BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UM _______

In the Matter of	)
IDAHO POWER COMPANY	)
Application for Approval of Solar Integration Charge.	)

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

PHILIP B. DeVOL

August 10, 2016

Q. Please state your name and business address.

A. My name is Philip B. DeVol and my business address is 1221 West Idaho Street, Boise, Idaho 83702.

Q. By whom are you employed and in what capacity?

A. I am employed by Idaho Power Company ("Idaho Power" or "Company") as a Senior Planning Analyst.

Q. Please describe your educational background and work experience with Idaho Power.

A. In May of 1989, I received a Bachelor of Science Degree in Mathematics from Miami University in Oxford, Ohio. I then received a Master of Science Degree in Biostatistics from the University of Michigan in May of 1991.

Q. Please describe your work history at Idaho Power.

A. I began my employment with Idaho Power in 2001 in the Company's Water Management Department, where my responsibilities included modeling of the Idaho Power hydroelectric system for the Integrated Resource Plan ("IRP") and relicensing studies.

I transferred in 2005 to the Power Supply Planning Department at Idaho Power, where I remain employed as a Senior Planning Analyst. My responsibilities in Power Supply Planning have been varied, and have included several studies of renewable integration. My duties have included project management for the most recent (2013) Idaho Power wind integration study, and Idaho Power's first solar integration study completed in 2014.

I have been involved in regional and national proceedings related to the study of wind integration. I participated in methodology discussions for the 2007 Wind Integration Action Plan produced by the Northwest Wind Integration Forum. I have attended numerous Utility Wind Integration Group ("UWIG") workshops, and presented at UWIG workshops in Oklahoma City in 2006, Portland, Oregon, in 2007, and San Antonio, Texas in 2014. I also presented to the Idaho Wind Working Group at its September 2011 meeting. In November of 2013, I presented at a Centre for Energy Advancement through Technological Innovation workshop focused on forecasting uncertainties for renewable energy supply.

I led the Company's 2014 solar integration study, which was Idaho Power's first solar integration study. I also led the Company's 2016 solar integration study, along with Ronald Schellberg, Idaho Power Transmission Policy and Development, who has since retired from the Company.

Q. What is the purpose of your testimony in this matter?

A. The purpose of my testimony is to describe Idaho Power's second solar integration study ("Study" or "2016 Study") and to provide the results. The 2016 Solar Integration Study Report ("Study Report") is attached hereto as Idaho Power/101. The Study Report was completed in April 2016.

Q. Can you provide a high level description or summary of the Company's 2016 Study?

A. Yes. As stated in my prior testimony regarding the 2014 Study, electric power from solar generation resources exhibits greater variability and uncertainty than energy from conventional generation sources. The greater variability and uncertainty exhibited by solar resources requires an electric utility integrating solar to modify its operating practices by holding extra operating reserves on dispatchable generation resources. The effect of having to hold operating reserves on dispatchable resources is that the capacity held in reserve restricts the use of those resources and they cannot be economically dispatched to their fullest capability. The objective of the 2016 Study is to determine the costs of the operational modifications necessary to integrate intermittent generation from solar, where the operational modifications are in the form of differing system reserve requirements.

The Company's 2016 Study determined solar integration costs for four solar build-out scenarios at installed capacities of 400 megawatts ("MW"), 800 MW, 1,200 MW, and 1,600 MW. When the 2016 Study was initiated Idaho Power had more than 460 MW of solar generation under contract to be on-line by the end of 2016, as well as inquiries and requests for contracts that exceeded 1,100 MW. Today the Company has 289.5 MW of solar under contract to be online by the end of 2016, 49.5 MW of which are in Oregon, and solar QF projects requesting contracts for an additional 88.75 MW, 8.75 of which are in Oregon. The 2016 Study utilized geographically dispersed build-out scenarios with solar generation located across the Company's service territory at Parma, Murphy Flats, Boise, Grand View, Orchard, Bliss, Twin Falls, and Aberdeen. Pages 3 through 6 of the 2016 Study Report provide additional information regarding the build-out scenarios.

The 2016 Study determined solar integration costs through paired simulations of Idaho Power's system for each solar build-out scenario. Each pair of simulations consists of a test case in which extra capacity in reserve is required of dispatchable generators to allow them to respond to unplanned changes in solar generation and a base case in which no extra capacity in reserve is required. The solar integration costs indicated by the simulations are provided below. These costs are also found in Table 2, page vi of the 2016 Study Report, as well as Table 9 and Table 10 on pages 21 and 22 of the 2016 Study Report.

Average Integration Cost Per MWh
(2016 cost and dollars)

Build-out Scenarios	**0-400 MW**	**0-800 MW**	**0-1,200 MW**	**0-1,600 MW**
Integration Cost	**$0.27**	**$0.57**	**$0.69**	**$0.85**

Incremental Integration Cost Per MWh
(2016 cost and dollars)

Penetration Level	0-400 MW	400-800 MW	800-1,200 MW	1,200-1,600 MW
Integration Cost	$0.27	$0.88	$0.92	$1.31

Q. When did Idaho Power initiate the 2016 Study?

A. Idaho Power initiated the first communications with parties for the 2016 Study in January 2015, following the execution of the Settlement Stipulation by the parties to Idaho Power's initial 2014 solar integration case before the Idaho Public Utilities Commission ("IPUC"), Case No. IPC-E-14-18. The Settlement Stipulation is included in the 2016 Study Report at page 43. The Settlement Stipulation was executed by the parties on January 7, 2015, and filed with the IPUC for approval on January 9, 2015. On February 11, 2015, the IPUC approved the Settlement Stipulation, which implemented solar integration rates and charges for Idaho Power based upon the Company's 2014 Study.[1] The solar integration rates and charges were set forth in a new tariff Schedule 87, Variable Generation Integration Charges, at the incremental cost of solar integration for each 100 MW of solar nameplate penetration. These same solar integration rates were also included in Idaho Power's acknowledged 2015 Integrated Resource Plan. The Settlement Stipulation also acknowledged that there were disagreements with respect to the methodology used in the 2014 Study, and that Idaho Power would initiate a second solar integration study, to be completed as expeditiously as possible with the goal of not exceeding 12 months.[2] The Settlement Stipulation provides guidance regarding the conduct of the second solar

[1] Case No. IPC-E-14-18, Order No. 33227.

[2] Settlement Stipulation at 3.

integration study and sets forth a list of issues for consideration in that study.[3] The Settlement Stipulation states that the second solar integration study should utilize a Technical Review Committee ("TRC") and anticipated the participation of commission Staff from both the IPUC and the Public Utility Commission of Oregon ("Commission"), the appropriate personnel from Idaho Power, and a technical expert designated by each of the parties to the Settlement Stipulation.[4]

Q. How was the 2016 Study initiated?

A. As was the case for the 2014 Study, the Company initiated the 2016 Study with the formation of a TRC. Subsequent to the Commission's February 11, 2015, approval of the Settlement Stipulation, the TRC was selected and a kick-off phone conference was held on March 6, 2015. The intervening parties from the Settlement Stipulation (Idaho Conservation League, Sierra Club, and Snake River Alliance) requested the participation of Cameron Yourkowski, Renewable Northwest, and Michael Milligan, National Renewable Energy Laboratory ("NREL"), on the TRC. Idaho Power requested the participation of Brian Johnson, University of Idaho; Clint Kalich, Avista Utilities; and Kurt Myers, Idaho National Laboratory. Rick Sterling from the IPUC and Brittany Andrus and John Crider from the Commission participated as observers throughout the 2016 Study process and the TRC activities. During the 2016 Study, Barbara O'Neill became the NREL representative on the TRC. However, NREL funding did not permit its active TRC participation through the entire process, although Idaho Power continued to include NREL on electronic correspondence through study completion. A TRC Study Plan ("Study Plan") was developed and finalized by May 28, 2015, and the 2016 Study was subsequently conducted during

[3] *Id.* at 3-4.

[4] *Id.* at 3.

the remainder of 2015 according to that Study Plan. The Study Plan is found in the Appendix to the 2016 Study Report at page 44.

As stated in the "Acknowledgments" section of the 2016 Study Report, Idaho Power acknowledged the important contribution of the TRC in the development of the 2016 Study. The TRC was involved from the Study outset in February 2015, and provided substantial guidance and helped shape the study methods followed. Prior to finalizing the 2016 Study Report, the TRC was provided with a draft report for its review and comment. The TRC members and regulatory observers served either voluntarily or were paid by their own employers and received no compensation from Idaho Power.

Idaho Power believes that the members of the TRC positively support the 2016 Study and 2016 Study Report.

Q. How was the 2016 Study conducted?

A. The conduct of the 2016 Study was initially agreed to and set forth in the previously referenced TRC Study Plan, included at page 44 of the 2016 Study Report. The parties agreed to generally adhere to the Principles for Technical Review Committee Involvement in Studies of Variable Generation Integration into Electrical Power Systems produced by the NREL and Utility Variable-generation Integration Group (UVIG). The TRC Study Plan sets forth the expectations, functions, and requirements of the TRC; incorporates consideration of the issues set forth in the Settlement Stipulation; prioritizes the consideration of various issues into the Study; set forth the basic Study approach; and set forth a specific schedule for proceeding with the Study.

Q. What was the process followed in the 2016 Study?

A. The 2016 Study was organized into four primary steps: (1) data gathering and scenario development; (2) statistical-based analysis of solar characteristics; (3)

production cost simulation analysis; and (4) study conclusions and results. These steps were formulated based on an article published by the Institute of Electrical and Electronics Engineers ("IEEE") describing methods for studying wind integration.[5] While the IEEE article, which was authored by leading researchers at NREL, was written from the perspective of studying system integration of wind generation, the principles underlying the study of wind integration are readily transferrable to the study of solar integration. Both wind and solar bring increased variability to power system operation, and a key objective of an integration study for each is to understand how variability and uncertainty lead to system impacts and changed costs.

Q. Can you further describe how the 2016 Study progressed to completion?

A. Yes. The first step, data gathering and scenario development, is described on pages 3 through 6 of the 2016 Study Report. As stated in my summary above, the 2016 Study considered four solar build-out scenarios at installed capacities of 400 MW, 800 MW, 1,200 MW, and 1,600 MW. The 2016 Study utilized geographically dispersed build-out scenarios with solar generation located across the Company's service territory at Parma, Murphy Flats, Boise, Grand View, Orchard, Bliss, Twin Falls, and Aberdeen. The build-out scenarios were developed in consultation with the TRC to represent geographically dispersed build-outs of solar power plant capacity as informed by locations of proposed solar power plants in southern Idaho and eastern Oregon. Three years of solar data were developed for each build-out scenario. To acquire five-minute data for each site, data from either established U.S Bureau of Reclamation (USBR) AgriMet Network or modeled data acquired from SolarAnywhere was utilized. This data was used with water year data from water

[5] Ela et al. 2009.

years 2011, 2012, and 2013, which represent a high, medium, and low type of water year, respectively.

The 2016 Study data also incorporated a technique initiated by the TRC in the 2014 Study used to better reflect data conditions at a solar plant size, rather than data from a single point. A wavelet-based variability model (WVM) is utilized for simulating solar photovoltaic power plant output given a single irradiance point-sensor time series.

Q. How was the statistical based analysis of the data conducted?

A. The next phase of the 2016 Study was the statistical-based analysis of solar, wind, and load data. This phase is described on pages 6 through 16 of the 2016 Study Report. The statistical-based analysis focused around two components: (1) the statistical-based analysis to determine the extent to which solar brings additional variability and uncertainty to system balancing and (2) the follow-on analysis to translate the additional variability and uncertainty to additional capacity in reserve required on dispatchable generators.

In considering the impact of variability and uncertainty from the perspective of integration impacts and costs, the focus is primarily on the shorter-term operations. That is, for the system operator responsible for maintaining system balancing, integration impacts arise because of variability and uncertainty over the coming minutes, hours, or perhaps days. Viewed from this perspective, the relevant components of system balancing which bring variability and uncertainty are customer demand (load) and intermittent sources of energy (solar and wind). Because of the relevance of these three components—load, solar, and wind—to the challenges with maintaining shorter-term system balancing, the statistical-based analysis performed for the 2016 Study takes into account variability and uncertainty for the three components, as well as possible interrelationships in variability and uncertainty between the three.

The 2016 Study focused on the assessment of variability and uncertainty occurring from the perspective of hour-ahead forecasting. This assessment for each of load, solar, and wind was based on the extent to which five-minute observations differ from hour-ahead forecasts. These differences, or deviations, between intra-hour observations and hour-ahead forecasts drive the need to carry operating reserves to maintain system balancing. Thus, at a fundamental level, the statistical-based analysis to characterize variability and uncertainty was an analysis of deviations between five-minute observations and hour-ahead forecasts. Further, explanatory variables were identified that explain patterns in the deviations, and these explanatory variables were then used to more precisely define the operating reserve requirements.

A critical part of the statistical assessment was the determination of relationships describing the extent to which intra-hour observations for each of load, solar, and wind deviate from the hour-ahead forecasts. For example, the 2016 Study found that the extent of deviations between intra-hour solar observations and hour-ahead solar forecasts could be described as a function of two explanatory variables: (1) hour-ahead forecast solar production and (2) the period of day.

The individually determined relationships for load, solar, and wind were then added in a manner accounting for the combining effects occurring for the base case simulation of load netted with wind, and the test case simulation of load netted with wind and solar. The derivation of the operating reserve for the base and test case simulations is described on pages 13 through 15 of the 2016 Study Report, and an example reserve application is provided on page 16 of the 2016 Study Report. The accounting of the combining effects in the reserve methodology was discussed in great detail with the TRC, and is a notable change in methodology from the 2014 solar integration study. This change is thought to be a key driver of the comparatively lower solar integration costs in the 2016 Study.

Q. What was the next step in the Study process?

A. The next step was the production cost simulations, which are described on pages 17 through 20 of the 2016 Study Report. As described earlier in my testimony, the Study followed the conventional design of paired simulations, simulating two scenarios: a base case vs. the test case, with the sole difference between paired simulation being the amount of capacity in reserve. The base case capacity in reserve is based on reserve analysis for load netted with wind, and the test case capacity in reserve is based on reserve analysis for load netted with wind and solar. The average reserve amounts for the two cases and the four solar build-out scenarios are provided in Table 6, on page 15 of the 2016 Study Report.

Q. Please describe the conclusions and results of the 2016 Study.

A. The 2016 Study results and findings are discussed beginning on page 20 of the 2016 Study Report. The objective of the Study was to determine the costs of the operational modifications necessary to integrate solar generation. The integration costs are driven by the need to carry extra capacity in reserve to allow bidirectional response from dispatchable generators to unplanned variations in solar production. The simulations performed for the Study indicate the below costs associated with holding the extra solar-caused capacity in reserve.

Average Integration Cost Per MWh
(2016 cost and dollars)

Build-out Scenarios	**0-400 MW**	**0-800 MW**	**0-1,200 MW**	**0-1,600 MW**
Integration Cost	**$0.27**	**$0.57**	**$0.69**	**$0.85**

Incremental Integration Cost Per MWh
(2016 cost and dollars)

Penetration Level	0-400 MW	400-800 MW	800-1,200 MW	1,200-1,600 MW
Integration Cost	$0.27	$0.88	$0.92	$1.31

Michael J. Youngblood provides direct testimony setting forth the Company's request and proposal to update solar integration rates and charges utilizing the incremental cost at each 100 MW of solar generation penetration.

Pages 22 through 26 of the 2016 Study Report discuss the Study findings with regard to hour-ahead solar production forecasting; comparison to wind integration; geographic dispersion and solar variability; transmission and distribution; solar integration cost elements; Hells Canyon Complex spill; and spring-season integration. Without repeating the discussion from these sections, issues and assumptions from these areas significantly impact the Study results, and should actual results diverge from assumptions made, issues should be re-examined.

Additionally, the findings clarify some things that were and were not considered by the Study. In particular, the four studied build-outs have solar capacity dispersed widely across southern Idaho. The extent of this geographic dispersion is considered to strongly influence the impacts and costs of integration. As solar capacity is developed in the coming years, Idaho Power will evaluate the geographic dispersion of the build-out capacity in comparison to that assumed for the 2016 Study. In particular, observed production data will be reviewed when available to verify the Study's assessment of solar variability and uncertainty.

Q. Does this conclude your testimony?

A. Yes, it does.

Idaho Power/101
Witness: Philip B. DeVol

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IDAHO POWER COMPANY

Exhibit Accompanying Direct Testimony of Philip B. DeVol

2016 SOLAR INTEGRATION STUDY REPORT

August 2016

An IDACORP Company

Solar Integration Study Report

April 2016 ©

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EXECUTIVE SUMMARY

The development of solar photovoltaic (PV) resources has received markedly increased attention over recent years. The increased attention given to solar PV is a result of multiple factors:

1. Decline in solar PV module prices
2. Federal energy policy, including tax incentives, favoring carbon-free generation resources
3. Electricity customers interest in self generation
4. Increase in number of *Public Utility Regulatory Policies Act of 1978* (PURPA) solar projects under contract in Idaho Power's service area

Electric power from solar PV resources is widely acknowledged to exhibit greater uncontrolled variability and near-term uncertainty than energy from conventional generators. Because of the greater variability and uncertainty, electric utilities incur increased costs when the existing dispatchable generators are called on to integrate PV solar plant generation. The increased costs occur because power systems are operated less optimally to successfully plan for and react to solar plant generation without compromising the reliable delivery of electrical power to customers. Idaho Power has studied the operational modifications it must make to integrate solar PV power plant generation connecting to its system.

The objective of this solar integration study is to estimate the costs of the operational modifications necessary to integrate the intermittent generation from solar plants, where the operational modifications are in the form of differing system reserve requirements. This study determines these costs for four solar build-out scenarios provided in Table 1.

Table 1
Solar build-out scenarios studied

		Installed Capacity of Solar Build-Out Scenarios			
Site	**Data Source**	**400 megawatts (MW)**	**800 MW**	**1,200 MW**	**1,600 MW**
Parma, ID	USBR AgriMet	50	100	150	200
Murphy Flats, ID	SolarAnywhere	25	50	75	100
Boise, ID	USBR AgriMet	25	50	75	100
Grand View, ID	SolarAnywhere	75	150	225	300
Orchard, ID	SolarAnywhere	100	200	300	400
Bliss, ID	SolarAnywhere	25	50	75	100
Twin Falls, ID	USBR AgriMet	50	100	150	200
Aberdeen, ID	USBR AgriMet	50	100	150	200
Total MW		**400**	**800**	**1,200**	**1,600**

The study determines solar integration costs through paired simulations of the Idaho Power system for each solar build-out scenario. Each pair of simulations consists of a test case in which extra capacity in reserve is required of dispatchable generators to allow them to respond to unplanned changes in solar generation and a base case in which no extra capacity in reserve is required. The solar integration costs indicated by the simulations are provided in Table 2.

Table 2
Average integration cost per megawatt-hour (MWh) for solar build-out scenarios

	0–400 MW	0–800 MW	0–1,200 MW	0–1,600 MW
Integration cost (2016$)	$0.27/MWh	$0.57/MWh	$0.69/MWh	$0.85/MWh

ACKNOWLEDGMENTS

Idaho Power acknowledges the important contribution of the Technical Review Committee (TRC) in this solar integration study. The TRC has been involved from the study outset in February 2015 and has provided substantial guidance. Idaho Power especially thanks the TRC for the collegial discussions of solar integration during TRC meetings. These discussions helped shape the study methods followed and are consistent with the TRC guidelines as provided by the Utility Variable-Generation Integration Group (UVIG) and the National Renewable Energy Laboratory (NREL) (UVIG and NREL n.d.). The following are members of the Idaho Power solar integration study TRC:

- Brian Johnson, University of Idaho
- Cameron Yourkowski, Renewable Northwest
- Clint Kalich, Avista Utilities
- Kurt Myers, Idaho National Laboratory
- Barbara O’Neill, NREL
- Michael Milligan, NREL

Above representatives from NREL participated in the early stages of the study, and contributed to the study’s foundational development. However, NREL funding did not permit their active participation through study completion. Idaho Power continued to include NREL on electronic correspondence related to the study through study completion.

Staff from the Idaho and Oregon regulatory commissions have participated as observers throughout the process. The following staff have been observers of the process:

- Brittany Andrus, Public Utility Commission of Oregon (OPUC) staff
- John Crider, OPUC staff
- Rick Sterling, Idaho Public Utilities Commission (IPUC) staff

TRC members and regulatory observers serve either voluntarily or are paid by their own employers and receive no compensation from Idaho Power. The company is grateful for the TRC's time spent supporting the study and recognizes this support has led to a better study.

INTRODUCTION

The development of solar photovoltaic (PV) resources has received markedly increased attention over recent years. The increased attention given to solar PV is a result of multiple factors:

1. Decline in solar PV module prices
2. Federal energy policy, including tax incentives, favoring carbon-free generation resources
3. Electricity customers interest in self generation
4. Increase in number of *Public Utility Regulatory Policies Act of 1978* (PURPA) solar projects under contract in Idaho Power's service area

Idaho Power currently has 320 megawatts (MW) of utility-scale solar PV from PURPA contracts scheduled to be on-line by year-end 2016. Idaho Power also currently has about 5 MW of solar PV systems interconnected through the company's net metering service. However, while the prevalence of rooftop solar PV systems is growing, the far greater magnitude of potential capacity from utility-scale solar PV necessitates this study's focus on the integration of utility-scale solar PV alone. This solar integration study did not analyze rooftop solar and potential integration impacts on Idaho Power's distribution system.

Electric power from solar PV resources is widely acknowledged to exhibit greater uncontrolled variability and near-term uncertainty than energy from conventional generators. Because of the greater variability and uncertainty, electric utilities incur increased costs when the existing dispatchable generators are called on to integrate PV solar plant generation. The increased costs occur because power systems are operated less optimally to successfully plan for and react to solar plant generation without compromising the reliable delivery of electrical power to customers. Idaho Power has studied the operational modifications it must make to integrate solar PV power plant generation connecting to its system. The objective of this solar integration study is to estimate the costs of the operational modifications necessary to integrate the intermittent generation from solar plants, where the operational modifications are in the form of differing system reserve requirements. This report is intended to describe the operational modifications and the resulting costs.

Idaho Power organized the study into four primary steps:

1. Data gathering and scenario development
2. Statistical-based analysis of solar characteristics
3. Production cost simulation analysis
4. Study conclusions and results

These steps were formulated based on an article published by the Institute of Electrical and Electronics Engineers (IEEE) describing methods for studying wind integration (Ela et al. 2009). While the IEEE article, which was authored by leading researchers at NREL, was written from the perspective of studying system integration of wind generation, the principles underlying the study of wind integration are readily transferrable to the study of solar integration. Both wind and solar bring increased variability and uncertainty to power system operation, and a key objective of an integration study for each is to understand how variability and uncertainty lead to system impacts and changed costs.

Geographic Dispersion

It is recognized that the variability and uncertainty from solar PV resources, just like wind resources, are less severe where the installed capacity is geographically dispersed as compared to clustered. Analysis conducted for this study supports this principle. The solar futures, or build-outs, considered for this study are widely dispersed; solar PV capacity is spread east to west along the Snake River Plain from Aberdeen, Idaho to Parma, Idaho (Figure 2). The effect of dispersion is exemplified in Figure 1, which shows production for July 5, 2013 for three time series: 1) the 400-MW solar PV build-out assumed for the study, 2) a highly clustered build-out with 400 MW of solar PV sited at Grand View, Idaho, and 3) a less clustered build-out with 400 MW of solar PV sited evenly between Grand View, Idaho and Orchard, Idaho. A comparison of the plotted production for the three time series clearly indicates greater challenges associated with integration of the clustered build-outs; the steeper and more dramatic changes in production for the clustered build-outs are indicative of potential challenges in system integration. The solar integration costs identified in this study are relatively small. The small costs suggest solar PV resources can be inexpensively integrated without significant impact to system operations. However, these results are highly dependent on the level of dispersion in the solar PV resource. Impacts and costs associated with build-outs more clustered than assumed for this study are likely markedly greater than found by this study.

