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DONOVAN E. WALKER
Lead Counsel
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June 17, 2014

VIA HAND DELIVERY

Jean D. Jewell, Secretary
Idaho Public Utilities Commission
472 West Washington Street
Boise, Idaho 83720

Re: June 2014 Solar Integration Study Report

Dear Ms. Jewell:

In Order No. 33043, Case No. IPC-E-14-09, the Idaho Public Utilities Commission ("Commission") directed Idaho Power Company ("Idaho Power" or "Company") to "complete its solar integration study as soon as possible." The study is complete. Enclosed please find five (5) copies of Idaho Power's June 2014 Solar Integration Study Report.

Idaho Power is preparing an application case filing where it will ask the Commission to implement a solar integration charge based upon this study. The Company anticipates this filing will be made within the next two weeks. Please contact me at (208) 388-5317 if you have any questions.

Sincerely,

Donovan E. Walker

DEW:csb
Enclosures

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P.O. Box 70
Boise, ID 83707

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Solar Integration Study Report

June 2014

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EXECUTIVE SUMMARY

Electric power from solar photovoltaic resources exhibits greater variability and uncertainty than energy from conventional generators. The greater variability and uncertainty exhibited by solar photovoltaic resources require an electric utility integrating solar to modify the operation of dispatchable generating resources. The modified operation involves the sub-optimal dispatch of generators to carry extra capacity in reserve for responding to unplanned solar excursions.

The objective of the Idaho Power solar integration study is to determine the costs of the operational modifications necessary to integrate solar photovoltaic plant generation. 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	**100 megawatts (MW)**	**300 MW**	**500 MW**	**700 MW**
Parma, ID	10	30	50	100
Boise, ID	20	60	100	100
Grand View, ID	20	60	100	150
Twin Falls, ID	20	60	100	100
Picabo, ID	10	30	50	100
Aberdeen, ID	20	60	100	150
Total MW	**100**	**300**	**500**	**700**

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 solar excursions 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 MWh for solar build-out scenarios

	0-100 MW	**0-300 MW**	**0-500 MW**	**0-700 MW**
Integration cost	$0.40/MWh	$1.20/MWh	$1.80/MWh	$2.50/MWh

Note: Costs are in 2014 dollars and rounded from simulation results to the nearest $0.10.

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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 August 2013 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
- Jimmy Lindsay, Portland General Electric (formerly of Renewable Northwest Project)
- Kurt Myers, Idaho National Laboratory
- Paul Woods, (formerly of City of Boise)
- Cameron Yourkowski, Renewable Northwest Project (replacing Jimmy Lindsay)

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

Electric power from solar photovoltaic resources exhibits greater variability and uncertainty than energy from conventional generators. Because of the greater variability and uncertainty, electric utilities incur increased costs when their other generators are called on to integrate photovoltaic solar plant generation. These costs occur because power systems are operated less optimally in order to successfully integrate solar plant generation without compromising the reliable delivery of electrical power to customers. Idaho Power has studied the modifications it must make to power system operations to integrate solar photovoltaic power plant generation connecting to its system. The objective of this solar integration study is to determine the costs of the operational modifications necessary to integrate solar plant generation. This report is intended to describe the operational modifications and the resulting costs.

In collaboration with the TRC, 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 the NREL, was written from the perspective of studying grid 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 impacts and costs.

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	**100 megawatts (MW)**	**300 MW**	**500 MW**	**700 MW**
Parma, ID	10	30	50	100
Boise, ID	20	60	100	100
Grand View, ID	20	60	100	150
Twin Falls, ID	20	60	100	100
Picabo, ID	10	30	50	100
Aberdeen, ID	20	60	100	150
Total MW	**100**	**300**	**500**	**700**

The above build-out scenarios were developed in consultation with the TRC to represent geographically dispersed build-outs of solar power plant capacity. The importance of geographic dispersion in reducing integration impacts and costs is discussed in greater detail later in this report. The sites from the solar build-out scenarios are part of the established United States (U.S.) Bureau of Reclamation (USBR) AgriMet Network (AgriMet). 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. The six sites are spread across southern Idaho and cover over 220 miles from east to west (Figure 1). Sites represent elevations ranging from 2,300 feet to 4,900 feet (Table 4).

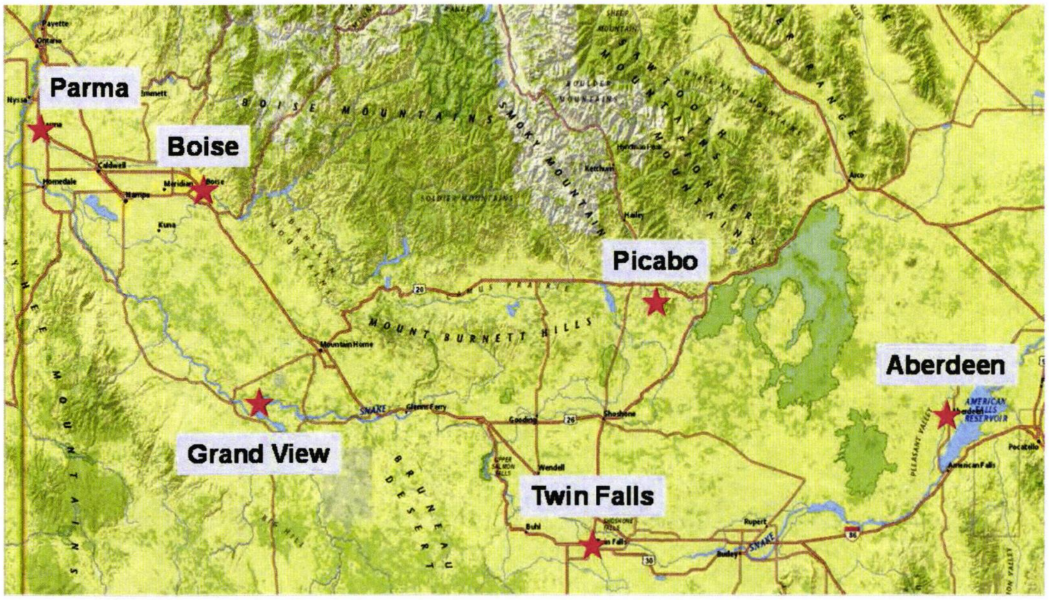

Figure 1
AgriMet sites used in IPC's solar integration study

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

Station	Latitude (N)	Longitude (west)	Elevation (feet)	Elevation (meter)
Parma	43.18	116.93	2,305	702
Boise	43.60	116.18	2,720	829
Grand View	42.91	116.06	2,580	786
Twin Falls	42.55	114.35	3,920	1,195
Picabo	43.31	114.17	4,900	1,494
Aberdeen	42.95	112.83	4,400	1,341

All data used in the integration study are 5-minute interval global horizontal irradiance data from each site. 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. The use of high-resolution (5-minute interval) data is critical to characterizing the variability of solar.

An alternative data-gathering approach was necessary for the Grand View site, for which only 15-minute data was available. To acquire 5-minute data for Grand View, 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.

Wavelet-Based Variability Model

AgriMet solar data represents conditions at a single point. To better reflect conditions at a solar plant size, the TRC recommended the use of 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 photovoltaic 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 into the WVM showed it is not useable at time steps (intervals) greater than 10 minutes and that times 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. Photovoltaic panels are assumed to be of standard crystalline silicon manufacture. Panels are assumed to be fixed south facing and tilted at latitude. While panel orientation and tracking capability are key factors in the determination of avoided costs, these attributes are of lesser importance with respect to the variability and uncertainty driving integration costs. Illustrations and data summarizing the solar production of the studied build-outs are provided in Appendix 1.

