ROCKY MOUNTAIN POWER
A DIVISION OF PACIFICORP

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May 30, 2017

VIA ELECTRONIC FILING

Public Service Commission of Utah
Heber M. Wells Building, 4th Floor
160 East 300 South
Salt Lake City, UT84111

Attn: Gary Widerburg
Commission Secretary

RE: Docket No. 17-035-T07
Advice Filing 17-08 – Schedule37
Avoided Cost Purchases from Qualifying Facilities (QF)

In its February 12, 2009 Order in Docket No. 08-035-78 on Net Metering Service, the Public Service Commission of Utah ("Commission") directed Rocky Mountain Power (the "Company") to calculate and file Schedule 37 avoided costs annually in order to establish the value or credit for net excess generation of large commercial customers under Schedule 135 Net Metering Service. In its November 28, 2012 Order in Docket No. 12-035-T10, the Commission directed that future annual filings should be made within 30 days of filing the Company's Integrated Resource Plan ("IRP") or IRP Update, or by April 30 of each year, whichever occurs first. Pursuant to Commission Rules R746-405, the Company hereby updates the inputs to the calculation of Schedule 37 rates.

On April 25, 2017, the Company requested a 30-day extension of the Company's Schedule 37 annual filing to update its methodology for Schedule 37 avoided cost pricing. On April 27, 2017 the Commission granted provisional approval of the Company's request for extension.

The Company's 2017 IRP preferred portfolio includes cost-effective wind and solar resources, but the deficiency period avoided costs under Schedule 37 are currently based on a proxy thermal resource and are, thus, outdated. The Company proposes to update the methodology for Schedule 37 consistent with the methodology used for Schedule 38, which does account for deferral of renewable resources in the preferred portfolio.

The Company's testimony herein provided describes and supports proposed changes to align the Schedule 37 pricing methodology with the methodology used for pricing under Schedule 38. The testimony also identifies and provides support for changes to several avoided cost inputs including market prices, which were updated to the Company's March 31, 2017 Official Forward Price Curve ("1703 OFPC"), as well as integration costs and wind and solar capacity contribution, which were updated based on the assumptions and results of the Company's 2017 IRP, filed on April 4, 2017. Finally, the testimony addresses the Utah Division of Public Utilities ("Division") recommendations for revisions to the Schedule 37 tariff and supporting documentation in the Company's prior Schedule 37 update in Docket No. 16-035-T06.

Proposed tariff sheets consistent with the Company's proposal and two appendices are submitted herewith for filing in the above referenced matter. The Company will also provide electronic versions of this filing to psc@utah.gov.

The enclosed proposed tariff sheets are associated with Tariff P.S.C.U No. 50 of PacifiCorp, d.b.a. Rocky Mountain Power, applicable to electric service in the State of Utah. Pursuant to the requirement of Rule R746-405D, PacifiCorp states that the proposed tariff sheets do not constitute a violation of state law or Commission rule.

PacifiCorp respectfully requests that the Commission approve its proposed update to the methodology for Schedule 37 consistent with the methodology used for Schedule 38, and requests an effective date of July 1, 2017 for the proposed tariff sheets.

Third Revision of Sheet No. 37.2	Schedule 37	Avoided Cost Purchases from Qualifying Facilities
Sixth Revision of Sheet No. 37.4	Schedule 37	Avoided Cost Purchases from Qualifying Facilities
Fifth Revision of Sheet No. 37.5	Schedule 37	Avoided Cost Purchases from Qualifying Facilities
Fifth Revision of Sheet No. 37.6	Schedule 37	Avoided Cost Purchases from Qualifying Facilities
Fifth Revision of Sheet No. 37.7	Schedule 37	Avoided Cost Purchases from Qualifying Facilities

It is respectfully requested that all formal correspondence and staff requests regarding this matter be addressed to:

By E-mail (preferred)	datarequest@pacificorp.com bob.lively@pacificorp.com
By Regular Mail	Data Request Response Center PacifiCorp 825 NE Multnomah, Suite 2000 Portland, OR97232

Informal inquiries may be directed to Bob Lively at (801) 220-4052.

Very truly yours,

Jeffrey K. Larsen
Vice President, Regulation

Enclosures

Rocky Mountain Power
Docket No. 17-035-T07
Witness: Daniel J. MacNeil

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF UTAH

ROCKY MOUNTAIN POWER

Direct Testimony of Daniel J. MacNeil

May 2017

Q. Please state your name, business address, and present position with PacifiCorp d/b/a Rocky Mountain Power (the "Company").

A. My name is Daniel J. MacNeil. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. My present position Resource and Commercial Strategy Adviser.

<u>QUALIFICATIONS</u>

Q. Briefly describe your education and professional experience.

A. I received a Master of Arts degree in International Science and Technology Policy from George Washington University and a Bachelor of Science degree in Materials Science and Engineering from Johns Hopkins University. Before joining PacifiCorp, I completed internships with the U.S. Department of Energy's Office of Policy and International Affairs and the World Resources Institute's Green Power Market Development Group. I have been employed by PacifiCorp since 2008, first as a member of the net power costs group, then as manager of that group from June 2015 until September 2016. In my current role, I provide analytical expertise on a broad range of topics related to PacifiCorp's resource portfolio and obligations, including oversight of the calculation of avoided cost pricing in the PacifiCorp's jurisdictions.

<u>PURPOSE OF TESTIMONY AND RECOMMENDATION</u>

Q. What is the purpose of your testimony?

A. My testimony supports the Company's May 30, 2017 filing to update Schedule 37, Avoided Cost Purchases from Qualifying Facilities. The Company is required to update Schedule 37 rates annually, with filings made by April 30 of each year or within 30 days of filing an integrated resource plan ("IRP") or IRP Update, whichever is sooner.

On April 27, 2017, the Commission granted the Company's request for an extension of the deadline for this year's filing to May 30, 2017 to allow time to prepare Schedule 37 pricing consistent with the methodology used for Schedule 38.

My testimony describes and supports the proposed changes to Schedule 37 pricing methodology, including changes to make Schedule 37 pricing consistent with the methodology used for pricing under Schedule 38. My testimony also identifies and provides support for changes to several avoided cost inputs including: (1) market prices, which were updated to PacifiCorp's March 31, 2017 official forward price curve ("1703 OFPC"); and (2) integration costs and wind and solar capacity contribution, which were updated based on the assumptions and results of PacifiCorp's 2017 IRP, filed April 4, 2017. Finally, my testimony addresses revisions to the Schedule 37 tariff and supporting documentation proposed by the Utah Division of Public Utilities ("Division") in Rocky Mountain Power's last Schedule 37 update in Docket No. 16-035-T06.

Q. What qualifying facility ("QF") resources qualify for Schedule 37 pricing?

A. Published rates under Schedule 37 are available to cogeneration facilities up to one megawatt ("MW") and other small power production facilities up to 3 MW, including wind and solar resources.

Q. Please describe the specific proposed changes to the calculation of Schedule 37 rates.

A. The Company proposes that Schedule 37 rates specific to each resource type be calculated using the Partial Displacement Differential Revenue Requirement ("PDDRR") methodology approved by the Commission for determining non-standard avoided costs under Schedule 38. Using the Schedule 38 methodology results in the following changes:

- Renewable resources displace the next deferrable "like" renewable resource identified in the 2017 IRP preferred portfolio, after accounting for the queue of potential qualified facilities ("QFs"). For non-renewable resources, or if no "like" renewables remain in the 2017 IRP preferred portfolio through the expected term, the next deferrable major thermal resource is displaced, again after accounting for the queue of potential QFs.
- Avoided energy costs are calculated using the expected output of a 10 MW resource of each type and are net of the value of displaced resources from the 2017 IRP preferred portfolio.

Q. Please describe the other proposed updates reflected in the calculation of Schedule 37 rates.

A. The Company's filing reflects the following updates to the calculation of avoided cost rates in Schedule 37:

- Market prices for electricity and gas have been updated to reflect PacifiCorp's 1703 OFPC.
- Integration costs for wind and solar QFs are updated consistent with the 2017 IRP.
- Capacity contribution values for intermittent QF resources are updated consistent with the 2017 IRP.

Q. When were the rates currently in effect approved by the Commission?

A. Utah Schedule 37 rates were last approved by the Commission on May 27, 2016.

Q. What is the impact of updating Schedule 37 avoided cost rates?

A. Table 1 summarizes the current Schedule 37 rates and the updated rates proposed in this filing. For each resource type, the Schedule 37 tariff includes summer and winter values for on- and off-peak periods of each calendar year. The updated rates are reflected in tariff sheets 37.4 through 37.7.

Table 1

15 Year (2018 to 2032) Nominal Levelized Prices ($/MWh)			
Methodology	**GRID/Proxy**	**PDDRR**	
Version	**Current Rates**	**Proposed**	**Change**
Base Load	$35.36	$23.82	($11.54)
Wind	$29.82	$23.86	($5.96)
Fixed-Tilt Solar	$31.77	$19.78	($11.99)
Tracking Solar	$32.72	$19.60	($13.12)

Q. What is the primary driver of the reduction in the updated avoided cost rates?

A. As shown in Table 2, the biggest impact to avoided costs is related to aligning the methodology used to calculate Schedule 37 avoided cost pricing with the PDDRR methodology used to establish avoided cost prices for Schedule 38. The update to the 1703 OFPC, with an updated sufficiency period, also results in a significant reduction in prices relative to current rates. The updated integration and capacity contribution assumptions both result in higher avoided cost while the other updates have a small impact that varies by resource type.

Table 2

Impact on 15 Year (2018 to 2032) Nominal Levelized Prices ($/MWh)						
Methodology	**GRID/Proxy**	**GRID/Proxy**	**GRID/Proxy**	**GRID/Proxy**	**PDDRR**	
Update	**+1703 OFPC/GRID Energy**	**+Integration**	**+Capacity Contribution**	**+Deficiency, Capacity, and Other**	**+PDDRR**	**Total**
Base Load	($5.99)	$0.00	$0.00	$0.12	($5.67)	($11.54)
Wind	($6.01)	$1.47	$0.05	($0.49)	($0.98)	($5.96)
Fixed-Tilt Solar	($5.97)	$2.17	$0.23	$0.01	($8.43)	($11.99)
Tracking Solar	($5.94)	$1.52	$1.23	($0.32)	($9.62)	($13.12)

Q. What other changes to QF contracting under Schedule 37 does the Company propose?

A. The Company proposes that during the portion of a QF's contract in which it receives a capacity payment based on the costs of a renewable resource, the Company will be entitled to the renewable energy credits ("RECs") associated with the QF's output. Beyond the renewable-resource-based capacity payment already identified, no additional compensation will be paid for these RECs. When a QF's capacity payment is not based on the costs of a renewable resource, the QF will continue to be entitled to the RECs associated with its output, as is currently the case today.

Q. Has the Commission previously ruled on REC ownership under QF contracts?

A. Yes. The Commission has previously ruled in its October 4, 2013 Order in Docket No. 12-035-100 that RECs are retained by the QF unless otherwise provided for in a negotiated contract.

Q. What was the basis for the Commission's prior ruling?

A. The Commission found that PacifiCorp's position on REC ownership in its request for clarification in Docket No. 12-035-100 was not sufficiently developed in the record. Furthermore, the Commission found that given the absence of cost-effective renewable resources in the IRP Action Plan that could be deferred by a QF, having QFs retain RECs did not represent an existing, potential, or threatened violation of PURPA's ratepayer indifference standard at that time. Because PacifiCorp's preferred portfolio now includes cost-effective solar and wind resources that are available to be deferred by QFs, it is appropriate to revisit this issue.

Q. What specific issue related to RECs did the Commission find to be insufficiently developed in the record in Docket No. 12-035-100?

A. The Commission found that there was inadequate support in the record to conclude that the IRP assumes PacifiCorp keeps the RECs from any cost-effective renewable resources it acquires through the IRP action plan.

Q. Does the 2017 IRP assume PacifiCorp keeps the RECs associated with the cost-effective renewable resources identified in the preferred portfolio?

