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November 29, 2017

VIA ELECTRONIC FILING

PUC Filing Center
Public Utility Commission of Oregon
P.O. Box 1088
Salem, OR 97308-1088

Re: UM ____ - In the Matter of IDAHO POWER COMPANY'S Compliance Filing Regarding the Resource Value of Solar Pursuant to Order No. 17-357

Attention Filing Center:

In accordance with Order No. 17-357, issued in docket UM 1716 on September 15, 2017, Idaho Power Company ("Idaho Power") hereby submits its initial resource value of solar ("RVOS") filing. As required by Order No. 17-357, this filing includes the direct testimony of Rick Haener and workpapers explaining Idaho Power's calculations.

Please contact this office with any questions.

Very truly yours,

Adam Lowney

Attachment

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

DOCKET NO. UM _____

IN THE MATTER OF IDAHO POWER COMPANY'S COMPLIANCE FILING REGARDING THE RESOURCE VALUE OF SOLAR PURSUANT TO ORDER NO. 17-357.	))))))

IDAHO POWER COMPANY

DIRECT TESTIMONY

OF

RICK HAENER

November 29, 2017

Q. Please state your name, business address, and present occupation.

A. My name is Rick Haener and my business address is 1221 West Idaho Street, Boise, Idaho 83702. I am employed by Idaho Power Company ("Idaho Power" or "Company") as the Power Supply Planning Leader.

Q. Please describe your educational background.

A. I received a Bachelor of Science degree in Accounting from the University of Idaho.

Q. Please describe your business experience with Idaho Power.

A. I began my employment with Idaho Power in 2003 as a Financial Analyst in Delivery Finance. In Delivery Finance, I gathered and analyzed financial and operational data, developed and reported benchmarking and key performance measures, and performed cost-benefit analysis, least-cost and marginal cost analysis, computer modeling, and process automation.

In 2004, I was promoted to a Senior Planning Analyst in Power Supply Planning. In this position, I modeled the Company's resource portfolio within the Western Electricity Coordinating Council and conducted resource portfolio analysis using the EPIS, LLC, AURORA electricity forecasting and analysis tool ("AURORA") and Vista computer model. I was one of the co-leaders for the development of Idaho Power's first Wind Integration Study Report, prepared and presented study results to internal and external stakeholders, and determined trends and projections for utility planning, forecasting, and operations.

In 2010, I accepted the position of the Fuels Management Coordinator in Power Supply Joint Projects. In this role, I worked with the Company's coal plant partners in developing fueling plans and negotiating and overseeing fuel and rail contracts.

In 2015, I was promoted to lead the Power Supply Planning Team, which is responsible for intermediate and long-term power supply planning and resource adequacy. Power Supply Planning also conducts integration studies, develops the Company's Integrated Resource Plan ("IRP"), and assists in the determination of avoided cost pricing for Public Utility Regulatory Policies Act of 1978 ("PURPA") projects.

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

A. The purpose of my testimony is to present Idaho Power's initial resource value of solar ("RVOS") calculation as directed by the Public Utility Commission of Oregon ("Commission") in Order No. 17-357 issued in Docket No. UM 1716. In Order No. 17-357, the Commission directed Portland General Electric Company, PacifiCorp, d/b/a Pacific Power, and Idaho Power ("utilities") to develop a 25-year marginal, levelized value for a generic, small-scale solar resource. The utilities are to develop these initial RVOS calculations using the specific elements, definitions, and inputs defined and adopted in Phase 1 of Docket No. UM 1716. The matrix which contains the elements, definitions, and inputs to be used in developing the utilities' RVOS calculations is attached to Order No. 17-357.

Q. How is your testimony organized?

A. My testimony begins with a brief discussion of Order No. 17-357, which contains the elements to be used in the utilities' initial RVOS calculations. I will then present Idaho Power's determination of the RVOS for a small-scale solar resource and discuss each element of the RVOS calculation in detail. Finally, I will present Idaho Power's determination of the RVOS for a utility scale size project, as ordered by the Commission.

Q. How many RVOS workbooks are submitted with your testimony and briefly describe their primary differences?

A. Idaho Power is submitting two versions of the RVOS workbook as part of the Company's workpapers. The first workbook is the Company's RVOS calculation for a standard size project (0.41 megawatts ("MW")). The second workbook presents the Company's RVOS calculation for a utility scale size project (30 MW), as directed by the Commission.

