PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

March 1, 2016

VIA ELECTRONIC FILING

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

Attention: Filing Center

RE: **UM 1729(1) – Schedule 37 Avoided Cost Purchases from Eligible Qualifying Facilities Compliance Filing Docket UM 1610**

In compliance with ORS 758.525 and Order 14-058 of docket UM 1610, PacifiCorp d/b/a Pacific Power (PacifiCorp or Company) hereby submits for filing updates to its standard avoided cost schedule (Schedule 37). The Company respectfully requests an effective date of April 1, 2016.

This filing satisfies the Company's obligation established in Order No. 14-058 to file avoided cost updates within 30 days of Integrated Resource Plan (IRP) acknowledgement. Consistent with Order No. 14-058, the proposed filing updates prices using inputs from the Company's 2015 IRP, acknowledged by the Commission on February 29, 2016, and its official forward price curve dated December 2015.

In support of this filing, PacifiCorp submits Appendix 1– Avoided Cost Study and Appendix 2-Method Write-up. Also included is an update of Sheet Nos. 37-5 and 37-6, which reflect the updates since the previous filing. Also provided is the supporting documentation in both "pdf" and original formats.

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
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Informal inquiries on this filing may be directed to Erin Apperson, Manager of Regulatory Affairs, at (503) 813-6642.

Sincerely,

R Bryce Dalley /[illegible]

R. Bryce Dalley
Vice President, Regulation
Enclosures
cc: UM 1610 Service List
UM 1396 Service List

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 1st day of March, 2016.

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Dated this 1st day of March 2016.

Carrie Meyer

Carrie Meyer
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 non-solar 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. (N)

Under Public Utility Commission of Oregon Order No. 15-241 (Docket No. UM 1734, Aug. 14, (N)
2015), for power purchased from solar Qualifying Facilities with a nameplate capacity of 3,000 (N)
kW or less or that, together with any other electric generating facility using the same motive (N)
force, owned or controlled by the same person(s) or affiliated person(s), and located at the (N)
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.

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.

On-Peak Hours or Peak Hours

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

(M) to pg. 2

(continued)

Definitions (continued) (M) from pg. 1

On-Peak Hours or Peak Hours (continued)

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.

Dispute Resolution

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.

(continued)

Dispute Resolution (continued)

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

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.

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.

(continued)

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

Fixed Prices ¢/kWh (C)

Deliveries During Calendar Year	Base Load QF (1)		Wind QF (2)		Fixed Solar QF		Tracking Solar QF	
	On-Peak Energy Price	Off-Peak Energy Price	On-Peak Energy Price	Off-Peak Energy Price	On-Peak Energy Price	Off-Peak Energy Price	On-Peak Energy Price	Off-Peak Energy Price
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
2016	2.32	1.79	2.01	1.48	2.32	1.79	2.32	1.79
2017	2.54	2.05	2.22	1.73	2.54	2.05	2.54	2.05
2018	2.75	2.23	2.42	1.90	2.75	2.23	2.75	2.23
2019	2.99	2.36	2.66	2.03	2.99	2.36	2.99	2.36
2020	3.16	2.51	2.82	2.17	3.16	2.51	3.16	2.51
2021	3.38	2.66	3.03	2.31	3.38	2.66	3.38	2.66
2022	3.62	2.93	3.27	2.57	3.62	2.93	3.62	2.93
2023	3.86	3.14	3.49	2.78	3.86	3.14	3.86	3.14
2024	4.09	3.33	3.72	2.95	4.09	3.33	4.09	3.33
2025	4.36	3.54	3.98	3.16	4.36	3.54	4.36	3.54
2026	4.50	3.65	4.11	3.26	4.50	3.65	4.50	3.65
2027	4.72	3.84	4.33	3.44	4.72	3.84	4.72	3.84
2028	6.33	3.34	3.69	2.93	4.30	3.34	4.44	3.34
2029	6.52	3.46	3.82	3.04	4.45	3.46	4.58	3.46
2030	6.76	3.63	4.00	3.21	4.64	3.63	4.78	3.63
2031	7.11	3.91	4.29	3.48	4.94	3.91	5.09	3.91
2032	7.23	3.96	4.34	3.51	5.01	3.96	5.16	3.96
2033	7.38	4.04	4.43	3.58	5.11	4.04	5.26	4.04
2034	7.62	4.20	4.60	3.73	5.30	4.20	5.45	4.20
2035	7.79	4.29	4.70	3.81	5.42	4.29	5.57	4.29
2036	8.01	4.43	4.85	3.94	5.58	4.43	5.74	4.43
2037	8.28	4.62	5.05	4.12	5.80	4.62	5.96	4.62
2038	8.52	4.77	5.21	4.26	5.98	4.77	6.15	4.77

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

(2) The standard avoided cost price for wind is reduced by an integration charge of $3.06/MWh ($2015). If Wind Qualifying Facility is not in PacifiCorp's balancing authority area, then no reduction is required.

(C)

(continued)

Avoided Cost Prices (Continued)

Renewable Fixed Avoided Cost Prices

(C)

Fixed Prices ¢/kWh

Deliveries During Calendar Year	Renewable Base Load QF (1)		Wind QF (1,2)		Fixed Solar QF (1)		Tracking Solar QF (2)	
	On-Peak Energy Price	Off-Peak Energy Price	On-Peak Energy Price	Off-Peak Energy Price	On-Peak Energy Price	Off-Peak Energy Price	On-Peak Energy Price	Off-Peak Energy Price
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
2016	2.32	1.79	2.01	1.48	2.32	1.79	2.32	1.79
2017	2.54	2.05	2.22	1.73	2.54	2.05	2.54	2.05
2018	2.75	2.23	2.42	1.90	2.75	2.23	2.75	2.23
2019	2.99	2.36	2.66	2.03	2.99	2.36	2.99	2.36
2020	3.16	2.51	2.82	2.17	3.16	2.51	3.16	2.51
2021	3.38	2.66	3.03	2.31	3.38	2.66	3.38	2.66
2022	3.62	2.93	3.27	2.57	3.62	2.93	3.62	2.93
2023	3.86	3.14	3.49	2.78	3.86	3.14	3.86	3.14
2024	4.09	3.33	3.72	2.95	4.09	3.33	4.09	3.33
2025	4.36	3.54	3.98	3.16	4.36	3.54	4.36	3.54
2026	4.50	3.65	4.11	3.26	4.50	3.65	4.50	3.65
2027	4.72	3.84	4.33	3.44	4.72	3.84	4.72	3.84
2028	5.00	4.11	4.59	3.70	5.00	4.11	5.00	4.11
2029	5.13	4.24	4.71	3.82	5.13	4.24	5.13	4.24
2030	5.30	4.39	4.88	3.96	5.30	4.39	5.30	4.39
2031	5.63	4.69	5.20	4.25	5.63	4.69	5.63	4.69
2032	5.75	4.80	5.30	4.36	5.75	4.80	5.75	4.80
2033	5.86	4.90	5.41	4.44	5.86	4.90	5.86	4.90
2034	5.97	5.09	5.51	4.62	5.97	5.09	5.97	5.09
2035	6.14	5.18	5.66	4.71	6.14	5.18	6.14	5.18
2036	6.25	5.30	5.77	4.81	6.25	5.30	6.25	5.30
2037	6.48	5.53	5.99	5.04	6.48	5.53	6.48	5.53
2038	6.65	5.74	6.14	5.23	6.65	5.74	6.65	5.74

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 extends beyond the published years.
2) During the Renewable Resource Sufficiency Period, the renewable avoided cost price for a Wind Qualifying Facility has been reduced by an integration charge of $3.06/MWh ($2015) for Wind Qualifying Facilities located in PacifiCorp's BAA (in-system). If a Wind Qualifying Facility is not in PacifiCorp's BAA, $3.06/MWh ($2015) will be added for avoided integration charges.

