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June 1, 2016

Via Electronic Filing

OREGON PUBLIC UTILITY COMMISSION
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RE: Docket No. UM 1716 – In the Matter of
PUBLIC UTILITY COMMISSION OF OREGON,
Investigation to Determine the Resource Value of Solar.

Attached for electronic filing are Staff Opening Testimony of Cindy Dolezel (Exhibit 100 – 101) and Arne Olson (Exhibit 200 - 201).

/s/ Kay Barnes
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PUBLIC UTILITY COMMISSION OF OREGON

UM 1716

STAFF DIRECT TESTIMONY OF

CINDY DOLEZEL
and
ARNE OLSON

In the Matter of
PUBLIC UTILITY COMMISSION OF OREGON, Investigation to Determine the Resource Value of Solar.

June 1, 2016

CASE: UM 1716
WITNESS: CINDY DOLEZEL

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 100

DIRECT TESTIMONY

June 1, 2016

Q. Please state your name, and business address.

A. I am Cindy Dolezel. My business address is 201 High Street SE, Suite 100, Salem, OR, 97301.

Q. Please describe your background and work experience.

A. I am employed as a Senior Renewable Energy Analyst at the Public Utility Commission of Oregon. My witness qualification statement is found in exhibit Staff/101.

Q. What is the purpose of your testimony?

A. I provide a brief background of this investigation and describe the process that Staff and its consultant used to arrive at a methodology for determining the resource value of solar for Oregon. I also provide Staff's recommendation as to which elements of solar generation to value for purposes of determining the resource value of solar (RVOS) and Staff's recommendation to adopt the valuation methodology presented by Staff's consultant.

Q. Please describe the procedural background of this docket.

A. In July 2014, the Commission submitted a report to the Legislature regarding the Effectiveness of Solar Programs in Oregon.[1] As part of that report, the Commission committed to opening a formal proceeding to determine the resource value of solar and the extent of cost-shifting, if any, from net metering, and to evaluating the reliability and operational impacts of increasing levels of solar generation.

[1] http://www.puc.state.or.us/electric_gas/Investigation%20into%20the%20Effectiveness%20of%20Solar%20Programs%20in%20Oregon%202014.pdf

The Commission commenced this three-part investigation in January 2015. The Commission has since entered an order closing its evaluation of the reliability and operational impacts of solar generation[2] and has put the examination into cost-shifting on hold pending a Commission determination of RVOS for each utility.[3]

Staff's investigation into methodologies to determine RVOS commenced with Staff-led workshops with parties to discuss what attributes (elements) of solar generation should be included in the determination of RVOS. With input from parties and stakeholders after several workshops in 2015,[4] Staff produced a list of 26 elements that could, at least theoretically, be included in the calculation of RVOS. The list included elements that accrue benefits or costs to the (1) utility ratepayer (i.e., avoided cost of energy that the utility would have acquired but for the solar generation); (2) the customer-generator (i.e., reduced utility bills); and (3) society (i.e., reduced carbon emissions).

In July 2015, Staff submitted the list of 26 elements to the Commission for a determination of which elements should be included in the RVOS. Parties filed comments regarding their recommendations as to which elements the Commission should include.[5]

Q. Did the Commission decide which elements to include in the RVOS?

A. No, the Commission declined to make such a determination, concluding that it would decide which elements to include in the model at the same time it

[2] Order No. 16-074 (January15, 2016).
[3] UM 1716 Ruling (February 29, 2016).
[4] Staff filed comments for UM1716 http://edocs.puc.state.or.us/efdocs/HAC/um1716hac165740.pdf
[5] Party comments can be found filed under docket UM1716.

determined the methodologies for valuing them.[6] But, the Commission clarified that it would only include elements in the RVOS "that could directly impact the cost of service to utility customers."[7] The Commission gave examples, noting "we would consider the potential financial costs to utilities of future carbon regulation," and "[o]n the other hand, for example, we will not consider job impacts of solar development."[8]

The Commission directed Staff to determine a procedural process that would allow the Commission to select the elements and methodologies for the RVOS and authorized Staff to hire a consultant to assist in evaluating which elements should be included in the RVOS and to develop methodologies to evaluate the elements.

Q. Did Staff hire a consultant?

A. Yes. Staff issued a Request for Proposals and ultimately contracted with Energy and Environmental Economics, Inc. (E3), to create a methodology for calculating RVOS based on elements that could directly impact the cost of service to utility customers. Staff Exhibit 200 is the testimony of Arne Olson, a partner at E3, which presents the methodology.

Q. Does E3's methodology only determine values for elements of solar generation that could directly impact the cost of service to utility customers?

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[6] Order No. 15-296 at 2.
[7] Ibid.
[8] Ibid.

A. Yes. In his testimony, Mr. Olson explains that in light of the Commission's direction about which elements should be included in the determination of RVOS,[9] E3 designed the model to determine the RVOS from the "ratepayer perspective" rather than the perspective of the solar generator or society in general.

Q. How did E3 and Staff select the elements that should be included in RVOS?

A. Staff and E3 started with the list of elements Staff produced through a collaborative process with parties. Based on its experience in other jurisdictions and on its analysis of studies done in the United States, E3 believed the parties had come up with a comprehensive list of the potential elements that could be included in the RVOS. In consultation with Staff, E3 excluded several of the 26 elements because they were not consistent with the Commission's criteria[10] and combined others that were redundant, resulting in the following ten elements that are valued in the methodology:

1. Energy
2. Generation Capacity
3. Line Losses
4. Transmission & Distribution Capacity
5. RPS Compliance
6. Integration
7. Administration

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[9] Order No. 15-296 at 2.
[10] Ibid.

8. Market Price Response
9. Hedging Costs
10. Environmental Compliance

Q. Do these elements meet the Commission's criteria of having the potential to have direct impacts on costs to utility customers?

A. Yes. Mr. Olson's testimony explains how these elements meet the criteria. Mr. Olson also explains that there is an additional element that could be included, "Security, Reliability, and Resiliency" that could have potential value for utility ratepayers if solar was deployed in a microgrid application that would provide electric service to utility ratepayers that are not themselves solar generators. As Mr. Olson notes in his testimony, such microgrid applications are not currently present in Oregon.

Q. Please describe E3's methodology.

A. Witness Olsen provide details of the methodology in his testimony, but in brief, E3 has provided a methodology (that is, a series of calculations), and an accompanying model (an excel spreadsheet workbook), that directly translates hourly data on individual avoided cost elements into an hourly avoided cost profile for each year of the economic lifetime of a solar photovoltaic (SPV) system, which the model assumes is 25 years. This model provides outputs on an hourly level of granularity so that an RVOS could be applied at different times of use during a day or combined into off-peak, mid-peak, and on-peak periods as in the Time of Use tariffs, but Staff notes that to achieve output from the model at hourly granularity demands that the input data from the utilities must be at hourly precision.

Q. What are the inputs to the model?

A. The inputs are derived from information provided by the utilities**.** Staff and E3 had teleconferences and meetings with the three regulated utilities to discuss what information the utilities have available and what information is needed, including at what granularity. Staff then issued Data Requests to the utilities to obtain information that could be used for inputs into E3's model. This discovery process allowed E3 and Staff to determine whether they would be able to obtain sufficient information from the utilities to run the model if it is approved by the Commission.

Q. Were the utilities able to provide sufficient information to test the model?

A. Yes. The utilities were responsive and helpful in providing sets of data which were sufficient to exercise and prove the model. Staff thanks the utilities for their efforts to explore this model and compile data for input into the model. It is important to note, though, that the precision of the model's RVOS output depends entirely on the precision of the input data. That is, if hourly data is available as input to the model, the resulting RVOS will have hourly precision; however, if the input data is available only over a longer time period, the model will produce an RVOS with corresponding granularity.

Q. Were the utilities able to provide data with hourly precision?

A. Yes, to some extent. Some of the data, such as the cost of energy, are routinely captured by the utility on an hourly basis. However, a good portion of the data provided by the utilities for testing the model was much less granular, provided on a daily, weekly, or monthly basis. It is Staff's understanding that at least some portion of the data that could be utilized in the model is simply not currently captured on an hourly basis by the utilities.

Q. Has E3 run the model to produce true RVOS values for each of the utilities?

A. No. The Commission previously ordered that it would not determine RVOS values for the utilities in the first phase of this investigation. The Commission stated:

> We envision a two-phase process. The first phase will examine elements and methodologies. The second phase will examine values for each utility using those adopted methodologies.[11]

E3 has produced some sample model runs to illustrate the use of the model, but the resulting RVOS values are not based specifically on information from any one utility and are not meant to be interpreted as an actual value.

Q. Does Staff recommend that the Commission adopt the methodology and model presented by E3?

A. Yes. First, the methodology and model present a sound theoretical framework for estimating RVOS. Second, the model is designed to value only the elements of solar generation that affect costs to the utility ratepayer, as the Commission has ordered. Finally, this methodology and model

[11] Order No. 15-296 at 2.

complements other avoided cost methodologies the Commission uses and is Oregon specific.

Q. Does Staff envision the RVOS methodology as a replacement for current avoided cost methodologies?

A. No. Staff anticipates that the RVOS methodology will only be used to determine the value of distributed solar generation and will not replace current avoided cost methodologies for the Public Utility Regulatory Policies Act (PURPA) implementation.

Q. Does Staff envision using the RVOS methodology to determine the value of utility scale solar?

A. No. As described in Mr. Olson's testimony, utility scale solar does not capture the same avoided cost stream as distributed solar. Although this methodology could be adapted to determine a value for utility scale solar, Staff believes the current valuation methods based on integrated resource planning (IRP) principles provides a more robust analysis of the value of utility scale solar.

Q. How does Staff recommend the model be used if adopted?

A. Staff recommends that the Commission direct the utilities to provide data for this model to develop an actual distributed solar RVOS for each utility. Staff recommends that the Commission open an investigation to allow parties to define solar generation profiles and differentiate these profiles by geographic zones. Staff and parties will verify the input data from each utility and have an opportunity to analyze the RVOS as developed for each of the defined solar profiles for each utility.

Staff envisions that the RVOS will be recalculated every two years, using the methodology adopted by the Commission.

Q. Why update the model on a two year basis?

A. Staff recommends that the model be updated every two years to keep the RVOS current with market trends and to be consistent with the IRP process and schedule.

Q. Does this conclude your testimony?

A. Yes

CASE: UM 1716
WITNESS: CINDY DOLEZEL

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 101

Witness Qualifications Statement

June 1, 2016

WITNESS QUALIFICATIONS STATEMENT

NAME:	Cindy Dolezel
EMPLOYER:	Public Utility Commission of Oregon
TITLE:	Senior Renewable Energy Analyst Energy Resources and Planning Division
ADDRESS:	201 High Street SE. Suite 100 Salem, OR. 97301
EDUCATION:	MSc Energy and Sustainable Development, DeMontfort University, United Kingdom BSc Environmental Studies, The Open University, United Kingdom Project Management Professional Certification, Project Management Institute, #2862825

EXPERIENCE:

I have over 20 years of experience in government regulation. I have worked extensively in the areas of solid waste franchising, small scale utility rate setting, resource planning, sustainability, utility program implementation, renewable energy, and emerging technologies. Prior to joining the PUC in 2014, I worked for over 13 years at the city of Beaverton, which included roles as the Sustainability Division Manager and the Central Plant Manager. As the Senior Renewable Energy Analyst at the PUC, I have led and worked extensively on investigations evaluating renewable energy, specifically solar programs, regulation, reporting, and rates.

CASE: UM 1716
WITNESS: ARNE OLSON

PUBLIC UTILITY COMMISSION
OF
OREGON

DIRECT TESTIMONY OF ARNE OLSON

ON BEHALF OF

OREGON PUBLIC UTILITY COMMISSION

DIRECT TESTIMONY

June 1, 2016

Contents

1. INTRODUCTION AND OVERVIEW OF TESTIMONY

Q. Please state your name, title, and business affiliation.

A. My name is Arne Olson. I am a Partner at Energy and Environmental Economics, Inc. (E3), located at 101 Montgomery Street, Suite 1600, San Francisco, California, 94104.

Q. Please state your qualifications and experience.

A. With over 20 years of experience in the electric utility business, I have worked extensively in the areas of resource planning, asset valuation, renewables and emerging technology, and energy and climate policy. Prior to joining E3 in 2002, I served for six years as an energy policy specialist at the Washington Department of Commerce.

I received my M.S. in International Energy Management & Policy from the University of Pennsylvania and my B.S. in Mathematical Sciences and Statistics from the University of Washington. The attached résumé further describes my qualifications, experiences, and publications.

