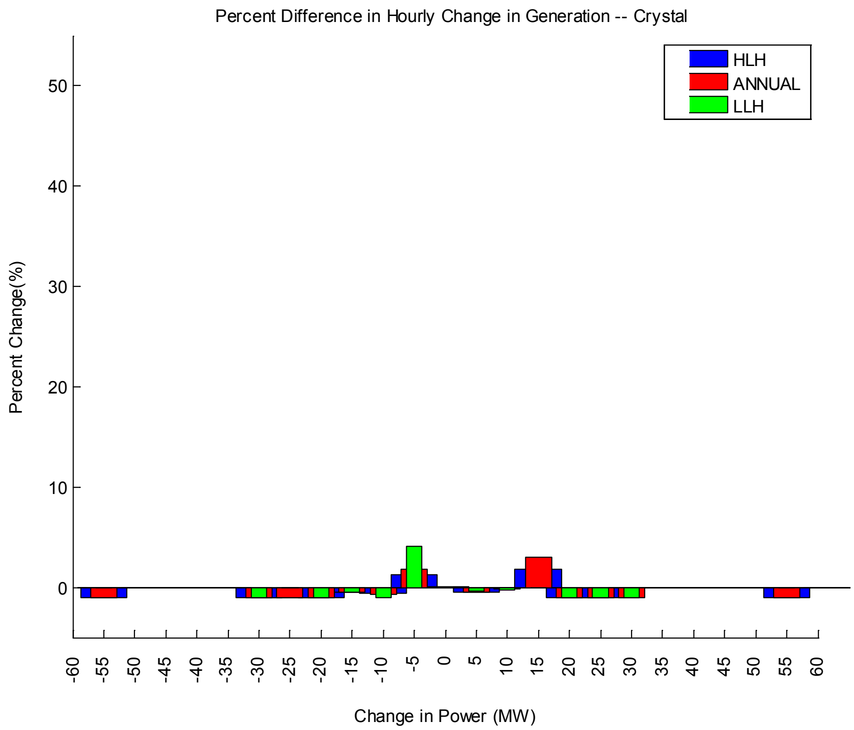

Figure 192: Percent difference in hourly change in generation between MAPS no-wind historical hydro operations versus actual hydro generation, Crystal dam.

Table 23: Statistics of hourly changes in generation between MAPS no-wind historical hydro operations versus actual hydro generation, Crystal dam.

Timeframe	Hourly Changes in Generation	Average (MW)	Standard Deviation (MW)	Average of the Absolute Value (MW)
Annual	actual	2.00e-3	2.41	0.519
	no-wind	1.78e-3	1.58	0.363
HLH	actual	2.82e-3	2.54	0.553
	no-wind	2.50e-3	1.58	0.382
LLH	actual	6.75e-3	2.04	0.431
	no-wind	6.07e-3	1.54	0.311

B.5 Morrow Point dam – MAPS Historical Hydro versus actual Hydro Generation

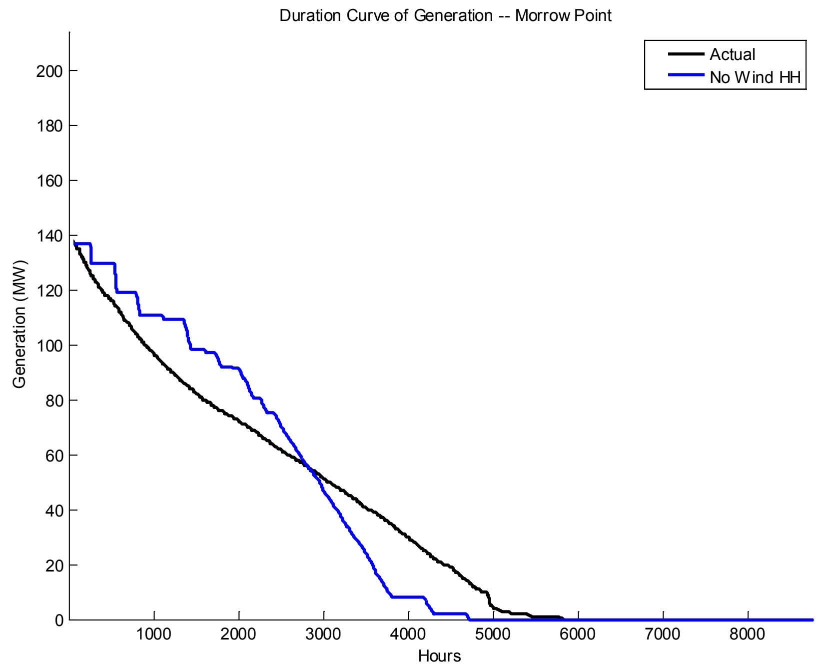

Figure 193: Generation duration curve of MAPS no-wind historical hydro operations versus actual hydro generation, Morrow Point dam.

