Implications on Hydropower from Large-Scale Integration of Wind and Solar

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1. Introduction & Background of WWSIS

NREL and research partner GE have conducted the Western Wind and Solar Integration Study (WWSIS) in order to provide insight into the costs and operational impacts caused by the variability and uncertainty of wind, photovoltaic, (PV) and concentrated solar power (CSP) employed to serve up to 35% of the load energy in the WestConnect region, see Figure 1 for study footprint. The estimated 2017 load being served is 60 GW, with up to 30 GW of wind power and 4 GW of existing hydropower.

3TIER developed the wind dataset, hour-ahead and day-ahead wind forecasts using the Weather Research and Forecasting (WRF) mesoscale Numerical Weather Prediction (NWP) model over the entire western U.S. at 2-km, 10-minute resolution for the consecutive years 2004-2006. Each domain was run in three-day blocks which were merged and smoothed together at the seams [3].

Historical load and weather patterns form years 2004, 2005, and 2006 were used to examine the details of the system operation and dispatch though an hourly cost production simulation of balancing areas 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 106 separate load areas (each with their own load profiles, generating portfolios, and transmission capacities with adjacent areas) [4].

Figure 1: WestConnect Footprint as used in the WWSIS. (Source: http://wind.nrel.gov/public/WWSIS/MilliganWWSISSWAT.pdf)

The entire system was committed and dispatched in a cost-effective, rational manner recognizing limits and cycling capabilities of the individual generators.

Three basic scenarios were considered concerning where the wind power was assumed to be installed. These scenarios are:

• *In-Area Scenario* – uses local resources within each transmission constrained area (defined roughly by state boundaries) by selecting the best sites in correspondence to a mix of energy value, geographic diversity and capacity factor.

•*Mega-Project Scenario* – created by trading out the lower ranked wind sites (by capacity factor) of the In-Area scenario by higher capacity factor remote resources (e.g. winds of Wyoming).

•*Local Priority Scenario* – uses a more realistic build-out of wind sites and transmission combining both in-state 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 derived from solar power was from CSP with six hours of storage and 30% from distributed PV systems.

Due the large number of scenarios, a shorthand naming convention was devised to describe the various cases as shown in Table 1. For example, a case named L20R would refer to the Local Priority scenario with 20% penetration and using the state of the art forecast. Also noted is the preselected penetration level corresponding to renewables in existence or in the process of being built (also called the "No New Wind" case [5].

Table 1: Scenario naming convention for the various penetration levels and forecasting methods.

Scenario	Penetration Level	Forecast
I – In Area	Pre – Preselected Sites	P – Perfect Forecast
M – Mega Project	10 – 10%	R – State of the Art Forecast
L – Local Priority	20 – 20%	N – No Forecast
10%	20 20 – 20/20%	
	30 – 30%	

2. Objectives

An in-depth analysis was conducted to compare a series of MAPS simulations, and contrast the simulation data to actual production patterns. Two of the largest hydropower facilities in the WWSIS footprint were selected and examined in-depth including Hoover Dam (Nameplate Capacity of 2,074MW) and Glen Canyon Dam (Nameplate Capacity of 1,296 MW). Figure 2 illustrates the hydropower facility locations in the lower Colorado region.

OBJECTIVES:
•What is the economic value and flexibility of hydropower as a balancing resources as high levels of renewables are integrated into the grid system?
•How will renewables impact and change hydro operations?

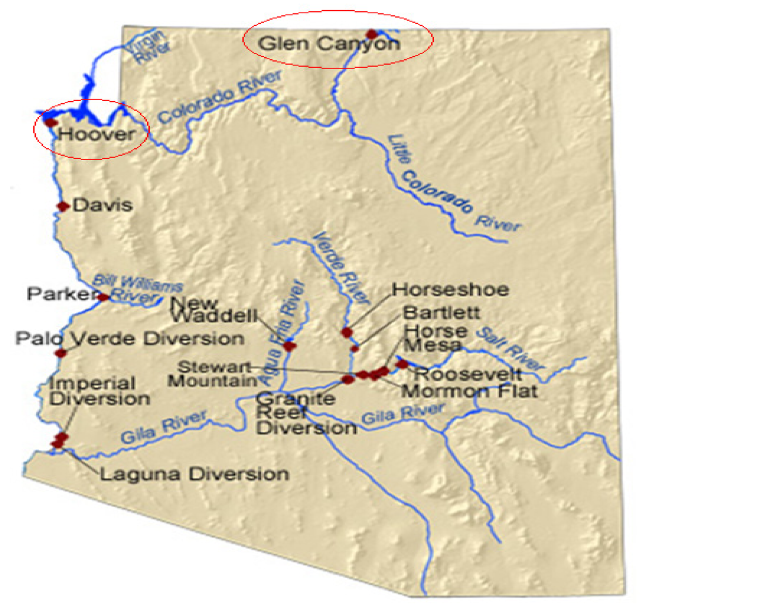

Figure 2: Hydropower facilities located in the lower Colorado region. (Source: United States Bureau of Reclamation)