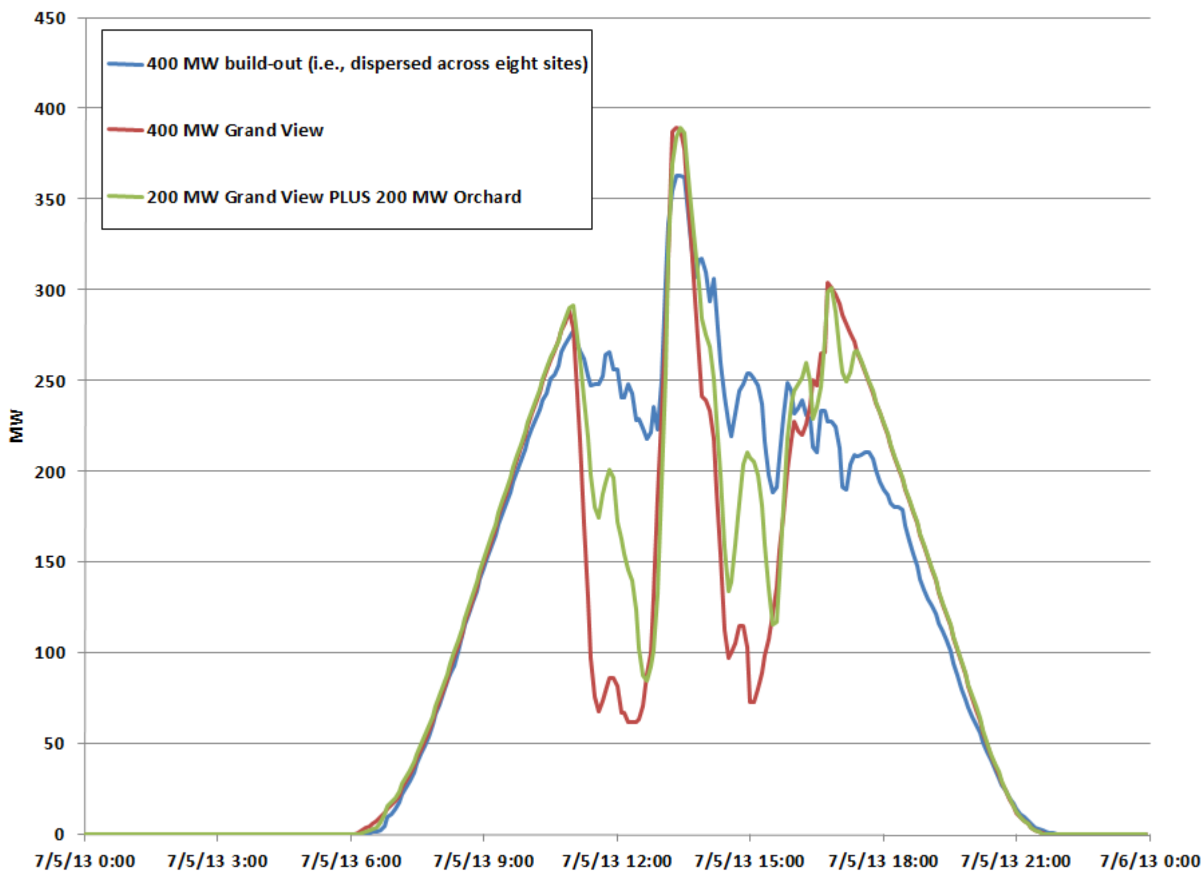

Figure 1
A comparison of 5-minute solar PV production on July 5, 2013.

2014 Solar Integration Study

The first Idaho Power solar integration study was completed in June 2014. The first study investigated integration of four solar PV build-outs: 100 MW, 300 MW, 500 MW, and 700 MW. The costs from the first study were the basis for solar integration costs included in Idaho Public Utilities Commission (IPUC) Schedule 87, which was part of a settlement stipulation approved by the IPUC in Order No. 33227 in February 2015 (Case No. IPC-E-14-18). In addition to Schedule 87, the parties to the settlement stipulation agreed that a second study of solar integration was to be initiated in January 2015 and completed as “expeditiously as possible with the goal of not exceeding 12 months”. The parties also agreed that Idaho Power and the Technical Review Committee (TRC) formed for the second solar integration study will determine whether the following issues should be included as part of the second study:

- Alternative water-year types (e.g., low-type and high-type), range of water years or normalized water year
- Intra-hour trading opportunities
- Shortening the hour-ahead forecast lead time from 45 minutes to 30 minutes
- Clustered solar build-out scenarios
- Other solar plant technologies (e.g., tracking systems or varied fixed-panel orientation)
- Correlation between solar, wind, and load variability, uncertainty, and forecasting error
- Improved forecasting methods
- Energy imbalance markets, or other market structures
- Voltage/frequency regulation
- Increased transmission capacity, changes in operation of hydroelectric facilities, addition of demand-side technologies
- Gas price forecasts
- Modeling of sub-hourly scheduling of load and generation
- Identification of the existence of low occurrence events that contribute to proportionately higher integration costs and possible remedies, including operational or contractual solutions to mitigate these events and reduce integration costs and charges

Idaho Power solicited from the TRC their feedback, including a prioritization, on the above issues. Idaho Power’s reporting on this feedback is included in Appendix 1 as the Technical Review Committee Study Plan. The settlement stipulation is also provided in Appendix 1.

This study’s treatment of correlation between solar, wind, and load is particularly noteworthy. Specifically, Idaho Power’s statistical analysis accounted for combining effects occurring when these three components of the load and resource balance—solar, wind, and load—are netted.

Data Gathering and Scenario Development

A critical element of the solar integration study is the solar generation data developed for the studied solar build-out scenarios. For Idaho Power’s solar integration study, the solar build-out scenarios in Table 3 were studied.

Table 3
Solar build-out scenarios studied

		Installed Capacity of Solar Build-Out Scenarios			
Site	**Data Source**	**400 MW**	**800 MW**	**1,200 MW**	**1,600 MW**
Parma, ID	USBR AgriMet	50	100	150	200
Murphy Flats, ID	SolarAnywhere	25	50	75	100
Boise, ID	USBR AgriMet	25	50	75	100
Grand View, ID	SolarAnywhere	75	150	225	300
Orchard, ID	SolarAnywhere	100	200	300	400
Bliss, ID	SolarAnywhere	25	50	75	100
Twin Falls, ID	USBR AgriMet	50	100	150	200
Aberdeen, ID	USBR AgriMet	50	100	150	200
Total MW		**400**	**800**	**1,200**	**1,600**

The above build-out scenarios were developed in consultation with the TRC to represent geographically dispersed build-outs of solar power plant capacity as informed by locations of proposed solar power plants in southern Idaho and eastern Oregon. Three years of solar data were developed for each build-out scenario: water years 2011, 2012, and 2013. By convention, a water year is from October 1 to September 30 and is designated by the calendar year in which the 12-month period ends. For example, water year 2013 is the 12-month period from October 1, 2012 through September 30, 2013.

The sites from the solar build-out scenarios are part of the established United States Bureau of Reclamation (USBR) AgriMet Network (AgriMet) and modeled data from SolarAnywhere. AgriMet is a satellite-based network of automated agricultural weather stations operated and maintained by the USBR. The stations are located in irrigated agricultural areas throughout the Pacific Northwest and are dedicated to regional crop water-use modeling, agricultural research, frost monitoring, and integrated pest and fertility management. Idaho Power worked directly with the USBR Pacific Northwest Region AgriMet manager to obtain data for the sites. AgriMet data was augmented with data from the University of Oregon Solar Radiation Monitoring Laboratory when AgriMet data was incomplete.

An alternative data-gathering approach was necessary for the Grand View, Murphy, Orchard, and Bliss sites, for which only 15-minute or no data was available. To acquire 5-minute data for these sites, Idaho Power contracted with SolarAnywhere to provide high-resolution modeled solar data. SolarAnywhere uses hourly satellite images processed using the most current algorithms developed and maintained by Dr. Richard Perez at the University at Albany (SUNY). The algorithm extracts cloud indices from the satellite’s visible channel using a self-calibrating feedback process capable of adjusting for arbitrary ground surfaces. The cloud indices are used to modulate physically-based radiative transfer models describing localized clear-sky climatology.

The eight sites are spread across southern Idaho and cover over 220 miles from east to west (Figure 2). Sites represent elevations ranging from 2,300 feet to 4,900 feet (Table 4). All data used in the integration study are 5-minute interval global horizontal irradiance data from each site. The use of high-resolution (5-minute interval) data is critical to characterizing the variability of solar.

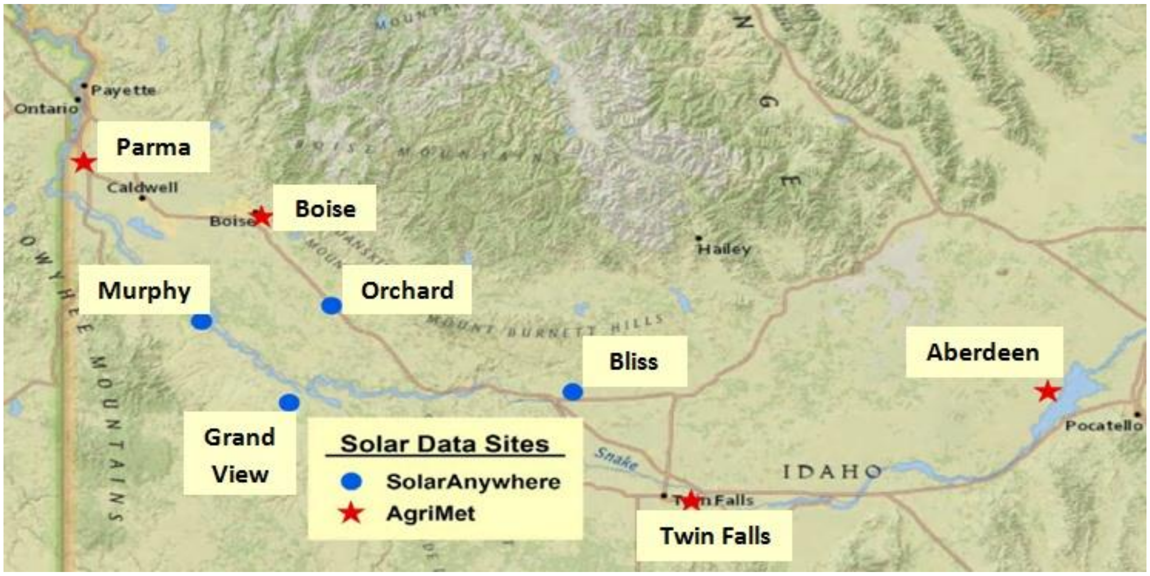

Figure 2
Solar data sites used in IPC's solar integration study

Table 4
Solar data site latitude, longitude, and elevation used in IPC's solar integration study

Station	Latitude (N)	Longitude (W)	Elevation (feet)	Elevation (meters [m])
Parma, ID	43.80	116.93	2,305	702
Murphy Flats, ID	43.21	116.43	3,029	923
Boise, ID	43.60	116.18	2,720	829
Grand View, ID	42.91	116.06	2,580	786
Orchard, ID	43.27	115.88	3,223	982
Bliss, ID	42.95	114.85	3,443	1,049
Twin Falls, ID	42.55	114.35	3,920	1,195
Aberdeen, ID	42.95	112.83	4,400	1,341

Wavelet-Based Variability Model

The available solar data represents conditions at a single point. To better reflect conditions at a solar plant size, Idaho Power used the wavelet-based variability model (WVM) developed by Dr. Matt Lave of Sandia National Labs (Lave et al. 2013a,b). WVM is designed for simulating solar PV power plant output given a single irradiance point-sensor time series. The application of the WVM to the point-sensor time series produces a variability reduction reflecting an upscaling of the point-source data to a solar plant-sized area. Research and use of the WVM showed it is not useable at time steps (intervals) greater than 10 minutes and that time steps greater than 5 minutes may under-represent variability in dispersed systems.

Solar Plant Characteristics

This study assumes solar plants comprising the build-out scenarios occupy 7 acres per MW of installed capacity. Solar plant sizes in the build-out scenarios, as well as figures presented for solar generation, are in terms of AC (alternating current) MW. PV panels are assumed to be of standard crystalline silicon manufacture. Panels are assumed to be single-axis tracking and tilted at latitude. Illustrations and data summarizing the solar production of the studied build-outs are provided in Appendix 1.

STATISTICAL-BASED ANALYSIS OF SOLAR, WIND, AND LOAD DATA

The impacts and costs of integrating an intermittent energy source, such as solar, are driven by the inherent variability and uncertainty in level of production. The variability and uncertainty in level of production has the impact of requiring dispatchable generators to carry additional capacity in reserve to enable the bulk power system to maintain a balance between customer demand and generation. Thus, the two critical components of studying the integration of solar, or other intermittent energy sources, are as follows:

1. The statistical-based analysis to determine the extent to which solar brings additional variability and uncertainty to system balancing
2. The follow-on analysis to translate the additional variability and uncertainty to additional capacity in reserve required on dispatchable generators.

In considering the impact of variability and uncertainty from the perspective of integration impacts and costs, the focus is primarily on shorter-term operations. That is, for the system operator responsible for maintaining system balancing, integration impacts arise because of variability and uncertainty over the coming minutes, hours, or perhaps days. Viewed from this perspective, the relevant components of system balancing which bring variability and uncertainty are customer demand (load) and intermittent sources of energy (solar and wind). Because of the relevance of these three components—load, solar, and wind—to the challenges with maintaining shorter-term system balancing, the statistical-based analysis performed for this study takes into account variability and uncertainty for the three components, as well as possible interrelationships in variability and uncertainty between the three.

The statistical-based analysis for the study first focused on separate characterizations of variability and uncertainty for load, wind, and solar. The products of the separate characterizations are defined mathematical relationships expressing the extent of variability and uncertainty for each of load, wind, and solar as functions of certain conditions. An August 2012 NREL Conference Paper (Ibanez et al. 2012) describes this approach as defining the operating reserves needed for each of load, wind, and solar as a function of explanatory variables, where differences in the amount of needed reserves can be expressed as a function of the explanatory variables.

After defining the amount of reserves needed separately for each of load, wind, and solar, the statistical-based analysis focused on determining how to combine the separately defined reserve amounts in an appropriate manner for the combination of load with wind, and for the combination of load with wind and solar. This step of the analysis necessarily takes into account the combining effects occurring when netting load with wind, or load with wind and solar. Because of the combining effects that occur when netting load, wind, and solar, the separately determined reserve amounts for each of the three are not added arithmetically, but instead are added through mathematical operations that properly account for the combining effects taking place (e.g., root-sum-of-squares operation). The derivation of the mathematical operations is described later in this section of the report.

Hour-Ahead Forecasting

This study was focused on the assessment of variability and uncertainty as occurring from the perspective of hour-ahead forecasting. This assessment for each of load, wind, and solar was based on the extent to which 5-minute observations differ from hour-ahead forecasts. These differences, or deviations, between intra-hour observations and hour-ahead forecasts drive the need to carry operating reserves to maintain system balancing. Thus, at a fundamental level, the statistical-based analysis to characterize variability and uncertainty was an analysis of deviations between 5-minute observations and hour-ahead forecasts. Further, explanatory variables were identified that explain patterns in the deviations, and these explanatory variables were then used to more precisely define the operating reserve requirements.

Load—Analysis of Variability and Uncertainty

This study found the amount of operating reserve necessary for load variability and uncertainty can be expressed as a function of the following explanatory variables:

- Month (January, February, …, December)
- Clock hour of day (00:00-01:00, 01:00-02:00, …, 23:00-00:00)

Hour-ahead forecast for load is based on a persistence of load occurring during the period from 45 to 30 minutes prior to the start of the hour being forecast, with a scaling factor applied equal to the percentage change for the same hour for the previous day. For example, the load forecast for June 15, 12:00–13:00 would be the observed load during the period from 11:15–11:30 multiplied by the ratio of 12:00–13:00 load to 11:15–11:30 load for June 14.

Deviations are calculated as the difference between observed 5-minute load and the corresponding hour-ahead hourly average load forecast (observed minus forecast). A positive deviation represents intra-hour load greater than hour-ahead forecast, an event requiring dispatchable generators to have generating capacity in reserve that can be turned up to respond. Conversely, a negative deviation represents intra-hour load less than hour-ahead forecast, requiring dispatchable generators to have generating capacity in reserve that can be turned down to respond. The period of record for the load data analyzed is December 2009 through November 2015.

The objective of the analysis of deviations is to determine the bidirectional reserve amounts capturing a target percentage of the deviations. For this study, the bidirectional reserve amounts were designed to capture a target of 99 percent of the deviations (one-half percent at each tail). The deviation data were binned based on month and then clock hour. Two values were then calculated for each bin: 1) P0.5, which is the 0.5^{th}-percentile value for the deviation data, and 2) P99.5, which is the 99.5^{th}-percentile value for the deviation data. Thus, for each combination of month and clock hour (12 x 24 = 288 combinations), the amount of load-caused bidirectional reserve can be specified.

For the purposes of this study, Idaho Power adopted the term INC for the up-direction reserve and DEC for the down-direction reserve. In the assessment of load variability and uncertainty, the P0.5 value represents DEC reserve and the P99.5 value represents INC reserve.

The target to capture 99 percent of deviations for this study is considered appropriate in ensuring generators have sufficient reserve requirements for all but approximately 90 hours per year. Importantly, the targeted 99 percent is the criterion held for both simulations performed for this study: the base case simulation of load combined with wind, and the test case simulation of load combined with wind and solar. This ensures both simulations are designed to bring about an equivalent level of system reliability, rendering the selected reliability level relatively immaterial from the perspective of comparing production cost differences between paired simulations.

Wind—Analysis Variability and Uncertainty

This study found the amount of operating reserve necessary for wind variability and uncertainty can be expressed as a function of the following explanatory variable:

- Hour-ahead forecast for wind production

Hour-ahead forecast for wind production is based on a persistence of wind production occurring during the period from 45 to 30 minutes prior to the start of the hour being forecast. For example, the wind production forecast for June 15, 12:00–13:00 would be the observed wind production during the period from 11:15–11:30.

Deviations are calculated as the difference between observed 5-minute wind production and the corresponding hour-ahead hourly average wind production forecast (observed minus forecast). To illustrate, the population of deviations for the wind production data analyzed is plotted in Figure 3. The plot illustrates the magnitude of deviations as a function of hour-ahead forecast wind production on the horizontal axis. The plot notes that a positive deviation represents intra-hour wind production greater than hour-ahead forecast, an event requiring dispatchable generators to have generating capacity in reserve that can be turned down to respond. Conversely, a negative deviation represents intra-hour wind production less than hour-ahead forecast, requiring dispatchable generators to have generating capacity in reserve that can be turned up to respond. The period of record for the wind production data analyzed is December 2012 through November 2015. The wind production data are observed production for wind projects having long-term energy sales agreements with Idaho Power during the period of record. The energy sales agreements are both through PURPA and power purchase agreement (PPA), and total installed capacity of the wind projects analyzed is 678 MW.

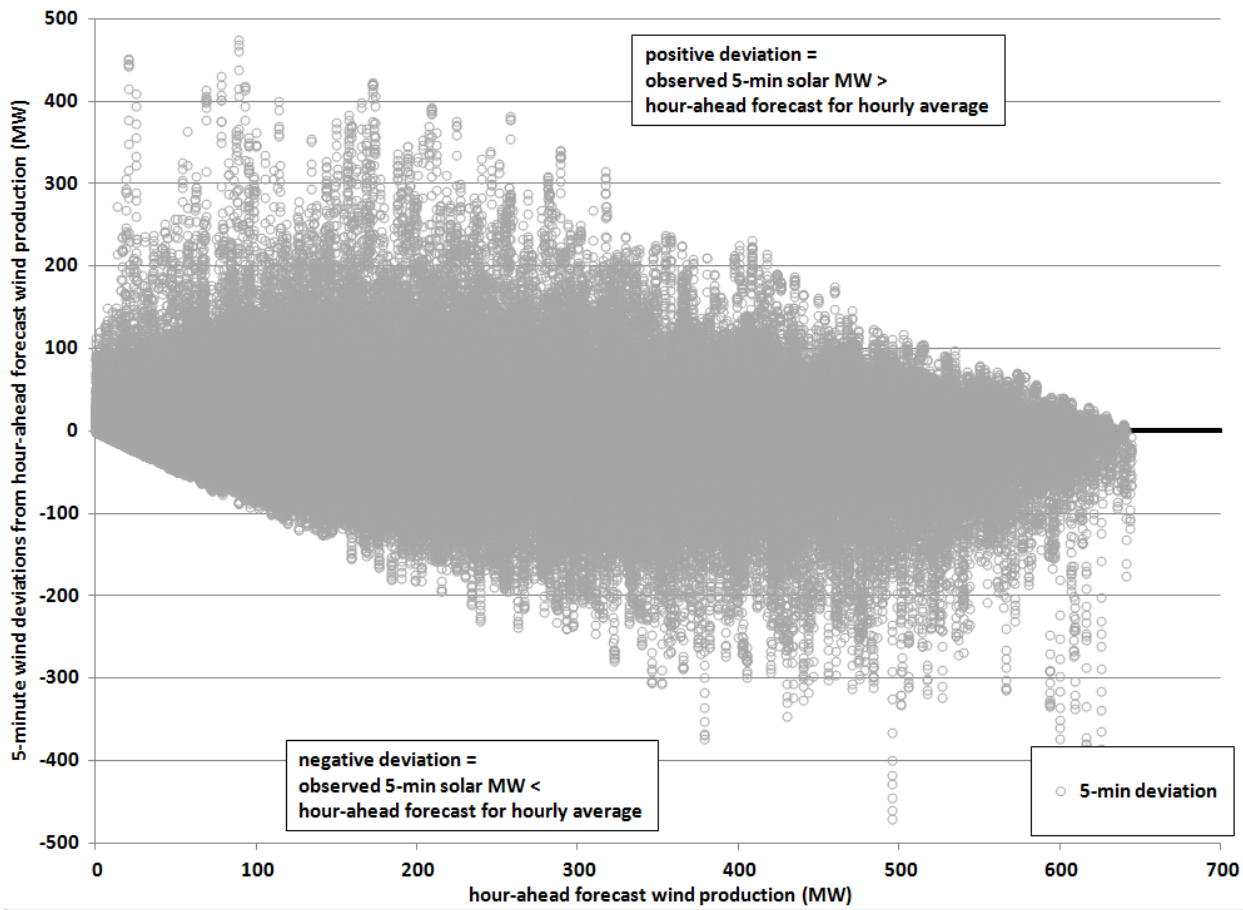

Figure 3
Wind production deviations (5-minute wind production minus hour-ahead forecast hourly average wind production). Period of record December 2012 through November 2015.

The objective of the analysis of deviations is to determine the bidirectional reserve amounts capturing a target percentage of the deviations. For this study, the bidirectional reserve amounts were designed to capture a target of 99 percent of the deviations (one-half percent at each tail). It is evident from the plot in Figure 3 that the magnitude of deviations varies as a function of hour-ahead forecast wind. Thus, the bidirectional reserve amounts can be more precisely defined if calculated after binning the data based on the level of hour-ahead forecast wind production.

The deviation data were divided into 20 equal-sized bins based on level of hour-ahead forecast wind production. Three values were calculated for each bin: 1) the median hour-ahead forecast, 2) P0.5, which is the 0.5^{th}-percentile value for the deviation data, and 3) P99.5, which is the 99.5^{th}-percentile value for the deviation data. Figure 4 illustrates the P0.5 and P99.5 values for the example deviations, as well as third-order polynomial trend lines fitted to both data streams.

The fitted trend lines were used to define the amounts of bidirectional reserve associated with wind variability and uncertainty. In the assessment of wind variability and uncertainty, the P0.5 value represents INC reserve, dispatchable generating capacity in reserve that can be turned up in response to lower than expected wind production. The P99.5 value represents DEC reserve, dispatchable generating capacity in reserve that can be turned down in response to higher than expected wind production.