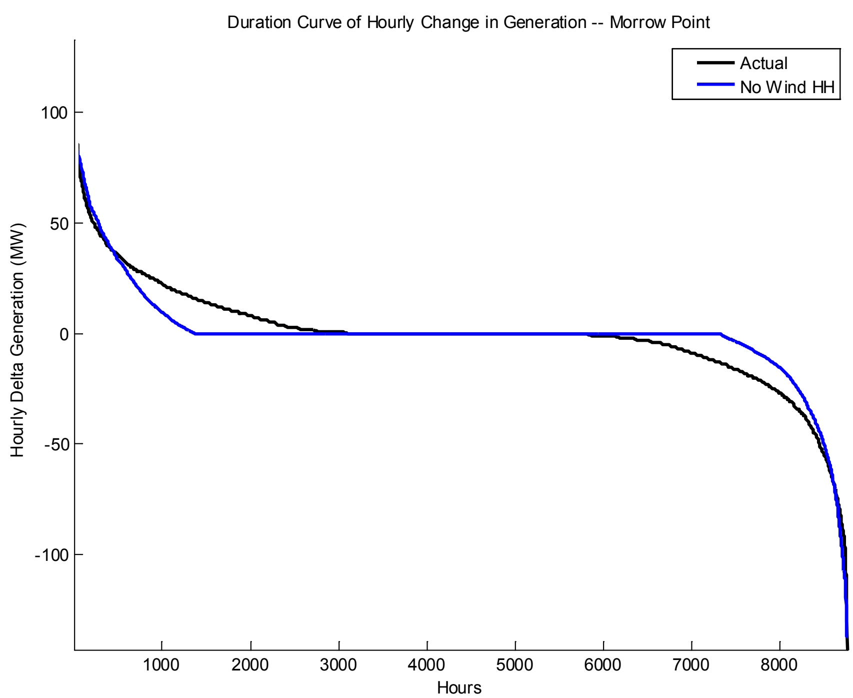

Figure 194: Hourly delta duration curves of MAPS no-wind historical hydro operations versus actual hydro generation, Morrow Point dam.

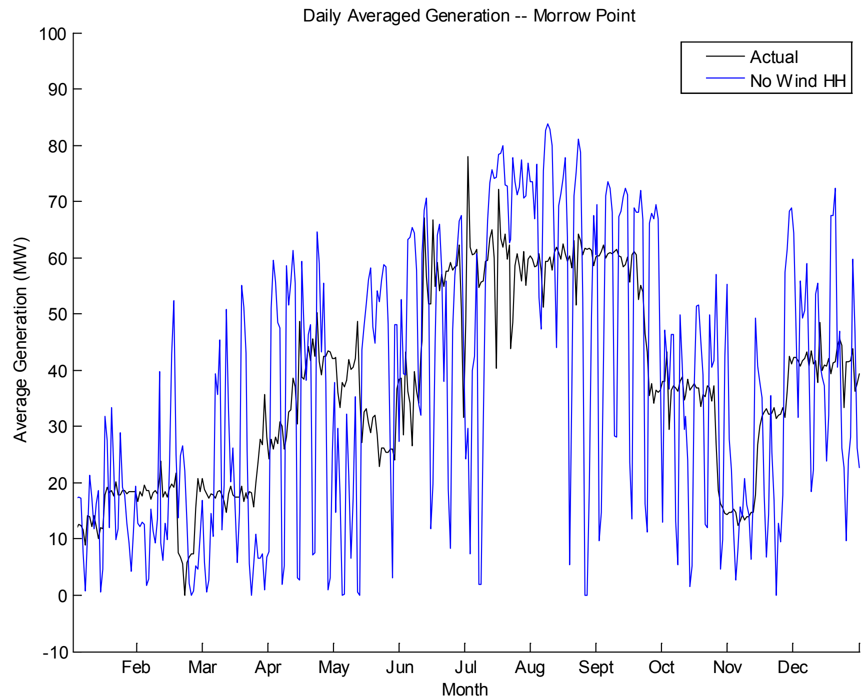

Figure 195: Daily averaged hydro generation of MAPS no-wind historical hydro operations versus actual hydro generation, Morrow Point dam.

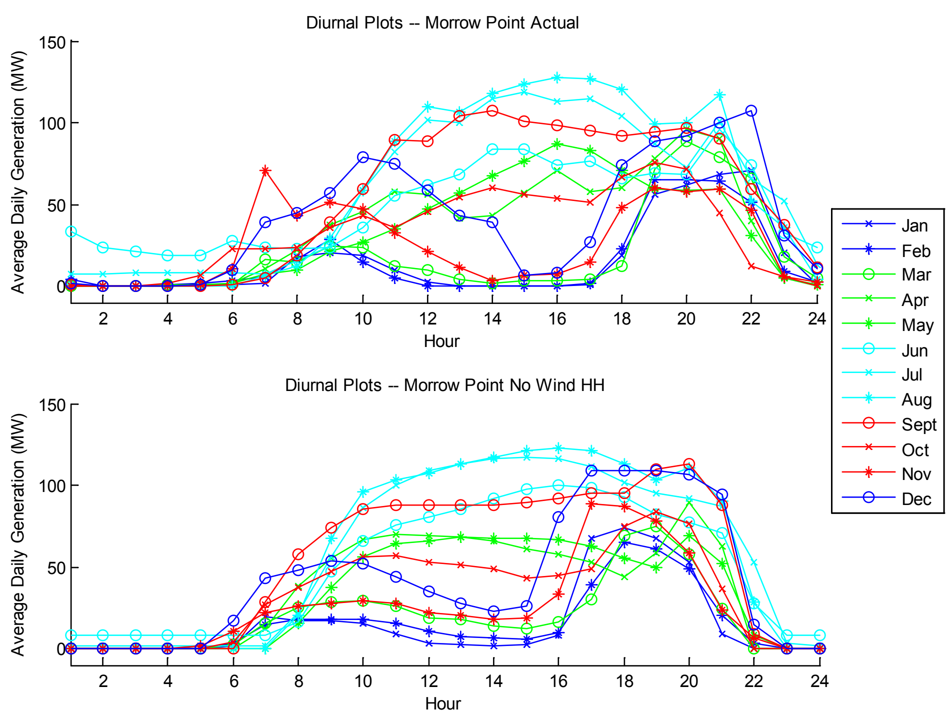

Figure 196: Monthly averaged diurnal plots of MAPS no-wind historical hydro operations versus actual hydro generation, Morrow Point dam.