A. Yes. The RECs associated with new renewable resources are explicitly assumed to contribute to meeting renewable portfolio standards ("RPS") targets in PacifiCorp's western states.[1] While existing owned and contracted resources are sufficient to meet Utah's 2025 state target for renewables, Utah customers receive benefits from RECs that are not needed to meet their compliance obligations.

Q. What benefits would Utah retail customers receive from RECs associated with the cost-effective renewable resources identified in the preferred portfolio?

A. Item 1d in the 2017 IRP Action Plan outlines two potential avenues by which Utah customers could benefit from RECs associated with new renewable resources. First, RECs could be reallocated to Oregon, Washington, or California for consideration to be determined among PacifiCorp's retail jurisdictions. Second, RECs can be sold to third-parties with the difference between REC revenues in Utah rates and actual REC sales revenues credited to or collected from Utah customers under Tariff Schedule 98.

[1] 2017 Integrated Resource Plan. Volume I. pages 240-241. Available online at: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeI_IRP_Final.pdf

Q. What do you conclude with regard to REC ownership?

A. The 2017 IRP assumes that RECs associated with new renewable resources will be allocated among all retail jurisdictions. Utah ratepayers are thus entitled to any resulting benefits from those RECs. Assigning REC ownership to PacifiCorp during periods when a QF is being paid for capacity from a cost-effective renewable resource of the same type in the preferred portfolio would ensure that Utah ratepayers are entitled to comparable quantities of RECs. Utah ratepayers should thus be indifferent between the renewable resource in the preferred portfolio and the QF resource. For the same reasons, if QFs continue to receive all RECs associated with their output, the ratepayer indifference standard under PURPA would not be met.

SCHEDULE 37 METHODOLOGY

Q. Please describe the current Commission-approved method for calculating avoided costs for small QFs qualifying for published rates under Schedule 37.

A. Under the current Schedule 37 methodology, sufficiency period avoided costs were calculated using two Generation and Regulation Initiative Decision ("GRID") model simulations. The first simulation does not include any new QF resources. The second simulation includes an additional 10-MW baseload QF resource at zero cost and displacement of front-office transactions ("FOTs")[2]. The difference in net power costs ("NPC") between the two GRID runs divided by the energy produced by the QF resource determines the avoided energy cost. Avoided costs during a deficiency period begin coincident with the next deferrable major thermal resource identified in

[2] FOTs are proxy resources, assumed to be firm, that represent procurement activity made on an on-going forward basis to help the Company cover short positions. FOTs represent short-term firm market purchases for physical delivery of power and contribute capacity toward meeting the IRP target planning reserve margin.

PacifiCorp's most recent IRP or IRP Update and are equal to the fixed and variable costs of a proxy resource, currently a combined cycle combustion turbine ("CCCT").

Q. Is the current Commission-approved method the same as that used to calculate non-standard avoided costs under Schedule 38?

A. No. Non-standard avoided costs for large QFs under Schedule 38 are calculated using the PDDRR method. The methods are similar in that both use the GRID model to determine avoided costs during the sufficiency period, with displacement of FOTs, and both include capacity costs in the deficiency period. The PDDRR method differs in that it allows for deferral of cost-effective "like" renewable resources identified in PacifiCorp's IRP preferred portfolio. The PDDRR method also uses a combination of the GRID model to determine energy costs and partial displacement of IRP preferred portfolio resources to determine capacity costs during the deficiency period, rather than basing avoided costs solely on proxy CCCT capacity and energy costs. Furthermore, the PDDRR method accounts for the specific characteristics of a proposed QF and a proxy resource, including geographic location and any transmission constraints, and prices are prepared for individual QF projects using project-specific generation profiles rather than providing the same published prices for all QFs. Finally, the Schedule 38 pricing methodology accounts for the resource characteristics and preferred portfolio displacement from the queue of potential QFs that are seeking to sell QF power to PacifiCorp.

Q. Can the PDDRR methodology used under Schedule 38 be used for Schedule 37?

A. Yes. The Company's Schedule 37 tariff currently includes standard rates for four resource types: base load, fixed solar, tracking solar, and wind. Rather than using a single avoided energy value based on a baseload resource, specific PDDRR pricing is calculated for each of the four resource types. Rather than using a CCCT as the proxy for all QF resource types, under the PDDRR methodology, QFs have the opportunity to displace cost-effective "like" renewables identified in the PacifiCorp's 2017 IRP preferred portfolio.

Q. Why is a change to the PDDRR methodology particularly appropriate at this time?

A. Cost-effective wind and solar resources are both included in PacifiCorp's 2017 IRP preferred portfolio.

Q. Please describe the cost-effective wind and solar resources in PacifiCorp's 2017 IRP preferred portfolio.

A. The 2017 IRP preferred portfolio includes 1,100 MW of new Wyoming resources online by 2021. These wind resources are assumed to fully qualify for federal wind production tax credits ("PTCs"). The 2017 IRP preferred portfolio also includes 85 MW of new Wyoming wind in 2031 and 774 MW of new Idaho wind in 2036. It also includes 1,040 MW of new solar resources added between 2028 and 2036. The solar additions include both fixed solar in Yakima, Washington, and tracking solar in southern Utah.

Q. How would displacement of renewables using the PDDRR methodology work?

A. Under the PDDRR methodology, QFs partially displace the next major thermal resource in the IRP preferred portfolio based on their capacity contribution. The Company proposes that renewable QFs would instead partially displace the next major renewable resource of the same type in the IRP preferred portfolio, again based on equivalent capacity contributions. While the GRID PDDRR methodology can reasonably account for the differences in value between resources in two geographic locations, to maintain a consistent load and resource balance, it is important to maintain the total effective capacity contribution identified in the preferred portfolio.

Based on the capacity contribution study prepared for the 2017 IRP, each megawatt of east-side tracking solar resources is estimated to provide approximately 92 percent of the capacity provided by each megawatt of west-side tracking solar resources.[3] As a result, a 10 MW Utah tracking solar QF could defer 10 MW of an east-side tracking solar resource from the IRP preferred portfolio or 9.2 MW of a west-side tracking solar resource. The same capacity contribution study indicates that an east-side wind resource provides approximately 134 percent of the capacity provided by each megawatt of west-side wind.[4] Consequently, a 10 MW Utah wind QF could defer 10 MW of an east-side wind resource from the IRP preferred portfolio or 13.4 MW of a west-side wind resource. If the QF queue fully displaces the IRP renewable resources of a given type, pricing would revert to partially displacing the next thermal resource (adjusted for the capacity contribution of the QF).

Q. What wind resources are available to be deferred by Utah wind QFs?

A. The 1,100 MW of new PTC-eligible Wyoming wind resources added by the end of 2020 in the 2017 IRP will use the transmission capability made available by constructing Energy Gateway Sub-Segment D2, a new 144-mile, 500 kV transmission project that will run from the Aeolus substation near Medicine Bow, Wyoming, to a new substation near the Jim Bridger plant. The wind and transmission additions provide

[3] East Tracking Solar: 59.7 percent. West Tracking Solar: 64.8 percent. 59.7 percent / 64.8 percent = 92 percent
[4] East Wind: 15.8 percent. West Wind: 11.8 percent. 15.8 percent / 11.8 percent = 134 percent.

all-in economic benefits to PacifiCorp customers in all jurisdictions when considered as a package.

Partial displacement is reasonable when capacity additions can be delayed or scaled down as a result of a QF resource addition. The addition of a Utah wind QF project would not defer the new wind and transmission planned to come online by the end of 2020 in PacifiCorp's 2017 IRP preferred portfolio. Given the net benefits these projects provide to PacifiCorp's retail customers, it will pursue these projects even if new QF projects were added to the system in Utah. As a result, Utah wind QFs can displace the 2031 and 2036 wind resource additions in the 2017 IRP preferred portfolio. After accounting for the QF queue, the proposed Schedule 37 pricing reflects deferral of 2031 wind resources from the 2017 IRP preferred portfolio.

Q. What solar resources are available to be deferred by Utah solar QFs?

A. Since the 2017 IRP was prepared, PacifiCorp executed power purchase agreements with two solar QFs totaling 95 MW. This displaces all of the 2028 solar resources in the 2017 IRP preferred portfolio and the majority of the 2029 solar resources in the preferred portfolio. After accounting for the potential QF queue, the proposed Schedule 37 pricing reflects deferral of 2035 solar resources from the 2017 IRP preferred portfolio.

Q. Are there additional considerations for resource deferral under the PDDRR methodology for Schedule 38?

A. Yes. The PDDRR method gives priority to QFs in the order of requests for avoided cost prices. As the earliest resources in the IRP preferred portfolio are displaced, successive requests receive capacity starting in later years. In addition, the generation from all QFs in the queue is included in the GRID model. The GRID model optimizes the dispatch of the system to minimize costs, so a QF's output displaces the resources with the highest variable cost in each interval and avoided energy costs decline as each successive QF is added. As a result, avoided cost prices are highest for the first QF in the queue and are lower for QFs later in the queue.

Q. Is it reasonable to incorporate a QF queue under Schedule 37?

A. Yes. As described above, Schedule 37 prices calculated without accounting for the pricing queue will reflect the earliest resource deferral and highest avoided costs. As QFs in Utah and other states sign long-term PPAs, the earliest resources would be deferred and Schedule 37 prices calculated without the QF queue would be overstated, which is inconsistent with the customer indifference standard under PURPA.[5] The Company therefore proposes that the PDDRR calculation for Schedule 37 rates incorporate the potential QF queue.

Q. What is the impact of switching to the proposed PDDRR methodology for Schedule 37?

A. As shown in Table 2 earlier in my testimony, the PDDRR methodology results in lower prices for all resource types relative to the current methodology. Once the deficiency period begins under the PDDRR methodology, wind and solar avoided cost prices are higher, reflecting the difference in the energy and capacity value of renewable

[5] FERC has affirmed the need to ensure customer indifference to utility purchases of QF power, noting that, in enacting PURPA, "[t]he intention [of Congress] was to make ratepayers indifferent as to whether the utility used more traditional sources of power or the newly-encouraged alternatives." Southern Cal. Edison Co., et al., 71 FERC ¶ 61,269 at 62,080 (1995) overruled on other grounds, Cal Pub. Util. Comm'n, 133 FERC ¶ 61,059 (2010). See also PSC of Oklahoma v. State ex. rel. Corp. Comm'n, 115 P.3d 861, 870-71 (Okla. 2005) ("The incremental cost standard is intended to leave ratepayers economically indifferent to the source of a utility's energy by ensuring that the cost to the utility of purchasing power from a QF does not exceed the cost the utility would incur in the absence of the QF purchase").

resources relative to the CCCT proxy used in the current methodology. The deficiency period for wind currently begins in 2031, while the deficiency period for solar begins in 2035. All thermal resources in the 2017 IRP preferred portfolio are displaced by the current QF queue, so the base load resource only includes displacement of FOTs.

