BEFORE THE
PUBLIC UTILITY COMMISSION OF OREGON

CASE NO. UE 235

Phase 1

IN THE MATTER THE PUBLIC UTILITY COMMISSION OF OREGON Investigation Into Avoided Cost Purchases from Qualifying Facilities - Schedule 37	RESPONSE BRIEF OF THE COMMUNITY RENEWABLE ENERGY ASSOCIATION

The Community Renewable Energy Association ("CREA") respectfully submits this Response Brief in Phase 1 of this docket pursuant to Administrative Law Judge Kirkpatrick's scheduling order dated October 5, 2011. CREA respectfully requests that the Public Utility Commission of Oregon ("Commission" or "OPUC") hold that no violation of the Public Utility Regulatory Policies Act of 1978 ("PURPA") or Oregon law occurs when PacifiCorp must pay for third-party transmission to move Schedule 37 qualifying facility ("QF") output from the point of delivery to PacifiCorp load. CREA respectfully requests that the Commission reject PacifiCorp's Advice No. 11-011 because Schedule 37 does not systematically require PacifiCorp to pay above the full avoided costs. Alternatively, if the Commission determines to pursue this investigation further, CREA respectfully requests that the Commission develop mechanisms to compensate Schedule 37 QFs for PacifiCorp's avoided interconnection and transmission costs to prevent PacifiCorp from compensating Schedule 37 QFs for *less* than PacifiCorp's full avoided costs.

I. PROCEDURAL BACKGROUND

On June 27, 2011, PacifiCorp filed Advice No. 11-011 seeking to revise Schedule 37. PacifiCorp's revised Schedule 37 would require a QF to pay the cost of any third- party transmission required to move QF output from the QF's point of delivery to PacifiCorp load. PacifiCorp's proposed Schedule 37 would invalidate the contract of any QF who refused to pay for such third-party transmission and was unable to reach another arrangement suitable to PacifiCorp within 15 days of PacifiCorp identifying the "load pocket" problem. The Commission held a series of public meetings addressing PacifiCorp's request and its impact on individual QFs seeking contracts, and in Order No. 11-341 suspended Advice No. 11-011, effective August 18, 2011. The Commission opened Docket No. UE 235 to investigate the tariff revisions proposed by PacifiCorp. On October 5, 2011, Administrative Law Judge Kirkpatrick established a scope and briefing schedule for Phase 1 of the investigation.

In Phase 1, the Commission will 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 three Questions Presented (set forth below), to identify any reliance on stipulated facts or issues, and to address the need for a second phase of the investigation.

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: No. PacifiCorp's assumed alternatives to Schedule 37 QF energy and capacity are market purchases and a natural gas fired combined cycle combustion turbine plant. Incremental increases in acquisition of energy and capacity from either of those QF alternatives would likely require acquisition of costly third-party transmission or costly upgrades to PacifiCorp's own transmission system to move power to PacifiCorp's disparate load pockets. That some similarly situated Schedule 37 QFs may also require PacifiCorp to acquire third-party transmission to move output to load does not violate PURPA. Further, Schedule 37 QFs do not ever receive compensation for transmission costs Schedule 37 QFs enable PacifiCorp to avoid individually or in the aggregate. The Commission would be well within its wide degree of discretion to conclude that the existing Schedule 37 properly implements PURPA by not adjusting avoided cost rates up or down for third-party and Company-owned transmission costs and benefits.

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: Not necessarily. The question assumes that, in the aggregate, Schedule 37 QFs do not provide offsetting transmission benefits associated with PacifiCorp's *existing use* of its *existing* transmission resources. Even assuming no benefit to existing transmission arrangements, incremental QF capacity defers the need for non-QF market purchases and gas plant additions and the incremental transmission costs needed to move those non-QF sources to load. Schedule 37 QFs receive no compensation through avoided cost rates for those actual avoided transmission costs. A PURPA violation would only occur if PacifiCorp were incurring no additional transmission costs to bring incremental additions of market purchases and gas plant output to 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.

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. Under the facts assumed in the question, Schedule 37 QFs in the aggregate provide PacifiCorp with transmission benefits in use of its *existing* transmission arrangements which offset the *additional incremental* third-party transmission costs imposed by some Schedule 37 QFs. In addition, under applicable Commission orders, Schedule 37 QFs do not receive compensation for actual avoided transmission costs associated with PacifiCorp's deferred need to acquire or build additional transmission for incremental additions of its non-QF alternative resources. Thus, the Commission's adoption of Advise No. 11-011 would violate PURPA because Schedule 37 rates alone would provide *less* than the full avoided costs.

III. MATERIAL FACTS

PacifiCorp included a list of material facts in its opening brief. CREA's response to PacifiCorp's alleged facts are set forth below (in italics with PacifiCorp's footnotes omitted). Also, CREA sets forth additional material facts below, as noted:

A. PacifiCorp's Alleged Material Facts with CREA's Objections Noted

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

CREA agrees with the general statement of the law. The complete statement of the law is that PacifiCorp has an obligation under PURPA to purchase net output from QFs at its full avoided costs.[1]

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.

CREA agrees.

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.

CREA disagrees that this conclusion of law is a fact. CREA also disagrees with the misleading and incomplete legal conclusion. QF contracts are not subject to later revision or invalidation after the time of execution, even if the actual avoided costs at the time of delivery differ from the rates calculated at the time of contracting.[2]

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.

CREA agrees.

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.

CREA agrees in part. CREA does not agree that Schedule 37 rates reflect PacifiCorp's full avoided cost rates, as explained below.

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.

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[1] *See American Paper Institute, Inc. v. FERC,* 461 U.S. 402, 413, 417-18, 103 S.Ct. 1921, 1928, 1930 (1983).

[2] *New York State Electric & Gas Corp.*, 71 FERC ¶ 61,027, at pp. 24-26 (1995) (distinguishing *Conn. Light & Power Co.*, 70 FERC 61,012 (1995)); *see also, e.g., Freehold Cogeneration Assoc., L.P. v. Bd. of Regulatory Commnrs. of State of N.J.,* 44 F.3d 1178, 1192-93 (3rd Cir. 1995); *Independent Energy Producers Assn., Inc. v. Calif. Pub. Utilities Commn.*, 36 F.3d 848, 858 (9th Cir. 1994); *Jersey Central Power and Light Co.*, 73 FERC 61,092, pp. 12-13 (1995).

CREA disagrees. Although there is no line item in Schedule 37 or the rate calculation to reduce the amount paid to QFs for such events, Schedule 37 rates can be read to take such events into account without reducing rates as suggested by PacifiCorp.[3]

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"). PacifiCorp refers to areas that are served by third-party controlled transmission and have small load relative to local generation as "load-constrained areas".

CREA agrees.

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. PacifiCorp refers to this circumstance as an "excess generation condition".

CREA disagrees. PacifiCorp's list fails to include all possible opportunities. Other opportunities may include, on individual cases, coordination of QF outages with expected light load periods. Also, in certain circumstances, QFs could agree to delay the online date of a new Schedule 37 QF until after completion of a planned transmission upgrade solving the "excess generation condition," if PacifiCorp were to make the QF aware of that option. In addition, "excess generation" can be sold or exchanged with other parties.

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.

CREA disagrees. There are several other factors involved in the cost of third-party transmission "needed to make full use of QF net output," including the success or failure of efforts to reduce such over-generation events as listed in CREA's supplement to PacifiCorp's Material Fact No. 8.

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3 *See* 18 C.F.R. 292.304(e) (2) (iii), (iv) (describing factors to consider in setting QF rates, including QF contract provisions and ability to coordinate QF outages usefully with the utility's system); PacifiCorp Schedule 37 Standard Contract, § 6.4 (requiring, "Seller shall exercise its best efforts to notify PacifiCorp of planned outages at least ninety (90) days prior, and shall reasonably accommodate PacifiCorp's request, if any, to reschedule such planned outage in order to accommodate PacifiCorp's need for Facility operation"), available online at http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Customer_Generation/Company_Qualified_Facility_Program_4.pdf. Also, as discussed below, PacifiCorp incurs transmission costs for its own incremental additions of non-QF generation, and therefore no reduction to avoided cost rates is necessary when QFs also impose incremental transmission costs.

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").***

CREA disagrees. PacifiCorp's list of relevant transmission agreements is incomplete. Every transmission agreement PacifiCorp uses to move its own generation and market purchases to its disparate service areas in its East and West control area is potentially relevant to this proceeding. Without extensive discovery and factual inquiry, it would be impossible for any party other than PacifiCorp to identify the universe of potential transmission paths, agreements, and planned upgrades through which QF generation enables PacifiCorp to avoid transmission costs.

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

CREA disagrees. PacifiCorp has not provided the parties with the entire agreement, and it is therefore not possible to agree that all relevant portions are attached.

12. Copies of 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.*

CREA agrees, without conceding that these are the only relevant portions of the applicable transmission providers' OATTs.

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

CREA disagrees. PacifiCorp has provided no evidence that prudent electric practice requires PacifiCorp to maintain transmission service into load constrained areas for the full capacity of all QFs delivering to the load pocket, or any evidence of any efforts to limit its expenses in this regard.

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.

CREA disagrees. PacifiCorp has not established that it must hold firm point to point OATT transmission rights for the entire year for the entire capacity of the QF. Mr. Bruce Griswold's affidavit does not address possible use of non-firm point to point transmission where excess transmission capacity exists, or possible use of conditional firm or more flexible Network Transmission rights to reduce the expense with which PacifiCorp is concerned. Nor does Mr. Griswold's affidavit establish that direct assignment of all costs to the QF is warranted because the firm transmission rights would sit idle and not be used by PacifiCorp for any other purpose when not needed for QF output.[4]

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.

CREA disagrees, in part. CREA agrees that under the plain terms of the BPA GTA QFs are likely to reduce PacifiCorp's costs to serve any portion of its service territory for which it uses that BPA GTA (not just load constrained areas). The rest of PacifiCorp's statement is speculative and unsupported by sufficient evidence. PacifiCorp offered a single example of a single 9.9 MW wind project to demonstrate that in one instance PacifiCorp believes its third party transmission costs will increase because of the QF.[5] PacifiCorp offered no evidence regarding the aggregate third-party transmission savings of all existing and potential future Schedule 37 QFs across its Oregon service territory, against which one could conclude the Schedule 37 third-party transmission costs outweigh all corresponding benefits.

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.

CREA agrees, without conceding the BPA GTA is the only transmission arrangement under which PacifiCorp could recognize cost savings from QFs.

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[4] *See generally Affidavit of Bruce Griswold* ("*Aff. Griswold*"), OPUC Docket No. UE 235. With regard to a prudency determination in rate recovery for retaining long-term transmission rights, the Commission recently stated it expects to see PacifiCorp provide evidence "precisely quantifying the level of benefits" provided by retaining the transmission rights. *See In re PacifiCorp 2012 Transition Adjustment Mechanism*, OPUC Docket No. UE 227, Order No. 11-435, p. 26 (Nov. 4, 2011). The assertions in Mr. Griswold's affidavit fall far short of meeting this test.

[5] *Aff. Griswold* at ¶¶ 10-17. Even PacifiCorp's single example is facially flawed because PacifiCorp included in its analysis the year of 2009 when the wind QF was not yet commercially operable by the time of the annual load peak. Therefore, the QF had no way to reduce third party transmission costs under the BPA GTA in one of the two years analyzed. *Id.* at ¶ 15.

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.

CREA disagrees.

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

CREA disagrees that this conclusion of law is a fact. CREA disagrees with PacifiCorp's legal conclusion, as explained in the Argument Section below.

B. CREA's Additional Material Facts[6]

1. The Commission approved methodology for standard Schedule 37 fixed rates requires calculation based on the alternative cost for PacifiCorp to acquire energy from market resources during a resource sufficiency period, and the marginal fixed and variable costs for a natural gas fired combined cycle combustion turbine ("CCCT") plant during a resource deficiency period.[7]

2. In PacifiCorp's 2011 Integrated Resource Plan ("IRP"), PacifiCorp uses a transmission topology consisting of 19 bubbles (geographical areas) in its eastern control area and 15 bubbles in its western control area designed to best describe major load and generation centers, regional transmission congestion impacts, import/export availability, and external market dynamics. Firm transmission paths link the bubbles.[8]

3. PacifiCorp states that its loads are growing.[9]

4. PacifiCorp's 2011 IRP states that it is currently using market purchases as one means to meet its growing load needs.[10] PacifiCorp engages in market electricity purchases from multiple market hubs throughout the western United States, including Mid-Columbia, Palo Verde, Four Corners, California-Oregon Border, Mead, Mona, the

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[6] CREA requests that the Commission take official notice of the facts cited in the documents cited and attached to its legal brief. O.A.R. 860-0001-0460. Those officially noticeable facts set forth in CREA's Material Facts are in materials which include filings with the OPUC, and rulings and reports of other regulatory agencies. Because PacifiCorp has had the opportunity to submit its own evidence into the record in this case, CREA respectfully requests that the Commission admit CREA's attachments into the record in this case. *See State of Oregon v. Bellah*, 242 Or.App. 73, 82, 252 P.3d 357, 362 (Or. App. 2011); *Pierce Auto Freight Lines, Inc. v. Flagg*, 177 Or. 1, 40, 159 P.2d 162 (1945).

[7] *In re Staff's Investigation into Electric Utility Purchases from Qualifying Facilities* ("*In re QF Investigation*"), OPUC Docket No. UM 1129, Order No.05-584, p. 27 (May 23, 2005).

[8] *See PacifiCorp's 2011 Integrated Resource Plan* (*hereinafter "PacifiCorp's 2011 IRP"*), Docket No. LC 52, pp. 157-58 (March 31, 2011) (excerpts attached). The map is included in the attachments.

[9] Direct Testimony of Gregory Duvall, OPUC Docket No. UE 227, PPL/100, Duvall/6 (March 2011) (excerpts of Mr. Duvall's testimony in UE 227 are attached).

[10] *See PacifiCorp's 2011 IRP*, Docket No. LC 52, pp. 150-51.

California market (Cal ISO), and the Nevada-Oregon Border. The third party transmission costs to move power from these hubs to load are included in Oregon customers' rates.[11]

5. PacifiCorp currently plans to build several additional transmission lines connecting the west control area (including Oregon) and other parts of its territory to meet its loads, expand regional resource needs, and access market resources. PacifiCorp's IRP includes a map demonstrating PacifiCorp's extensive expansions planned for its own transmission network, and includes as "Action Items" steps necessary to build six major transmission lines to link its generation resources and load sinks.[12]

6. PacifiCorp also must use third party transmission to connect its load and generation centers. PacifiCorp's 2010 Federal Energy Regulatory Commission ("FERC") Form No. 1 shows that PacifiCorp's 2010 total transmission expense was equivalent to an additional 10 percent cost over and above PacifiCorp's 2010 total power production expense (including Company-generated power and purchased power). It also showed that approximately 70 percent of PacifiCorp's transmission expanse was for third-party transmission, and that approximately 50 percent of PacifiCorp's transmission expense was for BPA transmission. Thus, 2010 BPA transmission expenses amounted to an added expense equivalent to approximately 5 percent of PacifiCorp's total power production expense.[13]

7. PacifiCorp will incur transmission costs to transmit incremental additions of generation to serve growing loads. In PacifiCorp's most-recent power cost update case, PacifiCorp testified that in 2011 and 2012 it will need to acquire "new transmission contracts to wheeling power [sic] to serve the Company's load obligations."[14]

8. PacifiCorp has several natural gas plants, including nine in Utah and two in Washington, but only two located in Oregon. PacifiCorp's two gas plants located in Oregon are the Hermiston plants.[15]

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[11] *See In re PacifiCorp 2012 Transition Adjustment Mechanism*, OPUC Docket No. UE 227, Order No. 11-435, at pp. 23-26 (Nov. 4, 2011)

[12] *PacifiCorp's 2011 IRP*, at pp. 157-58, 262-64.

[13] PacifiCorp's 2010 FERC Form No. 1 was filed with FERC on April 18, 2011, and can be downloaded online at http://www.ferc.gov/docs-filing/forms/form-1/data.asp. The cited excerpts are attached. The FERC Form No. 1, on Schedule page 321, states that PacifiCorp's 2010 total power production expense was $1,920,145,538, and 2010 total transmission expense was $195,628,269, which is approximately equivalent to an additional 10 percent. The same page also states that $136,854,649, approximately 70 percent of the transmission expense, was for "transmission of electricity by others." Schedule Page 332-332.1 shows that the payments to BPA for transmission totaled $97,156,076, which is over half of PacifiCorp's 2010 total annual transmission expenses. For description of FERC Form No. 1 accounts, *see* 18 C.F.R. Part 101.

[14] Direct Testimony of Gregory Duvall, OPUC Docket No. UE 227, at PPL/100, Duvall/20 & Exhibit PPL/104, Duvall/2. A complete list of all of PacifiCorp's existing transmission agreements with third-parties is contained in PacifiCorp's FERC Form No. 1, *supra* note 13, at pp. 332-332.4.

[15] *PacifiCorp's 2011 IRP*, Docket No. LC 52, p. 86.

9. None of PacifiCorp's gas plants are located in an Oregon load center. Even the Hermiston plants rely on transmission to serve at least two different load centers, and PacifiCorp is currently planning to construct a new transmission line to provide more transmission from the Hermiston plants to one load center. PacifiCorp's 2010 FERC Form No. 1 even states that PacifiCorp purchases transmission from the Hermiston Generating Company.[16]

10. PacifiCorp's Schedule 37 resource sufficiency period avoided cost rates, based on a market resource, do not include adders to the avoided cost rate to account for avoided transmission costs to bring the electricity to load.[17]

11. PacifiCorp's Schedule 37 resource deficiency period avoided cost rates, based on the gas plant costs, do not include adders to the avoided cost rate to account for avoided transmission costs to bring the electricity to load.[18]

12. The Commission determined that QFs provide the utility with capacity and should be compensated for that capacity even in resource sufficient periods.[19]

13. In the aggregate, QFs defer the need for market purchases and long-term generation resources. PacifiCorp includes firm QF power purchase agreements ("PPAs") in its load and resource balance for purposes of determining its capacity needs in the future.[20]

14. Schedule 37 QF capacity, in the aggregate, provides PacifiCorp with capacity that defers the need to acquire market resources and associated transmission rights over transmission owned by third parties, or upgrades to PacifiCorp's transmission system.

15. Schedule 37 QF capacity, in the aggregate, provides PacifiCorp with capacity that defers the need to acquire new generation resources, including gas plants, and associated transmission rights over transmission owned by third parties, or upgrades to PacifiCorp's transmission system.

16. Commission rules require Schedule 37 QFs to pay all costs for interconnection and associated local distribution and network upgrades to PacifiCorp's system necessitated by their project, and do not include cost-sharing provisions.[21]

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[16] *Id*. at p. 158; PacifiCorp's FERC Form No. 1, *supra* note 13, at p. 332.1.

[17] *See In re Staff's Investigation into Electric Utility Purchases from Qualifying Facilities* ("*In re QF Investigation*"), OPUC Docket No. UM 1129, Order No. 07-360, p. 27 (Aug. 20, 2007).

[18] *See id*.

[19] *In re QF Investigation*, Order No. 05-584, at p. 28 (With regard to resource sufficiency periods, the Commission stated: "We find this valuation mechanism to be appropriate given the likelihood that a utility will address probable gaps between increasing demand and actual resources, in the absence of incremental QF capacity, with purchases of energy and capacity on the market").

[20] *PacifiCorp's 2011 IRP*, Docket No. LC 52, pp. 95-96, 98, 100-02, 107.

[21] *In re Rules Related to Small Generator Interconnection*, OPUC Docket No. AR 521, Order No. 09-196, pp.

17. PacifiCorp and/or its ratepayers pay the costs of interconnection and local distribution upgrades, as well as any third-party transmission or upgrades to PacifiCorp's transmission system, needed for utility owned generation facilities, such as a new CCCT gas plant.

18. Commission rules allow for non-Schedule 37 QFs, exceeding 20 MW in size, to obtain a refund for network transmission upgrades to PacifiCorp's system if the QF can prove the upgrade will provide system-wide benefits.[22]

19. Under PacifiCorp's OATT, non-PURPA independent developers interconnecting to PacifiCorp's system may receive a refund for transmission upgrades to PacifiCorp's system required for their interconnection and delivery.[23] PacifiCorp and its ratepayers pay these refunds.

IV. ARGUMENT

A. FERC's PURPA regulations require the Commission to set Schedule 37 rates at the full avoided costs, including avoided transmission costs.

The mandatory purchase provisions of PURPA require electric utilities to purchase power produced by cogenerators or small power producers that obtain status as a QF. 16 U.S.C. § 824a-3(a)(2). PURPA directed the FERC to implement regulations "necessary to encourage cogeneration and small power production." 16 U.S.C. § 824a-3(a). PURPA directed FERC to implement regulations that would insure the rates for QF purchases met the following guidelines:

> [T]he rates for such purchase—
>
> (1) shall be just and reasonable to the electric consumers of the electric utility and in the public interest, and
>
> (2) shall not discriminate against qualifying cogenerators or qualifying small power producers.

4- 5 (June 8, 2009).

[22] *In re Investigation into Interconnection of PURPA Qualifying Facilities Larger than 20 Megawatts*, OPUC Docket No. UM 1401, Order No. 10-132, pp. 3-4 (April 7, 2011).

[23] *See Standardization of Small Generator Interconnection Agreements and Procedures*, FERC Docket No. RM02-12, Order No. 2006, at ¶ 40, (May 12, 2005) (addressing Small Generator Interconnection Agreements and cross referencing same rule in Order No. 2003 regarding Large Generator Interconnection Agreements).

> No such rule prescribed under subsection (a) of this section shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy.

16 U.S.C. § 824a-3(b).

FERC determined QFs are entitled to long-term contract rates set at the utilities' *full* avoided costs, not some lesser amount. *See* 18 C.F.R. § 292.304(a); *Small Power Production and Cogeneration Facilities; Regulations Implementing Section 210 of the Public Utility Regulatory Policies Act of 1978*, 45 Fed. Reg. 12,214, 12,222-12,223 (Feb. 25, 1980). The United States Supreme Court unanimously affirmed FERC's full avoided cost rule. *American Paper Institute, Inc. v. FERC*, 461 U.S. 402, 413, 417-18, 103 S.Ct. 1921, 1928, 1930 (1983). PURPA directs the state public utilities commissions to implement FERC's PURPA regulations. 16 U.S.C. § 824a-3(f); *see also* O.R.S. 758.505 *et seq.* Thus, state utility commissions must set rates that are no less than the utility's full avoided costs, yet do not exceed the utility's full avoided costs.

In determining the full avoided costs, FERC's regulations set forth several relevant factors a state commission should consider, to the extent practicable. 18 C.F.R. 292.304(e). Relevant to this case, those factors include:

> (2) The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:
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> * * *
>
> (vi) The individual *and aggregate value of energy and capacity* from qualifying facilities on the electric utility's system; and
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> (vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and
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> (3) The relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph (e)(2) of this section, to the ability of the electric utility to avoid costs, including the *deferral of capacity additions* and the reduction of fossil fuel use; and

> (4) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.
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> 18 C.F.R. 292.304(e)(2)-(4) (emphasis added).

