Docket No. UM 1910

Witness: Michael O’Brien

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1910

RENEWABLE NORTHWEST’S EXHIBIT 100

Opening Testimony of Michael O’Brien

March 16, 2018

INTRODUCTION

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

A. Michael O'Brien, Research Director at Renewable Northwest. My business address is 421 SW 6th Avenue, Suite 975, Portland, OR 97204–1625.

Q. On whose behalf are you testifying?

A. This testimony is on behalf of Renewable Northwest.

Q. Mr. O'Brien, please describe your educational background and work experience.

A. I hold a Ph.D. in Physics from the University of Birmingham, in the United Kingdom, which included an MSc in the Physics and Technology of Nuclear Reactors. I also hold a BSc(Hons) in Physics from the University of Birmingham. After post-doctoral research with the United Kingdom Atomic Energy Authority, I completed an MPhil in Technology Policy at the University of Cambridge. Following Cambridge I worked for the UK Parliamentary Office of Science and Technology as Energy Advisor, and then for the House of Commons Energy and Climate Change Select Committee as Committee Specialist. I have been working at Renewable Northwest since I moved to the United States in June 2012.

Q. What is the purpose of your opening testimony?

A. We appreciate the opportunity to testify to the Oregon Public Utility Commission ("the Commission") in response to Direct Testimonies contained within the Resource Value of Solar ("RVOS") Filing of PacifiCorp, in compliance with Commission Order No. 17-357, filed November 30, 2017.

Q. Would you please summarize your testimony?

A. Yes. First I discuss PacifiCorp's RVOS methodology generally and conclude that any estimate of the RVOS that is applied outside of this proceeding should use inputs from the latest acknowledged IRP. I also conclude that estimating the RVOS using methods that PacifiCorp relies on for its non-standard PURPA rates is not reasonable or appropriate. I then summarize the Commission's direction as well as the utility's methods for each element of PacifiCorp's RVOS estimate. With respect to the elements Energy, Generation Capacity, and RPS Compliance, I identify concerns that may result in an RVOS estimate that undervalues the RVOS. For Energy, I question how informative EIM pricing is in the context of estimating the RVOS. For Generation Capacity, I reiterate the importance of estimating this element with inputs from the latest acknowledged IRP before the RVOS is applied outside of this proceeding. Similarly, for RPS Compliance, I highlight the importance of determining a methodology and including a value for this element before the RVOS is useful.

Finally, I show that the RVOS values proposed by PacifiCorp, Idaho Power Company, and PGE are lower than one would expect based on available research.

GENERAL COMMENTS ON PACIFICORP'S RVOS ESTIMATE

Q. Did PacifiCorp provide a summary of its RVOS values by element?

A. Yes. PacifiCorp presented a summary of the RVOS values that it included in its filing in Table 1.

Element	Standard: 2015 IRP	PDDRR: 2017 IRP
Avoided energy cost	30.58	33.63
Avoided generation capacity cost	12.20	17.96
Avoided transmission and distribution capacity	0.08	0.08
Avoided line losses	1.96	2.14
Administration	(2.88)	(2.88)
Integration	(0.82)	(0.82)
Market price response	0.15	0.00
Avoided hedge value	1.54	1.68
Avoided environmental compliance	0.11	0.22
Avoided RPS compliance	0.00	0.00
Grid services	0.00	0.00
Total Resource Value of Solar	**42.92**	**52.00**

Table 1—RVOS Values by Element, $/MWh Nominal Levelized (2018–2042).[1]

Q. Did PacifiCorp present results beyond those required by the Commission?

A. Yes. PacifiCorp also included an RVOS value based on its Partial Displacement Differential Revenue Requirement ("PDDRR") methodology.[2] The Commission authorized PacifiCorp to include a PDDRR analysis but noted that it would "balance accuracy, transparency and accessibility in reviewing th[is] alternative approach[]."[3]

[1] PAC/100 MacNeil/3.
[2] *Id.*
[3] UM 1716, Order 17-357 at 6 (Sep. 15, 2017).

Q. Do you have any general comments about PacifiCorp's Table 1?

A. Yes. I would like to highlight that the values under "Standard" and "PDDRR" presented in Table 1 are not helpful for comparing the two methodologies because they rely on inputs from different IRPs.

Q. Do you have concerns regarding the inputs that PacifiCorp used for the RVOS estimates in its testimony?

Yes. As Table 1 shows, the Company used 2015 IRP inputs for the calculation of the RVOS that relies on the standard avoided cost rate methodology, as directed by the Commission. PacifiCorp's use of 2015 IRP inputs is understandable because the Company's 2017 IRP had not been acknowledged as of November 30, 2017, when the Company filed testimony in this docket. However, any RVOS estimate that may be used, for example, to determine the bill credit rate for community solar should rely on inputs from the latest acknowledged IRP. By the time that the RVOS is first applied, it will no longer appropriate for that RVOS to rely on 2015 IRP inputs.

Q. Does PacifiCorp propose to use the PDDRR methodology for the RVOS?

A. Yes. PacifiCorp proposes to use its PDDRR methodology in calculating the RVOS because the Company considers that it would lead to a "more up-to-date and accurate forecast of the value of solar."[4]

Q. Do you agree with the Company's proposal to use PDDRR for the RVOS?

A. No. Consistent with my reply testimony in UM 1716,[5] I do not consider use of PDDRR in calculating the RVOS reasonable or appropriate.

[4] PAC/100 MacNeil/3.
[5] UM 1716, RNW, OSEIA, NWEC, NW SEED/400/14-17.

