CASE: UM 1910, 1911,1912
WITNESS: BRITTANY ANDRUS

PUBLIC UTILITY COMMISSION
OF
OREGON

STAFF EXHIBIT 300

Cross-Reply Testimony

April 20, 2018

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

A. My name is Brittany Andrus. I am a senior utility analyst employed in the Energy Resources and Planning Division of the Public Utility Commission of Oregon (OPUC). My business address is 201 High Street SE., Suite 100, Salem, Oregon 97301.

Q. Have you previously provided testimony in these dockets?

A. Yes. I submitted Staff Exhibits 100 and 200 in each of the three dockets (Nos. UM 1910-12).

Q. Can you briefly summarize the history of these dockets and where we are today?

A. The Commission opened Docket Nos. UM 1910-12 as Phase II of its Investigation to Determine the Resource Value of Solar (RVOS). In Phase I, the Commission largely adopted, with some modifications, a methodology designed by Staff consultant Energy + Environmental Economics (E3) for calculating a 25-year marginal, levelized value for generic, small-scale solar resource (“RVOS Methodology” or “Methodology”).[1] The Commission also identified and defined the “elements” of solar generation that would be valued in the Methodology and specified for most of them how the utility should determine the appropriate input.[2]

[1] *In the Matter of the Public Utility Commission of Oregon Investigation to determine the Resource Value of Solar,* UM 1716, Order No. 17-357, p. 1-2.
[2] *Id.*

The Commission ordered Portland General Electric Company (PGE), Idaho Power Company (Idaho Power), and PacifiCorp to make individual compliance filings in new utility-specific dockets using the inputs and Methodology described in Order No. 17-357. The Commission ordered the utilities to explain how they went about determining the appropriate input for each element and implementing the Methodology and to provide workpapers to build a robust record that would facilitate the Commission's final determination of an RVOS Methodology. The Commission further specified that Staff and intervenors would have the opportunity to respond to the compliance filings and that all parties should address certain general issues such as the levelization period and how to determine RVOS for a utility-scale solar resource.

Notably, the Commission reserved the option of modifying the Methodology in Phase II. As discussed by the Commission in its order concluding Phase I, the Commission intended to use the utilities' Phase II compliance filings to further evaluate the E3 methodology and presumably, modify the methodology or how to determine inputs if information submitted in Phase II showed modification is appropriate.

PacifiCorp, PGE, and Idaho Power all submitted compliance filings in late 2017. Staff, the Oregon Department of Energy (ODOE), the Oregon Citizens' Utility Board (CUB), Renewable Northwest

(Renewable NW), the Oregon Solar Energy Industries Association (OSEIA) filed testimony on March 16, 2018.

This round of testimony is the final round in Phase II, and all parties are allowed to file testimony.

Q. What is the purpose of your testimony?

A. Staff discusses testimony filed by the intervenors on March 16, 2018. Staff also addresses questions left open in the Commission’s Phase I order regarding further improvements to the RVOS Methodology. These questions include (1) how to value incremental capacity additions during what are considered periods of “resource sufficiency” under the Commission’s avoided cost methodology for PURPA contracts for the purpose of determining the appropriate input for capacity; and (2) how to advance toward more location-specific values for the input for transmission and distribution (T&D) capacity. For the most part, Staff concludes that additional investigation and analysis should be done before modifying how generation and T&D capacity, or any other element, is valued for the RVOS Methodology. However, the testimony presented in Phase II has emphasized the need for these improvements and Staff recommends proceeding with additional investigation sooner rather than later.

Q. How is your testimony organized?

A. Although it did so in opening testimony in each of the dockets opened for the utilities’ compliance filings, Staff does not specifically address each utility's determination of each of the eleven elements valued in the RVOS Methodology. Staff finds that its conclusions regarding the utilities' compliance with Order No. 17-357 did not change upon review of testimony filed by intervenors. However, the intervenors did propose modifications to the RVOS Methodology itself that warrant further consideration. Accordingly, the focus of this cross-reply testimony is for the most part, on potential areas of improvement to the RVOS Methodology.

