PACIFIC POWER
A DIVISION OF PACIFICORP

825 NE Multnomah, Suite 2000
Portland, Oregon 97232

February 4, 2013

VIA ELECTRONIC FILING
AND OVERNIGHT DELIVERY

Oregon Public Utility Commission
550 Capitol Street NE, Ste 215
Salem, OR 97301-2551

Attn: Filing Center

RE: UM 1610 – Investigation into Qualifying Facility Contracting and Pricing Opening Testimony of PacifiCorp

PacifiCorp d/b/a Pacific Power (PacifiCorp or the Company) encloses for filing in the above-referenced docket its opening testimony and exhibits of Brian S. Dickman and Bruce W. Griswold. CDs containing the workpapers are also provided.

The Company requests that all data requests on this matter be sent to the following:

By email (preferred): datarequest@pacificorp.com

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

Please contact Joelle Steward, Director of Pricing, Cost of Service and Regulatory Operations, at (503) 813-5542 for questions on this matter.

Sincerely,

William R Griffith /JS

William R. Griffith
Vice President, Regulation

Enclosure

Cc: Service List – UM 1610

CERTIFICATE OF SERVICE

I hereby certify that I served a true and correct copy of the foregoing document, in Docket UM 1610, on the date indicated below by email and/or US Mail, addressed to said parties at his or her last-known address(es) indicated below.

Renee M. France (W) (C)
Oregon Department of Justice
Natural Resources Section
1162 Court St NE
Salem, OR 97301-4096
renee.m.france@doj.state.or.us

Matt Krumenauer (W) (C)
Senior Policy Analyst
Oregon Department of Energy
625 Marion St NE
Salem, OR 97301
matt.krumenauer@state.or.us

Vijay A. Satyal (W) (C)
Senior Policy Analyst
Oregon Department of Energy
625 Marion St NE
Salem, OR 97301
vijay.a.satyal@state.or.us

John W. Stephens (W) (C)
Esler Stephens & Buckley
888 SW Fifth Ave., Ste. 700
Portland, OR 97204-2021
stephens@eslerstephens.com
mec@eslerstephens.com

Dockets (W)
Idaho Power Company
dockets@idahopower.com

Donovan E. Walker (W)
Idaho Power Company
PO Box 70
Boise, ID 83707-0070
dwalker@idahopower.com

Lisa F. Rackner (W)
McDowell Rackner & Gibson PC
419 SW 11th Ave., Suite 400
Portland, OR 97205
dockets@mcd-law.com

Adam Lowney (W)
McDowell Rackner & Gibson PC
419 SW 11th Ave., Suite 400
Portland, OR 97205
adam@mcd-law.com

J. Richard George (W) (C)
Portland General Electric Company
121 SW Salmon St. – 1WTC1301
Portland, OR 97204
richard.george@pgn.com

Randy Dahlgren (W) (C)
Portland General Electric
121 SW Salmon St. – 1WTC0702
Portland, OR 97204
pge.opuc.filings@pgn.com

Brittany Andrus (W) (C)
Public Utility Commission of Oregon
PO Box 2148
Salem, OR 97308
brittany.andrus@state.or.us

Adam Bless (W) (C)
Public Utility Commission of Oregon
PO Box 2148
Salem, OR 97308
adam.bless@state.or.us

Stephanie S. Andrus (W) (C)
PUC Staff – Department of Justice
Business Activities Section
1162 Court St. NE
Salem, OR 97301-4096
stephanie.andrus@state.or.us

Megan Walseth Decker (W) (C)
Renewable Northwest Project
421 SW 6th Ave., Ste. 1125
Portland, OR 97204
megan@rnp.com

Mike McArthur (W)
Executive Director
Association of OR Counties
PO Box 12729
Salem, OR 97309
mmcarthur@aocweb.org

OPUC Dockets (W)
Citizens' Utility Board of Oregon
610 SW Broadway, Suite 400
Portland, OR 97205
dockets@oregoncub.org

G. Catriona McCracken (W) (C)
Citizens' Utility Board of Oregon
610 SW Broadway, Suite 400
Portland, OR 97205
catriona@oregoncub.org

Diane Henkels (W)
Cleantech Law Partners PC
6228 SW Hood
Portland, OR 97239
dhenkels@cleantechlawpartners.com

Irion A. Sanger (W) (C)
Davison Van Cleve
333 SW Taylor, Suite 400
Portland, OR 97204
ias@dvclaw.com

RNP Dockets (W)
Renewable Northwest Project
421 SW 6th Ave., Ste. 1125
Portland, OR 97204
dockets@rnp.org

Will K. Carey (W)
Annala, Carey, Baker, Et Al., PC
PO Box 325
Hood River, OR 97031
wcarey@hoodriverattorneys.com

Richard Lorenz (W)
Cable Houston Benedict Haagensen & Lloyd LLP
1001 SW Fifth Ave, Suite 2000
Portland, OR 97204-1136
rlorenz@cablehuston.com

Robert Jenks (W) (C)
Citizens' Utility Board of Oregon
610 SW Broadway, Suite 400
Portland, OR 97205
bob@oregoncub.org

David Tooze (W)
City of Portland – Planning & Sustainability
1900 SW 4th Suite 7100
Portland, OR 97201
David.tooze@portlandoregon.gov

Peter P Blood (W)
Columbia Energy Partners LLC
317 Columbia Street
Vancouver, WA 98660
pblood@columbiaenergypartners.com

Melinda J. Davison (W) (C)
Davison Van Cleve PC
333 SW Taylor, Suite 400
Portland, OR 97204
mjd@dvclaw.com; mail@dvclaw.com

S. Bradley Van Cleve (W) (C)
Davison Van Cleve PC
333 SW Taylor, Suite 400
Portland, OR 97204
bvc@dvclaw.com

John M. Volkman (W)
Energy Trust of Oregon
421 SW Oak Street, #300
Portland, OR 97204-1817
john.volkman@energytrust.org

John Harvey (W)
Exelon Wind LLC
4601 Westown Parkway, Suite 300
Wet Des Moines, IA 50266
John.harvey@exelon.com

Jeffrey S. Lovinger (W) (C)
Lovinger Kaufmann LLP
825 NE Multnomah, Suite 925
Portland, OR 97232-2150
lovinger@lklaw.com

Bill Eddie (W) (C)
One Energy Renewables
206 NE 28th Avenue
Portland, OR 97232
Bill@oneenergyrenewables.com

Kathleen Newman (W)
Oregonians for Renewable Energy Policy
1553 NE Greensword Drive
Hillsboro, OR 97214
kathleenoipl@frontier.com;
k.a.newman@frontier.com

R. Bryce Dalley (W)
Pacific Power
825 NE Multnomah Street, Suite 2000
Portland, OR 97232
Bryce.dalley@pacificorp.com

Elaine Prause (W)
Energy Trust of Oregon
421 SW Oak Street, #300
Portland, OR 97204-1817
Elaine.prause@energytrust.org

Paul D. Ackerman (W)
Exelon Business Services Company, LLC
100 Constellation Way, Suite 500C
Baltimore, MD 21202
Paul.ackerman@constellation.com

Kenneth Kaufmann (W) (C)
Lovinger Kaufmann LLP
825 NE Multnomah, Suite 925
Portland, OR 97232-2150
Kaufmann@lklaw.com

Daren Anderson (W)
Northwest Energy Systems Company LLC
1800 NE 8th Street, Suite 320
Bellevue, WA 98004-1600
da@thenescogroup.com

Glenn Montgomery (W)
Oregon Solar Energy Industries
Association
PO Box 14927
Portland, OR 97293
glenn@oseia.org

Mark Pete Pengilly (W)
Oregonians for Renewable Energy Policy
PO Box 10221
Portland, OR 97296
mpengilly@gmail.com

Mary Wiencke (W)
Pacific Power
825 NE Multnomah Street, Suite 1800
Portland, OR 97232
Mary.wiencke@pacificorp.com

Oregon Dockets (W)
PacifiCorp dba Pacific Power
825 NE Multnomah Street, Suite 2000
Portland, OR 97232
Oregondockets@pacificorp.com

John Lowe (W)
Renewable Energy Coalition
12050 SW Tremont Street
Portland, OR 97225-5430
jravenesanmarcos@yahoo.com

Peter J. Richardson (W) (C)
Richardson & O'Leary PLLC
PO Box 7218
Boise, ID 83702
peter@richardsonandoleary.com

James Birkelund (W)
Small Business Utility Advocates
548 Market Street, Suite 11200
San Francisco, CA 94104
james@utilityadvocates.org

Loyd Fery (W)
11022 Rainwater Lane SE
Aumsville, OR 97325
dlchain@wvi.com

Donald W. Schoenbeck (W) (C)
Regulatory & Cogeneration Services Inc
900 Washington St, Suite 780
Vancouver, WA 98660-3455
dws@r-c-s-inc.com

Gregory M. Adams (W) (C)
Richardson & O'Leary
PO Box 7218
Boise, ID 83702
greg@richardsonandoleary.com

Toni Roush (W)
Roush Hydro Inc
366 E Water
Stayton, OR 97383
tmroush@wvi.com

David A Lokting (W)
Stoll Berne
209 SW Oak Street, Suite 500
Portland, OR 97204
dlokting@stolberne.com

Thomas H. Nelson (W)
Attorney at Law
PO Box 1211
Welches, OR 97067-1211
nelson@thenelson.com

DATED: February 4, 2013

Amy Eissler
Coordinator, Regulatory Operations

Docket No. UM-1610
Exhibit PAC/100
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Brian S. Dickman

February 2013

Q. Please state your name, business address and present position with PacifiCorp (the Company).

A. My name is Brian S. Dickman. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon, 97232. My title is Manager, Net Power Costs.

Qualifications

Q. Briefly describe your education and business experience.

A. I received a Master of Business Administration from the University of Utah with an emphasis in finance and a Bachelor of Science degree in accounting from Utah State University. Prior to joining the Company, I was employed as an analyst for Duke Energy Trading and Marketing. I have been employed by the Company since 2003, including positions in revenue requirement and regulatory affairs, and I assumed my current role managing the Company's net power cost group in March 2012.

Purpose and Summary of Testimony

Q. What is the purpose of your testimony?

A. My testimony presents the Company's proposed changes to the methodology used to calculate avoided costs for qualifying facilities (QFs) in Oregon pursuant to the Public Utilities Regulatory Policies Act of 1978 (PURPA) and provides the Company's response to various items identified on the issues list adopted pursuant to Chief Administrative Law Judge Michael Grant's October 25, 2012 Ruling (Issues List). My testimony is structured to follow the Issues List as much as possible. Specifically I address Issue 1A and 1C, Issue 2A, Issue 3, and Issue

4A and 4C. These issues are related to the methodology for calculating avoided cost prices, including: identifying the appropriate methodology, determining a schedule for price updates, and accounting for specific QF characteristics.

Q. Are any other Company witnesses presenting testimony in this proceeding?

A. Yes. Mr. Bruce Griswold, Director of Short-Term Origination & Qualifying Facility Contracts, presents testimony regarding commercial issues related to QF contracting in Oregon. Specifically, Mr. Griswold addresses the Phase I eligibility issues and contracting issues on the Issues List, as well as issues involving levelization, environmental attributes, and third-party transmission costs.

Q. Please summarize your testimony.

A. The Company proposes that certain modifications should be made to the current method of calculating avoided cost prices in Oregon to ensure that those prices accurately reflect the true avoided cost of large QF resources and to maintain the customer indifference required under PURPA. The Company proposes to use two distinct methodologies: a standard method based on a proxy resource to calculate published avoided cost prices for small QFs under 3 megawatts on Schedule 37 (standard avoided costs), and a model-based approach that captures resource-specific characteristics and their impact on the utility system to calculate non-standard, or negotiated, avoided cost prices for larger QFs on Schedule 38 (non-standard avoided costs).

With respect to the published standard avoided cost prices, the Company recommends only minor modifications to the current method. First, the Company recommends that the eligibility cap be lowered from 10 megawatts to 3 megawatts. Mr. Griswold's testimony provides details regarding the rationale for the proposed reduction. Second, the Company proposes to use market prices from a single market hub rather than blended market prices to calculate standard avoided cost prices during the resource sufficiency period.

With respect to non-standard avoided cost prices, the Company recommends a modeling approach that relies on information from the Company's Integrated Resource Plan (IRP) and measures the impact a QF has on the Company's revenue requirement using the Generation and Regulation Initiative Decision Tools (GRID) production cost model. This approach, known as the Partial Displacement Differential Revenue Requirement (PDDRR) method, is commonly used by the Company in its other jurisdictions to calculate non-standard avoided cost prices. Utilizing the PDDRR method will improve the accuracy of the avoided cost prices for large QFs that do not qualify for standard avoided cost prices, compared to the current static proxy method for calculating non-standard avoided cost prices.

Additionally, the Company recommends the Commission not adopt preferential pricing options for current QF customers seeking a renewal of a contract. Doing so would result in offering contracts longer than 20 years, which the Commission currently does not allow.

Last, the Company recommends that the avoided cost calculations be updated as often as practical to reflect the best available information. For inputs to standard avoided cost prices that are tied to the IRP, the current schedule of updates at least every two years and within 30 days of acknowledgement of an IRP should be retained. Updates to forward market prices for electricity and natural gas, however, should be made on a quarterly basis in order to ensure that the published standard avoided cost prices more closely reflect the current avoided cost to the utility. Furthermore, inputs to non-standard avoided cost prices should reflect the best available information at the time a QF requests prices.

Q. Have you prepared an exhibit that summarizes the Company's proposals in the same format as the Issues List?

A. Yes. Please refer to Exhibit PAC/101 for a comprehensive list of the Company's proposals in the Issues List format.

Avoided Cost Price Calculation

Standard Avoided Cost Prices—Schedule 37

Q. Should the Commission retain the current method of calculating the Company's standard avoided cost prices for small QFs?

A. Yes, with only a couple of exceptions as discussed below. The current approach for calculating Oregon standard avoided cost prices relies on market prices during a resource sufficiency period and the cost of the next avoidable resource identified in the Company's IRP during the period of resource deficiency, which is defined by the timing of the next avoidable resource in the IRP (Proxy Method). This Proxy Method is reasonable only for resources that will not substantially impact a utility's load and resource plan because few, if any, of the QF resources that qualify for standard prices produce energy that provides equivalent value to the proxy resource energy. During the deficiency period, standard rates are based on a proxy plant that is fully dispatchable by the Company and is located at an optimum location relative to load. Prices paid to the QF are higher than they might otherwise be to the extent that a QF is not in an optimum location, is not dispatchable, is not reliable, does not provide reserves, produces intermittent power, or does not allow the Company to schedule maintenance.

Notwithstanding these differences, PURPA expressly contemplates that very small projects (100 kW and less) should get standard rates to minimize transaction costs that might otherwise keep the projects from going forward. The Company believes that for projects under three megawatts the Proxy Method used in Oregon is a reasonable balance between accuracy and transparency, and serves to minimize the transaction costs for smaller and less sophisticated project developers.