The Commission has not found PDDRR appropriate for use in calculating rates for systems of the size that the RVOS will likely be applied to. At this time, we know two likely applications of the RVOS: 1) to aid in the calculation of a bill credit rate for community solar that "reflects the resource value of solar energy"[6]; and 2) to inform the investigation into the extent of cost-shifting, if any, from net metering.[7] Both of these applications involve solar systems ranging from a few kW up to 3MW.[8]

Q. What alternative to PDDRR do you consider appropriate for use in estimating the RVOS?

A. Consistent with the Commission's direction in UM 1716,[9] I consider it appropriate for the company to use the inputs and methodologies associated with its standard avoided cost rates. PacifiCorp currently uses PDDRR in calculating its non-standard avoided cost rates. Non-standard avoided cost rates apply to solar QFs above 3 MW.

The Commission has not determined that using PDDRR is appropriate for solar resources 3 MW or smaller. Yet, as I mentioned above, the RVOS will be used to address issues related to systems below that threshold. For that reason, I consider that estimating the RVOS relying on standard avoided cost rate methodologies is more reasonable and appropriate than using PDDRR.

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6 S.B. 1547 §22(6)(a).
7 Investigation 2 of UM 1716.
8 OAR 860-088-0070(1)(b).
9 Order 17-357 at 3.

Q. Do have any additional concerns with PacifiCorp's proposal to use the PDDRR for the RVOS?

Yes, as I indicated in my reply testimony in UM 1716,[10] it is unclear whether PacifiCorp's ability to use PDDRR for its non-standard avoided cost rates is settled. In fact, Staff suggested in UM 1802 that it may be appropriate for the Commission to require the Company to stop using PDDRR and revert to the its method to calculate non-standard avoided cost rates.[11] The Commission has not issued an order in that docket.

Q. How do PacifiCorp's RVOS values by element compare to Portland General Electric ("PGE") (UM 1912) and Idaho Power ("IPCo") (UM 1911)?

A. Figure 1 shows the RVOS values by element for PGE, PacifiCorp and IPCo.

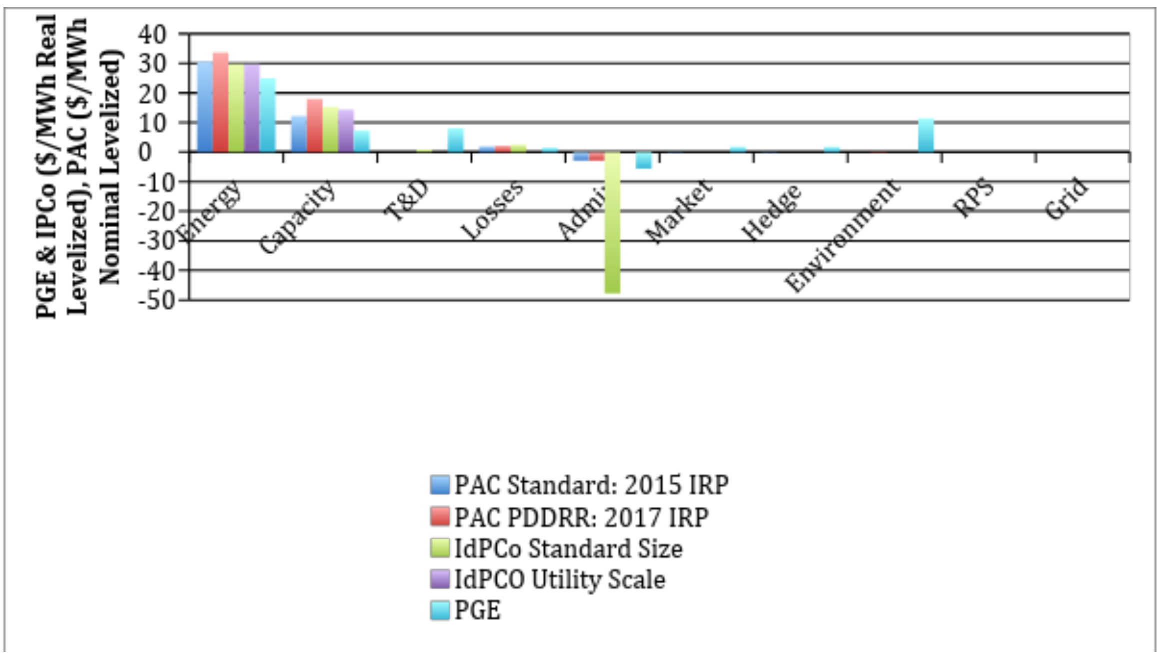

Figure 1—RVOS Values by Element for PGE, PAC, and IPCo.[12]

[10] UM 1716, RNW, OSEIA, NWEC, NW SEED/400/16.
[11] UM 1802, Staff/100 Andrus/17.
[12] PAC/100 MacNeil 3; UM 1911, Idaho Power/100 Haener/4; UM 1912, PGE/100 Goodspeed/7.