Q. Have you previously testified before the Oregon Public Utilities Commission?

A. Yes, I previously filed expert witness testimony on behalf of Portland General Electric Company (PGE) in Docket UM 1719, describing E3's calculation of solar and wind Effective Load Carrying Capability (ELCC), performed on behalf of PGE. I have also provided expert witness testimony in front of the California Public Utilities Commission, the California Energy Commission, the Alberta Utilities Commission, and a commercial arbitrator in Ontario.

Q. What is your experience with solar and other demand-side valuation projects?

A. E3 has been a pioneer in the area of time- and area-specific marginal costing, as I describe later in my testimony, and has performed avoided cost studies on behalf of many clients. For example, the “E3 Calculator”, developed for the California Public Utilities Commission (CPUC), is used by both investor-owned and publically-owned utilities in California for cost-effectiveness assessment of energy efficiency programs and has been adapted for use in a number of jurisdictions around the country. E3 has also performed avoided cost studies for demand response programs, California’s Self-Generation Incentive Program, Permanent Load Shifting, and energy storage. In 2013, E3 applied this framework in a landmark study on the cost-effectiveness of distributed solar developed under California’s net energy metering (NEM) program.

E3 is also well-known for our pioneering work in evaluating “non-wires” alternatives – including customer-side resources – to potential investments in new transmission and distribution facilities. In 2001, E3 was retained by the Bonneville Power Adminstration to provide an technical assistance to its “Transmission Roundtable” stakeholder group, establishing a process and analytical framework for evaluating non-wires alternatives to potential federal transmission projects. E3 has since worked with Bonneville to evaluate alternatives to specific projects in the Puget Sound area, the Olympic Peninsula, the Upper Snake River Valley, and most recently, the I-5 Corridor project.

At E3, I have led and worked extensively on these projects as well as others evaluating renewable energy production, particularly solar. In 2013, I led the technical analysis assessing the feasibility of a 50 percent renewable portfolio standard (RPS)[1] on behalf of the five largest utilities in California. I have also led several demand-side valuation projects that have helped to establish E3 as a national leader in resource evaluation and cost-effectiveness.

Q. What is your specific experience with resource value of solar (RVOS) studies?

A. E3 has completed resource value of solar studies for utility commissions in several of the largest and most heavily solar-focused states including California, New York, Nevada, Hawaii, and South Carolina. In each of these states, E3 has relied on our industry-leading approach that utilizes a granular, locational- and time-differentiated approach to accurately capture the value that solar provides.

Most recently, the CPUC retained E3 in 2015 to develop the “NEM Public Tool”, a publicly-available spreadsheet tool that projects solar PV adoption and cost shifts based on user-defined inputs for solar PV costs, retail rate levels, retail rate designs, and utility avoided costs. The tool was used by all intervenors to help inform the CPUC of the impact of rate design decisions on both adopters and non-adopters of behind-the-meter (BTM) PV.

Q. What is the scope of your testimony?

[1] Investigating a Higher Renewables Portfolio Standard in California, January 2014, https://ethree.com/documents/E3_Final_RPS_Report_2014_01_06_with_appendices.pdf

A. I was retained by Staff to develop and demonstrate a methodology for calculating the resource value of solar (RVOS). I supervised the development of a Microsoft Excel-based model for calculating RVOS for Oregon's three investor-owned utilities (IOUs)[2]. My testimony describes a theoretical framework for estimating RVOS and reviews the previous work of Oregon stakeholders and other jurisdictions in estimating the value of solar. I go on to describe the model and the element calculations within it. Finally, I present sample results calculated, in part, using data provided by Oregon IOUs.

Q. How is your testimony organized?

A. My testimony is organized as follows. In Section 2, I provide a high-level overview of time- and area-specific marginal costing and its application to avoided utility costs which provide value to utility ratepayers. I also discuss the ways in which time- and area-specific marginal costing can be applied to solar. In Section 3, I review the recommendations of stakeholders that were previously submitted as part of this ongoing proceeding regarding how to calculate the RVOS and which elements should be included.[3] I also provide a brief overview of existing RVOS studies that have been performed in other jurisdictions, both by E3 and others. I delineate different elements of value that accrue to three different groups of beneficiaries: (1) participating solar generators, (2) utility ratepayers, and (3) society as a whole. In Section 4, I present a methodology for calculating the RVOS from the perspective of utility ratepayers, including a detailed description of how the model calculates each

[2] Portland General Electric, PacifiCorp, and Idaho Power
[3] UM 1716

element of value. Section 5 provides illustrative results that were calculated using the methodology. This section also concludes my testimony, summarizing key concepts and support for my recommendations.

2. TIME- AND AREA-SPECIFIC MARGINAL COSTING

Q. What is time- and area-specific marginal costing?

A. The term "time- and area-specific marginal costing" refers to analytical techniques aimed at estimating the impact to the electric system of additional electric load or generation. This impact depends both on the time and the location at which the load or generation occurs. For example, energy tends to be more expensive during peak periods of the day and therefore the avoided cost to the utility of a demand-side resource is higher during peak periods. Additionally, the marginal cost of serving load may differ between areas due to transmission and distribution capacity constraints.

Time- and area-specific marginal costing has both short-term and long-term elements. Short-term impacts include changes to the operation of electric generators. Longer-term impacts include potential changes to the schedule of capital investments needed to maintain reliable and affordable electric service.[4,5]

Q. Is time- and area-specific marginal costing commonly used in the electric industry?

A. Yes, time- and area-specific costing is used broadly in the electric industry for the purpose of estimating the impact of demand-side programs such as energy efficiency or demand response. The results of these values can be used by

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[4] Orans, R., C.K. Woo and B. Horii (1994), *Targeting Demand Side Management for Electricity Transmission and Distribution Benefits*, Managerial and Decision Economics, 15, 169-175

[5] Woo, C.K., R. Orans, B. Horii, R. Pupp and G. Heffner (1994), *Area- and Time-Specific Marginal Capacity Costs of Electricity Distribution*, Energy - The International Journal, 19:12, 1213-1218

utilities and regulators to facilitate least-cost planning and set appropriate compensation and incentive levels for demand-side resources.

For example, the above-mentioned E3 Calculator uses a time- and area-specific marginal costing methodology to calculate energy efficiency avoided costs for California utilities. Specifically, the model calculates hourly avoided cost values for each of 16 zones based on climate.

Q. What values, specifically, are measured using avoided costing techniques?

A. Avoided costs measure the marginal cost of serving load on a time- and area-specific basis. In other words, the $/MWh avoided cost captures the cost to the utility of serving one additional MWh of load at a given time and location. This *marginal* cost will differ from the *average* cost to serve load because the average cost includes recovery of fixed costs associated with investments made in the past. These costs are not "avoidable", i.e., they are a legacy of past decisions and do not depend on future changes to electric loads or resources.

Q. What types of values are location-specific, and how are those elements of marginal costing incorporated into utility avoided costs?

A. There are two categories of marginal costs that can vary by location.

- In the **short run**, there may be locational differences in marginal energy costs due to transmission congestion. In addition, there may be location-specific operating parameters such as real power losses and the need for voltage control or other grid reliability services. These short-run marginal costs typically do not vary widely by location.

- In the **long run**, there may be locational differences in the ability of demand-side resources to avoid or defer investments in transmission or distribution system facilities that are intended to increase delivery capability. Utilities must ensure that transmission and distribution infrastructure is sufficiently sized to reliably serve load during peak load periods, when usage is highest. As peak loads grow over time, utilities traditionally invest in new infrastructure to ensure that the transmission and distribution systems are adequately sized. Distributed energy resources that reduce consumption or generate energy during the peak period might enable the utility to avoid or defer an investment, resulting in cost savings for the utility's customers. For example, if a utility has identified a potential overload on a distribution system transformer, a distributed resource that produces energy during the hours when the transformer overloads could contribute to deferring or avoiding an investment in a new transformer.

Q. How does deferring a transmission or distribution investment save costs for customers?

A. The benefit to consumers derives from delaying the investment to a later point in time. Spending that can be deferred into the future results in a monetary benefit based on the time value of money. The benefit is calculated as the utility's weighted average cost of capital multiplied by the total capital expenditure. For example, suppose an investment of $100 million is deferred by five years. If the utility's cost of capital is 10 percent, then the utility's revenue requirement would be reduced by approximately $10 million for each year that the investment is deferred. The net present value of a five-year deferral, using the utility's cost of capital as the discount rate, is approximately $38 million.

Q. Can any demand-side resource result in transmission and distribution system benefits?

A. Transmission and distribution system avoided costs are highly location-specific. The value can be quite high in areas of the utility's service area that are undergoing rapid growth andrequiring significant investment. Conversely, in areas where loads are not growing, adding demand-side resources is unlikely to result in the avoidance of distribution system capacity investments. As a general rule, only *growth-driven* transmission and distribution system investments are considered deferrable, and growth-driven investments make up only a portion of all utility transmission and distribution system investments.

In addition, there are a number of potential barriers that may prevent a utility from actually deferring a transmission and distribution system investment:

- The demand-side resource must produce energy (or reduce consumption) during the hours when the system is constrained. These hours may vary depending on the specific element that is targeted for investment. For example, peak hours for distribution system elements (feeders or substations) can vary depending on the types of loads that the element serves. Residential loads typically peak in the evening hours, while commercial loads peak during daylight hours. Customer-side solar is therefore likely to provide higher distribution system deferral value in commercial areas as compared to residential areas.

- Demand-side resources such as energy efficiency or rooftop solar may be viewed as more risky or less reliable than wires investments due to uncertainty about resource performance. The performance of conventional transmission and distribution system assets such as conductors or transformers are very predictable; utility planners know with a high degree of certainty how the resource will perform in the field. Demand-side resources may be less predictable due to uncertainty about customer usage patterns, resource availability, and the timing of the peak load when the resource is needed.
- Utilities may not have certainty about adoption rates for demand-side technologies, thus they may not have reliable information about the cumulative size of available demand-side resources.
- If demand-side resources require the utility to follow a specific operating procedure, this may introduce complexity and the potential for error into utility operations.

As a general rule, utilities must know about and incorporate demand-side resources into their distribution planning processes in order to actualize these cost savings. If utility distribution planners do not account for these resources, they may overbuild the distribution system relative to desired reliability and not capture these potential benefits of demand-side resources.

Q. Is it common for utilities to collect and study this locational-specific data?

A. Advances in technology, such as internet connected smart meters, are making the collection and analysis of locational specific data possible where historically it hasn't been. Several states have tackled this new opportunity, notably California through its Distribution Resource Plan proceeding.[6] California utilities are currently developing plans to "more fully integrate [distributed energy resources] into system planning, operations, and investment."[7] As part of these plans, utilities will be required to demonstrate the capacity to integrate distributed resources into their systems, the locational benefits that different resources can offer, and actionable pilot programs and tariffs to incentivize and capture this value. These distribution-level resource plans are expected to provide valuable information about where distributed energy resources can be targeted to achieve the highest value.

In the absence of location-specific distribution system planning data, more general data can be gathered from utility capital budgets. Depending on the use of the RVOS, these more general values may be sufficient to provide high-level estimates of avoidable utility transmission and distribution expenditures.

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6 http://www.cpuc.ca.gov/General.aspx?id=5071
7 http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M103/K223/103223470.pdf

Q. How can time- and area-specific marginal costing be used in estimating the Oregon RVOS?

A. The RVOS Model that I describe in Section 4 has the capability to incorporate hourly avoided costs at a given location on the system. Hourly avoided costs are estimated for a variety of categories such as energy, capacity, distribution deferral value, and others. The RVOS Model can be run multiple times with different assumptions to generate different values for different locations. However, in order for accurate time- and area-specific marginal costing to be incorporated into the RVOS, the utilities must collect and provide data on the location-specific benefits described above. In particular, Oregon IOUs may benefit from studying how the value of solar and other distributed energy resources differ between geographic locations based on the specific transmission and distribution system characteristics in that area. Because this level of granularity is not available at this time, my testimony focuses on the methodology for developing an RVOS and provides a sample value for solar at a generic location.

3. ELEMENTS OF VALUE

Q. Have you reviewed the comments from stakeholders in this proceeding, UM 1716, regarding potential elements of value that could be provided by solar?

