Variable Energy Resource (VER) Integration Analysis

July 2018

TABLE OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

1. INTRODUCTION

This report summarizes the actions taken in compliance with the Public Utility Commission of Oregon's (OPUC) Order Nos. 17-075 and 17-223 from Case No. UM 1793. The OPUC's final orders from UM 1793 adopted Idaho Power's *2016 Solar Integration Study* and approved the implementation of solar integration charges based on that study. The OPUC also directed Idaho Power to work with a Technical Review Committee (TRC), similar to what was done with the *2016 Solar Integration Study*, to conduct a new wind integration study, evaluate potential impacts of participation in the Energy Imbalance Market (EIM) on integration costs, and evaluate whether to conduct a joint wind and solar integration cost study. In clarifying its direction to Idaho Power, the OPUC stated:

> At page 7 of our order, [Order No. 17-075] we affirmed our intent that integration studies, as well as the additional factor of EIM participation, should be addressed in the annual IRP update and IRP acknowledgement processes. We therefore order Idaho Power, as soon as the 2017 IRP had been filed, to work with the TRC to conduct a new wind integration study, perform an analysis of the impact of participation in the EIM and thoroughly evaluate whether to conduct a joint wind and solar integration cost study. We also ordered the company to, as part of this assessment, examine different methods for allocating jointly determined costs between wind and solar and to submit a study report and recommendation to us no later than April 30, 2018, well ahead of the beginning of the 2019 IRP. Order No. 17-223. [The April 30, 2018, deadline was extended to July 31, 2018.][1]

Idaho Power initiated the study process by organizing a TRC as summarized below. Idaho Power held regular meetings and communications with the TRC to receive and incorporate feedback throughout the process. A comprehensive wind integration study was conducted, the results of which are set forth in this report. Additionally, Idaho Power examined a combined integration approach for both wind and solar, as well as conducting some initial evaluation of the differences participation in the EIM may make on such determinations.

This report concludes that the varied analyses of wind, solar, load, EIM, and reserves indicate a unified variable energy resources (VER) integration analysis approach may be the best way to assess costs for additional increments of variable and intermittent generation resources, like wind and solar, going forward from current levels of penetration. However, the analysis also indicates Idaho Power's system is nearing a point where the current configuration can no longer integrate additional VERs. Additional investigation is warranted into the combined effect of wind and solar, in a unified VER integration analysis and cost impact determination, along with the potential effects of participation in the EIM and its unique requirements, attributes, costs, and benefits.

[1] Order No. 18-130.

2. Technical Review Committee

Idaho Power greatly appreciates the involvement of the TRC members:

- Michael Eldred, Mike Louis, and Yao Yin—Idaho Public Utilities Commission (IPUC)
- Kurt Myers—Idaho National Laboratory
- Ben Kujala—Northwest Power and Conservation Council
- Cameron Yourkowski—Renewable Northwest
- Brian Johnson Ph.D., P.E.—University of Idaho
- Brittany Andrus and Jean-Pierre Batmale—OPUC

The TRC provided important guidance in the design and vetting of the approach Idaho Power adopted in re-evaluating the cost of integrating wind and solar resources. Specifically, TRC discussions led to Idaho Power adopting the North American Electric Reliability Corporation (NERC) Real Power Balancing Control Performance standard (NERC BAL standard)[2] for defining the reserves; sharing the diversity benefits of reduced reserves across load and wind and solar generation; and using incremental standard deviation methods to calculate the contributions of load, wind, and solar to their netted variability. These three study improvements are foundational to the fair treatment of variability in a generation resource on Idaho Power's system.

3. 2018 Wind Integration Study

3.1. Background

The *2018 Wind Integration Study* (WIS) is the third Idaho Power study evaluating the impact of increased variability on the cost of power supply operations. The first two studies were completed in 2007 and 2013. The 2007 WIS evaluated three hydro condition years and four wind levels using meteorological simulations of 300, 600, 900, and 1,200 megawatts (MW). The matrix of the results from the 2007 WIS is shown in Table 1.

[2] Standard BAL-001-2—Real Power Balancing Control Performance: nerc.com/pa/Stand/Reliability%20Standards/BAL-001-2.pdf.

Table 1
2007 WIS results using historical Mid-C prices as benchmark

Study Year	Penetration Level (MW)	Cost Per MWh* Wind
1998	300	$3.19
1998	600	$4.73
1998	900	$6.06
1998	1,200	$6.92
2000	300	$21.89
2000	600	$30.30
2000	900	$39.06
2000	1,200	$39.40
2005	300	$10.69
2005	600	$9.32
2005	900	$10.58
2005	1,200	$8.12

*Megawatt-hour

The second WIS was completed in 2013 and evaluated integration costs at wind levels of 800, 1,000, and 1,200 MW using three hydro condition years. Idaho Power had 678 MW of wind generation on-line as of January 2013. The results from the 2013 WIS are shown in Table 2.

Table 2
2013 WIS integration costs ($/MWh)

Water Condition	800 MW	1,000 MW	1,200 MW
Average (2009)	$7.18	$11.94	$18.15
Low (2004)	$7.26	$12.44	$18.15
High (2006)	$9.73	$14.79	$20.73
Average	**$8.06**	**$13.06**	**$19.01**

The 2018 WIS evaluates integration costs at wind levels of 300, 500, 727, 800, 900, 1,000, and 1,100 MW using a median, low, and high hydro forecast. Actual Idaho Power system wind production data from 727 MW of nameplate capacity was used to develop the 300-, 500-, 800-, 900-, 1,000-, and 1,100-MW levels. The results from the 2018 WIS are shown in tables 3 and 4. Table 3 provides the integration charges for varying levels of nameplate wind capacity. As noted in Table 3, increasing levels of wind capacity result in times where the model of Idaho Power's system cannot meet its reserve obligations, which would indicate times when generation curtailment would likely be required to meet compliance. Table 4 indicates the number of reserve violations for varying levels of wind capacity.

Table 3
2018 WIS results

Wind Nameplate (MW)	300	500	727	800	900	1,000	1,100
Integration Charge ($/MWh)*	$2.29	$2.88	$4.52	$4.88	$5.56	$5.96	$5.17

*Costs included in the Integration Charge do not include mitigation for periods when the requested operating reserves were unable to be provided by the model.

Table 4
Number of reserve violations

Nameplate (MW)	Regulation Up (RegUp)	Regulation Down (RegDn)	Spin	NonSpin	Total Reserve Violations	Percent of Hours
300	2	1	–	–	3	<0.1%
500	1	7	–	6	14	0.2%
727	23	52	–	1	76	0.9%
800	91	133	–	8	232	2.6%
900	255	522	–	22	799	9.1%
1,000	435	988	–	11	1,434	16.4%
1,100	690	1,736	–	8	2,434	27.8%

The 2018 WIS was initiated in compliance with OPUC Order No. 17-075. In Order No. 17-075, the OPUC allowed Idaho Power to adopt their *2016 Solar Integration Study* and directed the company to file amendments to Schedule 85 setting forth the incremental costs of integrating solar and wind generation into its operations. The order further directed the company to do the following:

- **Conduct a new WIS and improve the wind integration cost methodology.**
- Evaluate the quantitative benefits of participation in the western EIM on the costs of integrating variable resources into its operations.
- Establish a TRC that, along with the company, will assess the feasibility of estimating the unified costs of integrating wind and solar into its system and evaluate methods for sharing those estimated costs between wind and solar resources.
- Submit the updated solar integration study, new wind integration study, and assessment of joint integration cost study to the OPUC.

The 2018 WIS focuses on the first item from the order. The objective of an integration study is to investigate the operational impacts of the variability and uncertainty of intermittent resources, like wind and solar, on the electric power grid, and to estimate the costs incurred to integrate these types of generation resources. The estimation of these integration costs is used by the company to facilitate a comparative evaluation of intermittent generation resources to other resource options during the company's integrated resource planning process. Integration costs are also used as a cost offset to the avoided cost price paid for must-take generation from qualifying facilities as defined under the *Public Utility Regulatory Policies Act of 1978* (PURPA).

The new WIS incorporates several changes and improvements from previous studies. The primary changes and improvements are as follows:

- Using actual observed Idaho Power system wind data
- Using the actual two-hour ahead (2HA) load and wind forecasts available to operations
- Using the AURORA market model to simulate Idaho Power's system

- Basing the hydro conditions under which the integration costs are determined on 50-percent exceedance, 10-percent exceedance, and 90-percent exceedance hydro conditions
- Deriving operating reserves from application of the NERC BAL standard.

Each of these changes will be discussed in more detail later in this report.

3.1.1. Wind and Idaho Power's System

The amount of wind connected to Idaho Power's system has grown considerably over the past decade, and at the time of the 2018 WIS analysis, totaled 727 MW of nameplate capacity.[3] The most rapid growth occurred during 2011 and 2012, during which nearly 500 MW of capacity were added. See Figure 1 for a graphical depiction of Idaho Power's wind resource additions over the years.

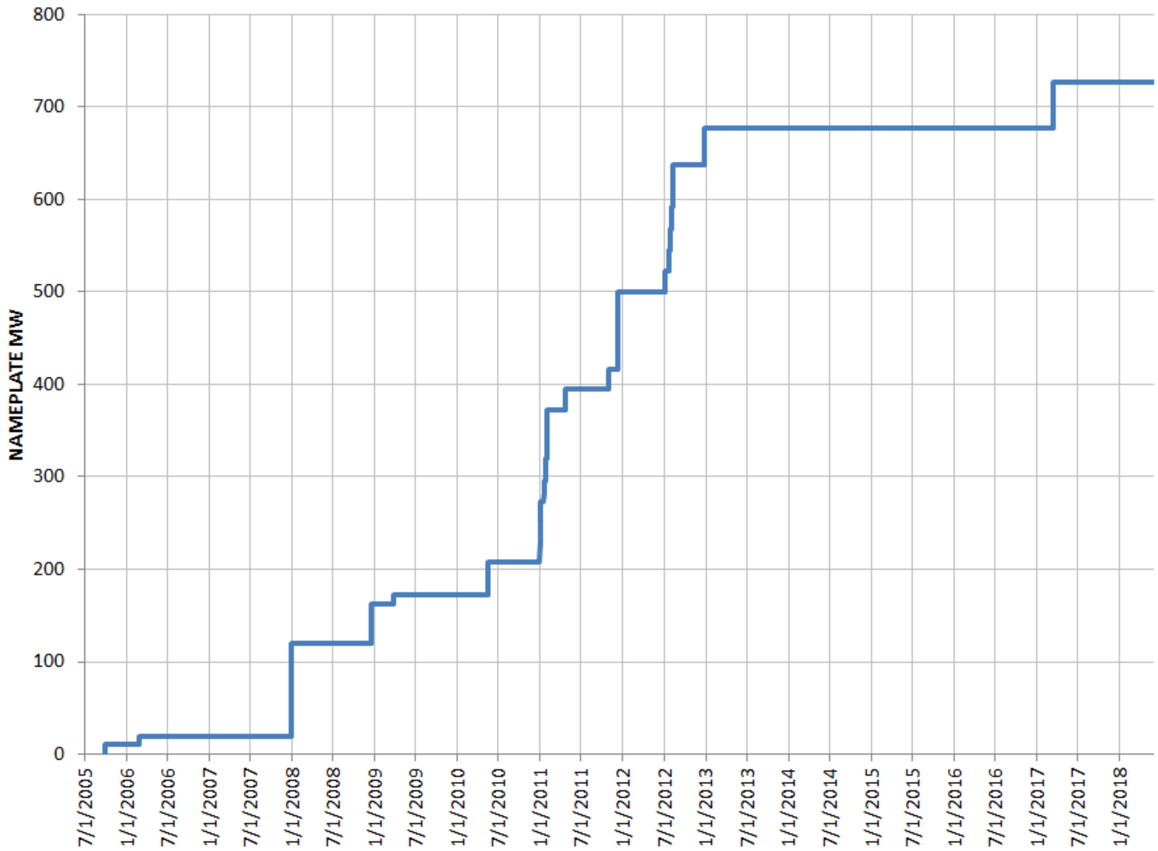

Figure 1
Wind resources on Idaho Power's system

[3] Idaho Power is required to sell renewable energy credits (REC) associated with the wind production from the wind projects connected to its system. Thus, while the company has enabled the development of this wind capacity through the energy sales agreement process, it cannot explicitly represent the output from the wind projects under contract as energy delivered to customers.