ELEMENT 1—ENERGY

Q. How did Commission Order No. 17-357 define Element 1—Energy?

A. The Commission defined Energy as "[t]he marginal avoided cost of procuring or producing energy, including fuel, O&M, pipeline costs and all other variable costs."[13]

Q. What inputs did Commission Order No. 17-357 require the utilities to use in calculating Element 1—Energy?

A. The Commission required utilities to "produce a 12 x 24 block for energy prices and include a detailed explanation of how they created the block."[14] The Commission also required utilities to "demonstrate through statistical analysis that their energy values are scaled to represent the average price under a range of hydro conditions."[15]

Q. How did PacifiCorp propose to create a 12x24 hourly price shape?

A. PacifiCorp proposed to create a 12x24 hourly price shape using "15-minute [Energy Imbalance Market ("EIM")] market prices for the … 12 months ending September 2017."[16]

Q. Do you have any concerns with PacifiCorp's use of EIM pricing data in creating the 12x24 hourly price shape?

A. Yes. I question how informative pricing data from a 5-15 minute spot energy market may be in creating the 12x24 hourly price shape that could be used for the valuation of a long-term firm resource.

[13] Order No. 17-357 at 21.
[14] *Id*.
[15] *Id*.
[16] PAC/100 MacNeil/12–13.

Q. How did PacifiCorp value for Element 1—Energy compare with the value calculated by PGE and IPCo?

A. PacifiCorp calculated a nominal levelized (2018-2042) value of 30.58 \$/MWh using the standard methodology, and 33.63 \$/MWh using the PDDRR methodology .[17] PGE calculated a real levelized value for Element 1—Energy of 24.98 \$(2017)/MWh.[18] IPCo calculated a real levelized value for standard size and utility scale size projects of 29.74 \$/MWh.[19]

Q. Do you have anything else to say about PacifiCorp's value for Element 1—Energy.

A. Not at this time.

[17] *Id*. at 3.
[18] UM 1912, PGE/100 Goodspeed/7.
[19] UM 1911, Idaho Power/100/Haener/4

ELEMENT 2—GENERATION CAPACITY

Q. How did Commission Order No. 17-357 define Element 2—Generation Capacity?

A. The Commission defined Generation Capacity as "[t]he marginal avoided cost of building and maintain the lowest net cost generation capacity resource."[20]

Q. What inputs did Commission Order No. 17-357 require the utilities to use in calculating Element 2—Generation Capacity?

A. The Commission directed utilities to "determine the capacity value consistent with the Commission's standard nonrenewable QF avoided cost guidelines. When the utility is resource sufficient, the value is based on the market energy price. When the utility is resource deficient, the value is based on the contribution to peak of solar PV, multiplied by the cost of a utility's avoided proxy resource."[21]

Q. What were the next steps for Element 2—Generation Capacity outlined in Commission Order No. 17-357?

A. In addition to requiring the utilities to propose a value for this element, the Commission directed Staff to "convene a workshop to explore options for valuing capacity additions incrementally."[22]

Q. How did PacifiCorp determine whether a solar resource contributed to capacity?

A. PacifiCorp stated that a "[…] solar resource would receive a capacity contribution based on its expected output during those hours with LOLP greater than zero."[23]

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[20] Order No. 17-357 at 21.
[21] *Id*.
[22] *Id*.
[23] PAC/100 McNeil/21.

Q. How did PacifiCorp apply that understanding of capacity contribution to the determination of Element 2—Generation Capacity?

A. PacifiCorp stated that "[t]he generation profile of the indicative RVOS resource discussed previously has an effective capacity contribution of 26.1 percent, which equates to a capacity payment of $23/MWh starting in 2028, or a 25-year levelized value of $12/MWh."[24]

Q. Do you have any concerns with the accuracy of PacifiCorp's value of Element 2—Generation Capacity?

A. Yes. As I mentioned in my introduction, PacifiCorp uses 2015 IRP inputs to calculate the value of this and other elements of the RVOS. I understand the Company's decision to do so given the timeline for acknowledgement for its 2017 IRP. However, an RVOS estimate should reflect the latest acknowledged IRP before being applied to any program or before informing any policy decisions.

Q. In ordering the utilities to calculate Element 2—Generation Capacity, the Commission directed utilities to use the "last acknowledged IRP resource-balance year, and then remove new incremental expected distributed solar from that forecast, and then if applicable, provide an adjusted deficiency date."[25] How did PacifiCorp follow this order?

A. PacifiCorp "[…] started with the 2028 resource-balance year from the 2015 IRP, and then removed the new incremental expected distributed solar photovoltaic (PV) from the forecast. The incremental Oregon distributed generation delivered during the time of system peak in the 2015 IRP load forecast is equivalent to

[24] *Id*.
[25] Order No. 17-357 at 8.

approximately 13 megawatt (MW) of nameplate solar resource, with a capacity contribution of approximately four MW. In addition to a thermal resource, the 2015 IRP preferred portfolio calls for over 400 MW more front-office transactions (FOTs) in 2028 than 2027, so the remaining FOTs available in 2027 are well in excess of the incremental four MW of capacity contribution from Oregon distributed generation. As a result, distributed generation would not be sufficient to change the resource deficiency date established in the 2015 IRP."[26]

Q. How does PacifiCorp's value for Element 2—Generation Capacity compare with the value calculated by PGE and IPCo?

A. PacifiCorp calculated a nominal levelized (2018-2042) value of 12.20 $/MWh using the standard methodology, and 17.96 $/MWh using the PDDRR methodology.[27] PGE calculated a real levelized value for Element 2—Generation Capacity of 7.30 $(2017)/MWh.[28] IPCo calculated a real levelized value for standard size of 15.30 $/MWh and 14. 34 $/MWh for utility scale size projects.[29]

Q. Do you have anything else to say about PacifiCorp's value for Element 2—Generation Capacity.

A. Not at this time.

[26] PAC/100 MacNeil/22.
[27] *Id*. at 3.
[28] UM 1912, PGE/100 Goodspeed/7.
[29] UM 1911, Idaho Power/100 Haener/4.