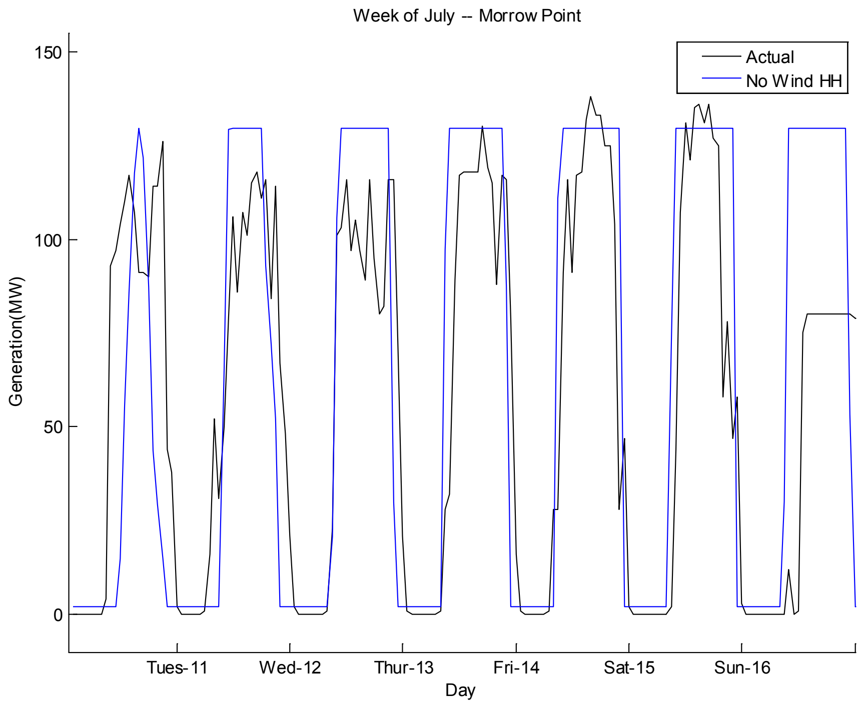

Figure 197: Hourly generation for week of April between MAPS no-wind historical hydro operations versus actual hydro generation, Morrow Point dam.

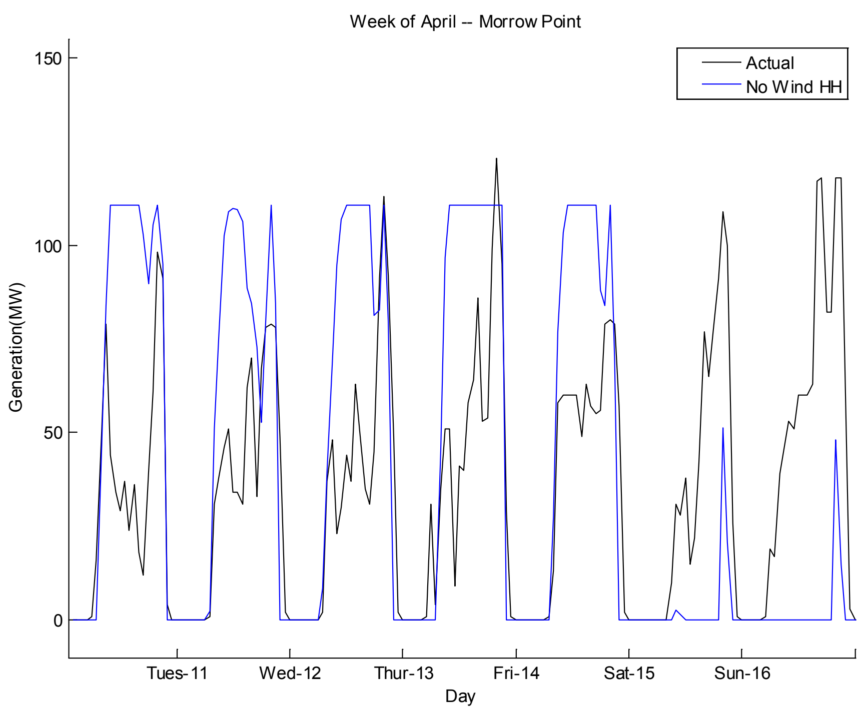

Figure 198: Hourly generation for week of April between MAPS no-wind historical hydro operations versus actual hydro generation, Morrow Point dam.