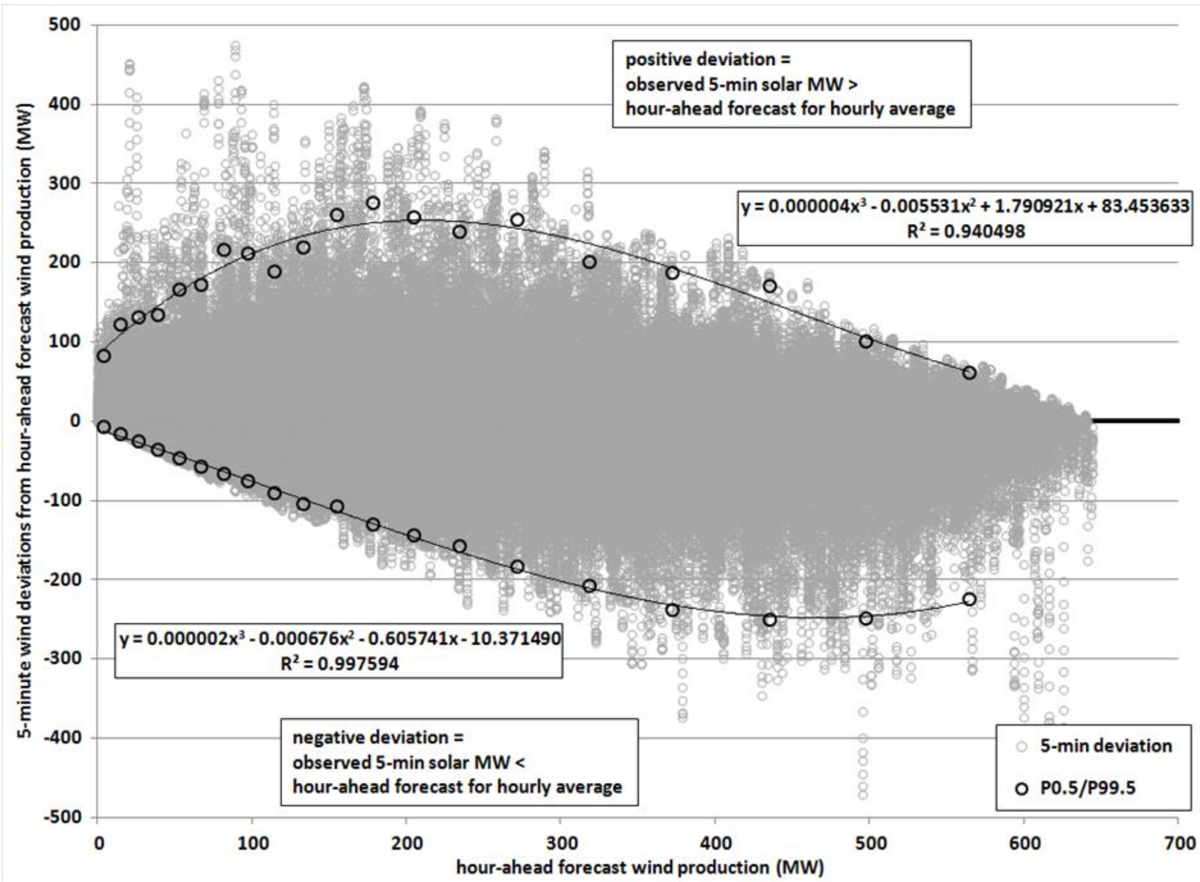

Figure 4
Wind production deviations with fitted trend lines for bidirectional wind reserve as function of hour-ahead forecast wind production

As a result of the analysis of wind production data, the amount of wind-caused bidirectional reserve can be defined for any given hour based on the level of hour-ahead forecast wind production.

Solar—Analysis of Variability and Uncertainty

This study found the amount of operating reserve necessary for solar variability and uncertainty can be expressed as a function of the following explanatory variables:

- Hour-ahead forecast for solar production
- Time of day (eight, 3-hour blocks: 00:00–03:00, 03:00–06:00, …, 21:00–00:00)

Hour-ahead forecast for solar production is based on a persistence of percentage of clear-sky production, where clear-sky production is the physically determinable maximum production level for a given date and time. The forecast is based on the observed percentage of clear-sky production occurring during the period from 45 to 30 minutes prior to the start of the hour being forecast. For example, the solar production forecast for June 15, 12:00–13:00 would be the observed percentage of clear-sky production during the period from 11:15–11:30.

Deviations are calculated as the difference between observed 5-minute solar production and the corresponding hour-ahead hourly average solar production forecast (observed minus forecast). To illustrate, the population of deviations for the three years of solar production data at the 800-MW build-out for the time of day from 12:00–15:00 is plotted in Figure 5. The plot illustrates the magnitude of deviations as a function of hour-ahead forecast solar production on the horizontal axis. The plot notes that a positive deviation represents intra-hour solar production greater than hour-ahead forecast, an event requiring dispatchable generators to have generating capacity in reserve that can be turned down to respond. Conversely, a negative deviation represents intra-hour solar production less than hour-ahead forecast, requiring dispatchable generators to have generating capacity in reserve that can be turned up to respond.

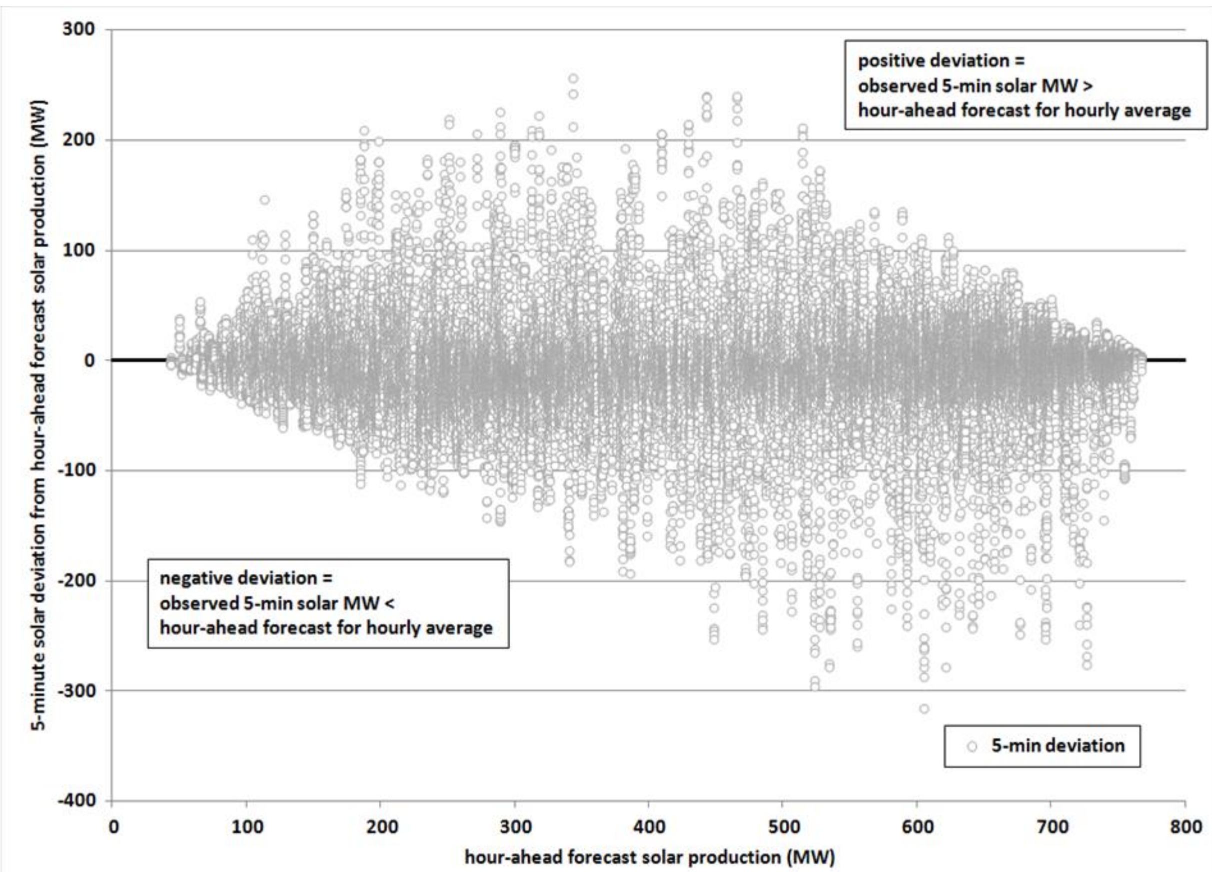

Figure 5
Solar production deviations (5-minute solar production minus hour-ahead forecast hourly average solar production). Period of record October 2010 through September 2013. 800-MW solar build-out. Period of day 12:00–15:00.

The objective of the analysis of deviations is to determine the bidirectional reserve amounts capturing a target percentage of the deviations. For this study, the bidirectional reserve amounts were designed to capture a target of 99 percent of the deviations (one-half percent at each tail). It is evident from the plot in Figure 5 that the magnitude of deviations varies as a function of hour-ahead forecast solar. Thus, the bidirectional reserve amounts can be more precisely defined if calculated after binning the data based on the level of hour-ahead forecast solar production.

The deviation data were divided into 24 equal-sized bins based on the level of hour-ahead forecast solar production. Three values were calculated for each bin: 1) the median hour-ahead forecast, 2) P0.5, which is the 0.5^{th}-percentile value for the deviation data, and 3) P99.5, which is the 99.5^{th}-percentile value for the deviation data. Figure 6 illustrates the P0.5 and P99.5 values for the example deviations, as well as second-order polynomial trend lines fitted to both data streams. The fitted trend lines were used to define the amounts of bidirectional reserve associated with solar variability and uncertainty. Similarly derived trend lines were determined for the other seven time-of-day periods, although it is noted that the first two time-of-day periods (00:00–03:00, 03:00–06:00) have no deviation data and consequently no solar-caused reserve requirements, and the last time-of-day period (21:00–00:00) has minimal data and small solar-caused reserve requirements. The process was replicated for each solar build-out.

In the assessment of solar variability and uncertainty, the P0.5 value represents INC reserve, dispatchable generating capacity in reserve that can be turned up in response to lower than expected solar production. The P99.5 value represents DEC reserve, dispatchable generating capacity in reserve that can be turned down in response to higher than expected solar production.

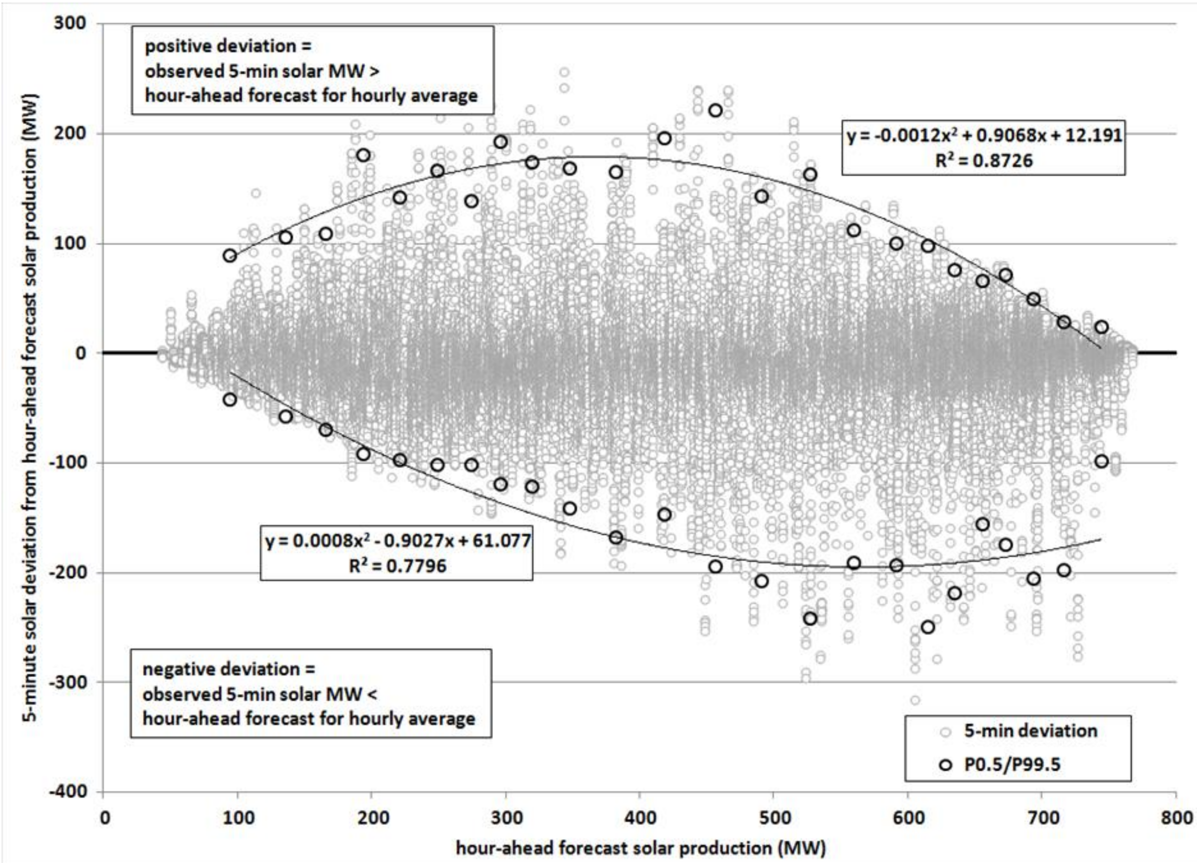

Figure 6
Solar production deviations (5-minute solar production minus hour-ahead forecast hourly average solar production). Period of record October 2010 through September 2013. 800-MW solar build-out. Period of day 12:00–15:00. Fitted trend lines for bidirectional solar reserve as function of hour-ahead forecast solar production.

As a result of the analysis of solar production data, the amount of solar-caused bidirectional reserve can be defined for any given hour based on two explanatory variables: 1) hour-ahead forecast solar production, and 2) time of day.

Reserve for Load Combined with Wind

The base case production cost simulations assumed operating reserve necessary to manage variability and uncertainty for load combined with wind. As noted earlier in this section, because of combining effects that occur when netting load and wind, the amount of operating reserve necessary for the combination is not the arithmetic addition of the separately determined operating reserve amounts. In fact, wind and load are widely recognized as independent (near zero correlation), and the operating reserve for the combined wind and load is commonly considered to be theoretically formed by combining the separately determined operating reserve amounts for load and wind through the root sum of squares (RSS) operation (Ela et al. 2009).

The RSS formulas for INC and DEC are stated as follows:

$$INC_{\text{load with wind}} = \text{sqrt}(INC_{\text{load}}^2 + INC_{\text{wind}}^2)$$
$$DEC_{\text{load with wind}} = \text{sqrt}(DEC_{\text{load}}^2 + DEC_{\text{wind}}^2)$$

Thus, for any given hour in the study's production cost simulations, the separate amounts of INC/DEC associated with load and wind variability can be determined based on the explanatory variables occurring for the hour (e.g., level of wind production forecast), and the amount of INC/DEC for the combined load and wind is then based on combining the separate amounts through the RSS operation provided above.

The effectiveness of the RSS operation in covering variability and uncertainty occurring when load and wind are combined was tested by applying the RSS to observed load and wind data for water year 2013. When the separate INC/DEC amounts are combined through the RSS operation, the percentage of intra-hour (i.e., 5-minute) observations for load combined with wind occurring outside of the hourly INC/DEC reserve levels are 0.4 and 0.3 percent for the INC and DEC reserve bounds, respectively. Recalling that the separately determined INC/DEC reserve amounts for load and wind are based on a 99 percent confidence level (P99.5 and P0.5), the percentages of observations *not* covered by the RSS-determined INC/DEC reserve levels support the appropriateness of the RSS operation.

Reserve for Load Combined with Wind and Solar

The base case production cost simulations are compared to test case simulations, where the test case simulations have INC/DEC necessary to manage variability and uncertainty in load netted with wind *and solar*. As noted previously, because of combining effects, the amount of INC/DEC reserve necessary when load, wind, and solar are netted is not the arithmetic sum of the separately determined INC/DEC amounts. The preceding subsection of this report describes the appropriateness of the RSS operation in determining the amount of INC/DEC reserve for load combined with wind.

A challenge in deriving the amount of reserve for the test case (i.e., for load combined with wind and solar) is determining the amount of solar-caused INC/DEC reserve to add to the RSS-determined base case amount. Because of combining effects, the use of 100 percent of the solar-caused INC/DEC is excessive, and results in fewer occurrences of insufficient INC/DEC reserves than occurring in the base case. However, because of the incremental variability and uncertainty associated with solar, it is also recognized that ignoring the solar-caused INC/DEC (i.e., using 0 percent) is incorrect, and results in a frequency of insufficient INC/DEC reserves exceeding that of the base case. Idaho Power determined the amount of incremental solar-caused INC/DEC reserve to add to the RSS-determined base case level empirically by adjusting the amount of solar-caused INC/DEC reserve (between 0 and 100 percent) until the frequency of INC/DEC reserve insufficiencies matches that of the base case (0.4 and 0.3 percent respectively for INC and DEC reserve bounds). This empirical approach ensures base and test case simulations are held to the same standard with respect to stringency of reserve obligations.

The formula statements for INC/DEC reserve for the load combined with wind and solar are as follows:

$$INC_{\text{load with wind and solar}} = \text{sqrt}(INC_{\text{load}}^2 + INC_{\text{wind}}^2) + X \cdot INC_{\text{solar}}$$

$$DEC_{\text{load with wind and solar}} = \text{sqrt}(DEC_{\text{load}}^2 + DEC_{\text{wind}}^2) + Y \cdot DEC_{\text{solar}}$$

Where: Coefficients X and Y are determined empirically such that INC/DEC insufficiencies for load with wind and solar match the frequency of INC/DEC insufficiencies for load with wind

The empirically determined coefficients applied to solar-caused INC/DEC are provided in Table 5. It is noted that for the 400-MW solar build-out the coefficient yielding the equivalent frequency of DEC insufficiencies is 0.00.

Table 5
Coefficients for bidirectional solar reserve by solar build-out

Solar Build-Out	INC Coefficient	DEC Coefficient
400 MW	0.23	0.00
800 MW	0.43	0.25
1,200 MW	0.56	0.37
1,600 MW	0.64	0.40

The amounts of INC/DEC averaged over all hours for the three simulated water years for the two cases are provided in Table 6.

Table 6
Average INC/DEC base and test cases by solar build-out (water year [WY] 2011–2013)

Solar Build-Out	Base Case Average INC (MW)	Test Case Average INC (MW)	Base Case Average DEC (MW)	Test Case Average DEC (MW)
400 MW	169	175	226	226
800 MW	169	193	226	242
1,200 MW	169	215	226	263
1,600 MW	169	239	226	279

Example Reserve Application

A key objective of the statistical analysis of variability and uncertainty is the development of operating reserve guidelines, or rules, which provide to the system scheduler the appropriate amount of reserve for any given load, wind, and solar combination. This subsection of the report illustrates an example application of the operating reserve rules.

The following conditions are assumed for the example hour:

- Hour being scheduled: June 15, 13:00–14:00
- Hour-ahead wind forecast: 400 MW
- Hour-ahead solar forecast: 500 MW (assume 800 MW of installed solar capacity)
- Hour-ahead load forecast: 2,100 MW

For wind, Figure 4 provides that for an hour having a 400 MW hour-ahead forecast:

- $Wind_{INC}$ ≈ 250 MW (based on third-order polynomial below the zero axis)
- $Wind_{DEC}$ ≈ 180 MW (based on third-order polynomial above the zero axis)

For solar, Figure 6 provides that for an hour during the period 12:00–15:00 and having a 500 MW hour-ahead forecast:

- $Solar_{INC}$ ≈ 190 MW (based on third-order polynomial below the zero axis)
- $Solar_{DEC}$ ≈ 155 MW (based on third-order polynomial above the zero axis)

For load, analysis of deviations in hour-ahead load forecasts for June hour 13:00–14:00 provides:

- $Load_{INC}$ ≈ 95 MW
- $Load_{DEC}$ ≈ 85 MW

Given this information, the hour-ahead system scheduler for this example hour would schedule the following reserve amounts on dispatchable generators for the base case (i.e., for the load combined with wind case):

- INC = sqrt(95^2 + 250^2) = 267 MW
- DEC = sqrt(85^2 + 180^2) = 199 MW

The reserve amounts for the test case (i.e., for the load combined with wind and solar case) are:

- INC = 267 MW + 0.43*($Solar_{INC}$) = 267 MW + 0.43*190 MW = 349 MW
- DEC = 199 MW + 0.25*($Solar_{DEC}$) = 199 MW + 0.25*155 MW = 238 MW

Finally, the system scheduler for both cases is assured of the appropriateness of the reserve amounts on the basis of the rigor of the supporting statistical analysis of load, wind, and solar data. That is, the statistical analysis indicates scheduling the above-calculated reserve amounts positions the system in both cases to cover approximately 99 percent of possible observations for both time series (load combined with wind, and load combined with wind and solar).

PRODUCTION COST SIMULATION ANALYSIS

Hourly production cost simulations for the study were performed using a paired, base case versus test case design. The critical difference between the cases is the amount of capacity in reserve (i.e., INC/DEC). The amount of capacity in reserve for the base case simulation is based on that carried for the load combined with wind time series described in the preceding section, whereas the amount of capacity in reserve for the test case is based on that carried for the load combined with wind and solar time series. All other inputs are identical between the paired simulations.

The incremental reserve requirements of the test case (summarized in Table 6) lead to production cost differences between it and the base case. Over a simulated year, the test case costs exceed those of the base case. Because inputs between the cases are identical with the exception of the amount of capacity in reserve, the greater costs of the test case can be attributed to its incremental reserve requirements. This production cost difference is considered the cost to integrate solar.

Design of Simulations

Three water years were simulated for the production cost simulations: water years 2011, 2012, and 2013. The three simulated water years correspond well to high-type (2011), medium-type (2012), and low-type (2013) water years for the Snake River Basin. An illustration of the water conditions for 2011–2013 in relation to other historical years is provided in Appendix 1.

The Idaho Power generating and transmission system as it exists at the time of issue of this report is assumed for the production cost simulations. Critical elements of the simulated system of generating resources include 17 hydroelectric facilities totaling 1,709 MW of nameplate capacity, 3 coal-fired facilities totaling 1,118 MW of nameplate capacity, and 3 natural gas-fired facilities totaling 762 MW of nameplate capacity. An illustration of the generating resources is provided in Appendix 1.

Idaho Power's critical interconnections to the regional market are over the Idaho–Northwest, Idaho–Utah (Path C), and Idaho–Montana paths. For the solar integration study modeling, the separate paths were combined to an aggregate path for off-system access. Purchases from the regional market are treated separately from sales to the regional market. Net firm purchases from the market are limited on a monthly basis to only the capacity and energy required to serve Idaho Power's retail load. Sales to the market are limited to 500 MW in every hour. This profile of purchases and sales reflects the current capabilities of Idaho Power's transmission system.

Idaho Power is pursuing the development of the Boardman to Hemingway Transmission Project (B2H), which will increase Idaho Power's access to the Northwest to make additional purchases and sales. However, the transmission line's current in-service date is at least five years into the future. Previous integration studies have shown that unless there is a liquid capacity balancing market, B2H will not significantly impact the solar integration cost. Idaho Power is actively engaged in discussions about regional markets that could exist when B2H is completed. The benefits of a market are highly dependent on its design. This study investigated as a sensitivity analysis a market design similar to that existing for the California Independent System Operator (CAISO) Energy Imbalance Market (EIM).

Simulation Inputs

Table 7 provides key inputs to the solar integration study hourly production cost simulations of water years 2011, 2012, and 2013. To capture interrelationships between variables, inputs to the simulations are synchronous, with the exception of production from non-wind PURPA resources and geothermal PPAs, which is not interrelated to the other inputs.

Table 7
Inputs for the solar integration study hourly production cost simulations

Input	Water Year 2011	Water Year 2012	Water Year 2013
Solar production	Water year 2011	Water year 2012	Water year 2013
Snake River streamflows	Water year 2011	Water year 2012	Water year 2013
Customer demand	Water year 2011	Water year 2012	Water year 2013
Nymex—Natural gas prices	Water year 2011	Water year 2012	Water year 2013
Mid-C—Electric power market prices	Water year 2011	Water year 2012	Water year 2013
Non-wind PURPA[1]	------------Forecast calendar year 2016----------		
Wind (PURPA and PPA)[1]	Water year 2011	Water year 2012	Water year 2013
Geothermal PPAs	-----------------Water year 2015---------------------		

[1] PPA and PURPA represent facilities from which generation is contractually purchased as a PPA or under PURPA.

Wind capacity under contract more than tripled during the three consecutive water years being simulated; capacity under contract was 208 MW at the start of water year 2011 and grew to the current level of 678 MW by January 2013. Because of the substantial growth in wind capacity, observed wind generation occurring prior to reaching the current capacity level was adjusted upwards to normalize this production to the current capacity level. For example, observed wind production occurring during October through December 2010 was adjusted upwards by a factor of 3.3 (678 MW ÷ 208 MW) to normalize the observed production from the 208 MW actually on-line during the 3-month period to the current capacity level of 678 MW. The expansion in wind capacity under contract is illustrated as Figure 7. Monthly wind energy production used in the modeling, at unadjusted and adjusted levels, is included in Appendix 1.

