PACIFIC POWER
A DIVISION OF PACIFICORP

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June 21, 2016

VIA ELECTRONIC FILING

Public Utility Commission of Oregon
201 High Street SE, Suite 100
Salem, OR 97301-1166

Attn: Filing Center

Re: UM 1729(1) – Schedule 37 Avoided Cost Purchases from Eligible Qualifying Facilities

PacifiCorp d/b/a Pacific Power (PacifiCorp or Company) respectfully asks the Public Utility Commission of Oregon (Commission) to approve this supplemental update to its standard avoided cost schedule (Schedule 37). The Company respectfully requests an effective date of August 3, 2016.

I. BACKGROUND

PacifiCorp's currently effective Schedule 37 prices are significantly outdated and do not reflect PacifiCorp's actual avoided cost prices. On June 23, 2015, the Commission approved PacifiCorp's limited May 1, 2015 Schedule 37 update.[1] These prices are stale because they still reflect inputs and assumptions (e.g., capital costs, capacity factors) from PacifiCorp's 2013 Integrated Resource Plan (IRP).

On March 1, 2016, PacifiCorp submitted a post-IRP Schedule 37 avoided cost pricing update for Commission approval. PacifiCorp's March 1, 2016 filing complied with OAR 860-029-0080 and the requirements established in Order No. 14-058 to submit updated avoided cost pricing within 30 days of IRP acknowledgement.[2] The March 1 filing requested an update to prices using inputs from the Company's 2015 IRP, acknowledged by the Commission on February 29, 2016,[3] and its December 2015 official forward price curve (OFPC). Specifically, the March 1 filing incorporated a deficiency period for standard avoided cost prices beginning in 2028. Because the 2015 IRP did not identify a need for a new renewable resource during the 20-year planning period, it did not include deficiency period pricing for the standard renewable price stream.

On March 23, 2016, the Commission issued Order No. 16-117, where it declined to approve the Company's March 1, 2016 Schedule 37 filing and instead directed parties to work together to propose an expedited, non-contested case process to update the Company's avoided costs in light of the passage of Senate Bill (SB) 1547.[4] In its recommendation to the

[1] Order No. 15-205, Docket No. UM 1729 (June 23, 2015).

[2] Order No. 14-058, Docket No. UM 1610 at 2 (Feb. 14, 2014).

[3] Order No. 16-071, Docket No. LC 62 (Feb. 29, 2016).

[4] Order No. 16-117, Docket No. UM 1729(1) (March 23, 2016).

Commission, Staff noted that SB 1547 is likely to significantly impact the utilities' resource acquisition plans, although Staff did not take a position on whether the Commission should reject the Company's avoided cost update.[5] At the Commission's March 22, 2016, public meeting, the Commission expressed concerns about the impact of SB 1547 on the renewable resource sufficiency/deficiency demarcation acknowledged in PacifiCorp's 2015 IRP.[6] The Commission ordered PacifiCorp and stakeholders to "develop a process for purposes of this avoided cost update that takes into account the new information and new resource circumstances of the utility in light of [SB] 1547."[7]

Following multiple settlement discussions, PacifiCorp, Staff, and interested stakeholders were unable to resolve issues regarding the Company's Schedule 37 update, but agreed to the non-contested process described in section II(d) below, for seeking resolution by the Commission.

On April 29, 2016, PacifiCorp filed a letter notifying the Commission that it would not make its annual May 1 avoided cost update given the ongoing work to resolve the Commission's directive regarding the Company's March 1 Schedule 37 filing.

On April 29, 2016, Portland General Electric Company (PGE) and Idaho Power Company (Idaho Power) each filed limited May 1 updates. On June 7, 2016, the Commission approved PGE's and Idaho Power's May 1 limited update filings. In Order No. 16-220, the Commission approved PGE's May 1 filing, which included a renewable resource deficiency period of 2020.

II. DISCUSSION

A. PacifiCorp's Avoided Cost Pricing Must Conform with the Customer Indifference Standard

Avoided cost pricing approved by the Commission must conform with the standard that retail customers should be indifferent to the Company's purchase of qualifying facility (QF) power. Prices paid to QFs may not exceed "the incremental cost to the electric utility of alternative electric energy."[8] The incremental cost to a utility means the amount it would cost the utility to generate or purchase the electricity but-for the purchase from the QF.[9] The incremental cost standard is intended to leave customers 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 have otherwise incurred without the QF purchase.[10] The

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[5] Order No. 16-117.

[6] *See, e.g.*, Mar. 22, 2016 Public Meeting (Commissioner Savage: "I think this is a very real issue of what constitutes deficiency and sufficiency for the avoided cost for the renewable stream in a Senate Bill 1547 world."). Archived audio available at http://www.puc.state.or.us/Pages/meetings/pmemos/2016/2016-history.aspx.

[7] *Id.* (quoting Chair Ackerman).

[8] 16 U.S.C. § 824a-3.

[9] *Id.* at § 824a-3(d).

[10] *Indep. Energy Producers Ass'n, Inc. v. Ca. Pub. Util. Comm'n*, 36 F.3d 848, 858 (9th Cir. 1994) ("If purchase rates are set at the utility's avoided cost, consumers are not forced to subsidize QFs because they

Commission has repeatedly acknowledged the importance of the customer indifference standard[11] and has identified the ratepayer indifference standard as its "primary aim."[12]

B. PacifiCorp's Proposed Renewable Schedule 37 Prices

PacifiCorp has structured this Schedule 37 update to conform to the immutable customer indifference standard while addressing concerns the Commission has expressed regarding the implications of SB 1547. The key elements of PacifiCorp's proposed filing are discussed below.

1. 2018 Renewable Resources Deficiency Period

In light of concerns raised by the Commission at the March 22, 2016 public meeting and in Order No. 16-117, the Company has proposed a deficiency period for renewable resources beginning in 2018. The Company does not believe that SB 1547 renders the Company immediately deficient. The Company's current renewable energy credit (REC) bank is sufficient through 2025. In its requests for proposals (RFPs), the Company is not looking to satisfy a specifically-identified need. Rather, the Company is seeking to fully evaluate its renewable portfolio standard (RPS) compliance alternatives, including potential near-term, time-sensitive resource procurement or REC purchase opportunities. The Company issued its RFPs on April 11, 2016, to allow the best opportunity for customers to benefit from taking full advantage of federal tax credits, including the production tax credit (PTC) and investment tax credit (ITC).

2. Updated Capital Costs, Capacity Factors, and Forward Price Curve Data

Based on the Commissioner comments that SB 1547 rendered the Company's 2015 Integrated Resource Plan (IRP) out of date, PacifiCorp has updated avoided cost inputs consistent with its 2015 IRP Update, filed with the Commission on March 31, 2016. These updates include utilizing current capital costs, capacity factors, and production tax credits (PTCs) for a renewable proxy resource in order to produce more complete and up-to-date avoided cost prices. In its 2015 IRP, PacifiCorp estimated that a 2018 wind resource located in Oregon would

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are paying the same amount they would have paid if the utility had generated energy itself or purchased energy elsewhere.")

[11] *See, e.g.,* Docket No. UM 1129, Order No. 05-584 at 11 (May 13, 2005) ("We seek to provide maximum incentives for the development of QFs of all sizes, while ensuring that ratepayers remain indifferent to QF power by having utilities pay no more than their avoided costs."); Docket UM 1129, Order No. 06-538 at 37 ("[O]ur overriding goals in this docket are to encourage QF development, while ensuring that ratepayers are indifferent to QF power."); Docket No. UM 1129, Order No. 07-360 at 1 (Aug. 20, 2007) ("This Commission's goal is to encourage the economically efficient development of QFs, while protecting ratepayers by ensuring that utilities incur costs no greater than they would have incurred in lieu of purchasing QF power (avoided costs)"); Order No. 14-058 at 12 ("We first return to the goal of this docket: to ensure that our PURPA policies continue to promote QF development while ensuring that utilities pay no more than avoided costs."); Docket No. UM 1734, Order No. 15-241 at 3 (Aug. 14, 2015) (The Commission must "protect ratepayers from the possibility of being charged more than PacifiCorp's avoided power costs….")

[12] *See, e.g.,* Order No. 05-584 at 45 ("In balancing the goals of facilitating QF contracts while sufficiently protecting ratepayers, we recognize that the primary aim is to ensure that ratepayers remain indifferent to the source of power that serves them.")

have a capital cost of $2,302/kW and operate at a 29% capacity factor. In its 2015 IRP Update, PacifiCorp estimates that a 2018 wind resource located in Oregon would have a capital cost of $1,803/kW and operate a capacity factor between 29% and 35%. Preliminary review of the lowest cost bids for wind projects located in the Pacific Northwest submitted into the 2016 resource RFP have a capacity-weighted average capital cost of $1,810/kW and a capacity-weighted average capacity factor of 34.9%. If a 2018 renewable resource deficiency period is used to establish avoided cost rates, the wind resource capital cost and capacity factor of 35% as reported in PacifiCorp's 2015 IRP Update should be used. Moreover, as assumed in PacifiCorp's 2015 IRP Update, and consistent with bids received in the 2016 resource RFP, it should be assumed that the 2018 renewable proxy resource can take full advantage of PTCs. If the wind resource costs and performance are at the level previously assumed in the 2015 IRP it is clear they would not be representative of the current cost and performance of an avoidable proxy renewable resource and would not be indicative of the cost of a resource potentially acquired through the RFP.

This Schedule 37 update also includes the Company's March 2016 OFPC which is the latest OFPC available and is the OFPC that would have been used had the Company made its May 1 annual update.

The data used to calculate the proposed Schedule 37 prices reflects the most current and accurate data available. Approving avoided cost pricing based on stale inputs and assumptions would only harm customers by ensuring they are paying costs exceeding actual avoided cost prices.

PacifiCorp has presented a balanced proposal that updates prices to reflect the requirements of SB 1547 while incorporating the most accurate cost, performance, and price curve data. Avoided cost prices that include an updated 2018 deficiency period while relying on stale cost and performance data would result in pricing that violates the customer indifference standard and would harm PacifiCorp customers vis-à-vis customers of other investor-owned utilities in Oregon. The tables below compare PacifiCorp's proposed Schedule 37 renewable prices (based on 2018 deficiency period and updated cost, performance, and OFPC data) to: (1) PacifiCorp's March 1, 2016, proposed renewable avoided cost prices; (2) hypothetical prices that include an assumed 2018 deficiency demarcation but that utilizes cost and performance from the 2015 IRP rather than updated cost and performance data for a proxy resource; and (3) the current Commission-approved renewable avoided cost prices.

15 Year (2017-2031) Nominal Levelized Price - $/MWh

	Renewable Fixed Avoided Cost Prices				Comparison to Proposed Renewable Prices			
	Base Load QF	Wind QF	Fixed Solar QF	Tracking Solar QF	Base Load QF	Wind QF	Fixed Solar QF	Tracking Solar QF
Proposed Renewable Prices	$52.61	$38.59	$45.91	$46.84				
March 1, 2016 Proposal	$34.99	$31.35	$36.99	$36.99	($17.62)	($7.24)	($8.93)	($9.85)
2018 Defiency Start, 2015 IRP Proxy	$78.61	$64.59	$73.44	$74.37	$26.00	$26.00	$27.52	$27.52
Current Commission Approved	$63.70	$53.09	$60.68	$60.68	$11.09	$14.50	$14.76	$13.84

Inputs/Assumptions

	Renewable Deficiency Start	OFPC	Renewable Proxy
Proposed Renewable Prices	2018	Mar 2016	2015 IRP Update OR Wind 35% CF
March 1, 2016 Proposal	N/A	Dec 2015	No Renewable Proxy
2018 Defiency Start, 2015 IRP Proxy	2018	Mar 2016	2015 IRP OR Wind 29% CF
Current Commission Approved	2024	Mar 2015	2013 IRP WY Wind 40% CF

The pricing summary above illustrates the harm that PacifiCorp's customers would sustain if the deficiency demarcation is moved up to 2018 while proxy inputs from the 2015 IRP are retained. Indeed, discarding some inputs from the 2015 IRP (i.e., deficiency demarcation) while retaining others (proxy cost and performance inputs) would result in arbitrarily high prices that conflict with the customer indifference standard. For a 3 MW tracking solar QF, this price disparity would result in higher payments from customers to the QF in excess of $3 million over a 15-year fixed-price contract.[13]

The Commission seemed to recognize this issue at the March 22, 2016, public meeting when it concluded that SB 1547 represented a "significant change" and that the Company's updated avoided costs should reflect "new information and new resource circumstances … in light of SB 1547."[14] PacifiCorp's proposed Schedule 37 prices incorporate "new information and new resources circumstances" as ordered by the Commission and satisfies the customer indifference standard.[15]

C. No Changes Proposed to Standard/Baseload Renewable Prices

Since SB 1547 does not impact baseload pricing, the Company's proposed standard avoided cost rates are consistent with those filed on March 1, 2016, but with the market price curve updated to the March 2016 OFPC which would have been used had the Company made its May 1 annual update. The sufficiency period in the 2015 IRP Update is consistent with the sufficiency period acknowledged by the Commission in the 2015 IRP. The Commission did not express concerns about the standard price stream in Order No. 16-117, and there is no evidence that changes are needed.

The tables below compare PacifiCorp's proposed Schedule 37 standard prices (based on 2028 deficiency period and updated OFPC data) to: (1) PacifiCorp's March 1, 2016, proposed

[13] ($74.48/MWh - $46.84/MWh) * 3 MW * 8,760 hours/year * 29.2% capacity factor * 15 years = $3,181,540

[14] Mar. 22, 2016 Public Meeting (quoting Chair Ackerman).

[15] The Company has not reflected any changes associated with Order No. 16-174 in this filing. The Company will make its UM 1610 Phase II compliance filing within 60 days of Order No. 16-174.

standard avoided cost prices; and (2) the current Commission-approved standard avoided cost prices.

15 Year (2017-2031) Nominal Levelized Price - $/MWh

	Standard Fixed Avoided Cost Prices				Comparison to Proposed Standard Prices			
	Base Load QF	Wind QF	Fixed Solar QF	Tracking Solar QF	Base Load QF	Wind QF	Fixed Solar QF	Tracking Solar QF
Proposed Standard Prices	$36.70	$30.67	$36.43	$36.64				
March 1, 2016 Proposal	$35.85	$29.83	$35.73	$35.94	($0.85)	($0.84)	($0.70)	($0.70)
Current Commission Approved	$42.16	$31.55	$37.32	$37.32	$5.46	$0.88	$0.89	$0.68

Inputs/Assumptions

	Renewable Deficiency Start	OFPC	CCCT Proxy
Proposed Standard Prices	2028	Mar 2016	2015 IRP CCCT
March 1, 2016 Proposal	2028	Dec 2015	2015 IRP CCCT
Current Commission Approved	2024	Mar 2015	2013 IRP CCCT

D. Proposed Procedural Schedule

Staff, PacifiCorp, and stakeholders who participated in the settlement discussions have agreed to the following proposed schedule for addressing PacifiCorp's avoided cost update, which will allow for Commission consideration of PacifiCorp's pricing update at the August 2, 2016 public meeting.

UM 1729 Preliminary Schedule for August 2, 2016 Public Meeting	
PacifiCorp files amended Schedule 37 and supporting workpapers	Tuesday, June 21, 2016
Comments on proposed Schedule 37 filed	Friday, July 1, 2016
Staff releases draft public meeting memo for review	Tuesday, July 12, 2016
Comments on draft memo filed	Tuesday, July 19, 2016
Final memo posted with comments incorporated	Tuesday, July 26, 2016
Public meeting	Tuesday, August 2, 2016

III. CONCLUSION

PacifiCorp respectfully asks the Commission to approve this supplemental update to Schedule 37 as described above.

It is respectfully requested that all formal data requests regarding this matter be addressed to:

By E-Mail (preferred): datarequest@pacificorp.com

By regular mail: Data Request Response Center
PacifiCorp
825 NE Multnomah Street, Suite 2000
Portland, Oregon, 97232

Informal inquiries may be directed to me at (503) 813-6389.

Sincerely,

R Bryce Dalley / eam

R. Bryce Dalley
Vice President, Regulation

CERTIFICATE OF SERVICE

I certify that I served a true and correct copy of PacifiCorp's Compliance Filing on the parties listed below via electronic mail and/or US mail in compliance with OAR 860-001-0180.

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Dated this 21st day of June 2016.

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CERTIFICATE OF SERVICE

I certify that I served a true and correct copy of PacifiCorp's Compliance Filing on the parties listed below via electronic mail and/or US mail in compliance with OAR 860-001-0180.

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Dated this 21st day of June, 2016.

Jennifer Angell

Jennifer Angell
Supervisor, Regulatory Operations

Available

To owners of Qualifying Facilities making sales of electricity to the Company in the State of Oregon.

Applicable

- For power purchased from Base Load and Wind Qualifying Facilities with a nameplate capacity of 10,000 kW or less or that, together with any other electric generating facility using the same motive force, owned or controlled by the same person(s) or affiliated person(s), and located at the same site, has a nameplate capacity of 10,000 kW or less. (C)
- For power purchased Fixed and Tracking Solar Qualifying Facilities with a nameplate capacity of 3,000 kW or less or that, together with any other electric generating facility using the same motive force, owned or controlled by the same person(s) or affiliated person(s), and located at the same site, has a nameplate capacity of 3,000 kW or less. (N)

Owners of these Qualifying Facilities will be required to enter into a written power sales contract with the Company. (N)

Definitions

Cogeneration Facility
A facility which produces electric energy together with steam or other form of useful energy (such as heat) which are used for industrial, commercial, heating or cooling purposes through the sequential use of energy.

