PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

August 22, 2016

VIA ELECTRONIC FILING

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

Attn: Filing Center

Re: UM 1610 – PacifiCorp's Schedule 37 Updated Replacement Compliance Filing

PacifiCorp d/b/a Pacific Power (PacifiCorp or Company) hereby submits for filing the enclosed updated Schedule 37 standard non-renewable and standard renewable avoided cost prices for purchases from eligible qualifying facilities, replacing in their entirety the Schedule 37 avoided cost portion of the compliance filings submitted in this docket on July 12, 2016. The updated prices reflect the changes made in the Company's August 22, 2016 compliance filing in docket UM 1729. In the UM 1729 compliance filing, the Company updated Schedule 37 standard non-renewable and standard renewable avoided cost prices in compliance with Order No. 16-307 with an August 24, 2016, effective date.

On July 12, 2016, the Company submitted its compliance filing in UM 1610 reflecting the rulings in Order Nos. 16-174 and 15-130. The Commission's recent Order No. 16-307 in UM 1729 rendered moot aspects of the pricing portion of PacifiCorp's compliance filing in this docket. The Company, therefore, respectfully requests to replace in their entirety the UM 1610 Schedule 37 avoided cost prices submitted July 12, 2016, with new Schedule 37 prices that reflect the Commission's ruling in docket UM 1729, Order No. 16-307.[1] Per Order No. 16-307, the effective date of the UM 1729 Schedule 37 pricing is August 24, 2016.[2]

The Company's July 12, 2016, UM 1610 compliance filing also included updated standard power purchase agreements as listed below and revised Schedule 38 Non-Standard Avoided Cost prices pursuant to Order Nos. 16-174 and 15-130:

a. Oregon Standard Power Purchase Agreement with a New Firm Qualifying Facility with 10,000 kW Facility Capability Rating, or Less and not an Intermittent Resource;

b. Oregon Standard Power Purchase Agreement with a Firm Qualifying (new or existing) located in non-PacifiCorp Control Area, Interconnecting to Non-PacifiCorp System, with 10,000 kW Facility Capacity Rating, or Less, and Uninterruptible Transmission to the Point of Delivery;

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[1] In the July 12, 2016 compliance filing in UM 1610, the Company noted: "depending on the outcome of UM 1729(1), an additional filing may be necessary to reconcile any outstanding issues." The enclosed filing reflects Order No. 16-307 issued in UM 1729(1) with regard to Schedule 37 standard and renewable avoided cost prices.

[2] PacifiCorp "shall file an amended Schedule 37, with prices to be effective two business days after filing …." Order No. 16-307, Docket No. UM 1729(1) (Aug. 18, 2016).

c. Oregon Standard Power Purchase Agreement with a New Firm Qualifying Facility with 10,000 kW Facility Capability Rating, or Less and an Intermittent Resource with Mechanical Availability Guarantee;

d. Oregon Standard Power Purchase Agreement with a New Non-Firm Qualifying Facility with 10,000 kW Facility Capability Rating, or Less; and

Pursuant to ordering paragraph 2 in Order No. 16-174, these updated standard power purchase agreements became effective 30 days after the July 12, 2016 compliance filing, on August 11, 2016.

As noted in the July 12, 2016, docket UM 1610 compliance filing, the Company's Application for Reconsideration of the Commission's decision in Order No. 16-174 of Issue 7 – Calculating Non-Standard Avoided Cost Prices is pending Commission decision. Thus, the Company requested to stay a decision on Schedule 38 Non-Standard Avoided Cost prices.

To clarify the purpose of this filing, the table below summarizes the impact of this filing compared to the July 12, 2016 compliance filing.

Elements filed in July 12, 2016, UM 1610 Compliance Filing	Impact of this August 22, 2016 Replacement Filing
1. Tables showing how the changes required by Orders 16-174 and 15-130 were incorporated into PacifiCorp's Standard Avoided Cost Rate (Schedule 37), Non-Standard Avoided Cost Rate (Schedule 38), and standard power purchase agreements;	No impact
2. PacifiCorp's revised Standard Avoided Cost Rate (Schedule 37) layered onto the June 21, 2016 filing in UM 1729(1);	Schedule 37 pages are replaced in their entirety with the August 22, 2016 filing.
3. PacifiCorp's revised Standard Avoided Cost Rate (Schedule 37) layered onto the currently-effective pages (i.e., before changes requested as part of pending filing in UM 1729(1));	Order No. 16-137 issued August 18, 2016 in docket UM 1729 renders this section moot. This element is withdrawn in its entirety.
4. PacifiCorp's revised Non-Standard Avoided Cost Rate (Schedule 38);	No impact.
5. PacifiCorp's revised Power Purchase Agreements, identified below:	Pursuant to Order No. 16-174, these standard power purchase agreements became effective August 11, 2016.