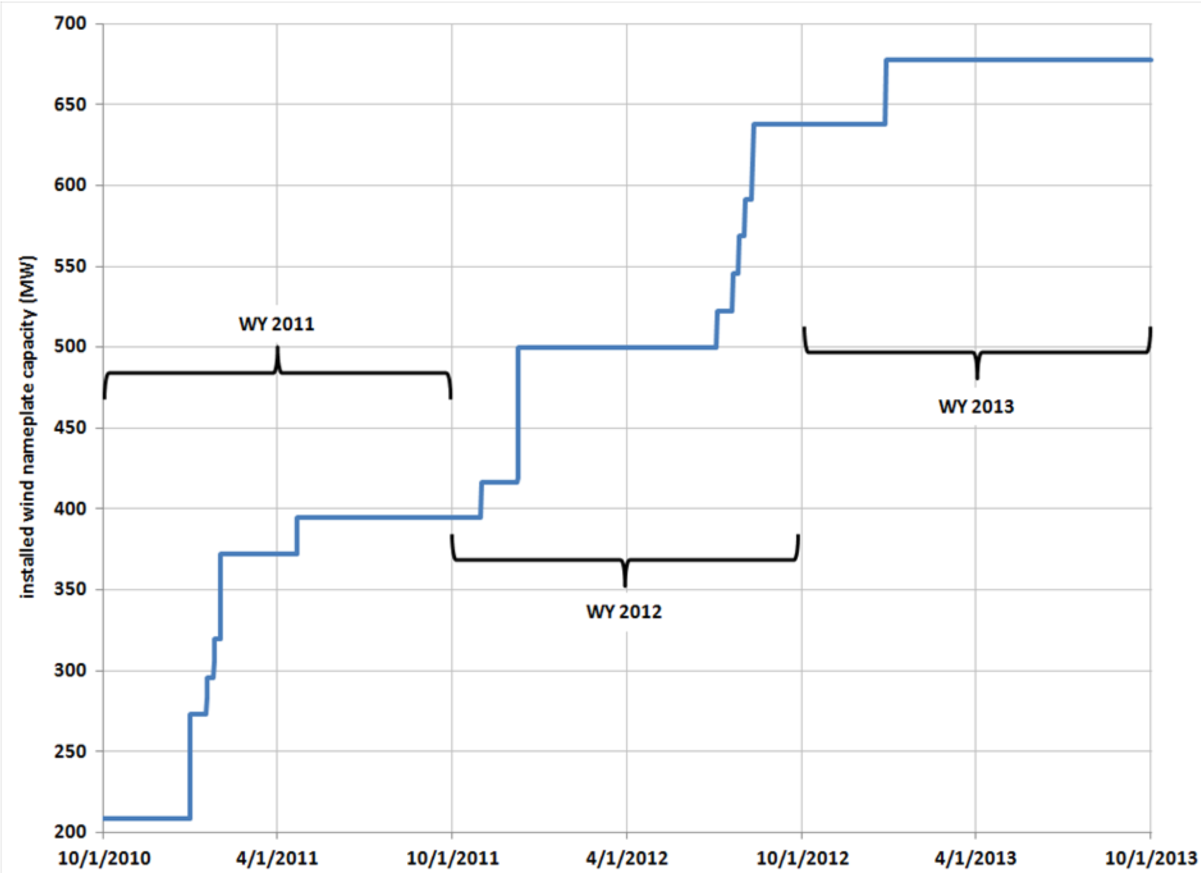

Figure 7
Installed nameplate wind capacity under contract, water years 2011–2013.

Energy purchased from non-wind PURPA qualifying facilities is input to the simulations as forecast in April 2015 for calendar year 2016. The monthly energy from the non-wind PURPA facilities is included in Appendix 1.

Baseload generation from geothermal facilities contractually selling to Idaho Power under PPAs is input as currently projected from these facilities. The amount of baseload generation delivered from these facilities varies seasonally. The amount used in the production cost simulations ranges from 22 MW to 32 MW.

Simulation model

Idaho Power used an internally developed system operations model for the solar integration study. The model determines optimal hourly scheduling of dispatchable hydro and thermal generators with the objective of minimizing production costs while honoring constraints imposed on the system. System constraints used in the model capture numerous restrictions governing the operation of the power system, including the following:

- Reservoir headwater constraints
- Minimum reservoir outflow constraints
- Reservoir outflow ramping rate constraints

- Generator minimum/maximum output levels
- Market purchase/sale constraints
- Generator ramping rates

The model also stipulated that load and resource were exactly in balance and, importantly, that hourly reserve requirements were satisfied. The differing amount of capacity in reserve held to manage variability and uncertainty in solar production drives the production cost differences between the study's two cases. The derivation of the capacity in reserve for the two simulation cases is described previously in this report.

Contingency Reserve Obligation

The study of integration impacts and costs focuses on the need to carry bidirectional capacity in reserve for maintaining compliance with reliability standards. However, balancing authorities, such as Idaho Power, are also required to carry unloaded capacity in reserve for responding to system contingency events, which have traditionally been viewed as large and relatively infrequent system disturbances affecting the production or transmission of power (e.g., the loss of a major generating unit or major transmission line). System modeling for the solar integration study imposes a contingency reserve intended to reflect this obligation equal to 3 percent of load and 3 percent of generation, setting aside this capacity for both study cases (i.e., base and test).

Flexible Capacity Resources

The focus of the production cost simulations for the solar integration study is the real-time market activities occurring as part of hour-ahead system scheduling. The study assumes hour-ahead schedulers require the delivery of hour-ahead forecasts for load, wind, and solar 30 minutes prior to the start of the operating hour being scheduled. Hour-ahead scheduling is then assumed binding, and excursions from hour-ahead forecast levels occurring during the operating hour being scheduled must be managed by Idaho Power's system.

To manage the excursions from hour-ahead forecasts during the operating hour, Idaho Power must schedule bidirectional (INC/DEC) capacity in reserve on dispatchable generators. In the modeling for the study, this capacity in reserve is scheduled on Hells Canyon Complex (HCC) hydroelectric generators (Brownlee, Oxbow, and Hells Canyon), natural gas-fired generators (Langley Gulch, Danskin, and Bennett Mountain), and Jim Bridger coal-fired generators. The allocation of reserve to these generators matches Idaho Power's practice for balancing variations in wind production and load.

RESULTS

The objective of the Idaho Power solar integration study is to determine the costs of the operational modifications necessary to integrate solar PV power plant generation. The integration costs are driven by the need to carry extra capacity in reserve to allow bidirectional response from dispatchable generators to unplanned changes in solar production. The simulations performed for the Idaho Power solar integration study indicate the following costs associated with holding the extra solar-caused capacity in reserve (Table 8). Integration costs are provided in nominal terms for the simulated years and in terms assuming a base year of 2016. The costs are not averaged or levelized over the life of a solar plant.

Table 8
Integration cost per MWh for solar build-out scenarios

Solar Build-Out Scenario	Water Year with Hydro Level	Test – Base Cost Difference	Solar MWh	Nominal Solar Integration Costs per megawatt-hour (MWh)	2016$ Solar Integration Costs per MWh[1]
400 MW	2011 (high)	$303,954	607,961	$0.50	$0.56
	2012 (med)	$85,288	607,960	$0.14	$0.15
	2013 (low)	$58,014	607,529	$0.10	$0.10
800 MW	2011 (high)	$1,079,810	1,219,244	$0.89	$0.99
	2012 (med)	$338,632	1,225,743	$0.28	$0.30
	2013 (low)	$496,770	1,217,423	$0.41	$0.44
1,200 MW	2011 (high)	$1,654,781	1,831,956	$0.90	$1.01
	2012 (med)	$730,371	1,844,933	$0.40	$0.43
	2013 (low)	$1,088,246	1,828,441	$0.60	$0.64
1,600 MW	2011 (high)	$2,492,214	2,451,006	$1.02	$1.13
	2012 (med)	$1,307,219	2,475,258	$0.53	$0.58
	2013 (low)	$1,914,841	2,451,870	$0.78	$0.83

[1] Escalation to 2016 base year using 2015 *Integrated Resource Plan* (IRP) general operations and maintenance (O&M) escalation rate of 2.2%.

The integration costs provided in Table 8 indicate a consistent pattern of higher integration costs for higher water conditions. Idaho Power has discussed this result with the TRC, and has communicated that during higher water years system flexibility can be highly constrained. Averaging over the three simulated water years yields the following integration costs (Table 9).

Table 9
Average integration cost per MWh for solar build-out scenarios

	0–400 MW	0–800 MW	0–1,200 MW	0–1,600 MW
Integration cost (2016$)	$0.27/MWh	$0.57/MWh	$0.69/MWh	$0.85/MWh

The integration cost results in Table 9 are the cost per MWh (2016$) to integrate the full installed solar power plant capacity at the respective scenarios studied. For example, the integration cost results indicate the total solar power plant capacity making up the 400 MW build-out scenario brings about costs of $0.27 for each MWh integrated.

Integration costs can be expressed alternatively in terms of incremental costs. Integration costs when expressed incrementally assume early projects are assessed lesser integration costs, and later projects need to make up the difference to allow full cost recovery for a given build-out scenario. For example, if solar plants comprising the first 400-MW build-out are assessed integration costs of $0.27/MWh, then plants comprising the increment between 400 MW and 800

MW need assessed integration costs of $0.88/MWh to allow full recovery of the $0.57/MWh costs to integrate 800 MW of solar plant capacity. Incremental solar integration costs are provided in Table 10.

Table 10
Incremental integration cost results for solar build-out scenarios

	0–400 MW	400–800 MW	800–1,200 MW	1,200–1,600 MW
Integration cost (2016$)	$0.27/MWh	$0.88/MWh	$0.92/MWh	$1.31/MWh

Energy Imbalance Market Sensitivity Analysis

Idaho Power is currently investigating costs and benefits of participation in EIMs such as that managed by the Western EIM (formerly referred to as the California Independent System Operator or CAISO). Among the benefits commonly associated with an EIM is its capability to provide flexibility for balancing variable energy sources, such as solar. It is noted that Idaho Power's current investigation of EIM costs and benefits is a comprehensive analysis focusing on benefits beyond those associated with integration of variable energy sources.

Idaho Power conducted a sensitivity analysis for the solar integration study to provide preliminary assessment of EIM benefits related to solar integration. For this preliminary EIM sensitivity analysis, the company assumed wholesale energy market trading is performed on a 15-minute window instead of hourly. The shortened trading window is assumed to allow a reduction in operating reserve requirements. The EIM sensitivity analysis indicates potential integration benefits associated with EIM participation, including the potential for reduced integration costs. Idaho Power emphasizes that contemplated EIMs are not expected to trade capacity products (i.e., operating reserves); thus, the capability to satisfy all or part of INC/DEC reserve requirements through EIM participation is not anticipated.

The sensitivity's indication of integration benefits is considered preliminary. Idaho Power will continue its ongoing investigation of costs and benefit of participating in an EIM. Once that investigation is completed, the company will have more information for estimating the potential level of impact an EIM might have on solar integration costs.

Study Findings

Hour-ahead Solar Production Forecasting

Analyses suggest a persistence-based forecast with adjustment to account for known changes in the sun's position provides a reasonable production forecast for hour-ahead operations scheduling. The persistence-based, hour-ahead solar production forecast used for the study is based on observed production and, consequently, could be readily adopted in practice.

While a day-ahead solar production forecast would be necessary in practice for a balancing authority integrating solar, this study assumes deviations from the day-ahead forecast can be managed through a combination of market transactions and operations modifications, and, consequently, the study imposes no reserve requirement to cover deviations for day-ahead solar production forecasts.

Compared to wind, system operators managing a balancing authority integrating solar would have the benefit of at least 6 hours at the start of day with no or little solar production. During this period of no or little solar production, system operators could evaluate the day-ahead solar production forecast using information from updated weather forecast products and begin to plan for necessary actions to manage deviations from the day-ahead solar production forecast.

Figure 8 plots daily production (MWh) versus month for the 678 MW of wind capacity Idaho Power integrates (January 2013–September 2015 data) and for the 800-MW solar build-out (data for water years 2011–2013). The graph (Figure 8) demonstrates that daily production for solar follows an intuitive seasonal pattern of high summer and low winter production, and that the distribution of daily production is markedly narrower for solar compared to wind. The lower variability in daily solar production, evident by the narrower distribution for all months, is indicative of the relative challenges associated with day-ahead forecasting of wind and solar production.

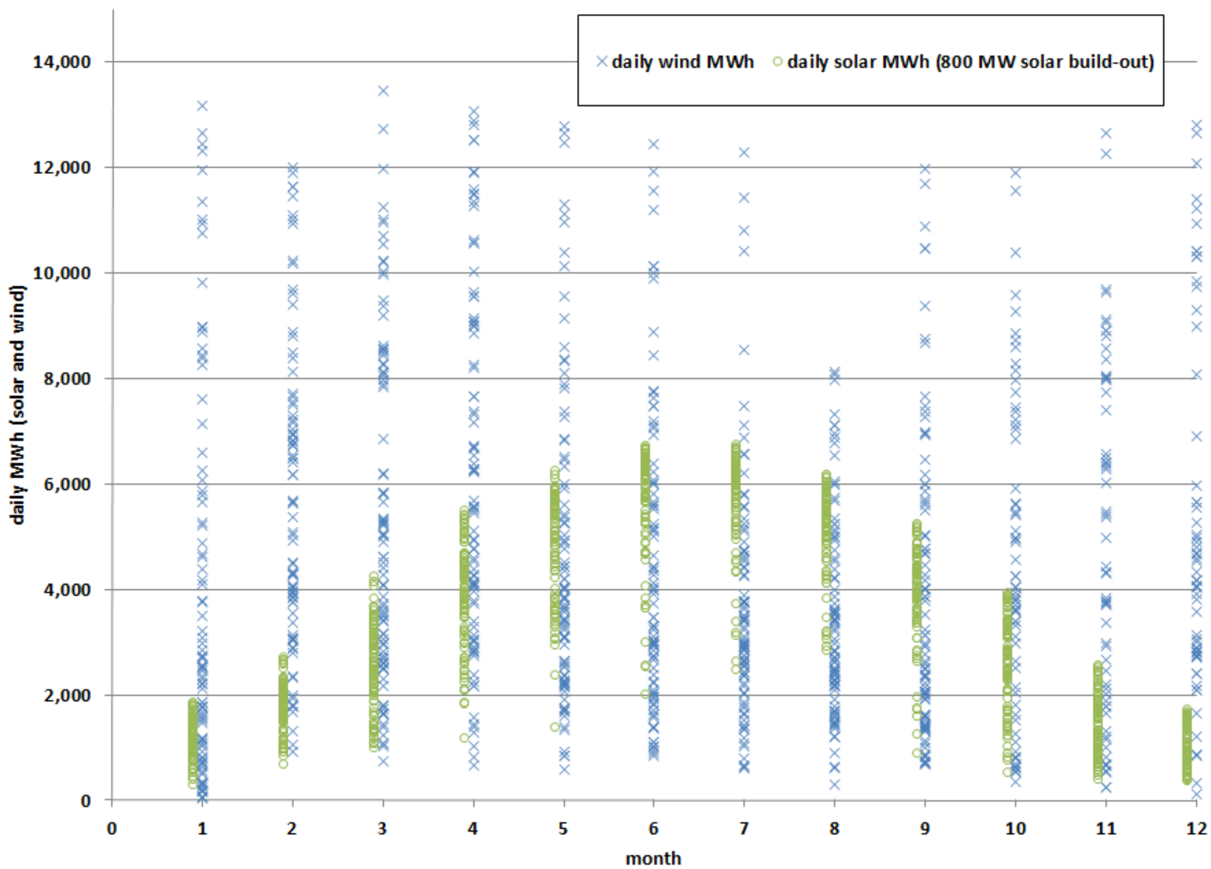

Figure 8
Distributions of daily MWh by month for wind and solar (800-MW solar build-out).

In contrast to day-ahead production forecasting, deviations from the hour-ahead solar production forecast can only be covered by Idaho Power's dispatchable generators. By design, the analysis for the solar integration study determines the amounts of bidirectional capacity in reserve that system operators would need to schedule to position dispatchable generators to cover possible deviations from the hour-ahead solar production forecast. The integration costs found by the study are a result of the solar-caused capacity in reserve, specifically the sub-optimal scheduling of dispatchable generators associated with the extra reserve amounts.

Comparison to Wind Integration

This study indicates solar plant integration costs are substantially lower than wind plant integration costs found by Idaho Power studies of wind integration. The lower integration costs associated with solar are fundamentally the result of less variability and uncertainty.
As described in the preceding section, the study assumes deviations in solar plant production from day-ahead forecast levels can be managed through a combination of market transactions and operations modifications, allowing day-ahead generation scheduling to avoid extra reserve burden. Therefore, reserve carried for solar generation can be focused on readying dispatchable generators to respond to unplanned solar excursions from hour-ahead production forecasts.

Qualitatively, the study data suggest solar is more predictable than wind generation connected to the Idaho Power system. Sunrise and sunset times, as well as the time of solar noon, are a certainty. The theoretical maximum level of production can be readily derived, reflecting patterns on daily, monthly, and seasonal time scales. Finally, land requirements for a solar power plant are likely to promote a relatively high level of dispersion, which is critical to the mitigation of impacts from severe and abrupt ramps in production exhibited by individual panels in response to passing clouds. The effects of geographic dispersion are discussed further in the following section.

Geographic Dispersion and Solar Variability

Production for a single solar PV panel exhibits severe and abrupt intermittency during variably cloudy conditions. The effect of severe and abrupt intermittency is commonly attributed to the absence of inertia in the PV process. While the intermittency effect is severe for a single panel, dampening occurs when considering the production from a solar plant-sized aggregation of panels, and even further dampening occurs when considering the production from several solar plants spread over a region such as southern Idaho. Therefore, geographic dispersion has significant influence on solar integration impacts and is perhaps of greater importance for solar than wind.

The four studied solar build-out scenarios each have capacity installed at eight southern Idaho locations spread over more than 220 miles from east to west. Because of the substantial geographic dispersion, severe instantaneous ramps in solar production for the study data are relatively infrequent. If solar plant development in southern Idaho occurs in a more clustered fashion than assumed for this study, actual integration impacts and costs will be higher than the results of this study.

The study's characterizations of solar variability and uncertainty are based on solar production time series as derived from AgriMet and SolarAnywhere point-source data; actual production data for solar power plant locations in the southern Idaho area were not available for the study. As production data become available over the coming years from solar projects connecting to the Idaho Power system, the actual production data will be analyzed to compare their variability and uncertainty characteristics to those of the derived production data used for the study.
The evidence of significant disparities in variability and uncertainty between the actual and study production data will require a re-examination of the results of this study.

Transmission and Distribution

The focus of Idaho Power's solar integration study is a macro-level investigation of the operations modifications necessary to maintain balance between power supply and customer demand for a balancing authority integrating PV solar plant generation. The objective is to understand the impacts and costs of the sub-optimal operation of dispatchable generating capacity. The study is not an investigation of integration issues related to the delivery of energy from proposed solar PV power plants to the retail customer; these issues are addressed in individual interconnection studies performed on a plant-by-plant basis.

Solar Integration Cost Elements

Idaho Power and the TRC engaged in several conceptual-level discussions on solar integration as part of TRC meetings. These discussions are valuable opportunities to further the collective conceptual-level understanding of Idaho Power and the TRC with respect to factors driving solar integration costs and impacts. These discussions also highlighted the need to provide a listing of those factors, or elements, considered to influence costs, and conversely those elements *not* considered to influence costs. Based on this solar integration study, Idaho Power considers the following as key elements influencing solar integration costs:

- The need to carry bidirectional capacity in reserve on dispatchable generators to respond to next-hour variability and uncertainty
- Incremental Hells Canyon Complex spill attributable to solar-caused capacity in reserve requirements

Conversely, the following are not considered as elements influencing solar integration costs:

- Uncertainty in day-ahead forecasting of solar production
- Solar production profiles, specifically coincidence between solar production and high/low load, or coincidence between solar production and high/low wholesale electric power market prices

Hells Canyon Complex Spill

The results indicate that spill at the Hells Canyon Complex increases with increasing solar build-out. Corresponding to the increase in spill is a decrease in Hells Canyon Complex production. For example, the decrease in simulated Hells Canyon Complex production for water year 2012 from the 400 MW to 1,600 MW solar build-out was about 250,000 MWh, which represents approximately 13 percent of the incremental generation of the additional 1,200 MW of installed solar capacity. The 250,000 MWh of lost Hells Canyon Complex generation is not included in the integration costs in this report.

The finding of increased spill with increasing solar build-out is roughly equivalent for the paired simulations; that is, spill increases for the base cases and test cases alike. This suggests that the increased spill is more the result of energy oversupply than driven by solar-caused operating reserves, noting that the paired simulations are energy equivalent and differ only in their INC/DEC reserve requirements.

The lost hydro generation is partially an artifact of a modeling assumption of keeping the weekly volumetric reservoir releases in the simulations equal to the historical record and partially a cost that would be borne by the excessive development of solar via the avoided cost process. The historic hydro operation would likely be modified in anticipation of the solar energy in an attempt to use the hydro in the most economic way possible and reducing the spilled energy. The avoided cost process with an increase of zero marginal cost energy has more hours where the highest cost marginal resource is zero. The solar energy value during these hours is zero and consequently does not “cost” the system anything. The solar is valued at the cost of the displaced hydro which is zero.

Spring-Season Integration

The production cost simulations suggest reserve requirements are particularly problematic when hydroelectric resources are highly constrained, such as frequently occurs during spring-season periods characterized by high water, low customer demand, and high generation from variable generating resources, such as wind and solar. Experience has shown wind integration to be particularly challenging during these periods, and the simulations suggest similar challenges integrating solar. This study finding is corroborated by NREL in the Western Wind and Solar Integration Study Phase 2 (Lew et al. 2013), which reports the need for flexibility is notably high during the spring and that during these periods the curtailment of variable generation is one source of flexibility along with dispatchable generators enabling the balancing of generation and customer demand. Under futures with high penetrations of solar and wind, the production from the solar and wind resources could conceivably exceed customer demand for the Idaho Power system. Even for the current system without high penetrations of solar, issues related to energy oversupply are periodically encountered because of high wind production and must-run generation (e.g., run-of-river hydro).

CONCLUSIONS

The cost to integrate the variable and uncertain delivery of energy from solar PV power plants is driven by the need to carry extra capacity in reserve. This extra capacity in reserve is necessary to allow bidirectional response from dispatchable generators to unplanned excursions in solar production relative to hour-ahead forecasting. The simulations performed for this Idaho Power solar integration study indicate costs as provided in the Results section associated with holding the extra capacity in reserve (Tables 8 through 10).

The four studied build-outs have solar capacity dispersed widely across southern Idaho. The extent of this geographic dispersion is considered to strongly influence the impacts and costs of integration. As solar capacity is developed in the coming years, Idaho Power will evaluate the geographic dispersion of the built-out capacity in comparison to that assumed for this study. In particular, observed production data will be reviewed when available to verify this study's assessment of solar variability and uncertainty.

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Appendix 1
Solar integration study appendix

Table of Contents

INTRODUCTION

This appendix contains supporting data and explanatory materials used to develop Idaho Power's *2016 Solar Integration Study*.

The main document, the *2016 Solar Integration Study*, contains a full narrative of Idaho Power's process for studying solar integration costs. For information or questions concerning the study, contact Idaho Power:

Idaho Power—Power Supply Planning
1221 W. Idaho St.
Boise, Idaho 83702
208-388-5365

TECHNICAL REVIEW COMMITTEE

The Technical Review Committee (TRC) was formed during early 2015 to provide input, review, and guidance for the study. It is comprised of participants from outside Idaho Power that have an interest and/or expertise with the integration of intermittent resources onto utility systems.

Representatives from National Renewable Energy Laboratory (NREL) participated in the early stages of the study, and contributed to the study's foundational development. However, NREL funding did not permit their active participation through study completion. Idaho Power continued to include NREL on electronic correspondence related to the study through study completion.