A. Yes. I have reviewed the comments and feedback from stakeholders regarding which elements should be included in the RVOS. Oregon stakeholders developed a list of twenty-six elements of potential solar value.[8]

1) Energy
2) Generation Capacity
3) Line Losses
4) Transmission and Distribution Capacity
5) RPS Compliance
6) Security, Reliability, and Resiliency
7) Integration
8) Administration
9) Interconnection
10) Market Price Response
11) Ancillary Services
12) Fuel Price Hedge
13) Operational Impacts
14) Natural Gas Pipeline Impacts
15) Net Metering Credits
16) Economic Development
17) Health and Other Societal Impacts
18) Capital Risk
19) Production Impacts
20) Behind-the-Meter Production
21) Resource Need
22) Lost Utility Revenue
23) Tax Credits
24) DSM Alternative Impacts
25) Environmental Compliance

[8] http://edocs.puc.state.or.us/efdocs/HAC/um1716hac165740.pdf

26) Environmental Externalities

Q. Have you reviewed RVOS studies that have been conducted in other states?

A. Yes. I have reviewed a number of RVOS studies that have been conducted in other states which are applicable to this proceeding. In total, I reviewed twenty studies across the U.S., four of which were conducted by E3. While all of the studies focused on solar, they differ both in the perspectives for which they calculate value and the elements that are included in the value calculation. Table 1 summarizes the elements that each study incorporated into the value of solar calculations.

Table 1: Review of Recent RVOS Studies from States, Utilities, Consultancies, and Stakeholders

Included	●
Included as sensitivity	◆
Meant to be represented/captured in other values	○

ROW	STATE	STUDY	ELEMENTS ANALYZED											
			Avoided Energy (incl. O&M, fuel costs)	Avoided Fuel Hedge	Avoided Capacity (generation and reserves)	Avoided Losses	Avoided or Deferred T&D Investment	Avoided Ancillary Services	Market Price Reduction	Avoided Renewables Procurement	Monetized Environmental	Social Environmental	Security Enhancement/Risk	Societal (incl. economic/jobs)
1	ARIZONA	Crossborder Energy (2013)	●		●	●	●	●	○	●	●		○	○
2	ARIZONA	APS/SAIC (2013)	●		●	○	●							
3	CALIFORNIA	E3 (2013)	●		●	●	●	●		●	●			
4	CALIFORNIA	Crossborder Energy (2013)	●		●	●	●	●		●	●			
5	COLORADO	Xcel (2013)	●	●	●	●	●	○			●			
6	HAWAII	E3 (2014)	●		●	●	◆	●				◆		
7	MAINE	Clean Power Research (2015)	●	●	●	○	●	○	●			●		
8	MASSACHUSETTS	La Capra Associates (2013)	●		●	○	●		●	●	●		◆	◆
9	MICHIGAN	NREL (2012)	●	●	●	●	●	●		○	●			
10	MINNESOTA	Clean Power Research (2014)	●	○	●	●	●					●		
11	MISSISSIPPI	Synapse Energy Economics (2014)	●	●	●	●	●				●			
12	NORTH CAROLINA	Crossborder Energy (2013)	●	●	●	○	●	○	○	●	●	◆	○	○
13	NEW JERSEY	Clean Power Research (2012)	●	●	●	●	●		●	○		●	●	●
14	NEW YORK	E3 (2015)	●	●	●	●	●	●	●	●	●	●	●	
15	NEVADA	E3 (2014)	●		●	●	●	●		●	●			
16	PENNSYLVANIA	Clean Power Research (2012)	●	●	●	●	●		●	○		●	●	●
17	TENNESSEE	TVA (2015)	●		●	○	●				●	◆		
18	TEXAS (AUSTIN)	Clean Power Research (2014)	●	○	●	●	●			○	●			
19	TEXAS (SAN ANTONIO)	Clean Power Research (2013)	●	○	●	●	●				●			
20	VERMONT	Vermont PSC (2013)	●		●	○	●	●	●	●	●	◆		

Q. Is the list of elements compiled through stakeholder input for UM 1716 comprehensive in capturing all values of solar?

A. Yes, based on my experience and a review of studies that have been conducted on this topic across the U.S., I believe that all elements of the value of solar are captured in the Oregon stakeholder list. I commend stakeholders and Staff for their work in compiling this comprehensive list.

Q. Studies conducted for other jurisdictions have resulted in a wide range of solar value estimates. What are the principal reasons for the differences in value of solar in the existing literature?

A. There are three main sources of difference:

1. **<u>Differences in system characteristics</u>**. The value of solar can differ depending on the system to which it is connected. For example, solar may provide a significant amount generation capacity deferral value in regions where the load peaks during daylight hours in the summer, when solar production is high. In regions where retail load peaks during wintertime or after dark, this value would be significantly lower.
2. **<u>Differences in calculation methodologies or input assumptions</u>**. Methodologies for calculating the value of solar or other distributed energy resources are not uniform across the country. In particular I have observed differences in the methods for estimating the potential for and value of deferrals in distribution system investment. There are also significant differences in the methods used for estimating market price effects.
3. **<u>Difference in perspective from which solar value is calculated</u>**. Some of the potential values of solar do not accrue to utility ratepayers; rather, they accrue to society as a whole. Whether the study uses a

societal perspective or a ratepayer perspective has a significant impact of the calculated value of solar.

Q. Do all of the elements compiled through stakeholder input for UM 1716 provide value to utility ratepayers?

A. No. Many of the elements listed above provide value to society as a whole, but not directly to utility ratepayers. In order to be clear about the beneficiaries of various RVOS elements, I adopt the following "perspectives", which are commonly used to calculate value in the electric utility regulatory framework:

1) Utility Ratepayer
2) Participating Solar Generators
3) Society

The value that accrues to utility ratepayers and society are costs that the utility avoids such as reduced purchases of traditional energy. Improvement in environmental quality is a value that accrues to society but may not affect the utility bills paid by utility ratepayers. Moreover, whereas participating solar generators experience a *benefit* in the form of reduced utility bills, this reduction in utility revenue is a *cost* to non-participating customers whose rates must increase to ensure the utility continues to recover its revenue requirement.

Q. Is it common practice to evaluate value from these three perspectives?

A. Yes, these perspectives are incorporated into the Standard Practice Manual,[9] used across the U.S. to evaluate demand-side measures including solar, energy efficiency, demand response, electric vehicles, and others. The

[9] Standard Practice Manual http://www.calmac.org/events/spm_9_20_02.pdf

alternative perspectives provide a holistic analytical and methodological framework for regulators to evaluate costs and benefits.

Q. How is value defined from each of these perspectives?

A. The following provides an overview of the elements of value that accrue to the different perspectives:

1) Utility Ratepayer
   - Utility avoided costs with a direct link to the electric utility rates
2) Solar Generators
   - Direct payments from the utility such as reductions in utility bills plus subsidies and tax incentives
3) Society
   - Utility avoided costs with a direct link to the electric utility rates as well as non-monetizable environmental and health benefits

Q. Which of these three perspectives do you focus on in your testimony?

A. As part of UM 1716, Order No. 15-296[10] states that the Commission "will only consider elements that could directly impact the cost of service to utility customers." Therefore, I present a calculation methodology for the RVOS from the utility ratepayer perspective.

Q. Which avoided costs provide value to the utility ratepayer?

A. As described above in Section 2, avoided costs are the monetary savings that accrue to the utility due to the addition of a specific resource, such as solar. Because solar PV systems produce energy, the utility's cost to serve its load

[10] http://apps.puc.state.or.us/orders/2015ords/15-296.pdf

through conventional means is reduced. In the short run, the utility avoids costs such as the production or purchase of additional energy. In the long run, the utility may avoid the cost of building or upgrading power plants, transmission, and distribution power lines.

Q. Do all of the elements in the Oregon stakeholder list provide value that accrues to the utility ratepayer?

A. No, they do not. While many of the elements provide value that accrues to the utility ratepayer, several of the elements are exclusively applicable to either the solar generator perspective or the societal perspective.

Q. Do all of the elements in the Oregon stakeholder list represent unique elements of value?

A. There is some overlap between some of the elements listed above. In developing the RVOS methodology, I have condensed the overlapping values into a smaller number of elements.

Q. Based on your previous two responses, please provide the condensed list of elements that are considered in your testimony.

A. Table 2 lists 16 unique elements of value derived from the Oregon stakeholder list. I also list the relevant perspective[s] to which each element applies. Each element from the numbered stakeholder list has been mapped to an element of value in the RVOS methodology. I have also provided a definition for each unique element.

Table 2: Condensed List of Oregon RVOS Elements

Row #	Element of Value	Definition	Encompassed Stakeholder Elements	Perspective: Participant	Perspective: Utility Ratepayer	Perspective: Society
1	Energy	Marginal avoided cost of purchasing or selling electricity into the wholesale market -- OR -- Marginal avoided cost of producing energy from conventional wholesale generating resources including the cost of fuel (and associated transportation costs), variable operations and maintenance, labor, and all other variable costs	(1) Energy; (13) Operational Impacts; (14) Natural Gas Pipeline Impacts		✓	✓
2	Generation Capacity	Marginal avoided cost of building and maintaining the lowest net cost generation capacity resource	(2) Generation Capacity; (14) Natural Gas Pipeline Impacts; (18) Capital Risk; (19) Production Impacts (21) Resource Need		✓	✓
3	Line Losses	Avoided marginal electricity losses from the point of generation to the point of delivery	(3) Line Losses		✓	✓
4	Transmission & Distribution Capacity	Avoided or deferred costs of expanding, replacing, or upgrading transmission and distribution infrastructure such as substations, lines, and transformers	(4) Transmission & Distribution Capacity		✓	✓
5	RPS Compliance	Avoided incremental cost of purchasing renewable energy to	(5) RPS Compliance		✓	✓

		satisfy the Oregon RPS requirement. The incremental cost is defined as the levelized cost of a renewable resource less the value of that resource provides from energy, capacity, and environmental compliance plus the cost of that resource due to renewable integration.				
6	Integration and Ancillary Services	Increased costs associated with integrating solar PV into the electrical system. These costs include additional spinning reserve and ancillary service requirements necessary to facilitate the variability and intermittency of solar PV production, as well as any change in ancillary service procurement due to reduction in metered load.	(6) Reliability; (7) Integration Impacts; (11) Ancillary Services		✓	✓
7	Administration	Increased costs to administer distributed solar PV programs such as net energy metering (NEM). This includes the cost of additional utility staff, incremental billing software, incremental costs of interconnection and any other utility-specific costs. Incremental costs of interconnection are defined as the total cost of interconnection less the portion of this cost paid by the interconnecting solar generator.	(8) Administration (9) Interconnection		✓	✓
8	Market Price Response	The change in utility costs due to lower wholesale energy market prices caused by increased solar PV production, affecting the price at which the utility transacts in the wholesale market when managing its portfolio of resources on behalf of its retail customers. Lower market prices result in lower costs for utility market purchases, but reduced margins for utility market sales. The net effect on the utility could	(10) Market Price Response		✓	

		be either positive or negative, depending on the relative magnitude and timing of market purchases and sales. Lower market prices are not a societal benefit, because they represent a transfer of wealth from one member of society (electricity producers) to another member (electricity consumers).				
9	Hedging Costs	Avoided cost of utility fuel cost hedging activites, i.e., transactions intended solely to provide a more stable retail rate over time. Solar generators may experience additional hedging value due to more stable electricity costs.	(12) Fuel Price Hedge	✓	✓	
10	Environmental Compliance	Avoided cost of complying with existing and anticipated carbon standards due to a reduction in carbon emissions from the marginal generating unit. The cost of compliance with criteria pollution regulations is assumed to be captured in the avoided cost of generation capacity.	(2) Generation Capacity; (25) Environmental Compliance		✓	✓
11	Security, Reliability, Resiliency	The potential capability of solar, when deployed in combination with other technologies, to provide backup energy or microgrid islanding capabilities during a loss of service from the utility.	(6) Resiliency, Disaster Recovery	✓	✓	✓
12	Participant Bill Savings	The reduction in bills due to the installation of solar at the utility customer location	(15) Net Energy Metering Credits; (22) Lost Utility Revenue; (24) DSM Alternative Impacts	✓		
13	Economic Development	Economic impacts such as creation of jobs from installing solar PV. These consist of both direct impacts (e.g., increase in jobs for solar installers) and	(16) Economic Development			✓

		indirect impacts (e.g., reduction in jobs due to higher electricity rates paid by businesses and residential consumers).				
14	Societal Externalities	Avoided health costs and risks, including morbidity and mortality, due to avoided air pollution from the marginal avoided electricity generating unit as well as avoided environmental impacts such as ecosystem loss and environmental degradation.	(17) Health and Other Societal Impacts; (26) Environmental Externalities			✓
15	Tax Credits	State and federal tax credits that accrue to the participating solar generators	(23) Tax Credits	✓		✓
16	n/a		(20) Behind-the-Meter Solar Production			

4. METHODOLOGY AND MODEL DESCRIPTION

Q. Please describe your engagement with Staff in this docket.

A. I was retained by Staff to develop a calculation methodology for the RVOS and deliver an accompanying Microsoft Excel-based spreadsheet model, the RVOS Model, that performs this calculation. As Ms. Dolezel's testimony states, this model can be used by Oregon IOUs going forward and populated with their data to calculate the RVOS.