Qualifying Facilities
Qualifying cogeneration facilities or qualifying small power production facilities within the meaning of section 201 and 210 of the Public Utility Regulatory Policies Act of 1978 (PURPA), 16 U.S.C. 796 and 824a-3.

Qualifying Electricity
Electricity that meets the requirements of “qualifying electricity” set forth in the Oregon Renewable Portfolio Standards: ORS 469A.010, 469A.020, and 469A.025.

Renewable Qualifying Facility
A Qualifying Facility that generates Qualifying Electricity.

Wind Qualifying Facility
A Renewable Qualifying Facility that generates Qualifying Electricity using wind as its motive force.

Baseload Renewable Qualifying Facility
A Renewable Qualifying Facility that generates Qualifying Electricity using any qualifying resource other than wind or solar.

Small Power Production Facility
A facility which produces electric energy using as a primary energy source biomass, waste, renewable resources or any combination thereof and has a power production capacity which, together with other facilities located at the same site, is not greater than 80 megawatts.

(continued)

Definitions (continued)

On-Peak Hours or Peak Hours (M)
On-Peak hours are defined as 6:00 a.m. to 10:00 p.m. Pacific Prevailing Time Monday through Saturday, excluding NERC holidays.

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. (M)

Off-Peak Hours
All hours other than On-Peak.

Excess Output
Excess Output shall mean any increment of Net Output delivered at a rate, on an hourly basis, exceeding the Facility Nameplate Capacity. PacifiCorp shall pay Seller the Off-Peak Price as described and calculated under pricing option 4 (Non-Firm Market Index Avoided Cost Price) for all Excess Output.

Same Site
Generating facilities are considered to be located at the same site as the QF for which qualification for the standard rates and standard contract is sought if they are located within a five-mile radius of any generating facilities or equipment providing fuel or motive force associated with the QF for which qualification for the standard rates and standard contract is sought.

Person(s) or Affiliated Person(s)
A natural person or persons or any legal entity or entities sharing common ownership, management or acting jointly or in concert with or exercising influence over the policies or actions of another person or entity. Two facilities will not be held to be owned or controlled by the same person(s) or affiliated person(s) solely because they are developed by a single entity. Two facilities will not be held to be owned or controlled by the same person(s) or affiliated person(s) if such common person or persons is a “passive investor” whose ownership interest in the QF is primarily related to utilizing production tax credits, green tag values and MACRS depreciation as the primary ownership benefit and the facilities at issue are independent family-owned or community-based projects. A unit of Oregon local government may also be a “passive investor” in a community-based project if the local governmental unit demonstrates that it will not have an equity ownership interest in or exercise any control over the management of the QF and that its only interest is a share of the cash flow from the QF, which share will not exceed 20%. The 20% cash flow share limit may only be exceeded for good cause shown and only with the prior approval of the Commission.

Shared Interconnection and Infrastructure
QFs otherwise meeting the separate ownership test and thereby qualified for entitlement to the standard rates and standard contract will not be disqualified by utilizing an interconnection or other infrastructure not providing motive force or fuel that is shared with other QFs qualifying for the standard rates and standard contract so long as the use of the shared interconnection complies with the interconnecting utility’s safety and reliability standards, interconnection contract requirements and Prudent Electrical Practices as that term is defined in the interconnecting utility’s approved standard contract.

(continued)

Dispute Resolution (M)

Upon request, the QF will provide the purchasing utility with documentation verifying the ownership, management and financial structure of the QF in reasonably sufficient detail to allow the utility to make an initial determination of whether or not the QF meets the above-described criteria for entitlement to the standard rates and standard contract.

Any dispute concerning a QF's entitlement to the standard rates and standard contract shall be presented to the Commission for resolution. (M)

Self Supply Option

Owner shall elect to sell all Net Output to PacifiCorp and purchase its full electric requirements from PacifiCorp or sell Net Output surplus to its needs at the Facility site to PacifiCorp and purchase partial electric requirements service from PacifiCorp, in accordance with the terms and conditions of the power purchase agreement and the appropriate retail service.

Pricing Options

1. Standard Fixed Avoided Cost Prices

Prices are fixed at the time that the contract is signed by both the Qualifying Facility and the Company and will not change during the term of the contract. Standard Fixed Avoided Cost Prices are available for a contract term of up to 15 years and prices under a longer term contract (up to 20 years) will thereafter be under the Firm Market Indexed Avoided Cost Price, The Standard Fixed Avoided Cost pricing option is available to all Qualifying Facilities. The Standard Fixed Avoided Cost Price for Wind Qualifying Facilities will reflect integration costs as set forth on page 5.

2. Renewable Fixed Avoided Cost Prices

Prices are fixed at the time that the contract is signed by both the Renewable Qualifying Facility and the Company and will not change during the term of the contract. Renewable Fixed Avoided Cost Prices are available for a contract term of up to 15 years and prices under a longer term contract (up to 20 years) will thereafter be under the Firm Market Indexed Avoided Cost Price. The Renewable Fixed Avoided Cost pricing option is available only to Renewable Qualifying Facilities. A Renewable Qualifying Facility choosing the Renewable Fixed Avoided Cost pricing option must cede all Green Tags generated by the facility, as defined in the standard contract, to the Company during the Renewable Resource Deficiency Period identified on page 6, except that a Renewable Qualifying Facility retains ownership of all Environmental Attributes generated by the facility, as defined in the standard contract, during the Renewable Resource Sufficiency Period identified on page 6 and during any period after the first 15 years of a longer term contract (up to 20 years).

3. Firm Market Indexed Avoided Cost Prices

Firm Market Index Avoided Cost Prices are available to Qualifying Facilities that contract to deliver firm power. Monthly on-peak / off-peak prices paid are a blending of Intercontinental Exchange (ICE) Day Ahead Power Price Report at market hubs for on-peak and off-peak prices. The monthly blending matrix is available upon request.

(continued)

Pricing Options (continued) (M)

4. Non-Firm Market Index Avoided Cost Prices

Non-Firm Market Index Avoided Cost Prices are available to Qualifying Facilities that do not elect to provide firm power. Qualifying Facilities taking this option will have contracts that do not include minimum delivery requirements, default damages for construction delay or, for under delivery or early termination, or default security for these purposes. Monthly On-Peak / Off-Peak prices paid are 93 percent of a blending of ICE Day Ahead Power Price Report at market hubs for on-peak and off-peak firm index prices. The monthly blending matrix is available upon request. The Non-Firm Market Index Avoided Cost pricing option is available to all Qualifying Facilities. The Non-Firm Market Index Avoided Cost Price for Wind Qualifying Facilities will reflect integration costs. (M)

Monthly Payments

A Qualifying Facility shall select the option of payment at the time of signing the contract under one of the Pricing Options specified above. Once an option is selected the option will remain in effect for the duration of the Facility's contract.

Renewable or Standard Fixed Avoided Cost Prices

In accordance with the terms of a contract with a Qualifying Facility, the Company shall pay for all separately metered kilowatt-hours of On-Peak and Off-Peak generation at the renewable or standard fixed prices as provided in this schedule. On-Peak and Off-Peak are defined in the definitions section of this schedule.

Firm Market Indexed and Non-Firm Market Index Avoided Cost Prices

In accordance with the terms of a contract with a Qualifying Facility, the Company shall pay for all separately metered kilowatt-hours of On-Peak and Off-Peak generation at the market prices calculated at the time of delivery. On-Peak and Off-Peak are defined in the definitions section of this schedule.

(continued)

Avoided Cost Prices

Standard Fixed Avoided Cost Prices for Base Load and Wind QF (C)

Deliveries During Calendar Year	Base Load QF (1,3) On-Peak Energy Price	Base Load QF (1,3) Off-Peak Energy Price	Wind QF (2,3) On-Peak Energy Price	Wind QF (2,3) Off-Peak Energy Price
	(a)	(b)	(c)	(d)
2016	2.34	1.99	2.03	1.67
2017	2.63	2.17	2.31	1.85
2018	2.82	2.30	2.50	1.97
2019	2.94	2.38	2.61	2.05
2020	3.10	2.51	2.76	2.17
2021	3.30	2.71	2.95	2.36
2022	3.60	3.00	3.24	2.64
2023	4.03	3.37	3.66	3.00
2024	4.44	3.73	4.07	3.36
2025	4.66	3.93	4.28	3.55
2026	4.84	4.09	4.45	3.70
2027	5.06	4.27	4.66	3.87
2028	6.23	3.25	3.59	2.84
2029	6.39	3.34	3.69	2.92
2030	6.66	3.55	3.91	3.12
2031	6.82	3.64	4.01	3.20
2032	6.99	3.74	4.12	3.29
2033	7.19	3.86	4.25	3.40
2034	7.38	3.98	4.37	3.51
2035	7.56	4.09	4.49	3.61

(C)

(continued)

Avoided Cost Prices (Continued)

Standard Fixed Avoided Cost Prices for Fixed and Tracking Solar QF (N)

Deliveries During Calendar Year	Fixed Solar QF (3)		Tracking Solar QF (3)	
	On-Peak Energy Price	Off-Peak Energy Price	On-Peak Energy Price	Off-Peak Energy Price
	(e)	(f)	(g)	(h)
2016	2.34	1.99	2.34	1.99
2017	2.63	2.17	2.63	2.17
2018	2.82	2.30	2.82	2.30
2019	2.94	2.38	2.94	2.38
2020	3.10	2.51	3.10	2.51
2021	3.30	2.71	3.30	2.71
2022	3.60	3.00	3.60	3.00
2023	4.03	3.37	4.03	3.37
2024	4.44	3.73	4.44	3.73
2025	4.66	3.93	4.66	3.93
2026	4.84	4.09	4.84	4.09
2027	5.06	4.27	5.06	4.27
2028	4.21	3.25	4.34	3.25
2029	4.32	3.34	4.46	3.34
2030	4.55	3.55	4.69	3.55
2031	4.66	3.64	4.81	3.64
2032	4.78	3.74	4.93	3.74
2033	4.93	3.86	5.08	3.86
2034	5.07	3.98	5.22	3.98
2035	5.21	4.09	5.36	4.09

(N)

(1) Capacity Contribution to Peak for Avoided Proxy Resource and Base Load Qualifying Facility resource are assumed 100%. (M) (M)

(2) The standard avoided cost price for wind is reduced by an integration charge of $3.06/MWh ($2014). If Wind Qualifying Facility is not in PacifiCorp's balancing authority area, then no reduction is required. (C)(M) (M)

(3) Standard Resource Sufficiency Period ends December 31, 2027 and Standard Resource Deficiency Period begins January 1, 2028. (N) (N)

(continued)

Avoided Cost Prices (Continued)

Renewable Fixed Avoided Cost Prices for Base Load and Wind QF (M)(C)

Deliveries During Calendar Year	Renewable Base Load QF (1,4)		Wind QF (1,2,3)	
	On-Peak Energy Price	Off-Peak Energy Price	On-Peak Energy Price	Off-Peak Energy Price
	(a)	(b)	(c)	(d)
2016	2.34	1.99	2.03	1.67
2017	2.63	2.17	2.31	1.85
2018	6.04	3.40	3.94	3.08
2019	6.18	3.48	4.03	3.15
2020	6.29	3.62	4.08	3.28
2021	6.41	3.75	4.15	3.40
2022	6.58	3.81	4.27	3.45
2023	6.74	3.88	4.38	3.51
2024	6.88	3.98	4.47	3.61
2025	7.03	4.08	4.56	3.70
2026	7.17	4.18	4.65	3.79
2027	7.33	4.28	4.75	3.88
2028	7.49	4.37	4.86	3.96
2029	7.65	4.46	4.95	4.05
2030	7.82	4.55	5.07	4.12
2031	7.99	4.65	5.18	4.22
2032	8.16	4.77	5.29	4.32
2033	8.33	4.88	5.39	4.43
2034	8.51	5.00	5.51	4.53
2035	8.67	5.13	5.61	4.66

(M)(C)

(continued)

Avoided Cost Prices (Continued)

Renewable Fixed Avoided Cost Prices for Fixed and Tracking Solar QF (N)

Deliveries During Calendar Year	Fixed Solar QF (1,4) On-Peak Energy Price	Fixed Solar QF (1,4) Off-Peak Energy Price	Tracking Solar QF (1,4) On-Peak Energy Price	Tracking Solar QF (1,4) Off-Peak Energy Price
	(e)	(f)	(g)	(h)
2016	2.34	1.99	2.34	1.99
2017	2.63	2.17	2.63	2.17
2018	4.42	3.40	4.53	3.40
2019	4.53	3.48	4.64	3.48
2020	4.59	3.62	4.71	3.62
2021	4.67	3.75	4.79	3.75
2022	4.80	3.81	4.92	3.81
2023	4.93	3.88	5.05	3.88
2024	5.03	3.98	5.15	3.98
2025	5.13	4.08	5.26	4.08
2026	5.24	4.18	5.37	4.18
2027	5.34	4.28	5.48	4.28
2028	5.47	4.37	5.60	4.37
2029	5.58	4.46	5.72	4.46
2030	5.71	4.55	5.85	4.55
2031	5.83	4.65	5.97	4.65
2032	5.95	4.77	6.10	4.77
2033	6.08	4.88	6.22	4.88
2034	6.21	5.00	6.36	5.00
2035	6.32	5.13	6.48	5.13

(N)

(1) For the purpose of determining: (i) when the Renewable Qualifying Facility is entitled to renewable avoided cost prices; and (ii) the ownership of Environmental Attributes and the transfer of Green Tags to PacifiCorp, the Renewable Resource Sufficiency Period ends December 31, 2017, and the Renewable Resource Deficiency Period begins January 1, 2018. (C) (C) (D)

(2) During the Renewable Resource Deficiency Period, the renewable avoided cost price for a Wind Qualifying Facility will be adjusted by adding the difference between the avoided integration costs and the Qualifying Facility's integration costs. If the Wind Qualifying Facility is in PacifiCorp's Balancing Authority Area (BAA), the adjustment is zero (integration costs cancel each other out). If the Wind Qualifying Facility is not in PacifiCorp's BAA, the renewable avoided cost price will be increased by avoided integration charge of $3.06/MWh ($2014). (C) (C) (C)

(3) During Renewable Resource Sufficiency Period, the renewable avoided cost price for a Wind Qualifying Facility is reduced by an integration charge of $3.06/MWh ($2014) for Wind Qualifying Facilities located in PacifiCorp's BAA (in-system). If a Wind Qualifying Facility is not in PacifiCorp's BAA, the renewable avoided cost price will be increased by avoided integration charge of $3.06/MWh ($2014). (C) (C)

(4) During the Renewable Resource Deficiency Period, the renewable avoided cost price for Base Load, Fixed Solar and Tracking Solar is increased by an integration charge of $3.06/MWh ($2014). (N) (N)

(continued)

Qualifying Facilities Contracting Procedure (M)

Interconnection and power purchase agreements are handled by different functions within the Company. Interconnection agreements (both transmission and distribution level voltages) are handled by the Company's transmission function (PacifiCorp Transmission Services) while power purchase agreements are handled by the Company's merchant function (PacifiCorp Commercial and Trading).

It is recommended that the owner initiate its request for interconnection 18 months ahead of the anticipated in-service date to allow time for studies, negotiation of agreements, engineering, procurement, and construction of the required interconnection facilities. Early application for interconnection will help ensure that necessary interconnection arrangements proceed in a timely manner on a parallel track with negotiation of the power purchase agreement.

1. Eligible Qualifying Facilities (C)

APPLICATION: To owners of eligible existing or proposed QFs with a design capacity less than or equal to 10,000 kW for Base Load and Wind QF resources and less than or equal to 3,000 kW for Solar QF resources who desire to make sales to the Company in the state of Oregon. Such owners will be required to enter into a written power purchase agreement with the Company pursuant to the procedures set forth below. (C) (C)

I. Process for Completing a Power Purchase Agreement

A. Communications

Unless otherwise directed by the Company, all communications to the Company regarding QF power purchase agreements should be directed in writing as follows:

PacifiCorp
Manager-QF Contracts
825 NE Multnomah St, Suite 600
Portland, Oregon 97232

The Company will respond to all such communications in a timely manner. If the Company is unable to respond on the basis of incomplete or missing information from the QF owner, the Company shall indicate what additional information is required. Thereafter, the Company will respond in a timely manner following receipt of all required information. (M)

(continued)

(M)

B. Procedures

1. The Company's approved generic or standard form power purchase agreements may be obtained from the Company's website at www.pacificorp.com, or if the owner is unable to obtain it from the website, the Company will send a copy within seven days of a written request.

2. In order to obtain a project specific draft power purchase agreement the owner must provide in writing to the Company, general project information required for the completion of a power purchase agreement, including, but not limited to:

   (a) demonstration of ability to obtain QF status;
   (b) design capacity (MW), station service requirements, and net amount of power to be delivered to the Company's electric system;
   (c) generation technology and other related technology applicable to the site;
   (d) proposed site location;
   (e) schedule of monthly power deliveries;
   (f) calculation or determination of minimum and maximum annual deliveries;
   (g) motive force or fuel plan;
   (h) proposed on-line date and other significant dates required to complete the milestones;
   (i) proposed contract term and pricing provisions as defined in this Schedule (i.e.,standard fixed price, renewable fixed price);
   (j) status of interconnection or transmission arrangements;
   (k) point of delivery or interconnection;

3. The Company shall provide a draft power purchase agreement when all information described in Paragraph 2 above has been received in writing from the QF owner. Within 15 business days following receipt of all information required in Paragraph 2, the Company will provide the owner with a draft power purchase agreement including current standard avoided cost prices and/or other optional pricing mechanisms as approved by the Public Utility Commission of Oregon in this Schedule 37.