Q. Should the Commission change the eligibility cap for the standard contract?

A. Yes. Company witness Mr. Griswold provides testimony supporting the Company's proposal to reduce the eligibility cap from 10 megawatts to 3 megawatts.

Q. Does the Company propose to make any modifications to the calculation of standard avoided cost prices under the Proxy Method?

A. Yes. The Company proposes to use market prices from a single market hub rather than blended market prices to calculate standard avoided cost prices during the resource sufficiency period.

Q. Has the Company previously raised the issue of market blending with the Commission?

A. Yes. On March 5, 2012, the Company filed Advice No. 12-005 for changes to standard avoided cost prices, where it proposed to remove market blending from standard avoided cost calculations. Following discussions with Staff for the Public Utility Commission of Oregon (Staff), it was determined that issues regarding market blending should be addressed in a formal proceeding. On March 21, 2012, the Company revised the proposed standard avoided cost prices in the sufficiency period to use market blending, and these rates are currently in effect.

Q. How does market blending impact the standard avoided cost calculation.

A. In Order No. 05-584 in Docket No. UM 1129, the Commission required the Company to use monthly on- and off-peak forward market prices to calculate avoided cost prices when it was in a resource sufficient position.[1] Rather than use a single market index price, the Company has been required to use multiple markets across its system and to apply weightings to the markets based on an analysis performed in the GRID production cost model.

Q. Why does the Company propose to eliminate market blending?

A. Market blending introduces unnecessary complexity and administrative burden into the Company's standard avoided cost calculation without having a material impact on prices. If market blending were eliminated, it would not be necessary for the Company to perform any GRID model runs to calculate the standard

[1] *In the Matter of Public Utility Commission of Oregon Staff's Investigation Relating to Electric Utility Purchases from Qualifying Facilities*, Order No. 05-584, Docket UM 1129 at 28 (May 13, 2005).

avoided costs. In its March 21, 2012, standard avoided cost filing, market blending had a $0.20/MWH impact on avoided costs.

Q. What market does the Company propose to use in the period of resource sufficiency if market blending were eliminated?

A. The Company proposes to use forward Mid-Columbia market prices to calculate avoided costs in the period of resource sufficiency. The Mid-Columbia market is an active market in the Company's western balancing authority area (PACW) and fairly represents short-term energy value of small QF resources in Oregon. This is also the same method authorized by the Commission for Portland General Electric.

Q. Should standard avoided costs include a separate stream of prices for renewable resources?

A. Yes. The Company supports a renewable avoided cost price option in Schedule 37 as approved by the Commission in Order No. 11-505 in Docket No. UM 1396, subject to modifications in market blending discussed above and the eligibility limits as discussed in the testimony of Mr. Griswold. Later in my testimony I will discuss the appropriate calculation of avoided cost prices for renewable resources, including accounting for integration charges.

Non-Standard Avoided Cost Prices—Schedule 38

Q. Should the Commission adopt a new method for calculating non-standard avoided cost prices for large QFs?

A. Yes. The Company proposes to calculate non-standard avoided cost prices for large QFs using the PDDRR method, a modeling approach that relies on information from the Company's IRP and measures the impact a QF has on the Company's revenue requirement. The PDDRR method is commonly used by the Company in Utah, Wyoming, and Idaho to calculate non-standard avoided cost prices. The Company proposes that the PDDRR replace the current practice of making individual adjustments to the Proxy Method prices for standard avoided costs. Independently calculating the avoided cost of large QFs using the PDDRR method is a more accurate approach for determining the value of the energy and capacity on the Company's system, taking into account the unique characteristics of each QF.

Q. Why is a differential revenue requirement approach more accurate than basing avoided cost prices on a proxy plant?

A. The costs that are assumed to be avoided by the Company under the Proxy Method are not always being incurred. Specifically, under the Proxy Method, it is assumed that the Company is always able to use the QF output to make additional wholesale sales or avoid making wholesale purchases during the resource sufficiency period, and is always able to save the variable cost of the IRP proxy resource during the resource deficiency period. In reality this is not the case. For example, there may be times during the sufficiency period where the highest avoidable variable cost is fuel for generation, not market prices. During the deficiency period, the IRP proxy resource, which is a natural-gas fired plant, is not dispatched when it is more expensive to run compared to other resources available to the Company or compared to wholesale market prices. If a plant is not dispatched, it cannot be displaced. Both of these deficiencies cause the prices derived from the Proxy Method to be higher than the costs that the Company can avoid.

Q. Does the PDDRR method remedy the deficiencies of the Proxy Method?

A. Yes. The PDDRR method directly measures the impact each QF facility has on the Company's power costs by utilizing the Company's production cost model, GRID, to calculate the value of energy and capacity from QFs based on the unique characteristics of the QF resource and the Company's system.

Q. How are non-standard avoided cost prices for QFs calculated now?

A. Currently, non-standard avoided cost prices are determined based on the same Proxy Method used to set standard avoided cost prices, with a limited set of discrete adjustments meant to recognize some resource-specific characteristics. In Order No. 07-360 the Commission adopted the current methodology to calculate non-standard avoided cost prices for large QFs.[2] The list of authorized resource-specific adjustments was derived based on the seven factors outlined in 18 CFR § 292.304(e)(2). Many adjustments identified in 18 CFR § 292.304(e)(2) are interdependent, and it is often not possible to calculate a particular adjustment viewed in isolation. The Company's experience in its other jurisdictions is that a differential revenue requirement approach using the PDDRR method is best suited to account for the factors in 18 CFR § 292.304(e)(2).

Q. What are the seven factors identified in 18 CFR § 292.304(e)(2)?

A. 18 CFR § 292.304(e)(2) states that the following factors shall, to the extent practicable, be taken into account:

[2] *See In the Matter of Public Utility Commission of Oregon Staff's Investigation Relating to Electric Utility Purchases from Qualifying Facilities*, Order No. 07-360, Docket UM 1129 (Aug. 20, 2007).

i) The ability of the utility to dispatch the qualifying facility;
ii) The expected or demonstrated reliability of the qualifying facility;
iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirements, and sanctions for non-compliance;
iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;
v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;
vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and
vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities.

Q. In Order No. 07-360, did the Commission prescribe a method to account for each of the seven factors?

A. No. Of the seven factors, the Commission adopted adjustments to the standard avoided cost prices to address i) dispatchability, and ii) reliability. The Commission determined the issues related to iii) contract terms, iv) outages, and v) system emergencies were better addressed in contract provisions rather than as adjustments to avoided costs. The Commission did not adopt any specific framework for addressing vi) the individual and aggregate value of energy and capacity from QFs on the utility system, or vii) the smaller capacity increments and shorter lead times available from QFs, citing a lack of proposed methods from parties. The Commission did, however, recognize that an adjustment should be made if it can be done in a practical and reasonable way.

Q. Are there additional resource-specific factors that should also be considered when calculating the avoided cost of energy and capacity of large QFs?

A. Yes. Because large QFs may have specific characteristics that materially impact the value of the energy and capacity on the Company's system, additional factors such as the QF's location, delivery pattern, and capacity contribution need to be considered to accurately calculate its specific value to the Company. Modeling each specific QF in the Company's GRID model allows for these characteristics to be taken into account in the calculation of avoided costs.

Q. Please provide an overview of the PDDRR method.

A. Under the PDDRR method, the Company performs two simulations using the GRID model to determine the system energy value of a QF resource, taking into account its specific operating characteristics and point of delivery on the Company's system. In addition, the PDDRR method provides a capacity payment based on the cost of the "next deferrable resource" in the preferred portfolio. In applying the capacity payment, the method accounts for the difference between the capacity value provided by QF resources and the next deferrable resource, including the capacity contribution of the QF resource.

Q. What are the components of the avoided cost calculations under the PDDRR method?

A. Using the PDDRR, QF avoided cost prices consist of three main components: avoided capacity costs, avoided energy costs, and integration costs (where appropriate).

Q. Please describe how the Company calculates avoided costs of energy under the PDDRR method?

A. The calculation of the avoided energy cost begins with existing and planned resources that represent the Company's most recent preferred resource portfolio. This portfolio can come from the IRP, the IRP Update, or other sources such as the resource need assessment the Company provided in the recent all-source Request for Proposals (RFP). Using the preferred portfolio, the Company runs two simulations using the GRID model to determine the avoided energy cost. The first simulation (the Base Simulation) calculates net power costs of the preferred portfolio. The second simulation (the Avoided Cost Simulation) calculates net power costs of the preferred portfolio with two modifications: the operating characteristics of the proposed QF are added with its energy included at zero cost, and the capacity of the next deferrable resource is reduced by an amount equal to the QF's capacity contribution. This reduction in the capacity of the next deferrable resource, known as partial displacement, reflects the deferral of a portion of the next avoidable resource in a manner that maintains resource adequacy and system reliability equivalent to that of the Base Simulation. Front Office Transactions are typically the next avoidable resources partially displaced during the sufficiency period, followed by the proxy natural-gas fired resource during the deficiency period. The difference in net power costs between the Avoided Cost Simulation and the Base Simulation equals the avoided energy cost. The avoided energy cost does not include the benefit of deferring the fixed costs (avoided capacity costs) of the next deferrable resource in the deficiency period.

Q. Please describe how the Company calculates avoided costs of capacity during the deficiency period under the PDDRR method.

A. The Company calculates the avoided cost of capacity during the deficiency period outside of the GRID model using the fixed costs associated with partial displacement of the "next deferrable resource" in the IRP. The calculation is similar to the calculation currently used in the Proxy Method for standard avoided costs.

Specifically, the deferred fixed costs are calculated per kilowatt-year using the resource operating characteristics and payment factor from the most recent IRP. To convert the proxy plant capital cost, grossed up for revenue requirement, to an annual cost per kilowatt, the method uses the IRP resource payment factor as the basis for a real levelized annual cost per kilowatt-year. Inflation is then applied to convert the first year fixed costs to a nominal payment stream. The capacity component is calculated based on the amount of capacity expected to be provided by the QF resource. Different types of QF resources (i.e. wind, solar, hydro and thermal) have different abilities to defer the capacity of the next deferrable resource. The Company refers to this as a resource's capacity contribution.

Q. What is capacity contribution?

A. Capacity contribution is the ability of QF resources to contribute towards meeting the Company's hourly summer peak obligation to serve system load.

Q. Has the Company developed capacity contribution levels for various types of resources?

A. Yes. For intermittent resources, such as wind and solar, the Company developed capacity contribution values using historical operating data from existing projects that have contributed to the Company's summer peak obligation to determine the capacity contribution. If historical operating data was not available—which is the case for solar—the Company used third party information to develop the capacity contribution. For non-intermittent thermal QF resources, such as cogeneration or biomass resources, the Company assumes the QF's entire rated capacity can contribute towards the Company's summer peak obligation.

Q. How did the Company determine the capacity contribution for wind and solar QFs?

A. In its analysis, the Company matched the hourly generation profile for each of these technologies against historical hourly loads from 2007 through 2011 and identified the quantity of generation from each technology during the Company's top 100 summer peak hours in each year. Next, the Company identified the amount of capacity contribution each technology would be expected to provide at least 90 percent of the time. This percentage is the capacity contribution for wind and solar QFs.

Q. What capacity contribution did the Company calculate for wind and solar resources?

A. The Company calculated capacity contributions of 4.1 percent for wind resources. Capacity contributions of solar resources depend on the facility's configuration

11.5 percent for a fixed solar facility that maximizes its energy across all hours, and 25.9 percent for a fixed or tracking solar facility that is configured to produce greater energy during the Company's peak times. For further detail on the capacity contribution percentages for each resource please refer to Exhibit PAC/102, which describes and illustrates the assumptions and calculations.

Q. Would an integration charge be applied under the PDDRR method for intermittent resources such as wind and solar?

A. Yes. Avoided cost rates under the PDDRR method are reduced for integration costs. The cost of integration is calculated by GRID based on the additional reserves required to regulate and follow wind as identified in the Company's most recent wind integration study.

Q. Do previously signed QFs also impact the deferrable capacity available from the next deferrable resource?

A. Yes. The capacity contribution of all signed QF contracts executed subsequent to the development of the IRP preferred portfolio reduce the deferrable capacity of the next avoidable resource and therefore are included in the GRID simulation used in the PDDRR method. This ensures that the Company includes the IRP-determined level of avoidable capacity in the simulated resource portfolios as newly signed QFs are added into the resource portfolio.

Q. Are inputs to the production cost model runs used to calculate avoided costs under the PDDRR method updated after completion of an IRP?

A. Yes. Modeling inputs are based on the best information available to the Company at the time the QF pricing is prepared. Accordingly, all modeling inputs should be subject to update, including but not limited to the forecast of wholesale market prices for electricity and natural gas, executed purchase and sale contracts, wheeling contracts, coal contracts, and the retail load forecast. The resource additions outlined in the IRP preferred portfolio will be updated with a new IRP or IRP update, or if there is a known change to the IRP action plan, such as a delay or abandonment of a resource addition that causes a change to the preferred portfolio. Updating modeling assumptions in this manner ensures that the PDDRR method provides accurate avoided cost prices and maintains retail customer indifference.

Contract Renewals

Q. Should existing QFs seeking to renew a standard contract during a utility's sufficiency period be given a price during the sufficiency period that is different than the market price?

A. No. It would not be appropriate to differentiate pricing, either for standard avoided cost prices or negotiated prices, based on whether a QF has an existing contract. A QF has an expected life and contract term that is incorporated into utility planning processes, and a utility cannot expect QFs to be available to provide capacity beyond their useful lives or contract terms. Offering preferential pricing when a contract is renewed has the same effect as offering contracts longer than 20 years, which the Commission currently does not allow.

Renewable Avoided Cost Price Calculation

Q. Should there be distinct avoided cost prices for renewable resources that supply intermittent generation?

A. Yes. The Company proposes to include an adjustment for integration costs in the calculation of avoided cost prices for renewable QFs supplying the Company with intermittent generation. For standard avoided costs for renewable resources, rather than include multiple price streams in Schedule 37, the Company proposes to specify in the tariff that the price offered to intermittent QFs during the renewable resource sufficiency period will be reduced for the cost of integration.

Q. Does the Company intend to adjust the standard renewable avoided cost prices for integration costs during the renewable resource deficiency period?

A. No. Consistent with the Company's position in its February 2012 compliance filing in Docket No. UM 1396, an adjustment for integration costs will not be included in the renewable avoided cost pricing option during the deficiency period. Because the proxy wind resource would also incur wind integration costs, an intermittent QF will not impose incremental integration costs under the renewable avoided cost pricing option.

