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April 29, 2013

Via Electronic and Priority Mail

Public Utility Commission of Oregon
Attn: Filing Center
P.O. Box 2148
Salem, OR 97308-2148
puc.filingcenter@state.or.us

Re: OPUC Docket No. UM 1610

Attention Filing Center:

Enclosed for filing in the above-captioned docket are an original and five copies of the *Reply Testimony and Exhibits of Bill Eddie on behalf of OneEnergy, Inc.*

An extra copy of this letter is enclosed. Please date stamp the extra copy and return it to me in the envelope provided.

Thank you in advance for your assistance.

Sincerely,

Ken Kaufmann

Ken Kaufmann
Attorney for OneEnergy, Inc.

cc: UM 1610 Service List

Enclosures

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that, on the 29th day of April 2013, I have caused to be served the foregoing *Reply Testimony and Exhibits of Bill Eddie on behalf of OneEnergy, Inc.* in OPUC Docket No. UM 1610 to those parties listed on the service list attached hereto, all of whom have waived their right to service by mail agreed to accept service by electronic mail at the address provided, below.

DATED this 29th day of April 2013.

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Docket No. UM 1610
Exhibit OneEnergy/200
Witness: Bill Eddie

BEFORE THE PUBLIC UTILITY COMMISSION
OF THE STATE OF OREGON

ONEENERGY, INC.

Reply Testimony of Bill Eddie

April 29, 2013

Table of Contents

I. About the Witness

Q. Please briefly introduce yourself and OneEnergy.

A. My name is Bill Eddie. I am President and one of the founders of OneEnergy, Inc. OneEnergy is a Washington corporation with headquarters in Seattle and an office in Portland. We develop renewable energy projects, and plan to develop solar photovoltaic projects under 5 MW in Oregon. We also provide renewable energy credits ("RECs") to customers around the country, including numerous investor-owned and public utilities in the West.

II. Overview of Reply Testimony

Q. From your perspective, what are the key policies the Commission should consider in this case?

A. The changes to the avoided cost rate framework utilities propose would apply a level of particularity that the Commission rejected in UM 1129 in favor of simplicity. Previously the Commission opted not to take such an approach, recognizing that more granularity did not necessarily mean greater accuracy or efficiency.[1] Staff appears to agree with the utilities that changing to resource-specific capacity values and resource specific integration charges in the standard offer would improve the existing framework. Utilities and staff are correct that there are differences in the predicted value between a megawatt-hour (MWh) generated by a wind project and, for example, a CCCT. However there are offsetting instances where QF energy is

[1] *In the Matter of PUC of Oregon Staff's Investigation Related to Electric Utility Purchases from Qualifying Facilities*, OPUC Docket No. UM 1129, Order No. 05-584, 16 (2005) ("With standard contracts, project characteristics that cause the utility's cost savings to differ from its actual avoided costs are ignored.").

undervalued. For example, the current methodology does not capture the costs a utility must pay to procure a firm fuel supply for the CCCT proxy resource. It does not capture the savings utility customers enjoy from deferral of large investments in new generation attributable to QF purchases (a/k/a "lumpiness"). It does not capture avoided transmission and distribution costs, avoided natural gas fuel price volatility, and avoided CO2 costs, and other savings properly included in the "full avoided cost" of a utility owned resource. If Oregon chooses to move to a high granularity PURPA framework proposed by the utilities, then the utilities' requested refinements to the framework should only be implemented simultaneously with implementation of the refinements raised by the QFs. Until then, the current framework should be retained.

In UM 1610 the Commission should adopt rules necessary to fully implement the Renewable Avoided Cost consistent with its Order No. 11-505. It should also address other gaps raised by the parties including: the need for clarification on the definition of Nameplate Capacity as applied to solar PV QFs; whether QFs should have the option under the standard offer to be curtailable in exchange for a higher contract rate, and whether distributed generation QFs under 3 MW should receive credit for additional benefits they provide to the system.

Q. Has OneEnergy changed its position on any issues since it filed its Response Testimony?

A. Yes. Please refer to Exhibit OneEnergy/214 for a comprehensive list of OneEnergy's positions in the Issues List format with redlines indicating any change to OneEnergy's previously stated position.

III. Global Issues (applicable to all projects using the standard contract system)

Q. Should the Commission change the 10-MW cap for the standard contract? [Issues List 5(A)]

A. No. The 10-MW cap should be retained, but projects under 3 MW which connect at distribution voltage to the purchasing utility should receive 3 benefits in recognition of their unvalued contributions to the system. These projects should receive: (1) an enhanced rate for reducing transmission losses on the system compared to other QFs; (2) a 25-year fixed contract term; and (3) levelized (or partially levelized) prices.

Q. Do you recommend any changes to how the eligibility cap is applied? [Issues List 5(C)]

A. In my opening testimony, I explained why it would be helpful to clarify how the size of a PV solar QF is determined for purposes of determining its eligibility for standard rates and terms. OneEnergy/100, Eddie/9. I did not propose a specific solution in my opening testimony, but I now recommend defining "nameplate capacity" for PV solar QFs as 0.85 times the manufacturer's DC wattage rating of the solar modules. This definition is consistent with Oregon's administrative rules implementing the Solar Pilot Program,[2] and I think this is a reasonable way to clarify the existing ambiguity.

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[2] OAR 860-084-0040. Measurement of Capacity under the Solar Photovoltaic Capacity Standard

(1) The capacity of solar photovoltaic systems used to satisfy the requirements of OAR 860-084-0020 must be measured on the alternating current side of the system's inverter.

(2) Each electric company must convert nameplate capacity ratings reported by manufacturers in terms of direct current watts under standard test conditions to an alternating

Q. If the Commission decides to use resource-specific capacity values in the standard PPA, should resources that agree to be curtailable receive a higher capacity credit than those that do not?

A. Yes.

Q. How does curtailability reduce customer risk?

A. By helping the utility avoid shutting down a thermal unit during periods of excess generation and then not having the thermal unit available to meet the utility's next peak period.

Q. Do utilities already have this right to curtail?

A. No, a QF has the right under PURPA to sell all of its output at all times. I propose that QFs be given the option to agree to a clause in the standard PPA permitting the utility to curtail the QF at any time, provided that the utility pays the QF for the energy (and RECs owned by the QF, if any) the QF would have produced if it had not been curtailed. For QFs selecting this option the right to curtail will be limited to 100 hours per year. This would give the utility another option for balancing its loads and resources. QFs that elect this option should receive a higher capacity credit (and hence be paid a higher rate) than those that do not.

Q. Should the Commission specify what avoided cost factors can be updated in mid-cycle (such as factors including but not limited to gas price or status of production tax credit)? [Issues List 3(C)]

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current rating in watts to account for inverter and other system component losses and to account for the effect of normal operating temperature on solar module output. This conversion will be calculated as 85 percent of the manufacturer's nameplate rating.

A. Yes. Certain inputs are amenable to mid-cycle updates because the updates can be made transparently, without exercise of independent judgment, using data from an independent source. So long as the utilities are merely replacing old input data with updated data from the same external source or sources without changing the methodology or making other subjective changes, a hearing to review the reasonableness of the update is not necessary. I agree with Staff's recommendation (Staff/100, Bless/20) that the utilities be required to file updated gas price forecasts and on-peak and off-peak market price forecasts at the same time each year. I would also include the Production Tax Credit (i.e. whether this Credit exists or not) in mid-cycle updates of the Renewable Avoided Cost. Changes to the Production Tax Credit translate dollar-for-dollar to changes in the renewable avoided cost, and therefore can be updated without a hearing to review the reasonableness of the change.

Q. Do you agree with CREA witness Dr. Don Reading (CREA/200, Reading/25-28) that the value of deferred investments, or "lumpiness", can be quantified? [Issues List 4(C)]

A. Yes. As I also explained in my direct testimony at OneEnergy/100, Eddie/10-15, PacifiCorp has calculated investment deferral benefits from non-dispatchable energy efficiency measures, which it calls Class 2 DSM. CREA cites several peer-reviewed studies that provide alternative formulas for quantifying investment deferral benefits created by the addition of small capacity increments. These studies show that the debate over whether investment deferral benefit can be quantified is settled. Whether or not the formula used by PacifiCorp for Class 2

DSM can be adapted for QFs, it is clear that the investment deferral benefit can be calculated.

Q. Do you have a specific recommendation regarding lumpiness? [Issues List 4(C)]

A. If the Commission chooses to move to a "high granularity" analysis leading to different avoided cost values paid to different types of small QFs, then investment deferral value should be included in the analysis.

Q. Do you agree with ODOE Witness Phil Carver (ODOE/100, Carver/8) that PacifiCorp's proposal to use just the Mid-Columbia (Mid-C) hub to determine market prices during the sufficiency period is appropriate? [Issues List 1(A)(ii)]

A. I question whether Mid-C is the appropriate index for projects selling to PacifiCorp in southern Oregon. Mr. Carver explained in his testimony that "the more local price hub would seem to best represent the costs that would be avoided by purchasing from the QF." ODOE/100, Carver/8. This logic supports the use of the California-Oregon Border (COB) index to price power delivered to the purchasing utility in southern Oregon. Public domain data available from IntercontinentalExchange (ICE) show that its index price for peak hour trades is significantly higher at COB. Exhibit OneEnergy/201 shows the ICE Day Ahead Power Price Report for Mid-C Peak prices and for COB peak prices for every day in 2012 from www.theICE.com and annual average price calculated with Excel. The average peak price at Mid-C was $22.70/MWh whereas the average peak price at COB was $26.96/MWh—a difference of $4.25/MWh, or almost 19%. Recognizing this difference would incentivize QF development in locations where the power is more valuable. I recommend utilities use COB prices rather than Mid-C prices for power delivered to the purchasing utility in southern Oregon—the geographic cutoff to be determined.

Q. How should environmental attributes be defined for purposes of PURPA transactions? [Issues List 2(B)]

A. After the April 2 Settlement Conference, several parties proposed that "Green Tags", as defined in the standard renewable avoided cost power purchase agreement, should not include (1) environmental attributes that are greenhouse gas offsets from methane capture not associated with the generation of electricity and not needed to ensure that there are zero net emissions associated with the generation of electricity, and (2) any other environmental attributes that are not required in order to provide utility with a renewable energy certificate for "qualifying electricity," as that term is defined in Oregon's Renewable Portfolio Standard Act, ORS 469A.010, in effect at the time of execution of the PPA. OneEnergy supports this proposal.

IV. Renewable Avoided Cost Calculation

Q. Have the utilities demonstrated the reasonableness of their proposed renewable avoided cost rates?

A. No. CREA witness Tom Svendsen asserts that PacifiCorp did not include costs for transmission from the Wyoming wind plant to PacifiCorp load (CREA/300, Svendsen/14), and I think he is correct. PacifiCorp's renewable avoided cost appears to omit the incremental transmission costs needed to bring power from the Wyoming wind resource out of a generation bubble. PacifiCorp provided a summary of its calculation of the Wyoming wind facility it has selected as the basis for its renewable avoided cost. In its compliance filing for Commission Order No. 11-505, PacifiCorp explained:

> For the period of resource deficiency, the Company used the capital costs assumed in the 2011 IRP.[3] For example, the total capital cost of the Wyoming wind facility assumes a $/kilowatt ("kW") of $2,239.[4] This capital cost amount, plus fixed operation and maintenance costs are then used to calculate a $/megawatt-hour ("MWh") based on the expected annual capacity factor (35 percent) of the Wyoming wind resource. Lastly, the Company utilized a Mid-C market price weighting to develop an on-and-off peak deficiency period price.

Direct Testimony of Kelcey Brown, PAC/100, Brown/6-7, OPUC Docket No. UM 1396 (Feb. 13, 2012) (footnotes in original). I have attached as Exhibit OneEnergy/202 the Table 6.3 that shows the $2,239/kW figure cited in Ms. Brown's testimony, above. Ms. Brown's testimony does not mention incremental transmission costs of the Wyoming wind resource.

However, pages 128-130 of PacifiCorp's 2011 IRP (attached as OneEnergy/202) explain PacifiCorp's incremental transmission costs. PacifiCorp's IRP explains "Incremental transmission costs are expressed as dollars-per-kW values that are applied to costs of wind resources added in wind-generation-only bubbles."[5] A footnote after that sentence explains further that "Incremental transmission costs also *could have been added directly to the wind capital costs*. However, assigning a cost to a wind generation bubble avoids the need to

[3] *See* PacifiCorp's 2011 IRP, at Page 117, Table 6.3.

[4] *Id.* All figures from the 2011 IRP are reflected in 2010 real dollars. For the applicable start date of the deficiency period (2018) the Company escalated the 2011 IRP capital cost estimates using the official inflation forecast dated December 2011.

[5] PacifiCorp 2011 IRP, Vol. I, p. 128.

individually adjust costs for many wind resources."[6] This footnote appears to recognize that the incremental transmission costs are not included in the $2,239/kW figure in Table 6.3. Table 6.10 gives Wyoming wind capacity costs adjusted to include those incremental transmission costs that were not added directly to the wind capital costs: 3,147 $/kW.[7] I believe this number (which apparently includes costs of transmission necessary to move the new generation out of the Wyoming wind-generation-only bubble) more accurately represents PacifiCorp's avoided cost than does the $2,239/kW figure proposed by PacifiCorp.

Q. Are there other costs that PacifiCorp and PGE have not included in their renewable avoided cost?

A. Yes. Based on Mr. Svendsen's testimony that Balancing Authority curtailments significantly reduce the capacity factor of wind (CREA/300, Svendsen/16). The utility proposing its renewable avoided cost should include and demonstrate a reasonable assumption about the amount of lost generation due to Balancing Authority curtailments.

Q. Are there any others?

A. Yes. I would say that degradation of performance of the renewable proxy resource, and applicable state and local taxes (income tax, sales tax, property tax, excise tax, and tax credits) should be included because they are calculable and are avoided when the utility buys from a QF.

Q. What is your recommended solution?

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[6] *Id.* (emphasis added).

[7] *Id.* at 130

A. One solution would be for the utilities to amend their compliance filings regarding Order No. 11-505 to document and justify the assumptions used to determine their proposed avoided cost rate. This should be done without delay to minimize harm to QF developers waiting for the renewable avoided cost rates to take effect.

V. Non-Renewable (CCCT) Avoided Cost Calculation

Q. In your direct testimony (OneEnergy/100, Eddie/21-31), you presented evidence to show that avoided cost rates fail to account for the significant cost of firming natural gas supply to the CCCT proxy. In addition, CREA (CREA/200, Reading/23-25) and the Oregon Department of Energy (ODOE/100, Carver/8) recommended firm gas transportation costs be included in avoided cost rates. Do you have anything new to add? [Issues List 1(A)(i)]

A. Yes. After additional data requests to the utilities, I continue to be concerned that the current avoided cost framework is sending the wrong price signal because it under-accounts for the fuel firming component of the CCCT proxy particularly given current constraints in regional gas supply. One major source of under-accounting is that all three utilities' methodologies fail to account for the significant upgrades and expansions to trunk gas pipelines forecasted in reports released in 2012 by the Northwest Gas Association ("NGA") and the Bonneville Power Administration ("BPA").[8] As explained in my direct testimony (OneEnergy/100, Eddie/23-24), the reports forecast that the region will need significant upgrades to support additional

[8] Excerpts of the NGA and BPA reports are attached to my direct testimony as Exhibits OneEnergy/103 and OneEnergy/102, respectively.

CCCTs.[9] The second is that the utilities' methodologies inadequately account for modifications to branch pipelines (e.g., addition of laterals, expansions and upgrades of pipeline capacity) needed to provide firm gas supply to CCCTs.

Q. Regarding upgrades and expansions to regional trunk gas pipelines, have the utilities studied the need forecasted by BPA and NGA?

A. No. OneEnergy asked each of the utilities whether it has "studied, forecasted, or projected the potential for gas transport costs to increase due to limited available regional capacity referred to in the BPA and NGA reports and Idaho Power's IRP." All three responded that they had not.[10] PGE suggested that an additional resource may use capacity that PGE stated is available on the GTN pipeline.[11] Idaho Power stated that "[w]ithout knowing exact details of plant size, site location, or service pipeline, Idaho Power would not have the essential details needed to conduct such a study."[12] In the absence a plant-specific study, Idaho Power assumes pipeline transportation costs for additional CCCT units will "approximately double".[13] However, as explained below, the doubling of costs is not reflected in Idaho Power's avoided cost rates.

Q. Regarding upgrades to branch pipelines, do you have additional information regarding the nature and magnitude of the cost of firming the gas supply?

[9] The needed trunk upgrades may be similar in scale to the $3,712,000,000 Ruby Pipeline expansion discussed in my direct testimony (OneEnergy/100, Eddie/24).

[10] Idaho Power Co.'s Response to OneEnergy's Data Request No. 4.2 (attached as Exhibit OneEnergy/203); PGE Response to OneEnergy, Inc. Data Request No. 017 (Renumbered from 4.2) (attached as Exhibit OneEnergy/204); PacifiCorp Response to OneEnergy Data Request 4.2 (attached as Exhibit OneEnergy/205).

[11] PGE Response to OneEnergy, Inc. Data Request No. 017 (OneEnergy/205).

[12] Idaho Power Response to OneEnergy Data Request 4.2 (OneEnergy/203).

[13] *Id*.

A. Yes. I believe the firming costs associated with PacifiCorp's Lake Side 2 CCCT and PGE's contemplated Carty CCCT demonstrate that the costs of local branch pipeline upgrades needed to firm fuel supply are significant. Fixed price demand charges such as these arise from long-term contracts wherein the pipeline company builds out its system and commits to providing firm gas transport capacity to the CCCT. The total monthly fixed price demand charges for incremental firm service to Lake Side 2 is [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL] per month for 30 years.[14] Based on public filings by Gas Transmission Northwest LLC, the cost to PGE for the lateral to provide firm gas transportation to Carty CCCT, if built, would be $10,880,000, $10,516,000, and $10,105,000 in each of the first three years.[15] The Carty gas transportation contract would be for 30 years.[16] As explained, above, these gas firming costs are not currently accounted for in the CCCT proxy avoided cost rates for any of the three utilities except possibly with respect to PGE to the extent these costs are included in PGE's system-average firm gas transportation cost.

Q. Can you further clarify the categories of gas transportation costs that are omitted from current avoided cost calculations?

A. Yes. OneEnergy submitted data requests asking the utilities to identify whether specific categories of gas transportation costs are included in avoided costs. The three utilities use three different methodologies. All three utilities include the

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[14] PacifiCorp Response to OneEnergy Data Requests 3.4, 4.5 (OneEnergy/205).

[15] Gas Transmission Northwest LLC, "Abbreviated Application for Certificate of Public Convenience and Necessity", FERC Docket No. CP12-494-000, Exhibit N (OneEnergy/206).

[16] OneEnergy/100, Eddie/26 n.31. Annual costs after year three are unknown because PGE objected to a data request to state the gas firming costs to the Carty CCCT on the basis of relevancy.

variable fuel transportation costs. PGE includes fixed price demand charges for firm gas transportation, but Idaho Power and PacifiCorp do not.[17] Idaho Power includes, as capital costs, the costs of gas interconnection and lateral, but PacifiCorp do not. PacifiCorp and Idaho Power do not account for the costs of upgrading the gas system (either local pipelines or trunk pipelines) or gas storage costs in avoided cost rates. PGE was unable to confirm whether several categories of gas firming costs are included, instead suggesting that the costs "may be embedded in" a confidential Black & Veatch study.[18]

Q. How does Idaho Power account for firm gas transportation costs in avoided cost rates?

A. Idaho Power assumes that fuel can be purchased at the forecasted market price.[19] This assumption contradicts Idaho Power's IRP, which asserts that "the capacity of the existing gas pipeline system is almost fully allocated."[20] In other words, the CCCT proxy is derived from a resource that does not account for the gas pipeline capacity costs anticipated in the IRP.