Statistical-Based Analysis of Solar Characteristics

The intent of the statistical-based analysis of solar characteristics is to translate solar's variability and uncertainty into an increased requirement for ancillary services, where ancillary services in this context relate to the electrical system's capacity to maintain a balance between customer demand and generation. For the study, the variability and uncertainty associated with solar generation were viewed from the perspective of hour-ahead scheduling of the Idaho Power system. There are three critical elements from this perspective:

1. Forecast hourly average solar production for the operating hour being scheduled
2. Lower bound for instantaneous solar production during the operating hour
3. Upper bound for instantaneous solar production during the operating hour

From the perspective of real-time generation scheduling in practice, the lower and upper bounds would be considered an interval or band on solar production, and the occurrence of solar production outside the interval at any moment during the hour is highly unlikely. Moreover, while under prudent operating practices the occurrence of solar production outside the lower and upper bounds should be infrequent, occasional solar excursions outside these bounds do not necessarily bring about events for which system reliability is jeopardized. Conversely, the occurrence of solar production within the interval between the lower and upper bounds would be considered likely enough to warrant the scheduling of dispatchable generators to have capacity to respond if solar production varies during the hour from the forecasted level of production toward either bound.

An understanding of Idaho Power's participation in the regional electric power market is critical to this approach. Idaho Power primarily participates in the Pacific Northwest's Mid-Columbia (Mid-C) electric power market. The company participates in the Mid-C market at multiple time frames ranging from years or months in advance for long-term operations planning to hour-ahead generation scheduling in real time.

The focus for this 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 forecast hourly average solar production and the above-described lower and upper bounds 45 minutes prior to the start of the operating hour being scheduled. Hour-ahead scheduling is assumed binding, and unexpected conditions occurring during the operating hour being scheduled must be managed by changing production for Idaho Power-owned dispatchable resources.

Idaho Power recognizes efforts to establish intra-hour trading in U.S. electric power markets. However, company experience has shown the intra-hour market to be currently highly illiquid. Therefore, the last opportunity to participate in the electric power market is at the hour-ahead time frame; unexpected conditions occurring during the operating hour (e.g., unexpected levels of solar production) cannot be managed through market activity at this time.

Hour-Ahead Solar Production Forecast

The hour-ahead solar production forecast was developed to predict hourly average solar production for the operating hour being scheduled and lower and upper bounds for instantaneous solar production during the operating hour. This forecast was developed using a persistence-based technique that relies on observations from the previous hours to inform the model about subsequent forecast hours. The results of the forecast are a unique set of values (average production, upper bound, and lower bound) for every hour in the year.

The average production forecast is derived based on two components. The first component accounts for the amount of generation the system observed from the last 20 minutes of the preceding forecast hour. This component is referred to as the persistence component.
The persistence component serves as a mechanism to increase the average forecast during times of high solar production and decrease the average forecast during times of low solar production. These increases and decreases are made to the forecast hourly and account for changes in solar production. In general, the shape of the production from a solar photovoltaic system increases before solar noon and decreases after solar noon. Every day of the year has a unique clear-day shape. Generally, summer days are long and have a high potential for solar production while winter days are shorter and have less potential. The forecast accounts for the uniqueness of each

day by applying an hourly shaping factor. This shaping component, or shaping factor, is a unique value for every hour in the year. The shaping component is a ratio of the maximum solar potential of the forecast hour divided by the maximum potential of the previous hour. By utilizing a shaping component and a persistence component, the average production forecast captures hourly changes due to atmospheric conditions and seasonal effects. Table 5 provides the forecast error for the hour-ahead solar production forecast.

Table 5
Forecast error for the hour-ahead solar production forecast

	100 MW	300 MW	500 MW	700 MW
Absolute Mean Hourly Error (MW)	1.9	5.8	9.6	12.2

Table 5 reports the absolute mean error calculated on an hourly basis for water year 2012. The absolute hourly error is calculated as the absolute difference between the average hourly forecast and the average of 5-minute observed production data for a given hour. It is noted that the 5-minute observed production data is the output of the WVM. The absolute mean hour errors range from 1.9 MW to 12.2 MW for the 100 MW and 700 MW build-out scenarios, respectively.

The lower bound for instantaneous solar production during the operating hour is forecasted as a percentage of the forecast average. In addition to the application of a percentage of average, the forecasting tool adjusts the lower bound forecast upward if the previous lower bound forecast was substantially too low. As a result of this secondary adjustment to the lower bound, the amount of incremental capacity held in reserve for the coming hour is reduced.

Similar to the lower bound, the upper bound for instantaneous solar production during the operating hour is forecasted as a percentage of the forecast average. In addition to the application of a percentage of average, the forecasting tool adjusts the upper bound forecast downward if the previous upper bound forecast was substantially too high. As a result of this secondary adjustment to the upper bound, the amount of decremental capacity held in reserve for the coming hour is reduced.

The upper and lower bounds are expected to capture the overwhelming majority of the variability observed in solar production. The upper bound is forecasted in such a way that only 2.5 percent of all observations exceed the upper bound for the entire year. Similarly, the lower bound is defined in such a way that only 2.5 percent of all observations are below the lower bound for the entire year.

The hour-ahead forecast for the average production, lower bound for instantaneous solar, and upper bound for instantaneous solar are calculated for every hour of the year. The amount of incremental capacity held in reserve for a given hour is calculated as the difference between the average production forecast and the lower bound. The amount of decremental capacity held in reserve for a given hour is calculated as the difference between the average production forecast and the upper bound. The total amount of capacity held in reserve for a given hour is used by the production cost model to calculate an integration cost. These reserve amounts, as well as the hour-ahead forecast for solar production, are input to the production cost model on an hour-by-hour basis, simulating the practice of real-time generation scheduling. Table 6 reports the forecasted amount of capacity held in reserve for water year 2012. Further explanation of the derivation of the hour-ahead solar production forecast and the lower and upper bounds is provided in Appendix 1.

Table 6
Forecasted incremental and decremental capacity held in reserve, water year 2012

	Solar Build-Out Scenarios			
	100 MW	300 MW	500 MW	700 MW
Average hourly production (MW)	17.0	52.5	89.0	118.2
Average hourly capacity held in reserve—incremental (MW)	4.9	13.2	21.2	27.6
Average hourly capacity held in reserve—decremental (MW)	4.9	15.2	26.9	34.8

PRODUCTION COST SIMULATION ANALYSIS

The production cost simulations are designed to isolate the effects on the system associated with integrating solar. Under this design, production cost simulations are paired into a base case and test case, with all inputs to the paired simulations equivalent except an amount of capacity held in reserve in the test case simulation for integrating solar. The capacity held in reserve for the test case varies hourly depending on the hour-ahead forecast of solar production for a given operating hour and the lower and upper bounds on instantaneous solar production for the operating hour. The derivation of the hour-ahead solar production forecast and the lower and upper bounds is described in the previous section of this report.

Design of Simulations

The production cost simulations are set up on a water-year calendar, where 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 Idaho Power generating 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 regional market discussions that could exist when B2H is completed, but the benefits of a market are highly dependent on its design, and it is premature to speculate or incorporate in this integration study.

Simulation Inputs

Table 7 provides key inputs to the solar integration study production cost simulations.