The UM 1729 avoided cost pricing update was set via a non-contested case, and data requests or other discovery are not permitted. Please address all formal data requests regarding matters related to UM 1610 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 Natasha Siores at (503) 813-6583.

Sincerely,

R.B.Dalley

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 22nd day of August, 2015.

Jennifer Angell
Jennifer Angell
Supervisor, Regulatory Operations

REVISED TARIFF SHEETS

STANDARD AVOIDED COST RATE

Definitions (continued) (N)

Family Owned
After excluding the ownership interest of the passive investor whose ownership interests are primarily related to green tag values and tax benefits as the primary ownership benefit, five or fewer individuals own 50 percent or more of the equity of the project entity, or fifteen or fewer individuals own 90 percent or more of the project entity. A "look through" rule applies to closely held entities that hold the project entity, so that equity held by LLCs, trusts, estates, corporations, partnerships or other similar entities is considered held by the equity owners of the look through entity. An individual is a natural person. In counting to five or fifteen, spouses or children of an equity owner of the project owner who also have an equity interest are aggregated and counted as a single individual.

Community-Based
A community project (or a community sponsored project) must have a recognized and established organization located within the county of the project or within 50 miles of the project that has a genuine role in helping the project be developed and must have a significant continuing role with or interest in the project after it is completed and placed in service. Many varied and different organizations may qualify under this exception. For example, the community organization could be a church, a school, a water district, an agricultural cooperative, a unit of local government, & local utility, a homeowners' association, a charity, a civic organization, and etc.

After excluding the passive investor whose ownership interests are primarily related to green tag values and tax benefits as the primary ownership benefit, the equity (ownership) interests in a community sponsored project must be owned in substantial percentage (80 percent or more) by the following persons (individuals and entities): (i) the sponsoring organization, or its controlled affiliates; (ii) members of the sponsoring organization (if it is a membership organization) or owners of the sponsorship organization (if it is privately owned); (iii) persons who live in the county in which the project is located or who live a county adjoining the county in which the project is located; or (iv) units of local government, charities, or (v) other established nonprofit organizations active either in the county in which the project is located or active in a county adjoining the county in which the project is located. (N)

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.

Any dispute concerning a QF's entitlement to the standard rates and standard contract shall be presented to the Commission for resolution. The QF may file a complaint asking the Commission to adjudicate disputes regarding the formation of the standard contract. The QF may not file such a complaint during any 15-day period in which the utility has the obligation to respond, but must wait until the 15-day period has passed. The utility may respond to the complaint within ten days of service. The Commission will limit its review to the issues identified in the complaint and response, and utilize a process similar to the arbitration process adopted to facilitate the execution of interconnection agreements among telecommunications carriers. See OAR 860, Division 016. The Administrative Law Judge will act as an administrative law judge, not as an arbitrator. (N)

(continued)

(N)
(M) to page 4

Self Supply Option

(M) from page 3

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: (a) 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 8 including during any period after the first 15 years of a longer term contract (up to 20 years); and (b) will retain ownership of all Environmental Attributes generated by the facility, as defined in the standard contract, during the Renewable Resource Sufficiency Period identified on page 8. (C) (C)

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. (C) (C) (C)

(M) from page 3

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) to page 5

(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. (M) from page 4

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.

(M) from page 4

Avoided Cost Prices

Standard Fixed Avoided Cost Prices for Base Load and Wind QF (¢/kWh) (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	6.28	3.25	5.18	2.84
2029	6.44	3.34	5.31	2.92
2030	6.71	3.55	5.56	3.12
2031	6.88	3.64	5.70	3.20
2032	7.04	3.74	5.84	3.29
2033	7.24	3.86	6.01	3.40
2034	7.43	3.98	6.17	3.51
2035	7.62	4.09	6.33	3.61

(C)

(continued)

Avoided Cost Prices (Continued)

(C)

Standard Fixed Avoided Cost Prices for Fixed and Tracking Solar QF (¢/kWh)

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	5.84	3.25	5.79	3.25
2029	5.98	3.34	5.93	3.34
2030	6.25	3.55	6.20	3.55
2031	6.40	3.64	6.35	3.64
2032	6.56	3.74	6.51	3.74
2033	6.74	3.86	6.69	3.86
2034	6.93	3.98	6.87	3.98
2035	7.10	4.09	7.05	4.09

(C)

(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 ($2014). If Wind Qualifying Facility is not in PacifiCorp's balancing authority area, then no reduction is required.