3. Hydropower Considerations

There are many generation resources located in the study footprint, including significant amounts of hydropower. Hydropower can be considered a very flexible generation resource but can be heavily constrained due to higher priority functions and non-power regulations and constraints. For this reason, the use of hydropower as simulated in a cost production model such as maps can easily be incorrectly modeled. With respect to the WWSIS, concerns that arise are directly related to proper modeling of the constraints and hydrological conditions (i.e. available capacity, generation limits, ramping, ect.), proper commitment and dispatch of the hydropower and accuracy of the supporting hydropower data.

For example, due to recent drought years in the southwest region of the U.S., the water elevations behind many reservoirs have dramatically decreased. Due to the fact power production is directly related to height of the water behind the dam, available capacity levels have decreases dramatically on the order of 40% for some months. Figure 3 represents the available generation capacity as a function of water release and water elevation (shown in feet above sea level). As shown, slight variations in elevation have significant impacts on available generation.

Hydropower plants can be considered energy rich but capacity poor (on the order of 20% to mid-40% range), from a system operators perspective, the extra capacity, though not often used, can be available as a fast responding reserve (spinning – available in less then a second and non-spinning – available within 10 minutes). Since reserves can be a very expensive ancillary service if provided by thermal resources, it is important to model the reserves available at the hydro plants in order to correctly model the integration impacts of renewable energy resources [4].

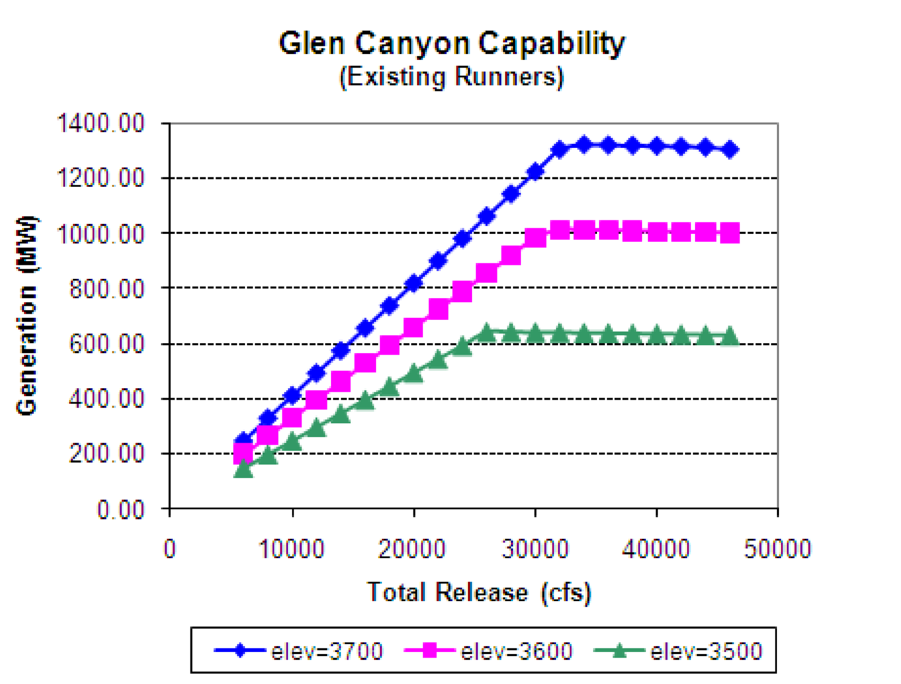

Figure 3: Glen Canyon available generation capacity as a function of water elevation and release levels.

4. Methodologies

To investigate the changes in hydro operations, a statistical study was conducted to compare several scenarios including:

- *2006 Historical Hydro Baseline* – Using historical hydro production data, capacity limits and monthly energy was adjusted in MAPS to compare actual hourly generation data.
- *2006 No Wind vs. L20R* – MAPS "No Wind" scenario generation data (using 10 year average energy database) was compared to that of L20R data also using the original 10 year average energy database.