4. If the owner desires to proceed with the power purchase agreement after reviewing the Company's draft power purchase agreement, it may request in writing that the Company prepare a final draft power purchase agreement. In connection with such request, the owner must provide the Company with any additional or clarified project information that the Company reasonably determines to be necessary for the preparation of a final draft power purchase agreement. Within 15 business days following receipt of all information requested by the Company in this paragraph 4, the Company will provide the owner with a final draft power purchase agreement.

(M)

(continued)

(M)

B. Procedures (continued)

5 After reviewing the final draft power purchase agreement, the owner may either prepare another set of written comments and proposals or approve the final draft power purchase agreement. If the owner prepares written comments and proposals the Company will respond in 15 business days to those comments and proposals.

6. When both parties are in full agreement as to all terms and conditions of the draft power purchase agreement, the Company will prepare and forward to the owner within 15 business days, a final executable version of the agreement. Following the Company's execution a completely executed copy will be returned to the owner. Prices and other terms and conditions in the power purchase agreement will not be final and binding until the power purchase agreement has been executed by both parties.

II. Process for Negotiating Interconnection Agreements

[NOTE: Section II applies only to QFs connecting directly to PacifiCorp's electrical system. An off-system QF should contact its local utility or transmission provider to determine the interconnection requirements and wheeling arrangement necessary to move the power to PacifiCorp's system.]

In addition to negotiating a power purchase agreement, QFs intending to make sales to the Company are also required to enter into an interconnection agreement that governs the physical interconnection of the project to the Company's transmission or distribution system. The Company's obligation to make purchases from a QF is conditioned upon the QF completing all necessary interconnection arrangements. It is recommended that the owner initiate its request for interconnection 18 months ahead of the anticipated in-service date to help ensure that necessary interconnection arrangements proceed in a timely manner on a parallel track with negotiation of the power purchase agreement.

Because of functional separation requirements mandated by the Federal Energy Regulatory Commission, interconnection and power purchase agreements are handled by different functions within the Company. Interconnection agreements (both transmission and distribution level voltages) are handled by the Company's transmission function (including but not limited to PacifiCorp Transmission Services) while power purchase agreements are handled by the Company's merchant function (including but not limited to PacifiCorp's Commercial and Trading Group). (M)

(continued)

(M)

II. Process for Negotiating Interconnection Agreements (continued)

A. Communications

Initial communications regarding interconnection agreements should be directed to the Company in writing as follows:

PacifiCorp
Director – Transmission Services
825 NE Multnomah St, Suite 1600
Portland, Oregon 97232

Based on the project size and other characteristics, the Company will direct the QF owner to the appropriate individual within the Company's transmission function who will be responsible for negotiating the interconnection agreement with the QF owner. Thereafter, the QF owner should direct all communications regarding interconnection agreements to the designated individual, with a copy of any written communications to the address set forth above.

B. Procedures

Generally, the interconnection process involves (1) initiating a request for interconnection, (2) undertaking studies to determine the system impacts associated with the interconnection and the design, cost, and schedules for constructing any necessary interconnection facilities, and (3) executing an interconnection agreement to address facility construction, testing, acceptance, ownership, operation and maintenance issues. Consistent with PURPA and Oregon Public Utility Commission regulations, the owner is responsible for all interconnection costs assessed by the Company on a nondiscriminatory basis. For interconnections impacting the Company's Transmission and Distribution System, the Company will process the interconnection application through PacifiCorp Transmission Services.

(M)

PACIFIC POWER
AVOIDED COST CALCULATION

STANDARD RATES FOR AVOIDED COST PURCHASES FROM ELIGIBLE QUALIFYING FACILITIES

OREGON – June 2016

Exhibit 1

Standard Avoided Cost Prices for Base Load QF (1)

$/MWH

	Standard Avoided Resource			Base Load QF Resource	
Year	Capacity Price	Capacity Cost Allocated to On-Peak Hours	Energy Only Price	On-Peak	Off-Peak
	$/kW-yr	($/MWh)	$/MWh	$/MWh	$/MWh
	(a)	(b)	(c)	(d)	(e)
		(a) /(8.76 x 100.0% x 57%)		(b) + (c)	= (c)
2016	Market Based Prices 2016 through 2027			$23.43	$19.86
2017				$26.30	$21.68
2018				$28.22	$22.97
2019				$29.44	$23.80
2020				$30.99	$25.14
2021				$33.03	$27.14
2022				$35.96	$30.03
2023				$40.26	$33.69
2024				$44.43	$37.30
2025				$46.61	$39.32
2026				$48.41	$40.90
2027				$50.57	$42.74
2028	$149.06	$29.85	$32.45	$62.30	$32.45
2029	$152.18	$30.48	$33.37	$63.85	$33.37
2030	$155.56	$31.15	$35.46	$66.61	$35.46
2031	$158.99	$31.84	$36.37	$68.21	$36.37
2032	$162.49	$32.54	$37.35	$69.89	$37.35
2033	$166.05	$33.26	$38.59	$71.85	$38.59
2034	$169.68	$33.98	$39.77	$73.75	$39.77
2035	$173.39	$34.73	$40.88	$75.61	$40.88

(1) Capacity Contribution of the Avoided Proxy and Base Load QF resources are assumed to be 100%.

Columns

- (a) Full fixed cost of a proxy CCCT less capitalized energy
- (b) 100.0% is the on-peak capacity factor of the Proxy Resource
  57.0% is the percent of all hours that are on-peak
- (c) Fuel and Capitalized Energy Cost of the Proxy CCCT
- (d) 2016-2027 On-Peak Blended Market Prices for QF resource
- (e) 2016-2027 Off-Peak Blended Market Prices for QF resource

Exhibit 2
Standard Avoided Cost Prices for Wind QF (1,2)
$/MWH

	Standard Avoided Resource			Wind QF Resource			
Year	Capacity Price	Capacity Cost Allocated to On-Peak Hours	Energy Only Price	Capacity Contribution	Capacity Payment On-Peak Hours	On-Peak	Off-Peak
	$/kW-yr	($/MWh)	$/MWh		$/MWh	$/MWh	$/MWh
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		(a) /(8.76 x 100.0% x 57%)			= (b) * (d)	= (c) + (e)	= (c)
2016						$20.31	$16.74
2017						$23.11	$18.49
2018		Market Based Prices				$24.95	$19.70
2019		2016 through 2027				$26.09	$20.45
2020		less Wind Integration (2)				$27.56	$21.71
2021						$29.52	$23.63
2022						$32.37	$26.44
2023						$36.59	$30.02
2024						$40.68	$33.55
2025						$42.78	$35.49
2026						$44.50	$36.99
2027						$46.57	$38.74
2028	$149.06	$29.85	$32.45	25.40%	$7.58	$35.94	$28.36
2029	$152.18	$30.48	$33.37	25.40%	$7.74	$36.93	$29.19
2030	$155.56	$31.15	$35.46	25.40%	$7.91	$39.10	$31.19
2031	$158.99	$31.84	$36.37	25.40%	$8.09	$40.10	$32.01
2032	$162.49	$32.54	$37.35	25.40%	$8.27	$41.16	$32.89
2033	$166.05	$33.26	$38.59	25.40%	$8.45	$42.48	$34.03
2034	$169.68	$33.98	$39.77	25.40%	$8.63	$43.74	$35.11
2035	$173.39	$34.73	$40.88	25.40%	$8.82	$44.94	$36.12

(1) The standard avoided cost price is reduced by a wind integration charge of $3.06/MWh ($2014) for wind QF resources located in PacifiCorp's Balancing Area Authority (BAA) (in-system) .
If QF wind resource is not in PacifiCorp's BAA, prices will be increased by the $3.06/MWh ($2014) integration charges

(2) Wind Integration Charge is $3.06 (2014 $ per MWh) - 2015 IRP Volume II-Appendix H, Table H.3
Table 11 - Wind Integration Cost

Columns
- (a) Full fixed cost of a proxy CCCT less capitalized energy
- (b) 100.0% is the on-peak capacity factor of the Proxy Resource
  57.0% is the percent of all hours that are on-peak
- (c) Fuel and Capitalized Energy Cost of the Proxy CCCT
- (d) Peak Capacity Contribution values for renewables (% of nameplate capacity), 2015 IRP
  (2015 IRP Volume II-Appendix N, Table N.1, page 405)
- (f) 2016-2027 On-Peak Blended Market Prices for QF resource
- (g) 2016-2027 Off-Peak Blended Market Prices for QF resource

Wind Capacity Contribution 25.4%

Exhibit 3
Standard Avoided Cost Prices for Fixed Solar QF
$/MWH

	Standard Avoided Resource			Fixed Solar QF			
Year	Capacity Price	Capacity Cost Allocated to On-Peak Hours	Energy Only Price	Capacity Contribution	Capacity Payment On-Peak Hours	On-Peak	Off-Peak
	$/kW-yr	($/MWh)	$/MWh		$/MWh	$/MWh	$/MWh
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		(a) /(8.76 x 100.0% x 57%)			= (b) * (d)	= (c) + (e)	= (c)
2016	Market Based Prices 2016 through 2027					$23.43	$19.86
2017						$26.30	$21.68
2018						$28.22	$22.97
2019						$29.44	$23.80
2020						$30.99	$25.14
2021						$33.03	$27.14
2022						$35.96	$30.03
2023						$40.26	$33.69
2024						$44.43	$37.30
2025						$46.61	$39.32
2026						$48.41	$40.90
2027						$50.57	$42.74
2028	$149.06	$29.85	$32.45	32.20%	$9.61	$42.06	$32.45
2029	$152.18	$30.48	$33.37	32.20%	$9.81	$43.18	$33.37
2030	$155.56	$31.15	$35.46	32.20%	$10.03	$45.49	$35.46
2031	$158.99	$31.84	$36.37	32.20%	$10.25	$46.62	$36.37
2032	$162.49	$32.54	$37.35	32.20%	$10.48	$47.83	$37.35
2033	$166.05	$33.26	$38.59	32.20%	$10.71	$49.30	$38.59
2034	$169.68	$33.98	$39.77	32.20%	$10.94	$50.71	$39.77
2035	$173.39	$34.73	$40.88	32.20%	$11.18	$52.06	$40.88

Columns

- (a) Full fixed cost of a proxy CCCT less capitalized energy
- (b) 100.0% is the on-peak capacity factor of the Proxy Resource
  57.0% is the percent of all hours that are on-peak
- (c) Fuel and Capitalized Energy Cost of the Proxy CCCT
- (d) Peak Capacity Contribution values for renewables (% of nameplate capacity), 2015 IRP
  (2015 IRP Volume II-Appendix N, Table N.1, page 405)
- (f) 2016-2027 On-Peak Blended Market Prices for QF resource
- (g) 2016-2027 Off-Peak Blended Market Prices for QF resource

Fixed Solar Capacity Contribution 32.2%

Exhibit 4
Standard Avoided Cost Prices for Tracking Solar QF
$/MWH

	Standard Avoided Resource			Tracking Solar QF			
Year	Capacity Price	Capacity Cost Allocated to On-Peak Hours	Energy Only Price	Capacity Contribution	Capacity Payment On-Peak Hours	On-Peak	Off-Peak
	$/kW-yr	($/MWh)	$/MWh		$/MWh	$/MWh	$/MWh
	(a)	(b)	(c)	(d)	(e)	(f)	(g)
		(a) /(8.76 x 100.0% x 57%)			= (b) * (d)	= (c) + (e)	= (c)
2016	Market Based Prices 2016 through 2027					$23.43	$19.86
2017						$26.30	$21.68
2018						$28.22	$22.97
2019						$29.44	$23.80
2020						$30.99	$25.14
2021						$33.03	$27.14
2022						$35.96	$30.03
2023						$40.26	$33.69
2024						$44.43	$37.30
2025						$46.61	$39.32
2026						$48.41	$40.90
2027						$50.57	$42.74
2028	$149.06	$29.85	$32.45	36.70%	$10.95	$43.40	$32.45
2029	$152.18	$30.48	$33.37	36.70%	$11.19	$44.56	$33.37
2030	$155.56	$31.15	$35.46	36.70%	$11.43	$46.89	$35.46
2031	$158.99	$31.84	$36.37	36.70%	$11.69	$48.06	$36.37
2032	$162.49	$32.54	$37.35	36.70%	$11.94	$49.29	$37.35
2033	$166.05	$33.26	$38.59	36.70%	$12.21	$50.80	$38.59
2034	$169.68	$33.98	$39.77	36.70%	$12.47	$52.24	$39.77
2035	$173.39	$34.73	$40.88	36.70%	$12.75	$53.63	$40.88

Columns
- (a) Full fixed cost of a proxy CCCT less capitalized energy
- (b) 100.0% is the on-peak capacity factor of the Proxy Resource
  57.0% is the percent of all hours that are on-peak
- (c) Fuel and Capitalized Energy Cost of the Proxy CCCT
- (d) Peak Capacity Contribution values for renewables (% of nameplate capacity), 2015 IRP
  (2015 IRP Volume II-Appendix N, Table N.1, page 405)
- (f) 2016-2027 On-Peak Blended Market Prices for QF resource
- (g) 2016-2027 Off-Peak Blended Market Prices for QF resource

Tracking Solar Capacity Contribution 36.7%

Exhibit 5

Renewable Avoided Cost Prices for Base Load QF(1)
$/MWH

Year	Renewable Wind Avoided Resource On-Peak ($/MWh) (a)	Renewable Wind Avoided Resource Off-Peak ($/MWh) (b)	Renewable Base Load QF Resource Capital Cost Allocated to Capacity (On-Peak Hours) ($/MWh) (c)	Renewable Base Load QF Resource QF Capacity Adder ($/MWh) (d) = (c) * 74.6%	On-Peak $/MWh (e) = (a) + (d)	Off-Peak $/MWh (f) = (b)
2016					$23.43	$19.86
2017					$26.30	$21.68
2018	$39.36	$30.75	$23.81	$17.76	$60.39	$34.02
2019	$40.28	$31.46	$24.39	$18.19	$61.82	$34.81
2020	$40.82	$32.80	$24.97	$18.63	$62.88	$36.23
2021	$41.50	$33.97	$25.57	$19.08	$64.09	$37.48
2022	$42.65	$34.50	$26.16	$19.52	$65.76	$38.09
2023	$43.78	$35.14	$26.76	$19.96	$67.41	$38.81
2024	$44.67	$36.06	$27.38	$20.43	$68.85	$39.81
2025	$45.56	$36.99	$27.98	$20.87	$70.26	$40.82
2026	$46.51	$37.85	$28.59	$21.33	$71.75	$41.76
2027	$47.46	$38.80	$29.22	$21.80	$73.26	$42.80
2028	$48.57	$39.58	$29.85	$22.27	$74.93	$43.67
2029	$49.54	$40.45	$30.48	$22.74	$76.46	$44.63
2030	$50.73	$41.22	$31.15	$23.24	$78.24	$45.49
2031	$51.75	$42.16	$31.84	$23.75	$79.86	$46.52
2032	$52.85	$43.23	$32.54	$24.27	$81.58	$47.69
2033	$53.93	$44.26	$33.26	$24.81	$83.30	$48.82
2034	$55.08	$45.32	$33.98	$25.35	$85.09	$49.98
2035	$56.07	$46.58	$34.73	$25.91	$86.74	$51.34

Columns
(e) 2016-2027 On-Peak Blended Market Prices for QF resource
(f) 2016-2027 Off-Peak Blended Market Prices for QF resource

(1) The renewable avoided cost price during the deficiency period is increased by the avoided integration charge

Exhibit 6
Renewable Avoided Cost Prices for Wind QF (1) (2) (3)
$/MWH

Year	Renewable Wind Avoided Resource On-Peak ($/MWh)	Renewable Wind Avoided Resource Off-Peak ($/MWh)	Wind QF Resource Capital Cost Allocated to Capacity (On-Peak Hours) ($/MWh)	Wind QF Resource QF Capacity Adder ($/MWh)	Wind QF Resource On-Peak $/MWh	Wind QF Resource Off-Peak $/MWh
	(a)	(b)	(c)	(d)	(e)	(f)
				= (c) * 0.0%	= (a) + (d)	= (b)
2016					$20.31	$16.74
2017					$23.11	$18.49
2018	$39.36	$30.75	$23.81	$0.00	$39.36	$30.75
2019	$40.28	$31.46	$24.39	$0.00	$40.28	$31.46
2020	$40.82	$32.80	$24.97	$0.00	$40.82	$32.80
2021	$41.50	$33.97	$25.57	$0.00	$41.50	$33.97
2022	$42.65	$34.50	$26.16	$0.00	$42.65	$34.50
2023	$43.78	$35.14	$26.76	$0.00	$43.78	$35.14
2024	$44.67	$36.06	$27.38	$0.00	$44.67	$36.06
2025	$45.56	$36.99	$27.98	$0.00	$45.56	$36.99
2026	$46.51	$37.85	$28.59	$0.00	$46.51	$37.85
2027	$47.46	$38.80	$29.22	$0.00	$47.46	$38.80
2028	$48.57	$39.58	$29.85	$0.00	$48.57	$39.58
2029	$49.54	$40.45	$30.48	$0.00	$49.54	$40.45
2030	$50.73	$41.22	$31.15	$0.00	$50.73	$41.22
2031	$51.75	$42.16	$31.84	$0.00	$51.75	$42.16
2032	$52.85	$43.23	$32.54	$0.00	$52.85	$43.23
2033	$53.93	$44.26	$33.26	$0.00	$53.93	$44.26
2034	$55.08	$45.32	$33.98	$0.00	$55.08	$45.32
2035	$56.07	$46.58	$34.73	$0.00	$56.07	$46.58

(1) During the deficiency period, avoided cost prices will be adjusted by adding the difference between the avoided integration costs and Qualifying Facility's integration costs. If the Wind QF resource is in PacifiCorp's Balancing Area Authority (BAA), the adjustment is zero (integration costs cancel each other out).
If Qualifying Facility Wind resource is not in PacifiCorp's BAA, $3.06/MWh ($2014) will be added for avoided integration charges.