(C)

(continued)

Qualifying Facilities Contracting Procedure

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 who desire to make sales (C)
to the Company in the state of Oregon. Such owners will be required to enter into a written (D)
power purchase agreement with the Company pursuant to the procedures set forth below.

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.

(continued)

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.

(continued)

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).

(continued)

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.

Appendix 1

PACIFIC POWER
AVOIDED COST CALCULATION

STANDARD RATES FOR AVOIDED COST PURCHASES FROM ELIGIBLE QUALIFYING FACILITIES

OREGON – March 2016

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

Year	Standard Avoided Resource			Base Load QF Resource	
	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			$23.23	$17.94
2017				$25.36	$20.47
2018				$27.49	$22.29
2019				$29.93	$23.60
2020				$31.61	$25.13
2021				$33.82	$26.59
2022				$36.22	$29.26
2023				$38.60	$31.42
2024				$40.91	$33.26
2025				$43.61	$35.40
2026				$45.01	$36.48
2027				$47.24	$38.37
2028	$149.51	$29.94	$33.37	$63.31	$33.37
2029	$152.83	$30.61	$34.61	$65.22	$34.61
2030	$156.22	$31.29	$36.31	$67.60	$36.31
2031	$159.80	$32.00	$39.11	$71.11	$39.11
2032	$163.31	$32.71	$39.57	$72.28	$39.57
2033	$166.89	$33.42	$40.36	$73.78	$40.36
2034	$170.75	$34.20	$41.99	$76.19	$41.99
2035	$174.69	$34.99	$42.90	$77.89	$42.90
2036	$178.71	$35.79	$44.27	$80.06	$44.27
2037	$182.81	$36.61	$46.17	$82.78	$46.17
2038	$186.99	$37.45	$47.73	$85.18	$47.73

(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

Year	Standard Avoided Resource			Wind QF Resource			
	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 less Wind Integration (2)					$20.12	$14.83
2017						$22.18	$17.29
2018						$24.24	$19.04
2019						$26.61	$20.28
2020						$28.21	$21.73
2021						$30.34	$23.11
2022						$32.65	$25.69
2023						$34.94	$27.76
2024						$37.17	$29.52
2025						$39.79	$31.58
2026						$41.11	$32.58
2027						$43.25	$34.38
2028	$149.51	$29.94	$33.37	25.40%	$7.60	$36.89	$29.29
2029	$152.83	$30.61	$34.61	25.40%	$7.77	$38.21	$30.44
2030	$156.22	$31.29	$36.31	25.40%	$7.95	$40.00	$32.05
2031	$159.80	$32.00	$39.11	25.40%	$8.13	$42.88	$34.75
2032	$163.31	$32.71	$39.57	25.40%	$8.31	$43.42	$35.11
2033	$166.89	$33.42	$40.36	25.40%	$8.49	$44.29	$35.80
2034	$170.75	$34.20	$41.99	25.40%	$8.69	$46.02	$37.33
2035	$174.69	$34.99	$42.90	25.40%	$8.89	$47.02	$38.13
2036	$178.71	$35.79	$44.27	25.40%	$9.09	$48.48	$39.39
2037	$182.81	$36.61	$46.17	25.40%	$9.30	$50.48	$41.18
2038	$186.99	$37.45	$47.73	25.40%	$9.51	$52.14	$42.63

(1) The avoided cost prices have been reduced by a wind integration charge of $3.06/MWh ($2015) 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 ($2015) integration charge.

(2) Wind Integration Charge is $3.06 (2015 $ per MWh) - 2015 IRP Volume II-Appendix H, Table H.3 See 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) Wind Resource Peak Contribution (% of nameplate capacity), 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

Year	Standard Avoided Resource			Fixed Solar QF			
	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					$23.23	$17.94
2017						$25.36	$20.47
2018						$27.49	$22.29
2019						$29.93	$23.60
2020						$31.61	$25.13
2021						$33.82	$26.59
2022						$36.22	$29.26
2023						$38.60	$31.42
2024						$40.91	$33.26
2025						$43.61	$35.40
2026						$45.01	$36.48
2027						$47.24	$38.37
2028	$149.51	$29.94	$33.37	32.20%	$9.64	$43.01	$33.37
2029	$152.83	$30.61	$34.61	32.20%	$9.86	$44.47	$34.61
2030	$156.22	$31.29	$36.31	32.20%	$10.08	$46.39	$36.31
2031	$159.80	$32.00	$39.11	32.20%	$10.30	$49.41	$39.11
2032	$163.31	$32.71	$39.57	32.20%	$10.53	$50.10	$39.57
2033	$166.89	$33.42	$40.36	32.20%	$10.76	$51.12	$40.36
2034	$170.75	$34.20	$41.99	32.20%	$11.01	$53.00	$41.99
2035	$174.69	$34.99	$42.90	32.20%	$11.27	$54.17	$42.90
2036	$178.71	$35.79	$44.27	32.20%	$11.52	$55.79	$44.27
2037	$182.81	$36.61	$46.17	32.20%	$11.79	$57.96	$46.17
2038	$186.99	$37.45	$47.73	32.20%	$12.06	$59.79	$47.73

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) Solar Resource Peak Contribution (% of nameplate capacity), 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

Year	Standard Avoided Resource			Tracking Solar QF			
	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						$23.23	$17.94
2017						$25.36	$20.47
2018		Market Based Prices				$27.49	$22.29
2019		2016 through 2027				$29.93	$23.60
2020						$31.61	$25.13
2021						$33.82	$26.59
2022						$36.22	$29.26
2023						$38.60	$31.42
2024						$40.91	$33.26
2025						$43.61	$35.40
2026						$45.01	$36.48
2027						$47.24	$38.37
2028	$149.51	$29.94	$33.37	36.70%	$10.99	$44.36	$33.37
2029	$152.83	$30.61	$34.61	36.70%	$11.23	$45.84	$34.61
2030	$156.22	$31.29	$36.31	36.70%	$11.48	$47.79	$36.31
2031	$159.80	$32.00	$39.11	36.70%	$11.74	$50.85	$39.11
2032	$163.31	$32.71	$39.57	36.70%	$12.00	$51.57	$39.57
2033	$166.89	$33.42	$40.36	36.70%	$12.27	$52.63	$40.36
2034	$170.75	$34.20	$41.99	36.70%	$12.55	$54.54	$41.99
2035	$174.69	$34.99	$42.90	36.70%	$12.84	$55.74	$42.90
2036	$178.71	$35.79	$44.27	36.70%	$13.13	$57.40	$44.27
2037	$182.81	$36.61	$46.17	36.70%	$13.44	$59.61	$46.17
2038	$186.99	$37.45	$47.73	36.70%	$13.74	$61.47	$47.73