Q. Which elements of value have you incorporated into the methodology?

A. I have incorporated all of the elements that provide value to the utility ratepayer. As reproduced from Table 2, the elements of value that accrue value to the utility ratepayer are:

1. Energy
2. Generation Capacity
3. Line Losses
4. Transmission & Distribution Capacity
5. RPS Compliance
6. Integration
7. Administration
8. Market Price Response
9. Hedging Costs
10. Environmental Compliance

There is one additional element, "Security, Reliability, and Resiliency" that could potentially have value for utility ratepayers. However, this would depend on solar being deployed in a microgrid application that would provide electric service to utility ratepayers who do not adopt solar PV. These applications are quite expensive, and I am not aware of any such applications in Oregon at this time. Therefore, I have not incorporated any quantification of these potential benefits into the RVOS Model.

Q. How are these elements used to calculate an RVOS?

A. For each element, a marginal avoided cost is calculated for each of the 8760 hours of the calendar year. These values are then added together to create an 8760-hour avoided cost profile which is the basis for the RVOS. Specifically, the mathematical formula and example chart of this hourly profile is as follows

$$
\begin{aligned}
&\forall h \in [1,\ldots,8760] \\
&Value_h = \quad Energy_h \\
&\qquad + Generation\ Capacity_h \\
&\qquad + Line\ Losses_h \\
&\qquad + T\&D\ Capacity_h \\
&\qquad + RPS\ Compliance_h \\
&\qquad + Market\ Price\ Response_h \\
&\qquad + Hedge_h \\
&\qquad - Integration_h \\
&\qquad + Environmental\ Compliance_h \\
&\qquad - Administration_h
\end{aligned}
$$

Figure 1 shows how the marginal avoided costs can vary throughout the year. The different colors represent different elements of value as described above. As the chart shows, avoided costs can vary both by season and by time of day.

Figure 1: Example Hourly Avoided Cost Profile

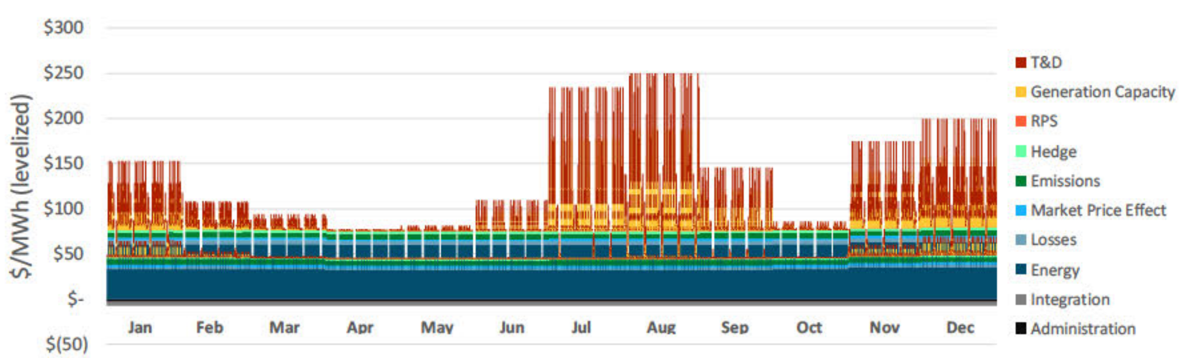
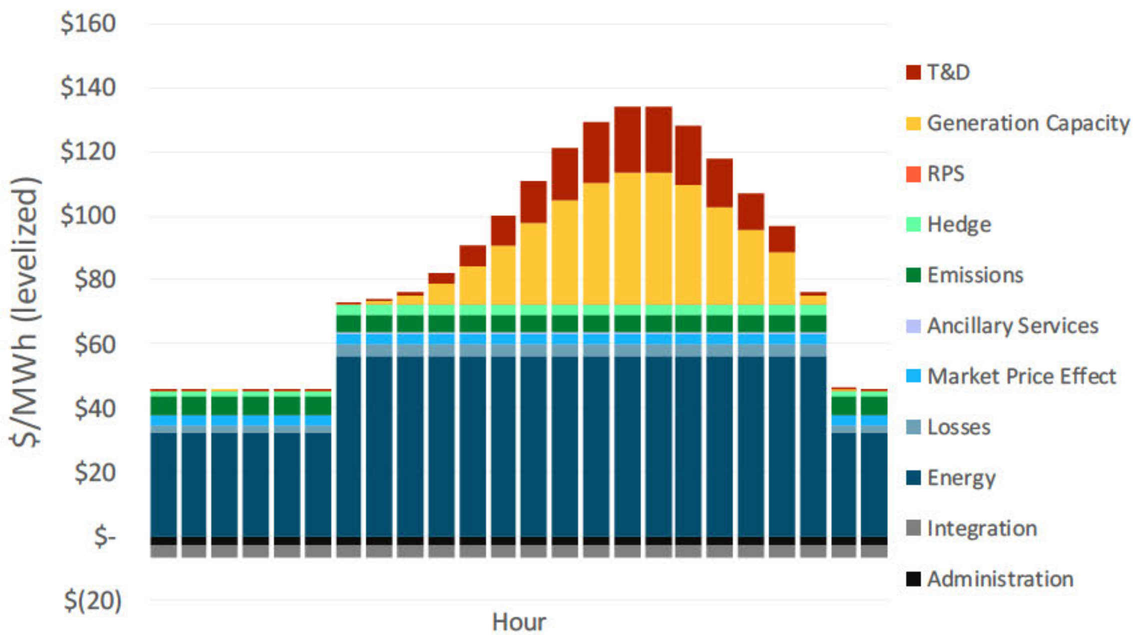


Figure 2 shows an hourly avoided cost profile for an average summer day. Generation and T&D avoided costs are allocated to the peak hours of the day, when there is a potential for distribution, transmission or generation system insufficiencies. Energy values are also higher during peak hours.

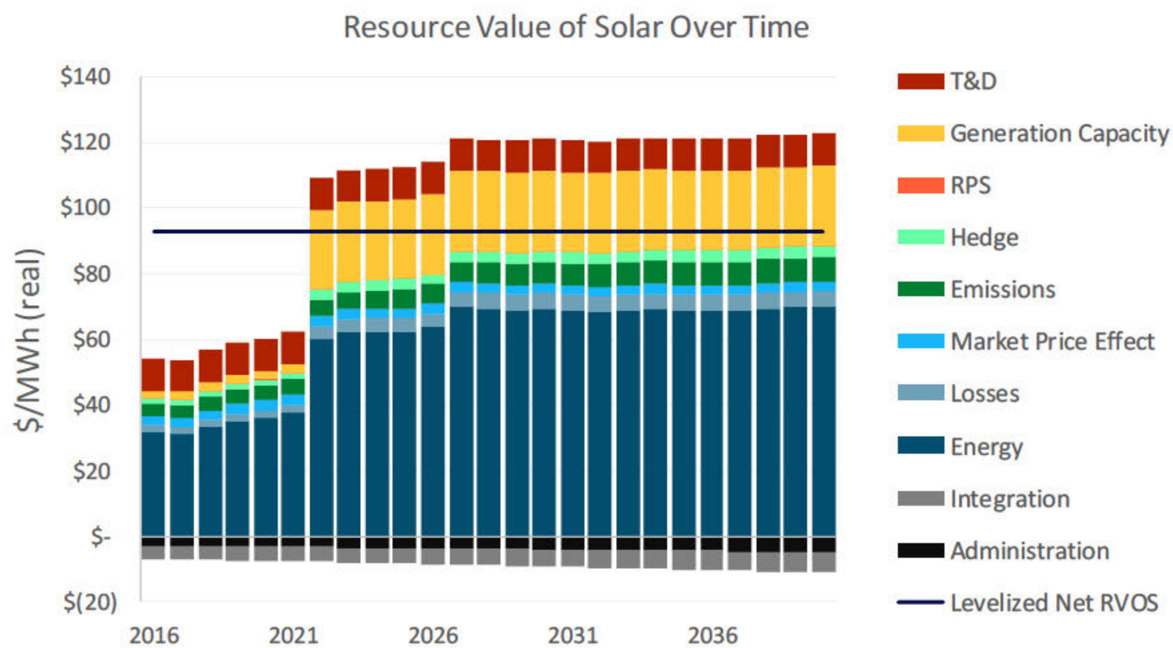
Figure 2: Example Average Summer Day Hourly Avoided Cost Profile



Q. Does the value of each element change over time?

A. The value of each element can change over time due to changes in underlying data. For example, projected increases or decreases in fuel prices will affect the energy value. The generation capacity value is strongly affected by the utility's generation resource sufficiency; the value is typically assumed to be very low (or even zero) during years when the utility has a capacity surplus, rising to the net cost of a new capacity resource once the system reaches resource deficiency. The values shown in Figure 2 are levelized values that incorporate annual changes. Figure 3 shows how these values change over time as well as the levelized RVOS in real dollars. There is a noticeable step upward in 2022 as the example utility reaches load-resource balance and begins to require new generation capacity (priced at the capitalized cost of a new utility generating plant).

Figure 3: Resource Value of Solar Over Time



Q. Does the RPS compliance value change over time to reflect potential future changes in the cost of wind or solar?

A. No, the values calculated in the RVOS Model represent the levelized value of solar resources that are installed in 2016. RPS-compliant resources are generally procured under long-term contract. As such, the RPS value of distributed solar is based on a utility-scale resource that is also procured in 2016. The proxy RPS contract may have an escalator embedded within it, but it does not reflect future changes in the cost of wind or solar, or future changes to the state and/or federal tax codes that change the net cost of wind or solar to a utility off-taker.

Q. How is utility data used to calculate these hourly avoided costs?

A. The methodology described here, and the accompanying RVOS Model, directly translate hourly data on individual avoided cost elements into an hourly avoided cost profile for each year of the economic lifetime of the PV system. This methodology can be thought of as an accounting framework that is entirely reliant on data provided by the utilities. This is important to ensure that the RVOS calculated here is consistent with values used by the utility in other regulatory proceedings. For the purpose of this testimony, I have used placeholder data to calculate a sample range of RVOS estimates.

Q. Why is hourly data used as the basis for the RVOS?

A. It is the most granular level of data that is readily available from utilities and practicable for use in a spreadsheet model. Hourly values are able to capture the changing value of solar across the day and the calendar year as energy and capacity becomes more or less expensive depending on load levels and other factors. In cases where utilities do not have hourly values, a single value can be duplicated over many hours. For instance, for the sample utility I have used energy values for heavy-load hours (HLH) and light-load hours (LLH),[11] rather than unique values for every hour. Hourly values can be aggregated after-the-fact into longer timeframes such as seasonal or time-of-day periods.

[11] HLH consists of 6 AM – 10 PM, Monday through Saturday, excluding North American Electric Reliability Council holidays; LLH consists of all other hours.

Q. Can you please explain the methodology to calculate the hourly avoided cost value of each of these elements?

A. Yes. Table 3 explains the calculation methodology for each element that I list above. In all cases, the RVOS Model that I have provided contains working examples of these calculations and is a useful supplement for understanding the methodology.