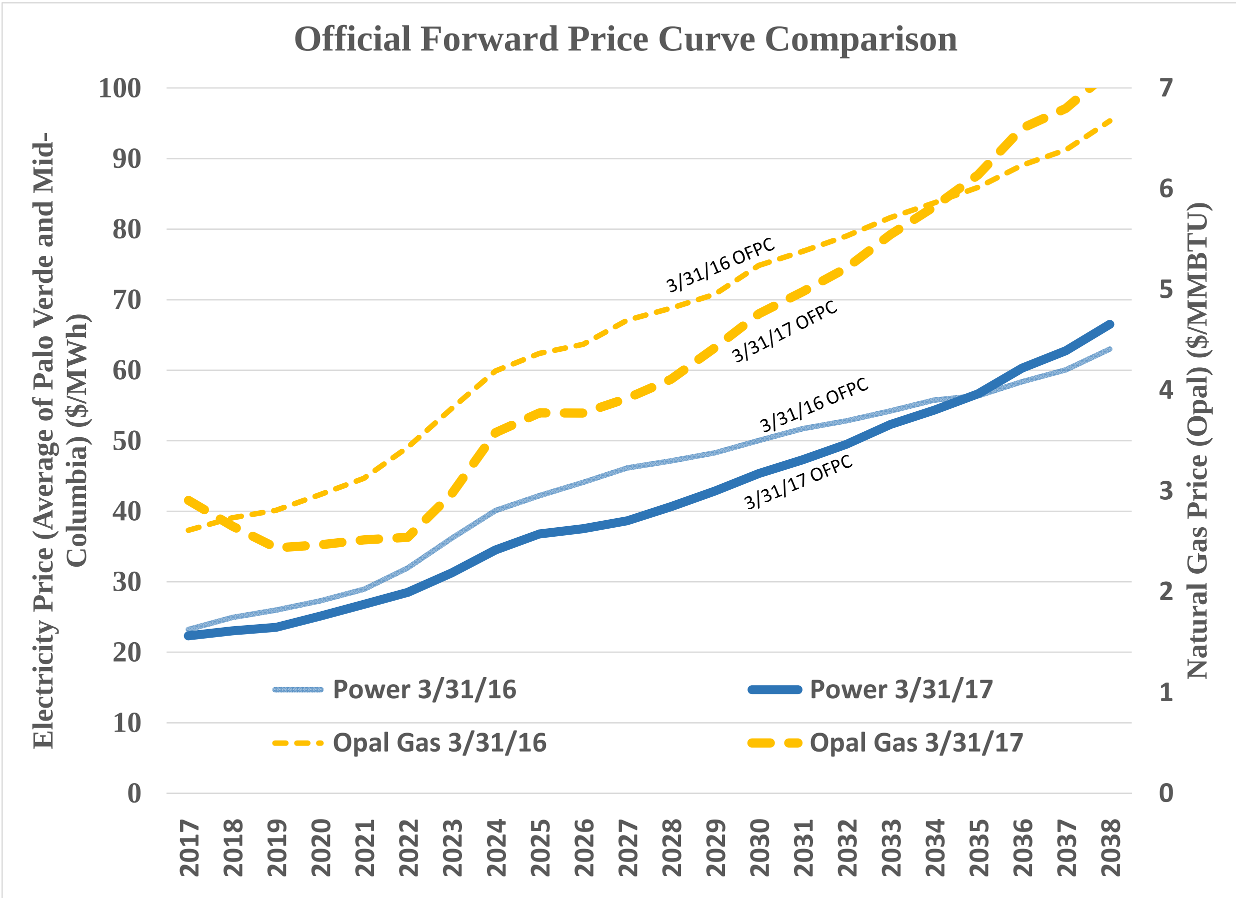
PROPOSED UPDATES

Official Forward Price Curve

Q. Has PacifiCorp's official forward price curve changed significantly since current Schedule 37 prices were prepared?

A. Yes. The current Schedule 37 prices reflect the PacifiCorp's March 31, 2016 official forward price curve. In the past year, market prices for electricity and natural gas in the fifteen years starting 2018 have fallen by 11 percent and 14 percent, respectively, as shown in Figure 1.

Figure 1



Q. How do market prices affect avoided costs?

A. As described above, avoided costs during the sufficiency period are based on two GRID runs. When the avoided cost resource is added in the GRID model, it can support incremental wholesale market sales, avoid wholesale market purchases, or displace PacifiCorp's resources, thereby avoiding fuel costs, as applicable. When electricity prices drop, the value of incremental wholesale sales and avoided wholesale purchases also drops. Similarly, when gas prices drop, the avoided fuel cost from displacing PacifiCorp's gas resources also drops. Because the PacifiCorp has limited transmission to market hubs, QF resources frequently displace generation from PacifiCorp's resources rather than affect market transactions. This is especially true for solar resources, which have the highest output at the same time as existing solar resources in PacifiCorp's resource portfolio.

Integration Costs

Q. What is the Company's proposal for integration costs in Schedule 37?

A. The Company proposes to update wind and solar integration costs to reflect the values calculated and used in the 2017 IRP. The wind integration values in the current Commission-approved Schedule 37 were calculated in the 2015 IRP and the 2015 Q2 Avoided Cost Inputs Compliance Filing. The solar integration values in the current Commission-approved Schedule 37 were established in Docket No. 12-035-100.

Q. Please describe the outcome related to solar integration costs in Docket No. 12-035-100.

A. In Docket No. 12-035-100, the Company proposed applying the integration cost for wind resources to solar resources. The Commission denied the request and directed that solar integration cost be set at $2.83 per megawatt hour for fixed solar resources and $2.18 per megawatt hour for tracking solar resources, pending the Company filing a solar integration study. The Company has prepared studies to calculate wind integration costs in the last several IRPs. For the first time, the study for the 2017 IRP also calculated solar integration costs. The "Flexible Reserve Study" was included as Appendix F in Volume II of the 2017 IRP.[6]

Q. How are integration costs calculated?

A. Wind and solar integration studies are performed to estimate the operating reserves

[6] 2017 Integrated Resource Plan. Volume II. Appendix F: Flexible Reserve Study. Available online at: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeII_2017_IRP_Final.pdf

required to maintain PacifiCorp's system reliability and comply with North American Electric Reliability Corporation ("NERC") reliability standards. PacifiCorp must provide sufficient operating reserves to allow its balancing authority areas to meet NERC's control performance criteria at all times. These incremental operating reserves are necessary to maintain area control error within required parameters due to sources outside the direct control of system operators, including intra-hour changes in load demand and wind generation. The study results in a volume of operating reserves and the associated cost of these operating reserves required to manage the variation of load and resources in PacifiCorp's balancing authority areas. In addition, the Flexible Reserve Study determines the system balancing costs required to manage load, wind, and solar resources. System balancing costs capture the costs associated with the need to commit resources on a day-ahead basis, but operating those resources against actual conditions that occur the next day. In the proposed Schedule 37 update, the Company used the costs calculated in its 2017 Flexible Reserve Study to adjust the avoided costs for wind and solar QFs.

Q. What is the impact of updating integration costs?

A. As shown in Table 3, wind and solar integration costs based on the 2017 IRP are lower than the costs currently in effect. The reduction in integration costs is partly driven by declining market prices since the previous integration costs were established. The 2017 Flexible Reserve Study also reflects a revised NERC reliability standard and includes benefits from managing a diverse portfolio including load, wind, solar, and other non-dispatchable resources.

Table 3

15 Year (2018 to 2032) Nominal Levelized Prices ($/MWh)		
Integration Cost	**Proposed**	**Current**
Wind	$0.68	$2.10
Fixed-Tilt Solar	$0.72	$2.83
Tracking Solar	$0.72	$2.18

Capacity Contribution

Q. What does the Company propose for capacity contribution in Schedule 37?

A. The Company proposes to update capacity contribution values for wind and solar resources to reflect the values calculated and used in its 2017 IRP. The values in the current Commission-approved Schedule 37 reflect values calculated and used in its 2015 IRP.

Q. What is capacity contribution?

A. The capacity contribution of wind and solar resources, represented as a percentage of a resource's nameplate capacity, is a measure of the ability of these resources to reliably meet demand. For purposes of calculating the current Commission-approved Schedule 37 avoided cost prices, the capacity contribution of a QF resource is applied to the fixed costs of the deferred proxy CCCT to determine the capacity costs that can be avoided due to the addition of the QF resource. Under the proposed PDDRR methodology, the QF resource displaces a capacity contribution equivalent amount of the next remaining "like" renewable resource or deferrable major thermal resource from the IRP preferred portfolio after accounting for the queue of potential QFs.

Q. How is the capacity contribution of wind and solar resources calculated?

A. PacifiCorp calculated peak capacity contribution values for wind and solar resources using the capacity factor approximation method ("CF Method") as outlined in a 2012 report produced by the National Renewable Energy Laboratory.[7] This methodology was previously used in the 2015 IRP, and the resulting capacity contribution values were approved by the Commission in its June 26, 2015 Order in Docket No. 14-035-140. For the 2017 IRP the inputs to the calculation have been updated to reflect changes to PacifiCorp's portfolio of loads and resources and the results are present in the "Wind and Solar Capacity Contribution Study" included as Appendix N in Volume II of the 2017 IRP.[8] Table 4 below shows the capacity contribution levels for wind, fixed-tilt solar, and tracking solar resources based on the 2017 IRP and the 2015 IRP.

Table 4

Peak Capacity Contribution	East BAA			West BAA		
	Wind	Fixed Tilt Solar PV	Single Axis Tracking Solar PV	Wind	Fixed Tilt Solar PV	Single Axis Tracking Solar PV
2017 IRP Results	15.8%	37.9%	59.7%	11.8%	53.9%	64.8%
2015 IRP Results	14.5%	34.1%	39.1%	25.4%	32.2%	36.7%

Q. Can you provide an example of equivalent capacity contributions?

A. The 2017 IRP preferred portfolio includes fixed tilt solar resources located in the West Balancing Authority Area ("BAA") with a capacity contribution of 53.9 percent and a 10 MW tracking solar resource in Utah has a capacity contribution of 59.7 percent. The 10 MW tracking solar resource in Utah provides 5.97 MW of capacity, while it would take 11.1 MW of West BAA fixed tilt solar to provide 5.97 MW of capacity.[9] As a

[7] Madaeni, S. H.; Sioshansi, R.; and Denholm, P. "Comparison of Capacity Value Methods for Photovoltaics in the Western United States." NREL/TP-6A20-54704, Denver, CO: National Renewable Energy Laboratory, July 2012 (NREL Report). http://www.nrel.gov/docs/fy12osti/54704.pdf

[8] 2017 Integrated Resource Plan. Volume II. Appendix N: Wind and Solar Capacity Contribution Study. Available online at: http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2017_IRP/2017_IRP_VolumeII_2017_IRP_Final.pdf

[9] 10 MW East tracking solar * 59.7 percent = 5.97 MW. 5.97 MW / 53.9 percent = 11.1 MW West fixed tilt solar

result, a 10 MW tracking solar resource in Utah can displace 11.1 MW of West BAA fixed tilt solar, while maintaining equivalent capacity levels before and after adding the QF.

Q. What is the impact of updating capacity contribution?

A. For resources in Utah, the capacity contribution results from the 2017 IRP are higher than the levels reflected in the current Schedule 37 rates. As previously shown in Table 2, the higher capacity contribution increases avoided cost prices for wind and solar resources, but it primarily impacts the deficiency period.

DIVISION RECOMMENDATIONS

Q. Please describe the Division's recommendations in Docket No. 16-035-T06.

A. The Division made two recommendations in Docket No. 16-035-T06. First, the Division recommended that a footnote in Table 3 of Appendix 1 of the Company's application be modified to correctly describe the capitalized energy calculation. Second, the Division identified alternating usage of "Peak" and "On-Peak" to refer to on-peak hours.

Q. Has the Company modified its current filing to address these recommendations?

A. Yes. In the workpaper demonstrating the previous methodology, the Company modified the footnote to correctly describe the capitalized energy calculation as recommended by the Division. Note, however, that with the adoption of the Schedule 38 PDDRR methodology, the capitalized energy calculation is no longer applicable. The Company also modified the Schedule 37 tariff to use "On-Peak" throughout, resulting in revisions to tariff sheet 37.2.

Q. Does this conclude your testimony?

A. Yes.

Proposed Tariff Sheets

ELECTRIC SERVICE SCHEDULE NO. 37 - Continued

DEFINITIONS (continued)

Solar Facility

A facility which produces electric energy using the sun as the primary energy source. A Solar Facility may be configured either with a) fixed solar panels (Fixed Solar), or b) with a tracking device (Tracking Solar).

Wind Facility

A facility which produces electric energy using wind as the primary energy source.

Winter Season

The months of October through May.

Summer Season

The months of June through September.

On-Peak Hours

On-Peak hours are defined as 6:00 a.m. to 10:00 p.m. Monday through Saturday, excluding holidays.

Holidays include only New Year's Day, President's Day, Memorial Day, Independence Day, Pioneer Day, Labor Day, Thanksgiving Day and Christmas Day. When a holiday falls on a Sunday, the Monday following the holiday will be the holiday and will be Off-Peak.

Off-Peak Hours

All hours other than On-Peak.