(2) During the sufficiency period, avoided cost prices is reduced by an integration charge of $3.06/MWh ($2014) for a Qualifying Facility wind resource located in PacifiCorp's BAA (in-system).
If Qualifying Facility wind resource is not in PacifiCorp's BAA, the renewable avoided cost price will be increased by the $3.06/MWh ($2014) integration charges.

(3) Wind Integration Charge is $3.06 (2014 $ per MWh) - 2015 IRP Volume II-Appendix H, Table H.3
Table 11 - Wind Integration Cost

Columns
(e) On-Peak Blended Market Prices.
(f) Off-Peak Blended Market Prices.

Exhibit 7

Renewable Avoided Cost Prices for Fixed Solar QF (1)
$/MWH

Year	Renewable Wind Avoided Resource On-Peak ($/MWh) (a)	Renewable Wind Avoided Resource Off-Peak ($/MWh) (b)	Fixed Solar QF Resource Capital Cost Allocated to Capacity (On-Peak Hours) ($/MWh) (c)	Fixed Solar QF Resource QF Capacity Adder ($/MWh) (d) = (c) * 6.8%	Fixed Solar QF On-Peak $/MWh (e) = (a) + (d)	Fixed Solar QF Off-Peak $/MWh (f) = (b)
2016					$23.43	$19.86
2017					$26.30	$21.68
2018	$39.36	$30.75	$23.81	$1.62	$44.25	$34.02
2019	$40.28	$31.46	$24.39	$1.66	$45.29	$34.81
2020	$40.82	$32.80	$24.97	$1.70	$45.95	$36.23
2021	$41.50	$33.97	$25.57	$1.74	$46.75	$37.48
2022	$42.65	$34.50	$26.16	$1.78	$48.02	$38.09
2023	$43.78	$35.14	$26.76	$1.82	$49.27	$38.81
2024	$44.67	$36.06	$27.38	$1.86	$50.28	$39.81
2025	$45.56	$36.99	$27.98	$1.90	$51.29	$40.82
2026	$46.51	$37.85	$28.59	$1.94	$52.36	$41.76
2027	$47.46	$38.80	$29.22	$1.99	$53.45	$42.80
2028	$48.57	$39.58	$29.85	$2.03	$54.69	$43.67
2029	$49.54	$40.45	$30.48	$2.07	$55.79	$44.63
2030	$50.73	$41.22	$31.15	$2.12	$57.12	$45.49
2031	$51.75	$42.16	$31.84	$2.17	$58.28	$46.52
2032	$52.85	$43.23	$32.54	$2.21	$59.52	$47.69
2033	$53.93	$44.26	$33.26	$2.26	$60.75	$48.82
2034	$55.08	$45.32	$33.98	$2.31	$62.05	$49.98
2035	$56.07	$46.58	$34.73	$2.36	$63.19	$51.34

Columns
(e) On-Peak Blended Market Prices for QF resource
(f) Off-Peak Blended Market Prices for QF resource

(1) The renewable avoided cost price during the deficiency period is increased by the avoided integration charge

Exhibit 8

Renewable Avoided Cost Prices for Tracking Solar QF (1)
$/MWH

Year	Renewable Wind Avoided Resource		Tracking Solar QF Resource		Tracking Solar QF	
	On-Peak	Off-Peak	Capital Cost Allocated to Capacity (On-Peak Hours)	QF Capacity Adder	On-Peak	Off-Peak
	($/MWh)	($/MWh)	($/MWh)	($/MWh)	$/MWh	$/MWh
	(a)	(b)	(c)	(d)	(e)	(f)
				= (c) * 11.3%		
2016					$23.43	$19.86
2017					$26.30	$21.68
2018	$39.36	$30.75	$23.81	$2.69	$45.32	$34.02
2019	$40.28	$31.46	$24.39	$2.76	$46.39	$34.81
2020	$40.82	$32.80	$24.97	$2.82	$47.07	$36.23
2021	$41.50	$33.97	$25.57	$2.89	$47.90	$37.48
2022	$42.65	$34.50	$26.16	$2.96	$49.20	$38.09
2023	$43.78	$35.14	$26.76	$3.02	$50.47	$38.81
2024	$44.67	$36.06	$27.38	$3.09	$51.51	$39.81
2025	$45.56	$36.99	$27.98	$3.16	$52.55	$40.82
2026	$46.51	$37.85	$28.59	$3.23	$53.65	$41.76
2027	$47.46	$38.80	$29.22	$3.30	$54.76	$42.80
2028	$48.57	$39.58	$29.85	$3.37	$56.03	$43.67
2029	$49.54	$40.45	$30.48	$3.44	$57.16	$44.63
2030	$50.73	$41.22	$31.15	$3.52	$58.52	$45.49
2031	$51.75	$42.16	$31.84	$3.60	$59.71	$46.52
2032	$52.85	$43.23	$32.54	$3.68	$60.99	$47.69
2033	$53.93	$44.26	$33.26	$3.76	$62.25	$48.82
2034	$55.08	$45.32	$33.98	$3.84	$63.58	$49.98
2035	$56.07	$46.58	$34.73	$3.92	$64.75	$51.34

Columns
- (e) On-Peak Blended Market Prices for QF resource
- (f) Off-Peak Blended Market Prices for QF resource

(1) The renewable avoided cost price during the deficiency period is increased by the avoided integration charge

Exhibit 9
Market Price - Blending Matrix (1)

	On-Peak				Off-Peak			
Period	COB	Mid Columbia	Palo Verde	Total	COB	Mid Columbia	Palo Verde	Total
1/1/2016	9.1%	24.0%	66.8%	100.0%	11.1%	0.4%	88.5%	100.0%
2/1/2016	28.2%	20.1%	51.7%	100.0%	8.1%	69.1%	22.7%	100.0%
3/1/2016	31.9%	5.6%	62.4%	100.0%	12.9%	0.0%	87.1%	100.0%
4/1/2016	27.8%	12.2%	60.0%	100.0%	19.1%	0.8%	80.2%	100.0%
5/1/2016	20.1%	0.0%	79.9%	100.0%	0.8%	0.0%	99.2%	100.0%
6/1/2016	13.9%	0.0%	86.1%	100.0%	9.3%	0.0%	90.7%	100.0%
7/1/2016	12.2%	77.2%	10.6%	100.0%	23.2%	6.3%	70.6%	100.0%
8/1/2016	8.1%	86.8%	5.0%	100.0%	11.1%	62.3%	26.7%	100.0%
9/1/2016	1.0%	97.4%	1.6%	100.0%	12.3%	18.1%	69.6%	100.0%
10/1/2016	9.6%	72.0%	18.4%	100.0%	14.5%	55.5%	30.0%	100.0%
11/1/2016	13.8%	79.6%	6.5%	100.0%	39.8%	16.0%	44.2%	100.0%
12/1/2016	26.4%	56.5%	17.1%	100.0%	19.1%	19.6%	61.3%	100.0%
1/1/2017	73.3%	9.4%	17.3%	100.0%	23.5%	13.0%	63.5%	100.0%
2/1/2017	52.4%	10.1%	37.5%	100.0%	19.8%	20.5%	59.7%	100.0%
3/1/2017	43.4%	9.7%	46.9%	100.0%	22.8%	14.2%	63.1%	100.0%
4/1/2017	36.1%	3.2%	60.8%	100.0%	21.1%	0.7%	78.2%	100.0%
5/1/2017	22.7%	0.7%	76.5%	100.0%	24.8%	0.0%	75.2%	100.0%
6/1/2017	32.4%	1.5%	66.1%	100.0%	37.4%	3.1%	59.5%	100.0%
7/1/2017	26.6%	18.1%	55.3%	100.0%	44.4%	11.2%	44.4%	100.0%
8/1/2017	22.4%	51.5%	26.1%	100.0%	21.8%	27.4%	50.8%	100.0%
9/1/2017	10.7%	64.7%	24.6%	100.0%	17.7%	18.5%	63.8%	100.0%
10/1/2017	26.6%	26.5%	46.9%	100.0%	9.5%	32.4%	58.1%	100.0%
11/1/2017	60.5%	11.4%	28.2%	100.0%	28.2%	0.6%	71.2%	100.0%
12/1/2017	63.5%	7.9%	28.7%	100.0%	27.6%	5.4%	66.9%	100.0%
1/1/2018	84.1%	6.9%	9.0%	100.0%	18.7%	6.7%	74.6%	100.0%
2/1/2018	61.5%	8.9%	29.7%	100.0%	18.9%	14.0%	67.1%	100.0%
3/1/2018	28.6%	14.6%	56.7%	100.0%	24.6%	27.6%	47.9%	100.0%
4/1/2018	54.5%	11.2%	34.3%	100.0%	59.5%	7.0%	33.5%	100.0%
5/1/2018	28.8%	0.0%	71.2%	100.0%	25.8%	0.0%	74.2%	100.0%
6/1/2018	13.6%	0.0%	86.4%	100.0%	14.2%	0.0%	85.8%	100.0%
7/1/2018	29.1%	38.7%	32.2%	100.0%	39.9%	7.3%	52.7%	100.0%
8/1/2018	12.2%	63.4%	24.4%	100.0%	16.6%	58.4%	25.1%	100.0%
9/1/2018	13.6%	65.0%	21.4%	100.0%	33.0%	6.9%	60.1%	100.0%
10/1/2018	21.2%	15.7%	63.1%	100.0%	27.1%	30.1%	42.8%	100.0%
11/1/2018	59.6%	9.6%	30.9%	100.0%	15.5%	2.2%	82.2%	100.0%
12/1/2018	69.9%	7.0%	23.1%	100.0%	22.7%	4.4%	72.9%	100.0%
1/1/2019	100.0%	0.0%	0.0%	100.0%	4.5%	13.2%	82.3%	100.0%
2/1/2019	73.2%	6.8%	20.0%	100.0%	16.4%	15.9%	67.7%	100.0%
3/1/2019	44.4%	7.6%	48.0%	100.0%	14.5%	23.8%	61.7%	100.0%
4/1/2019	55.5%	11.9%	32.6%	100.0%	58.8%	9.0%	32.1%	100.0%
5/1/2019	21.6%	1.1%	77.3%	100.0%	20.8%	6.6%	72.6%	100.0%
6/1/2019	19.5%	0.0%	80.5%	100.0%	27.0%	0.0%	73.0%	100.0%
7/1/2019	19.8%	42.4%	37.8%	100.0%	42.6%	8.4%	49.0%	100.0%
8/1/2019	14.8%	59.9%	25.3%	100.0%	30.9%	40.4%	28.6%	100.0%
9/1/2019	5.1%	77.9%	17.0%	100.0%	38.0%	13.8%	48.3%	100.0%
10/1/2019	19.7%	16.0%	64.3%	100.0%	31.3%	21.7%	47.0%	100.0%
11/1/2019	54.8%	6.0%	39.1%	100.0%	17.1%	2.0%	81.0%	100.0%
12/1/2019	26.7%	1.6%	71.7%	100.0%	15.9%	5.6%	78.5%	100.0%

Exhibit 9

Market Price - Blending Matrix (1)

	On-Peak				Off-Peak			
Period	COB	Mid Columbia	Palo Verde	Total	COB	Mid Columbia	Palo Verde	Total
1/1/2020	81.7%	1.1%	17.3%	100.0%	12.7%	0.2%	87.1%	100.0%
2/1/2020	62.6%	5.8%	31.5%	100.0%	15.3%	3.9%	80.8%	100.0%
3/1/2020	39.4%	6.3%	54.3%	100.0%	19.7%	12.2%	68.1%	100.0%
4/1/2020	60.2%	11.1%	28.6%	100.0%	56.3%	3.0%	40.7%	100.0%
5/1/2020	24.4%	0.4%	75.2%	100.0%	24.6%	0.3%	75.1%	100.0%
6/1/2020	27.2%	0.0%	72.8%	100.0%	13.7%	0.0%	86.3%	100.0%
7/1/2020	15.4%	39.1%	45.4%	100.0%	25.1%	9.3%	65.6%	100.0%
8/1/2020	20.8%	48.5%	30.7%	100.0%	22.7%	37.0%	40.3%	100.0%
9/1/2020	12.3%	63.4%	24.4%	100.0%	22.3%	4.5%	73.2%	100.0%
10/1/2020	28.7%	13.7%	57.7%	100.0%	11.9%	23.1%	65.0%	100.0%
11/1/2020	59.4%	6.4%	34.2%	100.0%	9.9%	2.4%	87.7%	100.0%
12/1/2020	63.7%	9.4%	26.9%	100.0%	19.9%	3.0%	77.1%	100.0%
1/1/2021	81.2%	4.1%	14.7%	100.0%	14.0%	8.0%	78.0%	100.0%
2/1/2021	62.0%	5.9%	32.1%	100.0%	11.6%	8.8%	79.6%	100.0%
3/1/2021	50.8%	5.2%	44.0%	100.0%	14.5%	18.8%	66.7%	100.0%
4/1/2021	70.7%	6.3%	23.0%	100.0%	62.0%	1.8%	36.2%	100.0%
5/1/2021	28.2%	0.0%	71.8%	100.0%	17.3%	0.9%	81.8%	100.0%
6/1/2021	16.6%	0.0%	83.4%	100.0%	15.5%	0.0%	84.5%	100.0%
7/1/2021	25.5%	6.1%	68.4%	100.0%	19.5%	8.8%	71.8%	100.0%
8/1/2021	18.9%	48.8%	32.2%	100.0%	7.6%	39.5%	52.9%	100.0%
9/1/2021	15.3%	60.5%	24.2%	100.0%	13.7%	8.0%	78.3%	100.0%
10/1/2021	22.1%	13.1%	64.8%	100.0%	11.1%	25.8%	63.1%	100.0%
11/1/2021	59.2%	13.6%	27.1%	100.0%	12.9%	0.4%	86.7%	100.0%
12/1/2021	64.1%	5.0%	30.9%	100.0%	24.4%	1.6%	74.0%	100.0%
1/1/2022	82.6%	0.1%	17.4%	100.0%	13.7%	8.4%	77.9%	100.0%
2/1/2022	67.8%	2.8%	29.4%	100.0%	10.3%	16.9%	72.9%	100.0%
3/1/2022	36.1%	10.5%	53.4%	100.0%	21.0%	14.9%	64.1%	100.0%
4/1/2022	47.5%	10.1%	42.4%	100.0%	47.4%	0.0%	52.6%	100.0%
5/1/2022	27.3%	0.0%	72.7%	100.0%	20.8%	3.8%	75.4%	100.0%
6/1/2022	21.8%	2.1%	76.1%	100.0%	21.4%	6.2%	72.4%	100.0%
7/1/2022	29.3%	26.1%	44.6%	100.0%	20.6%	9.7%	69.7%	100.0%
8/1/2022	19.3%	50.2%	30.5%	100.0%	25.1%	45.4%	29.4%	100.0%
9/1/2022	7.1%	50.5%	42.3%	100.0%	19.5%	3.1%	77.4%	100.0%
10/1/2022	20.6%	16.1%	63.2%	100.0%	17.2%	34.2%	48.7%	100.0%
11/1/2022	39.7%	9.0%	51.3%	100.0%	33.4%	9.4%	57.2%	100.0%
12/1/2022	59.9%	10.1%	30.0%	100.0%	25.6%	9.7%	64.6%	100.0%
1/1/2023	83.1%	3.3%	13.6%	100.0%	21.4%	9.1%	69.5%	100.0%
2/1/2023	48.1%	13.8%	38.1%	100.0%	25.4%	22.0%	52.7%	100.0%
3/1/2023	39.8%	9.3%	50.9%	100.0%	23.3%	24.9%	51.8%	100.0%
4/1/2023	48.1%	6.5%	45.4%	100.0%	25.0%	7.8%	67.3%	100.0%
5/1/2023	15.3%	0.3%	84.4%	100.0%	35.2%	6.0%	58.8%	100.0%
6/1/2023	24.9%	9.3%	65.7%	100.0%	53.3%	12.1%	34.5%	100.0%
7/1/2023	30.4%	28.0%	41.6%	100.0%	30.4%	7.5%	62.2%	100.0%
8/1/2023	17.5%	51.3%	31.2%	100.0%	29.8%	43.7%	26.4%	100.0%
9/1/2023	5.9%	37.9%	56.2%	100.0%	25.6%	11.4%	63.0%	100.0%
10/1/2023	20.9%	15.0%	64.1%	100.0%	19.4%	30.1%	50.5%	100.0%
11/1/2023	41.0%	10.4%	48.6%	100.0%	31.6%	10.3%	58.2%	100.0%
12/1/2023	35.4%	7.4%	57.3%	100.0%	22.1%	7.6%	70.3%	100.0%
1/1/2024	60.0%	14.1%	26.0%	100.0%	30.1%	10.9%	59.0%	100.0%
2/1/2024	35.2%	18.4%	46.4%	100.0%	28.6%	19.3%	52.1%	100.0%
3/1/2024	44.9%	12.2%	42.9%	100.0%	38.3%	26.6%	35.2%	100.0%
4/1/2024	50.8%	16.5%	32.8%	100.0%	28.2%	14.7%	57.1%	100.0%
5/1/2024	14.1%	0.0%	85.9%	100.0%	24.4%	5.5%	70.1%	100.0%
6/1/2024	19.5%	5.0%	75.6%	100.0%	32.4%	8.3%	59.3%	100.0%
7/1/2024	20.3%	45.1%	34.5%	100.0%	35.1%	16.8%	48.2%	100.0%
8/1/2024	21.2%	49.5%	29.3%	100.0%	25.1%	47.4%	27.5%	100.0%
9/1/2024	5.2%	47.9%	46.9%	100.0%	25.7%	11.8%	62.5%	100.0%
10/1/2024	24.7%	17.2%	58.1%	100.0%	20.1%	31.2%	48.7%	100.0%
11/1/2024	36.6%	10.3%	53.0%	100.0%	33.6%	23.3%	43.1%	100.0%
12/1/2024	59.3%	19.2%	21.5%	100.0%	6.9%	25.3%	67.8%	100.0%