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) Solar Resource Peak Contribution (% of nameplate capacity), 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
$/MWH

Year	Renewable Wind Avoided Resource		Renewable Base Load QF Resource			
	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)
2016					$23.23	$17.94
2017					$25.36	$20.47
2018	Market Based Prices				$27.49	$22.29
2019					$29.93	$23.60
2020					$31.61	$25.13
2021					$33.82	$26.59
2022					$36.22	$29.26
2023					$38.60	$31.42
2024					$40.91	$33.26
2025					$43.61	$35.40
2026					$45.01	$36.48
2027					$47.24	$38.37
2028					$50.02	$41.10
2029					$51.25	$42.40
2030					$53.04	$43.89
2031					$56.32	$46.86
2032					$57.46	$48.03
2033					$58.63	$48.99
2034					$59.71	$50.86
2035					$61.39	$51.84
2036					$62.54	$52.99
2037					$64.84	$55.34
2038					$66.51	$57.39

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

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

Year	Renewable Wind Avoided Resource		Wind QF Resource		Wind QF Resource	
	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)
2016					$20.12	$14.83
2017					$22.18	$17.29
2018	Market Based Prices				$24.24	$19.04
2019					$26.61	$20.28
2020					$28.21	$21.73
2021					$30.34	$23.11
2022					$32.65	$25.69
2023					$34.94	$27.76
2024					$37.17	$29.52
2025					$39.79	$31.58
2026					$41.11	$32.58
2027					$43.25	$34.38
2028					$45.94	$37.02
2029					$47.08	$38.23
2030					$48.78	$39.63
2031					$51.96	$42.50
2032					$53.00	$43.57
2033					$54.07	$44.43
2034					$55.05	$46.20
2035					$56.62	$47.07
2036					$57.66	$48.11
2037					$59.85	$50.35
2038					$61.41	$52.29

(1) The avoided cost prices have been reduced by a wind integration charge of $3.06/MWh ($2015) 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 ($2015) integration charge.

(2) Wind Integration Charge is $3.06 (2015 $ per MWh) - 2015 IRP Volume II-Appendix H, Table H.3
See 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
$/MWH

Year	Renewable Wind Avoided Resource		Fixed Solar QF Resource		Fixed 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)
2016					$23.23	$17.94
2017					$25.36	$20.47
2018	Market Based Prices				$27.49	$22.29
2019					$29.93	$23.60
2020					$31.61	$25.13
2021					$33.82	$26.59
2022					$36.22	$29.26
2023					$38.60	$31.42
2024					$40.91	$33.26
2025					$43.61	$35.40
2026					$45.01	$36.48
2027					$47.24	$38.37
2028					$50.02	$41.10
2029					$51.25	$42.40
2030					$53.04	$43.89
2031					$56.32	$46.86
2032					$57.46	$48.03
2033					$58.63	$48.99
2034					$59.71	$50.86
2035					$61.39	$51.84
2036					$62.54	$52.99
2037					$64.84	$55.34
2038					$66.51	$57.39

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

Exhibit 8
Renewable Avoided Cost Prices for Tracking Solar QF
$/MWH

Year	Renewable Wind Avoided Resource On-Peak ($/MWh) (a)	Renewable Wind Avoided Resource Off-Peak ($/MWh) (b)	Tracking Solar QF Resource Capital Cost Allocated to Capacity (On-Peak Hours) ($/MWh) (c)	Tracking Solar QF Resource QF Capacity Adder ($/MWh) (d)	Tracking Solar QF On-Peak $/MWh (e)	Tracking Solar QF Off-Peak $/MWh (f)
2016					$23.23	$17.94
2017					$25.36	$20.47
2018	Market Based Prices				$27.49	$22.29
2019					$29.93	$23.60
2020					$31.61	$25.13
2021					$33.82	$26.59
2022					$36.22	$29.26
2023					$38.60	$31.42
2024					$40.91	$33.26
2025					$43.61	$35.40
2026					$45.01	$36.48
2027					$47.24	$38.37
2028					$50.02	$41.10
2029					$51.25	$42.40
2030					$53.04	$43.89
2031					$56.32	$46.86
2032					$57.46	$48.03
2033					$58.63	$48.99
2034					$59.71	$50.86
2035					$61.39	$51.84
2036					$62.54	$52.99
2037					$64.84	$55.34
2038					$66.51	$57.39