These regulations call for inclusion of avoided transmission costs that a particular utility may realize from the aggregate incremental additions of QF capacity that allow it to defer resources that would use more costly transmission arrangements.

FERC directly so held in *Calif. Pub. Util. Commn.*, 133 FERC ¶ 61,059 (2010). There, the California Public Utility Commission ("CPUC") asserted that "for CHP systems located in transmission constrained areas, a permissible component of the avoided cost consideration should be a 10 percent price 'adder' (or location 'bonus') to reflect the avoided costs of construction of distribution and transmission upgrades that would otherwise be needed." 133 FERC ¶ 61,059, ¶ 31. FERC held "if the CPUC bases the avoided cost 'adder' or 'bonus' on an actual determination of the expected costs of upgrades to the distribution or transmission system that the QFs will permit the purchasing utility to avoid, such an 'adder' or 'bonus' would constitute an actual avoided cost determination and would be consistent with PURPA and our regulations." *Id.*

B. The Oregon Commission has determined that PacifiCorp should not adjust Schedule 37 QF rates to account for transmission costs and benefits because allowing for such adjustments would undermine transparency, simplicity, timeliness and economy of the standard contracting process.

In Docket No. UM 1129, the Commission conducted extensive investigations into QF rates and contracts, and devised Oregon's current QF scheme, including PacifiCorp's Schedule 37 for standard QFs sized 10 MW or less. PacifiCorp proposed pricing flexibility for certain project-specific characteristics, such as integration costs, debt imputation, or commercial or operational costs associated with intermittent QFs. *See In re Staff's Investigation into Electric Utility Purchases from Qualifying Facilities* ("*In re QF Investigation*"), OPUC Docket No. UM 1129, Order No.05-584, pp. 38-39 (May 23, 2005). The Commission noted that it had incorporated limited adjustments, including seasonality and on-peak and off-peak price adjustments. *Id.* at p. 39. But the Commission determined "further flexibility in negotiating the terms of a standard contract would fundamentally undermine the purposes and advantages of standard contracts . . . ." *Id.* "Standard contracts are designed to minimize the need for parties to engage in contract negotiations." *Id.* "It is inappropriate to request that standard contracts be subject to potential negotiation to address project specific characteristics." *Id.*

The Commission has similarly determined that Schedule 37 QFs may receive no credit on top of the published rates for avoided transmission and distribution costs that the QF's point of delivery would allow the utility to realize. *See In re Staff's Investigation into Electric Utility Purchases from Qualifying Facilities* ("*In re QF Investigation*"), OPUC Docket No. UM 1129, Order No. 07-360, p. 27 & Attachment A, Guideline 14 (Aug. 20, 2007). Indeed, the Commission's rules even require any Schedule 37 QFs imposing additional interconnection and network transmission costs to pay for all such costs without providing an opportunity to show entitlement to refunds for upgrades benefiting the transmission system. *CREA Material Facts*, No. 16.

In contrast, for QFs over 10 MW, the Commission specifically allowed for adjustment to QF contract rates for project specific characteristics such as transmission benefits. *See In re QF Investigation*, OPUC Order No. 07-360, p. 27 & Attachment A, Guideline 14. There, the

Commission stated that for large QFs "avoided [transmission and distribution] costs should be taken into account in determining avoided costs." Likewise, QFs over 20 MW pay the upfront costs for transmission upgrades needed for their projects, but receive a refund if they can demonstrate a system-wide benefit. *CREA Material Facts*, No. 18.

In short, the Commission has a policy that transparency and simplicity for standard Schedule 37 contracts warrant assuming that the aggregate project specific costs balance out with the aggregate project specific benefits, and adjustments in pricing up or down for transmission are not warranted.

C. Under normal circumstances – where no third-party transmission is required for QF output – Schedule 37 QFs are not compensated for the full avoided costs because Schedule 37 QFs are not compensated for any avoided transmission costs.

PacifiCorp relies heavily on transmission to string together its disparate load pockets spanning several states. PacifiCorp's 2011 IRP demonstrates this fact well with a dizzying display of the various Company-owned and third-party transmission paths PacifiCorp must use to move electricity between the Company's 19 load and generation "bubbles" in its eastern control area and the 15 "bubbles" in its western control area. *CREA Material Facts*, No. 2. PacifiCorp's transmission expense for 2010 was approximately equivalent to a 10 percent added cost to its total power production costs. *Id.* at No. 6. The 2010 costs for BPA transmission alone were equivalent to approximately a 5 percent cost adder. *Id.*

PacifiCorp is currently acquiring *additional* third-party transmission rights, or self-building its own costly new transmission facilities, to serve growing loads with generation from market purchases and gas plants. *See id.* at Nos. 2-5, 7-9. The map in PacifiCorp's IRP showing PacifiCorp's needed transmission upgrades and PacifiCorp's own testimony in its recent power cost update docket undeniably demonstrate these facts. *Id.* at Nos. 2, 7. According to PacifiCorp's own IRP, QFs' capacity in the aggregate defers the need for incremental additions of non-QF alternatives and the associated incremental transmission costs. *Id.*, at No. 13.

QFs using PacifiCorp's existing distribution and transmission facilities, or paying for the network upgrades to PacifiCorp's transmission system themselves, therefore allow PacifiCorp to avoid the transmission costs it would incur in procuring alternative incremental capacity. QFs requiring PacifiCorp to purchase no additional third-party transmission impose no transmission costs on PacifiCorp. *See PacifiCorp's Opening Brief (Phase One)*, at p. 12 ("in a non-load constrained area, PacifiCorp Merchant uses network transmission service and there is no additional cost to move QF output to load"). PacifiCorp itself acknowledges QFs reduce its existing transmission expenses. *See PacifiCorp's Opening Brief (Phase One)*, at p. 8 ("the QF reduces the energy PacifiCorp needs to import using transmission service from BPA to the 40 MW load pocket, and *may* reduce PacifiCorp's BPA GTA transmission costs into the load pocket"). There is no question that QFs reduce PacifiCorp's costs under *existing* transmission arrangements like the BPA GTA. But more importantly QF capacity in the aggregate also allows PacifiCorp to avoid transmission expenses it would otherwise incur in acquiring the assumed alternatives to Schedule 37 QF output – market purchases or CCCT additions.

In an analogous situation, the Idaho Public Utilities Commission imposed an avoided transmission expense as a component of PacifiCorp's avoided cost rates at a time when the avoided resource was a surrogate Wyoming coal plant that would rely upon costly transmission to reach loads in Idaho. *In re Investigation and Determination of Utility Specific Variables for the Setting of Avoided Cost Rates and the Establishment of Such Rates for PacifiCorp* ("*In re*

PacifiCorp's Idaho QF Rates"), Idaho PUC Case No. PPL-E-89-3/UPL-E-89-5, Order No. 23358, pp. 11-16 (October 1, 1990).[24] In that case, the Idaho Commission found that it was appropriate to consider PacifiCorp's entire integrated system for determining the amount and cost of avoidable transmission associated with the avoided coal plant, and calculated an avoided transmission cost adder which it incorporated into the QF rates. *Id.*

Yet no Schedule 37 QFs' rates include any additional compensation for avoided transmission costs. *See In re QF Investigation*, OPUC Order No. 07-360, p. 27. PacifiCorp obviously will acquire additional third-party or newly built Company-owned transmission to make use of the assumed non-QF alternatives at its various load pockets. To ignore this fact results in under-compensation of Schedule 37 QFs under normal circumstances where the QFs require no additional third-party transmission from the point of delivery to PacifiCorp load. 18 C.F.R. 292.304(e)(2)-(4); *Calif. Pub. Util. Commn.*, 133 FERC ¶ 61,059, ¶ 31. Such under-compensation to Schedule 37 QFs violates PURPA by providing less than the full avoided cost rates. *See Whitehall Wind, LLC v. Montana Pub. Service Commn.*, 355 Mont. 15, 21, 223 P.3d 907, 911 (2010) (reversing state commission determination of avoided costs because record on the whole demonstrated rates relying on stale data were below the actual avoided costs).

The Commission's orders also under compensate Schedule 37 QFs by requiring any Schedule 37 QFs imposing interconnection and transmission costs to pay for all such costs when PacifiCorp would pay for similar upgrade costs required by alternative sources of generation. *Compare CREA Material Facts*, Nos. 16-19, *with In re NorthWestern Energy's Application for Approval of Avoided Cost Tariff for New Qualifying Facilities*, Montana PSC Docket No.

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24 For the Convenience of the Commission and other parties, CREA has attached this ruling.

D2010.7.77, Order No. 7108e, p. 32, ¶ 84 (Oct. 19, 2011)[25] (stating NorthWestern Energy "improperly sought to assign *all* network upgrade costs to the QF instead of the amount of those costs that exceeded what [NorthWestern Energy] otherwise would incur to connect its avoidable resource").

With the ample publicly available evidence of costly transmission necessary to serve PacifiCorp's Oregon loads with incremental additions of the assumed non-QF alternatives, the Commission should hold that Schedule 37 QFs imposing no incremental third-party transmission costs are not compensated for the full avoided costs.

C. PacifiCorp has failed to identify a "systematic" overpayment to QFs that would constitute a violation of PURPA.

PacifiCorp incorrectly asserts that there is a "systematic" flaw with Schedule 37 because PacifiCorp has had to purchase third-party transmission to move QF output out of a single load pocket. PacifiCorp's argument ignores that PacifiCorp must acquire incremental amounts of third-party transmission, or costly upgrades to its own transmission system, to enable use of non-QF resources. PacifiCorp's argument therefore fails.

The situation here is analogous to that in *S. Cal. Edison Co. v. Pub. Util. Commn. of Cal.*, 128 Cal. App. 4th 1 (Cal. Ct. App. 2005) ("*Edison II*"). There, the CPUC found that the utility's evidence "only demonstrates that during some periods SRAC formula costs exceeded spot market costs." *Id.* at 11. The *Edison II* court agreed with the CPUC that such evidence did not demonstrate the formula was "systematically exceeding avoided costs in violation of PURPA, and the evidence in the proceeding does not show systematic and continuously excessive prices."

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[25] Available online at http://psc.mt.gov/Docs/ElectronicDocuments/.

Id. Because the utility provided no proof that the avoided cost rates systematically exceeded actual avoided costs, the CPUC acted within its discretion. *Id.*

Here too, PacifiCorp has simply failed to show that there is a systemic overpayment of Schedule 37 QFs. Determining PacifiCorp's precise avoided transmission costs and expenses related to QFs is obviously a very complex question regarding materials solely within PacifiCorp's possession. PacifiCorp should bear a heightened burden to demonstrate that the limited costs it has identified outweigh the system-wide, aggregate benefits of Schedule 37 QFs.[26] It is without merit for PacifiCorp to speculate with the data provided in this case so far – regarding the single 9.9 MW Three Mile Canyon wind project in perhaps the Company's most load constrained load pocket – that in the aggregate QFs impose costs for third-party transmission that outweigh QF transmission benefits. *See PacifiCorp's Opening Brief (Phase One)*, at p. 8 & n.21; *Aff. Griswold* at ¶¶ 10-17. PacifiCorp has provided no evidence or even argument regarding system-wide benefits of deferred transmission acquisitions to demonstrate its point.

Further, PacifiCorp primarily relies upon a single, entirely distinguishable case. *See S. Cal. Edison Co. v. Pub. Util. Commn. of Cal.* ("*Edison I*"), 101 Cal. App. 4th 384 (Cal. Ct. App. 2002). The actual facts of that case are quite instructive and useful here. The CPUC had determined to update stale line loss figures in its avoided cost rates, and ultimately relied upon the generation meter multiplier method ("GMM") devised by the California Independent System Operator ("ISO"). *Id.* at 393-94. The CPUC stated the advantages of the GMMs:

[26] The Commission recently imposed a heightened burden on PacifiCorp in a similar context where PacifiCorp possessed the complex materials relevant to an issue. *See In re PacifiCorp 2012 Transition Adjustment Mechanism*, Order No. 11-435, at p. 23 ("Because the company has control of the complex modeling and better access to the details and choices behind it, we expect the company to provide excellent reasons for its modeling choices.").

> 1. GMMs have been *developed and are calculated by the ISO, a neutral, knowledgeable party*; 2. GMMs are *specific to individual QFs*, and consequently more accurate than any single number applied to all QFs; 3. GMMs vary by hour, and thus more accurately reflect the impact on line losses; 4. GMMs have been developed expressly to calculate the impact on system line losses due to power inputs from a given generator; 5. GMMs are being used by the market for purposes of calculating line losses; and 6. GMMs are *readily available, and practical*.
>
> *Id.* at 395 (emphasis added).

Over the objection of a QF, the *Edison I* court held that the CPUC had properly adopted the GMM line loss method. *Id.* at 396. However, the CPUC had also found that "societal benefits associated with resource diversity and environmentally preferred energy production offered by renewable resources merits special treatment for renewable QFs," and thus adopted a "floor for the [Transmission Loss Factor] of 0.95 for QFs relying on renewable resources . . . ." *Id.* The *Edison I* court held that setting an arbitrary floor on the transmission loss factors for renewable QFs required utilities to pay above the avoided cost rates, and therefore violated PURPA. *Id.* at 398-99.

Here, the Commission's current policy does not impose an arbitrary floor on transmission costs to promote "societal" benefits, and PacifiCorp has proposed no alternative formula devised by a neutral third party to precisely and easily calculate the transmission costs and benefits in each individual case. Rather, the Commission has determined that calculating the precise transmission costs and benefits for incremental QF additions to PacifiCorp's system will require fact specific inquiry in each individual case, and that such inquiry would defeat the purpose of standard contracts. *In re QF Investigation*, OPUC Order No. 05-584, at pp. 38-39. Unlike promotion of "societal" benefits in *Edison I*, the Commission's stated purpose of reducing transaction costs for small QFs taking standard Schedule 37 rates is entirely consistent with

FERC's directives. *See* 45 Fed. Reg. at 12,223-24 (promulgating 18 C.F.R. § 292.304(c) to require standard rates that will reduce transaction costs for small QFs). FERC stated, "To the extent that . . . aggregate capacity value can be reasonably estimated, it should be reflected in standard rates." 45 Fed. Reg. at 12,224. The Commission's policy does just that – considers the aggregate capacity value that Schedule 37 QFs provide and allows small QFs to avoid the expense of negotiating precise avoided cost rate increases or decreases related to their individual project specifics.

PacifiCorp's use of its Company-owned and third-party transmission is at least as complicated as the line losses issue in *Edison I.* If PacifiCorp wished to make the facts analogous to those in *Edison I*, PacifiCorp should engage a neutral third party to devise a formula calculating the precise transmission costs and benefits of incremental QF additions at each potential point of delivery in Oregon. CREA would welcome such an approach. But instead PacifiCorp has identified a small handful of QFs that require the purchase of third-party transmission and attempted to impute PacifiCorp's flawed transmission cost-benefit analysis for those QFs to all other Schedule 37 QFs in the aggregate. PacifiCorp completely ignores that all Schedule 37 QFs enable it to avoid transmission costs. That PacifiCorp may incur some additional third-party transmission expense for a few Schedule 37 QFs does not constitute a PURPA violation because PacifiCorp's assumed alternatives to QF resources will also use ample third-party transmission, or PacifiCorp's own costly transmission system upgrades. PacifiCorp has failed to demonstrate the likelihood of a systematic PURPA problem ever arising.

D. The Commission should exercise its "wide discretion" to dismiss Advise No. 11-011, or, alternatively, require a mechanism compensating Schedule 37 QFs for avoided transmission costs.

PURPA and FERC's regulations delegate to state commissions the difficult task of precisely valuing the rates paid to QFs at no more and no less than the utility's full avoided costs. Precisely valuing QF output is difficult, particularly when setting standard rates pursuant to 18 C.F.R. § 292.304(c) for Schedule 37 QFs that should be applicable without extensive project-specific negotiations. It is reasonable therefore that FERC has ruled that state regulatory authorities "are to be accorded a 'wide degree of latitude' in order to accommodate 'local interests and concerns.'" *Cogeneration Coalition of America, Inc.*, 61 FERC ¶ 61,262, p. 9 (1992) (internal quotation omitted); *see also Metropolitan Edison Co.*, 72 FERC 61,269 (1995), *grant'g clar. and den'g reh'g* (rejecting challenge to state avoided cost determination, and stating "we see no reason to second guess the findings of the Pennsylvania Commission in this regard").

The Commission's policy of not allowing adjustment up or down for the standard rates in Schedule 37 QF contracts for transmission expenses is reasonable, and well within the Commission's wide degree of discretion. If PacifiCorp wished to challenge that policy, the time to do so was during UM 1129, not as a subsequent collateral challenge muddying the waters for Schedule 37 QFs currently seeking contracts. On the record in this case, the Commission has the authority to reject PacifiCorp's proposed revisions to Schedule 37, and CREA respectfully requests that the Commission do so.

Alternatively, if the Commission resolves to allow PacifiCorp to assign third-party transmission charges to Schedule 37 QFs, the Commission should also require PacifiCorp to compensate Schedule 37 QFs for the avoided transmission costs they obviously allow PacifiCorp to realize. *Pub. Service Co. of Colo. v. Public Util. Commn. of State of Colo*., 687 P.2d 968, 974 (Colo. 1984) (affirming state commission's inclusion of capacity payment in avoided cost rates because utility's own resource plan showed utility needed additional capacity); *In re PacifiCorp's Idaho QF Rates*, Idaho PUC Order No. 23358, pp. 11-16. PacifiCorp's proposal would only consider transmission costs and benefits of Schedule 37 QFs when doing so will reduce Schedule 37 rates. That is simply unfair.

If the Commission proceeds further, adequate procedural timelines and Commission Staff resources will be necessary to fully address the question of all Schedule 37 QF transmission costs and benefits. The result should include an avoided transmission adder to account for the aggregate impact of QFs that defer the need for additional transmission for PacifiCorp's avoidable resources. The Commission should also require PacifiCorp to include information in its tariffs describing how much QF output it can absorb at each load pocket without the need for third-party transmission, and conversely points of delivery where a Schedule 37 QF would receive an avoided transmission cost adder. Such publicly available information would allow small QFs to locate their projects in a manner that would most effectively utilize PacifiCorp's existing transmission system, and provide the transparency needed to reduce the transaction costs for small QFs. If the Commission proceeds further, it should leave its current policy in place pending completion because PacifiCorp has not demonstrated that in the aggregate, or "systematically," Schedule 37 QF transmission costs outweigh the obvious transmission benefits.

V. CONCLUSION

CREA respectfully requests that the Public Utility Commission of Oregon hold that no violation of the Public Utility Regulatory Policies Act of 1978 or Oregon law occurs when PacifiCorp must pay for third-party transmission to move Schedule 37 qualifying facility output from the point of delivery to PacifiCorp load. CREA respectfully requests that the Commission reject PacifiCorp's Advice No. 11-011 because Schedule 37 does not systematically require PacifiCorp to pay above the full avoided costs. Alternatively, if the Commission decides to further pursue this investigation, CREA respectfully requests that the Commission develop adequate mechanisms to compensate Schedule 37 QFs for avoided interconnection and transmission costs to prevent PacifiCorp from systematically compensating Schedule 37 QFs for *less* than the full avoided costs.

RESPECTFULLY SUBMITTED this 17th day of November 2011.

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CERTIFICATE OF SERVICE

I HEREBY CERTIFY that on the 17th day of November, 2011, a true and correct copy of the within and foregoing **RESPONSE BRIEF** was served as shown to:

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PUBLIC UTILITY COMMISSION OF OREGON CASE NO. UE 235

Phase 1

RESPONSE BRIEF OF THE COMMUNITY RENEWABLE ENERGY ASSOCIATION

ATTACHMENT 1

Excerpts from

PacifiCorp's 2011 Integrated Resource Plan, Docket No. LC 52 (March 31, 2011)

Plant	PacifiCorp Percentage Share (%)	State	Load and Resource Balance Capacity (MW)
Jim Bridger 3	67	Wyoming	353
Jim Bridger 4	67	Wyoming	353
Naughton 1	100	Wyoming	160
Naughton 2	100	Wyoming	210
Naughton 3	100	Wyoming	330
Wyodak	80	Wyoming	271
TOTAL – Coal			**6,173**

Table 5.4 – Natural Gas Plants

Natural Gas-fueled	PacifiCorp Percentage Share (%)	State	Load and Resource Balance Capacity (MW)
Chehalis	100	Washington	509
Currant Creek	100	Utah	506
Gadsby 1	100	Utah	57
Gadsby 2	100	Utah	69
Gadsby 3	100	Utah	100
Gadsby 4	100	Utah	41
Gadsby 5	100	Utah	39
Gadsby 6	100	Utah	39
Hermiston 1 *	50	Oregon	233
Hermiston 2 *	50	Oregon	233
Lake Side	100	Utah	545
Little Mountain	100	Utah	12
James River Cogen (CHP)	100	Washington	14
TOTAL – Gas and Combined Heat & Power			**2,397**

* Remainder of Hermiston plant is purchased under contract by the Company for a plant total of 932 MW.

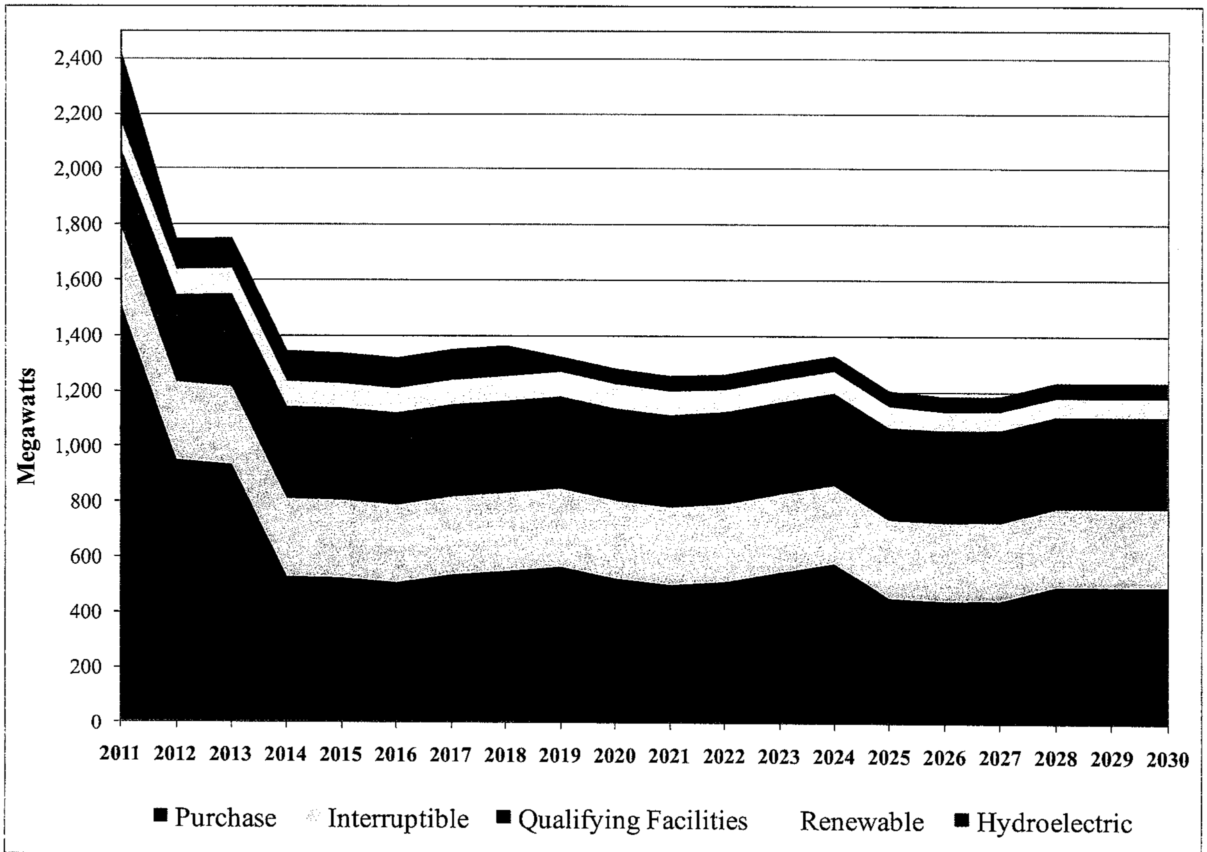
Renewables

PacifiCorp's renewable resources, presented by resource type, are described below.

