Energy Storage for Variable Renewable Energy Resource Integration - A Regional Assessment for the Northwest Power Pool (NWPP)

Michael Kintner-Meyer, *Member IEEE*; Chunlian Jin, *Member IEEE;* Patrick Balducci; Marcelo Elizondo, *Member IEEE;* Xinxin Guo, *Member IEEE;* Tony Nguyen, *Member IEEE;* Frank Tuffner, *Member IEEE;* Vilayanur Viswanathan

Abstract –This paper addresses the following key questions in the discussion on the integration of renewable energy resources in the Pacific Northwest power grid: a) what will be the future balancing requirement to accommodate a simulated expansion of wind energy resources from 3.3 GW in 2008 to 14.4 GW in 2019 in the Northwest Power Pool (NWPP), and b) what are the most cost effective technological solutions for meeting the balancing requirements in the Northwest Power Pool (NWPP). A life-cycle analysis was performed to assess the least-cost technology option for meeting the new balancing requirement. The technologies considered in this study include conventional turbines (CT), sodium sulfur (NaS) batteries, lithium ion (Li-ion) batteries, pumped hydro energy storage (PH), and demand response (DR). Hybrid concepts that combine 2 or more of the technologies above are also evaluated. This analysis was performed with collaboration by the Bonneville Power Administration and funded by the Energy Storage Systems Program of the U.S. Department of Energy.

Index Terms – **Balancing requirements, decomposition of balancing requirements, sizing energy storage, economics of energy storage technologies, power system planning, renewable integration, NaS battery, Li-Ion battery, pumped-hydro energy storage, demand response, hybrid energy storage system.**

I. Introduction

As the electricity industry across the United States considers options for reducing their carbon footprint while meeting expanding demand for electricity, service providers are actively searching for more cost effective and environmentally sustaining sources of energy. From 1995 to 2009, installed wind capacity expanded worldwide from less than 10 GW to nearly 150 GW, and the growth trend is forecast to continue reaching roughly 240 GW by 2012 [2]. Wind power production, however, is uncontrollable and intermittent or variable in nature. Thus, while ample wind resources are available in the Northwest region, integrating high levels of wind energy plants into power systems poses significant challenges to system generation scheduling and ancillary services [3-4].

Earlier studies have found that energy storage can compensate for the stochastic nature of variable energy sources by absorbing the excessive energy when generation exceeds predicted levels and providing it back to the grid when generation levels fall short. Energy storage could also be used to enhance the efficiency of the U.S. power system. During most hours, with the exception of peak hours, less than 50% of electricity system capacity is utilized. Thus, a significant amount of power system assets have been built to meet only a few hundred hours of peak demand each year. Including energy storage could reduce the peak demand by storing energy during off-peak hours and selling it back into the grid during peak times, offering a cost effective alternative to expanding power system capacity.

In recent years, utilities have recognized that energy storage could be an important element of the future power system and have begun to demonstrate energy storage units in their systems. Examples of recent installations include:

- Pacific Gas & Electric (PG&E) has installed a flywheel at the Distributed Utility Integration Test (DUIT) development facility in San Ramon, CA and is planning to install a 4 MW, 28 MWh sodium sulfur (NaS) battery for energy, regulation and load following services.
- American Electric Power (AEP) built a 1.2 MW, 7.2 MWh NaS battery in 2006 for peak shaving, and has a goal of achieving 1,000 megawatts of advanced storage capacity on its system in the next decade.
- Austin Energy placed a 4 MW NaS battery into service in 2009.

While these and other recent energy storage investments signal an advance in the efficient management of the electric power system, additional engineering and economic analyses are required as part of grid operator energy storage planning prior to wide deployment of energy storage.

With the growing contributions of variable energy resources across the U.S. and in the Northwest Power Pool (NWPP), load balancing requirements are expected to grow [3]. The variability of the electricity production from a wind site is attributable to the inherent fluctuations in the wind resources as well as imperfect wind velocity forecasting. With sophisticated wind production forecasting methods, the error can be reduced. The inherent variability of the resource still remains.