Table 3: Element Avoided Cost Calculation Methodology

Line	Element	Calculation Methodology
1	Energy	Hourly marginal cost of energy including fuel (and associated fuel transportation costs), variable operations and maintenance, labor, and all other variable costs. $\forall \mathrm{h} \in [1, \ldots, 8760]$ $\mathrm{Energy}_{\mathrm{h}}$
2	Generation Capacity	Annual carrying cost of new generation capacity ($/MW-yr) allocated to hours of the year using hourly normalized capacity value allocators. The allocators represent an hourly system need profile (based on loss of load probability (LOLP) or another method), multiplied by the modeled hourly solar generation, and scaled so that the allocators sum to one across the hours of the year. Annual carrying cost of new generation capacity ($/MW-yr) is defined as net cost of new entry (net CONE). Net CONE is calculated as the levelized carrying cost of a capacity resource – the levelized fixed cost of the resource (likely a new simple cycle combustion turbine (SCCT)) minus expected revenues that resource could earn through market dispatch. In the near-term years when the utility is not in a period of resource deficiency, a value of zero is used since there are no deferrable capacity investments. Solar's contribution to peak is a technical concept that captures solar's ability to serve peak loads. Through OPUC Docket UM 1719, the utilities have worked to develop a methodology for calculating this value. Many utilities across the country use a metric called effective load carrying capability (ELCC) to calculate the contribution to peak. The hourly capacity allocators (net

		CONE, allocated using LOLP) are scaled to ensure that the final generation capacity value of solar results are consistent with the utility-estimated solar contribution to peak. $\forall h \in [1, \ldots, 8760]$ $\mathrm{GenerationCapacity_h} = \mathrm{CapVal} * \mathrm{LOLP_h} * \frac{\mathrm{CTP}}{\mathrm{SolarLOLPCoincidence}}$ where: CapVal = annual carrying cost of CT (\$/MW-yr) – expected energy market revenues (\$/MW-yr) in years of resource deficiency and fixed operations & maintenance (\$/MW-yr) in years of resource sufficiency $\mathrm{LOLP_h}$ = hourly loss of load probability allocators $\sum_{h=1}^{8760} \mathrm{LOLP_h} = 1$ CTP = 'Contribution to Peak' (%) calculated through separate analysis $\mathrm{SolarLOLPCoincidence} = \frac{\sum_{h=1}^{8760} \mathrm{LOLP_h} * \mathrm{SolarGeneration_h}}{\sum_{h=1}^{8760} \mathrm{SolarGeneration_h}}$
3	Line Losses	Hourly marginal T&D loss factors multiplied to corresponding avoided cost of energy. For generation capacity and transmission & distribution capacity, these values are grossed up based on peak marginal T&D loss factors. $\forall h \in [1, \ldots, 8760]$ $\mathrm{LineLosses_h} = \mathrm{Energy_h} * \mathrm{LossFactor_h}$
4	Transmission & Distribution Capacity	Marginal cost of transmission and distribution (\$/MW-yr) allocated to hours of the year using transmission and distribution specific hourly profiles (perhaps based on LOLP). $\forall h \in [1, \ldots, 8760]$ $\mathrm{T\&DCapacity_h} = \mathrm{T\&Dcost} * \mathrm{T\&DLOLP_h}$ where: T&Dcost = marginal cost of T&D (\$/MW-yr) $\mathrm{T\&DLOLP_h}$ = T&D hourly loss of load probability allocators

		$$\sum_{h=1}^{8760} \mathrm{T\&DLOLP_h} = 1$$
5	RPS Compliance	The net incremental cost of a renewable resource multiplied by the RPS requirement. The net incremental cost of a renewable resource is calculated as the levelized cost of the marginal renewable resource minus its energy value, generation capacity value, and avoided emission value plus the integration and transmission costs of that resource. The RPS requirement (%) is incorporated since this represents the quantity of RPS purchases that are avoided for every unit of solar generation. $$\begin{aligned}\mathrm{RPS\ Compliance_h} = (\ & \mathrm{RPS\ Price} \\ & -\mathrm{RPS\ Energy\ Value} \\ & -\mathrm{RPS\ Capacity\ Value} \\ & -\mathrm{RPS\ Emission\ Value} \\ & +\mathrm{RPS\ Integration\ Cost}) * \mathrm{RPS\ \%}\end{aligned}$$ where: RPS price = levelized power purchase agreement (PPA) cost of marginal RPS resource ($/MWh) $$\mathrm{RPS\ Energy\ Value} = \frac{\sum_{h=1}^{8760} \mathrm{Energy_h} * \mathrm{RPSGeneration_h}}{\sum_{h=1}^{8760} \mathrm{RPSGeneration_h}}$$ $$\mathrm{RPS\ Capacity\ Value} = \frac{\mathrm{CapVal} * \mathrm{RPS\ CTP}}{\sum_{h=1}^{8760} \mathrm{RPSGeneration_h}}$$ $$\mathrm{RPS\ Emission\ Value} = \frac{\mathrm{EmissionCost} * \mathrm{EmissionRate_h} * \mathrm{RPSGeneration_h}}{\sum_{h=1}^{8760} \mathrm{RPSGeneration_h}}$$ RPS Integration Cost ($/MWh) is calculated exogenously RPS % is the RPS requirement defined as a % of retail sales
6	Integration and Ancillary Services	$/MWh value provided by utilities that represents the net incremental cost of providing additional operating reserves, balancing services, and system operations required to integrate the solar resource.

7	Administration	\$/MWh value provided by utility that represents the cost of interconnecting solar generators and any ongoing administrative costs such as billing. This value is uniform across all hours of the year.
8	Market Price Response	Estimated impact on Mid-Columbia price under a specified solar penetration (\$/MWh) multiplied by utility net market purchases or sales (MWh). This total \$ amount is then allocated to all solar generation (MWh) to yield a final \$/MWh avoided cost value which is allocated equally to all hours. $\text{Market Price Response} = \frac{\Delta\,\text{Market Price} * \text{Utility Net Short (Long)}}{\text{SolarGeneration}}$ where: Δ Market Price = change in Mid-Columbia market price (\$/MWh) due to solar Utility Net Short (Long) = the annual net sales or purchases (MWh) that each utility transacts at Mid-Columbia Solar Generation = total quantity of annual solar generation (MWh), note this quantity must be consistent with the quantity assumed to create the Δ Market Price
9	Hedge Value	Fixed % multiplied by the avoided cost of energy that represents the cost of utility hedging that is not already included in the energy value estimate described above. $\text{Hedge}_h = \text{Energy}_h * \%$
10	Environmental Compliance	Hourly marginal emission factor of carbon dioxide multiplied by the monetary cost of carbon dioxide. $\text{Environmental Compliance}_h = \text{EmissionFactor}_h * \text{EmissionCost}$ where: EmissionFactor_h = hourly marginal emission factor (tonne CO2 per kWh) EmissionCost = compliance cost of CO2 emissions (\$ per tonne)

Q. How do you translate these hourly avoided costs into an RVOS?

A. The 8760 hourly avoided cost profile is multiplied by the 8760 hourly solar generation profile, and then divided by the total annual solar generation to yield an annual average RVOS.

$$\text{ResourceValueOfSolar} = \frac{\sum_{h=1}^{8760}(\text{Value}_h * \text{SolarGeneration}_h)}{\sum_{h=1}^{8760}\text{SolarGeneration}_h}$$

Q. For how many locations and types of solar can the model calculate an RVOS?

A. As currently configured, the model calculates the value of one type of solar at a single location. However, the model can be used to value the generation of any type of solar resource at any location, provided the correct data is input into the model. Different locational solar values can be calculated through successive model runs, substituting location-specific inputs such as distribution avoided costs. Additionally, the RVOS for different types of PV systems such as residential or commercial can be calculated through successive model runs with different solar generation profiles.

Q. For how many locations and types of solar should a separate RVOS be calculated?

A. The answer depends on the purpose for which the RVOS is calculated. In theory, a separate RVOS could be calculated for every distribution system feeder or substation in the state. However, this would require hundreds or even thousands of model runs to establish these highly-granular, location-specific values. Alternatively, a single RVOS could be calculated for each utility or even for Oregon as a whole. There are tradeoffs in terms of workability and simplicity for calculating the RVOS for more or less locations and types.

If the purpose of the calculation is to provide information for the purpose of utility planning, it may be better to consider more locations and types in order to provide better information for the planning process. However, calculating these values at a very granular level requires the collection and processing of a significant quantity of location-specific data.

If the purpose of the calculation is to develop utility rates for solar compensation, there are tradeoffs around understandability and customer acceptance. Generally accepted ratemaking principles[12] suggest that rates should be simple, understandable, and accepted by customers. Customers in one distribution planning area may have a difficult time understanding why customers in an adjacent area have a different RVOS.

Q. Do both distributed and utility-scale solar provide these elements of value?

A. Distributed solar provides all of these elements. Utility-scale solar, which is not located at the customer site, must be transported over the transmission & distribution system and therefore cannot provide avoided line losses or transmission & distribution capacity value. Additionally, since utility-scale solar can be counted toward the RPS requirement, the RPS compliance value is the

[12] Bonbright, James C. *Principles of Public Utility Rates*, 1961.

full net incremental cost of the marginal renewable resource and is not multiplied by the RPS percent requirement.

Q. Do you recommend use of the RVOS methodology and model for calculating the value of utility-procured solar?

A. No, I do not. While the RVOS methodology and model can serve as reasonable proxies for the value of utility scale solar, utilities already conducted a detailed integrated resource planning (IRP) process for considering the value of solar relative to conventional and renewable alternatives. The RVOS methodology and model necessarily involve a number of simplifications and should not be considered a substitute for the values determined by the utilities through their IRP processes.

Q. Do you recommend use of the RVOS methodology and model for determining avoided cost rates under the Public Utility Regulatory Policies Act (PURPA)?

A. No, I do not. The IOUs already have a detailed process for determining avoided cost rates under PURPA. The RVOS methodology is broadly similar to the methodologies used by the IOUs under PURPA, but it is not intended to replace these IOU filings. Rather, the RVOS methodology is intended to calculate avoided costs for PV installations that are not contracted for under PURPA.

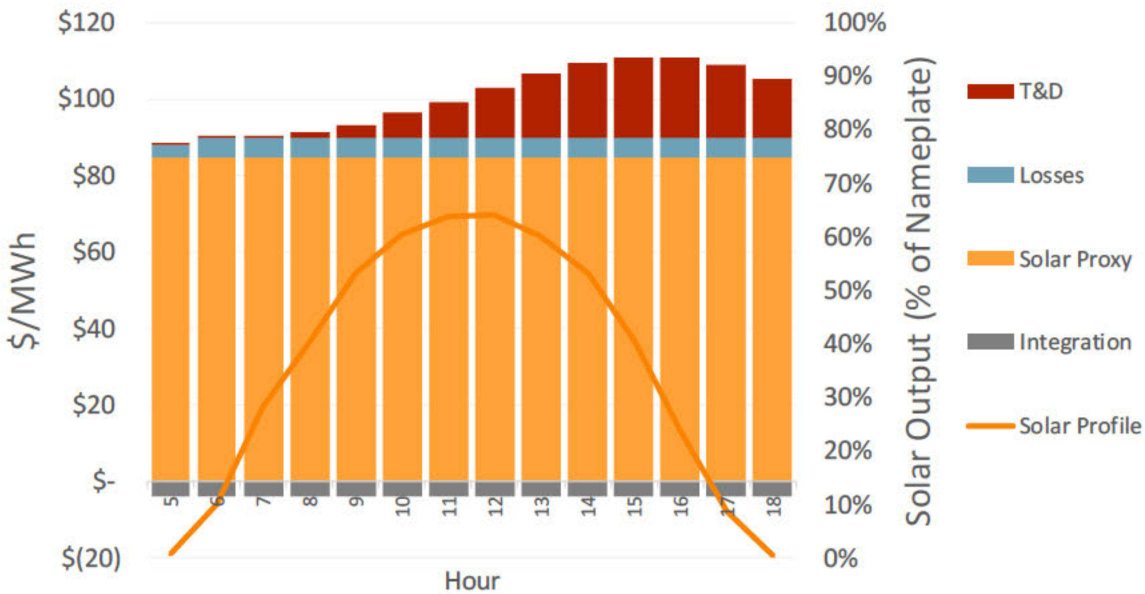
Q. Should the cost of a utility-scale solar PV resource at times be used as the avoided cost proxy, rather than the cost of a conventional fossil resource?

A. Yes, under some plausible future scenarios, the cost to the utility of serving load with conventional generating resources (either natural gas-fired resources or market purchases) may exceed the cost to the utility of acquiring a like amount of solar energy at utility scale. This could be the case under future scenarios that include some combination of high natural gas prices, high CO_2 prices, and/or low solar PV costs. In such cases, utility-procured solar should be used as the proxy resource for avoided costing and determining the RVOS. Utility-scale solar resources, which can be procured by the utility at any time, provide very similar value in terms of energy, generation capacity, emission reduction, market price effect, and RPS compliance value that behind-the-meter solar provides. It would be inappropriate for the RVOS to deviate significantly from the cost of utility-scale solar for those elements of value.