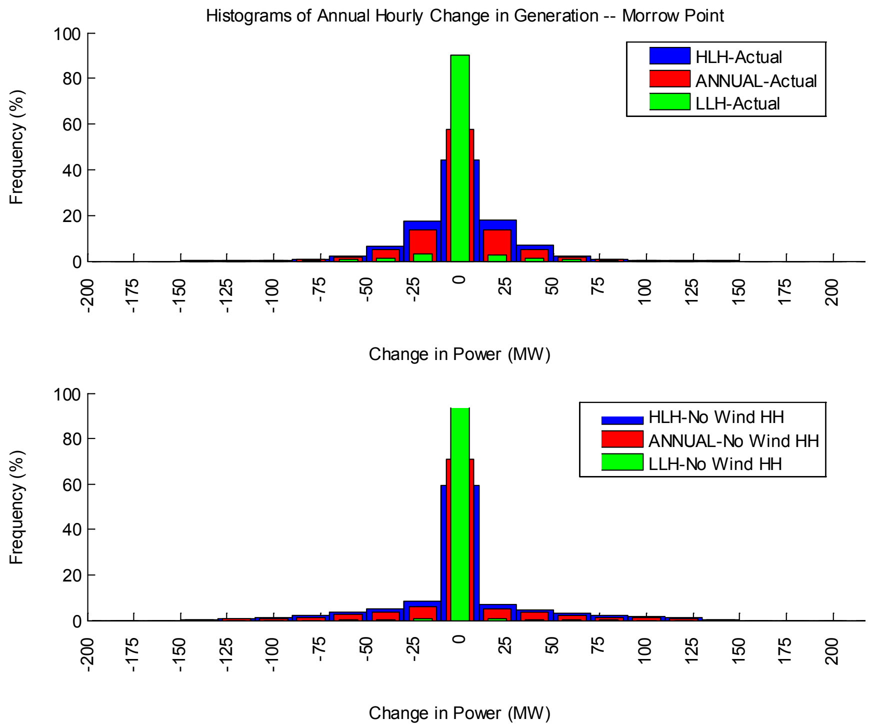

Figure 199: Histograms of hourly change in generation between MAPS no-wind historical hydro operations versus actual hydro generation, Morrow Point dam.

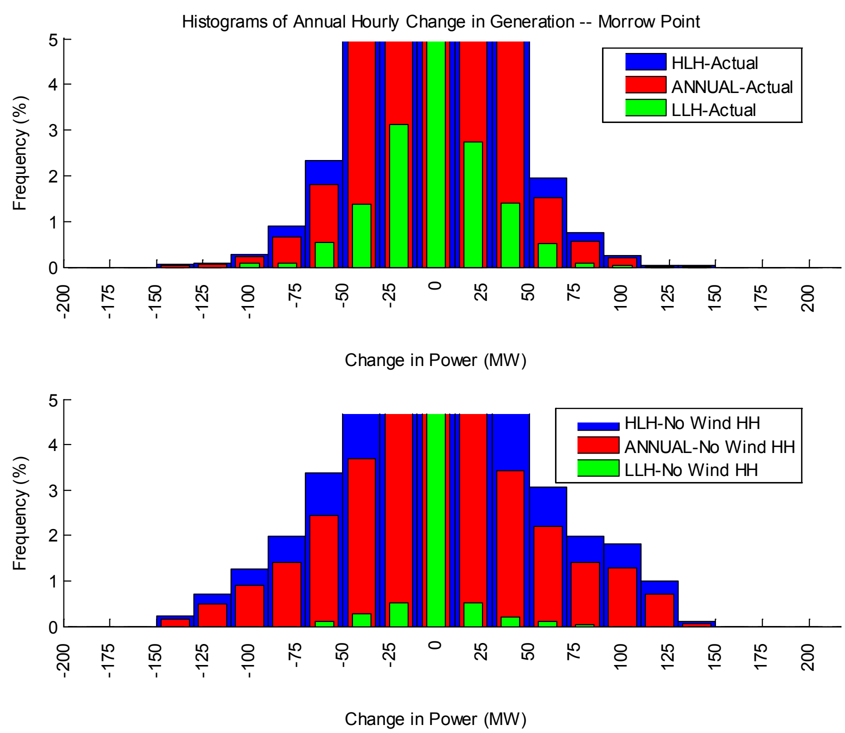

Figure 200: Enhanced view of histograms between MAPS no-wind historical hydro operations versus actual hydro generation, Morrow Point dam.

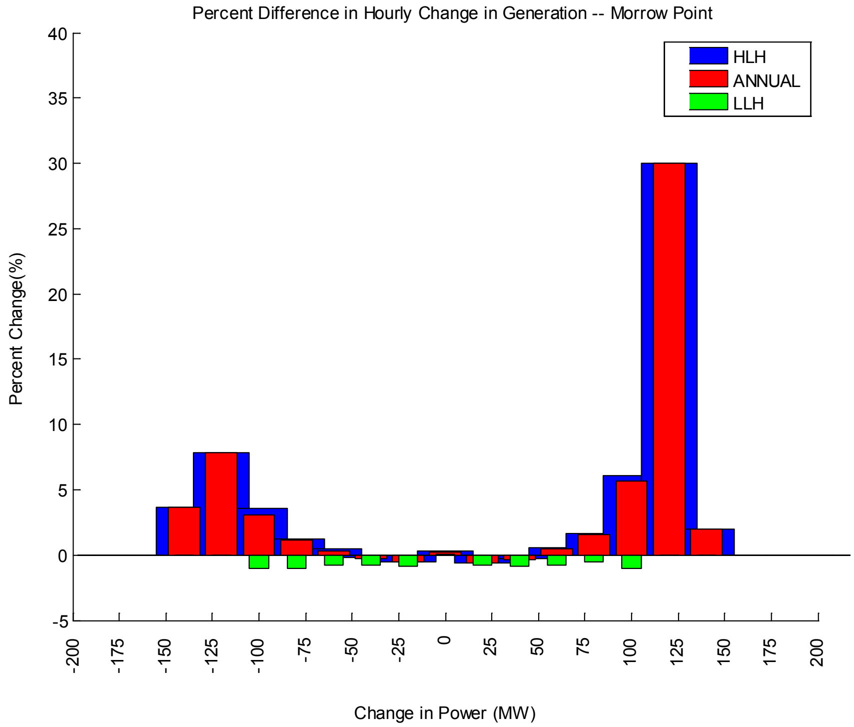

Figure 201: Percent difference in hourly change in generation between MAPS no-wind historical hydro operations versus actual hydro generation, Morrow Point dam.