I. RVOS CALCULATION REQUIREMENTS

Q. Please describe Order No. 17-357, which modified and adopted the straw proposal for utility RVOS calculations.

A. In Order No. 17-357, the Commission largely adopts the RVOS methodology proposed by Energy and Environmental Economics, Inc. ("E3") to produce a 25-year marginal, levelized value for a generic, small-scale solar resource installed in 2017. Order at 1. The Order adopts 11 specific elements to be included in the utilities' RVOS calculations. Four elements make up the majority of the calculation: energy, generation capacity, transmission and distribution ("T&D") capacity, and line losses. As noted by the Commission, the values of these four elements will largely come from utilities' existing avoided cost prices or existing cost studies, with additional granularity to properly value the shape of solar production. Order No. 17-357 at 2.

Two elements, administration and integration, are specific costs to the utility. The values for these two elements will come from existing utility studies. The next two elements, hedge value and market price response, will use assigned proxy values for the initial RVOS Phase II filings. The next element, environmental compliance, will be treated as an informational placeholder in the initial RVOS Phase II filings. The last two elements, renewable portfolio standard ("RPS") compliance and grid services, will be valued at zero in the utilities' initial RVOS Phase II filings.

Q. Using the prescribed methodology established by the Commission, what value did Idaho Power determine for the RVOS?

A. Idaho Power's calculation, using the Commission's prescribed methodology, and specific model input changes made by the Company, results in a net levelized RVOS of $1.61 per megawatt-hour ("MWh") for a standard size project and $45.01 per MWh for a utility scale size project. The table below presents the quantification of each element of the RVOS calculation and the net levelized RVOS for both a standard size project and a utility scale size project.

Element	**Value Standard Size Project** ($/MWh Real Levelized)	**Value Utility Scale Size Project** ($/MWh Real Levelized)
1. Energy	29.74	29.74
2. Generation Capacity	15.30	14.34
3. T&D Capacity	0.87	-
4. Line Losses	2.54	-
5. Administration	(47.77)	-
6. Integration	(0.56)	(0.56)
7. Market Price Response	0.00	0.00
8. Hedge Value	1.49	1.49
9. Environmental Compliance	0.00	0.00
10. RPS Compliance	0.00	0.00
11. Grid Services	0.00	0.00
Net Levelized RVOS	**1.61**	**45.01**

Each element of the RVOS calculation, as well as the model inputs, are discussed in detail in the following section of my testimony.

II. RVOS ELEMENTS

Element #1 – Energy

Q. How has the Commission defined element #1, energy?

A. The Commission defined energy as the marginal avoided cost of procuring or producing energy, including fuel, operations and maintenance, pipeline costs, and all other variable costs.

Q. What is the Commission's direction for developing the energy component of the RVOS calculation?

A. For energy, the Commission directed utilities to use a 12-month x 24-hour block, or solar output capacity profile, to develop energy prices. The Commission's expectation is that for each of the 12 months in a year, utilities will develop a typical day shape of prices across 24 hours from the same pricing source used to develop their average monthly or annual standard Qualifying Facility ("QF") avoided cost pricing. The Commission notes that it requires this more granular approach because a daily shape is important for solar compensation. The Commission also directed utilities to provide a detailed explanation of how they created the 12-month x 24-hour solar output capacity profile as well as an explanation and analysis demonstrating how energy values are scaled to represent the average price under a range of hydro conditions.

Q. Did Idaho Power develop a 12-month x 24-hour solar capacity output profile?

A. Yes. Idaho Power created a 12-month x 24-hour solar capacity output profile using actual 2011-2016 hourly solar energy shapes collected from Idaho Power's participants in the Solar Photovoltaic Pilot Program, Oregon Schedule 88. This program includes 54 fixed plate solar projects with a total cumulative generation capacity of 0.41 MW. However, while Idaho Power developed a 12-month x 24-hour solar capacity output profile as suggested in Order No. 17-357, the Company recognized the Commission's desire to use granular values when available to achieve the best estimate of RVOS. With the availability of more granular data, the Company believed it was more appropriate to use the actual hourly capacity output to develop energy shapes for the RVOS, rather than a 12-month x 24-hour profile. The Company has included the actual hourly solar output capacity profile as part of its workpapers. If the Phase II review process determines that a more aggregate energy shape is appropriate, the Company can apply the 12-month x 24-hour solar output capacity profile rather than the hourly solar output capacity profile.