Q. How does PacifiCorp account for firm gas transportation costs in avoided cost rates?

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[17] PGE Response to OneEnergy, Inc. Data Request No. 018 (Renumbered from 4.3) (attached as Exhibit OneEnergy/204); PacifiCorp Response to OneEnergy Data Request 4.3 (attached as Exhibit OneEnergy/205); Idaho Power Co.'s Response to OneEnergy's Data Request No. 4.3 (attached as Exhibit OneEnergy/203).

[18] PGE Response to OneEnergy, Inc. Data Request No. 018 (OneEnergy/204).

[19] "In the Oregon Method used to calculate avoided cost rates, it is assumed that natural gas can be purchased at the forecast market price of the fuel. No additional costs are assumed for firming." Idaho Power Response to OneEnergy Data Request 3.5 (OneEnergy/203).

[20] Idaho Power 2011 IRP, p. 46.

A. PacifiCorp acknowledges that it does not include fuel-firming costs in its avoided cost rates. PacifiCorp's avoided cost gas prices are "burner tip" which includes the cost of fuel and variable gas transportation costs.[21] Variable gas transportation costs are distinct from fixed costs emblematic of firm gas supply.[22] In short, the fixed price demand charges triggered by firm transportation service are not included in PacifiCorp's avoided cost rates.

Q. How does PGE account for firm gas transportation costs in avoided cost rates?

A. As noted, above, PGE's avoided cost methodology does include firm gas transportation costs. However, as noted in my direct testimony (OneEnergy/100, Eddie/28), it is apparent that PGE uses its current system-average fixed gas transportation costs, not the incremental fixed gas transportation costs needed to accommodate the next CCCT proxy.

Q. Have your recommendations for addressing potential costs of new gas infrastructure changed from your direct testimony.

A. My recommendations are unchanged from those I made in OneEnergy/100, Eddie/29-30. I wish to emphasize that new evidence, summarized above, shows clearly that avoided cost rates, as currently calculated, fail to account for significant gas transportation costs associated with building a CCCT resource; they fail to account for significant trunk upgrades anticipated by BPA and NWGA; and they fail to adequately account for branch upgrades.

[21] PacifiCorp Response to OneEnergy Data Request 3.5 (OneEnergy/205).

[22] "There are also variable cost obligations that are based on eventual usage of the transportation service subject to rates defined in the Questar Pipeline Company and Questar Gas Company Tariffs." PacifiCorp Response to OneEnergy Data Request 3.4(a) (OneEnergy/205).

I would like to add an observation. Historically, the avoided cost methodology has been based on a generic CCCT plant in no particular location.[23] As the utilities have acknowledged, gas transportation costs depend to a great degree on the location of the gas-fired generator. This is true of many other cost and production inputs, including transmission (on- and off-system), altitude, water rights, wet versus dry cooling, and state taxes. Thus, in order to make a firm gas transportation cost input that is both accurate and subject to meaningful public review, the CCCT proxy may need to be assigned to a specified location.

Q. Does Staff's recommendation to include avoided transmission costs in the calculation of avoided costs inform your proposal to specify the location of the CCCT proxy?

A. Yes. Staff recommended that, if an avoided resource, standard *or* renewable, is off-system, the avoided transmission costs should be included in avoided cost rates. Staff/100, Bless/5. Staff's recommendation cannot be carried out unless the location of the avoided resource is specified. In addition to access to firm gas and transmission, site-dependent factors such as altitude and availability water for cooling can have a significant effect on the $/MWh value of a CCCT. I believe, given these site-dependent variables, the logical solution to setting a transparent avoided cost for an avoided CCCT is to specify its location. This would better facilitate the examination of the reasonableness of the utility's assumptions.

[23] *See, e.g., In the Matter of PUC of Oregon Investigation Into Resource Sufficiency Pursuant to Order No. 06-538*. OPUC Docket No. UM 1396, Order No. 11-505, 4 (2011) ("[T]he CCCT proxy avoided cost calculation can be reduced to basic assumptions regarding capacity, capacity factor, capital costs, and heat rate").

VI. Proposed Changes for Small Distributed Generation

Q. What changes do you propose to aid small distributed generation QFs? [Issues List 4(C)]

A. I proposed in opening testimony that QFs under 3 MW which connect at distribution voltage directly to the purchasing utility ("DG QFs") receive three contract changes. These changes are: (1) pay DG QFs a 3.9% higher rate to account for avoided transmission system losses; (2) allow DG QFs to take up to a 25-year fixed price contract; and (3) allow DG QFs to accept a levelized (or partially levelized) price. The basis of these added options for DG QFs is to improve their finance-ability by accounting for some of the unique benefits they provide.[24] To my knowledge, not one solar QF has yet been constructed using a standard Oregon QF PPA. This will continue to be the case for the foreseeable future unless the Commission enacts changes like the ones I am proposing.

Q. Do you have anything more to say about your proposal in your direct testimony (OneEnergy/100, Eddie/35-37) that DG QFs receive a 3.9% increase to the standard rate to reflect average avoided transmission system losses? [Issues List 4(C)]

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[24] Portland General Electric stated in its 2009 IRP:

> Distributed generation has well-known advantages over central station generation: it provides enhanced localized reliability; it is more efficient because it avoids line losses; for customers who have installed distributed generation, it can provide a hedge against changing power costs; and it can help defer transmission and distribution (T&D) investment.
>
> The benefits are difficult to quantify for IRP purposes. The first is a reliability benefit rather than an economic benefit. Avoided line losses are incorporated into the economics of the portfolio analysis.

PGE 2009 IRP at page 148.

A. Yes. Subsequent to filing opening testimony, OneEnergy asked the utilities whether they had the current capability to model system losses that would be avoided by the installation of a new generator interconnected to the distribution system. Idaho Power responded that it "has the capability to model the change in system losses due to the installation of a new generator connected to the distribution system at a specific location."[25] PGE responded that it can model such losses on an On-peak and Off-peak basis only.[26] PacifiCorp responded that it has two models, FeederAll, and PSS®E, that can model such losses.[27] None of the utilities have yet studied or estimated avoided losses associated with siting small generation at distribution voltages, however.[28]

Q. Do you have any changes to your opening testimony that 3.9% is a reasonable approximation of losses on a utility's transmission system that are avoided by an under-3-MW QF interconnected to the distribution system?

A. Yes. In my opening testimony, I stated that PacifiCorp embraced 3.9% as a reasonable estimate of line losses on the transmission system that are avoided by energy efficiency measures (OneEnergy/100, Eddie/36). I subsequently realized that the 3.9% estimate was actually used by the Northwest Power and Conservation Council as a WECC-wide estimate cited in a PacifiCorp regulatory filing.

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[25] Idaho Power Response to OneEnergy's Data Request 3.1 (attached as Exhibit OneEnergy/207).

[26] PGE Response to OneEnergy Data Request 011 (attached as Exhibit OneEnergy/208).

[27] PacifiCorp Response to OneEnergy PacifiCorp Data Request 4.4 (attached as Exhibit OneEnergy/209).

[28] PGE Response to Energy Data Request 012 (OneEnergy/208); PacifiCorp Response to OneEnergy Data Request 3.3 (OneEnergy/209); Idaho Power Response to OneEnergy Data Request 3.3 (OneEnergy/207).

Q. Do you continue to believe that 3.9% is a reasonable approximation of losses on a utility's transmission system that are avoided by an under-3-MW QF interconnected to the distribution system?

A. Yes. Utilities incur losses in transmitting energy from the generator to the customer. When generation from a distribution-interconnected QF serves load on the same distribution circuit, it is avoiding the portion of system losses otherwise incurred to move energy from a generator interconnected to the transmission system to the distribution circuit where the QF is located. The Northwest Power and Conservation Council estimated this avoided loss at 3.9%. Southern California Edison, in its 2009 General Rate Case application, assumed 4.4%.[29] If the utilities do not agree that 3.9% is reasonable, they have the capability to model avoided losses and seek revision from the Commission, if justified. In the mean time, a 3.9% adjustment for QFs under 3 MW interconnected to the purchasing utility's distribution system would be more accurate than continuing to ignore such avoided losses altogether.

Q. Is a 25-year fixed price for a renewable generator unusual? [Issues List 6(I)]

A. No. PGE and Idaho Power have both signed 25-year PPAs with renewable facilities recently. PGE's recent power purchase agreement with the Outback Solar, LLC has a 25-year term. Idaho Power Company entered 25-year power purchase agreements with the 80-MW Rockland Wind Project in Idaho (achieved operations in 2011) and the 25-megawatt Neal Hot Springs geothermal project in Oregon (operations in 2012). Idaho Power also signed 25-year power purchase

[29] See *A Review of Transmission Losses in Planning Studies*, Staff Report, California Energy Commission, August 2011, p. 22 (http://www.energy.ca.gov/2011publications/CEC-200-2011-009/CEC-200-2011-009.pdf).

agreements with the Interconnect and Grandview solar projects in Idaho, although these projects have not been built.

Q. You also proposed that DG QFs be able to select levelized pricing. What is the core reason you propose levelization?

A. I read Tom Elliot's testimony filed on behalf of ODOE. He explained that the Loan Program relies on the QF's PPA prices to project a QF's ability to repay a loan. ODOE/200, Elliott/5. The current published rate structure presents a significant obstacle to financing a renewable QF because the price paid for energy during the sufficiency period is so low. The low prices paid for the first several years of operation restrict a QF's ability to get financing because the QF will have a very low debt service coverage ratio during that period. Debt service coverage ratio ("DSCR") is a measure for whether a project earns enough money to meet its expenses, including loan payments. A DSCR value of 1 means a project would earn exactly enough cash to make its payments. Most financing entities require a minimum DSCR of 1.25 to 1.5 in order to approve a loan. It is my understanding that ODOE's State Energy Loan Program requires a minimum DSCR of 1.25 to approve a loan.

Q. Staff opposed levelization (Staff/100, Bless/11-12). Does Staff's position change your view?

A. Staff opposed levelization because there is a risk that the utility will over-pay for power in the early contract years, only to have the QF fail at some point in the contract term such that the utility does not capture the savings of levelization in later years. I believe this risk is small, especially if levelization is offered only to DG QFs.

However, it would be fair to address Staff's concern by offering *partial* levelization through a rate structure that escalates at 2% per year. A 2% escalating rate lowers the risk of overpayment while improving financing for the QF. Furthermore, staff is mistaken at Staff/100, Bless/12 that the Commission decided against levelization in Order No. 05-584. Rather, the Commission stated that it had no need to address levelization.[30]

Q. How is a 2% escalating rate different from the current published rate and from a levelized rate?

A. Each of these three rate structures would have one thing in common: they would have the same net present value. A fully levelized rate would have a constant $/MWh amount for each year of the PPA, while a 2% escalating rate would increases at a constant 2% each year of the PPA. Below is a table showing three rate structures applicable to a solar QF starting a 15-year PPA in 2014 using (a) annual average renewable rates proposed by PGE as Schedule No. 211 in UM 1396 (6/7 of hours On Peak, and 1/7 Off Peak); (b) a 2% escalating rate; and (c) a levelized rate:

Year	Published Rate ($/MWh)	2% Escalating Rate ($/MWh)	Levelized Rate ($/MWh)
2014	32.27	76.42	85.67
2015	83.89	77.95	85.67
2016	84.98	79.50	85.67
2017	86.09	81.09	85.67
2018	87.70	82.72	85.67
2019	89.50	84.37	85.67
2020	91.23	86.06	85.67

[30] Order No. 05-584 at 28 n.46 ("As we do not adopt Staff's proposed methodology that would separately value capacity and pay levelized rates, *we need not address the issue of levelization in this Order*." (emphasis added)).

2021	92.95	87.78	85.67
2022	94.66	89.53	85.67
2023	96.48	91.33	85.67
2024	98.47	93.15	85.67
2025	100.47	95.01	85.67
2026	102.74	96.91	85.67
2027	104.67	98.85	85.67
2028	106.56	100.83	85.67
Net Present Value (8% discount rate)	791.91	791.91	791.91

Q. Is there a precedent for such a rate structure in Oregon or other states?

A. [BEGIN CONFIDENTIAL] [redacted] [END CONFIDENTIAL][31]

Other states currently employee levelization for the purpose of making QFs financeable, including Idaho, Utah, Vermont, South Dakota, and Georgia.

Q. Have you prepared a quantitative analysis to show the impact of longer fixed price contract terms?

A. Yes. I analyzed the effects using the National Renewable Energy Laboratory (NREL) System Advisor Model (SAM) version 2013.1.15, downloaded from NREL's website: https://sam.nrel.gov/. The SAM model is broadly used by developers of renewables as a tool to evaluate basic project financial performance. NREL's website describes SAM as follows:

> The System Advisor Model (SAM) is a performance and financial model designed to facilitate decision making for people involved in the renewable energy industry. * * * SAM makes performance predictions and cost of energy estimates for grid-connected power projects based on installation and operating costs and system design parameters that you specify as inputs to the model. Projects can be either on the customer side of the utility meter, buying and selling electricity at retail

[31] PGE Response to OneEnergy Data Request No. 020 (attached as Exhibit OneEnergy/210).

> rates, or on the utility side of the meter, selling electricity at a price negotiated through a power purchase agreement (PPA).

OneEnergy uses it in parallel with our own financial models as a screening tool and to check for errors in our models. Different capital structures or special allocations of cash or other value among different owners cannot be modeled through SAM. However, it is publicly available for no cost, and allows for a sufficient number of inputs to clearly demonstrate the impact of different price structures.

I compared two hypothetical projects that are identical in all respects except for contract length. Project 1 sells its power for a 15-year term at an initial starting price of $75/MWh, plus 2% annual price escalation. Project 2 sells its power for a 25-year term at an initial starting price of $75/MWh, plus 2% annual price escalation. My intent in comparing these two projects is simply to isolate the impact of contract length on project financial performance.

Q. What other assumptions did you make for these projects?

A. I assumed the cost of installation would be $2.12 per watt. I would characterize this as an aggressively low cost in the current market, but potentially achievable for projects being built in late 2013 or early 2014. I assumed the projects borrow 33% of capital cost for a 10-year loan tenor at a rate of 7%. I also assumed the projects received an incentive payment (such as from the Energy Trust of Oregon) equal to $400,000, equivalent to 40 cents per watt. That assumed incentive payment is toward the low end of range of incentives that Energy Trust has provided to other large projects in Oregon (the lowest being 23 cents per watt for the 2.5 megawatt Black Cap solar project).

Q. Overall, do you believe all these assumptions are reasonable?

A. Yes. Arguments could arise over each of these assumptions, as each project is unique. I believe the assumptions I made are reasonably likely to occur for a solar project in Oregon. My intent was to pick reasonable input values and hold them constant for two hypothetical projects, adjusting only contract length for comparison.

Q. What was the outcome of this modeling exercise?

A. The table below summarizes the results. In short, the 25-year contract length had a very strong impact on Internal Rate of Return, boosting it by 3.29 percentage points over the project using a 15-year contract length. It also increased the project's overall net present value by over $100,000. In my experience, differences of that magnitude would be consequential for project financing.

	Project 1: 15 year PPA; $75/MWh + 2% escalation	Project 2: 25 year PPA; $75/MWh + 2% escalation
Project Internal Rate of Return	7.72%	11.01%
Project Net Present Value	-$99,704	$4,775
DSCR with 40% of project capital as debt	1.33	1.33

Q. What performance assurances should be required of QFs receiving levelized or escalated rates?

A. In my opening testimony, I proposed that QFs under 3 MW that meet creditworthiness conditions not be required to post security. OneEnergy/100, Eddie/39-40. I continue to believe that, given the state of solar PV technology in particular, the performance assurances I propose would make the risk to the utilities of a levelized PPA commensurate with that of other risks the utilities take on regularly.

Q. Are you concerned your proposed treatment of DG QFs will unnecessarily complicate the Oregon standard contract system?

A. No. The current standard contract system does not offer just one contract or just one price. The system has worked well despite some existing moderate complexity. The system has worked well despite having: (1) different contract forms for intermittent versus non-intermittent resources; (2) different contract forms for new versus existing QFs; (3) different contract forms for on-system versus off-system QFs; (4) a range of contract terms available (<1 year to 20 years); (5) different pricing options offered (albeit some of those options are unused); (6) different credit requirements for projects over 3 MW versus smaller projects; and (7) a variety of ways for larger projects to meet security requirements. The contract changes I propose are not unduly complex viewed in this context.

Q. Can QFs wait until the end of the sufficiency period to start a project?

A. No. Since the Commission implemented the current avoided cost framework in UM 1129, the sufficiency periods for PGE and PacifiCorp have invariably been just out of reach for many new QFs.[32] The term of sufficiency periods in PGE's and PacifiCorp's new rates have ranged from a low of three years to a high of five years.[33]

Q. Do you believe levelized rates would increase customer rates?

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[32] Until recently, Idaho Power has not had sufficiency periods because it has used a different avoided cost methodology.

[33] PGE Response to REC Data Request No. 022 (attached as Exhibit OneEnergy/212); PacifiCorp Response to OneEnergy Data Request No. 4.6 (attached as Exhibit OneEnergy/213).

A. No. The net present value of the levelized PPA prices is exactly the same as the current published rates, thus the “cost” of the levelized PPA to the utility is no different than the cost of a published rate PPA. The difference is that, with levelized prices, payments are shifted to more efficiently match the QFs finance costs. This shifting of payments would allow QFs to finance projects in proportion to the net present value of the projects without paying QFs more than avoided cost over the term of the contract.

Q. Do you have any other changes to your proposal for distributed generation QFs? [Issues List 1(B)]

A. Yes. In my opening testimony I proposed that QFs under 3 MW should not have to post security in order to elect levelized pricing. Several parties have since expressed concern that this proposal puts utility customers at risk, and I have decided to recommend that rates be only partially levelized in order to reduce overpayment in early years.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

ONEENERGY, INC.