Exhibit 9
Market Price - Blending Matrix (1)

	On-Peak				Off-Peak			
Period	COB	Mid Columbia	Palo Verde	Total	COB	Mid Columbia	Palo Verde	Total
1/1/2025	64.2%	8.6%	27.2%	100.0%	59.5%	0.5%	40.0%	100.0%
2/1/2025	55.1%	16.9%	28.0%	100.0%	31.2%	14.2%	54.6%	100.0%
3/1/2025	41.1%	19.2%	39.7%	100.0%	33.7%	32.4%	33.9%	100.0%
4/1/2025	54.0%	12.0%	34.0%	100.0%	23.3%	12.3%	64.3%	100.0%
5/1/2025	20.5%	0.0%	79.5%	100.0%	25.5%	5.1%	69.5%	100.0%
6/1/2025	24.0%	4.1%	71.9%	100.0%	29.9%	14.7%	55.4%	100.0%
7/1/2025	16.7%	56.5%	26.8%	100.0%	39.4%	7.5%	53.0%	100.0%
8/1/2025	19.1%	64.1%	16.8%	100.0%	25.8%	48.8%	25.4%	100.0%
9/1/2025	4.6%	78.0%	17.4%	100.0%	25.8%	12.9%	61.2%	100.0%
10/1/2025	30.6%	19.2%	50.1%	100.0%	28.8%	34.1%	37.0%	100.0%
11/1/2025	38.8%	14.3%	46.9%	100.0%	32.2%	30.2%	37.6%	100.0%
12/1/2025	51.2%	13.7%	35.2%	100.0%	20.3%	19.0%	60.8%	100.0%
1/1/2026	51.3%	8.4%	40.3%	100.0%	26.5%	24.5%	49.0%	100.0%
2/1/2026	38.5%	14.4%	47.2%	100.0%	27.4%	13.5%	59.1%	100.0%
3/1/2026	38.7%	24.3%	37.0%	100.0%	39.4%	26.6%	34.0%	100.0%
4/1/2026	53.3%	14.7%	32.0%	100.0%	32.8%	20.2%	47.1%	100.0%
5/1/2026	30.3%	1.6%	68.1%	100.0%	33.4%	5.9%	60.7%	100.0%
6/1/2026	24.2%	7.4%	68.4%	100.0%	33.1%	14.8%	52.1%	100.0%
7/1/2026	18.4%	56.4%	25.2%	100.0%	42.2%	8.1%	49.7%	100.0%
8/1/2026	20.2%	60.3%	19.5%	100.0%	21.7%	55.1%	23.2%	100.0%
9/1/2026	8.1%	61.4%	30.4%	100.0%	17.5%	17.6%	64.9%	100.0%
10/1/2026	23.1%	23.8%	53.1%	100.0%	26.0%	35.9%	38.2%	100.0%
11/1/2026	37.2%	9.5%	53.3%	100.0%	40.7%	29.1%	30.1%	100.0%
12/1/2026	48.6%	13.8%	37.6%	100.0%	33.6%	17.3%	49.2%	100.0%
1/1/2027	49.2%	10.2%	40.6%	100.0%	26.3%	32.2%	41.5%	100.0%
2/1/2027	40.9%	15.8%	43.3%	100.0%	18.8%	31.2%	50.0%	100.0%
3/1/2027	46.3%	20.9%	32.8%	100.0%	33.7%	34.2%	32.1%	100.0%
4/1/2027	54.7%	16.1%	29.3%	100.0%	36.1%	17.4%	46.4%	100.0%
5/1/2027	25.1%	0.8%	74.1%	100.0%	26.3%	7.4%	66.3%	100.0%
6/1/2027	28.9%	9.5%	61.6%	100.0%	42.1%	15.9%	42.0%	100.0%
7/1/2027	19.1%	57.8%	23.2%	100.0%	38.6%	12.0%	49.4%	100.0%
8/1/2027	17.5%	62.0%	20.5%	100.0%	22.4%	50.8%	26.8%	100.0%
9/1/2027	10.1%	60.8%	29.1%	100.0%	24.1%	15.4%	60.5%	100.0%
10/1/2027	28.9%	21.4%	49.7%	100.0%	19.8%	41.3%	38.9%	100.0%
11/1/2027	39.1%	14.8%	46.1%	100.0%	27.7%	32.1%	40.2%	100.0%
12/1/2027	57.2%	13.5%	29.3%	100.0%	34.7%	21.2%	44.2%	100.0%
1/1/2028	32.7%	11.7%	55.6%	100.0%	30.4%	26.0%	43.7%	100.0%
2/1/2028	27.6%	10.5%	61.9%	100.0%	32.2%	21.8%	46.0%	100.0%
3/1/2028	29.6%	18.9%	51.5%	100.0%	42.4%	31.0%	26.6%	100.0%
4/1/2028	45.2%	15.0%	39.8%	100.0%	26.4%	9.7%	63.9%	100.0%
5/1/2028	24.0%	3.5%	72.5%	100.0%	29.5%	5.0%	65.5%	100.0%
6/1/2028	23.8%	10.9%	65.3%	100.0%	32.1%	9.7%	58.2%	100.0%
7/1/2028	19.9%	64.1%	16.0%	100.0%	31.6%	15.8%	52.6%	100.0%
8/1/2028	16.6%	69.3%	14.1%	100.0%	24.1%	59.0%	16.9%	100.0%
9/1/2028	7.7%	58.9%	33.4%	100.0%	25.4%	14.2%	60.4%	100.0%
10/1/2028	28.5%	10.9%	60.6%	100.0%	20.5%	29.1%	50.3%	100.0%
11/1/2028	29.4%	8.9%	61.7%	100.0%	33.8%	20.0%	46.1%	100.0%
12/1/2028	27.5%	4.6%	67.9%	100.0%	25.4%	20.6%	54.0%	100.0%
1/1/2029	29.8%	7.0%	63.3%	100.0%	34.0%	19.0%	47.0%	100.0%
2/1/2029	30.7%	5.5%	63.8%	100.0%	28.1%	16.4%	55.5%	100.0%
3/1/2029	35.1%	12.0%	52.9%	100.0%	36.7%	35.9%	27.4%	100.0%
4/1/2029	45.2%	12.2%	42.6%	100.0%	28.8%	17.8%	53.5%	100.0%
5/1/2029	30.2%	1.5%	68.3%	100.0%	38.2%	6.4%	55.5%	100.0%
6/1/2029	26.9%	8.4%	64.7%	100.0%	22.2%	11.7%	66.2%	100.0%
7/1/2029	17.0%	68.2%	14.8%	100.0%	30.8%	14.6%	54.6%	100.0%
8/1/2029	20.0%	66.5%	13.5%	100.0%	25.2%	57.4%	17.4%	100.0%
9/1/2029	4.8%	63.1%	32.2%	100.0%	24.0%	0.0%	76.0%	100.0%
10/1/2029	22.6%	19.5%	57.9%	100.0%	25.3%	28.1%	46.5%	100.0%
11/1/2029	29.1%	11.3%	59.5%	100.0%	30.8%	26.6%	42.7%	100.0%
12/1/2029	30.7%	7.3%	62.0%	100.0%	24.3%	21.6%	54.1%	100.0%

Exhibit 9
Market Price - Blending Matrix (1)

	On-Peak				Off-Peak			
Period	COB	Mid Columbia	Palo Verde	Total	COB	Mid Columbia	Palo Verde	Total
1/1/2030	26.7%	9.2%	64.2%	100.0%	30.6%	29.1%	40.4%	100.0%
2/1/2030	23.0%	4.1%	72.9%	100.0%	37.5%	21.4%	41.0%	100.0%
3/1/2030	35.1%	14.3%	50.6%	100.0%	36.2%	32.1%	31.7%	100.0%
4/1/2030	43.3%	13.1%	43.6%	100.0%	37.9%	10.5%	51.6%	100.0%
5/1/2030	28.3%	0.0%	71.7%	100.0%	30.2%	3.0%	66.7%	100.0%
6/1/2030	31.9%	9.7%	58.4%	100.0%	15.4%	4.1%	80.5%	100.0%
7/1/2030	23.4%	57.6%	19.0%	100.0%	22.6%	13.0%	64.5%	100.0%
8/1/2030	13.4%	69.7%	16.8%	100.0%	36.8%	21.0%	42.2%	100.0%
9/1/2030	7.3%	62.5%	30.2%	100.0%	23.2%	13.6%	63.1%	100.0%
10/1/2030	24.8%	16.3%	58.9%	100.0%	26.3%	33.4%	40.3%	100.0%
11/1/2030	29.1%	10.9%	60.0%	100.0%	36.0%	31.0%	33.1%	100.0%
12/1/2030	37.8%	9.3%	52.9%	100.0%	31.9%	22.9%	45.2%	100.0%
1/1/2031	22.4%	6.3%	71.3%	100.0%	37.6%	21.2%	41.2%	100.0%
2/1/2031	24.6%	9.6%	65.8%	100.0%	28.7%	17.5%	53.8%	100.0%
3/1/2031	41.1%	16.2%	42.7%	100.0%	44.3%	25.1%	30.6%	100.0%
4/1/2031	44.8%	11.0%	44.1%	100.0%	35.0%	26.8%	38.2%	100.0%
5/1/2031	24.0%	4.6%	71.4%	100.0%	22.7%	5.0%	72.3%	100.0%
6/1/2031	22.0%	7.3%	70.8%	100.0%	18.5%	11.1%	70.4%	100.0%
7/1/2031	21.5%	71.9%	6.6%	100.0%	37.9%	16.3%	45.8%	100.0%
8/1/2031	16.4%	79.8%	3.7%	100.0%	18.2%	64.7%	17.1%	100.0%
9/1/2031	10.8%	67.1%	22.1%	100.0%	37.1%	3.1%	59.8%	100.0%
10/1/2031	23.9%	13.7%	62.5%	100.0%	26.4%	39.0%	34.5%	100.0%
11/1/2031	34.6%	7.7%	57.7%	100.0%	42.0%	15.2%	42.8%	100.0%
12/1/2031	20.5%	4.4%	75.1%	100.0%	40.5%	12.6%	46.9%	100.0%
1/1/2032	28.9%	6.1%	65.0%	100.0%	37.3%	24.3%	38.4%	100.0%
2/1/2032	29.2%	7.6%	63.2%	100.0%	34.5%	19.5%	46.0%	100.0%
3/1/2032	40.1%	13.0%	46.9%	100.0%	40.8%	27.9%	31.3%	100.0%
4/1/2032	44.4%	10.4%	45.2%	100.0%	42.8%	20.3%	36.9%	100.0%
5/1/2032	22.4%	5.0%	72.6%	100.0%	20.0%	5.0%	75.1%	100.0%
6/1/2032	23.2%	11.5%	65.3%	100.0%	14.8%	11.9%	73.4%	100.0%
7/1/2032	24.1%	67.8%	8.2%	100.0%	35.3%	17.0%	47.7%	100.0%
8/1/2032	21.6%	70.6%	7.8%	100.0%	23.0%	60.8%	16.1%	100.0%
9/1/2032	13.1%	61.2%	25.7%	100.0%	31.2%	7.1%	61.7%	100.0%
10/1/2032	25.4%	13.9%	60.7%	100.0%	24.0%	42.3%	33.7%	100.0%
11/1/2032	33.6%	9.5%	56.9%	100.0%	41.5%	23.1%	35.3%	100.0%
12/1/2032	25.7%	6.7%	67.6%	100.0%	41.4%	15.1%	43.5%	100.0%
1/1/2033	35.2%	4.3%	60.5%	100.0%	42.9%	13.0%	44.1%	100.0%
2/1/2033	15.4%	13.2%	71.4%	100.0%	47.2%	4.1%	48.7%	100.0%
3/1/2033	40.0%	17.1%	42.9%	100.0%	47.5%	21.2%	31.3%	100.0%
4/1/2033	46.8%	11.1%	42.1%	100.0%	41.4%	18.7%	39.9%	100.0%
5/1/2033	28.8%	0.6%	70.6%	100.0%	18.3%	8.7%	73.0%	100.0%
6/1/2033	24.1%	9.2%	66.7%	100.0%	14.0%	13.1%	73.0%	100.0%
7/1/2033	14.8%	70.2%	15.0%	100.0%	30.7%	8.9%	60.4%	100.0%
8/1/2033	17.3%	77.9%	4.8%	100.0%	28.7%	56.2%	15.1%	100.0%
9/1/2033	11.1%	63.1%	25.8%	100.0%	30.4%	6.8%	62.8%	100.0%
10/1/2033	25.8%	13.0%	61.3%	100.0%	27.2%	41.7%	31.1%	100.0%
11/1/2033	28.8%	7.8%	63.4%	100.0%	43.5%	13.1%	43.5%	100.0%
12/1/2033	24.2%	5.8%	70.0%	100.0%	35.2%	13.6%	51.3%	100.0%
1/1/2034	23.2%	4.3%	72.5%	100.0%	31.1%	18.2%	50.7%	100.0%
2/1/2034	26.3%	5.2%	68.5%	100.0%	38.6%	11.1%	50.3%	100.0%
3/1/2034	40.0%	17.0%	43.0%	100.0%	39.7%	28.3%	32.0%	100.0%
4/1/2034	46.0%	9.6%	44.4%	100.0%	43.5%	14.1%	42.4%	100.0%
5/1/2034	30.5%	4.8%	64.7%	100.0%	23.1%	3.2%	73.7%	100.0%
6/1/2034	27.1%	7.4%	65.4%	100.0%	19.9%	10.5%	69.6%	100.0%
7/1/2034	15.2%	76.3%	8.5%	100.0%	33.4%	9.7%	56.8%	100.0%
8/1/2034	17.6%	74.8%	7.6%	100.0%	21.1%	55.1%	23.8%	100.0%
9/1/2034	11.5%	62.3%	26.2%	100.0%	26.0%	5.0%	69.0%	100.0%
10/1/2034	32.1%	14.1%	53.8%	100.0%	28.7%	25.2%	46.1%	100.0%
11/1/2034	28.7%	5.9%	65.4%	100.0%	34.7%	30.1%	35.2%	100.0%
12/1/2034	24.6%	4.2%	71.2%	100.0%	35.7%	13.6%	50.7%	100.0%

Exhibit 9
Market Price - Blending Matrix (1)

	On-Peak				Off-Peak			
Period	COB	Mid Columbia	Palo Verde	Total	COB	Mid Columbia	Palo Verde	Total
1/1/2035	22.0%	5.1%	72.9%	100.0%	26.2%	15.9%	57.9%	100.0%
2/1/2035	14.2%	6.3%	79.5%	100.0%	34.2%	16.8%	49.0%	100.0%
3/1/2035	36.7%	17.8%	45.5%	100.0%	36.5%	36.0%	27.6%	100.0%
4/1/2035	44.8%	11.2%	44.0%	100.0%	49.4%	10.9%	39.7%	100.0%
5/1/2035	24.6%	1.9%	73.4%	100.0%	23.9%	6.1%	70.0%	100.0%
6/1/2035	29.0%	7.9%	63.1%	100.0%	9.4%	7.9%	82.7%	100.0%
7/1/2035	18.3%	65.2%	16.5%	100.0%	26.7%	8.8%	64.6%	100.0%
8/1/2035	21.1%	69.6%	9.3%	100.0%	32.6%	42.1%	25.3%	100.0%
9/1/2035	15.0%	68.5%	16.5%	100.0%	24.4%	7.2%	68.4%	100.0%
10/1/2035	25.0%	17.1%	57.9%	100.0%	39.0%	24.5%	36.5%	100.0%
11/1/2035	31.4%	9.3%	59.3%	100.0%	38.9%	26.0%	35.2%	100.0%
12/1/2035	27.6%	2.5%	69.9%	100.0%	32.6%	17.2%	50.2%	100.0%

(1) Blending weights are calculated using system balancing purchases and sales from GRID run using March 2016 Official Forward Market Price Curve

Table 1
2015 IRP Preferred Portfolio
Excerpt from 2015 IRP Table 8.7

		Capacity (MW)													
	Resource	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
East	**Expansion Resources**														
	CCCT - DJohns - F 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	CCCT - DJohns - J 1x1	-	-	-	-	-	-	-	-	-	-	-	-	-	423
	CCCT - Utah-N - F 2x1	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, UT-DLC-RES	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1 Total	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 2, ID	4	4	5	5	5	4	4	4	5	5	5	5	5	5
	DSM, Class 2, UT	69	78	84	86	92	81	84	90	91	93	75	76	80	80
	DSM, Class 2, WY	6	8	10	12	14	12	13	14	15	16	13	13	14	15
	DSM, Class 2 Total	79	90	99	102	111	97	101	108	110	114	92	94	99	99
	FOT Mona Q3	-	-	-	-	-	-	-	-	-	-	-	-	-	161
West	**Expansion Resources**														
	Oregon Solar Capacity Standard	-	7	-	-	-	-	-	-	-	-	-	-	-	-
	DSM, Class 1, OR-Curtail	-	-	-	-	-	-	-	-	10.6	-	-	10.6	-	-
	DSM, Class 1, OR-Irrigate	-	-	-	-	-	-	-	5.0	-	-	-	-	-	-
	DSM, Class 1 Total	-	-	-	-	-	-	-	5.0	10.6	-	-	10.6	-	-
	DSM, Class 2, CA	1	2	2	2	2	1	1	2	2	2	1	1	1	1
	DSM, Class 2, OR	44	39	36	33	29	27	25	25	23	23	21	22	22	22
	DSM, Class 2, WA	8	9	10	10	11	9	10	10	11	11	9	9	9	9
	DSM, Class 2 Total	54	49	47	44	42	38	36	36	36	35	31	32	32	32
	FOT COB Q3	-	62	29	-	60	104	-	-	-	-	-	-	-	268
	FOT MidColumbia Q3 - 2	227	375	375	370	375	375	269	291	261	254	271	292	335	375
	Total Annual Additions	860	1,084	1,050	1,016	1,088	1,113	906	941	917	903	893	928	965	1,859

The 2015 IRP was prepared using a 13% planning reserve margin. See 2015 IRP, page 81.