Q. How did Idaho Power scale energy values to represent the average energy price under a range of hydro conditions?

A. Idaho Power developed an average energy price by considering the effects on price, if any, of five separate hydro conditions. The Company sorted 82 years of streamflow data into percentiles and determined the effect on the electric price for each of the following hydro conditions: 10th percentile, 30th percentile, 50th percentile, 70th percentile, and 90th percentile. Specifically, the Company completed five simulations in AURORA to determine annual average Mid-Columbia ("Mid-C") electric prices for 2018-2034, extrapolated to 2042[1], under each of the hydro conditions noted above, with all other inputs held constant. The Company calculated the differentials in Mid-C prices between each of the simulations and the median hydro condition and applied those differentials to the current approved Cogeneration and Small Power Production Standard Contract Rates, Schedule 85 ("Standard Contract Rates") for a solar QF to develop a range of hydro-varied energy prices for 2018-2042. Finally, the Company averaged the resulting range of prices to determine annual average prices under a range of hydro conditions. The average prices under a range of hydro conditions were used to populate the Annual Average Energy Price ($/MWh nominal) on the "General Input" tab of the RVOS workbook. The analysis used to determine the average prices under a range of hydro conditions has been included as part of the Company's workpapers.

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[1] Order No. 17-357 directs utilities to use a 25-year timeframe for RVOS calculations. However, Idaho Power's IRP horizon is limited to 20 years, as are QF commitments. The AURORA simulations used to develop the average price under a range of hydro conditions were completed as part of the 2015 IRP process, and therefore produced Mid-C electric prices for the 20-year timeframe of 2015-2034. Idaho Power extrapolated Mid-C prices for the years 2035-2042, as well as Standard Contract Rates for the year 2042, using a compound average growth rate.

Element #2 – Generation Capacity

Q. **How has the Commission defined element #2, generation capacity?**

A. The Commission defined generation capacity as the marginal avoided cost of building and maintaining the lowest net cost generation capacity resource.

Q. **What is the Commission's direction for developing the generation capacity component of the RVOS?**

A. For generation capacity, the Commission directed utilities to provide the capacity value and timing (deficiency date) in line with their current approved standard non-renewable QF avoided cost capacity value. Per the current standard non-renewable QF capacity calculation, during resource sufficient years, the utility uses forward market prices to calculate avoided cost prices. During a resource deficient period, a utility multiplies the contribution to peak of a QF's resource type by the capacity cost of the utility's avoided proxy resource. Order No. 17-357 at 6-7.

Q. **Did Idaho Power determine the generation capacity value in accordance with the standard non-renewable QF avoided cost approach?**

A. Yes. The Company used the current approved avoided capacity costs from its Standard Contract Rates in the RVOS calculation, beginning in the first year of deficiency, 2024. Per the Company's current approved Standard Contract Rates, the capacity cost of Idaho Power's avoided proxy resource, a combined cycle combustion turbine, in 2024 is $92.90 per kilowatt-year ("kW-year"). This value has been included in the RVOS workbook for the Cost of Marginal Capacity on the "General Inputs" tab.

Q. **Does removal of incremental expected distributed solar photovoltaic ("PV") from the load forecast change Idaho Power's resource deficiency date?**

A. No. Per the Commission's direction, utilities are to remove incremental distributed solar PV from the load forecast used in the last acknowledged IRP and then, if applicable, provide an adjusted deficiency date. Order No. 17-357 at 8. The load forecast used by Idaho Power in the 2015 IRP did not include an adjustment for incremental distributed solar PV; therefore, distributed solar PV had no impact on capacity deficiency timing for the 2015 IRP. The first year of resource deficiency, as determined in the Company's 2015 IRP, is 2024.

<u>Element #3 – T&D Capacity</u>

Q. How has the Commission defined element #3, T&D capacity?

A. The Commission defines T&D capacity as the avoided or deferred costs of expanding, replacing, or upgrading T&D infrastructure.

Q. What is the Commission's direction for developing the T&D capacity component of the RVOS?

A. The Commission directed that the utilities' initial RVOS compliance filings should use a system-wide average of the avoided or deferred costs of expanding, replacing, or upgrading T&D infrastructure attributable to incremental solar penetration in Oregon service areas.

Q. Does Idaho Power's RVOS calculation use a system-wide average avoided cost for T&D infrastructure attributable to incremental solar penetration?

A. Yes. Idaho Power's RVOS calculation includes a system-wide average value of $3.76/kW-year for the avoided T&D infrastructure cost. The $3.76/kW-year was divided evenly between the Transmission Deferral Value and the Distribution Deferral Value on the "General Inputs" tab of the RVOS workbook, resulting in $1.88/kW-year for each input.