Exhibit Accompanying Reply Testimony of Bill Eddie

IntercontinentalExchange (ICE) Day Ahead Power Price Report for Mid-C Peak prices and for COB Peak prices

TRADE DATE	BEGIN DATE	END DATE	HIGH	LOW	AVG	CHG	VOL (MWH)	# DEALS	# CPART
Mid C Peak									
3-Jan-12	4-Jan-12	4-Jan-12	26.5	25.3	25.89	-1.23	64,400	154	28
4-Jan-12	5-Jan-12	5-Jan-12	25.25	24	24.65	-1.24	62,800	153	30
5-Jan-12	6-Jan-12	7-Jan-12	26.55	25.25	26.09	1.44	106,400	127	26
6-Jan-12	9-Jan-12	9-Jan-12	27.25	25.15	26.36	0.27	66,400	157	27
9-Jan-12	10-Jan-12	10-Jan-12	29	27.25	28.05	1.69	85,200	190	27
10-Jan-12	11-Jan-12	11-Jan-12	29.25	28	28.84	0.79	54,000	135	28
11-Jan-12	12-Jan-12	13-Jan-12	29	27.75	28.51	-0.33	150,400	156	26
12-Jan-12	14-Jan-12	14-Jan-12	26	25	25.54	-2.97	53,600	134	23
13-Jan-12	16-Jan-12	17-Jan-12	29.75	27	28.23	2.69	124,000	147	26
17-Jan-12	18-Jan-12	18-Jan-12	29.5	26.25	27.41	-0.82	64,400	156	30
18-Jan-12	19-Jan-12	19-Jan-12	30	25	27.54	0.13	75,600	171	28
19-Jan-12	20-Jan-12	21-Jan-12	25.75	23.75	25.08	-2.46	115,200	137	25
20-Jan-12	23-Jan-12	23-Jan-12	25	22.25	23.59	-1.49	45,200	109	25
23-Jan-12	24-Jan-12	24-Jan-12	26	22.75	24.57	0.98	45,600	113	26
24-Jan-12	25-Jan-12	25-Jan-12	23.5	22.4	23.22	-1.35	38,400	96	23
25-Jan-12	26-Jan-12	26-Jan-12	24.5	23.25	23.99	0.77	48,400	119	21
26-Jan-12	27-Jan-12	28-Jan-12	25.75	24.75	25.25	1.26	118,400	129	24
27-Jan-12	30-Jan-12	30-Jan-12	24.25	23.75	24.04	-1.21	45,200	113	26
30-Jan-12	31-Jan-12	31-Jan-12	24.75	23.75	24.09	0.05	44,400	108	23
31-Jan-12	1-Feb-12	1-Feb-12	24.5	22.25	23.56	-0.53	54,000	132	30
1-Feb-12	2-Feb-12	2-Feb-12	25.5	23.75	24.94	1.38	52,400	127	27
2-Feb-12	3-Feb-12	4-Feb-12	25.5	23.75	24.19	-0.75	99,200	118	28
3-Feb-12	6-Feb-12	6-Feb-12	25.25	24.5	24.88	0.69	51,200	125	30
6-Feb-12	7-Feb-12	7-Feb-12	25	24	24.34	-0.54	52,400	126	31
7-Feb-12	8-Feb-12	8-Feb-12	26.25	24.75	25.39	1.05	70,000	162	29
8-Feb-12	9-Feb-12	9-Feb-12	25.25	23.75	24.88	-0.51	68,400	167	28
9-Feb-12	10-Feb-12	11-Feb-12	24	22.5	23.51	-1.37	102,400	127	28
10-Feb-12	13-Feb-12	13-Feb-12	25.5	24.25	25.01	1.5	53,200	125	32
13-Feb-12	14-Feb-12	14-Feb-12	24.75	23.5	24.09	-0.92	48,400	112	25
14-Feb-12	15-Feb-12	15-Feb-12	24.5	23.25	23.89	-0.2	50,800	119	27
15-Feb-12	16-Feb-12	17-Feb-12	25.75	23.8	24.2	0.31	84,000	94	25
16-Feb-12	18-Feb-12	18-Feb-12	23	21.5	22.18	-2.02	57,200	133	25
17-Feb-12	20-Feb-12	21-Feb-12	25.25	24.25	24.7	2.52	89,600	108	26
21-Feb-12	22-Feb-12	22-Feb-12	23.75	22.5	23.22	-1.48	54,000	134	30
22-Feb-12	23-Feb-12	23-Feb-12	24.5	22.75	24	0.78	46,800	115	26
23-Feb-12	24-Feb-12	25-Feb-12	24.75	22.75	23.91	-0.09	105,600	127	26
24-Feb-12	27-Feb-12	27-Feb-12	28.75	26.25	27.45	3.54	42,000	102	23
27-Feb-12	28-Feb-12	28-Feb-12	29	27.75	28.3	0.85	26,400	66	24
28-Feb-12	29-Feb-12	29-Feb-12	25.75	24	25.11	-3.19	56,400	134	22
29-Feb-12	1-Mar-12	1-Mar-12	24.5	23	24.09	-1.02	42,800	101	26
1-Mar-12	2-Mar-12	3-Mar-12	22.5	20.75	21.57	-2.52	128,000	135	24
2-Mar-12	5-Mar-12	5-Mar-12	23.5	21.25	22.14	0.57	68,400	156	26
5-Mar-12	6-Mar-12	6-Mar-12	22.5	21.75	22.08	-0.06	43,200	106	27
6-Mar-12	7-Mar-12	7-Mar-12	23.25	22	22.64	0.56	38,400	94	26
7-Mar-12	8-Mar-12	8-Mar-12	21.25	19.65	20.25	-2.39	38,800	91	25
8-Mar-12	9-Mar-12	10-Mar-12	18.5	17.5	17.9	-2.35	132,000	131	26
9-Mar-12	12-Mar-12	12-Mar-12	20	18.25	19.13	1.23	76,800	163	27

Source: ICE DAY AHEAD POWER PRICE REPORT (WWW.THEICE.COM)

TRADE DATE	BEGIN DATE	END DATE	HIGH	LOW	AVG	CHG	VOL (MWH)	# DEALS	# CPART
Mid C Peak									
12-Mar-12	13-Mar-12	13-Mar-12	19.25	18	18.41	-0.72	42,000	91	23
13-Mar-12	14-Mar-12	14-Mar-12	20.75	19.5	19.84	1.43	56,000	129	23
14-Mar-12	15-Mar-12	15-Mar-12	18	16.55	17.7	-2.14	54,000	128	23
15-Mar-12	16-Mar-12	17-Mar-12	17.5	17	17.29	-0.41	95,200	104	25
16-Mar-12	19-Mar-12	19-Mar-12	20.75	18	19.23	1.94	44,000	106	23
19-Mar-12	20-Mar-12	20-Mar-12	18.5	18	18.28	-0.95	60,000	138	27
20-Mar-12	21-Mar-12	21-Mar-12	20.25	18.25	18.66	0.38	90,800	218	25
21-Mar-12	22-Mar-12	22-Mar-12	19.75	17	18.49	-0.17	70,400	154	28
22-Mar-12	23-Mar-12	24-Mar-12	18.25	16	17.62	-0.87	156,000	187	25
23-Mar-12	26-Mar-12	26-Mar-12	18	16	17.18	-0.44	80,800	187	26
26-Mar-12	27-Mar-12	27-Mar-12	19.5	14	17.34	0.16	100,800	217	27
27-Mar-12	28-Mar-12	28-Mar-12	17.5	16.25	17.17	-0.17	88,400	191	24
28-Mar-12	29-Mar-12	29-Mar-12	16	14	15.28	-1.89	101,200	201	28
29-Mar-12	30-Mar-12	31-Mar-12	13.5	7	11.92	-3.36	240,800	240	28
30-Mar-12	2-Apr-12	2-Apr-12	20	13.5	16.32	4.4	58,800	130	28
2-Apr-12	3-Apr-12	3-Apr-12	18.75	16.25	17.56	1.24	46,400	113	27
3-Apr-12	4-Apr-12	5-Apr-12	22	17	18.36	0.8	117,600	134	27
4-Apr-12	6-Apr-12	7-Apr-12	20	16.75	17.9	-0.46	140,000	160	29
5-Apr-12	9-Apr-12	9-Apr-12	20	17.5	18.25	0.35	51,600	115	26
9-Apr-12	10-Apr-12	10-Apr-12	18.25	14.25	17.14	-1.11	76,800	160	27
10-Apr-12	11-Apr-12	11-Apr-12	16.5	14	14.81	-2.33	93,600	210	30
11-Apr-12	12-Apr-12	12-Apr-12	16.75	13.7	15.03	0.22	82,800	186	29
12-Apr-12	13-Apr-12	14-Apr-12	13.25	11	12.52	-2.51	181,600	200	30
13-Apr-12	16-Apr-12	16-Apr-12	15.5	14	15.04	2.52	76,000	169	29
16-Apr-12	17-Apr-12	17-Apr-12	17	15	15.58	0.54	60,400	131	26
17-Apr-12	18-Apr-12	18-Apr-12	17	14	15.19	-0.39	54,400	132	30
18-Apr-12	19-Apr-12	19-Apr-12	18.75	17	18.04	2.85	54,000	126	30
19-Apr-12	20-Apr-12	21-Apr-12	14.5	12.25	13.36	-4.68	196,800	203	31
20-Apr-12	23-Apr-12	23-Apr-12	17	15.25	16.3	2.94	68,800	160	27
23-Apr-12	24-Apr-12	24-Apr-12	16.35	13	15.4	-0.9	62,400	152	28
24-Apr-12	25-Apr-12	25-Apr-12	17.5	14.75	16.4	1	57,600	135	26
25-Apr-12	26-Apr-12	26-Apr-12	14.25	7.75	13	-3.4	94,000	216	29
26-Apr-12	27-Apr-12	28-Apr-12	11	8	9.44	-3.56	146,400	169	28
27-Apr-12	30-Apr-12	30-Apr-12	12	6.75	8.44	-1	92,800	197	28
30-Apr-12	1-May-12	1-May-12	10	1.5	6.21	-2.23	102,000	230	28
1-May-12	2-May-12	2-May-12	11	6.8	8.01	1.8	88,400	203	31
2-May-12	3-May-12	3-May-12	14.5	9	12.45	4.44	71,600	174	26
3-May-12	4-May-12	5-May-12	6.25	3.5	5.13	-7.32	164,800	187	29
4-May-12	7-May-12	7-May-12	15.5	13.25	14.36	9.23	88,400	211	31
7-May-12	8-May-12	8-May-12	16.15	13.5	15.3	0.94	82,400	194	35
8-May-12	9-May-12	9-May-12	11.75	9	9.91	-5.39	79,600	178	25
9-May-12	10-May-12	10-May-12	17.95	16	17.08	7.17	61,200	139	24
10-May-12	11-May-12	12-May-12	18	12.75	13.79	-3.29	152,800	180	24
11-May-12	14-May-12	14-May-12	27	18.1	20.3	6.51	74,400	176	29
14-May-12	15-May-12	15-May-12	18.5	16.75	17.6	-2.7	76,800	182	26
15-May-12	16-May-12	16-May-12	16.5	8	13.8	-3.8	101,600	217	30
16-May-12	17-May-12	17-May-12	11	7.5	9.56	-4.24	64,400	149	28

Source: ICE DAY AHEAD POWER PRICE REPORT (WWW.THEICE.COM)

TRADE DATE	BEGIN DATE	END DATE	HIGH	LOW	AVG	CHG	VOL (MWH)	# DEALS	# CPART
Mid C Peak									
17-May-12	18-May-12	19-May-12	9.25	4	8.1	-1.46	174,400	203	30
18-May-12	21-May-12	21-May-12	14.5	8.75	11.84	3.74	56,000	137	25
21-May-12	22-May-12	22-May-12	10.5	4	6.89	-4.95	76,000	188	27
22-May-12	23-May-12	23-May-12	6	2.5	3.97	-2.92	69,200	173	28
23-May-12	24-May-12	25-May-12	13	7	9.02	5.05	107,200	130	24
24-May-12	26-May-12	26-May-12	5	-0.5	2.47	-6.55	40,000	95	25
25-May-12	29-May-12	29-May-12	18	7	9.98	7.51	72,400	168	28
29-May-12	30-May-12	30-May-12	16.25	12.8	13.83	3.85	56,800	133	30
30-May-12	31-May-12	31-May-12	15.25	12.25	13.98	0.15	41,600	98	26
31-May-12	1-Jun-12	2-Jun-12	13	9.5	10.71	-3.27	100,800	124	29
1-Jun-12	4-Jun-12	4-Jun-12	24.5	17	19.27	8.56	29,600	73	24
4-Jun-12	5-Jun-12	5-Jun-12	7.5	4.75	6.18	-13.09	56,800	136	27
5-Jun-12	6-Jun-12	6-Jun-12	6.75	2.5	4.79	-1.39	64,400	152	28
6-Jun-12	7-Jun-12	7-Jun-12	12	6	9.49	4.7	74,800	168	25
7-Jun-12	8-Jun-12	9-Jun-12	3	-1	0.49	-9	129,600	161	26
8-Jun-12	11-Jun-12	11-Jun-12	14	12	13.23	12.74	77,600	181	28
11-Jun-12	12-Jun-12	12-Jun-12	8.75	6.75	7.36	-5.87	60,000	147	25
12-Jun-12	13-Jun-12	13-Jun-12	4	0	1.69	-5.67	113,600	222	30
13-Jun-12	14-Jun-12	14-Jun-12	7.75	5	6.88	5.19	60,400	149	28
14-Jun-12	15-Jun-12	16-Jun-12	14.25	11	12.21	5.33	172,000	199	22
15-Jun-12	18-Jun-12	18-Jun-12	3.5	0	2.24	-9.97	65,200	157	27
18-Jun-12	19-Jun-12	19-Jun-12	7.5	1.5	4.16	1.92	82,000	191	29
19-Jun-12	20-Jun-12	20-Jun-12	17	13	15.03	10.87	83,600	204	28
20-Jun-12	21-Jun-12	21-Jun-12	22	14.75	17.93	2.9	64,000	148	29
21-Jun-12	22-Jun-12	23-Jun-12	6	0	2.4	-15.53	116,000	137	23
22-Jun-12	25-Jun-12	25-Jun-12	16	10	12.4	10	71,200	175	29
25-Jun-12	26-Jun-12	26-Jun-12	1	0	0.54	-11.86	63,200	155	26
26-Jun-12	27-Jun-12	27-Jun-12	21.5	18	20.29	19.75	79,200	191	27
27-Jun-12	28-Jun-12	28-Jun-12	21	10	14.69	-5.6	73,600	181	28
28-Jun-12	29-Jun-12	30-Jun-12	16	12	13.65	-1.04	162,400	188	28
29-Jun-12	2-Jul-12	2-Jul-12	26	16.5	19.62	5.97	82,800	202	27
2-Jul-12	3-Jul-12	3-Jul-12	10	4.75	6.55	-13.07	106,400	248	27
3-Jul-12	5-Jul-12	5-Jul-12	22.25	19	21.03	14.48	50,800	114	20
5-Jul-12	6-Jul-12	7-Jul-12	24.5	20	21.51	0.48	117,600	147	26
6-Jul-12	9-Jul-12	9-Jul-12	33.5	26	28.49	6.98	65,600	160	27
9-Jul-12	10-Jul-12	10-Jul-12	28	23.75	26.21	-2.28	68,800	171	29
10-Jul-12	11-Jul-12	11-Jul-12	33	25	28.39	2.18	88,000	220	26
11-Jul-12	12-Jul-12	12-Jul-12	37	29	31.37	2.98	86,400	209	30
12-Jul-12	13-Jul-12	14-Jul-12	27	22.25	25.26	-6.11	158,400	196	28
13-Jul-12	16-Jul-12	16-Jul-12	27	21.5	25.15	-0.11	62,000	142	27
16-Jul-12	17-Jul-12	17-Jul-12	25.5	20.25	23.03	-2.12	74,800	176	26
17-Jul-12	18-Jul-12	18-Jul-12	19.25	15	17.62	-5.41	74,400	178	26
18-Jul-12	19-Jul-12	19-Jul-12	23.25	21	22.36	4.74	65,200	159	27
19-Jul-12	20-Jul-12	21-Jul-12	16	12	13.69	-8.67	140,800	170	27
20-Jul-12	23-Jul-12	23-Jul-12	25.5	22	22.77	9.08	76,800	170	30
23-Jul-12	24-Jul-12	24-Jul-12	29.75	26.5	28.56	5.79	54,800	136	22
24-Jul-12	25-Jul-12	25-Jul-12	31.5	28.25	30.43	1.87	64,400	150	22

Source: ICE DAY AHEAD POWER PRICE REPORT (WWW.THEICE.COM)

TRADE DATE	BEGIN DATE	END DATE	HIGH	LOW	AVG	CHG	VOL (MWH)	# DEALS	# CPART
Mid C Peak									
25-Jul-12	26-Jul-12	26-Jul-12	28.5	26.5	27.59	-2.84	38,400	92	19
26-Jul-12	27-Jul-12	28-Jul-12	15.5	1	13	-14.59	87,200	109	22
27-Jul-12	30-Jul-12	30-Jul-12	27.5	23.75	26.22	13.22	50,400	120	23
30-Jul-12	31-Jul-12	31-Jul-12	26.5	23.5	24.64	-1.58	46,400	115	23
31-Jul-12	1-Aug-12	1-Aug-12	26.5	23	25.75	1.11	61,200	144	29
1-Aug-12	2-Aug-12	2-Aug-12	25.55	23.5	24.76	-0.99	41,600	100	27
2-Aug-12	3-Aug-12	4-Aug-12	30.5	26.75	29	4.24	121,600	144	22
3-Aug-12	6-Aug-12	6-Aug-12	29	27	28.12	-0.88	39,200	95	25
6-Aug-12	7-Aug-12	7-Aug-12	37	30.5	33.69	5.57	44,400	109	26
7-Aug-12	8-Aug-12	8-Aug-12	27	23	24.83	-8.86	59,600	148	30
8-Aug-12	9-Aug-12	9-Aug-12	38.75	33.5	36.77	11.94	48,800	119	27
9-Aug-12	10-Aug-12	11-Aug-12	32.5	25	29.72	-7.05	106,400	130	26
10-Aug-12	13-Aug-12	13-Aug-12	29.5	27	28.64	-1.08	44,400	111	26
13-Aug-12	14-Aug-12	14-Aug-12	35	28	33.09	4.45	70,800	176	27
14-Aug-12	15-Aug-12	15-Aug-12	72.75	37	49.85	16.76	68,400	168	24
15-Aug-12	16-Aug-12	16-Aug-12	108	63	84.16	34.31	74,800	183	26
16-Aug-12	17-Aug-12	18-Aug-12	50	38	43.49	-40.67	133,600	165	24
17-Aug-12	20-Aug-12	20-Aug-12	30	27.75	28.46	-15.03	36,400	91	23
20-Aug-12	21-Aug-12	21-Aug-12	23	21.25	22.06	-6.4	45,600	112	24
21-Aug-12	22-Aug-12	22-Aug-12	23.5	21.5	22.25	0.19	49,600	122	26
22-Aug-12	23-Aug-12	23-Aug-12	22.5	20.75	21.51	-0.74	44,400	110	25
23-Aug-12	24-Aug-12	25-Aug-12	24	21.75	22.83	1.32	94,400	115	22
24-Aug-12	27-Aug-12	27-Aug-12	27.5	23.25	24.72	1.89	58,400	145	25
27-Aug-12	28-Aug-12	28-Aug-12	25.5	23	24.35	-0.37	56,800	140	24
28-Aug-12	29-Aug-12	29-Aug-12	25	21	23.84	-0.51	60,000	139	23
29-Aug-12	30-Aug-12	31-Aug-12	31	24.25	25.19	1.35	78,400	98	26
30-Aug-12	1-Sep-12	1-Sep-12	24.5	21	23.13	-2.06	76,000	177	25
31-Aug-12	4-Sep-12	4-Sep-12	31	26	28.31	5.18	40,000	96	21
4-Sep-12	5-Sep-12	5-Sep-12	30	25	27.86	-0.45	56,800	140	27
5-Sep-12	6-Sep-12	6-Sep-12	30	28	28.86	1	61,200	151	21
6-Sep-12	7-Sep-12	8-Sep-12	27.75	24.25	26.19	-2.67	88,000	110	22
7-Sep-12	10-Sep-12	10-Sep-12	23.75	20.75	21.76	-4.43	68,800	164	25
10-Sep-12	11-Sep-12	11-Sep-12	26	24	25.05	3.29	53,600	132	24
11-Sep-12	12-Sep-12	12-Sep-12	27.5	25.75	26.29	1.24	59,200	147	23
12-Sep-12	13-Sep-12	13-Sep-12	32	28.6	29.65	3.36	50,800	127	22
13-Sep-12	14-Sep-12	15-Sep-12	26.75	24.25	25.69	-3.96	93,600	115	27
14-Sep-12	17-Sep-12	17-Sep-12	28.5	24	26.53	0.84	48,000	116	23
17-Sep-12	18-Sep-12	18-Sep-12	27.75	25	26.61	0.08	34,800	87	24
18-Sep-12	19-Sep-12	19-Sep-12	27	25.25	26.15	-0.46	34,800	85	21
19-Sep-12	20-Sep-12	20-Sep-12	26.25	25.1	25.51	-0.64	30,000	74	20
20-Sep-12	21-Sep-12	22-Sep-12	26	22.75	23.74	-1.77	98,400	119	22
21-Sep-12	24-Sep-12	24-Sep-12	25.5	24.25	24.69	0.95	44,400	104	25
24-Sep-12	25-Sep-12	25-Sep-12	24.5	22.5	23.34	-1.35	38,400	88	23
25-Sep-12	26-Sep-12	26-Sep-12	27	24.75	25.42	2.08	48,400	113	23
26-Sep-12	27-Sep-12	28-Sep-12	26.5	24	25.63	0.21	103,200	119	21
27-Sep-12	29-Sep-12	29-Sep-12	25.75	24.75	25.31	-0.32	50,800	114	25
28-Sep-12	1-Oct-12	1-Oct-12	32	28.75	30.95	5.64	60,800	135	23