3.1.2. Dispatchable Generating Capacity

Dispatchable generating capacity owned and operated by Idaho Power is critical to system reliability. This generating capacity has long been used to follow customer load ramps. With the growth in VERs over the past decade, dispatchable generating capacity is increasingly used to provide the regulating reserves necessary for balancing VER output. For the 2018 WIS modeling, Idaho Power designated a blend of resources capable of providing regulating reserves to respond to intra-hour ramping needs. The blend of regulating reserve resources for the WIS modeling totals 1,365 MW of nameplate capacity and consists of coal-fired generation (Jim Bridger Plant), natural gas-fired generation (Langley Gulch Plant), and hydro generation (Brownlee, Oxbow, and Hells Canyon plants).

3.1.3. 2017 Operations Issues

In addition to the influx of wind generation, from 2016 to 2017 approximately 289 MW of PURPA solar were added to Idaho Power's system, resulting in a total of 1,016 MW of VER projects. Prior to 2016, Idaho Power had limited operational experience with utility-scale solar projects. VER curtailments in 2017 exceeded all previous years' curtailments combined.

Multiple factors—the addition of non-dispatchable, must-take generation resources; relatively flat load growth; high spring hydro conditions; and a low-priced energy market in the West—contributed to the increased number of curtailment events in Idaho's balancing area (BA).

VER projects are curtailed when Idaho's BA is unable to maintain sufficient dispatchable generation resources to respond to contingencies and provide regulating reserves to respond to changes in load and non-dispatchable generation. High river conditions with dam operating restrictions and flood-control target levels will not allow Idaho Power's dispatchable resources, such as hydro units, to reduce generation when VERs generate above forecast levels.
Low market prices make keeping thermal resources on-line and spinning to respond when VERs generate below their forecast or down ramp unexpectedly very expensive. Additionally, other possible reliability events, such as a line outage, require some dispatchable unit generation be maintained in reserve to respond for reliability, public safety, or the protection of Idaho Power or public equipment.

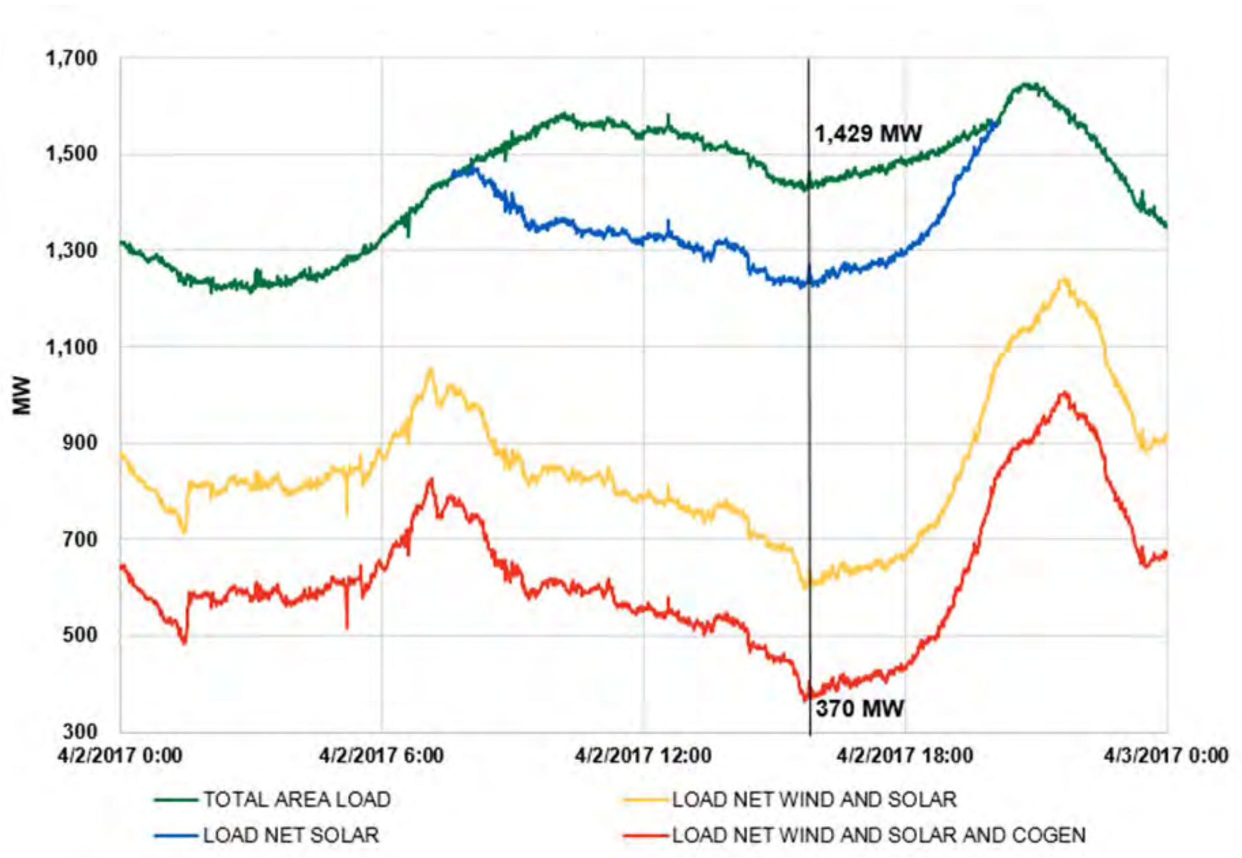

Figure 2
Load and net load after VERs

Figure 2 illustrates an instance of the impact of VER (wind, solar) and cogeneration netted against load, resulting in an integration problem. The top line (green) in Figure 2 represents the total area load profile for a day in April 2017. The second line (blue) is the load netted with solar generation, and the third line (yellow) is the load netted with solar and wind generation. The fourth line (red) is the load netted with solar, wind, and cogeneration. The vertical reference line indicates a point during the middle of the day when the total area load was 1,429 MW, yet the load when netted with must-take resources was only 370 MW. Figure 2 does not include the dispatchable hydro and coal generation required to be operated for environmental and flood-control requirements and for contingency events and balancing.

As part of the Northwest Power Pool (NWPP), Idaho Power meets contingency reserve requirements by maintaining capacity in reserve equal to 3 percent of load and 3 percent of generation at all times. During the hour in the case shown in Figure 2, if there were no energy imports or exports, the contingency reserve requirement would be 86 MW ([load of 1,429 MW x 0.03] + [generation of 1,429 MW x 0.03] = 86 MW). The portion of the load available to be served by conventional generation is 370 MW. The conventional generation would be required to carry 23 percent of its output as contingency reserve (86 MW/370 MW = 23 percent). Further complicating this operating scenario is the need for regulating reserves (up and down), river-flow minimum constraints, adverse environmental effects of spill, and a lack of positive unit controllability in the operating range required to maintain the balance of load and generation in these conditions.

When overgeneration conditions exist as described above, Idaho Power must export the excess generation through off-system sales or curtail the contributing VER generation if no market exists or transmission constraints prohibit further energy exports.

3.1.4. Issues Not Addressed by the Study

The 2018 WIS focused on impacts and costs associated with errors in 2HA wind production forecasts and the regulating reserves needed to respond to the forecast errors without compromising compliance with the NERC reliability standard. The production cost modeling performed for the study indicates higher production costs as a direct consequence of having to carry the incremental, wind-caused regulating reserves. In this section, Idaho Power identifies other impacts and costs associated with wind integration beyond the relatively narrow focus of the 2018 WIS.

3.1.4.1. Day-Ahead Uncertainty

Idaho Power, similar to other regional BAs, performs day-ahead generation scheduling.[4] In the 2018 WIS, Idaho Power did not include impacts and costs associated with building readiness into day-ahead generation scheduling to cover day-ahead uncertainty in wind production.
Idaho Power recognizes that capacity held in reserve to cover day-ahead uncertainty does not necessarily provide response capability as readily as capacity held in reserve to cover 2HA uncertainty. Nevertheless, the day-ahead forecasting of wind plant production, particularly the timing of ramping events, can be problematic, and substantial and costly intra-day modifications to day-ahead generation scheduling may be necessary.

3.1.4.2. Cycling Costs (Variable Operation and Maintenance Costs)

As noted earlier in this section, the 2018 WIS focused on the higher production costs associated with having to carry incremental regulating reserves to cover errors in 2HA wind production forecasts. The hourly production cost modeling performed for the study simulates the scheduling of the incremental regulating reserves, but the actual intra-hour deployment of these reserves is not simulated. In contrast to contingency reserves, which are deployed only in response to relatively infrequent system disturbances (i.e., contingency events), regulating reserves are frequently deployed. The deployment of regulating reserves leads to a substantial increase in intra-hour cycling of dispatchable hydro and thermal generating units, which is likely to cause an increase in maintenance costs. Idaho Power has not estimated the increased maintenance costs for the 2018 WIS.

[4] Day-ahead scheduling is performed at intervals ranging from one day prior to several days prior for weekends and holidays. For example, day-ahead scheduling for Sunday and Monday of a given week is typically performed on Friday morning of the preceding week.

3.1.4.3. Sub-Hourly Costs of Responding to Variability

The cost of deploying reserves to respond to intra-hour variability is not captured in the integration analysis.

3.1.4.4. Reserve Violation Impacts on Integration Costs

AURORA does not include a cost for reserve violations in the total portfolio cost. Integration costs for intermittent resources are driven by a BA's need to carry incremental operating reserves. Thus, to fully account for integration costs, production cost simulations should reflect the necessary operating reserve requirements. If the production cost simulations are unable to meet operating reserve requirements, as observed for the WIS, the production cost simulations are not fully accounting for integration costs.

3.2. Study Design

Idaho Power designed the 2018 WIS with the objective of isolating the effects of integrating wind generation in the operations modeling. Idaho Power used a common study design to meet this objective, simulating system operations for a test year under the following two scenarios:

- **Load-alone share scenario:** Base scenario for which the system is not burdened with regulating reserves associated with wind and instead only has regulating reserves associated with load's share of the total regulating reserves.[5]

- **Load net wind scenario:** Test scenario for which the system is burdened with regulating reserves associated with the netted load and wind time series.