Q. Please describe how Idaho Power developed the average avoided cost for T&D.

A. The value is based on an analysis performed as part of the 2017 IRP[2,3], which estimates T&D deferral benefits associated with energy efficiency. The T&D deferral benefits associated with energy efficiency were determined using all growth projects from Idaho Power's officer-reviewed, three-year budget for 2016. The limiting capacity (determined by feeder or transformer) was identified for each project along with the anticipated in-service date, projected cost, peak loading, and projected growth rate.

Next, the forecast for the penetration of energy efficiency was incorporated into the analysis. Independent energy efficiency demand reduction forecasts for different rate classes were applied at summer and winter peak. If the adjusted forecast was below the limiting capacity, it was assumed the project could be deferred. The financial savings of deferring the project were then calculated.

The total savings from all the deferrable projects was divided by the total annual energy efficiency reduction forecast over the service area. Based on the analysis, a value of $3.76/kW-year was determined as the T&D deferral value for energy efficiency. This is the same system-wide average value the Company has included for the avoided T&D infrastructure cost attributable to incremental solar penetration. This value was also the basis for T&D deferral benefits assumed in the analysis for the Company's proposed community solar project in Idaho.[4]

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[2] http://edocs.puc.state.or.us/efdocs/HTB/um1610htb104330.pdf.

[3] 2017 IRP at 53.

[4] *In the Matter of Idaho Power Company's Application for Approval of New Tariff Schedule 63, A Community Solar Pilot Program*, Case No. IPC-E-16-14, Settlement Stipulation, Attachment 1 – d (Sept. 26, 2016).

Q. Did the Commission request any additional information regarding the T&D capacity element of the RVOS calculation?

A. Yes. The Commission also requested that utilities explain what information and methodologies they currently have for location specific distribution planning and how those could be used or adapted in the near term to advance toward more location-specific values for this element.

Q. Does Idaho Power currently have any location-specific methodologies for distribution planning?

A. No. However, the Company desires to value this benefit in a manner fair to all potential rooftop solar installations, regardless of whether a given rooftop installation actually provides benefit. Thus, the estimated value would be spread evenly (i.e., without bias) across all potential installations.

Idaho Power's current plan to obtain a relevant T&D deferral value includes the following:

- Collect information on existing growth projects in the current capital budget.
- Remove from consideration those that cannot be deferred by rooftop solar penetration. This includes projects for substation transformers and distribution circuits that do not peak during the day or are not capacity constrained.
- Determine the value of the deferrals and the amount of rooftop solar generation required to achieve the deferrals.
- Project the results over a 20-year period. The Company will include large transmission projects, such as Boardman to Hemingway, in the projection.

- Calculate the benefit of T&D deferrals obtained from rooftop solar penetration, calculated in dollars per kW-year. Please note the deferral value in this calculation would be spread over the projected full penetration of rooftop solar.

The Company may attempt to quantify and include the increased infrastructure and operating costs associated with high levels of rooftop solar penetration.

Q. Does Idaho Power view rooftop solar PV as potentially allowing the deferral of T&D investment?

A. The Company agrees with E3 witness Arne Olson in his May 2016 testimony in Docket No. UM 1716 that deferral benefits are "highly location-specific."[5] An example of this location-specific benefit may be demonstrated by considering a remote section of a distribution circuit where the following occurs: the load peak occurs during daylight hours, customer demand is either not increasing or increasing slowly, and the voltage drops below American National Standard for Electric Power Systems and Equipment C84.1 (Voltage Ratings) standard steady-state voltage tolerance during peak load conditions only. A traditional utility solution in this example, such as reconductoring of a line section, might be deferred by a sufficient amount of solar PV generation. In fact, in their review of the Company's distribution system, Idaho Power engineers found one location meeting the highly location-specific criteria described above, and installed a pilot PV project in 2016. Company engineers are presently monitoring the pilot PV and circuit voltage performance. More detail on this project can be found beginning on page 10 of the Company's

[5] http://edocs.puc.state.or.us/efdocs/HTB/um1716htb101623.pdf, Olson/10, lines 9-10.

2016 Smart Grid Report and page 12 of the Company's 2017 Smart Grid Report.[6,7]

Q. Does the potential exist for rooftop solar or other distributed energy resources ("DER") to bring about incremental infrastructure costs?

A. High penetration of DER, including rooftop solar, on a distribution circuit may bring about additional infrastructure costs to mitigate the operational challenges that accompany them, such as voltage management, short circuit detection, and islanding. Islanding occurs when a customer's generation is capable of supporting the load of other customers physically located near the customer's generator when that section of the electrical circuit is isolated from the Idaho Power system. Particular challenges relate to the impacts DERs can have on distribution circuit voltage. When DER is contributing power to the circuit, it changes the power requirement from the distribution substation transformer. This change in power flow causes the typical voltage drop to change.