Source: ICE DAY AHEAD POWER PRICE REPORT (WWW.THEICE.COM)

OneEnergy/201
Eddie/5

TRADE DATE	BEGIN DATE	END DATE	HIGH	LOW	AVG	CHG	VOL (MWH)	# DEALS	# CPART
Mid C Peak									
1-Oct-12	2-Oct-12	2-Oct-12	26.75	24.5	26.09	-4.86	32,800	78	22
2-Oct-12	3-Oct-12	3-Oct-12	27.1	25	26.08	-0.01	54,400	127	26
3-Oct-12	4-Oct-12	4-Oct-12	32	27.5	28.49	2.41	51,200	118	24
4-Oct-12	5-Oct-12	6-Oct-12	29.5	28	28.88	0.39	109,600	132	22
5-Oct-12	8-Oct-12	8-Oct-12	31.5	28.75	30.58	1.7	37,200	85	20
8-Oct-12	9-Oct-12	9-Oct-12	33	30.5	31.2	0.62	45,600	107	24
9-Oct-12	10-Oct-12	10-Oct-12	32.5	31	31.56	0.36	57,200	123	22
10-Oct-12	11-Oct-12	11-Oct-12	34	31.75	32.23	0.67	72,000	177	26
11-Oct-12	12-Oct-12	13-Oct-12	31	27.75	28.96	-3.27	98,400	119	24
12-Oct-12	15-Oct-12	15-Oct-12	37	33.5	34.95	5.99	70,400	172	24
15-Oct-12	16-Oct-12	16-Oct-12	32.5	30.25	31.57	-3.38	75,200	188	30
16-Oct-12	17-Oct-12	17-Oct-12	41.75	37.75	39.79	8.22	57,200	140	27
17-Oct-12	18-Oct-12	18-Oct-12	45	41.75	43.57	3.78	60,800	147	25
18-Oct-12	19-Oct-12	20-Oct-12	34	30.3	32.74	-10.83	107,200	133	24
19-Oct-12	22-Oct-12	22-Oct-12	42	36.25	40.01	7.27	61,600	152	26
22-Oct-12	23-Oct-12	23-Oct-12	37.5	35.25	36.63	-3.38	58,400	139	29
23-Oct-12	24-Oct-12	24-Oct-12	35.5	33.25	34.87	-1.76	66,000	158	25
24-Oct-12	25-Oct-12	25-Oct-12	34.5	33.3	33.92	-0.95	50,000	122	24
25-Oct-12	26-Oct-12	27-Oct-12	35.5	32.5	33.26	-0.66	120,800	146	24
26-Oct-12	29-Oct-12	29-Oct-12	34	32	32.92	-0.34	53,200	127	22
29-Oct-12	30-Oct-12	30-Oct-12	35	32.75	33.61	0.69	47,600	118	24
30-Oct-12	31-Oct-12	31-Oct-12	33.5	28.5	31.22	-2.39	57,600	138	22
31-Oct-12	1-Nov-12	1-Nov-12	30.5	28.5	29.65	-1.57	77,200	189	25
1-Nov-12	2-Nov-12	3-Nov-12	30.5	28.5	29.92	0.27	148,000	174	25
2-Nov-12	5-Nov-12	5-Nov-12	29.25	26	27.91	-2.01	74,400	171	24
5-Nov-12	6-Nov-12	6-Nov-12	30	24.25	25.3	-2.61	73,200	167	24
6-Nov-12	7-Nov-12	7-Nov-12	28.4	26	27.48	2.18	82,000	187	25
7-Nov-12	8-Nov-12	9-Nov-12	32.75	29.5	31.48	4	171,200	206	26
8-Nov-12	10-Nov-12	10-Nov-12	30.25	29	29.75	-1.73	67,200	158	23
9-Nov-12	12-Nov-12	13-Nov-12	30	29.25	29.78	0.03	112,800	138	25
13-Nov-12	14-Nov-12	14-Nov-12	31	29.5	30.03	0.25	72,800	176	23
14-Nov-12	15-Nov-12	15-Nov-12	31.5	29.05	30.61	0.58	71,600	173	25
15-Nov-12	16-Nov-12	17-Nov-12	29.5	28	28.45	-2.16	153,600	178	23
16-Nov-12	19-Nov-12	19-Nov-12	27.5	26.5	27.18	-1.27	68,000	161	23
19-Nov-12	20-Nov-12	21-Nov-12	25.75	24	24.79	-2.39	124,000	148	25
20-Nov-12	23-Nov-12	23-Nov-12	29.5	27	27.69	2.9	72,800	160	25
21-Nov-12	24-Nov-12	26-Nov-12	31	29	29.6	1.91	123,200	153	24
26-Nov-12	27-Nov-12	27-Nov-12	34.25	30.1	30.92	1.32	61,600	153	26
27-Nov-12	28-Nov-12	28-Nov-12	31.25	29.8	30.5	-0.42	71,600	177	25
28-Nov-12	29-Nov-12	30-Nov-12	29.5	28.4	28.67	-1.83	150,400	183	25
29-Nov-12	1-Dec-12	1-Dec-12	26.5	25	25.37	-3.3	80,800	182	27
30-Nov-12	3-Dec-12	3-Dec-12	29.5	27	27.92	2.55	84,800	200	27
3-Dec-12	4-Dec-12	4-Dec-12	28.5	26.5	27.76	-0.16	63,200	141	25
4-Dec-12	5-Dec-12	5-Dec-12	28.5	27	27.86	0.1	79,200	187	26
5-Dec-12	6-Dec-12	6-Dec-12	28	23.5	27.02	-0.84	76,000	170	25
6-Dec-12	7-Dec-12	8-Dec-12	23.25	21.25	22.44	-4.58	159,200	191	23
7-Dec-12	10-Dec-12	10-Dec-12	25.25	21.25	23.45	1.01	74,800	176	25

Source: ICE DAY AHEAD POWER PRICE REPORT (WWW.THEICE.COM)

TRADE DATE	BEGIN DATE	END DATE	HIGH	LOW	AVG	CHG	VOL (MWH)	# DEALS	# CPART
Mid C Peak									
10-Dec-12	11-Dec-12	11-Dec-12	23.75	20.75	22.51	-0.94	92,800	209	26
11-Dec-12	12-Dec-12	12-Dec-12	24.5	23	23.84	1.33	100,800	222	27
12-Dec-12	13-Dec-12	13-Dec-12	28	25.5	26.88	3.04	80,800	182	26
13-Dec-12	14-Dec-12	15-Dec-12	27.75	26.5	27.13	0.25	152,000	171	25
14-Dec-12	17-Dec-12	17-Dec-12	25.75	23.25	24.43	-2.7	76,000	180	25
17-Dec-12	18-Dec-12	18-Dec-12	30	26.5	27.38	2.95	63,600	140	22
18-Dec-12	19-Dec-12	19-Dec-12	30	28.5	29.5	2.12	65,200	158	22
19-Dec-12	20-Dec-12	21-Dec-12	29	26.75	27.94	-1.56	115,200	139	27
20-Dec-12	22-Dec-12	22-Dec-12	27	25.75	26.34	-1.6	52,400	123	24
21-Dec-12	24-Dec-12	26-Dec-12	28	26.5	27.16	0.82	120,800	146	22
26-Dec-12	27-Dec-12	27-Dec-12	28	26.5	27.16	0	58,800	138	24
27-Dec-12	28-Dec-12	29-Dec-12	27	25	26.07	-1.09	132,000	146	23
28-Dec-12	31-Dec-12	31-Dec-12	27.75	26	26.3	0.23	55,600	130	23
31-Dec-12	2-Jan-13	2-Jan-13	29	27.5	28.57	2.27	72,000	175	24

Annual Average ($/MWh)= 22.70

Source: ICE DAY AHEAD POWER PRICE REPORT (WWW.THEICE.COM)

TRADE DATE	BEGIN DATE	END DATE	HIGH	LOW	AVG	CHG	VOL (MWH)	# DEALS	# CPARTIES
COB Peak									
3-Jan-12	4-Jan-12	4-Jan-12	28.25	27	27.51	-0.74	9,200	22	15
4-Jan-12	5-Jan-12	5-Jan-12	27.25	26.75	26.98	-0.53	10,400	26	14
5-Jan-12	6-Jan-12	7-Jan-12	28.5	27	27.48	0.5	14,400	18	11
6-Jan-12	9-Jan-12	9-Jan-12	28	27	27.42	-0.06	9,600	24	12
9-Jan-12	10-Jan-12	10-Jan-12	30.5	29.25	29.85	2.43	8,800	21	10
10-Jan-12	11-Jan-12	11-Jan-12	30.75	30	30.29	0.44	7,200	18	10
11-Jan-12	12-Jan-12	13-Jan-12	30.25	29.05	29.62	-0.67	8,800	10	9
12-Jan-12	14-Jan-12	14-Jan-12	27	26.75	26.78	-2.84	5,200	13	9
13-Jan-12	16-Jan-12	17-Jan-12	29.5	28.75	29.21	2.43	14,400	18	10
17-Jan-12	18-Jan-12	18-Jan-12	30	28.6	29.08	-0.13	4,000	10	8
18-Jan-12	19-Jan-12	19-Jan-12	30.5	28.75	29.45	0.37	6,000	15	8
19-Jan-12	20-Jan-12	21-Jan-12	26.75	25.25	25.75	-3.7	8,000	10	11
20-Jan-12	23-Jan-12	23-Jan-12	26.25	24.75	25.3	-0.45	4,000	10	9
23-Jan-12	24-Jan-12	24-Jan-12	27.65	25.75	26.45	1.15	5,200	13	8
24-Jan-12	25-Jan-12	25-Jan-12	25.75	25.25	25.47	-0.98	9,600	19	19
25-Jan-12	26-Jan-12	26-Jan-12	26	25.5	25.85	0.38	6,000	15	16
26-Jan-12	27-Jan-12	28-Jan-12	27.25	27	27.13	1.28	3,200	4	4
27-Jan-12	30-Jan-12	30-Jan-12	27.5	26.5	27.09	-0.04	8,800	22	16
30-Jan-12	31-Jan-12	31-Jan-12	27.5	27	27.09	0	3,200	7	10
31-Jan-12	1-Feb-12	1-Feb-12	26.75	25.75	26.51	-0.58	6,800	17	16
1-Feb-12	2-Feb-12	2-Feb-12	28.25	27.5	27.93	1.42	5,600	14	14
2-Feb-12	3-Feb-12	4-Feb-12	27.25	26	26.66	-1.27	11,200	14	13
3-Feb-12	6-Feb-12	6-Feb-12	27.5	26.6	26.79	0.13	4,000	10	6
6-Feb-12	7-Feb-12	7-Feb-12	27.25	26.75	26.86	0.07	2,800	7	8
7-Feb-12	8-Feb-12	8-Feb-12	27.75	27.25	27.45	0.59	4,000	10	11
8-Feb-12	9-Feb-12	9-Feb-12	27	26.5	26.75	-0.7	4,400	11	10
9-Feb-12	10-Feb-12	11-Feb-12	25.25	24.75	25	-1.75	7,200	9	7
10-Feb-12	13-Feb-12	13-Feb-12	26.5	25.5	26.2	1.2	5,200	13	11
13-Feb-12	14-Feb-12	14-Feb-12	26	24.9	25.54	-0.66	7,600	19	15
14-Feb-12	15-Feb-12	15-Feb-12	26	25.5	25.76	0.22	3,200	8	10
15-Feb-12	16-Feb-12	17-Feb-12	27	26	26.19	0.43	9,600	12	12
16-Feb-12	18-Feb-12	18-Feb-12	24.5	23.5	24.1	-2.09	4,800	12	12
17-Feb-12	20-Feb-12	21-Feb-12	27.2	26.5	26.87	2.77	7,200	9	12
21-Feb-12	22-Feb-12	22-Feb-12	25.25	24.75	25	-1.87	3,600	9	9
22-Feb-12	23-Feb-12	23-Feb-12	26	25	25.63	0.63	7,600	14	12
23-Feb-12	24-Feb-12	25-Feb-12	25.25	24.5	24.91	-0.72	6,400	8	10
24-Feb-12	27-Feb-12	27-Feb-12	29	28.5	28.87	3.96	2,400	6	6
27-Feb-12	28-Feb-12	28-Feb-12	29.5	28.75	29	0.13	2,400	6	6
28-Feb-12	29-Feb-12	29-Feb-12	27	26.25	26.58	-2.42	4,000	10	9
29-Feb-12	1-Mar-12	1-Mar-12	25.25	25	25.06	-1.52	2,000	5	5
1-Mar-12	2-Mar-12	3-Mar-12	23	22.5	22.59	-2.47	15,200	17	9
2-Mar-12	5-Mar-12	5-Mar-12	24.25	23.45	23.67	1.08	8,800	22	11
5-Mar-12	6-Mar-12	6-Mar-12	23.95	23.5	23.55	-0.12	5,600	13	11
6-Mar-12	7-Mar-12	7-Mar-12	24	23.25	23.58	0.03	1,200	3	5
7-Mar-12	8-Mar-12	8-Mar-12	22.5	21.75	22.14	-1.44	6,400	16	12

Source: ICE DAY AHEAD POWER PRICE REPORT (WWW.THEICE.COM)

TRADE DATE	BEGIN DATE	END DATE	HIGH	LOW	AVG	CHG	VOL (MWH)	# DEALS	# CPARTIES
COB Peak									
8-Mar-12	9-Mar-12	10-Mar-12	24	21.75	22.65	0.51	4,000	5	5
9-Mar-12	12-Mar-12	12-Mar-12	21.05	21	21.01	-1.64	2,800	7	6
12-Mar-12	13-Mar-12	13-Mar-12	21.25	20.5	20.89	-0.12	7,200	17	13
13-Mar-12	14-Mar-12	14-Mar-12	22	21	21.53	0.64	8,000	20	11
14-Mar-12	15-Mar-12	15-Mar-12	20.75	20	20.33	-1.2	10,400	23	13
15-Mar-12	16-Mar-12	17-Mar-12	21.25	21	21.07	0.74	5,600	7	7
16-Mar-12	19-Mar-12	19-Mar-12	22.5	21.7	22.08	1.01	2,400	6	6
19-Mar-12	20-Mar-12	20-Mar-12	22	21.25	21.59	-0.49	8,800	22	15
20-Mar-12	21-Mar-12	21-Mar-12	22.25	21.5	21.83	0.24	9,200	23	17
21-Mar-12	22-Mar-12	22-Mar-12	23.25	22.25	22.71	0.88	10,000	25	17
22-Mar-12	23-Mar-12	24-Mar-12	20.5	20	20.3	-2.41	16,000	20	12
23-Mar-12	26-Mar-12	26-Mar-12	21	20.25	20.64	0.34	10,800	25	15
26-Mar-12	27-Mar-12	27-Mar-12	20	19	19.45	-1.19	4,400	11	11
27-Mar-12	28-Mar-12	28-Mar-12	20.25	19.25	20.06	0.61	10,400	25	13
28-Mar-12	29-Mar-12	29-Mar-12	21	18.5	19.43	-0.63	8,400	21	14
29-Mar-12	30-Mar-12	31-Mar-12	16	14.5	15.12	-4.31	22,400	28	12
30-Mar-12	2-Apr-12	2-Apr-12	23	18.75	21.32	6.2	2,800	7	6
2-Apr-12	3-Apr-12	3-Apr-12	22.75	20	22.01	0.69	7,600	16	10
3-Apr-12	4-Apr-12	5-Apr-12	23	21.5	22.24	0.23	13,600	17	12
4-Apr-12	6-Apr-12	7-Apr-12	21.25	20	20.88	-1.36	8,000	10	11
5-Apr-12	9-Apr-12	9-Apr-12	22	19.5	21.13	0.25	6,400	16	13
9-Apr-12	10-Apr-12	10-Apr-12	21.5	19	20.72	-0.41	4,000	9	12
10-Apr-12	11-Apr-12	11-Apr-12	18.25	16.25	17.61	-3.11	3,600	9	10
11-Apr-12	12-Apr-12	12-Apr-12	17.75	16.25	17.18	-0.43	5,600	14	9
12-Apr-12	13-Apr-12	14-Apr-12	15	13	13.52	-3.66	14,400	18	10
13-Apr-12	16-Apr-12	16-Apr-12	18	16.25	17.38	3.86	6,000	15	10
16-Apr-12	17-Apr-12	17-Apr-12	18	16.5	16.77	-0.61	10,400	18	11
17-Apr-12	18-Apr-12	18-Apr-12	18.5	17.5	17.95	1.18	6,000	13	10
18-Apr-12	19-Apr-12	19-Apr-12	20.5	19.75	20.33	2.38	6,000	15	12
19-Apr-12	20-Apr-12	21-Apr-12	16	14.25	14.71	-5.62	16,000	18	8
20-Apr-12	23-Apr-12	23-Apr-12	19.25	18.25	18.87	4.16	6,400	16	10
23-Apr-12	24-Apr-12	24-Apr-12	18	17.5	17.74	-1.13	9,600	23	13
24-Apr-12	25-Apr-12	25-Apr-12	18.5	17	18	0.26	6,000	15	12
25-Apr-12	26-Apr-12	26-Apr-12	16	11	14.93	-3.07	4,400	11	11
26-Apr-12	27-Apr-12	28-Apr-12	13.25	10	12.09	-2.84	13,600	17	11
27-Apr-12	30-Apr-12	30-Apr-12	12.5	10	11.48	-0.61	9,200	23	11
30-Apr-12	1-May-12	1-May-12	12.25	9.5	11.05	-0.43	12,400	28	12
1-May-12	2-May-12	2-May-12	16.5	11.5	12.25	1.2	8,800	20	11
2-May-12	3-May-12	3-May-12	18.25	17	17.16	4.91	8,800	21	12
3-May-12	4-May-12	5-May-12	10.75	9	9.65	-7.51	20,800	23	13
4-May-12	7-May-12	7-May-12	19.25	18.25	18.61	8.96	9,600	20	13
7-May-12	8-May-12	8-May-12	20.5	18.5	19.8	1.19	12,000	22	13
8-May-12	9-May-12	9-May-12	18.25	16.5	16.98	-2.82	12,800	32	15
9-May-12	10-May-12	10-May-12	24	19.75	22.58	5.6	14,800	29	13
10-May-12	11-May-12	12-May-12	18.75	18	18.45	-4.13	23,200	26	11

Source: ICE DAY AHEAD POWER PRICE REPORT (WWW.THEICE.COM)