Due to the expansions of Daylight Saving Time (DST) as adopted under Section 110 of the U.S. Energy Policy Act of 2005 the time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April, and for the period between the last Sunday in October and the first Sunday in November.

MONTHLY PAYMENTS: The Qualifying Facility will be paid winter and summer energy prices for On-Peak and Off-Peak hours. Winter and summer energy payments for On-Peak and Off-Peak hours are provided separately for a base load facility, Solar Facility and a Wind Facility.

(continued)

ELECTRIC SERVICE SCHEDULE NO. 37 - Continued

Base Load Facility

Volumetric Winter and Summer Energy Prices for On-Peak and Off-Peak hours
¢/kWh

Non-Levelized Prices

Deliveries During	On-Peak Energy Prices (¢/kWh)		Off-Peak Energy Prices (¢/kWh)	
Calendar Year	Winter	Summer	Winter	Summer
2017	1.986	2.157	1.818	1.575
2018	2.126	2.204	1.893	1.610
2019	1.900	2.216	1.604	1.506
2020	1.807	1.951	1.528	1.233
2021	1.913	2.007	1.671	1.300
2022	1.979	2.102	1.771	1.445
2023	2.110	2.252	1.917	1.696
2024	2.169	2.439	1.989	1.981
2025	2.528	2.647	2.297	2.116
2026	2.475	2.575	2.254	2.077
2027	2.730	2.740	2.513	2.239
2028	3.016	3.343	2.779	2.763
2029	3.300	3.688	3.064	3.078
2030	3.827	3.933	3.598	3.278
2031	4.046	4.127	3.784	3.459
2032	4.246	4.393	3.971	3.726
2033	4.732	5.215	4.461	4.460
2034	5.134	5.553	4.858	4.776
2035	5.566	6.521	5.259	5.585
2036	5.861	6.893	5.559	5.913
2037	6.195	6.890	5.879	5.944

Levelized Prices (Nominal)

	On Peak Energy Prices (¢/kWh)		Off-Peak Energy Prices (¢/kWh)	
	Winter	Summer	Winter	Summer
15-year (2018-2032) Nominal Levelized	2.487	2.649	2.250	2.037

(continued)

ELECTRIC SERVICE SCHEDULE NO. 37 - Continued

Fixed Solar Facility

Volumetric Winter and Summer Energy Prices for On-Peak and Off-Peak hours ¢/kWh

Non-Levelized Prices

Deliveries During Calendar Year	On-Peak Energy Prices (¢/kWh) Winter	On-Peak Energy Prices (¢/kWh) Summer	Off-Peak Energy Prices (¢/kWh) (1) Winter	Off-Peak Energy Prices (¢/kWh) (1) Summer
2017	1.845	2.202	1.689	1.611
2018	1.844	2.250	1.625	1.646
2019	1.628	1.964	1.372	1.341
2020	1.404	1.662	1.162	1.060
2021	1.522	1.798	1.302	1.176
2022	1.589	1.870	1.396	1.298
2023	1.743	2.026	1.583	1.534
2024	1.760	1.990	1.607	1.594
2025	1.891	2.143	1.727	1.706
2026	1.884	2.159	1.709	1.747
2027	2.062	2.348	1.886	1.925
2028	2.222	2.529	2.046	2.090
2029	2.336	2.627	2.159	2.189
2030	2.683	3.040	2.527	2.520
2031	2.814	3.158	2.636	2.646
2032	3.016	3.392	2.812	2.893
2033	3.663	4.160	3.447	3.555
2034	4.295	4.799	4.055	4.132
2035	7.508	8.571	7.066	7.357
2036	7.756	8.857	7.356	7.619
2037	8.122	9.194	7.689	7.965

Levelized Prices (Nominal)

	On-Peak Energy Prices (¢/kWh) Winter	On-Peak Energy Prices (¢/kWh) Summer	Off-Peak Energy Prices (¢/kWh) Winter	Off-Peak Energy Prices (¢/kWh) Summer
15-year (2018-2032) Nominal Levelized	1.909	2.212	1.714	1.691

(continued)

ELECTRIC SERVICE SCHEDULE NO. 37 - Continued

Tracking Solar Facility

Volumetric Winter and Summer Energy Prices for On-Peak and Off-Peak hours ¢/kWh

Non-Levelized Prices

Deliveries During	On-Peak Energy Prices (¢/kWh)		Off-Peak Energy Prices (¢/kWh) (1)	
Calendar Year	Winter	Summer	Winter	Summer
2017	1.840	2.200	1.683	1.602
2018	1.820	2.249	1.568	1.637
2019	1.627	1.991	1.295	1.332
2020	1.384	1.655	1.098	1.043
2021	1.487	1.772	1.219	1.146
2022	1.549	1.839	1.309	1.263
2023	1.688	1.988	1.503	1.493
2024	1.580	1.818	1.425	1.450
2025	1.865	2.152	1.682	1.704
2026	1.935	2.259	1.736	1.817
2027	2.031	2.351	1.839	1.918
2028	2.233	2.585	2.035	2.124
2029	2.366	2.705	2.159	2.239
2030	2.708	3.120	2.521	2.573
2031	2.848	3.246	2.638	2.704
2032	3.047	3.479	2.808	2.946
2033	3.737	4.304	3.481	3.653
2034	4.351	4.921	4.068	4.212
2035	8.304	9.577	7.741	8.174
2036	8.517	9.822	8.014	8.408
2037	8.812	10.076	8.279	8.685

Levelized Prices (Nominal)

	On-Peak Energy Prices (¢/kWh)		Off-Peak Energy Prices (¢/kWh)	
	Winter	Summer	Winter	Summer
15-year (2018-2032) Nominal Levelized	1.888	2.219	1.657	1.684

(1): On- and off- peak prices are reduced by integration charges and reflect 0.5% annual degradation rate

(continued)

ELECTRIC SERVICE SCHEDULE NO. 37 - Continued

Wind Facility

Volumetric Winter and Summer Energy Prices for On-Peak and Off-Peak hours
¢/kWh

Non-Levelized Prices

Deliveries During	On-Peak Energy Prices (¢/kWh)		Off-Peak Energy Prices (¢/kWh) (1)	
Calendar Year	Winter	Summer	Winter	Summer
2017	1.860	2.001	1.688	1.459
2018	2.040	2.046	1.795	1.491
2019	1.866	2.132	1.560	1.451
2020	1.744	2.009	1.477	1.264
2021	1.850	2.052	1.601	1.321
2022	1.866	2.116	1.663	1.447
2023	1.972	2.179	1.779	1.632
2024	2.218	2.356	1.981	1.903
2025	2.363	2.517	2.118	2.000
2026	2.414	2.399	2.180	1.930
2027	2.529	2.686	2.294	2.177
2028	2.922	3.570	2.670	2.917
2029	3.329	3.623	3.049	2.987
2030	3.856	3.969	3.535	3.296
2031	5.133	7.047	4.955	5.907
2032	5.265	7.354	5.080	6.224
2033	5.404	7.648	5.249	6.514
2034	5.559	7.811	5.376	6.702
2035	5.597	8.205	5.487	6.994
2036	6.987	10.013	6.875	8.608
2037	7.013	9.942	6.809	8.551

Levelized Prices (Nominal)

	On Peak Energy Prices (¢/kWh)		Off-Peak Energy Prices (¢/kWh)	
	Winter	Summer	Winter	Summer
15-year (2018-2032) Nominal Levelized	2.510	2.862	2.266	2.209

(1): On- and off- peak prices are reduced by integration charges

ELECTRIC SERVICE SCHEDULE NO. 37 - Continued

DEFINITIONS (continued)

Solar Facility

A facility which produces electric energy using the sun as the primary energy source. A Solar Facility may be configured either with a) fixed solar panels (Fixed Solar), or b) with a tracking device (Tracking Solar).

Wind Facility

A facility which produces electric energy using wind as the primary energy source.

Winter Season

The months of October through May.

Summer Season

The months of June through September.

On-Peak Hours

On-~~p~~Peak hours are defined as 6:00 a.m. to 10:00 p.m. Monday through Saturday, excluding holidays.

Holidays include only New Year's Day, President's Day, Memorial Day, Independence Day, Pioneer Day, Labor Day, Thanksgiving Day and Christmas Day. When a holiday falls on a Sunday, the Monday following the holiday will be the holiday and will be Off-~~p~~Peak.

Off-Peak Hours

All hours other than On-~~p~~Peak.

Due to the expansions of Daylight Saving Time (DST) as adopted under Section 110 of the U.S. Energy Policy Act of 2005 the time periods shown above will begin and end one hour later for the period between the second Sunday in March and the first Sunday in April, and for the period between the last Sunday in October and the first Sunday in November.

MONTHLY PAYMENTS: The Qualifying Facility will be paid winter and summer energy prices for On-Peak and Off-Peak hours. Winter and summer energy payments for On-Peak and Off-Peak hours are provided separately for a base load facility, Solar Facility and a Wind Facility.

(continued)

ELECTRIC SERVICE SCHEDULE NO. 37 - Continued

Base Load Facility

Volumetric Winter and Summer Energy Prices for On-Peak and Off-Peak hours ¢/kWh

Non-Levelized Prices

Deliveries During Calendar Year	On-Peak Energy Prices (¢/kWh) Winter	On-Peak Energy Prices (¢/kWh) Summer	Off-Peak Energy Prices (¢/kWh) Winter	Off-Peak Energy Prices (¢/kWh) Summer
2017	1.986	2.157	1.818	1.575
2018	2.126	2.204	1.893	1.610
2019	1.900	2.216	1.604	1.506
2020	1.807	1.951	1.528	1.233
2021	1.913	2.007	1.671	1.300
2022	1.979	2.102	1.771	1.445
2023	2.110	2.252	1.917	1.696
2024	2.169	2.439	1.989	1.981
2025	2.528	2.647	2.297	2.116
2026	2.475	2.575	2.254	2.077
2027	2.730	2.740	2.513	2.239
2028	3.016	3.343	2.779	2.763
2029	3.300	3.688	3.064	3.078
2030	3.827	3.933	3.598	3.278
2031	4.046	4.127	3.784	3.459
2032	4.246	4.393	3.971	3.726
2033	4.732	5.215	4.461	4.460
2034	5.134	5.553	4.858	4.776
2035	5.566	6.521	5.259	5.585
2036	5.861	6.893	5.559	5.913
2037	6.195	6.890	5.879	5.944

~~Deliveries During Calendar Year~~	~~On-Peak Energy Prices (¢/kWh) Winter~~	~~On-Peak Energy Prices (¢/kWh) Summer~~	~~Off-Peak Energy Prices (¢/kWh) Winter~~	~~Off-Peak Energy Prices (¢/kWh) Summer~~
~~2016~~	~~1.924~~	~~2.274~~	~~1.650~~	~~1.717~~
~~2017~~	~~2.146~~	~~2.321~~	~~1.885~~	~~1.863~~
~~2018~~	~~2.407~~	~~2.528~~	~~2.134~~	~~1.960~~
~~2019~~	~~2.472~~	~~2.789~~	~~2.180~~	~~2.176~~
~~2020~~	~~2.709~~	~~2.832~~	~~2.390~~	~~2.171~~
~~2021~~	~~2.832~~	~~3.113~~	~~2.494~~	~~2.453~~
~~2022~~	~~3.009~~	~~3.495~~	~~2.665~~	~~2.849~~
~~2023~~	~~3.182~~	~~3.813~~	~~2.831~~	~~3.194~~
~~2024~~	~~3.644~~	~~4.148~~	~~3.235~~	~~3.459~~

(continued)