To deduce the value of all hydropower as a balancing resource and estimate the economic impact of hydropower flexibility in the Western Electricity Coordinating Council (WECC), a series of comparisons were made looking at the hydro system collectively. The following methods were used:

- *All Hydro Generation* – annual generation duration curves where looked at to investigate any shifts in hydro operations as compared to the No New Wind scenario as renewable penetration levels increased.
- *Load to Load net Wind*– Hydro was scheduled to load only rather than load net wind to answer the question of additional costs required to balance the system load (i.e. hydro is not adjusted to account for day-ahead wind and solar forecasts).
- *Flat Block Hydro* – to answer the question of the benefit of hydropower's plays as a balancing resource, hydro plants were modeled as flat block monthly outputs thus removing all flexibility and reserve capabilities of hydro in the MAPS model.

5. Results – Glen Canyon Dam Actual vs. No New Wind

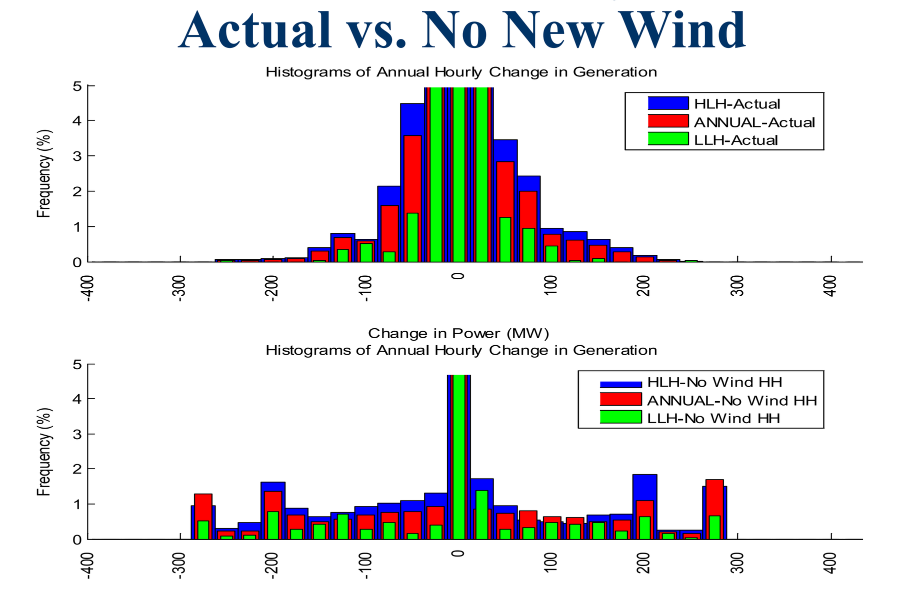

Figure 4: Histograms of hourly changes in generation for Actual and No Wind at Glen Canyon.

Table 2: Histograms of hourly changes in generation for Actual and No Wind at Glen Canyon. (Note: High Load Hours (HLH) is defined as the time period between 6am to 10 pm and Low Load Hours (LLH) is between 10pm to 6am)

Hourly Changes in Generation	Average (MW)	Standard Dev. (MW)	Avg. of Absolute Value (MW)
Annual–Actual	1.06e-2	35.9	18.5
Annual–No Wind	6.28 e-4	68.8	23.9
HLH–Actual	1.49 e-2	40.6	22.8
HLH–No Wind	4.73 e-3	72.3	27.4
LLH–Actual	-1.69 e-2	20.7	7.98
LLH–No Wind	0.111	48.2	12.6

6. Results – Hoover Dam No New Wind vs. 20% (L20R)

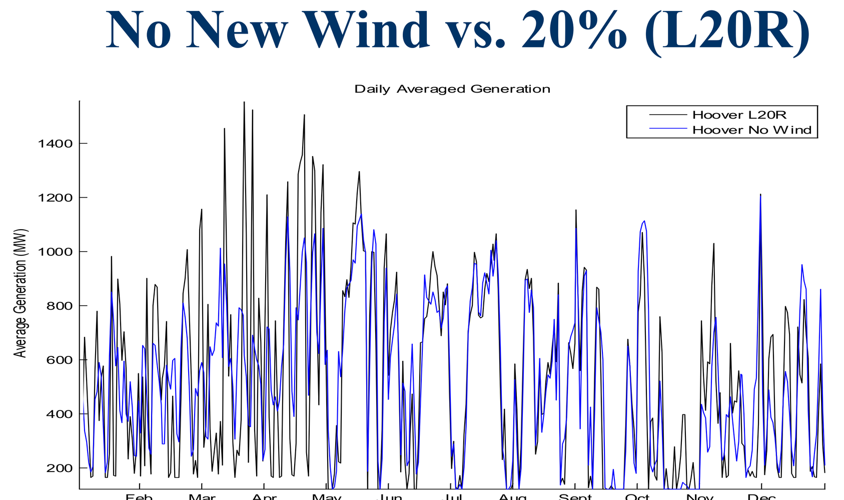

Figure 5: Daily averaged generation for No New Wind and L20R for Hoover Dam.