Staff filed separate opening testimony in each of the three dockets opened for Phase II to address the utilities' compliance with Order No. 17-357. Staff does not do so now. Instead, Staff files the same testimony (Staff/300, Andrus), in each of the Phase II dockets that includes some discussion of each utility's filing and regarding the RVOS Methodology itself.

INPUTS FOR RVOS METHODOLOGY

Energy

Q. Did other parties address the RVOS Methodology input for energy?

A. Yes. Like Staff, Renewable NW questions PacifiCorp's use of information from the Energy Imbalance Market (EIM) for shaping the hourly energy prices.[3] Conversely, OSEIA supports the use of EIM and recommends that PGE and Idaho Power also use the EIM-based methodology. OSEIA asserts that EIM provides the "most granular market data available for the Pacific Northwest wholesale energy market."[4]

Renewable NW also notes the need to use inputs based on the most recently acknowledged integrated resource plan.[5]

Q. Does Staff agree with OSEIA's proposal regarding the use of EIM information?

A. No. While information from the EIM may inform the shaping for hourly energy prices, it should not be the sole basis for the shape of any of the utilities' prices because EIM transactions are only a small portion of each utility's transactions.

Q. Does Staff agree with RNW regarding the use of the most recently-acknowledged IRP?

[3] RNW/100, O'Brien/4.
[4] OSEIA/100, Beach/5.
[5] RNW/100, O'Brien/4.

A. Yes.

Generation Capacity

Q. Does Staff have additional comments regarding the generation capacity input?

A. Yes. The Commission has previously indicated its interest in improving the RVOS Methodology to capture the value of incremental additions of distributed solar resources. Staff agrees changes are necessary because the method used to determine avoided cost prices for PURPA contracts is not necessarily well suited for determining the capacity value of distributed generation solar resources.

Q. Do other parties address potential improvements to the Methodology with respect to the generation capacity input?

A. Yes. CUB and OSEIA discuss the Methodology's shortcoming in terms of capturing the capacity value of incremental additions of solar generation. CUB objects to the use of the avoided cost sufficiency/deficiency demarcation because solar projects provide some capacity value even during the sufficiency period. CUB notes that under the RVOS Methodology the utility doesn't pay solar resources for capacity during sufficiency periods, yet is building resources that will move sufficiency out out again, reducing the value of the RVOS capacity under the current Methodology. OSEIA recommends advancing the resource balance (deficiency) year by three years for PGE and by four years for Idaho Power and PacifiCorp to take into account the smaller capacity increments and the shorter lead times available with additions solar DG facilities.[6]

Q. Does Staff recommend that the Commission modify the RVOS Methodology with respect to the generation capacity element as suggested by CUB or OSEIA?

A. Not at this time. Staff recommends that the Commission allow Staff and the parties to continue with the process outlined in Order No. 17-357 for addressing improvements to the RVOS Methodology:

> For next steps on valuing generation capacity during resource sufficiency, we direct Staff to convene a workshop at a future time it chooses. We ask Staff and the parties to explore options for valuing capacity additions incrementally during resource sufficiency. The issues to be explored at the workshop include: (1) allowing the full capacity value up to a reasonable number of years before the deficiency year (e.g., three or four years) as recognition that it takes several years to ramp up infrastructure to avoid a major resource; (2) using the short run marginal cost affixed operations and maintenance (O&M) as a proxy value as suggested by E3; and (3) other ideas arising from related Commission dockets or those raised by the parties.[7]

Q. Is there any other testimony from intervenors regarding the generation capacity input?

A. Yes. RNW testifies that utilities should use the “capacity factor method” from Order No. 16-326 in Docket No. UM 1719.

