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SUBMITTED VIA E-TARIFF FILING

February 10, 2016

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, NE
Washington, DC 20426

Re: ***Puget Sound Energy, Inc.***
Docket No. ER16-___-000
Amendments to the Puget Sound Energy, Inc. Open Access Transmission Tariff to Facilitate Entry into the Energy Imbalance Market

Dear Secretary Bose:

Pursuant to Section 205 of the Federal Power Act ("FPA")[1] and Part 35 of the Commission's regulations,[2] Puget Sound Energy, Inc. ("PSE") hereby submits for filing revisions to its Open Access Transmission Tariff ("OATT"). The attached revisions are designed to facilitate PSE's participation in the Energy Imbalance Market ("EIM") administered by the California Independent System Operator ("CAISO"), with parallel operations targeted for August 1, 2016 and full participation scheduled to commence on October 1, 2016. The OATT revisions are the culmination of a stakeholder process lasting several months during which PSE received and incorporated feedback from OATT customers. The tariff changes include:

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[1] 16 U.S.C. § 824d (2012).

[2] 18 C.F.R. Part 35 (2015).

(i) the qualifications and requirements for generation resources physically or electrically located in PSE's balancing authority area ("BAA") to participate in the EIM;

(ii) the roles and responsibilities of PSE as a balancing authority ("EIM Entity") and of CAISO as the market operator ("MO");

(iii) the flow of information from transmission and interconnection customers taking service in PSE's BAA to PSE that is then amalgamated into a resource plan and transmitted to CAISO in order to facilitate CAISO's economic dispatch modeling;

(iv) the manner in which capacity on PSE's transmission system will be made available for EIM transfers into and out of the PSE BAA; and

(v) the settlement of EIM-related payments and charges between PSE and its transmission and interconnection customers.

While the CAISO OATT acknowledges the need for EIM Entities to determine the manner in which they will participate as a BAA in the EIM on a case-by-case basis,[3] PSE is the third EIM Entity to announce its participation and its proposed OATT revisions consequently are guided by the prior efforts of others. Specifically, the OATT revisions proposed by PSE herein are modeled on, and substantively consistent with, the most recent Commission-accepted tariff changes adopted by current EIM participants PacifiCorp and Nevada Power Co. and Sierra Pacific Power Co. (the latter two, collectively, d/b/a "NV Energy").[4] The EIM-related provisions of PSE's OATT are further designed to work in concert with parallel provisions of the CAISO OATT, which define CAISO's role and responsibility as the EIM MO. To that end, PSE's proposed tariff provisions are designed to be consistent with the CAISO tariff revisions recently adopted by the CAISO in order to automatically recognize and account for capacity an EIM Entity has available to maintain reliable operations in its own BAA, but has not bid into the EIM, known as "Available Balancing Capacity" ("ABC").[5] PSE has modeled its

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[3] *See* Cal. Indep. Sys. Operator Corp., Fifth Replacement FERC ElectricTariff (OATT), Roles and Responsibilities, § 29.4(b)(3), version 3.0.0 (effective Jan. 5, 2016) ("CAISO Tariff").

[4] *See*, *e.g. PacifiCorp*, 147 FERC ¶ 61,227 ("PacifiCorp EIM Order"), *order on rehearing, clarification, and compliance*, 149 FERC ¶ 61,057 (2014) ("First PacifiCorp Compliance Order"), *order accepting compliance filings*, 151 FERC ¶ 61,261 (2015) ("Second PacifiCorp Compliance Order"); *Nev. Power Co.*, 151 FERC ¶ 61,131 ("NV Energy EIM Order"), *reh'g denied*, 153 FERC ¶ 61,306 (2015). *See also PacifiCorp*, Docket No. ER14-2544-001, Letter Order Accepting Compliance Filing (June 30, 2015); *PacifiCorp*, 152 FERC ¶ 61,241(2015).

[5] *See Cal. Indep. Sys. Operator Corp.*, 153 FER ¶ 61,305 (2015) (accepting ABC-related CAISO tariff revisions effective Jan. 5, 2016). CAISO subsequently requested and received deferral of the requested effective until no later than March 1, 2016 to allow time to resolve certain implementation issues. *See Cal.*

ABC-related tariff revisions off of those filed by PacifiCorp and NV Energy in Docket Nos. ER16-682-00 and ER15-1196-005, respectively, which are currently pending before the Commission.[6]

As a new EIM participant, PSE's proposed tariff revisions are also consistent with the measurable readiness criteria approved by the Commission on November 19, 2015 for new BAAs participating in the EIM, including the requirement to complete a sufficient amount of parallel operations prior to certification of readiness.[7] PSE is on track to complete all readiness requirements prior to its scheduled October 1, 2016 go-live date, and has already made considerable progress in that regard.

In Docket No. ER15-1347-000, the Commission accepted as just and reasonable the agreement between CAISO and PSE memorializing PSE's commitment to participate in the EIM ("Implementation Agreement").[8] CAISO's filing of the Implementation Agreement was accompanied by a benefits analysis,[9] included herewith as Attachment D ("Benefits Analysis"), describing millions of dollars in benefits for customers in the PSE BAA as well as other BAAs participating in the EIM, resulting from optimized sub-hourly economic dispatch of resources, greater availability of flexible ramping capacity, and reduced curtailment of renewable generation, among other benefits. PSE now asks the Commission to issue an order no later than May 1, 2016 that accepts the proposed tariff changes included with this filing, effective as of the dates requested herein, so that customers may begin realizing the significant benefits of EIM participation on October 1, 2016.

I. BACKGROUND

A. Description of PSE

PSE is a public utility within the meaning of the Federal Power Act and is incorporated in the State of Washington. PSE is an investor-owned utility that provides

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Indep. Sys. Operator Corp., 154 FERC ¶ 61,001 (2016) (letter order approving request to defer effective date of ABC tariff revisions).

[6] PacifiCorp and NV Energy each requested an effective date of the later of February 16, 2016 or the CAISO's actual EIM ABC activation date.

[7] *See Cal. Indep. Sys. Operator Corp*., 153 FERC 61,205 at P 85 (2015).

[8] *See Cal. Indep. Sys. Operator Corp.*, 151 FERC ¶ 61,158 (2015).

[9] *See Cal. Indep. Sys. Operator Corp.*, Docket No. ER15-1347-000, Filing of ISO Rate Schedule No. 77, Attachment C-Economic Assessment, PSE and CAISO, *Benefits Analysis of Puget Sound Energy's Participation in the ISO Energy Imbalance Market* Filing of ISO Rate Schedule No. 77, Attachment C-Economic Assessment, PSE and CAISO, *Benefits Analysis of Puget Sound Energy's Participation in the ISO Energy Imbalance Market*, (Mar. 20, 2015), also available at: http://pse.com/aboutpse/EnergySupply/Documents/PSE-ISO_EIM_Report_wb.pdf ("Benefits Analysis"), Attachment D.

retail electric and natural gas services in a service territory covering approximately 6,000 square miles in the Puget Sound region of the State of Washington. PSE's retail and wholesale utility business includes the generation, purchase, transmission, distribution, and sale of electric energy, plus the purchase, transportation, storage, distribution, and sale of natural gas. PSE owns and operates electric transmission facilities and a BAA in Washington State. PSE is responsible for providing load and resource balancing service to its transmission customers, including both native load and third-party customers in Washington. PSE lacks direct transmission interconnections with PacifiCorp, or any other current EIM Entity, and will initially utilize transmission service on the Bonneville Power Administration's ("BPA") system to facilitate transfers of imbalance energy into and out of the PSE BAA once PSE enters the EIM.

B. Genesis and Evolution of the EIM

The CAISO-administered EIM emerged from the efforts of Western utility regulators earlier this decade to explore the benefits of a multi-state market for imbalance energy. In response to that initiative, the CAISO proposed to utilize its existing market platform to integrate BAAs outside California with the CAISO BAA for purposes of supplying imbalance energy under a single, intra-hour economic dispatch model. By using the only existing organized market on the West Coast as a platform, EIM participants could avoid some of the expense and delays associated with developing a market from whole cloth.

PacifiCorp was the first utility to announce its intent to join the EIM, filing OATT revisions to facilitate participation of its East and West BAAs on February 28, 2014 in Docket No. ER14-1578. The Commission ultimately accepted those tariff changes, subject to a compliance filing, on June 19, 2014.[10] On the same day, the Commission conditionally accepted revisions to the CAISO OATT providing for the administration of a multi-state EIM by CAISO.[11] Following multiple compliance filings by both PacifiCorp and CAISO and Commission orders thereon,[12] the EIM was activated and became fully operational on November 1, 2014 with PacifiCorp as the first non-CAISO participant.

On March 6, 2015, NV Energy filed its own tariff revisions in Docket No. ER15-1196 designed to facilitate its participation in the EIM. NV Energy's proposed revisions were conditionally accepted, subject to a compliance filing, by FERC order on May 14, 2015,[13] and NV Energy commenced participation in the EIM on December 1, 2015.

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[10] *See* PacifiCorp EIM Order.

[11] *Cal. Indep. Sys. Operator Corp*., 147 FERC ¶ 61,231 (2014).

[12] *See* First PacifiCorp Compliance Order; *see also Cal. Indep. Sys. Operator Corp*., 149 FERC ¶ 61,058 (2014).

[13] *See* NV Energy EIM Order.

Along the way, the CAISO, PacifiCorp, and NV Energy OATT provisions related to EIM participation have evolved and been refined through compliance filings or separate proceedings designed to enhance the functioning of the market based on preliminary experience. For example, in Docket No. ER14-2544, the Commission accepted for filing PacifiCorp tariff revisions to modify the allocation of operating reserve payments,[14] while in Docket No. ER15-2365 the Commission accepted PacifiCorp tariff revisions designed to accommodate the use of available transfer capability ("ATC") between the PacifiCorp BAAs and the NV Energy BAA, and to implement changes consistent with CAISO's EIM Year 1 Enhancements Phase I.[15]

C. PSE Participation in the EIM

PSE became the third utility to announce its intent to join the EIM on March 5, 2015. PSE's decision was based on extensive internal due diligence and was informed by the benefits realized by PacifiCorp from the outset of the market, as well as the significant benefits predicted by a consultant's independent analysis.

1. Expected Benefits of Participation

The PSE Benefits Analysis filed by CAISO as Attachment C to the Implementation Agreement filing in Docket No. ER15-1347,[16] and included with this filing as Attachment D, predicted significant consumer benefits resulting from PSE participation in the EIM. Specifically, the Benefits Analysis identified $18.3 million in sub-hourly dispatch and flexibility reserve benefits in a scenario where 300 MW of real-time transfer capability is made available for EIM Transfers,[17] $9.1 million in savings related to PSE's ability to locally balance wind generation currently balanced in an external BAA,[18] and savings from reduced renewable curtailment both within and external to PSE's BAA of up to $0.8 million per year.[19] These benefits are expected to contribute to significant savings for consumers in Washington State.

2. Implementation Agreement and Project Milestones

PSE executed an Implementation Agreement with CAISO on March 5, 2015. CAISO filed the agreement at FERC on March 20, 2015, and it was approved by the

[14] *PacifiCorp*, Docket No. ER14-2544-001, Letter Order Accepting Tariff Changes (June 30, 2015).

[15] *PacifiCorp*, 152 FERC ¶ 61,241 (2015).

[16] Benefits Analysis, Attachment D.

[17] *Id*. at 40.

[18] *Id*. at 57.

[19] *Id*.

Commission on May 19, 2015.[20] The Implementation Agreement identifies a number of project and financial milestones in its Exhibit A leading to PSE's full participation in the EIM on October 1, 2016. PSE and CAISO have already completed Milestone 1, as: (i) the Implementation Agreement was made effective through acceptance by the Commission on May 19, 2015;[21] (ii) CAISO recommended and PSE received a seat on the Transitional Committee, which completed a draft EIM Governance proposal that was approved by the Board of Governors; and (iii) PSE and CAISO have taken material steps to engage regarding a memorandum of understanding ("MOU") with BPA subject to the terms of the Implementation Agreement, Section 3(c). Through discussions among PSE, BPA, PacifiCorp, and CAISO regarding entry into a potential MOU, BPA confirmed that an MOU was not necessary for PSE to utilize its existing BPA transmission rights in the EIM. Therefore, BPA determined that the MOU contemplated in the Implementation Agreement is not necessary. However, discussions with BPA regarding dynamic transfer limits and transmission use in the EIM are ongoing. Additionally, PSE is participating in a stakeholder process BPA initiated in January 2016 to work through the relevant business practices and operational controls associated with PSE's and other potential EIM Entities' participation in the EIM. The stakeholder process timeline contemplates completion well before PSE's implementation date and prior to PSE's parallel testing period in July 2016. PSE will continue to work diligently with all stakeholders to ensure its timely, productive and smooth entry into the EIM October 1, 2016.

Upcoming implementation milestones include:

- March 2016: Modeling PSE into the CAISO's Full Network Model through their Energy Management System (EMS), which will be deployed into a non-production test environment using the ISO's network and resource modeling process.
- May 2016: CAISO will promote the market network model, including the PSE area, to non-production system, and allow PSE to connect and exchange data in advance of market simulation.
- July 2016: EIM market simulation will allow PSE and CAISO to conduct specific market scenarios in a test environment prior to the production deployment to ensure that all system interfaces are functioning as expected to produce simulated market results. The commencement of EIM simulation will signal that PSE and CAISO have independently completed EIM system design, development and testing to participate in joint testing.[22]

[20] *See Cal. Indep. Sys. Operator Corp.*, 151 FERC ¶ 61,158 (2015).

[21] *Id*.

[22] *Cal. Indep. Sys. Operator Corp.*, Docket No. ER15-1347-000, Implementation Agreement, Exhibit A, Project Scope and Schedule (filed Mar. 20, 2015).

3. PSE Stakeholder Process

Following its March 5, 2015 public announcement, PSE posted on its OASIS a letter to OATT customers on July 17, 2015 to invite customers to participate in its stakeholder process.[23] PSE posted an initial draft of proposed tariff changes to implement EIM participation on July 29, 2015, and hosted a stakeholder meeting at PSE's offices in Bellevue on August 7, 2015. Customers were given the opportunity to file written comments on the initial draft between July 31, 2015 and August 21, 2015.

PSE considered the comments received during the stakeholder meeting and in written comments, and posted a matrix responding to stakeholder comments and a revised draft of tariff revisions on November 10, 2015. PSE modified its OATT revisions in response to customer feedback in several areas, including elimination of penalty bands for Energy Imbalance Service and Generator Imbalance Service, and the addition of tariff language that allocates payments to customers from CAISO for operating reserves during periods when imbalance energy is being exported from the PSE BAA. Another stakeholder meeting was held in Bellevue on November 17, 2015, and customers were invited to submit written comments between November 10, 2015 and December 1, 2015. PSE responded to stakeholder comments and posted responses on December 15, 2015, which then led to the final stakeholder comment period between December 15, 2015 and December 31, 2015. PSE reviewed and took account of stakeholder feedback in filing the attached proposed tariff revisions. Matrices compiling stakeholder comments from PSE's stakeholder process are available in the EIM folder on PSE's OASIS website at: http://www.oatioasis.com/psei/.

Among the issues identified during the later stages of the stakeholder process was a concern on the part of the Industrial Customers of Northwest Utilities ("ICNU") trade association, representing certain PSE retail access customers, that pricing energy imbalance service using locational EIM prices would be inconsistent with a 2001 settlement agreement that implemented retail choice for certain large industrial customers of PSE in Washington State (the "Stipulation Agreement"),[24] and also inconsistent with the current provisions of PSE Schedules 448 and 449 on file with the Washington Utilities and Transportation Commission ("WUTC") pursuant to which certain ICNU members receive unbundled retail access services. Under the terms of the Stipulation Agreement and Schedules 448 and 449, PSE's retail access customers currently pay for energy imbalance service under Schedule 4R of the PSE OATT using the Intercontinental Exchange ("ICE") day-ahead on and off peak index price at the Mid-Columbia trading hub.

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[23] Letter from Josh Jacobs, Director, Load Serving Operations (July 17, 2015), *available at*: http://www.oatioasis.com/PSEI/PSEIdocs/EIM_Stakeholder_Process_Letter_7.17.15.pdf.

[24] *Air Liquide America Corp. v. Puget Sound Energy, Inc.*, Docket Nos. UE-001952 and UE-001959 (consolidated), Stipulation of Settlement (Wash. Utils. & Transp. Comm'n Mar. 9, 2001).

PSE proposes revisions in this tariff filing to Schedule 4R to price imbalance energy settlements using the same LAP price PSE will use to settle imbalance with its other transmission customers under Schedule 4. PSE has worked with its retail access customers and ICNU to reach a consensus on revisions to its retail access rate Schedules 448 and 449 and is requesting that the WUTC modify its associated orders related to the Stipulation Agreement with respect to the provision of imbalance energy so that the pricing provisions for imbalance energy under Schedule 4R of the OATT and retail rate schedules are consistent.

D. The EIM is Gaining Momentum in the Region

As mentioned above PSE was the third utility to announce its intent to participate in the EIM, joining PacifiCorp and NV Energy. Since PSE entered into an Implementation Agreement with CAISO in March 2015, Arizona Public Service Company ("APS") has similarly announced its intent to enter the market and is also targeting an October 1, 2016 participation date.[25] On November 20, 2015, CAISO filed an implementation agreement between itself and Portland General Electric Company ("PGE"), with a target implementation date of October 1, 2017.[26] Other utilities in the Western Interconnection have also expressed interest in joining the EIM.

It is an exciting time in the West. The benefits currently enjoyed by EIM market participants will only be increased through broader participation as a greater diversity of loads and resources are integrated through CAISO's economic dispatch. The EIM that PSE joins on October 1, 2016 will include loads in 8 states and envelop roughly half of the load in the Western Interconnection.

E. EIM Preparations and Readiness Criteria

Preparing for entry into the EIM is a complex process that PSE has been diligently working toward through operational and technological improvements, coordinating closely with the CAISO, discussing lessons learned with NV Energy and PacifiCorp, and training key personnel. PSE participated in the stakeholder process held by CAISO in development of the readiness criteria, which were approved by the Commission in Docket No. ER15-861-004 on November 19, 2015, to ensure new entities are prepared for financially binding EIM operations upon their entry into the market.[27] PSE has reviewed NV Energy's readiness criteria Certification, filed in Docket No. ER15-861-005 on October 1, 2015 and has been working with CAISO to ensure its own

[25] *Cal. Indep. Sys. Operator Corp*., 152 FERC ¶ 61,090 (2015) (accepting implementation agreement between CAISO and APS).

[26] *See* Filing of ISO Rate Schedule No. 81, Attachment A, *Cal. Indep. Sys. Operator Corp.*, Docket No. ER16-366 (Nov. 20, 2015).

[27] *See Cal. Indep. Sys. Operator Corp.*, 153 FERC ¶ 61,205 (2015) (Order on Compliance Filing, accepting CAISO's August 28, 2015 filing effective March 16, 2015).

satisfaction of the readiness criteria, with the aim of obtaining a certification of the same in accordance with the requirements and timeline approved by the Commission. PSE has dedicated necessary resources and is making concerted efforts to ensure reliable, compliant, efficient, and optimal performance upon its entry into the EIM on October 1, 2016.

PSE is working with CAISO to satisfy the readiness criteria outlined in CAISO's Tariff, Section 29, and the applicable thresholds prescribed in CAISO's Energy Imbalance Market Business Practice Manual, including criteria and thresholds applicable to full network model integration, agreements, training, forecasting, balanced schedules, operating procedures, system readiness and integration, market simulation, settlements, monitoring, parallel operations, communications, and EIM ABC. PSE will work with CAISO to determine whether the systems and processes are ready for participation as measured by the applicable thresholds in the Energy Imbalance Market Business Practice Manual. Once PSE has satisfied the readiness criteria, PSE and CAISO will execute a market readiness certificate and file it with the Commission at least 30 days prior to PSE's implementation date.

II. DESCRIPTION OF TARIFF FILING

PSE expects the EIM and corresponding provisions of each participant's OATT to continue evolving as additional experience is gained and additional BAAs are added to the market. The tariff revisions proposed by PSE in this filing reflect a snapshot of the latest guidance from the Commission with respect to the justness and reasonableness of the PacifiCorp and NV Energy tariffs, recognizing that the snapshot is a moving target. PSE will continue to adapt its OATT as necessary in response to guidance from the Commission and to be consistent with the corresponding OATT provisions of CAISO and other EIM Entities.

A. Overview of Tariff Changes

PSE's proposed tariff changes closely track those already accepted as just and reasonable for PacifiCorp and NV Energy,[28] in addition to pending changes recently filed by each entity to address and accommodate CAISO's ability to incorporate ABC into its economic dispatch model. PSE, like PaciCorp and NV Energy, proposes to adopt a new OATT attachment dedicated to defining the rights and responsibilities of PSE and its OATT customers with respect to the EIM. Attachment O works "in concert with" the EIM provisions of the CAISO tariff without establishing privity between PSE's OATT customers and the CAISO. Consistent with the approach accepted as just and reasonable in the PacifiCorp EIM Order,[29] the provisions of PSE's Attachment O are controlling to

[28] *See* PacifiCorp EIM Order; First PacifiCorp Compliance Order; Second PacifiCorp Compliance Order; NV Energy EIM Order. *See also PacifiCorp*, Docket No. ER14-2544-001, Letter Order Accepting Compliance Filing (June 30, 2015); *PacifiCorp*, 152 FERC ¶ 61,241 (2015).

[29] PacifiCorp EIM Order at P 102.

the extent they conflict with other provisions of the PSE OATT. This provision recognizes that Attachment O is an integral part of the OATT and is intended to govern the relationship between the PSE EIM Entity, transmission customers, and interconnection customers.

As will be discussed in greater detail below, Attachment O describes:

- the applicability of Attachment O to PSE customers taking transmission and/or interconnection service under the OATT (Section 1);
- the eligibility requirements and mechanism for a generating resource to participate in the EIM as a "PSE EIM Participating Resource" (Sections 2 and 3);
- the obligations of PSE as the PSE EIM Entity and PSE EIM Entity Scheduling Coordinator (Section 4);
- the obligations of PSE transmission customers to provide forecast data,[30] including Transmission Customer Base Schedules,[31] to PSE at certain intervals before the start of the operating hour (Section 4);
- the provision of transmission capacity on PSE transmission assets for EIM Transfers into and out of the PSE BAA (Section 5);
- the management of the transmission system by PSE during normal and emergency operating conditions (Section 6);
- transmission and generation outage reporting requirements in the PSE BAA (Section 7);
- settlements and billing of EIM charges (Section 8);
- compliance obligations of transmission customers, rules of conduct, and enforcement oversight of FERC with respect to the EIM (Section 9); and
- rules and procedures during market contingencies (Section 10).

PSE's Attachment O is organized in the same fashion as the FERC-accepted OATTs of PacifiCorp (Attachment T) and NV Energy (Attachment P). And, like both PacifiCorp and NV Energy, PSE has proposed a series of corresponding revisions to existing provisions of its OATT to accommodate EIM participation. In particular, PSE has proposed:

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[30] PSE proposes to add a new definition of "Forecast Data" to Section 1 of its OATT. "Forecast Data" is "[i]nformation provided by Transmission Customers regarding expected load (as determined pursuant to Section 4.2.4.3 of Attachment O of this Tariff), generation, Intrachange, and Interchange, as specified in Section 4.2.4 of Attachment O and the PSE EIM BP. The Transmission Customer Base Schedule includes Forecast Data that is used by the PSE EIM Entity as the baseline by which to measure Imbalance Energy for purposes of EIM settlement." Attachment A, Proposed Tariff Revision § 1.14B.

[31] "Transmission Customer Base Schedule" is defined in PSE's proposed tariff revisions as: "[a]n energy schedule that provides Transmission Customer hourly-level Forecast Data and other information that is used by the PSE EIM Entity as the baseline by which to measure Imbalance Energy for purposes of EIM settlement. The term 'Transmission Customer Base Schedule' as used in this Tariff may refer collectively to the components of such schedule (resource, Interchange, Intrachange, and load determined pursuant to Section 4.2.4.3 of Attachment O) or any individual components of such schedule." Attachment A, Proposed Tariff Revision § 1.49.

- Revisions to Section 1 (Definitions) to add a number of new defined terms used in Attachment O related to the EIM;
- The addition of a new Section 12.4A to address resolution of EIM-related disputes;
- Minor revisions to Parts II (Point-to-Point Transmission Service) and III (Network Integration Transmission Service) of its OATT to clarify the manner in which transmission service will be provided for EIM-related dispatch;
- The addition of a new Schedule 1A to Schedule 1 that will allow PSE to recover CAISO EIM administrative costs;
- Revisions to Schedules 4 (Energy Imbalance Service), 4R (Energy Imbalance Service for customers taking service under PSE Schedules 448 and 449 retail tariffs), and 9 (Generator Imbalance Service) to provide for settlement of imbalance charges and payments at locational EIM prices;
- Addition of a new Schedule 12 (Real Power Losses – Washington Area) and Schedule 12A (Real Power Losses – Colstrip and Southern Intertie) to provide for the financial settlement of losses using locational EIM prices; and
- Certain additional revisions to Annex A, Standard Large Generator Interconnection Procedures ("LGIP"), and Annex B, Standard Small Generator Interconnection Procedures ("SGIP"), to clarify requirements for interconnection customers related to the EIM.

The Commission has accepted as just and reasonable this same overall OATT structure for EIM implementation in the PacifiCorp EIM Order and the NV Energy EIM Order, and should make consistent findings here. PSE has included as Attachment C to this filing a chart summarizing all proposed tariff changes and identified PSE's requested effective date for each such change.

B. Summary of Differences Between PSE's Tariff Changes and FERC-Accepted Tariff Provisions of PacifiCorp and NV Energy

While PSE's proposed tariff revisions are generally consistent with tariff language that has already been accepted as just and reasonable in the case of PacifiCorp and NV Energy (recognizing pre-existing differences in PSE's tariff), PSE has deviated from previously accepted language in the following areas:[32]

- PSE's Attachment O, Section 5 offers two mechanisms for the provision of PSE transmission capacity to effectuate EIM Transfers: namely, the provision of capacity by an interchange rights holder, and the provision of capacity utilizing

[32] As discussed above and in greater detail below, this list does not include PSE's proposed tariff revisions related to ABC that are modeled on the tariff revisions recently filed by PacifiCorp and NV Energy in Docket Nos. ER16-682-00 and ER15-1196-005, respectively, which are currently pending before the Commission. The list also excludes pre-existing tariff deviations, such as the existence of PSE's Schedule 4R, Energy Imbalance Service for Retail Customers.

ATC. This two-pronged approach is consistent with PacifiCorp's currently accepted OATT.[33] PacifiCorp also added a new Section 23.4 to its OATT which stipulates that the reassignment provisions of the OATT do not apply to donations of capacity to the EIM by interchange rights holders. In the PacifiCorp EIM Order, the Commission held that PacifiCorp's interchange rights holder "proposal does not appear to be a sale, assignment, or transfer of transmission service that would fall under section 23 of the *pro forma* OATT."[34] PSE has therefore declined to adopt PacifiCorp's Section 23.4 and instead relies on the existing provisions of Section 23 of the *pro forma* OATT which, on their face, would not apply to the provision of transfer capability to the EIM.

- PSE proposes in Schedules 12 and 12A to require customers to settle losses financially at the LAP price produced by the EIM, while PacifiCorp and NV Energy both give customers the option to settle losses financially at the LAP price or through an in-kind replacement. This proposed distinction is not specifically related to the EIM, as financial settlement of losses at the LAP price has been accepted as just and reasonable and in fact was mandated as a replacement for a regional index price by the Commission in the PacifiCorp EIM Order.[35] Requiring financial settlement of losses to the exclusion of in-kind replacement has also been found to be just and reasonable and consistent with Order Nos. 888 and 890.[36] Financial settlement more closely tracks actual costs because in-kind replacement has an inherent lag that can be exploited to, for example, take advantage of on-peak and off-peak pricing differences or other temporal variations in the price of energy. For the same reasons, PSE has also proposed to require financial settlement of losses to the exclusion of in-kind replacement at the ICE-reported MidC Index price during EIM market contingencies, as reflected in proposed Attachment O, Sections 10.4.4 and 10.4.5.
- PSE proposes under Attachment O, Section 8.12 to allocate payments and charges for operating reserves related to EIM transfers consistent with the approach that was accepted for NV Energy.[37] Unlike NV Energy, however, PSE will allocate charges for operating reserve obligations incurred under Section 29.11(n)(2) of the CAISO tariff on the basis of Measured Demand, rather than the customer's relative load imbalance compared to other customers with load imbalance during the hour. As discussed in greater detail below, operating reserve obligations are incurred any time imbalance energy is exported out of the CAISO BAA and into

[33] *PacifiCorp*, 152 FERC ¶ 61,241 (2015).

[34] PacifiCorp EIM Order at P 114.

[35] *Id.* at P 162.

[36] *Ariz. Pub. Serv. Co.*, 143 FERC ¶ 61,280 at P 28 (2013) ("We find that Order Nos. 888 and 890 do not preclude the use of a financial settlement mechanism to the exclusion of in-kind replacement."), *order on reh'g*, 148 FERC ¶ 61,125 (2014).

[37] *See generally* NV Energy EIM Order.

the PSE BAA, which could occur for economic reasons even in the absence of any imbalance in the PSE BAA. For example, when Participating Resources in the PSE BAA have submitted decremental bids and are replaced by lower-cost generation in the CAISO BAA, the PSE BAA will incur operating reserve obligations under the CAISO tariff even if the BAA is perfectly in balance. In such a circumstance, it would be inconsistent with cost causation principles to allocate reserve obligations to load on the basis of its own imbalance when the import of EIM energy from the CAISO was for purely economic reasons.

- PSE proposes to require transmission customers without generation or load in the PSE BAA to submit a Transmission Customer Base Schedule that includes intrachange Forecast Data. While PacifiCorp and NV Energy have limited scheduling requirements to Interchange for customers without load or generation in the BAA, it is possible that transmission customers that are scheduling intrachange within the BAA could also give rise to imbalance if the intrachange schedule deviates from the metered source, even if the transmission customer with the load or generation in the BAA has submitted an accurate Transmission Customer Base Schedule.
- PSE proposes to limit the EIM-related scheduling requirements in Section 4 of Attachment O to generation resources of 5 MW or more, whereas PacifiCorp and NV Energy utilized a 3 MW threshold for generation resource scheduling requirements. PSE submits that this deviation is just and reasonable because the CAISO affords EIM Entities discretion to select the size threshold for scheduling obligations below the 10 MW threshold for telemetry specified in Section 29.10(a) of the CAISO Tariff, and 5 MW is a more appropriate cut-off for scheduling requirements in the PSE BAA given that there are few resources between 3 MW and 5 MW that would be subject to the scheduling requirements if 3 MW were chosen as the threshold.

C. EIM Roles and Responsibilities

1. Responsibilities of PSE as an EIM Entity

PSE has a variety of responsibilities as the EIM Entity and functions as the direct link with CAISO on behalf of load, Non-Participating Resources, interchange, and intrachange customers in the PSE BAA. As an initial matter, PSE must have effective provisions in its OATT to enable it to receive the information it needs to manage EIM operations and conduct accurate settlements. In addition, PSE, as an EIM Entity, must: (1) qualify or secure representation as an EIM Entity Scheduling Coordinator;[38] (2) process PSE EIM Participating Resource applications;[39] (3) provide required information regarding modeling data to the CAISO and register all Non-Participating Resources with

[38] Attachment A, Proposed Attachment O, § 4.1.1.1 (“Attachment O”).

[39] *Id*., § 4.1.1.2.

the CAISO;[40] (4) provide data to the CAISO regarding the day-to-day operation of the EIM, including the submissions of "EIM Base Schedules"[41] and Resource Plans and any changes to such plans;[42] (5) provide the CAISO with information regarding the reserved use of the transmission system and interties and any changes to transmission capacity;[43] and (6) submit information regarding planned and unplanned outages and derates.[44] These responsibilities are necessary to facilitate the operation of the EIM in accordance with the requirements for EIM Entities specified in Section 29 of the CAISO Tariff.

Participation in the EIM does not change PSE's existing responsibilities as a BAA. As it does today in the performance of its BAA system-balancing responsibilities, PSE will set aside resource capacity at specific generators for contingency reserve, up-regulation, and down-regulation for system balancing service for PSE's BAA.

2. Significant Determinations for EIM Implementation

a. Load Aggregation Points

Under Section 29.4(b)(3)(F) of the CAISO Tariff the EIM Entity must identify its LAP used for settlement purposes. PSE's proposal to use a single LAP for its single BAA simplifies the process of market participation for transmission customers and allows PSE to gain experience as to the locational marginal prices ("LMP") created by the EIM. Currently, PSE does not have historical data regarding LMPs.[45] Additionally, PSE does not currently have any transmission constraints within its BAA that warrant multiple LAPs. The Commission has recognized the reasonableness of a single LAP approach, at least initially, for both PacifiCorp and NV Energy.[46]

b. Use of CAISO Load Forecast

PSE has elected to use the CAISO load forecast for the purpose of preparing its

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[40] *Id*., § 4.1.2.

[41] "EIM Base Schedules" are defined by the CAISO as "[a]n hourly forward Energy Schedule that does not take into account Dispatches from the Real-Time Market." CAISO Tariff, Appendix A, Definitions, version 0.0.0 (effective Sept. 9, 2014).

[42] Attachment O, § 4.1.3.

[43] *Id*., § 5.1.

[44] *Id*., § 7.

[45] Multiple LAPs are justified when significant differences between regional LMPs are identified. As an example, the CAISO is currently exploring creating additional LAPs based upon actual LMP and congestion data and history for its BAAs. Currently, PSE's BAA does not have historical LMP data.

[46] *See* PacifiCorp EIM Order at P 259. *See generally* NV Energy EIM Order.

Resource Plan.[47] Under the CAISO's market design, an EIM Entity may elect to use either its own load forecast or a load forecast produced by the CAISO.[48] If the EIM Entity Scheduling Coordinator chooses to submit a Resource Plan using the CAISO load forecast, it can minimize exposure to charges for under- or over-scheduling.[49] There is no incremental cost to PSE or its customers for the use of the CAISO forecast. Furthermore, in accordance with Section 29.34(d) of the CAISO's Tariff, the option to use the CAISO's load forecast does not preclude the EIM Entity from balancing to its own forecast in a given hour if it concludes it is appropriate to do so. PSE's determination to use the CAISO load forecast is also consistent with the approach taken by PacifiCorp and NV Energy.

c. Determination to Use Option to be a Scheduling Coordinator Metered Entity

In accordance with Section 29.10 of the CAISO Tariff, the PSE EIM Entity and all transmission customers with PSE EIM Participating Resources have the option to be either CAISO Metered Entities or Scheduling Coordinator Metered Entities.[50] PSE has elected to become a Scheduling Coordinator Metered Entity on behalf of its customers,

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[47] Attachment O, Section 4.1.1.3(3). A "Resource Plan" is defined in PSE's proposed tariff revisions as "[t]he combination of load, resource and Interchange components of the Transmission Customer Base Schedule, ancillary services plans of the PSE EIM Entity, bid ranges submitted by PSE EIM Participating Resources, and the EIM Available Balancing Capacity of Balancing Authority Area Resources."

[48] The MO's load forecast will be based on historical data, applicable meteorological data, and the CAISO's State Estimator solution. It will be produced separately for each LAP and then aggregated for each BAA. PacifiCorp has one LAP for each of its BAAs, which results in one load forecast for each of its BAAs. NV Energy has a single LAP for its BAA, resulting in a single load forecast. PSE is proposing a single LAP for its BAA, which also will result in a single load forecast. The MO recovers the costs associated with the gathering and processing of required information to establish the load forecast through its EIM Administrative Charge.

[49] If an EIM Entity Scheduling Coordinator using the CAISO load forecast submits an EIM Base Schedule forecast for the entire BAA that is within +/- 1% of the CAISO load forecast, the EIM Entity Scheduling Coordinator would not be exposed to under- or over-scheduling penalties, which in turn would be sub-allocated to its load.

[50] Attachment O, § 4.1.1.3(4). Pursuant to the CAISO Tariff, a Scheduling Coordinator Metered Entity is "(1) a Generator, Eligible Customer, End-User, Reliability Demand Response Resource, or Proxy Demand Resource that is not a CAISO Metered Entity; (2) an EIM Entity; [or] (3) an EIM Participating Resource that elects to be a Scheduling Coordinator Metered Entity" and a CAISO Metered Entity is:

> (a) any one of the following entities that is directly connected to the CAISO Controlled Grid:
>
> > i. a Generator other than a Generator that sells all of its Energy (excluding any Station Power that is netted pursuant to Section 10.1.3) and Ancillary Services to the Utility Distribution Company or Small Utility Distribution Company in whose Service Area it is located;
> >
> > ii. an MSS Operator; or

including transmission customers with Non-Participating Resources.[51] Accordingly, the PSE EIM Entity shall submit load, resource, and Interchange meter data to the MO in accordance with the MO Tariff's format and timeframes on behalf of transmission customers with Non-Participating Resources, loads, and Interchange.[52] The PSE EIM Entity must fulfill this role in order to meet the requirements of the CAISO Tariff and provide the MO timely and accurate meter data for EIM settlements.

d. Adoption of 5 MW Threshold for Applicability of Mandatory Submission of Transmission Customer Base Schedules by Generators in PSE's BAA

Section 29.10(a) of the CAISO tariff imposes mandatory telemetry requirements on all generation resources within an EIM BAA with a rated capacity of 10 MW or greater. Telemetry affords CAISO or, in the case of Non-Participating Resources, PSE, the ability to settle imbalance between the generator's Transmission Customer Base Schedule and its generation output. It is up to the individual EIM Entity whether to require smaller generators to submit Transmission Customer Base Schedules and to maintain telemetry meeting the CAISO's requirements to facilitate settlement of imbalance. PacifiCorp and NV Energy each adopted a 3 MW threshold for generator base scheduling requirements in their EIM-related OATT revisions, and this approach

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iii. a Utility Distribution Company or Small Utility Distribution Company; and

(b) any one of the following entities:

i. a Participating Generator;

ii. a Participating TO in relation to its Tie Point Meters with other TOs or Balancing Authority Areas;

iii. a Participating Load;

iv. a Participating Intermittent Resource;

v. an EIM Participating Resource that has elected not to be a Scheduling Coordinator Metered Entity, with regard to the EIM Resources it specifies that it represents as a CAISO Metered Entity; or

vi. a utility that requests that Unaccounted For Energy for its Service Area be calculated separately, in relation to its meters at points of connection of its Service Area with the systems of other utilities.

CAISO Tariff, Appendix A, Definitions, Scheduling Coordinator Metered Entity, version 5.0.0, CAISO Metered Entity, version 1.0.0 (effective Oct. 24, 2014).

[51] Attachment O, § 4.1.1.3(4).

[52] Attachment O, § 4.1.4.

was accepted by the Commission without discussion.[53] In the case of PSE's BAA, 5 MW is a more logical threshold. The benefits to PSE and the EIM of capturing additional generation that is between 3 and 5 MW – which is fairly insignificant compared to the 5,000 MW of load in the PSE BAA – are outweighed by the administrative and cost burden that would be imposed on the generators and on PSE if base scheduling and telemetry requirements were imposed. Moreover, 5 MW is still well within the 10 MW minimum requirements imposed by the CAISO under Section 29.10(a) of its tariff. Accordingly, the Commission should find that, given the facts and circumstances of PSE's BAA and discretion afforded by the CAISO tariff, it is just and reasonable for PSE to establish a 5 MW threshold for generator base scheduling requirements. PSE will continue to evaluate whether a different threshold is warranted within its BAA, and if so will file corresponding tariff revisions with the Commission.

3. Transmission Customer Responsibilities

Section 4.2 of Attachment O outlines the responsibilities of customers with respect to the EIM. These include providing: (1) initial registration data, including operational characteristics of generators; (2) updates to the initial registration data; (3) planned and forced outage and derate information; and (4) Forecast Data. These requirements are just and reasonable and necessary to facilitate operation of the EIM.[54] Because the EIM is the manner in which PSE will provide imbalance services to all of its Transmission and Interconnection Customers, it is appropriate for all such customers to bear the responsibilities and duties set forth in Attachment O to facilitate the EIM. [55]

Registration and outage information is necessary to comply with requirements established under proposed CAISO Tariff Sections 29.4(c)(4)(C) and (D) (registration) and 29.9 (outages). As a matter of Good Utility Practice and operation, many customers today already provide this type of information to PSE on their respective facilities and outages. These limited data requirements will enhance reliable operation of the EIM as the MO will have up-to-date and accurate information on resource capabilities and availability. In addition, the information should be readily available to customers and is not burdensome to produce. Outage and derate data is necessary to ensure that the MO has accurate operational data to administer the EIM, to produce accurate and appropriate Dispatch Instructions, and to mitigate the potential for congestion and imbalance on PSE's transmission system.

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[53] *See generally* PacifiCorp EIM Order; NV Energy EIM Order.

[54] PacifiCorp EIM Order at P 101.

[55] *See, e.g.* PacifiCorp EIM Order at P 191 ("we find that PacifiCorp's filing and the EIM Benefits Study adequately demonstrate that the EIM will provide both quantitative and qualitative benefits to PacifiCorp's customers. Accordingly, in order to realize those benefits, PacifiCorp, and by extension, its transmission customers, must submit forecast data consistent with the timelines established by the CAISO in order for CAISO to run its security-constrained economic dispatch.").

Similarly, most customers today already schedule their projected day-ahead and hour-ahead load and generation requirements either through the submission of e-Tag schedules or through the provision of manual scheduling data. The EIM simply formalizes and centralizes the manner in which Forecast Data is communicated in a way that facilitates EIM dispatch and settlement. Forecast Data is necessary for the EIM to be able to properly model and account for expected load, generation, imports, and exports during the operating hour. In addition, Forecast Data comprise the Transmission Customer Base Schedule that is used by the PSE EIM Entity as the baseline by which to measure Imbalance Energy for purposes of EIM settlement. Overall, the requirements are just and reasonable as they facilitate efficient implementation of the EIM in accordance with requirements established by CAISO as the MO.