In this paper, we present a general methodology for estimating balancing requirements for the 2019-2020 timeframe under a 14.4 GW wind scenario (20% wind penetration) in the NWPP. Further, we examine 11 cases for meeting balancing requirements using an array of technologies, including NaS and lithium ion (Li-ion) batteries, combined cycle power plants (CC), combustion turbines (CT), demand response (DR), and pumped hydro energy storage (PH).

This paper addresses several key questions in the broader discussion on the integration of renewable energy resources into the Northwestern power grid. The questions are:

- For the Northwest Power Pool (NWPP), what are the future balancing requirements necessary to accommodate an assumed expansion of wind energy resources from 3.3 GW in 2008 to 14.4 GW in 2019?
- What are the most cost effective technological solutions for meeting the new balancing requirements?

II. Balancing Requirements

Various approaches [5-10] have been developed to evaluate additional regulation and load following requirements needed for the integration of wind energy. The methodology developed by PNNL combines the advantages of two existing approaches. The PNNL methodology is briefly explained below, a full description of the methodology can be found in [3]. The methodology uses historical data and stochastic processes to simulate the load balancing processes. Capacity, ramp rate and ramp duration characteristics are extracted from the simulation results.

In the analysis, the NWPP is assumed to be consolidated to one balancing area. Furthermore, neither import or export power is considered in the generation schedule. We also assume that the generation schedule to meet internal system load (i.e., not including interchange) is the same as load forecast, and there is no deviation of actual generation from schedule (Actual generation deviation from schedule can be included in the simulation if it is a concern.) With these assumptions, the regulation and load following requirements can be derived by using the following data sets: actual load, load forecast, actual wind and wind forecast.

A. Wind datasets

BPA's existing wind production data (with a 1-minute time scale) was used within the BPA footprint. For the wind capacity additions (both wind capacity within BPA service territory and outside), the National Renewable Energy Laboratory (NREL) Wind Integration Datasets [11] were utilized, which provided wind production backcast for 32,043 wind sites in the WECC system with 10-minute intervals.

A 20% wind penetration scenario is hypothesized. In other words, the installed capacity of wind generation will reach 14.4 GW in NWPP by 2019. The placement of the new wind capacity is done with some judgment whereby only the best wind class (classes 6 and 7) were selected while maintaining the proportions of existing wind capacities by states. The wind capacity additions are comprised of literally thousands of hypothetical wind production sites from the Wind Integration Datasets. The average capacity factor (CF) of the wind farms is around 35%. Figure 1 shows the wind distribution by state for both the existing and new capacity additions through 2019.

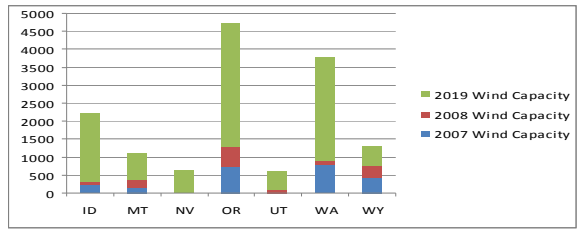

Figure 1: Distribution of Wind Capacity by States in MW

Wind hourly forecast is obtained by averaging wind production of every hour and superimposing BPA wind forecast error on the hourly average. The projected wind production in 2020 of each existing wind plant is assumed the same as that of 2006, including the statistical characteristics of the wind forecast error, which is represented by a truncated normal distribution (parameters of the distribution such as mean, standard deviation, and autocorrelation are consistent with the statistical features of the BPA wind forecast). The statistical information of BPA hour-ahead wind forecast error is shown in Table 1.

Table 1: Statistics of Hour-Ahead Forecast Error

	Wind Forecast	Load Forecast
Mean error	0%	0%
Standard deviation	7%	2%
Auto correlation	0.6	0.9

B. Load Datasets

The minute-by-minute actual load data and hour-ahead load forecast for the BPA service territory are obtained from BPA. In this analysis, we assume the hourly generation schedule is the same as the hour-ahead load forecast. BPA's annual load growth projections throughout the period to 2019 were adopted, which is assumed to be about 1.19% annual growth. No modifications of the current load shape were assumed. For the remaining balancing authorities within the NWPP, hourly load data from Ventyx PowerBase® are utilized with similar annual load growth assumptions as used for the BPA footprint.