A critical feature of this design is to hold equivalent model parameters and inputs between the two scenarios, except for the regulating reserves. The incremental regulating reserves built into the load net wind scenario simulations necessarily result in higher production costs for the system, a cost difference that can be attributed to wind integration.

Idaho Power estimated the regulating reserves associated with the current buildout of wind connected to its system, 727 MW of nameplate capacity. The company performed simulations under the above-described two-scenario study design for the current buildout case. Alternative buildouts, larger and smaller than the current buildout, were also simulated, where the regulating reserves for the alternative buildouts were estimated based on determined relationships between wind variability and installed wind nameplate capacity. The analysis to determine the relationships between wind variability and installed capacity are described later in

[5] Diversity benefit when netting load and wind results in a total regulating reserve requirement less than the sum of the separate regulating reserve requirements. Because of the diversity benefit, the total regulating reserve requirement for the netted load and wind time series is found as X% × (load regulating reserve) + X% × (wind regulating reserve), where X is less than 100. The regulating reserves for the load-share alone simulations were the first term only, X% × (load regulating reserve). Both terms of the total regulating reserve formula were used for the load net wind simulations.

this report. The following alternative buildouts were simulated, defined in terms of installed nameplate capacity:

- 300 MW
- 500 MW
- 800 MW
- 900 MW
- 1,000 MW
- 1,100 MW

The test year selected by Idaho Power for the study was 2017. Median hydro conditions for the Snake River Basin and regionally for the Columbia River system were used for the simulations. To investigate the effect of Snake River hydro conditions on the cost of providing regulating reserves, sensitivity analyses were performed using very low (90-percent exceedance) and very high (10-percent exceedance) hydro conditions.

The hourly wind production profile used for the WIS simulations was identical for the two scenarios (load-alone share and load net wind) and was also the same as that used for the regulating reserve analysis described in the following sections. The referenced wind production profile was for the 12-month period from December 2016 through November 2017. To simulate a calendar year (i.e., January through December), wind data for December 2016 were appended to the profile after November 2017.

3.3. Regulating Reserve Calculations and Other Operating Reserves

3.3.1. Area Control Error

In performing the analysis to estimate regulating reserve requirements, Idaho Power analyzed time-synchronous 1-minute time-step data for wind production and BA load from December 2016 through November 2017. The actual wind and BA load data were compared to their respective 2HA forecasts, where the 2HA forecast is a prediction of the hourly average.
The 2HA forecast assumption is predicated on the system's need to have adequate resources available. 2HA has been determined as a reasonable amount of time for system Load Serving Operations to schedule or procure resources in an economic fashion for the study reserve calculations. For both wind and BA load, the 2HA forecast was assumed to transition in a linear fashion over the 20-minute period centered on the top of a given hour. Figure 3 illustrates the 20-minute ramping of 2HA forecast BA load from 2,850 MW for the hour 14:00 to 15:00 to 3,000 MW for the hour 15:00 to 16:00.

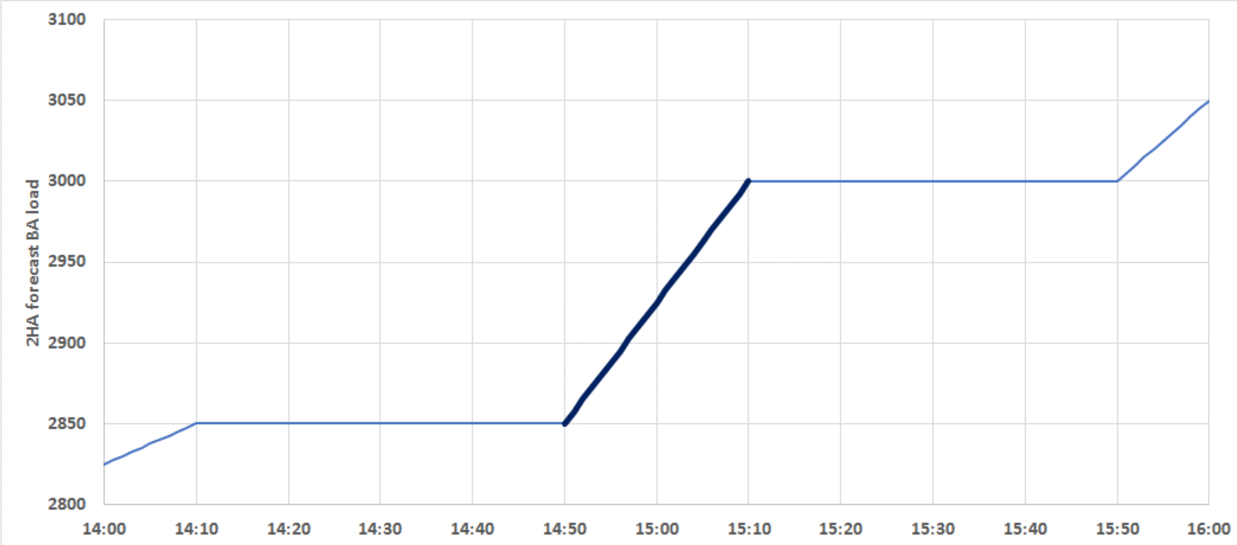

Figure 3
Twenty-minute ramping of 2HA forecast BA load

The area control error (ACE) was then calculated from these data as the difference between an actual 1-minute observation and its corresponding 2HA forecast:

$$ACE = \text{Observed 1-minute observation for load (or wind)} - \text{2HA hourly average forecast for load (or wind)}$$

3.3.2. NERC BAL Standard

The 1-minute ACE data for the 12-month period were analyzed to estimate the amount of bidirectional regulating reserve that would have been necessary to comply with the NERC BAL standard. Under this standard, non-zero ACE can be held for up to 29 consecutive clock minutes, or non-zero ACE can be maintained for 30 consecutive minutes or longer provided ACE is below the BA ACE limit (BAAL). For the study, Idaho Power assumed a BAAL of 0 MW; the implication of this assumption is the analysis assumed ACE needed to be brought to 0 MW for at least 1 minute for every 30-minute interval. In other words, the company's analysis of the historical load and wind data derived the amount of regulating reserve resulting in no occurrences of 30 consecutive clock minutes of non-zero ACE for the 12-month period.

3.3.3. Estimation of RegUp/RegDn for Wind

Idaho Power is using the terms RegUp and RegDn for the bidirectional regulating reserve necessary for balancing wind and load. RegUp is generating capacity that can be ramped up intra-hour to respond to ACE undersupply conditions (load exceeding supply), and RegDn is generating capacity that can be similarly ramped down to respond to ACE oversupply conditions (supply exceeding load).

RegUp and RegDn for wind were expressed as a function of the 2HA wind forecast. Specifically, RegUp was expressed as a percentage of the 2HA forecast:

$$\text{RegUp MW} = \text{RegUp\%} \times \text{2HA wind forecast}$$

RegDn was expressed as a percentage of the total nameplate wind capacity above the 2HA wind forecast:

$$RegDn\ MW = RegDn\% \times (total\ nameplate\ wind\ capacity - 2HA\ wind\ forecast)$$

Idaho Power estimated the amount of RegUp and RegDn for wind by iterative methods. Under this approach, differing values for RegUp% and RegDn% were evaluated for the 12-month historical data period (December 2016 through November 2017) until compliance with the NERC BAL standard was achieved. The determined reserve percentages accounted for the nameplate potential from the 2HA forecast to the bounds of possible generation, from 0 to 727 MW. To capture seasonal effects and effects at different wind levels, the wind data were binned first by season, then by 2HA forecast. Seasons were defined as follows:

- Winter = December, January, February
- Spring = March, April, May
- Summer = June, July, August
- Fall = September, October, November

The binning by 2HA forecast was defined as follows:

- Bin 1 → 2HA wind forecast < 143 MW
- Bin 2 → 143 MW ≤ 2HA wind forecast < 321 MW
- Bin 3 → 321 MW ≤ 2HA wind forecast < 536 MW
- Bin 4 → 2HA wind forecast ≥ 536 MW

The 2HA forecast for RegUp and RegDn regulating reserve requirements for wind are provided in Table 5. The equations for RegUp and RegDn providing the application of RegUp% and RegDn% are provided earlier in this section.

Table 5
RegUp and RegDn percentages for wind reserves based on 2HA wind forecast

	Winter		Spring		Summer		Fall	
Bin	**RegUp%**	**RegDn%**	**RegUp%**	**RegDn%**	**RegUp%**	**RegDn%**	**RegUp%**	**RegDn%**
1	100%	28%	100%	62%	100%	48%	100%	66%
2	86%	51%	94%	79%	93%	75%	80%	65%
3	55%	65%	71%	81%	68%	85%	76%	75%
4	49%	34%	43%	69%	59%	82%	39%	43%

3.3.4. Estimation of RegUp/RegDn for Load

RegUp and RegDn for BA load were both expressed as a percentage of the 2HA forecast for BA load:

$$RegUp = RegUp\% \times 2HA\ BA\ load\ forecast$$

$$RegDn = RegDn\% \times 2HA\ BA\ load\ forecast$$

Similar to wind, Idaho Power estimated the amount of RegUp and RegDn for BA load by trial-and-error methods. Under this approach, differing amounts of RegUp and RegDn were evaluated for the 12-month historical data period (December 2016 through November 2017) until compliance with the NERC BAL standard was achieved. Seasonal binning identical to that used for wind was applied to the BA load data. The BA load data were also binned based on time of day (TOD), where TOD binning for summer differed from non-summer seasons. The different TOD binning for summer reflects the unique shape of summer loads relative to the other seasons. The TOD bins were defined as follows:

Table 6
Winter, spring, fall

Hour Start	Hour End	BA Load Bin
0:00	1:00	1
1:00	2:00	1
2:00	3:00	1
3:00	4:00	1
4:00	5:00	2
5:00	6:00	2
6:00	7:00	2
7:00	8:00	3
8:00	9:00	3
9:00	10:00	3
10:00	11:00	4
11:00	12:00	4
12:00	13:00	4
13:00	14:00	1
14:00	15:00	1
15:00	16:00	1
16:00	17:00	2
17:00	18:00	2
18:00	19:00	3
19:00	20:00	3
20:00	21:00	3
21:00	22:00	3
22:00	23:00	4
23:00	0:00	4

Table 7
Summer

Hour Start	Hour End	BA Load Bin
0:00	1:00	1
1:00	2:00	1
2:00	3:00	2
3:00	4:00	2
4:00	5:00	2
5:00	6:00	2
6:00	7:00	2
7:00	8:00	2
8:00	9:00	3
9:00	10:00	3
10:00	11:00	3
11:00	12:00	3
12:00	13:00	3
13:00	14:00	3
14:00	15:00	4
15:00	16:00	4
16:00	17:00	4
17:00	18:00	4
18:00	19:00	4
19:00	20:00	4
20:00	21:00	4
21:00	22:00	4
22:00	23:00	1
23:00	0:00	1

The derived RegUp and RegDn percentages for BA load are provided in Table 8. The equations for RegUp and RegDn providing the application of the RegUp% and RegDn% are provided earlier in this section.