Q. Please summarize Idaho Power's views on rooftop solar's impacts on deferred T&D infrastructure investment.

A. As demonstrated by the pilot project described earlier, Idaho Power sees the potential for benefit from solar installations and the associated deferral of infrastructure investment; there are specific locations on the distribution system where customer-sited solar could bring about this benefit. Thus, for this initial Phase II filing, the Company used the value of $3.76/kW-year as its estimate for T&D infrastructure deferral cost. However, the Company cautions that grid locations exist where high penetration of rooftop solar capacity could give rise to additional

[6] https://www.idahopower.com/pdfs/AboutUs/CompanyInformation/SmartGrid/2016OregonSmartGridReport.pdf.

[7] https://www.idahopower.com/pdfs/AboutUs/CompanyInformation/SmartGrid/2017OregonSmartGridReport.pdf.

infrastructure costs. Idaho Power proposes to monitor its grid over the coming years as rooftop solar grows in penetration, evaluating not only resulting grid benefits, but also grid costs.

Q. Does Idaho Power favor a system-wide average benefit associated with deferred infrastructure or a benefit that varies from location to location across its service area?

A. Idaho Power favors the system-wide benefit approach described above. The location based benefit valuation may bring about a "moving target" situation, which would likely result in an unstable or time-varying RVOS as grid locations are in and out of consideration as beneficial locations. Moreover, the assignment of a higher benefit for a certain grid location may lead to the installation of rooftop solar capacity, but there is no guarantee that the installed solar capacity occurring in response to the higher benefit will be sufficient to realize the assumed infrastructure deferment. The desired benefit may not be obtained, infrastructure not deferred, and both participating and non-participating customers fund both the localized incentive and infrastructure investment. The system-wide average approach is more practicable to implement, and would lead to more stable RVOS.

Element #4 – Line Losses

Q. How has the Commission defined element #4, line losses?

A. The Commission defines line losses as avoided marginal electricity losses.

Q. What is the Commission's direction for calculating the line losses component of the RVOS?

A. For line losses, the Commission directed utilities to develop hourly averages of line losses by month for the daytime hours when load on the system is higher, losses are greater, and solar is generating. The Commission notes that it does not expect a true hourly value to this element, but asks utilities to provide the most granular value they reasonably can inclusive of daytime and seasonal variation, and to provide an explanation of the value.

Q. What is Idaho Power's estimate of incremental avoided marginal line losses?

A. Using loss data collected for calendar year 2012, Idaho Power has populated the hourly averages of line losses using the Electricity System Losses table on the "General Inputs" tab of the RVOS workbook, as shown in the table below. The loss values represent the percentage of produced energy consumed as losses in the transmission and distribution facilities owned by Idaho Power, and include both wire losses and transformer core losses.

May - Oct: 2pm-7pm	Summer On-Peak	8.6%
May - Oct: 5am-2pm, 7pm-9pm	Summer Mid-Peak	8.5%
May - Oct: 9pm-5am	Summer Off-Peak	8.7%
Nov - Apr: 6am-10am, 5pm-8pm	Winter On-Peak	8.5%
Nov - Apr: 10am-5pm, 8pm-10pm	Winter Mid-Peak	8.5%
Nov - Apr: 10pm-6am	Winter Off-Peak	8.5%

Q. What are the key drivers of system losses?

A. Losses occur over high-voltage transmission, lower-voltage distribution, and transformer core losses (noting that transformer losses are nearly constant and therefore not a function of load). The near-constant nature of transformer core losses has the tendency to increase the loss value during off-peak hours when losses are expressed as a percentage of produced energy. System losses, when expressed as watt-hours, tend to increase during on-peak hours and decrease during off-peak hours. Idaho Power also took into account transmission system loading, where such loading also includes third-party use of the system, which does not necessarily correspond with on-peak or off-peak hours.

Q. In Order No. 17-357, the Commission states that energy, generation capacity, T&D capacity, and line losses make up the majority of the RVOS calculation. Based on these four elements, what value did Idaho Power determine for RVOS?

A. Based on the energy, generation capacity, T&D capacity and line loss elements discussed above, Idaho Power determined a levelized net RVOS of $48.45 per MWh.