Hourly data are interpolated to generate minute-by-minute actual load data. For the whole NWPP, the hourly load forecast is generated by adding load forecast error to the hourly average of load. The load forecast error is assumed to have truncated normal distribution with the same statistical characteristics as BPA current load forecast. The load forecast error statistics is also shown in Table 1.

C. Balancing Service Requirement

The power system control objective is to minimize its area control error (ACE) to the extent that complies with the North

American Electric Reliability Corporation (NERC) Control Performance Standards. Therefore, the "ideal" regulation/load following signal is the signal that minimizes deviations of ACE from zero.

To simplify the analysis, one single consolidated balancing authority (BA) comprised of all individual balancing authorities in the NWPP was assumed. This simplification reduces the analysis complexity significantly. Instead of performing a BA-by-BA analysis and combining the finding for the NWPP, the consolidation collapsed the complexity into a single zone. There are implications to this simplification. The consolidation of balancing authorities will provide greater sharing of balancing and reserve resources among all constituents and offer opportunities to more effectively utilize the higher degrees of diversity of the variable renewable energy resources across the entire NWPP footprint. As a consequence, the balancing requirements are likely to be smaller in a consolidated large BA area than the sum of all individual BA areas as they currently exist. This will lead to an underestimation of the future requirements under the existing BA regime.

The total balancing requirements of the NWPP are assessed by using a stochastic approach developed by PNNL, utilizing the wind and load datasets as discussed above. Figure 2 and Figure 3 illustrate the resulting balancing requirements signal for the NWPP for the whole month of August 2020 and one typical day in August 2020, respectively. The balancing-up power capacity requirement is 3916 MW and the balancing-down power capacity is -3683 MW. These figures are based on BPA's customary 99.5% probability bound that meets 99.5% of all balancing requirements. That means that 0.5% of all of the anticipated balancing capacity exceeds that bound. For a 100% probability bound, the maximal balancing requirements are about 5000 MW in for the balancing-up and about -4000 MW for the balancing-down.

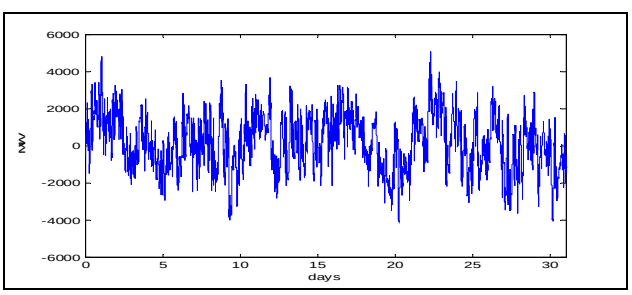

Figure 2: Total Balancing Requirements for NWPP for the Month of August 2020

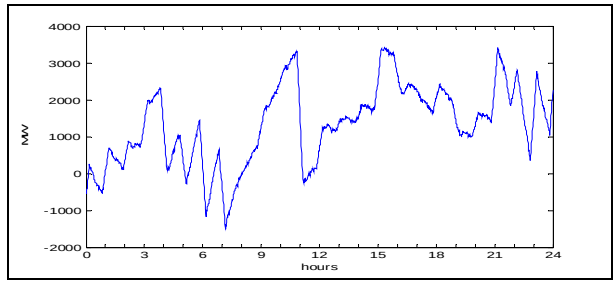

Figure 3: Total Balancing Requirements for NWPP for One Typical Day in August 2020

The balancing signal shown in Figure 3 exhibits a spectrum of cycling or oscillatory content. Cycles at lower frequencies with periods of several hours (intra-day) are considered to be addressed by the energy markets that re-dispatch generators on an hourly basis. The deviations from the day-ahead schedule generally do not require fast ramp rates and, thus, are not considered part of the balancing requirements. Cycles within the hour (intra-hour balancing) are a key focus of this analysis. The following section discusses the filtering strategies to the extract the intra-hour cycling from the original balancing signal.

D. Spectral Analysis and Extraction of Intra-Hour Balancing Signal

A high-pass filter was designed to filter out the fast cycles (intra-hour and real-time components) from the original balancing signal. The cut-off frequencies for the filter were f_l=1.157e-5 Hz and f_u=0.2 Hz. The spectral analysis of the balancing signal illustrates the oscillatory content in the signal. The results of the spectral analysis are shown conceptually in Figure 4. Table 2 displays the frequency limits for the high-pass filter design.