Table 8
Derived RegUp and RegDn percentages for BA load reserves based on 2HA load forecast

	Winter		Spring		Summer		Fall	
Bin	RegUp%	RegDn%	RegUp%	RegDn%	RegUp%	RegDn%	RegUp%	RegDn%
1	4.9%	9.1%	8.1%	10.5%	7.9%	11.5%	8.0%	10.6%
2	9.3%	6.8%	6.8%	11.3%	8.1%	6.0%	7.5%	8.9%
3	9.5%	5.8%	9.9%	6.7%	9.7%	9.8%	9.9%	8.5%
4	7.9%	6.9%	8.3%	7.0%	6.2%	13.3%	7.3%	7.1%

3.3.5. Estimation of RegUp/RegDn for Load Netted with Wind

When netting load and wind, Idaho Power found compliance with the NERC BAL standard does not require the full arithmetic addition of the respective load and wind regulating reserve levels. Idaho Power proportionally adjusted the respective load and wind regulating reserve levels downward until compliance with the NERC BAL standard was achieved. Idaho Power referred to the adjusted levels as allocation factors. The company found the following seasonal allocation factors:

Table 9
Allocation factors for netted load and wind

	RegUp	RegDn
Winter	86.0%	78.4%
Spring	84.6%	78.3%
Summer	92.6%	70.5%
Fall	81.0%	83.1%

As an example, the company's analysis found that the sum of 86 percent of each of load-associated RegUp and wind-associated RegUp readies the system during the winter to comply with the NERC BAL standard from an undersupply perspective, and 78.4 percent of each respective RegDn similarly readies the system to comply from an oversupply perspective.

3.3.5.1. Diversity Benefit

The allocation factors provided in the previous section are related to the diversity benefit; load and wind are relatively uncorrelated, and consequently the errors in their 2HA forecasts do not always augment each other (i.e., errors for each can be partially offsetting). Past studies have credited this benefit entirely to the wind resource. For this study, Idaho Power is sharing this diversity benefit between the load and wind elements of the load and resource balance. Therefore, for the example described above, Idaho Power's simulation of production costs for a system only needing readiness to respond to load variability and uncertainty carries only 86 percent of the load-associated RegUp and 78.4 percent of the load-associated RegDn. Under this method, load benefits from its diversity with wind, just as wind benefits from its diversity with load.

3.3.5.2. Contingency Reserve

For the production cost simulations, Idaho Power assumed a contingency reserve obligation equal to 6 percent of system load, with at least half of the obligation required to be provided by resources synchronized to the grid (Spin) and the remainder to be provided by resources capable of responding within 10 minutes (NonSpin).This level of contingency reserve approximates relatively well the current NWPP reserve-sharing contingency reserve obligation of 3 percent of load and 3 percent of generation. The level also reflects the need to set aside generating capacity for operating reserve requirements to comply with disturbance control standards and control performance standards. Contingency reserves remained constant for all simulations.

3.3.5.3. Estimation of RegUp/RegDn for Alternative Wind Buildouts

Idaho Power analyzed 10-minute time-step wind production data to estimate the effect of geographic dispersion on wind variability. The objective of this analysis is to characterize the variability associated with alternative wind buildouts having differing geographic dispersion from the current wind buildout of 727 MW of nameplate capacity. To estimate the effect of geographic dispersion on wind variability, the company calculated the standard deviation of progressively larger buildouts:

- Buildout 1: Fossil Gulch—Total nameplate = 10.5 MW
- Buildout 2: Fossil Gulch plus Elkhorn—Total nameplate = 111.2 MW
- Buildout 16: Fossil Gulch plus Elkhorn plus … plus Huntington—Total nameplate = 726.9 MW

Figure 4 is the standard deviation of the 10-minute time-step wind production data for summer 2017 (June–August) of the 16 progressively larger buildouts plotted as a function of the buildout nameplate capacity. The standard deviation increases with increased nameplate capacity; however, the increase in standard deviation is proportionally slightly less than the increase in nameplate capacity. This is likely the product of geographic dispersion occurring as wind capacity is added to a buildout. Based on the analysis of the summer wind production data, Idaho Power estimates that for every 1 percent increase in nameplate capacity there is an approximately 0.93 percent increase in standard deviation.

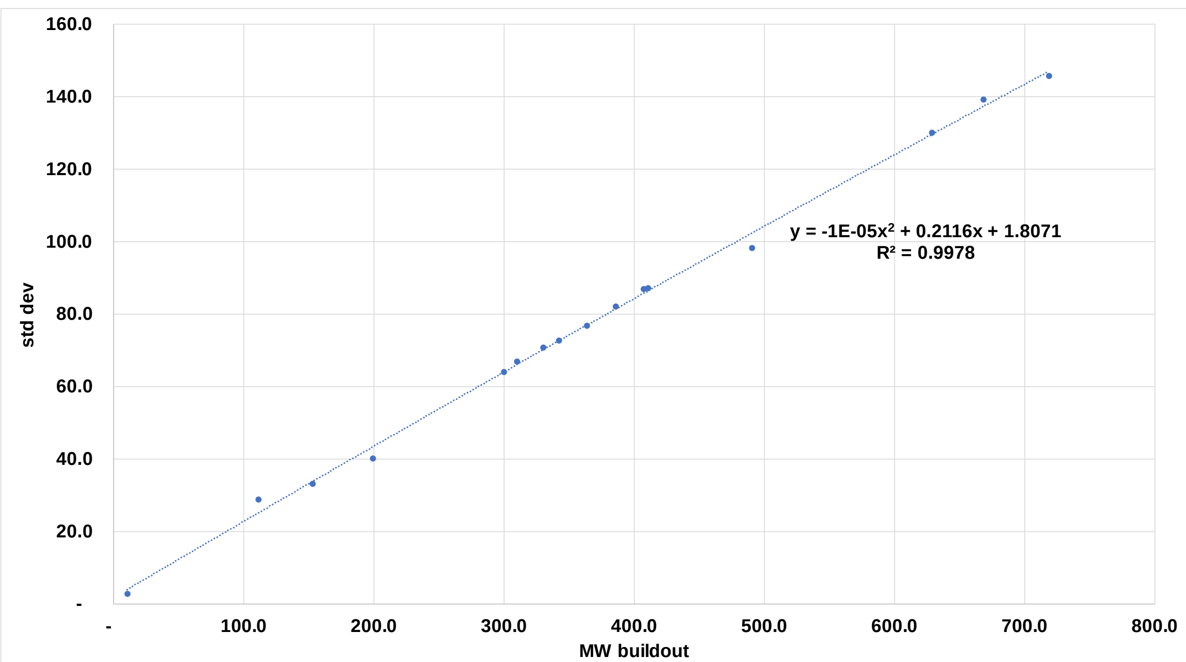

Figure 4
Standard deviation of the 10-minute time-step wind production data for summer 2017

Table 10 provides the increase in standard deviation found to occur with increased nameplate capacity for all seasons.

Table 10
Increase in standard deviation

	% Increase Installed MW	% Increase Standard Deviation (Variability)
Winter	1%	0.99%
Spring	1%	0.92%
Summer	1%	0.93%
Fall	1%	0.94%

Idaho Power used the analysis of standard deviation versus wind buildout to estimate the regulating reserve requirement of alternative buildout futures. Under this approach, an increase in standard deviation is considered to bring about proportionally an equivalent increase in regulating reserve requirements. As an example, expanding the current buildout of 727 MW of wind generation by 10 percent results in a new buildout of 800 MW of nameplate capacity. Based on the standard deviation analysis, Idaho Power estimates the regulating reserve requirements for the new (800 MW) buildout would seasonally increase by the following percentages:

- Winter: 9.9 percent
- Spring: 9.2 percent
- Summer: 9.3 percent
- Fall: 9.4 percent

Idaho Power analyzed alternative buildout futures ranging up as well as down from the current buildout. Lower alternative buildouts at 300 and 500 MW were analyzed primarily to develop a trend of integration costs as a function of buildout. Identifying a trend in changing costs at different wind MW levels is informative to predicting costs at higher levels not studied.
The following alternative buildout futures were analyzed (defined in terms of nameplate capacity and percent lesser or greater than the current buildout):

- 300 MW (59 percent decrease from the current buildout)
- 500 MW (31 percent decrease from the current buildout)
- 727 MW (current buildout)
- 800 MW (10 percent increase from the current buildout)
- 900 MW (24 percent increase from the current buildout)
- 1,000 MW (38 percent increase from the current buildout)
- 1,100 MW (51 percent increase from the current buildout)

While the short-term variability of the aggregate time series, as evaluated by the standard deviation statistic, decreases with expanded buildout and associated increased geographic dispersion, the longer-term average energy production is assumed to simply scale with expanded buildout. For example, the 800-MW buildout, which constitutes an expansion of 10 percent from the current buildout, was modeled as also having 10 percent more energy production.

3.4. System Modeling

The company used the AURORA model to perform the operational analysis and determine the reserve component of the integration costs for the wind integration study. AURORA determines the total portfolio cost for Idaho Power's system using Idaho Power's system resources and market purchases and sales. The AURORA model is the same model the company uses for its integrated resource plan (IRP), PURPA pricing, regulatory filings, and other types of operational modeling and analyses.

The AURORA setup for the 2018 WIS includes the assumptions from the 2017 IRP updated to include the actual load, wind, and solar production observed during the study period. AURORA also incorporates the operational and contingency reserves in the form of hourly inputs for RegUp, RegDn, Spin, and NonSpin. A total generating resource nameplate capacity of 1,365 MW was designated to provide reserves for RegUp, RegDn, and Spin, and an additional 444 MW of capacity were designated to provide reserves for NonSpin. The total 1,809 MW of reserve carrying capacity included hydro, coal, and natural gas generation.

3.5. Modeling Results

3.5.1. Cost Results for Simulation at Current Wind Buildout

To estimate the costs of integrating wind, the company used a comparison of annual production costs between two scenarios having different regulating reserves requirements, where the difference in regulating reserves is related to wind's variability and uncertainty. The production cost difference between scenarios was divided by the annual MWh of wind generation to yield an estimated integration cost expressed per MWh of wind generation. The integration cost calculation is summarized as follows:

- **Load-alone share scenario:** Base scenario for which the system is not burdened with regulating reserves associated with wind and instead only has regulating reserves associated with load's share of the total regulating reserves.

- **Load net wind scenario:** Test scenario for which the system is burdened with regulating reserves associated with the netted load and wind time series.

The wind integration cost is the cost difference of the two scenarios divided by the MWh of wind generation, where the quantity and shape of wind generation was the same in both scenarios:

Wind integration cost = (Load net wind scenario production cost – Load-share alone scenario production cost) ÷ Wind generation in MWh

The estimated integration costs for the current wind buildout are provided in Table 11.

Table 11
Estimated integration costs for the current wind buildout

AURORA 727 MW simulation	Production costs
Load-share alone simulation	$428,220,656
Load net wind simulation	$436,434,800
Incremental cost	$8,214,144
Wind MWh	1,815,626
Cost per wind MWh	$4.52

3.5.2. Simulated Dispatch of Reserve-Providing Resources

The differing production costs between the paired simulations (load-alone share and load net wind) are a consequence of the differing dispatch of resources designated as capable of providing regulating reserves. For the load net wind simulations, the reserve-providing resources are dispatched less optimally to ready those resources to respond to the greater variability and uncertainty of the load net wind time series. Figures 5 through 10 illustrate AURORA's simulated operation of reserve-providing resources under the two scenarios.