TRADE DATE	BEGIN DATE	END DATE	HIGH	LOW	AVG	CHG	VOL (MWH)	# DEALS	# CPARTIES
COB Peak									
11-May-12	14-May-12	14-May-12	29.5	24.75	26.53	8.08	8,800	18	13
14-May-12	15-May-12	15-May-12	25.5	22.5	25.03	-1.5	10,000	18	13
15-May-12	16-May-12	16-May-12	22	16.25	19.58	-5.45	18,000	44	14
16-May-12	17-May-12	17-May-12	17.5	15	16.68	-2.9	12,000	26	13
17-May-12	18-May-12	19-May-12	14	12	13.59	-3.09	28,000	32	16
18-May-12	21-May-12	21-May-12	17.75	15	16.16	2.57	8,800	21	9
21-May-12	22-May-12	22-May-12	16	12	13.36	-2.8	8,000	18	13
22-May-12	23-May-12	23-May-12	18	12.25	16.54	3.18	7,200	18	14
23-May-12	24-May-12	25-May-12	18.5	17.75	17.94	1.4	28,000	28	12
24-May-12	26-May-12	26-May-12	13	11.5	12.35	-5.59	18,400	45	17
25-May-12	29-May-12	29-May-12	19	17	17.85	5.5	14,400	30	11
29-May-12	30-May-12	30-May-12	21	19.75	20.43	2.58	8,000	20	15
30-May-12	31-May-12	31-May-12	24.2	20	22.35	1.92	11,200	20	15
31-May-12	1-Jun-12	2-Jun-12	22	18.5	20.2	-2.15	25,600	30	16
1-Jun-12	4-Jun-12	4-Jun-12	29	27	28.14	7.94	11,600	27	15
4-Jun-12	5-Jun-12	5-Jun-12	20.5	15	17.39	-10.8	14,400	35	16
5-Jun-12	6-Jun-12	6-Jun-12	16	12.5	14.06	-3.33	17,200	39	16
6-Jun-12	7-Jun-12	7-Jun-12	17	13.25	16.44	2.38	14,400	34	14
7-Jun-12	8-Jun-12	9-Jun-12	7.25	2.5	5.49	-11	32,000	40	15
8-Jun-12	11-Jun-12	11-Jun-12	18.75	17.5	18.54	13.05	12,400	29	13
11-Jun-12	12-Jun-12	12-Jun-12	15.9	15	15.11	-3.43	11,600	25	14
12-Jun-12	13-Jun-12	13-Jun-12	12.5	8.75	10.07	-5.04	11,600	28	14
13-Jun-12	14-Jun-12	14-Jun-12	14.75	13	14.25	4.18	11,600	26	12
14-Jun-12	15-Jun-12	16-Jun-12	19	18	18.34	4.09	29,600	35	14
15-Jun-12	18-Jun-12	18-Jun-12	10.25	8.5	9.15	-9.19	15,600	37	13
18-Jun-12	19-Jun-12	19-Jun-12	10.5	9.5	10.05	0.9	10,800	26	11
19-Jun-12	20-Jun-12	20-Jun-12	22	20.5	21.04	10.99	14,800	37	13
20-Jun-12	21-Jun-12	21-Jun-12	24.5	22.5	22.96	1.92	18,400	43	12
21-Jun-12	22-Jun-12	23-Jun-12	11.75	9.5	10.66	-12.3	35,200	44	16
22-Jun-12	25-Jun-12	25-Jun-12	19	18	18.09	7.43	14,400	36	11
25-Jun-12	26-Jun-12	26-Jun-12	9	8	8.13	-9.96	12,800	30	16
26-Jun-12	27-Jun-12	27-Jun-12	27	24.25	26.02	17.89	20,800	50	15
27-Jun-12	28-Jun-12	28-Jun-12	24.25	20	20.89	-5.13	16,800	39	16
28-Jun-12	29-Jun-12	30-Jun-12	21	18.5	19.55	-1.34	43,200	50	13
29-Jun-12	2-Jul-12	2-Jul-12	29.5	25	27	7.45	8,800	21	12
2-Jul-12	3-Jul-12	3-Jul-12	22	17	19.29	-7.71	10,000	20	15
3-Jul-12	5-Jul-12	5-Jul-12	28	27	27.86	8.57	8,400	20	12
5-Jul-12	6-Jul-12	7-Jul-12	28.5	28.5	28.5	0.64	2,400	3	4
6-Jul-12	9-Jul-12	9-Jul-12	39.5	34	36.85	8.35	4,000	10	13
9-Jul-12	10-Jul-12	10-Jul-12	37	34	35.63	-1.22	7,600	19	13
10-Jul-12	11-Jul-12	11-Jul-12	38.25	35	37.04	1.41	2,800	7	11
11-Jul-12	12-Jul-12	12-Jul-12	43	40	41.85	4.81	5,200	13	13
12-Jul-12	13-Jul-12	14-Jul-12	32.75	31	31.75	-10.1	10,400	13	11
13-Jul-12	16-Jul-12	16-Jul-12	30.25	28.5	29.68	-2.07	2,800	7	10
16-Jul-12	17-Jul-12	17-Jul-12	24.75	24.25	24.5	-5.18	6,000	15	8

Source: ICE DAY AHEAD POWER PRICE REPORT (WWW.THEICE.COM)

TRADE DATE	BEGIN DATE	END DATE	HIGH	LOW	AVG	CHG	VOL (MWH)	# DEALS	# CPARTIES
COB Peak									
17-Jul-12	18-Jul-12	18-Jul-12	23.5	22.5	23.28	-1.22	4,000	10	9
18-Jul-12	19-Jul-12	19-Jul-12	27.75	26	27.09	3.81	5,600	12	7
19-Jul-12	20-Jul-12	21-Jul-12	17.5	17	17.16	-9.93	13,600	16	9
20-Jul-12	23-Jul-12	23-Jul-12	28.5	26.75	27.21	10.05	5,200	13	12
23-Jul-12	24-Jul-12	24-Jul-12	36	35	35.3	8.09	2,000	5	5
24-Jul-12	25-Jul-12	25-Jul-12	32.25	32	32.05	-3.25	2,000	5	7
25-Jul-12	26-Jul-12	26-Jul-12	33.25	33	33.11	1.06	2,800	7	9
26-Jul-12	27-Jul-12	28-Jul-12	25	22.5	23.17	-9.94	9,600	12	9
27-Jul-12	30-Jul-12	30-Jul-12	33	32	32.81	9.64	4,400	11	9
30-Jul-12	31-Jul-12	31-Jul-12	29.5	28.75	29.04	-3.77	4,800	12	11
31-Jul-12	1-Aug-12	1-Aug-12	34	32	33.22	4.18	8,800	20	15
1-Aug-12	2-Aug-12	2-Aug-12	31.25	29.5	30.79	-2.43	10,000	25	14
2-Aug-12	3-Aug-12	4-Aug-12	35.25	32	34.12	3.33	15,200	19	13
3-Aug-12	6-Aug-12	6-Aug-12	33	28.75	31.99	-2.13	7,200	18	13
6-Aug-12	7-Aug-12	7-Aug-12	41	38.5	39.62	7.63	7,600	19	12
7-Aug-12	8-Aug-12	8-Aug-12	40	30	33.33	-6.29	4,800	12	11
8-Aug-12	9-Aug-12	9-Aug-12	48	42	44.92	11.59	6,400	16	14
9-Aug-12	10-Aug-12	11-Aug-12	41	36.5	38.85	-6.07	10,400	13	14
10-Aug-12	13-Aug-12	13-Aug-12	45.5	41	43.33	4.48	9,200	22	13
13-Aug-12	14-Aug-12	14-Aug-12	43	39	42.22	-1.11	7,600	19	13
14-Aug-12	15-Aug-12	15-Aug-12	76	47	64.02	21.8	5,200	13	13
15-Aug-12	16-Aug-12	16-Aug-12	135	80	101.29	37.27	6,800	17	12
16-Aug-12	17-Aug-12	18-Aug-12	54	44.25	48.73	-52.6	10,400	13	12
17-Aug-12	20-Aug-12	20-Aug-12	35	33.5	34.36	-14.4	6,400	16	12
20-Aug-12	21-Aug-12	21-Aug-12	25.75	25	25.14	-9.22	3,600	9	12
21-Aug-12	22-Aug-12	22-Aug-12	27.5	25.75	27.05	1.91	4,000	10	10
22-Aug-12	23-Aug-12	23-Aug-12	26	24.25	24.87	-2.18	5,200	13	12
23-Aug-12	24-Aug-12	25-Aug-12	26	24	24.85	-0.02	10,400	13	11
24-Aug-12	27-Aug-12	27-Aug-12	37	29	32.45	7.6	4,400	11	9
27-Aug-12	28-Aug-12	28-Aug-12	42.5	36	39.1	6.65	6,000	15	8
28-Aug-12	29-Aug-12	29-Aug-12	35.5	29.5	33.78	-5.32	4,000	10	9
29-Aug-12	30-Aug-12	31-Aug-12	32	29	30.27	-3.51	10,400	13	11
30-Aug-12	1-Sep-12	1-Sep-12	27.5	24.25	25.5	-4.77	5,600	14	9
31-Aug-12	4-Sep-12	4-Sep-12	32	28.75	30.07	4.57	8,800	22	11
4-Sep-12	5-Sep-12	5-Sep-12	35	33.5	34.04	3.97	9,200	23	13
5-Sep-12	6-Sep-12	6-Sep-12	34	30.25	32.42	-1.62	6,400	16	9
6-Sep-12	7-Sep-12	8-Sep-12	27	26.5	26.75	-5.67	1,600	2	2
7-Sep-12	10-Sep-12	10-Sep-12	27.5	26.25	27.25	0.5	2,400	6	7
10-Sep-12	11-Sep-12	11-Sep-12	28.25	27	28.08	0.83	6,400	16	10
11-Sep-12	12-Sep-12	12-Sep-12	29.75	29	29.34	1.26	4,400	11	8
12-Sep-12	13-Sep-12	13-Sep-12	33.25	33	33.01	3.67	8,000	19	9
13-Sep-12	14-Sep-12	15-Sep-12	33	31	32.33	-0.68	16,000	20	12
14-Sep-12	17-Sep-12	17-Sep-12	37	35	35.54	3.21	5,200	13	12
17-Sep-12	18-Sep-12	18-Sep-12	35	33.5	34.38	-1.16	6,400	16	12
18-Sep-12	19-Sep-12	19-Sep-12	33.5	30.5	31.66	-2.72	7,600	19	12

Source: ICE DAY AHEAD POWER PRICE REPORT (WWW.THEICE.COM)

TRADE DATE	BEGIN DATE	END DATE	HIGH	LOW	AVG	CHG	VOL (MWH)	# DEALS	# CPARTIES
COB Peak									
19-Sep-12	20-Sep-12	20-Sep-12	32	29.75	30.5	-1.16	4,800	12	11
20-Sep-12	21-Sep-12	22-Sep-12	28.75	28	28.45	-2.05	12,800	15	13
21-Sep-12	24-Sep-12	24-Sep-12	30.75	30	30.46	2.01	7,600	19	13
24-Sep-12	25-Sep-12	25-Sep-12	34	31	32.14	1.68	4,800	12	10
25-Sep-12	26-Sep-12	26-Sep-12	34	32.4	33.25	1.11	7,200	18	13
26-Sep-12	27-Sep-12	28-Sep-12	32.5	30	31.55	-1.7	15,200	19	13
27-Sep-12	29-Sep-12	29-Sep-12	30.5	29.25	29.94	-1.61	7,200	18	14
28-Sep-12	1-Oct-12	1-Oct-12	38	36.5	37.65	7.71	6,000	15	13
1-Oct-12	2-Oct-12	2-Oct-12	31	28.75	30.12	-7.53	5,200	13	10
2-Oct-12	3-Oct-12	3-Oct-12	30.1	28	28.76	-1.36	6,400	16	13
3-Oct-12	4-Oct-12	4-Oct-12	33	31.75	32.2	3.44	6,000	15	11
4-Oct-12	5-Oct-12	6-Oct-12	32.5	30.75	31.97	-0.23	8,800	10	11
5-Oct-12	8-Oct-12	8-Oct-12	32.25	31.5	31.81	-0.16	1,600	4	6
8-Oct-12	9-Oct-12	9-Oct-12	35	33	33.4	1.59	6,000	15	13
9-Oct-12	10-Oct-12	10-Oct-12	35.5	35.25	35.38	1.98	800	2	3
10-Oct-12	11-Oct-12	11-Oct-12	34.25	34	34.1	-1.28	1,200	3	5
11-Oct-12	12-Oct-12	13-Oct-12	34	34	34	-0.1	1,600	2	4
12-Oct-12	15-Oct-12	15-Oct-12	40	38	38.81	4.81	3,200	8	5
15-Oct-12	16-Oct-12	16-Oct-12	35.75	34.5	34.88	-3.93	3,200	8	9
16-Oct-12	17-Oct-12	17-Oct-12	42.75	41	42	7.12	2,400	6	7
17-Oct-12	18-Oct-12	18-Oct-12	46.25	45.5	46.12	4.12	6,000	15	13
18-Oct-12	19-Oct-12	20-Oct-12	34.25	33.25	33.75	-12.4	2,400	3	5
19-Oct-12	22-Oct-12	22-Oct-12	41.5	38	39.58	5.83	2,400	6	8
22-Oct-12	23-Oct-12	23-Oct-12	38	37	37.21	-2.37	8,800	19	12
23-Oct-12	24-Oct-12	24-Oct-12	35.75	35	35.43	-1.78	8,800	18	15
24-Oct-12	25-Oct-12	25-Oct-12	35.5	34.75	35.14	-0.29	5,600	12	9
25-Oct-12	26-Oct-12	27-Oct-12	34	33	33.87	-1.27	15,200	19	10
26-Oct-12	29-Oct-12	29-Oct-12	36	34	34.55	0.68	4,400	11	10
29-Oct-12	30-Oct-12	30-Oct-12	37	35.75	36.33	1.78	4,800	12	9
30-Oct-12	31-Oct-12	31-Oct-12	35.75	33.75	34.25	-2.08	7,200	18	13
31-Oct-12	1-Nov-12	1-Nov-12	34.5	33.5	33.83	-0.42	4,800	12	12
1-Nov-12	2-Nov-12	3-Nov-12	35.25	33.5	34	0.17	21,600	27	16
2-Nov-12	5-Nov-12	5-Nov-12	33	31.25	31.95	-2.05	7,600	19	11
5-Nov-12	6-Nov-12	6-Nov-12	30	29.25	29.71	-2.24	5,200	13	10
6-Nov-12	7-Nov-12	7-Nov-12	32	30	30.84	1.13	6,800	17	12
7-Nov-12	8-Nov-12	9-Nov-12	36.25	34.75	35.33	4.49	12,800	16	13
8-Nov-12	10-Nov-12	10-Nov-12	33.95	33.5	33.7	-1.63	7,200	18	12
9-Nov-12	12-Nov-12	13-Nov-12	34.25	33.75	34.11	0.41	14,400	17	13
13-Nov-12	14-Nov-12	14-Nov-12	34.5	34	34.21	0.1	8,000	20	12
14-Nov-12	15-Nov-12	15-Nov-12	35	34.25	34.62	0.41	6,800	17	12
15-Nov-12	16-Nov-12	17-Nov-12	33.95	33.25	33.63	-0.99	10,400	13	10
16-Nov-12	19-Nov-12	19-Nov-12	31.65	30.75	31.03	-2.6	6,000	15	10
19-Nov-12	20-Nov-12	21-Nov-12	29.75	29.25	29.52	-1.51	11,200	12	12
20-Nov-12	23-Nov-12	23-Nov-12	32.5	30.5	31.5	1.98	1,600	4	6
21-Nov-12	24-Nov-12	26-Nov-12	34.75	33.5	34.3	2.8	4,000	5	6

Source: ICE DAY AHEAD POWER PRICE REPORT (WWW.THEICE.COM)

TRADE DATE	BEGIN DATE	END DATE	HIGH	LOW	AVG	CHG	VOL (MWH)	# DEALS	# CPARTIES
COB Peak									
26-Nov-12	27-Nov-12	27-Nov-12	36.25	34	35.12	0.82	5,200	12	10
27-Nov-12	28-Nov-12	28-Nov-12	34	32.5	32.83	-2.29	3,600	9	8
28-Nov-12	29-Nov-12	30-Nov-12	32.85	32	32.4	-0.43	11,200	14	9
29-Nov-12	1-Dec-12	1-Dec-12	30.5	29.5	29.99	-2.41	4,000	10	8
30-Nov-12	3-Dec-12	3-Dec-12	32	31.5	31.83	1.84	1,200	3	5
3-Dec-12	4-Dec-12	4-Dec-12	32	28.5	30.47	-1.36	3,200	6	7
4-Dec-12	5-Dec-12	5-Dec-12	31	29.75	29.99	-0.48	7,200	16	13
5-Dec-12	6-Dec-12	6-Dec-12	29.5	28	28.61	-1.38	8,400	16	13
6-Dec-12	7-Dec-12	8-Dec-12	25	25	25	-3.61	13,600	14	11
7-Dec-12	10-Dec-12	10-Dec-12	25.25	24	24.45	-0.55	6,000	13	10
10-Dec-12	11-Dec-12	11-Dec-12	24.5	24	24.14	-0.31	5,600	11	8
11-Dec-12	12-Dec-12	12-Dec-12	26	25	25.15	1.01	6,800	14	9
12-Dec-12	13-Dec-12	13-Dec-12	29.75	28.75	29.45	4.3	4,400	10	8
13-Dec-12	14-Dec-12	15-Dec-12	30	28.5	29.22	-0.23	12,800	15	10
14-Dec-12	17-Dec-12	17-Dec-12	28	27.25	27.78	-1.44	6,000	14	12
17-Dec-12	18-Dec-12	18-Dec-12	31	30.5	30.55	2.77	4,400	11	5
18-Dec-12	19-Dec-12	19-Dec-12	32.5	31.75	32.06	1.51	3,200	8	7
19-Dec-12	20-Dec-12	21-Dec-12	30.75	30	30.39	-1.67	7,200	9	7
20-Dec-12	22-Dec-12	22-Dec-12	29	29	29	-1.39	800	2	3
21-Dec-12	24-Dec-12	26-Dec-12	30.25	30	30.06	1.06	3,200	4	5
26-Dec-12	27-Dec-12	27-Dec-12	29.5	29	29.34	-0.72	4,400	11	11
27-Dec-12	28-Dec-12	29-Dec-12	27.5	27.25	27.45	-1.89	4,000	5	7
28-Dec-12	31-Dec-12	31-Dec-12	29.5	28	28.32	0.87	6,000	15	11
31-Dec-12	2-Jan-13	2-Jan-13	32.25	29.75	30.33	2.01	2,400	6	7

Annual Average ($/MWh)= 26.96

Source: ICE DAY AHEAD POWER PRICE REPORT (WWW.THEICE.COM)

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ONEENERGY, INC.