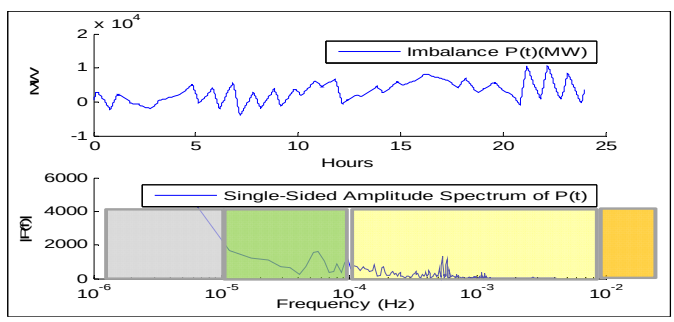

Figure 4: Spectral Analysis of Balancing Signal

Table 2: Frequency Limits of Components of the Balancing Signal

No.	Component	f_l (Hz)	f_u (Hz)	Period of f_l	Period of f_u
1	Intra-week	0	1.157e-05	Inf	24 hours
2	Intra-day	1.157e-05	1.388e-04	24 hours	2 hours
3	Intra-hour	1.388e-04	0.0083	2 hours	2 minutes
4	Real-time	0.0083	0.2	2 minutes	5 seconds

E. Capacity Requirements for Meeting 2020 Balancing Needs

Extensive systems modeling was performed to estimate the power and energy capacity requirements to meet the future balancing needs. Each technology and technology group required careful simulation that incorporated the specific technical features of a technology, as well as the interaction with each other if more than one technology was modeled. The results of the simulations were a pairing of power (GW) capacity, and energy (GWh) capacity requirements to meet future balancing needs.

The capacity requirements assessment methodology was used to compute cost estimates for 11 cases using combinations of several energy generation or storage technologies.

Table 3 shows the results of power and energy requirements for all the 11 cases in this study. It should be noted that the capacity requirements or the minimal size of the battery is based on 100% DOD of the battery. This means that the size of the energy storage is fully utilized. The storage will be cycled from fully charged to fully discharged. As will be discussed, there are good economic reasons for upsizing the battery to a DOD of less than 100% to improve the life of the battery. For instance, a battery with a DOD of 50% only uses its energy storage capability to 50%. Significant simulation efforts were performed to determine the minimal capacity (power and energy rating) for the various technology options. The key driver that set the size of the technology was specific operational constraints that force the technology to be operated in a certain way, for instance, the limited change modes and the change over delay of the pumped hydro technology [12].

Table 3: Power and Energy Requirements for Each Scenario. Note: the energy capacity (GWh) for the batteries are nominated at a depth of discharge of 100%.

Cases	Technology	GW	GWh
C1	CT	1.85	-
C2	NaS	1.85	0.91
C3	Li-ion	1.85	0.90
C4	Pumped hydro, changeover delay = 4 min	1.85	0.83
	Requirements during changeover delay	1.21	0.17
C5	Pumped hydro, night pumping/day generation, changeover delay = 4 min	3.61	21.72
	Requirements during changeover delay	0.82	0.05
C6	DR	8.64	-
C7	NaS	1.49	0.73
	DR	1.72	-
C8	Li-ion	1.49	0.72
	DR	1.72	-
C9	Pumped hydro, changeover delay = 4 min	0.5	0.22
	NaS	1.35	0.69
C10	Pumped hydro, night pumping/day generation, changeover delay = 4 min	0.97	5.87
	NaS	1.35	0.67
C11	Pumped hydro, changeover delay = 4 min	0.5	0.22
	DR	1.72	-
	NaS	0.98	0.50

III. Economic Analysis Methodology and Results

A. Cost Analysis Framework

The cost model used to support this analysis has the capacity to examine all initial and recurrent costs, property and income taxes, depreciation, borrowing costs, and insurance premiums. It expresses cost in terms of constant 2010 dollars, treats interest and inflation in a systematic manner, and distinguishes between costs that occur annually and those that occur in a single year. Based on input provided by BPA analysts, however, much of the cost elements typically considered in utility financial analyses (e.g., property and income taxes, depreciation, borrowing costs, and insurance premiums) were excluded from this analysis. Thus, this analysis considers the annual costs associated with initial and recurrent capital costs, fixed and variable operations and maintenances (O&M) costs, fuel costs, and emissions costs. These costs were, in turn, collapsed into a single present value cost value using a real discount rate of 10.3 percent. This discount rate was recommended by BPA analysts and was computed by subtracting a 1.7 percent rate of inflation from a 12 percent nominal discount rate. The analysis time horizon is 50 years.