List of TRC Members

Brian Johnson...................University of Idaho

Cameron Yourkowski ......Renewable Northwest

Clint Kalich......................Avista Corporation

Kurt Myers.......................Idaho National Laboratory

Barbara O'Neill................National Renewable Energy Laboratory

Michael Milligan..............National Renewable Energy Laboratory

Regulatory Commission Staff Observers

Brittany Andrus................Public Utility Commission of Oregon (OPUC) staff

John Crider.......................OPUC Staff

Rick Sterling ....Idaho Public Utilities Commission (IPUC) staff

DATA INPUTS AND ASSUMPTIONS

Natural Gas Price Assumptions

Table 1
Actual monthly average Idaho Citygate natural gas price for water years 2011–2013

Month	Water Year (WY) 2011 Average Monthly Price	WY 2012 Average Monthly Price	WY 2013 Average Monthly Price
October	$3.15	$3.30	$3.32
November	$3.63	$3.33	$3.48
December	$4.00	$3.18	$3.35
January	$4.22	$2.68	$3.38
February	$3.91	$2.53	$3.32
March	$3.76	$2.05	$3.71
April	$3.93	$1.83	$3.92
May	$3.98	$2.21	$3.82
June	$4.23	$2.16	$3.22
July	$4.00	$2.55	$3.36
August	$3.80	$2.61	$3.05
September	$3.73	$2.63	$3.21

Market Power Price Assumptions

Table 2
Actual average Mid-Columbia dollars/megawatt-hour (MWh) for water years 2011–2013

Month	WY 2011 Average Monthly Price	WY 2012 Average Monthly Price	WY 2013 Average Monthly Price
October	$28.78	$24.27	$26.92
November	$31.13	$27.40	$25.42
December	$31.59	$28.96	$20.04
January	$25.22	$24.51	$27.37
February	$20.70	$21.64	$25.24
March	$15.78	$13.61	$27.89
April	$16.93	$7.02	$20.10
May	$16.57	$6.56	$19.99
June	$13.09	$4.40	$25.15
July	$18.51	$7.90	$27.68
August	$25.29	$19.16	$31.28
September	$28.14	$22.63	$29.80

IPC Customer Load Data

Table 3
Actual average megawatt (MW) for water years 2011–2013

Month	WY 2011 Average Monthly Load	WY 2012 Average Monthly Load	WY 2013 Average Monthly Load
October	1,417	1,400	1,453
November	1,577	1,559	1,474
December	1,699	1,731	1,640
January	1,745	1,683	1,912
February	1,650	1,600	1,624
March	1,509	1,463	1,442
April	1,411	1,505	1,502
May	1,489	1,737	1,802
June	1,823	2,111	2,162
July	2,275	2,393	2,419
August	2,128	2,200	2,232
September	1,807	1,683	1,660

Idaho Power Existing Generation

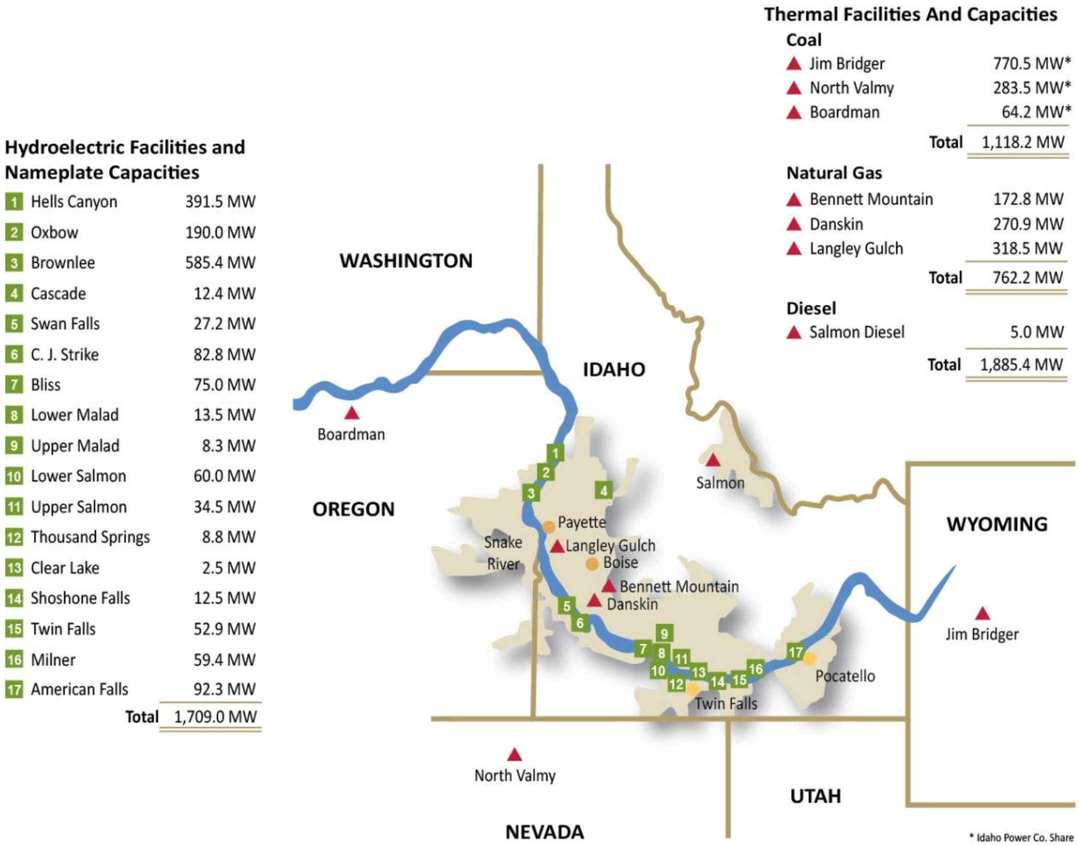


Figure 1
Existing Idaho Power generating resources

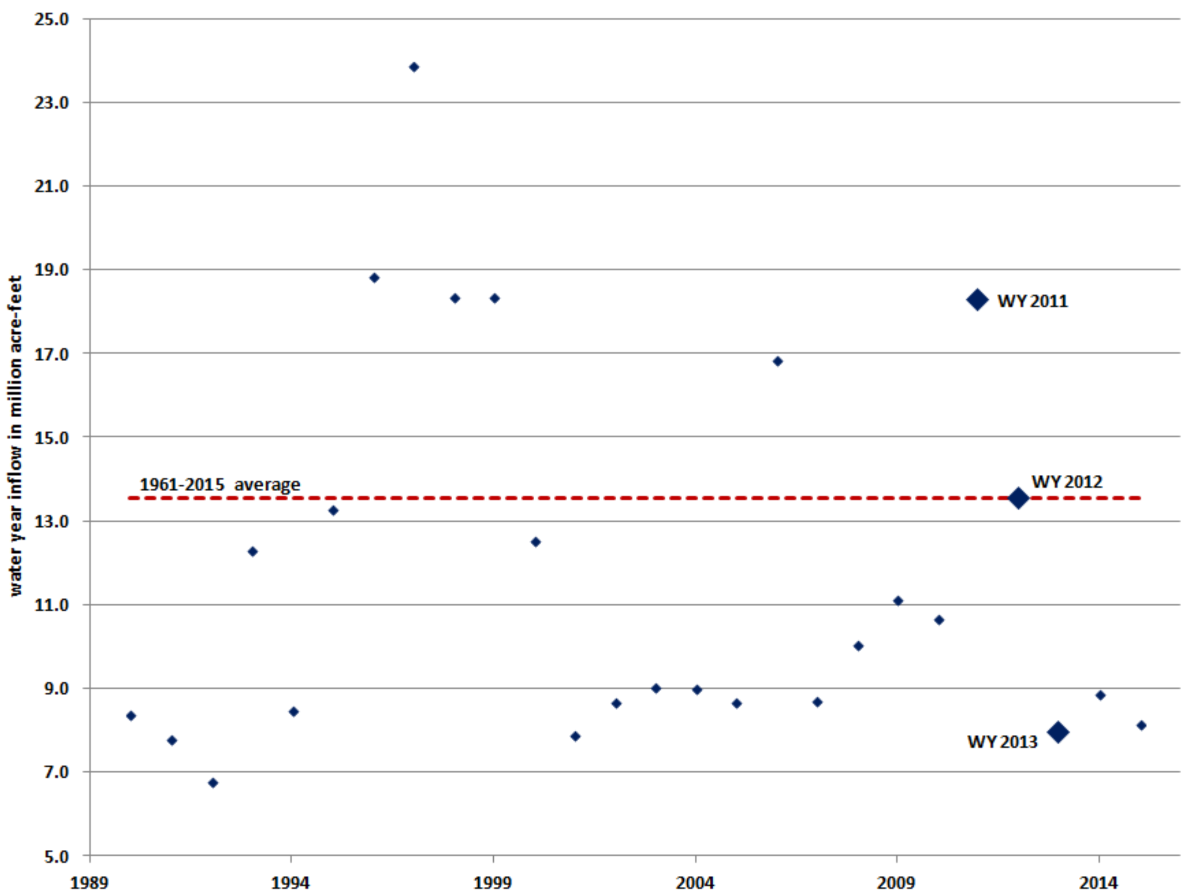


Figure 2
Brownlee Reservoir inflow by water year

Hydroelectric Generation Data

Run-of-River Projects

Table 4
Actual monthly average MW (aMW) for water years 2011–2013

Month	WY 2011 aMW	WY 2012 aMW	WY 2013 aMW
October	435	451	191
November	374	423	166
December	470	419	177
January	346	360	178
February	373	369	188
March	348	383	178
April	505	391	164

Table 4 (Continued)

Month	WY 2011 aMW	WY 2012 aMW	WY 2013 aMW
May	517	256	351
June	510	341	231
July	418	295	227
August	435	254	218
September	458	211	197

Wind Generation Data

Aggregate PPA and PURPA Projects

Table 5
Actual monthly aMW for water years 2011–2013, unadjusted and adjusted (normalized) to 678 MW on-line capacity level

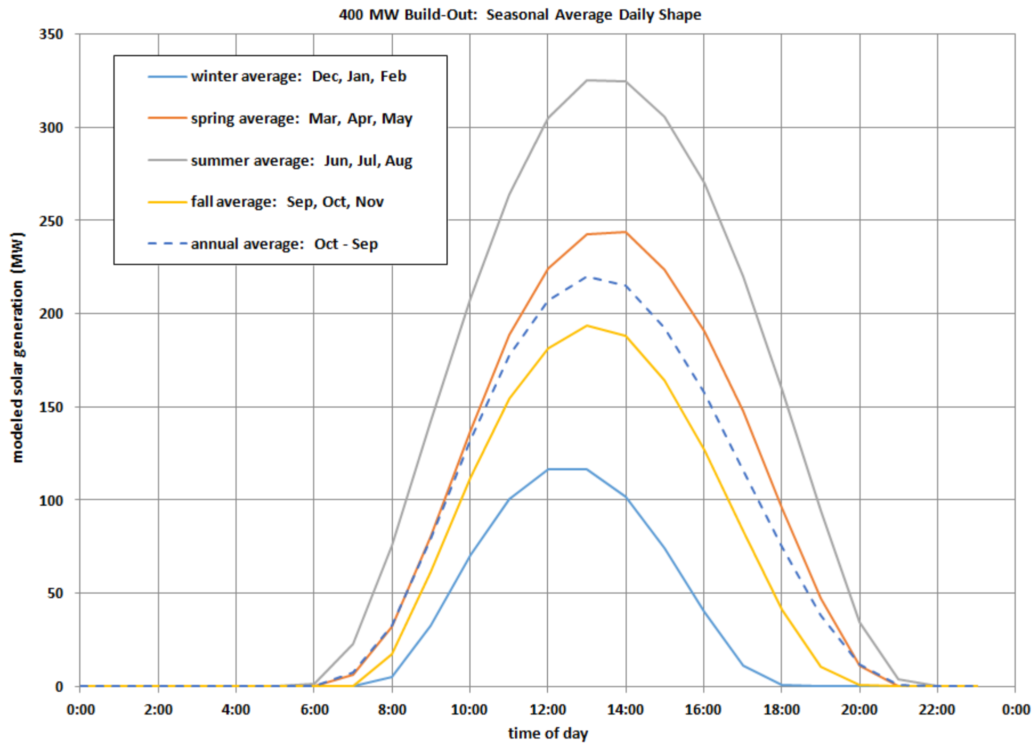
	WY 2011			WY 2012			WY 2013		
Month	**aMW**	**Online capacity**	**Adjusted aMW**	**aMW**	**Online capacity**	**Adjusted aMW**	**aMW**	**Online capacity**	**Adjusted aMW**
October	51	208	167	95	395	164	151	638	161
November	74	208	241	190	417	309	201	638	214
December	84	208	272	120	500	162	221	638	234
January	80	273	200	194	500	264	181	678	181
February	110	373	200	167	500	227	261	678	261
March	125	373	228	191	500	259	240	678	240
April	141	373	257	172	500	233	267	678	267
May	141	395	241	166	500	225	209	678	209
June	119	395	205	163	500	221	176	678	176
July	93	395	160	144	523	187	152	678	152
August	79	395	135	131	638	139	141	678	141
September	73	395	125	116	638	123	196	678	196

Non-Wind PURPA Generation Data

Table 6
Based on April 2015 projections for calendar year 2016

Month	WY 2011 aMW	WY 2012 aMW	WY 2013 aMW
October	78	78	78
November	49	49	49
December	48	48	48
January	45	45	45
February	47	47	47
March	51	51	51
April	81	81	81
May	122	122	122
June	127	127	127
July	125	125	125
August	119	119	119
September	108	108	108

Solar Production Data



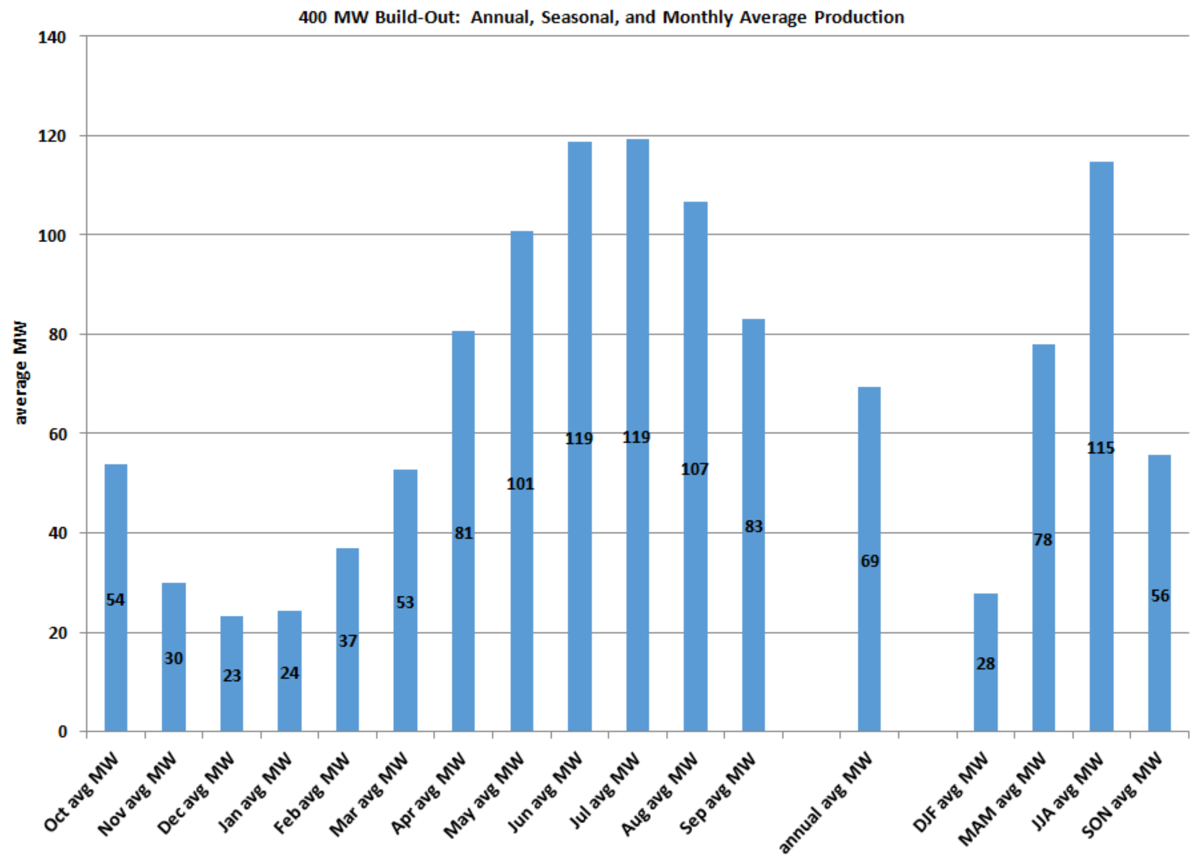
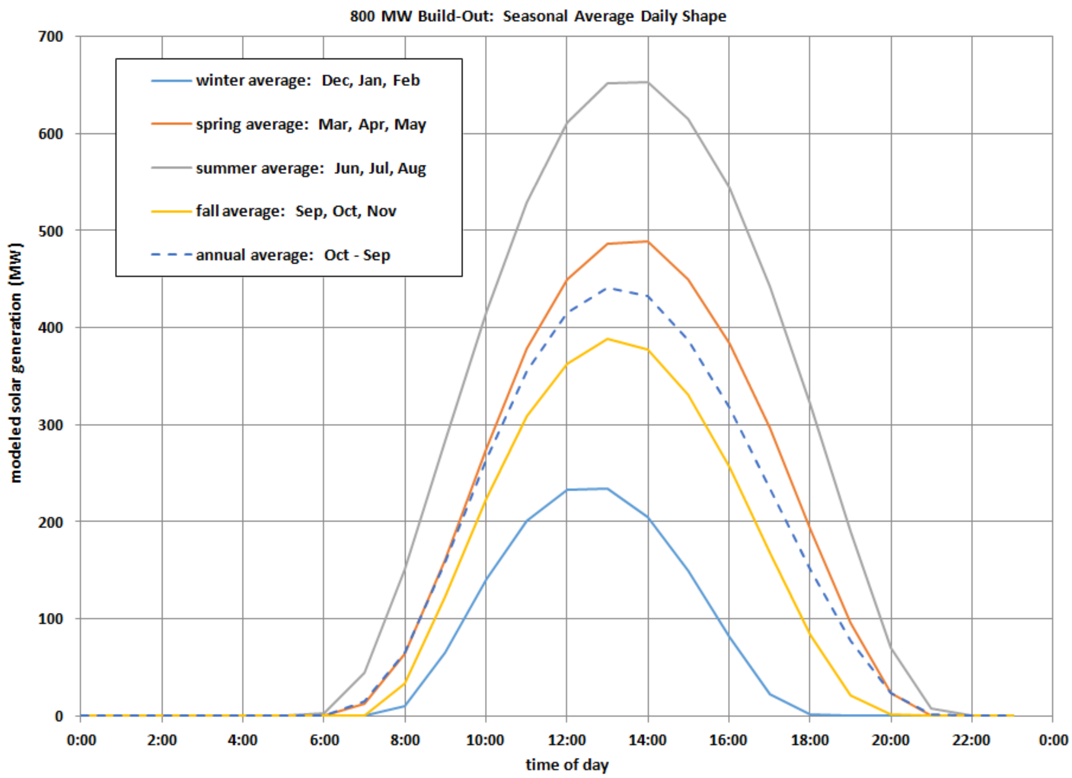


Figure 3
400 MW build-out production graphs



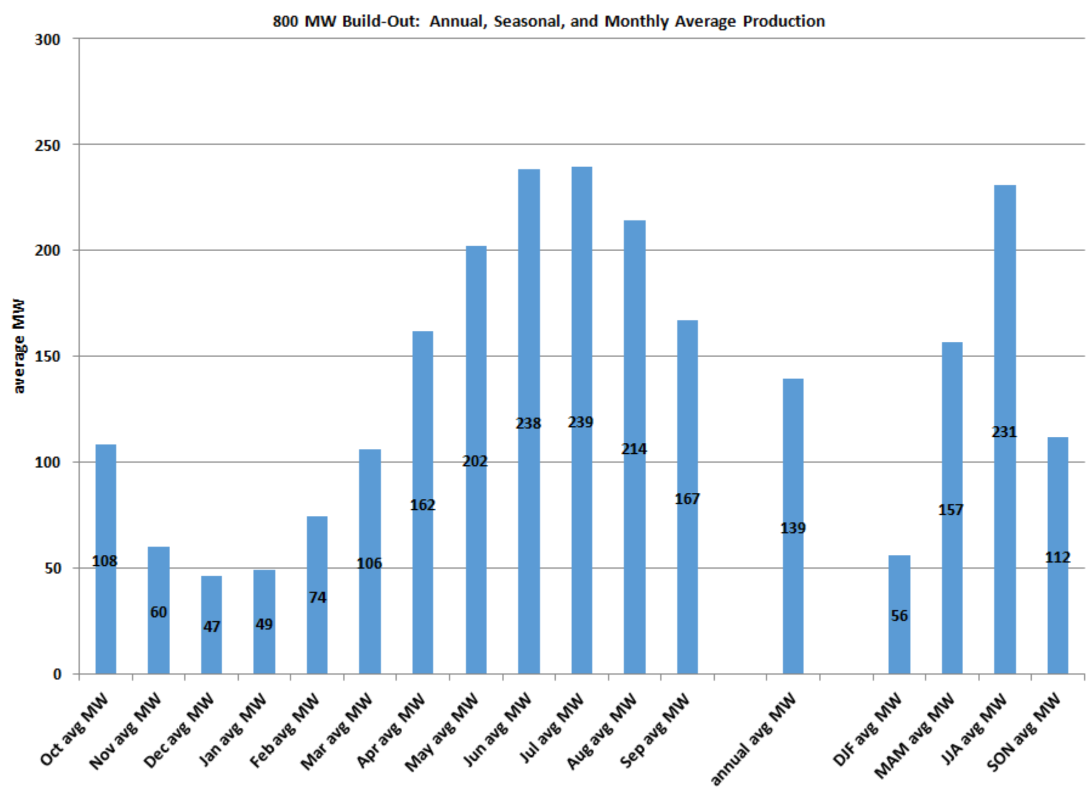
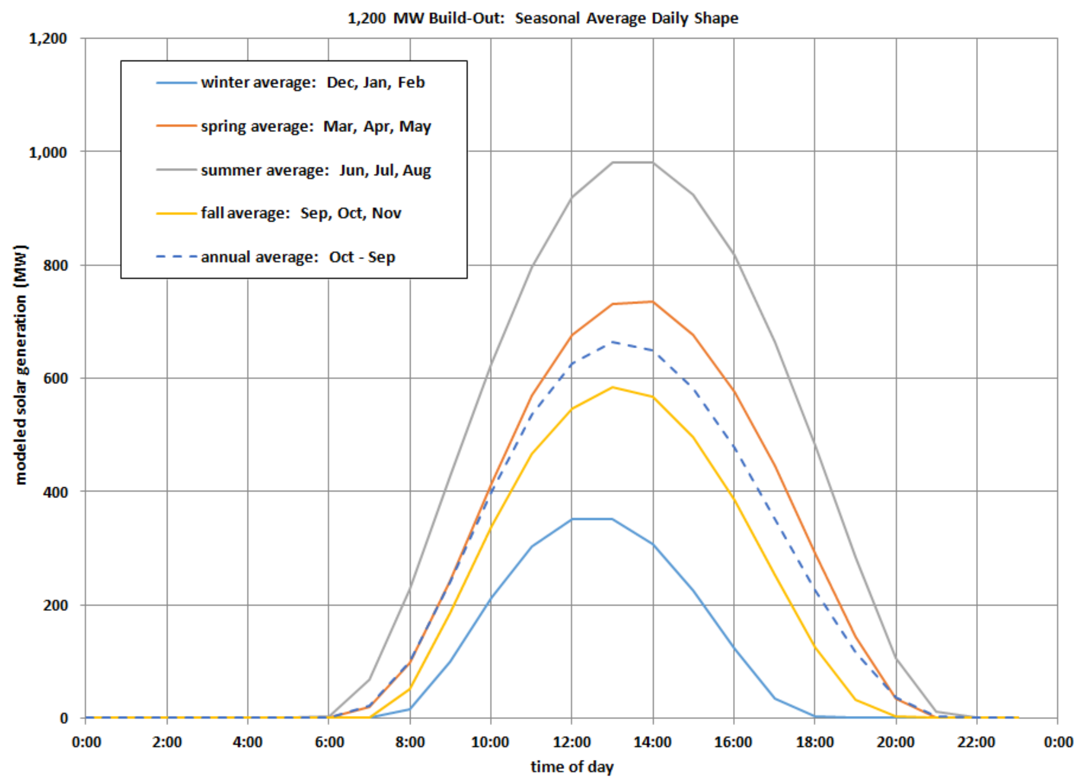