Figures 5 and 6 illustrate the total hourly generation for the reserve-providing resources for the two scenarios. These graphs illustrate that for the load-alone share simulation, Bridger is dispatched during most of the year, except April, May, June, and October. In contrast, the load net wind simulation dispatches Bridger in all months throughout the year.

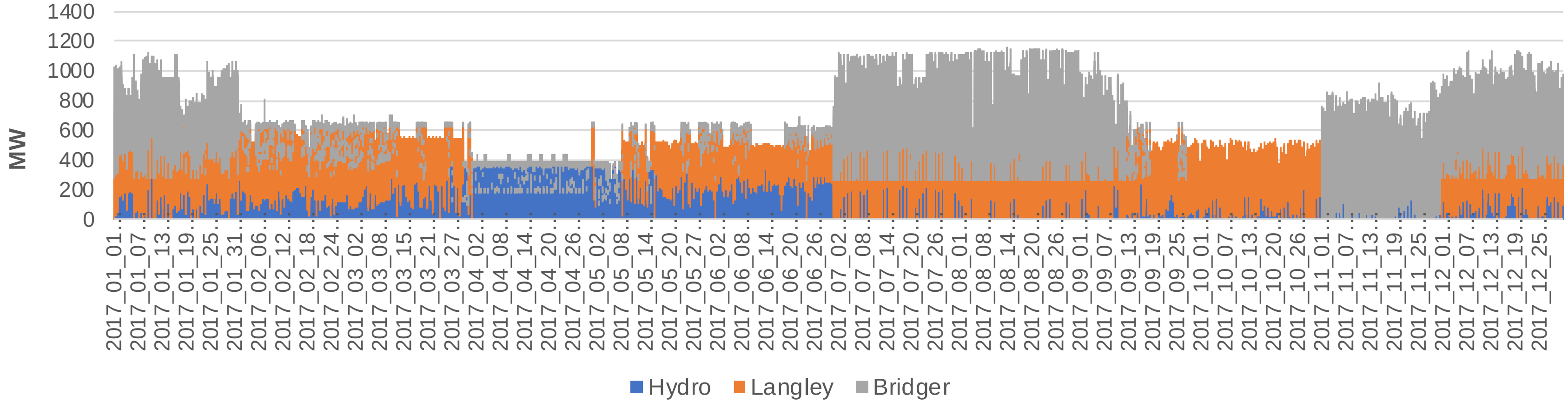

Figure 5
Load alone—generation from units providing reserves

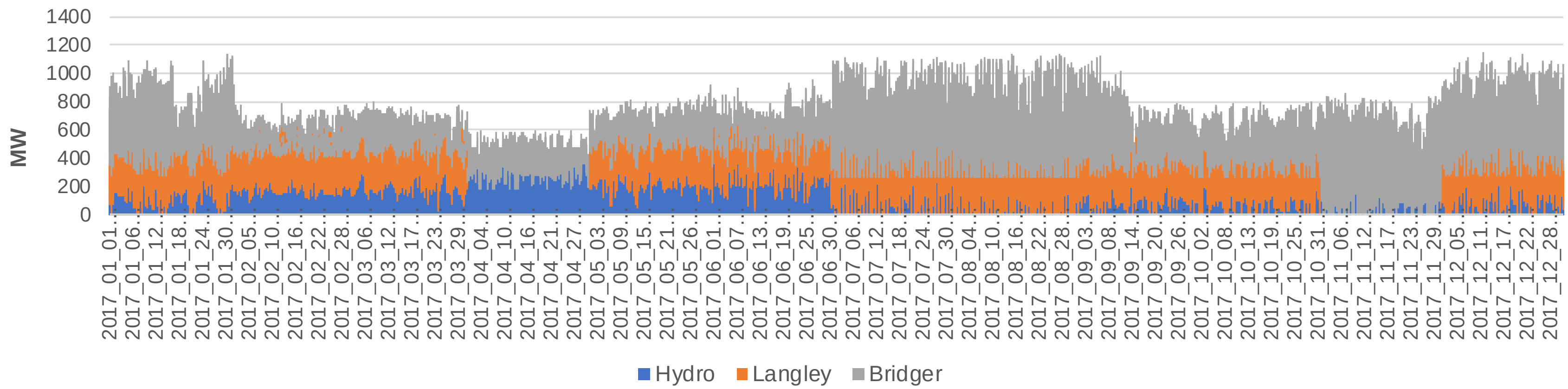

Figure 6
Load net wind—generation from units providing reserves

Figures 5 and 6 represent the generation output from the resources used in integrating the load with 727 MW of wind.

Table 12 summarizes the total output by fuel type from the various dispatchable units used in maintaining the regulating reserves.

Table 12
Total output by fuel type

(000) MWh	Load	Load Net Wind	Difference
Hydro	1,774	1,774	–
Gas	1,824	1,938	114
Coal	1,808	2,497	689
Total	5,406	6,209	803

The 1.815 million MWh of wind required an additional 803,000 MWh of thermal generation to integrate it. At the 727-MW level of nameplate wind for each 2.26 MWh of wind, an additional 1 MWh of thermal generation is required to integrate it. The additional thermal generation required to integrate the wind may have implications for any carbon taxes or carbon caps on wind generation integration costs. Additional costs for carbon to integrate the wind generation are not included in this study.

Figures 7 through 10 illustrate how the additional dispatch of resources shown in the preceding graphs is used for providing regulation reserves.