Columns

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

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

Exhibit 9
Market Price - Blending Matrix

	On-Peak				Off-Peak			
Period	COB	Mid Columbia	Palo Verde	Total	COB	Mid Columbia	Palo Verde	Total
1/1/2016	0.0%	46.3%	53.7%	100.0%	0.0%	5.5%	94.5%	100.0%
2/1/2016	2.7%	43.9%	53.4%	100.0%	0.0%	65.9%	34.1%	100.0%
3/1/2016	0.8%	78.1%	21.1%	100.0%	4.4%	91.9%	3.6%	100.0%
4/1/2016	10.1%	67.2%	22.7%	100.0%	7.4%	86.9%	5.8%	100.0%
5/1/2016	35.7%	41.3%	23.0%	100.0%	42.1%	55.6%	2.3%	100.0%
6/1/2016	37.3%	56.7%	6.0%	100.0%	70.2%	29.8%	0.0%	100.0%
7/1/2016	33.3%	65.3%	1.3%	100.0%	32.9%	66.2%	0.9%	100.0%
8/1/2016	12.4%	86.2%	1.4%	100.0%	1.0%	99.0%	0.0%	100.0%
9/1/2016	0.8%	97.4%	1.8%	100.0%	0.0%	100.0%	0.0%	100.0%
10/1/2016	0.0%	100.0%	0.0%	100.0%	0.0%	87.2%	12.8%	100.0%
11/1/2016	0.8%	46.6%	52.6%	100.0%	0.0%	8.1%	91.9%	100.0%
12/1/2016	0.0%	68.8%	31.2%	100.0%	0.9%	19.4%	79.8%	100.0%
1/1/2017	0.0%	100.0%	0.0%	100.0%	0.0%	78.7%	21.3%	100.0%
2/1/2017	0.6%	94.6%	4.8%	100.0%	0.0%	67.3%	32.7%	100.0%
3/1/2017	24.2%	75.0%	0.8%	100.0%	1.5%	81.6%	16.9%	100.0%
4/1/2017	3.4%	58.9%	37.8%	100.0%	2.0%	86.6%	11.4%	100.0%
5/1/2017	14.7%	65.9%	19.4%	100.0%	25.4%	74.6%	0.0%	100.0%
6/1/2017	7.2%	90.1%	2.7%	100.0%	67.2%	32.8%	0.0%	100.0%
7/1/2017	6.4%	93.6%	0.0%	100.0%	55.8%	44.2%	0.0%	100.0%
8/1/2017	2.7%	94.5%	2.9%	100.0%	0.0%	98.1%	1.9%	100.0%
9/1/2017	1.0%	68.5%	30.5%	100.0%	0.0%	23.7%	76.3%	100.0%
10/1/2017	0.0%	74.3%	25.7%	100.0%	0.0%	87.8%	12.2%	100.0%
11/1/2017	0.8%	33.5%	65.7%	100.0%	5.5%	10.7%	83.8%	100.0%
12/1/2017	0.0%	55.9%	44.1%	100.0%	0.0%	0.0%	100.0%	100.0%
1/1/2018	0.0%	72.2%	27.8%	100.0%	0.0%	45.1%	54.9%	100.0%
2/1/2018	15.3%	56.6%	28.0%	100.0%	0.0%	32.8%	67.2%	100.0%
3/1/2018	8.6%	58.1%	33.3%	100.0%	12.6%	39.0%	48.4%	100.0%
4/1/2018	3.8%	63.8%	32.4%	100.0%	1.1%	83.5%	15.3%	100.0%
5/1/2018	1.9%	71.7%	26.4%	100.0%	14.8%	79.6%	5.6%	100.0%
6/1/2018	7.2%	91.8%	1.0%	100.0%	54.3%	45.7%	0.0%	100.0%
7/1/2018	4.4%	94.8%	0.8%	100.0%	55.6%	44.4%	0.0%	100.0%
8/1/2018	3.2%	95.1%	1.7%	100.0%	0.0%	93.8%	6.2%	100.0%
9/1/2018	1.2%	77.1%	21.7%	100.0%	0.1%	3.3%	96.6%	100.0%
10/1/2018	2.7%	36.6%	60.7%	100.0%	0.0%	69.3%	30.7%	100.0%
11/1/2018	7.5%	37.3%	55.2%	100.0%	4.4%	5.1%	90.5%	100.0%
12/1/2018	0.0%	60.2%	39.8%	100.0%	0.7%	17.8%	81.6%	100.0%
1/1/2038	15.2%	82.9%	1.9%	100.0%	0.0%	94.5%	5.5%	100.0%
2/1/2038	37.6%	59.1%	3.3%	100.0%	37.9%	48.4%	13.8%	100.0%
3/1/2038	21.7%	75.5%	2.8%	100.0%	24.5%	63.5%	12.0%	100.0%
4/1/2038	31.8%	60.9%	7.2%	100.0%	7.4%	75.2%	17.4%	100.0%
5/1/2038	13.0%	79.6%	7.4%	100.0%	42.7%	43.6%	13.8%	100.0%
6/1/2038	16.9%	75.5%	7.5%	100.0%	54.1%	36.6%	9.3%	100.0%
7/1/2038	45.1%	36.5%	18.5%	100.0%	16.3%	65.6%	18.1%	100.0%
8/1/2038	34.7%	49.1%	16.2%	100.0%	8.4%	87.1%	4.5%	100.0%
9/1/2038	40.2%	55.1%	4.7%	100.0%	16.3%	49.4%	34.3%	100.0%
10/1/2038	14.2%	80.5%	5.2%	100.0%	19.9%	79.4%	0.7%	100.0%
11/1/2038	24.2%	67.9%	7.9%	100.0%	18.4%	70.7%	10.8%	100.0%
12/1/2038	33.7%	59.0%	7.2%	100.0%	14.0%	66.1%	19.9%	100.0%

Table 1
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

Year	Winter Season					Summer Season				Winter Season		
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
On-Peak (HLH Market Purchase)												
2016		23.70	20.50	19.04	18.54	18.51	25.82	27.49	25.80	23.46	25.14	27.49
2017	26.25	25.59	23.99	22.19	20.57	19.43	26.01	30.36	28.03	26.28	26.90	28.73
2018	28.45	28.21	25.80	23.90	21.97	20.92	27.98	32.83	30.84	28.85	29.10	31.01
2019	30.84	29.92	28.14	26.41	25.22	23.33	30.94	35.59	32.88	31.41	31.14	33.39
2020	32.66	32.88	30.08	28.17	27.00	25.35	32.79	37.41	34.98	32.30	31.75	33.90
2021	34.55	34.03	32.37	30.01	28.39	26.69	34.05	38.94	36.75	35.81	35.87	38.41
2022	36.11	37.66	34.51	32.49	28.95	30.85	36.79	41.15	39.84	37.57	38.79	39.97
2023	38.30	40.57	36.31	34.57	29.91	35.47	39.33	43.04	43.08	39.42	41.15	42.06
2024	40.71	42.82	38.40	37.35	30.78	35.47	41.42	45.94	47.02	42.14	44.02	44.88
2025	43.34	46.20	41.19	39.83	32.77	39.14	44.66	49.73	50.36	44.18	45.19	46.74
2026	45.07	48.06	42.33	40.42	34.00	40.01	45.62	50.95	51.45	45.77	47.71	48.71
2027	46.40	49.13	44.51	41.64	35.16	42.35	47.50	53.10	53.81	49.10	52.37	51.82
2028	49.14	52.08	46.74	44.51	39.76	45.92	51.53	56.19	55.96	51.59	53.20	53.65
2029	51.45	54.96	48.77	47.52	42.31	45.40	52.47	57.82	57.56	51.13	51.96	53.59
2030	51.78	55.85	49.93	47.86	40.37	46.49	54.31	60.51	60.92	54.86	56.25	57.33
2031	56.23	60.42	52.76	51.68	43.35	50.27	58.60	63.36	64.00	57.05	58.02	60.13
2032	58.22	62.05	54.39	53.27	45.35	51.43	59.09	64.61	64.19	57.02	59.30	60.65
2033	58.45	62.94	54.70	53.20	44.36	51.59	60.00	65.81	65.66	59.94	63.42	63.47
2034	60.54	64.40	55.90	54.68	46.73	54.08	61.11	66.75	66.65	60.38	62.28	62.97
2035	61.96	66.51	57.94	56.64	49.10	53.77	62.16	70.39	69.47	61.06	62.12	65.58
2036	63.57	66.31	57.96	56.84	49.35	54.29	63.97	70.69	70.88	63.60	65.94	67.13
2037	66.61	70.08	59.95	58.08	52.09	57.03	67.80	73.53	72.36	63.52	66.99	70.02
2038	67.71	70.57	61.41	60.00	55.09	59.58	69.33	76.00	72.41	65.02	69.46	71.53

