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October 26, 2011

Via Electronic and U.S. Mail

Public Utility Commission of Oregon
Attn: Filing Center
P.O. Box 2148
Salem, OR 97308-2148

Re: In the Matter of PUBLIC UTILITY COMMISSION OF OREGON Investigation into Avoided Cost Purchases from Qualifying Facilities-Schedule 37
OPUC Docket No. UE 235

Attention Filing Center:

Enclosed for filing in the above-captioned docket are an original and five copies of *PacifiCorp's Opening Brief (Phase One).*

An extra copy of this cover 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
Attorney for PacifiCorp

cc: UE 235 Service List

Enclosures

BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UE 235

IN THE MATTER OF PUBLIC UTILITY COMMISSION OF OREGON, Investigation into Avoided Cost Purchases from Qualifying Facilities – Schedule 37	**PACIFICORP'S OPENING BRIEF (PHASE ONE)**

PacifiCorp, dba Pacific Power, respectfully submits its opening brief in Phase One of UE 235. PacifiCorp respectfully requests an order from the Public Utility Commission of Oregon ("Commission") holding that the Public Utility Regulatory Policies Act of 1978 ("PURPA")[1] and Oregon policy are violated if PacifiCorp is required to pay standard avoided cost rates under PacifiCorp's Oregon Tariff Schedule 37 ("Schedule 37") and PacifiCorp must also pay for third-party transmission to move qualifying facility ("QF") output from the point of delivery to PacifiCorp load. PacifiCorp further requests that the Commission's order hold that any third-party transmission cost associated with a Schedule 37 QF (and any third-party transmission savings associated with a Schedule 37 QF) should be directly assigned to, and borne by, the Schedule 37 QF.

I. PROCEDURAL BACKGROUND

On June 27, 2011, PacifiCorp filed Advice No. 11-011 seeking to revise Schedule 37. The revisions clarify that a Schedule 37 QF must pay the cost of any third-

[1] 16 U.S.C. §§ 824a-3 *et seq.*

party transmission required to move QF output from the QF's point of delivery to PacifiCorp load. Effective August 18, 2011, the Commission suspended Advice No. 11-011 and opened Docket No. UE 235 to investigate the tariff revisions proposed by PacifiCorp. On October 5, 2011, administrative law judge Traci Kirkpatrick established a scope and briefing schedule for Phase One of the investigation (the "October 5 Ruling").

The October 5 Ruling establishes a phased investigation, with Phase One intended to consider whether PURPA is violated if PacifiCorp is required to purchase QF output at Schedule 37 rates and is required to pay for third-party transmission to move the output of the QF from the point of delivery to PacifiCorp load. The October 5 Ruling directs the parties to address the Parties' Questions Presented (set forth therein), to identify any reliance on stipulated facts or issues, and to address the need for a second phase of the investigation. PacifiCorp's Opening Brief provides short answers to the Parties' Questions Presented (Section II), identifies the ultimate facts upon which PacifiCorp relies (Section III), and addresses the need for a second phase (at the end of Section IV).

II. PARTIES' QUESTIONS PRESENTED AND SHORT ANSWERS

1. Is PURPA violated if PacifiCorp is required to pay Schedule 37 prices and PacifiCorp must also pay for third-party transmission to move QF output from the point of delivery to PacifiCorp load?

Short Answer: Yes; qualified. PURPA and Oregon policy prohibit requiring PacifiCorp to pay more than its full avoided cost for QF output. Schedule 37 rates represent PacifiCorp's full avoided cost. If PacifiCorp is required to pay both Schedule 37 rates and is required to pay for third-party transmission to move QF output from the point of delivery to PacifiCorp load, and if such third-party transmission costs exceed any offsetting savings to PacifiCorp, PacifiCorp is required to pay more than its full avoided cost in violation of PURPA.

2. **Is PURPA violated if PacifiCorp is required to pay Schedule 37 prices and PacifiCorp must also pay for third-party transmission to move QF output from the point of delivery to PacifiCorp load; and the cost to purchase third-party transmission service to move QF output to PacifiCorp load is not, in aggregate, offset by savings in third-party transmission service costs created by other Schedule 37 QFs?**

Short Answer: Yes. Under the facts assumed in the second question presented, PURPA is violated because third-party transmission related savings arising from Schedule 37 QFs do not fully offset third-party transmission related costs arising from Schedule 37 QFs, meaning that PacifiCorp's cost for Schedule 37 QFs would exceed its full avoided cost, on a system-wide basis for all Schedule 37 QFs. As discussed in Section IV(C) below, due to the manner in which third-party transmission providers charge for point-to-point transmission service, savings (if any) from Schedule 37 QFs do not fully offset third-party transmission related costs caused by Schedule 37 QFs.

3. **Is PURPA violated if PacifiCorp is required to pay Schedule 37 prices and PacifiCorp must also pay for third-party transmission to move QF output from the point of delivery to PacifiCorp load; and the cost to purchase third-party transmission service to move QF output to PacifiCorp load is, in aggregate, offset by savings in third-party transmission service costs created by other Schedule 37 QFs?**

Short Answer: No. On these assumed facts PURPA is not violated because third-party transmission related savings arising from Schedule 37 QFs fully offset third-party transmission related costs arising from Schedule 37 QFs. Under such facts PacifiCorp's cost for Schedule 37 QFs does not exceed its full avoided cost, on a system-wide basis for all Schedule 37 QFs. However, the physical and contractual circumstances in which savings are equal to or greater than third-party transmission costs, on an aggregated basis, do not exist (*see* Section IV(C) below).

III. MATERIAL FACTS

PacifiCorp alleges the following material facts:[2]

1. PacifiCorp has an obligation under PURPA to purchase net output from QFs at its avoided cost.[3]

2. Avoided cost is the cost that PacifiCorp would pay to acquire the net output from another source, if it did not purchase such output from the QF.[4]

3. Power purchase agreements that have the effect of requiring PacifiCorp to pay more than its full avoided cost for QF output violate PURPA and are therefore void *ab initio*.[5]

4. PacifiCorp's Oregon Tariff Schedule 37 and associated standard power purchase agreements set forth the terms, conditions, and pricing for PacifiCorp's purchases in Oregon of net output from QFs with capacity of 10 MW or less.[6]

5. The standard avoided cost rates established by Schedule 37 are intended to reflect PacifiCorp's full avoided cost to purchase output from QFs with nameplate capacity of 10 MW or less.[7]

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[2] OAR 860-0001-0460 provides:

(1) The Commission or ALJ may take official notice of the following:

(a) All matters of which the courts of the State of Oregon take judicial notice;
(b) Rules, regulations, administrative rulings, and reports of the Commission and other governmental agencies;
(c) Permits, certificates, and licenses issued by the Commission;
(d) Documents and records in the files of the Commission that have been made a part of the files in the regular course of performing the Commission's duties;
(e) General, technical, or scientific facts within the specialized knowledge of the agency;
(f) The results of the Commission's or ALJ's inspection of property at issue in the proceedings if advance notice of the inspection was provided to the parties.

[3] 18 C.F.R. § 292.303(a); 18 C.F.R. § 292.304(b).

[4] 18 C.F.R. § 292.101(b)(6) ("*Avoided costs* means the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."); ORS 758.505(1) ("'Avoided cost' means the incremental cost to an electric utility of electric energy or energy and capacity that the utility would generate itself or purchase from another source but for the purchase from a qualifying facility.").

[5] *Conn. Light & Power Co.*, 70 FERC ¶ 61,012, 61,029 (1995) ("[I]f parties are required by state law or policy to sign contracts that reflect rates for QF sales at wholesale that are in excess of avoided cost, those contracts will be considered to be void *ab initio.*").

[6] Order No. 05-584, 17.

6. The rates set forth in Schedule 37 do not take into account either (a) net costs of third-party transmission during excess generation events; or (b) net costs of curtailment during excess generation events.

7. PacifiCorp's system consists of multiple load areas—some large, some small—each interconnected with other PacifiCorp load areas by the high-voltage transmission system. Some of the interconnecting transmission paths are controlled by third parties such as the Bonneville Power Administration ("BPA").[8] PacifiCorp refers to areas that are served by third-party controlled transmission and have small load relative to local generation as "load-constrained areas".