Wind

PacifiCorp acquires wind power from owned plants and various purchase agreements. Since the 2008 IRP Update, PacifiCorp has acquired several large wind resources including McFadden Ridge I at 28.5 MW and Dunlap I at 111 MW. These projects came on line in 2009 and 2010, respectively. The Company also entered into 20-year power purchase agreements for the total output of several projects that include Top of the World at 200.2 MW, and four other projects due online in 2011 and 2012 that include Power County Wind Park North and South for a total of 43.6 MW, and Pioneer Wind I and II at a total of 99 MW.

Figure 5.1 – Contract Capacity in the 2011 Load and Resource Balance

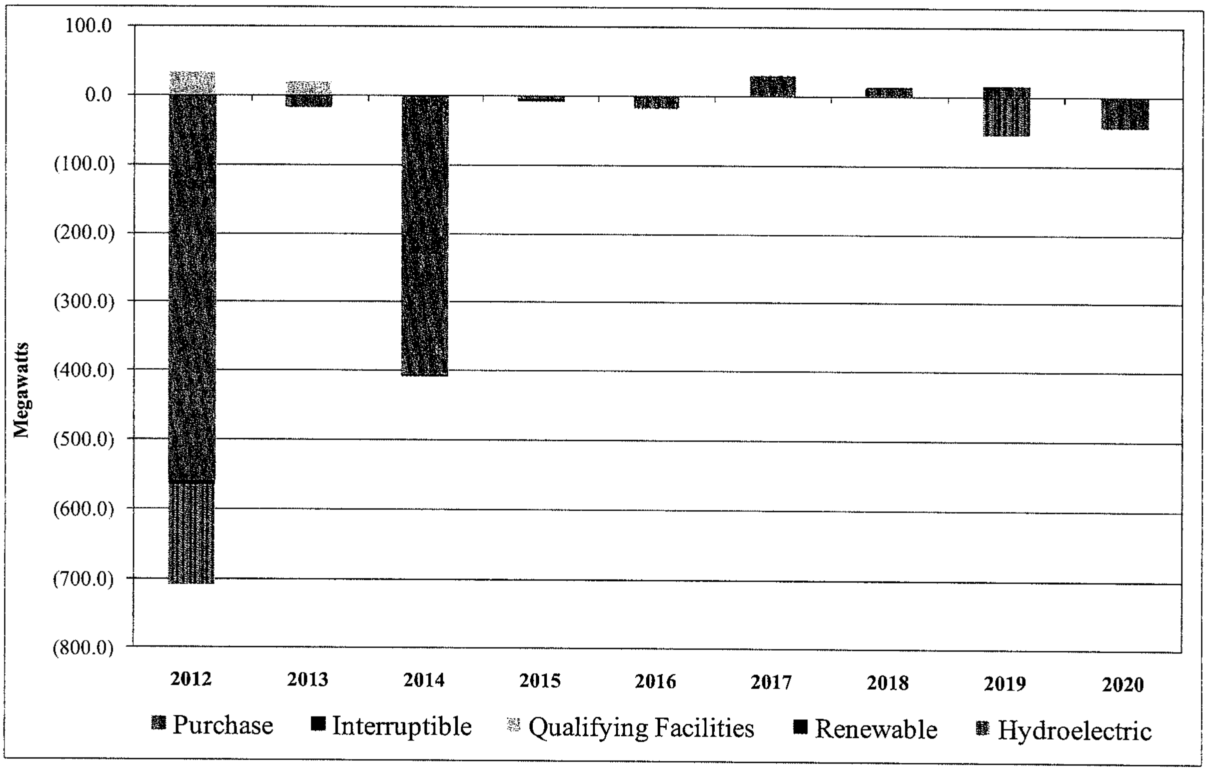


Listed below are the major contract expirations expiring between the summer 2011 and summer 2012:

- BPA Peaking – 575 MW
- Morgan Stanley – 100 MW
- Morgan Stanley – 100 MW
- Colockum Capacity Exchange – 108MW
- Rocky Reach – 65 MW
- Grant Displacement – 63 MW

Figure 5.2 shows the year-to-year changes in contract capacity. Early year fluctuations are due to changes in short-term balancing contracts of one year or less, and expiration of the contracts cited above.

Figure 5.2 – Changes in Power Contract Capacity in the Load and Resource Balance



Load and Resource Balance

Capacity and Energy Balance Overview

The purpose of the load and resource balance is to compare the annual obligations for the first ten years of the study period with the annual capability of PacifiCorp's existing resources, absent new resource additions. This is done with respect to two views of the system, the capacity balance and energy balance.

The capacity balance compares generating capability to expected peak load at time of system peak load hours. It is a key part of the load and resource balance because it provides guidance as to the timing and severity of future resource deficits. It was developed by first determining the system coincident peak load hour for each of the first ten years (2011-2020) of the planning horizon. The peak load and the firm sales were added together for each of the annual system peak hours to compute the annual peak-hour obligation. Then the annual firm-capacity availability of the existing resources was determined for each of these annual system peak hours. The annual resource deficit (surplus) was then computed by multiplying the obligation by the planning reserve margin (PRM), and then subtracting the result from the existing resources.

The energy balance shows the average monthly on-peak and off-peak surplus (deficit) of energy over the first ten years of the planning horizon (2011-2020). The average obligation (load plus sales) was computed and subtracted from the average existing resource availability for each month and time-of-day period. This was done for each side of the PacifiCorp system as well as at the system level. The energy balance complements the capacity balance in that it also indicates when resource deficits occur, but it also provides insight into what type of resource will best fill the need. The usefulness of the energy balance is limited as it does not address the cost of the available energy. The economics of adding resources to the system to meet both capacity and energy needs are addressed with the portfolio studies described in Chapter 8.

Load and Resource Balance Components

The capacity and energy balances make use of the same load and resource components in their calculation. The main component categories consist of the following: existing resources, obligation, reserves, position, and reserve margin. This section provides a description of these various components.

Existing Resources
A description of each of the resource categories follows:

- **Thermal.** This category includes all thermal plants that are wholly-owned or partially-owned by PacifiCorp. The capacity balance counts them at maximum dependable capability at time of system peak. The energy balance also counts them at maximum dependable capability, but de-rates them for forced outages and maintenance. This includes the existing fleet of 11 coal-fired plants, six natural gas-fired plants, and one cogeneration unit. These thermal resources account for roughly two-thirds of the firm capacity available in the PacifiCorp system.

- **Hydro**. This category includes all hydroelectric generation resources operated in the PacifiCorp system as well as a number of contracts providing capacity and energy from various counterparties. The capacity balance counts these resources by the maximum capability that is sustainable for one hour at the time of system peak, an approach consistent with current WECC capacity reporting practices. The energy associated with critical level stream flow is estimated and shaped by the hydroelectric dispatch from the Vista Decision Support System model. The energy impacts of hydro relicensing requirements, such as higher bypass flows that reduce generation, are also accounted for. Over 90 percent of the hydroelectric capacity is situated on the west side of the PacifiCorp system.

  The Public Service Commission of Utah, in its 2008 IRP acknowledgment order, directed the Company to continue investigating the hydro capacity accounting methodology currently under consideration for regional resource adequacy reporting purposes in the Pacific Northwest. This accounting methodology extends the one-hour sustained peaking period to an 18-hour sustained peaking period: the six highest load hours over three consecutive days of highest demand. Appendix K provides PacifiCorp's assessment of the applicability and impact of moving to the 18-hour standard.

- **Dispatchable Load Control (Class 1 DSM).** In 2011, there are projected to be approximately 324 MW of Class 1 DSM programs included as existing resources. These are projected to increase to 329 MW by 2012. Both the capacity balance and the energy balance count DSM programs by program capacity available for system dispatch. Dispatchable load control resources directly curtail load and thus planning reserves are not held for them.[34]

- **Renewable.** This category contains one geothermal project, 21 existing wind projects and two planned wind projects. The capacity balance counts the geothermal plant by the maximum dependable capability while the energy balance counts the maximum dependable capability after forced outages. Project-specific capacity credits for the wind resources were statistically determined using a peak load carrying capability (PLCC) methodology.[35] Wind energy is counted according to hourly generation data used to model the projects.

- **Purchase.** This includes all of the major contracts for purchases of firm capacity and energy in the PacifiCorp system. The capacity balance counts these by the maximum contract availability at time of system peak. The energy balance counts the optimum model dispatch. Purchases are considered firm and thus planning reserves are not held for them.

- **Qualifying Facilities (QF).** All QF that provide capacity and energy are included in this category. Like other power purchases, the capacity balance counts them at maximum system peak availability and the energy balance counts them by optimum model dispatch. It is assumed that all QF agreements will stay in place for the entire duration of the 20-year planning period. It should be noted that three of the QF resources (Kennecott, Tesoro, and US Magnesium) are considered non-firm and thus do not contribute to capacity planning.

- **Interruptible.** There are three east-side load curtailment contracts in this category. These agreements with Monsanto, MagCorp and Nucor provide 281 MW of load interruption capability at time of system peak. Both the capacity balance and energy balance count these resources at the level of full load interruption on the executed hours. Interruptible resources directly curtail load and thus planning reserves are not held for them.

Obligation

The obligation is the total electricity demand that PacifiCorp must serve, consisting of forecasted retail load and firm contracted sales of energy and capacity. The following are descriptions of each of these components:

- **Load**. The largest component of the obligation is the retail load. The capacity balance counts the peak load (MW) at the hour of system coincident peak load. The system coincident peak hour is determined by summing the loads for all locations (topology bubbles with loads). Loads reported by East and West control areas thus reflect loads at the time of PacifiCorp's

[34] Energy efficiency measures—Class 2 DSM programs—are treated as future resources that reduce forecasted loads (see Appendix A). Consequently, they are not included as existing resources in the capacity load and resource balance.

[35] See, Dragoon, K., Dvortsov, V, "Z-method for power system resource adequacy applications" IEEE Transactions on Power Systems (Volume 21, Issue 2, May 2006), pp. 982 – 988.

coincident system peak. The energy balance counts the load as an average of monthly as well as annual time-of-day energy (MWa).

- **Sales**. This includes all contracts for the sale of firm capacity and energy. The capacity balance counts these contracts by the maximum obligation at time of system peak and the energy balance counts them by optimum model dispatch. All sales contracts are firm and thus planning reserves are held for them in the capacity view.

Reserves
The reserves are the total megawatts of planning and non-owned reserves that must be held for this load and resource balance. A description of the two types of reserves follows:

- **Planning reserves**. This is the total reserves that must be held to provide the planning reserve margin (PRM). The planning reserve margin accounts for WECC operating reserves[36], load forecast errors, and other long-term resource adequacy planning uncertainties. The following equation expresses the planning reserve requirement.

  Planning reserves *= (Obligation – Firm Purchases – Class 1 DSM – Interruptible) x PRM*

- **Non-owned reserves**. There are a number of counterparties that operate in the PacifiCorp control areas that purchase operating reserves. This amounts to an annual reserve obligation of about 7 MW and 70 MW on the west and east-sides, respectively. As the balancing authority, PacifiCorp is required to hold reserves for these counterparties but is not required to serve any associated loads.

Position
The position is the resource surplus (deficit) after subtracting obligation plus required reserves from the resource total. While similar, the position calculation is slightly different for the capacity and energy views of the load and resource balance. Thus, the position calculation for each of the views will be presented in their respective sections.

Reserve Margin
The reserve margin is the difference between system capability and anticipated peak demand, measured either in megawatts or as a percentage of the peak load. A positive reserve margin indicates that system capabilities exceed system obligations. Conversely, a negative reserve margin indicates that system capabilities do not meet obligations. If system capabilities equal obligations, then the reserve margin is zero. It should be pointed out that the position can be negative when the corresponding reserve margin is non-negative. This is because the reserve margin is measured relative only to obligation, while the position is measured relative to obligation plus reserves. PacifiCorp adopted a 13 percent target planning reserve margin for the 2011 IRP. Note that a resource can only serve load in another topology location if there is adequate transfer capacity. PacifiCorp captures transfer capacities as part of its capacity expansion planning process. The supporting loss of load probability study is included as Appendix J.

[36] As part of the WECC, PacifiCorp is currently required to maintain at least 5 percent and 7 percent operating reserve margins on hydro and thermal load-serving resources, respectively.

Capacity Balance Determination

Methodology

The capacity balance is developed by first determining the system coincident peak load hour for each of the first ten years of the planning horizon. Then the annual firm-capacity availability of the existing resources is determined for each of these annual system peak hours and summed as follows:

Existing Resources *= Thermal + Hydro + Class 1 DSM + Renewable + Firm Purchases + QF + Interruptible*

The peak load and firm sales are then added together for each of the annual system peak hours to compute the annual peak-hour obligation:

Obligation *= Load + Sales*

The amount of reserves to be added to the obligation is then calculated. This is accomplished by first removing the firm purchase and load curtailment components of the existing resources from the obligation. This resulting amount is then multiplied by the planning reserve margin. The non-owned reserves are then added to this result to yield the megawatts of required reserves. The formula for this calculation is the following:

Reserves *= (Obligation – Firm Purchases – Class 1 DSM – Interruptible) x PRM + Non-owned reserves*

Finally, the annual capacity position is derived by adding the computed reserves to the obligation, and then subtracting this amount from existing resources as shown in the following formula:

Capacity Position *= Existing Resources – Obligation – Reserves*

Firm capacity transfers from PacifiCorp's west to east control areas are reported for the east capacity balance, while capacity transfers from the east to west control areas are reported for the west capacity balance. Capacity transfers represent the optimized control area interchange at the time of the system coincident peak load as determined by the System Optimizer model.[37]

Load and Resource Balance Assumptions

The assumptions underlying the current load and resource balance are generally the same as those from the 2008 IRP update with a few exceptions. The following is a summary of these assumption changes:

- **Wind Commitment.** In October 2010, the Company's commitment to acquire 1,400 MW of renewable resources was met with recent wind projects:

[37] West-to-east and east-to-west transfers should be identical. However, decimal precision of a transmission loss parameter internal to the System Optimizer model results in a slight discrepancy (less than 2 MW) between reported values.

- Dunlap 1 – 111 MW
- Top of the World purchase – 200.2 MW

Additionally, the Company acquired other renewable projects since the last IRP, which include

- McFadden Ridge 1 – 28.5 MW
- Three Buttes Wind – 99 MW
- Casper Wind – 16.5 MW
- Four Mile Canyon Wind – 10 MW
- Four Corners Wind – 10 MW

New Qualifying Facility Wind Plants under construction

- Power County Wind Park North – 21.8 MW
- Power County Wind South – 21.8 MW
- Pioneer Wind I – 49.5 MW
- Pioneer Wind II – 49.5 MW

- **Coal plant turbine upgrades.** The current load and resource balance assumes 65 MW of coal plant turbine upgrades, which is down from the 134 MW assumed in the 2008 IRP Update Report. The reduction is due to capital reprioritization and issues with Sub-Synchronous Resonance (SSR) at the Jim Bridger plants.

Capacity Balance Results

Table 5.11 shows the annual capacity balances and component line items using a target planning reserve margin of 13 percent to calculate the planning reserve amount. Balances for the system as well as PacifiCorp's east and west control areas are shown. (It should be emphasized that while west and east balances are broken out separately, the PacifiCorp system is planned for and dispatched on a system basis.) Also note that the new QF wind projects listed above are reported under the Qualifying Facilities line item rather than the Renewables line item.

Figures 5.3 through 5.5 display the annual capacity positions (resource surplus or deficits) for the system, west control area, and east control area, respectively. The large decrease in 2012 is primarily due to the expiration of the BPA peaking contract in August 2011.

Table 5.11 – System Capacity Loads and Resources Without Resource Additions

Calendar Year	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
East										
Thermal	6,019	6,026	6,028	6,028	6,028	6,046	6,046	6,046	6,046	6,046
Hydroelectric	133	133	133	133	133	129	129	129	129	129
Class 1 DSM	324	329	329	329	329	329	329	329	329	329
Renewable	179	179	179	178	176	176	176	176	176	176
Purchase	655	705	604	304	304	283	283	283	283	283
Qualifying Facilities	152	187	206	206	207	206	207	207	206	206
Interruptible	281	281	281	281	281	281	281	281	281	281
Transfers	810	451	414	456	311	499	547	299	361	328
East Existing Resources	8,553	8,290	8,174	7,916	7,768	7,949	7,997	7,749	7,811	7,778
Load	7,184	7,344	7,566	7,805	8,009	8,201	8,377	8,544	8,712	8,896
Sale	758	997	1,045	745	745	745	659	659	659	659
East Obligation	7,942	8,341	8,611	8,550	8,754	8,946	9,036	9,203	9,371	9,555
Planning reserves	869	913	962	993	1,019	1,047	1,059	1,080	1,102	1,126
Non-owned reserves	70	70	70	70	70	70	70	70	70	70
East Reserves	939	984	1,032	1,063	1,090	1,117	1,129	1,151	1,173	1,196
East Obligation + Reserves	8,881	9,324	9,643	9,613	9,844	10,063	10,165	10,354	10,544	10,752
East Position	(328)	(1,034)	(1,469)	(1,698)	(2,076)	(2,114)	(2,168)	(2,605)	(2,732)	(2,974)
East Reserve Margin	9%	1%	(4%)	(7%)	(11%)	(11%)	(11%)	(15%)	(16%)	(18%)
West										
Thermal	2,552	2,552	2,556	2,556	2,556	2,556	2,541	2,550	2,550	2,550
Hydroelectric	1,103	958	958	957	958	959	958	958	902	745
Class 1 DSM	-	-	-	-	-	-	-	-	-	-
Renewable	77	71	71	71	71	71	71	71	71	71
Purchase	856	247	331	226	221	225	255	269	285	242
Qualifying Facilities	136	136	136	136	136	136	136	136	136	136
Transfers	(809)	(452)	(416)	(457)	(311)	(499)	(547)	(300)	(360)	(330)
West Existing Resources	3,915	3,512	3,636	3,489	3,631	3,447	3,415	3,684	3,584	3,414
Load	3,266	3,374	3,395	3,448	3,491	3,541	3,584	3,650	3,666	3,713
Sale	290	258	258	258	158	108	108	108	108	108
West Obligation	3,556	3,632	3,653	3,706	3,649	3,649	3,692	3,758	3,774	3,821
Planning reserves	351	440	432	452	446	445	447	454	454	465
Non-owned reserves	7	7	7	7	7	7	7	7	7	7
West Reserves	357	447	438	459	452	452	453	460	460	472
West Obligation + Reserves	3,913	4,079	4,092	4,165	4,101	4,100	4,145	4,218	4,234	4,293
West Position	2	(567)	(456)	(676)	(470)	(653)	(730)	(534)	(650)	(879)
West Reserve Margin	13%	(3%)	1%	(5%)	0%	(5%)	(7%)	(1%)	(4%)	(10%)
System										
Total Resources	12,468	11,802	11,810	11,404	11,399	11,397	11,412	11,433	11,395	11,192
System Obligation	11,497	11,973	12,264	12,256	12,403	12,595	12,728	12,961	13,145	13,376
Reserves	1,297	1,430	1,470	1,522	1,542	1,569	1,582	1,611	1,633	1,668
Obligation + 13% Planning Reserves	12,794	13,403	13,735	13,778	13,945	14,164	14,310	14,572	14,777	15,044
System Position	(326)	(1,601)	(1,925)	(2,373)	(2,546)	(2,767)	(2,898)	(3,139)	(3,383)	(3,852)
Reserve Margin	10%	(0%)	(3%)	(6%)	(8%)	(9%)	(10%)	(11%)	(13%)	(16%)