Q. Are there some additional values that distributed solar provides that are not provided by utility-scale solar?

A. Yes, distributed solar provides additional value in the form of avoided energy losses and T&D capacity that utility-scale solar does not provide. Therefore, these elements should still be included separately in the RVOS. An example of the hourly avoided cost value on a summer day using this approach is shown below.

Figure 4: Example Average Day Hourly Avoided Cost Profile – Solar Proxy



Q. Can you please list all elements that are included in the RVOS when utility avoided costs are based on a utility-scale solar proxy resource?

A. Yes, in practice the levelized cost of a new utility-scale solar power purchase agreement is substituted for the calculated energy, generation capacity, emission reduction, market price effect, and RPS value. The mathematical formula is listed below.

$$\begin{aligned} &\forall h \in [1, \dots, 8760] \\ &Value_h = \quad Utility\ Scale\ PPA_h \\ &\qquad\qquad + Line\ Losses_h \\ &\qquad\qquad + T\&D\ Capacity_h \\ &\qquad\qquad - Integration_h \end{aligned}$$

This substitution should occur whenever the cost of utility scale solar proxy is lower than the cost of the utility scale conventional resource proxy.

Q. Have other value of solar studies calculated the RVOS based on an equivalent utility-scale solar resource?

A. As discussed above, there is no standard method for calculating RVOS, and industry practice varies widely as to which elements are included and how their values are calculated. Given the rapidly declining cost of solar (both utility scale and rooftop), it is necessary to include the functionality to calculate the value of distributed solar using a utility-scale solar proxy. I am not aware of any other "value of solar" study that has incorporated a utility-scale solar proxy; however, First Solar commissioned the Brattle Group to study the relative costs of rooftop and utility scale solar in 2015 in the Xcel Energy service area.[13] The study found that "utility-scale solar photovoltaic (PV) systems in the U.S. are significantly more cost effective than residential-scale (rooftop) PV systems as a vehicle for achieving the economic and policy benefits of PV solar."

Q. Have you included the functionality to calculate the RVOS using utility solar as the avoided cost proxy in the RVOS Model?

A. Yes, I have included functionality to calculate the RVOS using both a conventional and a utility solar avoided cost proxy. The model user will need to determine whether to use the conventional or the utility solar avoided cost proxy.

Q. Have you incorporated different characteristics of utility-scale solar relative to distributed solar in the RVOS model?

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13 Tsuchida, B., S. Sergici, B. Mudge, W. Gorman, P. Fox-Penner, J. Schoene, *Comparative Generation Costs of Utility-Scale and Residential-Scale PV in Xcel Energy Colorado's Service Area,* July 2015, accessed at http://www.brattle.com/system/news/pdfs/000/000/901/original/Comparative_Generation_Costs_of_Utility-Scale_and_Residential-Scale_PV_in_Xcel_Energy_Colorado's_Service_Area.pdf?1436800302

A. No, I have not. Utility-scale solar installations can have different operating characteristics than residential solar. Utility-scale solar tends to have a higher capacity factor due to the use of tracking technology and overbuild of the solar field to maximize capacity factor. Utility-scale solar may also be dispatchable in response to grid conditions and can provide voltage support through power factor control. As a result, utility-scale solar likely has higher value than residential or commercial solar. Nevertheless, in the interest of simplicity, I have assumed that the utility scale solar has exactly the same characteristics as the distributed solar. This allows the model to perform a “like-for-like” substitute, avoiding a detailed and complex accounting of the relative value of the two different (but in many ways similar) solar generation profiles.

5. CONCLUSIONS

Q. Do you derive an independent estimate of the resource value of solar within the state of Oregon?

A. No, I do not. I was retained by Staff to develop a methodology and RVOS model. Going forward, the utilities will be able to use the spreadsheet model and populate it with their data to present RVOS results to the Commission.

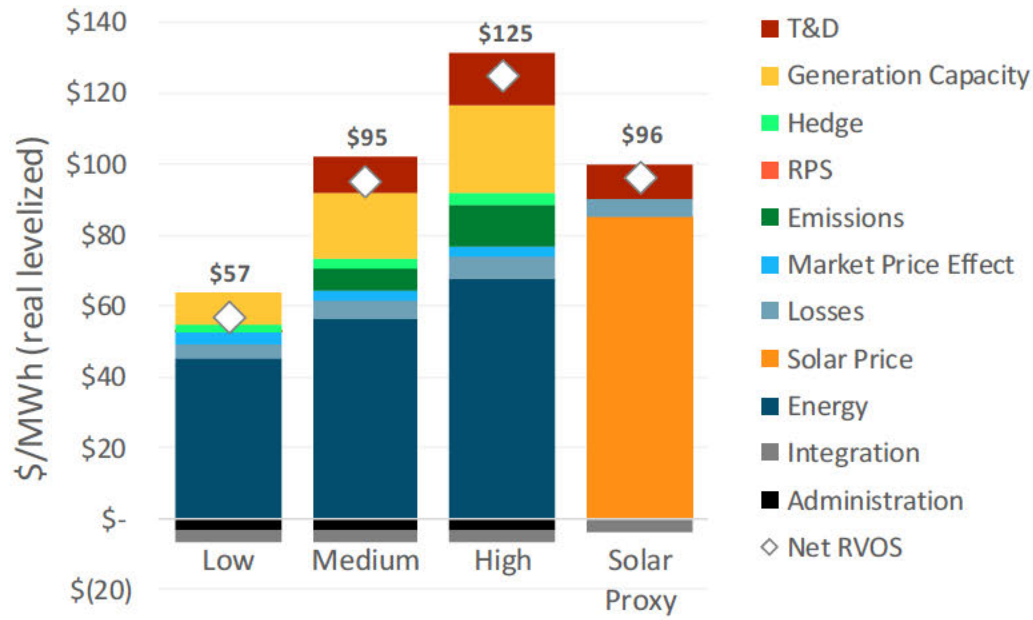
Q. Are you able to produce sample solar values to help stakeholders understand the model structure?

A. Yes, I have produced a low, medium, and high samle values using data the IOUs have provided along with other data with which I am familiar. I have also provided a sample calculation of the RVOS using the utility-scale proxy. Table 4 shows sample, 25-year levelized RVOS results for a 2016 vintage system.

Table 4: Illustrative Resource Value of Solar Results

Low ($/kWh)	Medium ($/kWh)	High ($/kWh)	Solar Proxy ($/kWh)
$0.057	$0.095	$0.125	$0.096

Figure 5: Illustrative Resource Value of Solar Results



Q. Can you please list the assumptions you used to calculate the low, medium, and high scenario results?

A. Yes. My assumptions are as follows:

- **<u>Medium</u>**
  - Energy: $27/MWh (nominal) in 2016, escalating to $97/MWh by 2040
  - T&D losses: 9%
  - Generation capacity: $157/kW-yr ($2016)
    - Annual energy revenues: $30/kW-yr
    - Solar contribution to peak: 25%
    - Resource deficiency year: 2021
    - Fixed O&M: $13.45/kW-yr
  - T&D deferal value: $49/kW-yr

        - T&D coincidence factor: 26%
    - Carbon: $10/ton, escalating to $34/ton by 2040
    - Hedge: 5% of energy
    - Market price effect: +$3/MWh
    - Integration: $4/MWh
    - Administration: $3/MWh
- **<u>Low</u>**
    - Energy: multiplied by 80%
    - Resource deficiency year: 2030
    - Fixed O&M: $0/kW-yr
    - T&D deferral value: $0/kW-yr
    - Carbon: $0/ton
    - All other assumptions identical to Medium case
- **<u>High</u>**
    - Energy: multiplied by 120%
    - Resource deficiency year: 2016
    - T&D deferral value: multiplied by 150%
    - Carbon: multiplied by 200%
    - All other assumptions identical to Medium case
- **<u>Utility Scale Proxy</u>**
    - Solar Price of $85/MWh (real levelized) replaces the following elements: energy, generation capacity, ancillary services,

emissions, RPS compliance, hedge, market price effect, administration

- All other assumptions identical to medium case

Q. Do you expect these values to change over time?

A. The values calculated in the RVOS Model represent the levelized value of solar resources that are installed in 2016. In future years, the value of solar will change due to changing fuel and CO2 price projections, changes in the configuration of utility transmission and distribution systems, and other factors. The RVOS Model will need to be updated regularly as market conditions change or utility resource plans change.

Q. Does this conclude your testimony?

A. Yes, it does.

APPENDIX A. OLSON RESUME

Arne Olson

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arne@ethree.com

ENERGY AND ENVIRONMENTAL ECONOMICS, INC. San Francisco, CA
Partner

Since joining E3 in 2002, Mr. Olson has been a lead in the practice areas of Resource Planning; Renewables and Emerging Technology; Transmission Planning and Pricing; and Energy and Climate Policy. He is an expert in evaluating the impacts of aggressive state and federal policies to promote clean and renewable energy production. He led the technical analysis and drafting of the recent report *Investigating a Higher Renewable Portfolio Standard for California*, prepared for the five largest utilities in California. He led a multi-company team that developed the Renewable Energy Flexibility (REFLEX) Model, a new stochastic production simulation model that calculates the need for power system flexibility under high renewable penetration, which was used for the California utility report as well as for separate renewable integration analysis performed on behalf of the California ISO. He has led numerous other resource planning studies on behalf of utilities, government agencies and electricity consumers, including studies of a 33% RPS for the California Public Utilities Commission and multiple studies of the economic benefits of long-line transmission projects. In 2007, he served as advisor, facilitator and drafter to the Idaho Legislature in developing the 2007 Idaho Energy Plan, the state of Idaho's first comprehensive, state-wide energy plan in 25 years. His clients include the California Independent System Operator, California Public Utilities Commission, Colorado Public Utilities Commission, the Western Electric Coordinating Council, the Western Electric Industry Leaders' Group, the Western Interstate Energy Board, the City of Seattle, Pacific Northwest Generating Cooperative, Mid-American, AltaLink, Pacific Gas & Electric Company, Southern California Edison Company, the Sacramento Municipal Utilities District, the Bonneville Power Administration, TransElect, BC Hydro, and Hydro-Quebec TransEnergie.

Resource Planning and Valuation:

- Currently leading a team that is evaluating the need for flexible generation capacity on behalf of Portland General Electric.
- Led a team that assessed electricity-natural gas infrastructure issues on behalf of the Western Interstate Energy Board.
- Led a team that investigated the capacity contribution of new wind, solar and demand response (DR) resources on behalf of the Sacramento Municipal Utilities District.
- Assisted the Colorado Public Utilities Commission in developing long-term scenarios to use across a range of energy infrastructure planning dockets.
- Assisted BC Hydro in evaluating the impact of BC's provincial greenhouse gas reduction policies on future electric load as part of BC Hydro's 2011 Integrated Resource Plan.
- Provided expert testimony in front of the California Public Utilities Commission on rates and revenue requirements associated with several alternative portfolios of demand-side and supply-side resources, on behalf of Pacific Gas and Electric Company, Southern California Edison, and San Diego Gas & Electric.

- Served as lead investigator in assisting the California Public Utilities Commission (CPUC) in its efforts to reform the long-term procurement planning process in order to allow California to meet its aggressive renewable energy and greenhouse gas reduction policy goals.
- Prepared an integrated resource plan (IRP) on behalf of Umatilla Electric Cooperative, a 200-MW electric cooperative based in Hermiston, Oregon. The IRP considered a number of different resource and rate product options, and addressed ways in which demand-side measures such as energy efficiency, distributed generation and demand response can help UEC reduce its wholesale energy and bulk transmission costs.
- Served as lead investigator in developing integrated resource plans for numerous publicly-owned utilities including PNGC Power, Lower Valley Energy, and Platte River Power Authority.
- Provided generation and transmission asset valuation services to a number of utility and independent developer clients.