Q. How does the Company calculate the cost of integrating intermittent resources on its system?

A. The Company has performed several wind integration analyses including the 2010 Wind Integration Study and the current draft 2012 Wind Integration Study. The Company's studies determine the incremental level of reserves required to integrate intermittent wind generation. The studies are developed using a collaborative process involving input from various stakeholders, and the draft 2012 Wind Integration Study also involved a technical review committee. These studies are used in the IRP and to set rates in general rate cases and should form the basis for the integration costs used in the calculation of renewable avoided costs.

Q. How will avoided cost prices be adjusted to reflect integration costs?

A. Standard avoided cost prices for intermittent renewable resources will be adjusted by the cost of integration identified in the IRP. For large QFs, the non-standard avoided cost prices will also be adjusted for integration costs that are calculated for each year of the contract based on differential GRID model runs. The differential GRID model runs utilize the results of the wind integration study to calculate the cost of incremental reserves required to integrate the intermittent generation over the term of the QF contract using on the updated modeling inputs (such as forward market prices) in GRID.

Q. Is an adjustment made to the standard renewable avoided cost prices to reflect avoided integration costs during the deficiency period if the renewable QF is a base load resource?

A. No. In Order No. 11-505 the Commission ordered that, rather than calculating a separate avoided cost for each type of renewable resource, a QF has "the option of choosing between the renewable resource QF rate—likely to be based on a wind resource—or the standard QF rate based on the CCCT proxy."[3] Because a base load renewable QF already has the ability to choose an avoided cost price that

[3] *In the Matter of Public Utility Commission of Oregon Investigation Into Resource Sufficiency Pursuant to Order No. 06-538*, Order No. 11-505, Docket UM 1396 Phase II at 5 (December 13, 2011).

includes the benefit of deferring a base load resource, the renewable avoided cost prices should not be adjusted for avoided integration costs during the period of renewable resource deficiency.

Q. Has the Company calculated separate integration costs for solar resources?

A. No. The Company proposes to use its calculated wind integration costs as a proxy for integrating solar resources at this time.

Q. Should the Renewable Portfolio Implementation Plan be used in lieu of the IRP to determine renewable resource sufficiency?

A. No. The RPS Implementation Plan filed pursuant to ORS 469A.075 and OAR 860-083-0400 is not sufficient for a determination of resource deficiency for purposes of setting a renewable resource avoided cost rate. Fundamentally, the calculation of standard avoided costs for a renewable resource should be consistent with the calculation of the standard avoided costs for a non-renewable resource, with the primary difference being the proxy resource. The RPS Implementation Plan is limited in that its purpose is to calculate only the cost limitation of complying with the RPS and that it covers only a five year period. On the other hand, the IRP includes an evaluation of future RPS compliance obligations over a longer time horizon and identifies the timing of the Company's next deferrable renewable resource. Furthermore, the IRP forms the basis for various assumptions in the RPS Implementation Plan and evaluates renewable resource needs across PacifiCorp's six-state service territory.

Schedule of Avoided Cost Updates

Q. Should the Commission revise the current schedule for updating the inputs used to calculate avoided cost prices?

A. Yes. Inputs to the avoided cost calculation should be updated as often as practical to reflect the best information available. Consistent with the Company's proposal to have two different methodologies for calculating avoided costs, updates under each method may be made at different times.

Q. How often should the standard avoided cost prices be updated?

A. For the standard avoided cost prices, including standard prices for renewable QFs, the Company proposes to segregate the ability to update information for inputs that are directly tied to the IRP and those that are not. The Company recommends that forward market prices for electricity and natural gas used to calculate standard avoided costs be updated on a quarterly basis when the Company creates an official forward price curve (OFPC). All other inputs that are tied to the IRP, such as the timing of resource additions and the fixed costs of proxy resources, should continue to be updated at least every two years and within 30 days following the acknowledgement of an IRP or IRP Update. The Company also proposes that the standard avoided cost calculation should be subject to updates when there are known changes to the IRP preferred portfolio, such as the delay or abandonment of a future resource acquisition or a change in the Company's resource need assessment.

Q. Why is it necessary to segregate the schedule of updates for those inputs that are tied to the IRP and those that are not?

A. Biennial updates to standard avoided cost prices are too infrequent to ensure published prices are accurate reflections of avoided costs. Acknowledgement of an IRP recognizes the preferred resource portfolio and action plan in the IRP, not the snapshot of projected market prices used to develop that portfolio and action plan. For example, during the two-year period spanning 2009 to 2011, market prices at Mid-Columbia dropped by over 27 percent.

Q. For what purpose does the Company develop its quarterly OFPCs?

A. The Company issues quarterly OFPCs for use in regulatory filings, business planning, and long-term avoided cost pricing. The OFPC reflects the most current information available at the time they are prepared, is subjected to a rigorous review process by the Company, is available for review by others, and has been used for several years as the basis for updating the Company's Transition Adjustment Mechanism (TAM) filings.

Q. Would a quarterly update cycle for forward market prices require additional regulatory review by the Commission?

A. No. The process used to develop the Company's OFPC is routine and well understood by parties. The Company's OFPCs and the process underlying their creation has been the subject of extensive debate and review in previous TAM filings and market price updates to standard avoided cost prices would require only minimal review.

Q. What would be the process for the quarterly updates?

A. Within 30 days of the end of each quarter, the Company would submit updated standard avoided cost prices to the Commission that reflect the new OFPC. Ten days following submission to the Commission, the updated standard avoided cost prices would become effective and be published on the Company website.

Q. How often should the inputs to the PDDRR method for non-standard avoided cost prices be updated?

A. As discussed earlier in my testimony, inputs used to calculate non-standard avoided cost prices for large QFs using the PDDRR method should be updated at the time a QF requests prices in order to reflect the best available information. An accurate determination of non-standard avoided cost prices requires a more involved calculation than the Proxy Method, and merits the use of updated inputs. In order for retail customers to be indifferent to the calculated avoided cost prices, the underlying assumptions and modeling inputs must be based on the best information available. For example, forward market prices for electricity and natural gas should be based on the Company's most recent OFPC, and purchase and sale contracts for energy and capacity as well as contracts for wheeling, transportation of natural gas, and coal should be updated to include all executed transactions.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UM-1610
Exhibit PAC/101
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Brian S. Dickman

February 2013

PacifiCorp's Summary of Issues

1. **Avoided Cost Price Calculation**

A. What is the most appropriate methodology for calculating avoided cost prices?

1. Should the Commission retain the current method based on the cost of the next avoidable resource identified in the company's current IRP, allow an "IRP" method-based on computerized grid modeling, or allow some other method?

The current method is reasonable only for very small QFs. Changes should be made to standard prices (Schedule 37) to: 1) reduce the eligibility cap to 3 MW [See Exhibit PAC/200 (Direct Testimony of Bruce W. Griswold)] and 2) use a single market price in the resource sufficiency period. [See Exhibit PAC/100 (Direct Testimony of Brian S. Dickman)]

Non-standard avoided cost prices (Schedule 38) for large QFs should be calculated using the partial displacement differential revenue requirement modeling approach. [See Exhibit PAC/100]

2. Should the methodology be the same for all three electric utilities operating in Oregon?

The Company takes no position

B. Should QFs have the option to elect avoided cost prices that are levelized or partially levelized?

No. Levelization increases risk to customers and increases administrative complexity of managing the PPA. [See Exhibit PAC/200]

C. Should QFs seeking renewal of a standard contract during a utility's sufficiency period be given an option to receive an avoided cost price for energy delivered during the sufficiency period that is different than the market price?

No. Differentiation is equivalent to extending the length of a contract. [See Exhibit PAC/100]

D. Should the Commission eliminate unused pricing options?

Yes. The Schedule 37 Gas Market Indexed and Banded Gas Market Indexed options should be eliminated. [See Exhibit PAC/200]

2. **Renewable Avoided Cost Price Calculation**

A. Should there be different avoided cost prices for different renewable generation sources? (for example different avoided cost prices for intermittent vs. base load renewables; different avoided cost prices for different technologies, such as solar, wind, geothermal, hydro, and biomass.)

Yes. Prices for intermittent renewable resources should be adjusted for integration costs. [See Exhibit PAC/100]

B. How should environmental attributes be defined for purposes of PURPA transactions?

Environmental attributes should be defined as the environmental, social, and other positive, non-energy characteristics of electricity generation from a renewable resource. [See Exhibit PAC/200]

C. Should the Commission amend OAR 860-022-0075, which specifies that the non-energy attributes of energy generated by the QF remain with the QF unless different treatment is specified by contract?

Yes. The Commission should amend OAR 860-022-0075 to be consistent with Order No. 11-505. [See Exhibit PAC/200]

3. Schedule for Avoided Cost Price Updates

A. Should the Commission revise the current schedule of updates at least every two years and within 30 days of each IRP acknowledgement?

Yes. For standard prices (Schedule 37), market prices for electricity and natural gas should be updated quarterly. For non-standard prices (Schedule 38), all model inputs should reflect the best available information. [See Exhibit PAC/100]

B. Should the Commission specify criteria to determine whether and when mid-cycle updates are appropriate?

Yes. Known changes in the preferred resource portfolio should trigger an update to standard prices (Schedule 37). [See Exhibit PAC/100]

C. Should the Commission specify what factors can be updated in mid-cycle? (such as factors including but not limited to gas price or status of production tax credit.)

Yes. For standard prices (Schedule 37), market prices for electricity and natural gas should be updated quarterly. For non-standard prices (Schedule 38), all model inputs should reflect the best available information. [See Exhibit PAC/100]

D. To what extent (if any) can data from IRPs that are in late stages of review and whose acknowledgement is pending be factored into the calculation of avoided cost prices?

For non-standard prices (Schedule 38), all model inputs should reflect the best available information. [See Exhibit PAC/100]

E. Are there circumstances under which the Renewable Portfolio Implementation Plan should be used in lieu of the acknowledged IRP for purposes of determining renewable resource sufficiency?

No. The RPS Implementation Plan is not sufficient to determine the timing of the next deferrable renewable resource. [See Exhibit PAC/100]

4. Price Adjustments for Specific OF Characteristics

A. Should the costs associated with integration of intermittent resources (both avoided and incurred) be included in the calculation of avoided cost prices or otherwise be accounted for in the standard contract? If so, what is the appropriate methodology?

Yes. PacifiCorp proposes to annotate the standard avoided cost Schedule 37 tariff with a separate provision stating that the price offered to intermittent QFs during the renewable resource sufficiency period will be reduced for the cost of integration.

Non-standard (Schedule 38) prices will also be adjusted to reflect the cost of integration. [See Exhibit PAC/100]

B. Should the costs or benefits associated with third party transmission be included in the calculation of avoided cost prices or otherwise accounted for in the standard contract?

Yes. Costs or benefits associated with third party transmission captured should be accounted for on a project-by-project basis and addressed as an addendum to the PPAs. [See Exhibit PAC/200]

C. How should the seven factors of 18 CPR 292.304(e)(2) be taken into account?

The PDDRR method proposed for non-standard avoided costs accounts for the resource specific characteristics. [See Exhibit PAC/100]

5. Eligibility Issues

A. Should the Commission change the 10 MW cap for the standard contract?

Yes. The Company proposes that the eligibility cap of 10 MW to qualify for standard prices (Schedule 37) should be reduced to 3 MW. [See Exhibit PAC/200]

B. What should be the criteria to determine whether a QF is a "single QF" for purposes of eligibility for the standard contract?

The Partial Stipulation adopted in UM 1129 should be modified to remove the passive investor exception. [See Exhibit PAC/200]

C. Should the resource technology affect the size of the cap for the standard contract cap or the criteria for determining whether a QF is a "single QF"?

Yes. Wind and photovoltaic solar resources are capable of disaggregating into multiple projects. [See Exhibit PAC/200]

D. Can a QF receive Oregon's Renewable avoided cost price if the QF owner will sell the RECs in another state?

Yes. During the resource sufficiency period the QF assumes all ownership risk. [See Exhibit PAC/200]

6. Contracting Issues

A. Should the standard contracting process, steps and timelines be revised? (Possible revisions include but are not limited to: when an existing QF can enter into a new PP A and the inclusion of conditions precedent to the PPA including conditions requiring a specific interconnection agreement status.)

B. When is there a legally enforceable obligation?

It is reasonable to establish that a legally enforceable obligation has arisen when the QF approves the final draft PPA as contemplated in B(5) on page 10 of Schedule 37. [See Exhibit PAC/200]

C. What is the maximum time allowed between contract execution and power delivery?

D. Should QFs smaller than 10 MW have access to the same dispute resolution process as those greater than 10 MW?

E. How should contracts address mechanical availability?

F. Should off-system QFs be entitled to deliver under any form of firm point to point transmission that the third party transmission provider offers? If not, what type of method of delivery is required or permissible? How does method of delivery affect pricing?

G. What terms should address security and liquidated damages?

H. May utilities curtail QF generation based on reliability and operational considerations, as described at 18 CPR §292.304(f)(l)? If so, when?

I. What is the appropriate contract term? What is the appropriate duration for the fixed price portion of the contract?

The current term length of up to twenty years with a fixed price period of the initial ten years is appropriate. [See Exhibit PAC/200]

J. What is the appropriate process for updating standard form contracts, and should the utilities recently filed standard contracts be amended by edits from the stakeholders or the Commission?

7. <u>Interconnection Process</u>

A. Should PPAs include conditions that reference the timing of the interconnection agreement and interconnection milestones? If so, what types of conditions should be included?

B. Should QFs have the ability to elect a larger role for third party contractors in the interconnection process? If so, how could that be accomplished?

Docket No. UM-1610
Exhibit PAC/102
Witness: Brian S. Dickman

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Brian S. Dickman

February 2013

HISTORICAL CAPACITY CONTRIBUTION OF WIND AND SOLAR RESOURCES

OVERVIEW

PacifiCorp uses the historical capacity contribution provided by its portfolio of existing intermittent resources to evaluate the capacity value of new intermittent resources. Capacity contribution represents the percentage of a generator's nameplate capacity that PacifiCorp can use to reliably satisfy peak load requirements. The methodology used to measure historical capacity contribution compares the reliability of intermittent resources during peak load hours with the expected reliability of the next deferrable resource in the integrated resource plan ("IRP"). Based on the assumption that the full capacity of the next deferrable resource in the IRP will be available in approximately 90 percent of peak load hours, the methodology measures the level of power provided by PacifiCorp's portfolio of intermittent resources that was achieved or exceeded in 90 percent of the largest 100 summer peak load hours.

Using historical data, the average capacity contribution of wind and solar resources in calendar years 2007 to 2011[1] was as follows:

Resource Class	Capacity Contribution
Wind	4.1%
Solar (Energy-oriented)	11.5%
Solar (Peak-oriented)	25.9%

METHODOLOGY

The approach used by PacifiCorp to measure historical capacity contribution is commonly referred to as an exceedance methodology. The concept behind this methodology is to measure the level of intermittent capacity necessary to provide the same level of reliability in peak hours as expected from the next deferrable resource in the IRP. Because the full output of the next deferrable resource in the IRP is expected to be available in more than 90 percent of peak load hours, the methodology measures the level of power achieved or exceeded by the intermittent resources in 90 percent of the largest 100 summer peak load hours.