B. Technology Cost Parameters

The cost analytical framework outlined in the previous section and the cost model supporting this research rely on a number of assumptions regarding major cost elements, including capital costs, O&M costs, fuel costs, and emissions costs. Costs are segmented according to each of these four cost

categories within each of the cases considered in the results section of this report.

C. Capital and Operations and Maintenance Costs

The capital cost of energy storage consists of an energy component ($/MWh) and a power component ($/MW). The first element represents the costs associated with the storage medium while the latter element is tied to power electronics costs. To determine the capital costs, energy storage devices were sized based on both the power and energy needs of the application. Based on the values obtained from an extensive literature review and through many consultations with domain experts, Table 4 summarizes the values used in this study, with 2019 forecast values in parenthesis. Forecast values include assumptions regarding cost reductions tied to technology advancement.

Table 4: Summary of Capital and O&M Costs for Batteries and Pumped Hydro

Parameter	NaS battery	Li-ion battery	Pumped hydro	Combustion turbine	Combined cycle	Demand response
Battery Capital cost $/kWh	415	1,000				
System Capital cost $/kW			1750 (1890)	695 (723)	998 (1038)	489
PCS ($/kW)	200 (150)	200 (150)				
BOP ($/kW)	100	100				
O&M fixed $/kW-year	0.46[1]	0.46[1]	4.6	12.75	13.79	
O&M fixed $/kW-year (PCS)	2	2				
O&M variable cents/kWh	0.7	0.7	0.4	0.376	0.217	
Round trip efficiency	0.78	0.80	0.81	0.315		

In addition to the battery and pumped hydro storage costs, one case considers the capital costs of combustion turbines and several cases include capital costs associated with demand response (DR). The costs of implementing DR are assumed to be $50.70 per kW per year based on data presented by the Electric Power Research Institute [13]. Over 50 years, the present value of DR capital and O&M costs are $489 per kW, discounted at 10.3 percent. Combustion turbine capital costs are estimated at $723 per KW based on the estimates presented in the 2010 Annual Energy Outlook or AEO [14]. Note that combined cycle capital costs are not included in this analysis because those costs are assumed to be sunk within the existing system. The costs of operating those combined cycle plants, however, are included in the cost estimates presented for each case.

Combined cycle O&M costs are estimated at $13.79 per kW and $2.17 per MWh for fixed and variable, respectively [14]. For batteries technologies and pumped hydro, O&M costs were split into fixed and variable components and were estimated based on an extensive literature review and analysis of current systems.

D. Fuel Costs

Fuel costs for each alternative were developed using average daily energy requirements as measured in million Btu (MMBtu). These energy requirements were generated based on the combustion and combined cycle turbine production schedules designed to meet load balancing requirements for the BPA region in 2019. Average daily energy requirements were expanded to annual energy requirements, which were in turn multiplied by natural gas prices ($9.34 per MMBtu) to compute annual fuel costs for each alternative. The fuel price used in this analysis represents the average real price forecast for the 2010 to 2040 time horizon.[2]

E. Emissions Costs

Fuel combustion levels were used to establish emissions levels through the application of U.S. Environmental Protection Agency coefficients for converting quadrillion BTUs into metric tons [15]. These emissions levels were, in turn, used to construct emissions cost estimates. NO_x prices ($600 per ton) were obtained from the July 2009 NO_x Market Monthly Market Update (annual NOx allowances) published by Evolution Markets [16]. SO_2 prices ($71.75 per ton) were also obtained through Evolution Markets in the June SO_2 Monthly Market Update. Prices for CO_2 allowances ($45 per ton) were derived from the Sixth Northwest Power Plan [17].