Table 7
Inputs for the solar integration study production cost simulations

Input	Assumed input level
Solar production	Water year 2012
Snake River streamflows	Water year 2012 (median-type streamflows)
Customer demand	Water year 2012
Nymex—Natural gas prices	Water year 2012
Mid-C—Electric power market prices	Water year 2012
Non-wind PURPA[1]	Water year 2012
Wind (PURPA and PPA)[1]	Water year 2013
Geothermal PPAs	Water year 2014

[1] PPA and PURPA represent facilities from which generation is contractually purchased as a power purchase agreement (PPA) or under the federal *Public Utility Regulatory Policies Act of 1978* (PURPA).

The selection of water year 2012 for the majority of the inputs was driven by the selection of Snake River streamflows for water year 2012 (October 1, 2011–September 30, 2012) and the objective to use time-synchronous input data to the greatest possible extent. Snake River Basin streamflow conditions as observed in water year 2012 were selected because the observed water year 2012 Brownlee reservoir inflow volume of 13.6 million acre-feet is representative of median-type streamflow conditions. A graph of Brownlee inflow volumes for water years 1990 to 2013 is provided in Appendix 1.

The solar production data used in the production cost simulations are considered to be the solar production that would have been observed during water year 2012 had the four studied solar build-out scenarios existed. As described previously, the solar production data is developed by applying a wavelet smoothing transformation technique to 5-minute interval AgriMet and SolarAnywhere data. Importantly, the use of observed customer demand from water year 2012 allows time synchronization between solar and customer demand data in the study.
While customer demand has grown since 2012, the benefit of using time-synchronous

customer demand and solar production data is considered to justify the use of 2012 customer demand data. Monthly average customer demand used in the modeling is provided in Appendix 1.

Water year 2012 Nymex natural gas prices and Mid-C electric power market prices are inputs to the simulations. These prices, expressed as a monthly average, are provided in Appendix 1.

Wind capacity under contract with Idaho Power grew by more than 60 percent during water year 2012, expanding from 395 MW of installed capacity to 638 MW. Because of the non-constant amount of on-line wind capacity during water year 2012, the simulations used observed hourly wind production data for water year 2013. The amount of on-line wind capacity during water year 2013 changed only by the addition of a single 40 MW project added during December 2013 that brought wind to the current on-line capacity of 678 MW. Monthly energy production used in the modeling is included in Appendix 1.

The remaining energy purchased from non-wind PURPA qualifying facilities is input into the simulations as observed during water year 2012. The monthly energy from the non-wind PURPA facilities in 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 demand and resources were exactly in balance and importantly that hourly reserve requirements were satisfied. The extra 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 extra capacity in reserve held for solar is described previously in this report.

Wind and Load Reserves

Capacity in reserve to manage variability and uncertainty in load and wind is included in the simulations in equivalent amounts for the study's two cases. By carrying equivalent amounts in reserve for load and wind, the production cost differences yielded by the study's simulations can be attributed to the extra capacity held in reserve for solar. Thus, while reserves carried for load and wind are not drivers of production cost differences in the paired simulations, it is nevertheless desirable in simulating the system as accurately as possible to incorporate reserve levels for load and wind representative of levels carried in practice.

To manage variability and uncertainty in load, capacity in reserve equal to 3 percent of load is held on dispatchable generators in the modeling for the solar integration study. The amount of simulated capacity in reserve for balancing wind is based on an analysis performed for the Idaho Power wind integration study as described in the February 2013 *Wind Integration Study Report* (Idaho Power 2013). The simulated reserves for the solar integration study are based on a scaling of the reserves at the wind study's 800 MW wind build-out scenario to the water year 2013 wind build-out of 678 MW.

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

As described previously, 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 forecast hourly average solar production and the lower and upper bounds for solar production 45 minutes prior to the start of the operating hour being scheduled. Hour-ahead scheduling is then assumed binding, and unexpected levels of solar production occurring during the operating hour being scheduled must be managed by Idaho Power's system.

To manage deviations in solar production from the forecast during the operating hour, Idaho Power must schedule incremental and decremental 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 photovoltaic 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 excursions in solar production. The simulations performed for the Idaho Power solar integration study indicate the following costs associated with holding the extra capacity in reserve (Table 8). The provided costs are the costs to integrate solar production for calendar year 2014, and are not costs averaged or levelized over the life of a solar power plant.

Table 8
Average integration cost per MWh for solar build-out scenarios

	0-100 MW	0-300 MW	0-500 MW	0-700 MW
Integration cost	$0.40/MWh	$1.20/MWh	$1.80/MWh	$2.50/MWh

Note: Costs are in 2014 dollars and rounded from simulation results to the nearest $0.10.

The integration cost results in Table 8 are the cost per MWh 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 500 MW build-out scenario brings about costs of $1.80 for each megawatt-hour (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 100 MW build-out are assessed integration costs of $0.40/MWh, then plants comprising the increment between 100 MW and 300 MW need assessed integration costs of $1.50/MWh to allow full recovery of the $1.20/MWh costs to integrate 300 MW of solar plant capacity. Incremental solar integration costs are provided in Table 9.

Table 9
Incremental integration cost results for solar build-out scenarios

	0–100 MW	100–300 MW	300–500 MW	500–700 MW
Incremental integration cost	$0.40/MWh	$1.50/MWh	$2.80/MWh	$4.40/MWh

Note: Costs are in 2014 dollars and rounded from simulation results to the nearest $0.10.

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 entirely 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, 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 six 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.

In contrast, deviations from the hour-ahead solar production forecast can only be covered by Idaho Power's dispatchable generators. The analysis for the solar integration study by design 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. Integration costs are a result of the sub-optimal scheduling of the dispatchable generators associated with holding the solar-caused capacity in reserve.

Comparison to Wind Integration

This study indicates solar plant integration costs are lower than wind plant integration costs. 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, reserves carried for solar generation can be focused on readying dispatchable generators to respond to unplanned solar excursions from hour-ahead production forecasts. Moreover, logic incorporated in the derivation of lower and upper bounds on the hour-ahead production forecast, which can be readily adopted in practice, allows the adjustment of the bounds in response to observed solar production patterns. In effect, the hour-ahead forecast is based on a persistence of level of production (adjusted for the known change in the sun's position), as well as a persistence of variability in production. The consequence of these methods is that bidirectional capacity held in reserve on dispatchable generators to respond to solar variability and uncertainty is less than that required for responding to wind.

Qualitatively, solar is more predictable than wind. 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

Production for a single solar photovoltaic panel exhibits severe and abrupt intermittency during variably cloudy conditions; a TRC member expressed during a meeting that for a single panel, the drop in production from a cloud is effectively instantaneous. The effect of severe and abrupt intermittency is commonly attributed to the absence of inertia in the photovoltaic 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 six 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.

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 photovoltaic 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 photovoltaic power plants to the retail customer; these issues are addressed in individual interconnection studies performed on a plant-by-plant basis.

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 enabling the balancing of generation and customer demand.

CONCLUSIONS

The cost to integrate the variable and uncertain delivery of energy from solar photovoltaic 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. The simulations performed for Idaho Power's solar integration study indicate the costs associated with holding the extra capacity in reserve (Table 8).

Further Study

The integration of variable generation, including the study of methods for determining integration impacts and costs, continues to be the subject of considerable research. The breadth of this research highlights the interest in variable-generation integration, as well as the evolution of study methods. Idaho Power appreciates the level of interest in its study of integration of variable generation and recognizes the likelihood of a second-phase study with expanded scope.