<u>Element #5 – Administration</u>

Q. How has the Commission defined element #5, administration?

A. The Commission defines administration as the increased utility costs of administering solar PV programs.

Q. What is the Commission's direction for calculating the administration component of the RVOS?

A. Utilities are to develop estimates of the direct, incremental costs of administering solar PV programs, including staff, software, incremental distribution investments, and other utility costs.

Q. What is Idaho Power's estimate of the direct, incremental costs of administering solar PV programs?

A. Idaho Power determined its estimate for the direct, incremental costs of administering solar PV programs in Oregon by reviewing the actual costs incurred for the Oregon Solar Photovoltaic Pilot Program in 2016. The Company's estimate of administering solar PV programs is $47.77 per MWh, escalated at the 2015 IRP inflation rate of 2.2 percent annually. The $47.77 per MWh cost is based on 2016 actual expenses for the Oregon Solar Photovoltaic Pilot Program, including $14,065 in labor costs, $23,899 in communication service fees, and $638 in other operational expenses, totaling $38,601 in costs, divided by the 808 MWh of generation from the program for 2016. It is Idaho Power's understanding that the RVOS will be used for compensation for participants in the Oregon Solar Photovoltaic Pilot Program when the existing projects seek renewal contracts. As these are the actual costs of administering these projects, Idaho Power believes it is appropriate to reflect these costs in the administration component of the RVOS.

Q. Did Idaho Power consider any other estimates for calculating the administration component of the RVOS?

A. Yes. Idaho Power recognizes that the administration component is relatively large and may be driving down the RVOS calculation. For a comparative analysis, the Company removed $23,899 of the administration costs associated with communication service fees, which represents 62 percent of the total administration costs. The Company believes that while these costs are appropriately included in this initial RVOS calculation because they are actual costs being incurred for participants in the PV pilot, these same costs may not be included once the pilot is completed. Removal of these costs from the administration component of the RVOS calculation results in a net levelized RVOS of $31.18 per MWh.

Q. Was this reduced amount of administration costs the amount used for the Company's initial RVOS calculation?

A. No. This reduced amount for administration costs may be considered in future RVOS calculations; however, for the Company's initial RVOS calculation, all administration costs have been included, resulting in a Company estimate of administering solar PV programs of $47.77 per MWh, escalated at the 2015 IRP inflation rate of 2.2 percent annually.

Element #6 – Integration

Q. How has the Commission defined element #6, integration?

A. The Commission defines integration as the costs of a utility holding additional reserves in order to accommodate unforeseen fluctuations in system net loads due to the addition of renewable energy resources.

Q. What is the Commission's direction for calculating the integration component of the RVOS?

A. The Commission directed utilities to estimate integration costs based on acknowledged integration studies.

Q. What value did Idaho Power use for integration costs?

A. Idaho Power used the current Commission-approved solar integration costs included in the development of the Company's Standard Contract Rates. The values reflected in the Company's Standard Contract Rates were derived from an integration cost study which was published in the Idaho Power Company Solar Integration Study Report dated April 2016. The RVOS calculation includes an integration cost of $0.56 per MWh, for projects beginning in 2018 at the Company's current solar penetration level of 301-400 MW, and is escalated annually at 2.2 percent per the E3 workbook methodology.

Element #7 – Market Price Response

Q. How has the Commission defined element #7, market price response?

A. The Commission defines market price response as the change in utility costs due to lower wholesale energy market prices caused by increased solar PV production.

Q. What is the Commission's direction for calculating the market price response component of the RVOS?

A. The Commission directed Staff to coordinate or facilitate use of E3's model to create a proxy value for market price response to increased solar PV production that utilities will use in their RVOS calculations.

Q. Has Staff provided any direction for use of a proxy value for market price response?

A. Staff sent an e-mail to stakeholders in this docket on November 7, 2017, in an attempt to provide direction on this component. The e-mail included guidance from Arne Olson of E3, in which he recommended that utilities use one of two options for calculating the market price response component in their initial RVOS calculations.

The first option is to use a market price elasticity of -0.001 to -0.002 for each MWh of renewable energy. The elasticity is measured separately for heavy-load and light-load hours. The second option is for utilities to complete sequential runs in a production simulation model, such as AURORA, with the addition of a significant enough increment of solar generation to affect the calculated market price during each hour. The price differences would then be used to derive a market price elasticity per MWh of energy produced from customer-owned solar resources. Mr. Olson notes that with either option, the change in market price would be multiplied by the utility's net short or long position during each hour; i.e., the change in market price would be a benefit if the utility is short and a cost if the utility is long.