ASSUMPTIONS

The measurement of historical capacity contribution is based on the following principles and assumptions:

- The measurement is based on the aggregate capacity benefit of the resource class taken as a whole, not the capacity benefit of an individual resources analyzed in isolation.
    - A resource class is defined as group resources that rely on the same generation technology and possess the same supply characteristics, such as wind and solar resources.

[1] Calendar years 2007 to 2011 were used in order to present a multiyear view of the capacity provided by particular resources.

  - The use of an aggregate capacity value is required because a geographically dispersed array of facilities may produce a level of reliability greater than any one resource taken separately.

  - The use of aggregate output ensures that all of the generators in a resource class share proportionally in the capacity benefit provided by the class as a whole.

- The measurement calculates the reliability of generation output from a resource class based on a 90% reliability requirement.

  - The methodology calculates the level of generation that was achieved or exceeded in 90 percent of peak load hours.

  - Because incremental IRP resources are added to provide capacity, the capacity contribution of the intermittent resource must be measured based on the level of capacity necessary to provide the same level of reliability as the incremental IRP resource.

- The measurement is performed on an annual basis over the top 100 summer peak load hours to ensure that it is representative of PacifiCorp's peak system load obligation, while preserving the statistical significance of the calculation.

  - Due to varying correlations between the output from intermittent resources and peak load hours, the number of hourly intervals used in the measurement must be sufficiently large to preserve the natural variability the resource output and sufficiently small to preserve the relationship between generation output and peak load hours.

  - The period of measure is restricted to summer load hours since PacifiCorp's system peak occurs in the summer months and will continue to do so in the foreseeable future. On a weather normalized basis, a winter peak does not occur until the top 160th hour.

CALCULATION

PacifiCorp measured the historical capacity contribution provided by a particular resource class based on the level of power that was achieved or exceeded in 90 percent of the top 100 summer load hours. The measurement was performed separately for each resource class over the five year period from 2007 to 2011. PacifiCorp then calculated the average of five annual values to be representative of the ongoing capacity value provided by the resource class in the future.

The calculation was based on the following steps:

- Compile the aggregate energy output from all resources within the resource class in each hour of the year.

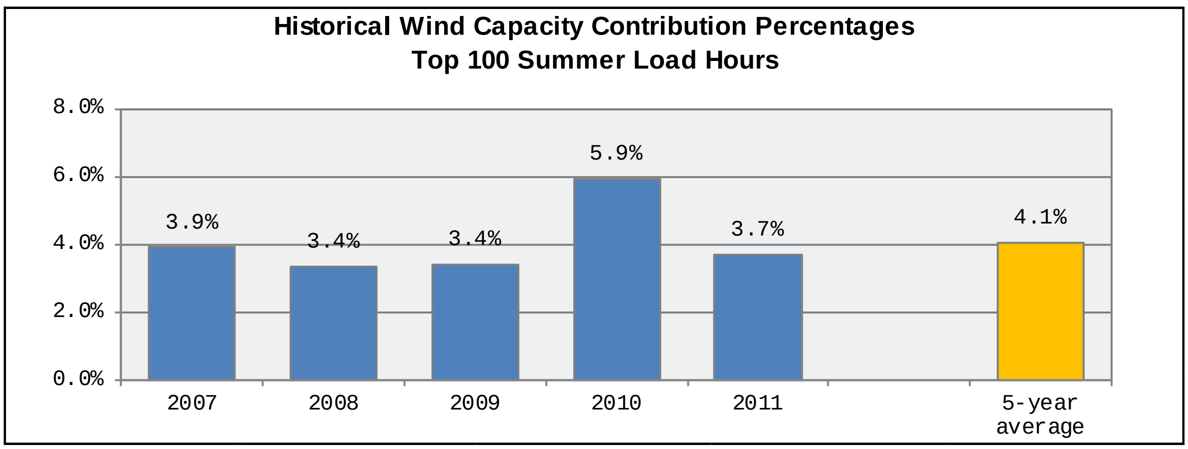
- Calculate the aggregate nameplate capacity from all resources in the resource class in each hour of the year.

- Divide the aggregate energy output by the aggregate nameplate capacity to arrive at the aggregate capacity factor for each hour of the year.

- Use actual hourly system load data to determine the top 100 load hours that occurred in each year between the months of June and September. The resulting hours are the top 100 summer peak load hours for 2007-2010 for each year.
- Filter the hourly aggregate capacity factors to the top 100 summer peak load hours.
- Calculate the capacity factor that was achieved or exceeded in 90 percent of the top 100 summer load hours for each year.

WIND

Over the period 2007 to 2011 PacifiCorp's portfolio of wind resources provided an average capacity contribution of 4.1 percent. This value is comparable to the 5 percent wind capacity contribution assumption used by the Northwest Power and Conservation Council.[2] The annual capacity contribution values were as follows:



[2] Sixth Northwest Conservation and Electric Power Plan, N.W.P.C.C. Chapter 12, 4, http://www.nwcouncil.org/energy/powerplan/6/final/SixthPowerPlan_Ch12.pdf .

Hourly generation logs were used to measure the historical capacity contribution from the PacifiCorp's system wind resources. The analysis included both owned and non-owned wind resources where PacifiCorp acquired the output under a power purchase agreement. The analysis did not include wind resource where PacifiCorp did not acquire the final output from the facility, such as under an exchange agreement. The wind resources included in the measurement were as follows:

Wind Resource	COD	Type	Nameplate Capacity
Chevron Wind QF	12/1/2009	PPA	16.5
Combine Hills	12/22/2003	PPA	41.0
Dunlap I Wind	10/1/2010	Owned	111.0
Foote Creek Generation	7/21/1997	Owned	32.1
Glenrock III Wind	1/17/2009	Owned	39.0
Glenrock Wind	12/31/2008	Owned	99.0
Goodnoe Wind	5/31/2008	Owned	94.0
High Plains Wind	9/13/2009	Owned	99.0
Leaning Juniper 1	9/14/2006	Owned	100.5
Marengo 1 & 2	8/3/2007	Owned	210.6
McFadden Ridge Wind	9/29/2009	Owned	28.5
Mountain Wind 1 & 2 QF	7/2/2008	PPA	140.7
Oregon Wind Farm QF	3/31/2009	PPA	64.6
Rock River I	11/7/2001	PPA	50.0
Rolling Hills Wind	1/17/2009	Owned	99.0
Seven Mile II Wind	12/31/2008	Owned	19.5
Seven Mile Wind	12/31/2008	Owned	99.0
Spanish Fork Wind 2 QF	7/31/2008	PPA	18.9
Three Buttes Wind	12/1/2009	PPA	99.0
Threemile Canyon Wind QF	9/1/2009	PPA	9.9
Top of the World Wind	10/1/2010	PPA	200.2
Wolverine Creek	2/12/2006	PPA	64.5
		Total Wind:	**1,736.5**

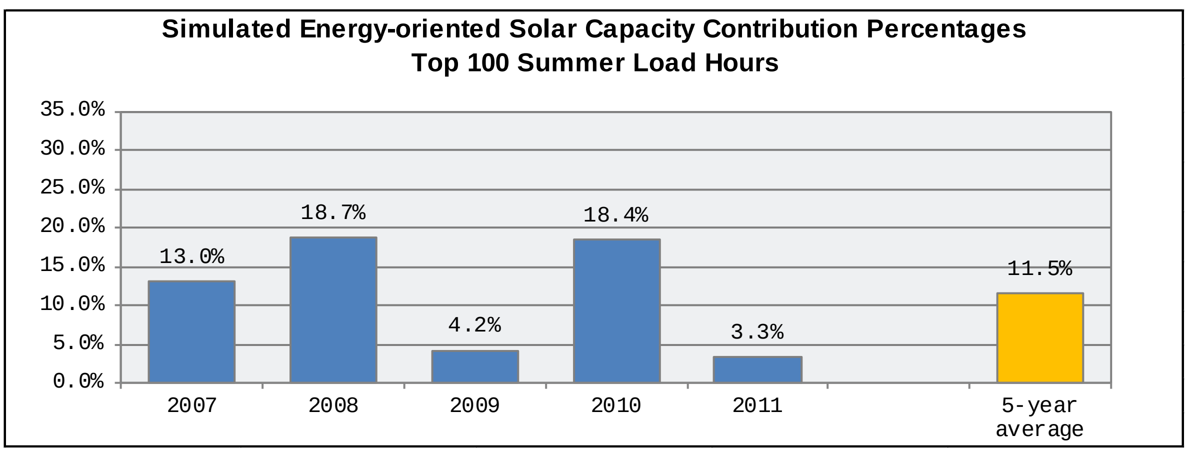
SOLAR

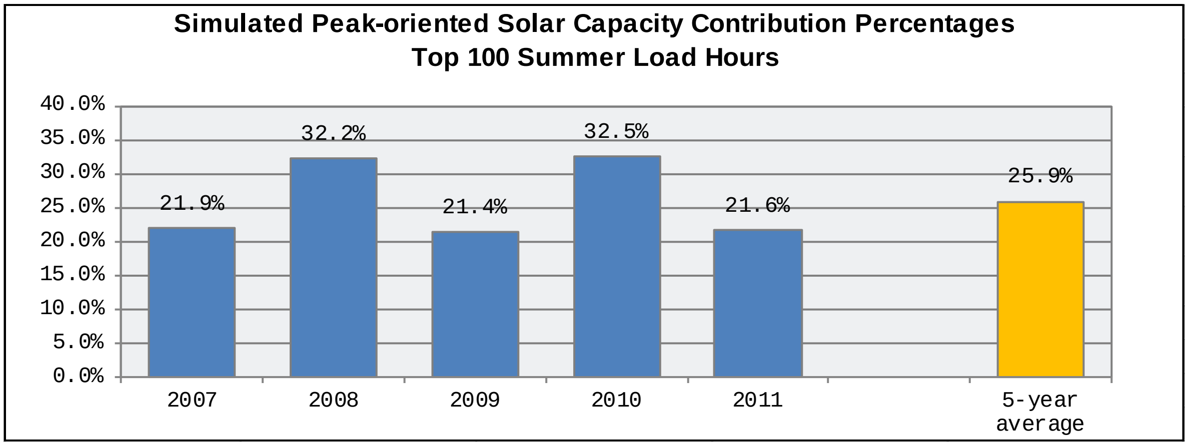
PacifiCorp has limited historical solar data necessary to develop the capacity contribution value of a class of geographically distributed solar resources on its system. Accordingly, PacifiCorp relied on simulated hourly solar profile data developed by the National Renewable Energy Laboratory (NREL). The simulated hourly data is compared against the top 100 summer load hours in each year 2007 – 2011 using the methodology described above. Unlike wind, where the levels of generation change in each year depending on the output of the resource set, the simulated solar output remains constant in each year and is compared to changes in the timing of the top 100 peak summer load hours from year-to-year.

Differences in the panel configuration of a solar resource impact the capacity value provided by the resource. Accordingly, it is necessary to differentiate between classes of solar resources based on whether the resource has been configured to maximize energy output or whether it has been configured to maximize output during peak load periods. A solar resource configured to maximize energy output may operate at a low capacity factor during peak loads that occur in the evening, where a solar resource aligned more towards the west or with a tracking device may operate at a higher capacity factor during evening peaking periods. Based on these panel configurations the following capacity contribution measurements resulted:

Configuration	Energy-orientation	Peak-orientation*
Tilt	Latitude	Latitude minus 15°
Azimuth	Due South	Due South plus 25°
Capacity Contribution	11.5%	25.9%

*A solar resource with a tracking system is considered a peak orientation.





In developing the solar generation profile PacifiCorp used an NREL tool, PVWatts, to simulate hourly solar generation levels based on historical meteorological solar radiation data. The PVWatts tool develops a solar profile based on input parameters such as the location, size, array type, tilt angle, and azimuth angle of the solar resource.

The capacity contribution measurement was based on a simulated class of solar resources representative of locations throughout the PacifiCorp's service territory. It was developed using the combined simulated profiles from five locations: Pocatello, ID; Yakima, WA; Pendleton, OR; Lander, WY; and Salt Lake City, UT. The analysis was performed twice, first with all of the resources configured to energy and second with all of the resources configured to peak, as detailed above.

Docket No. UM-1610
Exhibit PAC/200
Witness: Bruce W. Griswold

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Bruce W. Griswold

February 2013

Q. Please state your name, business address and present position with PacifiCorp (the Company).

A. My name is Bruce W. Griswold. My business address is 825 NE Multnomah Street, Suite 600, Portland, Oregon 97232. I am employed by PacifiCorp (PacifiCorp or Company) as Director of Short-Term Origination and Qualifying Facility (QF) Contracts for PacifiCorp Energy, a division of PacifiCorp.

Qualifications

Q. Briefly describe your education and business experience.

A. I have a B.S. and M.S. degree in Agricultural Engineering from Montana State University and Oregon State University, respectively. I have been employed by the Company for over 25 years in various positions of responsibility in retail energy services, engineering, marketing and wholesale energy services. I have also worked at an environmental firm as a project engineer.

My current responsibilities as Director of Short-term Origination and QF Contracts include the negotiation and management of wholesale power supply and resource acquisition through requests for proposals (RFP) as well as overall responsibility for the Company's QF power purchase agreements (PPA). I have appeared as a witness on behalf of the Company in multiple proceedings across its six state jurisdictions.

Purpose and Overview of Testimony

Q. What is the purpose of your testimony?

A. The purpose of my testimony today is to respond to Issues 1B, 1D, 2B, 2C, 4B, 5A, 5B, 5C, 5D, 6B and 6I listed in Appendix A – Issues list to Chief

Administrative Law Judge Michael Grant's December 21 2012 Ruling.

Q. Please summarize your testimony.

A. I have summarized the Company's position on each of the issues below.

- Issue 1B. Should QFs have the option to elect avoided cost prices that are levelized or partially levelized? No. The Company recommends that QFs not be given the option to elect levelization of avoided cost prices over the term of a QF PPA. A levelization option may lead to increased risks to customers if the QF defaults in the early years. Further, if levelization is an option, credit and security requirements need to be sufficient to cover the associated front-loaded cost and risk.
- *Issue 1D. Should the Commission eliminate unused pricing options?* Yes. The Company proposes to eliminate the Gas Market Indexed and Banded Gas Market Indexed avoided cost pricing options from Schedule 37, which sets forth the Company's standard avoided costs.
- *Issue 2B. How should environmental attributes be defined for purposes of PURPA transactions?* Environmental attributes are included in the Oregon Department of Energy (ODOE) promulgated rules, codified at OAR 330-160-0015(13) that defines Renewable Energy Certificate.
- *Issue 2C. Should the Commission amend OAR 860-022-0075, which specifies that the non-energy attributes of energy generated by the QF remain with the QF unless different treatment is specified by contract?* The Company recommends that the Commission amend OAR 860-022-0075 to be consistent with Order No. 11-505 and state that the utility

receives the non-energy attributes during periods of renewable resource deficiency.