ODOE notes that PacifiCorp develops a capacity contribution value using a west-side fixed tilt solar resource and a representative

[6] OSEIA/100, Beach 6.
[7] Order No. 17-357 at 7.

utility scale solar profile for Lakeview, Oregon. ODOE testifies that "in the past year, the Solar Development Incentive program administered by Business Oregon announced148.5 MW of new solar capacity in the state. Of the 148.5MW of new capacity, 141.9MW (95%) will utilize single axis trackers."[8] ODOE testifies that "[g]iven the prominence of single axis trackers and the likely disparity between capacity values for fixed tilt west-side resources and east-side tracking resources, an analysis should be completed to determine the difference to capacity RVOS values between the two scenarios."[9]

Q. Does Staff agree with the intervenors on these points?

A. Staff agrees that it is appropriate to examine these issues in the workshops planned for exploring improvements to the Methodology for valuing generation capacity.

T&D Capacity

Q. Does Staff have additional comments regarding the utilities' compliance with the Commission's instructions on the value for transmission and distribution capacity?

A. No. As with generation capacity, Staff has little to add regarding the utilities' compliance with the Commission's instructions on this element. Staff's primary concern is improving the granularity of the RVOS Methodology with respect to T&D capacity.

[8] ODOE/100, Delmar/5.
[9] ODOE/100, Delmar/5.

Q. Do the intervenors address the T&D capacity element?

A. Yes. OSEIA suggests enhancements to the RVOS Methodology that, for all three utilities, would increase the value of the T&D capacity element in the RVOS. In general, OSEIA agrees that T&D capacity should only be avoided at peak,[10] that T&D benefits can be quantified using marginal costs as the Commission stated in the order,[11] and that T&D avoided capacity costs should be locational but that it makes sense to determine these avoided costs on a system basis for now.[12] OSEIA also provides a table with revised calculations of the T&D capacity RVOS value and explains how it derived the calculations throughout its testimony.

Q. Please summarize key the differences of OSEIA's proposal as compared to how the utilities' implemented the Methodology.

A. With respect to PacifiCorp and Idaho Power, OSEIA disagrees with the idea that estimated capacity deferrals should be restricted to a limited time horizon. For example, both utilities base T&D capacity deferrals on current potential upgrades. OSEIA indicates in its testimony that because solar resources have useful lives of up to 30 years, future T&D capacity deferrals can be avoided. According to

[10] OSEIA/100, Beach/12.
[11] OSEIA/100, Beach/13.
[12] OSEIA/100, Beach/13.

OSEIA, the RVOS estimates only consider current deferrals and do not take into account avoiding the need to build future infrastructure.[13]

OSEIA presents a methodology for measuring the value of avoiding distribution capacity costs in the long term specifically derived from E3's methodology in a California docket. Instead of only considering deferral at peak, the methodology takes into account load within ten percent of peak, which consequently would increase the value of RVOS for T&D capacity deferrals.[14]

Q. Does Staff agree with the methodology OSEIA has presented?

A. Staff generally believes OSEIA makes good points about the long-term nature of solar capacity deferrals. It seems reasonable to Staff that basing solar deferrals on a short-term basis may undervalue the RVOS. However, Staff is not convinced of using numbers based on ten percent of load. Staff would need to investigate these numbers further.

Q. What other pertinent analysis did OSEIA present in its testimony?

A. Staff found OSEIA's use of the three utilities' substation data compelling. OSEIA obtained hourly loading data of relevant substations (those currently planned for an upgrade, and therefore

[13] OSEIA/100, Beach/13-14.
[14] OSEIA/100, Beach/15-16.

potentially eligible for solar upgrades), which revealed which substations were closest to needing capacity.

While OSEIA utilized data within ten percent of peak and not just at peak, OSEIA discovered which areas would benefit from solar resources more than others, thereby determining optimal locational placement. OSEIA determined that "there is significant variation in marginal distribution costs by location, and constrained parts of the distribution system will have marginal costs that are far higher than the system average."[15] Staff believes this overall approach to be a reasonable first-step determinant of the locational element of T&D capacity.