ELECTRIC SERVICE SCHEDULE NO. 37 - Continued

~~2025~~	~~3.908~~	~~4.336~~	~~3.497~~	~~3.606~~
~~2026~~	~~3.910~~	~~4.501~~	~~3.491~~	~~3.796~~
~~2027~~	~~4.169~~	~~4.694~~	~~3.726~~	~~3.987~~
~~2028~~	~~6.135~~	~~6.135~~	~~3.222~~	~~3.222~~
~~2029~~	~~6.290~~	~~6.290~~	~~3.315~~	~~3.315~~
~~2030~~	~~6.562~~	~~6.562~~	~~3.521~~	~~3.521~~
~~2031~~	~~6.720~~	~~6.720~~	~~3.613~~	~~3.613~~
~~2032~~	~~6.889~~	~~6.889~~	~~3.713~~	~~3.713~~
~~2033~~	~~7.085~~	~~7.085~~	~~3.839~~	~~3.839~~

Levelized Prices (Nominal)

	On Peak Energy Prices (¢/kWh)		Off-Peak Energy Prices (¢/kWh)	
	Winter	Summer	Winter	Summer
15-year (2018~~7~~-2032~~1~~) Nominal Levelized	~~3.612~~ 2.487	~~3.899~~ 2.649	~~2.792~~ 2.250	~~2.841~~ 2.037

(continued)

ELECTRIC SERVICE SCHEDULE NO. 37 - Continued

Fixed Solar Facility

Volumetric Winter and Summer Energy Prices for On-Peak and Off-Peak hours ¢/kWh

Non-Levelized Prices

Deliveries During Calendar Year	On-Peak Energy Prices (¢/kWh) Winter	On-Peak Energy Prices (¢/kWh) Summer	Off-Peak Energy Prices (¢/kWh) (1) Winter	Off-Peak Energy Prices (¢/kWh) (1) Summer
2017	1.845	2.202	1.689	1.611
2018	1.844	2.250	1.625	1.646
2019	1.628	1.964	1.372	1.341
2020	1.404	1.662	1.162	1.060
2021	1.522	1.798	1.302	1.176
2022	1.589	1.870	1.396	1.298
2023	1.743	2.026	1.583	1.534
2024	1.760	1.990	1.607	1.594
2025	1.891	2.143	1.727	1.706
2026	1.884	2.159	1.709	1.747
2027	2.062	2.348	1.886	1.925
2028	2.222	2.529	2.046	2.090
2029	2.336	2.627	2.159	2.189
2030	2.683	3.040	2.527	2.520
2031	2.814	3.158	2.636	2.646
2032	3.016	3.392	2.812	2.893
2033	3.663	4.160	3.447	3.555
2034	4.295	4.799	4.055	4.132
2035	7.508	8.571	7.066	7.357
2036	7.756	8.857	7.356	7.619
2037	8.122	9.194	7.689	7.965

~~Deliveries During Calendar Year~~	~~On-Peak Energy Prices (¢/kWh) (1,2) Winter~~	~~On-Peak Energy Prices (¢/kWh) (1,2) Summer~~	~~Off-Peak Energy Prices (¢/kWh) (2) Winter~~	~~Off-Peak Energy Prices (¢/kWh) (2) Summer~~
~~2016~~	~~1.641~~	~~1.991~~	~~1.367~~	~~1.434~~
~~2017~~	~~1.863~~	~~2.038~~	~~1.602~~	~~1.580~~
~~2018~~	~~2.124~~	~~2.245~~	~~1.851~~	~~1.677~~
~~2019~~	~~2.189~~	~~2.506~~	~~1.897~~	~~1.893~~
~~2020~~	~~2.426~~	~~2.549~~	~~2.107~~	~~1.888~~
~~2021~~	~~2.549~~	~~2.830~~	~~2.211~~	~~2.170~~

(continued)

ELECTRIC SERVICE SCHEDULE NO. 37 - Continued

~~2022~~	~~2.726~~	~~3.212~~	~~2.382~~	~~2.566~~
~~2023~~	~~2.899~~	~~3.530~~	~~2.548~~	~~2.911~~
~~2024~~	~~3.361~~	~~3.865~~	~~2.952~~	~~3.176~~
~~2025~~	~~3.625~~	~~4.053~~	~~3.214~~	~~3.323~~
~~2026~~	~~3.627~~	~~4.218~~	~~3.208~~	~~3.513~~
~~2027~~	~~3.886~~	~~4.411~~	~~3.443~~	~~3.704~~
~~2028~~	~~3.933~~	~~3.933~~	~~2.939~~	~~2.939~~
~~2029~~	~~4.046~~	~~4.046~~	~~3.032~~	~~3.032~~
~~2030~~	~~4.275~~	~~4.275~~	~~3.238~~	~~3.238~~
~~2031~~	~~4.390~~	~~4.390~~	~~3.330~~	~~3.330~~
~~2032~~	~~4.513~~	~~4.513~~	~~3.430~~	~~3.430~~
~~2033~~	~~4.663~~	~~4.663~~	~~3.556~~	~~3.556~~

Levelized Prices (Nominal)~~(3)~~

	On-Peak Energy Prices (¢/kWh)		Off-Peak Energy Prices (¢/kWh)	
	Winter	Summer	Winter	Summer
15-year (2018-2032) Nominal Levelized	1.909	2.212	1.714	1.691

	~~On Peak Energy Prices (¢/kWh)~~		~~Off-Peak Energy Prices (¢/kWh)~~	
~~15-year (2017-2031) Nominal Levelized with degradation (3)~~	~~Winter~~	~~Summer~~	~~Winter~~	~~Summer~~
	~~2.947~~	~~3.234~~	~~2.491~~	~~2.539~~

~~(1): On-Peak prices reflect 34.1% capacity contribution of Fixed Solar QF.~~
~~(2): On- and Off- peak prices are reduced by integration charges.~~
~~(3): Assuming annual degradation of 0.7%.~~

(continued)

ELECTRIC SERVICE SCHEDULE NO. 37 - Continued

Tracking Solar Facility

Volumetric Winter and Summer Energy Prices for On-Peak and Off-Peak hours ¢/kWh

Non-Levelized Prices

Deliveries During	On-Peak Energy Prices (¢/kWh)		Off-Peak Energy Prices (¢/kWh) (1)	
Calendar Year	Winter	Summer	Winter	Summer
2017	1.840	2.200	1.683	1.602
2018	1.820	2.249	1.568	1.637
2019	1.627	1.991	1.295	1.332
2020	1.384	1.655	1.098	1.043
2021	1.487	1.772	1.219	1.146
2022	1.549	1.839	1.309	1.263
2023	1.688	1.988	1.503	1.493
2024	1.580	1.818	1.425	1.450
2025	1.865	2.152	1.682	1.704
2026	1.935	2.259	1.736	1.817
2027	2.031	2.351	1.839	1.918
2028	2.233	2.585	2.035	2.124
2029	2.366	2.705	2.159	2.239
2030	2.708	3.120	2.521	2.573
2031	2.848	3.246	2.638	2.704
2032	3.047	3.479	2.808	2.946
2033	3.737	4.304	3.481	3.653
2034	4.351	4.921	4.068	4.212
2035	8.304	9.577	7.741	8.174
2036	8.517	9.822	8.014	8.408
2037	8.812	10.076	8.279	8.685

~~Deliveries During~~	~~On-Peak Energy Prices (¢/kWh) (1,2)~~		~~Off-Peak Energy Prices (¢/kWh) (2)~~	
~~Calendar Year~~	~~Winter~~	~~Summer~~	~~Winter~~	~~Summer~~
~~2016~~	~~1.706~~	~~2.056~~	~~1.432~~	~~1.499~~
~~2017~~	~~1.928~~	~~2.103~~	~~1.667~~	~~1.645~~
~~2018~~	~~2.189~~	~~2.310~~	~~1.916~~	~~1.742~~
~~2019~~	~~2.254~~	~~2.571~~	~~1.962~~	~~1.958~~
~~2020~~	~~2.491~~	~~2.614~~	~~2.172~~	~~1.953~~
~~2021~~	~~2.614~~	~~2.895~~	~~2.276~~	~~2.235~~
~~2022~~	~~2.791~~	~~3.277~~	~~2.447~~	~~2.631~~
~~2023~~	~~2.964~~	~~3.595~~	~~2.613~~	~~2.976~~
~~2024~~	~~3.426~~	~~3.930~~	~~3.017~~	~~3.241~~
~~2025~~	~~3.690~~	~~4.118~~	~~3.279~~	~~3.388~~

(continued)

ELECTRIC SERVICE SCHEDULE NO. 37 - Continued

~~2026~~	~~3.692~~	~~4.283~~	~~3.273~~	~~3.578~~
~~2027~~	~~3.951~~	~~4.476~~	~~3.508~~	~~3.769~~
~~2028~~	~~4.143~~	~~4.143~~	~~3.004~~	~~3.004~~
~~2029~~	~~4.260~~	~~4.260~~	~~3.097~~	~~3.097~~
~~2030~~	~~4.492~~	~~4.492~~	~~3.303~~	~~3.303~~
~~2031~~	~~4.610~~	~~4.610~~	~~3.395~~	~~3.395~~
~~2032~~	~~4.737~~	~~4.737~~	~~3.495~~	~~3.495~~
~~2033~~	~~4.890~~	~~4.890~~	~~3.621~~	~~3.621~~

Levelized Prices (Nominal)~~(3)~~

	On-Peak Energy Prices (¢/kWh)		Off-Peak Energy Prices (¢/kWh)	
	Winter	Summer	Winter	Summer
15-year (2018-2032) Nominal Levelized	1.888	2.219	1.657	1.684

(1): On- and off- peak prices are reduced by integration charges and reflect 0.5% annual degradation rate

	~~On-Peak Energy Prices (¢/kWh)~~		~~Off-Peak Energy Prices (¢/kWh)~~	
~~15-year (2017-2031) Nominal Levelized with degradation (3)~~	~~Winter~~	~~Summer~~	~~Winter~~	~~Summer~~
	~~3.037~~	~~3.325~~	~~2.556~~	~~2.604~~

~~(1): On-Peak prices reflect 39.1% capacity contribution of Tracking Solar QF.~~
~~(2): On- and Off-Peak prices are reduced by integration charges.~~
~~(3): Assuming annual degradation of 0.7%.~~

(continued)

ELECTRIC SERVICE SCHEDULE NO. 37 - Continued

Wind Facility

Volumetric Winter and Summer Energy Prices for On-Peak and Off-Peak hours ¢/kWh

Non-Levelized Prices

Deliveries During	On-Peak Energy Prices (¢/kWh)		Off-Peak Energy Prices (¢/kWh) (1)	
Calendar Year	Winter	Summer	Winter	Summer
2017	1.860	2.001	1.688	1.459
2018	2.040	2.046	1.795	1.491
2019	1.866	2.132	1.560	1.451
2020	1.744	2.009	1.477	1.264
2021	1.850	2.052	1.601	1.321
2022	1.866	2.116	1.663	1.447
2023	1.972	2.179	1.779	1.632
2024	2.218	2.356	1.981	1.903
2025	2.363	2.517	2.118	2.000
2026	2.414	2.399	2.180	1.930
2027	2.529	2.686	2.294	2.177
2028	2.922	3.570	2.670	2.917
2029	3.329	3.623	3.049	2.987
2030	3.856	3.969	3.535	3.296
2031	5.133	7.047	4.955	5.907
2032	5.265	7.354	5.080	6.224
2033	5.404	7.648	5.249	6.514
2034	5.559	7.811	5.376	6.702
2035	5.597	8.205	5.487	6.994
2036	6.987	10.013	6.875	8.608
2037	7.013	9.942	6.809	8.551

~~Deliveries During~~	~~On Peak Energy Prices (¢/kWh) (1,2)~~		~~Off Peak Energy Prices (¢/kWh) (2)~~	
~~Calendar Year~~	~~Winter~~	~~Summer~~	~~Winter~~	~~Summer~~
~~2016~~	~~1.745~~	~~2.095~~	~~1.471~~	~~1.538~~
~~2017~~	~~2.008~~	~~2.183~~	~~1.747~~	~~1.725~~
~~2018~~	~~2.246~~	~~2.367~~	~~1.973~~	~~1.799~~
~~2019~~	~~2.301~~	~~2.618~~	~~2.009~~	~~2.005~~
~~2020~~	~~2.549~~	~~2.672~~	~~2.230~~	~~2.011~~
~~2021~~	~~2.675~~	~~2.956~~	~~2.337~~	~~2.296~~
~~2022~~	~~2.842~~	~~3.328~~	~~2.498~~	~~2.682~~
~~2023~~	~~2.989~~	~~3.620~~	~~2.638~~	~~3.001~~
~~2024~~	~~3.446~~	~~3.950~~	~~3.037~~	~~3.261~~
~~2025~~	~~3.704~~	~~4.132~~	~~3.293~~	~~3.402~~