Figure 5.3 – System Capacity Position Trend

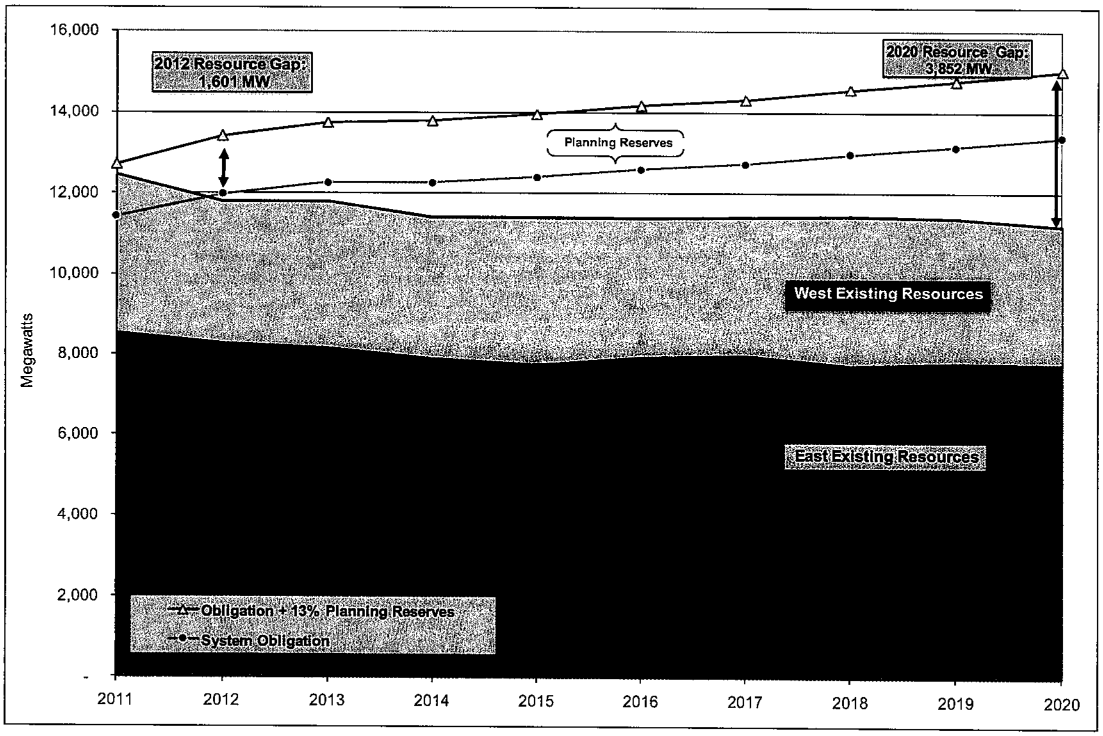


Figure 5.4 – West Capacity Position Trend

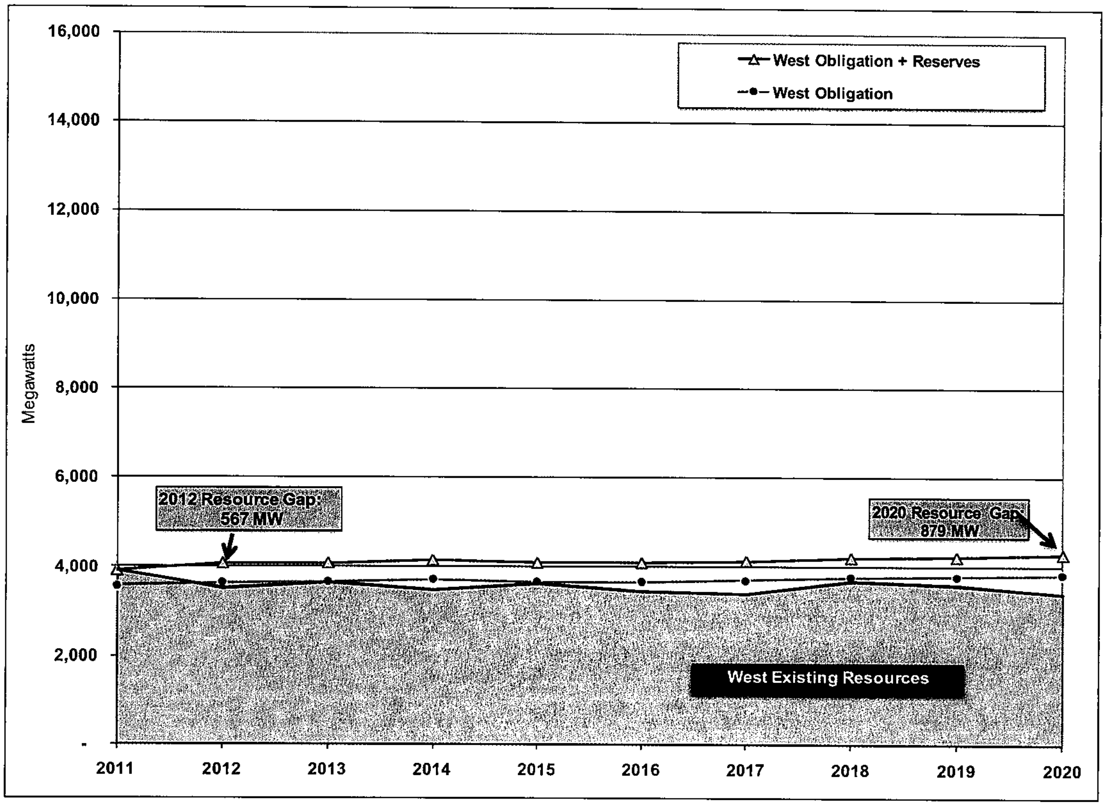
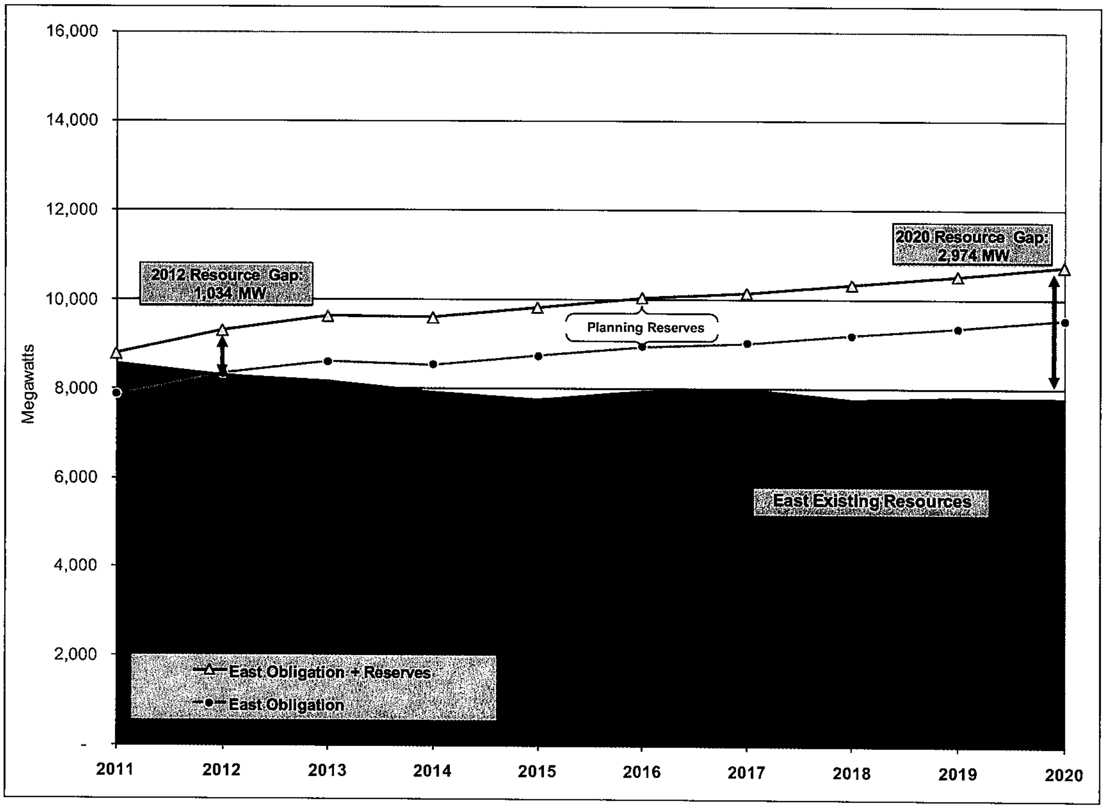


Figure 5.5 – East Capacity Position Trend



Energy Balance Determination

Methodology

The energy balance shows the average monthly on-peak and off-peak surplus (deficit) of energy. The on-peak hours are weekdays and Saturdays from hour-ending 7:00 am to 10:00 pm; off-peak hours are all other hours. Peaking resources such as the Gadsby units are counted only for the on-peak hours. This is calculated using the formulas that follow. Please refer to the section on load and resource balance components for details on how energy for each component is counted.

Existing Resources = *Thermal + Hydro + Class 1 DSM + Renewable + Firm Purchases + QF + Interruptible*

The average obligation is computed using the following formula:

Obligation = *Load + Sales*

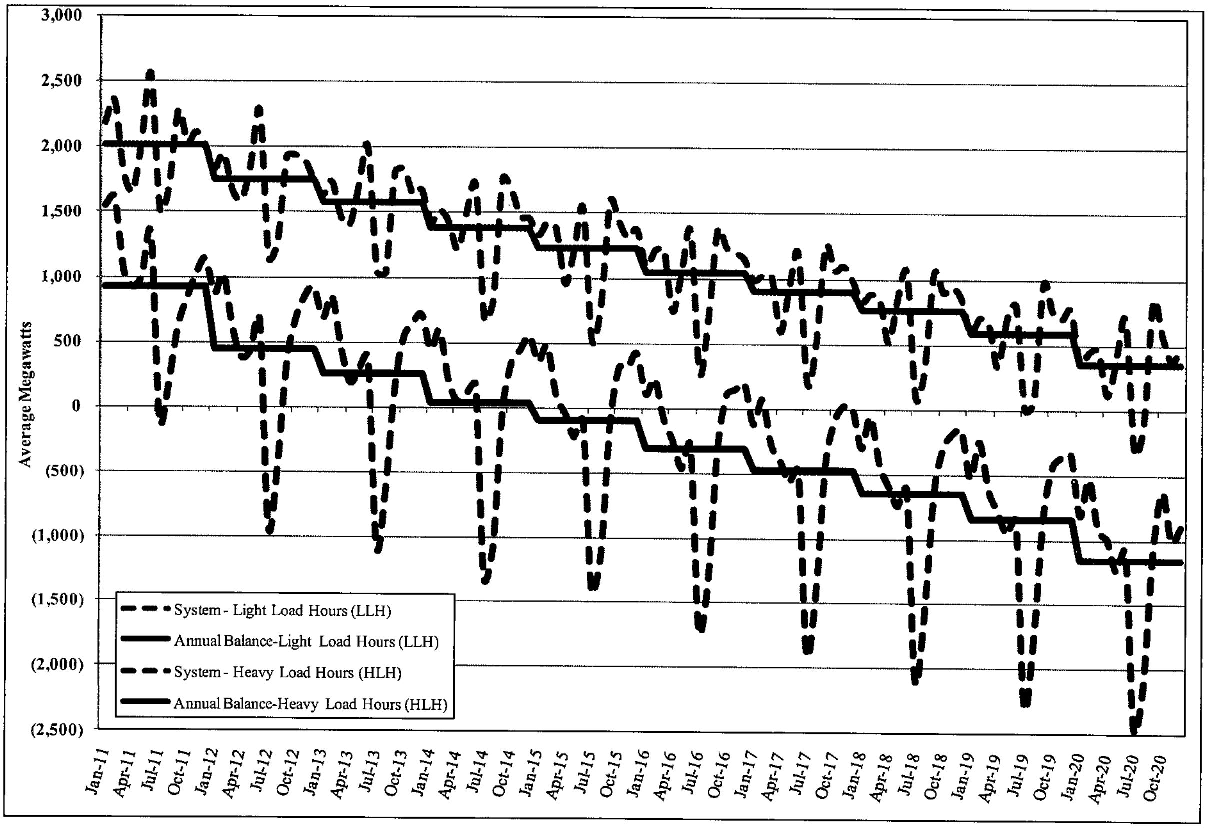
The energy position by month and daily time block is then computed as follows:

Energy Position = *Existing Resources – Obligation – Reserve Requirements (13 percent PRM)*

Energy Balance Results

Figures 5.6 through 5.8 show the energy balances for the system, west control area, and east control area, respectively. They indicate the energy balance on a monthly and annual average basis across heavy load hours and light load hours.[38] The monthly cross-over point, where the system starts to become energy deficient during the summer is 2011.

Figure 5.6 – System Average Monthly and Annual Energy Positions



[38] Heavy load hours constitute the daily time block of 16 hours, Hour-Ending 7 am – 10 pm, for Monday through Saturday, excluding NERC-observed holidays.

Figure 5.7 – West Average Monthly and Annual Energy Positions

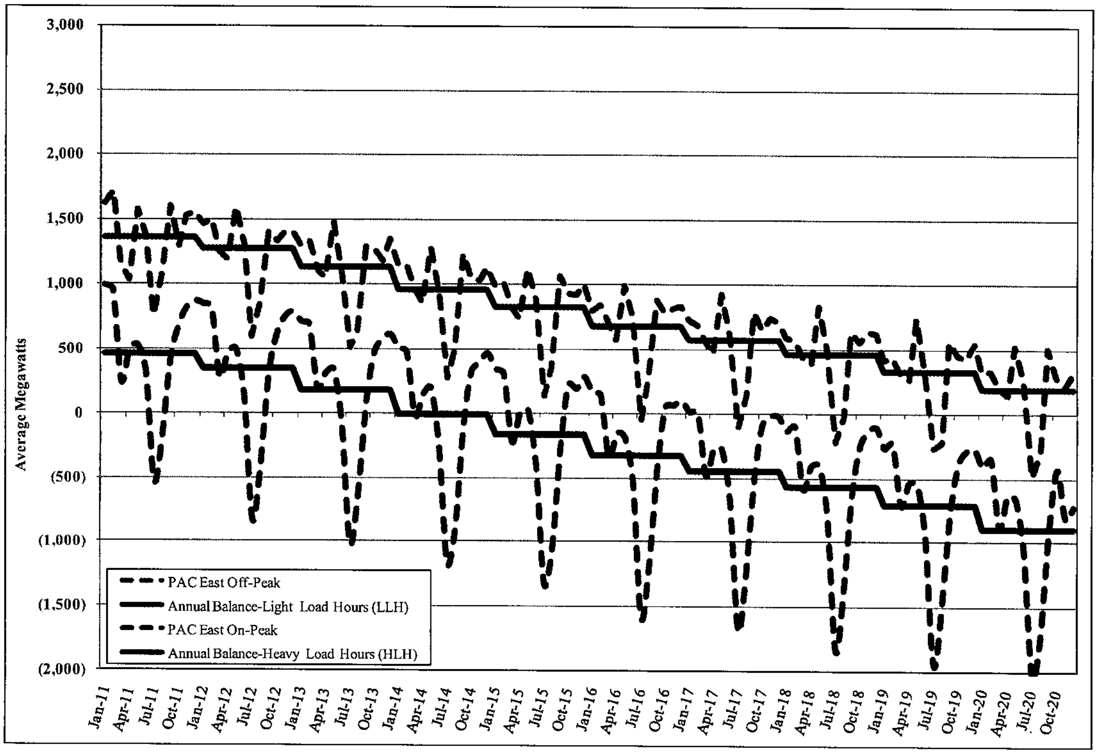
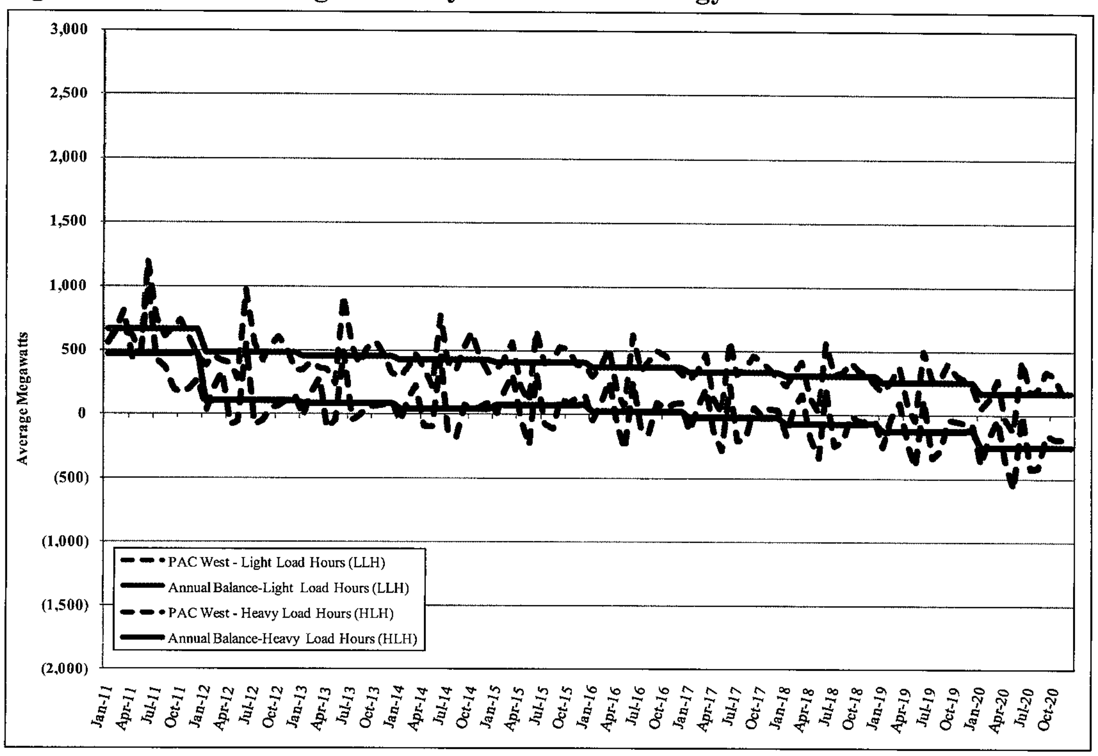


Figure 5.8 – East Average Monthly and Annual Energy Positions



Load and Resource Balance Conclusions

Without additional resources the Company projects a summer peak system resource deficit of 326 MW beginning in 2011. The near-term deficit will be filled by additional DSM programs, renewables, and market purchases. The Company will consider other options during this time frame if they are cost-effective and provide other system benefits. Then, beginning 2014, base load and/or intermediate load resource additions will be necessary to cover the widening capacity deficit.

Transmission Resources

For this IRP, PacifiCorp investigated seven Energy Gateway scenarios, consisting of various combinations of transmission segments. Preliminary evaluation of the seven scenarios using the System Optimizer model resulted in the selection of four scenarios for portfolio modeling. Detailed information on the scenarios and associated modeling approach and findings are provided in Chapter 4.

Market Purchases

PacifiCorp and other utilities engage in purchases and sales of electricity on an ongoing basis to balance the system and maximize the economic efficiency of power system operations. In addition to reflecting spot market purchase activity and existing long-term purchase contracts in the IRP portfolio analysis, PacifiCorp modeled front office transactions (FOT). Front office transactions are proxy resources, assumed to be firm, that represent procurement activity made on an annual forward basis to help the Company cover short positions.

As proxy resources, front office transactions represent a range of purchase transaction types. They are usually standard products, such as heavy load hour (HLH), light load hour (LLH), and/or daily HLH call options (the right to buy or "call" energy at a "strike" price) and typically rely on standard enabling agreements as a contracting vehicle. Front office transaction prices are determined at the time of the transaction, usually via a third party broker and based on the view of each respective party regarding the then-current forward market price for power. An optimal mix of these purchases would include a range in terms for these transactions.

Solicitations for front office transactions can be made years, quarters or months in advance. Annual transactions can be available up to as much as three or more years in advance. Seasonal transactions are typically delivered during quarters and can be available from one to three years or more in advance. The terms, points of delivery, and products will all vary by individual market point.

Two front office transaction types were included for portfolio analysis: an annual flat product, and a HLH third quarter product. An annual flat product reflects energy provided to PacifiCorp at a constant delivery rate over all the hours of a year. Third-quarter HLH transactions represent purchases received 16 hours per day, six days per week from July through September. Because these are firm products the counterparties back the full purchase. For example, a 100 MW front office purchase requires the seller to deliver 100 MW to PacifiCorp regardless of circumstance.[50] Thus, to insure delivery, the seller must hold whatever level of reserves as warranted by its system to insure firmness. For this reason, PacifiCorp does not need to hold additional reserves on its 100 MW firm front office purchase. Table 6.18 shows the front office transaction resources included in the IRP models, identifying the market hub, product type, annual megawatt capacity limit, and availability.

[50] Typically, the only exception would be under force majeure. Otherwise, the seller is required to deliver the full amount even if the seller has to acquire it at an exorbitant price.

Table 6.18 – Maximum Available Front Office Transaction Quantity by Market Hub

Market Hub/Proxy FOT Product Type	Megawatt Limit and Availability
Mid-Columbia Flat Annual ("7x24") and 3rd Quarter Heavy Load Hour ("6x16")	400 MW + 375 MW with 10% price premium, 2011-2030
California Oregon Border (COB) Flat Annual ("7x24") and 3rd Quarter Heavy Load Hour ("6x16")	400 MW, 2011-2030
Southern Oregon / Northern California 3rd Quarter Heavy Load Hour ("6x16")	50 MW, 2011-2030
Mead 3rd Quarter, Heavy Load Hour (6x16)	190 MW, 2011-2012 264 MW, 2013-2014 100 MW, 2015-2016 0 MW, 2017+
Mona 3rd Quarter, Heavy Load Hour (6x16)	200 MW, 2011-2012 300 MW, 2013+
Utah North 3rd Quarter, Heavy Load Hour (6x16)	250 MW, 2011-2030

To arrive at these maximum quantities, PacifiCorp considered the following:

- Historical operational data and institutional experience with transactions at the market hubs.
- The Company's forward market view, including an assessment of expected physical delivery constraints and market liquidity and depth.
- Financial and risk management consequences associated with acquiring purchases at higher levels, such as additional credit and liquidity costs.

Prices for front office transaction purchases are associated with specific market hubs and are set to the relevant forward market prices, time period, and location, plus appropriate wheeling charges.

For this IRP, the Public Utility Commission of Oregon directed PacifiCorp to evaluate intermediate-term market purchases as resource options and assess associated costs and risks.[51] In formulating market purchase options for the IRP models, the Company lacked cost and quantity information with which to discriminate such purchases from the proxy FOT resources already modeled in this IRP. Lacking such information, the Company anticipated using bid information from the All-Source RFP reactivated in December 2009, if applicable, to inform the development of intermediate-term market purchase resources for modeling purposes. The Company received no intermediate-term market purchase bids; therefore, such resources were not modeled for this IRP.

[51] Public Utility Commission of Oregon, In the Matter of PacifiCorp, dba Pacific Power 2007 Integrated Resource Plan, Docket No. LC 42, Order No. 08-232, April 4, 2008, p. 36.