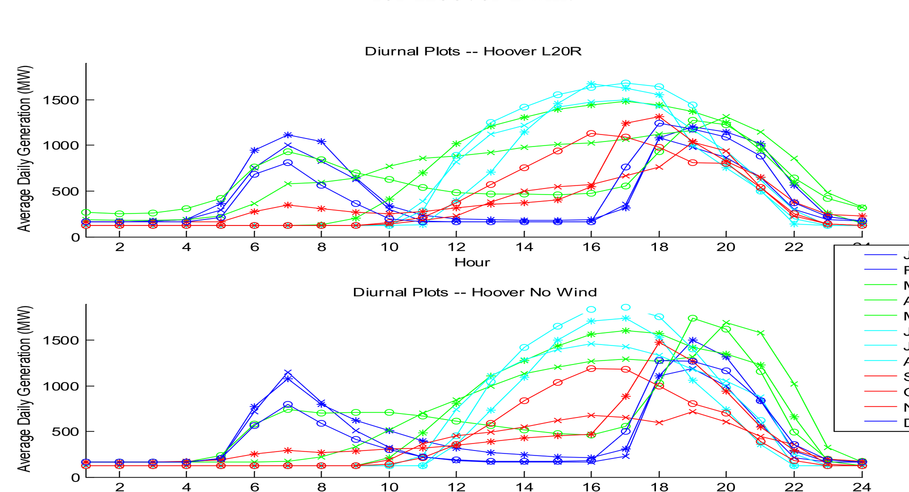

Figure 6: Monthly diurnal distributions of Hoover for MAPS No New Wind and L20R scenarios.

7. Results – All Hydropower

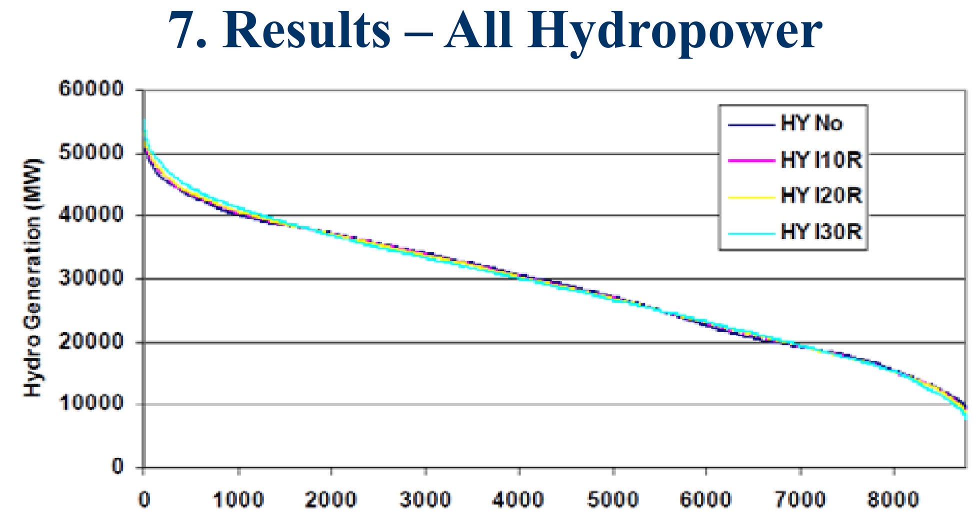

Figure 7: Duration curve of annual hydro generation in WECC.