F. Optimizing Battery Capacity

An important factor in minimizing the costs associated with each alternative involving energy storage is optimizing the battery capacity. In effect, one could size up the energy storage capacity to reduce the depth of discharge (DOD) during each cycle and increase the life of the battery systems. The minimum battery state of charge (SOC) was set to various levels in the 5 to 95 percent range during battery operation to perform tradeoffs between life time and battery size. As effective DOD decreases, a larger battery size is needed. This decreases the DOD for each cycle during the intra-hour balancing, thereby increasing the cycle life of the battery.

While increasing the battery capacity drives up initial capital costs, it also reduces the DOD requirements, thus extending the cycle life of the batteries and reducing interim capital costs. It is important to note that the life cycle calculations do not account for the natural rate of decline associated with material components of a battery occurring regardless of the energy storage requirements. To address this component, the maximum life for Li-ion batteries was constrained to 10 years, while the maximum life cycle for NaS batteries was constrained to 13 years.

[1] $/kWh

[2] Natural gas prices from 2010 to 2030 are based on EIA (2010). Prices were extended from 2030 to 2039 using the average annual growth rate reflected in the EIA 2009 forecasts.

Parameters in this cost minimization problem include effective depth of discharge, battery capacity, lifecycle, cost reductions resulting from battery technology advancement, and relevant discount rates. These parameters were used to establish the optimum battery size based on an assessment of the present value costs for each effective DOD level.

G. Economic Results

The economic assessment methodology was used to compute cost estimates for 11 cases using combinations of several energy generation or storage technologies. For each case, the objective was to meet the load balancing requirements for the BPA region over a 50-year time horizon.

The results of the economic analysis for the base or reference case are presented in Table 5. Of the 11 cases examined in this paper, Case 2, which employs NaS batteries, is the least cost alternative at $1.4 billion. Note that the values presented in Table x represent the present value of the stream of capital, O&M, fuel, and emissions costs over a 50-year time horizon.

Total costs under Case 7 are estimated at $1.9 billion, or 35.2 percent more than those for Case 2. The third most cost effective option is Case 9, which is 42.6 percent more expensive than Case 2. In the predominantly pumped hydro case with 40 mode changes per day (Case 4), total costs are also much higher at $4.0 billion. In most cases, the capital costs associated with the energy storage options are higher than those estimated for the combustion turbine case (Case 1) but these costs are offset by the higher fuel and emissions costs estimated for combustion turbines.

Table 5: Economic Analysis Results

Case	Capital	Fuel	O&M	Emissions	Total
1	1,759	905	276	312	3,252
2	1,076	125	129	43	1,372
3	2,139	91	122	31	2,383
4	3,720	120	120	41	4,000
5	6,949	422	372	145	7,889
6	4,222	-	-	-	4,222
7	1,619	100	102	34	1,855
8	2,425	73	97	25	2,620
9	1,671	123	121	42	1,957
10	2,550	205	190	71	3,016
11	2,331	98	100	34	2,562

H. Sensitivity Analysis

To explore the sensitivity of the results to varying a small number of key assumptions, the research team conducted a sensitivity analysis. Sensitivity analysis was performed by making the following adjustments to the assumptions underlying the results:

1. Use estimated 2010 prices for each technology estimated. The underlying assumption governing this first case is that the cost projections for 2019 are not realized.
2. Decrease the discount rate to 4 and 7 percent.
3. Consider minimum plausible variation around the capital costs for battery technologies and pumped hydro (Li-Ion battery costs are varied by +/- 20 percent, NaS battery costs are varied by +/- 12.4 percent, and pumped hydro capital costs are varied by +/- 20 percent)
4. Significantly increase variable O&M costs for pumped hydro (from $0.004 per kWh to as high as $0.04 per kWh under Cases 4, 5, 9, 10, and 11).

As a result of the forecasts underlying the base case, which include cost reductions for battery technologies and cost increases for all other systems, using current prices makes scenarios involving pumped hydro and DR relatively more cost efficient. The results of Sensitivity Analysis 1 show a closing gap between Case 2 and Cases 7 and 9, which are both 13 percent more expensive when using 2010 price data. Note that under the base case, Cases 7 and 9 were 35.2 percent and 42.6 percent more expensive than Case 2, respectively. When the discount rate is reduced, the pumped hydro scenarios become more cost efficient because the asset is long-lived (50 years) and does not require interim capital costs. Reducing the discount rate to 4 percent increases the costs associated with Case 2 (NaS batteries plus combined cycle) from $1.4 billion to $2.3 billion but increases the costs for Case 9 (NaS batteries plus combined cycle plus pumped hydro with 40 mode changes per day) from $2.0 billion to $2.8 billion. The final two sensitivity analyses, which include variability with respect to capital costs and increased variable O&M costs for pumped hydro, do not appear to lead to a re-ordering of the most cost efficient options.