During the course of the solar integration study, in discussions with the TRC and participants of the public workshop, Idaho Power has received suggestions for a second-phase study of solar integration. Suggestions for a second phase include the study of the following:

- Alternative water-year types (e.g., low-type and high-type)
- Intra-hour trading opportunities
- Shortening the hour-ahead forecast lead time from 45 minutes to 30 minutes
- Clustered solar build-out scenarios
- Smaller solar build-out scenarios (e.g., 50 MW of installed capacity)
- Other solar plant technologies (e.g., tracking systems or varied fixed-panel orientation)
- Distributed solar systems (i.e., rooftop systems)
- Correlation between solar, wind, and load variability and uncertainty
- Improved forecasting methods
- Energy imbalance markets
- Voltage/frequency regulation

Idaho Power will consider these suggestions during the development of scope for a second-phase study.

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[UVIG and NREL]. Utility Variable-Generation Integration Group and National Renewable Energy Laboratory. No date. Principles for Technical Review Committee (TRC) involvement in studies of variable generation integration into electric power systems. http://variablegen.org/wp-content/uploads/2009/05/TRCPrinciplesJune2012.pdf. Accessed June 2014.

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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 *2014 Solar Integration Study*.

The main document, the *2014 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—Resource Planning
1221 W. Idaho St.
Boise, Idaho 83702
208-388-2623

TECHNICAL REVIEW COMMITTEE

The Technical Review Committee (TRC) was formed during summer 2013 to provide input, review, and guidance for the study. It is comprised of participants from outside of Idaho Power that have an interest and/or expertise with the integration of intermittent resources onto utility systems.

As part of preparing the *2014 Solar Integration Study*, Idaho Power held one public meeting and four TRC meetings. Idaho Power values these opportunities to convene, and the TRC members have made significant contributions to this plan.

List of TRC Members

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

Jimmy Lindsay................Portland General Electric (formerly of Renewable Northwest Project)

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

Paul Woods.....................(formerly of City of Boise)

Cameron Yourkowski......Renewable Northwest Project (replacing Jimmy Lindsay)

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

TRC Schedule and Agenda

Meeting Dates		Agenda Items
2013	Thursday, August 15	Introductions and role of TRC Idaho Power system overview Formulation of basic study design Establish solar futures Techniques for building solar generation data Closing thoughts and comments
2013	Thursday, September 19	Study design Key study components Hydro—WY 2011 vs. WY 2012 vs. WY 2013 Solar—WY 2011 vs. WY 2012 vs. WY 2013 Market power prices Natural gas prices Solar penetration levels
2014	Monday, January 6	Review of Study Design Solar Data Availability Wavelet-based Variability Model Analysis Conclusions
2014	Friday, May 16	Review of Integration Study Design Review of IPUC Filing Development of Reserve Requirement for solar scenarios
2014	Thursday, May 29	Review of Operating Reserves Review of Production Cost Model

Public Workshop Schedule and Agenda

Meeting Dates		Agenda Items
2014	Thursday, May 1	Introduction of Technical Review Committee Idaho Power system overview Study objective Study design System modeling Next steps

DATA INPUTS AND ASSUMPTIONS

Natural Gas Price Assumptions

Table 1
Actual monthly average Nymex price for water year 2012

Year	Month	Average Monthly Price
2011	October	$3.76
	November	$3.52
	December	$3.36
2012	January	$3.08
	February	$2.68
	March	$2.45
	April	$2.19
	May	$2.04
	June	$2.43
	July	$2.77
	August	$3.01
	September	$2.63

Market Power Price Assumptions

Table 2
Actual average Mid-Columbia dollars/megawatt-hour (MWh) for water year 2012

Year	Month	Average Monthly Price
2011	October	$26.02
	November	$30.81
	December	$30.13
2012	January	$24.53
	February	$23.50
	March	$16.30
	April	$8.99
	May	$5.81
	June	$4.50
	July	$12.05
	August	$24.75
	September	$24.47

IPC Customer Load Data

Table 3
Actual average megawatt (MW) for water year 2012

Year	Month	Average Load
2011	October	1,403
	November	1,563
	December	1,729
2012	January	1,680
	February	1,597
	March	1,457
	April	1,504
	May	1,742
	June	2,108
	July	2,388
	August	2,197
	September	1,679