Renewables and Emerging Technology:

- Currently leading a team that is advising Portland General Electric Company on potential strategies for cost-effective procurement of distributed or utility scale solar generation.
- Currently leading a team that is evaluating flexible capacity needs under high renewable penetration across the Western Interconnection on behalf of the Western Electric Coordinating Council and the Western Interstate Energy Board. The team includes technical contributions from E3, NREL and Energy Exemplar.
- Led the technical analysis and drafting of the influential report *Investigating a Higher Renewable Portfolio Standard for California*. The report evaluated the operational challenges, costs and solutions for integrating a 40% or 50% Renewable Portfolio Standard on behalf of the five largest utilities in California.
- Led the team that developed the Renewable Energy Flexibility (REFLEX) model, commercial software that assesses power system flexibility needs under high renewable penetration.
- Led the team that developed the Renewable Energy Capacity Planning (RECAP) model, commercial software that calculates reliability metrics such as Loss of Load Probability (LOLP), Loss of Load Expectation (LOLE) and Planning Reserve Margin (PRM), along with Effective Load-Carrying Capability (ELCC) of wind and solar resource, demand response programs, and other dispatch-limited resources.
- Currently advising the CPUC on renewable energy resource policy and procurement.
- Currently leading the California Independent System Operator's (CAISO) renewable integration needs studies. The studies are evaluating the need for firming capacity and flexible resources to accommodate the variable and unpredictable nature of wind and solar generation. Results of the studies will be used to determine the need to procure new, flexible resources.
- Led the team that developed renewable and conventional resource cost and performance characteristics for use in the WECC's Regional Transmission Expansion Planning process.
- On behalf of the Wyoming Governor's Office, developed a model of the cost of developing wind resources in Wyoming relative to neighboring states to inform policy debate regarding taxation. The model included detailed representations of state-specific taxes and capacity factors.
- On behalf of the CPUC, investigated a number of strategies for achieving a 33% Renewables Portfolio Standard in California by 2020, and estimated their likely cost and rate impacts

using the 33% RPS Calculator, a publicly-available spreadsheet model developed for this project.

- Evaluated market opportunities and provided strategic advice for renewable energy developers in California and the Southwest.
- Investigated for Bonneville Power Administration (BPA) the economics and feasibility of investing in new, long-line transmission facilities connecting load centers in the Pacific Northwest with remote areas that contain large concentrations of high-quality renewable energy resources. The study informed BPA about cost-effective strategies for procuring renewable energy supplies in order to meet current and potential future renewable renewables portfolio standards and greenhouse gas reduction targets.
- Co-authored *Load-Resource Balance in the Western Interconnection: Towards 2020*, a study of west-wide infrastructure needs for achieving aggressive RPS and greenhouse gas reduction goals in 2020 for the Western Electric Industry Leaders (WEIL) Group, comprised of CEOs and executives from a number of utilities through the West, and presented results indicating that developing new transmission infrastructure to integrate remote renewable resources can result in cost savings for consumers under aggressive policy assumptions.

Transmission Planning and Pricing:

- Currently serving as technical support to the Western Electric Coordinating Council's Scenario Planning Steering Group (SPSG). The SPSG is developing scenarios for long-term transmission planning in the Western Interconnection.
- Currently advising several transmission developers seeking approval for projects through the CAISO's Transmission Planning Process.
- Led a team that investigated the use of Production Cost Modeling for the purpose of allocating costs of new transmission facilities on behalf of the Northern Tier Transmission Group, and contributed to NTTG's Order 1000 compliance filing.
- Served as an expert witness in front of the Alberta Utilities Commission in a case regarding the Alberta Electric System Operator's proposed methodology for allocating Available Transmission Capacity among interties during times of congestion.
- Led studies in 2009, 2011 and 2012 to develop generation and transmission capital cost assumptions for use in WECC's Transmission Expansion Planning and Policy Committee (TEPPC) studies.
- Contributed to a study of the benefits of North-South transmission expansion in Alberta on behalf of AltaLink.
- Led a study for WECC to estimate the benefits of developing a centralized Energy Imbalance Market (EIM) across the Western Interconnection. The study estimated benefits due to increased generation dispatch efficiency resulting from reduced market barriers and increased load and resource diversity among western Balancing Authorities. Led several follow-up studies of alternative Western EIM footprints for potential EIM participants.
- Retained by a consortium of southwestern utilities and state agencies including the Wyoming Infrastructure Authority, Xcel Colorado, Public Service Company of New Mexico, and the Salt River Project to perform an economic feasibility study of the proposed High Plains Express (HPX) transmission project, a roadmap for transmission development in the Desert Southwest and Rocky Mountain regions.
- Provided assistance to the Seattle City Council to develop guidelines for the evaluation of large electric distribution and transmission projects by Seattle City Light (SCL). Guidelines

- specified the types of evaluations SCL should perform and the information the utility should present to the City Council when it seeks approval for large distribution or transmission projects.
- Conducted screening studies of long-distance transmission lines connecting to remote renewable energy zones for multiple western utilities.
- Assisted in the development of a methodology for evaluating the renewable energy benefits of the Sunrise Powerlink transmission project in support of expert testimony on behalf of the California ISO.
- Assisted British Columbia Transmission Corporation and Hydro-Quebec TransEnergie with open access transmission tariff design.
- Represented BC Hydro in RTO West market design process in areas of congestion management, ancillary services, and transmission pricing.

Energy and Climate Policy:

- Developed policy themes and integrated them into the four long-term planning scenarios under consideration by WECC's Scenario Planning Steering Group.
- Led a team that developed a model of deep carbon dioxide emissions reductions scenarios in the western United States and Canada on behalf of the State-Provincial Steering Committee, a body of western state and provincial officials that provides oversight for WECC.
- Led a study of likely changes to power flows and market prices at western electricity trading hubs following California's adoption of a cap-and-trade system for regulating greenhouse gas emissions in 2013.
- Served as advisor, facilitator and drafter to the Interim Committee in developing Idaho's first comprehensive, statewide energy plan in 25 years. The Interim Committee and subcommittees held 18 days of public meetings and received input from dozens of members of the public in developing state-level energy policy recommendations. This process culminated in Mr. Olson drafting the 2007 Idaho Energy Plan, which was approved by the Legislature and adopted as the official state energy plan in March 2007.
- Developed a model that forecasted renewable and conventional generating resources in the WECC region in 2020 as part of an E3 project to advise the California Public Utilities Commission, California Energy Commission and California Air Resources Board about the cost and feasibility of reducing greenhouse gas emissions in the electricity and natural gas sectors.

WASHINGTON OFFICE OF TRADE AND ECONOMIC DEVELOPMENT Olympia, WA
Senior Energy Policy Specialist 1996-2002

- **Electricity Transmission**: Lead responsibility for developing and representing agency policy interests in a variety of regional forums, with a primary focus on pricing and congestion management issues. Lead negotiator on behalf of agency in IndeGO and RTO West negotiations in areas of Congestion Management, Ancillary Services, and Transmission Planning. Participated in numerous subgroups developing issues including congestion zone definition, nature of long-term transmission rights, and RTO role in transmission grid expansion.

- **Western Regional Transmission Association, 1996-2001:** Member, WRTA Board of Directors. Participated in WRTA Tariff, Access and Pricing Committee. Participated in sub-groups examining "seams" issues among multiple independent system operators in the West and developing a proposal for tradable firm transmission rights in the Western interconnection.
- **Wholesale Energy Markets:** Monitored and analyzed trends in electricity, natural gas and petroleum markets. Editor and principal author of Convergence: Natural Gas and Electricity in Washington, a survey of the Northwest's natural gas industry in the wake of the extreme price events of winter 2000-2001, and on the eve of a significant increase in demand due to gas-fired power plants. Authored legislative testimony on the ability of the Northwest's natural gas industry to meet the demand from new, gas-fired power plants.
- **Electricity Restructuring:** Co-authored Washington Electricity System Study, legislatively-mandated study of Washington's electricity system in the context of ongoing trends and potential methods of electric industry restructuring. Authored legislative testimony on the impact of restructuring on retail electricity prices in Washington, electric industry restructuring and Washington's tax system, and the interactions between restructured electricity and natural gas markets.
- **Energy Data:** Managed three-person energy data team that collected and maintained a repository of state energy data. Developed Washington's Energy Indicators, a series of policy benchmarks and key trends for Washington's energy system; second edition published in January 2001.

DECISION ANALYSIS CORPORATION OF VIRGINIA Vienna, VA
Associate 1993-1996

- **Energy Modeling and Analysis:** Developed energy demand forecasting models for Energy Information Administration's National Energy Modeling System. Results are published each year in EIA's Annual Energy Outlook.

Education

University of Pennsylvania Philadelphia, PA
Institut de Francais du Petrole Rueil-Malmaison, France
M.S., International Energy Management & Policy

University of Washington Seattle, WA
B.S., Mathematical Sciences, B.S. Statistics

Citizenship

United States

Expert Witness Testimony

1. *Oregon Public Utilities Commission, 2016, testified on behalf of Portland General Electric Company regarding methodologies for assessing the capacity contribution of variable renewable energy resources.*

2. *Province of Ontario, Commercial Arbitration, 2015, testified regarding policies related to renewable energy procurement and determination of available transmission capacity.*

3. *California Energy Commission, 2014, testified on behalf of Abengoa and BrightSource Energy regarding the cost and feasibility of distributed generation and energy storage alternatives to a large, concentrating solar power plant project in the context of a power plant siting case.*

4. *California Energy Commission, 2013, testified on behalf of BrightSource Energy regarding the cost and feasibility of distributed generation alternatives to a large, concentrating solar power plant project in the context of a power plant siting case.*

5. *Alberta Electric Utilities Commission, 2012, testified on behalf of Powerex Corporation reviewing industry practices regarding treatment of existing transmission capacity, in the case when new transmission lines are interconnected.*

6. *California Public Utilities Commission, 2011, provided testimony on behalf of Pacific Gas and Electric Company, Southern California Edison Company, and San Diego Gas & Electric Company regarding cost, revenue requirement, average retail rates, and cost of carbon reductions from alternative resource portfolios in the Long-Term Procurement Planning Proceeding.*

7. *California Energy Commission, 2010, testified on behalf of BrightSource Energy regarding the cost and feasibility of distributed generation alternatives to a large, concentrating solar power plant project in the context of a power plant siting case.*

Refereed Papers

1. *C.K. Woo, J. Moore, B. Schneiderman; A. Olson; R. Jones; T. Ho; N. Toyama; J. Wang; and J. Zarnikau, "Merit-order Effects of Day-ahead Wind Generation Forecast in the Hydro-rich Pacific Northwest", The Electricity Journal, Vol. 28, Issue 9, November 2015*

2. *Olson, A., R. Jones, E. Hart and J. Hargreaves, "Renewable Curtailment as a Power System Flexibility Resource," The Electricity Journal, Volume 27, Issue 9, November 2014, pages 49-61*

3. *Hargreaves, J., E. Hart, R. Jones and A. Olson, "REFLEX: An Adapted Production Simulation Methodology for Flexible Capacity Planning," IEEE Transactions on Power Systems, Volume:30, Issue: 3, September 2014, pages 1306 - 1315*

4. *C.K. Woo, T. Hob, J. Zarnikau, A. Olson, R. Jones, M. Chait, I. Horowitz, J. Wang, "Electricity-market price and nuclear power plant shutdown: Evidence from California", Energy Policy,* 2014, vol. 73, issue C, pages 234-244

5. *Woo, C.K., Zarnikau J, Kadish J, Horowitz I, Wang J, Olson A. (2013) "The Impact of Wind Generation on Wholesale Electricity Prices in the Hydro-Rich Pacific Northwest," IEEE Transactions on Power Systems, 28(4), 4245-4253.*

6. *Olson A., R. Jones (2012) "Chasing Grid Parity: Understanding the Dynamic Value of Renewable Energy," Electricity Journal, 25:3, 17-27.*

7. *Woo, C.K., H. Liu, F. Kahrl, N. Schlag, J. Moore and A. Olson (2012) "Assessing the economic value of transmission in Alberta's restructured electricity market," Electricity Journal, 25(3): 68-80.*

8. *DeBenedictis, A., D. Miller, J. Moore, A. Olson, C.K. Woo (2011) "How Big is the Risk Premium in an Electricity Forward Price? Evidence from the Pacific Northwest," Electricity Journal, 24:3, 72-76.*

9. *Woo, C.K., I. Horowitz, A. Olson, A. DeBenedictis, D. Miller and J. Moore (2011) "Cross-Hedging and Forward-Contract Pricing of Electricity in the Pacific Northwest," Managerial and Decision Economics, 32, 265-279.*

10. *Moore, J., C.K. Woo, B. Horii, S. Price and A. Olson (2010) "Estimating the Option Value of a Non-firm Electricity Tariff," Energy, 35, 1609-1614.*

11. *Olson A., R. Orans, D. Allen, J. Moore, and C.K. Woo (2009) "Renewable Portfolio Standards, Greenhouse Gas Reduction, and Long-line Transmission Investments in the WECC," Electricity Journal, 22:9, 38-46.*

12. *Moore, J., C.K. Woo, B. Horii, S. Price, A. Olson (2009) "Estimating the Option Value of a Non-firm Electricity Tariff," Energy, 35, 1609-1614.*