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

(continued)

Avoided Cost Prices (Continued)

Renewable Fixed Avoided Cost Prices for Base Load and Wind QF (¢/kWh) (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	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	10.26	6.60	7.59	6.19
2029	10.47	6.74	7.74	6.32
2030	10.72	6.87	7.93	6.44
2031	10.94	7.03	8.09	6.59
2032	11.18	7.20	8.26	6.76
2033	11.41	7.37	8.43	6.92
2034	11.65	7.55	8.61	7.08
2035	11.87	7.76	8.76	7.28

(C)

(continued)

Avoided Cost Prices (continued) (C)

Renewable Fixed Avoided Cost Prices for Fixed and Tracking Solar QF (¢/kWh) (C)

Deliveries During Calendar Year	Fixed Solar QF (1,4)		Tracking Solar QF (1,4)	
	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	8.55	6.60	8.78	6.60
2029	8.72	6.74	8.96	6.74
2030	8.93	6.87	9.17	6.87
2031	9.11	7.03	9.36	7.03
2032	9.30	7.20	9.56	7.20
2033	9.49	7.37	9.76	7.37
2034	9.70	7.55	9.97	7.55
2035	9.87	7.76	10.15	7.76

(C)

(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, 2027, and the (C) Renewable Resource Deficiency Period begins January 1, 2028. (C)

(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).

(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 (C) 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).

(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).

(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 Standard Avoided Cost Rate Schedule. (C)

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)

APPENDIX 1

PACIFIC POWER
AVOIDED COST CALCULATION

STANDARD RATES FOR AVOIDED COST PURCHASES FROM ELIGIBLE QUALIFYING FACILITIES

OREGON – AUGUST 2016

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

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						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
Off-Peak (LLH Market Purchase)												
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

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

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

Source Offical Market Price Forecast dated March 2016
Blended Market Prices (Blending weights which are used to calculate blended 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)	(d)
			((a) - (b))	(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 ($/MMBtu)	Combined Cycle Energy Cost ($/MWh)	Capitalized Energy Costs 72.1% CF ($/MWh)	Total Standard Avoided Energy Cost ($/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) x1000/(8760 x 0.75)	(b)+(a) x1000/(8760 x 0.85)	(b)+(a) x1000/(8760 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	$63.87	$60.89	$59.65
2034	$169.68	$39.77	$65.59	$62.56	$61.29
2035	$173.39	$40.88	$67.27	$64.16	$62.87

Columns
- (a) Table 3 Column (a) minus Column (c)
- (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 4,909 Hours	Off-Peak 3,851 Hours
	($/kW-yr)	($/MWh)	($/MWh)	($/MWh)	($/MWh)
	(a)	(b)	(c)	(d)	(e)
		(a) *1000 / (100.0% x 8760 x 56%		(b) + (c)	(c)
2028	$149.06	$30.36	$32.45	$62.82	$32.45
2029	$152.18	$31.00	$33.37	$64.37	$33.37
2030	$155.56	$31.69	$35.46	$67.14	$35.46
2031	$158.99	$32.39	$36.37	$68.76	$36.37
2032	$162.49	$33.10	$37.35	$70.45	$37.35
2033	$166.05	$33.82	$38.59	$72.42	$38.59
2034	$169.68	$34.56	$39.77	$74.33	$39.77
2035	$173.39	$35.32	$40.88	$76.20	$40.88

Columns

(a) Table 3 Column (a) minus Column (c)

(b) Table 9 100.0% is the on-peak capacity factor of the Proxy CCCT Resource
56% 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	Simple Cycle CT Fixed Costs	Capitalized Energy Costs	Capitalized Energy Costs 72.1% CF
	($/kW-yr)	($/kW-yr)	($/kW-yr)	($/MWh)
	(a)	(b)	(c)	(d)
			((a) - (b))	(c)/(8.760 x 72.1%)
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 4 (Renewable)
Avoided Capacity Costs