D. Eligibility of Resources to Participate

1. Application and Certification

The CAISO and the PSE EIM Entity must have a consistent and complete understanding of which resources: (1) are eligible to participate; (2) have voluntarily elected to participate; (3) have met all the CAISO's certification requirements; and (4) have met PSE's application and certification requirements. The PSE EIM Entity must know which resources are participating in the EIM (and thus settling imbalances directly with the CAISO) or not participating in the EIM (and thus settling imbalances under PSE's OATT Schedules 4, 4R and 9 as a Non-Participating Resource).[56] To that end, Section 3.3 of PSE's Attachment O includes a two-phase set of requirements for the application and certification of PSE EIM Participating Resources.

Consistent with Section 3.3.1 of Attachment O, to become a PSE EIM Participating Resource, an applicant must submit a completed application and provide a processing deposit of $1,500. The fee is necessary for PSE to recover its costs associated with processing the application, setting up the communications and billing accounts, and for evaluating and determining metering or telemetry requirements necessary for EIM participation. The PSE EIM Entity shall make a determination as to whether to accept or reject the application within 45 days of receipt of the application.[57] At minimum, the PSE EIM Entity shall validate, through the application, that the PSE EIM Participating Resource applicant has satisfied Sections 3.1 and 3.2 of Attachment O, as applicable, and met minimum telemetry and metering requirements, as set forth in the PSE EIM Business Practice. If the PSE EIM Entity approves the application, it will notify the PSE EIM Participating Resource applicant and the MO. If the PSE EIM Entity rejects the application, the PSE EIM Entity will notify the applicant and state the grounds for the rejection. Section 3.3.2 provides a mechanism for the applicant to cure the grounds for the rejection.

[56] Attachment O, § 3.3.4 clarifies that, unless certified by the PSE EIM Entity as a PSE EIM Participating Resource, the resource shall be deemed to be a Non-Participating Resource.

[57] Attachment O § 3.3.2.

Consistent with Section 3.3.3 of Attachment O, certification of the PSE EIM Participating Resource occurs upon approval of the application and once the Transmission Customer demonstrates, and the CAISO has confirmed, that the Transmission Customer has done the following:

- Met the CAISO's criteria to become an EIM Participating Resource[58] and executed the CAISO's *pro forma* EIM Participating Resource Agreement;

- Qualified to become or retained the services of a CAISO-certified EIM Participating Resource Scheduling Coordinator;

- Met the necessary metering requirements of PSE's OATT and Section 29.10 of the CAISO Tariff, and the EIM Participating Resource Scheduling Coordinator has executed the CAISO's pro forma Meter Service Agreement for Scheduling Coordinators;

- Met communication and data requirements of PSE's OATT and Section 29.6 of the CAISO Tariff; and

- Has the ability to receive and implement dispatch instructions every five minutes from the CAISO.

Section 3.3 of Attachment O also includes provisions regarding the treatment of resources pending certification, as well as the ongoing obligation of transmission customers with a PSE EIM Participating Resource to inform the PSE EIM Entity of any changes to any information submitted as part of the application process.[59]

2. Transmission Rights Required for EIM Participation

a. Internal Resources

PSE's proposed EIM eligibility requirements for resources within the BAA are set forth in Section 3.1 of Attachment O and simply require the execution of a transmission service agreement of some form. Thus, PSE allows for a resource to seek CAISO certification to become a PSE EIM Participating Resource if one of the following occurs:

(1) The resource is a Designated Network Resource of a Network Customer and the Network Customer elects to participate in the EIM through its Network Integration Transmission Service Agreement; or

[58] *See* CAISO Tariff, § 29.4, Roles and Responsibilities.

[59] Attachment O, § 3.3.5.

> (2) The resource is associated with either (i) a Service Agreement for Firm Point-to-Point Transmission Service or (ii) a Service Agreement for Non-Firm Point-to-Point Transmission Service, and such Transmission Customer elects to participate in the EIM.[60]

The execution of a service agreement is a reasonable requirement as it establishes the necessary contractual relationship with respect to performance of EIM-related responsibilities. Neither these provisions nor Attachment O, Section 8.7 impose any transmission service charge related to EIM transactions. PSE has also included a cross-reference to Attachment O, Section 8.7 in Section 13.7(c) and 14.5 of its OATT – dealing with unreserved use charges – to clarify that unreserved use penalties will not apply to generation output that is in response to an EIM-related instruction.

b. External Resources

In the proposed tariff provisions, PSE has adopted the same proposed EIM eligibility requirements for external resources as approved by the Commission for PacifiCorp and NV Energy.[61] Under Attachment O, Section 3.2.1, a resource that is not physically located inside the metered boundaries of the PSE BAA is eligible to become a PSE EIM Participating Resource, if the Transmission Customer:

(1) Implements a pseudo-tie into the PSE BAA;
(2) Has arranged firm transmission over any third-party transmission systems to the PSE BAA intertie boundary point equal to the amount of energy that will be dynamically transferred through a pseudo-tie into the PSE BAA; and
(3) Has entered into a transmission service agreement with PSE consistent with Section 3.1 of Attachment O.

This approach is not only consistent with NV Energy and PacifiCorp's approach, but the Commission recognized in the order conditionally accepting PacifiCorp's eligibility requirements that it is "consistent with the Commission's acceptance of a similar arrangement in the SPP's Energy Imbalance Service market requiring that external resources use a pseudo-tie in order to participate in that market."[62] Noting this consistency, the Commission did not impose a timetable for either PacifiCorp or NV Energy to begin a stakeholder process to address the feasibility of expanding the EIM to include intertie bidding, but noted that "permitting external resources to participate has the potential to expand the benefits of the EIM for all customers" and encouraged PacifiCorp and NV Energy to "explore this issue with stakeholders."[63]

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[60] *Id.* § 3.1.

[61] *See* PacifiCorp EIM Order at PP 130 – 131*; see also* NV Energy EIM Order at P 185.

[62] PacifiCorp EIM Order at P 130 (*citing Sw. Power Pool, Inc*., 123 FERC ¶ 61,062 at P 24 (2008)).

[63] *See, e.g.* NV Energy EIM Order at P 185.

In 2015 the CAISO, as part of its EIM Year 1 Enhancements Phase II stakeholder process, considered whether it would be appropriate to require that all EIM Entities implement intertie bidding in the EIM.[64] Recognizing that there are market design issues that must be addressed prior to implementing intertie bidding in the EIM, CAISO deferred the stakeholder process for EIM intertie bidding until it could complete a separate stakeholder process to evaluate those issues. PSE is engaged in these stakeholder processes and recognizes the broader market complexities that make this issue better suited for CAISO's stakeholder process, rather than PSE's own stakeholder process or independently proposed tariff revisions. PSE is currently focused on satisfying the readiness criteria and managing a smooth entry into the existing market construct. Adding the complexity of intertie bidding prior to PSE's targeted go-live date, particularly given that this will be the first implementation in which CAISO will bring two EIM Entities on line at the same time (Arizona Public Service is targeting the same go-live date of October 1, 2016), may create unnecessary difficulties. PSE asks at this time that the Commission defer this issue to CAISO's stakeholder process, and accept as just and reasonable PSE's tariff proposal, consistent with PacifiCorp and NV Energy, to limit external resource participation to resources pseudo-tied into the PSE BAA.

3. EIM Transmission Charges

In the PacifiCorp EIM Order, the Commission rejected PacifiCorp's proposal to require EIM resources to pay for transmission service associated with EIM participation in addition to any transmission charges they incurred as a Transmission Customer under the OATT.[65] The Commission directed PacifiCorp to submit a compliance filing "to revise its OATT to eliminate the additional transmission charge for EIM transactions for participating resources."[66] The Commission noted the commitment of the CAISO and PacifiCorp to reconsider the issue of an EIM-wide transmission charge once there was sufficient data available to provide a meaningful analysis.[67] Consistent with that order, PSE has been and will continue to be committed to engaging in any conversations or stakeholder processes with CAISO and other EIM Entities relating to a transmission access charge for the EIM. Based on the clear guidance from the Commission, PSE has included language in Attachment O, Section 8.7 which provides "[t]here shall be no incremental transmission charge assessed for transmission related to the EIM." Attachment O, Section 8.7 further provides that

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[64] CAISO, Energy Imbalance Year 1 Enhancements, Phase 2, Draft Final Proposal (Sept. 8, 2015), http://www.caiso.com/Documents/DraftFinalProposal_EnergyImbalanceMarketYear1Enhancements_Phase2.pdf.

[65] PacifiCorp EIM Order at P 144.

[66] *Id*.

[67] PacifiCorp First Compliance Order at P 63.

> Unreserved Use Penalties shall apply to any amount of actual metered generation in an Operating Hour, if any, which is in excess of the sum of both: (1) the greatest positive Dispatch Operating Point or Manual Dispatch of the PSE EIM Participating Resource received during the Operating Hour, and (2) the Transmission Customer's Reserved Capacity. Any ancillary service charges that are applicable to Unreserved Use Penalty charges shall apply.

The Commission accepted similar language for both PacifiCorp and NV Energy.[68]

E. Available Balancing Capacity

On August 19, 2015, as amended October 21, 2015,[69] the CAISO submitted a filing in Docket Nos. ER15-861 and EL15-53 proposing to enhance EIM functionality by automatically recognizing and accounting for capacity within EIM BAAs that is available to maintain reliable operations. By recognizing and deploying this available capacity, referred to as ABC, through the EIM's economic dispatch model, the CAISO will be able to resolve power balance infeasibilities without inappropriately triggering the $1,000/MWh parameter penalty price. On December 17, 2015, the Commission issued an order accepting, without modification, the CAISO's proposed tariff changes implementing ABC functionality.[70]

PacifiCorp and NV Energy each filed proposed OATT revisions on January 4, 2016 seeking to incorporate ABC-related provisions commensurate with CAISO's actual EIM ABC activation date.[71] Generally, PacifiCorp and NV Energy proposed revisions to their respective EIM-related OATT Attachments that will enable each entity to obtain default energy bids from the CAISO for selected Non-Participating Resources that may be used to supply ABC, communicate CAISO ABC dispatch instructions to Non-Participating Resources (unless the EIM Entity determines such capacity is not needed by the BAA), and provide for settlement of energy output associated with ABC dispatches

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[68] Second PacifiCorp Compliance Order at P 24; *see generally* NV Energy EIM Order.

[69] On September 24, 2015, the Commission issued a deficiency letter directing the CAISO to provide additional information regarding certain aspects of the CAISO's proposal in the August 19th Compliance Filing. On October 21, 2015, the CAISO filed its deficiency response.

[70] *Cal. Indep. Sys. Operator Corp.*, 153 FERC ¶ 61,305 (2015). CAISO subsequently requested and received deferral of the requested effective date until no later than March 1, 2016 to allow time to resolve certain implementation issues. *See Cal. Indep. Sys. Operator Corp.*, 154 FERC ¶ 61,001 (2016) (letter order approving request to defer effective date of ABC tariff revisions).

[71] *See* PacifiCorp Tariff Filing, Docket No. ER16-682 (Jan. 4, 2016); *see also* NV Energy Tariff Filing, Docket No. ER15-1196-006 (Jan. 4, 2016). These filings were made subsequent to filings made in Docket Nos. ER15-2591 (PacifiCorp) and ER15-1196 (NV Energy) proposing tariff language to integrate CAISO's ABC proposal prior to such proposal's acceptance by the Commission. The Commission issued orders rejecting these former filings as premature without prejudice (in October and December 2015 respectively).

by the CAISO as instructed imbalance energy. PacifiCorp and NV Energy have proposed to adopt new definitions of "Balancing Authority Area Resources" and "EIM Available Balancing Capacity," and to expand the existing definitions of "Resource Plan," "Dispatch Instruction," and "Dispatch Operating Point" to facilitate these tariff revisions. The ABC-related tariff changes of PacifiCorp and NV Energy are currently pending before the Commission.

As a new EIM entrant, it is important to PSE and its customers to avoid artificial price spikes at the outset of financially binding operations later this year. The Commission acknowledged in its order approving CAISO's ABC-related tariff modifications that

> the Available Balancing Capacity proposal will reduce the potential for imbalance energy price spikes by providing for greater visibility of the capacity each EIM Entity has available to it to resolve power balance violations within its own BAA, even when that capacity is not being offered into the EIM. . . . [W]e find that this visibility addresses a concrete problem of false scarcity conditions, while still allowing each EIM Entity the flexibility to determine what capacity it should retain outside of the EIM to maintain reliability within its own BAA.[72]

To ensure that its BAA is shielded from problems associated with false scarcity, PSE has included ABC-related language in the attached tariff changes that is virtually identical to that proposed by PacifiCorp and NV Energy described above. In Section 4.1.3.4 of PSE's proposed Attachment O, PSE has, consistent with PacifiCorp and NV Energy, proposed language that specifically permits the EIM Entity to determine whether additional capacity dispatched from a Non-Participating Resource in PSE's BAA is needed for the BAA or whether the EIM Entity has already taken (or will take) other actions to meet capacity needs. For example, following a contingency event, PSE may deploy contingency reserves rather than relaying a CAISO Dispatch Instruction to deploy ABC from a Balancing Authority Area Resource. In exercising discretion under Section 4.1.3.4 of Attachment O, PSE will follow all market requirements to notify the market as soon as possible when diverging from an ABC dispatch instruction and will continue to comply with all North American Electric Reliability Corporation ("NERC") and Western Electricity Coordinating Council ("WECC") reliability requirements as a BA.

PSE understands that the ABC-related tariff language proposed by PacifiCorp and NV Energy has not yet been accepted as just and reasonable. PSE nevertheless believes it is important to incorporate ABC functionality from the outset of its participation in the EIM, and respectfully asks that it be permitted to incorporate any modifications subsequently directed by the Commission with respect to the pending PacifiCorp and NV Energy ABC tariff filings in a compliance filing of its own so as not to delay the start of financially binding operations on October 1, 2016.

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[72] *Cal. Indep. Sys. Operator Corp.*, 153 FERC ¶ 61,305 at P 25.

F. Transmission Operations

1. Availability of Transmission for EIM Transfers

a. Transfer Capability on PSE Transmission System for EIM Transfers into or out of the PSE BAA

The Commission has accepted two different mechanisms for EIM Entities to utilize transmission capacity to effectuate EIM transfers into and out of the EIM Entity's BAA. First, in the PacifiCorp EIM Order, the Commission conditionally accepted PacifiCorp's proposal to "utilize firm transmission rights voluntarily offered by its marketing division and any other transmission customer to facilitate participation in the EIM."[73] The Commission directed PacifiCorp to revise Section 5.2 of its Attachment T (equivalent to PSE's Attachment O) to "include the requirements for scheduling and using transmission rights held by an Interchange Rights Holder" rather than merely referencing a business practice containing such requirements.[74] PacifiCorp's revisions to Section 5.2 of its Attachment T were accepted by the Commission in the First PacifiCorp Compliance Order.[75] PacifiCorp also adopted a new Section 23.4 of its OATT clarifying that the reassignment provisions of Section 23 of the OATT do not apply to the provision of transmission capacity to the EIM by Interchange Rights Holders.

Second, in the NV Energy EIM Order, the Commission accepted NV Energy's proposal to determine ATC available for EIM Transfers at 40 minutes prior to the operating hour and communicate the availability of such ATC to CAISO using an e-Tag with an OASIS identification reservation number created for EIM Transfers utilizing ATC.[76] The Commission subsequently accepted a variation of NV Energy's ATC provision when PacifiCorp adopted a similar but modified provision for use of ATC for EIM transfers in Docket No. ER15-2365.[77] PacifiCorp's OATT now authorizes provision of transfer capability for EIM transfers using both Interchange Rights Holder contributions and ATC.

PSE likewise proposes to make transmission capacity available for EIM Transfers using both Interchange Rights Holder Donations and ATC.[78] PSE's proposal differs

[73] PacifiCorp EIM Order at P 113.

[74] *Id*.

[75] First PacifiCorp Compliance Order at P 32.

[76] NV Energy EIM Order at PP 116-118.

[77] *PacifiCorp*, 152 FERC ¶ 61,241 (2015).

[78] *See* Attachment O, §§ 5.2 and 5.3.

slightly from PacifiCorp's in that PSE has added nonsubstantive clarifying language to Section 5.3 which clarifies that amounts made available using ATC "shall be in addition to any amounts made available by PSE Interchange Rights Holders pursuant to Section 5.2 of this Attachment O."[79] PSE has also chosen not to adopt a new Section 23.4 in Part II of its OATT, as PacifiCorp has, stipulating that donations of transmission rights to the EIM by Interchange Rights Holders are not subject to the reassignment provisions of Section 23 of the OATT. In the PacifiCorp EIM Order, the Commission held that PacifiCorp's interchange rights holder "proposal does not appear to be a sale, assignment, or transfer of transmission service that would fall under section 23 of the *pro forma* OATT."[80] PSE has accordingly elected to rely on the existing provisions of Section 23 of its OATT, which are consistent with the *pro forma* OATT, and which on their face do not apply to the provision of transmission capacity by an Interchange Rights Holder to the EIM as contemplated in Attachment O, Section 5.2.

b. Transfer Capability on External Transmission Systems for EIM Transfers

Unlike PacifiCorp and NV Energy, PSE's BAA lacks direct transmission interconnections with any other EIM Entity's BAA. Thus, while PSE can use Interchange Rights Holder donations of transmission rights and e-Tagged ATC to effectuate transfers into and out of its BAA on PSE transmission facilities in response to CAISO dispatch instructions, to access other BAAs in the EIM, PSE will require the use of intervening transmission facilities owned and operated by BPA to reach the PacifiCorp West BAA, which is the nearest BAA to the PSE BAA that is currently participating in the EIM. As other BAAs join the EIM over time, PSE may gain additional transmission paths for accessing the market.

To effectuate EIM exports across the BPA transmission system to PacifiCorp West, PSE submitted and BPA approved long-term firm redirect requests on the BPA OASIS in November 2015 to redirect 300 MW of capacity from an existing BPAT.PSEI to John Day reservation to multiple BPAT.PSEI to BPAT.PACW reservations. Simultaneously, to effectuate EIM imports from PacifiCorp West into the PSE BAA across the BPA transmission system, PSE submitted and BPA approved long-term firm redirect requests on the BPA OASIS to redirect 300 MW of capacity from existing Mid-C to BPAT.PSEI reservations to multiple BPAT.PACW to BPAT.PSEI reservations. Collectively, these redirect requests dependably provide 300 MW for EIM Transfers between PSE's BAA and the PacifiCorp West BAA in both directions.

PSE's redirected BPA transmission reservations will also allow for the use of some level of dynamic transfer capability. As with PacifiCorp's use of BPA transmission

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[79] *See id.*, § 5.3.

[80] PacifiCorp EIM Order at P 114.

for EIM transfers, the availability of dynamic transfer capability to accommodate five-minute CAISO dispatches will be determined by BPA, in accordance with its *Dynamic Transfer Limits: Operating Procedures for Use of Upper and Lower Transfer Limits on BPA's Transmission System* Business Practice, based on the historical impact of dynamic transfer capability across BPA's system attributable to generation resources that are or will be dispatchable in the EIM.

PSE continues to work with BPA, PacifiCorp, and CAISO to optimize transmission functionality and flexibility in the EIM consistent with BPA's other obligations as a transmission owner and operator, including five-minute market dynamic transfer capability. Additionally, as a capacity rights owner of BPA transmission on the Southern Intertie, PSE continues to participate in discussions to increase flexibility on this transmission segment. BPA is currently conducting a stakeholder process regarding the use of BPA transmission in the EIM by PSE and other EIM Entities, which began in January 2016 and is expected to complete relevant major milestones prior to PSE commencing parallel and financially binding EIM operations. PSE is engaged in this stakeholder process, in addition to coordinating in weekly calls with BPA and participating in periodic technical meetings with BPA, CAISO and other entities. Though PSE continues to work with BPA and other parties to improve transmission functionality and flexibility in the EIM, PSE believes that its planned use of transmission on BPA's system in accordance with its rights under the BPA transmission tariff and business practices (including its use of 300 MW of bi-directional firm transmission across the BPA system) will be sufficient to enable PSE to realize the annual benefits identified in the attached Benefits Analysis's low transfer assumption test case.

2. Timing of Transmission Customer Base Schedule Submissions

PSE's proposed Attachment O, Section 4.2.4.5 requires transmission customers to submit base schedules – which include Forecast Data on expected load, generation, interchange, and intrachange – during the following intervals:

(i) 7 days prior to each Operating Day ("T-7 days");
(ii) At least one update prior to 10 a.m. the day before the Operating Day;
(iii) A final Transmission Customer Base Schedule no later than 77 minutes prior to each Operating Hour ("T-77").[81]

Customers are permitted to modify the final Transmission Customer Base Schedule "up to and until 57 minutes prior to the Operating Hour ("T-57")."[82] At 55 minutes prior to the Operating Hour, the customer's Transmission Customer Base Schedule will be financially binding for purposes of determining imbalance charges under Schedules 4, 4R, and 9 of the OATT.[83]

[81] Attachment O, § 4.2.4.5.

[82] *Id*. § 4.2.4.5.2.

[83] *Id*.

PSE's proposed Section 4.2.4.5 is substantively the same as NV Energy's Attachment P, Section 4.2.4.5, which the Commission accepted as just and reasonable in the NV Energy EIM Order.[84] Therein, the Commission held that "[i]n order to effectuate the EIM it is necessary for NV Energy and its transmission customers to submit forecast data consistent with the timelines established by CAISO for CAISO's security-constrained economic dispatch to perform all the necessary complex calculations to accurately estimate operations for the operating hour."[85] The Commission rejected arguments raised by intervenors that implementation of financially binding scheduling requirements at T-57 would unduly interfere with the rights of customers to submit schedules at T-20, as is generally permissible in the WECC region, or to submit intra-hour schedules as required under Order No. 764.[86] The Commission instead "continues to find that the scheduling timelines are just and reasonable, given the complexities of the CAISO market, and are not prohibited by Order Nos. 764 and 888."[87]

PSE understands based on feedback received during the stakeholder process that customers would like greater flexibility to submit schedules closer to the start of the operating hour and within the operating hour. PSE commits to working with CAISO, the other EIM Entities, and stakeholders towards refinements to the EIM that may enable greater scheduling flexibility by transmission customers. However, for the reasons expressed in the NV Energy EIM Order,[88] the Commission should similarly accept as just and reasonable PSE's proposal to utilize a timeline for customer submission of base schedules that is consistent with the timelines established under the CAISO Tariff.

G. EIM Operations

1. System Operations Under Normal and Emergency Conditions

Section 6 of Attachment O (System Operations Under Normal and Emergency Conditions) is intended to ensure that operation of the EIM remains consistent with PSE's reliability responsibilities as a BA. Participation in the EIM does not modify,

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[84] NV Energy EIM Order at PP 161 – 164. *See also Cal. Indep. Sys. Operator Corp.*, 153 FERC ¶ 61,305 at P 93 (2015) ("We will not require CAISO to align scheduling timelines between the EIM and the OATT. The Commission has previously addressed the issue of the alignment of the EIM and OATT scheduling timelines and found that, in order for the EIM to operate properly, it is necessary that the EIM Entity and its transmission customers 'submit forecast data consistent with timelines established by CAISO in order for CAISO to run its security-constrained economic dispatch. Schedules submitted at T-20 would not give the market models sufficient time to function.'") (internal citations omitted)).

[85] NV Energy EIM Order at P 161.

[86] *Id*. at P 163.

[87] *Id*.

[88] *Id.* at P 161.

change, or otherwise alter the manner in which the participants comply with the applicable NERC" and WECC reliability standards.[89] The PSE EIM Entity remains responsible for: (1) maintaining appropriate operating reserves and for its obligations pursuant to any reserve sharing group agreements; (2) NERC and WECC responsibilities; (3) processing e-Tags and managing schedule curtailments at the interties; and (4) monitoring and managing real-time flows within system operating limits on all transmission facilities within PSE's BAA.[90] Attachment O, Section 6.2 requires that the PSE EIM Entity, transmission customers with Non-Participating Resources, and transmission customers with PSE EIM Participating Resources comply with Good Utility Practice.

PSE will remain responsible for real-time flow management and mitigation, including coordinated unscheduled flow mitigation consistent with procedures of the WECC. All Interchange between PSE's BAA and other BAAs will continue to be scheduled, which will allow for operational curtailments. The EIM will also be continually monitoring transmission, and will have the ability, either automatically or with Manual Dispatch[91] adjustments by the PSE EIM Entity, to re-dispatch generation across the EIM footprint to counter loop flow.[92] In that respect, PSE is gaining an additional tool through EIM Security Constrained Economic Dispatch ("SCED") that will be useful to mitigate unscheduled flow, without losing any of its existing capabilities or responsibilities.

2. Outage Reporting

Section 29.9 of the CAISO Tariff requires reporting of information on the operating status of the transmission system, PSE EIM Participating Resources, and Non-Participating Resources. This includes information on planned outages, unplanned outages and derates. PSE has structured Attachment O, Section 7 to ensure timely and accurate submission of the required information in a manner substantially similar to that accepted for PacifiCorp, and virtually identical to that accepted for NV Energy.[93]

H. EIM Settlements

[89] Attachment O, § 6.1.

[90] *Id.*

[91] "Manual Dispatch" as defined in PSE's proposed tariff revisions is: "[a]n operating order issued by the PSE EIM Entity to a Transmission Customer with a PSE EIM Participating Resource or a Non-Participating Resource in PSE's BAA, outside of the EIM optimization, when necessary to address reliability or operational issues in PSE's BAA that the EIM is not able to address through economic dispatch and congestion management." Attachment A, Proposed Tariff Revision § 1.19B.

[92] Attachment O, § 6.3.2.

[93] *See generally* NV Energy EIM Order. *See also* PacifiCorp EIM Order.

In evaluating the justness and reasonableness of cost allocations, the Commission follows the principle of cost-causation – that customers should be fairly allocated costs for which they are responsible or which are incurred for their benefit.[94] As discussed in the following sections of this filing letter, PSE has sought to follow the Commission's direction as reflected in the PacifiCorp EIM Order, which approach was accepted in the NV Energy EIM Order, in its proposed approach to imbalance charges, administrative fees, and uplift costs related to participation in the EIM. The proposals are just and reasonable and should be accepted.

1. Revisions to OATT Schedules

a. Schedule 1A

In the PacifiCorp EIM Order, the Commission accepted PacifiCorp's proposal regarding the recovery of the CAISO's EIM administrative charge[95] through a formula rate for Schedule 1 of its OATT.[96] The Commission concluded:

> The benefits of the EIM to PacifiCorp cannot be realized without incurring administrative charges from CAISO's implementation of the EIM. PacifiCorp will be submitting forecast data to CAISO on behalf of all transmission and interconnection customers, which CAISO will use to dispatch and settle its real-time market. The administrative fee for this service, charged by CAISO to PacifiCorp, is properly considered as a Scheduling, System Control and Dispatch Service and appropriately included in Schedule 1 of its OATT. Powerex's argument that the amount of the administrative charge assessed to PacifiCorp is solely related to the amount of supply and load imbalance is not accurate. Absent any imbalance, CAISO would still assess an administrative charge . . . In the case of PacifiCorp, that value would include non-participating transmission customers. Thus, even customers that do not use the EIM potentially cause PacifiCorp to incur EIM administrative charges on their behalf. Therefore, we are not persuaded by Powerex's argument.[97]

[94] *K N Energy, Inc. v. FERC*, 968 F.2d 1295, 1300 (D.C. Cir. 1992); *see also Penn. Elec. Co. v. FERC*, 11 F.3d 207, 211 (D.C. Cir. 1993) ("Utility customers should normally be charged rates that fairly track the costs for which they are responsible."); *Cal. Indep. Sys. Operator Corp.*, 108 FERC ¶ 61,022 at P 62 ("As a general matter, the Commission believes that the entities that cause costs should pay for such costs."), *order on reh'g*, 109 FERC ¶ 61,097 (2004); *Fla. Power & Light Co.*, 98 FERC ¶ 61,326 at P 79 (2002) ("Basic principles of equity and cost causation require the party that causes costs to be responsible for such costs.").

[95] The Commission recently accepted CAISO's proposed EIM Year 1 Enhancements, which included revisions to the EIM administrative charge to align it with the CAISO grid management charge. *Cal. Indep. Sys. Operator Corp.*, 153 FERC ¶ 61,087 (2015).

[96] PacifiCorp EIM Order at P 170.

[97] *Id*. (footnote omitted).

Like PacifiCorp and NV Energy, PSE will incur administrative charges from CAISO and therefore proposes under a new Schedule 1A to sub-allocate the EIM administrative charges to all transmission customers on the basis of Measured Demand.[98] The Commission accepted NV Energy's proposal to recover CAISO administrative charges on the basis of Measured Demand in its own Schedule 1-A,[99] and should similarly accept as just and reasonable PSE's proposed Schedule 1A. PSE's proposal is consistent with the Commission's determination in the PacifiCorp EIM Order that all transmission customers cause PSE to incur the CAISO's EIM administrative charges, and should pay according to their volumetric use of the PSE system as determined by Measured Demand.[100]

b. Revisions to Schedules 4, 4R, and 9

i. Use of LAPs and LMPs to Settle Energy and Generator Imbalance

PSE will price energy imbalance service provided to transmission customers serving load within PSE's BAA under Schedules 4 and 4R of the PSE OATT using the LAP price produced by the EIM.[101] Similarly, PSE will price generator imbalance service provided under Schedule 9 to customers with generating resources in the PSE BAA that are not PSE EIM Participating Resources using LMPs generated by the EIM. The Commission has held consistently that using the EIM-produced LAP price or LMP price to establish charges for energy and generator imbalance is just and reasonable.[102] For example, the Commission in Order 890 held that Energy Imbalance Service should be priced on the basis of the utility's incremental and decremental cost for when the system is deficient or in surplus, respectively. LMP is a form of incremental pricing where such charges reflect a pass through of the costs to provide the service, since PSE will utilize the EIM to balance its system within the hour. PSE's proposed revisions to Schedules 4, 4R, and 9 closely mirror the corresponding Commission-accepted Schedules 4 and 9 of PacifiCorp and NV Energy.

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[98] PSE proposes to include a new defined term, "Measured Demand," in Section 1 of its OATT. Measured Demand includes all metered demand plus e-Tagged export volumes from the PSE BAA. Attachment A, Proposed Tariff Revision § 1.19D.

[99] *See generally* NV Energy EIM Order.

[100] PacifiCorp EIM Order at P 170.

[101] PSE provides energy imbalance service to customers that take service under its WUTC-jurisdictional Schedules 448 and 449 – which customers are also OATT transmission customers – under Schedule 4R instead of Schedule 4. As discussed above, and below in more detail, PSE is not proposing, initially, to price imbalance service under Schedule 4R using locational EIM prices.

[102] *See* PacifiCorp EIM Order at PP 160-163. *See also* NV Energy EIM Order at PP 174-179.

Under Schedules 4 and 4R, a transmission customer will be charged or paid for Energy Imbalance Service measured as the deviation of the transmission customer's metered load from the load component of the Transmission Customer Base Schedule (as determined pursuant to Section 4.2.4 of Attachment O). The charge or payment is settled at the Uninstructed Imbalance Energy ("UIE") price, as determined by the MO under Section 29.11(b)(3)(C) of the CAISO Tariff, for the period of the deviation at the applicable LAP where the load is located.

Under Schedule 9, a transmission customer will be charged or paid for Generator Imbalance service when a difference occurs between the output of a generator that is not a PSE EIM Participating Resource and is located in the PSE BAA and the resource component of the Transmission Customer Base Schedule. For customers that have not received a Manual Dispatch or EIM Available Balancing Capacity dispatch instruction from the PSE EIM Entity, or communicated physical changes in the output of the resource to CAISO, any deviation between the transmission customer's metered generation and the resource component of the Transmission Customer Base Schedule will be settled as energy imbalance at the UIE price as determined by the MO under Section 29.11(b)(3)(B) of the MO Tariff for the period of the deviation at the applicable PNode RTD price where the generator is located.

For transmission customers who have received a Manual Dispatch or EIM ABC dispatch, or who have communicated physical changes in the output from resources to the MO, Generator Imbalance Service will apply under the following circumstances:

- A transmission customer shall be charged or paid for Generator Imbalance Service measured as the deviation of the transmission customer's metered generation compared to the Manual Dispatch amount, EIM ABC dispatch amount, or physical changes in the output of resources incorporated by the MO in the fifteen-minute market (FMM), settled as UIE for the period of the deviation at the applicable PNode FMM price where the generator is located, as determined by the MO under Section 29.11(b)(3)(B) of the MO Tariff;

- A transmission customer shall be charged or paid for Generator Imbalance Service measured as the deviation of the transmission customer's metered generation compared to the Manual Dispatch amount, EIM ABC dispatch amount, or physical changes in the output of resources incorporated by the MO in RTD, settled as UIE for the period of the deviation at the applicable PNode RTD price where the generator is located, as determined by the MO under Section 29.11(b)(3)(B) of the MO Tariff;

- A transmission customer shall be charged or paid for Generator Imbalance Service measured as the deviation of either the Manual Dispatch amount, EIM ABC dispatch amount, or physical changes in the output of resources incorporated by the MO in the FMM, compared to the resource component of the Transmission Customer Base Schedule, settled as instructed imbalance energy ("IIE") for the period of the deviation at the applicable PNode FMM price where the generator is located, as determined by the MO under Section 29.11(b)(1)(A)(ii) of the MO Tariff; or

- Generator Imbalance Service measured as the deviation of either the Manual Dispatch amount, EIM ABC dispatch amount, or physical changes in the output of resources incorporated by the MO in RTD, compared to the FMM schedule, as IIE for the period of the deviation at the applicable PNode RTD price where the generator is located, as determined by the MO under Section 29.11(b)(2)(A)(ii) of the MO Tariff.

In response to stakeholder feedback on preliminary draft tariff changes, PSE is, like PacifiCorp and NV Energy before it, proposing to eliminate penalty tiers for scheduling behavior under Schedules 4, 4R, and 9. PSE will monitor the scheduling practices of its transmission customers. If there is intentional over-scheduling or under-scheduling, PSE may seek to reinstate the penalty tiers through a future FPA Section 205 filing.

PSE is also proposing to settle imbalance under Schedules 4, 4R, and 9 using the full aggregated LAP price (for Schedules 4 and 4R) or LMP (for Schedule 9), which includes an energy loss component. As will be discussed below, PSE will only assess average system losses under Schedule 12 using the "balanced" component of the Transmission Customer Base Schedule, so that there will be no duplicative charge for energy losses on energy imbalance. This approach was accepted as just and reasonable in the NV Energy EIM Order,[103] and differs from PacifiCorp's method of backing out the loss component of the LAP price or LMP in the imbalance settlement and assessing system average losses on the full metered output or demand.

c. Adoption of New Schedules 12 and 12A – Real Power Losses

PSE's OATT currently does not contain a rate schedule delineating the price at which losses will be financially settled. In practice, PSE has been settling losses on the Washington Area System – as well as on the Colstrip and Southern Intertie segments – using the system average loss factor of 2.7% stipulated in Sections 15.7 and 28.5 of the OATT and the day ahead on and off peak Mid-Columbia Intercontinental Exchange, Inc. (ICE) Firm Power Index price (ICE Index). This is the same index price currently utilized to settle imbalance under Schedules 4, 4R, and 9. Upon commencement of EIM participation, PSE proposes, consistent with the Commission's direction in the PacifiCorp EIM Order,[104] to utilize the aggregated LAP price to financially settle losses as such price is a better representation than the ICE index of PSE's marginal cost of producing energy to replace real power losses in real-time.

[103] *See generally* NV Energy EIM Order.

[104] *See* PacifiCorp EIM Order at P 162.

PSE proposes to provide for LAP pricing for losses in new Schedules 12 (for Real Power Losses on the Washington Area System) and 12A (for Real Power Losses on the Southern Intertie and Colstrip segments). Under Schedule 12, Washington Area customers will be assessed losses in accordance with the process approved by the Commission in the NV Energy EIM Order using the Transmission Customer Base Schedule (and not the final e-Tag) because losses on Energy Imbalance Service and Generator Imbalance Service provided by PSE are reflected in the LMP or LAP price used to settle imbalance under Schedules 4, 4R, and 9. Under Schedule 12A, transmission customers taking service on the Colstrip and Southern Intertie transmission segments (outside PSE's BAA) do not submit Transmission Customer Base Schedules because those segments are not in the PSE BAA and such customers do not take energy or generator imbalance service from PSE. Colstrip and Southern Intertie customers will therefore be assessed losses based on the "actual transmission service provided (scheduled service less any curtailments, corrections or adjustments mutually agreed on by the Transmission Provider and the Transmission Customer)."[105]

PSE also proposes in Schedules 12 and 12A to require transmission customers to settle losses financially to the exclusion of in-kind replacement. The timing lag associated with in-kind replacement inherently allows for mismatches in value between the energy at the time it was lost and energy at the time it was replaced, including on-peak and off-peak pricing differences. The Commission has determined that requiring financial settlement of losses to the exclusion of in-kind replacement is just and reasonable and consistent with Order Nos. 888 and 890.[106] The Commission should accept as just and reasonable PSE's proposed Schedules 12 and 12A.

2. Allocation of CAISO EIM Charges and Payments

a. Instructed Imbalance Energy

PSE will settle IIE under Attachment O, Section 8.1. IIE may result from (1) operational adjustments of any affected Interchange or Intrachange, including changes made by transmission customers after T-57; (2) resource imbalances created by Manual Dispatch or EIM ABC dispatch; or (3) adjustment to resource imbalances created by adjustments to resource forecasts under Section 11.5 of the CAISO tariff. IIE settled under Section 8.1 will be at the RTD or FMM price at the applicable PNode and will be sub-allocated directly to the transmission customer with the affected resource. PSE has used language virtually identical in Section 8.1 to that of NV Energy.[107]

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[105] Attachment A, Proposed Tariff Revision, Schedule 12A.

[106] *Ariz. Pub. Serv. Co.*, 143 FERC ¶ 61,280 at P 28 (2013) ("We find that Order Nos. 888 and 890 do not preclude the use of a financial settlement mechanism to the exclusion of in-kind replacement.").

[107] *See generally* NV Energy EIM Order.

PSE has proposed one variation to the language of Section 8.1 that differs from PacifiCorp and NV Energy. Unlike PacifiCorp and NV Energy, PSE proposes to require its transmission customers without load or generation in the PSE BAA to submit Transmission Customer Base Schedules forecasting expected intrachange under Attachment O, Section 4.2.4.4. Intrachange is an e-tagged energy transfer that is entirely within the PSE BAA. Customers submitting intrachange schedules could produce an imbalance independent of any load or generation in the PSE BAA. Such intrachange imbalance would not be reflected in the imbalance settled by PSE with load or generation in the BAA, which submit their own base schedules and settle imbalance according to deviations between such schedule and metered output or demand. For example, consider a scenario where a generator submits a base schedule of 9 MWh and a separate transmission customer submits an intrachange e-tag for 10 MWh from the generator to a load (the load base schedule is deemed to be the e-tag value of 10 MWh). If the generator metered value for the hour is 9 MWh and the load metered value is 10 MWh, then the generator and load have no UIE assessed but the intrachange e-tag caused 1 MWh of IIE. The 1 MWh of imbalance energy was provided by the EIM. Accordingly, PSE proposes to settle as IIE any imbalance that results from a transmission customer's intrachange e-tag. PSE asks that FERC accept this deviation from the previously accepted tariff language of PacifiCorp and NV Energy because it appropriately assigns the imbalance costs and payments associated with intrachange tag changes to the responsible transmission customers, consistent with cost causation.

b. Uninstructed Imbalance Energy

Under Attachment O, Section 8.2, any charges or payments to the PSE EIM Entity pursuant to Section 29.11(b)(3)(B) and (C) of the CAISO Tariff for UIE not otherwise recovered under Schedules 4, 4R, or 9 shall not be sub-allocated to transmission customers. Residual UIE allocations can arise because PSE uses the transmission customers' individual derived load forecasts to settle imbalances under Schedule 4 or 4R, not an allocated share of the CAISO BAA load forecast. Thus, there can be a difference between the CAISO's projection and customers' individual expectations of their demand. In other words, if customers are 100% accurate, the CAISO will still assess charges to the PSE EIM Entity based on the difference between the CAISO load forecast for the BAA and actual metered amounts where the EIM Entity had to make an adjustment to the base schedule for the BAA after customers submitted their Forecast Data. While the CAISO allocates these costs to Measured Demand,[108] the proposed allocation by PSE insulates existing customers from potential costs due to the CAISO load forecast. This approach is consistent with the FERC-accepted OATT language of both PacifiCorp and NV Energy.[109]

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[108] *See* CAISO Tariff § 11.5.4.1(d), Imbalance Energy Pricing; Non-Zero Offset Allocation, version 11.0.0 (effective Oct. 27, 2015); *see also*, *Cal. Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274 at PP 273-74 (2006), *order on reh'g*, 119 FERC ¶ 61,076, *order on reh'g*, 120 FERC ¶ 61,271 (2007).

[109] *See generally* PacifiCorp EIM Order; NV Energy EIM Order.

c. Unaccounted For Energy

Under Attachment O, Section 8.3, any charges to the PSE EIM Entity pursuant to Section 29.11(c) of the CAISO Tariff for Unaccounted For Energy ("UFE") shall not be sub-allocated to transmission customers. This proposed allocation holds customers harmless and limits losses to the previously-approved loss factors, and is consistent with the tariff provisions of PacifiCorp and NV Energy.

d. Under- and Over-Scheduling Charges

To promote accurate forecasting, the CAISO allocates charges in Section 29.11(d) of the CAISO Tariff for both under-scheduling and over-scheduling of load. In Attachment O, Section 8.4, PSE proposes that any charges to the PSE EIM Entity for under- or over-scheduling be assigned to the transmission customers subject to Schedules 4 and 4R that contributed to the imbalance for that hour based on their respective under- and over-scheduling imbalance ratio share. This allocation is consistent with cost-causation because it proportionately assigns the charges to parties that contribute to the incurrence of the penalty.