- *Issue 4B. Should the costs or benefits associated with third party transmission be included in the calculation of avoided cost prices or otherwise accounted for in the standard contract?* Yes. The Company proposes that individual QFs should be responsible for the any third-party transmission costs incurred, or benefits realized, by the utility, associated with the purchase of that QF's energy. Third party transmission costs and benefits should not be incorporated into the calculation of the standard avoided cost price but the third-party transmission adjustment should be accounted for in the contract with the QF as a separate adjustment calculation in an addendum to the PPA.
- *Issue 5A. Should the Commission change the 10 MW cap for the standard contract?* Yes. The Company recommends reducing the eligibility cap for standard avoided cost prices and contracts to 3 MW. Projects over 3 MW would be eligible for non-standard avoided cost prices and contracts.
- *Issue 5B. What should be the criteria to determine whether a QF is a "single QF" for purposes of eligibility for the standard contract?* The Company recommends that the passive investor exemption be removed from the Partial Stipulation adopted in UM 1129 with a waiver available to individual family or community-owned projects.
- *Issue 5C. Should the resource technology affect the size of the cap for the standard contract cap or the criteria for determining whether a QF is a*

"single QF"? Yes. The Company views wind and photovoltaic (PV) solar as the two resource types capable of disaggregating from a large single project into multiple projects eligible for standard avoided cost prices and contract terms.

- *Issue 5D. Can a QF receive Oregon's Renewable avoided cost price if the QF owner will sell the RECs in another state?* Yes. The Company believes that Order No. 11-505 establishes REC ownership when receiving Oregon's renewable avoided cost prices. During the resource sufficiency period, the QF assumes all ownership risk of the RECs including registration of the QF facility with any appropriate agency or program, the qualification and application of those RECs for any mandatory renewable portfolio standard (RPS) or voluntary renewable program, management or accounting of those RECs, and the sales of those RECs to third parties.
- *Issue 6B. When is there a legally enforceable obligation?* The Company recognizes that the issue of a legally enforceable obligation involves many legal questions and proposes that the Commission set criteria for establishing a legally enforceable obligation using the milestone of the QF approving the final draft PPA as contemplated in B(5) on page 10 of Schedule 37.
- *Issue 6I. What is the appropriate contract term? What is the appropriate duration for the fixed price portion of the contract?* The Company recommends that the current term length of up to 20 years be continued with the fixed price period in the contract changed from the initial 15

years to the initial 10 years. The remaining years of the PPA would be at the Electric Market Option.

Issues

Issue 1B. Should QFs have the option to elect avoided cost prices that are levelized or partially levelized?

Q. Should QFs have the option to elect avoided cost prices that are levelized or partially levelized?

A. No, for several reasons. First, levelization in the avoided cost prices introduces additional customer risk in the early years of the QF PPA. In order to maintain customer indifference, contract prices for a given year should track the utility's avoided cost price stream for that year. Second, levelization provides an additional level of administrative complexity to manage the additional billing and security provisions contained in a PPA that incorporates levelization. Third, the Commission has addressed the concept of avoided cost price levelization on multiple occasions since 1980 and most recently in 2005. In Order No. 05-584, the Commission declined to apply levelization to published avoided cost rates. In that order, the Commission concluded that "since it was not adopting Commission Staff's (Staff) proposed methodology that would separately value capacity and pay levelization, we need not address the issue of levelization in this Order."[1] The Company is not aware of any reason to revisit this issue or for the Commission to reverse its 2005 decision.

However, in the event the Commission determines that levelization is warranted, the Company recommends that appropriate credit thresholds and

[1] OPUC Order No. 05-584 page 28 and at footnote 46.

security requirements be required to protect customers from the risk of default by the QF in the early years of levelization when the levelized contract price exceeds the non-levelized avoided cost price. Security should be in the form of a cash deposit or a letter of credit if the QF does not meet the Company's creditworthiness test.

Issue 1D. Should the Commission eliminate unused pricing options?

Q. Does the Company propose the Commission eliminate any of the avoided cost pricing options from the standard avoided cost price options?

A. Yes. The Company proposes to eliminate the Gas Market Indexed and Banded Gas Market Indexed avoided cost pricing options from the standard avoided cost price options included in Schedule 37.

Q. Have any QFs entering into a contract with the Company ever elected to use one of these options?

A. No. The Gas Market Indexed and Banded Gas Market Indexed avoided cost prices have been options for over seven years. During this time, no QF under the standard avoided cost eligibility cap has entered into a contract using either option. That includes both the option for the full term of an agreement or for the last five market option years of a 20 year agreement. QFs consistently utilize only the Firm Market Indexed option when they select it at all. Moreover, the Company rarely receives any questions on these two options other than to ask why they are offered.

Q. What is the Company's rationale for eliminating the options?

A. The Gas Market Indexed and Banded Gas Market Indexed options have not been used by QFs. In the interest of simplifying the standard avoided cost price options and reducing transactional costs for QFs, removing these options will eliminate the need for QFs to incur additional cost and time to research and conduct additional analysis on future gas as well as electric markets to assess the risk of market volatility.

Issue 2B. How should environmental attributes be defined for purposes of PURPA transactions?

Q. What are Environmental Attributes?

A. The Company proposes to define "Environmental Attributes" of electricity generation from a renewable resource as the environmental, social, and other positive, non-energy characteristics of that renewable generation. Environmental Attributes include not only the avoided emissions characteristics, and the proof of generation of renewable energy, but also the right to make a claim with respect to that energy; specifically, the exclusive right to claim to have performed the social and environmental good of generating renewable, as opposed to fossil fuel, energy. Renewable generation has environmental attributes. A key value of energy from renewable resources being purchased is the "renewableness" of the energy. The Environmental Attributes of the energy that give it the unique characteristic of being "renewable" can be separated from the energy itself and traded by definition. Some or all of the Environmental Attributes could be transferred in a transaction concerning them, depending on how the attribute being transferred is defined in the agreement or in regulation. A typically important characteristic is avoidance of emissions of carbon dioxide to the atmosphere.

Q. How are "Environmental Attributes," "renewable attributes," "green attributes," "non-energy attributes of energy," "Tradable Renewable Energy Credits," and "Renewable Energy Certificates" different?

A. All the terms refer to some of all of the positive attributes of generation from renewable resources. "Environmental Attributes" refers to all of the sticks in the bundle, and is often synonymous with "non-energy attributes of energy," "green attributes," and "renewable attributes." Not all of the sticks in the bundle are necessarily transferred in a transaction in "TRCs" or "RECs," which refers to an instrument including some or all such attributes separately tradable from the renewable energy. "Renewable Energy Certificates" is a common name for a tradable instrument that includes most or all of the environmental attributes of generation, depending on the definition used. It is often accompanied by proof of generation—for example a Western Renewable Energy Generation Information System (WREGIS) Certificate. Accordingly, both "Tradable Renewable Energy Credit" and "Renewable Energy Certificate" are generic names for a class of tradable instrument by which some or all of the positive attributes of renewable generation, as well as certification of the proof of generation, are transferred. What is in a REC or a TRC or an agreement to transfer environmental attributes or green attributes or non-energy attributes or renewable attributes will depend on the definition in the agreement or the applicable regulation.

Q. Has Oregon developed a definition of Renewable Energy Certificate?

A. Yes. The Oregon Department of Energy (ODOE) promulgated rules, codified at OAR 330-160-0015(13) that defines Renewable Energy Certificate as:

> a unique representation of the environmental, economic, and social benefits associated with the generation of electricity from renewable energy sources that produce Qualifying Electricity. One Certificate is created in association with the generation of one MegaWatt-hour (MWh) of Qualifying Electricity. While a Certificate is always directly associated with the generation of one MWh of electricity, transactions for Certificates may be conducted independently of transactions for the associated electricity.

This seems to refer to all, although it is unclear that it includes all, attributes other than the generation—be they called "renewable," "environmental," "green," or "non-generation" attributes. "Unique representation" could mean serial numbered, like WREGIS Certificates, which can therefore uniquely express each megawatt hour of generation, so there is no double counting.

Q. From these definitions, what do you conclude with respect to RECs or other environmental attributes in QF power purchase agreements?

A. It appears that "Environmental Attributes" are included in Oregon's definition of a REC. Therefore, during a period of renewable resource deficiency, when the QF transfers the facility's RECs to the utility, the Environmental Attributes, including avoided greenhouse gas emissions, are similarly transferred.

<u>Issue 2C. Should the Commission amend OAR 860-022-0075, which specifies that the non-energy attributes of energy generated by the QF remain with the QF unless different treatment is specified by contract?</u>

Q. Should the Commission amend OAR 860-022-0075, which specifies that the non-energy attributes of energy generated by the QF remain with the QF unless different treatment is specified by contract?

A. Yes. The Company recommends that the Commission amend OAR 860-022-0075 to be consistent with Order No. 11-505 and state that the utility receives the non-energy attributes during periods of renewable resource deficiency.

<u>Issue 4B. Should the costs or benefits associated with third party transmission be included in the calculation of avoided cost prices or otherwise accounted for in the standard contract?</u>

Q. Should the costs or benefits associated with third-party transmission be included in the calculation of avoided cost prices or otherwise accounted for in the standard contract?

A. Any costs and benefits of third-party transmission should be attributed to the individual QF and should be reflected as a contractual adjustment to the price in the contract. The costs and benefits of third-party transmission should not be incorporated into the actual calculation of the standard avoided cost, rather the costs and benefits should be captured on an individual QF project basis in the contract between the QF and Company as an addendum to the agreement. This is necessary because each project will be unique based on geographical location and the local electrical system loads and resources, and including costs or benefits associated with third party transmission would create unwarranted subsidization within QF prices depending on the location of the QF or local transmission loads.

Q. Under what circumstances would third-party transmission be required for a QF contract?

A. The Company's Oregon service territory is not one continuous system. Rather, it is composed of multiple allocated service territories across the state—some large, some small—all interconnected by transmission lines. In some instances, the Company's transmission function (PacifiCorp Transmission) controls the transmission system interconnecting elements of the Company's larger system. In other cases, the Company purchases service across transmission owned by a third party in order to deliver (or export) generation to (or from) an isolated portion of its service territory. The Company refers to these areas that are entirely or partially reliant on third-party transmission as *load pockets*. Excess generation in a load pocket is primarily expected to occur in the off-peak time period or during seasonal periods when customer loads are normally lower and cannot absorb the generation, but also may occur with the addition of a small number of large QF projects or significant numbers of standard QF projects. Under minimum load conditions, the Company must either back down its own resources, move the generation elsewhere (if feasible), or curtail the generator. While the Company recognizes that locational transmission constraints and the need for transmission upgrades should not prevent project development, any incremental cost resulting from the constraint or upgrade should be borne by the developer and not customers. Analysis of transmission system constraints and the cost of options for dealing with those constraints should be incorporated into the QF pricing and contract process so that appropriate adjustments can be made, either for the incremental cost borne by the utility or the benefits to the utility associated with localized generation. In many cases, the analysis of the transmission system will take additional time to complete and needs to be accounted for when establishing the contract process schedule.

Q. Please describe the nature of the issue.

A. The Company's Oregon load pocket's individual load and resource balances are a mix of conditions from those with surplus internal generation to those with inadequate internal generation, and some with seasonal variations between surplus and inadequate internal generation, relative to their loads. When new generation is interconnected to a load pocket and creates a surplus of local resources, then the Company must purchase transmission out of the load pocket or else curtail the local generation, to the extent the new generation exceeds local load. Thus, any time a new generator causes generation within a load pocket to exceed load, the Company will incur an additional cost to transmit the excess load pocket generation across third-party transmission to another load pocket that has inadequate internal generation.

The Company therefore can alleviate a load pocket surplus generation condition caused by proposed QFs if it can purchase firm point-to-point transmission from the third-party transmission provider under the provider's Open Access Transmission Tariff (OATT). An example is Bonneville Power Administration (BPA). Firm point-to-point (PTP) transmission may be purchased on a short-term or long-term basis where short-term is for a month, a day, or even an hour, and long-term is for a minimum one year but a minimum five-year commitment is required to obtain renewal rights for continuing service beyond the initial commitment. Long-term firm (LTF) PTP is the only form of transmission service that provides a dependable right to wheel surplus generation from a load pocket to the Company's larger system for the full term of a PPA. Short-term non-firm transmission may also be available but is not used for network load service because it is subject to displacement by other parties who have firm transmission or higher priority non-firm transmission. In the event another transmission customer owns or purchases firm or higher priority non-firm transmission from the transmission provider across the same path, the third-party transmission provider will deny the lower priority non-firm transmission use if there is not enough capacity for all customer uses. Therefore, in order to ensure that firm third-party transmission service will remain available over the term of the PPA, the Company purchases long-term firm PTP transmission, if it is available. In all cases in a load pocket where a QF's delivery exceeds load and the Company must rely on third-party transmission to wheel excess generation out of the load pocket, the Company expects to incur additional costs to secure such transmission services from the third-party transmission provider.

Q. Has the Company incurred third-party transmission costs with any of its current standard contracts under Schedule 37?

A. Yes. The Company's recent experience with the Threemile Canyon Wind Farm 1, LLC (Threemile) 9.9 MW wind QF project illustrates the incremental costs that are involved. In eastern Oregon, BPA owns transmission linking the Company's load pockets to other portions of PacifiCorp's system. Dalreed is a PacifiCorp load pocket near Arlington, Oregon where loads range from about 44 MW peak during the summer to less than 2 MW during the winter. Prior to the Threemile project becoming operational in 2009, the Company required no transmission service provision for energy exports out of the Dalreed load pocket as there was only load and no generation. In order to insure that any excess generation could be moved to load outside the Dalreed load pocket, the Company initiated the purchase of long-term firm PTP transmission (with rollover rights) from BPA and entered BPA's queue in the spring of 2009 to secure such transmission prior to initial start-up of the wind turbines. BPA determined it would not have firm long-term capacity available to grant this request until upgrades were completed on their system. In 2009, Threemile began commercial operation, and excess generation occurred throughout the winter months. As an interim measure, the Company purchased short-term firm PTP transmission during the winter and spring months to address the period when generation could exceed load. When LTF PTP transmission is available at Dalreed, the Company would secure the long-term to ensure firm rights in all hours for any excess generation.

In theory, the cost to export excess generation from Dalreed should be partially offset by any transmission service savings realized under the current transmission agreement with BPA. Therefore, if the QF generation reduced peak imports, the Company might realize a reduction in transmission service charges into the load pocket. In actuality, the amount of savings realized has been minimal. In 2009, there was no reduction in peak hourly demand and in 2010 Threemile reduced the annual peak hour demand at Dalreed by just over 300 kW.