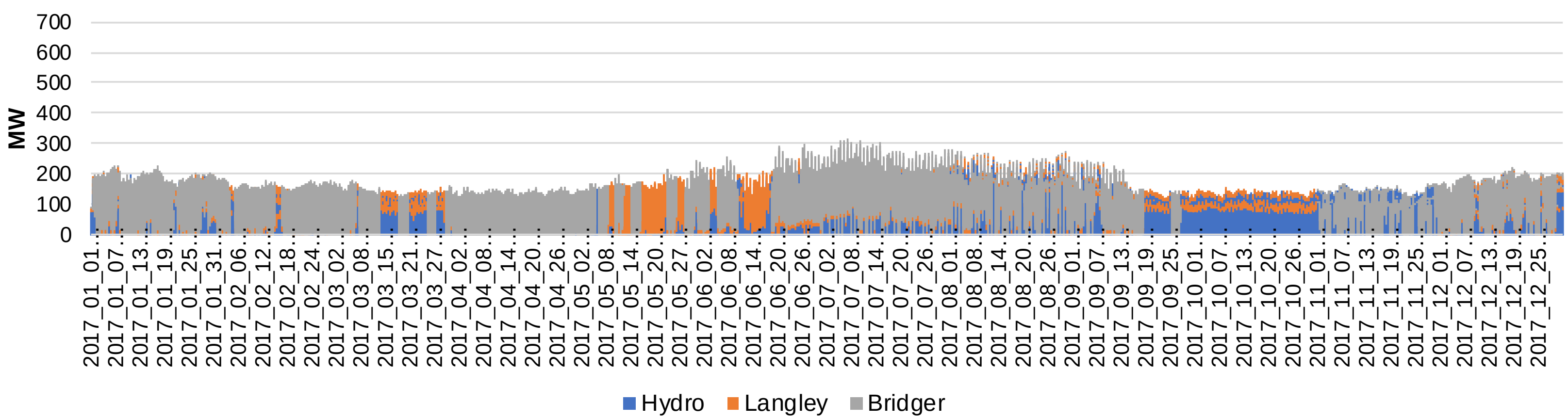

Figure 7
Load alone—RegUp

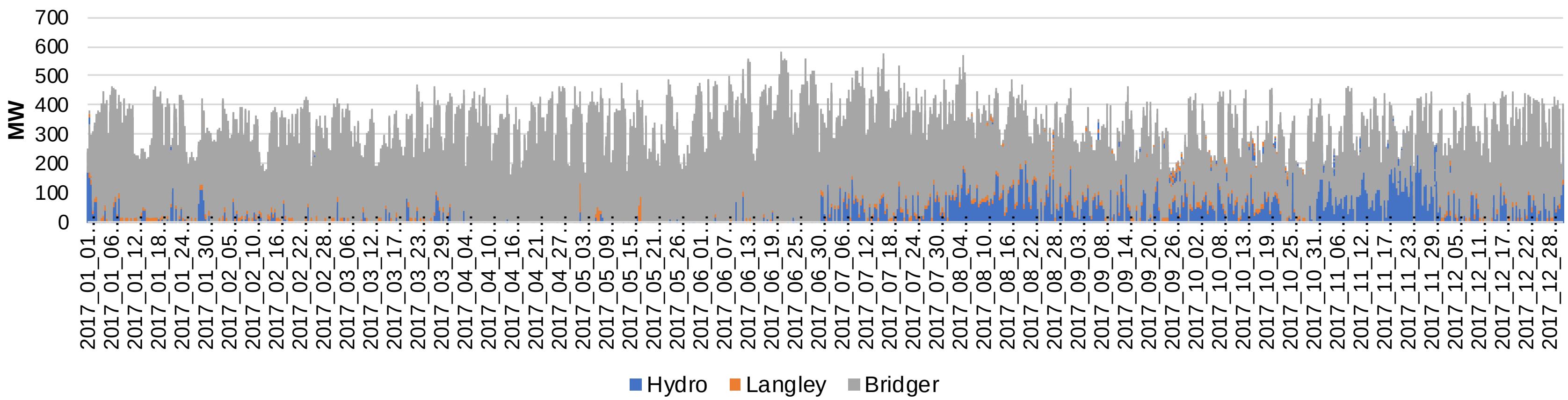

Figure 8
Load net wind—RegUp

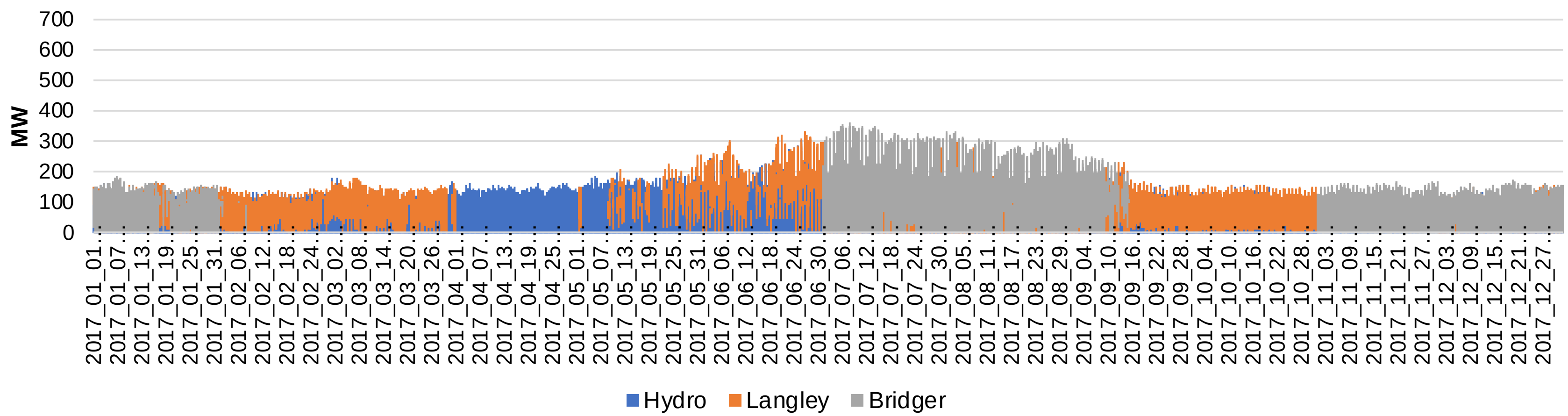

Figure 9
Load alone—RegDn

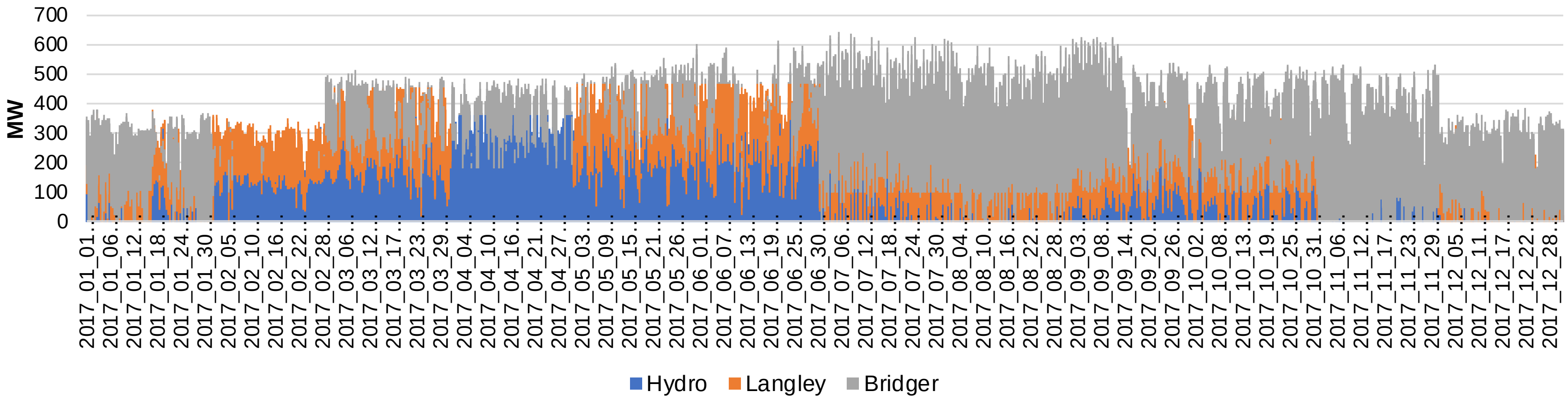

Figure 10
Load net wind—RegDn

3.5.3. *Cost Results for Simulations at Alternative Wind Buildouts*

Table 13 provides the estimated integration costs for the alternative wind buildouts.

Table 13
Estimated production costs for alternative wind buildouts

	0–300 MW	0–500 MW	0–727 MW	0–800 MW	0–900 MW	0–1,000 MW	0–1,100 MW
Load-share alone simulation	$381,999,250	$403,494,469	$428,220,656	$436,377,063	$447,578,031	$458,519,656	$470,210,344
Load net wind simulation	$383,805,750	$407,147,125	$436,434,800	$446,103,000	$459,982,844	$473,256,900	$484,234,600
Integration cost	$1,806,500	$3,652,656	$8,214,144	$9,725,937	$12,404,813	$14,737,244	$14,024,256
Wind MWh	789,017	1,269,998	1,815,626	1,991,358	2,231,841	2,472,311	2,712,808
Average cost per wind MWh	$2.29	$2.88	$4.52	$4.88	$5.56	$5.96	$5.17

The estimated production costs for the additional wind MWh included from the changing buildout size were determined by using the same methodology used to determine average PURPA costs. These costs are equivalent for each of the paired simulations at each wind buildout.

Results for the wind buildouts toward the upper end of the studied range should be qualified as likely underestimating the costs to integrate. As noted in the Regulating Reserve Violations section later in this report, the AURORA production cost simulations for the expanded wind buildouts identified occurrences in which the system modeling was unable to satisfy regulating reserve requirements for load net wind scenarios. Consequently, the production costs for these scenarios are not indicative of the full (and necessary) costs associated with regulating reserves; AURORA does not assess a penalty or cost associated with the occurrence of unmet regulating reserve constraints. As noted later, these occurrences may reflect the inability of the current system of dispatchable resources to allow the integration of expanded wind buildouts without compromising reliability. The decrease in integration costs reported in Table 13 for the 1,100-MW wind buildout relative to the 1,000-MW buildout is considered a manifestation of the above-described inability of the model to satisfy the regulating reserve requirements in production cost simulations and the consequential underestimation of production costs.

3.5.4. Incremental Integration Costs

The integration costs provided in Table 13 for the seven analyzed buildouts are the estimated per-MWh costs to integrate the total wind production for each of the seven buildouts. However, the cost results can also be expressed on an incremental basis. The expression of integration costs on an incremental cost basis is consistent with the principle of associating costs with the causes of those costs. For example, the cost results can be used to estimate the incremental per-MWh cost ($8.60/MWh) associated with expanding from the current 727-MW buildout to an 800-MW buildout. This calculation is summarized in Table 14.

Table 14
Incremental integration cost for 727 MW to 800 MW of nameplate wind

Wind Buildout (MW)	Annual Wind MWh	Integration Cost ($/MWh)	Total Annual Integration Cost	Incremental Cost	Incremental MWh	Incremental Cost ($/MWh)
727	1,815,626	$4.52	$8,214,144	–	–	–
800	1,991,358	$4.88	$9,725,937	$1,511,793	175,732	$8.60

The calculated incremental integration costs for the remaining incremental buildouts and the modeling reserve violations summary statistics are provided in Table 15.

Table 15
Summary integration costs and incremental integration costs per MWh with reserve violations

Wind Nameplate (MW)	Annual Wind (MWh)	Integration Charge ($/MWh)	Total Annual Integration Cost	Incremental Cost	Incremental Wind MWh	Incremental Cost per MWh	Count of Violations Hours	Total MWh of Violations	Max MW of Violations
0–300	789,017	$2.29	$1,806,500	–	0	$0	3	24	21
301–500	1,269,998	$2.88	$3,652,656	$1,846,156	480,981	$3.84	8	65	26
501–726	1,815,626	$4.52	$8,214,144	$4,561,488	545,628	$8.36	75	997	44
727–800	1,991,358	$4.88	$9,725,937	$1,511,793	175,732	$8.60	224	4,508	90
801–900	2,231,841	$5.56	$12,404,813	$2,678,876	240,483	$11.14	777	29,830	152
901–1,000	2,472,311	$5.96	$14,737,244	$2,332,431	240,470	$9.70	1,423	86,461	214
1,001–1,100	2,712,808	$5.17	$14,024,256	$(712,988)	240,497	$(2.96)	2,426	182,924	260

3.5.5. Hydro Condition Sensitivity Analysis

To investigate the effect of Snake River hydro conditions on the cost of providing regulating reserves, sensitivity analyses were performed using very high (10-percent exceedance) and very low (90-percent exceedance) hydro conditions. The hydro condition sensitivity analysis was performed using regulating reserves based on the current wind buildout (727 MW). As noted earlier, the average integration cost found under a median (50-percent exceedance) hydro condition is $4.52/MWh. The results of the hydro condition sensitivity analysis are provided in Table 16.

Table 16
Hydro condition sensitivity analysis results

AURORA 727-MW simulation	10% Exceedance Production Costs	90% Exceedance Production Costs
Load-share alone simulation	$380,270,400	$480,144,781
Load net wind simulation	$388,658,531	$489,051,600
Incremental cost	$8,388,131	$8,906,819
Wind MWh	1,815,626	1,815,626
Cost per wind MWh	$4.62	$4.91

The results of the hydro condition sensitivity analysis do not differ substantially from the median case result, suggesting basing integration costs on simulations using the median hydro condition is appropriate.

3.5.6. Regulating Reserve Violations

AURORA identifies periods when the model was unable to satisfy the imposed regulating reserve requirements, and to a lesser extent the contingency reserve requirements. Idaho Power designates these occurrences in which AURORA's modeling of the system indicates potential reliability issues as reserve violations. Table 17 shows the number of regulating reserve (RegUp and RegDn) and contingency reserve (Spin and NonSpin) violations occurring under the different wind buildout simulations. Simulations having regulating reserve for load-share alone had no reserve violations; violations only started to occur when reserves were added for wind. Under the current wind nameplate of 727 MW, there were 23 RegUp, 52 RegDn, and 1 NonSpin violations, which means 0.9 percent of the time the model cannot meet the reserve requirements. As more wind capacity is added, the violations increase substantially. AURORA's failure to maintain reserves at increasing levels of wind is a strong indication additional wind may not be accommodated without significant changes to Idaho Power's system load and resources, or changes to increase the control of wind during periods of low regulating reserves.

Table 17
Number of reserve violations, load net wind scenario

Nameplate (MW)	Regulation Up (RegUp)	Regulation Down (RegDn)	Spin	NonSpin	Total Reserve Violations	Percent of Hours
300	2	1	–	–	3	<0.1%
500	1	7	–	6	14	0.2%
727	23	52	–	1	76	0.9%
800	91	133	–	8	232	2.6%
900	255	522	–	22	799	9.1%
1,000	435	988	–	11	1,434	16.4%
1,100	690	1,736	–	8	2,434	27.8%

Table 18 shows the total MWh of deficiencies that occurred during the simulations.

Table 18
Total MWh of violations, load net wind scenario

Nameplate (MW)	RegUp	RegDn	Spin	NonSpin
300	3	21	0	0
500	4	61	0	69
727	297	700	0	24
800	2,325	2,183	0	103
900	11,075	18,755	0	264
1,000	28,323	58,138	0	117
1,100	60,102	122,822	0	56

Table 19 shows the largest MW violation that occurred during the simulations.

Table 19
Max MW of violations, load net wind scenario

Nameplate (MW)	RegUp	RegDn	Spin	NonSpin
300	2	21	0	0
500	4	26	0	15
727	44	36	0	22
800	90	54	0	17
900	152	117	0	21
1,000	214	179	0	15
1,100	260	242	0	17

4. Energy Imbalance Market and VER Integration

The western EIM, in which Idaho Power began participating in April 2018, requires each participant to be load-and-generation balanced going into each hour and to have sufficient operational flexibility to respond to forecast errors and load and resource variability. Participating in the EIM helps reduce the costs of responding to within-hour variability by including a greater number of resource alternatives than would otherwise be available to respond to errors and variability. The EIM is not designed to change the system reserve requirements and flexibility needs associated with maintaining the system to comply with the NERC BAL standard. The EIM improves Idaho Power's access to more cost-effective resources for responding to within-hour forecast errors and variability.

Idaho Power's short experience with participating in the EIM has resulted in a couple of observations. First, the NERC BAL standard allows for 29 minutes of system imbalance, but the EIM wants the system balanced every 15 minutes. Consequently, the EIM has required more frequent resource moves, either by Idaho Power resources or by other EIM participant resources balancing the Idaho Power schedule. The frequent sub-hourly balancing has periodically exposed Idaho Power to very high locational marginal pricing (LMP). The EIM LMP is capped at $1,000 per MWh, which Idaho Power has experienced. Part of the reason for the high LMP exposure is Idaho Power's system is frequently off forecast due to the high penetration levels of VERs with large forecast errors.