The CAISO Tariff also provides that the CAISO will calculate the total daily excess revenues received from under-scheduling charges and over-scheduling charges and allocate them to load in EIM BAAs that were not subject to under-scheduling or over-scheduling charges according to Metered Demand.[110] Under Attachment O, Section 8.4.3, "[a]ny payment to the PSE EIM Entity pursuant to Section 29.11(d)(3) of the [CAISO] Tariff shall be distributed to Transmission Customers . . . on the basis of Metered Demand." Again, this language is consistent with the FERC accepted tariff provisions of PacifiCorp and NV Energy.

e. Flexible Ramping Constraint

Under Section 29.34(m) of the CAISO Tariff, the CAISO will determine the flexible ramping requirement for each EIM Entity BAA based on the demand forecast change across consecutive intervals, demand forecast error, and energy production variability. The combined requirement for the entire EIM footprint may be less than the sum of the individual BAA requirements, recognizing the diversity benefits in the EIM footprint.

PSE proposes that any charges to the PSE EIM Entity pursuant to Section 29.11(g) of the CAISO Tariff for the flexible ramping constraint ("FRC") be sub-allocated to transmission customers on the basis of Measured Demand.[111] Use of a Measured Demand allocator for FRC costs ensures that "those customers benefiting from

[110] *See* CAISO Tariff § 29.11(d)(3), Settlements and Billing for EIM Market Participants, version 7.0.0 (effective Oct. 27, 2015).

[111] *See* Attachment O, § 8.5.6.

the reliability of the transmission system also are responsible for sharing the costs that incurred in maintaining that level of reliability."[112]

This approach is consistent with that authorized by the Commission for PacifiCorp and NV Energy.[113] In the PacifiCorp EIM Order, the Commission determined:

> With respect to the flexible ramping constraint charge, the Commission accepts PacifiCorp's rationale that it does not currently have the data to allocate that charge in the same manner as CAISO. However, we do agree that PacifiCorp should look into this issue as it gains experience with the EIM. Accordingly, we direct PacifiCorp to submit a report to the Commission 15 months after the commencement of the EIM analyzing whether continued use of the Measured Demand allocation is appropriate for the flexible ramping constraint charge and whether it now has sufficient operational data to use the 75/25 allocation factor used by CAISO.[114]

In the NV Energy EIM Order, the Commission similarly directed NV Energy "to submit an informational report to the Commission within 15 months after NV Energy's entry into the EIM addressing . . . whether continuing to allocate flexible ramping constraint charges on the basis of Measured Demand is appropriate."[115]

On February 1, 2016, PacifiCorp submitted its report and analysis of FRC, concluding that "the use of its current Measured Demand (which consists of PacifiCorp's balancing authority area metered load and exports) allocation continues to be appropriate for the flexible ramping constraint allocations."[116] PacifiCorp found that the 75/25 allocation utilized by CAISO for allocation of FRC charges to Scheduling Coordinators was more complex, required additional data, increased the risk of calculation errors, and lengthened invoice processing if PacifiCorp were to suballocate FRC charges to individual generators with daily gross negative supply deviations. According to PacifiCorp's analysis, the increased benefits of changing the FRC charge allocation was "very small and insignificant."[117]

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[112] *Midwest Indep. Transmission Sys. Operator, Inc.*, 117 FERC ¶ 61,237 at P 23 (2006).

[113] PacifiCorp EIM Order at P 184. *See also* NV Energy EIM Order at P 213.

[114] PacifiCorp EIM Order at P 184.

[115] NV Energy EIM Order at P 213.

[116] *PacifiCorp*, Docket No. ER14-1578-000, Letter Regarding Energy Imbalance Market at 1 (Feb. 1, 2016) (internal footnotes omitted).

[117] *Id.* at 3.

PSE proposes to follow PacifiCorp's and NV Energy's tariff language by suballocating FRC on the basis of Measured Demand. PSE believes there is value in maintaining a consistent approach to suballocation of FRC. Additionally, PSE echoes PacifiCorp's comments regarding the likely change in settlement structure due to the flexible ramping product currently under development at CAISO.[118] Should the Commission issue an Order in response to PacifiCorp's FRC report, or a future FRC report from NV Energy, or should FERC approve a new flexible ramping product proposed by CAISO, PSE will reevaluate the suballocation of FRC. PSE requests that if either of these items take place prior to PSE's targeted October 1, 2016 EIM go-live date, the Commission allow PSE to update its tariff language in a compliance filing.

f. EIM BAA Real Time Market Neutrality

Real-time market BAA neutrality can be charges or credits attributable to: "(1) an excessive rate mitigation measure in the pricing formula for [LAPs], (2) differences between the Load forecast and actual metered Load, (3) [UIE] of generation, (4) regulation energy in the [CAISO], (5) the real-time marginal loss surplus, and (6) [UFE]."[119] Each EIM Entity and the CAISO will have its own real-time market BAA neutrality account. However, because the EIM transfers energy between BAAs within the EIM, the CAISO will reallocate a portion of the amounts in each BAA's account to other BAAs' accounts. The reallocation will be based on the BAA's ratio of 5-minute energy transfers to other BAAs to overall UIE in the BAA including the energy transfers to other BAAs.

PSE proposes that any charges to the PSE EIM Entity pursuant to Section 29.11(e)(3) of the CAISO Tariff for EIM BAA real-time market neutrality (referred to as the Real-Time Imbalance Energy Offset) would be "sub-allocated to Transmission Customers on the basis of Measured Demand."[120] The Commission accepted this approach for PacifiCorp[121] and NV Energy.[122] Accordingly, the Commission should accept as just and reasonable PSE's consistently drafted language in Section 8.5.1 of Attachment O.

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[118] *See Id.* at 3-4.

[119] CAISO, Energy Imbalance Market Draft Final Proposal at 5 (Sept. 23, 2013) ("CAISO Draft Final Proposal"), http://www.caiso.com/Documents/EnergyImbalanceMarket-DraftFinalProposal092313.pdf

[120] Attachment O, § 8.5.1.

[121] PacifiCorp EIM Order at P 184.

[122] *See* Nevada Power Co. and Sierra Pacific Power Co. Open Access Transmission Tariff, Attachment P, Energy Imbalance Market § 8.5.1, version 0.2.0 (effective Sept. 30, 2015) ("NV Energy OATT").

g. BAA Real-Time Congestion Offset

Consistent with the discussion in the prior section, PSE proposes that any charges or payments to the PSE EIM Entity pursuant to Section 29.11(e)(2) of the CAISO Tariff for the EIM real-time congestion offset shall be allocated to transmission customers on the basis of Measured Demand.[123] Amounts in this account arise when the CAISO has to re-dispatch generation resources in real-time to manage congestion. These amounts can be either payments or charges, but if the re-dispatch is due to higher load or reduced transmission limits from when base schedules were established, the amount will be a charge.[124] Each EIM Entity, as well as the CAISO BAA, will have a separate BAA real-time congestion balancing account. The CAISO will allocate the costs of congestion attributable to transmission constraints located within each BAA to that EIM Entity's BAA real-time congestion balancing account.[125]

Commission policy states that enhanced reliability is a system-wide benefit and that the integrated transmission grid is a cohesive network in which impacts felt on one part of the grid have a cascading effect on other parts of the grid.[126] Congestion management is an essential grid reliability function. Accordingly, all transmission customers should receive a *pro rata* share of these costs.

h. EIM Entity Real-Time Marginal Cost of Losses Offset

PSE proposes to sub-allocate charges and payments for the EIM real-time marginal cost of losses offset pursuant to Section 29.11(e)(4) of the CAISO Tariff on the basis of Measured Demand.[127] While this deviates from PacifiCorp's approach, wherein the marginal cost of losses offset is not sub-allocated to customers, a change in approach is necessary in order to be consistent with the determination to use the full LMP or LAP pricing in Schedules 4, 4R, 9, 12, and 12A and not to remove the marginal loss component of the LMP for settlement of imbalance or losses. PSE's proposed

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[123] Attachment O, § 8.5.2.

[124] This is because the CAISO must dispatch generation resources up on the downstream side of a congested constraint at a relatively higher LMP while dispatching generation resources down on the upstream side at a relatively low LMP.

[125] CAISO Draft Final Proposal at 6, as reflected in the Section 11.5.4.1.1 of the CAISO Tariff.

[126] *See, e.g., Standardization of Generator Interconnection Agreements and Procedures*, Order No. 2003, FERC Stats. & Regs. ¶ 31,146 (2003), *order on reh'g,* Order No. 2003-A, FERC Stats. & Regs. ¶ 31,160 at P 590 (2004) ("all customers benefit from having a Transmission System that provides reliable service"), *order on reh'g,* Order No.2003-B, FERC Stats. & Regs. ¶ 31,171 (2004), *order on reh'g,* Order No. 2003-C, FERC Stats. & Regs. ¶ 31,190 (2005), *aff'd sub nom. Nat'l Ass'n of Regulatory Util. Comm'rs v. FERC,* 475 F.3d 1277 (D.C. Cir. 2007).

[127] Attachment O, § 8.5.3.

Attachment O, Section 8.5.3 is consistent with that of NV Energy,[128] which was accepted by the Commission.[129]

i. Real-Time Bid Cost Recovery

PSE proposes to sub-allocate real-time bid cost recovery charges assessed pursuant to Section 29.11(f) of the CAISO Tariff on the basis of Measured Demand. The proposed allocation is consistent with the allocation used by PacifiCorp[130] and NV Energy,[131] as well as current CAISO practice as accepted by the Commission.[132]

The EIM makes payments to generators, referred to as bid cost recovery, in the event real-time market revenues over a day do not cover a resource's real-time commitment and dispatched bid costs. These costs fall into two categories: (1) dispatched energy production deviation from a resource's Transmission Customer Base Schedule level, and (2) commitment costs, consisting of the costs to start a generator and operate it at its minimum operating level. Each EIM Entity has an account based upon the bid cost recovery payments made to resources located in its BAA(s). In allocating bid cost recovery costs to these accounts, the CAISO considers energy transfers between BAAs similar to the way it will for the real-time market BAA neutrality account.

j. Other EIM Neutrality Settlement Provisions

The CAISO is a revenue-neutral entity. It pays out to CAISO Creditors payments received from CAISO Debtors. The CAISO imposes Daily and Monthly Neutrality Adjustments and Daily and Monthly Rounding Adjustments to collect any shortfalls due to rounding. The CAISO allocates these charges on the basis of Measured Demand.[133] PSE proposes to use this same approach,[134] consistent with PacifiCorp and NV Energy.

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[128] NV Energy OATT, Attachment P, Section 8.5.3.

[129] NV Energy EIM Order.

[130] PacifiCorp Open Access Transmission Tariff , FERC Electric Tariff Vol. No. 11, Attachment T, § 8.5.5, version 7.0.0 (effective Sept. 30, 2015) ("PacifiCorp OATT").

[131] NV Energy OATT, Attachment P, Section 8.5.5.

[132] *Cal. Indep. Sys. Operator Corp.*, 119 FERC ¶ 61,076 at P 309 (2007) ("[t]he disparities between the forecast and real-time demand are problematic and could lead to costs which cannot accurately be attributed to a specific market participant. We agree that cost causation principles are difficult to follow in situations where procurements are made to assure grid reliability."). *See also*, *Pac. Gas & Elec. Co.*, Opinion No. 459, 100 FERC ¶ 61,160 at PP 15-16, 21 (finding that reliability services, including the costs of reliability agreements with generators, provide a system-wide benefit and "should be paid for by all users of the grid" including wholesale transmission customers), *order on reh'g*, Opinion No. 459-A, 101 FERC ¶ 61,139 (2002) *order rejecting request for reh'g*, Opinion No. 459-B, 102 FERC ¶ 61,009 (2003).

[133] *See* CAISO Tariff § 11.14, Neutrality Adjustments, version 1.0.0 (effective Sept. 23, 2014).

[134] *See* Attachment O, § 8.5.4.

There are certain CAISO charges that are more directly related to the timing of billing and payments. As these are more under the control of the PSE EIM Entity, PSE is proposing to hold transmission customers harmless from these charges.[135] They include the following: Invoice Deviation (distribution and allocation); Default Invoice Interest Payment; Default Invoice Interest Charge; Invoice Late Payment Penalty; Financial Security Posting (Collateral) Late Payment Penalty; Shortfall Receipt Distribution; Shortfall Reversal; Shortfall Allocation; Default Loss Allocation; and Generator-Interconnection Process Forfeited Deposit Allocation. The proposed allocation is reasonable as these charges relate to timing of payments and risk of market shortfalls. PSE's proposed Attachment O, Section 8.5.4 and 8.5.8 are consistent with those accepted as just and reasonable for PacifiCorp and NV Energy.[136]

k. Operating Reserves

An EIM transfer out of the PSE BAA to the CAISO BAA will result in the PSE EIM Entity receiving a payment for operating reserves, while an EIM transfer into the PSE BAA from the CAISO BAA will result in a charge to the PSE EIM Entity for operating reserves. In Attachment O, Section 8.12, PSE proposes to sub-allocate to customers both payments and charges for operating reserves.[137]

In Attachment O, Section 8.12.1, PSE proposes to sub-allocate payments on a "ratio share basis, defined as the proportion of the volume of Operating Reserves provided by a PSE EIM Participating Resource in the PSE BAA dispatched during the Operating Hour compared to the total volume of Operating Reserves provided by all PSE EIM Participating Resources dispatched in the PSE BAA for the Operating Hour."[138] This sub-allocation is appropriate because PSE EIM Participating Resources supply the energy for EIM Transfers out of the PSE BAA, as well as the corresponding operating reserves. PSE's proposed Attachment O, Section 8.12.1 is consistent with NV Energy's Attachment P, Section 8.12.1, which the Commission accepted in the NV Energy EIM Order.[139] The Commission should similarly accept PSE's proposed sub-allocation of operating reserve payments.

In Attachment O, Section 8.12.2, PSE proposes to sub-allocate charges for operating reserves on the basis of Measured Demand.[140] This sub-allocation differs from

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[135] *Seeid.*, § 8.5.8.

[136] *See generally* PacifiCorp EIM Order; NV Energy EIM Order.

[137] *See* Attachment O, § 8.12.

[138] *See id.* § 8.12.1.

[139] *See* NV Energy OATT, Attachment P, § 8.12.1. *See generally* NV Energy EIM Order.

[140] *See* NV Energy OATT, Attachment P, § 8.12.2.

the approach that was adopted by NV Energy and accepted by the Commission, wherein operating reserve charges from the CAISO are sub-allocated "based on the Transmission Customer's positive load imbalance ratio share, which is the ratio of the Transmission Customer's positive load imbalance amount (the amount that the Transmission Customer's load exceeds the Transmission Customer's resources) relative to the sum of the positive load imbalances of all other Transmission Customers with such load imbalance amounts for the Operating Hour, expressed as a percentage."[141] PSE's proposal to sub-allocate operating reserve payments using Measured Demand instead is appropriate because there are various factors that can cause EIM Transfers from the CAISO BAA into the PSE BAA that may be unrelated to a particular customer's load imbalance or to overall load imbalance in PSE's BAA.

For example, in a circumstance where locational prices in the CAISO BAA are lower than those in the PSE BAA, and one or more PSE EIM Participating Resources have submitted energy profiles offering decremental capacity into the EIM, such resources could receive a Dispatch Instruction from the CAISO to reduce output such that, even if PSE's BAA is perfectly in balance, an EIM Transfer out of the CAISO BAA into the PSE BAA would occur and result in charges for operating reserves. In such a circumstance, PSE believes it would not be appropriate or consistent with cost causation principles to identify all customers with a positive load imbalance and allocate the operating reserve charges to such customers on a *pro rata* basis because the import of CAISO energy was driven entirely by economics and not by any positive load imbalance within the BAA. In an extreme example, where only one small transmission customer has a positive load imbalance during an operating hour, and yet market conditions are such that significant generation in the PSE BAA is being supplanted by cheaper CAISO generation, that transmission customer would receive 100% of the operating reserve charges under NV Energy's method of sub-allocating reserve charges, while all customers benefit from reduction of locational prices that will result from the CAISO imports. Therefore, PSE proposes to sub-allocate operating reserve charges on the basis of Measured Demand and submits that this is a just and reasonable deviation from the FERC-accepted practice of NV Energy.

l. Direct Assignment Charges

Three types of charges will be directly assigned or sub-allocated to the customers that cause the costs to be incurred: (1) penalties for inaccurate or late settlement quality meter data; (2) tax liabilities; and (3) the Variable Energy Resource Forecast Charge. Each of these provisions appropriately matches cost payments with cost causation, and is consistent with the tariff provisions accepted for PacifiCorp and NV Energy.[142]

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[141] *Id.*

[142] *See generally* PacifiCorp EIM Order; NV Energy EIM Order.

3. Coordination with CAISO Settlements

a. Payment Calendar

Section 29.11(l) of the CAISO Tariff provides that the EIM Entity shall be subject to the CAISO's payment calendar for issuing settlement statements, exchanging invoice funds, submitting meter data, and submitting settlement disputes. Attachment O, Section 8.9 recognizes that while the PSE EIM Entity shall be subject to the CAISO's payment calendar, for issuing settlement statements, for example, PSE will follow Section 7 of its own OATT for issuing invoices regarding the EIM.

b. Price Correction

Pursuant to Sections 29.35 and 35 of the CAISO Tariff, the CAISO has the authority to correct prices.[143] In addition, the CAISO may modify settlement statements as a result of its dispute resolution process. Under Attachment O, Section 8.11, PSE proposes to make corresponding changes to its sub-allocations to pass through the CAISO's revisions to its settlements.

c. EIM Residual Balancing Account

To the extent that the CAISO's EIM-related charges or payments to the PSE EIM Entity are not captured elsewhere in the OATT, Section 8.10 of Attachment O permits those charges or payments to be placed in an EIM Residual Balancing Account until the PSE EIM Entity files for Commission approval of a proposed allocation methodology pursuant to FPA Section 205. Interest shall accrue on EIM Residual Balancing Account funds in accordance with the Commission's regulations.

The purpose of the EIM Residual Balancing Account is similar to that of commonly-used formula rate true-ups insofar as both mechanisms are ultimately designed to prevent cost over- or under-recovery.[144] That is, while CAISO EIM-related

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[143] Section 35.4 of the CAISO Tariff currently provides that

> [t]he CAISO may correct all financially binding prices . . . whenever the CAISO identifies an invalid market solution or invalid prices in an otherwise valid market solution. The circumstances in which the CAISO may determine that an invalid market solution or invalid prices exist include the following: the occurrence of data input failure; the occurrence of hardware or software failure; or a result that is inconsistent with the CAISO Tariff.

CAISO Tariff § 35.4, Scope of Price Corrections, version 1.0.0 (effective Sept. 30, 2010).

[144] *See, e.g., Midwest Indep. Transmission Sys. Operator, Inc.*, Letter Order, Docket No. ER13-263 (Feb. 11, 2013) (approving an October 2012 proposal by the Midwest Independent Transmission System Operator, Inc. ("MISO") and Participating MISO Transmission owners to add a true-up mechanism to the MISO OATT to ensure that the Participating MISO Transmission Owners collect the actual revenue requirements calculated under the MISO OATT, while protecting customers from cost over-recovery); *ISO*

charges or payments will be captured in the proposed OATT, such as in Attachment O Section 8, and/or Schedules 1A, 4, 4R and 9, it is possible that, for example, the CAISO could implement a new charge or amend an existing charge before the PSE EIM Entity is able to make a corresponding change to the OATT. Under such circumstances, the charge amount would be placed in the EIM Residual Balancing Account until such time that PSE files a proposed cost allocation methodology with the Commission. The Commission accepted this approach with respect to PacifiCorp's OATT[145] and NV Energy's OATT,[146] and should do likewise with respect to PSE's proposed Attachment O, Section 8.10.

I. Dispute Resolution

PSE proposes to adopt a new OATT Section 12.4A, "EIM Disputes," which provides a dispute resolution process for EIM-related charges and payments. Under Section 12.4A.1, disputes between the EIM Entity and a transmission customer regarding the manner in which the EIM Entity has sub-allocated EIM payments or charges from the MO are processed in accordance with Sections 12.1 to 12.4 of the OATT, in the same manner as any other dispute between the transmission provider and an OATT customer.

Section 12.4A.2 recognizes that disputes between the MO and an EIM Participating Resource Scheduling Coordinator related to settlement statements provided to the EIM Participating Resource Scheduling Coordinator from the MO will proceed in accordance with the process timeline under the MO Tariff. Section 12.4A.3 states that the EIM Entity may raise disputes with the MO regarding the settlement statements it receives from the MO in accordance with the process specified in the MO Tariff.

Finally, Section 12.4A.4 provides that, to the extent a dispute arises regarding an MO charge or payment to the EIM Entity that is subsequently charged to or paid by a transmission customer and the customer wishes to raise a dispute with the MO, the EIM Entity shall file a dispute on behalf of the customer in accordance with the MO Tariff and work with the customer to resolve the dispute pursuant to the process specified in the MO Tariff.

PSE's proposed Section 12.4A is virtually identical to that which was accepted by the Commission in the PacifiCorp EIM Order,[147] and similar to dispute resolution procedures proposed by NV Energy which were accepted without comment in the NV Energy EIM Order. Accordingly, the Commission should accept PSE's proposed Section 12.4A.

New England Inc., 113 FERC ¶ 61,341 at P 25 (2005) (stating true-up mechanisms protect market participants from over-collection).

[145] PacifiCorp OATT, Attachment T, § 8.10.

[146] NV Energy OATT, Attachment P, § 8.10.

[147] PacifiCorp EIM Order at P 213.

J. Compliance

Proposed Section 9 of Attachment O is consistent with a comparable provision approved for PacifiCorp's OATT and NV Energy's OATT and includes several provisions related to the expected code of conduct for customers. Section 9.1 governs the provision of data, under which PSE EIM Participating Resources and PSE EIM Participating Resource Scheduling Coordinators are responsible for complying with information requests they receive directly from the EIM market monitor or regulatory authorities. Transmission customers also must provide the PSE EIM Entity with all data necessary to respond to information requests received by the PSE EIM Entity from the MO, the EIM market monitor, or regulatory authorities concerning EIM activities. These provisions reasonably respond to the needs of those responsible for market oversight to have the information necessary to perform these tasks. Under the EIM, the activities of non-participants can have a material effect on the LMP price based on their need for imbalances or their excess generation. Accordingly, the provision appropriately recognizes the need that non-participants respond to data requests.

Responding to information does not mean the information will be disclosed publicly. Section 9.1 reiterates PSE's ongoing obligation to maintain the confidentiality of data and information obtained by the PSE EIM Entity from transmission customers and interconnection customers, unless the PSE EIM Entity is required or otherwise permitted to disclose the information. PSE shall continue to abide by the Commission's Standards of Conduct and handle customer information accordingly once the EIM is administered.

Proposed Section 9.2 specifies six general rules of conduct which are intended to provide fair notice of expected conduct and facilitate an environment in which all parties may fairly participate in the EIM. Customers must:

(1) Comply with Dispatch Instructions and PSE EIM Entity operating orders in accordance with Good Utility Practice. If some limitation prevents the party from fulfilling the action requested by the MO or the PSE Energy EIM Entity then the party must promptly and directly communicate the nature of any such limitation to the PSE EIM Entity.

(2) Submit bids for resources that are reasonably expected to be available and capable of performing at the levels specified in the bid, and to remain available and capable of so performing based on all information that is known or should have been known at the time of submission.

(3) Notify the MO and the PSE EIM Entity of outages in accordance with Section 7 of Attachment O.

(4) Provide complete, accurate, and timely meter data to the PSE EIM Entity in accordance with the metering and communication requirements of the Tariff, and maintain responsibility to ensure the

accuracy of such data communicated by any customer-owned metering or communications systems.

(5) Provide information to the PSE EIM Entity, including the information requested in Attachment O, by applicable deadlines.

(6) Use commercially-reasonable efforts to ensure that forecasts are accurate and based on all information that is known or should have been known at the time of submission to the PSE EIM Entity.

Proposed Section 9.3 states that the PSE EIM Entity may refer a violation of the rules of conduct to the Commission to be enforced in accordance with the Commission's rules and procedures. Nothing in Section 9 of Attachment O is meant to limit any other remedy before the Commission or any applicable court or agency.

These rules of conduct are necessary and appropriate. Courts and the Commission have recognized that parties are liable for violations of tariffs.[148] These provisions are designed to put customers on notice as to expected conduct with regard to data provision, bidding, and forecasts related to the EIM, among other actions. PSE's proposed Attachment O, Section 9 is also consistent with the parallel provisions of NV Energy's Attachment P, Section 9 and PacifiCorp's Attachment T, Section 9. The Commission should accept PSE's proposed terms and conditions of compliance.

K. Market Contingencies

PSE's proposal with respect to market contingencies in Attachment O, Section 10 is consistent with Section 10 of Attachment T of the PacifiCorp OATT, as modified by the Commission, and Section 10 of Attachment P of the NV Energy OATT. In particular, PSE has followed the Commission's requirement in the PacifiCorp EIM Order that PacifiCorp remove proposed language from Section 10 which would have allowed the EIM Entity the authority to unilaterally suspend its participation in the EIM due to a market design flaw.[149] Accordingly, the proposed remedies and termination processes proposed in Section 10 are unchanged from those accepted for PacifiCorp and NV Energy. The temporary schedules in Section 10.4 however, reflect the currently-approved, pre-EIM provisions of the PSE OATT, including penalty bands, which while similar, are not identical to their PacifiCorp and NV Energy counterparts.

[148] Under Section 309 of the FPA, "[t]he Commission shall have power to perform any and all acts, and to prescribe, issue, make, amend, and rescind such orders, rules, and regulations as it may find necessary or appropriate to carry out the provisions of this chapter." 16 U.S.C. § 825h. Courts have interpreted the provision as granting FERC "remedial authority to require that entities violating the [FPA] pay restitution for profits gained as a result of a statutory or tariff violation." *Pub. Util. Comm'n of Cal. v. FERC*, 462 F.3d 1027, 1047-48 (9th Cir. 2006).

[149] *See* PacifiCorp EIM Order at P 196.

Attachment O, Section 10 contains critical protections for PSE and its customers. If the PSE EIM Entity submits a notice of termination of its participation in the EIM to the MO, the PSE EIM Entity may invoke certain corrective actions to mitigate price exposure during the 180-day period between submission of the notice and the termination effective date.[150] In this case, the PSE EIM Entity may request that the MO effectuate both of the following actions: (1) prevent EIM transfers and separate the PSE BAA from operation of the EIM; and (2) suspend settlement of EIM charges with respect to the PSE EIM Entity.[151] The CAISO Tariff specifies that the MO will implement corrective actions requested by the PSE EIM Entity.[152] Once such corrective actions are implemented by the MO, the PSE EIM Entity shall use the temporary schedules.

Section 10 also addresses corrective actions that may be invoked by the PSE EIM Entity when it declares a temporary contingency. These protections are just and reasonable and reliability based. PSE must have the ability to take these corrective actions as part of its BA responsibilities. Accordingly, as it did for PacifiCorp and NV Energy, the Commission should accept PSE's proposed Attachment O, Section 10.

L. Other Proposed Tariff Changes to the OATT

1. Definitions

PSE has added to the definitions in Section 1 of the OATT terms associated with the new market structure. Most of the proposed definitions are intended to be consistent with terms and terminology in the CAISO tariff, the PacifiCorp and NV Energy OATTs, or the NERC Glossary, as applicable.

2. Changes to Ensure Applicability of Attachment O

The proper functioning of the EIM requires certain minimum information to be provided on an ongoing basis by transmission customers and/or interconnection customers subject to the OATT, even prior to PSE's initial participation in the EIM. To that end, PSE includes in Section 1 of Attachment O language making Attachment O applicable to all transmission customers and interconnection customers with new and existing service agreements under the OATT. The purpose of this language is to ensure that customers will provide the PSE EIM Entity the necessary information to meet the registration, outage reporting, and forecast requirements included throughout Attachment O in time both for the period of non-binding parallel operations and to ensure the information is in place prior to actual market participation.

[150] *See* CAISO Tariff, Appendix B.17, *pro forma* EIM Entity Agreement § 3.2.2, version 0.0.0 (effective July 1, 2014).

[151] Attachment O, § 10.2. This provision is consistent with Section 29.4(b)(5) of the CAISO Tariff.

[152] *See* CAISO Tariff § 29.4(b)(5)(B).

To further clarify the applicability of the EIM-related OATT modifications, PSE proposes the following additions to its OATT:

- A new Section 16.1(g) that provides "[t]he Transmission Customer must comply with the requirements of Attachment O regarding the EIM;"
- A modification to subsection 29.2(ix) to require the Network Customer to provide information identified in Attachment O; and
- A new Section 2.5 of the Large Generator Interconnection Procedure in Annex A and new Section 5 of the Small Generator Interconnection Procedure in Annex B that specify the "Interconnection Customer shall have a continuing duty to comply with Attachment O of this Tariff, as applicable."

These provisions were accepted by the Commission with respect to PacifiCorp's OATT and NV Energy's OATT. They are necessary and appropriate to make the EIM-related OATT provisions applicable to all customers and enable the PSE Entity to provide the CAISO with the necessary information to administer the market.

3. Use of Designated Network Resources

To implement the EIM, PSE proposes to amend the provisions in its OATT that require undesignation of Network Resources to make off-system sales (new Section 28.7, 30.1, and 30.4), so that Network Customers have the option to participate in the EIM without having to undesignate all or a portion of the resource. The Commission-accepted OATTs of PacifiCorp and NV Energy contain similar amendments.

Eliminating the requirement to undesignate network resources that are PSE EIM Participating Resources is justified for several reasons. First, it will not be possible to know in advance of any hour if a particular Network Resource will be used only to serve Network Load or will be awarded an EIM dispatch instruction. It will also not be possible in advance of any hour to know if an EIM dispatch instruction will be issued for load within the PSE BAA, PacifiCorp's BAAs, the NV Energy BAA, or the CAISO BAA. Notwithstanding this uncertainty, the EIM will be serving network load in the broader EIM footprint and, as such, use of Network Integration Transmission Service is justified and reasonable.

Second, the purpose of the Commission's undesignation requirements is to ensure nondiscriminatory access to available capacity. This purpose is achieved when Network Resources are used to serve any EIM load utilizing transmission capacity that is determined to be available based upon real-time information about the transmission system, and that would be otherwise unable to be used on a real-time basis. Third, the Commission has approved provisions in both the SPP and MISO that recognize the need for exemptions from the need to undesignate resources.[153]

[153] *See* MISO Tariff § 28.6, Restrictions on Use of Service, version 30.0.0 (effective Nov. 19, 2013) and Southwest Power Pool, Inc. Open Access Transmission Tariff, Sixth Rev. Vol. No. 1 § 30.4, Operation of Network Resources, version 1.0.0 (effective Mar. 1, 2014).

4. Standard of Liability for PSE's Responsibilities as an EIM Entity

While PSE proposes to maintain the existing ordinary negligence standard of liability for its responsibilities as the transmission provider under the *pro forma* OATT, PSE requests, consistent with the liability protection afforded PacifiCorp and NV Energy, that its new market responsibilities as an EIM Entity be subject to a gross negligence or intentional wrongdoing, standard.[154] This is reflected in a proposed addition to Section 10.2 of the OATT.

This gross negligence or intentional wrongdoing standard is consistent with what the Commission has accepted previously in other organized markets. In particular, the Commission has approved such a standard for the CAISO and its participating transmission owners under the Transmission Control Agreement and the CAISO Tariff.[155] The Commission recognized that a gross negligence standard is reasonable, as it offers an "equitable balance between lower rates for all market participants and the burden of limited recovery of liability for some."[156]

III. OTHER EIM IMPLEMENTATION ISSUES

A. EIM Business Practice

Utilizing customer feedback during the stakeholder process, PSE has developed an EIM Business Practice to help customers understand the terms and conditions of service stipulated in the PSE OATT related to the EIM. Decisions on whether to place an item in the OATT or the PSE EIM Business Practice are shaped by the Commission's "rule of reason" policy,[157] which dictates that provisions that "significantly affect rates,

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[154] *See* PacifiCorp OATT § 10.2, Force Majeure and Indemnification, version 1.0.0 (effective Sept. 23, 2014); *see also* NV Energy OATT § 10.2, Force Majeure and Indemnification, version 0.1.0 (effective May 15, 2015).

[155] *Cal. Indep. Sys. Operator Corp.*, 139 FERC ¶ 61,198 (2012). *See also Cal. Indep. Sys. Operator Corp.*, 123 FERC ¶ 61,285 at P 241 (2008) (accepting gross negligence standard in Section 14.5.1 of the CAISO Tariff).

[156] *Cal. Indep. Sys. Operator Corp.*, 123 FERC ¶ 61,285 at P 241.

[157] *See, e.g.*, *City of Cleveland v. FERC*, 773 F.2d 1368, 1376 (D.C. Cir. 1985) (finding that utilities must file "only those practices that affect rates and service significantly, that are reasonably susceptible of specification, and that are not so generally understood in any contractual arrangement as to render recitation superfluous"); *Pub. Serv. Comm'n of N.Y. v. FERC*, 813 F.2d 448, 454 (D.C. Cir. 1987) (holding that the Commission properly excused utilities from filing policies or practices that dealt with only matters of "practical insignificance" to serving customers); *Midwest Indep. Transmission Sys. Operator, Inc.*, 98 FERC ¶ 61,137, at p. 61,401, *clarification granted*, 100 FERC ¶ 61,262 (2002) ("It appears that the proposed Operating Protocols could significantly affect certain rates and services and as such are required to be filed pursuant to Section 205.").

terms, and conditions" must be included in the filed tariff.[158] The Commission has elaborated that it is appropriate for a business practice to contain "implementation details, such as instructions, guidelines, examples and charts, which guide internal operations and inform market participants of how the [public utility] conducts its operations under the . . . tariff."[159] The Commission has also found that the "rule of reason" test requires evaluation on a case-by-case basis, comparing what is in an OATT against what is in an unfiled business practice manual.[160]

Examples of guidance provided in the PSE EIM Business Practice include:

- the application and certification process delineated in Attachment O, Section 3 to become a PSE EIM Participating Resource;
- the information required for initial registration with the CAISO of PSE EIM Participating Resources and the process for providing updates to the information consistent with the requirements in Attachment O, Sections 4.2.2.1 and 4.2.2.2;
- the process used to report outage and derate information required by Attachment O, Section 4.2.3 and Section 7;
- implementation details for customers to provide Forecast Data required under Attachment O, Section 4.2.4;
- information matching the specific charge code numbers to the EIM cost allocations contained in Attachment O, Section 8;
- the methodology for distributing the under- and over-scheduling of load proceeds authorized under the allocation in Attachment O, Section 8.4.3; and
- information required to report disputes as required under Section 12.4A of the OATT.

PSE's EIM Business Practice provides guidance on the OATT EIM-related terms and conditions, without significantly affecting or altering those terms and conditions, and therefore strikes an appropriate balance under the Commission's rule of reason analysis.

B. Market-Based Rate Authority

In the PacifiCorp EIM Order, the Commission directed PacifiCorp to submit a "market-based rate change of status filing within nine months of the launch of the EIM market so that the Commission can assess whether PacifiCorp has market power in the EIM," noting that the EIM "will be a new relevant geographic market for market power purposes."[161] The Commission deemed it "unlikely that there will be sufficient data

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[158] *Cal. Indep. Sys. Operator Corp.*, 119 FERC ¶ 61,076 at P 656 (2007) (citing *ANP Funding I, LLC v. ISO-NE*, 110 FERC ¶ 61,040, at P 22 (2005); *Prior Notice and Filing Requirements Under Part II of the Federal Power Act*, 64 FERC ¶ at p. 61,986-89 (1993), *order on reh'g*, 65 FERC ¶ 61,081 (1993)).

[159] *Cal. Indep. Sys. Operator Corp.*, 122 FERC ¶ 61,271 at P 16 (2008).

[160] *Cal. Indep. Sys. Operator Corp.*, 116 FERC ¶ 61,274 at P 1370.

[161] PacifiCorp EIM Order at P 206.

available to perform a study" on the EIM for at least nine months.[162] Subsequently, in the NV Energy EIM Order, the Commission directed both PacifiCorp and its affiliate NV Energy to submit "a market power analysis to demonstrate that it does not have market power in the EIM market . . . prior to commencing financially binding participation in the EIM."[163] The Commission's requirement to submit a market power study no later than 60 days prior to NV Energy's commencement of financially binding operations seemed in large part predicated on the fact that NV Energy lacks market-based rate authority in its own BAA under its current MBR tariff, and for that reason, NV Energy and its affiliate PacifiCorp were directed to demonstrate a lack of market power in the EIM prior to NV Energy joining the market.

Following the submission of a market power study as directed, the Commission on November 19, 2015 issued an order conditioning participation of PacifiCorp and NV Energy in the EIM at market-based rates on the imposition of a default energy bid ("DEB") cap on all offers into the EIM by the Berkshire Hathaway affiliates.[164] For an entity like PSE, that has market-based rate authority in its own BAA and that has no affiliates participating in the EIM, the PacifiCorp EIM Order and NV Energy EIM Order give rise to considerable uncertainty about whether or not a market power study is needed prior to commencing financially binding participation in the EIM. The Commission's imposition of DEB bidding on PacifiCorp and NV Energy also raises concerns about whether the full panoply of benefits of EIM participation predicted in the Benefits Analysis appended hereto as Attachment D will be available to PSE if concerns over market power and the sufficiency of CAISO market mitigation measures are not addressed. PSE raised these and other points in a pending request for rehearing and clarification of the Berkshire MBR Order.[165] Nevertheless, out of an abundance of caution, PSE intends to submit, in a future filing, a change of status report including a market power analysis as soon as practicable. PSE will conform its analysis, to the extent possible, on the guidance provided in the PacifiCorp EIM Order, the NV Energy EIM Order, and the Berkshire MBR Order.

IV. EFFECTIVE DATE AND REQUEST FOR WAIVERS

PSE requests effective dates for its proposed OATT revisions as set forth in Attachment C to this transmittal letter. As indicated therein, PSE requests that revisions to the OATT cover page, table of contents, and Section 1, Definitions, be effective May

[162] *See id*. at P 206, n.332.

[163] NV Energy EIM Order at P 201.

[164] *Nev. Power Co.*, 153 FERC ¶ 61,206 at P 51 (2015) ("Berkshire MBR Order").

[165] *See* Puget Sound Energy, Inc. Motion to Intervene-Out-of-Time, Request for Clarification , and Request for Rehearing, Docket No. ER15-2281 et al. (filed Dec. 21, 2015).

1, 2016. PSE further requests that Tariff Sections 12.4A, 15.7, 16.1g, and 28.5;[166] Attachment O Sections 4.1.5, 4.1.6, 8, and 10; and Schedules 1A, 4, 4R, 9, 10, 12, and 12A take effect no earlier than October 1, 2016, or the implementation date of PSE's participation in the EIM, whichever is later. These are the provisions related to financial settlement of charges associated with the EIM and additional aspects related to implementation of the EIM, and should not take effect prior to the start of financially binding EIM operations.[167] For all other proposed tariff changes, PSE requests an effective date that is no earlier than July 25, 2016 or seven days prior to the start of parallel operations. This intermediate effective date reflects the need to have information supporting EIM operation in place several business days prior to the initiation of non-financially binding, parallel operations which is currently scheduled for August 1, 2016. The staggered effective dates proposed herein appropriately balance the need for customers and PSE to have certainty regarding EIM design as they prepare for the startup of PSE's EIM participation, while reserving a later effective date for provisions that are not needed prior to the start of parallel or financially binding operations, and may be inconsistent with current non-EIM operations.

Because the requested effective date of certain provisions will be more than 120 days after the date this OATT amendment is filed with the Commission, PSE seeks waiver of Section 35.3(a)(1) of the Commission's regulations, 18 C.F.R. § 35.3(a)(1). Good cause exists for granting this waiver as it will permit PSE's Tariff amendments to be in place in a timeframe necessary to support final design, testing, and startup, thereby providing all parties with necessary regulatory and operational certainty.[168]

In addition, consistent with 18 C.F.R. § 35.3(a)(1), PSE respectfully requests that the Commission issue an order no later than May 1, 2016. As described above, a timely order is necessary to facilitate PSE's and the CAISO's market testing scheduled to begin in July 2016, and PSE's customers' implementation of system changes necessary to accommodate the EIM.

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[166] PSE is revising three different subsections of Section 28 of the OATT. PSE is requesting an effective date of July 25, or seven days prior to the start of parallel operations for its proposed revisions to subsections 28.1 and 28.7, and an effective date of October 1, 2016, or the implementation date of PSE's participation in the EIM for its proposed revisions to sub-ection 28.5. In order to implement multiple effective dates for tariff sections within a single tariff section in the Commission's E-Tariff system, PSE has divided Section 28 of its OATT into seven subsections, 28.1-28.7, within its E-Tariff database. Other than this nonsubstantive reorganization of PSE's E-Tariff database, PSE is not proposing any revisions to subsections 28.2-28.4 or 28.6.

[167] Because new Attachment O of PSE's OATT will include three different proposed effective dates, PSE has requested an effective date for Attachment O of May 1, 2016 in its eTariff software and included language in Section 1 of Attachment O to set forth the subsequent effective dates and applicable sections. This is similar to the approach taken by NV Energy.

[168] *See, e.g.,* PacifiCorp EIM Order at P 82; *Midcontinent Indep. Sys. Operator, Inc*., 145 FERC ¶ 61,208 at P 13 (2013).

To the extent that any filing requirement in Part 35 of the Commission's regulations is not satisfied by this filing and the materials enclosed herewith, PSE respectfully requests waiver of such requirements.

V. COMMUNICATIONS

All communications, correspondence, and documents related to this proceeding should be directed to the following persons:

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VI. SERVICE

Pursuant to Rule 2010 of the Commission's Rules of Practice and Procedure, PSE is providing an electronic copy of this filing to all transmission and interconnection customers. In addition, PSE has served this filing on the CAISO and the Washington Utilities and Transportation Commission.

VII. CONTENTS OF FILING

This filing includes the following Attachments in addition to this transmittal:

Attachment A -	Clean Tariff Sheets of Amended OATT Sections
Attachment B -	Redlined Tariff Sheets of Amended OATT Sections
Attachment C -	Summary of Proposed OATT Changes and Identification of Proposed Effective Dates
Attachment D -	PSE – ISO Energy Imbalance Market Economic Assessment (Benefits Analysis)

VIII. CONCLUSION

For the reasons stated above, PSE asks the Commission to issue an order, no later than May 1, 2016, which accepts for filing the proposed OATT revisions included herewith with an effective date as discussed in Section IV above and as summarized in Attachment C to this filing.