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
Off-Peak (LLH Market Purchase)												
2016		21.01	17.45	14.01	11.63	10.82	17.59	19.82	20.25	20.39	21.62	22.77
2017	23.47	22.97	21.41	16.11	12.14	12.29	17.51	22.31	24.81	22.41	24.69	25.50
2018	25.31	24.65	23.41	17.88	14.52	14.13	18.80	23.01	26.49	25.40	26.40	27.53
2019	26.90	26.48	24.90	19.42	16.21	15.73	19.75	23.60	27.33	27.14	27.53	28.23
2020	28.45	28.09	26.81	20.49	17.39	16.88	21.83	25.65	27.83	28.25	29.49	30.41
2021	29.50	28.99	27.52	22.03	18.93	18.62	23.11	26.77	31.29	29.04	31.13	32.21
2022	30.68	31.86	29.31	26.27	21.92	23.52	27.02	29.09	33.38	30.55	33.23	34.28
2023	31.94	34.21	30.93	29.51	24.61	27.34	30.87	31.39	35.41	31.92	33.67	35.25
2024	33.49	35.87	32.42	32.07	25.24	29.01	32.37	33.67	37.86	33.65	35.70	37.81
2025	35.66	38.81	34.89	33.94	26.77	30.50	35.25	36.99	40.56	35.75	36.83	38.92
2026	36.91	39.70	35.85	34.62	28.66	30.82	35.58	38.06	41.30	36.82	39.00	40.42
2027	38.63	40.67	37.10	35.78	29.56	32.52	37.26	39.68	43.38	39.92	42.62	43.37
2028	41.51	43.76	39.56	38.71	31.57	35.22	41.77	42.18	46.52	42.47	44.13	45.84
2029	42.73	46.21	42.44	41.47	34.33	36.51	42.89	43.41	47.61	42.14	42.98	46.13
2030	42.92	47.12	43.35	41.87	34.28	38.18	42.61	45.28	49.99	45.22	46.73	49.18
2031	46.97	50.75	46.33	44.90	36.35	40.92	47.11	48.95	52.48	47.79	48.86	50.92
2032	48.73	52.31	47.42	46.83	39.52	42.23	47.07	49.84	52.53	48.43	49.76	51.73
2033	49.20	52.83	48.49	46.94	38.86	42.52	47.61	50.19	54.13	50.54	52.19	54.38
2034	55.72	54.95	49.97	48.42	40.49	44.95	49.49	51.89	55.88	50.99	53.08	54.53
2035	52.09	56.18	51.22	49.59	43.57	45.55	50.88	54.13	58.00	51.42	53.04	56.37
2036	53.89	54.99	52.60	50.20	43.97	47.46	51.06	55.68	58.82	53.31	56.51	57.33
2037	56.61	58.84	55.74	52.91	46.39	49.29	54.10	57.48	60.75	54.71	57.13	60.16
2038	58.51	60.19	56.91	55.28	50.26	51.68	55.83	59.73	61.94	56.92	59.46	61.95

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		22.54	19.19	16.88	15.57	15.21	22.28	24.19	23.41	22.14	23.62	25.46
2017	25.06	24.47	22.88	19.58	16.94	16.36	22.35	26.90	26.64	24.61	25.95	27.34
2018	27.10	26.68	24.77	21.31	18.77	18.00	24.03	28.61	28.97	27.36	27.94	29.51
2019	29.15	28.44	26.75	23.40	21.34	20.06	26.13	30.43	30.49	29.57	29.59	31.17
2020	30.85	30.82	28.67	24.87	22.86	21.71	28.08	32.36	31.90	30.56	30.78	32.40
2021	32.38	31.86	30.29	26.58	24.32	23.22	29.35	33.71	34.40	32.90	33.83	35.75
2022	33.77	35.16	32.27	29.82	25.93	27.69	32.59	35.96	37.06	34.55	36.40	37.52
2023	35.57	37.83	33.99	32.40	27.64	31.97	35.69	38.03	39.78	36.19	37.93	39.13
2024	37.61	39.83	35.83	35.08	28.40	32.69	37.53	40.66	43.08	38.49	40.44	41.84
2025	40.04	43.02	38.48	37.29	30.19	35.42	40.61	44.25	46.15	40.56	41.59	43.38
2026	41.56	44.47	39.54	37.93	31.70	36.06	41.30	45.41	47.09	41.92	43.97	45.15
2027	43.06	45.49	41.33	39.12	32.75	38.12	43.10	47.33	49.33	45.16	48.17	48.19
2028	45.86	48.50	43.65	42.02	36.24	41.32	47.33	50.17	51.90	47.67	49.30	50.29
2029	47.70	51.19	46.05	44.92	38.88	41.58	48.35	51.62	53.28	47.27	48.10	50.38
2030	47.97	52.10	47.10	45.28	37.75	42.92	49.28	53.96	56.22	50.72	52.16	53.82
2031	52.24	56.26	49.99	48.77	40.34	46.25	53.66	57.17	59.05	53.07	54.08	56.17
2032	54.14	57.86	51.39	50.50	42.84	47.47	53.92	58.26	59.17	53.32	55.19	56.81
2033	54.47	58.59	52.03	50.51	41.99	47.69	54.67	59.09	60.70	55.90	58.59	59.56
2034	58.47	60.34	53.35	51.99	44.05	50.15	56.11	60.36	62.02	56.34	58.32	59.34
2035	57.72	62.07	55.05	53.61	46.72	50.24	57.31	63.40	64.53	56.92	58.21	61.62
2036	59.41	61.44	55.66	53.98	47.04	51.36	58.42	64.23	65.69	59.17	61.88	62.91
2037	62.31	65.25	58.14	55.85	49.64	53.70	61.91	66.63	67.37	59.73	62.75	65.78
2038	63.75	66.11	59.48	57.97	53.01	56.18	63.52	69.00	67.91	61.53	65.16	67.41

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

Annual Average

	On-Peak	Off-Peak	Combined
2016	$23.23	$17.94	$20.95
2017	$25.36	$20.47	$23.26
2018	$27.49	$22.29	$25.25
2019	$29.93	$23.60	$27.21
2020	$31.61	$25.13	$28.82
2021	$33.82	$26.59	$30.71
2022	$36.22	$29.26	$33.23
2023	$38.60	$31.42	$35.51
2024	$40.91	$33.26	$37.62
2025	$43.61	$35.40	$40.08
2026	$45.01	$36.48	$41.34
2027	$47.24	$38.37	$43.43
2028	$50.02	$41.10	$46.19
2029	$51.25	$42.40	$47.44
2030	$53.04	$43.89	$49.11
2031	$56.32	$46.86	$52.25
2032	$57.46	$48.03	$53.41
2033	$58.63	$48.99	54.48
2034	$59.71	$50.86	$55.90
2035	$61.39	$51.84	$57.28
2036	$62.54	$52.99	$58.43
2037	$64.84	$55.34	$60.76
2038	$66.51	$57.39	$62.59