Figure 4
800-MW build-out production graphs



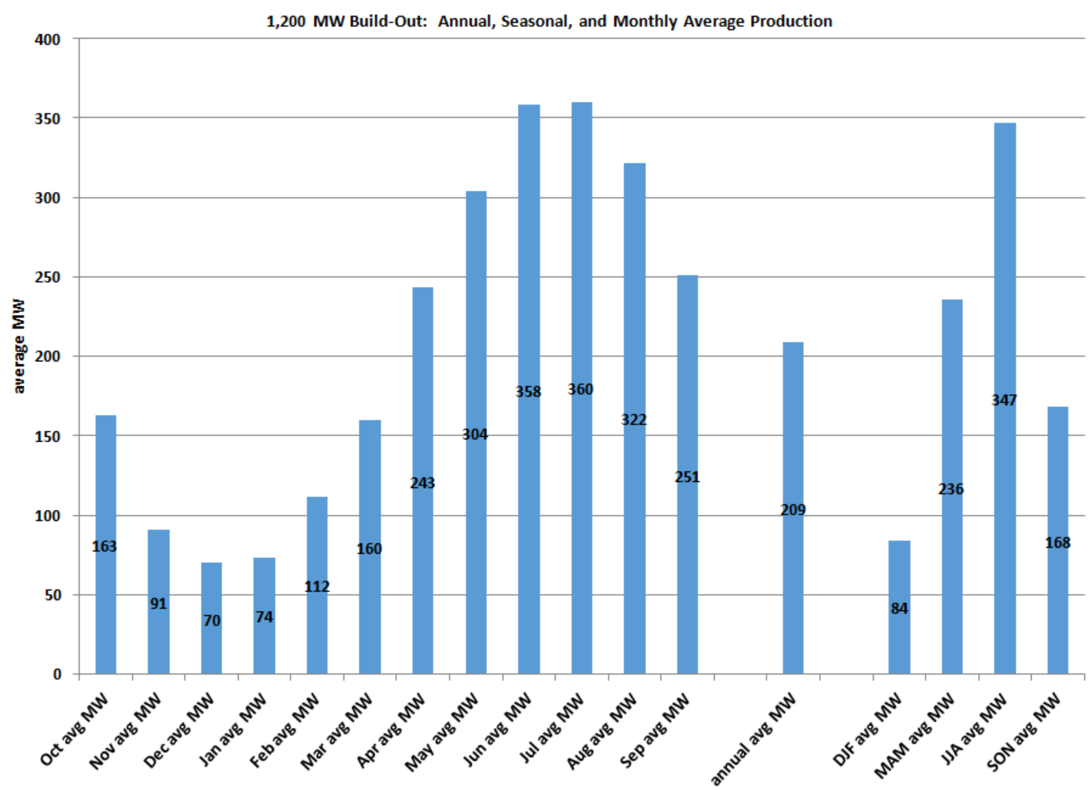
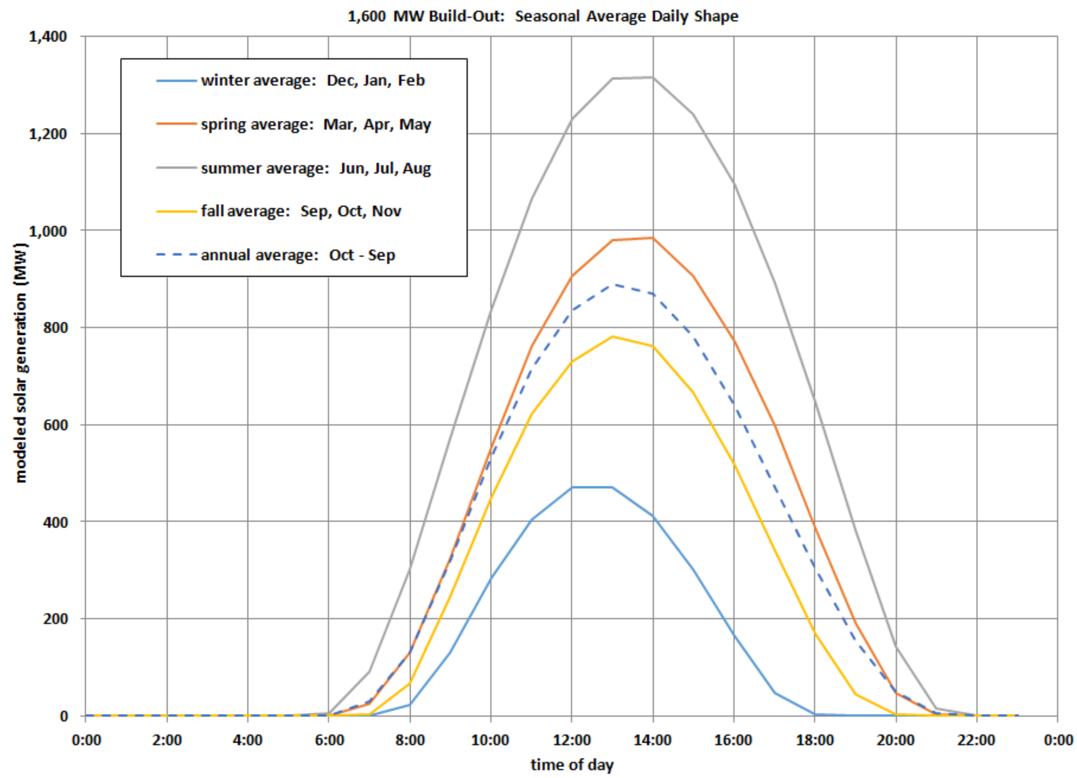


Figure 5
1,200-MW build-out production graphs



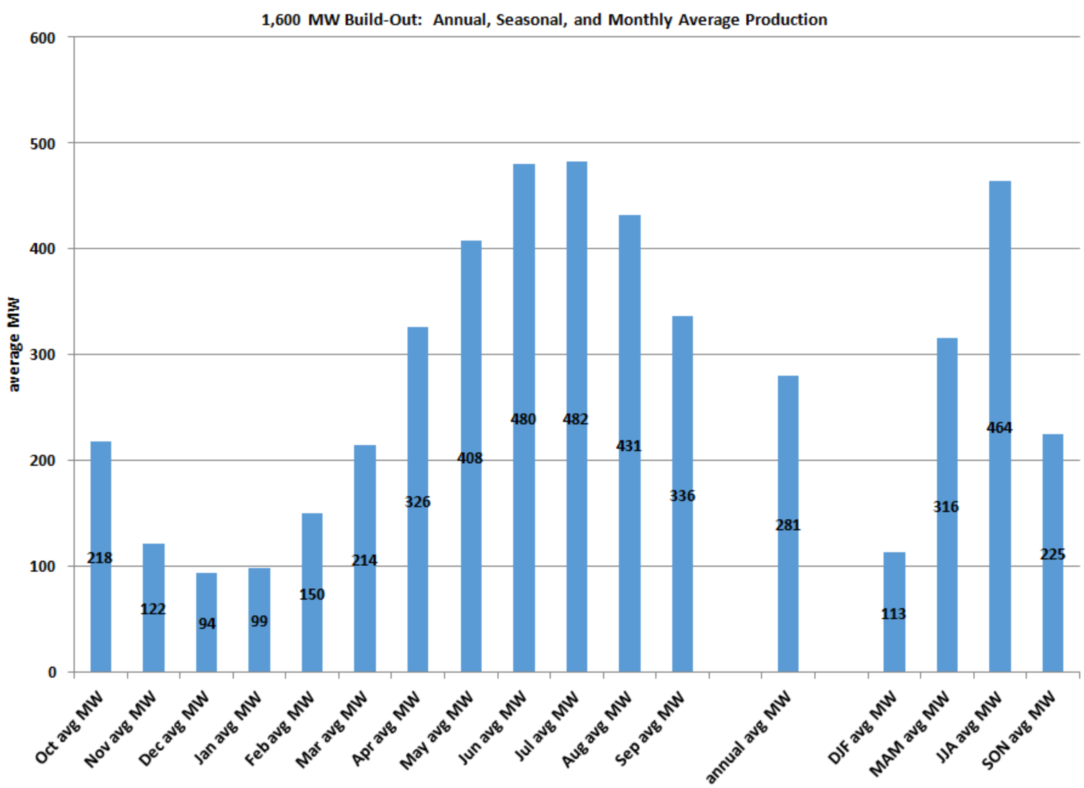


Figure 6
1,600-MW build-out production graphs

SETTLEMENT STIPULATION

The first Idaho Power solar integration study was completed in June 2014. The first study investigated integration of 4 solar PV build-outs: 100 MW, 300 MW, 500 MW, and 700 MW. The costs from the first study were the basis for solar integration costs included in the IPUC Schedule 87, which was part of a settlement stipulation approved by the IPUC in February 2015 (IPUC Case No. IPC-E-14-18). The settlement stipulation associated with the first Idaho Power solar integration study is provided here.

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BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF IDAHO POWER COMPANY'S APPLICATION TO IMPLEMENT SOLAR INTEGRATION RATES AND CHARGES.	CASE NO. IPC-E-14-18 SETTLEMENT STIPULATION AND MOTION TO APPROVE SETTLEMENT STIPULATION

This settlement stipulation ("Settlement Stipulation") is entered into between Idaho Power Company ("Idaho Power" or "Company"); Idaho Public Utilities Commission Staff ("Staff"); the Idaho Conservation League ("ICL"), the Sierra Club, and the Snake River Alliance ("SRA"), hereafter jointly referred to as "Parties." The Parties hereby agree as follows.

I. INTRODUCTION AND MOTION

1. The terms and conditions of this Settlement Stipulation are set forth herein. The Parties agree that this Settlement Stipulation represents a fair, just, and reasonable compromise of the dispute(s) between the Parties and that this Settlement Stipulation is in the public interest. The Parties maintain that the Settlement Stipulation as a whole and its acceptance by the Idaho Public Utilities Commission ("Commission") represent a reasonable resolution of all issues between the Parties identified herein.

Therefore, the Parties hereby respectfully move the Commission, in accordance with RP 56 and RP 274-76, for an Order approving the Settlement Stipulation executed between the Parties and all of its terms and conditions without material change or condition.

II. BACKGROUND

2. On July 1, 2014, Idaho Power filed an Application with the Commission requesting Commission approval of Idaho Power's proposed implementation of solar integration rates and charges as set forth in the proposed Schedule 87, Variable Generation Integration Charges, as indicated by the 2014 Solar Integration Study Report ("Solar Study") filed with the Application. On July 23, 2014, the Commission issued a Notice of Application and Notice of Intervention Deadline. Order No. 33079. ICL, the Sierra Club, and SRA petitioned for intervention which was granted. Order No. 33090; Order No. 33097.

3. On September 24, 2014, the Commission issued a Notice of Scheduling and Notice of Technical Hearing, Order No. 33137, setting forth deadlines for testimony and setting the Technical Hearing for November 13, 2014. On November 6, 2014, the Commission approved the Parties' request to suspend the procedural schedule by striking the rebuttal testimony filing deadline and Technical Hearing. The Parties agreed to meet for settlement discussions and that if settlement discussions were unsuccessful to re-establish mutually agreeable dates for the submission of rebuttal testimony and a Technical Hearing. Order No. 33173.

4. The Parties met on November 17, 2014, for settlement discussions and reached agreement resolving the issues in this case and between the Parties. Based upon the settlement discussions, as a compromise of the respective positions of the

parties, and for other consideration as set forth below, the Parties agree to the following terms:

III. TERMS OF THE SETTLEMENT STIPULATION

5. Implementation of Schedule 87, Variable Generation Integration Charges - The Parties agree to Commission approval and implementation of Schedule 87, Variable Generation Integration Charges, including the rates and charges as proposed and filed by Idaho Power in this proceeding to implement solar integration charges.

6. Initiation of a Second Solar Integration Study – The Parties acknowledge that there are disagreements with respect to the methodology used in the 2014 Solar Study. The Parties agree that Idaho Power will initiate a second solar integration study in January 2015. This second solar integration study should be completed as expeditiously as possible with the goal of not exceeding 12 months. Upon completion of the second solar integration study Idaho Power will file the same with the Commission seeking to update Schedule 87 with the results of said study.

7. Conduct of the Second Solar Integration Study - The Parties agree that the second solar integration study should utilize a Technical Review Committee ("TRC") that generally adheres to the *Principles for Technical Review Committee Involvement in Studies of Wind Integration into Electric Power Systems* authored by the National Renewable Energy Laboratory and the Utility Wind Integration Group. The TRC should include members with expertise in solar generation, variable energy integration, and electrical grid operations. The Parties also anticipate participation in the second solar integration study from the Idaho Public Utilities Commission Staff, the Public Utility Commission of Oregon Staff, the appropriate personnel from Idaho Power, and a technical expert designated by each of the Parties herein. The Parties agree that the

TRC will assist in developing the scope of the second solar integration study and provide advice on the best available methods to analyze solar integration needs, strategies, and costs on Idaho Power's system. The Parties agree and acknowledge that Idaho Power is ultimately responsible for determining how the study is conducted, the content of the study, and any results therefrom. If Idaho Power declines TRC member suggestions for the conduct of the study, Idaho Power shall provide explanation and basis for the same in writing as part of the study process.

8. Consideration of Issues in the Second Solar Integration Study - The Parties agree that Idaho Power, together with the TRC, will consider whether the second solar integration study should include the following – and if so, what would be the appropriate methodology to be used in connection with the following:

- Alternative water-year types (e.g., low-type and high-type), range of water years or normalized water year
- Intra-hour trading opportunities
- Shortening the hour-ahead forecast lead time from 45 minutes to 30 minutes
- Clustered solar build-out scenarios
- Other solar plant technologies (e.g., tracking systems or varied fixed-panel orientation)
- Correlation between solar, wind, and load variability, uncertainty, and forecasting error.
- Improved forecasting methods
- Energy imbalance markets, or other market structures
- Voltage/frequency regulation
- Increased transmission capacity, changes in operation of hydroelectric facilities, addition of demand-side technologies

- Gas price forecast(s)
- Modeling of sub-hourly scheduling of load and generation
- Identification of the existence of low occurrence events that contribute to proportionately higher integration costs and possible remedies, including operational or contractual solutions to mitigate these events and reduce integration costs and charges.

9. The Parties submit this Settlement Stipulation to the Commission and recommend approval in its entirety pursuant to RP 274-76. The Parties shall support this Settlement Stipulation before the Commission and shall not appeal a Commission order approving the Settlement Stipulation or an issue resolved by the Settlement Stipulation. If this Settlement Stipulation is challenged by anyone who is not a Party, then each Party reserves the right to file testimony, cross-examine witnesses, and put on such case as they deem appropriate to respond fully to the issues presented, including the right to raise issues that are incorporated in the settlements embodied in this Settlement Stipulation. Notwithstanding this reservation of rights, the Parties agree that they will continue to support the Commission's adoption of the terms of this Settlement Stipulation.

10. If the Commission or any reviewing body on appeal rejects any part or all of this Settlement Stipulation or imposes any additional material conditions on approval of this Settlement Stipulation, then each Party reserves the right, upon written notice to the Commission and the other Party to this proceeding within fourteen (14) days of the date of such action by the Commission, to withdraw from this Settlement Stipulation. In such case, no Party shall be bound or prejudiced by the terms of this Settlement Stipulation and each Party shall be entitled to seek reconsideration of the Commission's

order, file testimony as it chooses, cross-examine witnesses, and do all other things necessary to put on such case as it deems appropriate. In such case, the Parties immediately will request the prompt reconvening of a prehearing conference for purposes of establishing a procedural schedule for the completion of IPUC Case No. IPC-E-13-25, and the Parties agree to cooperate in development of a schedule that concludes the proceeding on the earliest possible date, taking into account the needs of the Parties in participating in hearings and preparing briefs.

11. The Parties agree that this Settlement Stipulation is in the public interest and that all of its terms and conditions are fair, just, and reasonable.

12. No Party shall be bound, benefited, or prejudiced by any position asserted in the negotiation of this Settlement Stipulation, except to the extent expressly stated herein, nor shall this Settlement Stipulation be construed as a waiver of rights unless such rights are expressly waived herein. Except as otherwise expressly provided for herein, execution of this Settlement Stipulation shall not be deemed to constitute an acknowledgment by any Party of the validity or invalidity of any particular method, theory, or principle of regulation or cost recovery, including the methodology employed for the 2014 solar integration study upon which the rates and charges contained in Schedule 87 are based. No Party shall be deemed to have agreed that any method, theory, or principle of regulation or cost recovery employed in arriving at this Settlement Stipulation is appropriate for resolving any issues in any other proceeding in the future. No findings of fact or conclusions of law other than those stated herein shall be deemed to be implicit in this Settlement Stipulation. This Settlement Stipulation sets forth the complete understanding of the Parties, and this Settlement Stipulation includes no other promises, understandings, representations, arrangements or agreements pertaining to

the subject matter of this Settlement Stipulation, or any other subject matter, not expressly contained herein.

13. The obligations of the Parties are subject to the Commission's approval of this Settlement Stipulation in accordance with its terms and conditions and upon such approval being upheld on appeal, if any, by a court of competent jurisdiction. All terms and conditions of this Settlement Stipulation are subject to approval by the Commission, and only after such approval, without material change or modification, has been received shall the Settlement Stipulation be valid.

14. This Settlement Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

IV. PROCEDURE

15. Pursuant to RP 274, the Commission has discretion to determine the manner with which it considers a proposed settlement. In this matter, the Parties have reached agreement on a final resolution to this case. This Settlement Stipulation is reasonable and in the public interest. The Parties request that the Commission approve the Settlement Stipulation without further proceedings.

16. In the alternative, should the Commission determine that further proceedings are required to consider the Settlement Stipulation, pursuant to RP 201, the Parties believe the public interest does not require a hearing to consider the issues presented by this Motion and request it be processed as expeditiously as possible by Modified Procedure, without waiving the right to a hearing on the previously disputed matters in this proceeding should the Commission reject the settlement.

V. REQUESTED RELIEF

NOW, THEREFORE, the Parties respectfully request that the Commission enter its Order approving the Settlement Stipulation without material change or condition, and without further proceedings.

DATED this 7th day of January 2015.

Idaho Power Company

By ______________________
Donovan E. Walker
Attorney for Idaho Power Company.

Commission Staff

By Kristine Sasser
Kristine A. Sasser
Attorney for IPUC Staff

Sierra Club

By ______________________
Dean J. Miller
Attorney for Sierra Club

Idaho Conservation League

By ______________________
Benjamin J. Otto
Attorney for Idaho Conservation League

Snake River Alliance

By ______________________
Kelsey Jae Nunez
Attorney for Snake River Alliance

V. REQUESTED RELIEF

NOW, THEREFORE, the Parties respectfully request that the Commission enter its Order approving the Settlement Stipulation without material change or condition, and without further proceedings.

DATED this 6 day of January 2015.

Idaho Power Company

By______________________________
Donovan E. Walker
Attorney for Idaho Power Company.

Commission Staff

By______________________________
Kristine A. Sasser
Attorney for IPUC Staff

Sierra Club

By______________________________
Dean J. Miller
Attorney for Sierra Club

Idaho Conservation League

By ______________________________
Benjamin J. Otto
Attorney for Idaho Conservation League

Snake River Alliance

By ______________________________
Kelsey Jae Nunez
Attorney for Snake River Alliance

V. REQUESTED RELIEF

NOW, THEREFORE, the Parties respectfully request that the Commission enter its Order approving the Settlement Stipulation without material change or condition, and without further proceedings.

DATED this 7th day of January 2015.

Idaho Power Company

By____________________________
Donovan E. Walker
Attorney for Idaho Power Company.

Commission Staff

By____________________________
Kristine A. Sasser
Attorney for IPUC Staff

Sierra Club

By____________________________
Dean J. Miller
Attorney for Sierra Club

Idaho Conservation League

By Ben Otto
Benjamin J. Otto
Attorney for Idaho Conservation League

Snake River Alliance

By Kelsey Jae Nunez
Kelsey Jae Nunez
Attorney for Snake River Alliance

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 9th day of January 2015 I served a true and correct copy of the SETTLEMENT STIPULATION AND MOTION TO APPROVE SETTLEMENT STIPULATION upon the following named parties by the method indicated below, and addressed to the following:

Commission Staff Kristine A. Sasser Deputy Attorney General Idaho Public Utilities Commission 472 West Washington (83702) P.O. Box 83720 Boise, Idaho 83720-0074	_X_ Hand Delivered ____U.S. Mail ____Overnight Mail ____FAX _X_ Email kris.sasser@puc.idaho.gov
Idaho Conservation League Benjamin J. Otto Idaho Conservation League 710 North Sixth Street (83702) P.O. Box 844 Boise, Idaho 83701	____Hand Delivered _X_ U.S. Mail ____Overnight Mail ____FAX _X_ Email botto@idahoconservation.org
Snake River Alliance Kelsey Jae Nunez Snake River Alliance P.O. Box 1731 Boise, Idaho 83701	____Hand Delivered _X_ U.S. Mail ____Overnight Mail ____FAX _X_ Email knunez@snakeriveralliance.org
Ken Miller Snake River Alliance P.O. Box 1731 Boise, Idaho 83701	____Hand Delivered _X_ U.S. Mail ____Overnight Mail ____FAX _X_ Email kmiller@snakeriveralliance.org
Sierra Club Dean J. Miller McDEVITT & MILLER LLP 420 West Bannock Street (83702) P.O. Box 2564 Boise, Idaho 83701	____Hand Delivered _X_ U.S. Mail ____Overnight Mail ____FAX _X_ Email joe@mcdevitt-miller.com heather@mcdevitt-miller.com

Matt Vespa
Sierra Club
85 Second Street, Second Floor
San Francisco, California 94105

____Hand Delivered
__X__U.S. Mail
____Overnight Mail
____FAX
__X__ Email matt.vespa@sierraclub.org

Christa Bearry, Legal Assistant

TECHNICAL REVIEW COMMITTEE STUDY PLAN

The following document was shared as a draft with the TRC after receiving their input on prioritization of issues for this solar integration study.

“Second” Idaho Power Solar Integration Study

Technical Review Committee Study Plan

Sponsored by:

Idaho Power Company

May 28 , 2015

Table of Contents

1. Objective

Study the integration of Solar onto the Idaho Power System.

2. Project Background

On July 1, 2014, Idaho Power filed an Application with the Idaho Public Utilities Commission requesting Commission approval of Idaho Power’s proposed implementation of solar integration rates and charges as set forth in the proposed Schedule 87, Variable Generation Integration Charges, as indicated by the 2014 Solar Integration Study Report (“Solar Study”) filed with the Application. On July 23, 2014, the Commission issued a Notice of Application and Notice of Intervention Deadline. Order No. 33079. The Idaho Conservation League (“ICL”), the Sierra Club, and the Snake River Alliance (“SRA”) petitioned for intervention which was granted. Order No. 33090; Order No. 33097.

The Parties met on November 17, 2014, for settlement discussions and reached agreement resolving the issues in this case and between the Parties. On January 9, 2015, pursuant to Rules of Procedure 56 and 274 through 276, the parties filed a Joint Motion for Approval of a Settlement Stipulation. The Stipulation, in Order No. 33227, calls for the formation of a Technical Review Committee (“TRC”), see section 3.

The parties agree that the second solar integration study should utilize a Technical Review Committee (TRC) that generally adheres to the *Principles for Technical Review Committee Involvement in Studies of Wind Integration into Electric Power System* authored by the National Renewable Energy Laboratory and the Utility Wind Integration Group. The TRC will advise Idaho Power of the scope and methods use in the analysis, however, Idaho Power is ultimately responsible for determining how the study is conducted, the content of the study, and any results therefrom.

This Study plan will guide the development of a second Solar Integration Study to be filed with the Idaho Commission by the first-quarter 2016.

2.1 2014 Solar Integration Study

The 2014 study performing an integration analysis of four solar penetration levels (100 MW, 300 MW, 500 MW, and 700MW). The analysis took each penetration level and completed two production cost simulations, one with the solar forecast assumed to be perfect and the other including the same level of energy but also holding capacity available in the Idaho Power system to accommodate a predicted level of uncertainty for any given hour. By using the difference method, the value of the energy produced due to the production uncertainties does not get incorporated into the integration cost result.

Idaho Power integration studies use a production cost model developed internally by Idaho Power to closely simulate operation of the Hells Canyon Complex (Brownlee, Oxbow and Hells Canyon hydro plants), the Idaho Power gas and coal thermal generation, and the Idaho Power transmission interconnections. The simulation model represents the three generation facilities in the Hells Canyon Complex in a cascaded fashion where water flows from Brownlee, through Oxbow, and then through the Hells Canyon dam, recognizing that many hydro constraints placed on the complex including flood control and environmental fish mitigation measures. The cascaded simulation means that each dam has separate dispatch considerations yet the dispatch decisions of the upstream plants constrain the dispatch decisions of the downstream plants.

3. Technical Review Committee (TRC)

The following members have agreed to participate in the TRC:

Cameron Yourkowski
Senior Policy Manager
Renewable Northwest
421 SW 6th Ave, Suite 1125
Portland, OR 97204
503-223-4544
971-634-0143
cameron@renewablenw.org

Michael Milligan, Ph.D.
Transmission and Grid Integration
National Renewable Energy Laboratory
15013 Denver West Parkway
Golden, CO 80401
303-384-6927
michael.milligan@nrel.gov

Clint Kalich
Manager, Resource Planning and Power Supply Analyses
Avista Corporation
clint.kalich@avistacorp.com
509.495.4532 work phone
509.777.6061 work fax

Kurt Myers
Project Manager, Idaho National Laboratory
kurt.myers@inl.gov
208-526-5002

Brian Johnson, Ph. D
University of Idaho
bjohnson@ee.uidaho.edu
208-885-6902

Rick Sterling
Idaho Public Utilities Commission
Rick.Sterling@puc.idaho.gov
208-334-0351

John Crider
Oregon Public Utilities Commission
John.crider@state.or.us
503-373-1536

3.1 TRC Principles

Based on the "Principles for Technical Review Committee (TRC) Involvement in Studies of Variable Generation Integration into Electric Power Systems" Paper:

What will the TRC Provide?

A properly constituted TRC will assist the project sponsors in ensuring that the quality of the technical work and the accuracy of results will be as high as possible. TRC participation will also enhance the credibility and acceptance of the study results throughout the affected stakeholder communities. And TRC members will be qualified to carry the key messages of the study to their respective sectors.

What is a Properly Constituted TRC?

TRC membership should include individuals that collectively provide expertise in all of the technical disciplines relevant to the study. A TRC facilitator should be selected from among the TRC membership. Sponsorship and facilitation of the TRC should be independent from, but closely coordinated with, the project sponsors and the team conducting the work. Observers from relevant government agencies and other interested parties may attend TRC meetings and be included in TRC communication at the discretion of the project sponsors. Alternatively, a separate stakeholder group can be considered in order to update interested parties on study progress and key results.