Respectfully submitted,

/s/ Gary D. Bachman

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Attachments

Attachment A

Clean Tariff Sheets of Amended OATT Sections

FERC ELECTRIC TARIFF
OF
PUGET SOUND ENERGY, INC.

filed with the

FEDERAL ENERGY REGULATORY COMMISSION

OPEN ACCESS TRANSMISSION TARIFF

Communication concerning this Tariff should be addressed to:

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Manager, Transmission Policy and Contracts
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TABLE OF CONTENTS

I. COMMON SERVICE PROVISIONS

SCHEDULE 13	Regulation and Frequency Response Service for Generators Selling Outside of Control Area
ATTACHMENT A	Form Of Service Agreement For Firm Point-To-Point Transmission Service
ATTACHMENT A-1	Form Of Service Agreement For The Resale, Reassignment Or Transfer Of Point-To-Point Transmission Service
ATTACHMENT B	Form Of Service Agreement For Non-Firm Point-To-Point Transmission Service
ATTACHMENT C	Methodology To Assess Available Transmission Capability
ATTACHMENT D	Methodology for Completing a System Impact Study
ATTACHMENT E	Index Of Point-To-Point Transmission Service Customers
ATTACHMENT F	Service Agreement For Network Integration Transmission Service
ATTACHMENT G	Network Operating Agreement
ATTACHMENT H	Annual Transmission Revenue Requirement For Network Integration Transmission Service
ATTACHMENT H-1	PSE’s Formula Rate
ATTACHMENT H-2	Formula Rate Implementation Protocols
ATTACHMENT I	Index Of Network Integration Transmission Service Customers
ATTACHMENT J	Procedures for Addressing Parallel Flows
ATTACHMENT J-1	Form of Service Agreement For Retail Network Integration Transmission Service
ATTACHMENT K	Transmission Planning Process
ATTACHMENT L	Creditworthiness Procedures
ATTACHMENT M	Form of Retail Network Operating Agreement
ATTACHMENT N	Point-to-Point Transmission Service Products Offered by PSE
ATTACHMENT O	Energy Imbalance Market

ANNEX A Standard Large Generator Interconnection Procedures

ANNEX B Standard Small Generator Interconnection Procedures

1 Definitions

1.1 Affiliate

With respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

1.2 Ancillary Services

Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

1.3 Annual Transmission Costs

The total annual cost of the Transmission System for purposes of Network Integration Transmission Service shall be the amount specified in Attachment H until amended by the Transmission Provider or modified by the Commission.

1.3A Annual Transmission Revenue Requirement (ATRR)

The transmission revenue requirement calculated annually using the formula rate set forth in Attachment H-1.

1.4 Application

A request by an Eligible Customer for transmission service pursuant to the provisions of the Tariff.

1.4A Balancing Authority (BA)

The responsible entity that integrates resource plans ahead of time, maintains load-Interchange-generation balance within a BAA, and supports interconnection frequency in real time.

1.4B Balancing Authority Area (BAA)

The collection of generation, transmission, and loads within the metered boundaries of the BA. The BA maintains load-resource balance within this area. For purposes of this Tariff, "BAA" shall have the same meaning as "Control Area."

1.4C Balancing Authority Area Resource

A resource owned by PSE, or voluntarily contracted for by PSE to provide EIM Available Balancing Capacity, that can provide regulation and load following services to enable the PSE EIM Entity to meet reliability criteria. No resource unaffiliated with the

PSE EIM Entity shall be a Balancing Authority Area Resource solely on the basis of one or more of the following reasons: (1) the resource is a Designated Network Resource; (2) the resource flows on a Point-to-Point Transmission Service reservation; and/or (3) the resource is an Interconnection Customer under the Tariff.

1.4D Bid Cost Recovery (BCR)

The MO EIM settlements process through which PSE EIM Participating Resources recover their bid costs.

1.4E California Independent System Operator Corporation (CAISO)

A state-chartered, California non-profit public benefit corporation that operates the transmission facilities of all CAISO participating transmission owners and dispatches certain generating units and loads. The CAISO is the MO for the EIM.

1.4F CAISO BAA or CAISO Controlled Grid

The system of transmission lines and associated facilities of the CAISO participating transmission owners that have been placed under the CAISO's operational control.

1.5 Commission

The Federal Energy Regulatory Commission.

1.6 Completed Application

An Application that satisfies all of the information and other requirements of the Tariff, including any required deposit.

1.7 Control Area

An electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

1. match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

2. maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

3. maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and

4. provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

1.8 Curtailment

A reduction in firm or non-firm transmission service in response to a transfer capability shortage as a result of system reliability conditions.

1.9 Delivering Party

The entity supplying capacity and energy to be transmitted at Point(s) of Receipt.

1.10 Designated Agent

Any entity that performs actions or functions on behalf of the Transmission Provider, an Interconnection Customer, an Eligible Customer, or the Transmission Customer required under the Tariff.

1.11 Direct Assignment Facilities

Facilities or portions of facilities that are constructed by the Transmission Provider for the sole use/benefit of a particular Transmission Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer and shall be subject to Commission approval.

1.11A Dispatch Instruction

An instruction by the MO for an action with respect to a specific PSE EIM Participating Resource or Balancing Authority Area Resource for increasing or decreasing its energy supply or demand.

1.11B Dispatch Operating Point

The expected operating point, in MW, of a PSE EIM Participating Resource that has received a Dispatch Instruction from the Market Operator or a Balancing Authority Area Resource to which the PSE EIM Entity has relayed a Dispatch Instruction received from the Market Operator. For purposes of Attachment O of this Tariff, the Dispatch Operating Point means the change, in MW output, of (i) a PSE EIM Participating Resource due to an EIM bid being accepted and the PSE EIM Participating Resource receiving a Dispatch Instruction; or (ii) a Balancing Authority Area Resource for which a Dispatch Instruction has been issued by the CAISO with respect to EIM Available Balancing Capacity. The Dispatch Operating Point is expressed either as a negative MW quantity for the downward movement of generation, or a positive MW quantity for the upward movement of generation.

1.11C Dynamic Transfer

The provision of the real-time monitoring, telemetering, computer software, hardware, communications, engineering, energy accounting (including inadvertent Interchange), and administration required to electronically move all or a portion of the real energy services associated with a generator or load out of one BAA into another. A Dynamic Transfer can be either:

(1) a Dynamic Schedule: a telemetered reading or value that is updated in real time and used as a schedule in the AGC/ACE equation and the integrated value of which is treated as an after-the-fact schedule for Interchange accounting purposes; or

(2) a Pseudo-Tie: a functionality by which the output of a generating unit physically interconnected to the electric grid in a native BAA is telemetered to and deemed to be produced in an attaining BAA that provides BA services for and exercises BA jurisdiction over the generating unit.

1.11D Energy Imbalance Market (EIM)

The real-time market to manage transmission congestion and optimize procurement of imbalance energy (positive or negative) to balance supply and demand deviations for the EIM Area through economic bids submitted by EIM Participating Resource Scheduling Coordinators in the fifteen-minute and five-minute markets.

1.11E EIM Area

The combination of PSE's BAA, the CAISO BAA, and the BAAs of any other EIM Entities.

1.11F EIM Available Balancing Capacity

Any upward or downward capacity from a Balancing Authority Area Resource that has not been bid into the EIM and is included in the PSE EIM Entity's Resource Plan.

1.11G EIM Entity

A BA, other than the PSE EIM Entity, that enters into the MO's pro forma EIM Entity Agreement to enable the EIM to occur in its BAA.

1.11H EIM Transfer

The transfer of real-time energy resulting from an EIM Dispatch Instruction: (1) between a PSE BAA and the CAISO BAA; (2) between the PSE BAA and an EIM Entity BAA; or (3) between the CAISO BAA and an EIM Entity BAA using transmission capacity available in the EIM.

1.12 Eligible Customer

i. Any electric utility (including the Transmission Provider and any power marketer), Federal power marketing agency, or any person generating electric energy for sale for resale is an Eligible Customer under the Tariff. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico.

However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Provider offer the unbundled transmission service, or pursuant to a voluntary offer of such service by the Transmission Provider.

ii. Any retail customer taking unbundled transmission service pursuant to a state requirement that the Transmission Provider offer the transmission service, or pursuant to a voluntary offer of such service by the Transmission Provider, is an Eligible Customer under the Tariff.

1.12A e-Tag

An electronic tag associated with a schedule in accordance with the requirements of the North American Electric Reliability Corporation (NERC), the Western Electricity Coordinating Council (WECC), or the North American Energy Standards Board (NAESB).

1.13 Facilities Study

An engineering study conducted by the Transmission Provider to determine the required modifications to the Transmission Provider's Transmission System, including the cost and scheduled completion date for such modifications, that will be required to provide the requested transmission service.

1.14 Firm Point-To-Point Transmission Service

Transmission Service under this Tariff that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to Part II of this Tariff.

1.14A Flexible Ramping Constraint

A requirement, established by the MO, that may be enforced in the MO's EIM optimization to ensure that the unit commitment or dispatch of resources for intervals beyond the applicable commitment or dispatch period provide for the availability of required capacity for dispatch in subsequent real-time dispatch intervals.

1.14B Forecast Data

Information provided by Transmission Customers regarding expected load (as determined pursuant to Section 4.2.4.3 of Attachment O of this Tariff), generation, Intrachange, and Interchange, as specified in Section 4.2.4 of Attachment O and the PSE EIM BP. The Transmission Customer Base Schedule includes Forecast Data that is used by the PSE EIM Entity as the baseline by which to measure Imbalance Energy for purposes of EIM settlement.

1.15 Good Utility Practice

Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act section 215(a)(4).

1.15A Hourly Pricing Proxy

The on-peak or off-peak price reported for the IntercontinentalExchange (ICE) Mid-Columbia Firm Power Index for the hour in which Transmission Service is provided. In the event that Transmission Service is provided during a time where no volumes are reported at the Mid-Columbia hub, the most recent firm on-peak and off-peak prices will be carried forward. If ICE permanently ceases to report day ahead pricing at the Mid-Columbia hub, or if the methodology used to determine the index at the Mid-Columbia hub is materially modified, Transmission Provider shall select a permanent replacement index, reported by a reputable third party, that reflects the actual same-day firm transactions at the Mid-Columbia hub.

1.15B Interconnection Customer

Any Eligible Customer (or its Designated Agent) that executes an agreement to receive generation interconnection service pursuant to Annexes A or B of this Tariff.

1.15C Imbalance Energy

The deviation of supply or demand from the Transmission Customer Base Schedule, positive or negative, as measured by metered generation, metered load, or real-time Interchange or Intrachange schedules.

1.15D Instructed Imbalance Energy (IIE)

There are three scenarios that can lead to settlement of imbalance as IIE: (1) operational adjustments of the Transmission Customer's affected Interchange or Intrachange, which includes changes by the Transmission Customer after T-57, (2) resource imbalances created by Manual Dispatch or an EIM Available Balancing Capacity dispatch, or (3) an adjustment to resource imbalances created by adjustments to resource forecasts pursuant to Section 11.5 of the MO Tariff. IIE will be settled at either the RTD or FMM price at the applicable PNode depending on the nature and timing of the imbalance.

1.15E Interchange

E-Tagged energy transfers from, to or through the PSE BAA or other BAAs, not including EIM Transfers.

1.15F Intrachange

E-Tagged energy transfers within the PSE BAA, not including real-time actual energy flows associated with EIM Dispatch Instructions.

1.16 Interruption

A reduction in non-firm transmission service due to economic reasons pursuant to Section 14.7.

1.17 Load Aggregation Point (LAP)

A set of Pricing Nodes that is used for the submission of bids and settlement of demand in the EIM.

1.17A Locational Marginal Price (LMP)

The marginal cost ($/MWh) of serving the next increment of demand at that PNode consistent with existing transmission constraints and the performance characteristics of resources.

1.18 Load Shedding

The systematic reduction of system demand by temporarily decreasing load in response to transmission system or area capacity shortages, system instability, or voltage control considerations under Part III of the Tariff.

1.19 Long-Term Firm Point-To-Point Transmission Service

Firm Point-To-Point Transmission Service under Part II of the Tariff with a term of one year or more.

1.19A Monthly Network Load

The monthly load of an entity receiving service under Part III of the Tariff as measured pursuant to Section 34.2 of the Tariff.

1.19B Manual Dispatch

An operating order issued by the PSE EIM Entity to a Transmission Customer with a PSE EIM Participating Resource or a Non-Participating Resource in PSE's BAA, outside of the EIM optimization, when necessary to address reliability or operational issues in PSE's BAA that the EIM is not able to address through economic dispatch and congestion management.

1.19C Market Operator (MO)

The entity responsible for operation, administration, settlement, and oversight of the EIM.

1.19D Measured Demand

Includes (1) Metered Demand, plus (2) e-Tagged export volumes from the PSE BAA (excluding EIM Transfers).

1.19E Metered Demand

Metered load volumes in PSE's BAA.

1.19F MO Tariff

Those portions of the MO's approved tariff, as such tariff may be modified from time to time, that specifically apply to the operation, administration, settlement, and oversight of the EIM.

1.20 Native Load Customers

The wholesale and retail power customers of the Transmission Provider on whose behalf the Transmission Provider, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Transmission Provider's system to meet the reliable electric needs of such customers.

1.21 Network Customer

An entity receiving transmission service pursuant to the terms of the Transmission Provider's Network Integration Transmission Service under Part III of the Tariff.

1.22 Network Integration Transmission Service

The transmission service provided under Part III of the Tariff.

1.23 Network Load

The load that a Network Customer designates for Network Integration Transmission Service under Part III of the Tariff. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Part II of the Tariff for any Point-To-Point Transmission Service that may be necessary for such non-designated load.

1.24 Network Operating Agreement

An executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service under Part III of the Tariff.

1.25 Network Operating Committee

A group made up of representatives from the Network Customer(s) and the Transmission Provider established to coordinate operating criteria and other technical considerations required for implementation of Network Integration Transmission Service under Part III of this Tariff.

1.26 Network Resource

Any designated generating resource owned, purchased or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program or output associated with an EIM Dispatch Instruction.

1.27 Network Upgrades

Modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all users of such Transmission System.

1.28 Non-Firm Point-To-Point Transmission Service

Point-To-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Section 14.7 under Part II of this Tariff. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

1.29 Non-Firm Sale

An energy sale for which receipt or delivery may be interrupted for any reason or no reason, without liability on the part of either the buyer or seller.

1.29A Non-Participating Resource

A resource in PSE's BAA that is not a PSE EIM Participating Resource.

1.30 Open Access Same-Time Information System (OASIS)

The information system and standards of conduct contained in Part 37 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

1.30A Operating Hour

The hour during the day when the EIM runs and energy is supplied to load.

1.30B PSE

Refers to Puget Sound Energy, Inc.

1.30C PSE's BAA

Refers to the BAA operated by PSE.

1.30D PSE BAA Transmission Owner

A transmission owner, other than the PSE EIM Entity, who owns transmission facilities in PSE's BAAs**.**

1.30E PSE EIM Business Practice (PSE EIM BP)

The business practice posted on PSE's OASIS that contains procedures related to PSE's implementation of EIM and the rights and obligations of Transmission Customers and Interconnection Customers related to EIM.

1.30F PSE EIM Entity

The Transmission Provider in performance of its role as an EIM Entity under the MO Tariff and this Tariff, including, but not limited to, Attachment O.

1.30G PSE EIM Entity Scheduling Coordinator

The Transmission Provider or the entity selected by the Transmission Provider who is certified by the MO and who enters into the MO's *pro forma* EIM Entity Scheduling Coordinator Agreement.

1.30H PSE EIM Participating Resource

A resource or a portion of a resource: (1) that has been certified in accordance with Attachment O by the PSE EIM Entity as eligible to participate in the EIM; and (2) for which the generation owner and/or operator enters into the MO's *pro forma* EIM Participating Resource Agreement.

1.30I PSE EIM Participating Resource Scheduling Coordinator

A Transmission Customer with one or more PSE EIM Participating Resource(s) or a third-party designated by the Transmission Customer with one or more PSE EIM Participating Resource(s), that is certified by the MO and enters into the MO's *pro forma* EIM Participating Resource Scheduling Coordinator Agreement.

1.30J PSE Interchange Rights Holder

A Transmission Customer who has informed the PSE EIM Entity that it is electing to make reserved firm transmission capacity available for EIM Transfers without compensation.

1.31 Part I

Tariff Definitions and Common Service Provisions contained in Sections 2 through 12.

1.32 Part II

Tariff Sections 13 through 27 pertaining to Point-To-Point Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.33 Part III

Tariff Sections 28 through 35 pertaining to Network Integration Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.34 Parties

The Transmission Provider and the Transmission Customer receiving service under the Tariff.

1.35 Point(s) of Delivery

Point(s) on the Transmission Provider's Transmission System where capacity and energy transmitted by the Transmission Provider will be made available to the Receiving Party under Part II of the Tariff. The Point(s) of Delivery shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

1.36 Point(s) of Receipt

Point(s) of interconnection on the Transmission Provider's Transmission System where capacity and energy will be made available to the Transmission Provider by the Delivering Party under Part II of the Tariff. The Point(s) of Receipt shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

1.37 Point-To-Point Transmission Service

The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Part II of the Tariff.

1.38 Power Purchaser

The entity that is purchasing the capacity and energy to be transmitted under the Tariff.

1.39 Pre-Confirmed Application

An Application that commits the Eligible Customer to execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service.

1.39A Pricing Node (PNode)

A single network node or subset of network nodes where a physical injection or withdrawal is modeled by the MO and for which the MO calculates an LMP that is used for financial settlements by the MO and the PSE EIM Entity.

1.39B Real Power Losses

Electrical losses associated with the use of the Transmission Provider's Transmission System and, where applicable, the use of the Transmission Provider's distribution system. Such losses are provided for in Sections 15.7 and 28.5 of the Tariff and settled financially under Schedule 12 and Schedule 12A.

1.40 Receiving Party

The entity receiving the capacity and energy transmitted by the Transmission Provider to Point(s) of Delivery.

1.41 Regional Transmission Group (RTG)

A voluntary organization of transmission owners, transmission users and other entities approved by the Commission to efficiently coordinate transmission planning (and expansion), operation and use on a regional (and interregional) basis.

1.42 Reserved Capacity

The maximum amount of capacity and energy that the Transmission Provider agrees to transmit for the Transmission Customer over the Transmission Provider’s Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II of the Tariff. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

1.42A Resource Plan

The combination of load, resource and Interchange components of the Transmission Customer Base Schedule, ancillary services plans of the PSE EIM Entity, bid ranges submitted by PSE EIM Participating Resources, and the EIM Available Balancing Capacity of Balancing Authority Area Resources.

1.43 Service Agreement

The initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the Transmission Provider for service under the Tariff.

1.44 Service Commencement Date

The date the Transmission Provider begins to provide service pursuant to the terms of an executed Service Agreement, or the date the Transmission Provider begins to provide service in accordance with Section 15.3 or Section 29.1 under the Tariff.

1.45 Short-Term Firm Point-To-Point Transmission Service

Firm Point-To-Point Transmission Service under Part II of the Tariff with a term of less than one year.

1.46 System Condition

A specified condition on the Transmission Provider's system or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm Point-to-Point Transmission Service using the curtailment priority pursuant to Section 13.6. Such conditions must be identified in the Transmission Customer's Service Agreement.

1.47 System Impact Study

An assessment by the Transmission Provider of (i) the adequacy of the Transmission System to accommodate a request for either Firm Point-To-Point Transmission Service or Network Integration Transmission Service and (ii) whether any additional costs may be incurred in order to provide transmission service.

1.48 Third-Party Sale

Any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Network Load under the Network Integration Transmission Service.

1.49 Transmission Customer

Any Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) requests in writing that the Transmission Provider file with the Commission, a proposed unexecuted Service Agreement to receive transmission service under Part II of the Tariff. This term is used in the Part I Common Service Provisions to include customers receiving transmission service under Part II and Part III of this Tariff.

1.49A Transmission Customer Base Schedule

An energy schedule that provides Transmission Customer hourly-level Forecast Data and other information that is used by the PSE EIM Entity as the baseline by which to measure Imbalance Energy for purposes of EIM settlement. The term "Transmission Customer Base Schedule" as used in this Tariff may refer collectively to the components of such schedule (resource, Interchange, Intrachange, and load determined pursuant to Section 4.2.4.3 of Attachment O) or any individual components of such schedule.

1.50 Transmission Provider

The public utility (or its Designated Agent) that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce and provides transmission service under the Tariff.

1.51 Transmission Provider's Monthly Transmission System Peak

The maximum firm usage of the Transmission Provider's Transmission System in a calendar month.

1.52 Transmission Service

Point-To-Point Transmission Service provided under Part II of the Tariff on a firm and non-firm basis.

1.53 Transmission System

The facilities owned, controlled or operated by the Transmission Provider that are used to provide transmission service under Part II and Part III of the Tariff.

1.54 Unreserved Use Penalty

Any penalty rate charged for unreserved use of Point-to-Point Transmission Service. Any Unreserved Use Penalty shall be as stated in Section 13.7(d) or Section 14.5 of this Tariff. Any Overrun System Use Charge specified in any Service Agreement shall not be assessed.

1.55 Uninstructed Imbalance Energy (UIE)

For Non-Participating Resources in an EIM Entity BAA, the MO shall calculate UIE as either (1) the algebraic difference between the resource's 5-minute meter data and the resource component of the Transmission Customer Base Schedule, or, if applicable, (2) the 5-minute meter data and any Manual Dispatch or EIM Available Balancing Capacity dispatch. For Transmission Customers with load in the PSE EIM Entity's BAA, the PSE EIM Entity shall calculate UIE as the algebraic difference between the

Transmission Customer's actual hourly load and the Transmission Customer Base Schedule.

1.56 Variable Energy Resource

A device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator.

1.57 Working Day

The days Monday through Friday, excluding any prescheduling holiday observed by the Western Electricity Coordinating Council.

10 Force Majeure and Indemnification

10.1 Force Majeure

An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event with respect to a Party does not include an act of negligence or intentional wrongdoing by such Party. Neither the Transmission Provider nor the Transmission Customer will be considered in default as to any obligation under this Tariff if prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Tariff is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Tariff.

10.2 Indemnification

The Transmission Customer shall, to the maximum extent permitted by applicable law, at all times indemnify, defend, and save the Transmission Provider harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the Transmission Provider's performance of its obligations under this Tariff on behalf of the Transmission Customer, except to the extent of negligence or intentional wrongdoing by the Transmission Provider. Provided, however, that the standard of liability for the actions of the PSE EIM Entity performed consistent with Attachment O of this Tariff shall be gross negligence or intentional wrongdoing.

12 Dispute Resolution Procedures

12.1 Internal Dispute Resolution Procedures

Any dispute between a Transmission Customer and the Transmission Provider involving transmission service under the Tariff (excluding applications for rate changes or other changes to the Tariff, or to any Service Agreement entered into under the Tariff, which shall be presented directly to the Commission for resolution) shall be referred to a designated senior representative of the Transmission Provider and a senior representative of the Transmission Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days [or such other period as the Parties may agree upon] by mutual agreement, such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below.

12.2 External Arbitration Procedures

Any arbitration initiated under the Tariff shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) days of the referral of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association and any applicable Commission regulations or any applicable provisions of the Governing Agreement of the Northwest Regional Transmission Association.

12.3 Arbitration Decisions

Unless otherwise agreed, the arbitrator(s) shall render a decision within ninety (90) days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of the Tariff and any Service Agreement entered into under the Tariff and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act and/or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with the Commission if it affects jurisdictional rates, terms and conditions of service or facilities.

12.4 Costs

Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable:

1. the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or

2. one half the cost of the single arbitrator jointly chosen by the Parties.

12.4A EIM Disputes

12.4A.1 Disputes between the PSE EIM Entity and a Transmission Customer or Interconnection Customer Related to Allocation of Charges or Payments from the MO

To the extent a dispute arises between the PSE EIM Entity and a Transmission Customer or Interconnection Customer regarding the PSE EIM Entity's implementation of this Tariff's provisions regarding the manner in which the PSE EIM Entity allocates charges or payments from the MO, the parties shall follow the dispute resolution procedures in Sections 12.1 to 12.4 of this Tariff.

12.4A.2 Disputes between the MO and PSE EIM Participating Resource Scheduling Coordinators Related to EIM Charges and Payments Directly From the MO

Disputes involving settlement statements between the MO and PSE EIM Participating Resource Scheduling Coordinators shall be resolved in accordance with the dispute resolution process of the MO Tariff. A Transmission Customer with a PSE EIM Participating Resource shall provide notice to the PSE EIM Entity if it raises a dispute with the MO, and such notice shall be provided in accordance with the process set forth in the PSE EIM BP.

12.4A.3 Disputes between the MO and the PSE EIM Entity

The PSE EIM Entity may raise disputes with the MO regarding the settlement statements it receives from the MO in accordance with the process specified in the MO Tariff. If the PSE EIM Entity submits a dispute it shall provide notice to Transmission Customers in accordance with the PSE EIM BP.

12.4A.4 Disputes Regarding MO Charges or Payments to the PSE EIM Entity Raised by Transmission Customers or Interconnection Customers

To the extent a dispute arises regarding a MO charge or a MO payment to the PSE EIM Entity that is subsequently charged or paid by the PSE EIM Entity to a Transmission Customer or an Interconnection Customer, and such Transmission Customer or Interconnection Customer wishes to raise a dispute with the MO, the PSE EIM Entity shall file a dispute on behalf of such Transmission Customer or Interconnection Customer in accordance with the MO Tariff and work with the Transmission Customer or the Interconnection Customer to resolve the dispute pursuant to the process specified in the MO Tariff.

12.5 Rights Under The Federal Power Act

Nothing in this section shall restrict the rights of any party to file a Complaint with the Commission under relevant provisions of the Federal Power Act.

13 Nature of Firm Point-To-Point Transmission Service

13.1 Term

The minimum term of Firm Point-To-Point Transmission Service shall be one day and the maximum term shall be specified in the Service Agreement.

13.2 Reservation Priority

(i) Long-Term Firm Point-To-Point Transmission Service shall be available on a first-come, first-served basis, i.e., in the chronological sequence in which each Transmission Customer has requested service.

(ii) Reservations for Short-Term Firm Point-To-Point Transmission Service will be conditional based upon the length of the requested transaction or reservation. However, Pre-Confirmed Applications for Short-Term Point-to-Point Transmission Service will receive priority over earlier-submitted requests that are not Pre-Confirmed and that have equal or shorter duration. Among requests or reservations with the same duration and, as relevant, pre-confirmation status (pre-confirmed, confirmed, or not confirmed), priority will be given to an Eligible Customer's request or reservation that offers the highest price, followed by the date and time of the request or reservation.

(iii) If the Transmission System becomes oversubscribed, requests for service may preempt competing reservations up to the following conditional reservation deadlines: one day before the commencement of daily service, one week before the commencement of weekly service, and one month before the commencement of monthly service. Before the conditional reservation deadline, if available transfer capability is insufficient to satisfy all requests and reservations, an Eligible Customer with a reservation for shorter term service or equal duration service and lower price has the right of first refusal to match any longer term request or equal duration service with a higher price before losing its reservation priority. A longer term competing request for Short-Term Firm Point-To-Point Transmission Service will be granted if the Eligible Customer with the right of first refusal does not agree to match the competing request within 24 hours (or earlier if necessary to comply with the scheduling deadlines provided in section 13.8) from being notified by the Transmission Provider of a longer-term competing request for Short-Term Firm Point-To-Point Transmission Service. When a longer duration request preempts multiple shorter duration reservations, the shorter duration reservations shall have simultaneous opportunities to exercise the right of first refusal. Duration, price and time of response will be used to determine the order by which the multiple shorter duration reservations will be able to exercise the right of first refusal. After the conditional reservation deadline, service will commence pursuant to the terms of Part II of the Tariff.

(iv) Firm Point-To-Point Transmission Service will always have a reservation priority over Non-Firm Point-To-Point Transmission Service under the Tariff. All Long-Term Firm Point-To-Point Transmission Service will have equal reservation priority with Native Load Customers and Network Customers. Reservation priorities for existing firm service customers are provided in Section 2.2.

(v) For any requests for Firm Transmission Service for which the Transmission Provider's business practices establish the earliest time such requests are permitted to be submitted, any requests for such service submitted within the five (5) minute window immediately following such earliest time shall be deemed to have been submitted simultaneously during such window. If sufficient transfer capability is not available to meet all such requests submitted within any such five minute window, the otherwise applicable priorities shall apply to allocation of transfer capability to such requests; provided that, if the otherwise applicable priorities would be to allocate transfer capability to transmission requests on a first-come, first-served basis (i.e., in the chronological sequence in which each Transmission Customer has requested service), transfer capability shall instead be allocated in equal amounts to each Transmission Customer that has submitted one or more of such requests but not in excess of the requested amount for any such request.

13.3 Use of Firm Transmission Service by the Transmission Provider

The Transmission Provider will be subject to the rates, terms and conditions of Part II of the Tariff when making Third-Party Sales under (i) agreements executed on or after May 13, 1997, or (ii) agreements executed prior to the aforementioned date that the Commission requires to be unbundled, by the date specified by the Commission. The Transmission Provider will maintain separate accounting, pursuant to Section 8, for any use of the Point-To-Point Transmission Service to make Third-Party Sales.

13.4 Service Agreements

The Transmission Provider shall offer a standard form Firm Point-To-Point Transmission Service Agreement (Attachment A) to an Eligible Customer when it submits a Completed Application for Long-Term Firm Point-To-Point Transmission Service. The Transmission Provider shall offer a standard form Firm Point-To-Point Transmission Service Agreement (Attachment A) to an Eligible Customer when it first submits a Completed Application for Short-Term Firm Point-To-Point Transmission Service pursuant to the Tariff. Executed Service Agreements that contain the information required under the Tariff shall be filed with the Commission in compliance with applicable Commission regulations. An Eligible Customer that uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved and that has not executed a Service Agreement will be deemed, for purposes of assessing any appropriate charges and penalties, to have executed the appropriate Service Agreement. The Service Agreement shall, when applicable, specify any conditional curtailment options selected by the Transmission Customer. Where the Service Agreement contains conditional curtailment options and is subject to a biennial reassessment as described in Section 15.4, the Transmission Provider shall provide the Transmission Customer notice of any changes to the curtailment conditions no less than 90 days prior to the date for imposition of new curtailment conditions. Concurrent with such notice, the Transmission Provider shall provide the Transmission Customer with the reassessment study and a narrative description of the study, including the reasons for changes to the number of hours per year or System Conditions under which conditional curtailment may occur.

13.5 Transmission Customer Obligations for Facility Additions or Redispatch Costs

In cases where the Transmission Provider determines that the Transmission System is not capable of providing Firm Point-To-Point Transmission Service without (1) degrading or impairing the reliability of service to Native Load Customers, Network Customers and other Transmission Customers taking Firm Point-To-Point Transmission Service, or (2) interfering with the Transmission Provider's ability to meet prior firm contractual commitments to others, the Transmission Provider will be obligated to expand or upgrade its Transmission System pursuant to the terms of Section 15.4. The Transmission Customer must agree to compensate the Transmission Provider for any necessary transmission facility additions pursuant to the terms of Section 27. To the extent the Transmission Provider can relieve any system constraint by redispatching the Transmission Provider's resources, it shall do so, provided that the Eligible Customer agrees to compensate the Transmission Provider pursuant to the terms of Section 27 and agrees to either (i) compensate the Transmission Provider for any necessary transmission facility additions or (ii) accept the service subject to a biennial reassessment by the Transmission Provider of redispatch requirements as described in Section 15.4. Any redispatch, Network Upgrade or Direct Assignment Facilities costs to be charged to the Transmission Customer on an incremental basis under the Tariff will be specified in the Service Agreement prior to initiating service.

13.6 Curtailment of Firm Transmission Service

In the event that a Curtailment on the Transmission Provider's Transmission System, or a portion thereof, is required to maintain reliable operation of such system and the system directly and indirectly interconnected with Transmission Provider's Transmission System, Curtailments will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint. If multiple transactions require Curtailment, to the extent practicable and consistent with Good Utility Practice, the Transmission Provider will curtail service to Network Customers and Transmission Customers taking Firm Point-To-Point Transmission Service on a basis comparable to the curtailment of service to the Transmission Provider's Native Load Customers. All Curtailments will be made on a non-discriminatory basis, however, Non-Firm Point-To-Point Transmission Service shall be subordinate to Firm Transmission Service. Long-Term Firm Point-to-Point Service subject to conditions described in Section 15.4 shall be curtailed with secondary service in cases where the conditions apply, but otherwise will be curtailed on a pro rata basis with other Firm Transmission Service. When the Transmission Provider determines that an electrical emergency exists on its Transmission System and implements emergency procedures to Curtail Firm Transmission Service, the Transmission Customer shall make the required reductions upon request of the Transmission Provider. However, the Transmission Provider reserves the right to Curtail, in whole or in part, any Firm Transmission Service provided under the Tariff when, in the Transmission Provider's sole discretion, an emergency or other unforeseen condition impairs or degrades the reliability of its Transmission System. The Transmission Provider will notify all affected Transmission Customers in a timely manner of any scheduled Curtailments. Transmission Provider shall take necessary measures to ensure reliability in PSE's BAA in accordance with Section 6 of Attachment O.

13.7 Classification of Firm Transmission Service

(a) The Transmission Customer taking Firm Point-To-Point Transmission Service may (1) change its Receipt and Delivery Points to obtain service on a non-firm basis consistent with the terms of Section 22.1 or (2) request a modification of the Points of Receipt or Delivery on a firm basis pursuant to the terms of Section 22.2.

(b) The Transmission Customer may purchase transmission service to make sales of capacity and energy from multiple generating units that are on the Transmission Provider's Transmission System. For such a purchase of transmission service, the resources will be designated as multiple Points of Receipt, unless the multiple generating units are at the same generating plant in which case the units would be treated as a single Point of Receipt.

(c) The Transmission Provider shall provide firm deliveries of capacity and energy from the Point(s) of Receipt to the Point(s) of Delivery. Each Point of Receipt at which firm transfer capability is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement for Long-Term Firm Transmission Service along with a corresponding capacity reservation associated with each Point of Receipt. Points of Receipt and corresponding capacity reservations shall be as mutually agreed upon by the Parties for Short-Term Firm Transmission. Each Point of Delivery at which firm transfer capability is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement for Long-Term Firm Transmission Service along with a corresponding capacity reservation associated with each Point of Delivery. Points of Delivery and corresponding capacity reservations shall be as mutually agreed upon by the Parties for Short-Term Firm Transmission. The greater of either (1) the sum of the capacity reservations at the Point(s) of Receipt, or (2) the sum of the capacity reservations at the Point(s) of Delivery shall be the Transmission Customer's Reserved Capacity. The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedule 7. The Transmission Customer may not exceed its firm capacity reserved at each Point of Receipt and each Point of Delivery except as otherwise specified in Section 22. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third-Party Sales by the Transmission Provider) exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved.

(d) Subject to Attachment O, Section 8.7 of this Tariff, in the event that a Transmission Customer exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved, the Transmission Customer shall pay an Unreserved Use Penalty charge equal to the sum of

(i) a charge for the unreserved service equal to twice the applicable rate(s) for Firm Point-to-Point Transmission Service (exclusive of any Ancillary Services rate(s)) and

(ii) a charge equal to the applicable rate(s) for any Ancillary Services (exclusive of charges pursuant to Schedules 4, 4R and 9) associated with such unreserved service and which is provided by Transmission Provider but for which Transmission Customer does not otherwise pay under the Tariff.

For unreserved use within a single day, the penalty charge shall be based on the daily rate. For unreserved use in two or more days in a calendar week, the penalty charge shall be based on the weekly rate. For multiple instances of unreserved use in more than one calendar week in a calendar month, the penalty charge shall be based on the monthly rate.

13.8 Scheduling of Firm Point-To-Point Transmission Service

Schedules for the Transmission Customer's Firm Point-To-Point Transmission Service must be submitted to the Transmission Provider no later than 10:00 a.m. (Pacific time) [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] of the day prior to commencement of such service. Schedules submitted after 10:00 a.m. will be accommodated, if practicable. Hour-to-hour and intra-hour (four intervals consisting of fifteen minute schedules) schedules of any capacity and energy that is to be delivered must be stated in increments of 1,000 kW per hour [or a reasonable increment that is generally accepted in the region and is consistently adhered to by the Transmission Provider]. Transmission Customers within the Transmission Provider's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 1,000 kW per hour, may consolidate their service requests at a common point of receipt into units of 1,000 kW per hour for scheduling and billing purposes. Scheduling changes will be permitted up to twenty (20) minutes [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] before the start of the next scheduling interval, provided that the Delivering Party and Receiving Party also agree to the schedule modification. The Transmission Provider will furnish to the Delivering Party's system operator, hour-to-hour and intra-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules; provided, however, that Transmission Customer's ability to schedule intra-hour transactions into, out of, or through-and-out of the Transmission Provider's Control Area may be subject to restrictions on intra-hour scheduling imposed by transmission providers in other Control Areas along the scheduled path. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the Transmission Provider, and the Transmission Provider shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

14 Nature of Non-Firm Point-To-Point Transmission Service

14.1 Term

Non-Firm Point-To-Point Transmission Service will be available for periods ranging from one (1) hour to one (1) month. However, a Purchaser of Non-Firm Point-To-Point Transmission Service will be entitled to reserve a sequential term of service (such as a sequential monthly term without having to wait for the initial term to expire before requesting another monthly term) so that the total time period for which the reservation applies is greater than one month, subject to the requirements of Section 18.3.

14.2 Reservation Priority

Non-Firm Point-To-Point Transmission Service shall be available from transfer capability in excess of that needed for reliable service to Native Load Customers, Network Customers and other Transmission Customers taking Long-Term and Short-Term Firm Point-To-Point Transmission Service. A higher priority will be assigned first to requests or reservations with a longer duration of service and second to Pre-Confirmed Applications. In the event the Transmission System is constrained, competing requests of the same Pre-Confirmation status and equal duration will be prioritized based on the highest price offered by the Eligible Customer for the Transmission Service. Eligible Customers that have already reserved shorter term service have the right of first refusal to match any longer term request before being preempted. A longer term competing request for Non-Firm Point-To-Point Transmission Service will be granted if the Eligible Customer with the right of first refusal does not agree to match the competing request: (a) immediately for hourly Non-Firm Point-To-Point Transmission Service after notification by the Transmission Provider; and, (b) within 24 hours (or earlier if necessary to comply with the scheduling deadlines provided in section 14.6) for Non-Firm Point-To-Point Transmission Service other than hourly transactions after notification by the Transmission Provider. Transmission service for Network Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service. Non-Firm Point-To-Point Transmission Service over secondary Point(s) of Receipt and Point(s) of Delivery will have the lowest reservation priority under the Tariff.

For any requests for Non-Firm Transmission Service for which this Tariff establishes the earliest time such requests are permitted to be submitted, any requests for such service submitted within the five (5) minute window immediately following such earliest time shall be deemed to have been submitted simultaneously during such window. If sufficient transfer capability is not available to meet all such requests submitted within any such five minute window, the otherwise applicable priorities shall apply to allocation of transfer capability to such requests; provided that, if the otherwise applicable priorities would be to allocate transfer capability to transmission requests on a first-come, first-served basis (i.e., in the chronological sequence in which each Transmission Customer has requested service), transfer capability shall instead be allocated in equal amounts to each Transmission Customer that has submitted one or more of such requests but not in excess of the requested amount for any such request.

14.3 Use of Non-Firm Point-To-Point Transmission Service by the Transmission Provider

The Transmission Provider will be subject to the rates, terms and conditions of Part II of the Tariff when making Third-Party Sales under (i) agreements executed on or after May 13, 1997, or (ii) agreements executed prior to the aforementioned date that the Commission requires to be unbundled, by the date specified by the Commission. The Transmission Provider will maintain separate accounting, pursuant to Section 8, for any use of Non-Firm Point-To-Point Transmission Service to make Third-Party Sales.

14.4 Service Agreements

The Transmission Provider shall offer a standard form Non-Firm Point-To-Point Transmission Service Agreement (Attachment B) to an Eligible Customer when it first submits a Completed Application for Non-Firm Point-To-Point Transmission Service pursuant to the Tariff. Executed Service Agreements that contain the information required under the Tariff shall be filed with the Commission in compliance with applicable Commission regulations.

14.5 Classification of Non-Firm Point-To-Point Transmission Service

Non-Firm Point-To-Point Transmission Service shall be offered under terms and conditions contained in Part II of the Tariff. The Transmission Provider undertakes no obligation under the Tariff to plan its Transmission System in order to have sufficient capacity for Non-Firm Point-To-Point Transmission Service. Parties requesting Non-Firm Point-To-Point Transmission Service for the transmission of firm power do so with the full realization that such service is subject to availability and to Curtailment or Interruption under the terms of the Tariff. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third-Party Sales by the Transmission Provider) exceeds its non-firm capacity reservation. Non-Firm Point-To-Point Transmission Service shall include transmission of energy on an hourly basis and transmission of scheduled short-term capacity and energy on a daily, weekly or monthly basis, but not to exceed one month’s reservation for any one Application, under Schedule 8.

Subject to Attachment O, Section 8.7 of this Tariff, in the event that a Transmission Customer exceeds its non-firm reserved capacity at any Point of Receipt or Point of Delivery or uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved, the Transmission Customer shall pay an Unreserved Use Penalty charge equal to the sum of

(i) a charge for the unreserved service equal to twice the applicable rate(s) for Firm Point-to-Point Transmission Service (exclusive of any Ancillary Services rate(s)) and

(ii) a charge equal to the applicable rate(s) for any Ancillary Services (exclusive of charges pursuant to Schedules 4, 4R and 9) associated with such unreserved service and which is provided by Transmission Provider but for which Transmission Customer does not otherwise pay under the Tariff.

For unreserved use within a single day, the penalty charge shall be based on the daily rate. For unreserved use in two or more days in a calendar week, the penalty charge shall be based on the weekly rate. For multiple instances of unreserved use in more than one calendar week in a calendar month, the penalty charge shall be based on the monthly rate.