ELECTRIC SERVICE SCHEDULE NO. 37 - Continued

~~2026~~	~~3.687~~	~~4.278~~	~~3.268~~	~~3.573~~
~~2027~~	~~3.950~~	~~4.475~~	~~3.507~~	~~3.768~~
~~2028~~	~~3.408~~	~~3.408~~	~~2.985~~	~~2.985~~
~~2029~~	~~3.468~~	~~3.468~~	~~3.037~~	~~3.037~~
~~2030~~	~~3.641~~	~~3.641~~	~~3.201~~	~~3.201~~
~~2031~~	~~3.724~~	~~3.724~~	~~3.273~~	~~3.273~~
~~2032~~	~~3.803~~	~~3.803~~	~~3.343~~	~~3.343~~
~~2033~~	~~3.983~~	~~3.983~~	~~3.513~~	~~3.513~~

Levelized Prices (Nominal)

	On Peak Energy Prices (¢/kWh)		Off-Peak Energy Prices (¢/kWh)	
	Winter	Summer	Winter	Summer
15-year (2018-2032) Nominal Levelized	2.510	2.862	2.266	2.209

(1): On- and off- peak prices are reduced by integration charges

	~~On Peak Energy Prices (¢/kWh)~~		~~Off-Peak Energy Prices (¢/kWh)~~	
	~~Winter~~	~~Summer~~	~~Winter~~	~~Summer~~
~~15-year (2017-2031) Nominal Levelized~~	~~2.951~~	~~3.238~~	~~2.595~~	~~2.645~~

~~(1): On-Peak prices reflect 14.5% capacity contribution of wind QF.~~
~~(2): On- and Off- peak prices are reduced by integration charges.~~

Appendix 1

Table 1
2017 IRP Preferred Portfolio
Excerpt from 2017 IRP Table 8.17

		Capacity (MW)																				Resource Totals 1/	
	Resource	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	10-year	20-year
East	**Expansion Resources**																						
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	477	-	-	-	-	477
	SCCT Frame DJ	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	200
	SCCT Frame UTN	-	-	-	-	-	-	-	-	-	-	-	-	200	-	-	-	-	-	-	-	-	200
	Wind, Djohnston	-	-	-	-	-	-	-	-	-	-	-	-	-	-	85	-	-	-	-	-	-	85
	Wind, GO	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	774	-	774
	Wind, WYAE	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	1,100	1,100
	Total Wind	-	-	-	-	1,100	-	-	-	-	-	-	-	-	-	85	-	-	-	-	774	1,100	1,959
	Utility Solar - PV - Utah-S	-	-	-	-	-	-	-	-	-	-	-	-	-	-	79	167	210	41	291	13	-	800
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	123.8	90.5	4.8	-	3.4	3.1	3.7	3.1	11.6	-	243.8
	DSM, Class 2 Total	97	74	79	75	81	77	85	85	82	84	82	77	73	73	74	62	55	47	44	44	819	1,450
	FOT Mona - SMR	-	-	-	-	-	-	-	-	-	27	27	300	300	291	300	300	300	300	300	300	3	137
West	**Expansion Resources**																						
	CCCT - WillamValcc - G 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Total CCCT	-	-	-	-	-	-	-	-	-	-	-	-	-	436	-	-	-	-	-	-	-	436
	Utility Solar - PV - Yakima	-	-	-	-	-	-	-	-	-	-	-	11	97	-	38	70	16	8	-	-	-	240
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	69.1	49.1	-	3.3	-	-	-	-	-	-	121.5
	DSM, Class 2 Total	57	53	52	46	42	37	33	33	29	27	27	25	23	23	22	21	20	19	19	18	410	627
	Geothermal, Greenfield - West	-	-	-	-	-	-	-	-	-	-	-	-	30	-	-	-	-	-	-	-	-	30
	FOT COB - SMR	-	-	3	-	-	41	-	10	167	76	137	400	400	400	400	400	400	400	400	364	30	200
	FOT MidColumbia - SMR	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400	400
	FOT MidColumbia - SMR - 2	-	21	375	307	299	375	344	375	375	375	375	375	375	375	375	375	375	375	375	375	285	330
	FOT NOB - SMR	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	FOT MidColumbia - WTR	281	332	273	307	-	308	-	287	295	-	-	-	400	41	390	351	-	377	4	291	208	197
	FOT MidColumbia - WTR2	-	-	-	-	319	-	306	-	-	297	289	312	51	375	-	-	337	-	375	375	92	152
	FOT NOB - WTR	-	-	-	-	-	-	-	-	53	54	8	100	100	100	100	100	100	100	100	100	11	51
	Existing Plant Retirements/Conversions	-	-	(257)	-	(387)	-	-	-	-	(82)	-	(762)	(354)	(357)	(78)	-	(717)	-	(82)	-		
	Annual Additions, Long Term Resources	154	128	131	122	1,223	114	118	118	112	111	109	306	563	536	303	323	980	117	356	861		
	Annual Additions, Short Term Resources	781	853	1,151	1,115	1,118	1,223	1,150	1,172	1,390	1,329	1,336	1,987	2,126	2,081	2,065	2,026	2,012	2,052	2,054	2,305		
	Total Annual Additions	935	981	1,282	1,236	2,341	1,337	1,268	1,289	1,501	1,440	1,445	2,293	2,688	2,618	2,368	2,349	2,992	2,169	2,411	3,166		

The 2017 IRP was prepared using a 13% planning reserve margin. See 2017 IRP, page 10.

QF Queue						
No.	**QF**	**Partial Displacement**	**Name plate**	**CF**	**Capacity Contribution**	**Start Date**
1	Boswell Springs I Wind	12.64	80.00	40.7%	15.8%	2018 12 31
2	Boswell Springs II Wind	12.64	80.00	40.7%	15.8%	2018 12 31
3	Boswell Springs III Wind	12.64	80.00	40.7%	15.8%	2018 12 31
4	Boswell Springs IV Wind	12.64	80.00	40.7%	15.8%	2018 12 31
Total Signed MW		50.56	320.00			
1	QF - 245 - WY - Wind	12.64	80.00	44.9%	15.8%	2018 11 01
2	QF - 246 - WY - Wind	12.64	80.00	42.0%	15.8%	2018 11 01
3	QF - 247 - WY - Wind	12.64	80.00	37.4%	15.8%	2018 11 01
4	QF - 249 - OR - Solar	25.92	40.00	29.1%	64.8%	2017 12 31
5	QF - 256 - UT - Solar	40.58	68.00	32.3%	59.7%	2019 07 01
6	QF - 277 - WY - Solar	11.93	20.00	28.2%	59.7%	2019 10 01
7	QF - 278 - WY - Solar	11.93	20.00	28.2%	59.7%	2019 10 01
8	QF - 279 - OR - Solar	25.92	40.00	31.0%	64.8%	2018 06 30
9	QF - 280 - OR - Solar	25.92	40.00	27.9%	64.8%	2018 12 01
10	QF - 281 - OR - Solar	25.92	40.00	24.5%	64.8%	2018 12 01
11	QF - 282 - WY - Solar	44.69	74.90	30.6%	59.7%	2018 03 01
12	QF - 289 - UT - Solar	47.74	80.00	31.2%	59.7%	2018 12 01
13	QF - 290 - UT - Solar	47.74	80.00	31.5%	59.7%	2018 12 01
14	QF - 291 - UT - Solar	47.74	80.00	31.9%	59.7%	2018 12 01
15	QF - 302 - WY - Solar	9.55	16.00	29.3%	59.7%	2019 10 01
16	QF - 304 - WY - Solar	17.90	30.00	27.4%	59.7%	2019 06 30
17	QF - 305 - WY - Solar	47.74	80.00	27.4%	59.7%	2019 06 30
18	QF - 308 - WY - Wind	12.64	80.00	46.6%	15.8%	2020 01 01
19	QF - 309 - WY - Wind	12.64	80.00	46.6%	15.8%	2020 01 01
20	QF - 310 - WY - Wind	12.64	80.00	46.6%	15.8%	2020 01 01
21	QF - 311 - WY - Wind	6.32	40.00	46.6%	15.8%	2020 01 01
22	QF - 284 - OR - Solar	11.65	17.97	26.0%	64.8%	2018 01 01
23	QF - 313 - UT - Solar	47.74	80.00	29.6%	59.7%	2019 12 01
24	QF - 315 - UT - Solar	47.74	80.00	29.6%	59.7%	2019 12 01
25	QF - 317 - UT - Solar	47.74	80.00	29.6%	59.7%	2019 12 01
26	QF - 319 - UT - Solar	47.74	80.00	29.6%	59.7%	2019 12 01
27	QF - 321 - UT - Solar	47.74	80.00	29.6%	59.7%	2019 12 01
28	QF - 323 - UT - Solar	47.74	80.00	29.6%	59.7%	2019 12 01
29	QF - 325 - UT - Solar	47.74	80.00	29.6%	59.7%	2019 12 01
30	QF - 326 - UT - Solar	12.53	21.00	34.9%	59.7%	2019 12 01
31	QF - 327 - OR - Solar	5.18	8.00	28.5%	64.8%	2018 12 01
32	QF - 328 - OR - Solar	29.81	46.00	28.7%	64.8%	2018 12 01
33	QF - 336 - UT - Solar	34.61	58.00	33.9%	59.7%	2018 07 01
34	QF - 337 - WY - Solar	7.95	13.33	26.7%	59.6%	2018 08 01
35	QF - 339 - WY - Wind	11.99	75.90	46.9%	15.8%	2018 10 01
36	QF - 340 - WY - Solar	47.74	80.00	27.4%	59.7%	2019 06 01
37	QF - 342 - UT - Solar	47.74	80.00	28.9%	59.7%	2018 12 01
38	QF - 348 - WY - Solar	47.74	80.00	27.3%	59.7%	2019 12 01
39	QF - 349 - WY - Solar	47.74	80.00	27.0%	59.7%	2019 12 01
40	QF - 350 - UT - Solar	3.58	59.00	34.9%	6.1%	2019 12 01
41	QF - 351 - OR - Solar	35.64	55.00	28.0%	64.8%	2019 01 01
42	QF - 356 - UT - Solar	47.74	80.00	30.0%	59.7%	2018 12 01
43	QF - 357 - UT - Solar	47.74	80.00	27.9%	59.7%	2020 04 01
44	QF - 358 - UT - Solar	47.74	80.00	29.7%	59.7%	2019 12 01
45	QF - 359 - UT - Solar	47.74	80.00	29.7%	59.7%	2019 12 01
46	QF - 360 - UT - Solar	47.74	80.00	29.7%	59.7%	2019 12 01
47	QF - 361 - UT - Solar	47.74	80.00	29.7%	59.7%	2019 12 01
48	QF - 362 - UT - Solar	47.74	80.00	29.7%	59.7%	2019 12 01
49	QF - 363 - UT - Solar	47.74	80.00	29.7%	59.7%	2019 12 01
50	QF - 364 - UT - Solar	47.74	80.00	29.7%	59.7%	2019 12 01
51	QF - 254 - OR - Solar	35.64	55.00	24.6%	64.8%	2020 12 31
52	QF - 365 - UT - Wind	12.64	80.00	31.4%	15.8%	2019 01 01
53	QF - 372 - WY - Solar	23.87	40.00	27.4%	59.7%	2019 06 30
54	QF - 380 - OR - Solar	32.40	50.00	25.8%	64.8%	2019 01 01
55	QF - 381 - OR - Solar	51.84	80.00	29.3%	64.8%	2021 01 01
56	QF - 382 - UT - Solar	47.74	80.00	31.5%	59.7%	2020 06 01
57	QF - 383 - OR - Solar	51.84	80.00	28.0%	64.8%	2019 12 01
58	QF - 384 - OR - Solar	51.84	80.00	28.0%	64.8%	2019 12 01
59	QF - 385 - OR - Solar	51.84	80.00	28.0%	64.8%	2019 12 01
60	QF - 386 - UT - Solar	47.74	80.00	30.8%	59.7%	2020 06 30
61	QF - 387 - UT - Solar	47.74	80.00	29.6%	59.7%	2019 12 01
Total Potential MW		2076.25	3968.10			
Total Partial Displacement		**2126.81**	**4288.10**			