What are the TRC's Functions & Requirements?

The TRC will:

- Review study objectives and approach, and offer suggestions when appropriate to strengthen the study.
- Help ensure that the study:
  - Builds upon prior peer-reviewed variable generation integration studies and related technical work;
  - Receives the benefit of findings from recent and current variable generation integration study work;
  - Incorporates broadly supported best practices for variable generation integration studies;
  - Is developed with broad stakeholder input.
- Engage actively in the project throughout its duration. In general, project review meetings should be held nominally on a regular basis.
- Engender collegial discussions of methods and results among TRC members, the study team, project sponsors and other interested parties. The aim of these discussions is to improve accuracy, clarity and understanding of the work, and reach consensus resolution on issues that arise.

- Avoid public disclosure of meeting discussions and preliminary results. In general, findings should not be released until accepted and generally agreed upon by project sponsors, the study team and the TRC. When advisable, possible and agreed to by all project participants, interim progress reports can be provided to a broader stakeholder group.
- Ensure that findings are based entirely on facts and accurate engineering and science. Project sponsors need to embrace this aim so that the results and findings are objectively developed and not skewed to support any desired outcome.
- Document results of TRC meetings and distribute meeting presentations and minutes.

To carry out these functions, the TRC requires

- Access to all relevant information needed to properly evaluate the work and the results. When required, TRC members will enter into confidentiality agreements to protect this information. In no case can certain information needed by the TRC be declared “off-limits.”
- Assurance that the study results will be made public through published documentation or other suitable means, with the understanding that business-sensitive information will not be made public.

4. Consideration of Issues

Parties agree that Idaho Power, together with the TRC, will consider whether the second solar integration study should include the following – and if so, what would be the appropriate methodology to be used in connection with the following:

- Alternative water-year types (e.g., low-type and high-type), range of water years or normalized water year
- Intra-hour trading opportunities
- Shortening the hour-ahead forecast lead time from 45 minutes to 30 minutes
- Clustered solar build-out scenarios
- Other solar plant technologies (e.g., tracking systems or carried fixed-panel orientation)
- Correlation between solar, wind, and load variability, uncertainty, and forecasting error
- Improved forecasting methods
- Energy imbalance markets, or other market structures
- Voltage/frequency regulation
- Increased transmission capacity, changes in operation of hydroelectric facilities, addition of demand-side technologies
- Gas price forecast(s)
- Modeling of sub-hourly scheduling of load and generation

- Identification of the existence of low occurrence events that contribute to proportionately higher integration costs and possible remedies, including operational or contractual solutions to mitigate there events and reduce integration costs and charges.

4.1 Discussion

As with the prior study, there continue to be challenges in studying the effects and associated costs of integrating variable generating resources, such as solar, onto a vertically integrated power system. Unfortunately Idaho Power and the TRC do not time to achieve resolution of all issues. Idaho Power and the TRC addressed the study scope and the issues in the stipulation that can be addressed given desire to complete the study by the end of 2015. Idaho Power and the TRC jointly agreed to limit the scope of the solar integration study.

4.2 Conclusion

Following a discussion and input from the TRC, Idaho Power and the TRC agreed to address the following issues in the second integration study:

- Correlation between solar, wind, and load variability, uncertainty, and forecasting error.

  Idaho Power will update the integration study method to replace plus or minus three percent load variability with time varying data. Idaho Power will study the correlation between solar, wind, and load variability, uncertainty, and forecasting error. In particular, Idaho Power will study the effects that different solar penetration levels will have on Idaho Power’s system variability considering the existing load and wind on the Idaho Power system.

- Clustered solar build-out scenarios

  Idaho Power will review build-out scenarios to align the scenarios to the expected solar development. Additional solar data will be acquired by Idaho Power. Idaho Power will perform a separate set of sensitivity cases at the 800 MW penetration level.

- Higher Penetration Levels

  With 320 MW under contract and many 100s more in study. Requests have surpassed the 2014 study levels. Idaho Power will analyze the integration costs at the 400 MW, 800 MW, 1200 MW and 1600 MW quantities to address a wide range of futures.

- Alternative water-year types (e.g., low-type and high-type), range of water years or normalized water year

  Idaho Power will use the water year data for 2011, 2012 and 2013 coincident with other wind and market data for those periods.

- Frequency and effect of low occurrence events

  Idaho Power will perform the analysis on higher penetration levels where the events may significantly exceed the reserve capacity held for such events.

The following issues that are more difficult to assess, or are of lower priority, these will be addressed by:

Rather than performing detail studies, using west wide system models for example, sensitivity cases at 800MW will be performed by adjusting the regulation requirement by an appropriate percentage. These sensitivities will provide some indication of the relative effect the issue has on the integration costs.

- Issues that require an interconnection-wide view of the system are costly and time consuming:
  - Intra-hour trading opportunities
  - Energy imbalance markets (EIM) or other market structures
  - Modeling of sub-hourly scheduling of load and generation

  Idaho Power applied the Plexos interconnection-wide model in the 2013 wind integration study, the study cost was high (over $100,000) and failed to produce reliable and rational results. There is no current active intra-hour market in the Pacific Northwest and any study involves numerous assumptions including how to represent current operations and whether the modeling package closely simulates an assumed intra-hour trading market.

  Idaho Power participated in the development of a joint initiative project with over fifteen other utilities called ITAP or Intra-hour Transaction Accelerator Platform. ITAP is an internet based tool designed to facilitate expedited energy trading. The ITAP tool has not been successfully deployed by the participating utilities.

  Sub-hourly dispatch affects the real-time market value. Resource capacity is still necessary to follow the uncertain output. Contemplated energy imbalance markets in the west are not expected to trade capacity products or perform unit commitment decisions. Capacity and unit commitment decisions are the focus of integration studies including the Idaho Power integration studies.

- Reducing the hour-ahead forecast lead time from 40 minutes to 30 minutes

  Power purchases and sales must be acquired and tagged by 20 minutes before the top of the hour. A 30 minute lead-time leaves 10-minutes to acquire and tag a transaction. The 10-minute interval is possible in some hours, but in high transaction volume hours, a ten-minute interval is problematic.

The following are of a lower priority that will not be addressed in this integration study:

- Improved forecasting methods

  As described in section 2, Idaho Power in the 2014 Solar Study did an excellent near-term forecast of the variability of expected solar production. Idaho Power does not see much opportunity for improvement.

- Voltage/Frequency regulation

  From a voltage perspective, Voltage and frequency issues may be considerations in some geographic locations, but voltage and frequency regulation is beyond the scope of this integration study. Idaho Power is performing other studies considering regulation issues.

  Solar production technology is displacing more typical resources that have governors making the generation resource responsive to large changes in frequency due to the loss of generation. As greater penetrations of solar are achieved in the western interconnection, system reliability may necessitate requiring inverters with frequency response. Voltage and frequency regulation is beyond the scope of this integration study.

- Gas Price Forecast(s)

  Different gas price forecasts can be considered, however, current data (2010-2013) is time synchronized. Changing Gas data will affect market prices and the dispatch of most resources. The selected simulation years contain a range of actual natural gas prices.

- Other solar plant technologies (e.g., tracking systems or varied fixed-panel orientation)

  Integration costs would not be generally affected because most solar uncertainty is a result of atmospheric conditions. Different solar plant technologies would likely affect energy value of the solar generation project.

- Increased transmission capacity, changes in operation of hydroelectric facilities, and addition of demand-side technologies

  The Idaho Power transmission system capacity is fully subscribed and no new construction is planned until Boardman to Hemingway. Idaho Power anticipates updating the solar integration study as conditions change.

  Restrictions at Hells Canyon would likely reduce the capability of the Idaho Power system to integrate variable generation resources.

Demand-side technologies reduce load and affect Reg Up capacity where intermittent generation output is below forecast. Present demand-side technologies are less useful when the intermittent generation exceeds the forecast.

- Energy storage with energy scheduling method to eliminate integration cost

  Battery storage of two hours of intermittent generation nameplate output may reduce integration costs. No integration study is required, but designing scheduling protocols would be necessary. Large-scale battery storage is not anticipated in the 2015 Idaho Power Integrated Resource Plan.

5. Study Approach

As with prior integration studies, the assessment will be made from the difference between two production cost cases:

1. one with capacity reserved for uncertainty,
2. and the other case assuming output follows a perfect forecast.

5.1 Solar Data

Solar data will be developed for 400 MW, 800 MW, 1200 MW and 1600 MW penetration levels. These data will be developed using information and patterns seen in signed and unsigned contracts. Idaho Power will acquire additional solar data to assist in the development of the generation profiles. Idaho Power will use the uncertainty forecasting method developed in the 2014solar integration study to establish the uncertainty capacity requirements at the solar generation levels at 400 MW, 800 MW, 1200 MW and 1600 MW of solar generation. Schedule

The following table presents a schedule for conducting this Solar Study starting in January 2015 and completing the study less than 12-months later in December 2015.

Activity	Period
TRC Formation	Jan 26 – Feb 15
TRC Kick Off Call	March 6
Develop Study Scope & Study Plan	March 6 - 31
Data Analysis	March 1 – May 31
TRC Meeting	May 5
TRC Call	June
Integration Study Analysis	July 1 – August 31
TRC In-Person Meeting	July
TRC Call	August
Draft Report	Sept 1 – Nov 15
TRC Call	September

TRC Call	October
TRC Review Draft Report	Nov 15 – Dec 1
Study Workshop	November
File Study at Idaho Commission	December 15

Table 1: Solar Integration Study #2 Schedule

Appendix A: Invitation/Introduction Letter

February 19, 2015

Subject: Second Solar Study Technical Review Committee

To: Potential Technical Review Committee Members

As part of a settlement stipulation approved by the Idaho Public Utilities Commission in Case No. IPC-E-14-18, Idaho Power has agreed to perform a second solar integration study. I have been asked lead this study for Idaho Power. The study is expected to be complete by December 2015 as outlined in the attached stipulation agreement. I am contacting you and others, as shown in the attached proposed Technical Review Committee (“TRC”) membership list. Your willingness to participate as a member of the TRC is much appreciated.

I anticipate the committee will meet via conference call or face to face once a month on average through the completion of the study. Initially the committee will meet to discuss the study issues, the study focus/scope, and the plan to accomplish the study. Later meetings will be used to discuss study progress and finally to review a draft study report in late fall. Idaho Power will strive to document the discussion of the issues and rational for any decisions made that impact the study. As the stipulation states, Idaho Power is ultimately responsible for the study.

As with the prior study, there continue to be challenges in studying the impacts and associated costs of integrating variable generating resources, such as solar, onto a vertically integrated power system. One significant challenge the TRC will have to address is the study scope and how many of the issues in the stipulation can be addressed given the compressed schedule. Unfortunately we do not have unlimited resources, the capability, or the time to achieve resolution of all these issues. To that end, we have attached a matrix list of the issues in the stipulation. I would like the TRC members to rank each issue with their view of the priority and complexity (High, Medium, Low rankings). For example, to address some issues it will be very complex and time consuming yet yield results of lesser value than other issues that are less complex and of higher value. Another question is whether there are other issues of high value that should be added to this list.

We understand that your time is valuable, and we will strive to minimize your time commitment. We will be using the doodle website to schedule the first kick-off conference call for everyone that is capable of web conferencing. If you have a preference for a face-to-face meeting, that can be arranged. We are extremely grateful for your participation as a member of the TRC. If you have additional questions, please don’t hesitate to contact me.

Best Regards,

Ronald Schellberg
Transmission Policy and Development
Idaho Power Company
Phone 208-388-2455

Appendix B: Settlement Stipulation Issues

Issue	Priority	Complexity
Alternative water-year types (e.g., low-type and high-type), range of water years or normalized water year		
Intra-hour trading opportunities		
Shortening the hour-ahead forecast lead time from 45 minutes to 30 minutes		
Clustered solar build-out scenarios		
Other solar plant technologies (e.g., tracking systems or varied fixed-panel orientation)		
Correlation between solar, wind, and load variability, uncertainty, and forecasting error.		
Improved forecasting methods		
Energy imbalance markets, or other market structures		
Voltage/frequency regulation		
Increased transmission capacity, changes in operation of hydroelectric facilities, addition of demand-side technologies		
Gas price forecast(s)		
Modeling of sub-hourly scheduling of load and generation		
Identification of the existence of low occurrence events that contribute to proportionately higher integration costs and possible remedies, including operational or contractual solutions to mitigate these events and reduce integration costs and charges.		

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UM _______

In the Matter of	)
IDAHO POWER COMPANY	)
Application for Approval of Solar Integration Charge.	)

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

MICHAEL J. YOUNGBLOOD

August 10, 2016

Q. Please state your name and business address.

A. My name is Michael J. Youngblood and my business address is 1221 West Idaho Street, Boise, Idaho 83702.

Q. By whom are you employed and in what capacity?

A. I am employed by Idaho Power Company ("Idaho Power" or "Company") as the Manager of Regulatory Projects in the Regulatory Affairs Department.

Q. Please describe your educational background.

A. In May of 1977, I received a Bachelor of Science Degree in Mathematics and Computer Science from the University of Idaho. From 1994 through 1996, I was a graduate student in the Executive MBA program of Colorado State University. Over the years, I have attended numerous industry conferences and training sessions, including Edison Electric Institute's "Electric Rates Advanced Course."

Q. Please describe your work experience with Idaho Power.

A. I began my employment with Idaho Power in 1977. During my career, I have worked in several departments of the Company and subsidiaries of IDACORP, including Systems Development, Demand Planning, Strategic Planning, Regulatory Affairs, and IDACORP Solutions.

In January of 2012, I became the Manager of Regulatory Projects for Idaho Power, which is my current position. In this position, I provide the regulatory support for many of the large individual projects and issues currently facing the Company. Most recently that has included providing regulatory support for the inclusion of the Langley Gulch power plant investment in rate base and supporting the Company's efforts to address numerous issues involving Qualifying Facilities ("QF") as defined under the Public Utility Regulatory Policies Act of 1978 ("PURPA"), including the Company's efforts in Case No. GNR-E-11-03, the review of PURPA QF contract provisions. I provided direct testimony for the Company in its Idaho Application to

Implement Solar Integration Rates and Charges based upon the initial 2014 Study, IPUC Docket IPC-E-14-18, as well as the Idaho docket to update those integration costs with the 2016 Study, IPUC Docket IPC-E-16-11.

Q. What is the purpose of your testimony in this matter?

A. Idaho Power is requesting that the Public Utility Commission of Oregon ("Commission") authorize the Company to implement solar integration rates and charges consistent with its 2016 solar integration study ("Study" or "2016 Study"). The 2016 Solar Study Report is attached as Idaho Power/101. Mr. DeVol's testimony provides a summary of the 2016 Study, a description of the Technical Review Committee and process utilized for the Study, and the results of the Study. The purpose of my testimony is to provide the Commission with the Company's request to implement solar integration rates and charges based upon the costs identified by the 2016 Study.

The Commission previously authorized Idaho Power to implement wind integration charges consistent with those included in Idaho Power's acknowledged IRP.[1] Idaho Power asks for the same determination regarding solar integration charges; however, the Company seeks initially to implement solar integration charges from the more up to date 2016 Study, which are substantially lower. The Company asks that solar integration charges, consistent with those identified in the 2016 Study, be implemented immediately, and that the Company be directed to, in the future, utilize solar integration charges that are included in the Company's most recently acknowledged IRP or IRP update.

Q. Have solar integration rates and charges been implemented in the Company's Idaho jurisdiction?

[1] *Re Investigation into Qualifying Facilities Contracting and Pricing*, Docket No. UM 1610, Order No. 14-058 at 14 (Feb. 24, 2014).

A. Yes they have. On February 11, 2015, the IPUC issued Order No. 33227 in Case No. IPC-E-14-18, approving a Settlement Stipulation between Idaho Power, the IPUC Commission Staff, the Idaho Conservation League, Sierra Club and Snake River Alliance, implementing the solar integration rates and charges as filed by the Company, based upon the initial 2014 Solar Integration Study ("2014 Study"). The costs identified from the initial 2014 Study were included in Idaho Power's acknowledged 2015 Integrated Resource Plan ("IRP"). Since completion of the 2016 Study, Idaho Power has filed an Application in Idaho to update solar integration charges with those identified by the 2016 Study, which are substantially lower. The matter was fully submitted for the IPUC's determination on August 3, 2016, and the IPUC issued an order approving the solar integration rates included in the 2016 Study on August 9, 2016.[2]

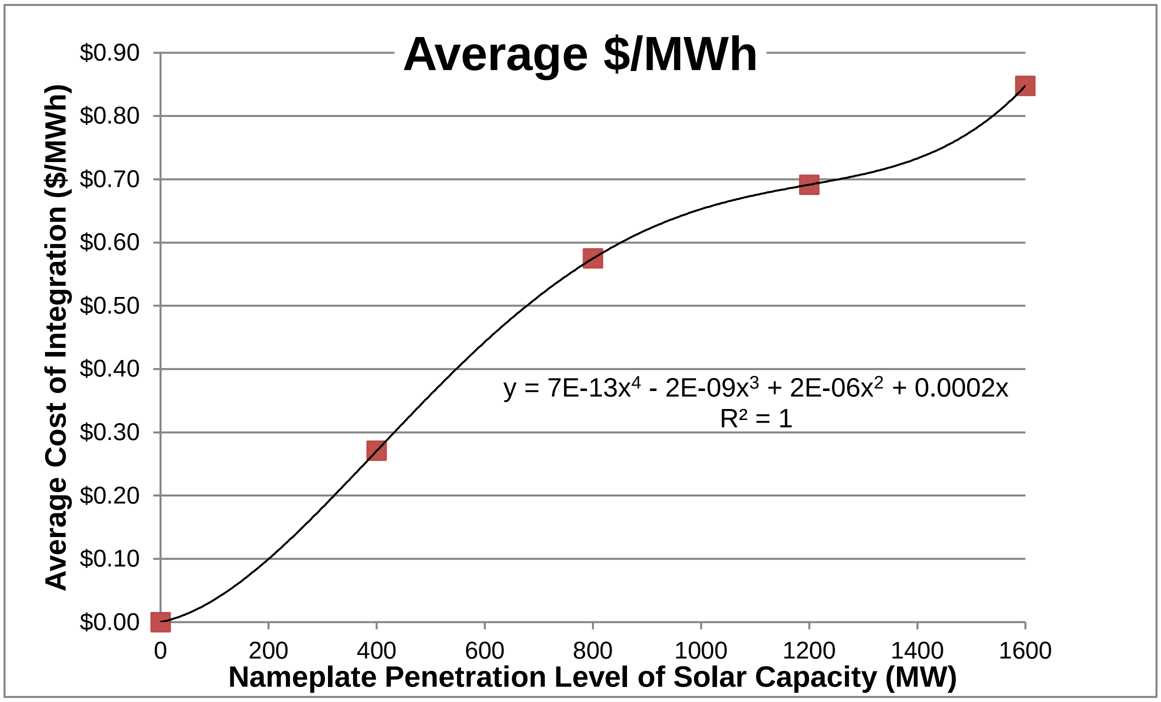
Q. Based on the results of the 2016 Solar Study, what is the cost of integrating solar generation on Idaho Power's electrical system?

A. As presented in Mr. DeVol's testimony, the 2016 Study analyzed four solar build-out scenarios at installed capacities of: 400 megawatts ("MW"), 800 MW, 1,200 MW, and 1,600 MW. Table 9 on page 21 of the Study Report shows the average integration costs per megawatt-hour ("MWh") for each of the four build-out scenarios. The costs identified by the 2016 Study reflect the costs to integrate solar generation for the calendar year 2016 and are reported in 2016 dollars. They are not averaged or levelized over the life of the solar project or plant. The Company proposes to implement solar integration charges according to the incremental integration cost for each 100 MW increment of solar penetration.

[2] IPUC Case No. IPC-E-16-11, Order No. 33563.

Q. Do the solar integration costs identified in the 2016 Study escalate in a linear manner as those from the 2014 Study and Idaho Power's wind integration studies do?

A. No. As demonstrated by the chart below, when a line connecting the average integration costs for each of the build-out scenarios is determined, it is apparent that the average cost of integrating solar generation is not a linear equation.



By using the formula for the polynomial equation for the trendline connecting the individual build-out average costs, the average cost of solar integration can be determined at any discrete point along the line. Therefore, based upon the average integration costs determined in the 2016 Solar Study for each of the four build-out scenarios, the average integration costs can be determined at 100 MW increments.

Q. Have you provided an exhibit which shows how the average costs of solar integration at 100 MW intervals are used to determine the incremental costs of solar integration on Idaho Power's system?

A. Yes, Idaho Power/201. The first four columns on Idaho Power/201 reflect the calculations of the average solar integration costs at 100 MW intervals, based upon the 2016 Solar Study build-out scenarios. Column A identifies the individual 100 MW interval designations. Column B uses the formula for the polynomial equation for the trendline shown on the chart above to determine the average dollar per MWh at each 100 MW interval. Column C reflects the cumulative MWh for the intervals based upon the average load factor for each of the 400 MW blocks in the Solar Study. Column D is the simple multiplication of the average dollar per MWh times the number of MWh in each block to determine the cumulative average annual cost for solar integration. The Solar Study's build-out scenarios of 400 MW, 800 MW, 1,200 MW, and 1,600 MW are highlighted. The average dollar per MWh for each of those build-out scenarios is the same as those presented in Table 9 on page 21 of the Solar Report.

Q. Please describe the remainder of Idaho Power/201.

A. The remainder of Idaho Power/201, columns E through H, develops the incremental costs for integrating solar generation at 100 MW intervals. Column E uses column D to determine the incremental annual cost in each 100 MW interval. Column F reflects the incremental MWh for each of the 400 MW build-out scenarios. Column G simply divides column E by column F to calculate the incremental cost of integration on a dollar-per-MWh basis. Column H calculates the cumulative incremental cost for solar integration. Please note that the cumulative incremental costs in column H are the same as the average annual costs in column D. However, with the costs being allocated on an incremental basis, the individual costs per MWh are more closely aligned with the cause of those costs; thus, the initial generation is assigned a lower cost than the later generation, which is costlier to integrate.

Q. Does column G in Idaho Power/201 also reflect a decrease in the incremental cost per MWh around the 800 MW through 1200 MW intervals? If so, please explain this decrease.

A. Yes, it does. While the average cost per MWh as shown on the chart on page 5 of my testimony is always increasing, as I noted before, it is not a linear equation. The Solar Study estimates the costs of the operational modifications necessary to integrate the intermittent generation from solar plants, where the operational modifications are in the form of differing system reserve requirements. Depending on the various resources that are required to be run at various levels of integration, the cost of those resources has an impact on the incremental cost of integration at any given level. Idaho Power/202 is a step-wise chart depicting the incremental cost at each 100 MW interval. You will note that the decrease in the incremental costs per MWh between the 800-1200 MW penetration levels align with the change in slope of the average cost per MWh shown in the chart on page 5. While the average cost per MWh is still increasing, it is increasing at a slower rate through that portion of the chart. It steepens once again after the 1200 MW level, just as does the incremental cost per MWh shown on Idaho Power/202.

Q. How do the incremental 2016 solar integration costs shown in column G on Idaho Power/201 compare to the incremental solar integration costs from the Company's 2014 Solar Study?

A. The 2014 Solar Study was used to calculate the solar integration charges currently included in IPUC Schedule 87, and the acknowledged 2015 IRP. In order to compare the costs between the two studies, I took the non-levelized rates for the year 2016 from each of the solar capacity penetration level sheets. (Schedule 87, Sheet Nos.

87-9 through 87-15.) When compared to the incremental integration costs from the 2016 Solar Study, there is a significant decrease in the integration costs at each interval. Idaho Power/203 is a chart which graphically depicts the comparison between incremental costs of solar integration based upon the 2014 Solar Study and updated values provided from the 2016 Solar Study.

Q. Are integration costs for wind and solar resources currently included in the Company's acknowledged 2015 IRP?

A. Yes. The incremental wind integration costs can be found on pages 107 through 118 of Appendix C – Technical Report of the 2015 IRP. The incremental integration costs for solar resources can be found on pages 92 through 106 of Appendix C. These solar integration costs are based upon the Company's 2014 Solar Study.

Q. Have you provided updated solar integration costs based upon the 2016 Study which the Company proposes to supersede the costs included on pages 92 through 106 of Appendix C?

A. Yes. Idaho Power/204 contains the solar integration costs based upon the 2016 Study at each 100 MW capacity level of solar penetration on Idaho Power's system.