Year	Avoided Firm Capacity Costs ($/kW-yr) (a)
2018	$118.91
2019	$121.77
2020	$124.70
2021	$127.70
2022	$130.64
2023	$133.64
2024	$136.70
2025	$139.70
2026	$142.76
2027	$145.88
2028	$149.06
2029	$152.18
2030	$155.56
2031	$158.99
2032	$162.49
2033	$166.05
2034	$169.68
2035	$173.39

Columns
(a) Table 3 (Renewable) Column (a) minus Column (c)

Table 7

Comparison between Proposed and Current Standard Fixed Avoided Costs

$/MWh

Year	Proposed Standard Base Load QF	Current Standard Base Load QF	Difference Standard Base Load QF	Proposed Standard Wind QF (2)	Current Standard Wind QF (2)	Difference Standard Wind QF (2)	Proposed Standard Fixed Solar QF	Current Standard Fixed Solar QF	Difference Standard Fixed Solar QF	Proposed Standard Tracking Solar QF	Current Standard Tracking Solar QF	Difference Standard Tracking Solar QF
2016	$21.86	$25.73	($3.87)	$18.67	$22.91	($4.24)	$22.87	$27.61	($4.74)	$22.87	$27.61	($4.74)
2017	$24.27	$28.24	($3.97)	$20.99	$25.35	($4.37)	$25.57	$30.22	($4.65)	$25.57	$30.22	($4.65)
2018	$25.91	$30.08	($4.17)	$22.54	$27.11	($4.57)	$27.39	$32.43	($5.04)	$27.39	$32.43	($5.04)
2019	$26.96	$31.89	($4.93)	$23.50	$28.86	($5.37)	$28.55	$34.18	($5.63)	$28.55	$34.18	($5.63)
2020	$28.42	$34.28	($5.86)	$24.87	$31.18	($6.31)	$30.07	$36.78	($6.71)	$30.07	$36.78	($6.71)
2021	$30.44	$36.99	($6.55)	$26.81	$33.82	($7.01)	$32.10	$39.59	($7.49)	$32.10	$39.59	($7.49)
2022	$33.35	$39.83	($6.48)	$29.64	$36.60	($6.95)	$35.02	$42.55	($7.53)	$35.02	$42.55	($7.53)
2023	$37.37	$42.67	($5.30)	$33.57	$39.35	($5.78)	$39.22	$45.58	($6.36)	$39.22	$45.58	($6.36)
2024	$41.30	$47.94	($6.65)	$37.40	$28.09	$9.31	$43.30	$34.12	$9.18	$43.30	$34.12	$9.19
2025	$43.41	$49.58	($6.18)	$39.43	$29.30	$10.13	$45.46	$35.46	$10.00	$45.46	$35.46	$10.00
2026	$45.11	$49.88	($4.78)	$41.05	$29.17	$11.87	$47.22	$35.46	$11.76	$47.22	$35.46	$11.76
2027	$47.13	$51.57	($4.44)	$42.97	$30.42	$12.55	$49.33	$36.84	$12.49	$49.33	$36.84	$12.49
2028	$49.47	$54.98	($5.51)	$41.00	$33.39	$7.61	$54.26	$39.94	$14.32	$53.89	$39.94	$13.94
2029	$50.74	$56.39	($5.65)	$42.09	$34.37	$7.72	$55.63	$41.06	$14.57	$55.25	$41.06	$14.19
2030	$53.22	$57.58	($4.36)	$44.38	$35.11	$9.26	$58.21	$41.94	$16.28	$57.82	$41.94	$15.89
2031	$54.52	$60.41	($5.89)	$45.49	$37.47	$8.02	$59.63	$44.44	$15.19	$59.23	$44.44	$14.79
2032	$55.90	$61.88	($5.98)	$46.67	$38.46	$8.21	$61.12	$45.58	$15.54	$60.71	$45.58	$15.14
2033	$57.55	$62.91	($5.36)	$48.11	$38.99	$9.12	$62.88	$46.26	$16.63	$62.47	$46.26	$16.21
2034	$59.14	$64.77	($5.64)	$49.49	$40.35	$9.14	$64.59	$47.77	$16.81	$64.16	$47.77	$16.39
2035	$60.67	$66.87	($6.20)	$50.82	$41.94	$8.88	$66.24	$49.52	$16.73	$65.81	$49.52	$16.29