ELEMENT 3—TRANSMISSION AND DISTRIBUTION CAPACITY

Q. How did Commission Order No. 17-357 define Element 3—Transmission And Distribution Capacity?

A. The Commission defined Transmission and Distribution Capacity as the "[a]voided or deferred cost of expanding, replacing, or upgrading transmission and distribution (T&D) infrastructure."[30]

Q. What inputs did Commission Order No. 17-357 require the utilities to use in calculating Element 3—T&D Capacity?

A. The Commission required utilities to "develop a system-wide average of the avoided or deferred costs of expanding, replacing, or upgrading T&D infrastructure attributable to incremental solar penetration in Oregon service areas."[31]

Q. What were the next steps for Element 3—T&D Capacity outlined in Commission Order No. 17-357?

A. In addition to requiring that the utilities propose values for this element, the Commission asked them to comment on "how their distribution planning could advance the granularity of this element."[32]

Q. Did PacifiCorp assume that solar is capable of deferring transmission upgrades?

A. No. PacifiCorp states that "based on solar generation profiles and reliability concerns, solar resources are assumed not to be capable of deferring transmission capacity upgrades."[33]

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[30] Order No. 17-357 at 21.
[31] *Id*.
[32] *Id*.

Q. Did PacifiCorp assume solar is capable of deferring distribution upgrades?

A. Yes. PacifiCorp stated that "[t]he amount of distribution capacity assumed to be deferred is based on the year and amount of distribution upgrade capacity needs in Oregon for which solar is a viable alternative, the hours with the highest distribution system loading for the viable projects, and the capacity factor of the proposed solar resource in those hours."[34]

Q. What value did PacifiCorp determine for Element 3—T&D Deferral?

A. PacifiCorp determined "a nominal levelized benefit of $0.08/MWh."[35] The Company found some variation. For example, "if the indicative solar resource was located solely in the area where solar was a viable distribution upgrade alternative, the value would increase to $2.28/MWh, with 10 MW of solar nameplate deferring 1.5 MW of distribution upgrade capacity. The value for peak-oriented or west-facing solar resources would be even higher, as these resources have more output during peak distribution loading and lower overall capacity factors."[36]

Q. How did PacifiCorp's value for Element 3—T&D Capacity compare with the value calculated by PGE and IPCo?

A. PacifiCorp calculated a nominal levelized (2018-2042) value of 0.08 $/MWh using the standard methodology and the PDDRR methodology.[37] PGE calculated a real levelized value for Element 3—T&D Capacity of 8.08 $(2017)/MWh.[38]

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[33] PAC/100 McNeil/23.
[34] *Id*.
[35] *Id*. at 24.
[36] *Id*.
[37] *Id*. at 3.
[38] UM 1912, PGE/100 Goodspeed/7.

IPCo calculated a real levelized value for standard size of 0.87 \$/MWh and 0.00 \$/MWh for utility scale size projects.[39]

Q. Do you have anything else to say about PacifiCorp's value for Element 3—T&D Capacity.

A. Not at this time.

[39] UM 1911, Idaho Power/100 Haener/4.

ELEMENT 4—LINE LOSSES

Q. How did Commission Order No. 17-357 define Element 4—Line Losses?

A. The Commission defined Line Losses as the "[a]voided marginal electricity losses."[40]

Q. What inputs did Commission Order No. 17-357 require the utilities to use in calculating Element 4—Line Losses?

A. The Commission required that utilities "develop hourly averages of avoided marginal line losses attributable to increased penetration of solar PV systems in Oregon service areas. The incremental line loss estimates shall reflect the hours solar PV systems are generating electricity."[41]

Q. How did PacifiCorp incorporate the effects of lines losses in Element 1—Energy?

A. PacifiCorp stated that "[s]ince the avoided energy value is reported without losses, the energy value for the incremental output associated with losses is reported in the value for the avoided line losses element".[42]

Q. How did PacifiCorp incorporate the effects of lines losses in Element 2—Generation Capacity?

A. PacifiCorp stated that after accounting for avoided lines losses, "[…] the RVOS resources' effective output is higher—and this higher output is used to determine the avoided generation capacity."[43]

[40] Order No. 17-357 at 22.
[41] *Id*.
[42] PAC/100/MacNeil/26.
[43] *Id*.

Q. How did PacifiCorp's value for Element 4—Line Losses compare with the value calculated by PGE and IPCo?

A. PacifiCorp calculated a nominal levelized (2018-2042) value of 1.96 $/MWh using the standard methodology and 2.14 $/MWh using the PDDRR methodology.[44] PGE calculated a real levelized value for Element 4—Line Losses of 1.48 $(2017)/MWh.[45] IPCo calculated a real levelized value for standard size of 2.54$/MWh and 0.00 $/MWh for utility scale size projects.[46]

Q. Do you have anything else to say about PacifiCorp's value for Element 4—Line Losses.

A. Not at this time.

[44] *Id*. at 3.
[45] UM 1912, PGE/100 Goodspeed/7.
[46] UM 1911, Idaho Power/100 Haener/4.