Table 7.1 – Resource Book Lives

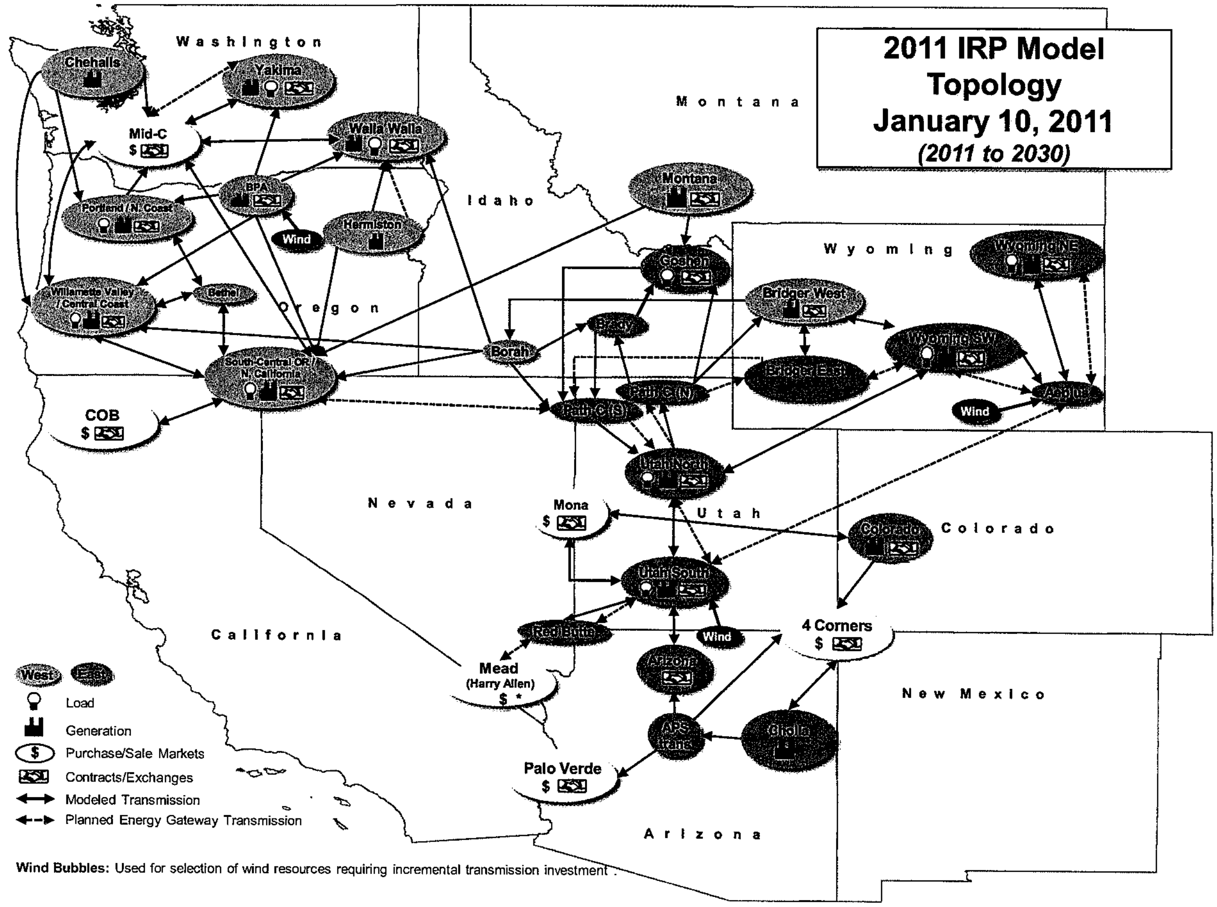
Resource	Book Life (Years)
Supercritical pulverized coal/Integrated Gasification Combined-Cycle	40
Coal plant retrofit with carbon capture and sequestration	20
Combined Cycle Combustion Turbine	40
Pumped Storage	50
Simple Cycle Combustion Turbine (SCCT) Frame	35
Geothermal	40
Solar Photovoltaic	25
Solar Thermal	30
Compressed Air Energy Storage	30
Single Cycle Combustion Turbine (SCCT) Frame	35
Intercooled Aeroderivative SCCT	30
Internal Combustion Engine	30
Fuel Cells	25
Utility-Scale Combined Heat & Power (CHP)	25
Wind	25
Battery Storage	30
Biomass	30
Hydrokinetic, Wave - Floating Buoy	20
Nuclear Plant	40
CHP-Reciprocating Engine	20
CHP - Gas Turbine	20
CHP - Microturbine	15
CHP - Fuel Cell	10
CHP - Commercial Biomass, Anaerobic Digester	15
CHP - Industrial Biomass Waste	15
Solar - Rooftop Photovoltaic	30
Solar - Water Heaters	15
Solar - Attic Fans	10
Dispatchable Standby Generators	20
Microturbine	15

Transmission System Representation

PacifiCorp uses a transmission topology consisting of 19 bubbles (geographical areas) in its eastern control area and 15 bubbles in its western control area designed to best describe major load and generation centers, regional transmission congestion impacts, import/export availability, and external market dynamics. Firm transmission paths link the bubbles. The transfer capabilities for these links represent PacifiCorp Merchant function's current firm rights on the transmission lines. This topology is defined for both the System Optimizer and Planning and Risk models, and was also used for IRP modeling support for PacifiCorp's 2011 business plan.

Figure 7.2 shows the IRP transmission system model topology. Segments of the planned Energy Gateway Transmission Project are indicated with red dashed lines.

Figure 7.2 – Transmission System Model Topology



The most significant change to the model topology from the one used for the 2008 IRP Update is the disaggregation of the previously named "West Main" bubble into four new bubbles: Portland/North Coast, Willamette Valley/Central Coast, South-Central Oregon/Northern California and the Bethel Substation. This disaggregation supports a more refined view of Oregon load areas and transmission constraints, mainly to capture benefits of the Hemingway – Boardman – Bethel ("Cascade Crossing") transmission project option described in Chapter 6. Links from the Chehalis generation bubble to these new bubbles were added to better represent generation exports.

Finally, PacifiCorp added special wind generation bubbles to Oregon, Utah, and Wyoming to enable assignment of applicable incremental transmission investment costs to wind selected by the model for Energy Gateway transmission scenario studies.

Progress on Previous Action Plan Items

This section describes progress that has been made on previous active action plan items documented in the 2008 Integrated Resource Plan Update report filed with the state commissions on March 31, 2010. Many of these action items have been superseded in some form by items identified in the current IRP action plan.

Action Item 1: Acquire an incremental 890 MW of renewable resource by 2019. Successfully add 230 MW of wind resources in 2010 and 200 MW of wind resources in 2011 that are currently committed to.

- Procure up to an additional 460 MW of cost-effective wind resources for commercial operation, subject to transmission availability, in the 2017 to 2019 time frame via RFPs or other opportunities.
- Monitor geothermal, solar and emerging technologies, and government financial incentives; procure geothermal, solar or other cost-effective renewable resources during the 10-year investment horizon.
- Continue to evaluate the prospects and impacts of Renewable Portfolio Standard rules and CO_2 emission regulations at the state and federal levels, and adjust the renewable acquisition timeline accordingly.

Status: PacifiCorp acquired 348 MW of wind in 2010. The Company is on track to acquire an additional 93 MW in 2011 and 2012, reaching a total of 490 MW by year end 2012. This positions the Company well towards the goal of 890 MW by 2019 and takes advantage of currently available tax incentives and renewable energy credit sales opportunities to further reduce costs for customers. PacifiCorp completed its geothermal resource study in 2010, identifying a number of commercially viable sites for 2011 IRP modeling and further investigation. PacifiCorp issued its Oregon solar photovoltaic Request for Proposals (RFP) in November 2010 for acquisition of at least 2 MW in 2011.

Action Item 2: Implement a bridging strategy to support acquisition deferral of long-term intermediate/base load resource(s) in the east control area until the beginning of summer 2015, unless cost-effective long term resources such as renewables or thermal plant assets are available and their acquisition is in the best interests of customers.

- Acquire the following resources:
  - Up to 1,250 MW of economic front office transactions on an annual basis as needed through 2015, taking advantage of favorable market conditions.
  - At least 200 MW of long term power purchases.
  - Cost-effective interruptible customer load contract opportunities (focus on opportunities in Utah).
  - PURPA Qualifying Facility contracts and cost-effective distributed generation alternatives.
- Resources will be procured through multiple means: (1) the All Source RFP reissued on December 2, 2009, which seeks third quarter summer products and customer physical

curtailment contracts among other resource types, (2) periodic mini-RFPs that seek resources less than five years in term, and (3) bilateral negotiations.
- Closely monitor the near term need for front office transactions and reduce acquisitions as appropriate if load forecasts indicate recessionary impacts greater than assumed for the February 2009 load forecast, or if renewable or thermal plant assets are determined to be cost-effective alternatives.

Status: Based on its updated resource needs assessment and all-source RFP bid evaluation, the Company is proceeding with plans to acquire a gas-fired combined-cycle plant at the Lake Side site in Utah by June of 2014. The Company has so far acquired front office transactions at favorable market prices for 2011 through 2013 (350 MW for 2011, 400 MW for 2012, 300 MW for 2013), and continues to consider entering into power purchase agreements. As noted in Chapter 5, a number of Qualifying Facility contracts have also been signed by the Company.

Action Item 3: Procure through acquisition and/or Company construction long-term firm capacity and energy resources for commercial service in the 2012-2016 time frame.

- The proxy resource included in the 2010 business plan portfolio consists of a Utah wet-cooled gas combined-cycle plant with a capacity rating of 607 MW, acquired by the summer of 2015.
- Procure through the 2008 all-source RFP issued in December 2009.
- The Company submitted a benchmark resource, specified as the addition of a second combined-cycle block at PacifiCorp's Lake Side Plant.
- In recognition of the unsettled U.S. economy, expected continued volatility in natural gas markets, and regulatory uncertainty, continue to seek cost-effective resource deferral and acquisition opportunities in line with near-term updates to load/price forecasts, market conditions, transmission plans, and regulatory developments.
- PacifiCorp will reexamine the timing and type of gas resources and other resource changes as part of a comprehensive assumptions update and portfolio analysis to be conducted for the 2008 RFP final short-list evaluation in the RFP approved in Docket UM 1360, the next business plan, and 2008 IRP update.

Status: As noted above, the Company is proceeding with the acquisition of a Utah wet-cooled gas-fired combined-cycle plant located at the Lake Side site. Acknowledgment of the all-source RFP bidder final short list was received by the Oregon Public Utility Commission. PacifiCorp filed an application for pre-approval of the Lake Side 2 combined cycle plant with the Public Service Commission of Utah.

Action Item 4: Pursue economic plant upgrade projects—such as turbine system improvements and retrofits—and unit availability improvements to lower operating costs and help meet the Company's future CO_2 and other environmental compliance requirements.

- Successfully complete the dense-pack coal plant turbine upgrade projects by 2019, which are expected to add 86 MW of incremental capacity in the east and 48 MW in the West with zero incremental emissions.
- Seek to meet the Company's aggregate coal plant net heat rate improvement goal of 213 Btu/kWh by 2018.

- Monitor turbine and other equipment technologies for cost-effective upgrade opportunities tied to future plant maintenance schedules.

Status: This action item has been updated to reflect planned turbine upgrade projects included in the 2011 business plan. Planned projects now total 65 MW from 2011 through 2021, a drop of 49 MW from the amount reported in the 2008 IRP Update. PacifiCorp filed its second heat rate improvement plan with the Utah Commission in April 2010. This plan increases the 2018 improvement goal by 285 Btu/kWh (213 to 498 Btu/kWh).

Action Item 5: Acquire up to 200 MW of cost-effective Class 1 demand-side management programs for implementation in the 2010-2019 time frame.

- Pursue up to 30 MW of expanded Utah Cool Keeper program participation by 2019; revisit the program's growth assumptions in light of the recent passage of Utah legislation that permits an opt-out program design.
- Pursue up to 100 MW of additional cost-effective class 1 DSM products including commercial curtailment and customer-owned standby generation (55 MW in the east side and 45 MW in the west side) to hedge against the risk of higher gas prices and a faster-than-expected rebound in load growth resulting from economic recovery; procure through the currently active 2008 DSM RFP and subsequent DSM RFPs.
- For 2010, continue to implement a standardized Class 1 DSM system benefit estimation methodology for products modeled in the IRP. The modeling will compliment the supply curve work by providing additional resource value information to be used to evolve current Class 1 products and evaluate new products with similar operational characteristics that may be identified between plans.

Status: The Company exceeded its 2010 Class 1 DSM acquisition goal by 24 MW, achieving 482 MW versus the goal amount of 458 MW. This action item has been superseded by Action Item no. 5 in Table 9.1. Note that Governor Herbert vetoed the legislation permitting an opt-out program design.

Action Item 6: Acquire 900 - 1,000 MW of cost-effective Class 2 programs by 2019, equivalent to about 4.1 to 4.6 million MWh.

- Procure through the currently active DSM RFP and subsequent DSM RFPs

Status: The Company exceeded its 2010 Class 2 DSM acquisition goal by 56,137 MWh, achieving 499,059 MWh versus the goal amount of 442,922 MWh. This action item has been superseded by Action Item no. 6 in Table 9.1.

Action Item 7: Acquire cost-effective Class 3 DSM programs by 2018

- Procure programs through the currently active DSM RFP and subsequent DSM RFPs.
- Continue to evaluate program attributes, size/diversity, and customer behavior profiles to determine the extent that such programs provide a sufficiently reliable firm resource for long-term planning.
- Portfolio analysis with Class 3 DSM programs included as resource options indicated that at least 100 MW may be cost-effective; continue to evaluate program specification and cost-effectiveness in the context of IRP portfolio modeling.

Status: This action item has been superseded by Action Item no. 3 in Table 9.1.

Action Item 8: Planning Process Improvements

- For the next IRP planning cycle, complete the implementation of System Optimizer capacity expansion model enhancements for improved representation of CO_2 and RPS regulatory requirements at the jurisdictional level. Use the enhanced model to provide more detailed analysis of potential hard-cap regulation of carbon dioxide emissions and achievement of state or federal emissions reduction goals. Also use the capacity expansion model to evaluate the cost-effectiveness of coal facility retirement as a potential response to future regulation of carbon dioxide emissions.
- Refine modeling techniques for DSM supply curves/program valuation, and distributed generation.
- Investigate and implement, if beneficial, the Loss of Load Probability (LOLP) reliability constraint functionality in the System Optimizer capacity expansion model
- Continue to coordinate with PacifiCorp's transmission planning department on improving transmission investment analysis using the IRP models.
- For the next IRP planning cycle, provide an evaluation of, and continue to investigate, intermediate-term market purchase resources for purposes of portfolio modeling
- Consider developing one or more scenarios incorporating plug-in electric vehicles and Smart Grid technologies.

Status: PacifiCorp successfully implemented the planned System Optimizer enhancements for improved representation of CO_2 and RPS regulatory requirements. Carbon dioxide hard cap scenarios for the first time incorporated assignment of emission rates to spot market system balancing transactions. PacifiCorp used for the first time System Optimizer's plant betterment functionality to evaluate coal plant idling scenarios. Refinements to DSM supply curves included updating the T&D investment deferral credit, applying risk mitigation cost credits to DSM supply curve prices (see Chapter 6), and reclassifying cost bundle breakpoints (also Chapter 6). Ventyx, the model vendor, advised PacifiCorp that the LOLP reliability constraint functionality requires additional design work and is not ready for a production environment. No intermediate-term market purchases were available for evaluation through the Company's all-source RFP. Plug-in electric vehicles and Smart Grid technology scenarios is addressed in Action Item no. 8 in Table 9.1.

Action Item 9: Obtain Certificates of Public Convenience and Necessity and conditional use permits for Utah/Wyoming/Idaho segments of the Energy Gateway Transmission Project to support PacifiCorp loads, regional resource expansion needs, access to markets, grid reliability, and congestion relief.

- Obtain Certificate of Public Convenience and Necessity for a 500 kV line between Mona and Oquirrh.
- Obtain Certificate of Public Convenience and Necessity for 230 kV and 500 kV line between Windstar and Populus.
- Obtain Certificate of Public Convenience and Necessity for a 500 kV line between Populus and Hemingway.

Status: The Utah Public Service Commission issued a Certificate of Public Convenience and Necessity for the Mona to Oquirrh project in June 2010. PacifiCorp has begun permitting efforts and right of way research for Windstar-Populus project. A contract will be issued during the 4th Quarter of 2011 for right-of-way acquisition, which will begin in 2012. The Company hopes to complete the Environmental Impact Statement process with the Bureau of Land Management in 2012. As with the Windstar-Populus project, PacifiCorp has partnered with Idaho Power to build the Populus to Hemingway segment of Gateway West. The companies hope to complete the Environmental Impact Statement process and all necessary permitting in 2012, and to begin construction as early as 2015. See Chapter 10, Transmission Expansion Action Plan, for more details.

Action Item 10: Complete Utah/Idaho segments of the Energy Gateway Transmission Project to support PacifiCorp loads, regional resource expansion needs, market access, grid reliability, and congestion relief.

Permit and construct a 345 kV line between Populus to Terminal.

Status: PacifiCorp completed the Populus to Terminal project in November 2010. See Chapter 10, Transmission Expansion Action Plan.

Action Item 11: Permit and build Utah segment of the Energy Gateway Transmission Project to support PacifiCorp loads, regional resource expansion needs, access to markets, grid reliability, and congestion relief

Permit and construct a 500 kV line between Mona and Oquirrh.

Status: Right-of-way efforts are ongoing and construction is scheduled to begin in 2011. The Mona to Oquirrh segment is scheduled for completion in 2013, while the Oquirrh to Terminal segment is scheduled for completion in 2014. See Chapter 10, Transmission Expansion Action Plan.

Action Item 12: Permit and build segments of the Energy Gateway Transmission Project to support PacifiCorp loads, regional resource expansion needs, access to markets, grid reliability, and congestion relief

- Permit and construct 230 kV and 500 kV line between Windstar and Populus.
- Permit and construct a 345 kV line between Sigurd and Red Butte.

Status: The 2008 IRP Update reported an in-service date range of 2014-2016 for Windstar to Populus, but delays in the BLM's Environmental Impact Statement process have delayed the project resulting in revised plans to complete it in the 2015-2017 timeframe. PacifiCorp hopes to complete all permitting and right of way acquisitions for Sigurd-Red Butte by 2012 and to place the project in-service in 2014. See Chapter 10, Transmission Expansion Action Plan.

Action Item 13: Permit and build Northwest/Utah segments of the Energy Gateway Transmission Project to support PacifiCorp loads, regional resource expansion needs, access to markets, grid reliability, and congestion relief

Permit and construct a 500 kV line between Populus and Hemingway.

Status: The Company has previously estimated an in-service date range of 2014-2018 for the Populus to Hemingway project, but now plans to complete the project in the 2015-2018 timeframe. The delay on the front end of the project is primarily the result of the BLM's delay of the draft Environmental Impact Statement. See Chapter 10, Transmission Expansion Action Plan.

Action Item 14: Permit and build Wyoming/Utah segment of the Energy Gateway Transmission Project to support PacifiCorp loads, regional resource expansion needs, access to markets, grid reliability, and congestion relief

Permit and construct a 500 kV line between Aeolus and Mona

Status: The project is scheduled for completion in the 2017-2019 timeframe. The Company began its public scoping process during the first quarter of 2011. See Chapter 10, Transmission Expansion Action Plan.

Action Item 15: Obtain rights of way and construct the Wallula-McNary line segment.

Status: PacifiCorp has received all state and local permits and is currently pursuing the final federal permits and interconnection at the McNary substation. The line route has been determined and initial line design has been completed. The Company continues to work with property owners and expects to have all necessary rights of way for the project by April 2011. PacifiCorp estimated in its 2008 IRP Update that the line would be constructed and in service by late 2011. However, due to extended lead times required to receive all federal agency approvals, the project is now expected to be completed in the 2012-2013 timeframe. See Chapter 10, Transmission Expansion Action Plan.

Action Item 16: For future IRP planning cycles, include on-going financial analysis with regard to transmission, which includes: a comparison with alternative supply side resources, deferred timing decision criteria, the unique capital cost risk associated with transmission projects, the scenario analysis used to determine the implications of this risk on customers, and all summaries of stochastic annual production cost with and without the proposed transmission segments and base case segments.

Status: See Chapter 4, Transmission Planning.

Action Item 17: By August 2, 2010, complete a wind integration study that has been vetted by stakeholders through a public participation process.

Status: PacifiCorp completed the wind integration study and distributed it to the public via email and Web site posting on September 1, 2010. The Public Utility Commission of Oregon granted a deadline extension from August 1 to September 1, 2010. The study is included in the 2011 IRP as Appendix I.

Action Item 18: During the next planning cycle, work with parties to investigate carbon dioxide emission levels as a measure for portfolio performance scoring.

Status: PacifiCorp incorporated CO_2 emission levels as a final portfolio screening measure for preferred portfolio selection. See Chapter 7, Modeling and Portfolio Evaluation Approach.

Action Item 19: In the next IRP, provide information on total CO_2 emissions on a year-to year basis for all portfolios, and specifically, how they compare with the preferred portfolio.

Status: Appendix D contains System Optimizer CO_2 emissions on a year-by basis for each portfolio, including the preferred portfolio.

Action Item 20: For the next IRP planning cycle, work with parties to investigate a capacity expansion modeling approach that reduces the influence of out-year resource selection on resource decisions covered by the IRP Action Plan, and for which the Company can sufficiently show that portfolio performance is not unduly influenced by decisions that are not relevant to the IRP Action Plan.

Status: PacifiCorp conducted a two-phased System Optimizer simulation to test the impact of limiting the model's optimization foresight to 12 years relative to a simulation based on the full 20 years. The results are documented in Chapter 8.

Action Item 21: In the next IRP planning cycle, incorporate assessment of distribution efficiency potential resources for planning purposes.

Status: PacifiCorp is conducting a conservation voltage reduction study, targeting 19 distribution feeders in Washington. The study is expected to be completed by the end of May 2011. Based on preliminary data provided by the contractor for the study, PacifiCorp developed a distribution efficiency resource for testing with the System Optimizer model. Results of the portfolio development testing are provided in Chapter 8. This action item has been superseded by Action Item 6 in Table 9.1.

Acquisition Path Analysis

Resource Strategies

Of most concern from a planning perspective are so called regime shifts in which conditions change abruptly and permanently, sometimes with little or no warning. The Energy Gateway scenario analysis outlined in Chapter 4 considered Incumbent and Green Future scenarios defined by combinations of associated CO_2/natural gas price trajectories and regulatory intervention in the form of a federal RPS requirement (Waxman-Markey renewable energy targets). Other scenarios, similarly defined by a trigger event that causes sustained departure from expectations, are considered for the acquisition path analysis. Specifically, PacifiCorp focuses on fundamentals-based shifts in natural gas prices, enactment of regulatory policies, and different load trajectories. For a specific resource already planned for acquisition, the path analysis also addresses procurement delays.

PUBLIC UTILITY COMMISSION OF OREGON CASE NO. UE 235

Phase 1

RESPONSE BRIEF OF THE COMMUNITY RENEWABLE ENERGY ASSOCIATION

ATTACHMENT 2

Excerpts from

Testimony of Gregory Duvall, OPUC Docket No. UE 227

Docket No. UE-
Exhibit PPL/100
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Direct Testimony of Gregory N. Duvall

March 2011

the Company's total system load, changes in the Company's portfolio of wholesale purchase and sales contracts, and increases in coal costs. The offsetting factors that drive NPC downward in 2012 include more generation from the Company's thermal resources, which limits or reduces the impact of higher load and the expiration of long-term firm contracts.

Q. How does the retail load forecast impact the Company's NPC?

A. This filing reflects an increase of approximately 4.3 million megawatt-hours, or 7.5 percent, in the total company load forecast compared to loads reflected in UE 216. All else held constant, increased load increases NPC.

Q. What are the major changes to power contracts in the calendar year 2012 test period?

A. The 2012 test period in the current filing reflects a full year impact of the contracts that expired during the 2011 TAM test period. NPC increased when those contracts expired because the prices of those contracts were more favorable as compared to the current market prices. The increase in NPC is offset somewhat by the expiration in 2012 of relatively expensive qualifying facility ("QF") contracts, such as the Biomass QF.