8. When generation, including generation from one or more Schedule 37 QFs, exceeds the load served by PacifiCorp in a load-constrained area, PacifiCorp must curtail generation or purchase point-to-point transmission service from a third party (to move some excess generation to other PacifiCorp load outside the load-constrained area), or both.[9] PacifiCorp refers to this circumstance as an "excess generation condition".

9. The cost of third-party transmission needed to make full use of QF net output depends upon the volume of net output transmitted and the transmission rates set forth in the third-party transmission agreement.[10]

10. Third-party transmission agreements applicable to the Parties Questions Presented are: (a) the *General Transfer Agreement* between Bonneville Power Administration and PacifiCorp (BPA Contract No. DE-MS79-828P90049) dated May 4, 1982 (the "**BPA GTA**"); and point-to-point transmission service agreements pursuant to (b) the Bonneville Power Administration's Open Access Transmission Tariff ("**BPA OATT**"); (c) the Portland General Electric Open Access Transmission Tariff ("**PGE OATT**"); and (d) the Idaho Power Company Open Access Transmission Tariff ("**Idaho Power OATT**").

11. A copy of the relevant portions of the BPA GTA is attached as **Attachment A**.

12. Copies *Attachment A-Form of Service Agreement for Firm Point-to-Point Transmission Service* for BPA, PGE, and Idaho Power are attached as **Attachment B**, **Attachment C**, and **Attachment D**, respectively.

13. When a QF delivers into a load-constrained area, prudent utility practice requires that PacifiCorp maintain transmission services into the load-constrained area (or

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[7] Schedule 37 at 1; Order No. 05-584, 17.

[8] Affidavit of Bruce Griswold in Support of PacifiCorp's Advice No. 11-011 ("Aff. Griswold"), ¶3.

[9] *Id.* at ¶ 4.

[10] *See* Attachments A-D.

local resources, if any) sufficient to serve the load-constrained area's full requirements when the QF is unavailable.

14. If PacifiCorp uses OATT transmission service to import energy into a load-constrained area, QF deliveries to the load-constrained area do not reduce the cost of such service (there is no third-party transmission savings) because PacifiCorp pays the same whether or not it uses the OATT service.[11]

15. If PacifiCorp uses BPA GTA transmission service to serve a load-constrained area, QF deliveries to the load-constrained area *may* reduce the 12-month ratchet demand (and hence reduce the cost of transmission into the load-constrained area); *however*, such reduction in costs, if any, is likely to be small and is very likely to be more than offset, on an aggregate basis, by the cost of point to point transmission service needed to export excess generation out of the load-constrained area.[12]

16. The amount PacifiCorp saves in Transfer Charges under the BPA GTA due to a QF, if any, can be determined after the fact by calculating the peak demand in the load-constrained area with and without the QF.

17. In aggregate, third-party transmission costs associated with *all* Schedule 37 QFs exceed any third-party transmission savings associated with *all* Schedule 37 QFs.

18. Direct assignment of third-party transmission costs (and benefits, if any) to Schedule 37 QFs does not violate PURPA or Oregon law.

IV. ARGUMENT

A. Background and framework

PURPA requires PacifiCorp to interconnect with and purchase net output from qualifying facilities ("QFs").[13] PacifiCorp must pay its "avoided cost" for such QF output.[14] In Oregon, PacifiCorp must buy the output of QFs 10 MW and smaller under the standard rates contained in Schedule 37.[15] These standard rates reflect PacifiCorp's

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[11] *See, infra* Section IV(C)(3)(ii).

[12] *Id.*

[13] 18 C.F.R. § 292.303.

[14] 18 C.F.R. § 292.304(d)(2)(ii).

[15] Order No. 05-584, 17.

full avoided cost.[16] It is announced Commission policy to protect customers by ensuring that the rates paid by PacifiCorp do not exceed full avoided cost.[17] Further, PURPA prohibits the Commission from requiring PacifiCorp to pay more than its full avoided cost.[18]

PacifiCorp's electric system consists of multiple load areas—some large, some small—each interconnected with other PacifiCorp load areas by the high-voltage transmission system. Some of the interconnecting transmission paths are owned by third parties such as the BPA.[19] In some cases, Portland General Electric Company ("PGE") provides third-party transmission; in other places, Idaho Power Company provides third-party transmission. The relevant point for purposes of this investigation is that all load-constrained areas are linked to PacifiCorp's greater electric system via transmission that is controlled by another utility.

When a QF delivers net output to a PacifiCorp load area with limited demand ("load-constrained area"), that delivery may create a third-party transmission cost, or a third-party transmission savings, or both. By way of example, PacifiCorp serves a load-constrained area (or load pocket) near its Dalreed substation. This Dalreed load pocket has minimum load that fluctuates from 40 MW in the irrigation season to 2 MW in the

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[16] OPUC Order No. 05-584, 2, 32, 34, 59 (ordering utilities to include a "Fixed Price Method" in QF tariffs that "would remit a total avoided energy cost").

[17] Order No. 05-584, 8 (2005) ("Therefore, as a general policy, the Commissioner endorses adherence to avoided costs as the best pricing method." (quoting Order No. 84-742, 3 (1984))).

[18] *Am. Paper Inst., Inc. v. Am. Elec. Power Serv. Corp.*, 461 U.S. 402, 413 (1983) (PURPA "sets full avoided cost as the maximum rate that the Commission may prescribe"); *accord Indep. Energy Producers Ass'n v. Pub. Util. Comm'n of Cal.*, 36 F.3d 848, 850 (9th Cir. 1994); *see also Conn. Light & Power Co.*, 70 FERC ¶ 61,012, 61,029 (1995) (state imposed rates for purchase of QF output which exceed the purchasing utility's avoided cost violate PURPA and FERC regulations).

[19] Material Facts, *supra* ¶ 7, at 5.

non-irrigation season. The Dalreed load pocket is connected to the rest of PacifiCorp's system only by BPA transmission facilities. Historically, PacifiCorp had no generation resources in the Dalreed load pocket. As a result, all of the energy needed to serve load in the pocket was wheeled over BPA's system. In 2009, a Schedule 37 QF—Threemile Canyon Wind I ("Threemile Canyon")—began to deliver net output to PacifiCorp in the Dalreed load pocket. Threemile Canyon has a nameplate capacity of 9.9 MW. As a result, during the irrigation season when load in the pocket is approximately 40 MW, the QF reduces the energy PacifiCorp needs to import using transmission service from BPA to serve the 40 MW load in the pocket, and *may* reduce PacifiCorp's BPA GTA transmission costs into the load pocket.[20] However, in the non-irrigation season when load is approximately 2 MW, Threemile Canyon creates third-party transmission costs in excess of any BPA-GTA savings because PacifiCorp must purchase transmission from BPA to move approximately 7.9 MW of QF output from the 2 MW Dalreed load pocket to some other location on PacifiCorp's system with adequate load to consume the QF output.[21]

[20] PacifiCorp has three years of actual data on the costs and savings associated with third-party transmission into and out of the Dalreed load pocket in association with the Threemile Canyon project. PacifiCorp provided this information as part of its memorandum of law and associated affidavits submitted in Advice No. 11-011 on June 27, 2011 ("Memorandum of Law in Support of Advice 11-011"). The memorandum and affidavits have been incorporated as part of the record in this UE 235 investigative proceeding. As noted on page 5 of the Advice No. 11-011 memorandum of law, the third-party transmission savings associated with the Threemile Canyon project has been between $0 and $800 per year.

[21] The third-party transmission costs to move excess QF generation out of the Dalreed load pocket during the non-irrigation season has cost approximately $100,000 per year. *See* Memorandum of Law in Support of Advice No. 11-011 at 5. For the Threemile Canyon QF, third-party transmission costs have been orders of magnitude larger than third-party transmission savings. As discussed in Section IV(C) below, given the nature of the applicable third-party transmission contracts, PacifiCorp believes third-party transmission costs will always substantially and systematically outweigh third-party transmission savings on an average or system-wide basis.