Q. What else does OSEIA discuss pertaining to the T&D capacity element?

A. OSEIA states that it is reasonable to use existing Bonneville Power Administration (BPA) transmission rates as an estimate for that component of the RVOS. However, OSEIA notes that these transmission rates are generally based on average and not marginal costs and that this would undervalue the RVOS.[16]

With respect to Idaho Power and PacifiCorp, OSEIA disputes the use of demand-side management for currently planned projects for an estimation of T&D deferral. OSEIA states that the calculations are not

[15] OSEIA/100, Beach/20.
[16] OSEIA/100, Beach/22.

on a system level because the denominator of the deferral values represents an aggregate of the maximum capacities of the deferral projects, and not increase in system peak.[17]

As an alternative, OSEIA recommends using an approach developed by the National Economic Research Associates (NERA). The NERA regression model utilizes 15 years of data to approximate the utility's long-term marginal cost of capacity. OSEIA uses the NERA model to estimate marginal distribution costs for PacifiCorp and Idaho Power as an alternative to what was presented in testimony.[18]

Q. What are Staff's thoughts on OSEIA's proposed alternatives?

A. Staff is not opposed to using the firm transmission rates as proposed by PGE and OSEIA. Staff also believes the NERA calculation for distribution capacity deferrals aligns more with a system-basis approach. Staff does not believe the methodology is unreasonable because it is a systematic approach that attempts to account for actual distribution capacity expenditures using historical data.[19] However, Staff would need more time to assess the assumptions in the model. OSEIA's approximation of distribution deferrals for the utilities was consistently significantly higher than that of the utilities, and as such, Staff would need to further investigate the discrepancies.

[17] OSEIA/100, Beach/23.
[18] OSEIA/100, Beach/23.
[19] OSEIA/100, Beach/24.

Line Losses

Q. Do any of the intervenors suggest improvements to how the input for line losses is determined in the RVOS Methodology?

A. OSEIA observes that the utilities' estimates of avoided line losses are based on the average loss factors they use to set retail rates and asserts that the use of average line losses fails to capture the fact that the reductions in line losses on the margin from small changes in load on the system, are significantly greater than average losses.[20]

Q. Does Staff agree with OSEIA's proposal regarding line losses?

A. Staff believes that the Commission addressed this issue in Order No. 17-357. E3 recommended the use of marginal line losses. The Commission directed utilities to use average line losses:

> We ask the utilities to develop hourly averages of line losses by month for the daytime hours when load on the system is higher, losses are greater, and solar is generating. We expect the utilities' values to recognize and reflect that there are seasonal and daily variations in line loss impacts with higher temperatures and higher loads having higher losses. We do not expect a time hourly value to this element, but ask the utilities to provide the most granular value they reasonably can inclusive of daytime and seasonal variation, with an explanation of the value in their filing.[21]

Staff does agree that marginal line losses are higher than average losses, increasing as load increases, and that this issue merits further review when considering changes to the RVOS Methodology.

---

[20] OSEIA/100, Beach/25.
[21] Order No. 17-357 at 10.

However, Staff believes that the application of a 50 percent increase to average line losses, as proposed by OSEIA,[22] needs further review.

RPS Compliance

Q. What did the Commission direct the utilities to do for the Renewable Portfolio standard (RPS) compliance element?

A. The Commission directed "the utilities to assign a zero value as a placeholder for this element in their initial RVOS filings." The Commission explained that it would "revisit the proper inputs for this element, and will endeavor to assign a methodology before the end of Phase II * * * because the value or cost of avoided RPS compliance overlaps with several other pending dockets.[23] It is Staff's understanding that the other pending dockets referred to by the Commission are not yet complete. Accordingly, the value for the RPS element remains at zero at this stage of Phase II.

If directed to do so, Staff can include discussions of a value for the RPS Compliance element in future workshop regarding improvements to the RVOS Methodology.

Environmental Compliance

Q. What did the Commission order with respect to the input for the environmental compliance element?

---

[22] OSEIA/100, Beach/25.
[23] Order No. 17-357 at 13-14.