Table 2
Avoided Costs ($/MWh)
Energy Prices 2016 through 2027

On-Peak (HLH Market Purchase)

Year	Winter Season					Summer Season				Winter Season		
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016						20.04	21.37	24.22	22.76	22.61	24.68	28.30
2017	28.10	27.24	24.24	20.50	21.04	22.62	29.23	29.77	26.71	26.67	28.41	31.07
2018	29.79	28.94	26.33	23.17	21.95	24.24	29.83	31.81	29.60	29.50	30.42	33.03
2019	32.09	30.86	27.99	25.24	23.50	25.55	31.43	33.26	30.83	30.25	30.85	31.47
2020	33.12	32.06	29.29	26.86	24.92	26.79	33.10	34.79	32.24	31.61	32.34	34.74
2021	34.57	33.59	31.17	28.73	26.70	28.77	37.09	36.40	33.89	33.67	34.74	36.97
2022	36.62	35.72	32.79	29.57	30.74	33.74	38.16	39.81	37.98	36.73	38.60	41.04
2023	41.99	41.58	37.56	34.65	35.30	38.47	40.84	43.22	41.89	39.85	43.27	44.47
2024	46.83	47.64	42.08	39.19	37.38	40.61	43.58	47.29	46.90	45.08	48.36	48.20
2025	49.39	50.84	44.82	43.01	38.83	43.19	45.48	50.58	50.20	45.79	46.97	50.20
2026	51.16	52.51	46.47	44.71	41.03	45.02	47.65	52.40	51.63	46.98	49.47	51.89
2027	52.90	54.45	48.57	45.76	42.20	46.53	49.09	54.20	53.79	50.20	53.48	55.69
2028	52.91	54.14	48.71	45.98	44.18	48.51	50.10	55.47	54.99	51.91	54.45	56.27
2029	55.93	57.02	51.69	48.80	45.15	48.09	50.50	57.34	56.00	51.53	54.14	56.32
2030	55.81	56.45	51.57	48.82	46.01	49.74	53.45	59.38	59.36	54.21	57.27	59.11
2031	57.61	58.12	52.52	49.88	46.99	51.83	54.56	60.88	61.55	54.98	57.32	59.71
2032	59.65	59.87	54.23	51.90	48.17	52.55	54.67	62.28	61.34	55.70	59.06	60.76
2033	60.61	61.29	55.04	52.92	49.52	54.07	56.52	63.63	62.30	57.32	61.14	62.09
2034	63.40	63.28	56.89	54.67	51.39	56.58	58.41	65.97	63.40	58.38	61.64	62.94
2035	62.61	62.85	57.48	55.52	53.11	56.30	60.06	67.28	64.71	59.12	61.39	64.05

Off-Peak (LLH Market Purchase)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2016						15.51	17.44	19.31	20.00	20.58	22.66	23.48
2017	24.39	23.42	21.01	18.47	16.22	16.23	20.21	23.40	24.19	22.79	24.25	25.63
2018	26.43	25.46	23.81	19.16	16.38	17.63	20.62	22.26	25.34	25.25	26.03	27.25
2019	27.27	26.57	25.05	19.74	16.35	17.41	21.16	23.77	25.98	26.78	27.20	28.34
2020	28.79	28.02	26.66	19.89	17.54	18.91	23.54	25.76	27.45	27.80	28.05	29.31
2021	29.51	28.68	27.18	23.82	21.40	22.45	26.21	28.54	29.61	28.82	29.08	30.44
2022	31.30	30.33	29.01	25.12	25.90	26.77	30.09	30.85	32.61	31.23	32.85	34.37
2023	35.73	35.42	32.92	30.35	29.45	29.46	33.81	33.13	35.56	34.00	36.26	38.24
2024	39.85	40.66	36.56	35.82	32.08	33.29	35.61	36.36	39.23	37.68	39.90	40.63
2025	42.17	43.70	39.26	39.08	33.88	34.72	38.15	39.61	41.32	38.00	39.40	42.53
2026	43.20	45.40	41.07	40.06	35.54	36.16	40.60	41.17	42.95	39.47	41.11	44.03
2027	44.67	46.47	42.26	41.25	36.74	37.03	42.19	42.93	45.36	42.23	44.64	47.12
2028	44.74	46.81	41.36	42.23	38.27	39.94	44.01	43.55	46.64	43.89	45.52	48.47
2029	47.22	49.59	43.92	43.76	38.93	40.71	44.59	44.70	47.67	43.49	45.31	48.56
2030	46.50	47.98	44.94	44.70	40.72	43.76	46.26	48.08	49.33	45.59	47.48	50.66
2031	47.86	50.26	46.33	44.98	42.15	44.19	46.81	47.99	49.36	46.41	48.13	50.71
2032	50.13	51.75	48.18	46.81	43.69	45.09	47.23	48.43	49.94	47.35	48.73	51.86
2033	51.84	52.66	49.42	48.18	44.52	46.30	49.84	49.80	51.33	48.83	50.61	54.14
2034	54.18	55.20	51.06	49.82	46.60	48.08	51.34	51.65	52.14	50.15	50.30	55.18
2035	54.58	55.22	51.55	50.76	47.87	49.18	53.14	53.65	54.15	50.27	51.35	56.12

Table 2
Avoided Costs ($/MWh)
Energy Prices 2016 through 2027

Year	Winter Season					Summer Season				Winter Season		
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Combined												
2016						18.09	19.68	22.11	21.57	21.74	23.81	26.23
2017	26.50	25.60	22.85	19.63	18.97	19.87	25.35	27.03	25.63	25.00	26.62	28.73
2018	28.35	27.44	25.25	21.44	19.55	21.40	25.87	27.70	27.77	27.67	28.53	30.54
2019	30.02	29.02	26.73	22.87	20.42	22.05	27.01	29.18	28.74	28.76	29.28	30.12
2020	31.26	30.32	28.16	23.86	21.75	23.40	28.99	30.91	30.18	29.97	30.50	32.41
2021	32.39	31.48	29.45	26.62	24.42	26.05	32.41	33.02	32.05	31.58	32.31	34.16
2022	34.34	33.40	31.16	27.66	28.66	30.74	34.69	35.96	35.67	34.37	36.12	38.17
2023	39.30	38.93	35.56	32.80	32.78	34.60	37.82	38.88	39.17	37.33	40.26	41.79
2024	43.83	44.64	39.70	37.74	35.10	37.46	40.15	42.59	43.60	41.90	44.72	44.95
2025	46.28	47.77	42.43	41.32	36.70	39.55	42.33	45.86	46.38	42.44	43.71	46.90
2026	47.74	49.45	44.15	42.71	38.67	41.21	44.62	47.57	47.90	43.75	45.87	48.51
2027	49.36	51.02	45.85	43.82	39.85	42.45	46.13	49.36	50.16	46.77	49.68	52.00
2028	49.40	50.99	45.55	44.36	41.64	44.83	47.48	50.35	51.40	48.46	50.61	52.92
2029	52.18	53.83	48.35	46.63	42.48	44.92	47.96	51.91	52.42	48.07	50.34	52.99
2030	51.81	52.81	48.72	47.05	43.73	47.17	50.36	54.52	55.05	50.51	53.06	55.48
2031	53.42	54.74	49.86	47.77	44.91	48.54	51.23	55.34	56.31	51.29	53.37	55.84
2032	55.56	56.38	51.63	49.71	46.24	49.34	51.47	56.33	56.44	52.11	54.62	56.93
2033	56.84	57.58	52.62	50.88	47.37	50.73	53.65	57.68	57.58	53.67	56.61	58.67
2034	59.43	59.80	54.38	52.58	49.33	52.93	55.37	59.81	58.56	54.84	56.76	59.60
2035	59.16	59.57	54.93	53.47	50.85	53.24	57.08	61.42	60.17	55.32	57.07	60.64

Annual Average

	On-Peak	Off-Peak	Combined
2016	$23.43	$19.86	$21.89
2017	$26.30	$21.68	$24.32
2018	$28.22	$22.97	$25.96
2019	$29.44	$23.80	$27.02
2020	$30.99	$25.14	$28.48
2021	$33.03	$27.14	$30.50
2022	$35.96	$30.03	$33.41
2023	$40.26	$33.69	$37.44
2024	$44.43	$37.30	$41.37
2025	$46.61	$39.32	$43.47
2026	$48.41	$40.90	$45.18
2027	$50.57	$42.74	$47.20
2028	$51.47	$43.79	$48.16
2029	$52.71	$44.87	$49.34
2030	$54.27	$46.33	$50.85
2031	$55.50	$47.10	$51.88
2032	$56.68	$48.27	$53.06
2033	$58.04	$49.79	54.49
2034	$59.74	$51.31	$56.12
2035	$60.37	$52.32	$56.91

Source Offical Market Price Forecast dated March 2016
Blending weights which are used to calculate blended market prices are based on system balancing purchases and sales from GRID run using March 2016 Official Forward Market Price Curve

Table 3
Capitalized Energy Costs

Year	Combined Cycle CT Fixed Costs ($/kW-yr)	Simple Cycle CT Fixed Costs ($/kW-yr)	Capitalized Energy Costs ($/kW-yr)	Capitalized Energy Costs 72.1% CF ($/MWh)
	(a)	(b)	(c) ((a) - (b))	(d) (c)/(8.760 x 72.1%)
2028	$149.06	$162.83	$0.00	$0.00
2029	$152.18	$166.26	$0.00	$0.00
2030	$155.56	$169.92	$0.00	$0.00
2031	$158.99	$173.66	$0.00	$0.00
2032	$162.49	$177.47	$0.00	$0.00
2033	$166.05	$181.39	$0.00	$0.00
2034	$169.68	$185.38	$0.00	$0.00
2035	$173.39	$189.45	$0.00	$0.00

Columns

(a) Table 9 Column (f)

(b) Table 9 Column (f)

(c) and (d) Capitalized energy costs are zero since fixed cost of CCCT is lower than the fixed cost of SCCT.

Table 4
Total Standard Avoided Energy Cost

Year	Combined Cycle Gas Price	Combined Cycle Energy Cost	Capitalized Energy Costs 72.1% CF	Total Standard Avoided Energy Cost
	($/MMBtu)	($/MWh)	($/MWh)	($/MWh)
	(a)	(b)	(c)	(d)
		(a) x 6.530		(b) + (c)
2028	$4.97	$32.45	$0.00	$32.45
2029	$5.11	$33.37	$0.00	$33.37
2030	$5.43	$35.46	$0.00	$35.46
2031	$5.57	$36.37	$0.00	$36.37
2032	$5.72	$37.35	$0.00	$37.35
2033	$5.91	$38.59	$0.00	$38.59
2034	$6.09	$39.77	$0.00	$39.77
2035	$6.26	$40.88	$0.00	$40.88

Columns
(a) Table 10
(b) 6.530 MWh/MMBtu Heat Rate - Table 9
(c) Table 3 Column (d)

Table 5
Total Standard Avoided Cost

Year	Avoided Firm Capacity Costs	Total Standard Avoided Energy Cost	Total Standard Avoided Costs At Stated Capacity Factor		
			75%	85%	90%
	($/kW-yr)	($/MWh)	($/MWh)	($/MWh)	($/MWh)
	(a)	(b)	(c)	(d)	(e)
			(b)+(a)/(8.76 x 0.75)	(b)+(a)/(8.76 x 0.85)	(b)+(a)/(8.76 x 0.9)
2028	$149.06	$32.45	$55.14	$52.47	$51.36
2029	$152.18	$33.37	$56.53	$53.81	$52.67
2030	$155.56	$35.46	$59.14	$56.35	$55.19
2031	$158.99	$36.37	$60.57	$57.72	$56.54
2032	$162.49	$37.35	$62.08	$59.17	$57.96
2033	$166.05	$38.59	$63.86	$60.89	$59.65
2034	$169.68	$39.77	$65.60	$62.56	$61.29
2035	$173.39	$40.88	$67.27	$64.17	$62.87

Columns
(a) Table 3 Column (a)
(b) Table 4 Column (d)

Table 6
On- & Off- Peak Energy Prices

Year	Avoided Firm Capacity Costs	Capacity Cost Allocated to On-Peak Hours	Total Standard Avoided Energy Cost	On-Peak 4,993 Hours	Off-Peak 3,767 Hours
	($/kW-yr)	($/MWh)	($/MWh)	($/MWh)	($/MWh)
	(a)	(b)	(c)	(d)	(e)
		(a) /(8.76 x 100.0% x 57%)		(b) + (c)	(c)
2028	$149.06	$29.85	$32.45	$62.30	$32.45
2029	$152.18	$30.48	$33.37	$63.85	$33.37
2030	$155.56	$31.15	$35.46	$66.61	$35.46
2031	$158.99	$31.84	$36.37	$68.21	$36.37
2032	$162.49	$32.54	$37.35	$69.89	$37.35
2033	$166.05	$33.26	$38.59	$71.85	$38.59
2034	$169.68	$33.98	$39.77	$73.75	$39.77
2035	$173.39	$34.73	$40.88	$75.61	$40.88

Columns

(a) Table 3 Column (a)
(b) Table 9 100.0% is the on-peak capacity factor of the Proxy Resource
57.0% is the percent of all hours that are on-peak
(c) Table 4 Column (d)

Table 3 (Renewable)
Capitalized Energy Costs

Year	Combined Cycle CT Fixed Costs ($/kW-yr)	Simple Cycle CT Fixed Costs ($/kW-yr)	Capitalized Energy Costs ($/kW-yr)	Capitalized Energy Costs 72.1% CF ($/MWh)
	(a)	(b)	(c)	(d)
			((a) - (b))	(c)/(8.760 x 72.1%)
2017	$116.10	$126.83	$0.00	$0.00
2018	$118.91	$129.88	$0.00	$0.00
2019	$121.77	$133.00	$0.00	$0.00
2020	$124.70	$136.19	$0.00	$0.00
2021	$127.70	$139.45	$0.00	$0.00
2022	$130.64	$142.66	$0.00	$0.00
2023	$133.64	$145.91	$0.00	$0.00
2024	$136.70	$149.27	$0.00	$0.00
2025	$139.70	$152.55	$0.00	$0.00
2026	$142.76	$155.90	$0.00	$0.00
2027	$145.88	$159.33	$0.00	$0.00
2028	$149.06	$162.83	$0.00	$0.00
2029	$152.18	$166.26	$0.00	$0.00
2030	$155.56	$169.92	$0.00	$0.00
2031	$158.99	$173.66	$0.00	$0.00
2032	$162.49	$177.47	$0.00	$0.00
2033	$166.05	$181.39	$0.00	$0.00
2034	$169.68	$185.38	$0.00	$0.00
2035	$173.39	$189.45	$0.00	$0.00

Columns
- (a) Table 9 Column (f)
- (b) Table 9 Column (f)
- (c) and (d) Capitalized energy costs are zero since fixed cost of CCCT is lower than the fixed cost of SCCT.