Another EIM observation is in the amount of flexible operating reserves Idaho Power is required to maintain. Since becoming a part of the western EIM, the company has experienced an increase in the quantity of flexible operating resources required by the EIM to pass the EIM flexibility tests compared to the operating reserves Idaho Power maintained prior to joining the EIM.

The 2018 WIS does not include the costs of responding to within-hour variability or error, but rather determines the cost of holding reserves to respond in the event they are needed. Integration costs identified in the 2018 WIS are the increased opportunity costs of maintaining adequate resources to reliably manage system 2HA forecast error and one-minute variability with added variable generation.

The 2018 WIS determines the appropriate amount of flexibility to be held to respond to forecast error and variability to comply with the NERC BAL standard using the December 2016 to November 2017 Idaho Power actual system data. The NERC BAL standard RegUp and RegDn reserves are then modeled in AURORA on a one-hour time step. The AURORA model simulates the system operations and maintains resource availability to respond to the RegUp, RegDn, and contingency reserves on Idaho Power's generating units. AURORA does not simulate the sub-hourly movement of generating units to balance the system to the NERC BAL standard. Although the reserves are determined using one-minute data, the AURORA model is set to run on a one-hour time step. Consequently, costs of moving the units to respond to the within-hour errors and variability are not captured in the AURORA modeling for the 2018 WIS.

As Idaho Power continues to gain experience participating in the EIM, the company will be better able to assess the resulting impact on VER integration costs.

5. Unified Wind and Solar Integration Costs

Previously, Idaho Power evaluated wind and solar integration costs in separate studies because wind and solar have significantly different generating characteristics and therefore different integration requirements and costs. Idaho Power has completed three wind integration studies and two solar integration studies. The OPUC directed Idaho Power to consider a unified look at the wind and solar integration costs. To accomplish a unified look, two analyses were completed to evaluate wind and solar reserve characteristics and costs.

The addition of 289 MW of solar in 2017 has given Idaho Power a unique opportunity to evaluate the differing generation and variability characteristics of wind and solar using actual data from its system. The solar data evaluated consists of the actual solar data from May 2017 to April 2018, which corresponds to the period when total solar equaled 289 MW for the entire study period. The wind was evaluated during the same 12-month period.

The first evaluation was designed to compare equal quantities of nameplate wind and solar. The output data for 289 MW of solar were used, and the output from a set of 14 wind projects that equaled 289 MW of nameplate wind were used.

The load, wind, and solar data were analyzed to investigate the effect of wind and solar on ramping requirements. The 10-minute changes[6] for the following time series were investigated:

- Load alone
- Wind
- Solar
- Load net wind and solar

The standard deviation for each time series was calculated. For each month, the standard deviation of the load net wind and solar time series exceeded that of the load alone time series; this result is an indication of the broader distribution of the 10-minute changes for the load net wind and solar time series and reflects the increased ramping requirements brought about by wind and solar. The monthly standard deviations for the two time series are provided in Table 20.

Table 20
Monthly standard deviation of 10-minute changes, load alone time series, and load net wind and solar time series

Month	Load Alone Std Dev	Load Net Wind and Solar Std Dev	Percent Increase Over Load Alone
JAN	15	19	28%
FEB	15	21	39%
MAR	14	21	57%
APR	15	23	48%

[6] For each quantity, the 10-minute change is defined as the difference between an observed value at time *t* and the preceding observed value at time *t – 10 minutes*.

Month	Load Alone Std Dev	Load Net Wind and Solar Std Dev	Percent Increase Over Load Alone
MAY	13	19	42%
JUN	16	20	29%
JUL	21	23	9%
AUG	19	21	12%
SEP	15	19	26%
OCT	14	19	39%
NOV	15	19	32%
DEC	15	18	15%

Figure 11 provides histograms of the 10-minute changes for the two time series for March 2018. The histograms illustrate the broader distribution of the changes for the load net wind and solar time series.

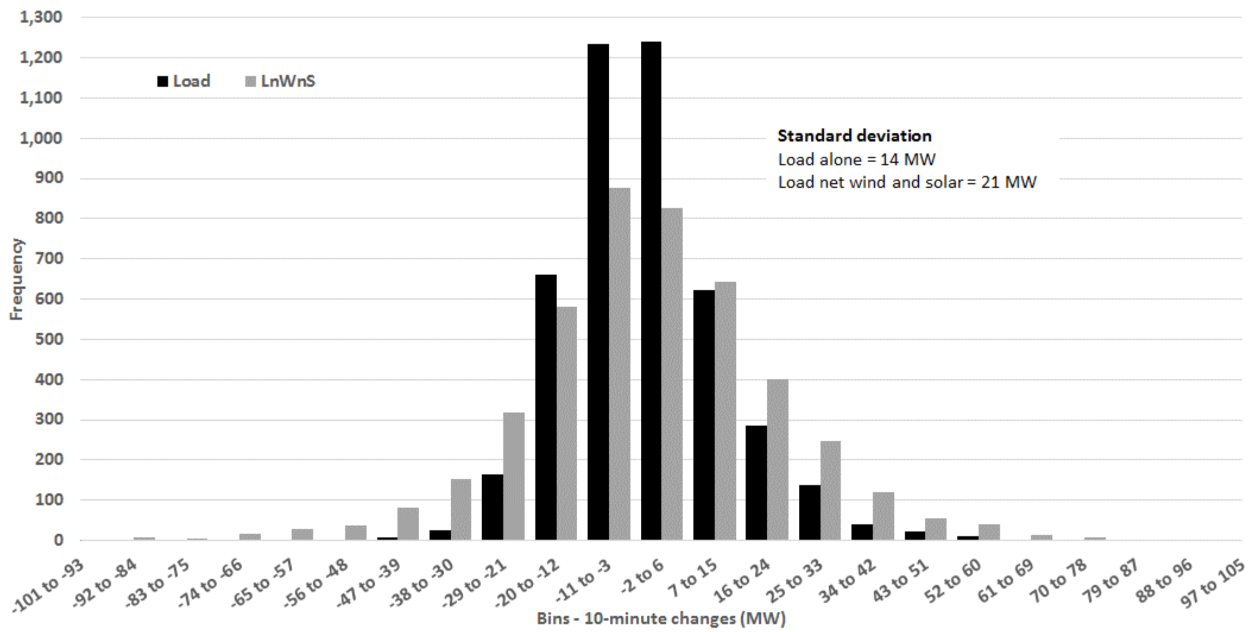

Figure 11
Histograms of 10-minute changes for March 2018, load alone time series and load net wind and solar time series

Idaho Power then used incremental standard deviation (ISD) methods to calculate the respective contributions of load, wind, and solar to the standard deviation of the load net wind and solar time series.[7,8] ISD methods are useful in determining the component drivers from a signal that is

[7] Bermejo, J., and L. Kirby. August 24, 2016. PowerPoint presentation, *Incremental Standard Deviation Methodology.* BPA. bpa.gov/Finance/RateCases/BP-18/bp18/Gen%20Input%20Workshop%2024%20August%202016%20Final.pdf.

[8] BPA. July 2011. 2012 BPA final rate proposal, *Generation Inputs Study*, BP-12-FS-BPA-05. bpa.gov/Finance/RateCases/InactiveRateCases/BP12/Final%20Proposal/BP-12-FS-BPA-05.pdf.

the sum of several signals. For this application, the 10-minute change in load net wind and solar time series is the summed signal, and the component signals are the respective 10-minute changes in load, wind, and solar. The following equation describes this application:

10-minute Δ load net wind and solar = 10-minute Δ load + 10-minute Δ wind + 10-minute Δ solar

Figure 12 provides for each month the calculated respective contributions of load, wind, and solar to the standard deviations of the totaled load net wind and solar time series. The line in the graph is the calculated monthly standard deviation of time series of 10-minute changes in load alone.

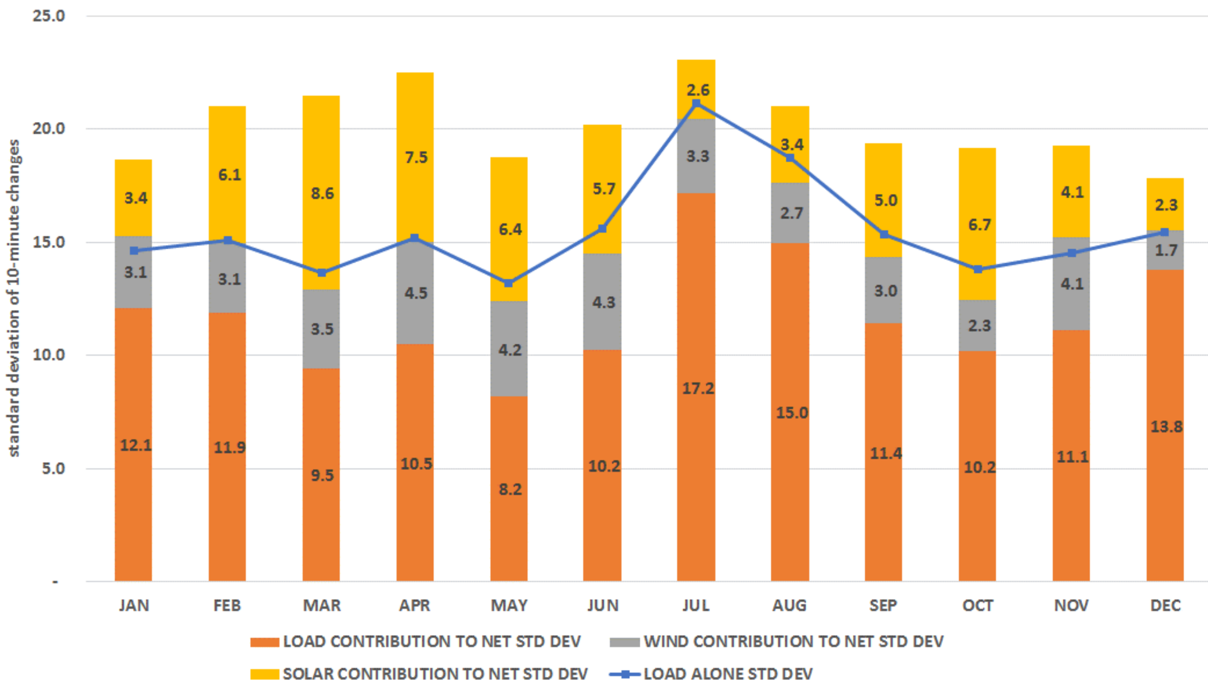

Figure 12
Monthly contributions of load, wind, and solar to the standard deviation of 10-minute time series

Under the ISD approach, the individual contributions equal the standard deviation of the total time series. For example, the standard deviation of the time series of 10-minute changes for load net wind and solar for March 2018 is 21 MW. Figure 12 illustrates for March 2018 contributions of 9 MW for load, 3 MW for wind, and 9 MW for solar; the three contributions sum to 21 MW, which matches the calculated standard deviation of the total time series.