14.6 Scheduling of Non-Firm Point-To-Point Transmission Service

Schedules for Non-Firm Point-To-Point Transmission Service must be submitted to the Transmission Provider no later than 2:00 p.m. (Pacific time) [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] of the day prior to commencement of such service. Schedules submitted after 2:00 p.m. will be accommodated, if practicable. Hour-to-hour and intra-hour (four intervals consisting of fifteen minute schedules) schedules of energy that is to be delivered must be stated in increments of 1,000 kW per hour [or a reasonable increment that is generally accepted in the region and is consistently adhered to by the Transmission Provider]. Transmission Customers within the Transmission Provider's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 1,000 kW per hour, may consolidate their schedules at a common Point of Receipt into units of 1,000 kW per hour. Scheduling changes will be permitted up to twenty (20) minutes [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] before the start of the next scheduling interval, provided that the Delivering Party and Receiving Party also agree to the schedule modification. The Transmission Provider will furnish to the Delivering Party's system operator, hour-to-hour and intra-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules; provided, however, that Transmission Customer's ability to schedule intra-hour transactions into, out of, or through-and-out of the Transmission Provider's Control Area may be subject to restrictions on intra-hour scheduling imposed by transmission providers in other Control Areas along the scheduled path. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the Transmission Provider, and the Transmission Provider shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

14.7 Curtailment or Interruption of Service

The Transmission Provider reserves the right to Curtail, in whole or in part, Non-Firm Point-To-Point Transmission Service provided under the Tariff for reliability reasons when an emergency or other unforeseen condition threatens to impair or degrade the reliability of its Transmission System or the systems directly and indirectly interconnected with Transmission Provider's Transmission System. The Transmission

Provider reserves the right to Interrupt, in whole or in part, Non-Firm Point-To-Point Transmission Service provided under the Tariff for economic reasons in order to accommodate (1) a request for Firm Transmission Service, (2) a request for Non-Firm Point-To-Point Transmission Service of greater duration, (3) a request for Non-Firm Point-To-Point Transmission Service of equal duration with a higher price, (4) transmission service for Network Customers from non-designated resources, or (5) transmission service for Firm Point-to-Point Transmission Service during conditional curtailment periods as described in Section 15.4. The Transmission Provider also will discontinue or reduce service to the Transmission Customer to the extent that deliveries for transmission are discontinued or reduced at the Point(s) of Receipt. Where required, Curtailments or Interruptions will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint, however, Non-Firm Point-To-Point Transmission Service shall be subordinate to Firm Transmission Service. If multiple transactions require Curtailment or Interruption, to the extent practicable and consistent with Good Utility Practice, Curtailments or Interruptions will be made to transactions of the shortest term (e.g., hourly non-firm transactions will be Curtailed or Interrupted before daily non-firm transactions and daily non-firm transactions will be Curtailed or Interrupted before weekly non-firm transactions). Transmission service for Network Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service under the Tariff. Non-Firm Point-To-Point Transmission Service over secondary Point(s) of Receipt and Point(s) of Delivery will have a lower priority than any Non-Firm Point-To-Point Transmission Service under the Tariff. The Transmission Provider will provide advance notice of Curtailment or Interruption where such notice can be provided consistent with Good Utility Practice. Transmission Provider will take necessary measures to ensure reliability in PSE's BAA in accordance with Section 6 of Attachment O.

15 Service Availability

15.1 General Conditions

The Transmission Provider will provide Firm and Non-Firm Point-To-Point Transmission Service over, on or across its Transmission System to any Transmission Customer that has met the requirements of Section 16.

15.2 Determination of Available Transfer Capability

A description of the Transmission Provider's specific methodology for assessing available transfer capability posted on the Transmission Provider's OASIS (Section 4) is contained in Attachment C of the Tariff. In the event sufficient transfer capability may not exist to accommodate a service request, the Transmission Provider will respond by performing a System Impact Study.

15.3 Initiating Service in the Absence of an Executed Service Agreement

If the Transmission Provider and the Transmission Customer requesting Firm or Non-Firm Point-To-Point Transmission Service cannot agree on all the terms and conditions of the Point-To-Point Service Agreement, the Transmission Provider shall file with the Commission, within thirty (30) days after the date the Transmission Customer provides written notification directing the Transmission Provider to file, an unexecuted Point-To-Point Service Agreement containing terms and conditions deemed appropriate by the Transmission Provider for such requested Transmission Service. The Transmission Provider shall commence providing Transmission Service subject to the Transmission Customer agreeing to (i) compensate the Transmission Provider at whatever rate the Commission ultimately determines to be just and reasonable, and (ii) comply with the terms and conditions of the Tariff including posting appropriate security deposits in accordance with the terms of Section 17.3.

15.4 Obligation to Provide Transmission Service that Requires Expansion or Modification of the Transmission System, Redispatch or Conditional Curtailment

(a) If the Transmission Provider determines that it cannot accommodate a Completed Application for Firm Point-To-Point Transmission Service because of insufficient capability on its Transmission System, the Transmission Provider will use due diligence to expand or modify its Transmission System to provide the requested Firm Transmission Service, consistent with its planning obligations in Attachment K, provided the Transmission Customer agrees to compensate the Transmission Provider for such costs pursuant to the terms of Section 27. The Transmission Provider will conform to Good Utility Practice and its planning obligations in Attachment K, in determining the need for new facilities and in the design and construction of such facilities. The obligation applies only to those facilities that the Transmission Provider has the right to expand or modify.

(b) If the Transmission Provider determines that it cannot accommodate a Completed Application for Long-Term Firm Point-To-Point Transmission Service because of insufficient capability on its Transmission System, the Transmission Provider will use due diligence to provide redispatch from its own resources until (i) Network Upgrades are completed for the Transmission Customer, (ii) the Transmission Provider determines through a biennial reassessment that it can no longer reliably provide the redispatch, or (iii) the Transmission Customer terminates the service because of redispatch changes resulting from the reassessment. A Transmission Provider shall not unreasonably deny self-provided redispatch or redispatch arranged by the Transmission Customer from a third party resource.

(c) If the Transmission Provider determines that it cannot accommodate a Completed Application for Firm Point-To-Point Transmission Service because of insufficient capability on its Transmission System, the Transmission Provider will offer the Firm Transmission Service with the condition that the Transmission Provider may curtail the service prior to the curtailment of other Firm Transmission Service for a specified number of hours per year or during System Condition(s). If the Transmission Customer accepts the service, the Transmission Provider will use due diligence to provide the service until (i) Network Upgrades are completed for the Transmission Customer, (ii) the Transmission Provider determines through a biennial reassessment that it can no longer reliably provide such service, or (iii) the Transmission Customer terminates the service because the reassessment increased the number of hours per year of conditional curtailment or changed the System Conditions.

15.5 Deferral of Service

The Transmission Provider may defer providing service until it completes construction of new transmission facilities or upgrades needed to provide Firm Point-To-Point Transmission Service whenever the Transmission Provider determines that providing the requested service would, without such new facilities or upgrades, impair or degrade reliability to any existing firm services.

15.6 Other Transmission Service Schedules

Eligible Customers receiving transmission service under other agreements on file with the Commission may continue to receive transmission service under those agreements until such time as those agreements may be modified by the Commission.

15.7 Real Power Losses

Real Power Losses are associated with all transmission service. The Transmission Provider is not obligated to provide Real Power Losses. The Transmission Customer shall compensate Transmission Provider for losses associated with all transmission service as provided in Schedule 12 and Schedule 12A. The applicable Real Power Loss factors are as follows:

(1) The loss factor for determining the amount of losses associated with any Transmission Service over the Colstrip Transmission Line facilities and

the Southern Intertie transmission facilities shall be two point seven percent (2.7%) of the scheduled capacity and energy for which Transmission Service is provided.

(2) The loss factor for determining the amount of losses associated with any Transmission Service over the Washington Area transmission facilities shall be two point seven percent (2.7%) of the scheduled capacity and energy for which Transmission Service is provided.

15.8 Distribution of Unreserved Use Penalty Amounts

For any month for which Transmission Provider assesses any Unreserved Use Penalty under Section 13.7(c) or Section 14.5 of this Tariff. Transmission Provider shall credit to Qualified Transmission Customers for such month an amount equal to fifty percent (50%) of the amount of such Unreserved Use Penalty (exclusive of any such amount arising from any charge for Ancillary Services). For each such month, the amount of such credit shall be allocated among Qualified Transmission Customers for such month in proportion to their respective Qualified Transmission Loads for such month.

For purposes of this Section 15.8, the following definitions shall apply:

(a) "Qualified Transmission Customer" for any month means each of the following in such month:

(i) Point-to-Point Transmission Service Customer for Transmission Service,

(ii) Network Customer for Transmission Service, or

(iii) Transmission Provider on behalf of its Native Load Customers;

provided, that any Transmission Customer that is assessed any Unreserved Use Penalty for such month shall not be a Qualified Transmission Customer under this Section 15.8 for such month.

(b) "Qualified Transmission Load" for any month means the following with respect to each Qualified Transmission Customer:

(i) for each Point-to-Point Transmission Service Customer, its Reserved Capacity for Transmission Service;

(ii) for each Network Customer, its monthly Network Load in such month computed in accordance with Section 34.2 of the Tariff; or

(iii) for Transmission Provider on behalf of its Native Load Customers, the hourly load in such month of its Native Load Customers coincident with the Transmission System Provider's Monthly

Transmission System Peak for such month (computed consistent with computations pursuant to Section 34 of the Tariff).

16 Transmission Customer Responsibilities

16.1 Conditions Required of Transmission Customers

Point-To-Point Transmission Service shall be provided by the Transmission Provider only if the following conditions are satisfied by the Transmission Customer:

(a) The Transmission Customer has pending a Completed Application for service;

(b) The Transmission Customer meets the creditworthiness criteria set forth in Section 11;

(c) The Transmission Customer will have arrangements in place for any other transmission service necessary to effect the delivery from the generating source to the Transmission Provider prior to the time service under Part II of the Tariff commences;

(d) The Transmission Customer agrees to pay for any facilities constructed and chargeable to such Transmission Customer under Part II of the Tariff, whether or not the Transmission Customer takes service for the full term of its reservation;

(e) The Transmission Customer provides the information required by the Transmission Provider's planning process established in Attachment K; and

(f) The Transmission Customer has executed a Point-To-Point Service Agreement or has agreed to receive service pursuant to Section 15.3.

(g) The Transmission Customer must comply with the requirements of Attachment O regarding the EIM.

16.2 Transmission Customer Responsibility for Third-Party Arrangements

Any scheduling arrangements that may be required by other electric systems shall be the responsibility of the Transmission Customer requesting service. The Transmission Customer shall provide, unless waived by the Transmission Provider, notification to the Transmission Provider identifying such systems and authorizing them to schedule the capacity and energy to be transmitted by the Transmission Provider pursuant to Part II of the Tariff on behalf of the Receiving Party at the Point of Delivery or the Delivering Party at the Point of Receipt. However, the Transmission Provider will undertake reasonable efforts to assist the Transmission Customer in making such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

28 Nature of Network Integration Transmission Service

28.1 Scope of Service

Network Integration Transmission Service is a transmission service that allows Network Customers to efficiently and economically utilize their Network Resources (as well as other non-designated generation resources) to serve their Network Load located in the Transmission Provider's Control Area and any additional load that may be designated pursuant to Section 31.3 of the Tariff. The Network Customer taking Network Integration Transmission Service must obtain or provide Ancillary Services pursuant to Section 3, and must comply with the requirements of Attachment O regarding the EIM.

28.2 Transmission Provider Responsibilities

The Transmission Provider will plan, construct, operate and maintain its Transmission System in accordance with Good Utility Practice and its planning obligations in Attachment K in order to provide the Network Customer with Network Integration Transmission Service over the Transmission Provider's Transmission System. The Transmission Provider, on behalf of its Native Load Customers, shall be required to designate resources and loads in the same manner as any Network Customer under Part III of this Tariff. This information must be consistent with the information used by the Transmission Provider to calculate available transfer capability. The Transmission Provider shall include the Network Customer's Network Load in its Transmission System planning and shall, consistent with Good Utility Practice and Attachment K, endeavor to construct and place into service sufficient transfer capability to deliver the Network Customer's Network Resources to serve its Network Load on a basis comparable to the Transmission Provider's delivery of its own generating and purchased resources to its Native Load Customers.

28.3 Network Integration Transmission Service

The Transmission Provider will provide firm transmission service over its Transmission System to the Network Customer for the delivery of capacity and energy from its designated Network Resources to service its Network Loads on a basis that is comparable to the Transmission Provider's use of the Transmission System to reliably serve its Native Load Customers.

28.4 Secondary Service

The Network Customer may use the Transmission Provider's Transmission System to deliver energy to its Network Loads from resources that have not been designated as Network Resources. Such energy shall be transmitted, on an as-available basis, at no additional charge. Secondary service shall not require the filing of an Application for Network Integration Transmission Service under the Tariff. However, all other requirements of Part III of the Tariff (except for transmission rates) shall apply to secondary service. Deliveries from resources other than Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service under Part II of the Tariff.

28.5 Real Power Losses

Real Power Losses are associated with all transmission service. The Transmission Provider is not obligated to provide Real Power Losses. The Network Customer shall compensate Transmission Provider for losses associated with all transmission service as provided in Schedule 12 and Schedule 12A. The applicable Real Power Loss factors are as follows:

(1) The loss factor for determining the amount of losses associated with any Network Integration Transmission Service over the Colstrip Transmission Line facilities and the Southern Intertie transmission facilities shall be two point seven percent (2.7%) of the scheduled capacity and energy for which Network Integration Transmission Service is provided.

(2) The loss factor for determining the amount of losses associated with any Network Integration Transmission Service over the Washington Area transmission facilities shall be two point seven percent (2.7%) of the scheduled capacity and energy for which Transmission Service is provided.

28.6 Restrictions on Use of Service

The Network Customer shall not use Network Integration Transmission Service for (i) sales of capacity and energy to non-designated loads, or (ii) direct or indirect provision of transmission service by the Network Customer to third parties. All Network Customers taking Network Integration Transmission Service shall use Point-To-Point Transmission Service under Part II of the Tariff for any Third-Party Sale which requires use of the Transmission Provider's Transmission System. The Transmission Provider shall specify any appropriate charges and penalties and all related terms and conditions applicable in the event that a Network Customer uses Network Integration Transmission Service or secondary service pursuant to Section 28.4 to facilitate a wholesale sale that does not serve a Network Load.

28.7 Participation in the EIM

Notwithstanding the limitations in Section 28.6, Network Customers may participate in the EIM utilizing a Network Integration Transmission Service Agreement without a requirement to terminate the designation of any Network Resource that is a PSE EIM Participating Resource consistent with Section 30.3 of this Tariff and without a requirement to reserve additional Point-To-Point Transmission Service for such transactions.

29 Initiating Service

29.1 Condition Precedent for Receiving Service

Subject to the terms and conditions of Part III of the Tariff, the Transmission Provider will provide Network Integration Transmission Service to any Eligible Customer, provided that (i) the Eligible Customer completes an Application for service as provided under Part III of the Tariff, (ii) the Eligible Customer and the Transmission Provider complete the technical arrangements set forth in Sections 29.3 and 29.4, (iii) the Eligible Customer executes a Service Agreement pursuant to Attachment F for service under Part III of the Tariff or requests in writing that the Transmission Provider file a proposed unexecuted Service Agreement with the Commission, and (iv) the Eligible Customer executes a Network Operating Agreement with the Transmission Provider pursuant to Attachment G, or requests in writing that the Transmission Provider file a proposed unexecuted Network Operating Agreement.

29.2 Application Procedures

An Eligible Customer requesting service under Part III of the Tariff must submit an Application, with a deposit approximating the charge for one month of service, to the Transmission Provider as far as possible in advance of the month in which service is to commence. Unless subject to the procedures in Section 2, Completed Applications for Network Integration Transmission Service will be assigned a priority according to the date and time the Application is received, with the earliest Application receiving the highest priority. Applications should be submitted by entering the information listed below on the Transmission Provider's OASIS. Prior to implementation of the Transmission Provider's OASIS, a Completed Application may be submitted by (i) transmitting the required information to the Transmission Provider by telefax, or (ii) providing the information by telephone over the Transmission Provider's time recorded telephone line. Each of these methods will provide a time-stamped record for establishing the service priority of the Application. A Completed Application shall provide all of the information included in 18 CFR § 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the party requesting service;

(ii) A statement that the party requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) A description of the Network Load at each delivery point. This description should separately identify and provide the Eligible Customer's best estimate of the total loads to be served at each transmission voltage level, and the loads to be served from each Transmission Provider substation at the same transmission voltage level. The description should include a ten (10) year forecast of summer and winter load and resource requirements beginning with the first year after the service is scheduled to commence;

(iv) The amount and location of any interruptible loads included in the Network Load. This shall include the summer and winter capacity requirements for each interruptible load (had such load not been interruptible), that portion of the load subject to interruption, the conditions under which an interruption can be implemented and any limitations on the amount and frequency of interruptions. An Eligible Customer should identify the amount of interruptible customer load (if any) included in the 10 year load forecast provided in response to (iii) above;

(v) A description of Network Resources (current and 10-year projection). For each on-system Network Resource, such description shall include:

- Unit size and amount of capacity from that unit to be designated as Network Resource
- VAR capability (both leading and lagging) of all generators
- Operating restrictions
  - Any periods of restricted operations throughout the year
  - Maintenance schedules
  - Minimum loading level of unit
  - Normal operating level of unit
  - Any must-run unit designations required for system reliability or contract reasons
- Approximate variable generating cost ($/MWH) for redispatch computations
- Arrangements governing sale and delivery of power to third parties from generating facilities located in the Transmission Provider Control Area, where only a portion of unit output is designated as a Network Resource;

For each off-system Network Resource, such description shall include:

- Identification of the Network Resource as an off-system resource
- Amount of power to which the customer has rights
- Delivery point(s) to the Transmission Provider's Transmission System
- Transmission arrangements on the external transmission system(s)

- Operating restrictions, if any
  - Any periods of restricted operations throughout the year
  - Maintenance schedules
  - Minimum loading level of unit
  - Normal operating level of unit
  - Any must-run unit designations required for system reliability or contract reasons
- Approximate variable generating cost ($/MWH) for redispatch computations;

(vi) Description of Eligible Customer's transmission system:

- Load flow and stability data, such as real and reactive parts of the load, lines, transformers, reactive devices and load type, including normal and emergency ratings of all transmission equipment in a load flow format compatible with that used by the Transmission Provider
- Operating restrictions needed for reliability
- Operating guides employed by system operators
- Contractual restrictions or committed uses of the Eligible Customer's transmission system, other than the Eligible Customer's Network Loads and Resources
- Location of Network Resources described in subsection (v) above
- 10 year projection of system expansions or upgrades
- Transmission System maps that include any proposed expansions or upgrades
- Thermal ratings of Eligible Customer's Control Area ties with other Control Areas;

(vii) Service Commencement Date and the term of the requested Network Integration Transmission Service. The minimum term for Network Integration Transmission Service is one year;

(viii) A statement signed by an authorized officer from or agent of the Network Customer attesting that all of the network resources listed pursuant to

Section 29.2(v) satisfy the following conditions: (1) the Network Customer owns the resource, has committed to purchase generation pursuant to an executed contract, or has committed to purchase generation where execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff; and (2) the Network Resources do not include any resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program; and

(ix) Any additional information required of the Transmission Customer as specified in (1) the Transmission Provider's planning process established in Attachment K; or (2) Attachment O.

Unless the Parties agree to a different time frame, the Transmission Provider must acknowledge the request within ten (10) days of receipt. The acknowledgement must include a date by which a response, including a Service Agreement, will be sent to the Eligible Customer. If an Application fails to meet the requirements of this section, the Transmission Provider shall notify the Eligible Customer requesting service within fifteen (15) days of receipt and specify the reasons for such failure. Wherever possible, the Transmission Provider will attempt to remedy deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the Transmission Provider shall return the Application without prejudice to the Eligible Customer filing a new or revised Application that fully complies with the requirements of this section. The Eligible Customer will be assigned a new priority consistent with the date of the new or revised Application. The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

29.3 Technical Arrangements to be Completed Prior to Commencement of Service

Network Integration Transmission Service shall not commence until the Transmission Provider and the Network Customer, or a third party, have completed installation of all equipment specified under the Network Operating Agreement consistent with Good Utility Practice and any additional requirements reasonably and consistently imposed to ensure the reliable operation of the Transmission System. The Transmission Provider shall exercise reasonable efforts, in coordination with the Network Customer, to complete such arrangements as soon as practicable taking into consideration the Service Commencement Date.

29.4 Network Customer Facilities

The provision of Network Integration Transmission Service shall be conditioned upon the Network Customer's constructing, maintaining and operating the facilities on its side of each delivery point or interconnection necessary to reliably deliver capacity and energy from the Transmission Provider's Transmission System to the Network Customer. The Network Customer shall be solely responsible for constructing or installing all facilities on the Network Customer's side of each such delivery point or interconnection.

29.5 Filing of Service Agreement

The Transmission Provider will file Service Agreements with the Commission in compliance with applicable Commission regulations.

30 Network Resources

30.1 Designation of Network Resources

Network Resources shall include all generation owned, purchased or leased by the Network Customer designated to serve Network Load under the Tariff. For purposes of temporary termination under Section 30.3, all or part of such generation associated with a NERC-registered Point of Receipt, behind which there are no transmission constraints, may be treated as a single Network Resource. Network Resources may not include resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program or participating in the EIM in accordance with Attachment O. Any owned or purchased resources that were serving the Network Customer's loads under firm agreements entered into on or before the Service Commencement Date shall initially be designated as Network Resources until the Network Customer terminates the designation of such resources.

30.2 Designation of New Network Resources

The Network Customer may designate a new Network Resource by providing the Transmission Provider with as much advance notice as practicable. A designation of a new Network Resource must be made through the Transmission Provider's OASIS by a request for modification of service pursuant to an Application under Section 29. This request must include a statement that the new network resource satisfies the following conditions: (1) the Network Customer owns the resource, has committed to purchase generation pursuant to an executed contract, or has committed to purchase generation where execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff; and (2) The Network Resources do not include any resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program. The Network Customer's request will be deemed deficient if it does not include this statement and the Transmission Provider will follow the procedures for a deficient application as described in Section 29.2 of the Tariff.

30.3 Termination of Network Resources

The Network Customer may terminate the designation of all or part of a generating resource as a Network Resource by providing notification to the Transmission Provider through OASIS as soon as reasonably practicable, but not later than the firm scheduling deadline for the period of termination. Any request for termination of Network Resource status must be submitted on OASIS, and should indicate whether the request is for indefinite or temporary termination. A request for indefinite termination of Network Resource status must indicate the date and time that the termination is to be effective, and the identification and capacity of the resource(s) or portions thereof to be indefinitely terminated. A request for temporary termination of Network Resource status must include the following:

(i) Effective date and time of temporary termination;

(ii) Effective date and time of redesignation, following period of temporary termination;

(iii) Identification and capacity of resource(s) or portions thereof to be temporarily terminated or, where appropriate, identification of the NERC-registered Point of Receipt to which Network Resources are assigned and the capacity to be temporarily terminated;

(iv) Resource description and attestation for redesignating the network resource following the temporary termination, in accordance with Section 30.2; and

(v) Identification of any related transmission service requests to be evaluated concomitantly with the request for temporary termination, such that the requests for undesignation and the request for these related transmission service requests must be approved or denied as a single request. The evaluation of these related transmission service requests must take into account the termination of the network resources identified in (iii) above, as well as all competing transmission service requests of higher priority.

A Network Customer's redesignation of a Network Resource following a temporary termination may incorporate by reference the description of such Network Resource as submitted to Transmission Provider pursuant to Section 29.2 of this Tariff prior to such temporary termination (to the extent such description is not changed by such temporary termination), provided that such Network Customer confirms that such description (to the extent not so changed) is and remains accurate. As part of a temporary termination, a Network Customer may only redesignate the same resource that was originally designated, or a portion thereof. Requests to redesignate a different resource and/or a resource with increased capacity will be deemed deficient and the Transmission Provider will follow the procedures for a deficient application as described in Section 29.2 of the Tariff.

30.4 Operation of Network Resources

The Network Customer shall not operate its designated Network Resources located in the Network Customer's or Transmission Provider's Control Area such that the output of those facilities exceeds its designated Network Load, plus Non-Firm Sales delivered pursuant to Part II of the Tariff, plus losses, plus power sales under a reserve sharing program, plus sales that permit curtailment without penalty to serve its designated Network Load. This limitation shall not apply to PSE EIM Participating Resources responding to Dispatch Instructions or to changes in the operation of a Transmission Customer's Network Resources at the request of the Transmission Provider to respond to an emergency or other unforeseen condition which may impair or degrade the reliability of the Transmission System. For all Network Resources not physically connected with the Transmission Provider's Transmission System, the Network Customer may not schedule delivery of energy in excess of the Network Resource's capacity, as specified in the Network Customer's Application pursuant to Section 29, unless the Network Customer supports such delivery within the Transmission Provider's Transmission System by either obtaining Point-to-Point Transmission Service or utilizing secondary service pursuant to Section 28.4. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that a Network Customer's schedule at the delivery point for a Network Resource not physically interconnected with the Transmission Provider's Transmission System exceeds the Network Resource's designated capacity, excluding energy delivered using secondary service or Point-to-Point Transmission Service.

30.5 Network Customer Redispatch Obligation

As a condition to receiving Network Integration Transmission Service, the Network Customer agrees to redispatch its Network Resources as requested by the Transmission Provider pursuant to Section 33.2. To the extent practical, the redispatch of resources pursuant to this section shall be on a least cost, non-discriminatory basis between all Network Customers, and the Transmission Provider.

30.6 Transmission Arrangements for Network Resources Not Physically Interconnected With The Transmission Provider

The Network Customer shall be responsible for any arrangements necessary to deliver capacity and energy from a Network Resource not physically interconnected with the Transmission Provider's Transmission System. The Transmission Provider will undertake reasonable efforts to assist the Network Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice.

30.7 Limitation on Designation of Network Resources

The Network Customer must demonstrate that it owns or has committed to purchase generation pursuant to an executed contract in order to designate a generating resource as a Network Resource. Alternatively, the Network Customer may establish that execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff.

30.8 Use of Interface Capacity by the Network Customer

There is no limitation upon a Network Customer's use of the Transmission Provider's Transmission System at any particular interface to integrate the Network Customer's Network Resources (or substitute economy purchases) with its Network Loads. However, a Network Customer's use of the Transmission Provider's total interface capacity with other transmission systems may not exceed the Network Customer's Load.

30.9 Network Customer Owned Transmission Facilities

The Network Customer that owns existing transmission facilities that are integrated with the Transmission Provider's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration the Network Customer must demonstrate that its transmission facilities are integrated into the plans or operations of the Transmission Provider, to serve its power and transmission customers. For facilities added by the Network Customer subsequent to the May 14, 2007, the Network Customer shall receive credit for such transmission facilities added if such facilities are integrated into the operations of the Transmission Provider's facilities; provided however, the Network Customer's transmission facilities shall be presumed to be integrated if such transmission facilities, if owned by the Transmission Provider, would be eligible for inclusion in the Transmission Provider's ATRR. Calculation of any credit under this subsection shall be addressed in either the Network Customer's Service Agreement or any other agreement between the Parties.

SCHEDULE 1A
EIM Administrative Service

This service recovers the administrative costs assessed by the CAISO as the MO of the EIM to the PSE EIM Entity in accordance with Sections 4.5.1.1.4, 4.5.1.3, 11.22.8, and 29.11(i) of the MO Tariff (EIM Administrative Costs). All Transmission Customers purchasing Long-Term Firm Point-to-Point Transmission Service, Short-Term Firm Point-to-Point Transmission Service, Non-Firm Point-to-Point Transmission Service, or Network Integration Transmission Service from the Transmission Provider shall be required to acquire EIM Administrative Service from the Transmission Provider.

EIM Administrative Costs assigned to the PSE EIM Entity shall be sub-allocated to Transmission Customers on the basis of Measured Demand for the month in which the EIM Administrative Costs were incurred.

SCHEDULE 4
Energy Imbalance Service

This Schedule 4 shall apply to Transmission Service for Transmission Customers other than Transmission Customers receiving service pursuant to Transmission Provider's Schedules 448 and 449, on file with the Washington Utilities and Transportation Commission. Transmission Customers receiving service pursuant to Transmission Provider's Schedules 448 and 449 shall take Energy Imbalance Service under Schedule 4R.

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a Control Area over a single hour. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements, which may include use of non-generation resources capable of providing this service, to satisfy its Energy Imbalance Service obligation. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

A Transmission Customer shall be charged or paid for Energy Imbalance Service measured as the deviation of the Transmission Customer's metered load compared to the load component of the Transmission Customer Base Schedule (as determined pursuant to Section 4.2.4 of Attachment O of this Tariff) settled as UIE for the period of the deviation at the applicable LAP price where the load is located, as determined by the MO under Section 29.11(b)(3)(C) of the MO Tariff.

SCHEDULE 4R
Energy Imbalance Service for Transmission Customers Taking Service Under Transmission Provider's Schedule 448 and Schedule 449

This Schedule shall apply to Transmission Service for Transmission Customers taking service under Transmission Provider's Schedule 448 and Schedule 449, on file with the Washington Utilities and Transportation Commission. Such service will not be subject to charges under Schedule 4.

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a Control Area over a single hour. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements, which may include use of non-generation resources capable of providing this service, to satisfy its Energy Imbalance Service obligation. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

4R.0 A Transmission Customer shall be charged or paid for Energy Imbalance Service measured as the deviation of the Transmission Customer's metered load compared to the load component of the Transmission Customer Base Schedule corresponding to the Transmission Customer's load (as determined pursuant to Section 4.2.4 of Attachment O of this Tariff) settled as UIE for the period of the deviation at the applicable LAP price where the load is located, as determined by the MO under Section 29.11(b)(3)(C) of the MO Tariff.

4R.1 Transmission Customers shall have the right to aggregate their Loads and Supplied Power for purposes of determining the hourly imbalance energy. Transmission Provider has no obligation to provide excess energy required for Energy Imbalance Service using its own generation resources, but shall make commercially reasonable efforts to obtain in the market such excess energy.

4R.2 Prior to commencing any complaint or court proceeding regarding any dispute between Transmission Provider and Transmission Customer, (i) Transmission Provider and Transmission Customer shall each make good faith efforts to resolve such dispute pursuant to alternative dispute resolution (ADR) procedures consistent with WAC 480-09-465 and (ii) pursuant to the foregoing, the Transmission Provider and Transmission Customer shall make use of ADR procedures to the maximum extent practicable in resolving such dispute.

SCHEDULE 9
Generator Imbalance Service

Generator Imbalance Service is provided when a difference occurs between the output of a generator, that is not a PSE EIM Participating Resource, located in the Transmission Provider's Control Area and the resource component of the Transmission Customer Base Schedule from that generator to (1) another Control Area or (2) a load within the Transmission Provider's Control Area over a single hour. The Transmission Provider must offer this service, to the extent it is physically feasible to do so from its resources or from resources available to it, when Transmission Service is used to deliver energy from a generator located within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements, which may include use of non-generation resources capable of providing this service, to satisfy its Generator Imbalance Service obligation. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area Operator.

The Transmission Provider shall establish charges for Generator Imbalance Service as follows (the following provisions do not apply to Transmission Customers which have received a Manual Dispatch or EIM Available Balancing Capacity dispatch, or which have communicated physical changes in the output of resources to the MO):

(1) A Transmission Customer shall be charged or paid for Generator Imbalance Service measured as the deviation of the Transmission Customer's metered generation compared to the resource component of the Transmission Customer Base Schedule settled as UIE for the period of the deviation at the applicable PNode RTD price where the generator is located, as determined by the MO under Section 29.11(b)(3)(B) of the MO Tariff.

The following provisions shall apply to Transmission Customers which have received a Manual Dispatch or EIM Available Balancing Capacity dispatch, or which have communicated physical changes in the output of resources to the MO:

(1) (a) A Transmission Customer shall be charged or paid for Generator Imbalance Service measured as the deviation of the Transmission Customer's metered generation compared to the Manual Dispatch amount, the EIM Available Balancing Capacity dispatch amount, or physical changes in the output of resources incorporated by the MO in the FMM, settled as UIE for the period of the deviation at the applicable PNode RTD price where the generator is located, as determined by the MO under Section 29.11(b)(3)(B) of the MO Tariff; or

(b) A Transmission Customer shall be charged or paid for Generator Imbalance Service measured as the deviation of the Transmission Customer's metered generation compared to the Manual Dispatch amount, the EIM Available Balancing Capacity dispatch amount, or physical changes in the output of resources incorporated by the MO in RTD, settled as UIE for the period of the deviation at the applicable PNode RTD price where the generator is located, as determined by the MO under Section 29.11(b)(3)(B) of the MO Tariff

(2) (a) A Transmission Customer shall be charged or paid for Generator Imbalance Service measured as the deviation of either the Manual Dispatch amount, the EIM Available Balancing Capacity dispatch amount, or physical changes in the output of resources incorporated by the MO in the FMM, compared to the resource component of the Transmission Customer Base Schedule, settled as IIE for the period of the deviation at the applicable PNode FMM price where the generator is located, as determined by the MO under Section 29.11(b)(1)(A)(ii) of the MO Tariff; or

(b) Generator Imbalance Service measured as the deviation of either the Manual Dispatch amount, the EIM Available Balancing Capacity dispatch amount, or physical changes in the output of resources incorporated by the MO in RTD, compared to the FMM schedule, as IIE for the period of the deviation at the applicable PNode RTD price where the generator is located, as determined by the MO under Section 29.11(b)(2)(A)(ii) of the MO Tariff.

<u>Applicability to Interconnection Customers</u>:

To the extent the Interconnection Customer is a different entity than the Transmission Customer and controls the output of a generator located in the Transmission Provider's Control Area, the Interconnection Customer may be subject to charges for Generator Imbalance Service (rather than the Transmission Customer) in accordance with this Schedule 9.

SCHEDULE 12
Real Power Losses on Washington Area Transmission Facilities

The Transmission Customer taking Network Integration Transmission Service, Firm Point-to-Point, or Non-Firm Point-to-Point Transmission Service, excluding Energy Imbalance Service and Generator Imbalance Service, shall reimburse the Transmission Provider for Real Power Losses as provided in Sections 15.7 and 28.5 of this Tariff. The Transmission Customer must financially settle for Real Power Losses by reimbursement as specified herein.

Settlement of Real Power Losses associated with Energy Imbalance Service provided under Schedule 4 or Schedule 4R shall be pursuant to Schedule 4 or Schedule 4R of this Tariff, and settlement of Real Power Losses associated with Generator Imbalance Service provided under Schedule 9 shall be pursuant to Schedule 9 of this Tariff. The procedures to determine the amount of Real Power Losses associated with a Transmission Customer Base Schedule, as well as the reimbursement for Real Power Losses are set forth below.

The amount of Real Power Losses assessed to a Transmission Customer in a given hour shall be the product of such Transmission Customer Base Schedule during the hour in MWhs and the applicable loss factor provided in Sections 15.7 and 28.5.

The Transmission Customer shall compensate the Transmission Provider at a rate equal to the amount of Real Power Losses assessed to such Transmission Customer in a given hour multiplied by the hourly LAP price for the PSE BAA in that hour as established by the MO under section 29.11 (b)(3)(C) of the MO Tariff.

SCHEDULE 12A
Real Power Losses on Colstrip and Southern Intertie Transmission Lines

The Transmission Customer taking service over the Colstrip and Southern Intertie High Voltage Direct Assignment Facilities pursuant to Schedule 10 shall reimburse Transmission Provider for Real Power Losses as provided in Sections 15.7 and 28.5 of this Tariff. The Transmission Customer must financially settle the losses by reimbursement as specified herein.

The Transmission Customer shall compensate the Transmission Provider for Real Power Losses assessed to such Transmission Customer in a given hour at a rate equal to the hourly LAP price for the PSE BAA as established by the MO under section 29.11 (b)(3)(C) of the MO Tariff based on the product of the actual transmission service provided (scheduled service less any curtailments, corrections or adjustments mutually agreed on by the Transmission Provider and the Transmission Customer) during each hour in MWhs and the applicable loss factor provided in Sections 15.7 and 28.5 of the Tariff.

ATTACHMENT O
Energy Imbalance Market

10.4.3 Temporary Schedule 9 Generator Imbalance Service

10.4.4 Temporary Schedule 12 – Real Power Losses on Washington Area Transmission Facilities

10.4.5 Temporary Schedule 12A – Real Power Losses on Colstrip and Southern Intertie Transmission Lines

ATTACHMENT O
EIM

1. General Provision - Purpose and Effective Date of Attachment O

Attachment O provides for Transmission Provider's participation as the PSE EIM Entity in the EIM administered by the MO. Attachment O shall be in effect upon its acceptance by the Commission, with the exceptions provided below, for as long as Transmission Provider implements the EIM and until all final settlements are finalized resulting from such implementation. Sections 4.1.5, 4.1.6, 8 and 10 of this Attachment O take effect no earlier than October 1, 2016 or the implementation date of Transmission Provider's participation in the EIM, whichever is later. All other sections of this Attachment O take effect no earlier than July 25, 2016 or seven (7) days prior to the start of parallel operations

This Attachment O shall apply to all Transmission Customers and Interconnection Customers, as applicable, with new and existing service agreements under Articles II and III and Annexes A and B of this Tariff, as well as all Transmission Customers with legacy transmission agreements that pre-existed this Tariff and that expressly incorporate by reference the applicability of PSE's Tariff and/or this Attachment O in particular. To the extent an Interconnection Customer controls the output of a generator located in PSE's BAA, the PSE EIM Entity may require the Interconnection Customer to comply with a requirement in this Attachment O that on its face applies to a Transmission Customer to the extent that the PSE EIM Entity makes a determination, in its sole discretion, that the Interconnection Customer is the more appropriate party to satisfy the requirements of Attachment O than any Transmission Customer.

This Attachment O shall work in concert with the provisions of the MO Tariff implementing the EIM to support operation of the EIM. To the extent that this Attachment O is inconsistent with a provision in the remainder of this Tariff with regard to the PSE EIM Entity's administration of the EIM, this Attachment O shall prevail.

This Attachment O governs the relationship between the PSE EIM Entity and all Transmission Customers and Interconnection Customers subject to this Tariff. This Attachment O does not establish privity between Transmission Customers and the MO or make a Transmission Customer subject to the MO Tariff. Any Transmission Customer duties and obligations related to the EIM are those identified in this Tariff, unless the Transmission Customer voluntarily elects to participate directly in the EIM with PSE EIM Participating Resources, in which case the MO Tariff provisions for EIM Participating Resources and EIM Participating Resource Scheduling Coordinators shall also apply.

2. Election of Transmission Customers to become PSE EIM Participating Resources

The decision of a Transmission Customer to participate in the EIM with resources as PSE EIM Participating Resources is voluntary. A Transmission Customer that chooses to have a resource become a PSE EIM Participating Resource must:

(1) Meet the requirements specified in Section 3 of this Attachment O and the PSE EIM BP;

(2) Become or retain a MO-certified EIM Participating Resource Scheduling Coordinator; and

(3) Follow the application and certification process specified in this Attachment O and the PSE EIM BP posted on the Transmission Provider's OASIS.

Transmission Customers which own or control multiple resources may elect to have any or all of their resources be PSE EIM Participating Resources, in which case any resources that are not elected by the Transmission Customer to be PSE EIM Participating Resources shall be treated as Non-Participating Resources for purposes of this Attachment O.

3. Eligibility to be a PSE EIM Participating Resource

3.1 Internal Resources - Transmission Rights

Resources owned or controlled by Transmission Customers and located within the metered boundaries of PSE's BAA are eligible to become PSE EIM Participating Resources. The Transmission Customer that owns or controls the resource must have associated transmission rights based on one of the following:

(1) The resource is a designated Network Resource of a Network Customer and the Network Customer elects to participate in the EIM through its Network Integration Transmission Service Agreement; or

(2) The resource is associated with either (i) a Service Agreement for Firm Point-to-Point Transmission Service or (ii) Service Agreement for Non-Firm Point-to-Point Transmission Service, and such Transmission Customer elects to participate in the EIM.

3.2 Resources External to PSE's BAA

3.2.1 Use of Pseudo-Ties

A resource owned or controlled by a Transmission Customer that is not physically located inside the metered boundaries of PSE's BAA may participate in the EIM as a PSE EIM Participating Resource if the Transmission Customer (1) implements a Pseudo-Tie into PSE's BAA, consistent with PSE's business practice posted on Transmission Provider's OASIS, (2) has arranged firm transmission over any third-party transmission systems to a PSEI BAA intertie boundary equal to the amount of energy that will be Dynamically Transferred through a Pseudo-Tie into PSE's BAA, consistent with PSE's business practice posted on Transmission Provider's OASIS, and (3) has secured transmission service consistent with Section 3.1 of this Attachment O.

3.2.2 Pseudo-Tie Costs

Pseudo-Tie implementation costs shall be allocated in a manner consistent with the treatment of Network Upgrades and Direct Assignment Facilities to facilitate a Pseudo-Tie into PSE's BAA.

3.3 Application and Certification of PSE EIM Participating Resources

3.3.1 Application

To become a PSE EIM Participating Resource, an applicant must submit a completed application, as set forth in the PSE EIM BP, and shall provide a deposit of $1,500 for the PSE EIM Entity to process the application. Upon completion of processing the completed application, the PSE EIM Entity shall charge and the applicant shall pay the actual costs of the application processing. Any difference between the deposit and the actual costs of the application processing shall be paid by or refunded to the PSE EIM Participating Resource applicant, as appropriate.

At the time of application, any PSE EIM Participating Resource applicant must elect to perform the duties of either a CAISO Metered Entity or Scheduling Coordinator Metered Entity, consistent with the MO's requirements and additional technical requirements set forth in the PSE EIM BP, as applicable.