Exhibit Accompanying Reply Testimony of Bill Eddie

Pages 117, 128-130 from PacifiCorp's 2011 IRP

Table 6.3 – Total Resource Cost for East Side Supply-Side Resource Options, $0 CO_2 Tax

$0 CO2 Tax Supply Side Resource Options Mid-Calendar Year 2010 Dollars ($) Resource Description	Capital Cost $/kW Total Capital Cost	Payment Factor	Annual Payment ($/kW-Yr)	Fixed Cost Fixed O&M $/kW-Yr O&M	Other	Total	Total Fixed ($/kW-Yr)	Convert to Mills Capacity Factor	Total Fixed (Mills/kWh)	Levelized Fuel ¢/mmBtu	Mills/kWh	Variable Costs (mills/kWh) O&M	Gas Transportation or Wind Integration	Tax Credits	Environmental	Total Resource Cost with PTC (Mills/kWh)	Total Resource Cost without PTC (Mills/kWh)
East Side Resource Options																	
Coal																	
Utah PC without Carbon Capture & Sequestration	$ 3,077	8.18%	$ 251.66	$ 38.80	$ 6.00	$ 44.80	$ 296.46	91%	37.03	254.41	23.17	$ 0.96	-	-	0.00	61.15	
Utah PC with Carbon Capture & Sequestration	$ 5,563	8.02%	$ 445.91	$ 66.07	$ 6.00	$ 72.07	$ 517.98	90%	65.70	254.41	33.29	$ 6.71	-	-	0.00	105.70	
Utah IGCC with Carbon Capture & Sequestration	$ 5,386	7.90%	$ 425.60	$ 53.24	$ 6.00	$ 59.24	$ 484.84	85%	65.11	254.41	27.54	$ 11.28	-	-	0.00	103.93	
Wyoming PC without Carbon Capture & Sequestration	$ 3,484	8.18%	$ 284.95	$ 36.00	$ 6.00	$ 42.00	$ 326.95	91%	40.84	247.56	22.81	$ 1.27	-	-	0.00	64.92	
Wyoming PC with Carbon Capture & Sequestration	$ 6,299	8.02%	$ 504.90	$ 61.37	$ 6.00	$ 67.37	$ 572.27	90%	72.59	247.56	32.78	$ 7.26	-	-	0.00	112.63	
Wyoming IGCC with Carbon Capture & Sequestration	$ 6,099	7.90%	$ 481.91	$ 58.00	$ 6.00	$ 64.00	$ 545.91	85%	73.32	247.56	27.35	$ 13.52	-	-	0.00	114.18	
Existing PC with Carbon Capture & Sequestration (500 MW)	$ 1,383	10.50%	$ 145.16	$ 66.07	$ 6.00	$ 72.07	$ 217.23	90%	27.55	247.56	35.58	$ 6.71	-	-	0.00	69.84	
Natural Gas (4500 feet)																	
Utility Cogeneration	$ 4,250	9.91%	$421.23	$ 1.86	$ 0.50	$ 2.36	$ 423.59	82%	58.97	539.00	26.81	$ 23.29	$ 3.33	-	0.00	112.40	
Fuel Cell - Large (solid oxide fuel cell)	$ 1,593	8.55%	$136.15	$ 8.40	$ 0.50	$ 8.90	$ 145.05	95%	17.43	539.00	39.14	$ 0.03	$ 4.87	-	0.00	61.47	
SCCT Aero	$ 1,000	8.88%	$88.77	$ 9.95	$ 0.50	$ 10.45	$ 99.22	21%	53.94	539.00	52.68	$ 5.63	$ 6.55	-	0.00	118.79	
Intercooled Aero SCCT (Utah, 186 MW)	$ 1,174	8.88%	$104.25	$ 7.01	$ 0.50	$ 7.51	$ 111.76	21%	60.75	539.00	50.55	$ 3.93	$ 6.28	-	0.00	121.52	
Intercooled Aero SCCT (Utah, 279 MW)	$ 1,174	8.88%	$104.25	$ 7.01	$ 0.50	$ 7.51	$ 111.76	21%	60.75	539.00	50.55	$ 3.93	$ 6.28	-	0.00	121.52	
Intercooled Aero SCCT (Wyoming, 257 MW)	$ 1,273	8.88%	$113.04	$ 7.60	$ 0.50	$ 8.10	$ 121.14	21%	65.85	539.00	50.55	$ 4.26	$ 5.46	-	0.00	126.12	
Internal Combustion Engines	$ 1,150	8.88%	$102.11	$ 6.49	$ 0.50	$ 6.99	$ 109.10	21%	59.30	539.00	47.46	$ 5.50	$ 5.90	-	0.00	118.17	
SCCT Frame (2 Frame "F")	$ 991	8.41%	$83.36	$ 5.41	$ 0.50	$ 5.91	$ 89.27	21%	48.53	539.00	56.30	$ 7.16	$ 7.00	-	0.00	118.99	
SCCT Frame (2 Frame "F")	$ 1,074	8.41%	$90.39	$ 5.87	$ 0.50	$ 6.37	$ 96.76	21%	52.60	539.00	56.30	$ 7.76	$ 6.08	-	0.00	122.75	
CCCT (Wet "F" 1x1)	$ 1,181	8.37%	$98.92	$ 13.48	$ 0.50	$ 13.98	$ 112.90	56%	23.01	539.00	39.36	$ 2.98	$ 4.89	-	0.00	70.25	
CCCT Duct Firing (Wet "F" 1x1)	$ 482	8.37%	$40.37	-	$ 0.50	$ 0.50	$ 40.87	16%	29.16	539.00	47.80	$ 0.55	$ 5.94	-	0.00	83.46	
CCCT (Wet "F" 2x1)	$ 1,067	8.37%	$89.34	$ 8.19	$ 0.50	$ 8.69	$ 98.04	56%	19.98	539.00	37.11	$ 2.98	$ 4.61	-	0.00	64.69	
CCCT Duct Firing (Wet "F" 2x1)	$ 538	8.37%	$45.08	-	$ 0.50	$ 0.50	$ 45.58	16%	32.52	539.00	46.79	$ 0.55	$ 5.82	-	0.00	85.68	
CCCT (Dry "F" 2x1)	$ 1,104	8.37%	$92.48	$ 9.69	$ 0.50	$ 10.19	$ 102.67	56%	20.93	539.00	37.53	$ 3.35	$ 4.67	-	0.00	66.48	
CCCT Duct Firing (Dry "F" 2x1)	$ 538	8.37%	$45.08	-	$ 0.50	$ 0.50	$ 45.58	16%	32.52	539.00	48.15	$ 0.55	$ 5.99	-	0.00	87.21	
CCCT (Wet "G" 1x1)	$ 1,117	8.37%	$93.53	$ 6.75	$ 0.50	$ 7.25	$ 100.78	56%	20.54	539.00	36.39	$ 4.56	$ 4.52	-	0.00	66.01	
CCCT Duct Firing (Wet "G" 1x1)	$ 473	8.37%	$39.60	-	$ 0.50	$ 0.50	$ 40.10	16%	28.61	539.00	48.62	$ 0.36	$ 6.04	-	0.00	83.63	
CCCT Advanced (Wet "H" 1x1)	$ 1,233	8.37%	$103.28	$ 6.75	$ 0.50	$ 7.25	$ 110.53	56%	22.53	539.00	35.58	$ 4.56	$ 4.42	-	0.00	67.09	
CCCT Advanced Duct Firing (Wet "H" 1x1)	$ 605	8.37%	$50.68	-	$ 0.50	$ 0.50	$ 51.18	16%	36.51	539.00	48.62	$ 0.36	$ 6.04	-	0.00	91.54	
Other - Renewables																	
Wyoming Wind (35% CF)	$ 2,239	8.55%	$191.33	$ 31.43	$ 0.50	$ 31.93	$ 223.26	35%	72.82	-	-	-	$ 9.70	(20.69)	-	61.82	82.52
Utah Wind (29% CF)	$ 2,239	8.55%	$191.33	$ 31.43	$ 0.50	$ 31.93	$ 223.26	29%	87.88	-	-	-	$ 9.70	(20.69)	-	76.89	97.58
Blundell Geothermal (Dual Flash)	$ 4,277	7.24%	$309.68	$ 110.85	$ 0.50	$ 111.35	$ 421.03	90%	53.40	-	-	$ 5.94		(20.69)	-	38.65	59.34
Greenfield Geothermal (Binary)	$ 6,132	7.24%	$444.03	$ 209.40	$ 0.50	$ 209.90	$ 653.93	90%	82.94	-	-	$ 5.94		(20.69)	-	68.19	88.88
Advance Battery Storage	$ 2,025	8.11%	$164.34	$ 1.00	$ 0.50	$ 1.50	$ 165.84	21%	90.15	539.00	59.29	$ 10.00	$ 7.37	-	0.00	166.81	
Pumped Storage	$ 1,723	7.97%	$137.25	$ 4.30	$ 1.35	$ 5.65	$ 142.90	20%	81.56	539.00	67.38	$ 4.30	$ 8.41	-	0.00	161.65	
Compressed Air Energy Storage (CAES)	$ 1,307	8.11%	$106.02	$ 3.80	$ 1.35	$ 5.15	$ 111.17	47%	27.18	539.00	64.57	$ 5.50	$ 6.97	-	0.00	104.22	
Nuclear (Advance Fission)	$ 5,307	8.09%	$429.48	$ 146.70	$ 6.00	$ 152.70	$ 582.18	85%	78.19	81.14	8.69	$ 1.63	-	-	-	88.50	88.50
Solar (Thin Film PV) - 19% CF	$ 4,191	8.55%	$358.24	$ 59.50	$ 6.00	$ 65.50	$ 423.74	19%	254.59	-	-	-	-	(20.69)	-	233.90	254.59
Solar Concentrating (Thermal Trough, NG backup) - 25% solar	$ 4,033	9.53%	$384.21	$ 120.99	$ 6.00	$ 126.99	$ 511.20	33%	176.84	539.00	14.62	-	$ 1.82	(20.69)	-	172.58	193.27
Solar Concentrating (Thermal Trough) - 30% solar	$ 4,519	7.93%	$358.43	$ 135.56	$ 6.00	$ 141.56	$ 499.99	30%	190.26	-	-	-	$ 1.82	(20.69)	-	171.38	192.07

Wind

Resource Supply, Location, and Incremental Transmission Costs

PacifiCorp revised its approach for locating wind resources to more closely align with Western Renewable Energy Zones (WREZ), facilitate assignment of incremental transmission costs for the Energy Gateway transmission scenario analysis, and allow the System Optimizer model to more easily select wind resources outside of transmission-constrained areas in Wyoming. Resources are now grouped into a number of wind-generation-only bubbles as well as certain conventional topology bubbles. Wind generation bubbles are intended to enable assignment of incremental transmission costs. Table 6.9 shows the relationship between the topology bubbles and corresponding WREZ.

Table 6.9 – Representation of Wind in the Model Topology

Topology Area	Bubble Type	Topology Bubble Linkage	Corresponding Western Renewable Energy Zone(s)
Wyoming	Wind Generation Only	Linked to *Aeolus*	Wyoming East Central (WY_EC) Wyoming North (WY_NO) Wyoming East (WY_EA) Wyoming South (WY_SO)
Utah	Wind Generation Only	Linked to *Utah South*	Utah West (UT_WE)
Oregon/Washington	Wind Generation Only	Linked to *BPA*	Washington South (WA_SO) Oregon Northeast (OR_NE) Oregon West (OR_WE)
Brady, Idaho	Conventional	N/A	Idaho East (ID_EA)
Walla Walla, WA	Conventional	N/A	Oregon Northeast (OR_NE)
Yakima, WA	Conventional	N/A	Washington South (WA_SO)

Incremental transmission costs are expressed as dollars-per-kW values that are applied to costs of wind resources added in wind-generation-only bubbles.[40] The only exception is for the Oregon/Washington bubble. PacifiCorp's transmission investment analysis indicated that supporting incremental wind additions of over 500 MW in the PacifiCorp west control area would require on the order of $1.5 billion in new transmission facilities (several new 500/230 kV segments would be needed). Since the model cannot automatically apply the transmission cost based on a given megawatt threshold, the incremental transmission cost was removed from this bubble for the base Energy Gateway scenario (which excludes the Wyoming transmission segment) and added as a manual fixed cost adjustment to the portfolio's reported cost if the west side wind additions exceed the 500 MW threshold. *It is important to note that the west-side transmission cost adjustment is only applicable to the Energy Gateway scenario analysis, and not core case portfolio development, which is based on the full Energy Gateway footprint. Only if a core case portfolio included at least 500 MW of west-side wind would PacifiCorp apply an out-of-model transmission cost adjustment. None of the core case portfolios reached this wind capacity threshold.*

[40] Incremental transmission costs also could have been added directly to the wind capital costs. However, assigning a cost to a wind generation bubble avoids the need to individually adjust costs for many wind resources.

In the case of east-side wind resources, the only resource location-dependent transmission cost was $71/kW assigned to Wyoming resources based on an estimated incremental expansion of at least 1,500 MW.

As noted above, the model can also locate wind resources in conventional bubbles. No incremental transmission costs are associated with conventional bubbles, other than wheeling charges where applicable. Transmission interconnection costs—direct and network upgrade costs for connecting a wind facility to PacifiCorp's transmission system (230 kV step-up)—are included in the wind capital costs. It should be noted that primary drivers of wind resource selection are the requirements of renewable portfolio standards and the availability of production tax credits.

Capital Costs

PacifiCorp started with a base set of wind capital costs. The source of these costs is the database of the IPM®, a proprietary modeling system licensed to PacifiCorp by ICF International. These wind capital costs are divided into levels that differentiate costs by site development conditions. PacifiCorp then applied adjustments to the base capital costs to account for federal tax credits, wind integration costs, fixed O&M costs, and wheeling costs as appropriate. (The cost adjustments are converted into discounted values and added to the base capital cost.) These adjusted capital cost values are used only in the System Optimizer model. Table 6.10 shows cost values, WREZ resource potentials, and resource unit limits.

To specify the number of discrete wind resources for a topology bubble, PacifiCorp divided the WREZ resource limit (or depth) by the number of cost levels, rounding to the nearest multiple of 100, and then divided by a 100 MW unit size. (Table 6.10) This formula does not apply to the 200 MW of Washington South and Oregon Northeast wind resources that are available without incremental transmission in the Yakima and Walla Walla bubbles. All wind resources are specified in 100 MW blocks, but the model can choose a fractional amount of a block.

Wind Resource Capacity Factors and Energy Shapes

All resource options in a topology bubble are assigned a single capacity factor. Wyoming resource options are assigned a capacity factor value of 35 percent, while wind resources in other states are assigned a value of 29 percent. Capacity factor is a separate modeled parameter from the capital cost, and is used to scale wind energy shapes used by both the System Optimizer and Planning and Risk (PaR) models. The hourly generation shape reflects average hourly wind variability. The hourly generation shape is repeated for each year of the simulation.

Wind Integration Costs

To capture the costs of integrating wind into the system, PacifiCorp applied a value of $9.70/MWh (in 2010 dollars) for portfolio modeling. The source of this value was the Company's 2010 wind integration study, which is included as Appendix H. Integration costs were incorporated into wind capital costs based on a 25-year project life expectancy and generation performance.

Annual Wind Selection Limits

To reflect realistic system resource addition limits tied to such factors as transmission availability, operational integration, rate impact, resource market availability, and procurement constraints, System Optimizer was constrained to select wind up to certain annual limits. The limit is 200 MW per year with the exception of the hard CO_2 emission cap cases, where the annual limit was specified as 500 MW. These limits apply on a system basis. Note that the effect of the annual limits is to spread wind additions across multiple years rather than cap the cumulative total wind added to a portfolio.

Table 6.10 – Wind Resource Characteristics by Topology Bubble

Utah South wind-only bubble

Zone	First year available	Capacity factor	Cost level	Adjusted construction cost ($/kW)	WREZ Resource Limit (MW)	Maximum cumulative 100 MW units
Utah	2016	29%	1	3,059	1,516	5
			2	3,508		5
			3	4,180		5

BPA wind-only bubble

Zone	First year available	Capacity factor	Cost level	Adjusted construction cost ($/kW)	WREZ Resource Limit (MW)	Maximum cumulative 100 MW units
Washington South (Yakima)	2016	29%	1	3,454	2,566	9
			2	3,927		9
			3	4,633		9
Oregon Northeast (Walla Walla)	2016	29%	1	3,597	1,464	5
			2	4,074		5
			3	4,788		5
Oregon West	2016	29%	1	3,597	196	1
			2	4,074		1
			3	4,788		1

Wyoming wind resources in *Aeolus* wind-only bubble

Zone	First year available	Capacity factor	Cost level	Adjusted construction cost ($/kW)	WREZ Resource Limit (MW)	Maximum cumulative 100 MW units
Wyoming South	2018	35%	1	3,147	1,324	13
Wyoming North	2018	35%	1	3,147	3,063	31
Wyoming East Central	2018	35%	1	3,147	2,594	26
Wyoming East	2018	35%	1	3,147	7,257	73

Idaho (Goshen) wind resources in *Brady* bubble

Zone	First year available	Capacity factor	Cost level	Adjusted construction cost ($/kW)	WREZ Resource Limit (MW)	Maximum cumulative 100 MW units
Idaho East	2016	29%	1	3,339	618	2
			2	3,788		2
			3	4,460		2

Oregon/Washington wind resources that do not require new incremental transmission *

Zone	First year available	Capacity factor	Cost level	Adjusted construction cost ($/kW)	WREZ Resource Limit (MW)	Maximum cumulative 100 MW units
Washington South (Yakima)	2013	29%	1	2,393	n/a	1
Oregon Northeast (Walla Walla)	2013	29%	1	2,393	n/a	1

* This section includes only the 200 MW of Oregon and Washington wind resources that do not require incremental transmission. Wind resources in these areas that require additional transmission are modeled with the parameters shown in the "*BPA* wind only bubble" section above.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

ONEENERGY, INC.

Exhibit Accompanying Reply Testimony of Bill Eddie

Idaho Power's Responses to OneEnergy's Data Requests 3.4-3.5, 4.2-4.3

<u>ONEENERGY'S DATA REQUEST NO. 3.4</u>:

For utility's recently constructed Langley Gulch CCCT:

a. What arrangements has Utility made (or will Utility make) to firm its gas supply (including gas transport and storage) and what is the cost of such arrangements?
b. What expansions to the gas delivery and/or storage system were triggered by the new CCCT and what is the cost of those expansions?
c. How are the costs in a. and b. recovered?

<u>IDAHO POWER COMPANY'S RESPONSE TO ONEENERGY'S DATA REQUEST NO. 3.4</u>:

a. Idaho Power has procured 55,584 MMBtu/day of firm transportation service (TF-1 rate schedule) on Williams Northwest Pipeline costing approximately $8.3 million per year in reservation charges. Of this capacity, 31,061 MMBtu/day costing approximately $4.6 million annually was procured specifically for Langley Gulch. Idaho Power has also contracted with a bi-lateral counterpart for an additional 10,000 MMBtu/day of summer-only firm "delivered" supply through 2016, which has a demand component costing $64,800 annually.

Idaho Power has entered into a long-term firm storage contract (rate schedule SGS-2F) with Williams for 131,453 MMBtu of capacity in their Jackson Prairie storage facility in southwestern Washington which costs approximately $333,000 per year in capacity and delivery charges. In additional to the Jackson Prairie capacity Idaho Power enters into seasonal flexible firm supply contracts for approximately 600,000 MMBtu per year which allows the Company to call on natural gas on all four nomination cycles on a firm basis. These contracts are generally entered into for the peak summer or winter months with total annual demand charges of approximately $250,000.

b. Langley Gulch required the construction of a 10-inch diameter pipeline lateral which cost $374,135.02 and an interstate pipeline tap and meter station costing $2,798,816.26.

c. Natural gas transportation and variable storage costs are accounted for as fuel expense and recovered as net power supply costs (through the Power Cost Adjustment); the cost of the Langley Gulch gas lateral and tap is accounted for as electric plant in service and is a rate base investment.

ONEENERGY'S DATA REQUEST NO. 3.5:

How do the costs in your answer to question 3.4.a and 3.4.b compare (in scope and magnitude) to the assumed costs for firming of fuel supply in utility's calculation of the CCCT proxy resource? Please quantify in net present value and $/MWh.

IDAHO POWER COMPANY'S RESPONSE TO ONEENERGY'S DATA REQUEST NO. 3.5:

The costs included for the CCCT proxy resource in the Company's standard avoided cost calculation using the Oregon Method were input directly from the costs used in Idaho Power's 2011 Integrated Resource Plan ("IRP") which are consistent with the cost estimates of the Langley Gulch CCCT. The Company accounts for these costs in the IRP resource stack through either the capital cost estimate or the variable operating cost estimate. Therefore, the costs stated in Response to OneEnergy's Data Request Nos. 3.4.a and 3.4.b would compare directly, both in scope and magnitude, to the assumed costs included in the Company's calculation of the CCCT proxy resource.

In the Oregon Method used to calculate avoided cost rates, it is assumed that natural gas can be purchased at the forecast market price of the fuel. No additional costs are assumed for firming. Once a Qualifying Facility contract is signed, actual natural gas prices can go up or down which will either benefit or harm the utility's customers. Regardless of whether actual prices end up being higher or lower than forecast, the developer receives the benefit associated with the certainty of fixed rates and forces the uncertainty and risk onto the utility customer.