A. The Commission stated that they would decide on the application of this element in the RVOS at a later time. They also stated that any proposed environmental compliance values would be treated only as informational placeholders for further consideration in Phase II of the RVOS process, which we are currently in.[24]

Q. Did other parties comment on the input for environmental compliance?

A. OSEIA testified that any carbon compliance regime would apply equally to all three utilities and so the utilities should not have a different carbon compliance cost.[25] OSEIA agreed with PGE's use of Synapse's forecasted carbon emission costs and OSEIA applied this value of carbon beginning in 2022 to the "burning of all fossil fuels to produce electricity" as that is how emissions policies operate in California and British Columbia. OSEIA assumed a single level of carbon emission based for all generators based on a marginal, natural gas unit that produced 117 lbs. of CO_2 per MMBtu at a heat rate of 7,500 Btu per kWh.

Q. Does Staff have any additional comments on this issue?

A. It is reasonable to anticipate that there will be a cost imposed on carbon emissions in Oregon. The cost of avoiding this cost can be included in RVOS at that time. Because the value of the element will

---

[24] Order No. 17-357 at 13.
[25] OSEIA/100, Beach.

depend on any legislation imposing a cost on carbon emissions, it is not clear there is much benefit from investigating possible methods of valuing avoided environmental compliance. Accordingly, Staff has no additional comments regarding the environmental compliance element.

Hedge Value

Q. Did any party suggest improvements for the hedge value component of RVOS?

A. While Renewable NW, CUB, and ODOE did not suggest changes from E3's recommended five percent value, OSEIA recommended the use of a different methodology.

Q. Did OSEIA propose an alternate methodology for determining the hedge value input?

A. No. Rather, OSEIA's comments highlight two studies that propose different methodologies for calculating the hedge value component of RVOS. The first, a 2013 study by Xcel Energy for the Colorado Public Utilities Commission, used gas options to calculate the hedge value of solar to be $6.60 per MWh.[26] The second, a 2015 study by Clean Power Research for the Maine Public Utilities Commission, estimated

---

[26] See pg. 43: http://www.eei.org/issuesandpolicy/generation/NetMetering/Documents/Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System Xcel Energy.pdf

the difference in returns between the weighted average cost of capital and risk-free investments.

Q. What avoided hedge value estimates did this method produce?

A. Estimated values (in $/MWh) for each IOU are listed below.

Table X: Actual vs proposed AHV ($2018/MWh, levelized)

	E3	OSEIA
PAC	1.21	18.14
PGE	1.25	22.75
IPC	1.49	20.69

Q. Please explain the methodology used in the two studies referenced by OSEIA.

A. To estimate the hedge value (which they call avoided fuel price uncertainty), the studies' authors assume a fuel escalation price going forward.[27] They then estimate two scenarios: one where a utility puts into a riskless asset money for fuel for a period 25 years multiplied by those future assumed fuel prices,[28] and one where the utility earns their weighted average cost of capital (WACC) on that money instead. The difference between those is then called the avoided fuel price uncertainty.

Q. Is this a hedge?

[27] Also here: OSEIA/100, Beach/33.
[28] US Treasury Bills, often assumed to be the least-risky asset available, as they are backed by the US government. For now. Buy gold.

A. No. By assuming future price movements, this analysis does not model behavior that protects the utility against future volatility, If in the first scenario the price of natural gas increases say 10 years from now, the utility would still be forced to pay those increased costs, even though they've set aside some 'fixed' amount to pay for fuel costs. An actual hedge would protect against volatility by locking in prices today, over the time of the contract. This is of course a gamble: when those actual prices spike, it is in hindsight viewed as smart (as actual costs paid would be lower), if prices decrease it is viewed less favorably. Either way, an important component of the hedge contract is the transfer of risk from the utility to the intermediary, which is entirely missing from this analysis. The Xcel study cited by OSEIA relies on a similar methodology, justifying its approach by citing two Clean Power Research reports.[29] One of these reports states:

> One area to improve this analysis is to obtain a single natural gas price forecast that is based on an actual contract that AE could obtain in the market today for a 30-year fixed price contract from an entity with very low default risk rather than using a natural gas price forecast.[30]