Q. Which method did Idaho Power use to determine the market price response component of the RVOS?

A. Idaho Power evaluated AURORA output to determine the hourly imports and exports from the Idaho Power system. The comparative result would reveal that the market price response should be positive, or a benefit to customers, if the majority of daylight hours showed market imports. Presumably, those benefits would accrue to the solar project developers by increasing the market price response component of the RVOS rate. Alternatively, if the majority of hours are exports to the market, then the reduced market price would be a detriment to customers and presumably solar project developers as the negative value of the market price component would reduce the RVOS rate.

The AURORA daylight hour import-export analysis indicated the majority of hours showed exports and that Idaho Power sold more energy to the market than it purchased from the market, resulting in a negative value for the market price response component of the RVOS calculation.

Based on the indication that the market price response component is negative, Idaho Power used a market price elasticity of -0.001 per MWh for the market price response component to the RVOS as suggested by Mr. Olson in the November 7, 2017, e-mail from Staff.

Q. Does Idaho Power have any concerns with the recommended methods for developing the market price response component?

A. Yes. Idaho Power does not envision its Oregon Solar Photovoltaic Pilot Program, currently consisting of 54 projects with a cumulative generation capacity of 0.41 MW, as significant enough to influence market prices. As such, Idaho Power does not see value in utilizing either of these methods for determining a proxy value for market price response, nor does it see value in including this component in the RVOS calculation at this time. Therefore, Idaho Power would recommend a value of zero for market price response for its initial Phase II filing. The Company also supports a revisit of this component in the future, when the number of projects in the Company's service area may have more of a potential to materially influence market prices.

Element #8 – Avoided Hedge Value

Q. How has the Commission defined element #8, avoided hedge value?

A. The Commission defines avoided hedge value as the avoided cost of utility hedging activities; i.e., transactions intended solely to provide a more stable retail rate over time.

Q. What is the Commission's direction for calculating the avoided hedge value component of the RVOS?

A. The Commission directed utilities to use E3's proxy value of 5 percent to reflect the avoided cost of utility hedging activities.

Q. Did Idaho Power use the 5 percent a proxy value for the avoided cost of hedging activities it its RVOS calculation?

A. Yes. The 5 percent proxy value is included as an input on the "General Inputs" tab of the RVOS workbook.

Q. Does Idaho Power have any concerns with using a 5 percent proxy hedge value?

A. Yes. As stated in prior testimony, Idaho Power has a specific Risk Management Policy which includes a prescribed process of when to initiate future power market purchases and sales. The 5 percent premium value of future energy purchases is not consistent with Idaho Power's Risk Management Policy, and therefore does not reflect the hedging activity on Idaho Power's system. Idaho Power has complied with the Commission's directive and used the 5 percent proxy value for this initial RVOS filing; however, the Company would recommend using a value of zero for the avoided hedge value.

Element #9 – Environmental Compliance

Q. How has the Commission defined element #9, environmental compliance?

A. The Commission defines environmental compliance as the avoided costs of complying with existing and anticipated environmental standards.

Q. What is the Commission's direction for calculating the environmental compliance component of the RVOS?

A. The Commission directed utilities to calculate a value for environmental compliance for informational purposes, to be used as a placeholder in their initial RVOS calculations. The utilities are to estimate the avoided cost based on a reduction in carbon emissions from the marginal generating unit with the carbon regulation assumptions from their IRPs.

Q. What value did Idaho Power calculate for environmental compliance?

A. Idaho Power used a value of zero for environmental compliance. Currently, Idaho Power has no environmental compliance costs; therefore, no environmental compliance costs are avoided with additional solar generation. A zero value is consistent with Idaho Power's 2015 IRP.

Element #10 – RPS Compliance

Q. What is the Commission's direction for calculating the RPS compliance component of the RVOS?

A. The Commission directed utilities to initially assign a zero value for RPS compliance. The zero value is intended be a placeholder until it can be revisited and assigned a methodology as part of Phase II in this docket.

Q. Did Idaho Power assign a value of zero to the RPS compliance component of the RVOS calculation?

A. Yes. Idaho does not have an RPS in the state of Idaho and the Company would already be in compliance with the Oregon RPS requirements to be met in 2025 without incurring additional costs.

Element #11 – Grid Services

Q. How has the Commission defined element #11, grid services?

A. The Commission defines grid services as the potential benefits of solar PV in advanced, uncommon applications and from utilities' increasing ability to capture the benefits of mass-market smart inverters.