<u>ONEENERGY'S DATA REQUEST NO. 4.2</u>:

Please refer to NWGA and BPA reports attached as Exhibits OneEnergy/103 and OneEnergy/104, respectively, to the Direct Testimony of Bill Eddie. Please also refer to page 69 of Idaho Power Co. 2011 Integrated Resource Plan, which states:

> **The 2011 IRP assumes existing pipeline transport capacity is sufficient to serve only existing demand. The cost of new gas resources includes an additional transportation cost to account for the cost of constructing new pipeline capacity. This additional cost is approximately twice the current tariff rate.**

Has Utility studied, forecasted, or projected the potential for gas transport costs to increase due to limited available regional capacity referred to in the BPA and NWGA reports and Idaho Power's IRP? If yes, please provide all documentation. Has Utility forecasted or otherwise analyzed whether current regional gas transport infrastructure will have sufficient excess capacity to add the CCCT proxy? If yes, please provide all documentation.

<u>IDAHO POWER COMPANY'S RESPONSE TO ONEENERGY'S DATA REQUEST NO. 4.2</u>:

Idaho Power has not conducted a study to forecast or project the potential cost of acquiring additional firm natural gas pipeline transportation capacity for construction of any additional CCCT units. Without knowing exact details of plant size, site location, or service pipeline, Idaho Power would not have the essential details needed to conduct such a study. Thus, Idaho Power has estimated future natural gas pipeline transportation costs for additional CCCT units to be approximately double the per-unit transportation cost of the present natural gas transportation capacity.

Mark Stokes will sponsor this answer at hearing.

ONEENERGY'S DATA REQUEST NO. 4.3:

For the following question:

"Gas interconnection costs" means Utility's cost to build gas facilities from the nearest existing gas pipeline to the proxy CCCT that would be accounted for as electric plant in service and rate base investment.

"Lateral upgrade costs" means Utility's cost associated with any construction of and changes to a gas pipeline lateral interconnecting to the proxy CCCT.

"Trunk upgrade costs" means Utility's cost associated with any construction of or changes to the gas trunk pipeline(s) supplying fuel to the proxy CCCT.

"Local upgrade costs" means Utility's cost associated with any construction of or changes to the gas pipeline(s) supplying fuel to the proxy CCCT other than the lateral or trunk pipelines.

"Storage costs" means Utility's cost to store gas (or other fuel) for the proxy CCCT.

"Fixed price demand charges" means Utility's cost for the contractual right to call on delivery of gas as needed to operate the proxy CCCT (including at peak capacity during any or all peak load periods).

"Variable fuel transportation costs" means Utility's cost to move fuel to the proxy CCCT not included in "fixed price demand charges".

"Other gas transportation costs" means any other cost to Utility relating to the delivery of fuel included in the proxy CCCT and not included in any of the other categories of costs, above.

For each of the costs (l)-(8) in the first column, please answer questions (a)-(d) in the first row. Please note where costs are double-counted across categories.

Costs:	(a) Included in CCCT proxy?	(b) How is it quantified for CCCT proxy?	(c) What is the cost in the proxy?	(d) Identify sheet(s) and cell(s) where cost appears in avoided cost worksheets.
(1) Gas interconnection cost				
(2) Lateral upgrade costs				
(3) Trunk upgrade costs				
(4) Local upgrade costs				
(5) Storage costs				
(6) Fixed price demand charges				
(7) Variable fuel transportation costs				
(8) Other gas transportation costs				

IDAHO POWER COMPANY'S RESPONSE TO ONEENERGY'S DATA REQUEST NO. 4.3:

Please see the table below:

Costs:	**(a) Included in CCCT proxy?**	**(b) How is it quantified for CCCT proxy?**	**(c) What is the cost in the proxy?**	**(d) Identify sheet(s) and cell(s) where cost appears in avoided cost worksheets.**
(1) Gas interconnection cost	Yes	It is included in the plant capacity cost	≈ \$9.33 / kW	Table 8 - C118 & H106
(2) Lateral upgrade costs	Yes	It is included in the plant capacity cost	≈ \$1.25 / kW	Table 8 - C118 & H106
(3) Trunk upgrade costs	No			
(4) Local upgrade costs	No			
(5) Storage costs	No			
(6) Fixed price demand charges	No			
(7) Variable fuel transportation costs	Yes	Included as part of the East-Side Delivered Gas Price Forecast	Included as part of the East-Side Delivered Gas Price Forecast	Table 8 - D9:D28 Table 4 - J11:J30
(8) Other gas transportation costs	N/A			

Michael Youngblood prepared this response. Mark Stokes will sponsor this answer at hearing.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

ONEENERGY, INC.

Exhibit Accompanying Reply Testimony of Bill Eddie

PGE's Responses to OneEnergy's Data Requests 017-019

April 17, 2013

TO: Ken Kaufmann
OneEnergy, Inc.

FROM: Jay Tinker
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UM 1610
PGE Response to OneEnergy, Inc. Data Request No. 017
(Renumbered from 4.2)
Dated March 29, 2013

Request:

Please refer to NWGA and BPA reports attached as Exhibits OneEnergy/103 and OneEnergy/104, respectively, to the Direct Testimony of Bill Eddie. Please also refer to page 69 of Idaho Power Co. 2011 Integrated Resource Plan, which states:

> **The 2011 IRP assumes existing pipeline transport capacity is sufficient to serve only existing demand. The cost of new gas resources includes an additional transportation cost to account for the cost of constructing new pipeline capacity. This additional cost is approximately twice the current tariff rate.**

Has Utility studied, forecasted, or projected the potential for gas transport costs to increase due to limited available regional capacity referred to in the BPA and NWGA reports and Idaho Power's IRP? If yes, please provide all documentation. Has Utility forecasted or otherwise analyzed whether current regional gas transport infrastructure will have sufficient excess capacity to add the CCCT proxy? If yes, please provide all documentation.

Response:

PGE has not conducted a pipeline capacity study, but an additional resource may utilize the GTN pipeline, which has available capacity. Capacity figures for GTN are public and available on their website.

April 17, 2013

TO: Ken Kaufmann
OneEnergy, Inc.

FROM: Jay Tinker
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UM 1610
PGE Response to OneEnergy, Inc. Data Request No. 018
(Renumbered from 4.3)
Dated March 29, 2013

Request:

For the following question:

"Gas interconnection costs" means Utility's cost to build gas facilities from the nearest existing gas pipeline to the proxy CCCT that would be accounted for as electric plant in service and rate base investment.

"Lateral upgrade costs" means Utility's cost associated with any construction of and changes to a gas pipeline lateral interconnecting to the proxy CCCT.

"Trunk upgrade costs" means Utility's cost associated with any construction of or changes to the gas trunk pipeline(s) supplying fuel to the proxy CCCT.

"Local upgrade costs" means Utility's cost associated with any construction of or changes to the gas pipeline(s) supplying fuel to the proxy CCCT other than the lateral or trunk pipelines.

"Storage costs" means Utility's cost to store gas (or other fuel) for the proxy CCCT.

"Fixed price demand charges" means Utility's cost for the contractual right to call on delivery of gas as needed to operate the proxy CCCT (including at peak capacity during any or all peak load periods).

"Variable fuel transportation costs" means Utility's cost to move fuel to the proxy CCCT not included in "fixed price demand charges".

"Other gas transportation costs" means any other cost to Utility relating to the delivery of fuel included in the proxy CCCT and not included in any of the other categories of costs, above.

UM 1610 PGE Response to OneEnergy Inc Data Request No. 018
April 17, 2013
Page 2

For each of the costs (l)-(8) in the first column, please answer questions (a)-(d) in the first row. Please note where costs are double-counted across categories.

Cost:	**(a) Included in CCT proxy?**	**(b) How is it quantified for CCT proxy?**	**(c) What is the cost in the proxy?**	**(d) Identify sheet(s) and cell(s) where cost appears in avoided cost worksheets.**
(1) Gas interconnection cost				
(2) Lateral upgrade costs				
(3) Trunk upgrade costs				
(4) Local upgrade costs				
(5) Storage costs				
(6) Fixed price demand charges				
(7) Variable fuel transportation costs				
(8) Other gas transportation costs				

<u>*Response:*</u>

Cost:	**(a) Included in CCT proxy?**	**(b) How is it quantified for CCT proxy?**	**(c) What is the cost in the proxy?**	**(d) Identify sheet(s) and cell(s) where cost appears in avoided cost worksheets.**
(1) Gas interconnection cost	*	*	*	*
(2) Lateral upgrade costs	*	*	*	*
(3) Trunk upgrade costs	*	*	*	*
(4) Local upgrade costs	*	*	*	*
(5) Storage costs	*	*	*	*
(6) Fixed price demand charges	Yes	$ per kilowatt year	$28.60 in 2011 $	O&M – Fuel Transmission.

(7) Variable fuel transportation costs	Yes	$/mmBTU	$0.0192	AECO and SUMAS sheets.
(8) Other gas transportation costs	Yes, losses are included.	% of gas commodity	1.86%	AECO and SUMAS sheets.

*Figures associated with this data may be embedded in the Black & Veatch study that is attached as Attachment 018-A, which is confidential and subject to Protective Order 12-461. PGE does not have these numbers broken out as stand-alone information.

UM 1610

Attachment 018-A

Provided in Electronic Format (CD) Only

Confidential and Subject to Protective Order No. 12-461

Black & Veatch Study

April 17, 2013

TO: Ken Kaufmann
OneEnergy, Inc.

FROM: Jay Tinker
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UM 1610
PGE Response to OneEnergy, Inc. Data Request No. 019
(Renumbered from 4.4)
Dated March 29, 2013

Request:

Regarding Utility's response to OneEnergy Data Requests 3.3 and 3.4 (renumbered 013 and 014), is PGE objecting to the requests, and, if so, what is the legal basis for the objection?

Response:

Yes. PGE objects to OneEnergy Data Request Nos. 013 and 014 on the basis of relevance. The Carty combined cycle combustion turbine (CCCT) is not the basis for avoided costs. Commission Order No. 05-584 specifies the use of a CCCT as the proxy resource for purposes of calculating the avoided cost for the resource deficiency period. PGE uses the costs from its integrated resource plan (IRP) as a basis for those costs. The Carty CCCT is the utility bid in the base load request for proposal (RFP). PGE received numerous bids in the RFP and the results are not known.

In addition, no party in this proceeding proposed the use of the utility bid in an RFP as the basis for the utility's avoided cost.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

ONEENERGY, INC.

Exhibit Accompanying Reply Testimony of Bill Eddie

PacifiCorp's Responses to OneEnergy's Data Requests 3.4-3.5, 4.2-4.3, 4.5

UM 1610/PacifiCorp
March 22, 2013
OneEnergy Data Request 3.4

OneEnergy Data Request 3.4

For utility's to be constructed Lake Side 2 CCCT:

(a) What arrangements has Utility made (or will Utility make) to firm its gas supply (including gas transport and storage) and what is the cost of such arrangements?
(b) What expansions to the gas delivery and/or storage system were triggered by the new CCCT and what is the cost of those expansions?
(c) How are the costs in a. and b. recovered?

Response to OneEnergy Data Request 3.4

The Company objects to this request as not reasonably calculated to lead to the discovery of admissible evidence. Without waiving this objection, the Company responds as follows:

(a) The Company issued a competitive process to secure transport which resulted in negotiated incremental firm transportation service from various supply points on the Questar Pipeline Company pipeline system to the Lake Side Plant site which is connected to the Questar Gas Company pipeline system. The total monthly fixed price demand charges for this incremental service is **[Begin Confidential]** [redacted] **[End Confidential]** per month. There are also variable cost obligations that are based on eventual usage of the transportation service subject to rates defined in the Questar Pipeline Company and Questar Gas Company Tariffs.

(b) Questar Corporation has planned changes to their pipeline systems operated by Questar Pipeline Company and Questar Gas Company. These changes will enable Questar Pipeline Company and Questar Gas Company to meet the commitments in the transportation service agreements referenced in previous response. Utility does not know the cost associated with those changes.

(c) The costs detailed in subparts (a) and (b) above will be reflected in the cost of fuel and will be included in the Company's transition adjustment mechanism (TAM) filings in Oregon.

Please refer to Confidential Attachment OneEnergy 3.4 for the non-redacted version of the response above.

The confidential attachment is designated as confidential under Protective Order No. 12-461 and may only be disclosed to qualified persons as defined in that order.

UM 1610/PacifiCorp
March 22, 2013
OneEnergy Data Request 3.5

OneEnergy Data Request 3.5

How do the costs in your answer to question 3.4.a and 3.4.b compare (in scope and magnitude) to the assumed costs for firming of fuel supply in utility's calculation of the CCCT proxy resource? Please quantify in net present value and $/MWh.

Response to OneEnergy Data Request 3.5

Avoided cost gas prices are "burner tip" which includes the cost of fuel and variable gas transportation costs. The Company has not prepared a quantification of the difference in transportation costs of the proxy combined-cycle combustion turbine (CCCT) in the integrated resource plan (IRP) and the transportation costs of Lake Side 2.

UM 1610/PacifiCorp
April 12, 2013
OneEnergy Data Request 4.2

OneEnergy Data Request 4.2

Please refer to NWGA and BPA reports attached as Exhibits OneEnergy/103 and OneEnergy/104, respectively, to the Direct Testimony of Bill Eddie. Please also refer to page 69 of Idaho Power Co. 2011 Integrated Resource Plan, which states:

> The 2011 IRP assumes existing pipeline transport capacity is sufficient to serve only existing demand. The cost of new gas resources includes an additional transportation cost to account for the cost of constructing new pipeline capacity. This additional cost is approximately twice the current tariff rate.

(a) Has Utility studied, forecasted, or projected the potential for gas transport costs to increase due to limited available regional capacity referred to in the BPA and NWGA reports and Idaho Power's IRP? If yes, please provide all documentation.
(b) Has Utility forecasted or otherwise analyzed whether current regional gas transport infrastructure will have sufficient excess capacity to add the CCCT proxy? If yes, please provide all documentation.

Response to OneEnergy Data Request 4.2

(a) No.

(b) No.

Sponsor: To Be Determined

UM 1610/PacifiCorp
April 12, 2013
OneEnergy Data Request 4.3

OneEnergy Data Request 4.3

For the following question:

"Gas interconnection costs" means Utility's cost to build gas facilities from the nearest existing gas pipeline to the proxy CCCT that would be accounted for as electric plant in service and rate base investment.

"Lateral upgrade costs" means Utility's cost associated with any construction of and changes to a gas pipeline lateral interconnecting to the proxy CCCT.

"Trunk upgrade costs" means Utility's cost associated with any construction of or changes to the gas trunk pipeline(s) supplying fuel to the proxy CCCT.

"Local upgrade costs" means Utility's cost associated with any construction of or changes to the gas pipeline(s) supplying fuel to the proxy CCCT other than the lateral or trunk pipelines.

"Storage costs" means Utility's cost to store gas (or other fuel) for the proxy CCCT.

"Fixed price demand charges" means Utility's cost for the contractual right to call on delivery of gas as needed to operate the proxy CCCT (including at peak capacity during any or all peak load periods).

"Variable fuel transportation costs" means Utility's cost to move fuel to the proxy CCCT not included in "fixed price demand charges".

"Other gas transportation costs" means any other cost to Utility relating to the delivery of fuel included in the proxy CCCT and not included in any of the other categories of costs, above.

For each of the costs (1)-(8) in the first column, please answer questions (a)-(d) in the first row. Please note where costs are double-counted across categories.

		(a)	(b)	(c)	(d)
	Cost:	**Included in CCCT proxy?**	**How is it quantified for CCCT proxy?**	**What is the cost in the proxy?**	**Identify sheet(s) and cell(s) where cost appears in avoided cost worksheets.**
(1)	**Gas interconnection cost**				
(2)	**Lateral upgrade costs**				
(3)	**Trunk upgrade costs**				
(4)	**Local upgrade costs**				
(5)	**Storage costs**				
(6)	**Fixed price demand charges**				
(7)	**Variable fuel transportation costs**				
(8)	**Other gas transportation costs**				

UM 1610/PacifiCorp
April 12, 2013
OneEnergy Data Request 4.3

Response to OneEnergy Data Request 4.3

Please refer to the table below:

		(a)	(b)	(c)	(d)
	Cost:	**Included in CCCT proxy?**	**How is it quantified for CCCT proxy?**	**What is the cost in the proxy?**	**Identify sheet(s) and cell(s) where cost appears in avoided cost worksheets.**
(1)	**Gas interconnection cost**	Not Included			
(2)	**Lateral upgrade costs**	Not Included			
(3)	**Trunk upgrade costs**	Not Included			
(4)	**Local upgrade costs**	Not Included			
(5)	**Storage costs**	Not Included			
(6)	**Fixed price demand charges**	Not Included			
(7)	**Variable fuel transportation costs**	Included	$/MMBtu included in burner tip gas price	Variable cost varies by year	Table 9 Column D
(8)	**Other gas transportation costs**	Not Included			

Sponsor: Brian Dickman

UM 1610/PacifiCorp
April 12, 2013
OneEnergy Data Request 4.5

OneEnergy Data Request 4.5

(a) Please identify the start and end date of the term(s) for which Utility is obligated to pay the monthly fixed price demand charges, or fraction thereof, identified in Utility's response to OneEnergy Data Request 3.4.
(b) Please also provide the corresponding firm transportation service agreement(s) between Utility and Questar Pipeline Company and/or Questar Gas Company.

Response to OneEnergy Data Request 4.5

The Company objects to this request as not reasonably calculated to lead to the discovery of admissible evidence. Without waiving this objection, the Company responds as follows:

(a) April 1, 2014 through March 31, 2044.

(b) There is/are no executed firm transportation service agreement(s) at this time.

Sponsor: To Be Determined

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

ONEENERGY, INC.

Exhibit Accompanying Reply Testimony of Bill Eddie

Gas Transmission Northwest LLC, “Abbreviated Application for Certificate of Public Convenience and Necessity”, FERC Docket No. CP12-494-000, Exhibit N, "Revenues, Expenses, Income" (July 31, 2012)

Gas Transmission Northwest LLC

Docket No. CP12-____-000

Abbreviated Application for Certificate of Public Convenience and Necessity

CARTY LATERAL PROJECT

Exhibit N

Revenues, Expenses, Income

PUBLIC

Carty Lateral Project
Revenue Summary
($000's)

Line No.	Shipper	Receipt Point	Delivery Point	Daily Delivery Volume (Dth/day)	Year 1 Negotiated Rate ($/Dth/day)	Year 1 Revenue	Year 2 Negotiated Rate ($/Dth/day)	Year 2 Revenue	Year 3 Negotiated Rate ($/Dth/day)	Year 3 Revenue
	(a)	(b)	(c)	(d)	(e)	(f)		(g)		(h)
1	Portland General Electric	Ione, OR	Carty Generating Station, OR	175,000	$ 0.170331	$ 10,880	$ 0.164633	$ 10,516	$ 0.158192	$ 10,105
2	Total Design Capacity			175,000		$ 10,880		$ 10,516		$ 10,105

Carty Lateral Project
Income Statement
($000's)

Line No.	Description	Year 1	Year 2	Year 3
	(a)	(b)	(c)	(d)
1	Operating Revenues	$ 10,880	$ 10,516	$ 10,105
2	Operation and Maintenance Expense /1	$ 1,042	1,065	1,089
3	Depreciation and Amortization Expense	$ 1,812	1,812	1,812
4	Other Taxes	$ 779	750	722
5	Net Operating Income (Pretax Return) (Line 1 - (lines 2 thru 4))	7,246	6,889	6,482
6	Interest Expense	1,625	1,547	1,457
7	Income Taxes	2,291	2,182	2,058
8	Net Income (line 5 - lines 6 and 7)	$ 3,330	$ 3,160	$ 2,967

/1 - Includes Administrative and General Expenses

Note: Any differences are a result of rounding

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

ONEENERGY, INC.

Exhibit Accompanying Reply Testimony of Bill Eddie

Idaho Power's Responses to OneEnergy's Data Requests 3.1-3.3

March 29, 2013

Subject: Docket No. UM 1610
Idaho Power Company's Responses to OneEnergy's Third Set of Data Requests (DRs 3.1-3.5)

ONEENERGY'S DATA REQUEST NO. 3.1:

Does Utility have the current capability to model system losses (line and transformation losses) that would be avoided by the installation of a new generator interconnected to the distribution system? Please describe these capabilities, including model inputs and outputs.