ELEMENT 5—ADMINISTRATION

Q. How did Commission Order No. 17-357 define Element 5—Administration?

A. The Commission defined Administration as the "[i]ncreased utility costs of administering solar PV programs."[47]

Q. What inputs did Commission Order No. 17-357 require the utilities to use in calculating Element 5—Administration?

A. The Commission required the utilities to "develop estimates of the direct, incremental costs of administering solar PV programs including staff, software, incremental distribution investments, and other utility costs."[48]

Q. What components did PacifiCorp include in the determination of Element 5—Administration?

A. PacifiCorp included three elements in the determination of administrative costs for inclusion in the RVOS: "(1) the incremental uncovered administrative and engineering costs associated with processing customer requests to participate as an RVOS resource; (2) the ongoing administration costs for customer service and billing of net metering customers that exceed the costs to provide those services to traditional customers; and (3) incremental distribution investments required to facilitate the interconnection of distributed generation but are unrecovered from the interconnecting customer."[49]

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[47] Order No. 17-357 at 22.
[48] *Id*.
[49] PAC/100 MacNeil/27-28.

Q. How did PacifiCorp determine uncovered administration and engineering costs?

A. PacifiCorp stated that it used "a similar methodology for administration costs as that used for its net metering program in Utah."[50] PacifiCorp explained that it has a dedicated department for customer generation resources and that "the overall expense of this department for 2016 was multiplied by the proportion of total capacity installed in 2016 in the Oregon net metering program. This amount was then reduced by the application fees received by certain net metering participants. This amount was then divided by the total interconnected capacity, which results in a one-time cost of $7.95 per installed kW."[51] PacifiCorp's statements seem to suggest that the application fees do not fully cover costs.

PacifiCorp also "estimated costs from the billing and customer service departments related to initial setup and interconnection requirements. This captures the costs of net metering specific customer calls, the processing of meter exchanges and transitioning customers to modified net metering billing [...] the total costs from 2016 were divided by the total interconnected capacity to establish a cost of $1.48 per installed kW."[52]

Q. How did PacifiCorp determine engineering review time and cost?

A. PacifiCorp stated that "[t]he cost of the average net metering application review is estimated at $32.10 per application [...] an engineering review cost per kW of $2.78."[53]

[50] *Id*. at 28.
[51] *Id*.
[52] *Id*. at 28-29.
[53] *Id*. at 29.

Q. What was PacifiCorp's combined cost for uncovered customer generation department administration, estimated billing and customer service department initial costs, and engineering review time costs?

A. These cost were combined by PacifiCorp to provide an incremental upfront administration cost of $12.21 per installed kW.[54]

Q. How did PacifiCorp determine ongoing administration costs?

A. PacifiCorp stated that ongoing administration costs "related to the additional administration and billing support required to facilitate net metering participation [...] manual reviewing of net metering bills, tracking of excess generation credits from month to month and manually computing aggregated billing [...] are attributable to all currently existing private generation."[55] PacifiCorp determined that this "produc[ed] an annual billing support fee of $1.61 per kW."[56]

Q. How did PacifiCorp determine incremental distribution investment?

A. PacifiCorp "established a specific amount that captures system upgrades and other capital expenditures that can be directly attributed to net metering installations. These are costs related to transformer upgrades, recloser modifications, and metering costs necessary to facilitate customer generation projects [...] a one-time cost of $16.53 per installed kW."[57]

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[54] *Id*.
[55] *Id*.
[56] *Id*. at 30.
[57] *Id*.

Q. What did all these administration costs come to?

A. PacifiCorp states that they determined Element 5—Administration "yields a 25 year levelized administration cost of $2.88/MWh for the indicative RVOS resource."[58]

Q. How did PacifiCorp's value for Element 5—Administration compare with the value calculated by PacifiCorp and IPCo?

A. PacifiCorp calculated a nominal levelized (2018-2042) value of -2.88 $/MWh using the standard methodology and the PDDRR methodology .[59] PGE calculated a real levelized value for Element 5—Administration of -5.58 $(2017)/MWh.[60] IPCo calculated a real levelized value for standard size of -47.77$/MWh and 0.00 $/MWh for utility scale size projects.[61]

Q. Do you have anything else to say about PacifiCorp's value for Element 5—Administration?

A. Not at this time.

[58] *Id*. at 31.
[59] *Id*. at 3.
[60] UM 1912, PGE/100 Goodspeed/7.
[61] UM 1911, Idaho Power/100/Haener/4

ELEMENT 6—INTEGRATION

Q. How did Commission Order No. 17-357 define Element 6—Integration?

A. The Commission defined Integration as "[t]he costs of a utility holding additional reserves in order to accommodate unforeseen fluctuations in system net loads due to addition of renewable resources."[62]

Q. What inputs did Commission Order No. 17-357 require the utilities to use in calculating Element 6—Integration?

A. The Commission required the utilities to "make estimates of integration costs based on acknowledged integration studies."[63]

Q. How did PacifiCorp determine the value for Element 6—Integration?

A. PacifiCorp stated that it does not have an acknowledged solar integration study, but "a Flexible Reserve Study that included solar integration costs was prepared as part of the 2017 IRP" which calculated solar integration costs of $0.60/MWh (2016$) escalating at inflation.[64]

Q. How did PacifiCorp's value for Element 6—Integration compare with the values calculated by PGE and IPCo?

A. PacifiCorp calculated a nominal levelized (2018-2042) value of -0.82 $/MWh using the standard methodology and the PDDRR methodology.[65] PGE calculated a real levelized value for Element 6—Integration of -0.83$(2017)/MWh.[66] IPCo

[62] Order No. 17-357 at 22.
[63] *Id*.
[64] PAC/100 MacNeil/31.
[65] *Id*. at 3.
[66] UM 1912, PGE/100 Goodspeed/7.

calculated a real levelized value of -0.56$/MWh for standard size and utility scale size projects.[67]

Q. Do you have anything else to say about PAC's value for Element 6—Integration?

A. Not at this time.

[67] UM 1911, Idaho Power/100 Haener/4.