PacifiCorp's standard rates under Schedule 37 do not account for third-party transmission costs or savings.[22] Implicitly, Schedule 37 rates assume that third-party transmission costs and savings cancel one another out. However, as discussed in Section IV(C) *infra*, third-party transmission costs and savings do not cancel one another out. Rather, third-party transmission costs exceed—systematically and substantially—any third-party transmission savings.[23]

As stated above, requiring PacifiCorp to pay current Schedule 37 rates (representing full avoided cost) plus an additional cost to obtain third-party transmission results in PacifiCorp paying more than full avoided cost and violates Commission policy and federal law.[24] Any power purchase agreements that cause PacifiCorp to pay more than full avoided cost will be void *ab initio*.[25] To conform to PURPA and Commission policy, PacifiCorp proposes to revise Schedule 37 to state that the QF must pay the net cost of third-party transmission to move QF output from the point of delivery to PacifiCorp load.[26]

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[22] Material Facts, *supra* ¶ 6, at 5.

[23] *Id.* ¶ 17, at 6.

[24] *See supra* n. 18; *S. Cal. Edison Co. v. Pub. Util. Comm'n of Cal.*, 101 Cal. App. 4th 384, 398 (2002) (systematic bias that added cost to standard avoided cost rates results in rates above the utility's full avoided cost in violation of PURPA).

[25] *Conn. Light &Power Co.*, 70 FERC at 61,029 ("[I]f parties are required by state law or policy to sign contracts that reflect rates for QF sales at wholesale that are in excess of avoided cost, those contracts will be considered to be void *ab initio.*").

[26] *See* PacifiCorp's Memorandum of Law in Support of Advice No. 11-011 at 7-8. PacifiCorp has proposed to revise Schedule 37 such that: (1) the QF must agree to pay for the required third-party transmission; or (2) the parties (PacifiCorp and the QF) may reach some mutually agreeable alternative solution; or (3) the Schedule 37 PPA will terminate—and the QF may seek a negotiated PPA under PacifiCorp's Oregon Tariff Schedule 38.

B. QF purchases that systematically exceed PacifiCorp's full avoided cost violate PURPA.

The question whether PURPA is violated if PacifiCorp is required to pay Schedule 37 rates *and* required to pay for third-party transmission to move QF output to PacifiCorp load is a matter of first impression in Oregon. However, in substantially analogous circumstances, the California Court of Appeal determined that *a standard rate QF contract violates PURPA if it is systematically biased above the utility's avoided cost.*[27] Applying this rule, the Court of Appeal found no PURPA violation where Southern California Edison Company ("*Edison II*") showed only that the avoided cost rate set by the California Public Utilities Commission ("CPUC") was at times in excess of the spot market price; such evidence did not show a systematic bias.

In another case—*S. Cal. Edison Co. v. CPUC*, 101 Cal. App. 4th 384 (2002) ("*Edison I*")—the California Court of Appeal held that the CPUC's imposition of a floor on line losses chargeable to QFs regardless of the true line loss abused the CPUC's discretion and *was* a violation of PURPA.[28] In *Edison I*, the question involved a CPUC imposed line loss adjustment to standard avoided cost rates. Edison challenged the CPUC's decision to impose a floor of 0.95 for line losses assessed to all QFs relying on renewable resources for their fuel sources, regardless of their actual line losses.[29] The

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[27] *S. Cal. Edison Co. v. Pub. Util. Comm'n. of Cal.*, 128 Cal. App. 4th 1, 11 (Ca. Ct. App. 2005) ("*Edison II*") (The CPUC found "the evidence cited by SCE only demonstrates that during some periods SRAC formula costs exceeded spot market costs . . . [t]his is not the same as systematically exceeding avoided costs in violation of PURPA, and the evidence does not show systematic and continuously excessive prices.").

[28] *Edison I*, 101 Cal. App. 4th at 398.

[29] *Id.* at 399 (The CPUC justified its line loss rule by finding that "the societal benefits associated with resource diversity and environmentally preferred energy production by renewable resources merits special treatment for renewable QFs."). The 0.95 line loss floor imposed by the CPUC meant that a renewable resource QF with 5% line losses and a renewable resource QF with line loses of 20% where both paid the

Court of Appeal agreed with Edison that the CPUC's 0.95 floor on QF transmission line loss factors violated PURPA:

> Here, by setting a 0.95 floor on transmission loss factors, the Commission crossed the line. Congress has clearly indicated an intent to preempt the field in the area of energy regulation and had expressed that intent in section 824(a) of 16 of the United States Code Annotated. * * * FERC has specifically stated that electric utilities are not to be required to pay more than the avoided cost for purchases of electricity from QFs. The Commission is mandated to follow and implement any rules that the FERC prescribes. The 0.95 ruling by the Commission essentially usurps the FERC's authority in determining that the ratepayers shall not support the alternative energy industry.[30]

As a result, the Court of Appeal nullified the CPUC's 0.95 floor.

Third-party transmission costs associated with Schedule 37 QFs are closely analogous to the QF line loss deductions in *Edison I*: both are quantifiable costs associated with a particular QF and neither are accounted for in the published standard rates.[31] The California Court of Appeal disapproved of the CPUC's methodology for allocating those costs among the QFs and the utility because capping a QF's liability for line losses at 5% amounted to an impermissible customer subsidy to QFs. Applying this principle to the issue of third-party transmission costs, the question presented is whether making PacifiCorp pay for third-party transmission costs amounts to the customer subsidizing QFs (e.g. paying more than its avoided cost). If third-party transmission costs are fully offset by third-party transmission savings (e.g. if "it all balances out"),

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standard published rate for 95% of the net output they generated notwithstanding the dramatic difference in line losses and the dramatic difference in amount of energy actually received by Edison. The net result of the 0.95 floor on line losses was to cause Edison to systematically pay more than its full avoided cost for output from renewable resource QFs with line loses greater than 5%.

[30] *Id.* at 398-399 (internal citations omitted).

[31] Line loss factors and third-party transmission charges also are similar in magnitude. In *Edison I*, the line losses were found to, at times, exceed 5%. PacifiCorp estimates the cost of third-party transmission to be approximately 7%.

then there is no unlawful customer subsidy of QFs. But if, as PacifiCorp believes, the costs of third-party transmission, in aggregate, substantially exceed any offsetting savings, then making PacifiCorp pay third-party transmission costs *and* Schedule 37 rates is tantamount to the 0.95 line loss floor struck down by the California Court of Appeal and it violates PURPA.

C. Third-party transmission costs associated with Schedule 37 QFs systematically outweigh third-party transmission savings (if any) associated with Schedule 37 QFs.

1. How QF generation affects PacifiCorp's use of third-party transmission

Any time a QF sells to PacifiCorp, PacifiCorp's merchant function ("PacifiCorp Merchant") submits a request asking PacifiCorp's transmission function ("PacifiCorp Transmission") to designate the new QF output as a Network Resource under the PacifiCorp OATT. Such designation permits PacifiCorp Merchant to use the QF's output to serve its network load using network resource transmission service (provided by PacifiCorp Transmission pursuant to PacifiCorp's OATT). PacifiCorp Merchant pays for network transmission service on the basis of the volume of load served. Therefore, in a non-load constrained area, PacifiCorp Merchant uses network transmission service and there is no additional cost to move QF output to load. But when a QF delivers net output to a load-constrained area, there may be insufficient network load within the load area to consume the QF's output. It may then be necessary for PacifiCorp to purchase point-to-point transmission service from a third-party transmission provider to move QF generation out of the load-constrained area to another location on PacifiCorp's system with adequate load to consume the QF output.

PacifiCorp network resource transmission service does not grant PacifiCorp rights to export power from a load-constrained area using third-party transmission. Likewise, PacifiCorp's existing third-party transmission rights used to import power *into* the load-constrained area do not authorize PacifiCorp to use third-party transmission facilities to move excess generation out of a load-constrained area. Therefore PacifiCorp must purchase third-party transmission service *out of* a load-constrained area.[32] If PacifiCorp does not purchase such third-party transmission service, then it must curtail generation in the load-constrained area to the extent such generation exceeds local load. Either way, there is a cost directly attributable to the QF that causes generation to exceed load in a load-constrained area. Figure 1, below, illustrates generically the conditions that give rise to third-party transmission related costs associated with small QFs.