Table 24: Statistics of hourly changes in generation between MAPS no-wind historical hydro operations versus actual hydro generation, Morrow Point dam.

Timeframe	Hourly Changes in Generation	Average (MW)	Standard Deviation (MW)	Average of the Absolute Value (MW)
Annual	actual	4.10e-3	22.6	13.5
	no-wind	0.0	30.3	14.2
HLH	actual	5.62e-3	25.9	17.6
	no-wind	0.0	35.9	19.8
LLH	actual	1.28e-3	11.1	3.5
	no-wind	0.0	4.54	0.577

B.6 Blue Mesa dam – MAPS Historical Hydro versus actual Hydro Generation

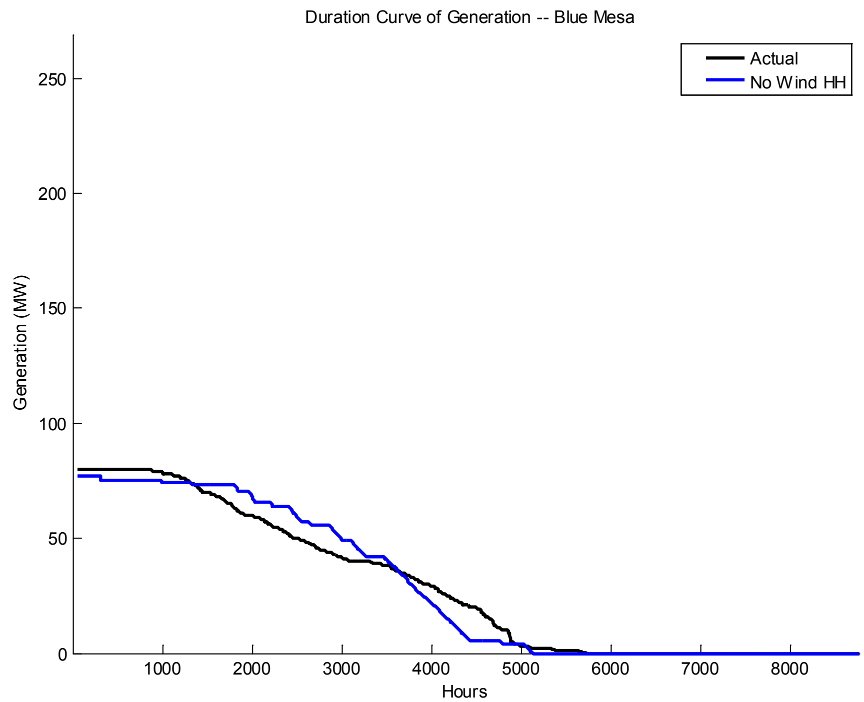

Figure 202: Generation duration curve of MAPS no-wind historical hydro operations versus actual hydro generation, Blue Mesa dam.

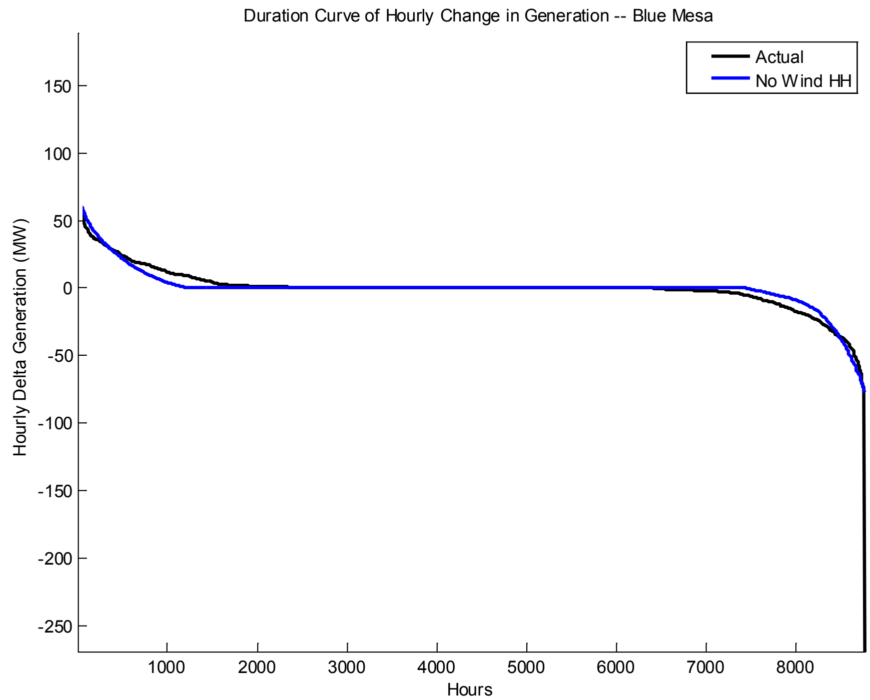

Figure 203: Hourly delta duration curves of MAPS no-wind historical hydro operations versus actual hydro generation, Blue Mesa dam.