Source Offical Market Price Forecast dated December 2015
Blended Market Prices

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)	(d)
			((a) - (b))	(c)/(8.760 x 72.1%)
2028	$149.51	$163.48	$0.00	$0.00
2029	$152.83	$167.08	$0.00	$0.00
2030	$156.22	$170.76	$0.00	$0.00
2031	$159.80	$174.69	$0.00	$0.00
2032	$163.31	$178.53	$0.00	$0.00
2033	$166.89	$182.46	$0.00	$0.00
2034	$170.75	$186.67	$0.00	$0.00
2035	$174.69	$190.96	$0.00	$0.00
2036	$178.71	$195.33	$0.00	$0.00
2037	$182.81	$199.84	$0.00	$0.00
2038	$186.99	$204.43	$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 ($/MMBtu)	Combined Cycle Energy Cost ($/MWh)	Capitalized Energy Costs 72.1% CF ($/MWh)	Total Standard Avoided Energy Cost ($/MWh)
	(a)	(b) (a) x 6.530	(c)	(d) (b) + (c)
2028	$5.11	$33.37	$0.00	$33.37
2029	$5.30	$34.61	$0.00	$34.61
2030	$5.56	$36.31	$0.00	$36.31
2031	$5.99	$39.11	$0.00	$39.11
2032	$6.06	$39.57	$0.00	$39.57
2033	$6.18	$40.36	$0.00	$40.36
2034	$6.43	$41.99	$0.00	$41.99
2035	$6.57	$42.90	$0.00	$42.90
2036	$6.78	$44.27	$0.00	$44.27
2037	$7.07	$46.17	$0.00	$46.17
2038	$7.31	$47.73	$0.00	$47.73

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 ($/kW-yr)	Total Standard Avoided Energy Cost ($/MWh)	Total Standard Avoided Costs At Stated Capacity Factor		
			75% ($/MWh)	85% ($/MWh)	90% ($/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	$149.51	$33.37	$56.13	$53.45	$52.33
2029	$152.83	$34.61	$57.87	$55.14	$53.99
2030	$156.22	$36.31	$60.09	$57.29	$56.12
2031	$159.80	$39.11	$63.43	$60.57	$59.38
2032	$163.31	$39.57	$64.43	$61.50	$60.28
2033	$166.89	$40.36	$65.76	$62.77	$61.53
2034	$170.75	$41.99	$67.98	$64.92	$63.65
2035	$174.69	$42.90	$69.49	$66.36	$65.06
2036	$178.71	$44.27	$71.47	$68.27	$66.94
2037	$182.81	$46.17	$73.99	$70.72	$69.36
2038	$186.99	$47.73	$76.19	$72.84	$71.45

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	$149.51	$29.94	$33.37	$63.31	$33.37
2029	$152.83	$30.61	$34.61	$65.22	$34.61
2030	$156.22	$31.29	$36.31	$67.60	$36.31
2031	$159.80	$32.00	$39.11	$71.11	$39.11
2032	$163.31	$32.71	$39.57	$72.28	$39.57
2033	$166.89	$33.42	$40.36	$73.78	$40.36
2034	$170.75	$34.20	$41.99	$76.19	$41.99
2035	$174.69	$34.99	$42.90	$77.89	$42.90
2036	$178.71	$35.79	$44.27	$80.06	$44.27
2037	$182.81	$36.61	$46.17	$82.78	$46.17
2038	$186.99	$37.45	$47.73	$85.18	$47.73

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

(c) Table 4 Column (d)

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

Year	Standard Fixed											
	Base Load QF			Wind QF (2)			Fixed Solar QF			Tracking Solar QF		
	Proposed	Current	Diff	Proposed	Current	Diff	Proposed	Current	Diff	Proposed	Current	Diff
2016	$20.96	$25.80	($4.84)	$17.85	$23.11	($5.26)	$22.42	$27.63	($5.22)	$22.42	$27.63	($5.22)
2017	$23.26	$28.30	($5.05)	$20.08	$25.56	($5.49)	$24.61	$30.25	($5.64)	$24.61	$30.25	($5.64)
2018	$25.25	$30.16	($4.91)	$22.00	$27.36	($5.36)	$26.69	$32.46	($5.78)	$26.69	$32.46	($5.78)
2019	$27.21	$31.97	($4.76)	$23.89	$29.11	($5.22)	$28.96	$34.22	($5.26)	$28.96	$34.22	($5.26)
2020	$28.82	$34.37	($5.54)	$25.42	$31.45	($6.02)	$30.61	$36.81	($6.20)	$30.61	$36.81	($6.20)
2021	$30.71	$37.08	($6.37)	$27.23	$34.10	($6.87)	$32.71	$39.63	($6.92)	$32.71	$39.63	($6.92)
2022	$33.23	$39.93	($6.70)	$29.66	$36.89	($7.23)	$35.15	$42.59	($7.44)	$35.15	$42.59	($7.44)
2023	$35.51	$42.77	($7.26)	$31.85	$39.66	($7.81)	$37.49	$45.63	($8.13)	$37.49	$45.63	($8.13)
2024	$37.62	$48.24	($10.62)	$33.88	$28.13	$5.75	$39.73	$34.14	$5.60	$39.73	$34.14	$5.60
2025	$40.08	$49.89	($9.81)	$36.26	$29.34	$6.92	$42.35	$35.48	$6.87	$42.35	$35.48	$6.87
2026	$41.34	$50.19	($8.85)	$37.44	$29.22	$8.23	$43.70	$35.48	$8.22	$43.70	$35.48	$8.22
2027	$43.43	$51.89	($8.46)	$39.44	$30.46	$8.97	$45.87	$36.86	$9.01	$45.87	$36.86	$9.01
2028	$50.44	$55.30	($4.86)	$33.62	$33.43	$0.20	$41.53	$39.96	$1.57	$42.67	$39.96	$2.71
2029	$52.06	$56.72	($4.66)	$34.87	$34.41	$0.46	$42.95	$41.08	$1.87	$44.11	$41.08	$3.04
2030	$54.15	$57.92	($3.77)	$36.58	$35.16	$1.42	$44.83	$41.96	$2.88	$46.03	$41.96	$4.07
2031	$57.35	$60.76	($3.41)	$39.38	$37.52	$1.87	$47.83	$44.46	$3.37	$49.05	$44.46	$4.58
2032	$58.21	$62.23	($4.02)	$39.85	$38.51	$1.34	$48.48	$45.60	$2.88	$49.73	$45.60	$4.13
2033	$59.41	$63.26	($3.85)	$40.64	$39.03	$1.60	$49.46	$46.28	$3.19	$50.74	$46.28	$4.46
2034	$61.48	$65.14	($3.65)	$42.28	$40.40	$1.88	$51.31	$47.80	$3.51	$52.61	$47.80	$4.81
2035	$62.84	$67.24	($4.40)	$43.20	$41.99	$1.21	$52.43	$49.54	$2.89	$53.76	$49.54	$4.23
2036	$64.67	$68.82	($4.15)	$44.57	$43.04	$1.53	$54.02	$50.74	$3.28	$55.38	$50.74	$4.64
2037	$67.04	$70.74	($3.71)	$46.48	$44.42	$2.06	$56.14	$52.29	$3.86	$57.54	$52.29	$5.25
2038	$69.08	$72.67	($3.59)	$48.05	$45.79	$2.26	$57.93	$53.83	$4.11	$59.36	$53.83	$5.53
15 Year (2016 - 2030) Nominal levelized Price at 6.660% Discount Rate (1)												
$/MWh	$33.52	$39.80	($6.28)	$28.26	$30.47	($2.22)	$33.92	$36.07	($2.15)	$34.08	$36.07	($2.00)