Compared to the cost the Company incurred for short-term firm transmission out of Dalreed, or the estimated annual cost the Company expects to incur once long-term firm transmission out of Dalreed is available, the reduction to import costs is negligible. Adding the Threemile facility to the Dalreed load pocket has had a net effect of increasing the Company's cost above the Schedule 37 standard avoided cost rates.

Q. Is the Threemile Canyon Wind Farm 1, LLC example an isolated case?

A. No. There are other QF projects in Oregon that have executed PPAs with the Company that are located within a load pocket.

Q. Are minimum load issues unique to QF resources?

A. No. However in the case of purchases from non-QF resources, minimum load issues are handled through contract price adjustment and/or curtailment of the resource.

Q. Are the costs or benefits associated with third-party transmission incorporated into non-standard avoided cost prices?

A. Yes. In the calculation of the project specific avoided cost prices for a non-standard QF, the costs or benefits associated with third-party transmission, if any, are calculated. The costs and benefits are included in the contract between the QF and the Company as an addendum to the PPA for any avoided cost price adjustment and/or curtailment of the resource.

Q. Would reducing the standard avoided cost eligibility cap have a beneficial impact on the load pocket issue?

A. Yes. In the case of QFs eligible for standard contracts and prices, the Company currently must pay the published standard avoided cost price even if the QF's generation exceeds load in the load pocket and requires delivery to load elsewhere on the Company's system. These incremental costs are borne by customers. Reducing the standard avoided cost eligibility cap to 3 MW, as proposed later in my testimony, would not eliminate the load pocket issue, but it would reduce the potential of a QF's generation to exceed the load in a load pocket and would thereby, reduce the magnitude and frequency of the Company to purchase firm PTP transmission.

<u>Issue 5A. Should the Commission change the 10 MW cap for the standard contract?</u>

Q. Should the Commission change the 10 MW cap for the standard contract?

A. Yes, the maximum nameplate capacity rating eligible for standard avoided cost prices should be reduced from 10 MW to 3 MW. Reducing the eligibility cap will help mitigate several of the current issues before the Commission including the disaggregation of large single projects into multiple projects and responsibility for third-party transmission costs; while at the same time it would maintain the objective of minimizing transaction costs for the small QFs. Standard avoided cost rates on Schedule 37 are based on a proxy plant that is fully dispatchable by the Company and is located at an optimum location relative to load. Those rates may reflect an inherent overpayment to the extent that a QF is not identical to the proxy plant's optimum operating characteristics or location. Few, if any, of the QF resources eligible for standard avoided cost prices produce energy that provides equivalent value to the proxy resource energy. Most QF resources receiving standard avoided cost prices are, to some degree, receiving incremental value based on the difference between the operating characteristics of the QF resource and the proxy plant, and therefore do not always reflect the true avoided cost to the utility. This divergence from applying the project specific characteristics to calculate the standard avoided cost pricing does not account for system impact costs of the individual QF, and will lead to the Company's customers carrying the burden of a higher-cost QF resource.

As the standard eligibility cap increases, the cost impact to customers increases. This is a major factor that the Commission should consider in determining the appropriate level at which to set the eligibility cap for standard avoided cost prices.

The difference in cost between the QF resource and the proxy plant has become more significant since the eligibility cap was raised from 1 MW to 10 MW. For example, since the 10 MW eligibility cap was established in 2005, wind QF PPAs eligible for standard avoided cost prices account for 114.5 MW, or 59 percent, of the Company's total QF projects. Nine of the 14 standard wind QF PPAs are sized at 9.9 MW or 10 MW and only one wind QF project is less than 3 MW. These large standard wind projects are all remote, intermittent resources with low capacity factors. The cost to the Company and its customers, for integration of the resource, capacity contribution, and system transmission costs are significant and yet they have not been reflected in the true cost of those projects due to the 10 MW eligibility cap. The Company's proposal for reducing the eligibility cap for standard avoided cost prices to 3 MW would mitigate the ability of the larger standard QF projects to shift those types of costs noted above to customers and address a number of the other issues under consideration in this docket.

Q. Did PURPA support the concept of small QF projects receiving standard rates?

A. Yes. PURPA expressly contemplates that standard rates should apply to very small projects or those under 100 kW in order to minimize transactions costs that might otherwise keep the projects from going forward. In its order implementing the PURPA regulations, the Federal Energy Regulatory Commission (FERC) stated:

> The Commission is aware that the supply characteristics of a particular facility may vary in value from the average rates set forth in the utility's standard rates required by this 12 paragraph. If the Commission were to require individualized rates, however, the transaction costs associated with administration of the program would likely render the program uneconomic for this size of qualifying facility. As a result, the Commission will require that standard tariffs be implemented for facilities 100 kW or less.[2]

In other words, the FERC acknowledged that standard rates may be higher than a project specific avoided cost rates, but approved an exception for projects less than 100 kW that might otherwise be unable to afford the transaction costs of negotiating an individual rate.

Q. Has this Commission previously acknowledged that the purpose of standard rates is to minimize transaction costs for small QFs?

A. Yes. In 1991, this Commission increased the ceiling for standard rates from 100 kW to 1 MW in Order No. 91-1605. The Commission explained:

> The parties' recommendation to increase the standard rate size limit to 1 MW derives from a report developed by PUC staff and staff of the Oregon

[2] FERC, 18 CFR Part 292, Docket RM79-55, Order No. 69.

> Department of Energy. The report concludes that the transaction costs associated with negotiating a QF/utility power purchase agreement could be prohibitive for small QFs and effectively eliminate them from the marketplace. The standard rate is intended to address this concern by minimizing the transaction costs of negotiating a power purchase agreement. The report concluded that the transaction costs associated with participating in a competitive bid could further disadvantage small QFs. Therefore, staff recommended increasing the size limit for QFs which are eligible to receive the standard rate to 1 MW.

Q. Does the eligibility cap serve a definitive purpose?

A. Yes. The standard eligibility cap is a clear delineation between projects that are deemed to be small to minimize their transaction costs for securing a PPA with the utility. These projects are generally categorized as being developed by individuals or organizations with limited resources that do not have the corporate backing, financial wherewithal, or technical skills to handle significant administrative issues or cost. These types of projects that PURPA intended should receive the benefit of standard avoided cost rates and contracts. As the eligibility cap has increased over time to the current 10 MW, the Company is now negotiating with well-funded, experienced developers who have successfully developed multiple QF and renewable projects across the country, and hire some of the most skilled technical and legal firms in the country. It is clear that there has been a shift from the “mom & pop” developer to the well-staffed development firm where there is a direct correlation between the size of the QF project and the amount of resources that can be applied to the project.

Q. Please summarize the factors to be considered when setting the maximum nameplate capacity eligible for standard avoided cost prices.

A. The desire to stimulate QF development should be balanced with the mandate that customers not pay more for QF power than for other resources. The primary rationale for standard rates is to minimize transaction costs for small projects. Rates for larger projects should take individual operating characteristics into account. In balancing these factors, the Commission should review and set the eligibility cap for standard avoided cost prices to include only projects that may otherwise be unable to afford the transaction costs of negotiating an individualized purchase rate.

Q. Do you have a specific recommendation as to the appropriate capacity ceiling?

A. Yes. The Company proposes that 3 MW is a reasonable eligibility cap for QF projects seeking standard avoided cost prices and standard contracts. Setting the eligibility cap to 3 MW would continue to encourage the development of additional community-scale QF resources across all resource types, while reducing the disaggregation of large single projects in multiple small projects. Further, 3 MW is consistent with the transaction cost rationale for standard avoided cost rates and contract terms noted earlier in my testimony. Any projects over 3 MW would still receive avoided cost prices. However, prices would be calculated under a non-standard methodology that incorporates the PURPA adjustment factors for the specific project operating characteristics and providing the appropriate avoided cost prices. Company witness Mr. Brian S. Dickman provides testimony supporting the Company's proposed methodology for calculating non-standard avoided cost rates.

Q. Is a 3 MW capacity ceiling consistent with the level in the other jurisdictions where the Company operates?

A. Yes. Exhibit PAC/201 shows the eligibility caps by state for the Company's multiple jurisdictions. While some states do have eligibility caps greater than 3 MW, those caps also have lower eligibility caps for specific resource type such as wind or solar. Oregon now has the highest eligibility cap across all resource types of the six states served by the Company. As explained above, both the FERC and Commission rationale for standard avoided cost rates is to minimize the transaction costs associated with negotiating an individualized rate that reflects the operating characteristics of the particular project and the Company's belief is that a 3 MW eligibility cap achieves this rationale.

<u>Issue 5B. What should be the criteria to determine whether a QF is a "single QF" for purposes of eligibility for the standard contract?</u>

Q. Why would a QF developer disaggregate a large project into smaller projects in Oregon?

A. A developer might disaggregate a large project into separate smaller projects under the standard avoided cost eligibility cap because it is economically advantageous to obtain published avoided cost prices. As previously discussed, the standard avoided cost prices do not accurately approximate the avoided cost of a large project because they do not take into account specific characteristics that may reduce the avoided cost associated with the large project. In addition, a QF that is eligible for the standard avoided cost price is also eligible to contract under the standard PPA which has defined and known terms and conditions that were approved by Commission and are more lenient than the non-standard avoided cost contract available in Schedule 38 which has negotiated terms and conditions. The standard PPA is largely not subject to negotiation.

Q. How has FERC defined a "single QF" for purposes of implementing PURPA?

A. In assessing whether a given electric generation facility is a QF, FERC evaluates "the power production capacity of a facility for which qualification is sought, together with the power production capacity of any other small power production facilities that use the same energy resource, are owned by the same person(s) or its affiliates, and are located at the same site."[3] In total these power production capacities must not exceed 80 megawatts.[4] FERC has also established that if a facility is located on the same site as the facility for which qualification is sought then a distance test is applied.[5] The distance test between facilities to determine whether they are considered to be on the same site is based on the distance between electric generating equipment of the respective locations.[6] If the electric generating equipment is within a one mile radius of each other then it is considered to be on the same site.

Q. What are Oregon's criteria for determining multiple QF project eligibility for standard avoided costs?

A. While FERC established the same site criteria at the federal level, FERC also looks to the individual state to implement. In Oregon, Docket No. UM 1129

[3] 18 CFR 292.204(a)(1).
[4] Id.
[5] Id. 292.204(a)(2).
[6] Id.

examined the issue and the parties agreed to a Partial Stipulation[7] in 2006. In Order No. 06-538, the Oregon Commission adopted clarifying language for determining when generating facilities located near each other and using the same motive force should be deemed a single facility for purposes of determining the Facility Capacity Rating which establishes the size threshold for eligibility for Oregon standard avoided cost prices and eligibility for the standard PPA terms and conditions. The clarifying language was contained in the Partial Stipulation. The purpose and intent of the Partial Stipulation was to develop a mechanism that would allow independent family or community-based QF projects the ability to have an exemption from the single site restriction so that these certain types of projects could share common infrastructure and have common passive investors without violating PURPA or state regulations.

Q. Was the Partial Stipulation successful in achieving its intent?

A. No. While the Partial Stipulation provided specific eligibility criteria, those criteria, as it turned out, did not prevent a large (64.5 MW) wind project from devising an ownership structure that technically enabled it to meet the eligibility criteria and therefore receive published rates. After the Partial Stipulation was approved by the Commission, the Company received a request from a developer for nine QF contracts ranging in size from 1.65 MW to 10 MW, totaling 64.5 MW. The projects were not independent family or community-based projects and clearly were a disaggregation of a large single wind project. Under the Partial Stipulation Eligibility Test, projects located at the same site using the same motive force are ineligible for the Oregon standard avoided costs if they are

[7] Attach hereto as Exhibit PAC/202.

owned or controlled by the same or affiliated person(s). In this case, there was a single common owner who owned at least 99 percent of each of the nine projects, which initially disqualified a number of the projects.

Q. How did the nine "projects" qualify for Oregon standard avoided costs on Schedule 37?

A. The Partial Stipulation provides an exception whereby individual projects may still be eligible even if they are owned by the same person. That exception provides:

> 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. (passive investor exception).

After significant due diligence by the Company and a review of the projects' ownership structure with the Commission staff and ODOE, it was agreed that a single majority owner for the nine projects technically met the passive investor exception and therefore could not be denied under the Partial Stipulation for Oregon Schedule 37. As a result, nine QF projects, each less than the 10 MW eligibility cap were built by a single developer who received standard avoided cost prices which were likely higher than the prices it would have otherwise received as a single large QF project due to project specific characteristics adjustments.

Q. Did disaggregation provide other benefits to the developer?

A. Yes. The projects retained the RECs and maximized the total amount of Oregon Business Energy Tax Credits (BETC) by establishing each project individually.

As a result, the RECs associated with the nine projects do not contribute toward the Company's renewable portfolio standard compliance requirements.

Q. What does the Company propose to improve the disaggregation requirements?

A. The Company recommends that the Commission remove the passive investor exception from the Partial Stipulation. The exception should not be generally applicable to all small projects.

Q. Should independent family or community-based projects still have an exemption?

A. Yes. The Commission could modify the current exemption to be a waiver that is applicable *only* for independent family or community-based projects. This would allow these types of projects to share common infrastructure and have common passive investors without violating PURPA or state regulations. To qualify for the independent family or community-based project waiver, the project proponents would simply need to present satisfactory evidence to the Commission Staff. The Commission could then approve the waiver during the consent agenda portion of a public meeting. This process is not expected to be burdensome for Commission Staff as the number of independent family or community-based projects is expected to be small.

Q. What does the Company propose if the Commission desires to retain the passive investor exception?

A. If the Commission seeks to retain the passive investor exception, the Company recommends the Commission direct its Staff to evaluate how to modify the Partial

Stipulation to maintain the intent of allowing only independent family or community-based projects to share common infrastructure and have common passive investors without violating PURPA or state regulations.

Issue 5C. Should the resource technology affect the size of the cap for the standard contract cap or the criteria for determining whether a QF is a "single QF"?

Q. Should the resource technology affect the size of the cap for the standard contract cap or the criteria for determining whether a QF is a "single QF"?

A. Yes. The Company views wind and photovoltaic (PV) solar as the two resource types capable of disaggregating from a large single project into multiple projects that would be eligible for standard avoided cost prices. As noted in my testimony under Issue 5B, 13 of the 14 Oregon wind QF projects are the result of a large wind project developed by a single developer that have been disaggregated into smaller wind QF projects that are less than or equal to 10 MW. While the projects met the Partial Stipulation through a creative ownership and management structure, they all share a single common interconnection and are operationally viewed as a common wind project on the Company's system. If the eligibility cap and additional criteria proposed by the Company were implemented, multiple projects would be more limited.