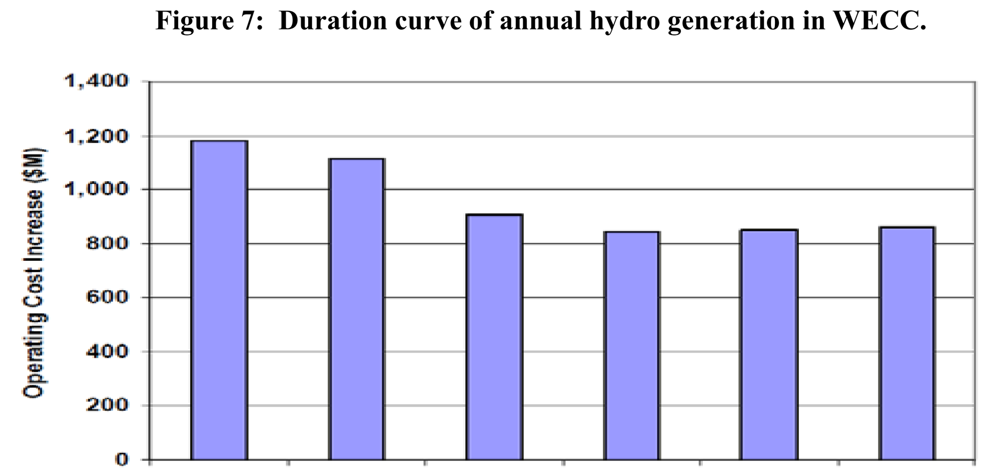

Figure 8: Incremental operating cost impact of modeling the hydro as flat block each month with no flexibility or reserve capacity. "N" implies No New Wind and "Hf" implies hydro modeled as flat block.

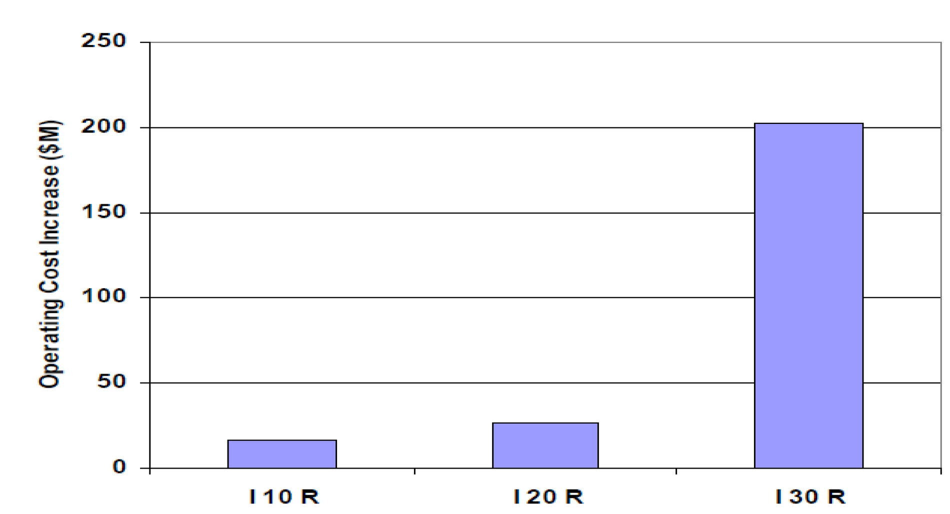

Figure 9: Operating cost increase in the WECC due to dispatching hydro to load only versus load net wind.

Duration Curves Results – It was found that there was no significant shift in hydro operation when compared to the No New Wind scenario. Additionally, there was little change in hourly generation between scenarios.

Flat Block Hydro Results – it was found that the operational costs varies from $1,180M for the No New Wind scenario to $860M for the I30R case or $4.00 to $10.00 per MWh of wind energy.

Scheduled to Load Only – Results show modest operating cost increases at the 10% and 20% ($16M to $27M or $0.17 to $0.22 per MWh of wind energy). At a 30% level, there is a more significant increase to $203M or $0.94 per MWh of wind energy.

8. Conclusions

In comparing the MAPS output to the 2006 actual data, it was found that the MAPS model dispatched significantly more hydro energy because it employed a 10-year average for the hydro, which was substantially more than the actual. The model tended to use the hydro more for peak shaving than for intra- and inter-hour ramping. Using historical hydro limits as inputs, it was found that the MAPS output was a fair match to the actual data, even with generation limitations due to the environmental constraints imposed on Glen Canyon.

Results have shown that as renewable energy penetration levels increase, the collective hydro system in WECC has little change in generation between scenarios. However, some significant changes at individual plants are seen.

By dispatching the hydro to load net wind for the In-Area Scenario, it was found that operating costs could be reduced by $200 million per year at the 30% penetration level, increasing the value of renewables in the system by roughly $1/MWh.

The balancing value of hydro was found to reduce WECC operating costs by up to $1 billion per year in the In-Area Scenario (from flat hydro analysis). On the other hand, if hydro operations were severely constrained (such as maintaining constant river flow) these costs savings may not be realized.

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