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 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

Table 8
Comparison between Proposed and Current Renewable Fixed Avoided Costs
$/MWh

Year	Renewable Fixed											
	Base Load QF			Wind QF (2)			Fixed Solar QF			Tracking Solar QF		
	Proposed	Current	Diff	Proposed	Current	Diff	Proposed	Current	Diff	Proposed	Current	Diff
2016	$20.96	$25.80	($4.84)	$17.85	$23.11	($5.26)	$22.42	$27.63	($5.22)	$22.42	$27.63	($5.22)
2017	$23.26	$28.30	($5.05)	$20.08	$25.56	($5.49)	$24.61	$30.25	($5.64)	$24.61	$30.25	($5.64)
2018	$25.25	$30.16	($4.91)	$22.00	$27.36	($5.36)	$26.69	$32.46	($5.78)	$26.69	$32.46	($5.78)
2019	$27.21	$31.97	($4.76)	$23.89	$29.11	($5.22)	$28.96	$34.22	($5.26)	$28.96	$34.22	($5.26)
2020	$28.82	$34.37	($5.54)	$25.42	$31.45	($6.02)	$30.61	$36.81	($6.20)	$30.61	$36.81	($6.20)
2021	$30.71	$37.08	($6.37)	$27.23	$34.10	($6.87)	$32.71	$39.63	($6.92)	$32.71	$39.63	($6.92)
2022	$33.23	$39.93	($6.70)	$29.66	$36.89	($7.23)	$35.15	$42.59	($7.44)	$35.15	$42.59	($7.44)
2023	$35.51	$42.77	($7.26)	$31.85	$39.66	($7.81)	$37.49	$45.63	($8.13)	$37.49	$45.63	($8.13)
2024	$37.62	$98.47	($60.85)	$33.88	$78.36	($44.48)	$39.73	$89.35	($49.62)	$39.73	$89.35	($49.62)
2025	$40.08	$100.64	($60.56)	$36.26	$80.09	($43.83)	$42.35	$91.15	($48.80)	$42.35	$91.15	($48.80)
2026	$41.34	$102.73	($61.39)	$37.44	$81.75	($44.31)	$43.70	$92.46	($48.77)	$43.70	$92.46	($48.77)
2027	$43.43	$104.89	($61.46)	$39.44	$83.46	($44.03)	$45.87	$94.22	($48.34)	$45.87	$94.22	($48.34)
2028	$46.18	$107.09	($60.91)	$42.10	$85.22	($43.11)	$48.65	$95.99	($47.34)	$48.65	$95.99	($47.34)
2029	$47.44	$109.22	($61.78)	$43.27	$86.91	($43.63)	$49.89	$97.70	($47.82)	$49.89	$97.70	($47.82)
2030	$49.11	$111.40	($62.29)	$44.85	$88.64	($43.80)	$51.63	$99.44	($47.80)	$51.63	$99.44	($47.80)
2031	$52.25	$113.68	($61.43)	$47.89	$90.44	($42.55)	$54.86	$100.98	($46.11)	$54.86	$100.98	($46.11)
2032	$53.41	$116.13	($62.73)	$48.95	$92.41	($43.46)	$56.01	$103.28	($47.28)	$56.01	$103.28	($47.28)
2033	$54.48	$118.54	($64.06)	$49.92	$94.32	($44.39)	$57.15	$104.81	($47.67)	$57.15	$104.81	($47.67)
2034	$55.90	$121.01	($65.10)	$51.24	$96.27	($45.03)	$58.35	$106.42	($48.07)	$58.35	$106.42	($48.07)
2035	$57.28	$123.53	($66.25)	$52.51	$98.28	($45.77)	$59.92	$108.66	($48.74)	$59.92	$108.66	($48.74)
2036	$58.43	$126.15	($67.71)	$53.55	$100.37	($46.81)	$61.07	$111.45	($50.38)	$61.07	$111.45	($50.38)
2037	$60.76	$128.78	($68.03)	$55.77	$102.45	($46.69)	$63.38	$113.14	($49.76)	$63.38	$113.14	($49.76)
2038	$62.59	$131.53	($68.95)	$57.49	$104.66	($47.17)	$65.11	$116.83	($51.72)	$65.11	$116.83	($51.72)

15 Year (2016 - 2030) Nominal levelized Price at 0.000% Discount Rate (1)

$/MWh	$32.92	$57.97	($25.05)	$29.35	$48.64	($19.29)	$34.83	$55.81	($20.97)	$34.83	$55.81	($20.97)

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 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

Table 9
Total Cost of Displaceable Resources

Year	Estimated Capital Cost	Capital Cost at Real Levelized Rate	Fixed O&M	Variable O&M	Total O&M at Expected CF	Total Resource Fixed Costs
	$/kW	$/kW-yr	$/kW-yr	$/MWh	$/kW-yr	$/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		$65.10	$46.87	$4.36	$59.47	$124.57
2017		$66.66	$47.99	$4.46	$60.88	$127.54
2018		$68.13	$49.05	$4.56	$62.23	$130.36
2019		$69.63	$50.13	$4.66	$63.60	$133.23
2020		$71.23	$51.28	$4.77	$65.07	$136.30
2021		$72.94	$52.51	$4.88	$66.62	$139.56
2022		$74.76	$53.82	$5.00	$68.27	$143.03
2023		$76.55	$55.11	$5.12	$69.91	$146.46
2024		$78.31	$56.38	$5.24	$71.53	$149.84
2025		$80.03	$57.62	$5.36	$73.11	$153.14
2026		$81.79	$58.89	$5.48	$74.73	$156.52
2027		$83.59	$60.19	$5.60	$76.38	$159.97
2028		$85.43	$61.51	$5.72	$78.05	$163.48
2029		$87.31	$62.86	$5.85	$79.77	$167.08
2030		$89.23	$64.24	$5.98	$81.53	$170.76
2031		$91.28	$65.72	$6.12	$83.41	$174.69
2032		$93.29	$67.17	$6.25	$85.24	$178.53
2033		$95.34	$68.65	$6.39	$87.12	$182.46
2034		$97.53	$70.23	$6.54	$89.14	$186.67
2035		$99.77	$71.85	$6.69	$91.19	$190.96
2036		$102.06	$73.50	$6.84	$93.27	$195.33
2037		$104.41	$75.19	$7.00	$95.43	$199.84
2038		$106.81	$76.92	$7.16	$97.62	$204.43