Idaho Power Existing Generation

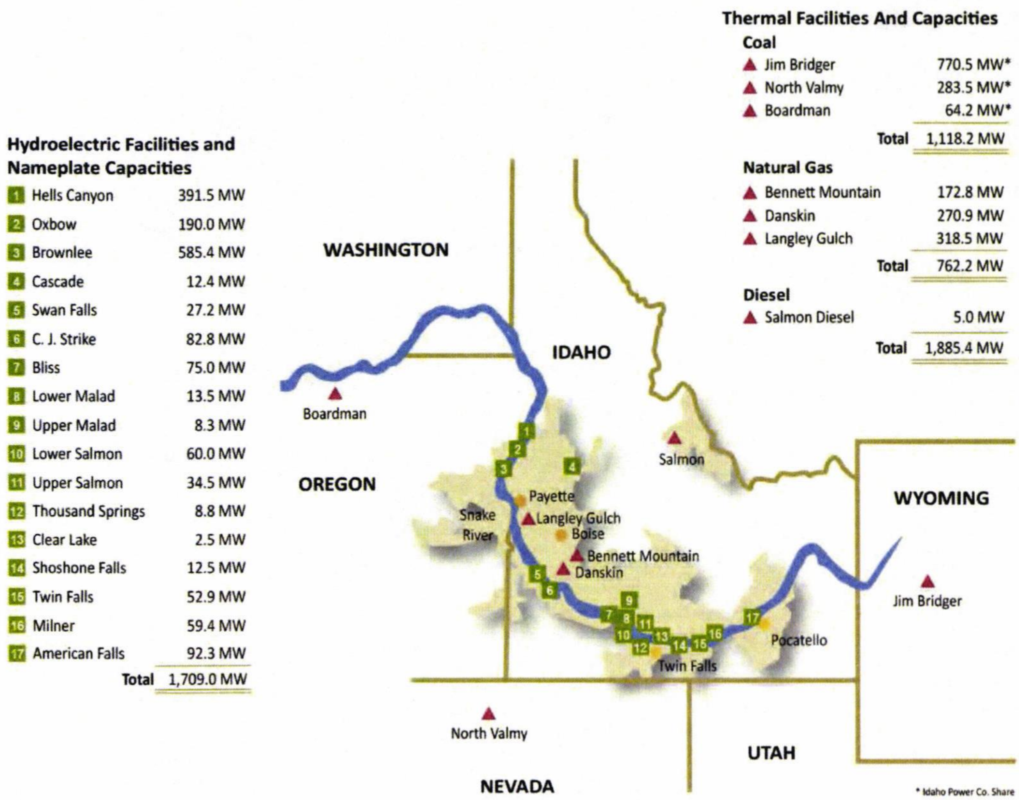


Figure 1
Existing Idaho Power generating resources

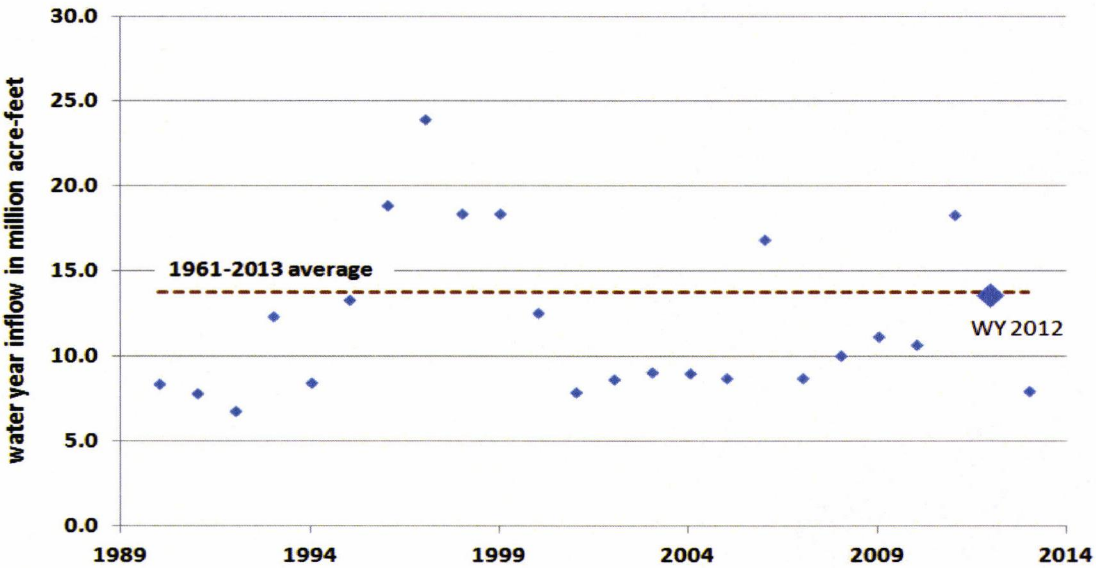


Figure 2
Brownlee Reservoir inflow by water year

Hydroelectric Generation Data

Run-of-River Projects

Table 4
Actual monthly average MW (aMW) for water year 2012

Year	Month	aMW
2011	October	447
	November	418
	December	415
2012	January	358
	February	365
	March	380
	April	388
	May	252
	June	337
	July	292
	August	251
	September	208

Wind Generation Data

Aggregate PPA and PURPA Projects

Table 5
Actual monthly aMW for water year 2013

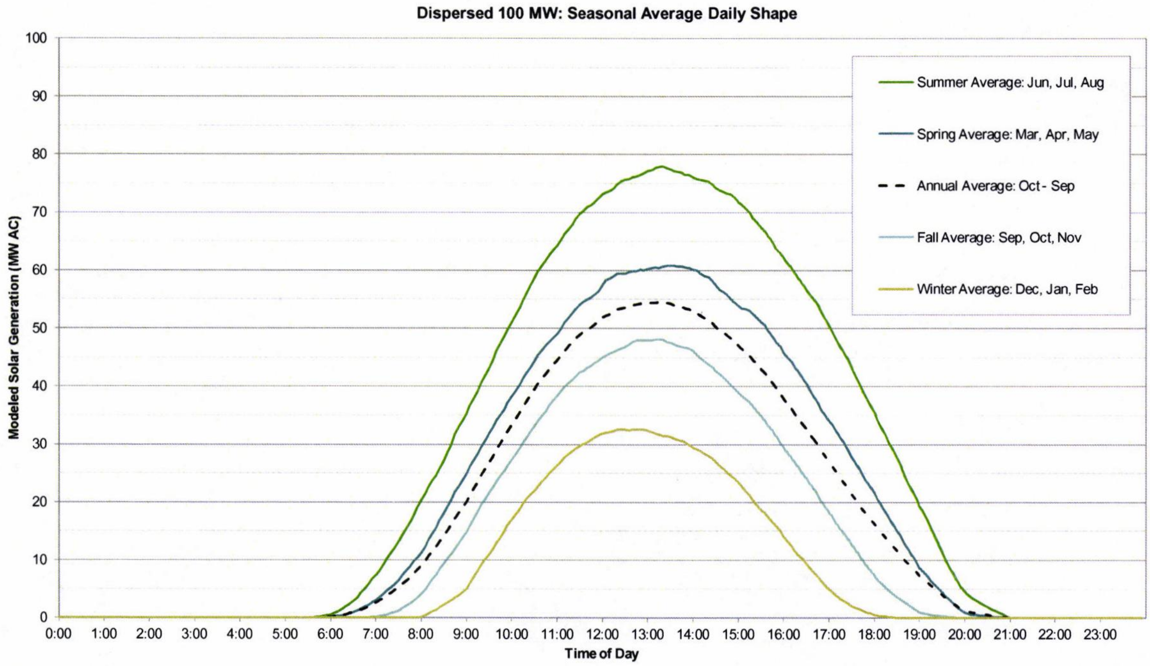
Year	Month	aMW
2011	October	95
	November	190
	December	120
2012	January	194
	February	167
	March	191
	April	172
	May	166
	June	163
	July	144
	August	131
	September	116

Non-Wind PURPA Generation Data

Table 6
Actual monthly aMW for water year 2012

Year	Month	aMW
2011	October	96
	November	52
	December	45
2012	January	43
	February	43
	March	54
	April	104
	May	135
	June	131
	July	140
	August	130
	September	111