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

$/MWh	$36.65	$41.98	($5.33)	$32.07	$31.38	$0.69	$38.95	$37.29	$1.66	$38.89	$37.29	$1.59

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

(2) Avoided cost prices have been reduced by a wind integration charge of $3.06/MWh ($2014) 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 ($2014) integration charges

15 Year (2018 - 2032) Nominal levelized Price at 6.660% Discount Rate (1)

$/MWh	$38.77	$44.27	($5.50)	$33.86	$32.32	$1.54	$41.30	$38.39	$2.91	$41.21	$38.39	$2.82

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

Year	Proposed	Current	Difference	Proposed	Current	Difference	Proposed	Current	Difference	Proposed	Current	Difference
	RenewableStandard	RenewableStandard	RenewableStandard	RenewableStandard	RenewableStandard	RenewableStandard	RenewableStandard	RenewableStandard	RenewableStandard	RenewableStandard	RenewableStandard	RenewableStandard
	Base Load QF	Base Load QF	Base Load QF	Wind QF (2)	Wind QF (2)	Wind QF (2)	Fixed Solar QF	Fixed Solar QF	Fixed Solar QF	Tracking Solar QF	Tracking Solar QF	Tracking Solar QF
2016	$21.86	$25.73	($3.87)	$18.67	$22.91	($4.24)	$22.87	$27.61	($4.74)	$22.87	$27.61	($4.74)
2017	$24.27	$28.24	($3.97)	$20.99	$25.35	($4.37)	$25.57	$30.22	($4.65)	$25.57	$30.22	($4.65)
2018	$25.91	$30.08	($4.17)	$22.54	$27.11	($4.57)	$27.39	$32.43	($5.04)	$27.39	$32.43	($5.04)
2019	$26.96	$31.89	($4.93)	$23.50	$28.86	($5.37)	$28.55	$34.18	($5.63)	$28.55	$34.18	($5.63)
2020	$28.42	$34.28	($5.86)	$24.87	$31.18	($6.31)	$30.07	$36.78	($6.71)	$30.07	$36.78	($6.71)
2021	$30.44	$36.99	($6.55)	$26.81	$33.82	($7.01)	$32.10	$39.59	($7.49)	$32.10	$39.59	($7.49)
2022	$33.35	$39.83	($6.48)	$29.64	$36.60	($6.95)	$35.02	$42.55	($7.53)	$35.02	$42.55	($7.53)
2023	$37.37	$42.67	($5.30)	$33.57	$39.35	($5.78)	$39.22	$45.58	($6.36)	$39.22	$45.58	($6.36)
2024	$41.30	$98.00	($56.70)	$37.40	$77.78	($40.38)	$43.30	$89.26	($45.95)	$43.30	$89.26	($45.95)
2025	$43.41	$100.16	($56.76)	$39.43	$79.51	($40.09)	$45.46	$91.06	($45.60)	$45.46	$91.06	($45.60)
2026	$45.11	$102.27	($57.16)	$41.05	$81.23	($40.18)	$47.22	$92.38	($45.16)	$47.22	$92.38	($45.15)
2027	$47.13	$104.42	($57.29)	$42.97	$82.95	($39.98)	$49.33	$94.13	($44.80)	$49.33	$94.13	($44.80)
2028	$86.51	$106.62	($20.11)	$69.44	$84.72	($15.27)	$82.37	$95.91	($13.53)	$84.37	$95.91	($11.53)
2029	$88.32	$108.75	($20.43)	$70.89	$86.42	($15.53)	$84.06	$97.62	($13.56)	$86.10	$97.62	($11.52)
2030	$90.27	$110.92	($20.65)	$72.45	$88.16	($15.71)	$86.01	$99.36	($13.34)	$88.10	$99.36	($11.26)
2031	$92.20	$113.22	($21.02)	$74.00	$90.01	($16.01)	$87.79	$100.90	($13.11)	$89.92	$100.90	($10.98)
2032	$94.29	$115.65	($21.37)	$75.68	$91.95	($16.27)	$89.70	$103.21	($13.50)	$91.88	$103.21	($11.33)
2033	$96.35	$118.07	($21.72)	$77.34	$93.92	($16.57)	$91.59	$104.74	($13.15)	$93.82	$104.74	($10.93)
2034	$98.49	$120.55	($22.06)	$79.07	$95.92	($16.86)	$93.58	$106.35	($12.78)	$95.85	$106.35	($10.50)
2035	$100.63	$123.06	($22.44)	$80.80	$97.92	($17.12)	$95.39	$108.60	($13.21)	$97.72	$108.60	($10.88)