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	Capital Cost at Real Levelized Rate	Fixed O&M	Variable O&M	Total O&M at Expected CF	Total Resource Fixed Costs	Fuel Cost	IRP Resource Energy Cost	Total Avoided Costs
	$/kW	$/kW-yr	$/kW-yr	$/MWh	$/kW-yr	$/kW-yr	$/MMBtu	$/MWh	$/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		$68.07	$31.51	$2.29	$45.97	$114.04			
2017		$69.70	$32.27	$2.34	$47.05	$116.75			
2018		$71.23	$32.98	$2.39	$48.08	$119.31			
2019		$72.80	$33.71	$2.44	$49.12	$121.92			
2020		$74.47	$34.49	$2.50	$50.28	$124.75			
2021		$76.26	$35.32	$2.56	$51.49	$127.75			
2022		$78.17	$36.20	$2.62	$52.75	$130.92			
2023		$80.05	$37.07	$2.68	$54.00	$134.05			
2024		$81.89	$37.92	$2.74	$55.23	$137.12			
2025		$83.69	$38.75	$2.80	$56.43	$140.12			
2026		$85.53	$39.60	$2.86	$57.66	$143.19			
2027		$87.41	$40.47	$2.92	$58.91	$146.32			
2028		$89.33	$41.36	$2.98	$60.18	$149.51	$5.11	$33.37	$57.04
2029		$91.30	$42.27	$3.05	$61.53	$152.83	$5.30	$34.61	$58.81
2030		$93.31	$43.20	$3.12	$62.91	$156.22	$5.56	$36.31	$61.04
2031		$95.46	$44.19	$3.19	$64.34	$159.80	$5.99	$39.11	$64.41
2032		$97.56	$45.16	$3.26	$65.75	$163.31	$6.06	$39.57	$65.43
2033		$99.71	$46.15	$3.33	$67.18	$166.89	$6.18	$40.36	$66.78
2034		$102.00	$47.21	$3.41	$68.75	$170.75	$6.43	$41.99	$69.02
2035		$104.35	$48.30	$3.49	$70.34	$174.69	$6.57	$42.90	$70.56
2036		$106.75	$49.41	$3.57	$71.96	$178.71	$6.78	$44.27	$72.56
2037		$109.21	$50.55	$3.65	$73.60	$182.81	$7.07	$46.17	$75.11
2038		$111.72	$51.71	$3.73	$75.27	$186.99	$7.31	$47.73	$77.34

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 December 2015

2015	0.6%	2021	2.4%	2027	2.2%	2033	2.2%
2016	1.6%	2022	2.5%	2028	2.2%	2034	2.3%
2017	2.4%	2023	2.4%	2029	2.2%	2035	2.3%
2018	2.2%	2024	2.3%	2030	2.2%	2036	2.3%
2019	2.2%	2025	2.2%	2031	2.3%	2037	2.3%
2020	2.3%	2026	2.2%	2032	2.2%	2038	2.3%

Table 10
Gas Price Forecast
$/MMBtu

Year	Burner tip West Side Gas Fuel Cost
2028	$5.11
2029	$5.30
2030	$5.56
2031	$5.99
2032	$6.06
2033	$6.18
2034	$6.43
2035	$6.57
2036	$6.78
2037	$7.07
2038	$7.31

Source
Offical Market Price Forecast dated December 2015

Table 11
Wind Integration Cost

Year	Official Inflation Forecast Dated December 2015 Forecast	Wind Integration Cost $/MWh
2015	0.6%	$3.06
2016	1.6%	$3.11
2017	2.4%	$3.18
2018	2.2%	$3.25
2019	2.2%	$3.32
2020	2.3%	$3.40
2021	2.4%	$3.48
2022	2.5%	$3.57
2023	2.4%	$3.66
2024	2.3%	$3.74
2025	2.2%	$3.82
2026	2.2%	$3.90
2027	2.2%	$3.99
2028	2.2%	$4.08
2029	2.2%	$4.17
2030	2.2%	$4.26
2031	2.3%	$4.36
2032	2.2%	$4.46
2033	2.2%	$4.56
2034	2.3%	$4.66
2035	2.3%	$4.77
2036	2.3%	$4.88
2037	2.3%	$4.99
2038	2.3%	$5.10

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

PACIFIC POWER
AVOIDED COST CALCULATION

STANDARD RATES FOR AVOIDED COST PURCHASES FROM ELIGIBLE QUALIFYING FACILITIES

OREGON – March 2016

PACIFIC POWER
AVOIDED COST CALCULATION

STANDARD RATES FOR AVOIDED COST PURCHASES FROM ELIGIBLE QUALIFYING FACILITIES

OREGON – March 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. 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. 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) at the Dave Johnston location starting in 2028. Therefore, the sufficiency period for the standard avoided cost rates is from 2016-2027 and the deficiency period starts in 2028. Since 2015 IRP's action plan does not include acquisition of any renewable proxy resource, the sufficiency period for renewable avoided cost rates extends beyond the end of the published term.

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 resource sufficiency (2016 through 2027); and (2) a period of resource deficiency (2028 and beyond). During the resource sufficiency period (2016 through 2027), standard avoided energy costs are based on market purchases. 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 QF. 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 renewable rates now extends beyond the end of the published term since the 2015 IRP preferred portfolio does not include any renewable proxy resources. As a result, renewable avoided cost rates are based on blended market prices for all years of published term.

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 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.

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

Because energy generated by a QF may vary, the Company has prepared total standard avoided costs at 75 percent, 85 percent and 90 percent 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 percent of all hours are on-peak and 43 percent are off-peak. **Table 6** shows the calculation of on-peak and off-peak avoided energy prices.

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[1] 423 MW CCCT - DJohns - J 1x1 –Available in 2028 as listed in Tables 6.1 and 6.2 of the 2015 IRP. Fuel costs are from the Company's December 2015 Official Forward Price Curve (1512 OFPC).
[2] SCCT Frame ("F"x1) - West Side Options (1500'), as listed in Tables 6.1 and 6.2 of the 2015 IRP.

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 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 December 2015 Official Forward Price Curve (1512 OFPC). **Table 10** shows the natural gas price used in this avoided cost calculation.

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 2015-2027. 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 percent). Standard avoided cost rates for a wind QF are reduced by a wind integration charge of \$3.06/MWh (\$2015).

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 2015-2027. 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 percent, tracking solar: 36.7 percent).

Exhibit 5- Renewable Base Load tab shows the calculation of proposed renewable avoided cost rates for a Renewable Base Load QF. The sufficiency period for renewable rates extends beyond the end of the published term since the action plan from 2015 IRP does not include any renewable proxy resources. As a result, renewable avoided cost prices are based on blended market prices.

Exhibit 6- Renewable Wind tab shows the calculation of proposed renewable avoided cost rates for a Wind QF. On and off-peak avoided cost rates are based on blended market rates for all years. The sufficiency period for renewable rates extends beyond the end of the published term since the action plan from 2015 IRP does not include any renewable proxy resources. As a result, renewable avoided cost prices are based on blended market prices.

Exhibits 7 & 8- Renewable Solar tab shows the calculation of proposed standard avoided cost rates for a Renewable Solar QF. The sufficiency period for renewable rates extends beyond the end of the published term since the action plan from 2015 IRP does not include any renewable proxy resources. As a result, renewable avoided cost prices are based on blended market prices.

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.**