IV. Summary and Conclusion

The study estimated the total balancing requirements for the NWPP for a scenario of 14.4 GW of wind energy in the 2019 time horizon. Under the assumption that the current individual balancing authorities (BAs) are consolidated to one single large balancing area, new total balancing requirements were determined. This assumption is likely to underestimate the new requirements if the current status quo in the grid operation for the pool is maintained. This assumption was made for no other reason but to manage the workload of this highly complex analysis. The results of this study estimated a total balancing requirement of approximately 4 GW of inc. capacity and about 3.6 GW of dec. capacity, using the BPA's customary 99.5% probability bound.

The intra-hour balancing requirement was filtered out of the total balancing signal. The intra-hour balancing requirement

is smaller than the total requirements, and tends to have higher ramp rate requirements. The intra-hour balancing requirements were estimated to be about 1.85 GW in both directions (increment and decrement).

A life-cycle cost analysis was performed that sought the cost optimal technology investment to meet the total intra-hour balancing requirements of a 50-year lifetime. Considered were capital, O&M costs, as well as fuel prices and typical prices for criteria emissions. The CO_2 emissions were valued at a cost of \$45/ton CO_2.

This study revealed several insights into the technology ranking under life-cycle cost optimality. First, the reference technology (CT) is not the least expensive option. Both batteries types (NaS and Li-ion) were comparatively less expensive to the CT. The following ranking (least cost to highest cost) was established for the base cases: NaS only, NaS+DR, NaS+pumped-hydro with many mode changes, Li-ion+DR, NaS+pumped-hydro with many mode changes+DR. The most costly cases were pumped-hydro with 2 mode changes and demand response alone.

The design of how pumped-hydro system is operated is critical for the overall size and, thus has direct impact on the lifecycle cost. For the 2-mode-change per day operation, the power rating must be doubled the size compared to the multiple-mode-change design. When only changing the mode twice a day, the machine must provide the full increment-to-decrement swing (inc/dec swing) in one single mode (pumping or generating). However, if the machine remains unconstrained in the number of mode changes a day, the full inc/dec swing (from maximum generation to full load pumping) can be utilized. The 4-minute delay between modes, in which the machine is neither pumping nor generating, necessitates other resources to substitute (back-up resource). The size of the back-up is considerable for the multiple-mode-change operation and relatively small when the pumped-hydro system changes modes only twice a day. Both the oversizing as well as the back-up resource requirements drive up the total life-cycle cost of pumped-hydro system when compared to a battery system.

Demand response strategies by itself appears costly. The reasons for this result follow a similar logic as for the 2-mode-change pumped-hydro storage. Unlike battery energy storage, which can be a load and a generator at times, DR must be large in capacity to perform the balancing only in the load mode. Thus, the total capacity size tends to be larger than the rate capacity of a battery. The size of the DR capacity (number homes) is determined by the lowest load condition just meeting the balancing requirement leaving a lot of capacity under-utilized for the remainder of the day. Because of a typical residential load shape, meeting all balancing requirements with demand response is unlikely to be economical. However, some DR capacity can reduce the energy requirements of the battery. There is an interesting trade-off between DR power capacity and the storage energy capacity when combining storage and demand response. Interesting shifts are seen in the optimal battery size as one adds demand response resource to the technology mix.

The results clearly indicate that energy storage and particularly the electro-chemical storage technology are likely to compete with conventional combustion turbine technologies with and without accounting for the emission externalities for short-cycling (intra-hour) balancing services. These services are generally referred to as regulation and load following services. In addition to these intra-hour balancing services, there are longer cycle balancing services that could be of interest, particularly to grid operators with significant hydro electric resources. Additional studies using the methodology described in this paper are necessary to reveal these longer cycle balancing values.

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