Q. Have the Company's coal costs impacted the NPC in the current proceeding?

A. Yes. NPC are higher due to increases in the costs of third-party coal supply and transportation agreements, and cost increases at the Company's captive mines. Approximately one-fourth of the NPC increase in this case is attributable to coal costs. Details on coal costs are provided in the direct testimony of Company witness Ms. Cindy A. Crane.

model used to calculate its NPC except, as previously mentioned, the addition of a new report consolidating several individual reports necessary for the screening process.

Q. Does this filing include updates to all NPC components identified in Attachment A to the TAM Guidelines?

A. Yes. All NPC components have been updated.

Q. Has the Company provided information regarding its anticipated subsequent TAM updates?

A. Yes. Exhibit PPL/104 contains a list of known contracts and Other Revenues that could be included in the Company's TAM updates in this filing based on the best information available at the time the NPC study was prepared. The Company will update this list as new information becomes available.

Q. Has the Company agreed to include other information in its initial TAM filing in this case?

A. Yes. The parties asked the Company to identify the 48-month historical period used to determine the outage rates and other inputs in the Initial Filing. The historical base period used for outage rates in the filing is 48-months ended June 2010.

Q. What workpapers did the Company provide with this filing?

A. Pursuant to the Attachment B of the TAM Guidelines, the Company provided access to the GRID model and workpapers concurrently with this Initial Filing. Specifically, the Company is providing the NPC report workbook and the GRID project report.

Docket No. UE-
Exhibit PPL/104
Witness: Gregory N. Duvall

BEFORE THE PUBLIC UTILITY COMMISSION

OF THE STATE OF OREGON

PACIFICORP

Exhibit Accompanying Direct Testimony of Gregory N. Duvall

List of Expected or Known Contract Updates

March 2011

List of Known Contracts Expected to be Updated During 2012 TAM

Sales and Purchases of Electricity and Natural Gas

1. New electricity sales and purchase contracts, physical and financial, including contracts with qualifying facilities.
2. Changes in contract terms of existing electricity sales and purchase and exchange contracts.
3. New natural gas sales and purchase contracts, physical and financial.
4. Changes in contract terms of existing natural gas sales and purchase contracts.
5. Contracts whose prices are linked to market indexes and inflation rates.
6. Five new qualifying facility contracts with Cedar Creek Wind, which are currently before the Idaho Public Utilities Commission.
7. New qualifying facility contract with Cargill, which is currently before the Idaho Public Utilities Commission.
8. Sales contract with Black Hills Company for energy price and fixed payments.
9. Purchase contracts for generation and fixed costs from the Mid Columbia projects.
10. Purchase contract with Tri-State Generation and Transmission Association Inc for energy price.
11. New purchase contract with Monsanto for ready reserves, or remove the expenses and impact on load of the assumed contract if new contract is not executed.
12. New purchase contract with Kennecott for generation incentives, or remove the expenses and impact on load of the assumed contract if new contract is not executed.
13. New qualifying facility purchase contracts with Kennecott, Tesoro and US Magnesium, or remove the assumed contracts if not executed.
14. Purchase contracts with Grant Public Utility District for 10 average megawatt energy and displacement energy for changes in BPA's Cost Recovery Adjustment Clause ("CRAC") and changes in BPA's transmission rates.
15. Purchase expenses of PGE Cove based on PGE projection.
16. Election decision for Grant Meaningful Priority.

Transportation and Storage of Natural Gas

17. New pipeline and storage contracts for transporting natural gas from market to Company's generating facilities.
18. Changes in contract terms of existing pipeline and storage contracts.
19. Contracts whose prices are linked to market indexes and inflation rates.

Wheeling Expenses and Transmission

20. New transmission contracts to wheeling power to serve the Company's load obligations.
21. Changes in contract terms of existing transmission contracts.
22. Wheeling expenses that are impacted by changes in third parties' transmission tariff rates.
23. Power, Transmission and Wind Integration rates that are impact by the current BPA rate cases.
24. Transmission from the Four Corners market to the SP15 market.
25. Contracts whose prices are linked to market indexes and inflation rates.

Generation Resources

26. Decommission date of Condit dam.

Other Revenue

27. Replacement contracts or changes in contract terms of existing contracts that will impact the Other Revenues reflected in Exhibit PPL/102.

PUBLIC UTILITY COMMISSION OF OREGON CASE NO. UE 235

Phase 1

RESPONSE BRIEF OF THE COMMUNITY RENEWABLE ENERGY ASSOCIATION

ATTACHMENT 3

Excerpts from

PacifiCorp's 2010 FERC Form No. 1, filed April 18, 2011

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/18/2011	End of 2010/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

If the amount for previous year is not derived from previously reported figures, explain in footnote.

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering	358,628	316,964
63	(547) Fuel	432,620,733	461,743,015
64	(548) Generation Expenses	14,638,002	15,739,485
65	(549) Miscellaneous Other Power Generation Expenses	18,701,556	18,635,853
66	(550) Rents	3,558,679	1,861,264
67	TOTAL Operation (Enter Total of lines 62 thru 66)	469,877,598	498,296,581
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures	1,240,594	1,544,031
71	(553) Maintenance of Generating and Electric Plant	8,996,404	14,986,840
72	(554) Maintenance of Miscellaneous Other Power Generation Plant	2,196,699	1,321,906
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)	12,433,697	17,852,777
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)	482,311,295	516,149,358
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	380,007,678	456,211,649
77	(556) System Control and Load Dispatching	877,454	1,514,461
78	(557) Other Expenses	63,870,496	49,819,215
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	444,755,628	507,545,325
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	1,920,145,538	1,957,705,482
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	5,041,115	6,088,583
84	(561) Load Dispatching	650,305	
85	(561.1) Load Dispatch-Reliability		
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	7,847,328	8,347,455
87	(561.3) Load Dispatch-Transmission Service and Scheduling		
88	(561.4) Scheduling, System Control and Dispatch Services		
89	(561.5) Reliability, Planning and Standards Development	816,883	
90	(561.6) Transmission Service Studies	83,476	76,671
91	(561.7) Generation Interconnection Studies	938,904	899,582
92	(561.8) Reliability, Planning and Standards Development Services		
93	(562) Station Expenses	2,124,825	1,506,478
94	(563) Overhead Lines Expenses	120,209	245,152
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	136,854,649	117,161,210
97	(566) Miscellaneous Transmission Expenses	4,257,862	2,393,112
98	(567) Rents	1,312,382	1,656,975
99	TOTAL Operation (Enter Total of lines 83 thru 98)	160,047,938	138,375,218
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	1,334,303	35,453
102	(569) Maintenance of Structures	395	788
103	(569.1) Maintenance of Computer Hardware	36,440	79,505
104	(569.2) Maintenance of Computer Software	1,065,683	974,621
105	(569.3) Maintenance of Communication Equipment	3,567,267	3,005,647
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	10,092,385	10,549,624
108	(571) Maintenance of Overhead Lines	19,173,510	19,620,066
109	(572) Maintenance of Underground Lines	36,881	51,599
110	(573) Maintenance of Miscellaneous Transmission Plant	273,467	182,001
111	TOTAL Maintenance (Total of lines 101 thru 110)	35,580,331	34,499,304
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	195,628,269	172,874,522

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report End of 2010/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Arizona Public Service	OS						
2	Arizona Public Service	LFP	370,348	370,348	1,093,316			1,093,316
3	Arizona Public Service	NF	20,773	20,773	80,392			80,392
4	Arizona Public Service	OS			6,197		3,745	9,942
5	Arizona Public Service	SFP	18,763	18,763	71,146			71,146
6	Ashland, City of	FNS	1,769	1,769		16,638		16,638
7	Avista Corporation	FNS	48,575	50,243	217,930			217,930
8	Avista Corporation	NF	12,732	12,732	73,464			73,464
9	Basin Elect. Power Coop	LFP				71,485		71,485
10	Big Horn Rural Electric	OS					181,813	181,813
11	Bonneville Power Admin.	OS						
12	Bonneville Power Admin.	AD	9,021	9,021	17,000	9,121		26,121
13	Bonneville Power Admin.	FNS			6,555,934			6,555,934
14	Bonneville Power Admin.	LFP	5,394,463	5,394,463	53,476,903		3,010,860	56,487,763
15	Bonneville Power Admin.	NF	309,750	309,750		1,341,217		1,341,217
16	Bonneville Power Admin.	OS	5,049,853	5,226,006	30,813,868	165,008	1,557,921	32,536,797
	TOTAL		17,570,670	17,871,426	111,398,582	4,675,874	20,780,193	136,854,649

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report End of 2010/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Bonneville Power Admin.	SFP	52,522	52,522		208,244		208,244
2	CA Ind. Sys. Operator	AD				-3,756	30,716	26,960
3	CA Ind. Sys. Operator	OS					1,829,210	1,829,210
4	CA Ind. Sys. Operator	SFP	533,427	533,427		2,867,483		2,867,483
5	Deseret Pwr Elect. Coop	AD	1,808	1,808	13,415			13,415
6	Deseret Pwr Elect. Coop	LFP	168,010	168,010	3,391,570			3,391,570
7	Deseret Pwr Elect. Coop	NF	183,089	183,089	1,327,332			1,327,332
8	El Paso Elect. Co.	AD	150	150	113			113
9	El Paso Elect. Co.	NF	200	200	181			181
10	Flathead Elect. Coop.	OS					63,922	63,922
11	Hermiston Generating Co	OS					175,965	175,965
12	Idaho Power Company	OS						
13	Idaho Power Company	AD			-183,020		697,502	514,482
14	Idaho Power Company	FNS			6,994			6,994
15	Idaho Power Company	LFP	3,206,147	3,257,310	6,121,548			6,121,548
16	Idaho Power Company	NF	311,953	365,715	1,050,762			1,050,762
	TOTAL		17,570,670	17,871,426	111,398,582	4,675,874	20,780,193	136,854,649

Total 30A
97,151,070

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/18/2011	End of 2010/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY: Magawatt-hours Received (c)	TRANSFER OF ENERGY: Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS: Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Idaho Power Company	OS					10,767,019	10,767,019
2	Idaho Power Company	SFP	1,032	1,032	2,180			2,180
3	Moon Lake Elect. Assoc.	FNS					182,791	182,791
4	Morgan City Corporation	AD	41	41		434		434
5	Nevada Power Company	NF	60,588	60,588	200,194			200,194
6	Nevada Power Company	OS					69,299	69,299
7	Nevada Power Company	SFP	79,037	79,037	214,659			214,659
8	NorthWestern Corp.	NF	94,374	94,852	391,630			391,630
9	NorthWestern Corp.	OS					26,991	26,991
10	NorthWestern Corp.	SFP	27,233	27,233	118,134			118,134
11	Platte River Power	LFP	173,713	173,713	966,000			966,000
12	Platte River Power	OS					15,333	15,333
13	Portland Gen. Electric	NF	1,617	1,617	1,759			1,759
14	Portland Gen. Electric	OS					908	908
15	Portland Gen. Electric	SFP			-1,025,820			-1,025,820
16	Powerex Corporation	SFP			-1,894,500			-1,894,500
	TOTAL		17,570,670	17,871,426	111,398,582	4,675,874	20,780,193	136,854,649

Name of Respondent PacifiCorp	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) 04/18/2011	Year/Period of Report End of 2010/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY Magawatt-hours Received (c)	TRANSFER OF ENERGY Magawatt-hours Delivered (d)	EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Public Service Co of CO	LFP	169,116	177,879	901,862			901,862
2	Public Service Co of CO	NF	855	855	4,524			4,524
3	Public Service Co of NM	LFP	116,760	116,760	591,311			591,311
4	Public Service Co of NM	OS					21,148	21,148
5	Salt River Project	NF	160	160	499			499
6	Sierra Pacific Power Co	NF	6,480	6,480	41,504			41,504
7	Sierra Pacific Power Co	OS					5,986	5,986
8	Surprise Valley Electr.	OLF					9,523	9,523
9	Tri-State Gen & Transm	LFP	203,428	212,197	901,862			901,862
10	Tri-State Gen & Transm	NF	249,472	249,472	563,215			563,215
11	Tri-State Gen & Transm	OS					222,304	222,304
12	Tucson Electric Power	NF	218	218	1,093			1,093
13	Tucson Electric Power	OS					127	127
14	Utah Assoc Muni Pwr Sys	AD	-1,512	-1,512	-107,800		-1,500	-109,300
15	Utah Assoc Muni Pwr Sys	NF	89	89	445			445
16	Westport Field Srv LLC	LFP			-2,310,796			-2,310,796
	TOTAL		17,570,670	17,871,426	111,398,582	4,675,874	20,780,193	136,854,649

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
PacifiCorp	(1) [X] An Original (2) [ ] A Resubmission	04/18/2011	End of 2010/Q4

TRANSMISSION OF ELECTRICITY BY OTHERS (Account 565)
(Including transactions referred to as "wheeling")

1. Report all transmission, i.e. wheeling or electricity provided by other electric utilities, cooperatives, municipalities, other public authorities, qualifying facilities, and others for the quarter.
2. In column (a) report each company or public authority that provided transmission service. Provide the full name of the company, abbreviate if necessary, but do not truncate name or use acronyms. Explain in a footnote any ownership interest in or affiliation with the transmission service provider. Use additional columns as necessary to report all companies or public authorities that provided transmission service for the quarter reported.
3. In column (b) enter a Statistical Classification code based on the original contractual terms and conditions of the service as follows: FNS - Firm Network Transmission Service for Self, LFP - Long-Term Firm Point-to-Point Transmission Reservations. OLF - Other Long-Term Firm Transmission Service, SFP - Short-Term Firm Point-to- Point Transmission Reservations, NF - Non-Firm Transmission Service, and OS - Other Transmission Service. See General Instructions for definitions of statistical classifications.
4. Report in column (c) and (d) the total megawatt hours received and delivered by the provider of the transmission service.
5. Report in column (e), (f) and (g) expenses as shown on bills or vouchers rendered to the respondent. In column (e) report the demand charges and in column (f) energy charges related to the amount of energy transferred. On column (g) report the total of all other charges on bills or vouchers rendered to the respondent, including any out of period adjustments. Explain in a footnote all components of the amount shown in column (g). Report in column (h) the total charge shown on bills rendered to the respondent. If no monetary settlement was made, enter zero in column (h). Provide a footnote explaining the nature of the non-monetary settlement, including the amount and type of energy or service rendered.
6. Enter "TOTAL" in column (a) as the last line.
7. Footnote entries and provide explanations following all required data.

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	TRANSFER OF ENERGY		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Western Area Power Adm.	OS						
2	Western Area Power Adm.	AD	-311	-311	-6,512		-819	-7,331
3	Western Area Power Adm.	FNS			4,812,992			4,812,992
4	Western Area Power Adm.	LFP	414,790	414,790	2,220,000			2,220,000
5	Western Area Power Adm.	NF	234,189	234,189	594,452			594,452
6	Western Area Power Adm.	OS					423,870	423,870
7	Western Area Power Adm.	SFP	45,948	45,948	80,650			80,650
8	Accrual True-up						1,485,559	1,485,559
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		17,570,670	17,871,426	111,398,582	4,675,874	20,780,193	136,854,649

Schedule Page: 332 Line No.: 1 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "ARIZONA PUBLIC SERVICE" ON PAGE 332: Complete name is Arizona Public Service Company.

Schedule Page: 332 Line No.: 1 Column: b

Legacy Contract executed between PacifiCorp and Arizona Public Service Company concerning the exchange of transmission services over agreed-upon facilities (Restated Transmission Agreement between PacifiCorp and Arizona Public Service Company, ("Restated TSA"), Rate Schedule 436). The contract terminates October 31, 2020. See also FERC Account 456.1 - Transmission of Electricity For Others, page 328 of this Form No. 1.

Schedule Page: 332 Line No.: 2 Column: b

Arizona Public Service Company - Contract Termination Dates: May 1, 2013, August 31, 2013, January 11, 2041 and May 31, 2047.

Schedule Page: 332 Line No.: 4 Column: g

Ancillary Services.

Schedule Page: 332 Line No.: 9 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "BASIN ELECT. POWER COOP" ON PAGES 332: Complete name is Basin Electric Power Cooperative.

Schedule Page: 332 Line No.: 9 Column: b

Basin Electric Power Cooperative - Contract Termination Date: One year written notice.

Schedule Page: 332 Line No.: 10 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "BIG HORN RURAL ELECTRIC" ON PAGE 332: Complete name is Big Horn Rural Electric Cooperative.

Schedule Page: 332 Line No.: 10 Column: g

Use of Facilities.

Schedule Page: 332 Line No.: 11 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "BONNEVILLE POWER ADMIN." ON PAGE 332: Complete name is Bonneville Power Administration.

Schedule Page: 332 Line No.: 11 Column: b

Legacy Contract executed between PacifiCorp and Bonneville Power Administration concerning the exchange of transmission services over agreed-upon facilities ("Midpoint-Meridian Transmission Agreement", Rate Schedule 369). This agreement runs concurrently with the AC Intertie Agreement (Rate Schedule 368), which terminates when the facilities subject to that agreement are taken out of service. See also FERC Account 456.1 - Transmission of Electricity For Others, page 328 of this Form No. 1.

Schedule Page: 332 Line No.: 12 Column: b

Settlement Adjustment.

Schedule Page: 332 Line No.: 14 Column: b

Bonneville Power Administration - Contract Termination Dates: January 1, 2011, July 1, 2011, September 1, 2011, December 1, 2011, April 1, 2012, July 1, 2012, November 1, 2012, July 1, 2013, September 1, 2013, October 1, 2013, December 1, 2013, January 1, 2014, October 1, 2027, November 1, 2033 and evergreen.

Schedule Page: 332 Line No.: 14 Column: g

Ancillary Services.

Schedule Page: 332 Line No.: 16 Column: g

Ancillary Services. Use of Facilities.

Schedule Page: 332.1 Line No.: 2 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "CA IND. SYS. OPERATOR" ON PAGE 332: Complete name is California Independent System Operator Corporation.

Schedule Page: 332.1 Line No.: 2 Column: b

Settlement Adjustment.

Schedule Page: 332.1 Line No.: 2 Column: g

Ancillary Services.

Schedule Page: 332.1 Line No.: 3 Column: g

Ancillary Services.

Schedule Page: 332.1 Line No.: 5 Column: a

THIS FOOTNOTE APPLIES TO ALL OCCURRENCES OF "DESERET PWR ELECT. COOP" ON PAGE 332: Complete name is

PUBLIC UTILITY COMMISSION OF OREGON CASE NO. UE 235

Phase 1

RESPONSE BRIEF OF THE COMMUNITY RENEWABLE ENERGY ASSOCIATION

ATTACHMENT 4

In re Investigation and Determination of Utility Specific Variables for the Setting of Avoided Cost Rates and the Establishment of Such Rates for PacifiCorp, Idaho PUC Case No. PPL-E-89-3/UPL-E-89-5, Order No. 23358, pp. 11-16 (October 1, 1990)

Office of the Secretary
Service Date

OCT 1- 1990

BEFORE THE IDAHO PUBLIC UTILITIES COMMISSION

IN THE MATTER OF THE INVESTIGATION AND DETERMINATION OF UTILITY SPECIFIC VARIABLES FOR THE SETTING OF AVOIDED COST RATES AND THE ESTABLISHMENT OF SUCH RATES FOR PacifiCorp DBA UTAH POWER AND LIGHT COMPANY AND PACIFIC POWER AND LIGHT COMPANY.	CASE NO. PPL-E-89-3/ UPL-E-89-5 ORDER NO. 23358

INTRODUCTION

This is a FINAL ORDER determining the Avoided Cost Rates applicable to Cogenerators and Small Power Producers (CSPPs or QFs) selling capacity and energy to PacifiCorp (PCp) under the Public Utility Regulatory Policies Act of 1978 (PURPA). PCp is an electrical utility supplying service to Sandpoint and southeast Idaho, and is therefore obligated by PURPA to purchase capacity and energy at its avoided cost from all *bona fide* QFs offering to sell such power. Under PURPA and the ensuing regulations promulgated by the Federal Energy Regulatory Commission (FERC), this Commission has jurisdiction to set avoided cost rates for PCp. The Avoided Cost Rates determined as a result of this Case represent a modest increase over previously approved avoided cost rates for PCp, and are shown in Appendix C, attached.

Interlocutory Order No. 23300 presented rates based on a "first deficit year" of 1993, which incorrectly resulted from Staff's inadvertent failure to apply the Commission approved 3% escalation rate to PCp's load from 1989 to 1990. That error has been corrected herein, resulting in a "first deficit year" of 1992. The -23300 rates were also based on avoidable transmission costs of $197/kW, which is incorrect because Staff erroneously failed to weight the avoidable transmission distance. That error is also corrected herein.

REVIEW OF PARTIES AND PROCEDURES

A public hearing to establish utility-specific variables in Case No. PPL-E-89-3/UPL-E-89-5 was held on May 30 and 31, 1990 in Boise, Idaho. The following parties appeared by and through their respective counsel and/or representatives:

APPEARANCES

For the Staff:	SCOTT D. WOODBURY, Esq. Deputy Attorney General 472 W. Washington Street Boise, Idaho 83720
For Pacific Power & Light Company:	STOEL RIVES BOLEY JONES & GREY by JAMES F. FELL, Esq. 900 SW Fifth Avenue, Suite 2300 Portland, Oregon 97204-1268
For Utah Power & Light Company:	JOHN M. ERIKSSON, Esq. Utah Power & Light Company 1407 West North Temple Salt Lake City, Utah 84140
For the Independent Energy Producers of Idaho: (Of Record)	DAVIS WRIGHT TREMAINE by PETER J. RICHARDSON, Esq. and ROY L. EIGUREN, Esq. 350 North Ninth Street-Suite 400 Boise, Idaho 83702

The proceedings conducted in this docket, Case No. PPL-E-89-3/UPL-E-89-5 are the third and final phase in the Commission's determination of avoided costs for PacifiCorp. The administratively determined avoided cost represents a price equivalent to the incremental costs to PacifiCorp (PCp) of electric energy or capacity or both, which but for the purchase from a qualifying cogeneration or small power production facility (QF), the Company would generate itself or purchase from another source. 18 CFR§292-101(b)(6)

In the generic first and second phase of this redetermination of avoided costs (Case No. U-1500-170, (-170)) the Commission established the approved administrative avoided cost rate methodology (Surrogate Avoided Resource, or SAR). The SAR to be used in determining avoided costs is a hypothetical single base load coal-fired steam generation plant with state of the art emission controls. The Commission also established the following generic variable set points for determining avoided costs:

<u>Generic Variables - Case No. U-1500-170</u>
(in 1989 $ where applicable)

Power Plant Capital Costs (includes AFUDC)	$1,450/kW
Fixed O&M Expenses	$25.00/kW-year
Variable O&M Expenses	1.60 mil/kWh
Coal (fuel) Expenses	5.78 mil/kWh
Interim (surplus period) Energy Costs	23.60 mil/kWh
SAR Equivalent Availability Factor	75.00%
SAR Construction Escalation	4.50%
SAR O&M Exp. Escalation	4.50%
General Inflation Escalation	4.50%
Coal (fuel) Escalation	5.25%
Wholesale Electricity Escalation	4.50%
SAR Plant Life	35 years
SAR Heat Rate	10,500 Btu/kWh

ANALYSIS OF ISSUES
(Table of Contents)

The issues considered in this case are as follows.