3.3.2 Processing the Application

The PSE EIM Entity shall make a determination as to whether to accept or reject the application within 45 days of receipt of the application. At minimum, the PSE EIM Entity shall validate through the application that the PSE EIM Participating Resource applicant has satisfied Sections 3.1 and 3.2 of this Attachment O, as applicable, and met minimum telemetry and metering requirements, as set forth in the MO's requirements and the PSE EIM BP. Within 45 days of receipt of the application and in accordance with the process outlined in the PSE EIM BP, the PSE EIM Entity may request additional information and will attempt to resolve any minor deficiencies in the application with the Transmission Customer. The PSE EIM Entity may extend the 45-day period to accommodate the resolution of minor deficiencies in the application in order to make a determination on an application.

If the PSE EIM Entity approves the application, it shall send notification of approval to both the PSE EIM Participating Resource applicant and the MO. The process by which the PSE EIM Entity sends notification of approval shall be set forth in the PSE EIM BP.

If the PSE EIM Entity rejects the application, the PSE EIM Entity shall send notification stating the grounds for rejection to the PSE EIM Participating Resource applicant. Upon request, the PSE EIM Entity may provide guidance to the applicant as to how the PSE EIM Participating Resource applicant may cure the grounds for the rejection. In the event that the PSE EIM Entity has granted an extension of the 45-day period but the applicant has neither provided the additional requested information nor otherwise resolved identified deficiencies within six (6) months of the PSE EIM Entity's initial receipt of the application, the application shall be deemed rejected by the PSE EIM Entity.

If an application is rejected, the PSE EIM Participating Resource applicant may resubmit its application at any time (including submission of a new processing fee deposit).

3.3.3 Certification Notice

Upon approval of an application and in accordance with the process specified in the PSE EIM BP, certification by the PSE EIM Entity of the PSE EIM Participating Resource to participate in the EIM shall occur once the Transmission Customer has demonstrated and the MO has confirmed that the Transmission Customer has:

(1) Met the MO's criteria to become an EIM Participating Resource and executed the MO's *pro forma* EIM Participating Resource Agreement;

(2) Qualified to become or retained the services of a MO-certified EIM Participating Resource Scheduling Coordinator;

(3) Met the necessary metering requirements of this Tariff and Section 29.10 of the MO Tariff and the EIM Participating Resource Scheduling Coordinator has executed the MO's *pro forma* Meter Service Agreement for Scheduling Coordinators; and

(4) Met communication and data requirements of this Tariff and Section 29.6 of the MO Tariff; and has the ability to receive and implement Dispatch Instructions every five minutes from the MO.

Upon receiving notice from the MO of the completion of the enumerated requirements by the Transmission Customer, the PSE EIM Entity shall provide notice to both the Transmission Customer with a PSE EIM Participating Resource and the MO that the PSE EIM Participating Resource is certified and therefore eligible to participate in the EIM. The process by which the PSE EIM Entity certifies Transmission Customers with a PSE EIM Participating Resource shall be set forth in the PSE EIM BP.

3.3.4 Status of Resource Pending Certification

If the Transmission Customer (i) has submitted an application for a resource to be a PSE EIM Participating Resource but the application has not been approved, or (ii) has not yet been certified by the PSE EIM Entity consistent with Section 3.3.3 of this Attachment O, the resource shall be deemed to be a Non-Participating Resource.

3.3.5 Notice and Obligation to Report a Change in Information

Each Transmission Customer with a PSE EIM Participating Resource has an ongoing obligation to inform the PSE EIM Entity of any changes to any of the information submitted as part of the application process under this Attachment O. The PSE EIM BP shall set forth the process and timing requirements for notifying the PSE EIM Entity of such changes.

This information includes, but is not limited to:

(1) Any change in the PSE EIM Participating Resource Scheduling Coordinator representing the resource;

(2) Any change in the ownership or control of the resource;

(3) Any change to the physical characteristics of the resource required to be reported to the MO in accordance with Section 29.4(c)(4)(C) of the MO Tariff; or

(4) If either the MO terminates the participation of the PSE EIM Participating Resource in the EIM or the Transmission Customer has terminated the PSE EIM Participating Resource's participation in the EIM; in either case, that resource shall be considered to be a Non-Participating Resource for purposes of this Tariff, including Attachment O.

4. Roles and Responsibilities

4.1 Transmission Provider as the PSE EIM Entity and the PSE EIM Entity Scheduling Coordinator

4.1.1 Responsibilities

4.1.1.1 Identification of EIM Entity Scheduling Coordinator

The PSE EIM Entity can serve as the PSE EIM Entity Scheduling Coordinator or retain a third-party to perform such role. If the PSE EIM Entity is not the PSE EIM Entity Scheduling Coordinator, the PSE EIM Entity shall communicate to the PSE EIM Entity Scheduling Coordinator the information required by the PSE EIM Entity Scheduling Coordinator to fulfill its responsibilities in the EIM.

The PSE EIM Entity Scheduling Coordinator shall coordinate and facilitate the EIM in accordance with the requirements of the MO Tariff. The PSE EIM Entity Scheduling Coordinator must meet the certification requirements of the MO and enter into any necessary MO agreements.

4.1.1.2 Processing PSE EIM Participating Resource Applications

The PSE EIM Entity shall be responsible for processing applications of Transmission Customers seeking authorization to participate in the EIM with resources as PSE EIM Participating Resources in accordance with Section 3.3 of this Attachment O.

4.1.1.3 Determination of EIM Implementation Decisions for PSE's BAA

The PSE EIM Entity is solely responsible for making any decisions with respect to EIM participation that the MO requires of EIM Entities. The PSE EIM Entity has made the following determinations:

(1) **Eligibility requirements**: Eligibility requirements are set forth in Section 3 of Attachment O.

(2) **Load Aggregation Points:** There shall be one LAP for PSE's BAA.

(3) **MO load forecast:** The PSE EIM Entity shall utilize the MO load forecast but shall retain the right to provide the load forecast to the MO in accordance with the MO Tariff.

(4) **MO metering agreements**: The PSE EIM Entity and all Transmission Customers with PSE EIM Participating Resources shall have the option to elect to be Scheduling Coordinator Metered Entities or CAISO Metered Entities in accordance with Section 29.10 of the MO Tariff. The PSE EIM Entity shall be a Scheduling Coordinator Metered Entity on behalf of all Transmission Customers with Non-Participating Resources in accordance with Section 29.10 of the MO Tariff.

4.1.1.4 PSE EIM Business Practice

The PSE EIM Entity shall establish and revise, as necessary, procedures to facilitate implementation and operation of the EIM through the PSE EIM BP that shall be posted on the Transmission Provider's OASIS.

4.1.1.5 Determination to Take Corrective Actions or Permanently Terminate Participation in the EIM

The PSE EIM Entity may take corrective actions in PSE's BAA in accordance with the requirements of Section 10.3 of Attachment O.

In addition, the PSE EIM Entity, in its sole and absolute discretion, may permanently terminate its participation in the EIM by providing notice of termination to the MO pursuant to applicable agreements and by making a filing pursuant to Section 205 of the Federal Power Act to revise this Tariff consistent with the Commission's requirements.

4.1.2 Responsibilities of the PSE EIM Entity to Provide Required Information

4.1.2.1 Provide Modeling Data to the MO

The PSE EIM Entity shall provide the MO information associated with transmission facilities within PSE's BAA, including, but not limited to, network constraints and associated limits that must be observed in PSE's BAA' network and interties with other BAAs.

4.1.2.2 Registration

The PSE EIM Entity shall register all Non-Participating Resources with the MO. The PSE EIM Entity may choose to obtain default energy bids from the MO for Non-Participating Resources that are Balancing Authority Area Resources. The PSE EIM Entity shall update this information in accordance with the MO's requirements as revised information is received from Transmission Customers with Non-Participating Resources in accordance with Section 4.2.1.2 of this Attachment O.

4.1.3 Day-to-Day EIM Operations

4.1.3.1 Submission of Transmission Customer Base Schedule, Forecast Data for Non-Participating Resources that are Variable Energy Resources, and Resource Plans

The PSE EIM Entity is responsible for providing the data required by the MO in accordance with Section 29.34 of the MO Tariff, including but not limited to: (1) hourly Transmission Customer Base Schedules; (2) Forecast Data for Non-Participating Resources that are Variable Energy Resources; and (3) Resource Plans.

4.1.3.2 Communication of Manual Dispatch Information

The PSE EIM Entity shall inform the MO of a Manual Dispatch by providing adjustment information for the affected resources in accordance with Section 29.34 of the MO Tariff.

4.1.3.3 Confirmation

The MO shall calculate, and the PSE EIM Entity shall confirm, actual values for Dynamic Schedules reflecting EIM Transfers to the MO within 60 minutes after completion of the Operating Hour to ensure the e-Tag author will be able to update these values in accordance with WECC business practices through an update to the e-Tag.

4.1.3.4 Dispatch of EIM Available Balancing Capacity of a Non-Participating Resource

Upon notification by the MO, the PSE EIM Entity shall notify the Non-Participating Resource of the Dispatch Operating Point for any EIM Available Balancing Capacity from the Non-

Participating Resource, except in circumstances in which the PSE EIM Entity determines the additional capacity is not needed for the BAA or has taken other actions to meet the capacity need.

4.1.4 Provision of Meter Data

The PSE EIM Entity shall submit load, resource, and Interchange meter data to the MO in accordance with the format and timeframes required in the MO Tariff on behalf of Transmission Customers with Non-Participating Resources, loads, and Interchange.

4.1.5 Settlement of MO Charges and Payments

The PSE EIM Entity shall be responsible for financial settlement of all charges and payments allocated by the MO to the PSE EIM Entity. The PSE EIM Entity shall sub-allocate EIM charges and payments in accordance with Schedules 1, 1A, 4, 4R and 9 of this Tariff or Section 8 of Attachment O, as applicable.

4.1.6 Dispute Resolution with the MO

The PSE EIM Entity shall manage dispute resolution with the MO for the PSE EIM Entity settlement statements consistent with Section 29.13 of the MO Tariff, Section 12 of this Tariff, and the PSE EIM BP. Transmission Customers with PSE EIM Participating Resources shall manage dispute resolution with the MO for any settlement statements they receive directly from the MO.

4.2 Transmission Customer Responsibilities

The following must comply with the information requirements of this section: (1) Transmission Customers with a PSE EIM Participating Resource; (2) Transmission Customers with a Non-Participating Resource; (3) Transmission Customers with load within PSE's BAA; and (4) Transmission Customers wheeling through PSE's BAA.

4.2.1 Initial Registration Data

4.2.1.1 Transmission Customers with a PSE EIM Participating Resource

A Transmission Customer with a PSE EIM Participating Resource shall provide the MO and the PSE EIM Entity with data necessary to meet the requirements established by the MO to register all resources with the MO as required by Section 29.4(e)(4)(D) of the MO Tariff.

4.2.1.2 Transmission Customers with Non-Participating Resources

A Transmission Customer with Non-Participating Resources shall provide the PSE EIM Entity with data necessary to meet the requirements established by the MO as required by Section 29.4(c)(4)(C) of the MO Tariff.

4.2.2 Responsibility to Update Required Data

4.2.2.1 Transmission Customers with a PSE EIM Participating Resource

Each Transmission Customer with a PSE EIM Participating Resource has an ongoing obligation to inform the MO and PSE EIM Entity of any changes to any of the information submitted by the Transmission Customer provided under Section 4.2.1 of this Attachment O that reflects changes in operating characteristics as required by Section 29.4(e)(4)(D) of the MO Tariff. The PSE EIM BP shall set forth the process and timing requirements of notifying the PSE EIM Entity of such changes.

4.2.2.2 Transmission Customers with Non-Participating Resources

Each Transmission Customer with a Non-Participating Resource has an ongoing obligation to inform the PSE EIM Entity of any changes to any of the information submitted by the Transmission Customer with a Non-Participating Resource provided under Section 4.2.1 of this Attachment O. The PSE EIM BP shall set forth the process and timing requirements of notifying the PSE EIM Entity of such changes.

4.2.3 Outages

Transmission Customers with PSE EIM Participating Resources and Transmission Customers with Non-Participating Resources shall be required to provide planned and unplanned outage information for their resources in accordance with Section 7 of this Attachment O. The PSE EIM BP shall set forth the outage information requirements for PSE EIM Participating Resources and Non-Participating Resources.

4.2.4 Submission of Transmission Customer Base Schedule

A Transmission Customer shall submit the Transmission Customer Base Schedule to the PSE EIM Entity. This submission must include Forecast Data on all resources, Interchange, and Intrachange which balance to the Transmission Customer's anticipated load, as applicable. If the Transmission Customer does not serve load within PSE's BAA, submission of the Transmission Customer Base Schedule shall include Forecast Data on all resources, Interchange, and Intrachange which shall balance to the Transmission Customer's anticipated actual generation within PSE's BAA. The submissions shall be in the format and within the timing requirements established by the MO and the PSE EIM Entity as required in Section 4.2.4.5 of this Attachment O and the PSE EIM BP.

4.2.4.1 Transmission Customers with a PSE EIM Participating Resource or Non-Participating Resource in the PSE BAA

A Transmission Customers with a PSE EIM Participating Resource or a Non-Participating Resource is not required to submit Forecast Data for:

(1) resources located in PSE's BAA that are less than five MW; or

(2) behind-the-meter generation which is not contained in the MO's network model.

Each PSE EIM Participating Resource Scheduling Coordinator shall provide to the PSE EIM Entity the energy bid range data (without price information) of the respective resources it represents that are participating in the EIM.

Each PSE EIM Participating Resource Scheduling Coordinator shall also provide the PSE EIM Entity with Dispatch Operating Point data of the respective resources it represents that are participating in the EIM.

4.2.4.2 Transmission Customers with Non-Participating Resources that are Variable Energy Resources

A Transmission Customer with a Non-Participating Resource that is a Variable Energy Resource shall submit (i) resource Forecast Data with hourly granularity and (ii) resource Forecast Data with 5-minute or 15-minute granularity. A Transmission Customer with a Non-Participating Resource that is a Variable Energy Resource shall provide, at minimum, a three-hour rolling forecast with 15-minute granularity, updated every 15 minutes, and may provide, in the alternative, a three-hour rolling forecast with 5-minute granularity, updated every 5 minutes, and in accordance with any additional procedures set forth in the PSE EIM BP.

A Transmission Customer with a Non-Participating Resource that is a Variable Energy Resource shall submit resource Forecast Data consistent with this Section 4.2.4.2 using any one of the following methods:

(1) The Transmission Customer may elect to use the PSE EIM Entity's Variable Energy Resource reliability forecast prepared for Variable Energy Resources within PSE's BAA, which shall be considered to be the basis for physical changes in the output of the resource communicated to the MO, for purposes of settlement pursuant to Schedule 9 of this Tariff;

(2) The Transmission Customer may elect to self-supply the Forecast Data and provide such data to the PSE EIM Entity, which shall be considered to be the basis for physical changes in the output of the resource communicated to the MO, for purposes of settlement pursuant to Schedule 9 of this Tariff. The PSE EIM BP will specify the manner in which Transmission Customers may self-supply Forecast Data; or

(3) The Transmission Customer may elect that the MO produce Forecast Data for the Variable Energy Resource, made available to the Transmission Customer in a manner consistent with Section 29.11(j)(1) of the MO Tariff, which shall be considered to be the basis for physical changes in the output of the resource communicated to the MO, for purposes of settlement pursuant to Schedule 9 of this Tariff.

A Transmission Customer with a Non-Participating Resource that is a Variable Energy Resource must elect one of the above methods prior to commencement of the EIM or prior to such other date in accordance with the procedures set forth in the PSE EIM BP. A Transmission Customer with a Non-Participating Resource that is a Variable Energy Resource may change its election by providing advance notice to the PSE EIM Entity, in accordance with the procedures set forth in the PSE EIM BP.

To the extent a Transmission Customer with a Non-Participating Resource that is a Variable Energy Resource elects method (2) above, and such Transmission Customer fails to submit resource Forecast Data for any time interval as required by this Section 4.2.4.2 of this Attachment O, the PSE EIM Entity shall apply method (1) for purposes of settlement pursuant to Schedule 9 of this Tariff.

4.2.4.3 Transmission Customers with Load

As set forth in Sections 4.2.4 of this Attachment O, a Transmission Customer is required to submit Forecast Data on all resources, Interchange, and Intrachange which balance to the Transmission Customer's anticipated load, as applicable.

For purposes of settling Energy Imbalance Service pursuant to Schedule 4 and Schedule 4R of this Tariff, the PSE EIM Entity shall calculate the load component of the Transmission Customer Base Schedule as the resource Forecast Data net of its Interchange Forecast Data and net of its Intrachange Forecast Data, as applicable.

4.2.4.4 Transmission Customers Without Resources or Load in PSE's BAA

A Transmission Customer which does not have any resources or load within PSE's BAA shall submit a Transmission Customer Base Schedule that includes Interchange and Intrachange Forecast Data to the PSE EIM Entity.

4.2.4.5 Timing of Transmission Customer Base Schedules Submission

4.2.4.5.1 Preliminary Submission of Transmission Customer Base Schedules

Transmission Customers shall submit their initial Transmission Customer Base Schedules 7 days prior to each Operating Day ("T - 7 days"). Transmission Customers may modify the proposed Transmission Customer Base Schedule at any time but shall submit at least one update by 10 a.m of the day before the Operating Day.

4.2.4.5.2 Final Submissions of Transmission Customer Base Schedules

Transmission Customers shall submit proposed final Transmission Customer Base Schedules, at any time but no later than 77 minutes prior to each Operating Hour ("T-77"). Transmission Customers may modify Transmission Customer Base Schedules up to and until 57 minutes prior to the Operating Hour ("T-57"). As of 55 minutes prior to each Operating Hour ("T-55"), the Transmission Customer Base Schedule data for the Operating Hour will be considered financially binding and Transmission Customers may not submit further changes. If the Transmission Customer fails to enter a Forecast Data value, the default will be 0 MW for that Operating Hour.

4.2.5 Metering for Transmission Customers with Non-Participating Resources

To assess imbalance, the MO shall disaggregate meter data into 5-minute intervals if the meter intervals are not already programmed to 5-minute intervals pursuant to a Transmission Customer's applicable interconnection requirements associated with any agreement pursuant to Annexes A and B of this Tariff. To the extent that a Transmission Customer owns the meter or communication to the meter, the Transmission Customer shall be responsible to maintain accurate and timely data accessible for the PSE EIM Entity to comply with Section 4.1.4 of this Attachment O.

5. Transmission Operations

5.1 Provision of Information Regarding Real-Time Status of the Transmission Provider's Transmission System

The PSE EIM Entity shall provide the MO information on:

(1) real time data for the Transmission System and interties; and

(2) any changes to transmission capacity and the Transmission System due to operational circumstances.

5.2 Provision of EIM Transfer Capacity by a PSE Interchange Rights Holder

The PSE EIM Entity shall facilitate the provision of transmission capacity for EIM Transfers offered by a PSE Interchange Rights Holder by providing the MO with information about the amounts made available by the PSE Interchange Rights Holder for EIM Transfers.

The provision of EIM Transfer capacity shall be implemented through the PSE Interchange Rights Holder's submission of an e-Tag by 75 minutes prior to the Operating Hour ("T-75"). The PSE Interchange Rights Holder shall include on the e-Tag the OASIS identification reservation number(s) associated with the transmission rights made available for EIM Transfers and shall also include the Market Operator, all transmission providers, and path operators associated with the OASIS identification reservation number(s) identified on the e-Tag. The PSE Interchange Rights Holder's rights associated with the submitted e-Tag shall be available for the EIM, subject to approval of the e-Tag by all required e-Tag approval entities.

The amount made available for EIM Transfers shall never exceed the PSE Interchange Rights Holder's transmission rights.

5.3 Provision of EIM Transfer Capability by the PSE EIM Entity

The PSE EIM Entity shall facilitate the provision of transmission capacity for EIM Transfers by providing the MO with information about the amounts available for EIM Transfers utilizing Available Transfer Capability ("ATC"). Such amounts shall be in addition to any amounts made available by PSE Interchange Rights Holders pursuant to Section 5.2 of this Attachment O.

The provision of EIM Transfer capacity corresponding to ATC shall be implemented by 40 minutes prior to the Operating Hour ("T-40") by the PSE EIM Entity. The PSE EIM Entity shall include an e-Tag, with an OASIS identification reservation number(s) created for EIM Transfers utilizing ATC, and shall also include the MO, all transmission providers, and path operators associated with the OASIS identification reservation number(s) identified in the e-Tag. The amount of ATC indicated on the e-Tag will be based upon the lower of the amount of ATC calculated by each EIM Entity at that interface by T-40. The ATC associated with the submitted e-Tag shall be available for the EIM, subject to approval of the e-Tag by all required e-Tag approval entities.

6. System Operations Under Normal and Emergency Conditions

6.1 Compliance with Reliability Standards

Participation in the EIM shall not modify, change, or otherwise alter the manner in which the Transmission Provider operates its Transmission System consistent with applicable reliability standards, including adjustments.

Participation in the EIM shall not modify, change, or otherwise alter the obligations of the PSE EIM Entity, Transmission Customers with PSE EIM Participating Resources, or Transmission Customers with Non-Participating Resources to comply with applicable reliability standards.

The PSE EIM Entity shall remain responsible for:

(1) maintaining appropriate operating reserves and for its obligations pursuant to any reserve sharing group agreements;

(2) NERC and WECC responsibilities including, but not limited to, informing the Reliability Coordinator of issues within PSE's BAA;

(3) processing e-Tags and managing schedule curtailments at the interties; and

(4) monitoring and managing real-time flows within system operating limits on all transmission facilities within PSE's BAA, including facilities of PSE BAA Transmission Owners. If requested by a Transmission Customer that is also a PSE BAA Transmission Owner, the PSE EIM Entity will provide additional information or data related to EIM operation as it may relate to facilities of a PSE BAA Transmission Owner.

6.2 Good Utility Practice

The PSE EIM Entity, Transmission Customers with Non-Participating Resources, and Transmission Customers with PSE EIM Participating Resources shall comply with Good Utility Practice with respect to this Attachment O.

6.3 Management of Contingencies and Emergencies

6.3.1 EIM Disruption

If the MO declares an EIM disruption in accordance with Section 29.7(j) of the MO Tariff, the PSE EIM Entity shall, in accordance with Section 29.7(j)(4) of the MO Tariff, promptly inform the MO of actions taken in response to the EIM disruption by providing adjustment information, updates to e-Tags, transmission limit adjustments, or outage and de-rate information, as applicable.

6.3.2 Manual Dispatch

The PSE EIM Entity may issue a Manual Dispatch order to a Transmission Customer with a PSE EIM Participating Resource or a Non-Participating Resource in PSE's BAA, to address reliability or operational issues in PSE's BAA that the EIM is not able to address through normal economic dispatch and congestion management.

The PSE EIM Entity shall inform the MO of a Manual Dispatch as soon as possible.

7. Outages

7.1. PSE EIM Entity Transmission Outages

7.1.1 Planned Transmission Outages and Known Derates

The PSE EIM Entity shall submit information regarding planned transmission outages and known derates to the MO's outage management system in accordance with Section 29.9(b) of the MO Tariff. The PSE EIM Entity shall update the submittal if there are changes to the transmission outage plan.

7.1.2 Unplanned Transmission Outages

The PSE EIM Entity shall submit information as soon as possible regarding unplanned transmission outages or derates to the MO's outage management system in accordance with Section 29.9(e) of the MO Tariff.

7.2 PSE BAA Transmission Owner Outages

Transmission Customers that are also PSE BAA Transmission Owners shall provide the PSE EIM Entity with planned and unplanned transmission outage data. Planned outages shall be reported to the PSE EIM Entity 7 or more days in advance and preferably at least 30 days in advance of the outage. Unplanned outages shall be reported to the PSE EIM Entity as soon as possible but no later than 30 minutes after the outage commences.

The PSE EIM Entity shall communicate information regarding planned and unplanned outages of PSE BAA Transmission Owner facilities to the MO as soon as practicable upon receipt of the information from the PSE BAA Transmission Owner.

7.3 PSE EIM Participating Resource Outages

7.3.1 Planned PSE EIM Participating Resource Outages and Known Derates

PSE EIM Participating Resource Scheduling Coordinators shall submit information regarding planned resource outages and known derates to the PSE EIM Entity. Planned outages and known derates shall be reported to the PSE EIM Entity 7 or more days in advance and preferably at least 30 days in advance of the outage or known derate. The PSE EIM Entity shall then submit this outage information to the MO's outage management system in accordance with Section 29.9(c) of the MO Tariff. PSE EIM Participating Resource Scheduling Coordinators shall update the submittal if there are changes to the resource outage plan.

7.3.2 Unplanned PSE EIM Participating Resource Outages

In the event of an unplanned outage required to be reported under Section 29.9(e) of the MO Tariff, the PSE EIM Participating Resource Scheduling Coordinator is responsible for notifying the PSE EIM Entity of required changes. Unplanned outages shall be reported to the PSE EIM Entity as soon as possible but no later than 30 minutes after the outage commences. The PSE EIM Entity shall then submit this information to the MO's outage management system.

7.3.3 Unplanned Derates

Changes in availability of 10 MW or 5% of Pmax (whichever is greater) lasting 15 minutes or longer must be reported to the PSE EIM Entity. These reports are due within 30 minutes of discovery, and are required only to include effective time and MW availability. The PSE EIM Entity shall then submit this information to the MO's outage management system.

7.4 Outages of Transmission Customers with Non-Participating Resources

7.4.1 Planned Outages and Known Derates of Transmission Customers with Non-Participating Resources

Transmission Customers with Non-Participating Resources shall report information regarding planned outages and known derates of resources to the PSE EIM Entity 7 or more days in advance and preferably at least 30 days in advance of the outage. The Transmission Customer with a Non-Participating Resource shall update the submittal if there are changes to the resource's outage plan.

The PSE EIM Entity shall submit planned resource outages and known derates of Non-Participating Resources to the MO's outage management system in accordance Section 29.9(c) of the MO Tariff.

7.4.2 Unplanned Outages of Resources of Transmission Customers with Non-Participating Resources

Unplanned outages of resources of a Transmission Customer with Non-Participating Resources shall be reported to the PSE EIM Entity as soon as possible but no later than 30 minutes after the outage commences.

In the event of a forced outage required to be reported under Section 29.9(e) of the MO Tariff, the PSE EIM Entity is responsible for notifying the MO of required changes through the MO's outage management system.

7.4.3 Unplanned Derates

Changes in availability of 10 MW or 5% of Pmax (whichever is greater) lasting 15 minutes or longer must be reported to the PSE EIM Entity. These reports are due within 30 minutes of discovery, and are required only to include effective time and MW availability. The PSE EIM Entity shall then submit this information to the MO's outage management system.

8. EIM Settlements and Billing

The PSE EIM BP shall include information on the specific charge codes applicable to EIM settlement.

8.1 Instructed Imbalance Energy (IIE)

The PSE EIM Entity shall settle as IIE imbalances that result from (1) operational adjustments of a Transmission Customer's affected Interchange or Intrachange, which includes changes by a Transmission Customer after T-57, (2) resource imbalances created by Manual Dispatch or an EIM Available Balancing Capacity dispatch, or (3) an adjustment to resource imbalances created by adjustments to resource forecasts pursuant to Section 11.5 of the MO Tariff and using the RTD or FMM price at the applicable PNode. Any allocations to the PSE EIM Entity pursuant to

Section 29.11(b)(1) and (2) of the MO Tariff for IIE that is not otherwise recovered under Schedule 9 of this Tariff shall be settled directly with each Transmission Customer according to this Section 8.1.

8.2 Uninstructed Imbalance Energy (UIE)

Any charges or payments to the PSE EIM Entity pursuant to Section 29.11(b)(3)(B) and (C) of the MO Tariff for UIE not otherwise recovered under Schedule 4, Schedule 4R, or Schedule 9 shall not be sub-allocated to Transmission Customers.

8.3 Unaccounted for Energy (UFE)

Any charges to the PSE EIM Entity pursuant to Section 29.11(c) of the MO Tariff for UFE shall not be sub-allocated to Transmission Customers.

8.4 Charges for Under-Scheduling or Over-Scheduling Load

8.4.1 Under-Scheduling Load

Any charges to the PSE EIM Entity pursuant to Section 29.11(d)(1) of the MO Tariff for under-scheduling load shall be assigned to the Transmission Customers subject to Schedule 4 and Schedule 4R based on each Transmission Customer's respective under-scheduling imbalance ratio share, which is the ratio of the Transmission Customer's under-scheduled load imbalance amount relative to all other Transmission Customers' under-scheduled load imbalance amounts who have under-scheduled load for the Operating Hour, expressed as a percentage.

8.4.2 Over-Scheduling Load

Any charges to the PSE EIM Entity pursuant to Section 29.11(d)(2) of the MO Tariff for over-scheduling load shall be assigned to the Transmission Customers subject to Schedule 4 and Schedule 4R based on each Transmission Customer's respective over-scheduling imbalance ratio share, which is the ratio of the Transmission Customer's over-scheduled load imbalance amount relative to all other Transmission Customers' over-scheduled load imbalance amounts who have over-scheduled load for the Operating Hour, expressed as a percentage.

8.4.3 Distribution of Under-Scheduling or Over-Scheduling Proceeds

Any payment to the PSE EIM Entity pursuant to Section 29.11(d)(3) of the MO Tariff shall be distributed to Transmission Customers that were not subject to underscheduling or over-scheduling charges during the Trading Day on the basis of Metered Demand and in accordance with the procedures outlined in the PSE EIM BP.

8.5 EIM Uplifts

8.5.1 EIM BAA Real-Time Market Neutrality (Real-Time Imbalance Energy Offset - BAA)

Any charges to the PSE EIM Entity pursuant to Section 29.11(e)(3) of the MO Tariff for EIM BAA real-time market neutrality shall be sub-allocated to Transmission Customers on the basis of Measured Demand.

8.5.2 EIM Entity BAA Real-Time Congestion Offset

Any charges to the PSE EIM Entity pursuant to Section 29.11(e)(2) of the MO Tariff for the EIM real-time congestion offset shall be allocated to Transmission Customers on the basis of Measured Demand.

8.5.3 EIM Entity Real-Time Marginal Cost of Losses Offset

Any charges to the PSE EIM Entity pursuant to Section 29.11(e)(4) of the MO Tariff for real-time marginal cost of losses offset shall be sub-allocated to Transmission Customers on the basis of Measured Demand.

8.5.4 EIM Neutrality Settlement

Any charges to the PSE EIM Entity pursuant to Section 29.11(e)(5) of the MO Tariff for EIM neutrality settlement shall be sub-allocated as follows:

Description	Allocation
Neutrality Adjustment (monthly and daily)	Measured Demand
Rounding Adjustment (monthly and daily)	Measured Demand

8.5.5 Real-Time Bid Cost Recovery

Any charges to the PSE EIM Entity pursuant to Section 29.11(f) of the MO Tariff for EIM real-time bid cost recovery shall be sub-allocated to Transmission Customers on the basis of Measured Demand.

8.5.6 Flexible Ramping Constraint

Any charges to the PSE EIM Entity pursuant to Section 29.11(g) of the MO Tariff for the Flexible Ramping Constraint shall be sub-allocated to Transmission Customers on the basis of Measured Demand.

8.5.7 Inaccurate or Late Actual Settlement Quality Meter Data Penalty

To the extent the PSE EIM Entity incurs a penalty for inaccurate or late actual settlement quality meter data, pursuant to Section 37.11.1 of the MO Tariff, the PSE EIM Entity shall directly assign the penalty to the offending Transmission Customer.

8.5.8 Other EIM Settlement Provisions

Any charges to the PSE EIM Entity pursuant to the MO Tariff for the EIM settlement provisions shown in the following table shall be sub-allocated as follows:

Description	**Allocation**
Invoice Deviation (distribution and allocation)	PSE EIM Entity
Generator Interconnection Process Forfeited Deposit Allocation	PSE EIM Entity
Default Invoice Interest Payment	PSE EIM Entity
Default Invoice Interest Charge	PSE EIM Entity
Invoice Late Payment Penalty	PSE EIM Entity
Financial Security Posting (Collateral) Late Payment Penalty	PSE EIM Entity
Shortfall Receipt Distribution	PSE EIM Entity
Shortfall Reversal	PSE EIM Entity
Shortfall Allocation	PSE EIM Entity
Default Loss Allocation	PSE EIM Entity

8.6 MO Tax Liabilities

Any charges to the PSE EIM Entity pursuant to Section 29.22(a) of the MO Tariff for MO tax liability as a result of the EIM shall be sub-allocated to those Transmission Customers triggering the tax liability.

8.7 EIM Transmission Service Charges

There shall be no incremental transmission charge assessed for transmission use related to the EIM.

Unreserved Use Penalties shall apply to any amount of actual metered generation in an Operating Hour, if any, which is in excess of the sum of both: (1) the greatest positive Dispatch Operating Point or Manual Dispatch of the PSE EIM Participating Resource received during the Operating Hour, and (2) the Transmission Customer’s Reserved Capacity. Any ancillary service charges that are applicable to Unreserved Use Penalty charges shall apply.

8.8 Variable Energy Resource Forecast Charge

Any costs incurred by the PSE EIM Entity related to the preparation and submission of resource Forecast Data for a Transmission Customer with a Non-Participating Resource electing either method (1) or (2), as set forth in Section 4.2.4.2 of this Attachment O, shall be allocated to the Transmission Customer with a Non-Participating Resource electing to use either such method.

For a Transmission Customer with a Non-Participating Resource electing method (3), as set forth in Section 4.2.4.2 of this Attachment O, any charges to the PSE EIM Entity pursuant to Section 29.11(j)(1) of the MO Tariff for Variable Energy Resource forecast charges shall be sub-allocated to the Transmission Customer with a Non-Participating Resource requesting such forecast.

8.9 EIM Payment Calendar

Pursuant to Section 29.11(l) of the MO Tariff, the PSE EIM Entity shall be subject to the MO's payment calendar for issuing settlement statements, exchanging invoice funds, submitting meter data, and submitting settlement disputes to the MO. The PSE EIM Entity shall follow Section 7 of this Tariff for issuing invoices regarding the EIM.

8.10 EIM Residual Balancing Account

To the extent that MO EIM-related charges or payments to the PSE EIM Entity are not captured elsewhere in Attachment H-1, Schedules 1, 1A, 4, 4R, and 9 of this Tariff, or this Section 8, those charges or payments shall be placed in a balancing account, with interest accruing at the rate established in 18 C.F.R. § 35.19(a)(2)(iii), until PSE makes a filing with the Commission pursuant to Section 205 of the Federal Power Act proposing an allocation methodology.

8.11 Market Validation and Price Correction

If the MO modifies the PSE EIM Entity settlement statement in accordance with the MO's market validation and price correction procedures in the MO Tariff, the PSE EIM Entity reserves the right to make corresponding or similar changes to the charges and payments sub-allocated under this Attachment O.

8.12 Allocation of Operating Reserves

8.12.1 Payments

Any payments to the PSE EIM Entity pursuant to Section 29.11(n)(1) of the MO Tariff for operating reserve obligations shall be sub-allocated to Transmission Customers with PSE EIM Participating Resources in the PSE BAA for Operating Hours during which EIM Transfers from the PSE BAA to another BAA occurred. Payments shall be sub-allocated on a ratio-share basis, defined as the proportion of the volume of Operating Reserves provided by a PSE EIM Participating Resource in the PSE BAA dispatched during the Operating Hour compared to the total volume of Operating Reserves provided by all PSE EIM Participating Resources dispatched in the PSE BAA for the Operating Hour.

8.12.2 Charges

Any charges to the PSE EIM Entity pursuant to Section 29.11(n)(2) of the MO Tariff for operating reserve obligations shall be sub-allocated to Transmission Customers on the basis of Measured Demand.

9. Compliance

9.1 Provision of Data

Transmission Customers with PSE EIM Participating Resources and PSE EIM Participating Resource Scheduling Coordinators are responsible for complying with information requests they receive directly from the EIM market monitor or regulatory authorities concerning EIM activities.

A Transmission Customer with PSE EIM Participating Resources or a Transmission Customer with Non-Participating Resources must provide the PSE EIM Entity with all data necessary to respond to information requests received by the PSE EIM Entity from the MO, the EIM market monitor, or regulatory authorities concerning EIM activities.

If the PSE EIM Entity is required by applicable laws or regulations, or in the course of administrative or judicial proceedings, to disclose information that is otherwise required to be maintained in confidence, the PSE EIM Entity may disclose such information; provided, however, that upon the PSE EIM Entity learning of the disclosure requirement and, if possible, prior to making such disclosure, the PSE EIM Entity shall notify any affected party of the requirement and the terms thereof. The party can, at its sole discretion and own cost, direct any challenge to or defense against the disclosure requirement. The PSE EIM Entity shall cooperate with the affected party to obtain proprietary or confidential treatment of confidential information by the person to whom such information is disclosed prior to any such disclosure.

The PSE EIM Entity shall treat all Transmission Customer and Interconnection Customer data and information provided to it as market-sensitive and confidential, unless the PSE EIM Entity is otherwise allowed or required to disclose. The PSE EIM Entity shall continue to abide by the Commission’s Standards of Conduct and handle customer information accordingly.

9.2 Rules of Conduct

These rules of conduct are intended to provide fair notice of the conduct expected and to provide an environment in which all parties may participate in the EIM on a fair and equal basis. Transmission Customers must:

(1) Comply with Dispatch Instructions and PSE EIM Entity operating orders in accordance with Good Utility Practice. If some limitation prevents the

Transmission Customer from fulfilling the action requested by the MO or the PSE EIM Entity, the Transmission Customer must immediately and directly communicate the nature of any such limitation to the PSE EIM Entity;

(2) Submit bids for resources that are reasonably expected to both be and remain available and capable of performing at the levels specified in the bid, based on all information that is known or should have been known at the time of submission;

(3) Notify the MO and/or the PSE EIM Entity, as applicable, of outages in accordance with Section 7 of this Attachment O;

(4) Provide complete, accurate, and timely meter data to the PSE EIM Entity in accordance with the metering and communication requirements of this Tariff, and maintain responsibility to ensure the accuracy of such data communicated by any customer-owned metering or communications systems. To the extent such information is not accurate or timely when provided to the PSE EIM Entity, the Transmission Customer shall be responsible for any consequence on settlement and billing;

(5) Provide information to the PSE EIM Entity, including the information requested in Sections 4.2.1, 4.2.2, 4.2.3, 4.2.4 and 9.1 of this Attachment O, by the applicable deadlines; and

(6) Utilize commercially-reasonable efforts to ensure that forecasts are accurate and based on all information that is known or should have been known at the time of submission to the PSE EIM Entity.

9.3 Enforcement

The PSE EIM Entity may refer a violation of Section 9.2 of this Attachment O to FERC. Violations of these rules of conduct may be enforced by FERC in accordance with FERC's rules and procedures. Nothing in this Section 9 is meant to limit any other remedy before FERC or any applicable judicial, governmental, or administrative body.

10. Market Contingencies

10.1 Temporary Suspension by the MO

In the event that the MO implements a temporary suspension in accordance with Section 29.1(d)(1) of the MO Tariff, including the actions identified in Section 29.1(d)(5), the PSE EIM Entity shall utilize Temporary Schedules 4, 4R, 9, 12, and 12A in accordance with Sections 10.4.1, 10.4.2, 10.4.3, 10.4.4, and 10.4.5 of this Attachment O until the temporary suspension is no longer in effect or, if the MO determines to extend the suspension, for a period of time sufficient to process termination of the PSE EIM Entity's participation in the EIM in accordance with Section 29.1(d)(2) of the MO Tariff.

10.2 Termination of Participation in EIM by the PSE EIM Entity

If the PSE EIM Entity submits a notice of termination of its participation in the EIM to the MO in accordance with the applicable agreements and Section 4.1.1.5 of this Attachment O, in order to mitigate price exposure during the 180-day period between submission of the notice and the termination effective date, the PSE EIM Entity may invoke the following corrective actions by requesting that the MO:

(1) prevent EIM Transfers and separate the PSE EIM Entity's BAA from operation of the EIM in the EIM Area; and

(2) suspend settlement of EIM charges with respect to the PSE EIM Entity.

Once such corrective actions are implemented by the MO, the PSE EIM Entity shall utilize Temporary Schedules 4, 4R, 9, 12 and 12A in accordance with Sections 10.4.1, 10.4.2, 10.4.3, 10.4.4, and 10.4.5 of this Attachment O.

If the PSE EIM Entity takes action under this Section 10.2, the PSE EIM Entity shall notify the MO and Transmission Customers.

10.3 Corrective Actions Taken by the PSE EIM Entity for Temporary Contingencies

The PSE EIM Entity may declare a temporary contingency and invoke corrective actions for the EIM when in its judgment -

(1) operational circumstances (including a failure of the EIM to produce feasible results in PSE's BAA) have caused or are in danger of causing an abnormal system condition in PSE's BAA that requires immediate action to prevent loss of load, equipment damage, or tripping system elements that might result in cascading outages, or to restore system operation to meet the applicable Reliability Standards and reliability criteria established by NERC and WECC; or

(2) communications between the MO and the PSE EIM Entity are disrupted and prevent the PSE EIM Entity, the PSE EIM Entity Scheduling Coordinator, or a PSE EIM Participating Resource Scheduling Coordinator from accessing MO systems to submit or receive information.

10.3.1 Corrective Actions for Temporary Contingencies

If either of the above temporary contingencies occurs, the PSE EIM Entity may invoke the following corrective actions by requesting that the MO:

(1) prevent EIM Transfers and separate the PSE EIM Entity's BAA from operation of the EIM in the EIM Area; and/or

(2) suspend settlement of EIM charges with respect to the PSE EIM Entity.

When corrective action under 10.3.1 (2) is implemented or if the MO Tariff requires the use of these temporary schedules to set an administrative price, the PSE EIM Entity shall utilize Temporary Schedules 4, 4R, 9, 12, and 12A in accordance with Sections 10.4.1, 10.4.2, 10.4.3, 10.4.4, and 10.4.5 of this Attachment O.

If the PSE EIM Entity takes action under this Section 10.3, the PSE EIM Entity shall notify the MO and Transmission Customers. The PSE EIM Entity and the MO shall cooperate to resolve the temporary contingency event and restore full EIM operations as soon as is practicable.