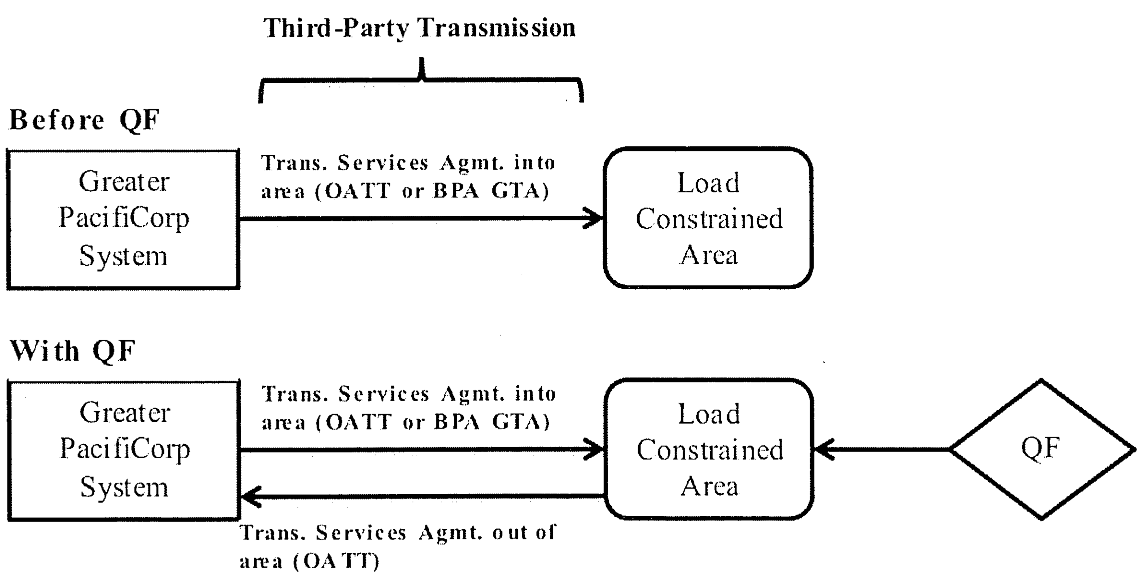

Figure 1: Generic Schematic of transmission service to PacifiCorp Load Constrained Area (assumes no existing generation in LCE)

[32] Material Facts, *supra* ¶ 8, at 5.

2. Agreements Governing Third-Party Transmission Services

The principle agreement governing PacifiCorp's third-party transmission costs is a *Service Agreement for Point-to-Point Transmission Service* under the third-party transmission provider's OATT.[33] In some locations, PacifiCorp receives BPA transmission service *into* a load-constrained area under the BPA GTA, a grandfathered transmission service agreement. The BPA GTA, by its terms, does not apply to any transmission *out of* a load-constrained area.

a. OATT Transmission Service (in or out of load-constrained area)

PacifiCorp may purchase firm point-to-point transmission service across a third-party's transmission system under its OATT. Such service may be used to bring power into or out of a load-constrained area. The cost of firm point-to-point transmission includes a Transmission Charge, Direct Assignment Facilities Charges (if any), and Ancillary Service charges, all of which are based upon the amount of capacity reserved; the cost is not affected by usage (or non-usage) of the reserved capacity. Additional, one-time, expenses include application fees and, potentially, System Impact and/or Facilities Study Charge(s). The costs for which the point-to-point transmission customer (PacifiCorp) is responsible are set forth in the point-to-point transmission service agreement, similar to the form agreements attached hereto as **Attachments B, C,** and **D**.

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[33] The relevant provisions of the OATTs of BPA, PGE, and Idaho Power are comparable. *See* Attachments B, C, and D. Also, compare the BPA OATT (http://transmission.bpa.gov/business/ts_tariff/); PGE OATT (http://www.oatioasis.com/PGE/PGEdocs/PGE-8_OATT.pdf), and the Idaho Power OATT (http://www.oatioasis.com/IPCO/IPCOdocs/IPC_OATT_Vol_6_Order_890A_205_Filing_Clean.pdf).

b. BPA GTA (into load-constrained area only)

PacifiCorp also has the option (for a subset of its load-constrained areas served by BPA) to purchase transmission service across BPA's transmission system under the BPA GTA. Such service may only be used to bring power into a load-constrained area.[34] The cost of BPA GTA service includes a Sole Use of Facilities Charge, which is fixed (e.g. not dependant upon whether PacifiCorp actually uses the facilities), and a Transfer Charge, which is based upon the customer's peak hour usage of the transmission path during the current month and the previous eleven months.[35]

3. Cost implications of adding QF generation to load constrained areas

a. Transmission cost implications

Because there are two types of transmission service available into a load-constrained area, there are two cases to look at when assessing the cost implications of adding a QF to a load-constrained area.

i. Case 1: OATT service in; (New) OATT service out

In circumstances where PacifiCorp takes OATT service in both directions, the additional third-party transmission cost is equal to the total cost of OATT service necessary to move excess generation from the QF *out of* the load-constrained area (see Fig. 1, *supra)*. PacifiCorp does not reduce OATT service into the load-constrained area when a QF is added because prudent utility practice requires that PacifiCorp maintain at all times transmission rights sufficient to serve the load-constrained area in the event of a

[34] The BPA GTA is a legacy agreement pre-dating FERC's pro-forma OATT. Use of the BPA GTA is restricted to certain legacy transmission paths. Over time, BPA and PacifiCorp have been replacing BPA GTA service with OATT service. For these reasons, BPA GTA service is available on a diminishing minority of BPA transmission paths serving PacifiCorp load areas.

[35] *See,* Attachment A (excerpts of the BPA GTA).

QF outage.[36] Since OATT transmission charges are the same whether or not the reserved transmission capacity is actually used, there is **<u>no</u>** off-setting savings resulting from QF delivering into a load-constrained area that is otherwise served by third-party transmission purchased under an OATT.[37]

ii. Case 2: BPA GTA service in; (New) OATT service out

In circumstances where PacifiCorp takes service into a load-constrained area under the BPA GTA, the additional third-party transmission cost is equal to the total cost of OATT service necessary to move excess generation from the QF *out of* the load-constrained area *less* offsetting savings under the BPA GTA, if any. PacifiCorp does not reduce BPA GTA service into the load-constrained area when a QF is added because prudent utility practice requires that PacifiCorp maintain at all times transmission rights sufficient to serve the load-constrained area in the event of a QF outage. However, since BPA GTA transmission charges include a ratcheted demand charge (Transfer Charge), savings on charges to import power into a load-constrained area can result from QF generation located in a load-constrained area, if the QF generation lowers the 12-month peak demand. The amount of such savings, if any, can be determined after the fact by calculating the peak demand in the load-constrained area with and without the QF.[38] In cases where the QF is non-dispatchable, the reduction in 12-month demand is likely small due to the variability of generation and the likelihood that it will at times be unavailable during peak demand periods. In the case of one, 9.9 MW wind QF, the observed reduction in ratcheted peak demand during its first two years of operation (2009 and

[36] Material Facts, *supra* ¶ 13, at 6.

[37] Material Facts, *supra* ¶ 14, at 6.

[38] Material Facts, *supra* ¶ 16, at 6.

2010) was 0kW and 334 kW, respectively.[39] In most cases (and almost certainly in the aggregate of all Schedule 37 PPAs), any third-party transmission savings realized under the BPA GTA will be dwarfed by the third-party transmission costs associated with purchasing third-party transmission out of the load-constrained area under the BPA OATT.[40]

b. Generation curtailment implications

If a load-constrained area receives generation from more than one local source, PacifiCorp may have an additional option of curtailing generation from the other source(s) in the load-constrained area. If PacifiCorp curtailed local generation rather than purchasing point-to-point transmission, the additional cost attributable to adding the QF to a load-constrained area is the cost to curtail the local resource with the lowest curtailment cost to PacifiCorp, whether it be the new QF or an existing resource. In most cases, the cost to purchase point-to-point transmission will be much less than the cost incurred by PacifiCorp if it curtails generation.

4. Summation

QF generation exceeding load in a load-constrained area causes PacifiCorp to incur additional costs in the form of third-party point-to-point transmission charges or

[39] Aff. Griswold ¶ 16.