Q. Do you believe that lowering the eligibility threshold for standard avoided cost prices from 10 MW to 3 MW would stop developers from disaggregating their large projects?

A. In combination with the suggested changes to the Partial Stipulation stated above, it would be much more difficult to disaggregate projects of all resource types for the purpose of qualifying for standard avoided cost prices.

<u>Issue 5D. Can a QF receive Oregon's Renewable avoided cost price if the QF owner will sell the RECs in another state?</u>

Q. Can a QF receive Oregon's Renewable avoided cost price if the QF owner will sell the RECs in another state?

A. Yes. As established in Order No. 11-505, if the QF selects the standard renewable avoided cost price, it retains ownership of the RECs during the resource sufficiency period. The Company is indifferent to the QF's management and disposition of those RECs during the resource sufficiency period and is only responsible to the QF for any administrative service established by WREGIS that the QF acquires from the Company. During that resource sufficiency period, the QF assumes all ownership risk of the RECs including registration of the QF facility with any appropriate agency or program, the qualification and application of those RECS for any mandatory renewable portfolio standard (RPS) or voluntary renewable program, management or accounting of those RECs, and the sales of those RECs to any third parties. Once the resource deficiency period begins, the RECs are transferred to the utility along with the net output of the QF.

<u>Issue 6B. When is there a legally enforceable obligation?</u>

Q. Why is it important to establish criteria for when a legally enforceable obligation arises?

A. FERC has established that PURPA allows a QF to sell to a utility under two commercial scenarios: (1) under a contract (PPA); or (2) through a non-contractual, but binding, legally enforceable obligation.[8] The legally enforceable obligation (LEO) is important in a couple of contexts. First, it acts to prevent the utility from avoiding purchases from a QF by refusing to sign a power purchase agreement with the QF.[9] Second, it acts as a threshold standard a QF must meet in order to qualify to sell to a utility (at a given avoided cost rate). Thus, the LEO acts to protect both the QF and the utility (and ultimately the utility customers that will pay the costs of avoided cost purchases from QFs).

In the Company's experience, QFs have attempted to establish a LEO by several means. In one case the QF simply downloaded a form power purchase agreement from the internet, signed it, and sent it to the Company. In a second case, the QF sent a letter to the Company days before the avoided cost rate was set to change and indicated it is willing and able to enter into a power purchase agreement immediately (with no prior negotiations or discussions). Finally, the QF contacted the Company months before about a potential PPA but failed to take any action. Then, days before a change in avoided cost rates was set to occur, the QF presented the Company with some project information and declared it was ready to sign a PPA. If the utility obtains purchase obligations upon the occurrence of a LEO, more than mere verbal statements about being willing and able to sign a power purchase agreement should be required of the QF to obtain the benefits of a LEO (and the attendant avoided cost rates). The Commission should establish, consistent with the implementing regulations of PURPA as

[8] Cedar Creek Wind , LLC, 137 FERC P 61006, 8 (October 4, 2011).
[9]Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978, 45 Fed. Reg. 12214, 12224, FERC Order No. 69 (February 25, 1980).

promulgated by FERC, criteria a QF must show in order to establish that it has "commit[ed] itself to sell all or part of its electric output to an electric utility" as required by FERC.[10]

Q. When is there a legally enforceable obligation?

A. As an initial matter, this question involves legal considerations and those are not addressed in my testimony. Nonetheless, in the last couple years FERC has issued at least three orders addressing various aspects of establishing a LEO.[11] Those orders have consistently established that "a QF, by committing itself to sell to an electric utility, also commits the electric utility to buy from the QF; these commitments result either in contracts or in non-contractual, but binding, legally enforceable obligations."[12] While FERC has stated that requiring a QF to enter into a power purchase agreement before finding a LEO has arisen is inconsistent with PURPA, FERC has not provided specific criteria a state regulatory commission can consider in establishing when a QF has "committed itself" and thereby created a legally enforceable obligation.[13] In the absence of specific criteria from FERC, the Commission can act, consistent with PURPA and its implementing regulations, to define the criteria for establishing a LEO.[14]

Q. How does the Commission currently address LEOs?

A. Under Oregon law and regulations, a LEO exists for purposes of establishing the

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[10]Cedar Creek Wind, LLC, 137 FERC P 61006, 8 (October 4, 2011).
[11] *See* Cedar Creek Wind, LLC, 137 FERC P 61006 (October 4, 2011); Rainbow Ranch Wind, LLC, 139 FERC P 61,077 (April 30, 2012); and, Murphy Flat Power, LLC, 141 FERC P 61145, (November 20, 2012).
[12] Murphy Flat Power, LLC, 141 FERC P 61145, 5 (November 20, 2012).
[13] *See* Cedar Creek Wind, LLC, 137 FERC P 61006, 7-11 (October 4, 2011).
[14] *Id*. at 9.

applicable avoided cost rate only when a utility and a QF owner have executed a PPA or executed an agreement stating that an LEO has arisen.[15]

Q. What criteria would you recommend the Commission adopt in connection with establishing a legally enforceable obligation?

A. Recognizing recent FERC decisions, the Company recommends that the Commission utilize, at least as pertaining to the Company, Schedule 37 to set criteria for establishing a LEO. Schedule 37 contains a step by step process for negotiating a power purchase agreement, including deadlines by which the utility must respond to various inquiries and submission from the QF. The Company believes that it is reasonable to establish that a LEO has arisen (in other words a QF has committed itself) when the QF approves the final draft power purchase agreement as contemplated in B(5) on page 10 of Schedule 37.

Some may argue that if such a standard were adopted the utility could frustrate the establishment of a LEO by dragging out negotiations or always demanding more information from the QF. This is simply not the case. Schedule 37 contains specific information the Company requires and timelines in which the Company must act. If the Company tries to request information beyond Schedule 37 or fails to act within the timeframes established in tariff the QF can seek relief from the Commission. Specifying the establishment of a LEO within Schedule 37 will allow both the utility and the QF to know the rules of establishing a LEO from the beginning and will create standards that the Commission can review and enforce if either the utility or the QF attempt to frustrate or manipulate the

[15] OAR 860-029-0010 (29). See also OPUC Order No. 09-439 at 6 (holding that a LEO was not formed because the parties had not executed a PPA or otherwise executed an agreement that a LEO existed).

establishment of a LEO. In a similar vein, the standards and procedures in Schedule 38 could be used to establish when a LEO arises for non-standard qualifying facilities.

Failure to adopt criteria that require some affirmative action on the part of the QF places the utility in the position of potentially being required to accept and pay for energy from a QF that the utility has little or no information about. This can present commercial, safety and resource planning issues for the utility. It is hard to imagine the Commission, in other circumstances, finding a contract prudent when the utility entered into that contract without conducting reasonable due diligence. By adopting the criteria already contained in Schedule 37 and Schedule 38 the Company is able to ensure it has information to conduct the minimum due diligence necessary prior to entering into a commercial relationship with a QF and yet does not allow the Company to avoid a power purchase agreement by refusing to execute such an agreement. The Company also acknowledges that there may be individual circumstances that do not squarely fit into the Schedule 37 or Schedule 38 criteria (though the majority will), thus the Commission should always retain the ability to look at the individual facts and circumstances of any QF's claim for a LEO.

Issue 6I. What is the appropriate contract term? What is the appropriate duration for the fixed price portion of the contract?

Q. What is the appropriate term for a QF contract?

A. The Company has found that that the current maximum term length of up to 20 years as described in Order No. 05-584 represents an appropriate balance between a term that allows the QF to secure financing, and the risks that accompany long range power price forecasting. The fundamental objective of the term of a QF contract is to enable eligible QFs to obtain adequate financing but also minimize the possible divergence of the QF contract prices from actual avoided costs. The Company does propose changes to the fixed price portion of the allowed contract term of the power purchase agreement under Schedule 37 and Schedule 38.

Q. What is the appropriate duration for the fixed price portion of the contract?

A. As noted above, a QF may receive a maximum contract term of 20 years. Under Order No. 05-584, the fixed price portion is the initial 15 years of the contract term, with a market price option available for the remaining term of the contract (up to five years).[16] The Company proposes that the initial fixed price portion of the contract term be reduced to 10 years and any additional years beyond the initial 10 years are at the market price option.

Q. Why is 10 years appropriate for the fixed price portion of the contract?

A. The Company believes that a 20 year contract containing the initial 10 years of fixed avoided cost prices is sufficient to secure financing. Having that balance in place between fixed and market prices provides the QF with certainty in the early years while aligning future QF contract prices with prices closer to actual avoided costs. Having short term contracts has not deterred the QF from securing financing, at least based on the Company's experience. Since Order No. 05-084, the Company has executed standard PPAs with 38 new construction QF projects totaling 195.5 MWs. These projects encompass multiple resource types including wind, biomass, biogas, cogeneration, hydro, and geothermal. All of those projects

[16] Order No. 05-584 at 20.

are commercially operating or are under construction except for one PPA that was terminated for default unrelated to financing. A large percentage of those new construct QF projects chose shorter term contracts. Forty-three percent elected terms of 15 years or less. Of those selecting terms 15 years or less, half chose terms of 10 years or less. In fact, two selected the Electric Market Option for full term of their contract of 10 years or less. Thus, a 20-year term with a 10-year fixed price period is adequate to secure financing. Because of the dynamics of energy prices in the utility industry, the longer the fixed price component of the contract term, the greater the risk to the Company and customers of incurring an uneconomic PPA. Furthermore, once the term of a QF's contract expires, they may choose to continue to make sales to the utility (if the PURPA obligation to purchase is still in-place) or sell to third parties, which would allow the QF the opportunity to continue to recover its investment if the plant is operational. The contract term does not limit the period of time in which a QF may recover its investment, it merely limits the time period for which fixed pricing is based on a snapshot projection of avoided costs.

Q. Does this conclude your direct testimony?

A. Yes.

Docket No. UM-1610
Exhibit PAC/201
Witness: Bruce W. Griswold

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Bruce W. Griswold

February 2013

Qualifying Facility ("QF") Eligibility for Standard Avoided Cost Prices and Contracts

State	MW Cap for Standard Avoided Cost Prices [1]
California	0.1 MW
Idaho	0.1 MW nameplate – Wind and solar 10 average MW output
Oregon	10 MW
Utah	1MW for cogeneration 3 MW for other small power production (wind, solar, biogas, etc.)
Washington	2 MW
Wyoming	1 MW (at or below 70% capacity factor) 10 MW (above 70% capacity factor)

[1] Nameplate Capacity Rating unless noted.

Docket No. UM-1610
Exhibit PAC/202
Witness: Bruce W. Griswold

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Bruce W. Griswold

February 2013

HARDY MYERS
Attorney General

PETER D. SHEPHERD
Deputy Attorney General

DEPARTMENT OF JUSTICE
GENERAL COUNSEL DIVISION

February 6, 2006

VIA ELECTRONIC MAIL AND HAND DELIVERY

Public Utility Commission of Oregon
Attention: Filing Center
550 Capitol Street NE, #215
P.O. Box 2148
Salem, OR 97308-2148
Puc.filingcenter@state.or.us

Re: *In the Matter of Public Utility Commission of Oregon Staff's Investigation Relating to Electric Utility Purchases from Qualifying Facilities*
OPUC Docket No. UM 1129
DOJ File No. 330-020-GN0041-04

Enclosed for filing are originals and five copies of Oregon Department of Energy's Motion to Admit Partial Stipulation, Partial Stipulation with attachment, and certificate of service in the above-captioned matter.

Sincerely,

/s/ *Janet L. Prewitt*

Janet L. Prewitt
Assistant Attorney General
Natural Resources Section

Enclosures

c: Phil Carver, ODOE (email only)
Jeff Keto, ODOE (email only)
UM 1129 Service List

JLP:jrs/GENP1683

BEFORE THE PUBLIC UTILITY COMMISSION

OF OREGON

UM 1129

In the Matter of the PUBLIC UTILITY COMMISSION OF OREGON Staff's Investigation Relating to Electric Utility Purchases from Qualifying Facilities	**OREGON DEPARTMENT OF ENERGY'S MOTION TO ADMIT PARTIAL STIPULATION**

The Oregon Department of Energy ("ODOE") moves to admit the Partial Stipulation resolving Issue Number 4 in the Issues List for Track I, as set forth in Appendix A of the Correct Ruling issued herein on November 29 2005.

Current parties to this stipulation are Idaho Power Company ("Idaho Power"), PacifiCorp, Portland General Electric, the Staff of the Public Utility Commission of Oregon ("Staff"), Sherman Count/J.R. Simplot ("Sherman County/Simplot"), and ODOE. Industrial Customer of Northwest Utilities ("ICNU") has indicated that it neither opposes nor supports the stipulation. The partial stipulation is available to any other parties to the docket, who may participate by signing and filing a copy of the Partial Stipulation.

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Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 947-4500 / Fax: (503) 378-3802

This stipulation is supported by the Rebuttal Testimony of Carel Dewinkel, ODOE Exhibit No. 8 and the statement made during the cross examination on February 2, 2006 by Staff witness Lisa Schwartz.

Dated this 6th day of February, 2006.

Respectfully submitted,

HARDY MYERS
Attorney General

/s/ *Janet L. Prewitt*

____
Janet L. Prewitt, #85307
Assistant Attorney Generals
Of Attorneys for Oregon
Department of Energy

Department of Justice
1162 Court Street NE
Salem, OR 97301-4096
(503) 947-4500 / Fax: (503) 378-3802

CERTIFICATE OF SERVICE

I hereby certify that on the 6th day of February, 2006, I served the foregoing MOTION TO ADMIT PARTIAL STIPULATION and PARTIAL STIPULATION upon the persons named on the attached UM 1129 service list by electronic mail and by mailing a full, true and correct copy thereof addressed to the persons at the addresses on the UM 1129 service list (with the exception of those parties who have waived paper service).