ELEMENT 7—MARKET PRICE RESPONSE

Q. How did Commission Order No. 17-357 define Element 7—Market Price Response?

A. The Commission defined Market Price Response as "[t]he change in utility costs due to lower wholesale energy market prices caused by increased solar PV production."[68]

Q. What inputs did Commission Order No. 17-357 require the utilities to use in calculating Element 7—Market Price Response?

A. The Commission required its Staff "to coordinate or facilitate use of E3's model to create a proxy value for market price response that utilities will use in their initial RVOS filings."[69]

Q. Did Staff facilitate use of E3's model to create a proxy value for market price response?

A. Yes. Staff (Mark Bassett) reached out to E3 (Arne Olsen) and asked if "[…] the $3 per MWh sample proxy value found in the E3 model is accurate[?]"[70] E3 replied:

> "The $3/MWh is a made-up number just put in as an example and shouldn't be used as a proxy. There are two ways that a better number could be calculated:
>
> 1. I've been involved in several studies of the impact of wind & solar generation on market prices in the West. See the attached papers. There are others out there as well. The papers estimate a market price elasticity of -0.001 to -0.002 for each MWh

[68] Order No. 17-357 at 22.
[69] *Id*.
[70] Staff (Mark Bassett) email to RVOS Stakeholders, November 7, 2017.

> of renewable energy. The elasticity is measured separately for Heavy Load Hours and Light Load Hours.
>
> 2. The utilities could do sequential runs in a production simulation model, e.g., Aurora, with a significant enough increment of solar added to affect the calculated market price during each hour. The price differences could be used to derive a market price elasticity per MWh of energy produced from customer owned solar resources. This would have the advantage that it could be used to derive granular values for various time periods, however real markets often behave differently from what production simulation models would imply."
>
> In either case, as you noted, the change in market price would be multiplied by the utility's net short or long position during each hour, so this would be a benefit if the utility is short and a cost if the utility is long."

Q. How did PacifiCorp determine the value for Element 7—Market Price Response?

A. PacifiCorp stated that "Staff's coordination resulted in the suggestion for utilities to perform sequential runs in a production simulation model, with a significant enough increment of solar added to affect the calculated market price, and using these price differences to derive a market price elasticity per MWh produced from solar resources."[71] PacifiCorp added that "[i]n the absence of a specific estimate of the market price response associated with incremental solar, the response measured for incremental hydro resources is a reasonable proxy."[72]

[71] PAC/100 MacNeil/33.
[72] *Id*.

Q. What expected solar resource addition did PacifiCorp use to determine Element 7—Market Price Response?

A. PacifiCorp "calculated the direct market price response based on the expected distributed solar resource additions in Oregon between 2018 and 2036 in the 2017 IRP, a total of 150 MW."[73] "Since March 2017, PacifiCorp stated that it "has executed contracts for approximately 150 MW of new solar resources, equivalent to what is considered in the RVOS analysis."[74]

PacifiCorp added that "[f]rom 2018 through 2027, the market price response element results in an increase to avoided energy costs by $0.21/MWh. During the deficiency period, the solar resource has avoided energy costs based on a CCCT resource so there is no net change in PacifiCorp's market position and thus no market price response."[75]

Q. How did PacifiCorp's value for Element 7—Market Price Response compare with the value calculated by PGE and IPCo?

A. PacifiCorp calculated a nominal levelized (2018-2042) value of 0.15 $/MWh using the standard methodology and 0.00 $/MWh using the PDDRR methodology.[76] PGE calculated a real levelized value for Element 7—Market Price Response of 1.81$(2017)/MWh.[77] IPCo calculated a real levelized value of 0.00$/MWh for standard size and utility scale size projects.[78]

[73] *Id*. at 34.
[74] *Id*.
[75] *Id*.
[76] *Id*. at 3.
[77] UM 1912, PGE/100 Goodspeed/7.
[78] UM 1911, Idaho Power/100 Haener/4.

Q. Do you have anything else to say about PacifiCorp's value for Element 7—Market Price Response?

A. Not at this time.

ELEMENT 8—HEDGE VALUE

Q. How did Commission Order No. 17-357 define Element 8—Hedge Value?

A. The Commission defined Hedge Value as the "[a]voided cost of utility hedging activities, *i.e.*, transactions intended solely to provide a more stable retail rate over time."[79]

Q. What inputs did Commission Order No. 17-357 require the utilities to use in calculating Element 8—Hedge Value?

A. The Commission required the utilities "to assign a proxy value of 5 percent of energy."[80]

Q. What was PacifiCorp's opinion about using a proxy value of 5 percent energy to calculate Element 8—Hedge Value?

A. PacifiCorp stated that "[…] this value is arbitrary and unrelated to either PacifiCorp's hedging policies or the composition of its resource portfolio and obligations."[81]

Q. How did PacifiCorp's value for Element 8—Hedge Value compare with the values calculated by PGE and IPCo?

A. PacifiCorp calculated a nominal levelized (2018-2042) value of 1.54 $/MWh using the standard methodology and 1.68 $/MWh using the PDDRR methodology.[82] PGE calculated a real levelized value for Element 8—Hedge

[79] Order No. 17-357 at 22.
[80] *Id*.
[81] PAC/100 MacNeil/35.
[82] *Id*. at 3.