Q. What is the Commission's direction for calculating the grid services component of the RVOS?

A. The Commission directed utilities to initially assign a zero value for grid services. The element of grid services will be retained to capture the potential incremental system benefits from solar PV in the future.

Q. Did Idaho Power assign a value of zero to the grid services component of the RVOS calculation?

A. Yes.

III. ADDITIONAL RVOS INPUTS

Q. Did Idaho Power make changes to other inputs of the RVOS calculation?

A. Yes. Idaho Power changed other inputs in the model, where appropriate, to reflect the values consistent with Idaho Power's assumptions and system.

Q. What other inputs did Idaho Power make changes to and what was the source for each of the changes?

A. Idaho Power made the following input changes to the model:

- Inflation was updated to 2.2 percent and the nominal discount rate was updated to 6.74 percent to be consistent with the 2015 IRP assumptions. The real discount rate was changed to be consistent with the inflation and nominal discount rate.

- The resource deficiency year was changed to 2024 consistent with the 2015 IRP load and resource balance first deficiency date of July 2024. Please note the table on pages 50-69 of Appendix C in the 2015 IRP displays a first capacity deficit occurring in July 2025. However, the July 2025 deficiency is based on 461 MW of installed PV solar capacity under contract at the time of portfolio design, and does not reflect the April 2015 cancellation of 141 MW of PV solar PURPA contracts. With removal of the 141 MW of PV solar PURPA contracts, the first deficit for capacity occurs in July 2024. *See* 2015 IRP, Appendix C at 119.
- The Hourly Loss of Load Probability ("LOLP") on the "Hourly Inputs" tab of the RVOS workbook reflects the 2017 IRP[8] analysis of LOLP, which used an approximate 2 hours per year Loss of Load Expectation (LOLE) average target over 500 outage iterations. The same hourly LOLP was used for all years. The resulting Solar-LOLP Coincidence is 32.9 percent.
- The Energy Price Shapes on the "Hourly Inputs" tab of the RVOS workbook were changed to reflect the Standard Contract Rates annual energy pricing under a range of hydro conditions.

Q. What is the result of using Idaho Power specific inputs for the RVOS model?

A. Idaho Power's RVOS calculation, using the Commission's prescribed methodology, and specific model input changes discussed above, results in a net levelized RVOS of $1.61 per MWh for a standard size project.

[8] For the RVOS calculation, Idaho Power attempted to use inputs from the 2015 Commission-acknowledged IRP. However, the LOLP input is from the 2017 IRP analysis as it was derived from the settlement stipulation in Docket No. UM 1719, Investigation to Explore Issues Related to a Renewable Generator's Contribution to Capacity.

IV. UTILITY SCALE ALTERNATIVE

Q. What is the Commission's direction regarding alternative RVOS calculations for utility scale solar resources?

A. The Commission stated, as a reference point only, that utilities should provide a separate workbook with an RVOS calculation assuming a utility scale solar proxy to replace all elements, and remove the cost components for T&D capacity, administration, and line losses, which are benefits/costs that rooftop solar provides that utility scale solar does not. The Commission also noted that utilities should explain their utility scale proxy and how it relates to their IRPs.

Q. Did Idaho Power develop an alternative RVOS calculation assuming a utility scale solar proxy?

A. Yes. Idaho Power's RVOS calculation assuming a utility scale solar proxy results in a levelized net RVOS of $45.01 per MWh.

Q. Please explain how Idaho Power developed the alternative RVOS calculation.

A. Idaho Power assumed a 30 MW utility scale single-axis tracking project, which is consistent with Idaho Power's 2017 IRP view of a representative size for utility scale solar projects the Company might contemplate in the future.

The utility scale RVOS calculation utilizes a representative 12-month x 24-hour solar output capacity profile submitted by a 15 MW Oregon solar PURPA project currently under contract. Each value within the 12-month x 24-hour solar output capacity profile was doubled to represent a 30 MW project. The solar output capacity profile was used to update the hourly input solar profile within the utility scale RVOS workbook. The solar output capacity profile utilized for the utility scale RVOS calculation has been included with the Company's workpapers.

Those elements that relate to the benefits of a distributed system, which include T&D capacity, line losses, and administration costs were eliminated from the utility scale RVOS calculation, per the Commission directive, by setting these components to “FALSE” on the “General Inputs” tab within the RVOS workbook.

All other element inputs for the utility scale RVOS calculation are consistent with the inputs used in the Company’s RVOS calculation for a standard size project. The resulting levelized RVOS calculation for a utility scale solar proxy is $45.01 per MWh.

Q. Does this conclude your testimony?

A. Yes.