10.4 Temporary Schedules 4, 4R, 9, 12, and 12A

10.4.1 Temporary Schedule 4 Energy Imbalance Service

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a Control Area over a single hour (plus real power losses). The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements, which may include use of non-generation resources capable of providing this service, to satisfy its Energy Imbalance Service obligation. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator. The Transmission Provider may charge a Transmission Customer a penalty for either hourly energy imbalances under this Temporary Schedule or a penalty for hourly generator imbalances under Temporary Schedule 9 for imbalances occurring during the same hour, but not both unless the imbalances aggravate rather than offset each other.

The Transmission Provider shall establish charges for energy imbalance based on the deviation bands as follows: (i) deviations within +/- 1.5 percent (with a minimum of 2 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be netted on a monthly basis and settled financially, at the end of the month, using the Hourly Pricing Proxy, (ii) deviations greater than +/- 1.5 percent up to 7.5 percent (or greater than 2 MW up to 10 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month, at 110 percent of the Hourly Pricing Proxy for under-scheduling or 90 percent of the Hourly Pricing Proxy for over-scheduling, and (iii) deviations greater than +/- 7.5 percent (or 10 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month, at 125 percent of the Hourly Pricing Proxy for under-scheduling or 75 percent of the Hourly Pricing Proxy for over-scheduling.

For any hour for which Transmission Provider assesses any charge for Energy Imbalance Service under this Temporary Schedule 4 based on 110 percent or 125 percent of the Hourly Pricing

Proxy, Transmission Provider shall credit to non-offending Transmission Customers for such hour the amount by which such charge exceeded the Hourly Pricing Proxy.

10.4.2 Temporary Schedule 4R Energy Imbalance Service for Transmission Customers Taking Service Under Transmission Provider's Schedule 448 and Schedule 449

This Temporary Schedule 4R applies only to Transmission Customers that take service under Transmission Provider's Schedules 448 and 449, on file with the Washington Utilities and Transportation Commission. Temporary Schedule 4R applies in place of Temporary Schedule 4 for any such customer; Transmission Customers will be charged or paid for imbalance energy under Temporary Schedule 4 or Temporary Schedule 4R but not both. Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a Control Area over a single hour (plus real power losses). The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must purchase this service from the Transmission Provider or make alternative comparable arrangements, which may include use of non-generation resources capable of providing this service, to satisfy its Energy Imbalance Service obligation. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator. The Transmission Provider may charge a Transmission Customer a penalty for either hourly energy imbalances under this Temporary Schedule or a penalty for hourly generator imbalances under Temporary Schedule 9 for imbalances occurring during the same hour, but not both unless the imbalances aggravate rather than offset each other.

The Transmission Provider shall establish charges for energy imbalance based on the deviation bands as follows: (i) deviations within +/- 1.5 percent (with a minimum of 2 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be netted on a monthly basis and settled financially, at the end of the month, using the Hourly Pricing Proxy, (ii) deviations greater than +/- 1.5 percent up to 7.5 percent (or greater than 2 MW up to 10 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month, at 110 percent of the Hourly Pricing Proxy for under-scheduling or 90 percent of the Hourly Pricing Proxy for over-scheduling, and (iii) deviations greater than +/- 7.5 percent (or 10 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month, at 125 percent of the Hourly Pricing Proxy for under-scheduling or 75 percent of the Hourly Pricing Proxy for over-scheduling.

For any hour for which Transmission Provider assesses any charge for Energy Imbalance Service under this Temporary Schedule 4R based on 110 percent or 125 percent of the Hourly Pricing Proxy, Transmission Provider shall credit to non-offending Transmission Customers for such hour the amount by which such charge exceeded the Hourly Pricing Proxy.

10.4.3 Temporary Schedule 9 Generator Imbalance Service

Generator Imbalance Service is provided when a difference occurs between the output of a generator located in the Transmission Provider’s Control Area and a delivery schedule from that generator to (1) another Control Area or (2) a load within the Transmission Provider’s Control Area over a single hour (plus real power losses). The Transmission Provider must offer this service, to the extent it is physically feasible to do so from its resources or from resources available to it, when transmission service is used to deliver energy from a generator located within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements, which may include use of non-generation resources capable of providing this service, to satisfy its Generator Imbalance Service obligation. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator. The Transmission Provider may charge a Transmission Customer a penalty for either hourly generator imbalances under this Temporary Schedule 9 or a penalty for hourly energy imbalances under Temporary Schedule 4 for imbalances occurring during the same hour, but not both unless the imbalances aggravate rather than offset each other. To the extent the Interconnection Customer is a different entity than the Transmission Customer and controls the output of a generator located in the Transmission Provider’s Control Area, the Interconnection Customer may be subject to charges for Generator Imbalance Service (rather than the Transmission Customer) in accordance with this Temporary Schedule 9.

The Transmission Provider shall establish charges for generator imbalance based on the deviation bands as follows: (i) deviations within +/- 1.5 percent (with a minimum of 2 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be netted on a monthly basis and settled financially, at the end of each month, at the Hourly Pricing Proxy, (ii) deviations greater than +/- 1.5 percent up to 7.5 percent (or greater than 2 MW up to 10 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month, at 110 percent of the Hourly Pricing Proxy for under-scheduling or 90 percent of the Hourly Pricing Proxy for over-scheduling, and (iii) deviations greater than +/- 7.5 percent (or 10 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled at 125 percent of the Hourly Pricing Proxy for under-scheduling or 75 percent of the Hourly Pricing Proxy for over-scheduling, except that an intermittent resource will be exempt from this deviation band and will pay the deviation band charges for all deviations greater than the larger of 1.5 percent or 2 MW. An intermittent resource, for the limited purpose of this Schedule is an electric generator that is not dispatchable and cannot store its fuel source and therefore cannot respond to changes in system demand or respond to transmission security constraints.

Notwithstanding the foregoing, deviations from scheduled transactions in order to respond to directives by the Transmission Provider, a balancing authority, or a reliability coordinator shall not be subject to the deviation bands identified above and, instead, shall be settled financially, at the end of the month, at 100 percent of the Hourly Pricing Proxy. Such directives may include instructions to correct frequency decay, respond to a reserve sharing event, or change output to relieve congestion.

For any hour for which Transmission Provider assesses any charge for Generator Imbalance Service under this Temporary Schedule 9 based on 110 percent or 125 percent of the Hourly Pricing Proxy, Transmission Provider shall credit to non-offending Transmission Customers for such hour the amount by which such charge exceeded the Hourly Pricing Proxy.

10.4.4 Temporary Schedule 12 – Real Power Losses on Washington Area Transmission Facilities

A transmission customer taking Network Integration Transmission Service, Firm or Non-Firm Point-to-Point Transmission Service shall be responsible for Real Power Losses as provided for in Sections 15.7 and 28.5 of the Tariff. For each hour where the Transmission Provider provides loss service, the Transmission Customer shall compensate the Transmission Provider at a rate equal to the Hourly Pricing Proxy for energy for such hour based on the product of the actual transmission service provided (scheduled service less any curtailments, corrections or adjustments mutually agreed on by the Transmission Provider and the Transmission Customer) during each hour in MWhs and the applicable loss factor provided in Sections 15.7 and 28.5 of the Tariff.

10.4.5 Temporary Schedule 12A – Real Power Losses on Colstrip and Southern Intertie Transmission Lines

A transmission customer taking service over the Colstrip and Southern Intertie High Voltage Direct Assignment Facilities pursuant to Schedule 10 of the Tariff shall be responsible for Real Power Losses as provided for in Sections 15.7 and 28.5 of the Tariff. For each hour where the Transmission Provider provides loss service, the Transmission Customer shall compensate the Transmission Provider at a rate equal to the Hourly Pricing Proxy for energy for such hour based on the product of the actual transmission service provided (scheduled service less any curtailments, corrections or adjustments mutually agreed on by the Transmission Provider and the Transmission Customer) during each hour in MWhs and the applicable loss factor provided in Sections 15.7 and 28.5 of the Tariff.

TABLE OF CONTENTS

## Section 2	Scope and Application

### 2.1	Application of Standard Large Generator Interconnection Procedures

Sections 2 through 13 apply to processing an Interconnection Request pertaining to a Large Generating Facility.

### 2.2	Comparability

Transmission Provider shall receive, process and analyze all Interconnection Requests in a timely manner as set forth in this LGIP. Transmission Provider will use the same Reasonable Efforts in processing and analyzing Interconnection Requests from all Interconnection Customers, whether the Generating Facilities are owned by Transmission Provider, its subsidiaries or Affiliates or others.

### 2.3	Base Case Data

Transmission Provider shall provide base power flow, short circuit and stability databases, including all underlying assumptions, and contingency list upon request subject to confidentiality provisions in LGIP Section 13.1. Transmission Provider is permitted to require that Interconnection Customer sign a confidentiality agreement before the release of commercially sensitive information or Critical Energy Infrastructure Information in the Base Case data. Such databases and lists, hereinafter referred to as Base Cases, shall include all (1) generation projects and (ii) transmission projects, including merchant transmission projects that are proposed for the Transmission System for which a transmission expansion plan has been submitted and approved by the applicable authority.

### 2.4	No Applicability to Transmission Service

Nothing in this LGIP shall constitute a request for transmission service or confer upon an Interconnection Customer any right to receive transmission service.

### 2.5	EIM Requirements

The Interconnection Customer shall have a continuing duty to comply with Attachment O of this Tariff, as applicable.

Annex B

SMALL GENERATOR
INTERCONNECTION PROCEDURES (SGIP)
(For Generating Facilities No Larger Than 20 MW)

TABLE OF CONTENTS

Section 1. Application

1.1 Applicability

1.1.1 A request to interconnect a certified Small Generating Facility (See Attachments 3 and 4 for description of certification criteria) to the Transmission Provider's Distribution System shall be evaluated under the section 2 Fast Track Process if the eligibility requirements of section 2.1 are met. A request to interconnect a certified inverter-based Small Generating Facility no larger than 10 kilowatts (kW) shall be evaluated under the Attachment 5 10 kW Inverter Process. A request to interconnect a Small Generating Facility no larger than 20 megawatts (MW) that does not meet the eligibility requirements of section 2.1, or does not pass the Fast Track Process or the 10 kW Inverter Process, shall be evaluated under the section 3 Study Process. If the interconnection Customer wishes to interconnect its Small Generating Facility using Network Resource Interconnection Service, it must do so under the Standard Large Generator Interconnection Procedures and execute the Standard Large Generator Interconnection Agreement.

1.1.2 Capitalized terms used herein shall have the meanings specified in the Glossary of Terms in Attachment 1 or the body of these procedures.

1.1.3 Neither these procedures nor the requirements included hereunder apply to Small Generating Facilities interconnected or approved for interconnection prior to 60 Business Days after the effective date of these procedures.

1.1.4 Prior to submitting its Interconnection Request (Attachment 2), the Interconnection Customer may ask the Transmission Provider's interconnection contact employee or office whether the proposed interconnection is subject to these procedures. The Transmission Provider shall respond within 15 Business Days.

1.1.5 Infrastructure security of electric system equipment and operations and control hardware and software is essential to ensure day-to-day reliability and operational security. The Federal Energy Regulatory Commission expects all Transmission Providers, market participants, and Interconnection Customers interconnected with electric systems to comply with the recommendations offered by the President's Critical Infrastructure Protection Board and best practice recommendations from the electric reliability authority. All public utilities are expected to meet basic standards for electric system infrastructure and operational security, including physical, operational, and cyber-security practices.

1.1.6 References in these procedures to interconnection agreement are to the Small Generator Interconnection Agreement (SGIA).

1.2 Pre-Application

1.2.1 The Transmission Provider shall designate an employee or office from which information on the application process and on an Affected System can be obtained through informal requests from the Interconnection Customer presenting a proposed project for a specific site. The name, telephone number, and e-mail address of such contact employee or officeshall be made available on the Transmission Provider's Internet web site. Electric system information provided to the Interconnection Customer should include relevant system studies, interconnection studies, and other materials useful to an understanding of an interconnection at a particular point on the Transmission Provider's Transmission System, to the extent such provision does not violate confidentiality provisions of prior agreements or critical infrastructure requirements. The Transmission Provider shall comply with reasonable requests for such information.

1.2.2 In addition to the information described in section 1.2.1, which may be provided in response to an informal request, an Interconnection Customer may submit a formal written request form along with a non-refundable fee of $300 for a pre-application report on a proposed project at a specific site. The Transmission provider shall provide the pre-application data described in section 1.2.3 to the Interconnection Customer within 20 Business Days of receipt of the completed request form and payment of the $300 fee. The pre-application report produced by the Transmission Provider is non-binding, does not confer any rights, and the Interconnection Customer must still successfully apply to interconnect to the Transmission Provider’s system. The written pre-application report request form shall include the information in sections 1.2.2.1 through 1.2.2. below to clearly and sufficiently identify the location of the proposed Point of Interconnection.

1.2.2.1 Project contact information, including name, address, phone number, and email address.

1.2.2.2 Project location (street address with nearby cross streets and town)

1.2.2.3 Meter number, pole number, or other equivalent information identifying proposed Point of Interconnection, if available.

1.2.2.4 Generator Type (e.g., solar, wind, combined heat and power, etc.)

1.2.2.5 Size (alternating current kW)

1.2.2.6 Single or three phase generator configuration

1.2.2.7 Stand-alone generator (no onsite load, not including station service - Yes or No?)

1.2.2.8 Is new service requested? Yes or No? If there is existing service, include the customer account number, site minimum and maximum current or proposed electric loads in kW (if available) and specify if the load is expected to change.

1.2.3. Using the information provided in the pre-application report request form in section 1.2.2, the Transmission Provider will identify the substation/area bus, bank or circuit likely to serve the proposed Point of Interconnection. This selection by the Transmission Provider does not necessarily indicate, after application of the screens and/or study, that this would be the circuit the project ultimately connects to. The Interconnection Customer must request additional pre-application reports if information about multiple Points of Interconnection is requested. Subject to section 1.2.4, the pre-application report will include the following information:

1.2.3.1 Total capacity (in MW) of substation/area bus, bank or circuit based on normal or operating ratings likely to serve the proposed Point of Interconnection.

1.2.3.2 Existing aggregate generation capacity (in MW) interconnected to a substation/area bus, bank or circuit (i.e., amount of generation online) likely to serve the proposed Point of Interconnection.

1.2.3.3 Aggregate queued generation capacity (in MW) for a substation/area bus, bank or circuit (i.e., amount of generation in the queue) likely to serve the proposed Point of Interconnection.

1.2.3.4 Available capacity (in MW) of substation/area bus or bank and circuit likely to serve the proposed Point of Interconnection (i.e., total capacity less the sum of existing aggregate generation capacity and aggregate queued generation capacity).

1.2.3.5 Substation nominal distribution voltage and/or transmission nominal voltage if applicable.

1.2.3.6 Nominal distribution circuit voltage at the proposed Point of Interconnection.

1.2.3.7 Approximate circuit distance between the proposed Point of Interconnection and the substation.

1.2.3.8 Relevant line section(s) actual or estimated peak load and minimum load data, including daytime minimum load as described in section 2.4.4.1.1 below and absolute minimum load, when available.

1.2.3.9 Number and rating of protective devices and number and type (standard, bi-directional) of voltage regulating devices between the proposed Point of Interconnection and the substation/area. Identify whether the substation has a load tap changer.

1.2.3.10 Number of phases available at the proposed Point of Interconnection. If a single phase, distance from the three-phase circuit.

1.2.3.11 Limiting conductor ratings from the proposed Point of Interconnection to the distribution substation.

1.2.3.12 Whether the Point of Interconnection is located on a spot network, grid network, or radial supply.

1.2.3.13 Based on the proposed Point of Interconnection, existing or known constraints such as, but not limited to, electrical dependencies at that location, short circuit interruptingcapacity issues, power quality or stability issues on the circuit, capacity constraints, or secondary networks.

1.2.4 The pre-application report need only include existing data. A pre-application report request does not obligate the Transmission Provider to conduct a study or other analysis of the proposed generator in the event that data is not readily available. If the Transmission Provider cannot complete all or some of a pre-application report due to lack of available data, the Transmission Provider shall provide the Interconnection Customer with a pre-application report that includes the data that is available. The provision of information on “available capacity” pursuant to section 1.2.3.4 does not imply that an interconnection up to this level may be completed without impacts since there are many variables studied as part of the interconnection review process, and data provided in the pre-application report may become outdated at the time of the submission of the complete Interconnection Request. Notwithstanding any of the provisions of this section, the Transmission Provider shall, in good faith, include data in the pre-application report that represents the best available information at the time of reporting.

1.3 Interconnection Request

The Interconnection Customer shall submit its Interconnection Request to the Transmission Provider, together with the processing fee or deposit specified in the Interconnection Request. The Interconnection Request shall be date- and time-stamped upon receipt. The original date- and time-stamp applied to the Interconnection Request at the time of its original submission shall be accepted as the qualifying date- and time-stamp for the purposes of any timetable in these procedures. The Interconnection Customer shall be notified of receipt by the Transmission Provider within three Business Days of receiving the Interconnection Request. The Transmission Provider shall notify the Interconnection Customer within ten Business Days of the receipt of the Interconnection Request as to whether the Interconnection Request is complete or incomplete. If the Interconnection Request is incomplete, the Transmission Provider shall provide along with the notice that the Interconnection Request is incomplete, a written list detailing all information that must be provided to complete the Interconnection Request. The Interconnection Customer will have ten Business Days after receipt of the notice to submit the listed information or to request an extension of time to provide such information. If the Interconnection Customer does not provide the listed information or a request for an extension of time within the deadline, the Interconnection Request will be deemed withdrawn. An Interconnection Request will be deemed complete upon submission of the listed information to the Transmission Provider.

1.4 Modification of the Interconnection Request

Any modification to machine data or equipment configuration or to the interconnection site of the Small Generating Facility not agreed to in writing by the Transmission Provider and the Interconnection Customer may be deemed a withdrawal of the Interconnection Request and may require submission of a new Interconnection Request, unless proper notification of each Party by the other and a reasonable time to cure the problems created by the changes are undertaken.

1.5 Site Control

Documentation of site control must be submitted with the Interconnection Request. Site control may be demonstrated through:

1.5.1 Ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing the Small Generating Facility;

1.5.2 An option to purchase or acquire a leasehold site for such purpose; or

1.5.3 An exclusivity or other business relationship between the Interconnection Customer and the entity having the right to sell, lease, or grant the Interconnection Customer the right to possess or occupy a site for such purpose.

1.6 Queue Position

The Transmission Provider shall assign a Queue Position based upon the date- and time-stamp of the Interconnection Request. The Queue Position of each Interconnection Request will be used to determine the cost responsibility for the Upgrades necessary to accommodate the interconnection. The Transmission Provider shall maintain a single queue per geographic region. At the Transmission Provider's option, Interconnection Requests may be studied serially or in clusters for the purpose of the system impact study.

1.7 Interconnection Requests Submitted Prior to the Effective Date of the SGIP

Nothing in this SGIP affects an Interconnection Customer's Queue Position assigned before the effective date of this SGIP. The Parties agree to complete work on any interconnection study agreement executed prior the effective date of this SGIP in accordance with the terms and conditions of that interconnection study agreement. Any new studies or other additional work will be completed pursuant to this SGIP.

Section 2. Fast Track Process

2.1 Applicability

The Fast Track Process is available to an Interconnection Customer proposing to interconnect its Small Generating Facility with the Transmission Provider's Distribution System if the Small Generating Facility's capacity does not exceed the size limits identified in the table below. Small Generating Facilities below these limits are eligible for Fast Track review. However, Fast Track eligibility is distinct from the Fast Track Process itself, and eligibility does not imply or indicate that a Small Generating Facility will pass the Fast Track screens in section 2.2.1 below or the Supplemental Review screens in section 2.4.4 below.

Fast Track eligibility is determined based upon the generator type, the size of the generator, voltage of the line and the location of and the type of line at the Point of Interconnection. All Small Generating Facilities connecting to lines greater than 69 kilovolt (kV) are ineligible for the Fast Track Process regardless of size. All synchronous and induction machines must be no larger than 2 MW to be eligible for the Fast Track Process, regardless of location. For certified inverter-based systems, the size limit varies according to the voltage of the line at the proposed Point of Interconnection. Certified inverter-based Small Generating Facilities located within 2.5 electrical circuit miles of a substation and on a mainline (as defined in the table below) are eligible for the Fast Track Process under the higher thresholds according to the table below. In addition to the size threshold,the Interconnection Customer's proposed Small Generating Facility must meet the codes, standards, and certification requirements of Attachments 3 and 4 of these procedures, or the Transmission Provider has reviewed the design or tested the proposed Small Generating Facility and is satisfied that it is safe to operate.

Fast Track Eligibility for Inverter-Based Systems		
Line Voltage	Fast Track Eligibility Regardless of Location	Fast Track Eligibility on a Mainline and ≤ 2.5 Electrical Circuit Miles from Substation
< 5 kV	≤ 500 kW	≤ 500 kW
≥ 5 kV and < 15 kV	≤ 2 MW	≤ 3 MW
≥ 15 kV and < 30 kV	≤ 3 MW	≤ 4 MW
≥ 30 kV and ≤ 69 kV	≤ 4 MW	≤ 5 MW

2.2 Initial Review

Within 15 Business Days after the Transmission Provider notifies the Interconnection Customer it has received a complete Interconnection Request, the Transmission Provider shall perform an initial review using the screens set forth below, shall notify the Interconnection Customer of the results, and include with the notification copies of the analysis and data underlying the Transmission Provider's determinations under the screens.

2.2.1 Screens

2.2.1.1 The proposed Small Generating Facility's Point of Interconnection must be on a portion of the Transmission Provider's Distribution System that is subject to the Tariff.

2.2.1.2 For interconnection of a proposed Small Generating Facility to a radial distribution circuit, the aggregated generation, including the proposed Small Generating Facility, on the circuit shall not exceed 15 % of the line section annual peak load as most recently measured at the substation. A line section is that portion of a Transmission Provider's electric system connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line.

2.2.1.3 For interconnection of a proposed Small Generating Facility to the load side of spot network protectors, the proposed Small Generating Facility must utilize an inverter-based equipment package and, together with the aggregated other inverter-based generation, shall not exceed the smaller of 5 % of a spot network's maximum load or 50 kW.

2.2.1.4 The proposed Small Generating Facility, in aggregation with other generation on the distribution circuit, shall not contribute more than 10 % to the distribution circuit's maximum fault current at the point on the high voltage (primary) level nearest the proposed point of change of ownership.

2.2.1.5 The proposed Small Generating Facility, in aggregate with other generation on the distribution circuit, shall not cause any distribution protective devices and equipment (including, but not limited to, substation breakers, fuse cutouts, and line reclosers), or Interconnection Customer equipment on the system to exceed 87.5 % of the short circuit interrupting capability; nor shall the interconnection be proposed for a circuit that already exceeds 87.5 % of the short circuit interrupting capability.

2.2.1.6 Using the table below, determine the type of interconnection to aprimary distribution line. This screen includes a review of the type of electrical service provided to the Interconnecting Customer, including line configuration and the transformer connection tolimit the potential for creating over-voltages on the Transmission Provider's electric power system due to a loss of ground during the operating time of any anti-islanding function.

Primary Distribution Line Type	Type of Interconnection to Primary Distribution Line	Result/Criteria
Three-phase, three wire	3-phase or single phase, phase-to-phase	Pass screen
Three-phase, four wire	Effectively-grounded 3 phase or Single-phase, line--to-neutral	Pass screen

2.2.1.7 If the proposed Small Generating Facility is to be interconnected on single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed Small Generating Facility, shall not exceed 20 kW.

2.2.1.8 If the proposed Small Generating Facility is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition shall not create an imbalance between the two sides of the 240 volt service of more than 20 % of the nameplate rating of the service transformer.

2.2.1.9 The Small Generating Facility, in aggregate with other generation interconnected to the transmission side of a substation transformer feeding the circuit where the Small Generating Facility proposes to interconnect shall not exceed 10 MW in an area where there are known, or posted, transient stability limitations to generating units located in the general electrical vicinity (e.g., three or four transmission busses from the point of interconnection).

2.2.1.10 No construction of facilities by the Transmission Provider on its own system shall be required to accommodate the Small Generating Facility.

2.2.2 If the proposed interconnection passes the screens, the Interconnection Request shall be approved and the Transmission Provider will provide the Interconnection Customer an executable interconnection agreement within five Business Days after the determination.

2.2.3 If the proposed interconnection fails the screens, but the Transmission Provider determines that the Small Generating Facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards, the Transmission Provider shall provide the Interconnection Customer an executable interconnection agreement within five Business Days after the determination.

2.2.4 If the proposed interconnection fails the screens, and the Transmission Provider does not or cannot determine from the initial review that the Small Generating Facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards unless the Interconnection Customer is willing to consider minor modifications or further study, the Transmission Provider shall provide the Interconnection Customer with the opportunity to attend a customer options meeting.

2.3 Customer Options Meeting

If the Transmission Provider determines the Interconnection Request cannot be approved without (1) minor modifications at minimal cost,(2) a supplemental study or other additional studies or actions, or (3) incurring significant cost to address safety, reliability, or power quality problems, the Transmission Provider shall notify the Interconnection Customer of that determination within five Business Days after the determination and provide copies of all data and analyses underlying its conclusion. Within ten Business Days of the Transmission Provider's determination, the Transmission Provider shall offer to convene a customer options meeting with the Transmission Provider to review possible Interconnection Customer facility modifications or the screen analysis and related results, to determine what further steps are needed to permit the Small Generating Facility to be connected safely and reliably. At the time of notification of the Transmission Provider's determination, or at the customer options meeting, the Transmission Provider shall:

2.3.1 Offer to perform facility modifications or minor modifications to the Transmission Provider's electric system(e.g., changing meters, fuses, relay settings) and provide a non-binding good faith estimate of the limited cost to make such modifications to the Transmission Provider's electric system. If the Interconnection Customer agrees to pay for the modifications to the Transmission Provider’s electric system, the Transmission Provider will provide the Interconnection Customer with an executable interconnection agreement within ten Business Days of the customer options meeting; or

2.3.2 Offer to perform a supplemental review in accordance with section 2.4 and provide a non-binding good faith estimate of the costs of such review; or

2.3.3 Obtain the Interconnection Customer's agreement to continue evaluating the Interconnection Request under the section 3 Study Process.

2.4 Supplemental Review

2.4.1 To accept the offer of a supplemental review, the Interconnection Customer shall agree in writing, and submit a deposit for the estimated costs of the supplemental review in the amount of the Transmission Provider’s good faith estimate of the costs of such review, both within 15 Business Days of the offer. If the written agreement and deposit have not been received by the Transmission Provider within that timeframe, the Interconnection Request shall continue to be evaluated under section 3 Study Process unless it is withdrawn by the Interconnection Customer.

2.4.2 The Interconnection Customer may specify the order in which the Transmission Provider will complete the screens in section 2.4.4.

2.4.3 The Interconnection Customer shall be responsible for the Transmission Provider's actual costs for conducting the supplemental review. The Interconnection Customer must pay any review costs that exceed the deposit within 20Business Days of receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced costs, the Transmission Provider will return such excess within 20 Business Days of the invoice without interest.

2.4.4 Within 30 Business Days following receipt of the deposit for a supplemental review, the Transmission Provider shall (1) perform a supplemental review using the screens set forth below; (2) notify in writing the Interconnection Customer of the results; and (3) include with the notification copies of the analysis and data underlying the Transmission Provider's determinations under the screens. Unless the Interconnection Customer provided instructions for how to respond to the failure of any of the supplemental review screens below at the time the Interconnection Customer accepted the offer of supplemental review, the Transmission Provider shall notify the Interconnection Customer following the failure of any of the screens, or if it is unable to perform the screen in section 2.4.4.1, within two Business Days of making such determination to obtain the Interconnection Customer's permission to: (1) continue evaluating the proposed interconnection under this section 2.4.4; (2) terminate the supplemental review and continue evaluating the Small Generating Facility under section 3; or (3) terminate the supplemental review upon withdrawal of the Interconnection Request by the Interconnection Customer.

2.4.4.1 Minimum Load Screen: Where 12 months of line section minimum load data (including onsite load but not station service load served by the proposed Small Generating Facility) are available, can be calculated, can be estimated from existing data, or determined from a power flow model, the aggregate Generating Facility capacity on the line section is less than 100% of the minimum load for all line sections bounded by automatic sectionalizing devices upstream of the proposed Small Generating Facility. If minimum load data is not available, or cannot be calculated, estimated or determined, the Transmission Provider shall include the reason(s) that it is unable to calculate, estimate or determine minimum load in its supplemental review results notification under section 2.4.4.

2.4.4.1.1 The type of generation used by the proposed Small Generating Facility will be taken into account when calculating, estimating, or determining circuit or line section minimum load relevant for the application of screen 2.4.4.1. Solar photovoltaic (PV) generation systems with no battery storage use daytime minimum load (i.e. 10 a.m. to 4 p.m. for fixed panel systems and 8 a.m. to 6 p.m. for PV systems utilizing tracking systems), while all other generation uses absolute minimum load.

2.4.4.1.2 When this screen is being applied to a Small Generating Facility that serves some station service load, only the net injection into the Transmission Provider's electric system will be considered as part of the aggregate generation.

2.4.4.1.3 Transmission Provider will not consider as part of the aggregate generation for purposes of this screen generating facility capacity known to be already reflected in the minimum load data.

2.4.4.2 Voltage and Power Quality Screen: In aggregate with existing generation on the line section: (1) the voltage regulation on the line section can be maintained in compliance with relevant requirements under all system conditions; (2) the voltage fluctuation is within acceptable limits as defined by Institute of Electrical and Electronics Engineers (IEEE) Standard 1453, or utility practice similar to IEEE Standard 1453; and (3) the harmonic levels meet IEEE Standard 519 limits.

2.4.4.3 Safety and Reliability Screen: The location of the proposed Small Generating Facility and the aggregate generation capacity on the line section do not create impacts to safety or reliability that cannot be adequately addressed without application of the Study Process. The Transmission Provider shall give due consideration to the following and other factors in determining potential impacts to safety and reliability in applying this screen.

2.4.4.3.1 Whether the line section has significant minimum loading levels dominated by a small number of customers (e.g., several large commercial customers).

2.4.4.3.2 Whether the loading along the line section uniform or even.

2.4.4.3.3 Whether the proposed Small Generating Facility is located in close proximity to the substation (i.e., less than 2.5 electrical circuit miles), and whether the line section from the substation to the Point of Interconnection is a Mainline rated for normal and emergency ampacity.

2.4.4.3.4 Whether the proposed Small Generating Facility incorporates a time delay function to prevent reconnection of the generator to the system until system voltage and frequency are within normal limits for a prescribed time.

2.4.4.3.5 Whether operational flexibility is reduced by the proposed Small Generating Facility, such that transfer of the line section(s) of the Small Generating Facility to a neighboring distribution circuit/substation may trigger overloads or voltage issues.

2.4.4.3.6 Whether the proposed Small Generating Facility employs equipment or systems certified by a recognized standards organization to address technical issues such as, but not limited to, islanding, reverse power flow, or voltage quality.

2.4.5 If the proposed interconnection passes the supplemental screens in sections 2.4.4.1, 2.4.4.2, and 2.4.4.3 above, the Interconnection Request shall be approved and the Transmission Provider will provide the Interconnection Customer with an executable interconnection agreement within the timeframes established in sections 2.4.5.1 and 2.4.5.2 below. If the proposed interconnection fails any of the supplemental review screens and the Interconnection Customer does not withdraw its Interconnection Request, it shall continue to be evaluated under the section 3 Study Process consistent with section 2.4.5.3 below.

2.4.5.1 If the proposed interconnection passes the supplemental screens in sections 2.4.4.1, 2.4.4.2, and 2.4.4.3 above and does not require construction of facilities by the Transmission Provider on its own system, the interconnection agreement shall be provided within ten Business Days after the notification of the supplemental review results.

2.4.5.2 If interconnection facilities or minor modifications to the Transmission Provider's system are required for the proposed interconnection to pass the supplemental screens in sections 2.4.4.1, 2.4.4.2, and 2.4.4.3 above, and the Interconnection Customer agrees to pay for the modifications to the Transmission Provider’s electric system, the interconnection agreement, along with a non-binding good faith estimate for the interconnection facilities and/or minor modifications, shall be provided to the Interconnection Customer within 15 Business Days after receiving written notification of the supplemental review results.

2.4.5.3 If the proposed interconnection would require more than interconnection facilities or minor modifications to the Transmission Provider's system to pass the supplemental screens in sections 2.4.4.1, 2.4.4.2, and 2.4.4.3 above, the Transmission Provider shall notify the Interconnection Customer, at the same time it notifies the Interconnection Customer with the supplemental review results, that the Interconnection Request shall be evaluated under the section 3 Study Process unless the Interconnection Customer withdraws its Small Generating Facility.

Section 3. Study Process

3.1 Applicability

The Study Process shall be used by an Interconnection Customer proposing to interconnect its Small Generating Facility with the Transmission Provider's Transmission System or Distribution System if the Small Generating Facility (1) is larger than 2 MW but no larger than 20 MW, (2) is not certified, or (3) is certified but did not pass the Fast Track Process or the 10 kW Inverter Process.

3.2 Scoping Meeting

3.2.1 A scoping meeting will be held within ten Business Days after the Interconnection Request is deemed complete, or as otherwise mutually agreed to by the Parties. The Transmission Provider and the Interconnection Customer will bring to the meeting personnel, including system engineers and other resources as may be reasonably required to accomplish the purpose of the meeting.

3.2.2 The purpose of the scoping meeting is to discuss the Interconnection Request and review existing studies relevant to the Interconnection Request. The Parties shall further discuss whether the Transmission Provider should perform a feasibility study or proceed directly to a system impact study, or a facilities study, or an interconnection agreement. If the Parties agree that a feasibility study should be performed, the Transmission Provider shall provide the Interconnection Customer, as soon as possible, but not later than five Business Days after the scoping meeting, a feasibility study agreement (Attachment 6) including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study.

3.2.3 The scoping meeting may be omitted by mutual agreement. In order to remain in consideration for interconnection, an Interconnection Customer who has requested a feasibility study must return the executed feasibility study agreement within 15 Business Days. If the Parties agree not to perform a feasibility study, the Transmission Provider shall provide the Interconnection Customer, no later than five Business Days after the scoping meeting, a system impact study agreement

(Attachment 7) including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study.

3.3 Feasibility Study

3.3.1 The feasibility study shall identify any potential adverse system impacts that would result from the interconnection of the Small Generating Facility.

3.3.2 A deposit of the lesser of 50 percent of the good faith estimated feasibility study costs or earnest money of $1,000 may be required from the Interconnection Customer.

3.3.3 The scope of and cost responsibilities for the feasibility study are described in the attached feasibility study agreement (Attachment 6).

3.3.4 If the feasibility study shows no potential for adverse system impacts, the Transmission Provider shall send the Interconnection Customer a facilities study agreement, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study. If no additional facilities are required, the Transmission Provider shall send the Interconnection Customer an executable interconnection agreement within five Business Days.

3.3.5 If the feasibility study shows the potential for adverse system impacts, the review process shall proceed to the appropriate system impact study(s).

3.4 System Impact Study

3.4.1 A system impact study shall identify and detail the electric system impacts that would result if the proposed Small Generating Facility were interconnected without project modifications or electric system modifications, focusing on the adverse system impacts identified in the feasibility study, or to study potential impacts, including but not limited to those identified in the scoping meeting. A system impact study shall evaluate the impact of the proposed interconnection on the reliability of the electric system.

3.4.2 If no transmission system impact study is required, but potential electric power Distribution System adverse system impacts are identified in the scoping meeting or shown in the feasibility study, a distribution system impact study must be performed. The Transmission Provider shall send the Interconnection Customer a distribution system impact study agreement within 15 Business Days of transmittal of the feasibility study report, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study, or following the scoping meeting if no feasibility study is to be performed.

3.4.3 In instances where the feasibility study or the distribution system impact study shows potential for transmission system adverse system impacts, within five

Business Days following transmittal of the feasibility study report, the Transmission Provider shall send the Interconnection Customer a transmission system impact study agreement, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study, if such a study is required.

3.4.4 If a transmission system impact study is not required, but electric power Distribution System adverse system impacts are shown by the feasibility study to be possible and no distribution system impact study has been conducted, the Transmission Provider shall send the Interconnection Customer a distribution system impact study agreement.

3.4.5 If the feasibility study shows no potential for transmission system or Distribution System adverse system impacts, the Transmission Provider shall send the Interconnection Customer either a facilities study agreement (Attachment 8), including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study, or an executable interconnection agreement, as applicable.

3.4.6 In order to remain under consideration for interconnection, the Interconnection Customer must return executed system impact study agreements, if applicable, within 30 Business Days.

3.4.7 A deposit of the good faith estimated costs for each system impact study may be required from the Interconnection Customer.

3.4.8 The scope of and cost responsibilities for a system impact study are described in the attached system impact study agreement.

3.4.9 Where transmission systems and Distribution Systems have separate owners, such as is the case with transmission-dependent utilities ("TDUs") - whether investor-owned or not - the Interconnection Customer may apply to the nearest Transmission Provider (Transmission Owner, Regional Transmission Operator, or Independent Transmission Provider) providing transmission service to the TDU to request project coordination. Affected Systems shall participate in the study and provide all information necessary to prepare the study.

3.5 Facilities Study

3.5.1 Once the required system impact study(s) is completed, a system impact study report shall be prepared and transmitted to the Interconnection Customer along with a facilities study agreement within five Business Days, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the facilities study. In the case where one or both impact studies are determined to be unnecessary, a notice of the fact shall be transmitted to the Interconnection Customer within the same timeframe.

3.5.2 In order to remain under consideration for interconnection, or, as appropriate, in the Transmission Provider's interconnection queue, the Interconnection Customer must return the executed facilities study agreement or a request for an extension of time within 30 Business Days.

3.5.3 The facilities study shall specify and estimate the cost of the equipment, engineering, procurement and construction work (including overheads) needed to implement the conclusions of the system impact study(s).

3.5.4 Design for any required Interconnection Facilities and/or Upgrades shall be performed under the facilities study agreement. The Transmission Provider may contract with consultants to perform activities required under the facilities study agreement. The Interconnection Customer and the Transmission Provider may agree to allow the Interconnection Customer to separately arrange for the design of some of the Interconnection Facilities. In such cases, facilities design will be reviewed and/or modified prior to acceptance by the Transmission Provider, under the provisions of the facilities study agreement. If the Parties agree to separately arrange for design and construction, and provided security and confidentiality requirements can be met, the Transmission Provider shall make sufficient information available to the Interconnection Customer in accordance with confidentiality and critical infrastructure requirements to permit the Interconnection Customer to obtain an independent design and cost estimate for any necessary facilities.

3.5.5 A deposit of the good faith estimated costs for the facilities study may be required from the Interconnection Customer.

3.5.6 The scope of and cost responsibilities for the facilities study are described in the attached facilities study agreement.

3.5.7 Upon completion of the facilities study, and with the agreement of the Interconnection Customer to pay for Interconnection Facilities and Upgrades identified in the facilities study, the Transmission Provider shall provide the Interconnection Customer an executable interconnection agreement within five Business Days.

Section 4. Provisions that Apply to All Interconnection Requests

4.1 Reasonable Efforts

The Transmission Provider shall make reasonable efforts to meet all time frames provided in these procedures unless the Transmission Provider and the Interconnection Customer agree to a different schedule. If the Transmission Provider cannot meet a deadline provided herein, it shall notify the Interconnection Customer, explain the reason for the failure to meet the deadline, and provide an estimated time by which it will complete the applicable interconnection procedure in the process.

4.2 Disputes

4.2.1 The Parties agree to attempt to resolve all disputes arising out of the interconnection process according to the provisions of this article.

4.2.2 In the event of a dispute, either Party shall provide the other Party with a written Notice of Dispute. Such Notice shall describe in detail the nature of the dispute.

4.2.3 If the dispute has not been resolved within two Business Days after receipt of the Notice, either Party may contact FERC's Dispute Resolution Service (DRS) for assistance in resolving the dispute.

4.2.4 The DRS will assist the Parties in either resolving their dispute or in selecting an appropriate dispute resolution venue (e.g., mediation, settlement judge, early neutral evaluation, or technical expert) to assist the Parties in resolving their dispute. DRS can be reached at 1-877-337-2237 or via the internet at<http://www.ferc.gov/legal/adr.asp.>

4.2.5 Each Party agrees to conduct all negotiations in good faith and will be responsible for one-half of any costs paid to neutral third-parties.

4.2.6 If neither Party elects to seek assistance from the DRS, or if the attempted dispute resolution fails, then either Party may exercise whatever rights and remedies it may have in equity or law consistent with the terms of these procedures.

4.3 Interconnection Metering

Any metering necessitated by the use of the Small Generating Facility shall be installed at the Interconnection Customer's expense in accordance with Federal Energy Regulatory Commission, state, or local regulatory requirements or the Transmission Provider's specifications.

4.4 Commissioning

Commissioning tests of the Interconnection Customer's installed equipment shall be performed pursuant to applicable codes and standards. The Transmission Provider must be given at least five Business Days written notice, or as otherwise mutually agreed to by the Parties, of the tests and may be present to witness the commissioning tests.

4.5. Confidentiality

4.5.1 Confidential information shall mean any confidential and/or proprietary information provided by one Party to the other Party that is clearly marked or otherwise designated "Confidential." For purposes of these procedures all design, operating specifications, and metering data provided by the Interconnection Customer shall be deemed confidential information regardless of whether it is clearly marked or otherwise designated as such.

4.5.2 Confidential Information does not include information previously in the public domain, required to be publicly submitted or divulged by Governmental Authorities (after notice to the other Party and after exhausting any opportunity to oppose such publication or release), or necessary to be divulged in an action to enforce these procedures. Each Party receiving Confidential Information shall hold such information in confidence and shall not disclose it to any third party nor tothe public without the prior written authorization from the Party providing that information, except to fulfill obligations under these procedures, or to fulfill legal or regulatory requirements.

4.5.2.1 Each Party shall employ at least the same standard of care to protect Confidential Information obtained from the other Party as it employs to protect its own Confidential Information.

4.5.2.2 Each Party is entitled to equitable relief, by injunction or otherwise, to enforce its rights under this provision to prevent the release of Confidential Information without bond or proof of damages, and may seek other remedies available at law or in equity for breach of this provision.