Value of 1.25 $(2017)/MWh.[83] IPCo calculated a real levelized value of 1.49 $/MWh for standard size and utility scale size projects.[84]

Q. Do you have anything else to say about PacifiCorp's value for Element 8—Hedge Value?

A. Not at this time.

[83] UM 1912, PGE/100 Goodspeed/7.
[84] UM 1911, Idaho Power/100 Haener/4.

ELEMENT 9—ENVIRONMENTAL COMPLIANCE

Q. How did Commission Order No. 17-357 define Element 9—Environmental Compliance?

A. The Commission defined Environmental Compliance as the "[a]voided cost of complying with existing and anticipated environmental standards."[85]

Q. What inputs did Commission Order No. 17-357 require the utilities to use in calculating Element 9—Environmental Compliance?

A. The Commission required the utilities to "estimate the avoided cost based on a reduction in carbon emissions from the marginal generating unit. To value future anticipated standards utilities should use the carbon regulation assumptions from their IRP."[86]

Q. How did PacifiCorps's determination of Element 9—Environmental Compliance relate to its 2017 IRP?

A. PacifiCorp's 2017 IRP included two primary environmental compliance scenarios: "Mass Cap A and Mass CapB, which were intended to incorporate constraints related to the Environmental Protection Agency Clean Power Plan (CPP). Under either Mass Cap A or Mass Cap B, PacifiCorp would have no environmental compliance costs associated with market transactions, so there are no avoided environmental compliance costs during the sufficiency period."[87]

[85] Order No. 17-357 at 23.
[86] *Id*.
[87] PAC/100 MacNeil/36.

Q. How does PacifiCorp's 2017 IRP treatment of Mass Cap A impact Element 9—Environmental Compliance?

A. PacifiCorp stated that, before 2028, "[u]nder Mass Cap A, a new CCCT such as the proxy plant used to set standard avoided costs would not be subject to emissions limits, so there would likewise be no avoided environmental compliance costs during the deficiency period."[88]

Q. How does PacifiCorp's 2017 IRP treatment of Mass Cap B impact Element 9—Environmental Compliance?

A. PacifiCorp described Mass Cap B as a fixed limit on emissions, "[…] including those from new resources, which is represented within the IRP modeling as shadow prices per ton of carbon dioxide emissions."[89] PacifiCorp added that "[s]tarting in 2029, coal retirements and renewable resource additions reduce emissions below the Mass Cap B threshold, so the shadow price for carbon dioxide drops to zero."[90] However, PacifiCorp stated that in 2028, "[a]fter accounting for the heat rate and emissions rate of the proxy plant, the shadow price for carbon dioxide emissions ... equates to a cost of $2.36 per MWh of output."[91]

Q. Did PacifiCorp develop an alternative calculation for determining Element 9—Environmental Compliance?

A. Yes. In addition to the standard avoided cost methodology approach, PacifiCorp also employed its PDDRR methodology, which it says "[…] identifies a range of

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[88] *Id.*
[89] *Id.*
[90] *Id.*
[91] *Id.*

avoided resources including coal and gas resources as well as market transactions. As a result, an RVOS resource *can impact emissions during the sufficiency period* [emphasis added]. During the deficiency period, rather than assuming a one-to-one relationship between RVOS resource output and the proxy resource, the PDDRR methodology accounts for the emissions of PacifiCorps entire portfolio and the generation profile of the proposed resource relative to the capacity equivalent output of a proxy resource from the preferred portfolio [...] The PDDRR methodology results in carbon dioxide emissions that exceed the Mass Cap B limit in 2024 and 2027, with avoided environmental compliance values of $2.09/MWh and $1.82/MWh, respectively, in those years." [92]

Q. How did PacifiCorp's value for Element 9—Environmental Compliance compare with the value calculated by PGE and IPCo?

A. PacifiCorp calculated a nominal levelized (2018-2042) value of 0.11 $/MWh using the standard methodology and 0.22 $/MWh using the PDDRR methodology.[93] PGE calculated a real levelized value for Element 9—Environmental Compliance of 11.41$(2017)/MWh.[94] IPCo calculated a real levelized value of 0.00 $/MWh for standard size and utility scale size projects.[95]

Q. Do you have anything else to say about PacifiCorp's value for Element 9—Environmental Compliance?

A. Not at this time.

[92] *Id*. at 37.
[93] *Id*. at 3.
[94] UM 1912, PGE/100 Goodspeed/7.
[95] UM 1911, Idaho Power/100 Haener/4.

ELEMENT 10—RPS COMPLIANCE

Q. How did Commission Order No. 17-357 define Element 10—RPS Compliance?

A. The Commission did not offer a definition of RPS Compliance, but instead said a definition was "[t]o be determined."[96]

Q. What inputs did Commission Order No. 17-357 require the utilities to use in calculating Element 10—RPS Compliance?

A. The Commission required the utilities to "use a value of zero in their initial Phase II filings."[97]

Q. Do you have any concerns regarding the current lack of a value for Element 10—RPS Compliance?

A. Yes. I am concerned about any potential application of an RVOS estimate that does not include a value for the element RPS Compliance. RPS Compliance was an element widely discussed during UM 1716. Mr. Arne Olson, who developed this RVOS methodology and testified in UM 1716 on behalf of Staff, indicated that a solar system provides an RPS Compliance value "if it reduces the utility's retail sales, e.g. through net energy metering."[98] The Commission did not adopt a definition of RPS Compliance in Order 17-357, instead signaling its intention to assign a methodology to that element before the end of this phase of the proceeding.[99]

[96] Order No. 17-357 at 23.
[97] *Id*.
[98] UM 1716, Staf/400 Olson/13.
[99] Order 17-357 at 2.