Table 6 (Renewable)
Avoided Capacity Costs

Year	Avoided Firm Capacity Costs ($/kW-yr)	Capacity Cost Allocated to On-Peak Hours ($/MWh)
	(a)	(b)
		(a) /(8.76 x 100.0% x 57%)
2017	$116.10	$23.25
2018	$118.91	$23.81
2019	$121.77	$24.39
2020	$124.70	$24.97
2021	$127.70	$25.57
2022	$130.64	$26.16
2023	$133.64	$26.76
2024	$136.70	$27.38
2025	$139.70	$27.98
2026	$142.76	$28.59
2027	$145.88	$29.22
2028	$149.06	$29.85
2029	$152.18	$30.48
2030	$155.56	$31.15
2031	$158.99	$31.84
2032	$162.49	$32.54
2033	$166.05	$33.26
2034	$169.68	$33.98
2035	$173.39	$34.73

Columns
- (a) Table 3 Column (a)
- (b) Table 9 100.0% is the on-peak capacity factor of the Proxy Resource
  57.0% is the percent of all hours that are on-peak

Table 7
Comparison between Proposed and Current Standard Fixed Avoided Costs
$/MWh

Year	Proposed Standard Fixed Base Load QF	Current Standard Fixed Base Load QF	Difference Standard Fixed Base Load QF	Proposed Standard Fixed Wind QF (2)	Current Standard Fixed Wind QF (2)	Difference Standard Fixed Wind QF (2)	Proposed Standard Fixed Fixed Solar QF	Current Standard Fixed Fixed Solar QF	Difference Standard Fixed Fixed Solar QF	Proposed Standard Fixed Tracking Solar QF	Current Standard Fixed Tracking Solar QF	Difference Standard Fixed Tracking Solar QF
2016	$21.89	$25.80	($3.90)	$18.77	$23.11	($4.33)	$22.88	$27.63	($4.75)	$22.88	$27.63	($4.75)
2017	$24.31	$28.30	($3.99)	$21.12	$25.56	($4.44)	$25.59	$30.25	($4.66)	$25.59	$30.25	($4.66)
2018	$25.96	$30.16	($4.20)	$22.69	$27.36	($4.67)	$27.41	$32.46	($5.05)	$27.41	$32.46	($5.05)
2019	$27.01	$31.97	($4.95)	$23.66	$29.11	($5.44)	$28.57	$34.22	($5.64)	$28.57	$34.22	($5.64)
2020	$28.47	$34.37	($5.89)	$25.04	$31.45	($6.40)	$30.09	$36.81	($6.73)	$30.09	$36.81	($6.73)
2021	$30.50	$37.08	($6.58)	$26.99	$34.10	($7.11)	$32.12	$39.63	($7.51)	$32.12	$39.63	($7.51)
2022	$33.41	$39.93	($6.52)	$29.82	$36.89	($7.07)	$35.05	$42.59	($7.55)	$35.05	$42.59	($7.55)
2023	$37.43	$42.77	($5.33)	$33.76	$39.66	($5.89)	$39.25	$45.63	($6.38)	$39.25	$45.63	($6.38)
2024	$41.36	$48.24	($6.88)	$37.61	$28.13	$9.48	$43.33	$34.14	$9.20	$43.33	$34.14	$9.20
2025	$43.48	$49.89	($6.41)	$39.65	$29.34	$10.31	$45.49	$35.48	$10.01	$45.49	$35.48	$10.01
2026	$45.18	$50.19	($5.01)	$41.27	$29.22	$12.06	$47.25	$35.48	$11.77	$47.25	$35.48	$11.77
2027	$47.20	$51.89	($4.68)	$43.20	$30.46	$12.74	$49.36	$36.86	$12.50	$49.36	$36.86	$12.50
2028	$49.46	$55.30	($5.84)	$32.68	$33.43	($0.75)	$40.58	$39.96	$0.62	$41.72	$39.96	$1.76
2029	$50.74	$56.72	($5.98)	$33.60	$34.41	($0.81)	$41.67	$41.08	$0.60	$42.83	$41.08	$1.76
2030	$53.22	$57.92	($4.70)	$35.70	$35.16	$0.54	$43.95	$41.96	$1.99	$45.13	$41.96	$3.18
2031	$54.52	$60.76	($6.24)	$36.62	$37.52	($0.90)	$45.04	$44.46	$0.58	$46.26	$44.46	$1.79
2032	$55.90	$62.23	($6.34)	$37.60	$38.51	($0.91)	$46.21	$45.60	$0.62	$47.45	$45.60	$1.86
2033	$57.55	$63.26	($5.72)	$38.85	$39.03	($0.19)	$47.65	$46.28	$1.37	$48.92	$46.28	$2.64
2034	$59.14	$65.14	($6.00)	$40.03	$40.40	($0.37)	$49.03	$47.80	$1.23	$50.32	$47.80	$2.52
2035	$60.68	$67.24	($6.57)	$41.15	$41.99	($0.84)	$50.34	$49.54	$0.80	$51.66	$49.54	$2.13

15 Year (2016 - 2030) Nominal levelized Price at 6.660% Discount Rate (1)

$/MWh	$34.52	$39.80	($5.28)	$29.25	$30.47	($1.23)	$34.74	$36.07	($1.34)	$34.89	$36.07	($1.18)

Notes: (1) Discount Rate - 2015 IRP Discount Rate
(2) Avoided cost prices have been reduced by a wind integration charge of $3.06/MWh ($2015) for wind QFs located resources located in PacifiCorp's Balancing Area Authority (BAA) (in-system) .
If the QF wind resource is not in PacifiCorp's BAA, prices will be increased by the $3.06/MWh ($2015) integration charges

15 Year (2017 - 2031) Nominal levelized Price at 6.660% Discount Rate (1)

$/MWh	$36.70	$42.16	($5.46)	$30.67	$31.55	($0.88)	$36.43	$37.32	($0.89)	$36.64	$37.32	($0.68)

Table 8

Comparison between Proposed and Current Renewable Fixed Avoided Costs

$/MWh

Year	Proposed Renewable Fixed Base Load QF	Current Renewable Fixed Base Load QF	Difference Renewable Fixed Base Load QF	Proposed Renewable Fixed Wind QF (2)	Current Renewable Fixed Wind QF (2)	Difference Renewable Fixed Wind QF (2)	Proposed Renewable Fixed Fixed Solar QF	Current Renewable Fixed Fixed Solar QF	Difference Renewable Fixed Fixed Solar QF	Proposed Renewable Fixed Tracking Solar QF	Current Renewable Fixed Tracking Solar QF	Difference Renewable Fixed Tracking Solar QF
2016	$21.89	$25.80	($3.90)	$18.77	$23.11	($4.33)	$22.88	$27.63	($4.75)	$22.88	$27.63	($4.75)
2017	$24.31	$28.30	($3.99)	$21.12	$25.56	($4.44)	$25.59	$30.25	($4.66)	$25.59	$30.25	($4.66)
2018	$49.05	$30.16	$18.89	$35.66	$27.36	$8.30	$42.67	$32.46	$10.21	$43.58	$32.46	$11.12
2019	$50.21	$31.97	$18.24	$36.49	$29.11	$7.38	$43.68	$34.22	$9.46	$44.60	$34.22	$10.39
2020	$51.42	$34.37	$17.05	$37.37	$31.45	$5.93	$44.45	$36.81	$7.64	$45.40	$36.81	$8.59
2021	$52.64	$37.08	$15.56	$38.26	$34.10	$4.16	$45.32	$39.63	$5.69	$46.30	$39.63	$6.67
2022	$53.86	$39.93	$13.93	$39.15	$36.89	$2.26	$46.49	$42.59	$3.90	$47.49	$42.59	$4.89
2023	$55.11	$42.77	$12.34	$40.06	$39.66	$0.41	$47.66	$45.63	$2.03	$48.68	$45.63	$3.05
2024	$56.36	$98.47	($42.11)	$40.97	$78.36	($37.39)	$48.67	$89.35	($40.68)	$49.71	$89.35	($39.64)
2025	$57.60	$100.64	($43.03)	$41.87	$80.09	($38.21)	$49.68	$91.15	($41.47)	$50.75	$91.15	($40.40)
2026	$58.85	$102.73	($43.88)	$42.79	$81.75	($38.97)	$50.73	$92.46	($41.73)	$51.82	$92.46	($40.64)
2027	$60.16	$104.89	($44.73)	$43.74	$83.46	($39.73)	$51.81	$94.22	($42.41)	$52.92	$94.22	($41.30)
2028	$61.49	$107.09	($45.60)	$44.70	$85.22	($40.51)	$52.99	$95.99	($43.00)	$54.13	$95.99	($41.86)
2029	$62.77	$109.22	($46.45)	$45.63	$86.91	($41.28)	$54.07	$97.70	($43.63)	$55.23	$97.70	($42.47)
2030	$64.16	$111.40	($47.24)	$46.64	$88.64	($42.00)	$55.33	$99.44	($44.11)	$56.51	$99.44	($42.92)
2031	$65.53	$113.68	($48.16)	$47.63	$90.44	($42.81)	$56.47	$100.98	($44.51)	$57.68	$100.98	($43.30)
2032	$67.01	$116.13	($49.12)	$48.71	$92.41	($43.69)	$57.70	$103.28	($45.58)	$58.94	$103.28	($44.34)
2033	$68.47	$118.54	($50.07)	$49.77	$94.32	($44.54)	$58.91	$104.81	($45.90)	$60.18	$104.81	($44.63)
2034	$69.99	$121.01	($51.01)	$50.88	$96.27	($45.39)	$60.19	$106.42	($46.22)	$61.49	$106.42	($44.93)
2035	$71.52	$123.53	($52.02)	$51.99	$98.28	($46.29)	$61.37	$108.66	($47.30)	$62.69	$108.66	($45.97)

15 Year (2016 - 2030) Nominal levelized Price at 6.660% Discount Rate (1)

$/MWh	$49.02	$57.97	($8.94)	$36.25	$48.64	($12.39)	$43.19	$55.81	($12.62)	$44.01	$55.81	($11.79)

Notes: (1) Discount Rate - 2015 IRP Discount Rate

(2) Avoided cost prices have been reduced by a wind integration charge of $3.06/MWh ($2015) for wind QFs located resources located in PacifiCorp's Balancing Area Authority (BAA) (in-system) .

If the QF wind resource is not in PacifiCorp's BAA, prices will be increased by the $3.06/MWh ($2015) integration charges

15 Year (2017 - 2031) Nominal levelized Price at 6.660% Discount Rate (1)

$/MWh	$52.61	$63.70	($11.09)	$38.59	$53.09	($14.50)	$45.91	$60.68	($14.76)	$46.84	$60.68	($13.84)

15 Year (2018 - 2032) Nominal levelized Price at 0.000% Discount Rate (1)

Table 9
Total Cost of Displaceable Resources

Year	Estimated Capital Cost $/kW	Capital Cost at Real Levelized Rate $/kW-yr	Fixed O&M $/kW-yr	Variable O&M $/MWh	Total O&M at Expected CF $/kW-yr	Total Resource Fixed Costs $/kW-yr
	(a)	(b)	(c)	(d)	(e)	(f)
SCCT Frame ("F"x1) - West Side Options (1500')						
2015	$825	$64.07	$46.13	$4.29	$58.54	$122.61
2016		$64.84	$46.69	$4.34	$59.24	$124.08
2017		$66.27	$47.72	$4.44	$60.56	$126.83
2018		$67.86	$48.87	$4.55	$62.02	$129.88
2019		$69.49	$50.04	$4.66	$63.51	$133.00
2020		$71.16	$51.24	$4.77	$65.03	$136.19
2021		$72.87	$52.47	$4.88	$66.58	$139.45
2022		$74.55	$53.68	$4.99	$68.11	$142.66
2023		$76.26	$54.91	$5.10	$69.65	$145.91
2024		$78.01	$56.17	$5.22	$71.26	$149.27
2025		$79.73	$57.41	$5.33	$72.82	$152.55
2026		$81.48	$58.67	$5.45	$74.42	$155.90
2027		$83.27	$59.96	$5.57	$76.06	$159.33
2028		$85.10	$61.28	$5.69	$77.73	$162.83
2029		$86.89	$62.57	$5.81	$79.37	$166.26
2030		$88.80	$63.95	$5.94	$81.12	$169.92
2031		$90.75	$65.36	$6.07	$82.91	$173.66
2032		$92.75	$66.80	$6.20	$84.72	$177.47
2033		$94.79	$68.27	$6.34	$86.60	$181.39
2034		$96.88	$69.77	$6.48	$88.50	$185.38
2035		$99.01	$71.30	$6.62	$90.44	$189.45

Source: (a)(c)(d) Plant Costs - 2015 IRP - Table 6.1 & 6.2
(b) = (a) x Payment Factor
(e) = (d) x (8.76 x 33%) + (c)
(f) = (b) + (e)

	SCCT Frame ("F"x1) - West Side Options (1500')	
212	MW Plant capacity	MW
$ 820	Plant capacity cost	$/kW
$ 10.73	Fixed O&M & Capitalized O&M	$/kW-yr
$ 35.13	Fixed Pipeline	$/kW-yr
$ 45.86	Fixed O&M Including Fixed Pipeline & Capitalized (	$/kW-yr
$ 4.27	Variable O&M and Other Costs	$/MWH
7.767%	Payment Factor	
33%	Capacity Factor	

Table 9
Total Cost of Displaceable Resources

Year	Estimated Capital Cost $/kW	Capital Cost at Real Levelized Rate $/kW-yr	Fixed O&M $/kW-yr	Variable O&M $/MWh	Total O&M at Expected CF $/kW-yr	Total Resource Fixed Costs $/kW-yr	Fuel Cost $/MMBtu	IRP Resource Energy Cost $/MWh	Total Avoided Costs $/MWh
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
CCCT (Dry "J" Adv 1x1) - West Side Options (1500')									
2015	$872	$67.00	$31.01	$2.25	$45.25	$112.25			
2016		$67.81	$31.39	$2.28	$45.79	$113.60			
2017		$69.30	$32.08	$2.33	$46.80	$116.10			
2018		$70.96	$32.85	$2.39	$47.95	$118.91			
2019		$72.66	$33.64	$2.45	$49.11	$121.77			
2020		$74.40	$34.45	$2.51	$50.30	$124.70			
2021		$76.19	$35.28	$2.57	$51.51	$127.70			
2022		$77.94	$36.09	$2.63	$52.70	$130.64			
2023		$79.73	$36.92	$2.69	$53.91	$133.64			
2024		$81.56	$37.77	$2.75	$55.14	$136.70			
2025		$83.35	$38.60	$2.81	$56.35	$139.70			
2026		$85.18	$39.45	$2.87	$57.58	$142.76			
2027		$87.05	$40.32	$2.93	$58.83	$145.88			
2028		$88.97	$41.21	$2.99	$60.09	$149.06	$4.97	$32.45	$56.05
2029		$90.84	$42.08	$3.05	$61.34	$152.18	$5.11	$33.37	$57.46
2030		$92.84	$43.01	$3.12	$62.72	$155.56	$5.43	$35.46	$60.09
2031		$94.88	$43.96	$3.19	$64.11	$158.99	$5.57	$36.37	$61.54
2032		$96.97	$44.93	$3.26	$65.52	$162.49	$5.72	$37.35	$63.08
2033		$99.10	$45.92	$3.33	$66.95	$166.05	$5.91	$38.59	$64.88
2034		$101.28	$46.93	$3.40	$68.40	$169.68	$6.09	$39.77	$66.64
2035		$103.51	$47.96	$3.47	$69.88	$173.39	$6.26	$40.88	$68.33

Table 9
Total Cost of Displaceable Resources

Sources, Inputs and Assumptions

Source: (a)(c)(d)	Plant Costs - 2015 IRP - Table 6.1 & 6.2
(b)	= (a) x 0.07682
(e)	= (d) x (8.76 x 72.1%) + (c)
(f)	= (b) + (e)
(g)	Gas Price Forecast
(h)	= 6530 x (g) / 1000
(i)	= (f) / (8.76 x 'Capacity Factor') + (h)

CCCT (Dry "J" Adv 1x1) - West Side Options (1500')

CCCT Statistics	MW	Percent	Cap Cost	Fixed
CCCT (Dry "J" Adv 1x1)	434	91.0%	$906	$30.82
CCCT Duct Firing (Dry "J" Adv 1x1)	43	9.0%	$481	$30.93
Capacity Weighted	477	100.0%	$867	$30.83

CCCT Statistics	MW	CF	aMW	Percent	Variable	Heat Rate
CCCT (Dry "J" Adv 1x1)	434	78.0%	339	98.5%	$2.27	6,495
CCCT Duct Firing (Dry "J" Adv 1x1)	43	12.0%	5	1.5%	0.10	8,611
Energy Weighted	477	72.1%	344	100.0%	$2.24	6,530
						Rounded

CCCT	Duct Firing	Plant Costs - 2015 IRP - Table 6.1 & 6.2
434	43	MW Plant capacity
$906	$481	Plant capacity cost
$7.50	$0.00	Fixed O&M & Capitalized O&M
$23.33	$30.93	Fixed Pipeline
$30.82	$30.93	Fixed O&M Including Fixed Pipeline & Capitalized O&M ($/kW-Yr)
$2.27	$0.10	Variable O&M and Other Costs
6,495	8,611	Heat Rate in btu/kWh
7.682%	7.682%	Payment Factor
78%	12%	Capacity Factor
	72.1%	Energy Weighted Capacity Factor
	100.0%	Capacity Factor - On-peak 72.1% / 57% (percent of hours on-peak)