Q. Does this conclude your testimony?

A. Yes, it does.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON
UM ____

IDAHO POWER COMPANY

Exhibit Accompanying Direct Testimony of Michael J. Youngblood

AVERAGE AND INCREMENTAL COSTS OF SOLAR INTEGRATION

August 2016

Average and Incremental Costs of Solar Integration

A	B	C	D	E	F	G	H
Nameplate Penetration MW	**Average $/MWh**	**Average MWH**	**Average Annual Cost**	**Incremental Annual Cost**	**Incremental MWH**	**Incremental $/MWH**	**Cumulative Incremental Cost**
0	$0.00	0	$ -	$ -		$ -	
100	$0.04	151,954	$ 5,424	$ 5,424	151,954	$ 0.04	$ 5,424
200	$0.10	303,908	$ 30,384	$ 24,960	151,954	$ 0.16	$ 30,384
300	$0.18	455,863	$ 82,755	$ 52,371	151,954	$ 0.34	$ 82,755
400	**$0.27**	**607,817**	**$ 164,597**	**$ 81,842**	**151,954**	**$ 0.54**	**$ 164,597**
500	$0.36	761,063	$ 273,949	$ 109,352	153,247	$ 0.71	$ 273,949
600	$0.44	914,310	$ 404,975	$ 131,026	153,247	$ 0.86	$ 404,975
700	$0.52	1,067,557	$ 550,222	$ 145,247	153,247	$ 0.95	$ 550,222
800	**$0.57**	**1,220,803**	**$ 701,722**	**$ 151,500**	**153,247**	**$ 0.99**	**$ 701,722**
900	$0.62	1,374,380	$ 852,539	$ 150,817	153,577	$ 0.98	$ 852,539
1000	$0.65	1,527,957	$ 997,514	$ 144,975	153,577	$ 0.94	$ 997,514
1100	$0.68	1,681,534	$ 1,135,168	$ 137,654	153,577	$ 0.90	$ 1,135,168
1200	**$0.69**	**1,835,110**	**$ 1,268,874**	**$ 133,706**	**153,577**	**$ 0.87**	**$ 1,268,874**
1300	$0.71	1,991,177	$ 1,409,964	$ 141,089	156,067	$ 0.90	$ 1,409,964
1400	$0.73	2,147,244	$ 1,573,902	$ 163,938	156,067	$ 1.05	$ 1,573,902
1500	$0.78	2,303,311	$ 1,786,808	$ 212,906	156,067	$ 1.36	$ 1,786,808
1600	**$0.85**	**2,459,378**	**$ 2,085,139**	**$ 298,331**	**156,067**	**$ 1.91**	**$ 2,085,139**

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON
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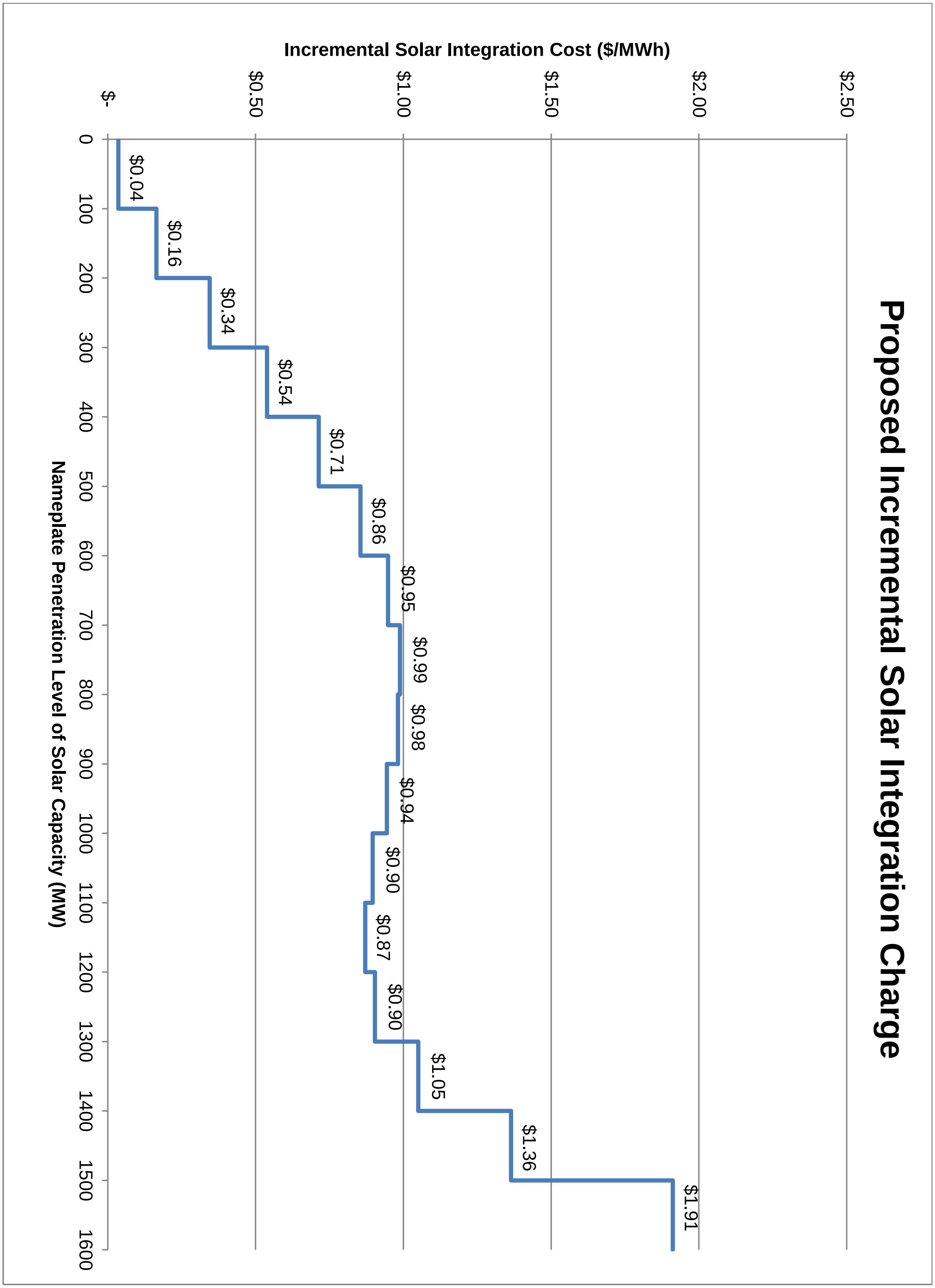
IDAHO POWER COMPANY

Exhibit Accompanying Direct Testimony of Michael J. Youngblood

PROPOSED INCREMENTAL SOLAR INTEGRATION CHARGE

August 2016


Proposed Incremental Solar Integration Charge
Incremental Solar Integration Cost ($/MWh)
$-
$0.50
$1.00
$1.50
$2.00
$2.50
$0.04
$0.16
$0.34
$0.54
$0.71
$0.86
$0.95
$0.99
$0.98
$0.94
$0.90
$0.87
$0.90
$1.05
$1.36
$1.91
0
100
200
300
400
500
600
700
800
900
1000
1100
1200
1300
1400
1500
1600
Nameplate Penetration Level of Solar Capacity (MW)

Idaho Power/203
Witness: Michael J. Youngblood

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON
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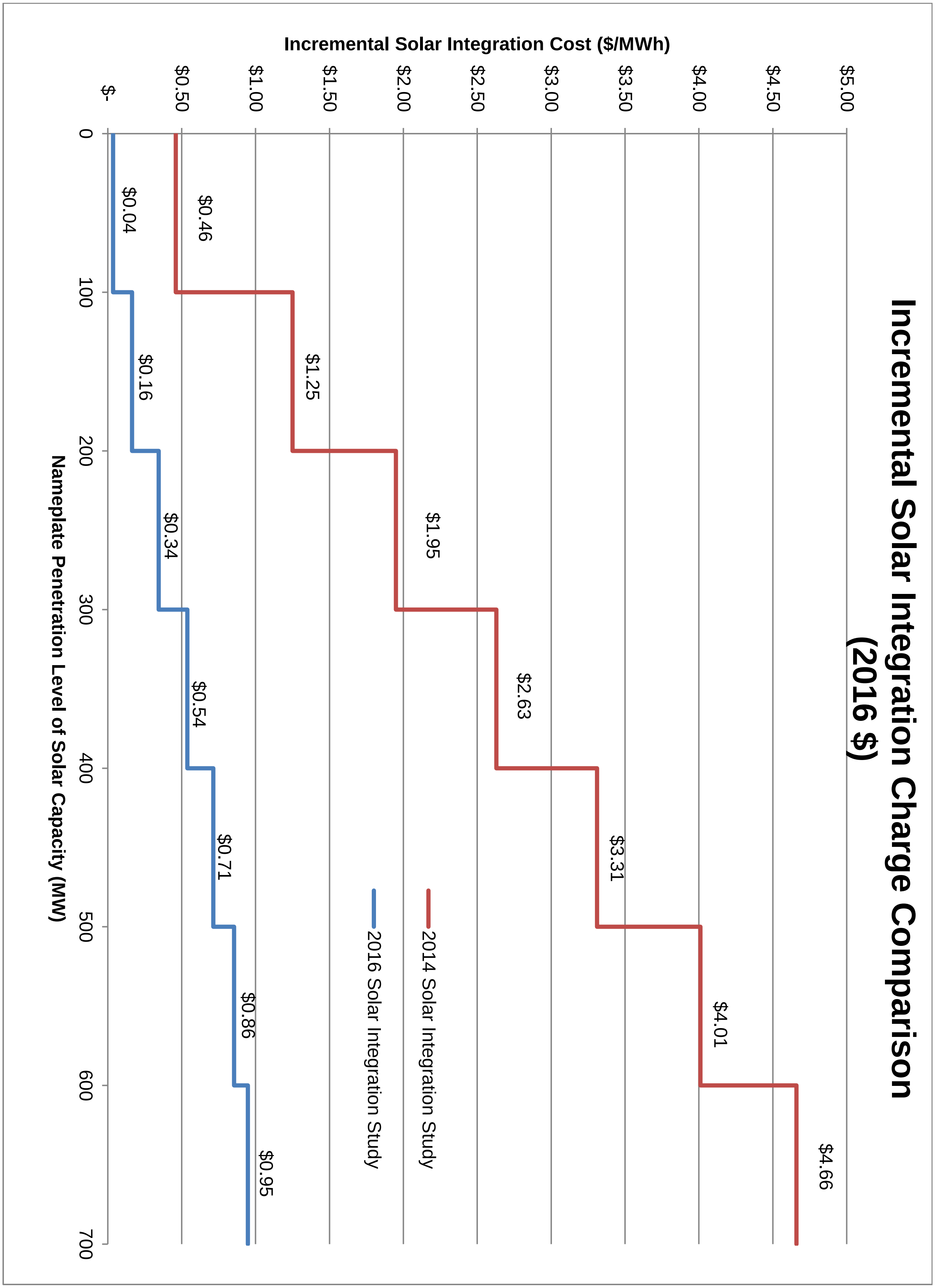
IDAHO POWER COMPANY

Exhibit Accompanying Direct Testimony of Michael J. Youngblood

INCREMENTAL SOLAR INTEGRATION CHARGE COMPARISON

August 2016



Incremental Solar Integration Charge Comparison
(2016 $)
Incremental Solar Integration Cost ($/MWh)
$5.00
$4.50
$4.00
$3.50
$3.00
$2.50
$2.00
$1.50
$1.00
$0.50
$-
0
100
200
300
400
500
600
700
Nameplate Penetration Level of Solar Capacity (MW)
$0.46
$1.25
$1.95
$2.63
$3.31
$4.01
$4.66
$0.04
$0.16
$0.34
$0.54
$0.71
$0.86
$0.95
2014 Solar Integration Study
2016 Solar Integration Study

Idaho Power/204
Witness: Michael J. Youngblood

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UM ____

IDAHO POWER COMPANY

Exhibit Accompanying Direct Testimony of Michael J. Youngblood

SOLAR INTEGRATION COSTS

August 2016

0 - 100 MW Solar Capacity Penetration Level

LEVELIZED	
ON-LINE YEAR	20 YEAR CONTRACT TERM LEVELIZED RATES ($/MWh)
2016	0.04
2017	0.04
2018	0.04
2019	0.05
2020	0.05
2021	0.05

NON-LEVELIZED	
CONTRACT YEAR	NON-LEVELIZED RATES ($/MWh)
2016	0.04
2017	0.04
2018	0.04
2019	0.04
2020	0.04
2021	0.04
2022	0.04
2023	0.04
2024	0.04
2025	0.04
2026	0.04
2027	0.05
2028	0.05
2029	0.05
2030	0.05
2031	0.05
2032	0.05
2033	0.05
2034	0.05
2035	0.05
2036	0.06
2037	0.06
2038	0.06
2039	0.06
2040	0.06
2041	0.06

101 - 200 MW Solar Capacity Penetration Level

LEVELIZED	
ON-LINE YEAR	20 YEAR CONTRACT TERM LEVELIZED RATES ($/MWh)
2016	0.19
2017	0.20
2018	0.20
2019	0.21
2020	0.21
2021	0.22

NON-LEVELIZED	
CONTRACT YEAR	NON-LEVELIZED RATES ($/MWh)
2016	0.16
2017	0.17
2018	0.17
2019	0.18
2020	0.18
2021	0.18
2022	0.19
2023	0.19
2024	0.20
2025	0.20
2026	0.20
2027	0.21
2028	0.21
2029	0.22
2030	0.22
2031	0.23
2032	0.23
2033	0.24
2034	0.24
2035	0.25
2036	0.25
2037	0.26
2038	0.27
2039	0.27
2040	0.28
2041	0.28

201 - 300 MW Solar Capacity Penetration Level

LEVELIZED	
ON-LINE YEAR	20 YEAR CONTRACT TERM LEVELIZED RATES ($/MWh)
2016	0.41
2017	0.42
2018	0.43
2019	0.44
2020	0.44
2021	0.45

NON-LEVELIZED	
CONTRACT YEAR	NON-LEVELIZED RATES ($/MWh)
2016	0.34
2017	0.35
2018	0.36
2019	0.37
2020	0.38
2021	0.38
2022	0.39
2023	0.40
2024	0.41
2025	0.42
2026	0.43
2027	0.44
2028	0.45
2029	0.46
2030	0.47
2031	0.48
2032	0.49
2033	0.50
2034	0.51
2035	0.52
2036	0.53
2037	0.54
2038	0.56
2039	0.57
2040	0.58
2041	0.59

301 - 400 MW Solar Capacity Penetration Level

LEVELIZED	
ON-LINE YEAR	20 YEAR CONTRACT TERM LEVELIZED RATES ($/MWh)
2016	0.64
2017	0.65
2018	0.67
2019	0.68
2020	0.70
2021	0.71

NON-LEVELIZED	
CONTRACT YEAR	NON-LEVELIZED RATES ($/MWh)
2016	0.54
2017	0.55
2018	0.56
2019	0.57
2020	0.59
2021	0.60
2022	0.61
2023	0.63
2024	0.64
2025	0.66
2026	0.67
2027	0.68
2028	0.70
2029	0.71
2030	0.73
2031	0.75
2032	0.76
2033	0.78
2034	0.80
2035	0.81
2036	0.83
2037	0.85
2038	0.87
2039	0.89
2040	0.91
2041	0.93

401 - 500 MW Solar Capacity Penetration Level

LEVELIZED	
ON-LINE YEAR	20 YEAR CONTRACT TERM LEVELIZED RATES ($/MWh)
2016	0.84
2017	0.86
2018	0.88
2019	0.90
2020	0.92
2021	0.94

NON-LEVELIZED	
CONTRACT YEAR	NON-LEVELIZED RATES ($/MWh)
2016	0.71
2017	0.73
2018	0.75
2019	0.76
2020	0.78
2021	0.80
2022	0.81
2023	0.83
2024	0.85
2025	0.87
2026	0.89
2027	0.91
2028	0.93
2029	0.95
2030	0.97
2031	0.99
2032	1.01
2033	1.03
2034	1.06
2035	1.08
2036	1.10
2037	1.13
2038	1.15
2039	1.18
2040	1.20
2041	1.23

501 - 600 MW Solar Capacity Penetration Level

LEVELIZED	
ON-LINE YEAR	20 YEAR CONTRACT TERM LEVELIZED RATES ($/MWh)
2016	1.01
2017	1.03
2018	1.06
2019	1.08
2020	1.10
2021	1.13

NON-LEVELIZED	
CONTRACT YEAR	NON-LEVELIZED RATES ($/MWh)
2016	0.86
2017	0.87
2018	0.89
2019	0.91
2020	0.93
2021	0.95
2022	0.97
2023	1.00
2024	1.02
2025	1.04
2026	1.06
2027	1.09
2028	1.11
2029	1.13
2030	1.16
2031	1.19
2032	1.21
2033	1.24
2034	1.26
2035	1.29
2036	1.32
2037	1.35
2038	1.38
2039	1.41
2040	1.44
2041	1.47

601 - 700 MW Solar Capacity Penetration Level

LEVELIZED	
ON-LINE YEAR	20 YEAR CONTRACT TERM LEVELIZED RATES ($/MWh)
2016	1.12
2017	1.15
2018	1.17
2019	1.20
2020	1.22
2021	1.25

NON-LEVELIZED	
CONTRACT YEAR	NON-LEVELIZED RATES ($/MWh)
2016	0.95
2017	0.97
2018	0.99
2019	1.01
2020	1.03
2021	1.06
2022	1.08
2023	1.10
2024	1.13
2025	1.15
2026	1.18
2027	1.20
2028	1.23
2029	1.26
2030	1.29
2031	1.31
2032	1.34
2033	1.37
2034	1.40
2035	1.43
2036	1.46
2037	1.50
2038	1.53
2039	1.56
2040	1.60
2041	1.63

701 - 800 MW Solar Capacity Penetration Level

LEVELIZED	
ON-LINE YEAR	20 YEAR CONTRACT TERM LEVELIZED RATES ($/MWh)
2016	1.17
2017	1.20
2018	1.22
2019	1.25
2020	1.28
2021	1.30

NON-LEVELIZED	
CONTRACT YEAR	NON-LEVELIZED RATES ($/MWh)
2016	0.99
2017	1.01
2018	1.03
2019	1.06
2020	1.08
2021	1.10
2022	1.13
2023	1.15
2024	1.18
2025	1.20
2026	1.23
2027	1.26
2028	1.28
2029	1.31
2030	1.34
2031	1.37
2032	1.40
2033	1.43
2034	1.46
2035	1.49
2036	1.53
2037	1.56
2038	1.60
2039	1.63
2040	1.67
2041	1.70

801 - 900 MW Solar Capacity Penetration Level

LEVELIZED	
ON-LINE YEAR	20 YEAR CONTRACT TERM LEVELIZED RATES ($/MWh)
2016	1.16
2017	1.19
2018	1.21
2019	1.24
2020	1.27
2021	1.30

NON-LEVELIZED	
CONTRACT YEAR	NON-LEVELIZED RATES ($/MWh)
2016	0.98
2017	1.00
2018	1.03
2019	1.05
2020	1.07
2021	1.09
2022	1.12
2023	1.14
2024	1.17
2025	1.19
2026	1.22
2027	1.25
2028	1.28
2029	1.30
2030	1.33
2031	1.36
2032	1.39
2033	1.42
2034	1.45
2035	1.48
2036	1.52
2037	1.55
2038	1.59
2039	1.62
2040	1.66
2041	1.69

901 - 1000 MW Solar Capacity Penetration Level

LEVELIZED	
ON-LINE YEAR	20 YEAR CONTRACT TERM LEVELIZED RATES ($/MWh)
2016	1.12
2017	1.14
2018	1.17
2019	1.19
2020	1.22
2021	1.25

NON-LEVELIZED	
CONTRACT YEAR	NON-LEVELIZED RATES ($/MWh)
2016	0.94
2017	0.96
2018	0.99
2019	1.01
2020	1.03
2021	1.05
2022	1.08
2023	1.10
2024	1.12
2025	1.15
2026	1.17
2027	1.20
2028	1.23
2029	1.25
2030	1.28
2031	1.31
2032	1.34
2033	1.37
2034	1.40
2035	1.43
2036	1.46
2037	1.49
2038	1.52
2039	1.56
2040	1.59
2041	1.63

1001 - 1100 MW Solar Capacity Penetration Level

LEVELIZED	
ON-LINE YEAR	20 YEAR CONTRACT TERM LEVELIZED RATES ($/MWh)
2016	1.06
2017	1.08
2018	1.11
2019	1.13
2020	1.16
2021	1.18

NON-LEVELIZED	
CONTRACT YEAR	NON-LEVELIZED RATES ($/MWh)
2016	0.90
2017	0.92
2018	0.94
2019	0.96
2020	0.98
2021	1.00
2022	1.02
2023	1.04
2024	1.07
2025	1.09
2026	1.11
2027	1.14
2028	1.16
2029	1.19
2030	1.22
2031	1.24
2032	1.27
2033	1.30
2034	1.33
2035	1.36
2036	1.39
2037	1.42
2038	1.45
2039	1.48
2040	1.51
2041	1.54

1101 - 1200 MW Solar Capacity Penetration Level

LEVELIZED	
ON-LINE YEAR	20 YEAR CONTRACT TERM LEVELIZED RATES ($/MWh)
2016	1.03
2017	1.05
2018	1.08
2019	1.10
2020	1.12
2021	1.15

NON-LEVELIZED	
CONTRACT YEAR	NON-LEVELIZED RATES ($/MWh)
2016	0.87
2017	0.89
2018	0.91
2019	0.93
2020	0.95
2021	0.97
2022	0.99
2023	1.01
2024	1.04
2025	1.06
2026	1.08
2027	1.11
2028	1.13
2029	1.16
2030	1.18
2031	1.21
2032	1.23
2033	1.26
2034	1.29
2035	1.32
2036	1.35
2037	1.37
2038	1.41
2039	1.44
2040	1.47
2041	1.50

1201 - 1300 MW Solar Capacity Penetration Level

LEVELIZED	
ON-LINE YEAR	20 YEAR CONTRACT TERM LEVELIZED RATES ($/MWh)
2016	1.07
2017	1.09
2018	1.12
2019	1.14
2020	1.17
2021	1.19

NON-LEVELIZED	
CONTRACT YEAR	NON-LEVELIZED RATES ($/MWh)
2016	0.90
2017	0.92
2018	0.94
2019	0.97
2020	0.99
2021	1.01
2022	1.03
2023	1.05
2024	1.08
2025	1.10
2026	1.12
2027	1.15
2028	1.17
2029	1.20
2030	1.23
2031	1.25
2032	1.28
2033	1.31
2034	1.34
2035	1.37
2036	1.40
2037	1.43
2038	1.46
2039	1.49
2040	1.52
2041	1.56

1301 - 1400 MW Solar Capacity Penetration Level

LEVELIZED	
ON-LINE YEAR	20 YEAR CONTRACT TERM LEVELIZED RATES ($/MWh)
2016	1.24
2017	1.27
2018	1.30
2019	1.33
2020	1.36
2021	1.39

NON-LEVELIZED	
CONTRACT YEAR	NON-LEVELIZED RATES ($/MWh)
2016	1.05
2017	1.07
2018	1.10
2019	1.12
2020	1.15
2021	1.17
2022	1.20
2023	1.22
2024	1.25
2025	1.28
2026	1.31
2027	1.33
2028	1.36
2029	1.39
2030	1.42
2031	1.46
2032	1.49
2033	1.52
2034	1.55
2035	1.59
2036	1.62
2037	1.66
2038	1.70
2039	1.73
2040	1.77
2041	1.81

1401 - 1500 MW Solar Capacity Penetration Level

LEVELIZED	
ON-LINE YEAR	20 YEAR CONTRACT TERM LEVELIZED RATES ($/MWh)
2016	1.61
2017	1.65
2018	1.69
2019	1.72
2020	1.76
2021	1.80

NON-LEVELIZED	
CONTRACT YEAR	NON-LEVELIZED RATES ($/MWh)
2016	1.36
2017	1.39
2018	1.42
2019	1.46
2020	1.49
2021	1.52
2022	1.55
2023	1.59
2024	1.62
2025	1.66
2026	1.70
2027	1.73
2028	1.77
2029	1.81
2030	1.85
2031	1.89
2032	1.93
2033	1.97
2034	2.02
2035	2.06
2036	2.11
2037	2.15
2038	2.20
2039	2.25
2040	2.30
2041	2.35

1501 - 1600 MW Solar Capacity Penetration Level

LEVELIZED	
ON-LINE YEAR	20 YEAR CONTRACT TERM LEVELIZED RATES ($/MWh)
2016	2.26
2017	2.31
2018	2.36
2019	2.41
2020	2.47
2021	2.52

NON-LEVELIZED	
CONTRACT YEAR	NON-LEVELIZED RATES ($/MWh)
2016	1.91
2017	1.95
2018	2.00
2019	2.04
2020	2.09
2021	2.13
2022	2.18
2023	2.23
2024	2.28
2025	2.33
2026	2.38
2027	2.43
2028	2.48
2029	2.54
2030	2.59
2031	2.65
2032	2.71
2033	2.77
2034	2.83
2035	2.89
2036	2.95
2037	3.02
2038	3.09
2039	3.15
2040	3.22
2041	3.29