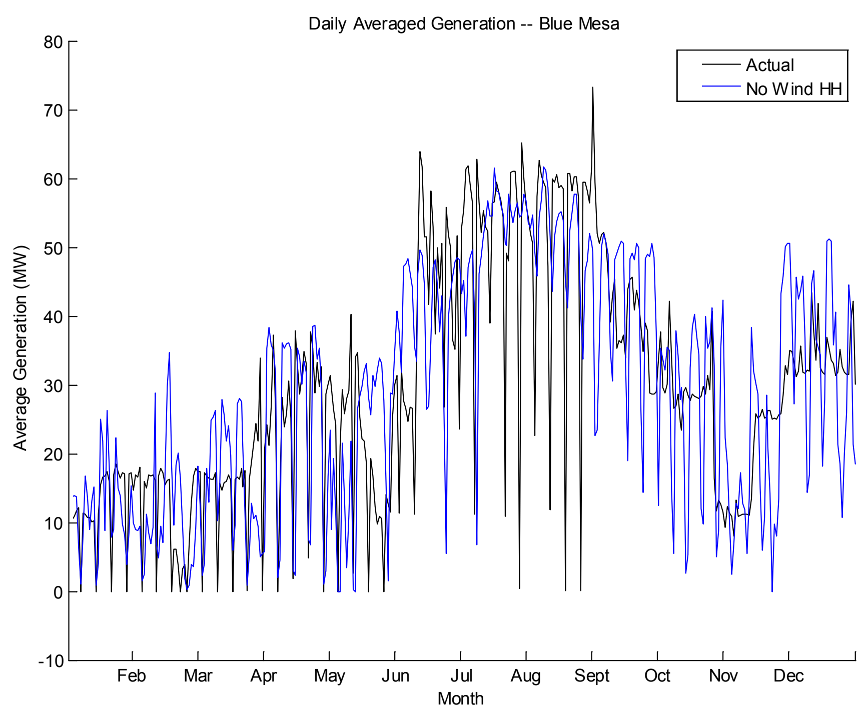

Figure 204: Daily averaged hydro generation of MAPS no-wind historical hydro operations versus actual hydro generation, Blue Mesa dam.

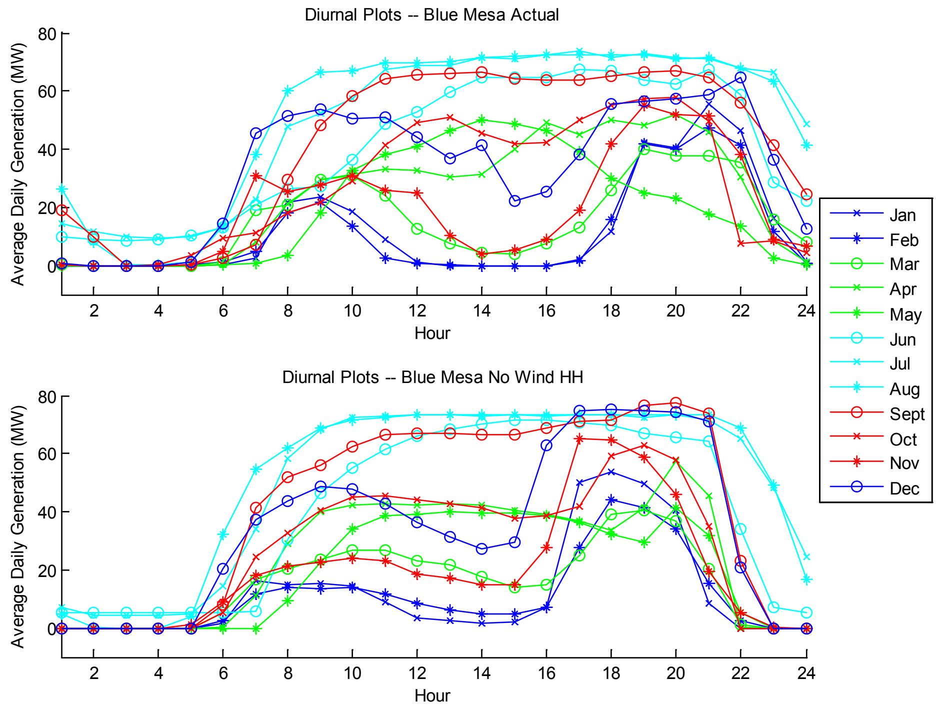

Figure 205: Monthly averaged diurnal plots of MAPS no-wind historical hydro operations versus actual hydro generation, Blue Mesa dam.