Solar Production Data



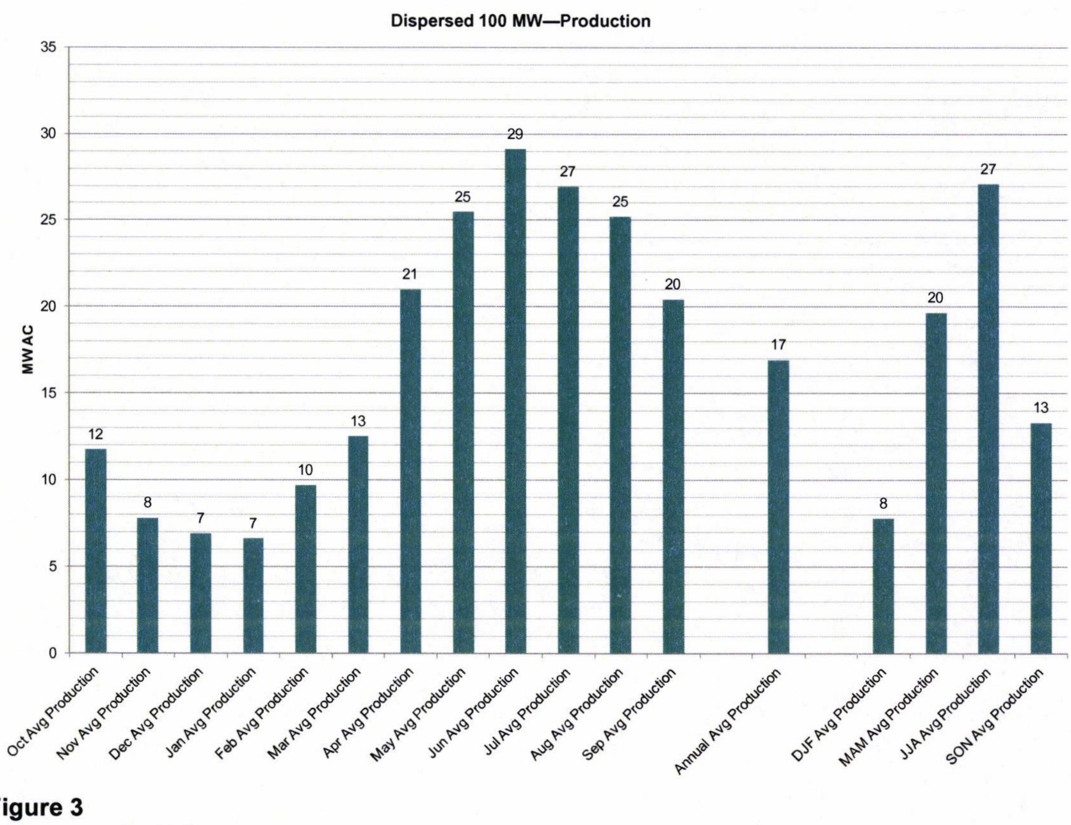
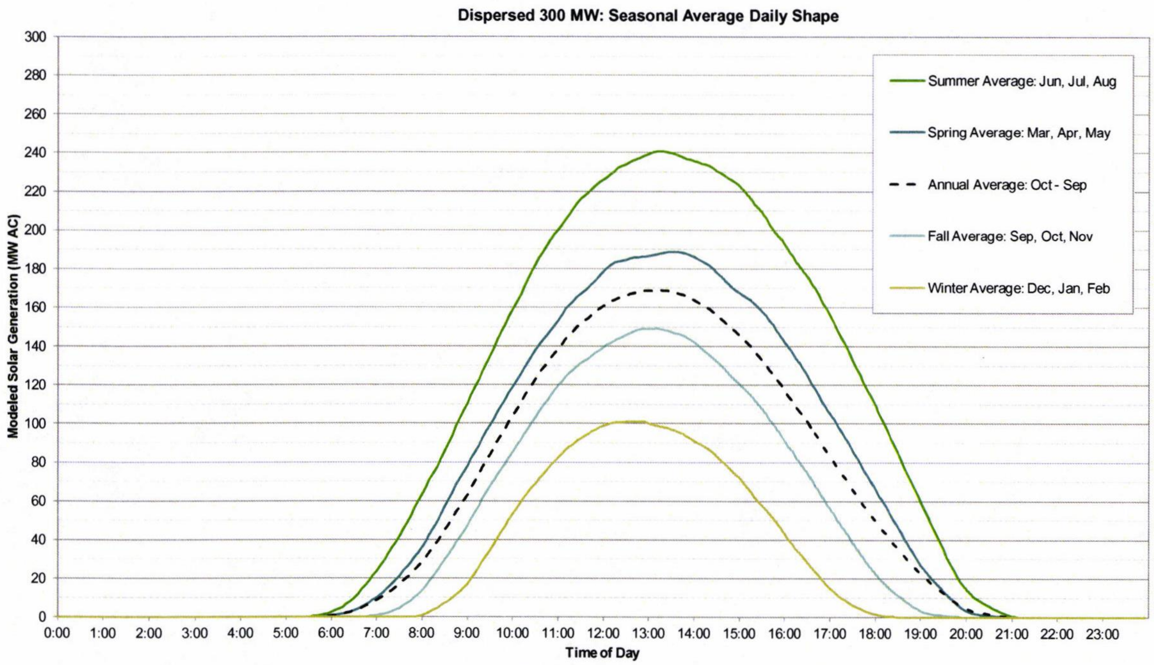


Figure 3
Dispersed 100 MW



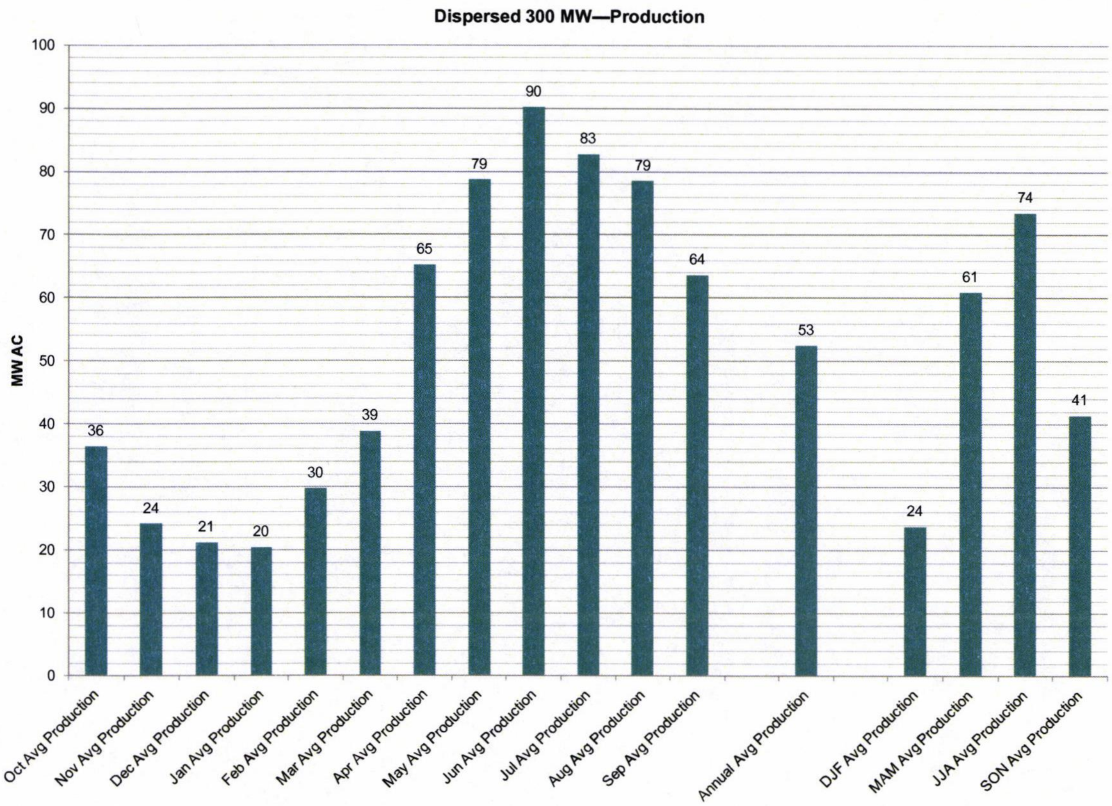
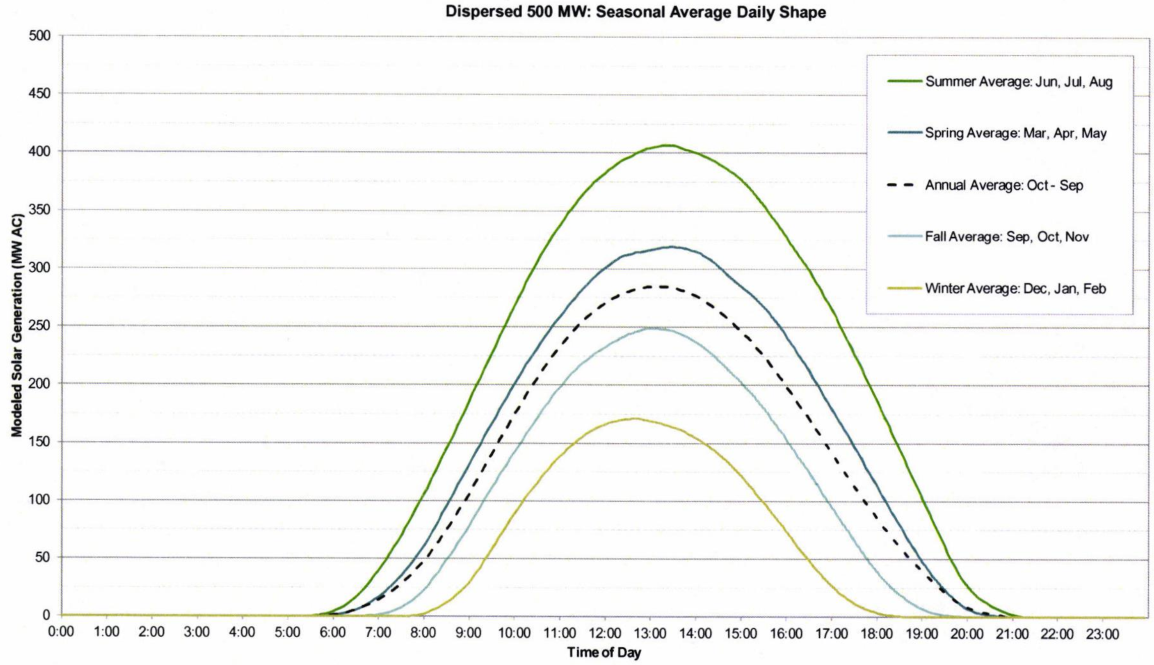