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

$/MWh	$43.39	$63.45	($20.07)	$37.21	$52.72	($15.52)	$44.03	$60.62	($16.59)	$44.40	$60.62	($16.22)

Notes: (1) Discount Rate - 2015 IRP Discount Rate
(2) Avoided cost prices have been reduced by a wind integration charge of $3.06/MWh ($2014) 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 ($2014) integration charges

15 Year (2018 - 2032) Nominal levelized Price at 6.660% Discount Rate (1)

$/MWh	$47.52	$69.37	($21.85)	$40.52	$57.27	($16.75)	$47.88	$65.63	($17.75)	$48.37	$65.63	($17.26)

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	$67.01	$31.01	$2.25	$45.25	$112.26			
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 0.0768230723930572
(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% / 56.0% (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

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

Table 12
2015 IRP WY Wind Resource
43% 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 WY Wind Resource - 43% Capacity Factor								
2015	$2,169	$160.48	$34.67	$51.81	$0.67	$0.00	$52.48	$3.08
2016		$162.41	$35.08	$52.43	$0.68	$0.00	$53.11	$3.12
2017		$165.98	$35.85	$53.58	$0.69	$0.00	$54.27	$3.19
2018		$169.96	$36.71	$54.87	$0.71	$0.00	$55.58	$3.27
2019		$174.04	$37.59	$56.18	$0.73	$0.00	$56.91	$3.35
2020		$178.22	$38.49	$57.53	$0.75	$0.00	$58.28	$3.43
2021		$182.50	$39.41	$58.91	$0.77	$0.00	$59.68	$3.51
2022		$186.70	$40.32	$60.27	$0.79	$0.00	$61.06	$3.59
2023		$190.99	$41.25	$61.65	$0.81	$0.00	$62.46	$3.67
2024		$195.38	$42.20	$63.07	$0.83	$0.00	$63.90	$3.75
2025		$199.68	$43.13	$64.46	$0.85	$0.00	$65.31	$3.83
2026		$204.07	$44.08	$65.88	$0.87	$0.00	$66.75	$3.91
2027		$208.56	$45.05	$67.33	$0.89	$0.00	$68.22	$4.00
2028		$213.15	$46.04	$68.81	$0.91	$0.00	$69.72	$4.09
2029		$217.63	$47.01	$70.26	$0.93	$0.00	$71.19	$4.18
2030		$222.42	$48.04	$71.80	$0.95	$0.00	$72.75	$4.27
2031		$227.31	$49.10	$73.38	$0.97	$0.00	$74.35	$4.36
2032		$232.31	$50.18	$74.99	$0.99	$0.00	$75.98	$4.46
2033		$237.42	$51.28	$76.64	$1.01	$0.00	$77.65	$4.56
2034		$242.64	$52.41	$78.33	$1.03	$0.00	$79.36	$4.66
2035		$247.98	$53.56	$80.05	$1.05	$0.00	$81.10	$4.76

Sources, Inputs and Assumptions

Source:	(c)(f)	Plant Costs 2015 IRP (Table 6.2) in $2014
	(a)	Plant capacity cost
	(b)	= (a) x 0.0739902205884359
	(d)	= ((b) + (c)) / (8.76 x 43.0%)
	(g)	= (d) + (f)
	(h)	2015 IRP (Table 6.2) in $2014