Dated: February 6, 2006

/s/ *Janet L. Prewitt*
____
Janet L. Prewitt, #85307
Assistant Attorney General

UM 1129 SERVICE LIST

SARAH J ADAMS LIEN STOEL RIVES LLP 900 SW FIFTH AVE - STE 2600 PORTLAND OR 97204-1268 sjadamslien@stoel.com	MARK ALBERT VULCAN POWER COMPANY 1183 NW WALL ST STE G BEND OR 97701 malbert@vulcanpower.com
RANDY ALLPHIN IDAHO POWER COMPANY PO BOX 70 BOISE ID 83707-0070 rallphin@idahopower.com	MICK BARANKO DOUGLAS COUNTY FOREST PRODUCTS PO BOX 848 WINCHESTER OR 97495 mick@dcfp.com
R THOMAS BEACH **-- CONFIDENTIAL** CROSSBORDER ENERGY 2560 NINTH ST - STE 316 BERKELEY CA 94710 tomb@crossborderenergy.com	LAURA BEANE PACIFICORP 825 MULTNOMAH STE 800 PORTLAND OR 97232-2153 laura.beane@pacificorp.com
KARL BOKENKAMP IDAHO POWER COMPANY PO BOX 70 BOISE ID 83707-0070 kbokenkamp@idahopower.com	LOWREY R BROWN CITIZENS' UTILITY BOARD OF OREGON 610 SW BROADWAY - STE 308 PORTLAND OR 97205 lowrey@oregoncub.org
JOANNE M BUTLER IDAHO POWER COMPANY PO BOX 70 BOISE ID 83707-0070 jbutler@idahopower.com	BRIAN COLE SYMBIOTICS, LLC PO BOX 1088 BAKER CITY OR 97814 bc@orbisgroup.org
BRUCE CRAIG ASCENTERGY CORP 440 BENMAR DR STE 2230 HOUSTON TX 77060 bcraig@asc-co.com	RANDY CROCKET D R JOHNSON LUMBER COMPANY PO BOX 66 RIDDLE OR 97469 randyc@drjlumber.com
CHRIS CROWLEY COLUMBIA ENERGY PARTNERS 100 E 19TH STE 400 VANCOUVER WA 98663 ccrowley@columbiaep.com	DATA REQUEST RESPONSE CENTER PACIFICORP 825 NE MULTNOMAH - STE 800 PORTLAND OR 97232 datarequest@pacificorp.com
CAREL DE WINKEL OREGON DEPARTMENT OF ENERGY 625 MARION STREET NE SALEM OR 97301 carel.dewinkel@state.or.us	CRAIG DEHART MIDDLEFORK IRRIGATION DISTRICT PO BOX 291 PARKDALE OR 97041 mfidcraig@hoodriverelectric.net

ELIZABETH DICKSON HURLEY, LYNCH & RE, PC 747 SW MILLVIEW WAY BEND OR 97702 eadickson@hlr-law.com	JASON EISDORFER CITIZENS' UTILITY BOARD OF OREGON 610 SW BROADWAY STE 308 PORTLAND OR 97205 jason@oregoncub.org
JOHN M ERIKSSON STOEL RIVES LLP 900 SW FIFTH AVE - STE 2600 PORTLAND OR 97204-1268 jmeriksson@stoel.com	RANDALL J FALKENBERG **-- CONFIDENTIAL** RFI CONSULTING INC PMB 362 8351 ROSWELL RD ATLANTA GA 30350 consultrfi@aol.com
JOHN R GALE IDAHO POWER COMPANY PO BOX 70 BOISE ID 83707-0070 rgale@idahopower.com	J RICHARD GEORGE **-- CONFIDENTIAL** PORTLAND GENERAL ELECTRIC COMPANY 121 SW SALMON ST PORTLAND OR 97204 richard.george@pgn.com
THOMAS M GRIM CABLE HUSTON BENEDICT ET AL 1001 SW FIFTH AVE STE 2000 PORTLAND OR 97204-1136 tgrim@chbh.com	DAVID HAWK J R SIMPLOT COMPANY PO BOX 27 BOISE ID 83707 david.hawk@simplot.com
STEVEN C JOHNSON CENTRAL OREGON IRRIGATION DISTRICT 2598 NORTH HIGHWAY 97 REDMOND OR 97756 stevej@coid.org	BARTON L KLINE IDAHO POWER COMPANY PO BOX 70 BOISE ID 83707-0070 bkline@idahopower.com
ALAN MEYER **-- CONFIDENTIAL** WEYERHAEUSER COMPANY 698 12TH ST - STE 220 SALEM OR 97301-4010 alan.meyer@weyerhaeuser.com	MONICA B MOEN IDAHO POWER COMPANY PO BOX 70 BOISE ID 83707-0070 mmoen@idahopower.com
THOMAS H NELSON THOMAS H NELSON & ASSOCIATES 825 NE MULTNOMAH STE 925 PORTLAND OR 97232 nelson@thnelson.com	LISA F RACKNER ATER WYNNE LLP 222 SW COLUMBIA ST STE 1800 PORTLAND OR 97201-6618 lfr@aterwynne.com
PGE-OPUC FILINGS RATES & REGULATORY AFFAIRS PORTLAND GENERAL ELECTRIC COMPANY 121 SW SALMON ST 1WTC0702 PORTLAND OR 97204 pge.opuc.filings@pgn.com	DON READING **-- CONFIDENTIAL** BEN JOHNSON ASSOCIATES 6070 HILL ROAD BOISE ID 83703 dreading@mindspring.com

PETER J RICHARDSON -- **CONFIDENTIAL** RICHARDSON & O'LEARY PO BOX 7218 BOISE ID 83707 peter@richardsonandoleary.com	IRION SANGER -- **CONFIDENTIAL** DAVISON VAN CLEVE 333 SW TAYLOR - STE 400 PORTLAND OR 97204 ias@dvclaw.com
LISA C SCHWARTZ -- **CONFIDENTIAL** PUBLIC UTILITY COMMISSION OF OREGON PO BOX 2148 SALEM OR 97308-2148 lisa.c.schwartz@state.or.us	MARK TALLMAN PACIFICORP 825 MULTNOMAH STE 800 PORTLAND OR 97232-2153 mark.tallman@pacificorp.com
S BRADLEY VAN CLEVE -- **CONFIDENTIAL** DAVISON VAN CLEVE PC 333 SW TAYLOR - STE 400 PORTLAND OR 97204 mail@dvclaw.com	MICHAEL T WEIRICH -- **CONFIDENTIAL** DEPARTMENT OF JUSTICE REGULATED UTILITY & BUSINESS SECTION 1162 COURT ST NE SALEM OR 97301-4096 michael.weirich@state.or.us
LINDA K WILLIAMS KAFOURY & MCDOUGAL 10266 SW LANCASTER RD PORTLAND OR 97219-6305 linda@lindawilliams.net	PAUL WOODIN WESTERN WIND POWER 282 LARGENT LN GOLDENDALE WA 98620-3519 pwoodin@gorge.net
TOM YARBOROUGH WEYERHAEUSER MAILSTOP: CH 1K32 PO BOX 9777 FEDERAL WAY WA 98063-9777 bruce.wittmann@weyerhaeuser.com	MICHAEL YOUNGBLOOD IDAHO POWER COMPANY PO BOX 70 BOISE ID 83707 myoungblood@idahopower.com

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UM 1129

In the Matter of Public Utility Commission of Oregon Staff's Investigation Relating to Electric Utility Purchases from Qualifying Facilities.	**PARTIAL STIPULATION**

This Partial Stipulation is entered into for the purpose of resolving a specific issue identified in this docket and does not address issues other than the specifically identified issue.

PARTIES

1. The initial parties to this Partial Stipulation are Idaho Power Company ("Idaho Power"), PacifiCorp, Portland General Electric Company ("PGE"), the Staff of the Public Utility Commission of Oregon ("Staff"), Sherman County Court/J.R. Simplot ("Sherman County/Simplot"), and the Oregon Department of Energy ("ODOE") (together "the Parties"). This Partial Stipulation will be made available to the other parties to this docket, who may participate by signing and filing a copy of this Partial Stipulation.

BACKGROUND

2. On May 13, 2005, the Commission issued Order No. 05-584 in this Docket which specified terms and conditions to be included in standard QF contracts. The order also indicated that a second phase of Docket No. UM 1129 would be opened to address issues that required further evidentiary development.

3. Each of the electric utilities filed avoided costs, revised tariffs and new standard QF contracts on July 12, 2005. On August 2, 2005, the Commission allowed the filings to go into effect, but ordered that an investigation of the filings be undertaken.

4. Phase II of this Docket was divided into tracks, with one track addressing compliance issues and another addressing the issues the Commission identified in Order No. 05-584 to be further investigated. Following the parties' development of proposed issues lists and the filing of comments, a Corrected Ruling was issued November 29, 2005, adopting an Issues List for Track I, as set forth in Appendix A of the Corrected Ruling, and an Issues List for Track II, as set forth in Appendix B of the Corrected Ruling.

5. Issue number 4 in Appendix A ("Issue 4") states:

> "Should the Commission adopt criteria for determining whether multiple energy projects are in fact a single Qualifying Facility to protect the intent of Order No. 05-584, which directs that only projects 10 MW and smaller are eligible for standard avoided cost rates and a standard contract? For example, if a 60 MW wind farm is divided into six 10 MW installments in close proximity to one another, all built in the same calendar year, and with underlying ownership structures containing similar persons or entities, should each installment be eligible for standard rates and standard contracts? What criteria determine when a Qualifying Facility is 10 MW or less and eligible for the standard contract when the project/site has multiple generating units?

6. Pursuant to Administrative Law Judge Kirkpatrick's August 23, 2005 Prehearing Conference Memorandum, a settlement conference on UM 1129 issues was held on November 1, and an additional settlement conference was held on December 13, 2005. The settlement conferences were open to all parties.

7. As a result of the settlement conferences, the Parties have reached agreement on the matters set forth below. The Parties submit this Partial Stipulation to the Commission and request that the Commission approve the settlement as presented.

AGREEMENT

8. The Parties agree that the definitions and terms set forth in Exhibit A, attached hereto and incorporated herein, are fair and reasonable and should be adopted by the Commission as a resolution to Issue 4.

9. The Parties agree that this Partial Stipulation represents a compromise in the positions of the Parties. As such, conduct, statements and documents disclosed in the negotiation of this Partial Stipulation shall not be admissible as evidence in this or any other proceeding.

10. This Partial Stipulation will be offered into the record of this proceeding as evidence pursuant to OAR 860-14-0085. The Parties agree to support this Partial Stipulation throughout this proceeding and any appeal, provide witnesses to sponsor this Partial Stipulation at the hearing and recommend that the Commission issue an order adopting the settlements contained herein.

11. The Parties agree that they will continue to support the Commission's adoption of the terms of this Partial Stipulation. If this Partial Stipulation is challenged by any other party to this proceeding, the Parties agree to cooperate in cross-examination and put on such a case as they deem appropriate to respond fully to the issues presented, which may include raising issues that are incorporated in the settlements embodied in this Partial Stipulation.

12. The Parties have negotiated this Partial Stipulation as an integrated document. If the Commission rejects all or any material portion of this Partial Stipulation or imposes additional material conditions in approving this Partial Stipulation, any party disadvantaged by such action shall have the rights provided in OAR 860-014-0085 and shall be entitled to seek reconsideration or appeal of the Commission's Order.

13. By entering into this Partial Stipulation, no party shall be deemed to have approved, admitted or consented to the facts, principles, methods or theories employed by any other party in arriving at the terms of this Partial Stipulation, other than those specifically identified in the body of this Partial Stipulation, including Exhibit A. No party shall be deemed to have agreed that any provision of this Partial Stipulation is appropriate for resolving issues in any other proceeding, except as previously identified in Paragraph 8 of the Partial Stipulation.

14. This Partial Stipulation may be executed in counterparts and each signed counterpart shall constitute an original document.

This Partial Stipulation is entered into by each party on the date entered below such party's signature.

Signatures follow on next page

IDAHO POWER COMPANY

By: ______________________

Date: January 19, 2006

STAFF

By: ______________________

Date: ______________________

PACIFICORP

By: ______________________

Date: ______________________

ODOE

By: ______________________

Date: ______________________

PORTLAND GENERAL ELECTRIC

By: ______________________

Date: ______________________

SHERMAN COUNTY/SIMPLOT

By: ______________________

Date: ______________________

IDAHO POWER COMPANY	STAFF
By: ______________	By: ______________
Date: ______________	Date: ______________
PACIFICORP	ODOE
By: ______________	By: ______________
Date: 1-18-06	Date: ______________
PORTLAND GENERAL ELECTRIC	SHERMAN COUNTY/SIMPLOT
By: ______________	By: ______________
Date: ______________	Date: ______________

IDAHO POWER COMPANY	STAFF
By:	By:
Date: January 19, 2006	Date:
PACIFICORP	ODOE
By:	By: Janet L. Prewitt
Date:	Date: January 31, 2006
PORTLAND GENERAL ELECTRIC	SHERMAN COUNTY/SIMPLOT
By:	By:
Date:	Date:

IDAHO POWER COMPANY	STAFF
By: [signature]	By: Mike [signature]
Date: January 19, 2006	Date: 1/26/06
PACIFICORP	ODOE
By: ______________	By: ______________
Date: ______________	Date: ______________
PORTLAND GENERAL ELECTRIC	SHERMAN COUNTY/SIMPLOT
By: ______________	By: ______________
Date: ______________	Date: ______________

IDAHO POWER COMPANY

By: ______________________

Date: January 19, 2006

STAFF

By: ______________________

Date: ______________________

PACIFICORP

By: ______________________

Date: ______________________

ODOE

By: ______________________

Date: ______________________

PORTLAND GENERAL ELECTRIC

By: ______________________

Date: 1/31/06

SHERMAN COUNTY/SIMPLOT

By: ______________________

Date: ______________________

IDAHO POWER COMPANY

By: ______________________________

Date: ______________________________

PACIFICORP

By: ______________________________

Date: 1-18-06

PORTLAND GENERAL ELECTRIC

By: ______________________________

Date: ______________________________

STAFF

By: ______________________________

Date: ______________________________

ODOE

By: ______________________________

Date: ______________________________

SHERMAN COUNTY/SIMPLOT

By: ______________________________

Date: 2/2/05

EXHIBIT "A"
TO PARTIAL STIPULATION

Definition of a Small Cogeneration Facility or Small Power Production Facility Eligible to Receive the Standard Rates and Standard Contract:

A Qualifying Facility (either a small power production facility or a cogeneration facility) ("QF") will be eligible to receive the standard rates and standard contract if the nameplate capacity of the QF, 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, does not exceed 10 MW.

Definition of Person(s) or Affiliated Person(s):

As used above, the term "same person(s)" or "affiliated person(s)" means 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. However, 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. Furthermore, 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. A unit of Oregon local government may also be a "passive investor" 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.

Definition of Same Site:

For purposes of the foregoing, 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.

Shared Interconnection and Infrastructure:

QFs otherwise meeting the above-described 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

EXHIBIT "A"
TO PARTIAL STIPULATION

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

Standard Contract Provision

To insure continued compliance with the requirements stated above, the standard contracts shall contain a representation in substantially the following form: "Seller will not make any changes in its ownership, control or management during the term of this Agreement that would cause it to not be in compliance with the *Definition of a Small Cogeneration Facility or Small Power Production Facility Eligible to Receive the Standard Rates and Standard Contract* approved by the Commission at the time this Agreement is executed. Seller will provide, upon request by Buyer not more frequently than every 36 months, such documentation and information as may be reasonably required to establish Seller's continued compliance with such Definition. Buyer agrees to take reasonable steps to maintain the confidentiality of any portion of the above-described documentation and information that the Seller identifies as confidential except Buyer will provide all such confidential information to the Public Utility Commission of Oregon upon the Commission's request."