Figure 4
Dispersed 300 MW



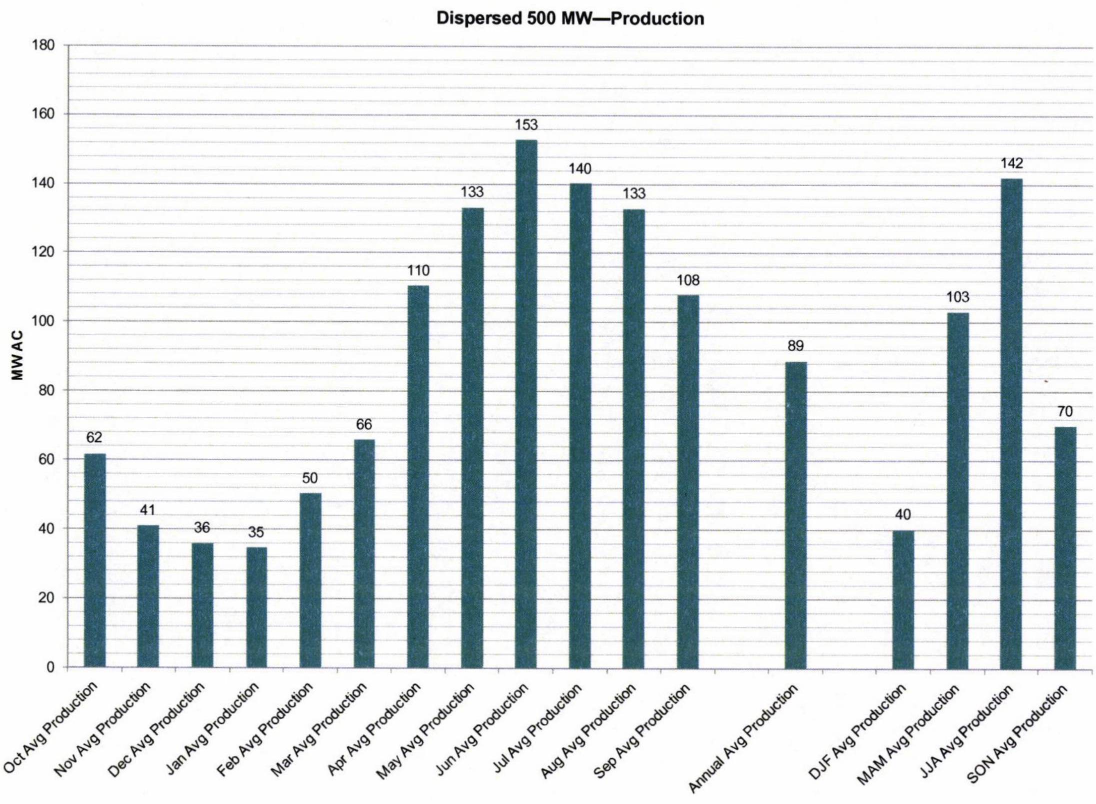
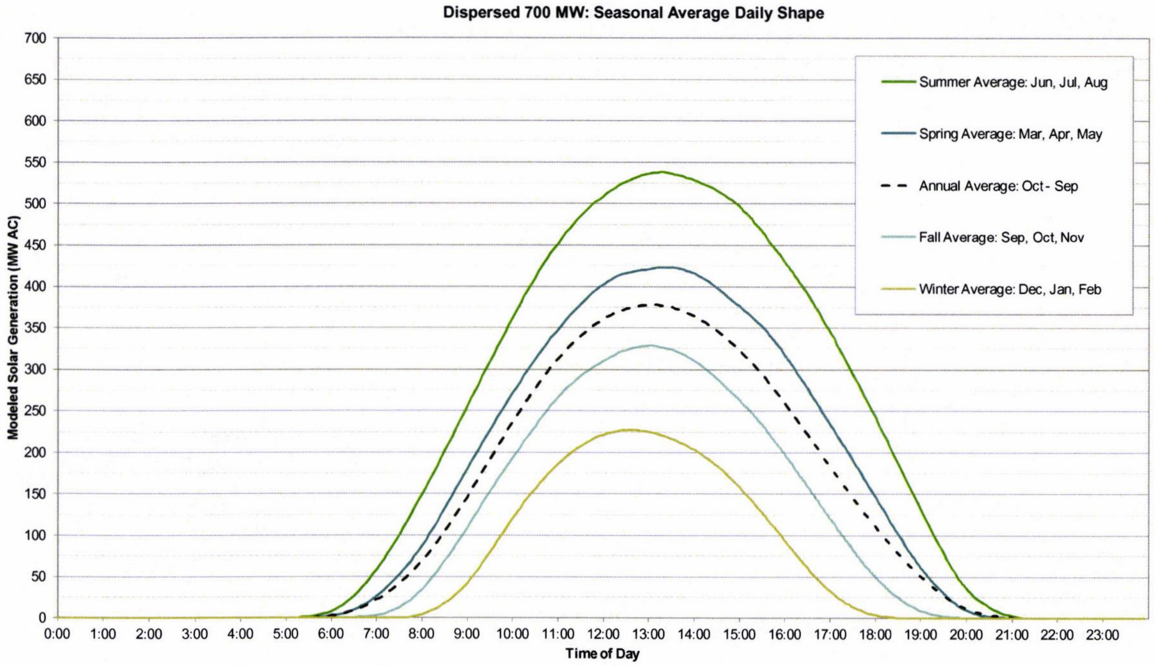