[40] As previousl;y discussed in footnotes 20 and 21 *supra*, as part of the memorandum of law supporting Advice No. 11-011 PacifiCorp submitted actual data regarding BPA GTA cost savings created by the existing 9.9 MW Threemile Canyon QF. Import of energy into the Dalreed load pocket (necessary during the irrigation season when load pocket loads average 40 MW) occurs over BPA's system under the BPA GTA. Export of Threemile Canyon generation out of the Dalreed load pocket (which is necessary during the non-irrigation season when load in the pocket averages 2 MW) occurs under the BPA OATT. Under these circumstances, third-party transmission savings under the BPA GTA are $0 to $900 per year while third-party transmission costs under the BPA OATT are approximately $100,000 to $150,000 per year. *See* PacifiCorp's Memorandum of Law In Support of Advice No. 11-011 at 5. In sum, savings in transmission into the load pocket under the BPA GTA are orders of magnitude smaller than costs of transmission out of the load pocket under the BPA OATT.

potential curtailment damages payable to the QF or another generator. These costs are only subject to offset if the QF generation in the load-constrained area reduces PacifiCorp's Transfer Charges under the BPA GTA. The BPA GTA—a legacy agreement—is only applicable in a limited subset of cases. When the BPA GTA applies, any third-party transmission savings realized under the BPA GTA have been, in practice, much smaller than the third-party transmission cost under the BPA GTA to move QF generation out of the load-constrained area. The net effect of QFs delivering into load-constrained area is to increase PacifiCorp's costs beyond the rate paid under Schedule 37, on a system-wide basis.[41]

D. Direct assignment of third-party transmission costs (and savings) to Schedule 37 QFs addresses the concerns raised above, avoids any PURPA violation, and is consistent with the Commission's approach of directly assigning costs associated with interconnection improvements.

As discussed above, third-party transmission costs systematically outweigh third-party transmission savings. Current Schedule 37 standard rates do not attempt to account for this systematic bias in cost. Rather, Schedule 37 rates represent PacifiCorp's full avoided cost as if there is no third-party transmission cost associated with Schedule 37 QFs (or as if third-party transmission costs are fully offset by third-party transmission savings). Under these circumstances, PacifiCorp is required to pay more than its full avoided cost (in violation of PURPA and Commission policy) if PacifiCorp is required to pay full Schedule 37 rates and PacifiCorp is required to pay for third-party transmission to move QF output from the point of delivery to PacifiCorp load. To avoid this result, PacifiCorp proposed in Advice No. 11-011 that third-party transmission costs be assigned

[41] Material Facts, *supra* ¶ 17, at 6.

directly to the Schedule 37 QF with which such costs are associated. Such direct assignment of third-party transmission costs (or savings) would mirror Commission policy reflected in UM 1401 and AR 521 regarding QF interconnection costs.

In Docket No. UM 1401 the Commission adopted rules and guidelines for interconnection of QFs larger than 20 MW nameplate capacity. The Commission found that such QFs should pay for system upgrades required to mitigate any adverse system impacts caused by the QF interconnection.[42] In Docket No. AR 521, the Commission adopted rules and guidelines for interconnection of QFs with nameplate capacity of 10 MW or less. The Commission found that QFs under 10 MW should "pay for system upgrades that are 'necessitated by the interconnection of a small generator facility' and 'required to mitigate' any adverse system impacts 'caused' by the interconnection."[43] To the extent it considered the issue, the Commission in both dockets found that the QF should pay for the cost of necessary system upgrades directly caused by the QF's interconnection. The Commission's reasoning in these interconnection dockets strongly suggests that third-party transmission costs necessary to move a QF's output from the point of delivery to PacifiCorp load should be directly assigned to the QF because such costs are the direct result of a QF's generation.

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[42] *Investigation into Interconnection of PURPA Qualifying Facilities With Nameplate Capacity Larger Than 20 Megawatts to a Public Utility's Transmission or Distribution System*, OPUC Docket No. UM 1401, Order No. 10-132, 7 (2010) ("Interconnection Customers are responsible for all costs associated with network upgrades unless they can establish quantifiable system-wide benefits, at which point the Interconnection Customer would be eligible for direct payments from the Transmission Provider in the amount of the benefit.").

[43] *In the Matter of a Rulemaking to Adopt Rules Related to Small Generator Interconnection*, OPUC Docket No. AR 521, Order No. 09-196, 5 (2009) (quoting OAR 860-082-0035(4). "Adverse system impact" is defined in OAR 860-082-0005, as "[a] negative effect caused by the interconnection of a small generator facility that may compromise the safety or reliability of a transmission or distribution system."

If the Commission were to decide, as a matter of policy, that third-party transmission costs (and savings, if any) should be assigned directly to the QF, the Commission would not have to determine whether QF-related third-party transmission costs are greater than QF-related third-party transmission savings. Because the solution of directly assigning costs and savings to QFs is within the Commission's authority to implement PURPA, and because the solution would be consistent with PURPA, the Commission need not make the determination that PURPA is violated by the status quo in order to implement the solution. PURPA would not be violated by direct assignment because PacifiCorp would not be required to pay Schedule 37 rates and to pay the costs of third-party transmission. QFs would not be prejudiced because individual QFs would enjoy the savings, if any, (and bear the costs) created by their specific projects. Finally, this approach would allow the Commission to resolve UE 235 and Advice No. 11-011 in a fair manner, within the mandatory time limits imposed by Commission rules.

E. Conclusions and Implications for Phase Two.

In Phase One, the Commission can conclude that PacifiCorp is not required to pay both Schedule 37 rates and the cost of third-party transmission to move QF output to PacifiCorp load: (1) because third-party transmission costs arising from the need to move QF output to load are likely to outweigh any offsetting third-party transmission savings; or, (2) because Commission policy favors direct assignment to each individual Schedule 37 QF the costs (and savings, if any) associated with third-party transmission. If the Commission reaches this conclusion, Phase Two of UE 235 can be used to consider whether the revisions to Schedule 37 proposed by PacifiCorp in Advice No. 11-011 acceptably accomplish such a direct assignment. In the alternative, if the Commission believes that it requires further evidence to determine whether third-party transmission costs and savings associated with Schedule 37 QFs result in a systematic net cost, the Commission can use Phase Two of UE 235 to address this question through a narrowly focused evidentiary inquiry.

V. CONCLUSION

PacifiCorp respectfully requests an order holding: (1) that PURPA and Oregon policy would be violated if PacifiCorp is required to pay both Schedule 37 rates and to pay for third-party transmission to move Schedule 37 QF output from the point of delivery to PacifiCorp load; and (2) that the third-party transmission cost (and savings, if any) associated with a Schedule 37 QF should be directly assigned to and borne by each Schedule 37 QF.

Dated this 26th day of October 2011.

Respectfully submitted,

By ______________________

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Attachment A

to

PACIFICORP'S
OPENING BRIEF (PHASE ONE)
UE 235

Excerpts from *General Transfer Agreement* between Bonneville Power Administration and PacifiCorp (BPA Contract No. DE-MS79-828P90049), May 4, 1982 ("BPA GTA")

October 26, 2011

Contract No. DE-MS79-82BP90049

5-3-82

GENERAL TRANSFER AGREEMENT

executed by the

UNITED STATES OF AMERICA

DEPARTMENT OF ENERGY

acting by and through the

BONNEVILLE POWER ADMINISTRATION

and

PACIFIC POWER & LIGHT COMPANY

Index to Sections

the new charges. A revised Exhibit D shall also be prepared to incorporate any change in Loss Factors pursuant to this section. Such revised Exhibit D shall be substituted for the Exhibit D then in effect and shall become effective as of the effective date of such new methodology or charges.

5. Provisions Relating to Delivery. Electric power and energy shall be made available by the Transferor at all times during the term hereof at the points of delivery described in Exhibits B and C, in the amount of the Transferee's requirements at such points and at the approximate voltages specified therefor. Amounts of electric energy, Integrated Demands therefor, and varhours delivered at such points during each month shall be determined from measurements made by meters installed at the locations and in the circuits specified in Exhibits B and C. Such amounts shall be increased for losses as determined by the parties hereto and specified in Exhibit D (Loss Factors). Such Loss Factors reflect all losses from the point of metering to the point of replacement specified in Exhibit B or C. Losses shall be determined on an incremental basis and the Transferee shall be assessed the incremental losses so determined. On or before July 1 of each year each party shall furnish the other party a five year forecast of the maximum demand for each of the points of delivery described in Exhibits B or C, as the case may be.