It is very important for the Commission to make that determination and for utilities to assign a value to RPS Compliance before an RVOS estimate is applied to other programs an before an RVOS estimate is useful to inform any policy considerations.

Q. Do you have anything else to say about PAC's value for Element 10—RPS Compliance?

A. Not at this time.

ELEMENT 11—GRID SERVICES

Q. How did Commission Order No. 17-357 define Element 11—Grid Services?

A. "The potential benefits of solar PV in advanced, uncommon applications and from utilities' increasing ability to capture the benefits of mass-market smart inverters."[100]

Q. What inputs did Commission Order No. 17-357 require from the utilities to calculate Element 11—Grid Services?

A. "The utilities shall use a value of zero for this element."[101]

Q. What were the next steps for Element 11—Grid Services outlined in Commission Order No. 17-357?

A. "To be evaluated based on future proposals."[102]

Q. Do you have anything else to say about PAC's value for Element 11—Grid Services?

A. Not at this time.

[100] Order No. 17-357 at 23.
[101] *Id*.
[102] *Id*.

CONCLUSION

Q. Do you have any concluding thoughts on PacifiCorp's RVOS proposal?

A. Yes. PacifiCorp bases its estimated RVOS on values for each element that appear to generally be significantly lower than one would expect based on existing research, resulting in what could be a depressed RVOS estimate. For example, Figure 2 compares the values of each RVOS element used by PacifiCorp (as well as Idaho Power Company and PGE) to the values of the same elements according to a meta-analysis performed by the Rocky Mountain Institute in 2013.[103] As a result, even where I have not noted specific disagreement with PacifiCorp's methodology, I retain some skepticism and respectfully suggest that the Commission take a hard look at PacifiCorp's proposal before approving a final RVOS estimate.

[103] Rocky Mountain Institute, "A Review of Solar PV Cost and Benefit Studies, 2nd Edition" (Sept. 2013), *available at* https://rmi.org/wp-content/uploads/2017/05/RMI_Document_Repository_Public-Reprts_eLab-DER-Benefit-Cost-Deck_2nd_Edition131015.pdf. The values included in Figure 2 above were derived from the range of values included in the Rocky Mountain Institute report for each element of the RVOS calculation.

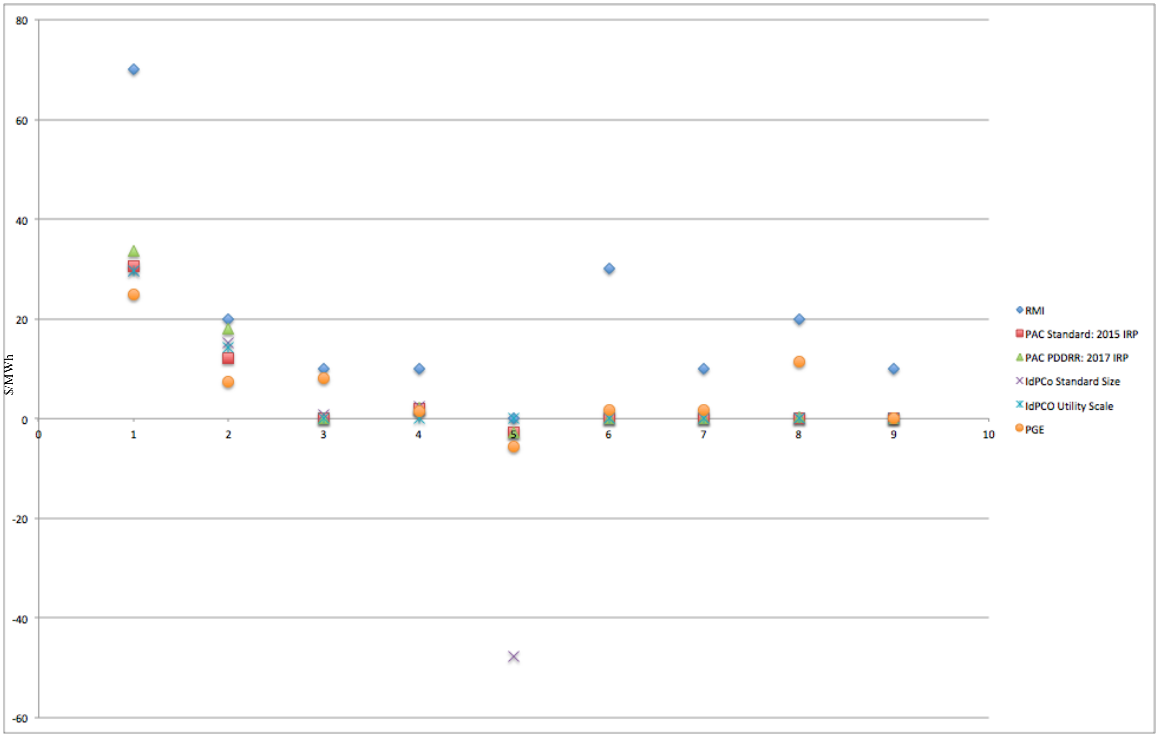

Figure 2: Comparison of PacifiCorp, PGE's and IPCo's values with values derived from RMI study

The following elements are represented in the x axis: 1) Energy, 2) Capacity, 3) T&D, 4) Losses, 5) Administration, 5) Market Price Response, 7) Hedge Value, 8) Environmental Compliance, 9) Grid Services