Figure 5
Dispersed 500 MW



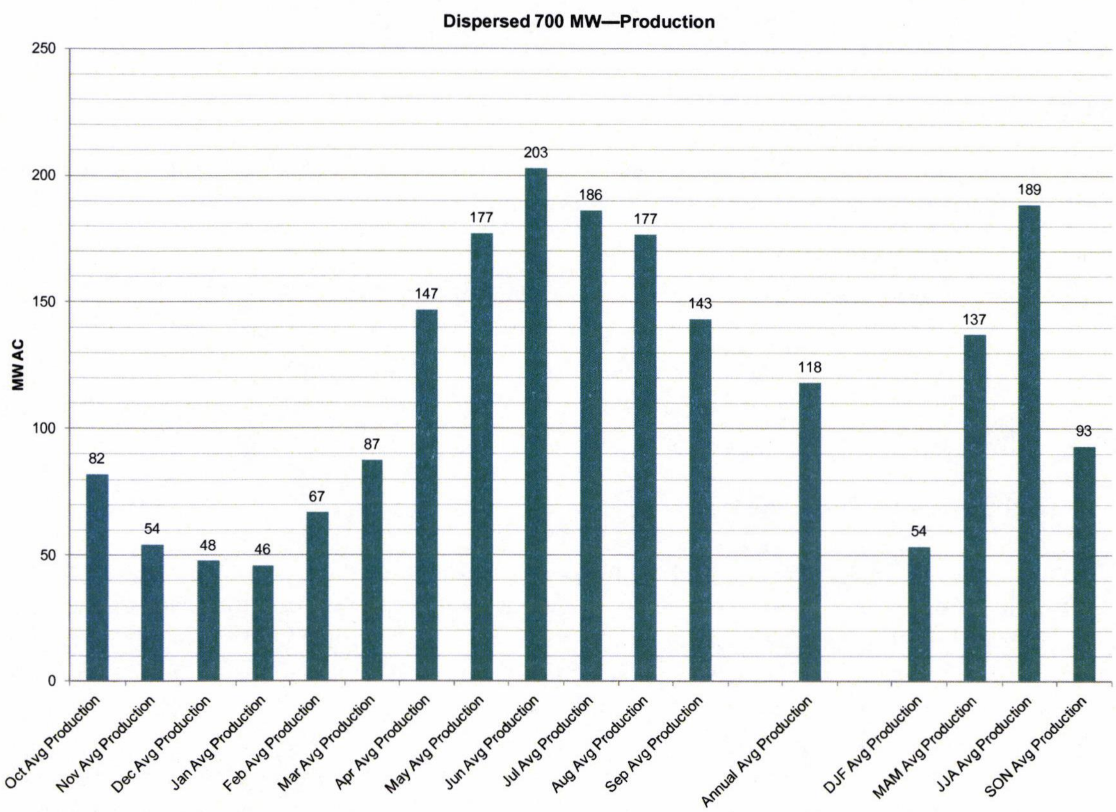


Figure 6
Dispersed 700 MW

Derivation of Hour-Ahead Solar Production Forecast and Upper/Lower Bounds

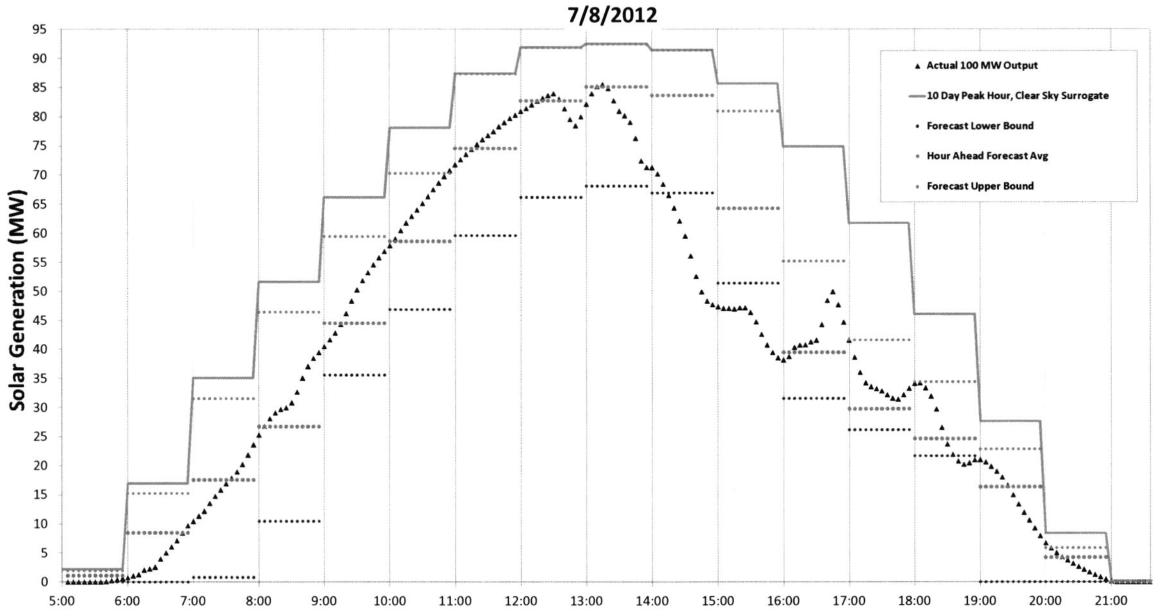


Figure 8
Hour-ahead forecast example

The average forecast is shown on Figure 8 as the green series. For each hour of the day, the forecast average is calculated by applying the follow equation:

$$Forecast\ Avg_{(t)} = Forecast\ Obs(MW)_{(t_{-1}:00 \rightarrow t_{-1}:15)} * \frac{Avg\ CSIS_{(t:00 \rightarrow t:55)}}{Avg\ CSIS_{(t_{-2}:20 \rightarrow t_{-1}:15)}}$$

Where:

t = forecast hour

CSIS = Clear Sky Index Surrogate

The Clear Sky Index Surrogate (CSIS) is an important measure of the maximum amount of solar generation the system could experience in any given hour. The CSIS is a component of the average solar production forecast and accounts for the seasonal changes that influence solar photovoltaic generation. This value is unique for every hour of the year. The CSIS is calculated using 5-minute, modeled production data from the wavelet-based variability model (WVM). The CSIS is calculated by taking the maximum 5-minute observation for a given hour. This maximum value is the absolute maximum for a given hour over a 10-day period. After identifying the absolute maximum from water year 2011, the forecast also identifies the absolute maxima for water years 2012 and 2013. With the three absolute maxima identified from the three water years analyzed, the forecast applies the maximum CSIS observed in three years of data for a given hour. It is noted that the ratio of the CSIS values, described in the above equation, result in the least amount of average production forecast error. Multiple variations of this ratio were tested, and the final version of the ratio was the most accurate. The process detailing the calculation of the CSIS is described in the equations below.

$$CSIS_{(t)} = Max\left(\left[CSIS_{(Water\,Year\,2011)}\right], \left[CSIS_{(Water\,Year\,2012)}\right], \left[CSIS_{(Water\,Year\,2013)}\right]\right)$$

Where:

$$CSIS_{(Water\,Year\,2011)} = Max\left(\left[5\min Obs(MW)_{(t)_{(d-1)}}\right], \left[5\min Obs(MW)_{(t)_{(d-2)}}\right], \dots, \left[5\min Obs(MW)_{(t)_{(d-10)}}\right]\right)$$

$$CSIS_{(Water\,Year\,2012)} = Max\left(\left[5\min Obs(MW)_{(t)_{(d-1)}}\right], \left[5\min Obs(MW)_{(t)_{(d-2)}}\right], \dots, \left[5\min Obs(MW)_{(t)_{(d-10)}}\right]\right)$$

$$CSIS_{(Water\,Year\,2013)} = Max\left(\left[5\min Obs(MW)_{(t)_{(d-1)}}\right], \left[5\min Obs(MW)_{(t)_{(d-2)}}\right], \dots, \left[5\min Obs(MW)_{(t)_{(d-10)}}\right]\right)$$

Where:

t= forecast hour

d= forecast day

Figure 8 is a good example of how the persistence-based forecast does very well under the majority of solar conditions and how a forecasting model struggles with extreme weather events. Despite the limitations of a persistence forecast, within a short period of time the forecast returned to accurate predictions. Figure 8 is a select, extremely variable generation profile. The afternoon observations that fall beneath the lower bound forecast are included in the 2.5 percent of lower forecast error reported in the solar integration study. Generally, the forecast does well capturing the variability in production due to solar. The forecast has the ability to tighten the range between the upper and lower bounds. This ensures the amount of capacity held in reserve is sufficient but not unduly large.

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