6. Replacement of Power Delivered. In exchange for electric power and energy delivered by the Transferor hereunder, the party receiving transfer service shall make electric power and energy available to the Transferor during each month in the term hereof, at the points of replacement specified in Exhibit B or C as the case may be. Such electric power and energy to be made available by the party receiving transfer service shall be computed by

increasing metered amounts, determined as provided in Exhibit B or C for each point of delivery, by the Loss Factors specified in Exhibit D.

The party receiving transfer service shall make available to the Transferor each hour in each month during the term hereof the amount of electric energy which is estimated to be the amount, so increased for losses, which the Transferor will deliver hereunder during such hour, and shall schedule such amount for delivery to the Transferor as provided in the Exchange Agreement.

7. Payment for Transfer of Power.

(a) For the use of Transferor services and facilities in transferring electric power and energy hereunder, the party receiving transfer service shall pay the Transferor each month in the term hereof an amount equal to the sum for all points of delivery of the greater of (1) or (2) below for each point of delivery:

(1) the product of the Transfer Charge for each point of delivery and the Transfer Demand for that month for such point of delivery after increasing such Transfer Demand by one percent for each one percent or major fraction thereof by which the average power factor, at which electric energy is delivered at the point of delivery hereunder during each month, is less than 95 percent lagging; or

(2) the largest product obtained by multiplying the Transfer Demand of each of the 11 immediately preceding months by the respective Transfer Charge for each such month.

(b) The "Transfer Charge" for each point of delivery mentioned in subsection (a) above shall be as shown in Exhibit D. Transfer Charges shall be determined pursuant to Exhibit F.

(c) The "Transfer Demand" mentioned in subsection (a) above shall be the largest of the Integrated Demands, increased by the Loss Factors specified in Exhibit D, at which electric energy is delivered by the Transferor hereunder during such month, determined as provided in Exhibits B or C, as the case may be, after eliminating all abnormal nonrecurring Integrated Demands resulting from emergency conditions.

(d) For determining power factor in subsection (a)(1) above, metered amounts shall be adjusted for losses between the point of metering and the point of delivery. These losses shall be calculated from factors contained in Exhibit H which are different from the Loss Factors contained in Exhibit D.

8. Payment for Sole Use of Facilities. In addition to the payment due the Transferor in accordance with section 7, the party receiving transfer service shall pay the Transferor each month the amounts specified in Exhibit D under "Sole Use of Facilities Charge" for sole use of facilities by the party receiving transfer service. Sole Use of Facilities Charges shall be determined pursuant to Exhibit F.

9. Payment of Bills.

(a) The Company shall reimburse Bonneville in accordance with applicable provisions of Exhibit E by cash payment or, upon mutual agreement of the parties, in accordance with the provisions of section 15 of Exhibit A, Net Billing Section.

(b) Bonneville shall reimburse the Company for services hereunder within 30 days following its receipt of an itemized statement of payments due pursuant to sections 7 and 8 hereof by cash payment or, upon mutual agreement of the parties, in accordance with the provisions of section 15 of Exhibit A, Net Billing Section. If the Company is unable to render Bonneville a timely monthly bill which includes a full disclosure of all billing factors, it may

GWP Form-3 (7-27-77)

GENERAL WHEELING PROVISIONS

Index to Sections

GENERAL APPLICATION

1. Interpretation.

(a) The provisions in the agreement to which these General Wheeling Provisions are an exhibit shall be deemed to be a part hereof for the purpose of determining the meaning of any provision contained herein. If a provision in such agreement is in conflict with a provision contained herein, the former shall prevail

(b) Nothing contained in this agreement shall, in any manner, be construed to abridge, limit, or deprive any party thereto of any means of enforcing any remedy, either at law or in equity, for the breach of any of the provisions thereof which it would otherwise have.

2. Definitions. . As used in this agreement:

(a) the words "Contractor", "Utility" or "Borrower" as used herein shall mean the party to this agreement other than the Administrator;

(b) the word "month" shall mean the period commencing at the time when the meters mentioned in this agreement are read by the Administrator and ending approximately 30 days thereafter when a subsequent reading of such meters is made by the Administrator;

(c) the words "Integrated Demand" shall mean the number of kilowatts which is equal to the number of kilowatt-hours delivered at any point during a clock hour;

(d) the words "System" or "Facilities" shall mean the transmission facilities: (1) which are owned or controlled by either party, or (2) which either party may use under lease, easement, or license.

3. Prior Demands. In determining any credit demand mentioned in, or money compensation to be paid under this agreement for any month, Integrated Demands at which electric energy was delivered by the Transferor at points of delivery mentioned herein for the account of the other party to this agreement prior to the date upon which the agreement takes effect shall be considered in the same manner as if this agreement had been in effect.

4. Measurements. Except as it is otherwise provided in section 7 hereof, each measurement of each meter mentioned in this agreement shall be the measurement automatically recorded by such meter, but if not so recorded, shall be the measurement as determined by the parties hereto.

If it is provided in this agreement that measurements made by any of the meters specified therein are to be adjusted for losses, such adjustments shall be made by using factors, or by compensating the meters, as agreed upon by representatives designated by the parties to such agreement. If changes in conditions occur which substantially affect any such loss factor or compensation, it will be changed in a manner which will conform to such changes in conditions.

POINTS OF DELIVERY FOR THE COMPANY

This revision No. 7 removes the Klondike, Gordon Hollow, Bandon, and Boyer Points of Delivery.

1. ALVEY POINT OF DELIVERY

Location. the point in the Government's Alvey Substation where the 115 kV facilities of the Company and Bonneville are connected;

Voltage. 115 kV;

Metering. in the Government's Alvey Substation, in the 115 kV circuit over which such electric power and energy flows;

Point of Replacement. the point in the Government's Alvey Substation where the 230 kV facilities of the Company and Bonneville are connected;

Exception. Company loads metered at Alvey Line 4 will be adjusted by subtracting Emerald PUD loads metered at Creswell adjusted for losses between the Creswell meter and the Alvey 115 kV bus.

2. CEDARVILLE JUNCTION POINT OF DELIVERY

Location. the point near the Government's 115/69 kV Cedarville Junction Substation where the 69 kV facilities of Surprise Valley and the Government are connected;

Voltage. 69 kV;

Metering. in Surprise Valley's Cedarville Substation, in the 12.5 kV circuit over which such electric power and energy flows;

Point of Replacement. the point in the Government's Cedarville Junction Substation where the 115 kV facilities of the Parties are connected.

3. DALREED POINT OF DELIVERY

Location. the point near structure 37/3 of the Government's McNary-Santiam 230 kV transmission line where the facilities of the Parties are connected;

Voltage. 230 kV;

Metering. in the Company's Dalreed Substation, in the 34.5 kV circuit over which such electric power and energy flows;

Point of Replacement. the point in the Government's McNary Substation where the 230 kV facilities of the Parties are connected.

4. KNAPPA-TAP POINT OF DELIVERY

Location. the point near structure 37/4 of the Government's Longview-Astoria 115 kV transmission line where the facilities of the Parties are connected;

Voltage. 115 kV;

Metering. in the Company's Knappa-Svenson Substation, in the 12.5 kV circuit over which such electric power and energy flows;

Exception. the instrument transformers are owned by the Company;

Point of Replacement. the point in the Company's Astoria Substation where the 115 kV facilities of the Parties are connected.

5. FERN HILL POINT OF DELIVERY

Location. the point near the Company's Fern Hill Substation where the 115 kV facilities of the Parties are connected;

Voltage. 115 kV;

Metering. in the Company's Fern Hill Substation, in the 12.5 kV circuit over which such electric power and energy flows;

Exception. losses in Exhibit D include an adjustment for losses between the POD and the POM;

Point of Replacement. the point in the Company's Astoria Substation where the 115 kV facilities of the Parties are connected.

REVISION NO. 17, EXHIBIT D
TRANSFER CHARGES, SOLE USE-OF-FACILITIES CHARGES, AND LOSS FACTORS

This exhibit revision removes the Bandon, Boyer, Gordon Hollow and Klondike POD's. Also, this revision updates the transfer charge of the remaining POD's where Bonneville is the Transferor.