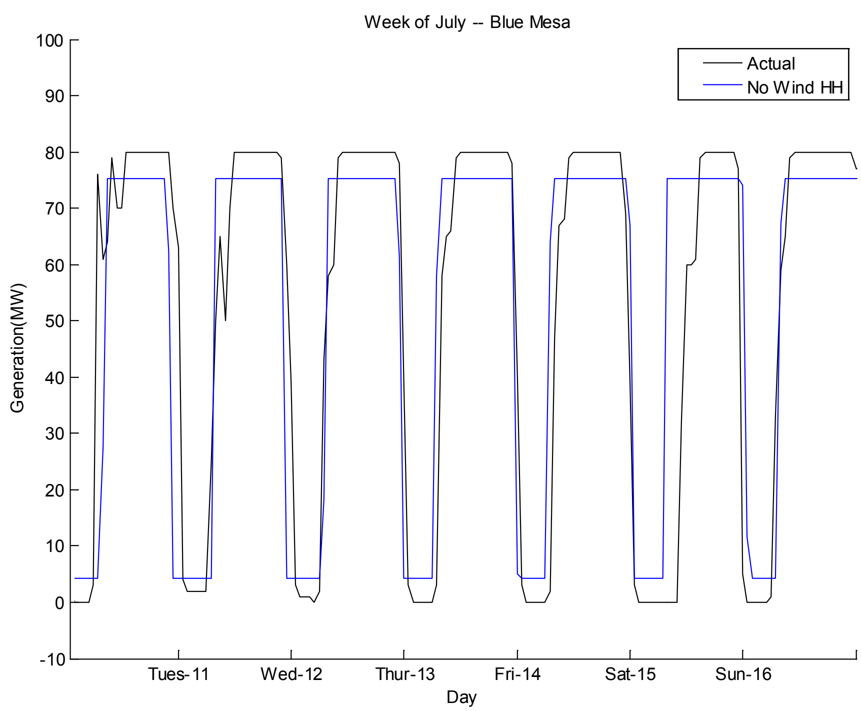

Figure 206: Hourly generation for week of April between MAPS no-wind historical hydro operations versus actual hydro generation, Blue Mesa dam.

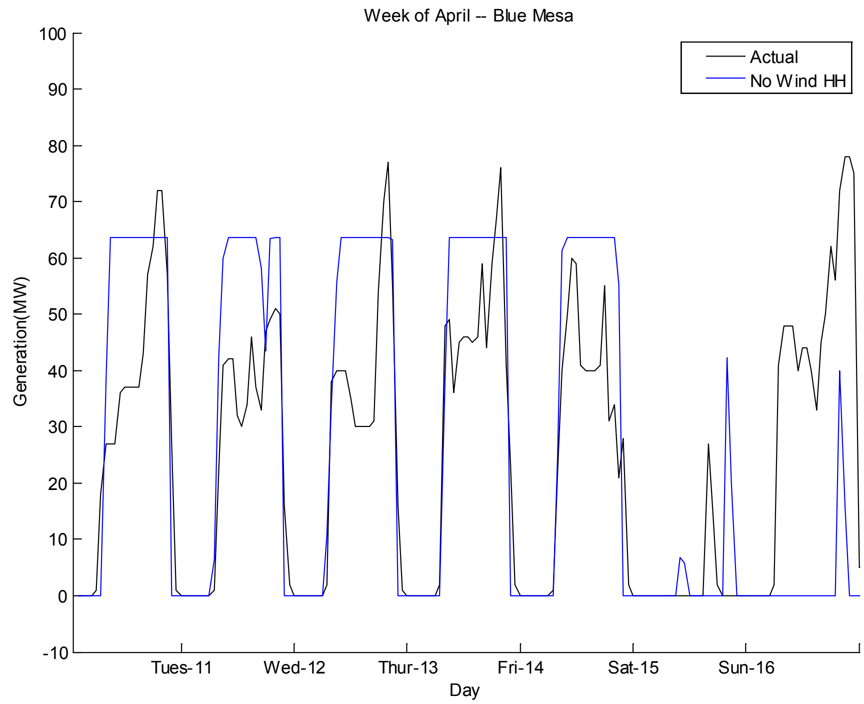

Figure 207: Hourly generation for week of April between MAPS no-wind historical hydro operations versus actual hydro generation, Blue Mesa dam.

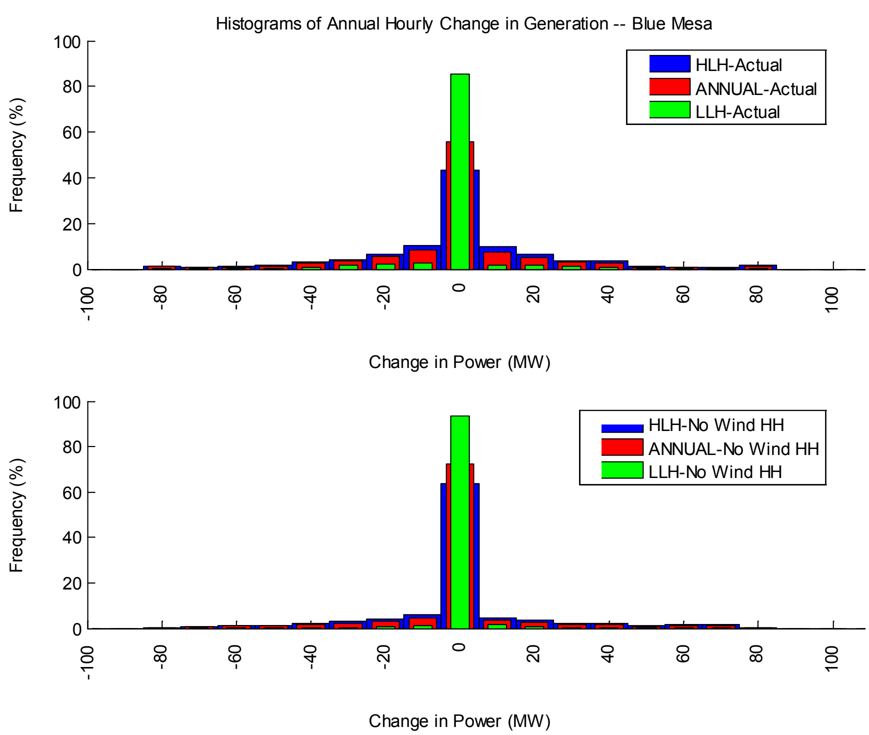

Figure 208: Histograms of hourly change in generation between MAPS no-wind historical hydro operations versus actual hydro generation, Blue Mesa dam.