Q. Do contracts like this exist?

A. No.

---

[29] See pg. 96: http://www.eei.org/issuesandpolicy/generation/NetMetering/Documents/Costs and Benefits of Distributed Solar Generation on the Public Service Company of Colorado System Xcel Energy.pdf

[30] See pg. 35: https://www.cleanpower.com/wp-content/uploads/034_PV_ValueReportAustinEnergy.pdf

Q. Why not?

A. There aren't two willing parties. No one *wants* risk; parties are only willing to accept more risk when they receive sufficient compensation. The cost required to incentivize anyone to offer 30-year hedges of (historically volatile) natural gas would be exceptional, quite sufficiently high to drive any potential buyers away. Storage might be considered as an exception, but is limited to LDCs.

Q. Why then did the studies use this method of estimating hedge value?

A. Similar to E3's five percent value, this method is only meant as a proxy value for the true hedge value associated with solar generation.

Q. Is this method driven by its assumptions?

A. Yes, these studies rely on a fixed price path going forward for natural gas. While long-term natural gas price forecasts are created with the best information available at the time, they are mere guesses, and should be accompanied by wide error bars. The particular estimates produced by the study are valid *only if prices follow that particular path*.

Q. Is this problematic?

A. Yes. The point of this RVOS exercise is to empirically estimate the appropriate value for compensating solar generation in order to develop it as part of the least-cost, least-risk portfolio. Relying on long-term natural gas forecasts adds risk to ratepayers. If prices are lower than forecasted, than the utility will over-pay, and vice versa.

Q. Have long-term natural gas price forecasts ever significantly differed from the realized values?

A. One need only review a forecast from the mid-2000s to see how poorly forecasts can perform.

Q. What does Staff propose instead for the hedge value element?

A. Given the limitations described above, Staff feels that the originally proposed methodology (provided by E3) is the most appropriate. That method provides a proxy to the true costs that are avoided by the region's IOUs, calculated (at five percent of the energy value) according to the best information available. Staff believes the costs associated with determining a more accurate value more in line with specific utility strategies and/or closer to actual avoided costs likely outweigh the benefit, and therefore this proxy value of five percent is appropriate for today's analysis.

Market Price Response (MPR)

Q. Did any party comment on the market price response (MPR) component of RVOS?

A. Renewable NW, CUB, and ODOE did not make any substantive comment on the MPR value. OSEIA testified that PGE's methodology was reasonable and that a value of 3.8 percent of the avoided energy cost should be applied to each IOU.

Q. How do those values compare to those proposed by the IOUs?

A. OSEIA's recommended values are compared to the proposed IOU values displayed below.

Table X: Actual vs proposed MPR values ($2018/MWh, levelized)

	IOU Proposed	OSEIA's Recommendation	Total IOU Proposed RVOS
PGE	1.81	1.00	49.88
IPC	0	1.06	1.61
PAC	0	1.05	42.92

Q. From where does the 3.8 percent come?

A. The 3.8 percent represents the share of the market price effect relative to the total energy price (both levelized). In PGE's originally submitted workbook, this value was estimated to be 6.9 percent. The reduction comes from OSEIA's proposed updates in modeling.[31] OSEIA cites a 2015 study that estimated the same percent change (labeled demand reduction induced price effects) of ~4 percent.[32]

[31] Proposed changes include: Setting administrative costs equal to PAC's real levelized value, using PAC's uncapped EIM shape, reducing the resource balance year by three years to 2018, using a Portland PV profile from PV Watts instead of PGE's profile, assuming 100 percent marginal losses using the 1.5 RAP Adjustment, using LOLP X CF as the generation capacity contribution rather than 15.3 percent ELCC, setting the distribution PCAF equal to 19.2 percent, and setting the distribution of avoided cost to 65.73 $/kW-yr. Note the results may not be sensitive to each of these individual changes.

[32] https://www9.nationalgridus.com/non_html/eer/ne/AESC2015%20merged%20report.pdf

Q. Did PacifiCorp and Idaho Power present comparable MPR values?

A. No. PacifiCorp presented an outboard model adjustment, reducing their energy element, and providing little clarity on their method. Idaho Power declared their current solar capacity too small to make an impact on actual wholesale prices. Neither provided the difference in utility purchases or calculated market price effects.