LOAD/RESOURCE ANALYSIS :

For purpose of avoided cost system resource analysis we find it helpful to review our prior pronouncements. Regarding system improvements, relicensing costs and conservation, the Commission in Order No. 22636 stated:

> System improvements: To the extent that deferrable low cost resources such as system efficiency improvements, refurbishments, power purchases/exchanges, or plant upgrades are used to extend a utility surplus period, the costs and quantities of those measures must be accurately and defendably estimated for inclusion in the avoided cost computations as capital investments. . . . The utility must specifically demonstrate that the proposed "low cost resource" is in fact available to the utility, that the life cycle cost of the resources is less than the avoided cost, that the life of the resource extends beyond the utility's surplus period, and that the utility plans to acquire the resource prior to the end of its surplus period.
>
> Relicensing costs: . . . It is possible that relicensing an existing project will be in the public interest even though, due to uncontrollable externalities, the costs thereof exceed the utility's avoided cost. Normally, however, . . . the present value will be expected to be less than that of other options (i.e., the avoided cost). Utilities should not presume that this Commission will find all upgrade costs prudently incurred for ratemaking purposes simply because they are related to a relicensing.
>
> Conservation: . . . Only conservation resources actually contracted for shall be used to extend the time until load/resource balance; estimated future conservation resources shall not. Utilities are expected to contract only for reasonably confirmable conservation resources. . . . As a result of the evidence presented to date, it is clear that estimated future conservation and QF resources should not be included as resources for determining avoided costs. The cost effectiveness and quantity of QF/conservation resource additions are dependent on the avoidable cost of traditional resources. Using

QF/conservation resource estimates to extend a utility surplus for determination of avoided cost rates is a circuitous process that falsely reduces QF rates.

The resources recommended by PCp for use in avoided cost computations are listed in Exhibit No. 2. Those resources that face unresolved challenges from at least one party are:

7. Spring Energy Purchase
11. Cogen Ownership
12. Gadsby
14. BPA NR Purchase/Utility Purchase

Each is considered separately below.

7. Spring Energy Purchase:

Staff witness Faull testifies that these resources should not be included as specific line items for avoided cost purposes because they are part of future purchases from the integrated Western Systems. Tr. p. 305. Although Intervenor witness Peseau does not specifically oppose the resources shown on line 7, he generally opposes all purchases shown in PCp's resource plan for which there are not specific existing contracts. Tr. pp. 177, 178.

We find PCp's proposed "Spring Energy Purchases" to be non-specified off-system purchases not unlike those represented by PCp's proposed BPA and utility purchases (Line 14). Therefore, we reject the inclusion of Spring Energy Purchases except as described in our discussion of BPA and utility purchases, below.

11. Cogen Ownership:

PCp includes this line on the ground that it represents resources that are the subject of contracts with industrial customers and that PCp has the ability to cause to be developed. Tr. pp. 21, 22. On cross examination Staff witness Faull testifies that he believes the language of the contracts between PCp and its industrial customers is not strong enough to allow PCp to unilaterally cause the cogen plants to be built. Tr. pp. 360, 362, 363. However, PCp also points out that part of the logic underlying these contracts is that they make the utility's obligation to serve contingent on the customers' ongoing commitment to purchase from the utility. Thus, PCp implies, if the utility is unable to develop resources to serve these industrial customers under the subject contracts, PCp can abandon the load, thus having the same effect as installing the anticipated cogen. Tr. pp. 49, 50.

We find that PCp's contractual control of this resource is inadequate to reasonably include it as a future company resource in the computation of avoided cost rates.

12. Gadsby:

PCp's existing Gadsby units are on cold standby and are not now considered by PCp as resources. PCp plans to rehabilitate these units and therefore includes them as future resources in its resource plan. Tr. pp. 23, 24. PCp estimates the levelized life cycle cost of these resources to be 23 mills per kWh. Exh. 4. Intervenor witness Peseau opposes including Gadsby as an avoidable resource because its natural gas fuel costs are unknown and unknowable. Tr. pp. 233, 234. Although Staff witness Faull believes PCp should have provided greater documentation of the costs included in the Gadsby resource, he accepts them as reasonable. Tr. p. 310.

We find PCp's inclusion of this resource in its load/resource estimate to be appropriate for avoided cost purposes.

14. BPA NR Purchase/Utility Purchase:

PCp includes this line item to represent future resources that will be available for firm purchase from within the integrated Western Systems. Tr. pp. 24, 25, 26. Staff witness Faull recommends disallowing these resources as a line item, but including them within an analysis that looks at the overall availability of purchased resources within the Western Systems. Tr. pp. 305, 306.

Intervenor witness Peseau objects to the inclusion of future purchased energy from unidentified resources on the grounds that either the energy, transmission for the energy, or both will be unavailable at reasonable prices in the future. Tr. pp. 177, 178, 179, 196 through 215. PCp witness Duvall testifies that Rocky Mountain Region and Desert Southwest resources are uniquely available to PCp because of its interconnections with those regions through its Utah Power and Light Division. Tr. pp. 31 through 35. Mr. Duvall opposes Mr. Faull's method of analyzing WSCC resources because it appears to presume equal access by all deficit utilities to all surplus resources. Tr. pp. 75, 76.

As Staff has pointed out in testimony, the language of Order No. 22636 did not preclude considering regional and integrated system resources in utility specific cases, but limited their consideration to comparison with utility specific resource plans. Staff's analysis dances on the border of this limitation, but stays within it and provides some interesting information. Therefore, we consider Staff's proposal first.

Staff makes a convincing case that there are substantial energy resources available outside the Northwest region. The Staff position that there is ample physical transmission capacity available, is also strong. Finally, Staff's contention that resource owners are likely to make business deals in their own best interest is practically a truism.

However, it is this final "truism" that causes Staff's proposal to fail. Staff's proposal is simply a variation on the Northwest Power Planning Council's (NWPPC) "firming non-firm hydro" scheme. Where the NWPPC proposes combustion turbines, staff witness Faull proposes wheeling-in off peak energy. As Dr. Peseau points out, any energy moving from the desert southwest to the northwest must travel over high voltage transmission paths owned by either PacifiCorp or a major California utility such as Pacific Gas & Electric (PG&E), Southern California Edison (SCE), Los Angeles Department of Water and Power (LADWP). Each of these southwest utilities has been buying non-firm hydro from the northwest at attractive prices for years. It is obviously not in their best interest to sell wheeling services at a relative pittance to permit northwest utilities to use that northwest non-firm hydro to serve northwest loads in lieu of southwest loads.

We therefore reject staff witness Faull's recommendation that WWP's load resource balance be predicated on the massive wheeling of southwest energy resources to northwest loads. However, we note that PCp has strong transmission interconnections with the desert southwest that are more than ample to serve all of PCp's non-firm hydro between critical and median water conditions; i.e. 150 average megawatts (aMW).

For years we have accepted as reasonable IPCo's practice of using median water conditions for both planning and avoided cost purposes because of IPCo's unique location and load profile. This practice has been very beneficial to IPCo's ratepayers. We see important parallels between IPCo's median water planning and PCp's proposed off-system purchases.

The evidence also convinces us that depending on *firm resources*, that is, resources that will be available when needed, although at an unknown price, to service *non-firm* hydro loads that are a small proportion of total loads is reasonable for planning purposes, even without firm contracts. The evidence is also convincing that the levelized life cycle cost of such dependence will be substantially less than avoided cost, which is the cost criteria set forth in Order No. 22636 to qualify as a "non-avoidable" resource. We find Dr. Peseau's assertion that non-avoidable resources must be available at non-firm energy cost to be unreasonable.

Therefore, we find that PCp's practice of planning to fill energy deficits with unidentified off system resources is reasonable, up to a point, for avoided cost purposes as well as for planning purposes, provided PCp continues to carefully monitor both energy and wheeling availability. PCp should include a comprehensive analysis of these availabilities in its biennial Avoided Cost Case applications.

We find that the reasonable limitation for including non-specified off-system resources in avoided cost computations under PCp's present level of integration is approximately 45% of the difference between critical and median water hydro capability, i.e. 65 aMW.

Load Growth :

In Order No. 22636, Case No. U-1500-170, the Commission stated that:

> The Commission will consider at utility specific public hearings whether each utility's estimates of load growth, proposed selection of future resources and water planning methodology are appropriate for avoided cost determination.

PCp proposes using an average load growth rate of 1.7% per year for determining the first deficit year applicable to avoided cost computations.

Tr. p. 86. No party indicated that this growth rate was not within the reasonable range of expectations. However, staff estimated that the reasonable range of potential average load growth rates could be from 6% per year to -1% per year for the period prior to the first deficit year. Tr. pp. 308, 309.

On cross examination PCp witness Davis declines to estimate a reasonable range of rates for short term load growth, but indicates that the Company's growth rate has been approximately 3% per year for the last three years and that present short term projections are for approximately 2.6% per year growth. Tr. pp. 88, 89, 90.

On cross examination Staff witness Faull indicates that he had testified in Case No. IPC-E-89-11 that a reasonable short term load growth range for the combined Western Systems is between 7% and 1% per year. Mr. Faull also testifies on cross examination that the Western Systems' loads had grown 5.6% in 1988 and 3.6% in 1989. Tr. pp. 359, 360.

The Commission finds the Company's average 20-year projection of system load growth to be too conservative for a near term forecast. In the near term, which for load growth is a reasonable period to look at for avoided cost purposes, we find a more robust growth projection of 3.0% per year to be reasonable for use in determining the first deficit year for PCp avoided cost purposes. Selection of this growth rate is buttressed by Independent Energy Producers of Idaho's (IEPI) case in chief and cross of Staff and Company. We further find that the factor for error in our adopted forecast is ameliorated by the 1% trigger which we have adopted for recalculation of avoided cost rates.

TRANSMISSION:

Although PCp witness Morris originally testifies that there would be no avoidable transmission integral with an SAR located in PCp's service territory (Tr. pp. 135, 136), on cross examination he states that "...there would be some avoided transmission [associated with a 500 MW SAR]." Tr. p. 136, 137, 149. According to Mr. Morris' testimony, the SAR would serve load growth only in the UP&L service territory (Tr. p. 129), and by a weighting methodology the avoidable transmission distance would be 336 miles. Exh. 11. Mr. Morris reduces this distance by 97 miles to account for "...transmission consequences when QFs in Idaho are the alternative to the (SAR)," yielding a total avoidable distance of 239 miles. Tr. pp. 132, 133.

Mr. Morris bases his 97 mile deduction on the fact that there is no firm west to east transmission capacity from Naughton to Monument, Wyoming. Tr. p. 141. Although no party challenged Mr. Morris' mileage estimate, a cursory review of the publicly available 1989 WSCC map of "Planned Facilities through 1999..." shows two interesting facts -- first, that it is less than 20 miles from Naughton to Monument, and second, that in 1989 PCp planned to increase transmission capacity from Naughton to Monument by building a 230 kV line from Naughton to Shute Creek via a new substation called Opal. According to page 4B-5 of the WSCC's publication entitled "Coordinated Bulk Power Supply Program, 1989-1999," this new line would be 32 miles long and enter service in December, 1993.

We find that the transmission constraint from Idaho to Rock Springs is insignificant and temporary. It is therefore inappropriate to reduce avoidable transmission costs associated with the SAR.

Staff witness Faull challenges PCp's underlying assumption that the SAR would serve only PCp's eastern territory. Tr. pp. 314, 315. The major effect of Mr. Faull's change is to increase the quantity of transmission loading that would be required into an eastern Idaho substation. Tr. p. 316, Exh. 104 & 107.

During the proceedings pursuant to the PP&L/UP&L merger, PCp was adamant in its assertion that it would operate the two companies as an integrated system. It is the purpose of this proceeding to determine the avoidable costs of the entire PCp system, as represented by the SAR. We therefore find that it is appropriate to consider PCp's entire integrated system for determining the amount and cost of avoidable transmission associated with the SAR.

PCp recommends assuming that Idaho loads will be served by the Goshen substation (430 mi.) and that Utah loads will be served by the Grace substation (400 mi.). Tr. pp. 130, 131. Mr. Faull testifies that it is most likely that the avoidable transmission would be built to a single substation and the energy distributed from there, and that the most probable substation for this purpose would be Borah (475 mi.). Tr. p. 316. Intervenor witness Peseau testifies that the transmission mileage ought not to include a component to Wyoming, but ought to be allocated entirely from the Powder River Basin to Grace, Goshen, or the weighted distance between them. Tr. p. 173.

In rebuttal testimony Mr. Morris concurs that the termination of the avoidable SAR transmission would be at a single substation in Idaho, but that the substation would be Goshen, not Borah. Using this assumption, Mr. Morris computes an avoidable transmission distance of 384 miles, less any reduction for QF transmission consequences. Tr. pp. 141, 142, 143. Under redirect examination Mr. Faull testifies that he is uncertain that Borah is a more reasonable termination for the avoidable SAR transmission than Grace or Goshen.

We find that it is appropriate to consider the nearest reasonable substation as the termination point for the SAR related avoidable transmission. We therefore use the 400 mile transmission distance to the Grace substation and the 230 mile distance to Rock Springs substation for determining avoidable transmission costs. This results in a total weighted avoidable transmission distance of:

$$400*(0.78)+230*(0.21) = 360 \text{ mi.}$$

Based on an estimate previously developed for a 105 mile 345 kV line from Bridger to Naughton substations, with a $37,000 per mile adder for series compensation, PCp recommends a transmission construction cost of $0.36/kW-mile. Tr. pp. 128, 139, Exh. 18). Based on an WWP estimate for a 500 mile 500 kV line from the Powder River Basin to Hot Springs, Montana, (as submitted in Case No. WWP-E-89-6) Mr. Faull recommends a transmission construction cost of $0.48/kW-mile. Tr. pp. 320, 321. Intervenor witness Peseau recommends using the average of the construction costs recommended by IPCo in Case No. IPC-E-89-11 ($0.62/kW-mile) and by WWP in Case No. WWP-E-89-6 ($0.48/kW-mile), or $0.55/kW-mile. Tr. p. 174.

On rebuttal, Mr. Morris testifies that PCp has under construction a 150 mile 230 kV line from Mustang to Bridger at an actual cost of about $140,000 to $150,000 per mile. Tr. pp. 385, 386. On cross examination Mr. Morris estimated the carrying capacity of the Mustang-Bridger line to be about 500 MW. Tr. p. 392.

$$((\$150{,}000+37{,}000)/500{,}000 = \$0.37/\text{kW-mile})$$

Cost data on this transmission line were submitted in a late filed exhibit. Thus, it would appear that PCp's estimate of $0.36/kW-mile is well supported, at least for wood pole lines in the 230-345 kV range with lengths between 100 and 150 miles.

However, in rebuttal testimony Mr. Morris discusses an alleged error in the WWP cost estimate specifically related to line length. According to Mr. Morris, WWP made its original estimate using a 600 mile 500 kV line capable of carrying 2000 MW to determine a cost per kW-mile, then reduced the length of line to 500 miles but forgot to increase the carrying capacity of the line to reflect reduced losses resulting form reduced length. Specifically, Mr. Morris states that a 20 percent reduction in line length will result in a 20 percent increase in carrying capacity, so that WWP should have used 2,400 MW as the capacity of the 500 mile 500 kV line. Tr. pp. 390, 391. This change alone would reduce the WWP estimate to $0.40/kW-mile. [(2000/2400)*.48 = .40] However, applying this same logic to the PCp estimate yields the following.

[(360 miles/105 miles)*$0.36 = $1.23/kW-mile]

It appears, therefore, that transmission construction costs increase dramatically as the distance of transmission increases. It also appears that the 500 kV transmission cost estimates submitted by IPCo and WWP are more reliable for the intended purpose than the PCp estimates, even though the PCp estimates appear to be quite accurate for the lines they represent.

In rebuttal Mr. Morris also testifies that the WWP estimate includes $60 million for 5 new substations that would not be needed for the PCp line. Tr. pp. 388, 389. However, Mr. Morris also states that he believes PCp would have substation costs of about 10% of the line costs. Tr. p. 389. (We note that the WWP estimate of $60 million equals roughly 10% of the WWP line cost estimate.) Important transcript references to the "$60 million substation costs" from Case No. WWP-E-89-6 are:

> Substation costs for **<u>additions</u>** to five substations would approximate $60 million. (WWP Tr. p. 89, ll. 4-5; emphasis added)
>
> Substation costs should be less than the $60 million used in the estimate for the 600 mile transmission alternative. Using the $60 million substation costs.... (WWP Tr. p. 90, ll. 21-23)
>
> Q. Well, Mr. Durreck (sic) included a fairly detailed transmission study that included substantial costs for a pertinent line and substation equipment, including series capacitors, shunt reactors, automatic transformers and circuit breakers, and in your testimony, you reference cost estimates from BPA for a double circuit 500 kV transmission, those estimates ranging from $784,000 per mile to $909,000. Do you know what is included in those estimates?
>
> A. Yes, those are transmission line costs only; that is, towers, conductors, insulators. I added to those costs $60 million to represent station equipment that we would need to install on what we considered an appropriate number of stations.
>
> Q. Substation equipment?
>
> A. Substation equipment, circuit breakers, reactors, shunt capacitors.
>
> Q. Any voltage support equipment?
>
> A. The voltage support equipment, the reactors and the series capacitors provide voltage controls. We did not include transformation and I did not review the surrogate plant cost to see if those costs included step-up transformation. We considered step-down transformation and considered that existing transformation was in place so that would not need to be included in these costs.
>
> Q. And you would agree that those adders that you just mentioned would have to be considered?
>
> A. Yes, those would be part of the transmission costs for a kind of system that we proposed. For other kinds of systems, they could vary depending on the specifics and I believe the costs we've included are appropriate and adequate for the needs.

WWP Tr. pp. 95, ln. 7 through p. 96.

In parallel Case No. WWP-E-89-6 we determined that the appropriate cost for WWP's 500 miles of avoidable transmission is $0.552/kW-mile based on a modified application of Mr. Morris' distance adjustment. Specifically, we determined that a direct proportion between transmission distance and cost per kW-mile was unreasonable, but that the square root of the distance proportion does yield reasonable results. Thus, in this Case we find that PCp's appropriate avoidable transmission cost is:

$$[((360/500)^{0.5})*.552)] = \$0.468/\text{kW-mile}$$

$$(\$0.468/\text{kW-mile})*(360/\text{mile}) = \$169/\text{kW}$$

ASSET DEFERRAL END EFFECTS (TILTING):

The computer model recommended by PCp for determining avoided costs includes a methodology that has been referred to as "tilting" of capital costs because its graph over time shows capital recovery rates as steadily increasing rather than as level. Staff included a mathematical "proof" of the correctness of this methodology to account for the fact that need for the SAR will be deferred rather than eliminated. The result of this methodology is often referred to as the "end effect" of deferral.

Noting that QF contracts are limited in length to 20 years regardless of the QF's being ready, willing, and able to contract for longer periods, and further noting that 20-year rates based on tilted capital costs are less than comparable 35-year rates, staff recommends that an alternate rate be computed for 20 year contracts based on level capital costs rather than on tilted capital costs. Staff recommends that the alternate 20-year rates be made available only to QFs that would be ready, willing, and able to contract for 35 years if permitted by the Commission. Tr. pp. 326 through 332.

Intervenor witness Peseau requests the Commission to consider reinstating the option for QFs to contract for up to 35 years of generation. Tr. p. 192. We note that the effect of tilting becomes *de minimus* for 35 year contracts.

Clearly, QFs willing and able to obligate themselves to provide capacity and energy for more than 20 years have a right under PURPA to full avoided costs for the power they produce. However, levelized or front-loaded rates are not a right under PURPA -- they are a QF incentive authorized by the Commission to facilitate project financing. With any front-loading there is attendant risk. To minimize the risk, the Commission has established a maximum contract length of 20 years for standard contracts with levelized rates (except under special circumstances described in Order No. 22636). Longer contracts to be considered must contain additioal protection for ratepayers.

Nonetheless, we consider Idaho's public interest to be well served by the addition of new long-lived fixed generating resources to the interconnected grid. Based on the evidence presented in this case, the least objectionable method for encouraging QFs to design, build, and operate plants to assure lives longer than 20 years is to provide a higher levelized rate for such projects. Because the primary reason for limiting contract lengths to 20 years is to protect ratepayers from the risk of QF non-performance after **inflation** has increased the value of energy, and because "tilting" accounts for the utility's construction costs increasing due to **inflation**, the fairest way to determine the level of incentive for long-lived projects is by eliminating the "tilt" from the computation.

The Commission believes that utilities' commitment to long-lived resources, whether by contract or by ownership, entail substantial risks.

Such risks are not costless. We find that the risk cost of long term commitments to capital assets is most accurately represented by the effect of the estimated inflation rate used to account for end effects. Therefore, we find that the total costs avoided by QF resources capable of providing power for the full 35-year life of the SAR, but contracting for only 20 years, is the "non-tilted" rate, as shown in Appendix C, attached.

To be eligible for the non-tilted rate, a QF must provide all Engineer's Certificates required under Order No. 21690, the final Order resulting from the "Security" Case No. U-1500-170, assuring normal operational life of 35 years or more for the QF.

ADMINISTRATIVE AND GENERAL (A&G) EXPENSES:

PCp originally proposes that A&G costs be included in the SAR's annual carrying charge, but in rebuttal testimony PCp witness Rust recommends that no A&G expense be included because those costs are already included in the fixed operating and maintenance (O&M) costs of the SAR. Tr. pp. 97, 98. Staff witness Faull also recommends that no A&G expense be included in the carrying charge, but on the alleged ground that A&G costs for QF resources are probably similar to A&G costs for the SAR and therefore SAR A&G costs are not avoidable. Tr. p. 325. Based on a statistical analysis comparing A&G costs to generated energy and purchased energy, intervenor witness Peseau recommends that A&G costs be included for avoided cost purposes. Tr. pp. 186 through 192. The rates of A&G recommended by Dr. Peseau are 1.49% of SAR cost for "A&G" and an additional 4.36% to 5.03% of SAR cost for "general plant" expense. Tr. p. 191.

Under cross examination Mr. Rust indicates that he relied on Dr. John Willmorth of IPCo in determining that A&G costs were included in the

SAR O&M costs, and that PCp accordingly removed A&G costs from the avoided cost recommendations to avoid double counting them. Tr. pp. 102, 103, 104. Under direct examination on the stand Dr. Peseau testifies that the 1.2% of SAR costs that PCp originally recommended results in A&G costs of $17.40 per kW-year while total SAR fixed O&M costs are only $25.00 per kW-year, thus leaving only $7.60 per kW-year for all other fixed O&M costs. Tr. pp. 216, 217, 218.