Table 3
Comparison between Proposed and Current Avoided Costs

Year	BASE LOAD			WIND			SOLAR FIXED			SOLAR TRACKING		
	Proposed Avoided Costs ($/MWH)	Current Avoided Costs ($/MWH)	Total Difference ($/MWH)	Proposed Avoided Costs ($/MWH)	Current Avoided Costs ($/MWH)	Total Difference ($/MWH)	Proposed Avoided Costs ($/MWH)	Current Avoided Costs ($/MWH)	Total Difference ($/MWH)	Proposed Avoided Costs ($/MWH)	Current Avoided Costs ($/MWH)	Total Difference ($/MWH)
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
			(a) - (b)			(d) - (e)			(g) - (h)			(j) - (k)
2018	$19.97	$22.84	($2.87)	$18.11	$20.46	($2.35)	$19.36	$21.06	($1.70)	$19.15	$21.53	($2.38)
2019	$18.15	$24.02	($5.88)	$16.79	$21.56	($4.76)	$16.89	$22.39	($5.51)	$16.80	$22.96	($6.16)
2020	$16.68	$25.60	($8.92)	$15.57	$23.09	($7.52)	$14.38	$23.98	($9.60)	$14.07	$24.42	($10.34)
2021	$17.69	$27.30	($9.61)	$16.49	$24.87	($8.38)	$15.64	$25.78	($10.15)	$15.17	$26.31	($11.14)
2022	$18.63	$29.76	($11.13)	$17.16	$27.31	($10.15)	$16.38	$28.33	($11.95)	$15.89	$28.97	($13.08)
2023	$20.20	$31.99	($11.79)	$18.40	$29.36	($10.96)	$18.02	$30.61	($12.60)	$17.47	$31.35	($13.88)
2024	$21.39	$35.91	($14.52)	$20.67	$33.06	($12.40)	$18.06	$34.65	($16.60)	$16.28	$35.29	($19.01)
2025	$24.22	$38.23	($14.01)	$21.99	$35.25	($13.26)	$19.41	$36.98	($17.57)	$19.23	$37.56	($18.32)
2026	$23.71	$38.81	($15.11)	$22.03	$35.72	($13.69)	$19.43	$37.62	($18.19)	$20.08	$38.30	($18.22)
2027	$25.96	$41.11	($15.15)	$23.72	$38.01	($14.29)	$21.25	$39.94	($18.69)	$21.04	$40.57	($19.53)
2028	$29.71	$48.55	($18.84)	$29.06	$31.41	($2.35)	$22.91	$37.70	($14.78)	$23.16	$39.03	($15.87)
2029	$32.71	$49.82	($17.11)	$31.74	$31.96	($0.22)	$24.00	$38.80	($14.80)	$24.42	$40.15	($15.73)
2030	$36.99	$52.25	($15.26)	$36.09	$33.63	$2.46	$27.68	$41.05	($13.37)	$28.10	$42.42	($14.32)
2031	$38.98	$53.54	($14.56)	$54.97	$34.39	$20.58	$28.92	$42.16	($13.24)	$29.42	$43.54	($14.13)
2032	$41.17	$54.93	($13.76)	$56.94	$35.12	$21.81	$31.05	$43.35	($12.31)	$31.53	$44.76	($13.22)
2033	$47.03	$56.58	($9.55)	$59.01	$36.86	$22.15	$37.89	$44.81	($6.92)	$38.87	$46.23	($7.36)
2034	$50.79	$58.28(x)	($7.49)	$60.54	$38.68(x)	$21.86	$44.18	$46.32(x)	($2.15)	$44.94	$47.75(x)	($2.81)
2035	$56.58	$60.04(x)	($3.46)	$62.28	$40.60(x)	$21.68	$77.85	$47.88(x)	$29.97	$86.49	$49.32(x)	$37.17

(x) Extrapolated
15 Year (2018 to 2032) Levelized Prices (Nominal) @ 6.570% Discount Rate

	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
$/MWH	$23.82	$35.39	($11.58)	$23.86	$29.05	($5.19)	$19.78	$31.65	($11.87)	$19.60	$32.42	($12.82)

	Generation Profile_Baseload	Generation Profile_Wind*	Generation Profile_Solar Fixed	Generation Profile_Solar Tracking
on-peak Summer	19%	13%	31%	33%
on-peak Winter	37%	24%	52%	46%
off-peak Summer	15%	25%	7%	10%
off-peak Winter	29%	39%	10%	11%

Table 4
Natural Gas Price - Delivered to Plant
$/MMBtu

Year	Pacific NW	IRP - Wyo NE
	(a)	(b)
2018	$2.72	$2.70
2019	$2.50	$2.48
2020	$2.50	$2.48
2021	$2.52	$2.53
2022	$2.53	$2.55
2023	$2.91	$2.99
2024	$3.50	$3.61
2025	$3.78	$3.81
2026	$3.77	$3.81
2027	$3.92	$3.95
2028	$4.15	$4.15
2029	$4.51	$4.47
2030	$4.88	$4.81
2031	$5.11	$5.04
2032	$5.38	$5.28
2033	$5.76	$5.62
2034	$6.02	$5.90
2035	$6.29	$6.23
2036	$6.80	$6.70
2037	$7.05	$6.90

Source

Official Forward Price Curve dated March 31 2017

Table 5
Electricity Market Prices
$/MWH

Year	Market Price $/MWH			
	HLH		LLH	
	Mid-Columbia	Palo Verde	Mid-Columbia	Palo Verde
	(a)	(b)	(c)	(d)
2018	$24.29	$26.33	$18.49	$21.86
2019	$25.11	$27.03	$19.18	$21.46
2020	$27.21	$28.64	$20.99	$22.01
2021	$28.78	$30.10	$23.04	$23.79
2022	$30.74	$31.49	$24.58	$25.76
2023	$33.50	$33.87	$27.47	$28.81
2024	$37.10	$36.76	$30.79	$32.08
2025	$39.49	$39.08	$33.18	$33.95
2026	$40.27	$39.84	$33.95	$34.69
2027	$41.36	$40.83	$35.10	$35.89
2028	$43.71	$42.66	$37.19	$37.74
2029	$45.85	$44.88	$39.29	$40.02
2030	$48.25	$47.33	$41.83	$42.63
2031	$50.32	$49.33	$43.73	$44.41
2032	$52.51	$51.66	$45.82	$46.63
2033	$55.22	$54.43	$48.63	$49.46
2034	$57.39	$56.37	$50.74	$51.45
2035	$59.90	$58.90	$52.71	$53.67
2036	$63.38	$62.67	$56.24	$57.42
2037	$66.12	$65.02	$58.81	$59.66

Source

Official Forward Price Curve dated March 31 2017

Table 6
Integration Costs
$/MWH

Year	System Balancing Integration Costs $/MWh	Wind Integration (Incremental) $/MWh	Tracking Solar Integration (Incremental) $/MWh	Fixed Solar Integraton Costs (Incremental) $/MWh
2016	$0.145	$0.429	$0.458	$0.458
2017	$0.15	$0.44	$0.47	$0.47
2018	$0.15	$0.45	$0.48	$0.48
2019	$0.15	$0.46	$0.49	$0.49
2020	$0.16	$0.47	$0.50	$0.50
2021	$0.16	$0.48	$0.51	$0.51
2022	$0.16	$0.49	$0.52	$0.52
2023	$0.17	$0.50	$0.53	$0.53
2024	$0.17	$0.51	$0.55	$0.55
2025	$0.18	$0.52	$0.56	$0.56
2026	$0.18	$0.53	$0.57	$0.57
2027	$0.18	$0.55	$0.58	$0.58
2028	$0.19	$0.56	$0.60	$0.60
2029	$0.19	$0.57	$0.61	$0.61
2030	$0.20	$0.59	$0.63	$0.63
2031	$0.20	$0.60	$0.64	$0.64
2032	$0.21	$0.61	$0.66	$0.66
2033	$0.21	$0.63	$0.67	$0.67
2034	$0.22	$0.65	$0.69	$0.69
2035	$0.22	$0.66	$0.71	$0.71
2036	$0.23	$0.68	$0.72	$0.72
2037	$0.23	$0.69	$0.74	$0.74
2038	$0.24	$0.71	$0.76	$0.76
2039	$0.25	$0.73	$0.78	$0.78
2040	$0.25	$0.75	$0.80	$0.80
2041	$0.26	$0.76	$0.82	$0.82
2042	$0.26	$0.78	$0.84	$0.84

Appendix 2

ROCKY MOUNTAIN POWER
AVOIDED COST CALCULATION

STANDARD RATES FOR AVOIDED COST PURCHASES FROM QUALIFYING FACILITIES THAT QUALIFY FOR SCHEDULE NO. 37

UTAH – APRIL 2017

ROCKY MOUNTAIN POWER
AVOIDED COST CALCULATION

STANDARD RATES FOR AVOIDED COST PURCHASES FROM QUALIFYING FACILITIES THAT QUALIFY FOR SCHEDULE NO. 37

UTAH – APRIL 2017

OVERVIEW

Schedule 37 contains avoided cost prices to be paid to small qualifying facilities ("QF") and applies to QFs with a design capacity of 1 MW or less for qualifying cogeneration facilities and 3 MW or less for small power production facilities. Prices are available for a cumulative total of 25 MW. In compliance with the Commission's February 12, 2009, Order in Docket No. 08-035-78 on Net Metering Service, PacifiCorp (the "Company") calculates and files Schedule No. 37 avoided costs annually in order to establish the value or credit for net excess generation of large commercial customers under the Schedule No. 135 Net Metering Service.[1]

In this annual update of Utah Schedule 37 avoided cost rates, the Company proposes to calculate Schedule 37 avoided costs rates by using the same Partial Displacement Differential Revenue Requirement ("PDDRR") methodology currently used for the calculation of Schedule 38 avoided cost rates for large QFs in order to better reflect 2017 Integrated Resource Plan ("IRP") preferred portfolio assumptions. The Company's most recent 2017 IRP Preferred Portfolio includes both cost effective thermal and renewable resources, including solar and wind, and the PDDRR method is better suited to reflect deferral of different type of IRP resources. The proposed schedule 37 rates also reflect updated Generation and Regulation Initiative Decision ("GRID") model inputs including the March 2017 dated Official Forward Price Curve ("1703 OFPC"), updated proxy plant costs based on 2017 IRP Preferred Portfolio, capacity contribution values for wind and solar from the 2017 IRP, and the latest integration costs used in 2017 IRP.

DESCRIPTION OF THE AVOIDED COST STUDY WORKPAPERS

17-035-T07 RMP Wkpr - UPSC Ordered AC Study 05-30-17.xlsx: Avoided cost study workbook containing calculation of the current Commission approved avoided cost Utah schedule 37 avoided cost rates using GRID/Proxy method.

17-035-T07 RMP Wkpr - UPSC Ordered AC Study-OFPC 05-30-17.xlsx: "17-035-T07 RMP Wkpr - UPSC Ordered AC Study 05-30-17.xlsx" workbook revised with 1703 OFPC.

1 Docket No. 08-035-78, February 12, 2009 Order, U.P.S.C 24 (2009).

17-035-T07 RMP Wkpr - UPSC Ordered AC Study-OFPC-Integ 05-30-17.xlsx: **“**17-035-T07 RMP Wkpr - UPSC Ordered AC Study 05-30-17).xlsx” workbook revised with 1703 OFPC and the Integration costs from 2017 IRP.