EFFECTIVE DATE. This exhibit revision shall take effect on November 1, 2009.

Point of Delivery	Transferor	Transfer Charge ($/kW/mo)	Sole Use-of-Facilities Charge ($/mo)	Loss Factors Peak	Loss Factors Energy
Alvey 115 kV (Line 4)	Bonneville	0.1067	0	1.0034	1.0014
Cedarville Junction	Bonneville	0.5470	0	1.0019	1.0008
Dalreed	Bonneville	0.0580	0	1.0059	1.0023
Fern Hill	Bonneville	0.0998	0	1.0056	1.0091
Knappa Tap	Bonneville	0.1783	0	1.0127	1.0110
Vansycle Tap	Bonneville	1.3009	0	1.0190	1.0190
Ashland (City of Ashland)	PacifiCorp	1.3869	0	1.0196	1.0111
Oak Knoll (City of Ashland)	PacifiCorp	1.8900	0	1.0245	1.0138
Mt. Avenue (City of Ashland)	PacifiCorp	1.0368	0	1.0124	1.0084
White Swan (Benton)	PacifiCorp	1.1204	0	1.0317	1.0234
Pilot Butte (Central Electric)	PacifiCorp	0.6489	0	1.0050	1.0024
Ariel (Cowlitz)	PacifiCorp	0.1197	0	1.0384	1.0221
Pilot Rock (Columbia Basin and Umatilla)	PacifiCorp	0.8423	0	1.1151	1.0661
Ukiah (Columbia Power)	PacifiCorp	0.2989	0	1.0887	1.0553
Dayton (Columbia REA)	PacifiCorp	2.9422	0	1.1236	1.0659
Looking Glass (Douglas)	PacifiCorp	1.6083	4,183	1.0786	1.0429
Creswell (Emerald)	PacifiCorp	0.1869	0	1.0063	1.0053
Powerline (Emerald)	PacifiCorp	1.6066	0	1.0224	1.0157
Woody Guthrie (Hood River)	PacifiCorp	0.4347	0	1.0573	1.0309
Bingen (Klickitat)	PacifiCorp	0.2372	0	1.0169	1.0111
Dorena (Lane)	PacifiCorp	0.0000	1,559	1.0069	1.0072
Oremet (Oremet)	PacifiCorp	0.4793	0	1.0095	1.0138
Garibaldi (Tillamook)	PacifiCorp	0.1160	0	1.0241	1.0140
Mohler (Tillamook)	PacifiCorp	0.2996	0	1.0452	1.0268
Nehalem Tap (Tillamook)	PacifiCorp	0.3602	0	1.0513	1.0285
Alturas (Surprise Valley)	PacifiCorp	1.3503	0	1.1796	1.1146
Austin (Surprise Valley)	PacifiCorp	3.8109	0	1.1005	1.0654
Cedarville (Surprise Valley)	PacifiCorp	2.2194	0	1.0406	1.0389
Davis Creek (Surprise Valley)	PacifiCorp	5.5103	0	1.2974	1.1910
Lakeview 69 kV (Surprise Valley)	PacifiCorp	5.7468	325	1.1011	1.0662
Malin (Surprise Valley)	PacifiCorp	0.4126	0	1.0416	1.0271
Hat Rock (Umatilla)	PacifiCorp	0.3993	0	1.0113	1.0099
Pendleton (Umatilla)	PacifiCorp	0.0405	110	1.0105	1.0061
Warm Springs (Wasco)	PacifiCorp	6.0632	0	1.2108	1.1115
Necanicum (West Oregon)	PacifiCorp	1.0431	0	1.0471	1.0337
Olney (West Oregon)	PacifiCorp	1.9403	0	1.6743	1.3385

Methodology for Calculating Transfer Charges and Sole Use of Facilities Charges

The Transfer Charge is the monthly charge per kilowatt of transfer demand as transfer demand is defined in the contract of which this exhibit is a part. The Transfer Charge is equal to one-twelfth of the sum of the Annual Costs of all facilities used in providing the service hereunder divided by the sum of the yearly non-coincidental peak demands as determined in (c) below. The Annual Costs of each facility are defined as the product of: (1) the capital cost of such facility as determined in (a) below; and (2) the Annual Cost Ratio as determined in (b) below. The Transfer Charge is therefore calculated from the formula:

$$\frac{\text{sum of } (I \times R) \text{ for all applicable facilities}}{D} \times 1/12$$

where:

I = Capital cost of such facility as determined in (a) below,
R = Annual Cost Ratio as determined in (b) below,
D = The sum of the yearly non-coincidental peak demands as determined in (c) below.

(a) Capital cost of each such facility as in the most recently published plant investment records of the parties hereto.

(b) Annual Cost Ratio for each such Bonneville facility using the most recent system average cost factors, or Annual Cost Ratio for each such Company facility which incorporates the most recent rate of return approved by the ~~Idaho Public Utility Commission, the Montana Public Service Commission, the~~ Oregon Public Utility Commission~~, or the Washington Utilities and Transportation Commission, as the case may be, for facilities located in the respective states.~~ The Annual Cost Ratio used herein includes the operation and maintenance component defined as "B" in the UFT-2 rate schedule.

RBK
KFJ

(c) The yearly noncoincidental peak demands of all users of such facilities, as determined in part by use of power flows agreed to by both parties and in part by forecasted peaks agreed to by both parties that are different from those used in the power flows. Since the noncoincidental peaks may occur at different times it may not be possible to include both in the same power flow. The parties shall initially use power flows, which are already existing as of January 1, 1982, which are based on 1981-82 Operating Year forecasted peak. Unless the parties subsequently agree to a different method, the following method shall be used to update power flows:

(1) the initial power flows shall be used through December 31, 1983 or such other date as agreed by the parties;

(2) new power flows shall then be prepared which shall use parameters forecasted to exist 2 years from the date that the power flow is prepared;

(3) such new power flows shall then be the basis for transfer charges for 3 years;

(4) every third year the procedure in (2) above shall be repeated and such new power flows shall be used for 3 years.

Sole Use of Facilities Charge

The Sole Use of Facilities Charge is the transfer charge where a party has sole use of a facility. In such cases the charge is expressed in dollars per month and is calculated as:

sum of (I x R) for all applicable facilities x 1/12

using the same quantities defined above.

Attachment B

to

PACIFICORP'S
OPENING BRIEF (PHASE ONE)
UE 235

Attachment A-Form of Service Agreement for Firm Point-to-Point Transmission Service
from Bonneville Power Administration Open Access Transmission Tariff

October 26, 2011

Service Agreement No. XXTX-XXXXX

ATTACHMENT A

Form of Service Agreement for

Point-to-Point Transmission Service

SERVICE AGREEMENT
for
POINT-TO-POINT
TRANSMISSION SERVICE
executed by the
UNITED STATES OF AMERICA
DEPARTMENT OF ENERGY
acting by and through the
BONNEVILLE POWER ADMINISTRATION
And
(CUSTOMER NAME)

1. This Service Agreement is entered into, by and between the Bonneville Power Administration Transmission Services (Transmission Provider) and (Customer Name) (Transmission Customer).
2. The Transmission Customer has been determined by the Transmission Provider to have a Completed Application for Point-to-Point (PTP) Transmission Service under the Transmission Provider’s Open Access Transmission Tariff (Tariff).
3. The Transmission Customer has provided to the Transmission Provider a deposit, if applicable, unless such deposit has been waived by the Transmission Provider, for Firm Point-to-Point Transmission Service in accordance with the provisions of Section 17.3 of the Tariff.
4. Service under this Service Agreement for a transaction shall commence on the later of (1) the Service Commencement Date as specified by the Transmission Customer in a subsequent request for transmission service, or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed. This Service Agreement shall terminate on such date as mutually agreed upon by the Parties.
5. The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Point-to-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6. Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated in Exhibit D.

7. The Tariff, Exhibit A (Transmission Service Request), Exhibit B (Direct Assignment and Use-of-Facilities Charges), Exhibit C (Ancillary Service Charges), Exhibit D (Notices), and Exhibit E (Creditworthiness and Prepayment) are incorporated herein and made a part hereof. Capitalized terms not defined in this Service Agreement are defined in the Tariff.