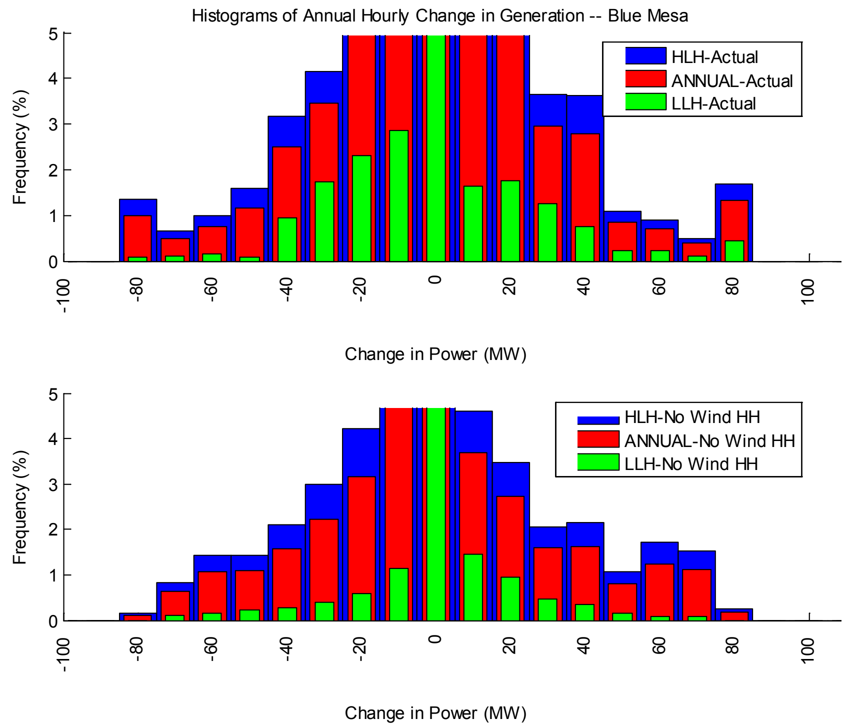

Figure 209: Enhanced view of histograms between MAPS no-wind historical hydro operations versus actual hydro generation, Blue Mesa dam.

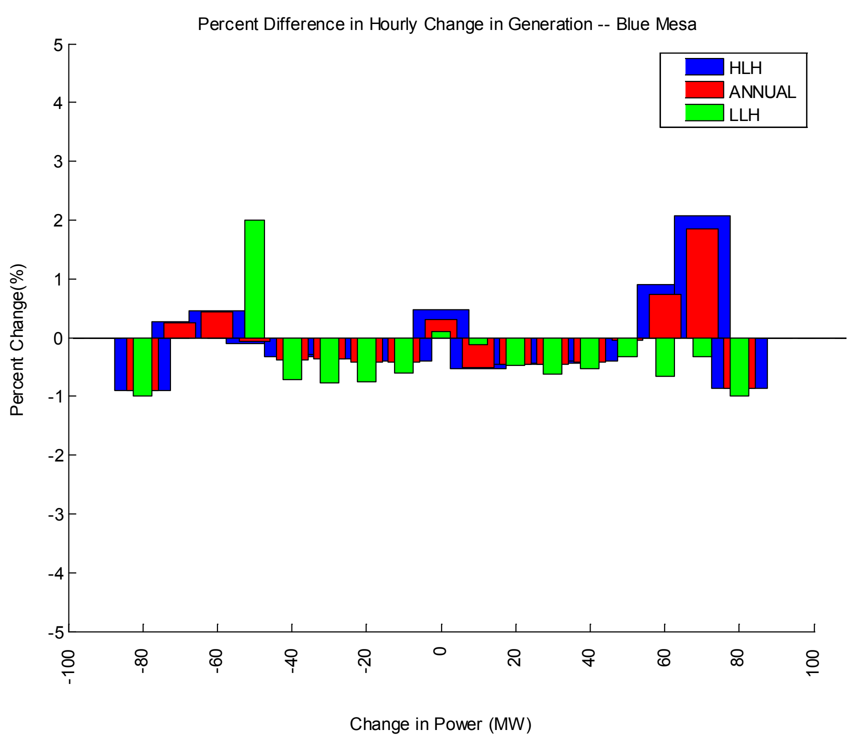

Figure 210: Percent difference in hourly change in generation between MAPS no-wind historical hydro operations versus actual hydro generation, Blue Mesa dam.

Table 25: Statistics of hourly changes in generation between MAPS no-wind historical hydro operations versus actual hydro generation, Blue Mesa dam.

Timeframe	Hourly Changes in Generation	Average (MW)	Standard Deviation (MW)	Average of the Absolute Value (MW)
Annual	actual	1.02e-4	16.9	10.0
	no-wind	-7.08e-4	16.8	5.36
HLH	actual	2.91e-3	18.2	11.4
	no-wind	-9.99e-4	19.1	6.86
LLH	actual	-6.98e-3	13.1	6.54
	no-wind	1.14e-2	8.98	1.73