Figure 12 shows that the contribution of solar to the standard deviation equals or exceeds that of wind for all months except July. This result indicates that solar, except during mid-summer, is likely to have greater influence on ramping requirements than wind.

The within-hour variability is a key component to determining reserves, which contributes to integration costs. Solar having a larger impact on a per-MW basis on variability and ramping requirements is an important component in integration and a significant takeaway from the analysis.

The second analysis evaluates the reserves calculated using the 2018 NERC BAL standard, which is the basis for the 2018 WIS. The analysis looked at the current Idaho Power 727 MW of wind, plus the 289 MW of solar output, to construct the reserves and compare them to the reserves constructed for 1,000 MW of wind used in the 2018 WIS. The aim was to evaluate the reserves required for approximately the same amount of total energy for the two VER energy mixes, one with 100% wind energy (1,000 MW of wind) and the second with approximately 74% wind and 26% solar (727 MW of wind + 289 MW of solar = 1,016 MW of wind and solar).

The VER comparison table (Table 21) shows the results for the base wind reserves for 727 MW wind, 1,000 MW of wind, and 727 MW of wind plus 289 MW of solar. The two wind-only reserve scenarios do not include additional reserves for the 640,492 MWh of solar energy provided by the 289 MW of solar included in the generation mix.

Table 21
Integration cost comparison of 727 MW wind, 1,000 MW of wind, and 727 MW wind plus 289 MW solar

	Base Reserves for 727 MW Wind	Base Reserves for 1,000 MW Wind	Base Reserves for Wind & Solar
Wind MWh	1,815,626	2,472,311	1,815,626
Solar MWh (* indicates no additional reserves included)	640,492*	640,492*	640,492
MWh used in determining reserves for VER	1,815,626	2,472,311	2,456,118
Wind MWh%	100%	100%	74%
Solar MWh%			26%
Total 1-year portfolio cost load net VER	$436,435,800	$473,256,900	$439,281,250
Total 1-year portfolio cost load alone	$428,220,656	$458,519,656	$428,191,844
Difference	$8,214,144	$14,737,244	$11,089,406
Integration cost per MWh in $	$4.52	$5.96	$4.52

Base Reserves for 727 MW wind + 289 MW solar	$11,089,406
Base reserves for 727 MW wind	$8,214,144
Difference	$2,875,262
Solar MWh	640,492
$ per solar MWh	$4.49

* No additional reserves included

Table 21 provides information for several observations. First, the total portfolio cost for reserves for 1,000 MW of wind is $14,737,244/2,472,311 MWh = $5.96 per MWh. The reserves integrate 2,472,311 MWh of wind energy. For essentially the same amount of total energy integrated, the total portfolio cost for reserves for a base of 727 MW of wind and 289 MW of solar is $11,089,406/2,456,118 MWh = $4.52 per MWh. The reserves integrate 1,815,626 MWh of wind energy and 640,492 MWh of solar energy, totaling 2,456,118 of VER energy. The portfolio cost for the 1,000 MW of wind-alone reserves resulted in a $3,647,838 higher integration cost

($14,737,244 − $11,089,406 = $3,647,838) compared to the portfolio cost for the combined wind and solar reserves. We attribute this savings in the combined wind and solar portfolio to the diversity benefit of the two resources' characteristics.

Wind is more uncertain, and solar is more variable. The sun rises and sets each day, limiting the number of hours of uncertainty during the day for a solar resource. Wind does not have a predictable schedule and is therefore more uncertain. Solar production is impacted by clouds, and clouds are frequent and impact electrical production quickly. Wind does not tend to turn on and off as quickly as solar. As the atmospheric pressure systems move through an area, the wind will rise and fall with periods of gusty, quick ramps. Although wind generation is variable, solar is more variable than wind.

It should also be observed that the integration portfolio cost to integrate 727 MW of wind generation is $8,214,144, integrating 1,815,626 MWh of wind energy and resulting in a $4.52 integration cost per MWh. However, this is the same integration cost as the $4.52-per MWh to integrate 2,456,118 MWh in the base wind and solar scenario.

The difference in total cost between the two energy mixes (727 MW wind and 727 MW wind plus 289 MW of solar) is $2,875,262. Dividing this amount by the increase of 640,492 MWh of solar energy integrated results in an integration cost nearly equivalent to the $4.52 per MWh for wind, at $4.49 cost per MWh for the incremental cost to integrate solar energy. The results show the cost to integrate solar when paired with wind results in an integration cost very nearly equal to that of integrating wind alone.

The number of violations for the 289 MW of solar with the 727 MW of wind are shown added to the WIS violations shown in Table 22.

Table 22
AURORA reserve violations count by scenario

Nameplate (MW)	RegUp	RegDn	Spin	NonSpin	Total Reserve Violations	Percent of Hours
300	2	1	–	–	3	<0.1%
500	1	7	–	6	14	0.2%
727	23	52	–	1	76	0.9%
800	91	133	–	8	232	2.6%
900	255	522	–	22	799	9.1%
1,000	435	988	–	11	1,434	16.4%
1,100	690	1,736	–	8	2,434	27.8%
727 Wind + 289 Solar	178	483	–	4	665	7.6%

The number of total reserve violations is higher than with the 727 MW wind alone but is lower than the 1,000 MW of wind. The fewer violations of wind and solar compared to the equivalent amount of wind alone is consistent with the lower costs discussed above.

The maximum hourly violations for the 289 MW of solar with the 727 MW of wind are shown in Table 23.

Table 23
AURORA reserve violations maximum MW by scenario

Nameplate (MW)	RegUp	RegDn	Spin	NonSpin
300	2	21	–	–
500	4	26	–	15
727	44	36	–	22
800	90	54	–	17
900	152	117	–	21
1,000	214	179	–	15
1,100	260	242	–	17
727 Wind + 289 Solar	131	199	–	17

6. System Limits and Maximum VER Buildout

Idaho Power recognizes its system has a limit to its capability to integrate VERs. Evidence from this study of wind integration, as well as situations encountered during actual operations, suggest the company is nearing the upper bound of this capability with the current VER buildout. As noted in the section on 2017 Operations Issues, VER curtailment has increased with the addition of 289 MW of solar generation. Curtailments are generally linked to the inability to provide flexible generating capacity for regulating reserve purposes during seasonal periods marked by severe oversupply and regionally depressed wholesale electric market prices. This inability to provide sufficient regulating reserves is evident in practice by the periodic VER curtailments and in model simulations by the increasing frequency of regulating reserve violations at expanded wind buildouts.

The exhausting of the current system's operating reserves has significant implications for the continued growth of reserve-intensive VERs. As the wind study has alluded, the practical limit of the current system is being encountered and is forecasted to increase in frequency with additional VERs. Altering the current system's reserve carrying capacity and providing additional tools to system operators to respond to forecast error and short-term variability may be necessary. Although beyond the scope of this study to evaluate new resources, it is anticipated that future IRPs will include an evaluation of operationally flexible resources, such as batteries and pumped storage, which can give operators flexibility to respond to real-time variability.

As an example, the costs for adding lithium-ion batteries to provide additional system flexibility would add an additional $13.67 per MWh to the current level of wind integration costs. (Using the IPC 2017 IRP resource cost assumptions and the results for the 727 MW of nameplate wind, a 44-MW lithium-ion battery to cover the 44 MW of maximum RegUp violations would result in a levelized annual cost of $24.8 million, which adds $13.67 per MWh to the integration costs for reserve violation mitigation.)

Results of the 2018 WIS indicate that once wind penetration exceeds 900 MW, reserve violations start to ramp up quickly, with violations exceeding 10 percent of all hours. That indicates an incremental increase in wind penetration on the current system is significantly constrained past an additional 173 MW (900 MW – 727 MW of current wind = 173 MW). Based only on the initial evaluation conducted by this study, and because solar generation is also a variable generation resource with similar integration costs as wind, Idaho Power proposes to define VER integration cost tables to a buildout of 173 MW of additional nameplate capacity. The 173 MW of additional VER results in approximately 1,190 MW of total nameplate VER (727 MW wind + 289 MW solar + 173 MW additional VER = approximately 1,190 MW of total VER) on a system with a 3,400 MW peak and average sales of 1,755 MW. Expansion beyond this level carries concerns that significant reliability issues will be encountered associated with the system's inability to provide sufficient regulating reserves. VER development past this level based on Idaho Power's current system configuration and the current state of technology for available resources may not be possible. The company recognizes the energy industry is experiencing a period of profound innovation, and developments such as new market tools (e.g., EIM) or advancements in VER forecasting may enable VER buildouts beyond the 173 MW of incremental VER penetration. However, the company also emphasizes VER capacity cannot realistically be "un-built," and consequently, expansion beyond 173 MW of additional VER nameplate capacity without verifying the ability to integrate such expansion would be imprudent.

7. CONCLUSIONS

Evaluating the combined effects of wind and solar on reserve requirements and costs has been a valuable exercise. The analysis has enhanced Idaho Power's understanding of the challenges and complementary characteristics of combining load, wind, and solar generation. The TRC was instrumental in providing feedback and guidance.

The results of this study and its varied analyses of wind, solar, load, EIM, and reserves indicates a unified VER integration analysis approach may be the best way to assess costs for incremental wind and solar. However, the analysis also indicates Idaho Power's system is nearing a point where the current configuration can no longer integrate additional VERs. Additional investigation is warranted into the combined effect of wind and solar, in a unified VER integration cost analysis, along with the potential effects of participation in the EIM and its unique requirements, attributes, costs, and benefits. The initial analysis as part of this study points toward wind being more uncertain and solar being more variable, particularly within the hour, which may have more identifiable impacts, implications, and/or costs as we move forward with additional experience and history of operating as part of the EIM and its additional/varying intra-hour requirements, timelines, and standards.

Based only on the initial evaluation conducted by this study, the cost of integrating 727 MW of wind is equivalent to integrating 727 MW of wind and 289 MW of solar ($4.52 per MWh). Therefore, the incremental integration charges that could apply to wind and solar per MWh of output associated with incremental nameplate additions could be the same as those for incremental wind (Table 24). Table 24 assigns a potential unified VER integration charge across two additional tiers of incremental VER resources up to the maximum incremental addition of 173 MW, indicated by this study as what the current system configuration can integrate without

unacceptable regulating reserve violations and/or system inability to supply sufficient reserves. However, as described in the 2017 Operational Issues section, the current quantity of variable resources on Idaho Power's system periodically exhausts the operating reserves available.
The modeling results and number of actual wind curtailments during 2017 suggest a strong case could be made that no additional VER resources should be put on the system to avoid periodic reserve deficiencies.

Table 24
Future integration cost recommendation for incremental VER project additions

Wind Nameplate (MW)	Total Combined Wind 727 and Solar 289 Nameplate (MW)	VER Additions Nameplate (MW)	Incremental Cost per MWh
727–800	1,016–1,089	0 73	$8.60
801–900	1,090–1,189	74 173	$11.14

The quantity of additional VERs and the costs described in Table 24 are proposed based on the AURORA modeling under median hydro conditions. It is strongly recommended that future VER contracts include language that allows additional curtailment.

Idaho Power also believes additional VER generation development may have significantly detrimental implications to maintaining adequate reserves.

Idaho Power's short experience with EIM will continue to be evaluated, as its impact to the VER costs identified in this filing is not yet clear.