8. This Service Agreement shall be interpreted, construed, and enforced in accordance with Federal law.

9. This Service Agreement shall inure to the benefit of and be binding upon the Parties and their respective successors and assigns.

10. The Transmission Customer and the Transmission Provider agree that provisions of Section 3201(i) of Public Law 104-134 (Bonneville Power Administration Refinancing Act) are incorporated in their entirety and hereby made a part of this Service Agreement.

11. Section 202 of Executive Order No. 11246, 30 Fed. Reg. 12319 (1965), as amended by Executive Order No. 12086, 43 Fed. Reg. 46501 (1978), as amended or supplemented, which provides, among other things, that the Transmission Customer will not discriminate against any employee or applicant for employment because of race, color, religion, sex, or national origin, is incorporated by reference in the Service Agreement the same as if the specific language had been written into the Service Agreement, except that Indian Tribes and tribal organizations may apply Indian preference to the extent permitted by Federal law.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

(CUSTOMER NAME)		UNITED STATES OF AMERICA Department of Energy Bonneville Power Administration	
By:	______________________	By:	______________________
Name: *(Print/Type)*	______________________	Name: *(Print/Type)*	______________________
Title:	______________________	Title:	Transmission Account Executive
Date:	______________________	Date:	______________________

EXHIBIT A
SPECIFICATIONS FOR LONG-TERM
FIRM POINT-TO-POINT TRANSMISSION SERVICE

TRANSMISSION SERVICE REQUEST
Assign Ref is:___________

1. TERM OF TRANSACTION

Service Commencement Date:
Termination Date:

2. DESCRIPTION OF CAPACITY AND ENERGY TO BE TRANSMITTED BY TRANSMISSION PROVIDER AND MAXIMUM AMOUNT OF CAPACITY AND ENERGY TO BE TRANSMITTED (RESERVED CAPACITY)

3. POINT(S) OF RECEIPT

4. POINT(S) OF DELIVERY

5. DESIGNATION OF PARTY(IES) SUBJECT TO RECIPROCAL SERVICE

6. NAMES OF ANY INTERVENING SYSTEMS PROVIDING TRANSMISSION SERVICE

7. SERVICE AGREEMENT CHARGES

Service under this Service Agreement will be subject to some combination of the charges detailed below and in Exhibits B and C. (The appropriate charges for transactions will be determined in accordance with the terms and conditions of the Tariff.)

7.1 Transmission Charge: *[all applicable charges or discounts shall be identified]*

7.2 System Impact and/or Facilities Study Charge(s):

7.3 Direct Assignment Facilities Charges:

7.4 Ancillary Service Charges:

8. OTHER PROVISIONS SPECIFIC TO THIS SERVICE AGREEMENT

EXHIBIT B
DIRECT ASSIGNMENT AND USE-OF-FACILITIES CHARGES

EXHIBIT C
ANCILLARY SERVICE CHARGES

EXHIBIT D
NOTICES

1. NOTICES RELATING TO PROVISIONS OF THE SERVICE AGREEMENT

Any notice or other communication related to this Service Agreement, other than notices of an operating nature (section 2 below), shall be in writing and shall be deemed to have been received if delivered in person, by First Class mail, by facsimile or sent by overnight delivery service.

2. NOTICES OF AN OPERATING NATURE

Any notice, request, or demand of an operating nature by the Transmission Provider or the Transmission Customer shall be made either orally or in writing by First Class mail or by facsimile.

EXHIBIT E
CREDITWORTHINESS AND PREPAYMENT

Attachment C

to

PACIFICORP'S
OPENING BRIEF (PHASE ONE)
UE 235

Attachment A-Form of Service Agreement for Firm Point-to-Point Transmission Service
from Portland General Electric Company Open Access Transmission Tariff

October 26, 2011

ATTACHMENT A

Form of Service Agreement For Firm Point-To-Point Transmission Service

1.0 This Service Agreement, dated as of _______________, is entered into, by and between ___________ (the Transmission Provider), and ____________ ("Transmission Customer").

2.0 The Transmission Customer has been determined by the Transmission Provider to have a Completed Application for Firm Point-To-Point Transmission Service under the Tariff.

3.0 The Transmission Customer has provided to the Transmission Provider an Application deposit in accordance with the provisions of Section 17.3 of the Tariff.

4.0 Service under this agreement shall commence on the later of (l)___________________, or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service under this agreement shall terminate on _____________________.

5.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

____
____
____

Transmission Customer:

____
____
____

7.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider:

By: ________________________ ________________ _______________
Name Title Date

Transmission Customer:

By: ________________________ ________________ _______________
Name Title Date

Specifications For Long-Term Firm Point-To-Point Transmission Service

l.0 Term of Transaction: ________________________________

Start Date: ____

Termination Date: __________________________________

2.0 Description of capacity and energy to be transmitted by Transmission Provider including the electric Control Area in which the transaction originates.

____

3.0 Point(s) of Receipt: ______________________________________

Delivering Party: ____

4.0 Point(s) of Delivery: _____________________________________

Receiving Party: ____

5.0 Maximum amount of capacity and energy to be transmitted (Reserved Capacity):

____

6.0 Designation of party(ies) subject to reciprocal service obligation: ____________________

7.0 Name(s) of any Intervening Systems providing transmission service: ____________________
____
____

8.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Transmission Charge: _________________________________

8.2 System Impact and/or Facilities Study Charge(s): _____________________________

8.3 Direct Assignment Facilities or Other Schedule 7 Charges: ______________________

8.4 Ancillary Services Charges: ____________________________

Attachment D

to

PACIFICORP'S
OPENING BRIEF (PHASE ONE)
UE 235

Attachment A-Form of Service Agreement for Firm Point-to-Point Transmission Service
from Idaho Power Company Open Access Transmission Tariff

October 26, 2011

ATTACHMENT A

Form Of Service Agreement For Firm Point-To-Point Transmission Service

1.0 This Service Agreement, dated as of ________________________, is entered into, by and between Idaho Power Company (the Transmission Provider), and CUSTOMER NAME & TSIN CODE (“Transmission Customer”).

2.0 The Transmission Customer has been determined by the Transmission Provider to have a Completed Application for Firm Point-To-Point Transmission Service under the Tariff.

3.0 The Transmission Customer has provided to the Transmission Provider an Application deposit in accordance with the provisions of Section 17.3 of the Tariff.

4.0 Service under this agreement shall commence on the later of (l) the requested service commencement date, or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed, or (3) such other date as it is permitted to become effective by the Commission. Service under this agreement shall terminate on such date as mutually agreed upon by the parties.

5.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

Idaho Power Company

1221 W. Idaho Street

Boise, ID 83702

Attn: Manager, Grid Operations

Transmission Customer:

CUSTOMER NAME

CUSTOMER ADDRESS

CUSTOMER CITY/STATE/ZIP

ATTENTION

7.0 The Tariff is incorporated herein and made a part hereof.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider:

By: ________________________ ________________________ ______________
Name Title Date

Transmission Customer:

By: ________________________ ________________________ ______________
Name Title Date

Specifications For Long-Term Firm Point-To-Point Transmission Service

1.0 Term of Transaction:

Start Date:

Termination Date:

2.0 Description of capacity and energy to be transmitted by Transmission Provider including the electric Control Area in which the transaction originates.

3.0 Point(s) of Receipt:

Delivering Party:

4.0 Point(s) of Delivery:

Receiving Party:

5.0 Maximum amount of capacity and energy to be transmitted (Reserved Capacity):

6.0 Designation of party(ies) subject to reciprocal service obligation:

7.0 Name(s) of any Intervening Systems providing transmission service:

8.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Transmission Charge:

8.2 System Impact and/or Facilities Study Charge(s):

8.3 Direct Assignment Facilities Charge:

8.4 Ancillary Services Charges:

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that, on the 26th day of October 2011, a true and correct copy of the foregoing *PacifiCorp's Opening Brief (Phase One)* regarding OPUC Docket No. UE 235 was served on the following named persons/entities by electronic mail:

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DATED this 26th day of October 2011.

LOVINGER KAUFMANN LLP

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