IDAHO POWER COMPANY'S RESPONSE TO ONEENERGY'S DATA REQUEST NO. 3.1:

Yes, Idaho Power Company ("Idaho Power" or "Company") has the capability to model the change in system losses due to the installation of a new generator connected to the distribution system at a specific location. The accuracy of results would depend on assumptions made.

Some distribution-connected generation resources may add system losses and others may decrease system losses at any given point in time or over the course of a given year.

There are many factors that impact the prediction of differences in system losses due to the presence of a distribution-connected generation resource. Some of these factors are difficult to predict. Factors include:

- Location of the resource in terms of distance to the substation.
- Location of the resource in relation to the utility transmission system.
- Location of the resource in relation to utility generation resources and loads.
- Availability/intermittency of the generation resource itself.
- Availability/intermittency of other non-utility generation resources connected to the same distribution circuit, if any.
- Year-to-year changes in availability and output patterns of the above.
- Loss differences may change significantly due to permanent changes in distribution or transmission system configuration over the course of time.

Idaho Power maintains models of the transmission system and primary distribution system, including line and transformer impedances, generation resources, and loads. In order to capture the change in losses in terms of watt-hours over the course of a year, these models would have to be run for each hour and assumptions would have to be made concerning the mix of loading levels, generation resource output distribution, and system configuration for each of the models. The output of the study would be largely dependent on the accuracy of these assumptions. If the assumptions do not reflect reality, the predicted result may be much different than the actual result over the course of a year.

<u>ONEENERGY'S DATA REQUEST NO. 3.2</u>:

Does Utility have the capability to model differences in system losses by simulating system operations with and without a specific generation resource at a specific location:

a. on an hourly basis?
b. on an peak and off-peak basis?
c. on an annual basis?

<u>IDAHO POWER COMPANY'S RESPONSE TO ONEENERGY'S DATA REQUEST NO. 3.2</u>:

Yes, Idaho Power has the capability to model the change in system losses due to the installation of a new generator connected to the distribution system at a specific location. Accuracy of results will be based on the assumptions made. Capabilities to generate results are as follows:

a. **On an hourly basis -** This type of analysis would involve a large amount of man hours. In order to obtain results for one year, 8,760 hourly models would have to be developed. Assumptions about system-wide loading levels, generation resource output, and configuration would have to be adjusted for each model. Results would only be accurate to the degree with which the assumptions end up matching reality.

b. **On a peak and off-peak basis -** Obtaining results for this type of analysis would be less onerous. A peak and off-peak model would be developed including assumptions about system-wide loading levels, generation resource output, and configuration.

c. **On an annual basis -** This type of analysis would involve a study similar to that described in Idaho Power's response to OneEnergy's Data Request No. 3.2.a. Instead of hourly models, a different increment in time could be used resulting in less models developed. However, this may lead to a decrease in accuracy of results.

<u>ONEENERGY'S DATA REQUEST NO. 3.3</u>:

Has Utility previously studied/estimated avoided losses associated with siting small (less than substation load) generation at distribution voltages? If so, please provide copies of such reports.

<u>IDAHO POWER COMPANY'S RESPONSE TO ONEENERGY'S DATA REQUEST NO. 3.3</u>:

No, Idaho Power has not previously studied systematic changes in losses resulting from past proposed distribution-connected generation projects.

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

ONEENERGY, INC.

Exhibit Accompanying Reply Testimony of Bill Eddie

PGE's Responses to OneEnergy's Data Requests 010-012

March 22, 2013

TO: Ken Kaufmann
OneEnergy, Inc.

FROM: Karla Wenzel
Manager, Pricing & Tariffs

PORTLAND GENERAL ELECTRIC
UM 1610
PGE Response to OneEnergy, Inc. Data Request No. 010
(Renumbered from 3.1)
Dated March 8, 2013

Request:

Does Utility have the current capability to model system losses (line and transformation losses) that would be avoided by the installation of a new generator interconnected to the distribution system? Please describe these capabilities, including model inputs and outputs.

Response:

PGE has the capability to model expected changes in the distribution system losses (feeder mainline) that may be affected by installation of new generation interconnected to the distribution system at specified locations. PGE can also model the impact to losses on substation distribution power transformers under normal system configuration. PGE utilizes the CYMEDIST software tool to analyze the distribution model, including inputs such as system load and power factor, feeder conductor type(s), and feeder length.

March 22, 2013

TO: Ken Kaufmann
OneEnergy, Inc.

FROM: Karla Wenzel
Manager, Pricing & Tariffs

PORTLAND GENERAL ELECTRIC
UM 1610
PGE Response to OneEnergy, Inc. Data Request No. 011
(Renumbered from 3.2)
Dated March 8, 2013

Request:

Does Utility have the capability to model differences in system losses by simulating system operations with and without a specific generation resource at a specific location:

a. on an hourly basis?
b. on an peak and off-peak basis?
c. on an annual basis?

Response:

PGE has the capability to model expected changes in the distribution system losses (feeder mainline) by simulating normal system operations with and without specific generation resources at specific locations. These simulations can be run for discreet system loading scenarios, which may include an on-peak and off-peak assessment. PGE does not have an accurate way of assessing the impact to system losses on an hourly or annualized basis.

March 22, 2013

TO: Ken Kaufmann
OneEnergy, Inc.

FROM: Karla Wenzel
Manager, Pricing & Tariffs

PORTLAND GENERAL ELECTRIC
UM 1610
PGE Response to OneEnergy, Inc. Data Request No. 012
(Renumbered from 3.3)
Dated March 8, 2013

Request:

Has Utility previously studied/estimated avoided losses associated with siting small (less than substation load) generation at distribution voltages? If so, please provide copies of such reports.

Response:

No.

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BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

ONEENERGY, INC.

Exhibit Accompanying Reply Testimony of Bill Eddie

PacifiCorp's Responses to OneEnergy's Data Requests 3.1-3.3, 4.4

UM 1610/PacifiCorp
March 22, 2013
OneEnergy Data Request 3.1

OneEnergy Data Request 3.1

Does Utility have the current capability to model system losses (line and transformation losses) that would be avoided by the installation of a new generator interconnected to the distribution system? Please describe these capabilities, including model inputs and outputs.

Response to OneEnergy Data Request 3.1

No. The Company has not studied nor provided estimates of avoided losses associated with small generators proposed or connected to the distribution system (below 100 kV).

UM 1610/PacifiCorp
March 22, 2013
OneEnergy Data Request 3.2

OneEnergy Data Request 3.2

Does Utility have the capability to model differences in system losses by simulating system operations with and without a specific generation resource at a specific location:

(a) on an hourly basis?
(b) on an peak and off-peak basis?
(c) on an annual basis?

Response to OneEnergy Data Request 3.2

(a) Yes. The Company has the capability to model differences in system losses with and without a specific generation resource for voltages over 100 kV. The Company performs a system impact study when specific generation interconnects are requested through the generation interconnect queue.

(b) Please refer to the Company's response to subpart (a) above.

(c) Please refer to the Company's response to subpart (a) above.

UM 1610/PacifiCorp
March 22, 2013
OneEnergy Data Request 3.3

OneEnergy Data Request 3.3

Has Utility previously studied/estimated avoided losses associated with siting small (less than substation load) generation at distribution voltages? If so, please provide copies of such reports.

Response to OneEnergy Data Request 3.3

No. The Company has not studied nor provided estimates of avoided losses associated with small generators proposed or connected to the distribution system (below 100 kV).

OneEnergy Data Request 4.4

Please refer to Utility's response to OneEnergy Data Request 3.1. Portland General Electric responded to an identical question:

> PGE has the capability to model expected changes in the distribution system losses (feeder mainline) that may be affected by installation of new generation interconnected to the distribution system at specified locations. PGE can also model the impact to losses on substation distribution power transformers under normal system configuration. PGE utilizes the CYMEDIST software tool to analyze the distribution model, including inputs such as system load and power factor, feeder conductor type(s), and feeder length.

PGE Response to OneEnergy, Inc. Data Request No. 010 (Renumbered from 3.1) dated March 8, 2013. Please also note that Idaho Power provided a detailed description of its system loss modeling capabilities (and limitations) in response to an identical question. Please confirm whether Utility has comparable modeling capability. If yes, please describe Utility's modeling capabilities with reference to OneEnergy Data Requests 3.1 – 3.3.

Response to OneEnergy Data Request 4.4

PacifiCorp has tools to model case studies for new generation interconnections and loads connected to distribution and transmission class facilities. FeederAll developed by ABB is the power flow tool used by distribution field engineers. PSS®E developed by Siemens Power Technologies International is the power flow tool used by transmission area planning engineers. These tools have the functionality to provide kilowatt and kilowatt-hour per year losses for each case study. The Company generally has not been utilizing this feature of the power flow tools and staff would require training if this calculation were necessary. Up to date economic inputs such as costs per kilowatt and kilowatt-hour would need to be provided to engineers from other departments within PacifiCorp to convert loss savings to cost savings.

Sponsor: To Be Determined

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

ONEENERGY, INC.

Exhibit Accompanying Reply Testimony of Bill Eddie

PGE's Responses to OneEnergy's Data Requests 015 & 020

March 22, 2013

TO: Ken Kaufmann
OneEnergy, Inc.

FROM: Karla Wenzel
Manager, Pricing & Tariffs

PORTLAND GENERAL ELECTRIC
UM 1610
PGE Response to OneEnergy, Inc. Data Request No. 015
(Renumbered from 3.6)
Dated March 8, 2013

Request:

For the Obsidian 5-MW Solar PV (Outback) project, please provide:

- **a. the term of the power purchase agreement (PPA);**
- **b. the levelized PPA purchase price**
- **c. the term of fixed prices (if shorter than the term of the contract); and**
- **d. a copy of the executed PPA.**

Response:

a. 25 years.
b. See Confidential Attachment 015-A.
c. Same as PPA term.
d. See Confidential Attachment 015-B.

April 17, 2013

TO: Ken Kaufmann
OneEnergy, Inc.

FROM: Jay Tinker
Director, Regulatory Policy & Affairs

PORTLAND GENERAL ELECTRIC
UM 1610
PGE Response to OneEnergy, Inc. Data Request No. 020
(Renumbered from 4.5)
Dated March 29, 2013

Request:

Please provide the following information regarding the PPA between PGE and Outback Solar LLC:

a. the purchase prices in $/MWh for all periods during the term of the PPA; and

b. the commercial terms for security requirements in the PPA, if any, including form of security, dollar amount of security, and periods when security must be maintained.

Response:

a. Please see Attachment 020-A, which is confidential and subject to Protective Order No. 12-461.
b. Please see Attachment 020-B, which is confidential and subject to Protective Order No. 12-461.

UM 1610

Attachment 020-A

Provided in Electronic Format (CD) Only

Confidential and Subject to Protective Order No. 12-461

Purchase Prices from Outback Solar

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

ONEENERGY, INC.

Exhibit Accompanying Reply Testimony of Bill Eddie

[Reserved]

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

ONEENERGY, INC.

Exhibit Accompanying Reply Testimony of Bill Eddie

PGE Response to REC Data Request 022

March 12, 2013

TO: Melinda Davison
Irion Sanger
Davison Van Cleve, PC

Donald Schoenbeck
Regulatory & Cogeneration Services, Inc

FROM: Jay Tinker
Manager, Pricing

PORTLAND GENERAL ELECTRIC
UM 1610
PGE Response to REC Third Set of Data Request No. 022
Dated February 26, 2013

Request:

Since 2005, please identify the resource sufficiency/deficiency period in the Company's avoided cost rates.

Response:

Effective Date	Sufficiency Period	Deficiency Period
8/11/2005	2005-2008	Starting in 2009
8/13/2007	2007-2011	Starting in 2012
9/9/2009	2009-2012	Starting in 2013
1/19/2011	2011-2014	Starting in 2015
1/19/2013	2013-2015	Starting in 2016

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

ONEENERGY, INC.

Exhibit Accompanying Reply Testimony of Bill Eddie

PacifiCorp's Response to OneEnergy's Data Request 4.6

UM 1610/PacifiCorp
April 12, 2013
OneEnergy Data Request 4.6

OneEnergy Data Request 4.6

Since 2005, please identify the resource sufficiency/deficiency period in the Utility's avoided cost rates using the following table format.

Effective Date of Rates	Sufficiency Period	Deficiency Period

Response to OneEnergy Data Request 4.6

Please refer to the table below:

Effective Date of Rates	Sufficiency Period	Deficiency Period (3)	Note
August 9, 2005	2005 - 2009	2010	
August 13, 2007	2007 - 2011	2012	
December 28, 2009	2009 - 2013	2014	(1)
March 30, 2010	2010 - 2013	2014	
March 27, 2012	2012 - 2015	2016	(2)

(1) Approved September 8, 2009, subject to review. Affirmed December 28, 2009.

(2) Deficit year determined by 2011 Integrated Resource Plan (IRP) Table 8.16.

(3) First year of the deficit period.

Sponsor: Brian Dickman

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

ONEENERGY, INC.

Exhibit Accompanying Reply Testimony of Bill Eddie

Summary of Issues Corresponding to December 21, 2012 Issues List with OneEnergy, Inc.'s positions

Summary of Issues Corresponding to December 21, 2012 Issues List

{Redlines indicate Revisions to the Summary of Issues filed with Direct Testimony}

1. *Avoided Cost Price Calculation*

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

i. 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?

OneEnergy: The avoided capacity cost methodology adopted in UM 1129 should be adjusted to include (1) cost to procure firm fuel capacity rights on gas pipeline; and (2) cost to build (if necessary) and reserve firm delivery rights on transmission system to utility's Oregon control area. Utilities should use incremental, not average, fixed gas transportation costs. [OneEnergy/100, Eddie/28].

OneEnergy: The standard power purchase agreement (Pac Schedule 37, IPC Schedule 201, IPC Schedule 85) should offer Distributed Generation QFs: (1) an adder for reduced losses, (2) fixed prices for 25-year term; and (3) levelized (or partially levelized) pricing. Distributed Generation means QFs under 3MW directly interconnected at distribution voltage. [OneEnergy/200, Eddie/3].

OneEnergy: The utilities should specify the location of the proxy CCCT in order to facilitate examination of the reasonableness of their assumptions. [OneEnergy/200, Eddie/15]

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

OneEnergy: Yes, generally.

OneEnergy: PacifiCorp has not shown that changing from a blended index to the Mid-C index for market prices is an insignificant change. Utilities should use the COB forward prices for QFs delivering output in southern Oregon. [OneEnergy/200, Eddie/7]

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

OneEnergy: QFs under 3 MW directly connected to the distribution system of the purchasing utility should have the option to receive levelized (or partially levelized) payments, provided that their site lease term and major equipment warranty term are at least as long as the PPA term. [OneEnergy/100, Eddie/] "Partially levelized" means rates with a uniform escalation rate (such as 2%) and a net present value equal to the present value of the non-levelized rates over the same term. [9/200, Eddie/16].

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?

OneEnergy: No position at this time.

D. Should the Commission eliminate unused pricing options?

OneEnergy: No position at this time.

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.)

OneEnergy: There should be on- and off-peak pricing for all Avoided Costs. Applying wind-specific integration costs to non-wind intermittent resources is unreasonable and should not be permitted.

OneEnergy: Staff's proposal to have resource specific capacity values, if implemented, should be implemented contemporaneously with the changes in 1(A). [OneEnergy/200, Eddie/2]

OneEnergy: QFs that agree to be curtailable on demand at a rate of the applicable PPA rate plus their lost RECs, if any, receive added capacity value compared to QFs that do not agree to this option. [OneEnergy/200, Eddie/4]

OneEnergy: PacifiCorp should include in its renewable avoided cost resource cost the capital construction cost to move output from its Wyoming wind bubble to load. [OneEnergy/200, Eddie/9]

OneEnergy: The renewable avoided cost should reasonably account for expected lost generation due to Balancing Authority curtailments of the renewable resource. [OneEnergy/200, Eddie/9-10]

OneEnergy: The renewable avoided cost should reasonably account for expected lost generation due to degradation in performance of the renewable resource over its lifetime. [OneEnergy/200, Eddie/s10]

OneEnergy: The renewable avoided cost should reasonably account for estimated state and local taxes paid by the renewable resource over its lifetime. [OneEnergy/200, Eddie/10]

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

OneEnergy: Clarification whether the Energy Trust of Oregon can support projects that do not control their environmental attributes is important prior to the Commission making a final determination.

OneEnergy: Green Tags" should not include (1) environmental attributes that are greenhouse gas offsets from methane capture not associated with the generation of electricity and not needed to ensure that there are zero net emissions associated with the generation of electricity, and (2) any other environmental attributes that are not required in order to provide utility with a renewable energy certificate for "qualifying electricity," as that term is defined in Oregon's Renewable Portfolio Standard Act, Ore. Rev. Stat. **469A.010,** in effect at the time of execution of this Agreement. [OneEnergy/200, Eddie/7]

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?

OneEnergy: ~~No Position at this time~~. No.

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?

OneEnergy: Annual ministerial updates at the same time each year would result in more accurate avoided costs than the current, 2-year update frequency. "Ministerial updates" are those updates that can be accomplished transparently without the exercise of independent judgment. [OneEnergy/200, Eddie/5]

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

OneEnergy: No position at this time.

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.)

OneEnergy: See 3(A), above. Mid-cycle updates should include ministerial updates only, such as updates to the market electricity forecast, market gas forecast, and the expiration or modification of the Production Tax Credit. [OneEnergy/200, Eddie/5]

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?

OneEnergy: See 3(A), above. OER will address this in its legal brief.

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?

OneEnergy: No position at this time.

4. Price Adjustments for Specific QF 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?

OneEnergy: Integration charges should apply to wind only until utilities quantify non-wind integration costs.

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?

OneEnergy: No position at this time.

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

OneEnergy: Item(vii), smaller capacity increments and shorter lead times, should be modeled using the PacifiCorp's approach used to model resource deferral benefits from Class 2 DSM in its 2011 IRP, or one of several other methodologies published in peer reviewed literature. [OneEnergy/200, Eddie/6]~~.~~

OneEnergy: QFs should have the option to select an adder to their avoided cost in exchange for agreeing to be curtailable up to 100 hours/year. (OneEnergy offers an alternative proposal in its Reply Testimony [OneEnergy/200, Eddie/4]. That alternative proposal is summarized in Section 2(A), above.

OneEnergy: DG under 3MW should receive a 3.9% avoided line loss (unless the utilities can justify a lower figure). [OneEnergy/200, Eddie/18].

OneEnergy: Directly connected DG under 3 MW ~~and~~ should have the option to elect a 25-year term with levelized (or partially levelized) prices. [OneEnergy/200, Eddie/16].

5. Eligibility Issues

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

OneEnergy: No, however, a subclass of QFs (those under 3MW directly interconnected to distribution system) should have additional options in the standard contract.

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

OneEnergy: Agree with PacifiCorp's proposal to reduce availability of the passive investor exception.

OneEnergy: PV Solar QF "nameplate capacity" should be 0.85 times the maximum DC~~AC~~ ~~capacity~~ output (kWdc) from the project. [OneEnergy/200, Eddie/3]

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"?

OneEnergy: No. This is an overly broad remedy for abuse of standard rates by disaggregators. The partial stipulation, with PacifiCorp's proposed modification to the passive investor exception, can prevent disaggregation without discriminating against solar and wind projects.

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

OneEnergy: Yes, during the sufficiency period.

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?

OneEnergy: No position at this time.

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)(I)? If so, when?

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

OneEnergy: The appropriate maximum term for fixed-price contracts for QFs under 3 MW directly connected to the purchasing utility's system is up to 25 years. [OneEnergy/200, Eddie/3].

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. **Interconnection Process**

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?