2015 IRP WY Wind Resource - 43% Capacity Factor

Wind	Cost and Input Assumptions	
$2,156	Plant capacity cost	$/kW-yr
$34.46	Fixed O&M, plus on-going capital cost 2015 IRP (Table 6.2) in $2014	$/kW-yr
$0.67	Variable O&M	$/MWH
-	Tax Credit $/MWh 2015 IRP (Table 6.2) in $2014	$/MWH
7.399%	Payment Factor	
43%	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	$55.58	1.1064	0.8644	$61.49	$48.04
2019	$56.91	1.1057	0.8638	$62.93	$49.16
2020	$58.28	1.0941	0.8791	$63.77	$51.23
2021	$59.68	1.0865	0.8892	$64.85	$53.07
2022	$61.06	1.0915	0.8829	$66.65	$53.91
2023	$62.46	1.0953	0.8792	$68.42	$54.92
2024	$63.90	1.0925	0.8819	$69.81	$56.36
2025	$65.31	1.0902	0.8851	$71.20	$57.81
2026	$66.75	1.0891	0.8862	$72.70	$59.16
2027	$68.22	1.0872	0.8888	$74.17	$60.63
2028	$69.72	1.0887	0.8872	$75.90	$61.86
2029	$71.19	1.0877	0.8879	$77.43	$63.21
2030	$72.75	1.0898	0.8855	$79.29	$64.42
2031	$74.35	1.0879	0.8863	$80.89	$65.90
2032	$75.98	1.0871	0.8891	$82.60	$67.56
2033	$77.65	1.0855	0.8909	$84.29	$69.18
2034	$79.36	1.0848	0.8925	$86.09	$70.82
2035	$81.10	1.0803	0.8975	$87.62	$72.79

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

APPENDIX 2

PACIFIC POWER
AVOIDED COST CALCULATION

STANDARD RATES FOR AVOIDED COST PURCHASES FROM ELIGIBLE QUALIFYING FACILITIES

OREGON – AUGUST 2016

PACIFIC POWER
AVOIDED COST CALCULATION

STANDARD RATES FOR AVOIDED COST PURCHASES FROM ELIGIBLE QUALIFYING FACILITIES

OREGON –AUGUST 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.

The start of the renewable resource deficiency period in this filing is revised to start in January 1, 2028, pursuant to Order No. 16-307 in docket UM 1729. The Production Tax Credit sunsets prior to this date, so it is not included as a credit against the proxy resource cost.

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 blended 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 2027 and the renewable resource deficiency period starts in 2028. During the renewable resource sufficiency period (2016 through 2027), 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.

During standard renewable resource deficiency period, the standard renewable avoided cost prices are based on on-peak and off-peak prices of a renewable proxy resource from the 2015 IRP. The standard renewable on-peak price also includes a capacity adder calculated based on the fixed costs of a thermal proxy CCCT adjusted by the incremental capacity contribution of QF resource relative to the avoided renewable proxy resource.

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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.

The capacity adder is allocated to on peak hours by using the on peak capacity factor of a QF resource.

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 56% of all hours are on-peak and 44% 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 from 2015 IRP. The total cost of the proxy 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 also includes a capacity adder based on the fixed costs a thermal proxy CCCT (in $/kW-yr). The adjusted capacity adder in $/kW-yr is allocated to on peak hours by using the on peak capacity factor of the base load QF resource, which is assumed to be equal to on peak capacity factor of CCCT proxy resource.

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 also includes a capacity adder calculated based on fixed costs of the thermal proxy CCCT (in $/kW-yr) adjusted by the expected capacity contribution of a wind QF as identified in the 2015 IRP (wind: 25.4%). The adjusted capacity adder (in $/kW-yr) is allocated to on peak hours by using the on peak capacity factor of a wind QF resource. 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 also includes a capacity adder calculated based on the fixed costs a thermal proxy CCCT (in $/kW-yr) adjusted by expected capacity contribution of a solar QF as identified in the 2015 IRP (fixed solar: 32.2%, tracking solar: 36.7%). The adjusted capacity adder (in $/kW-yr) is allocated to on peak hours by using the on peak capacity factor of a solar QF resource.

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 2016-2027. For 2028 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 also includes a capacity adder calculated based on the fixed costs of a thermal proxy CCCT (in $/kW-yr), adjusted by the incremental capacity contribution of a renewable Base Load QF relative to the avoided renewable wind resource. The adjusted capacity adder in $/kW-yr is allocated to on peak hours by using the on peak capacity factor of a base load QF resource, which is assumed to be equal to on peak capacity factor of CCCT proxy 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 2016-2027. For 2028 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 2016-2027. For 2028 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 also includes a capacity adder calculated based on the fixed costs of a thermal proxy CCCT (in $/kW-yr), adjusted by the incremental capacity contribution of a renewable Fixed and Tracking Solar QF relative to the avoided renewable wind resource. The adjusted capacity adder in $/kW-yr is allocated to on peak hours by using the on peak capacity factors of a solar QF 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.**