13. *Woo, C.K., I. Horowitz, N. Toyama, A. Olson, A. Lai, and R. Wan (2007) "Fundamental Drivers of Electricity Prices in the Pacific Northwest," Advances in Quantitative Analysis of Finance and Accounting, 5, 299-323.*

14. *Lusztig, C., P. Feldberg, R. Orans, and A. Olson (2006) "A survey of transmission tariffs in North America," Energy-The International Journal 31, 1017-1039.*

15. *Woo, C.K., A. Olson, I. Horowitz and S. Luk (2006) "Bi-directional Causality in California's Electricity and Natural-Gas Markets," Energy Policy, 34, 2060-2070.*

16. *Woo, C.K., I. Horowitz, A. Olson, B. Horii and C. Baskette (2006) "Efficient Frontiers for Electricity Procurement by an LDC with Multiple Purchase Options," OMEGA, 34:1, 70-80.*

17. *Woo, C.K., A. Olson and I. Horowitz (2006) "Market Efficiency, Cross Hedging and Price Forecasts: California's Natural-Gas Markets," Energy, 31, 1290-1304.*

18. *Woo, C.K., A. Olson and R. Orans (2004) "Benchmarking the Price Reasonableness of an Electricity Tolling Agreement," Electricity Journal, 17:5, 65-75.*

19. *Orans, R., A. Olson, C. Opatrny, Market Power Mitigation and Energy Limited Resources, Electricity Journal, March, 2003.*

Selected Public Presentations

1. *"The Role of Energy Storage as a Renewable Integration Solution under a 50% RPS", invited panelist, Joint California Energy Commission and California Public Utilities Commission Long-Term Procurement Plan Workshop on Bulk Energy Storage, Sacramento, California, November 20, 2015*

2. *"Planning for Variable Generation Integration Needs", invited panelist, Utility Variable-generation Integration Group, Operating Impact And Integration Studies Users Group Meeting, San Diego, California, October 13, 2015*

3. *"The Role of Renewables in a Post-Coal World", invited panelist, Energy Foundation, Beyond Coal to Clean Energy Conference, San Francisco, California, October 9, 2015,*

4. *"Implications of a 50% RPS for California", invited panelist, Argus Carbon Summit, Napa, California, October 6, 2015*

5. *"Western EIM: Status Report and Implications for Public Power", Keynote speaker, Large Public Power Council meeting, Seattle, Washington, September 16, 2015*

6. *"California's 50% RPS Goal: Opportunities for Western Wind Developers", Keynote speaker at a meeting of the Wyoming Infrastructure Authority, Berkeley, California, July 28, 2015*

7. *"Western Interconnection Flexibility Assessment", Western Electric Coordinating Council Board of Directors, Salt Lake City, Utah, June 24, 2015*

8. *"California's New GHG Goals: Implications for the Western Electricity Grid", invited panelist, National Association of State Energy Officials, Western Regional State and Territory Energy Office Meeting, Portland, Oregon, May 14, 2015*

9. *"Replacing Aging Fossil Generation," invited panelist, Northwest Energy Coalition NW Clean & Affordable Energy Conference, Portland, Oregon, November 7, 2014*

10. *"Investing in Power System Flexibility," invited panelist, State/Provincial Steering Committee & Committee on Regional Electric Power Cooperation System Flexibility Forum, San Diego, California, October 20, 2014*

11. *"Opportunities and Challenges for Higher Renewable Penetration in California", invited panelist, Beyond 33%: University of California at Davis Policy Forum Series, Sacramento, California, October 17, 2014*

12. *"Renewable Curtailment as a Power System Flexibility Resource," Boise State University Energy Policy Research Conference, San Francisco, California, September 4, 2014*

13. *"Natural Gas Infrastructure Adequacy: An Electric System Perspective", Pacific Northwest Utilities Conference Committee Board of Directors, Portland, Oregon, August 8, 2014*

14. *"The Future of Renewables in the American West," invited panelist, Geothermal Energy Association Annual Meeting, Reno, Nevada, August 6, 2014*

15. *"Long-Term Natural Gas Infrastructure Needs", invited panelist, U.S. Department of Energy Quadrennial Energy Review, Public Meeting #7, Denver, Colorado, July 28, 2014*

16. *"Meeting the Demands of Renewables Integration—New Needs, New Technologies, Emerging Opportunities", invited panelist, InfoCast 2nd Annual California Energy Summit, San Francisco, California, May 28, 2014*

17. *"Power System Flexibility Needs under High Renewables", EUCI Utility Resource Planning Conference, Chicago, Illinois, May 14, 2014*

18. *"Natural Gas Infrastructure Adequacy: An Electric System Perspective", Western Interstate Energy Board Annual Meeting, Denver, Colorado, April 24, 2014*

19. *"Power System Flexibility Needs under High RPS", invited panelist, joint meeting of the Committee on Regional Electric Power Cooperation, State-Provincial Steering Committee and Western Interconnection Regional Advisory Body, Tempe, Arizona, March 26, 2014*

20. *"Natural Gas Infrastructure Adequacy: An Electric System Perspective", joint meeting of the Committee on Regional Electric Power Cooperation, State-Provincial Steering Committee and Western Interconnection Regional Advisory Body, Tempe, Arizona, March 25, 2014*

21. *"Investigating a Higher Renewables Portfolio Standard for California", 19th Annual Power Conference on Energy Research and Policy, University of California Energy Institute, Berkeley, California, March 17, 2014*

22. *"Investigating a 50 Percent Renewables Portfolio Standard in California", invited panelist, Northwest Power and Conservation Council, Portland, Oregon, March 12, 2014*

23. *"Investigating a 50 Percent Renewables Portfolio Standard in California", invited panelist, Western Systems Power Pool, Spring Operating Committee Meeting, Whistler, B.C., March 5, 2014*

24. *"Investigating a Higher Renewables Portfolio Standard for California", invited speaker, Western Electric Coordinating Council, Transmission Expansion Planning and Policy Committee, Salt Lake City, Utah, February 25, 2014*

25. *"Investigating a 50 Percent Renewables Portfolio Standard in California", invited speaker, Committee on Regional Electric Power Cooperation, State-Provincial Steering Committee and Western Interconnection Regional Advisory Body, Webinar, February 12, 2014*

26. *"Flexibility Planning: Lessons From E3's REFLEX Model", EUCI Conference on Fast Ramp and Intra-Hour Market Incentives, San Francisco, California, January 29-30, 2014*

27. *"The Effect of High Renewable Penetration on California Markets and Carbon Balance", EUCI Conference on California Carbon Policy Impacts on Western Power Markets, January 27-28, San Francisco, California, 2014*

28. *"Reliance on Renewables: A California Perspective", invited panelist at Harvard Electricity Policy Group, Seventy-Third Plenary Session, Tucson, Arizona, December 13, 2013*

29. *"The Role of Renewables in Meeting Long-Term Greenhouse Gas Reduction Goals", State Bar Of California, Energy And Climate Change Conference, Berkeley, California, November 14, 2013*

30. *"Benefits, Costs and Cost Shifts from Net Energy Metering", invited expert panelist at Washington Utilities and Transportation Commission Workshop on Distributed Generation, Olympia, Washington, November 13, 2013*

31. *Pacific Northwest Utilities Conference Committee (PNUCC) California Power Industry Roundtable, invited panelist, Portland, Oregon, September 6, 2013*

32. *"After 2020: Prospects for Higher RPS Levels in California", invited speaker at Northwest Power and Conservation Council's California Power Markets Symposium, Portland, Oregon, September 5, 2013*

33. *"Determining Flexible Capacity Needs for the CAISO Area", invited speaker at Northwest Power and Conservation Council's California Power Markets Symposium, Portland, Oregon, September 5, 2013*

34. *"California Climate Policy and the Western Energy System", invited speaker at the Western Interstate Energy Board annual meeting, Reno, Nevada, June 13, 2013*

35. *"Determining Power System Flexibility Need", EUCI Conference on Resource Planning and Asset Valuation, Westminster, Colorado, May 21, 2013*

36. *"California Policy Landscape and Impact on Electricity Markets", EUCI Conference on Resource Planning and Asset Valuation, Westminster, Colorado, May 21, 2013*

37. *"Determining Power System Flexibility Need", EUCI Conference on Fast and Flexi-ramp Resources, Chicago, Illinois, April 23, 2013*

38. *"State-Provincial Steering Committee WECC Low Carbon Scenarios Tool", 3 Interconnections Meeting, Washington, DC, February 6, 2013*

39. *"Distributed Generation Benefits and Planning Challenges", Committee on Regional Electric Power Cooperation/State-Provincial Steering Committee, Resource Planners' Forum, San Diego, California, October 3, 2012*

40. *"Thoughts on the Flexibility Procurement Modeling Challenge", invited speaker at the California Public Utilities Commission, Long-Term Procurement Planning Workshop, San Francisco, California, September 19, 2012*

41. *"Generation Capital Cost Recommendations for WECC 10- and 20-Year Studies", Western Electric Coordinating Council, Transmission Expansion Planning and Policy Committee, Technical Advisory Subcommittee, Webinar, August 15, 2012*

42. *"Renewable Energy Benefits", California Energy Commission, Integrated Energy Policy Report Workshop, Sacramento, California, April 12, 2012*

43. *"The Role of Policy in WECC Scenario Planning", Western Electric Coordinating Council, Scenario Planning Steering Group, San Diego, CA, November 1, 2011*

44. *"WECC Energy Imbalance Market Benefit Study", Western Electric Coordinating Council, Board of Directors, Scottsdale, Arizona, June 22, 2011*

45. *"Renewable Portfolio Standard Model Methodology and Draft Results", California Public Utilities Commission Workshop, San Francisco, California, June 17, 2010*

46. *"Draft Results from 33% Renewable Energy Standard Economic Modeling", California Air Resources Board Workshop, Sacramento, California, May 20, 2010*

47. *"Market Opportunities for IPPs in the WECC", invited speaker at the Independent Power Producers of British Columbia Annual Meeting, Vancouver, British Columbia, November 2, 2009*

48. *"A Low-Transmission Alternative for Meeting California's 33% RPS Target", EUCI Webinar, July 31, 2009*

49. *"Remote Renewable and Low-Carbon Resource Options for the Pacific Northwest", Center for Research on Regulated Industries Conference, Monterey, California, June 19, 2009*

50. *"Engineers are from Mars, Policy-Makers are from Venus: The Effect of Policy on Long-Term Transmission Planning", invited speaker at the Western Electric Coordinating Council Long Term Transmission Planning Seminar, Phoenix, Arizona, February 2, 2009*

51. *"The Long-Term Path to a Stable Climate, and its Implications for BPA", invited speaker at the Bonneville Power Administration Managers' Retreat, Portland, Oregon, April 29, 2008*

52. *"Load-Resource Balance in the Western Interconnection: Towards 2020", Western Electric Industry Leaders Group, Las Vegas, Nevada, January 18, 2008*

53. *"Integrated Resource Planning for BPA Customers", invited speaker at the Bonneville Power Administration Allocation Conference, Portland, Oregon, September 19, 2006*

54. *"Idaho's Current Energy Picture", Energy, Environment and Technology Interim Committee, Boise, Idaho, July 11, 2006*

55. *"Locational Marginal Pricing – The Very Basics", Committee on Regional Electric Power Cooperation, San Diego, California, April 30, 2002*

56. *"Effect of 2000-2001 Energy Crisis on Washington's Economy", Conference on Business Economics, Seattle, Washington, July 19, 2001*

Research Reports

1. *Western Interconnection Flexibility Assessment, December 2015, project lead and contributing author, https://ethree.com/public_projects/western_interconnection_study.php*

2. *Natural Gas Infrastructure Adequacy in the Western Interconnection: An Electric Sector Perspective, July 2014, project lead and contributing author, https://ethree.com/public_projects/wieb.php*

3. *Investigating a Higher Renewables Portfolio Standard for California, January 2014, technical lead and lead author, http://www.ethree.com/public_projects/renewables_portfolio_standard.php*

4. *Optimal Investment in Power System Flexibility, E3 White Paper, December 2013, https://ethree.com/documents/Olson_Flexibility_Investment_2013-12-23.pdf*

5. *Cost and Performance Review of Generation Technologies: Recommendations for WECC 10- and 20-Year Study Process, October 2012, editor and contributor, http://www.wecc.biz/committees/BOD/TEPPC/TAS/121012/Lists/Minutes/1/121005_GenCapCostReport_finaldraft.pdf.*

6. *Economic Assessment of North/South Transmission Capacity Expansion in Alberta, January 2012, contributor.*

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