This issue is developed in much more detail in parallel Cases Nos. WWP-E-89-6 and IPC-E-89-11. In those cases we found that although the evidence is insufficient to fully resolve the issue, the combination of utility and staff arguments are persuasive. Therefore, A&G expenses not included in the SAR direct costs are not to be considered as avoidable costs in determining PCp's CSPP rates.

COST OF CAPITAL:

Based on long term (20 yr) forecasts plus an estimate for the cost of Pollution Control Revenue Bonds (PCRBs), PCp recommends using the following capital structure and costs for avoided cost computations. Tr. p. 94.

	STRUCTURE	COST
PCRBs	25%	8.00%
Debt	24%	9.60%
Preferred Equity	6%	8.65%
Common Equity	45%	13.00%
Weighted Totals	100%	10.67%

Arguing that debt and preferred costs are fixed once issued, Staff contends that a 20-year forecast period for cost of debt and preferred equity is inappropriate. To better recognize when the financial instruments are issued, Staff states that the cost should either be the current authorized costs or the costs forecast over a potential period of construction. Tr. p. 289. No capital costs have been authorized for PCp since the merger of UP&L with PP&L. The authorized capital costs of each of those companies is shown in Exhibit No. 108, page 1. Tr. p. 290. For a seven year financing period through 1996 Ms. Carlock estimates capital costs to be:

PCRBs	8.80%
Debt	10.30%
Preferred	10.29%
Common	12.75%

Tr. p. 291.

For either method Ms. Carlock recommends using the following idealized capital structure.

PCRBs	25%
Debt	25%
Preferred	10%
Common	40%

Tr. p. 292.

Thus, Ms. Carlock computes the weighted cost of capital for the financing period method to be 10.904%. Tr. p. 292, Exh. 108.

Intervenor witness Peseau agrees with PCp's use of long term debt in lieu of financing period debt, but estimates its cost to be 10.25% rather than the 9.6% estimated by PCp. Dr. Peseau also objects to PCp's estimate of equity cost at 13%, recommending that a more appropriate cost of equity for PCp would be 13.75%-14.00%. Tr. p. 185. In addition, Dr. Peseau objects to the use of PCRBs on the grounds that (1.) they do not represent the "marginal cost of debt" that he opines will be avoided by QFs (Tr. pp. 182, 183) and (2.) they are subsidized and therefore do not represent the full market costs of the debt.

Tr. p. 183. Dr. Peseau's estimate for the overall cost of capital for PCp's avoided cost computations is 11.73%. Tr. p. 186.

On rebuttal PCp witness Rush testifies that financing period costs of capital are "...not appropriate because individual security offerings cannot be segregated by specific plant investments." Tr. p. 98. Mr. Rush also objects to Ms. Carlock's estimate of preferred equity cost (Tr. p. 99) and to Dr. Peseau's removal of the PCRB costs from the capital cost computation. Tr. pp. 91 through 100.

Under cross examination Mr. Rust agrees that "...a company's securities support all utility plant but that project costs can be calculated or estimated...." Tr. p. 109.

Under cross examination Dr. Peseau supports his thesis that avoided costs should be set using marginal debt costs by opining that QFs will not be available in substantial quantity to avoid the entire SAR, but will only avoid a small portion of it. Tr. pp. 258, 259, 260.

Under cross examination Ms. Carlock concedes that long term debt used to finance the SAR might be refinanced after construction if interest rates drop substantially (Tr. pp. 296, 297, 298), and reiterates and expands on her support for including PCRBs in the debt mix for avoided cost purposes. Tr. pp. 300, 301, 302.

We reject Dr. Peseau's assertion that only marginal capital costs are avoidable by QFs. We also reject PCp's recommendation to use long term capital costs. Because no embedded cost of capital has been determined for the merged PP&L/UP&L system, we find that the most appropriate cost of capital to be used for PCp's avoided cost computations is that resulting from the "financing period" method recommended by Ms. Carlock. Therefore, PCp's avoided cost rates shall be computed using the following capital data.

COMPONENT	RATIO	COST
PCRBs	25.0%	8.80%
Debt	25.0%	10.30%
Preferred	10.0%	10.29%
Common	40.0%	12.75%

Weighted Cost of Capital: 10.904%

We note that without the PCRBs the weighted cost of capital for PCp would be 11.28%. We find this cost to be reasonable for now. However, we would be remiss if we did not mention that PCp's recent propensity to pursue relatively risky business strategies could substantially drive up the company's cost of capital. We will be watching the company carefully to assure that ratepayers are not penalized by PCp's adventurous business practices.

ADJUSTABLE PORTION:

PCp recommends that the adjustable portion of the avoided cost rates be set at 10 mills/kWh based on the average cost of fuel consumed at PCp's coal fired generating resources. Tr. p. 16.

In direct testimony, staff points out that the Commission has used a broad range of methodologies to set the adjustable portion of avoided costs. Among these are average system variable costs, average marginal energy cost, and SAR variable cost. Staff recommends that the adjustable portion be set at the 1989 cost of PCp's marginal 100 MW of energy production for retail sales, escalated at 4.50% per year, and adjusted monthly based on PCp's actual operating data. Staff estimates the adjustable portion to be approximately

14 mills/kWh based on IPCo's actual 1989 operating data. Staff's escalation rate recommendation is based on the Commission's -170 determination for electricity escalation. Tr. p. 332 through 335.

PCp objects to Mr. Faull's recommendation on the grounds that the adjustable portion should reflect the costs associated with the SAR coal plant, that Mr. Faull's recommendation would cause QFs to recover generation cost increases not related to inflation, and that Mr. Faull's recommendation "...does not meet the Commission's goal of simplicity and produces avoided cost payments that are extremely volatile." Tr. pp. 26, 27, 28.

We find that the methodology recommended by staff yields the most accurate reflection of actual avoided costs, and that it would most encourage QFs that best match each utility's power needs. However, because utilities' marginal costs are a large proportion of total levelized avoidable costs, we find that using this methodology would significantly reduce the value of rate levelization for encouraging QF development. Therefore, we reject staff's methodology. We select instead the methodology recommended by WWP in parallel Case No. WWP-E-89-6 for determining the adjustable portion of avoided cost rates. The adjustable portion and the escalation rate to be used in the avoided cost computation shall be 8.78 mills/kWh and 5.13%, respectively, based on actual variable operating costs of the Colstrip, Montana mine-mouth coal plant.

The Commission recognizes that using the actual variable costs of Colstrip generation to determine future adjustable costs may understate actual energy escalation rates for several reasons. We also recognize that because Colstrip's minemouth operation is well established, its fuel costs may not escalate as rapidly as coal costs in general. Furthermore, we recognize that future coal plant generating costs may escalate significantly from increased environmental capital cost requirements, thereby increasing the cost of energy without concurrently increasing variable costs, especially coal costs.

Nonetheless, for the time being we will use Colstrip variable costs for periodically resetting the adjustable portion of avoided cost rates established under this Order. However, we direct staff to monitor the effects of using Colstrip costs as a guideline. If this methodology fails to reasonably track energy cost escalation rates, we will institute a future case to determine a more appropriate methodology for recomputing the adjustable portion of avoided cost rates established under this Order. Contracts established under this order shall provide for resetting of the adjustable portion of the rate annually, starting June 1, 1991, based on actual Colstrip variable operating costs of the prior calendar year, or otherwise as established by the Commission in a future case.

SEASONALIZATION :

Although PCp recommends no seasonalization of rates, Staff witness Faull recommends that the Company be required to develop seasonalization and time-of-day factors for avoided cost rates. However, Mr. Faull testifies that the "adjustable portion" methodology he recommends inherently includes seasonalization, so no additional factor would be required in conjunction with that methodology. Tr. p. 336.

In rebuttal, PCp witness Rust testifies that seasonalization and time of day rates are inappropriate because the SAR is contemplated to be a base load plant, with costs independent of load. Tr. pp. 100, 108, 109.

We find PCp's testimony to be persuasive. Therefore, neither seasonal nor time-of-day variations shall be applicable to the Avoided Cost Rates resulting from this Case.

FIRST DEFICIT YEAR :

Appendix A is a load/resource estimate for PCp from 1990 through 2000 incorporating the changes discussed above. Incorporating the charges discussed above, this estimate indicates that the first deficit year for determining PCp's avoided cost rates is 1992. Appendix A shall be used to determine changes in the first deficit year resulting from PCp's resource pool increasing or decreasing by the "trigger" amount.

POST LOAD/RESOURCE BALANCE YEAR QF PROJECTS :

Obviously, QF projects coming on line after the load/resource balance year cannot provide energy in the prior load/resource balance year. Therefore, computation of avoided cost rates for QF projects with post-load/resource balance year on-line dates shall use the project's on-line year as the first deficit year.

FINDINGS OF FACT

Based on the record established in this Case, our findings as more fully described above, and on the Commission's general knowledge, we find that:

The fair, just, and reasonable estimate of future loads and resources for determining PCp's Avoided Cost Rates is as shown in Appendix A, attached;

The fair, just, and reasonable variables to use for determining PCp's Avoided Cost Rates is as shown in Appendix B, attached; and

The fair, just, and reasonable Avoided Costs applicable to PCp are as shown in Appendix C, attached.

CONCLUSIONS OF LAW

I

The Idaho Public Utilities Commission has jurisdiction over PacifiCorp dba Pacific Power and Light Company and Utah Power & Light Company pursuant to the authority and power granted it under Title 61 *Idaho Code* and pursuant to the Rules of Practice and Procedure of the Idaho Public Utilities Commission, IDAPA 31.A

II

The Idaho Public Utilities Commission has authority under the Public Utility Regulatory Policies Act of 1978 (PURPA) and implementing regulations of the Federal Energy Regulatory Commission (FERC) to set avoided costs, to order electric utilities to enter into fixed term obligations to purchase energy from qualifying cogeneration and small power production facilities, and to implement FERC rules. PURPA §§210, 210a, 210f, 16 U.S.C.A. §§824-A-3, 824-A-3(a), (f); *Afton Energy, Inc. vs. Idaho Power Company.* 107 Idaho 781, 693 P.2d 427, 1984.

ORDER

In consideration of the foregoing and as more fully described above, we find it reasonable and IT IS HEREBY ORDERED that:

1. The load/resource estimate to be used for determining PCp's avoided cost rates shall be as shown in Appendix A, attached.

2. The variables to be used for determining PCp's avoided cost rates shall be as shown in Appendix B, attached.

3. The avoided cost rates applicable to QFs selling power to PCp shall be as shown in Appendix C, attached.

4. Upon PCp's reaching a new resource trigger as described in Order No. 22636 and as more fully discussed herein, PCp shall determine a new "First Deficit Year" based on Appendix A, shall compute proposed new rates using the variables identified in Appendix B except for the new First Deficit Year, shall prepare the proposed new rates in a format similar to Appendix C, and shall submit the new rates to the Commission for approval. Prior to receiving approval for the new rates so computed and submitted, PCp shall negotiate in good faith with any prospective QFs on the basis of the proposed new rates.

5. On May 1, 1991, and annually thereafter, PCp shall submit to the Commission a proposed new Adjustable Portion based on actual Colstrip variable costs of the prior calendar year as published in WWP's FERC Form 1.

THIS IS A FINAL ORDER. Any person interested in this Order (or in issues finally decided by this Order) or in interlocutory Orders previously issued in this Case No. PPL-E-89-3/UPL-E-89-5 may petition for reconsideration within twenty-one (21) days of the service date of this Order with regard to any matter decided in this Order or in interlocutory Orders previously issued in this Case No. PPL-E-89-3/UPL-E-89-5. Within seven (7) days after any person has petitioned for reconsideration, any other person may cross-petition for reconsideration. See *Idaho Code* §61-626.

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DONE by Order of the Idaho Public Utilities Commission at Boise, Idaho, this 28th day of September 1990.

NOTE: See attached concurrence of Dean J. Miller

DEAN J. MILLER, PRESIDENT

Perry Swisher

PERRY SWISHER, COMMISSIONER

Ralph Nelson

RALPH NELSON, COMMISSIONER

ATTEST:

Myrna J. Walters

MYRNA J. WALTERS, SECRETARY

SW:nh:lf/O-1152

CONCURRING OPINION
DEAN J. MILLER

Although I fully concur in the decisions reached in Order Numbers 23357, 23349, and 23358, I write separately to express some personal comments and observations. This is appropriate because the -170 case was initiated, at least partially, at my request.

First, I extend my personal gratitude to all the parties who devoted considerable thought, resources and time to this project which has spanned almost three years. Staff engineer Faull and Deputy Attorney General Woodbury deserve special mention in this regard for their devotion to this project. Our transcript in the -170 case and subsequent utility-specific cases is more than 2,000 pages long, and this illustrates the magnitude of the effort devoted by all interested parties.

Second, it is appropriate to ask whether this significant expenditure of resources has been worth the effort. Have we accomplished anything of value? The answer to this question lies, in part, in the history of PURPA implementation in Idaho, which I will briefly review.

In 1978 Congress conceived the notion that electric utilities must purchase electricity from small power producers and cogenerators, but state commissions like this one were given the task of nurturing the infant industry. The regulated utilities had no programs in place to purchase these generators' output. In many instances, they distrusted CSPPs' reliability, resented CSPP legal priority over much of their own planned generation, and questioned the reasonableness of CSPP purchases driving up their rates. They had the resources to pursue these views with vigor.

These established utilities who generated and distributed electricity had not on their own initiative tapped the potential generation in their midst represented by CSPPs.

By contrast, the CSPP industry was unorganized, unsophisticated and unknown in the early days of the implementation of PURPA. The industry as a whole was not equipped to carry the legal and technical burden of proposing regulatory policy to this Commission.

Accordingly, the Commission carried much of the initial burden of formulating and implementing regulatory policy. This Commission's initiatives under PURPA gave the industry valuable guidance and education and laid down rules that selling generators and purchasing utilities alike were bound to follow. Many of these rules, consistent with federal standards, limited traditional management prerogatives, as this was necessary to comply with PURPA.

As expected following such a major statutory change in the way of doing business, disagreement inevitably ensued. Those whose former management discretion was constrained by the new law and those who were the beneficiaries of newly created rights under the new law used litigation before this Commission and the courts to explore the contours of the new legal balance that replaced the old. Of course, that new balance favored the emerging industry much more than the pre-PURPA status quo because that was PURPA's purpose.

But, was the early balance this Commission struck the appropriate one to guide the industry and the utilities prospectively as the industry matured and the utilities gained more experience purchasing small power and cogeneration? That question--the appropriate regulatory balance for a maturing industry--not a rehash of the appropriate regulatory balance for an emerging one--was a question waiting to be considered.

Thus, by 1987 there was a generalized perception in the utility and CSPP communities that it was time to review the assumptions and methodologies associated with the determination of avoided cost rates. The previously existing disputes raised the questions, or at least suspicions, as to whether the methodology was credible and whether the rates were fair to the ratepayers and CSPPs alike. Also in 1987 the composition of the commission changed so that two of its members, having not participated in the previous proceedings, did not carry with them the baggage resulting from the early implementation periods. Notwithstanding his prior involvement, our colleague Commissioner Swisher also approached this project with an open mind.

The -170 case was thus born from the desire to undertake an impartial and full review of the commission's PURPA policies and therefore to produce a result that was credible and sustainable. I realize that I lack to capability to make the result credible simply by declaring it to be so and that we must await the passage of time to know the degree of our success. Nonetheless, the following features of our decisions give me reason for optimism.

First, we have, after considering various alternatives, retained the Surrogate Avoided Resource methodology. I am satisfied that this method has the advantage of familiarity. It recognizes the impossibility of the commission trying to predict with certainty the exact identity of the next resource that might be acquired by any given utility. Rather, our task is to identify the costs avoided by a utility when it purchases CSPP production. This task is necessarily imprecise and the SAR methodology produces results as sustainable as any other method.

Second, as the CSPP industry has matured, we have recognized that the balancing of interests between the industry and the ratepayer should change. We have shortened the standard length of contracts from 35 to 20 years to diminish ratepayer risk and to recognize that a maturing industry no longer requires extremely long contracts in order to succeed. In a companion proceeding we determined that this maturing industry is capable of, and should be required to, provide the ratepayers with forms of assurance that in the event of project failure the ratepayer will be made whole.

Third, we have improved the methodology to make it more responsive to changing circumstances that affect avoided cost rates. This has the related advantage of reducing the number and length of contested proceedings and regulatory burden.

Our review has been careful and thorough. It is impossible to expect that any interested party agrees with every aspect of our decisions. Each party is entitled to know, however, that their arguments received careful consideration, and I hope that is apparent from our Orders.

In short, having conducted this through review and having reached our decisions, we now have revised methodologies that should guide our PURPA implementation for the next several years. In my opinion we have found an appropriate balance between the interests of the industry, our regulated utilities and their ratepayers. In the absence of dramatically changed and unforeseen circumstances there should not be a need to repeat this process for some time to come.

Dean J. Miller, President

lD/77/m

COMMISSION DETERMINED ENERGY LOAD/RESOURCE BALANCE FOR PCp'S AVOIDED COST COMPUTATIONS
(aMW)

CASE NO. PPL-E-89-6/UPL-E-89-5

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000
REQUIREMENTS											
1. System Firm Loads	4,927	5,075	5,227	5,384	5,546	5,712	5,883	6,060	6,242	6,429	6,622
2. Sales for Resale	480	537	556	556	556	556	527	527	527	466	445
3. Thermal Maintenance	394	426	421	439	359	389	433	407	402	428	393
99. TOTAL REQUIREMENTS	5,801	6,038	6,204	6,379	6,461	6,657	6,843	6,994	7,171	7,323	7,460
RESOURCES											
101. Total Hydro	435	436	437	438	439	440	441	442	443	444	444
102. Existing Thermal Generation	5,041	5,055	5,071	5,078	5,078	5,078	5,078	5,078	5,078	5,078	5,078
103. Existing Firm Resources	629	623	615	621	631	630	494	447	428	421	417
104. Voltage Regulation	2	4	6	8	10	10	10	10	10	10	10
105. T&D Improvements	2	4	6	8	10	10	12	14	18	20	22
106. BPA Settlement (WNP-3)	0	0	0	0	0	65	63	67	65	65	65
107. Cognen Ownership	0	0	0	0	0	0	0	0	0	0	0
108. Gadsby	0	0	0	0	0	0	118	118	118	118	118
109. SCE energy	0	0	0	0	0	0	36	72	108	108	108
110. Unspecified Off System Purchases	65	65	65	65	65	65	65	65	65	65	65
199. TOTAL RESOURCES	6,174	6,187	6,200	6,218	6,233	6,298	6,317	6,313	6,333	6,329	6,327
TOTAL SURPLUS(DEFICIT)................	373	149	(4)	(161)	(228)	(359)	(526)	(681)	(838)	(994)	(1,133)

Order No. 23358
Appendix A

* * DATA TYPE	PCp		
	DATA YEAR	DATA SOURCE	PCp DATA
FIRST DEFICIT YEAR:	1990	PPL-E-89-3	1992
SURPLUS ENERGY COST (mil/kWh):	1990	U-1500-170	23.60
SURPLUS COST BASE YEAR:	1990	U-1500-170	1989
"SAR" PLANT LIFE (YEARS):	1990	U-1500-170	35
"SAR" PLANT COST ($/kW):	1990	U-1500-170	$1,450
BASE YEAR OF "SAR" COST:	1990	U-1500-170	1989
"SAR" CAPACITY FACTOR (%):	1990	U-1500-170	75%
UTLTY WT'D COST OF CAPITAL (%):	1990	PPL-E-89-3	10.90%
RATEPAYER DISCOUNT RATE (%):	1990	PPL-E-89-3	10.90%
"SAR" FIXED O&M ($/kW):	1990	U-1500-170	$25.00
"SAR" VARIABLE O&M (mil/kWh):	1990	U-1500-170	1.60
TRANSMISSION O&M ($/kW-yr):	1990	PPL-E-89-3	$1.97
TRANSMISSION LOSSES (%):	1990	PPL-E-89-3	5.00%
"SAR" FUEL COST (mil/kWh):	1990	U-1500-170	5.78
BASE YEAR, "SAR" EXPENSES:	1990	U-1500-170	1989
ESCALATION RATE; GENERAL (%):	1990	U-1500-170	4.50%
ESCALATION RATE; "SAR" (%):	1990	U-1500-170	4.50%
ESCALATION RATE; SURPLUS (%):	1990	U-1500-170	4.50%
ESCALATION RATE; O&M (%):	1990	U-1500-170	4.50%
ESCALATION RATE; FUEL (%):	1990	U-1500-170	5.25%
ADJUSTABLE PORTION (mil/kWh):	1990	PPL-E-89-3	8.78
BASE YEAR; ADJUSTABLE COSTS:	1990	PPL-E-89-3	1990
CAPITAL CARRYING CHARGE (%):	1990	COMPUTED	13.79%
LEVEL CARRYING COST (mil/kWh):	1990	COMPUTED	43.12
ESCALATION RATE; ADJUSTABLE (%):	1990	PPL-E-89-3	5.13%
"TILTING" RATE (%):	1990	PPL-E-89-3	4.50%
TRANSMISSION CAPITAL COST:	1990	PPL-E-89-3	$169

PCp

CONTRACT LENGTH (YEARS)	1991	1992	1993	1994	1995	1996
	ADJUSTABLE PLUS NON-ADJUSTABLE COSTS (m/kWh) — ON-LINE YEAR					
1	25.32	39.47	40.84	42.27	43.77	45.34
2	32.03	40.12	41.52	42.98	44.51	46.11
3	34.67	40.76	42.19	43.69	45.25	46.88
4	36.28	41.40	42.86	44.39	45.98	47.64
5	37.49	42.03	43.52	45.08	46.70	48.40
6	38.48	42.66	44.18	45.76	47.41	49.14
7	39.35	43.28	44.82	46.43	48.12	49.88
8	40.14	43.89	45.46	47.10	48.81	50.60
9	40.87	44.48	46.08	47.75	49.49	51.32
10	41.56	45.07	46.70	48.39	50.17	52.02
11	42.22	45.65	47.30	49.02	50.82	52.71
12	42.84	46.22	47.89	49.64	51.47	53.38
13	43.44	46.77	48.47	50.25	52.10	54.04
14	44.02	47.31	49.04	50.84	52.72	54.69
15	44.57	47.84	49.59	51.42	53.33	55.32
16	45.11	48.36	50.13	51.98	53.92	55.94
17	45.63	48.87	50.66	52.53	54.49	56.54
18	46.13	49.36	51.17	53.07	55.05	57.12
19	46.61	49.83	51.67	53.59	55.60	57.69
20	47.08	50.30	52.16	54.10	56.12	58.24

FOR PROJECTS WITH ENGINEERS' CERTIFICATES SPECIFYING 35-YEAR OR GREATER LIVES, 20-YEAR CONTRACTS SHALL HAVE THE FOLLOWING RATES.

	1991	1992	1993	1994	1995	1996
20 **	51.57	54.69	57.02	59.18	61.44	63.80

(ALL RATES INCLUDE AN ADJUSTABLE PORTION OF 8.78 mills/kWh)