Q. Should OSEIA's method be applied to PGE?

A. Staff is unsure whether the MPR value from the New England region is applicable to the NW. Given that PGE's MPR value was transparently calculated through using E3's methodology, Staff does not see the need for improvement. Staff is investigating this matter further.

Q. Should OSEIA's method be applied to PacifiCorp and Idaho Power?

A. It would certainly be an improvement from the two company's proposals, though again Staff would prefer using a consistent methodology across utilities.

RVOS METHODOLOGY-OTHER ISSUES

Inflation Rate

Q. Did intervenors address other RVOS Methodology issues?

A. Yes. CUB recommends that each utility use the Federal Reserve medium-term inflation rate, currently two percent, as opposed to an inflation rate taken from each utility's IRP.[33]

Q. Does Staff agree with CUB's proposal?

A. Staff disagrees that the Commission should direct utilities to use an inflation rate assumption that differs from those used in IRPs. IRPs receive extensive vetting by Staff and stakeholders, and the use of the IRP for sources of various RVOS elements is reasonable.

<u>PDDRR Methodology</u>

Q. Are there other Methodology issues raised by intervenors?

A. Yes. Renewable NW opposes PacifiCorp's proposal to use its Partial Displacement Differential Revenue Requirement ("PDDRR") methodology.

Q. Does Staff agree with Renewable NW's position?

A. Yes. Staff believes that it is not timely to consider a different methodology that varies from the still-evolving RVOS Methodology.

<u>Real levelized vs. nominal levelized</u>

Q. What was Staff's recommendation in opening testimony regarding the reporting of utility RVOS values?

A. In opening testimony, Staff suggested that the utilities should report both real levelized and nominal levelized values in order to provide

[33] CUB/100, Gehrke/7.

more insight and transparency to stakeholders.[34] Staff also expressed interest in discussions of this and related topics to explore various options for representing the values for RVOS over a period of years.

Q. Is this still Staff's position?

A. Yes, Staff continues to support the reporting of RVOS results in both real levelized and nominal levelized values.

Forward market price curves

Q. What is Staff's concern regarding use of forward market price curves?

A. Staff is concerned that there may be confusion regarding the "vintage" of forward prices in RVOS. Staff believes that the utilities should use the same source of forward price curves that is used for their standard avoided cost prices, but not same vintage as those used for standard avoided cost prices unless the timing of the RVOS filing is close in time to the utility's filing of avoided costs.

Q. What does Staff recommend?

A. Staff recommends that the Commission clarify that the Phase I Methodology only requires the same source of forward market prices as is use for standard avoided cost prices and that the Commission expects utilities to use the most recent forward market price curve available at the time the RVOS filing is prepared.

---

[34] Staff/200, Andrus/16.

RECOMMENDATIONS

Q. Have you previously provided testimony in these dockets?

A. Yes. I submitted Staff Exhibits 100 and 200 in each of the three dockets (Nos. UM 1910-12). I presented recommendations regarding modifications to the utilities' methods of complying with Order No. 17-357 and regarding the RVOS Methodology. None of these recommendations have changed so I will not repeat them here.

Q. What process does Staff recommend for further review of and updates to the RVOS Methodology currently in place?

Q. What process does Staff recommend for further refinements and updates to the RVOS Methodology currently in place?

A. The Commission has directed Staff to conduct issue-specific workshops (i.e. for valuing incremental capacity and location-specific T&D). Staff proposes convening additional workshops to address the Methodology issues described above. Staff does not think it is necessary for these dockets (UM 1910-12) to be concluded before these workshops begin and plans on scheduling them soon.

Q. Will these workshops lead to a docket to change the Methodology.

A. Staff may seek to open a docket to modify the Methodology. In any event, Staff believes the Methodology should be subject to periodic review.

Q. Does this conclude your testimony?

A. Yes.