Company Official Inflation Forecast - Dated March 2016

2015	0.6%	2021	2.4%	2027	2.2%	2033	2.2%
2016	1.2%	2022	2.3%	2028	2.2%	2034	2.2%
2017	2.2%	2023	2.3%	2029	2.1%	2035	2.2%
2018	2.4%	2024	2.3%	2030	2.2%	2036	2.2%
2019	2.4%	2025	2.2%	2031	2.2%	2037	2.2%
2020	2.4%	2026	2.2%	2032	2.2%	2038	2.3%

Table 10
Gas Price Forecast
$/MMBtu

Year	Burner tip West Side Gas Fuel Cost
2028	$4.97
2029	$5.11
2030	$5.43
2031	$5.57
2032	$5.72
2033	$5.91
2034	$6.09
2035	$6.26

Source
Offical Market Price Forecast dated March 2016

Table 11
Wind Integration Cost

Year	Wind Integration Cost $/MWh
2014	$3.06
2015	$3.08
2016	$3.12
2017	$3.19
2018	$3.27
2019	$3.35
2020	$3.43
2021	$3.51
2022	$3.59
2023	$3.67
2024	$3.75
2025	$3.83
2026	$3.91
2027	$4.00
2028	$4.09
2029	$4.18
2030	$4.27
2031	$4.36
2032	$4.46
2033	$4.56
2034	$4.66
2035	$4.76

Note: Wind Integration Charge is $3.06 (2014 $ per MWh)
2015 IRP Volume II-Appendix H, Table H.3

Table 12
2015 IRP Update OR Wind Resource
35% Capacity Factor

Year	Estimated Capital Cost $/kW	Capital Cost at Real Levelized Rate $/kW-yr	Fixed O&M $/kW-yr	Fixed Costs $/MWh	Variable O&M $/MWh	Tax Credit $/MWh	Avoided Cost $/MWh	Wind Integration Cost $/MWh
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
2015 IRP Update OR Wind Resource - 35% Capacity Factor								
2015	$1,682	$124.45	$37.88	$52.95	$0.00	($19.36)	$33.59	$3.08
2016		$125.95	$38.33	$53.58	$0.00	($19.59)	$33.99	$3.12
2017		$128.72	$39.17	$54.76	$0.00	($20.02)	$34.74	$3.19
2018		$131.81	$40.11	$56.07	$0.00	($20.50)	$35.57	$3.27
2019		$134.97	$41.07	$57.42	$0.00	($20.99)	$36.43	$3.35
2020		$138.21	$42.06	$58.80	$0.00	($21.49)	$37.31	$3.43
2021		$141.53	$43.07	$60.21	$0.00	($22.01)	$38.20	$3.51
2022		$144.79	$44.06	$61.59	$0.00	($22.52)	$39.07	$3.59
2023		$148.12	$45.07	$63.01	$0.00	($23.04)	$39.97	$3.67
2024		$151.53	$46.11	$64.46	$0.00	($23.57)	$40.89	$3.75
2025		$154.86	$47.12	$65.88	$0.00	($24.09)	$41.79	$3.83
2026		$158.27	$48.16	$67.33	$0.00	($24.62)	$42.71	$3.91
2027		$161.75	$49.22	$68.81	$0.00	($25.16)	$43.65	$4.00
2028		$165.31	$50.30	$70.32	$0.00	($25.71)	$44.61	$4.09
2029		$168.78	$51.36	$71.80	$0.00	($26.25)	$45.55	$4.18
2030		$172.49	$52.49	$73.38	$0.00	($26.83)	$46.55	$4.27
2031		$176.28	$53.64	$74.99	$0.00	($27.42)	$47.57	$4.36
2032		$180.16	$54.82	$76.64	$0.00	($28.02)	$48.62	$4.46
2033		$184.12	$56.03	$78.33	$0.00	($28.64)	$49.69	$4.56
2034		$188.17	$57.26	$80.05	$0.00	($29.27)	$50.78	$4.66
2035		$192.31	$58.52	$81.81	$0.00	($29.91)	$51.90	$4.76

Sources, Inputs and Assumptions

Source:	(c)(f)	Plant Costs 2015 IRP Update (Table 4.4) in $2014
	(a)	Plant capacity cost
	(b)	= (a) x 0.0739902205884359
	(d)	= ((b) + (c)) / (8.76 x 35.0%)
	(g)	= (d) + (f)
	(h)	2015 IRP Update (Table 4.4) in $2014

2015 IRP Update OR Wind Resource - 35% Capacity Factor		
Wind	**Cost and Input Assumptions**	
$1,672	Plant capacity cost	$/kW-yr
$37.65	Fixed O&M, plus on-going capital cost 2015 IRP Update (Table 4.4) in $2014	$/kW-yr
$0.00	Variable O&M	$/MWH
(19.24)	Tax Credit $/MWh 2015 IRP Update (Table 4.4) in $2014	$/MWH
7.399%	Payment Factor	
35%	Capacity Factor	

Official Inflation Forecast Dated March 2016 Forecast

2015	0.6%	2021	2.4%	2027	2.2%	2033	2.2%
2016	1.2%	2022	2.3%	2028	2.2%	2034	2.2%
2017	2.2%	2023	2.3%	2029	2.1%	2035	2.2%
2018	2.4%	2024	2.3%	2030	2.2%	2036	2.2%
2019	2.4%	2025	2.2%	2031	2.2%	2037	2.2%
2020	2.4%	2026	2.2%	2032	2.2%	2038	2.3%

Table 13
2015 IRP Update Wind Resource Costs
Adjusted to On-Peak / Off-Peak Prices

	Renewable Price	On-Peak / Off-Peak Factors		On-Peak / Off-Peak Prices	
Year	$/MWH	On-Peak	Off-Peak	On-Peak	Off-Peak
	(a)	(b)	(c)	(d)	(e)
				(a) x (b)	(a) x (c)
2018	$35.57	1.1064	0.8644	$39.36	$30.75
2019	$36.43	1.1057	0.8638	$40.28	$31.46
2020	$37.31	1.0941	0.8791	$40.82	$32.80
2021	$38.20	1.0865	0.8892	$41.50	$33.97
2022	$39.07	1.0915	0.8829	$42.65	$34.50
2023	$39.97	1.0953	0.8792	$43.78	$35.14
2024	$40.89	1.0925	0.8819	$44.67	$36.06
2025	$41.79	1.0902	0.8851	$45.56	$36.99
2026	$42.71	1.0891	0.8862	$46.51	$37.85
2027	$43.65	1.0872	0.8888	$47.46	$38.80
2028	$44.61	1.0887	0.8872	$48.57	$39.58
2029	$45.55	1.0877	0.8879	$49.54	$40.45
2030	$46.55	1.0898	0.8855	$50.73	$41.22
2031	$47.57	1.0879	0.8863	$51.75	$42.16
2032	$48.62	1.0871	0.8891	$52.85	$43.23
2033	$49.69	1.0855	0.8909	$53.93	$44.26
2034	$50.78	1.0848	0.8925	$55.08	$45.32
2035	$51.90	1.0803	0.8975	$56.07	$46.58

Columns
- (a) Table 12 Column (f)
- (b) Ratio blended market On-Peak to annual prices
- (c) Ratio blended market Off-Peak to annual prices

PACIFIC POWER
AVOIDED COST CALCULATION

STANDARD RATES FOR AVOIDED COST PURCHASES FROM ELIGIBLE QUALIFYING FACILITIES

OREGON – JUNE 2016

PACIFIC POWER
AVOIDED COST CALCULATION

STANDARD RATES FOR AVOIDED COST PURCHASES FROM ELIGIBLE QUALIFYING FACILITIES

OREGON – June 2016

Standard avoided cost rates are paid to eligible small qualifying facilities (QFs). Oregon avoided cost filing requirements as listed in OAR 860-029-0040 and 860-029-0080 require the Company to file updated avoided costs at least every two years. The Commission Order No. 14-058, requires the Oregon investor owned utilities to update avoided cost prices annually on May 1 of each year and within 30-days of Integrated Resource Plan (IRP) acknowledgment. Annual updates, filed on May 1 of each year, are required to update the following data inputs: (1) natural gas prices; (2) on-peak and off-peak forward looking electricity market prices; (3) production tax credit status; and (4) any other action or change in an acknowledged IRP relevant to the calculation of avoided costs.

The last Oregon avoided costs were approved on June 23, 2015.

Sufficiency and Deficiency Periods

In Docket UM-1396 Order 10-488, the Commission directed that the start date of the first "major resource acquisition" in the action plan of the IRP determines the resource "sufficiency" and "deficiency" periods to be used in calculations of standard avoided cost prices. The sufficiency and deficiency periods used in this filing are based on the 2015 IRP which was acknowledged by the Commission on February 29, 2016.

Table 1 presents an excerpt from the 2015 IRP Table 8.7 and shows that the next major resource acquisition is a Combine Cycle Combustion Turbine (CCCT) starting in 2028. Therefore, the resource sufficiency period for the standard avoided cost rates is from 2016-2027 and the deficiency period starts in 2028.

For standard renewable avoided cost rates, the start of the renewable resource deficiency period and renewable proxy plant cost assumptions are revised due to the changed circumstances with the passing of Oregon Senate Bill 1547 legislation. The Company recently issued a renewable resource RFP in to identify potential time sensitive opportunities to acquire renewable resources or renewable energy credits that could be used to meet the Renewable Portfolio Standard requirements set forth in SB 1547. In this filing the renewable resource deficiency period is revised to start in 2018, assuming a new renewable resource that qualifies for 100% production tax credit (PTC) benefits is brought online by January 1, 2018.

Avoided Cost Calculation

Based on the 2015 IRP preferred portfolio shown in **Table 1**, the standard avoided cost calculation is separated into two distinct periods: (1) a period of standard resource sufficiency (2016 through 2027); and (2) a period of standard resource deficiency (2028 and beyond). During the resource sufficiency period (2016 through 2027), standard avoided energy costs are based on market prices. Market prices from the Company's Official Forward Price Curve are weighted by market transactions required to support the addition of an assumed 50 MW Oregon Qualified Facility. To calculate the weighting, two production cost studies are prepared. The only difference between the two studies is an assumed 50 aMW, zero running cost resource. System balancing sales and purchase volumes are extracted from both studies and the change between the two studies is calculated for each market hub. This volume impact is used to weight the Company's Official Market Price Forecast on-peak and off-peak market prices for COB, Mid-Columbia, and Palo Verde for each month. **Table 2** shows the result of this calculation.

The sufficiency period for standard renewable rates is 2016 through 2017 and the renewable resource deficiency period starts in 2018. During the renewable resource sufficiency period (2016 through 2017), the renewable avoided energy costs are based on weighted market prices.

During the resource deficiency period, standard avoided costs are the fixed and variable costs of a proxy resource that could be avoided or deferred. The current thermal proxy resource used to set standard avoided cost rates beginning in 2028 is a west side CCCT from the 2015 IRP.[1]

Since CCCTs are built as base load units that provide both capacity and energy, it is appropriate to split the fixed costs of this unit into capacity and energy components. The fixed cost of a simple cycle combustion turbine (SCCT), which is usually acquired as a capacity resource, defines the portion of the fixed cost of the CCCT that is assigned to capacity.[2] Fixed costs associated with the construction of a CCCT which are in excess of SCCT costs are assigned to energy and are added to the variable production (fuel) cost of the CCCT to determine the total avoided energy costs. **Table 3** shows the capitalized energy costs, which in this case are zero because the costs of an SCCT exceed those of the CCCT.

The fuel cost of the CCCT defines the avoided variable energy costs. The gas price forecast used as the basis for the CCCT fuel cost is discussed later in this document.

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[1] 477 MW CCCT (Dry "J" Adv 1x1) - West Side Options (1500') –available in 2028 as listed in Tables 6.1 and 6.2 of the 2015 IRP. Fuel costs are from the Company's March 2016 Official Forward Price Curve (1603 OFPC).

[2] SCCT Frame ("F"x1) - West Side Options (1500'), as listed in Tables 6.1 and 6.2 of the 2015 IRP.

Table 4 shows the CCCT fuel cost, the addition of capitalized energy costs at an assumed 72.1% capacity factor, and the total avoided energy costs.

Because energy generated by a QF may vary, we have prepared total standard avoided costs at 75%, 85% and 90% capacity factor to illustrate the impact of differing generation levels. This calculation is shown in **Table 5**.

Standard avoided costs are differentiated between on-peak and off-peak periods, with capacity costs allocated to on-peak periods. On an annual basis, approximately 57% of all hours are on-peak and 43% are off-peak. **Table 6** shows the calculation of on-peak and off-peak avoided energy prices.

For informational purposes, **Tables 7 and 8** show a comparison between current avoided costs currently in effect in Oregon and the proposed avoided costs in this filing.

Table 9 shows the calculation of the total fixed costs and fuel costs of the CCCT and SCCT that are used in **Table 3** and **Table 4**. In this filing, the Company's thermal proxy resource is a CCCT located on the west side of the Company's system. Current Commission approved avoided costs are also based upon a CCCT located on the west side of the Company's system.

Gas Price Forecast

Gas prices used in this filing utilize the Company's March 2016 Official Forward Price Curve (1603 OFPC). **Table 10** shows the natural gas price used in this avoided cost calculation.

Table 11 shows wind integration costs used in 2015 IRP.

Table 12 shows the calculation of total resource cost of the renewable proxy plant, which is an Oregon wind resource with a 35% capacity factor from 2015 IRP Update. The total cost of the Oregon wind resource is used in the calculation of standard renewable avoided cost rates as shown in "**Exhibits 5 through 8"**.

Table 13 shows the calculation of on-peak and off-peak standard renewable avoided cost prices by applying on-peak and off-peak factors. On-peak and off-peak factors are calculated as a ratio of the average annual on-peak Mid-C market price to the flat Mid-C market price.

Exhibit 1- Std Base Load QF tab shows the calculation of proposed standard avoided cost rates for a base load QF. On and off-peak avoided cost rates are based on blended market rates for 2016-2027. For 2028 and beyond, the off-peak price is based on the fuel and capitalized energy cost of the proxy CCCT. The on-peak price includes a capacity adder based on the fixed costs a thermal proxy CCCT.

Exhibit 2- Std Wind QF tab shows the calculation of proposed standard avoided cost rates for a wind QF. On and off-peak avoided cost rates are based on blended market rates for 2016-2027. For 2028 and beyond, the off-peak price is based on the fuel and capitalized energy cost of the proxy CCCT. The on-peak price includes a capacity adder calculated based on fixed costs of the thermal proxy CCCT adjusted by the expected capacity contribution of a wind QF as identified in the 2015 IRP (wind: 25.4%). Standard avoided cost rates for a wind QF are reduced by a wind integration charge of $3.06/MWh ($2014).

Exhibits 3 & 4- Std Solar QF tab shows the calculation of proposed standard avoided cost rates for a solar QF. On and off-peak avoided cost rates are based on blended market rates for 2016-2027. For 2028 and beyond, the off-peak price is based on the fuel and capitalized energy cost of the proxy CCCT. The on-peak price includes a capacity adder calculated based on the fixed costs a thermal proxy CCCT adjusted by expected capacity contribution of a solar QF as identified in the 2015 IRP (fixed solar: 32.2%, tracking solar: 36.7%).

Exhibit 5- Renewable Base Load tab shows the calculation of proposed standard renewable avoided cost rates for a Renewable Base Load QF. On- and off-peak renewable avoided cost rates are based on blended market rates for 2016-2017. For 2018 and beyond, on- and off-peak prices are based on on-peak and off-peak prices of the renewable wind proxy resource as calculated in Table 12 and Table 13. The standard renewable on-peak price includes a capacity adder calculated based on the fixed costs of a thermal proxy CCCT, adjusted by the incremental capacity contribution of a renewable base load QF relative to the avoided renewable wind resource. The renewable avoided cost rates for a base load QF are increased by the avoided wind integration charge of $3.06/MWh ($2014) during the renewable resource deficiency period.

Exhibit 6- Renewable Wind tab shows the calculation of proposed standard renewable avoided cost rates for a Wind QF. On- and off-peak renewable avoided cost rates are based on blended market rates for 2016-2017. For 2018 and beyond, on- and off-peak prices are based on on-peak and off-peak prices of the renewable wind proxy resource as calculated in Table 12 and Table 13.

Exhibits 7 & 8- Renewable Solar tab shows the calculation of proposed standard renewable avoided cost rates for a Renewable Solar QF. On- and off-peak renewable avoided cost rates are based on blended market rates for 2016-2017. For 2018 and beyond, on- and off-peak prices are based on on-peak and off-peak prices of the renewable wind proxy resource as calculated in Table 12 and Table 13. The standard renewable on-peak price includes a capacity adder calculated based on the fixed costs of a thermal proxy CCCT, adjusted by the incremental capacity contribution of a renewable Fixed and Tracking Solar QF relative to the avoided renewable wind resource. The standard renewable avoided cost rates for fixed and tracking solar QF resources are increased by the avoided wind integration charge of $3.06/MWh ($2014) during the renewable resource deficiency period.

Exhibit 9– Blending tab shows the market blending used to weight the Company's Official Forward Price Curve on-peak and off-peak market prices at COB, Palo Verde and Mid-Columbia by month, which are used in the calculation of rates shown in **Table 2.**