17-035-T07 RMP Wkpr - UPSC Ordered AC Study-OFPC-Integ-CC 05-30-17.xlsx: **“**17-035-T07 RMP Wkpr - UPSC Ordered AC Study 05-30-17.xlsx” workbook revised with 1703 OFPC, the Integration costs and capacity contribution values from 2017 IRP.

17-035-T07 RMP Wkpr - UPSC Ordered AC Study-Current Method-All Updates 05-30-17.xlsx: Avoided cost study workbook containing calculation of the avoided cost rates using rates using GRID/Proxy method and all input updates including 1703 OFPC, the Integration costs and capacity contribution values from 2017 IRP, and updated GRID runs reflecting 2017 IRP Preferred portfolio.

“17-035-T07 RMP Appendix 1 - AC Study Summary 05-30-17.xlsx” contains the summary of proposed avoided cost rates using PDDRR method by QF type, 2017 IRP Preferred Portfolio, the signed an potential QF queue, the comparison of proposed rates based on proposed methodology against the currently effective rates, and the revised rates based on current methodology, the summary of natural gas and electricity market price forecasts used in GRID runs, and the integration costs from 2017 IRP.

Table 1 presents the timing of deferrable resources as listed in Table 8.17 of the Company’s 2017 IRP filing dated April 4, 2017. Table 1 shows that the Company intends to acquire thermal, and renewable resources over the next 20-year planning period. The planned IRP thermal resources includes both Simple Cycle Combustion Turbines (“SCCTs”) and Combustion Turbines (“CCCT”). The planned renewable IRP resources includes solar resources located Yakima and Utah South, and the wind resources located at Dave Johnston plant and Idaho Goshen area.

The timing of the deficiency period for a base load QF is determined based on the next deferrable IRP Thermal resource that has not been already displaced by signed and potential QFs. **Table 2** shows current size of the signed and Potential QFs, which totals to 4,288 MW nameplate capacity. Due to the current size of the signed and potential QFs in the queue, an incremental baseload QF is not able to defer any IRP thermal resource, and therefore avoided cost rates assumes no deficiency period.

The timing of the deficiency period for a Solar QF is determined based on the next deferrable IRP solar resource that has not been already displaced by signed and potential QFs. Due to current size of the signed and potential QFs in the queue, an incremental solar QF is partially displacing 2035 Utah South Solar, and avoided cost rates for a solar QF assumes that deficiency period starts in 2035.

The timing of the deficiency period for a Wind QF is determined based on the next deferrable IRP wind resource that has not been already displaced by signed and potential

QFs. Due to current size of the signed and potential QFs in the queue, an incremental wind QF is partially displacing 2031 DJ Wind, and the avoided cost rates for Wind QF assumes that deficiency period starts in 2031.

In its Order in Docket No. 09-035-T14, the Commission directed the Company "to label Table 1 with the applicable planning reserve margin assumption (e.g., 12 or 15 percent) in all subsequent filings of Schedule No. 37 rates." The IRP uses planning reserves to account for operating reserves, regulating reserves, load forecast errors and other planning uncertainties. As shown on Table 1, the 2017 IRP utilized a 13 percent planning reserve margin.

Table 3 presents the comparison of the proposed avoided costs rates based on the proposed PDDRR methodology for each QF type with the currently effective rates and the revised rates based on current methodology. **Table 4** and **Table 5** summarizes natural gas and electricity market price forecasts used in the calculation of proposed rates in this filing. Finally Table 6 summarizes integration costs values from 2017 IRP that are used in calculations of proposed avoided cost rates.

<u>DESCRIPTION OF AVOIDED COST STUDY WORKPAPERS USING PDDRRR METHODOLOGY</u>

<u>*Baseload QF*</u>

The following supporting files contain calculations of avoided cost rates for Baseload QF using PDDRR methodology:

17-035-T07 RMP CONF Workpaper 1a - GRID AC Study Thermal 05-30-17.xlsx: contains results of the GRID runs for the Base Case and the Avoided Cost Case for 2018-2027

17-035-T07 RMP CONF Workpaper 1b - GRID AC Study Thermal 05-30-17 .xlsx: contains results of the GRID runs for the Base Case and the Avoided Cost Case for 2028-2037

17-035-T07 RMP Wkpr - Avoided Cost Study-Thermal 05-30-17.xlsx:

- **Table 1:** summarizes the annual avoided energy costs based on GRID runs and shows the calculation of the annual avoided capacity costs. During deficiency period, the avoided capacity costs is based on the avoided fixed costs of the next deferrable thermal resource from 2017 IRP (that has not been already displaced by signed and potential QFs). The avoided cost for a baseload QF is zero, since the since all of the IRP thermal resources are already deferred by the signed and potential QFs in the Queue, and baseload QF is not deferring any IRP thermal resources.
- **Table 2:** summarizes monthly avoided energy costs based on GRID runs

- **Table 3:** shows the total resource cost information for each the planned new resources in 2017 IRP preferred portfolio. Total resource cost information included capital costs, and fixed and variable Operation and Maintenance (O&M) expenses, and tax credits if applicable.
- **Table 4:** summarizes annual natural gas price forecasts for East and Wes side locations
- **Table 5:** shows the monthly calculation of avoided capacity costs and avoided energy costs. Total unit avoided costs ($/MWh) are calculated by summing the avoided energy costs dollars (based on GRID runs) and the avoided costs dollars (unit fixed costs of deferred resource multiplied by the capacity contribution of the QF) and dividing by the generation of the QF.

17-035-T07 RMP Wkpr - QF Pricing Detail-Thermal 05-30-17.xlsx: contains the calculations of the monthly on-peak (HLH) and off-peak (LLH) avoided cost rates by spreading total monthly avoided cost dollars (both energy and capacity) based on projected Palo Verde ("PV") HLH and LLH market prices.

Wind QF

The following supporting files contain calculations of avoided cost rates for Wind QF using PDDRR methodology:

17-035-T07 RMP CONF Workpaper 3a - GRID AC Study Wind 05-30-17.xlsx: contains results of the GRID runs for the Base Case and the Avoided Cost Case for 2018-2027.

17-035-T07 RMP CONF Workpaper 3b - GRID AC Study Wind 05-30-17.xlsx: contains results of the GRID runs for the Base Case and the Avoided Cost Case for 2028-2037

17-035-T07 RMP Wkpr - Avoided Cost Study-Wind 5-30-17.xlsx:

- **Table 1:** summarizes the annual avoided energy costs based on GRID runs and shows the calculation of the annual avoided capacity costs. During deficiency period, the avoided capacity costs is based on the avoided fixed costs of the next deferrable Wind resource from 2017 IRP (that has not been already displaced by signed and potential QFs). Specifically, the avoided cost for a Wind QF starts in 2031 based on DJ Wind resource from 2017 IRP.
- **Table 2:** summarizes monthly avoided energy costs based on GRID runs
- **Table 3:** shows the total resource cost information for each the planned new resources in 2017 IRP preferred portfolio. Total resource cost information included capital costs, and fixed and variable Operation and Maintenance (O&M) expenses, and tax credits if applicable.
- **Table 4:** summarizes annual natural gas price forecasts for East and West side locations

- **Table 5:** shows the monthly calculation of avoided capacity costs and avoided energy costs. Total unit avoided costs ($/MWh) are calculated by summing the avoided energy costs dollars (based on GRID runs) and the avoided costs dollars (unit fixed costs of deferred resource multiplied by the capacity contribution of the QF) and dividing by the generation of the QF.

17-035-T07 RMP Wkpr - QF Pricing Detail-Wind 05-30-17.xlsx: contains the calculations of the monthly on-peak (HLH) and off-peak (LLH) avoided cost rates for a Wind QF by spreading total monthly avoided cost dollars (both energy and capacity) based on projected Palo Verde ("PV") HLH and LLH market prices.

Tracking Solar QF

The following supporting files contain calculations of avoided cost rates for Tracking Solar QF using PDDRR methodology:

17-035-T07 RMP CONF Workpaper 2a - GRID AC Study Solar T 05-30-17.xlsx: contains results of the GRID runs for the Base Case and the Avoided Cost Case for 2018-2027

17-035-T07 RMP CONF Workpaper 2b - GRID AC Study Solar T 05-30-17.xlsx: contains results of the GRID runs for the Base Case and the Avoided Cost Case for 2028-2037

17-035-T07 RMP Wkpr - Avoided Cost Study-Solar T 05-30-17.xlsx:

- **Table 1:** summarizes the annual avoided energy costs based on GRID runs and shows the calculation of the annual avoided capacity costs. During deficiency period, the avoided capacity costs is based on the avoided fixed costs of the next deferrable Solar resource from 2017 IRP (that has not been already displaced by signed and potential QFs). Specifically, the avoided cost for a Tracking Solar QF starts in 2035 based on Utah South resource from 2017 IRP.
- **Table 2:** summarizes monthly avoided energy costs based on GRID runs
- **Table 3:** shows the total resource cost information for each the planned new resources in 2017 IRP preferred portfolio. Total resource cost information included capital costs, and fixed and variable Operation and Maintenance (O&M) expenses, and tax credits if applicable.
- **Table 4:** summarizes annual natural gas price forecasts for East and West side locations
- **Table 5:** shows the monthly calculation of avoided capacity costs and avoided energy costs. Total unit avoided costs ($/MWh) are calculated by summing the avoided energy costs dollars (based on GRID runs) and the avoided costs dollars (unit fixed costs of deferred resource multiplied by the capacity contribution of the QF) and dividing by the generation of the QF.

17-035-T07 RMP Wkpr - QF Pricing Detail-Solar T 05-30-17.xlsx: contains the calculations of the monthly on-peak (HLH) and off-peak (LLH) avoided cost rates for a tracking Solar QF by spreading total monthly avoided cost dollars (both energy and capacity) based on projected Palo Verde ("PV") HLH and LLH market prices.

Fixed Solar QF

The following supporting files contain calculations of avoided cost rates for Fixed Solar QF using PDDRR methodology:

17-035-T07 RMP CONF Workpaper 4a - GRID AC Study Solar F 05-30-17.xlsx: contains results of the GRID runs for the Base Case and the Avoided Cost Case for 2018-2027

17-035-T07 RMP CONF Workpaper 4b - GRID AC Study Solar F 05-30-17.xlsx: contains results of the GRID runs for the Base Case and the Avoided Cost Case for 2028-2037

17-035-T07 RMP Wkpr - Avoided Cost Study-Solar T 05-30-17.xlsx:

- **Table 1:** summarizes the annual avoided energy costs based on GRID runs and shows the calculation of the annual avoided capacity costs. During deficiency period, the avoided capacity costs is based on the avoided fixed costs of the next deferrable Solar resource from 2017 IRP (that has not been already displaced by signed and potential QFs). Specifically, the avoided cost for a Tracking Solar QF starts in 2035 based on Utah South resource from 2017 IRP.
- **Table 2:** summarizes monthly avoided energy costs based on GRID runs
- **Table 3:** shows the total resource cost information for each the planned new resources in 2017 IRP preferred portfolio. Total resource cost information included capital costs, and fixed and variable Operation and Maintenance ("O&M") expenses, and tax credits if applicable.
- **Table 4:** summarizes annual natural gas price forecasts for East and West side locations
- **Table 5:** shows the monthly calculation of avoided capacity costs and avoided energy costs. Total unit avoided costs ($/MWh) are calculated by summing the avoided energy costs dollars (based on GRID runs) and the avoided costs dollars (unit fixed costs of deferred resource multiplied by the capacity contribution of the QF) and dividing by the generation of the QF.

17-035-T07 RMP Wkpr - Avoided Cost Study-Solar T 05-30-17.xlsx: contains the calculations of the monthly on-peak ("HLH") and off-peak ("LLH") avoided cost rates for a fixed Solar QF by spreading total monthly avoided cost dollars (both energy and capacity) based on projected Palo Verde ("PV") HLH and LLH market prices.

CERTIFICATE OF SERVICE

Docket No. 17-035-T07
Advice 17-08

I hereby certify that on May 30, 2017, a true and correct copy of the foregoing was served by electronic mail to the following:

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