4.5.3 Notwithstanding anything in this article to the contrary, and pursuant to 18 CFR § 1b.20, if FERC, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to these procedures, the Party shall provide the requested information to FERC, within the time provided for in the request for information. In providing the information to FERC, the Party may, consistent with 18 CFR § 388.112, request that the information be treated as confidential and non-public by FERC and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Party prior to the release of the Confidential Information to FERC. The Party shall notify the other Party when it is notified by FERC that a request to release Confidential Information has been received by FERC, at which time either of the Parties may respond before such information would be made public, pursuant to 18 CFR § 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner if consistent with the applicable state rules and regulations.

4.6 Comparability

The Transmission Provider shall receive, process and analyze all Interconnection

Requests in a timely manner as set forth in this document. The Transmission Provider shall use the same reasonable efforts in processing and analyzing Interconnection Requests from all Interconnection Customers, whether the Small Generating Facility is owned or operated by the Transmission Provider, its subsidiaries or affiliates, or others.

4.7 Record Retention

The Transmission Provider shall maintain for three years records, subject to audit, of all Interconnection Requests received under these procedures, the times required to complete Interconnection Request approvals and disapprovals, and justification for the actions taken on the Interconnection Requests.

4.8 Interconnection Agreement

After receiving an interconnection agreement from the Transmission Provider, the Interconnection Customer shall have 30 Business Days or another mutually agreeable timeframe to sign and return the interconnection agreement, or request that the Transmission Provider file an unexecuted interconnection agreement with the Federal Energy Regulatory Commission. If the Interconnection Customer does not sign the interconnection agreement, or ask that it be filed unexecuted by the Transmission Provider within 30 Business Days, the Interconnection Request shall be deemed withdrawn. After the interconnection agreement is signed by the Parties, the interconnection of the Small Generating Facility shall proceed under the provisions of the interconnection agreement.

4.9 Coordination with Affected Systems

The Transmission Provider shall coordinate the conduct of any studies required to determine the impact of the Interconnection Request on Affected Systems with Affected System operators and, if possible, include those results (if available) in its applicable interconnection study within the time frame specified in these procedures. The Transmission Provider will include such Affected System operators in all meetings held with the Interconnection Customer as required by these procedures. The Interconnection Customer will cooperate with the Transmission Provider in all matters related to the conduct of studies and the determination of modifications to Affected Systems. A Transmission Provider which may be an Affected System shall cooperate with the Transmission Provider with whom interconnection has been requested in all matters related to the conduct of studies and the determination of modifications to Affected Systems.

4.10 Capacity of the Small Generating Facility

4.10.1 If the Interconnection Request is for an increase in capacity for an existing Small Generating Facility, the Interconnection Request shall be evaluated on the basis of the new total capacity of the Small Generating Facility.

4.10.2 If the Interconnection Request is for a Small Generating Facility that includes multiple energy production devices at a site for which the Interconnection Customer seeks a single Point of Interconnection, the Interconnection Request shall be evaluated on the basis of the aggregate capacity of the multiple devices.

4.10.3 The Interconnection Request shall be evaluated using the maximum capacity that the Small Generating Facilityis capable of injecting into the Transmission Provider's electric system. However, if the maximum capacity that the Small Generating Facility is capable of injecting into the Transmission Provider's electric system is limited (e.g., through use of a control system, power relay(s), or other similar device settings or adjustments), then the Interconnection Customer must obtain the Transmission Provider's agreement, with such agreement not to be unreasonably withheld, that the manner in which the Interconnection Customer proposes to implement such a limit will not adversely affect the safety and reliability of the Transmission Provider's system. If the Transmission Provider does not so agree, then the Interconnection Request must be withdrawn or revised to specify the maximum capacity that the Small Generating Facility is capable of injecting into the Transmission Provider's electric system without such limitations. Furthermore, nothing in this section shall prevent a Transmission Provider from considering an output higher than the limited output, if appropriate, when evaluating system protection impacts.

5. EIM Requirements

5.1 The Interconnection Customer shall have a continuing duty to comply with Attachment O of this Tariff, as applicable.

Attachment 1

Glossary of Terms

10 kW Inverter Process - The procedure for evaluating an Interconnection Request for a certified inverter-based Small Generating Facility no larger than 10 kW that uses the section 2 screens. The application process uses an all-in-one document that includes a simplified Interconnection Request, simplified procedures, and a brief set of terms and conditions. See SGIP Attachment 5.

Affected System - An electric system other than the Transmission Provider's Transmission System that may be affected by the proposed interconnection.

Business Day - Monday through Friday, excluding Federal Holidays.

Distribution System - The Transmission Provider's facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries directly from nearby generators or from interchanges with higher voltage transmission networks which transport bulk power over longer distances. The voltage levels at which Distribution Systems operate differ among areas.

Distribution Upgrades - The additions, modifications, and upgrades to the Transmission Provider's Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Small Generating Facility and render the transmission service necessary to effect the Interconnection Customer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Interconnection Facilities.

Fast Track Process - The procedure for evaluating an Interconnection Request for a certified Small Generating Facility that meets the eligibility requirements of section 2.1 and includes the section 2 screens, customer options meeting, and optional supplemental review.

Good Utility Practice - Any of the practices, methods and acts engaged in or approved by a significant portion of the electric industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

Interconnection Customer - Any entity, including the Transmission Provider, the Transmission Owner or any of the affiliates or subsidiaries of either, that proposes to interconnect its Small Generating Facility with the Transmission Provider's Transmission System.

Interconnection Facilities - The Transmission Provider's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Small Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Small Generating Facility to the Transmission Provider's Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades or Network Upgrades.

Interconnection Request - The Interconnection Customer's request, in accordance with the Tariff, to interconnect a new Small Generating Facility, or to increase the capacity of, or make a Material Modification to the operating characteristics of, an existing Small Generating Facility that is interconnected with the Transmission Provider's Transmission System.

Material Modification - A modification that has a material impact on the cost or timing of any Interconnection Request with a later queue priority date.

Network Resource - Any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

Network Resource Interconnection Service - An Interconnection Service that allows the Interconnection Customer to integrate its Generating Facility with the Transmission Provider's System (1) in a manner comparable to that in which the Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an RTO or ISO with market based congestion management, in the same manner as Network Resources. Network Resource Interconnection Service in and of itself does not convey transmission service.

Network Upgrades - Additions, modifications, and upgrades to the Transmission Provider's Transmission System required at or beyond the point at which the Small Generating Facility interconnects with the Transmission Provider's Transmission System to accommodate the interconnection with the Small Generating Facility to the Transmission Provider's Transmission System. Network Upgrades do not include Distribution Upgrades.

Party or Parties - The Transmission Provider, Transmission Owner, Interconnection Customer or any combination of the above.

Point of Interconnection - The point where the Interconnection Facilities connect with the Transmission Provider's Transmission System.

Queue Position - The order of a valid Interconnection Request, relative to all other pending valid Interconnection Requests, that is established based upon the date and time of receipt of the valid Interconnection Request by the Transmission Provider.

Small Generating Facility - The Interconnection Customer's device for the production and/or storage for later injection of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities.

Study Process - The procedure for evaluating an Interconnection Request that includes the section 3 scoping meeting, feasibility study, system impact study, and facilities study.

Transmission Owner - The entity that owns, leases or otherwise possesses an interest in the portion of the Transmission System at the Point of Interconnection and may be a Party to the Small Generator Interconnection Agreement to the extent necessary.

Transmission Provider - The public utility (or its designated agent) that owns, controls, or operates transmission or distribution facilities used for the transmission of electricity in interstate commerce and provides transmission service under the Tariff. The term Transmission Provider should be read to include the Transmission Owner when the Transmission Owner is separate from the Transmission Provider.

Transmission System - The facilities owned, controlled or operated by the Transmission Provider or the Transmission Owner that are used to provide transmission service under the Tariff.

Upgrades - The required additions and modifications to the Transmission Provider's Transmission System at or beyond the Point of Interconnection. Upgrades may be Network Upgrades or Distribution Upgrades. Upgrades do not include Interconnection Facilities.

Attachment 2

SMALL GENERATOR INTERCONNECTION REQUEST
(Application Form)

Transmission Provider: ____

Designated Contact Person: ____

Address: ____

Telephone Number: ____

Fax: ____

E-Mail Address:

An Interconnection Request is considered complete when it provides all applicable and correct information required below. Per SGIP section 1.5, documentation of site control must be submitted with the Interconnection Request.

Preamble and Instructions

An Interconnection Customer who requests a Federal Energy Regulatory Commission jurisdictional interconnection must submit this Interconnection Request by hand delivery, mail, e-mail, or fax to the Transmission Provider.

Processing Fee or Deposit:

If the Interconnection Request is submitted under the Fast Track Process, the non-refundable processing fee is $500.

If the Interconnection Request is submitted under the Study Process, whether a new submission or an Interconnection Request that did not pass the Fast Track Process, the Interconnection Customer shall submit to the Transmission Provider a deposit not to exceed $1,000 towards the cost of the feasibility study.

Interconnection Customer Information

Legal Name of the Interconnection Customer (or, if an individual, individual's name)

Name: ____

Contact Person: ____

Mailing Address: ____

City: ______________________ State: ______________________ Zip: ______________

Facility Location (if different from above): ____

Telephone (Day): ____________________ Telephone (Evening):____________________

Fax: ______________________________E-Mail Address: ________________________________

Alternative Contact Information (if different from the Interconnection Customer)

Contact Name: ____

Title: ____

Address:

Telephone (Day): ____________________ Telephone (Evening):

Fax: E-Mail Address:

Application is for: _____ New Small Generating Facility
_____ Capacity addition to Existing Small Generating Facility

If capacity addition to existing facility, please describe: ____________________________

Will the Small Generating Facility be used for any of the following?

Net Metering? Yes ___ No ___
To Supply Power to the Interconnection Customer? Yes ___No
___ To Supply Power to Others? Yes ____ No ____

For installations at locations with existing electric service to which the proposed Small Generating Facility will interconnect, provide:

(Local Electric Service Provider*) (Existing Account Number*)

[*To be provided by the Interconnection Customer if the local electric service provider is different from the Transmission Provider]

Contact Name: ____

Title: ____

Address:

Telephone (Day): ____________________________ Telephone (Evening):_____________________

Fax: ____ E-Mail Address:________________________

Requested Point of Interconnection:____

Interconnection Customer's Requested In-Service Date: ____

Small Generating Facility Information
Data apply only to the Small Generating Facility, not the Interconnection Facilities.

Energy Source: ___ Solar ___ Wind ___ Hydro ___ Hydro Type (e.g. Run-of-River):
Diesel ___ Natural Gas ___ Fuel Oil ___ Other (state type) ___________________

Prime Mover: Fuel Cell Recip Engine Gas Turb Steam Turb
Microturbine PV Other

Type of Generator: ____Synchronous ____Induction ____ Inverter

Generator Nameplate Rating: ________kW (Typical) Generator Nameplate kVAR:

Interconnection Customer or Customer-Site Load: _________________ kW (if none, so state)

Typical Reactive Load (if known):__________________

Maximum Physical Export Capability Requested:_______________ kW

List components of the Small Generating Facility equipment package that are currently certified:

Equipment Type Certifying Entity
1. ____________________
2. ____________________
3. ____________________
4. ____________________
5.

Is the prime mover compatible with the certified protective relay package? ____Yes ____No

Generator (or solar collector)
Manufacturer, Model Name & Number:____
Version Number:

Nameplate Output Power Rating in kW: (Summer)_______________ (Winter)
Nameplate Output Power Rating in kVA: (Summer)______________ (Winter)
Individual Generator Power Factor
Rated Power Factor: Leading:______________Lagging:

Total Number of Generators in wind farm to be interconnected pursuant to this
Interconnection Request: ___________ Elevation: ______ ___Single phase ___Three phase

Inverter Manufacturer, Model Name & Number (if used):__________________________________

List of adjustable set points for the protective equipment or software: ________________________

Note: A completed Power Systems Load Flow data sheet must be supplied with the Interconnection Request.

Small Generating Facility Characteristic Data (for inverter-based machines)

Max design fault contribution current: _____________ Instantaneous or RMS?

Harmonics Characteristics: ____

Start-up requirements: ____

Small Generating Facility Characteristic Data (for rotating machines)

RPM Frequency: ______________
(*) Neutral Grounding Resistor (If Applicable):

Synchronous Generators:

Direct Axis Synchronous Reactance, Xd: ________ P.U.
Direct Axis Transient Reactance, X'_d: ___________ P.U.
Direct Axis Subtransient Reactance, X''_d: ______________ P.U.
Negative Sequence Reactance, X_2: __________P.U.
Zero Sequence Reactance, X_0: _____________P.U.
KVA Base: ___________________________
Field Volts: ______________
Field Amperes: ______________

Induction Generators:

Motoring Power (kW): _______
I_2^2t or K (Heating Time Constant):
Rotor Resistance, Rr: ________

Stator Resistance, Rs: ______________
Stator Reactance, Xs: _______________
Rotor Reactance, Xr: _______________
Magnetizing Reactance, Xm: ______________
Short Circuit Reactance, Xd'': ______________
Exciting Current: _______________
Temperature Rise: _______________
Frame Size: ______________
Design Letter: _______________
Reactive Power Required In Vars (No Load): ______________
Reactive Power Required In Vars (Full Load): _______________

Total Rotating Inertia, H: ______________ Per Unit on kVA Base

Note: Please contact the Transmission Provider prior to submitting the Interconnection Request to determine if the specified information above is required.

Excitation and Governor System Data for Synchronous Generators Only

Provide appropriate IEEE model block diagram of excitation system, governor system and power system stabilizer (PSS) in accordance with the regional reliability council criteria. A PSS may be determined to be required by applicable studies. A copy of the manufacturer's block diagram may not be substituted.

Interconnection Facilities Information

Will a transformer be used between the generator and the point of common coupling? ___Yes ___No

Will the transformer be provided by the Interconnection Customer? ____Yes ____No Transformer Data

(If Applicable, for Interconnection Customer-Owned Transformer):

Is the transformer: ____single phase _____three phase? Size: __________ kVA
Transformer Impedance: _______ % on _________ kVA Base

If Three Phase:
Transformer Primary: _____ Volts _____ Delta _____Wye _____ Wye Grounded
Transformer Secondary: _____ Volts _____ Delta _____Wye _____ Wye Grounded
Transformer Tertiary: _____ Volts _____ Delta _____Wye _____ Wye Grounded

Transformer Fuse Data (If Applicable, for Interconnection Customer-Owned Fuse):

(Attach copy of fuse manufacturer's Minimum Melt and Total Clearing Time-Current Curves)

Manufacturer: __________________Type: _______________ Size: ________ Speed: _____

Interconnecting Circuit Breaker (if applicable):

Manufacturer: ____________________________ Type: _________
Load Rating (Amps): _______Interrupting Rating (Amps): ________ Trip Speed (Cycles): _______

Interconnection Protective Relays (If Applicable):

If Microprocessor-Controlled:

List of Functions and Adjustable Setpoints for the protective equipment or software:

Setpoint Function	Minimum	Maximum
1. ______________________________	__________	__________

3. ______________________________________ _____________ _____________

5. ______________________________________ _____________ _____________

If Discrete Components:

(Enclose Copy of any Proposed Time-Overcurrent Coordination Curves)

Manufacturer:	Type:	Style/Catalog No.:	Proposed Setting:
Manufacturer:	Type:	Style/Catalog No.:	Proposed Setting:
Manufacturer:	Type:	Style/Catalog No.:	Proposed Setting:
Manufacturer:	Type:	Style/Catalog No.:	Proposed Setting:
Manufacturer:	Type:	Style/Catalog No.:	Proposed Setting:

Current Transformer Data (If Applicable):

(Enclose Copy of Manufacturer's Excitation and Ratio Correction Curves)

Manufacturer: ____
Type: ______________ Accuracy Class: Proposed Ratio Connection: ____

Manufacturer: ____
Type: ______________ Accuracy Class: Proposed Ratio Connection: ____

Potential Transformer Data (If Applicable):

Manufacturer:

Type: _______________ Accuracy Class: Proposed Ratio Connection: ____

Manufacturer: ____
Type: _______________ Accuracy Class: Proposed Ratio Connection: ____

General Information

Enclose copy of site electrical one-line diagram showing the configuration of all Small Generating Facility equipment, current and potential circuits, and protection and control schemes. This one-line diagram must be signed and stamped by a licensed Professional Engineer if the Small Generating Facility is larger than 50 kW. Is One-Line Diagram Enclosed? ____Yes ____No

Enclose copy of any site documentation that indicates the precise physical location of the proposed Small Generating Facility (e.g., USGS topographic map or other diagram or documentation).

Proposed location of protective interface equipment on property (include address if different from the Interconnection Customer's address)

Enclose copy of any site documentation that describes and details the operation of the protection and control schemes. Is Available Documentation Enclosed? ___Yes ____No

Enclose copies of schematic drawings for all protection and control circuits, relay current circuits, relay potential circuits, and alarm/monitoring circuits (if applicable). Are Schematic Drawings Enclosed? ___Yes ____No

Applicant Signature

I hereby certify that, to the best of my knowledge, all the information provided in this Interconnection Request is true and correct.

For Interconnection Customer: Date:

Attachment 3

Certification Codes and Standards

IEEE1547 Standard for Interconnecting Distributed Resources with Electric Power Systems (including use of IEEE 1547.1 testing protocols to establish conformity)

UL 1741 Inverters, Converters, and Controllers for Use in Independent Power Systems

IEEE Std 929-2000 IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems

NFPA 70 (2002), National Electrical Code

IEEE Std C37.90.1-1989 (R1994), IEEE Standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems

IEEE Std C37.90.2 (1995), IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers

IEEE Std C37.108-1989 (R2002), IEEE Guide for the Protection of Network Transformers

IEEE Std C57.12.44-2000, IEEE Standard Requirements for Secondary Network Protectors

IEEE Std C62.41.2-2002, IEEE Recommended Practice on Characterization of Surges in Low Voltage (1000V and Less) AC Power Circuits

IEEE Std C62.45-1992 (R2002), IEEE Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (1000V and Less) AC Power Circuits

ANSI C84.1-1995 Electric Power Systems and Equipment - Voltage Ratings (60 Hertz)

IEEE Std 100-2000, IEEE Standard Dictionary of Electrical and Electronic Terms
NEMA MG 1-1998, Motors and Small Resources, Revision 3

IEEE Std 519-1992, IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems

NEMA MG 1-2003 (Rev 2004), Motors and Generators, Revision 1

Attachment 4

Certification of Small Generator Equipment Packages

1.0 Small Generating Facility equipment proposed for use separately or packaged with other equipment in an interconnection system shall be considered certified for interconnected operation if (1) it has been tested in accordance with industry standards for continuous utility interactive operation in compliance with the appropriate codes and standards referenced below by any Nationally Recognized Testing Laboratory (NRTL) recognized by the United States Occupational Safety and Health Administration to test and certify interconnection equipment pursuant to the relevant codes and standards listed in SGIP Attachment 3, (2) it has been labeled and is publicly listed by such NRTL at the time of the interconnection application, and (3) such NRTL makes readily available for verification all test standards and procedures it utilized in performing such equipment certification, and, with consumer approval, the test data itself. The NRTL may make such information available on its website and by encouraging such information to be included in the manufacturer's literature accompanying the equipment.

2.0 The Interconnection Customer must verify that the intended use of the equipment falls within the use or uses for which the equipment was tested, labeled, and listed by the NRTL.

3.0 Certified equipment shall not require further type-test review, testing, or additional equipment to meet the requirements of this interconnection procedure; however, nothing herein shall preclude the need for an on-site commissioning test by the parties to the interconnection nor follow-up production testing by the NRTL.

4.0 If the certified equipment package includes only interface components (switchgear, inverters, or other interface devices), then an Interconnection Customer must show that the generator or other electric source being utilized with the equipment package is compatible with the equipment package and is consistent with the testing and listing specified for this type of interconnection equipment.

5.0 Provided the generator or electric source, when combined with the equipment package, is within the range of capabilities for which it was tested by the NRTL, and does not violate the interface components' labeling and listing performed by the NRTL, no further design review, testing or additional equipment on the customer side of the point of common coupling shall be required to meet the requirements of this interconnection procedure.

6.0 An equipment package does not include equipment provided by the utility.

7.0 Any equipment package approved and listed in a state by that state's regulatory body for interconnected operation in that state prior to the effective date of these small generator interconnection procedures shall be considered certified under these procedures for use in that state.

Attachment 5

Application, Procedures, and Terms and Conditions for Interconnecting a Certified Inverter-Based Small Generating Facility No Larger than 10 kW ("10 kW Inverter Process")

1.0 The Interconnection Customer ("Customer") completes the Interconnection Request ("Application") and submits it to the Transmission Provider ("Company").

2.0 The Company acknowledges to the Customer receipt of the Application within three Business Days of receipt.

3.0 The Company evaluates the Application for completeness and notifies the Customer within ten Business Days of receipt that the Application is or is not complete and, if not, advises what material is missing.

4.0 The Company verifies that the Small Generating Facility can be interconnected safely and reliably using the screens contained in the Fast Track Process in the Small Generator Interconnection Procedures (SGIP). The Company has 15 Business Days to complete this process. Unless the Company determines and demonstrates that the Small Generating Facility cannot be interconnected safely and reliably, the Company approves the Application and returns it to the Customer. Note to Customer: Please check with the Company before submitting the Application if disconnection equipment is required.

5.0 After installation, the Customer returns the Certificate of Completion to the Company. Prior to parallel operation, the Company may inspect the Small Generating Facility for compliance with standards which may include a witness test, and may schedule appropriate metering replacement, if necessary.

6.0 The Company notifies the Customer in writing that interconnection of the Small Generating Facility is authorized. If the witness test is not satisfactory, the Company has the right to disconnect the Small Generating Facility. The Customer has no right to operate in parallel until a witness test has been performed, or previously waived on the Application. The Company is obligated to complete this witness test within ten Business Days of the receipt of the Certificate of Completion. If the Company does not inspect within ten Business Days or by mutual agreement of the Parties, the witness test is deemed waived.

7.0 Contact Information - The Customer must provide the contact information for the legal applicant(i.e., the Interconnection Customer). If another entity is responsible for interfacing with the Company, that contact information must be provided on the Application.

8.0 Ownership Information - Enter the legal names of the owner(s) of the Small Generating Facility. Include the percentage ownership (if any) by any utility or public utility holding company, or by any entity owned by either.

9.0 UL1741 Listed - This standard ("Inverters, Converters, and Controllers for Use in Independent Power Systems") addresses the electrical interconnection design of various forms of generating equipment. Many manufacturers submit their equipment to a Nationally Recognized Testing Laboratory (NRTL) that verifies compliance with UL1741. This "listing" is then marked on the equipment and supporting documentation.

Application for Interconnecting a Certified Inverter-Based SmallGenerating Facility No Larger than 10kW

This Application is considered complete when it provides all applicable and correct information required below. Per GSIP section 1.5, documentation of site control must be submitted with the Interconnection Request. Additional information to evaluate the Application may be required.

Processing Fee

A non-refundable processing fee of $100 must accompany this Application.

Interconnection Customer

Name: ____

Contact Person: ____

Address: ____

City: ________________________________ State: ____________________ Zip: ____________

Telephone (Day): ________________________ (Evening): ______________________________

Fax: E-Mail Address:

Contact (if different from Interconnection Customer)

Name: ____

Address: ____

City: ________________________________ State: ____________________ Zip: ____________

Telephone (Day): ________________________ (Evening): ______________________________

Fax: E-Mail Address:

Owner of the facility (include % ownership by any electric utility): ________________________

Small Generating Facility Information

Location (if different from above): ____

Electric Service Company: ____

Account Number:

Inverter Manufacturer: ______________________ Model ______________________________

Nameplate Rating: ______ (kW) _____ (kVA) _______(AC Volts)

Single Phase _______ Three Phase _____

System Design Capacity: _________ (kW) ______ (kVA)

Prime Mover: Photovoltaic Reciprocating Engine Fuel Cell

Turbine Other

Energy Source: Solar Wind Hydro Diesel Natural Gas

Fuel Oil Other (describe) _________________

Is the equipment UL1741 Listed? Yes _____ No
If Yes, attach manufacturer's cut-sheet showing UL1741 listing

Estimated Installation Date: Estimated In-Service Date:

The 10 kW Inverter Process is available only for inverter-based Small Generating Facilities no larger than 10 kW that meet the codes, standards, and certification requirements of Attachments 3 and 4 of the Small Generator Interconnection Procedures (SGIP), or the Transmission Provider has reviewed the design or tested the proposed Small Generating Facility and is satisfied that it is safe to operate.

List components of the Small Generating Facility equipment package that are currently certified:

Equipment Type Certifying Entity
1. ____________________
2. ____________________
3. ____________________
4. ____________________
5.

Interconnection Customer Signature

I hereby certify that, to the best of my knowledge, the information provided in this Application is true. I agree to abide by the Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW and return the Certificate of Completion when the Small Generating Facility has been installed.

Signed: ____

Title: ____ Date: _____________

Contingent Approval to Interconnect the Small Generating Facility (For Company use only)

Interconnection of the Small Generating Facility is approved contingent upon the Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW and return of the Certificate of Completion.

Company Signature: ________________________________

Title: _______________________________________ Date:

Application ID number: _________________

Company waives inspection/witness test? Yes___No___

Small Generating Facility Certificate of Completion

Is the Small Generating Facility owner-installed? Yes______ No ______

Interconnection Customer:____

Contact Person: ____

Address:____

Location of the Small Generating Facility (if different from above):

City:____ State: ____________________ Zip Code: ________

Telephone (Day):_____________________________ (Evening): ___________________________________

Fax: ____ E-Mail Address: _____________________________

Electrician:

Name:____

Address:____

City:____ State: ____________________ Zip Code: ________

Telephone (Day):_____________________________ (Evening): ___________________________________

Fax: ____ E-Mail Address: _____________________________

License number:

Date Approval to Install Facility granted by the

Company: Application ID number:

Inspection:

The Small Generating Facility has been installed and inspected in compliance with the local

building/electrical code of ____

Signed (Local electrical wiring inspector, or attach signed electrical inspection):

Print Name:

Date:

As a condition of interconnection, you are required to send/fax a copy of this form along with a copy of the signed electrical permit to (insert Company information below):

Name: ____

Company: ____

Address:

City,

State

ZIP:

Fax:

Approval to Energize the Small Generating Facility (For Company use only)

Energizing the Small Generating Facility is approved contingent upon the Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW

Company Signature: ____

Title: Date:

Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW

1.0 **Construction of the Facility**
The Interconnection Customer (the "Customer") may proceed to construct (including operational testing not to exceed two hours) the Small Generating Facility when the Transmission Provider (the "Company") approves the Interconnection Request (the "Application") and returns it to the Customer.

2.0 **Interconnection and Operation**
The Customer may operate Small Generating Facility and interconnect with the Company's electric system once all of the following have occurred:

2.1 Upon completing construction, the Customer will cause the Small Generating Facility to be inspected or otherwise certified by the appropriate local electrical wiring inspector with jurisdiction, and

2.2 The Customer returns the Certificate of Completion to the Company, and

2.3 The Company has either:

2.3.1 Completed its inspection of the Small Generating Facility to ensure that all equipment has been appropriately installed and that all electrical connections have been made in accordance with applicable codes. All inspections must be conducted by the Company, at its own expense, within ten Business Days after receipt of the Certificate of Completion and shall take place at a time agreeable to the Parties. The Company shall provide a written statement that the Small Generating Facility has passed inspection or shall notify the Customer of what steps it must take to pass inspection as soon as practicable after the inspection takes place; or

2.3.2 If the Company does not schedule an inspection of the Small Generating Facility within ten business days after receiving the Certificate of Completion, the witness test is deemed waived (unless the Parties agree otherwise); or

2.3.3 The Company waives the right to inspect the Small Generating Facility.

2.4 The Company has the right to disconnect the Small Generating Facility in the event of improper installation or failure to return the Certificate of Completion.

2.5 Revenue quality metering equipment must be installed and tested in accordance with applicable ANSI standards.

3.0 **Safe Operations and Maintenance**
The Customer shall be fully responsible to operate, maintain, and repair the Small Generating Facility as required to ensure that it complies at all times with the interconnection standards to which it has been certified.

4.0 **Access**

The Company shall have access to the disconnect switch (if the disconnect switch is required) and metering equipment of the Small Generating Facility at all times. The Company shall provide reasonable notice to the Customer when possible prior to using its right of access.

5.0 **Disconnection**

The Company may temporarily disconnect the Small Generating Facility upon the following conditions:

5.1 For scheduled outages upon reasonable notice.

5.2 For unscheduled outages or emergency conditions.

5.3 If the Small Generating Facility does not operate in the manner consistent with these Terms and Conditions.

5.4 The Company shall inform the Customer in advance of any scheduled disconnection, or as is reasonable after an unscheduled disconnection.

6.0 **Indemnification**

The Parties shall at all times indemnify, defend, and save the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or inactions of its obligations under this agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

7. 0 **Insurance**

The Parties agree to follow all applicable insurance requirements imposed by the state in which the Point of Interconnection is located. All insurance policies must be maintained with insurers authorized to do business in that state.

8.0 **Limitation of Liability**

Each party’s liability to the other party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney’s fees, relating to or arising from any act or omission in its performance of this Agreement, shall be limited to the amount of direct damage actually incurred. In no event shall either party be liable to the other party for any indirect, incidental, special, consequential, or punitive damages of any kind whatsoever, except as allowed under paragraph 6.0.

9.0 **Termination**

The agreement to operate in parallel may be terminated under the following conditions:

9.1 **By the Customer**

By providing written notice to the Company.

9.2 **By the Company**

If the Small Generating Facility fails to operate for any consecutive 12 month period or the Customer fails to remedy a violation of these Terms and Conditions.

9.3 **Permanent Disconnection**

In the event this Agreement is terminated, the Company shall have the right to disconnect its facilities or direct the Customer to disconnect its Small Generating Facility.

9.4 **Survival Rights**

This Agreement shall continue in effect after termination to the extent necessary to allow or require either Party to fulfill rights or obligations that arose under the Agreement.

10.0 **Assignment/Transfer of Ownership of the Facility**

This Agreement shall survive the transfer of ownership of the Small Generating Facility to a new owner when the new owner agrees in writing to comply with the terms of this Agreement and so notifies the Company.

Attachment 6

Feasibility Study Agreement

THIS AGREEMENT is made and entered into this_____day of___________________ 20___ by and between ____ , a___________________________________ organized and existing under the laws of the State of ____, ("Interconnection Customer,") and ____ , a ________________ existing under the laws of the State of ____, ("Transmission Provider"). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, Interconnection Customer is proposing to develop a Small Generating Facility or generating capacity addition to an existing Small Generating Facility consistent with the Interconnection Request completed by Interconnection Customer on____________________________; and

WHEREAS, Interconnection Customer desires to interconnect the Small Generating Facility with the Transmission Provider's Transmission System; and

WHEREAS, Interconnection Customer has requested the Transmission Provider to perform a feasibility study to assess the feasibility of interconnecting the proposed Small Generating Facility with the Transmission Provider's Transmission System, and of any Affected Systems;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the standard Small Generator Interconnection Procedures.

2.0 The Interconnection Customer elects and the Transmission Provider shall cause to be performed an interconnection feasibility study consistent the standard Small

Generator Interconnection Procedures in accordance with the Open Access Transmission Tariff.

3.0 The scope of the feasibility study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 The feasibility study shall be based on the technical information provided by the Interconnection Customer in the Interconnection Request, as may be modified as the result of the scoping meeting. The Transmission Provider reserves the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the feasibility study and as designated in accordance with the standard Small Generator Interconnection Procedures. If the Interconnection Customer modifies its Interconnection Request, the time to complete the feasibility study may be extended by agreement of the Parties.

5.0 In performing the study, the Transmission Provider shall rely, to the extent reasonably practicable, on existing studies of recent vintage. The Interconnection Customer shall not be charged for such existing studies; however, the Interconnection Customer shall be responsible for charges associated with any new study or modifications to existing studies that are reasonably necessary to perform the feasibility study.

6.0 The feasibility study report shall provide the following analyses for the purpose of identifying any potential adverse system impacts that would result from the interconnection of the Small Generating Facility as proposed:

6.1 Initial identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;

6.2 Initial identification of any thermal overload or voltage limit violations resulting from the interconnection;

6.3 Initial review of grounding requirements and electric system protection; and

6.4 Description and non-binding estimated cost of facilities required to interconnect the proposed Small Generating Facility and to address the identified short circuit and power flow issues.

7.0 The feasibility study shall model the impact of the Small Generating Facility regardless of purpose in order to avoid the further expense and interruption of operation for reexamination of feasibility and impacts if the Interconnection Customer later changes the purpose for which the Small Generating Facility is being installed.

8.0 The study shall include the feasibility of any interconnection at a proposed project site where there could be multiple potential Points of Interconnection, as requested by the Interconnection Customer and at the Interconnection Customer's cost.

9.0 A deposit of the lesser of 50 percent of good faith estimated feasibility study costs or earnest money of $1,000 may be required from the Interconnection Customer.

10.0 Once the feasibility study is completed, a feasibility study report shall be prepared and transmitted to the Interconnection Customer. Barring unusual circumstances, the feasibility study must be completed and the feasibility study report transmitted within 30 Business Days of the Interconnection Customer's agreement to conduct a feasibility study.

11.0 Any study fees shall be based on the Transmission Provider's actual costs and will be invoiced to the Interconnection Customer after the study is completed and delivered and will include a summary of professional time.

12.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 calendar days on receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the Transmission Provider shall refund such excess within 30 calendar days of the invoice without interest.

13.0 Governing Law, Regulatory Authority, and Rules

The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the state of________________________ (where the Point of Interconnection is located), without regard to its conflicts of law principles. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.

14.0 Amendment

The Parties may amend this Agreement by a written instrument duly executed by both Parties.

15.0 No Third-Party Beneficiaries

This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and where permitted, their assigns.

16.0 Waiver

16.1 The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

16.2 Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Termination or default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Transmission Provider. Any waiver of this Agreement shall, if requested, be provided in writing.

17.0 Multiple Counterparts

This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

18.0 No Partnership

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

19.0 Severability

If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to

restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

20.0 Subcontractors

Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Party for the performance of such subcontractor.

20.1 The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall the Transmission Provider be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

20.2 The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.

21.0 Reservation of Rights

The Transmission Provider shall have the right to make a unilateral filing with FERC to modify this Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and the Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this Agreement under any applicable provision of the Federal Power Act and FERC's rules and regulations; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this Agreement shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations, except to the extent that the Parties otherwise agree as provided herein.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

[Insert name of Transmission Provider]	**[Insert name of Interconnection Customer]**
Signed ______________________________	Signed
Name (Printed):	Name (Printed):
Title	Title

Assumptions Used in Conducting the Feasibility Study

The feasibility study will be based upon the information set forth in the Interconnection Request and agreed upon in the scoping meeting held on ____________________ :

1) Designation of Point of Interconnection and configuration to be studied.

2) Designation of alternative Points of Interconnection and configuration.

1) and 2) are to be completed by the Interconnection Customer. Other assumptions (listed below) are to be provided by the Interconnection Customer and the Transmission Provider.

Attachment 7

System Impact Study Agreement

THIS AGREEMENT is made and entered into this_____day of__________________ 20___ by and between ____ , a__________________________________ organized and existing under the laws of the State of ____, ("Interconnection Customer,") and ____ , a ________________ existing under the laws of the State of ____, ("Transmission Provider"). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Small Generating Facility or generating capacity addition to an existing Small Generating Facility consistent with the Interconnection Request completed by the Interconnection Customer on__________________________; and

WHEREAS, the Interconnection Customer desires to interconnect the Small Generating Facility with the Transmission Provider's Transmission System;

WHEREAS, the Transmission Provider has completed a feasibility study and provided the results of said study to the Interconnection Customer (This recital to be omitted if the Parties have agreed to forego the feasibility study.); and

WHEREAS, the Interconnection Customer has requested the Transmission Provider to perform a system impact study(s) to assess the impact of interconnecting the Small Generating Facility with the Transmission Provider's Transmission System, and of any Affected Systems;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the standard Small Generator Interconnection Procedures.

2.0 The Interconnection Customer elects and the Transmission Provider shall cause to be performed a system impact study(s) consistent with the standard Small Generator Interconnection Procedures in accordance with the Open Access Transmission Tariff.

3.0 The scope of a system impact study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 A system impact study will be based upon the results of the feasibility study and the technical information provided by Interconnection Customer in the Interconnection Request. The Transmission Provider reserves the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the system impact study. If the Interconnection Customer modifies its designated Point of Interconnection, Interconnection Request, or the technical information provided therein is modified, the time to complete the system impact study may be extended.

5.0 A system impact study shall consist of a short circuit analysis, a stability analysis, a power flow analysis, voltage drop and flicker studies, protection and set point coordination studies, and grounding reviews, as necessary. A system impact study shall state the assumptions upon which it is based, state the results of the analyses, and provide the requirement or potential impediments to providing the requested interconnection service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. A system impact study shall provide a list of facilities that are required as a result of the Interconnection Request and non-binding good faith estimates of cost responsibility and time to construct.

6.0 A distribution system impact study shall incorporate a distribution load flow study, an analysis of equipment interrupting ratings, protection coordination study, voltage drop and flicker studies, protection and set point coordination studies, grounding reviews, and the impact on electric system operation, as necessary.

7.0 Affected Systems may participate in the preparation of a system impact study, with a division of costs among such entities as they may agree. All Affected Systems shall be afforded an opportunity to review and comment upon a system impact study that covers potential adverse system impacts on their electric

systems, and the Transmission Provider has 20 additional Business Days to complete a system impact study requiring review by Affected Systems.

8.0 If the Transmission Provider uses a queuing procedure for sorting or prioritizing projects and their associated cost responsibilities for any required Network Upgrades, the system impact study shall consider all generating facilities (and with respect to paragraph 8.3 below, any identified Upgrades associated with such higher queued interconnection) that, on the date the system impact study is commenced -

8.1 Are directly interconnected with the Transmission Provider's electricsystem; or

8.2 Are interconnected with Affected Systems and may have an impacton the proposed interconnection; and

8.3 Have a pending higher queued Interconnection Request tointerconnect with the Transmission Provider's electric system.

9.0 A distribution system impact study, if required, shall be completed and the results transmitted to the Interconnection Customer within 30 Business Days after this Agreement is signed by the Parties. A transmission system impact study, if required, shall be completed and the results transmitted to the Interconnection Customer within 45 Business Days after this Agreement is signed by the Parties, or in accordance with the Transmission Provider's queuing procedures.

10.0 A deposit of the equivalent of the good faith estimated cost of a distribution system impact study and the one half the good faith estimated cost of a transmission system impact study may be required from the Interconnection Customer.

11.0 Any study fees shall be based on the Transmission Provider's actual costs and will be invoiced to the Interconnection Customer after the study is completed and delivered and will include a summary of professional time.

12.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 calendar days on receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the Transmission Provider shall refund such excess within 30 calendar days of the invoice without interest.

13.0 Governing Law, Regulatory Authority, and Rules
The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the state of________________________ (where the Point of Interconnection is located), without regard to its conflicts of law principles. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.

14.0 Amendment
The Parties may amend this Agreement by a written instrument duly executed by both Parties.

15.0 No Third-Party Beneficiaries
This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and where permitted, their assigns.

16.0 Waiver

16.1 The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

16.2 Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Termination or default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Transmission Provider. Any waiver of this Agreement shall, if requested, be provided in writing.

17.0 Multiple Counterparts

This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

18.0 No Partnership

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

19.0 Severability

If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

20.0 Subcontractors

Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Party for the performance of such subcontractor.

20.1 The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall the Transmission Provider be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

20.2 The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.

21.0 Reservation of Rights

The Transmission Provider shall have the right to make a unilateral filing with FERC to modify this Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and the Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this Agreement under any applicable provision of the Federal Power Act and FERC's rules and regulations; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this Agreement shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations, except to the extent that the Parties otherwise agree as provided herein.

IN WITNESS THEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

[Insert name of Transmission Provider]	**[Insert name of Interconnection Customer]**
______________________________	______________________________
Signed: ________________________	Signed: ________________________
Name (Printed):	Name (Printed):
______________________________	______________________________
Title: __________________________	Title: __________________________

Assumptions Used in Conducting the System Impact Study

The system impact study shall be based upon the results of the feasibility study, subject to any modifications in accordance with the standard Small Generator Interconnection Procedures, and the following assumptions:

1) Designation of Point of Interconnection and configuration to be studied.

2) Designation of alternative Points of Interconnection and configuration.

1) and 2) are to be completed by the Interconnection Customer. Other assumptions (listed below) are to be provided by the Interconnection Customer and the Transmission Provider.

Attachment 8

Facilities Study Agreement

THIS AGREEMENT is made and entered into this_____day of___________________ 20___ by and between ____ , a____________________________________ organized and existing under the laws of the State of ____, ("Interconnection Customer,") and ____ , a _________________ existing under the laws of the State of ____, ("Transmission Provider"). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Small Generating Facility or generating capacity addition to an existing Small Generating Facility consistent with the Interconnection Request completed by the Interconnection Customer on________________________ ; and

WHEREAS, the Interconnection Customer desires to interconnect the Small Generating Facility with the Transmission Provider's Transmission System;

WHEREAS, the Transmission Provider has completed a system impact study and provided the results of said study to the Interconnection Customer; and

WHEREAS, the Interconnection Customer has requested the Transmission Provider to perform a facilities study to specify and estimate the cost of the equipment, engineering, procurement and construction work needed to implement the conclusions of the system impact study in accordance with Good Utility Practice to physically and electrically connect the Small Generating Facility with the Transmission Provider's Transmission System.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the standard Small Generator Interconnection Procedures.

2.0 The Interconnection Customer elects and the Transmission Provider shall cause a facilities study consistent with the standard Small Generator Interconnection Procedures to be performed in accordance with the Open Access Transmission Tariff.

3.0 The scope of the facilities study shall be subject to data provided in Attachment A to this Agreement.

4.0 The facilities study shall specify and estimate the cost of the equipment, engineering, procurement and construction work (including overheads) needed to implement the conclusions of the system impact study(s). The facilities study shall also identify (1) the electrical switching configuration of the equipment, including, without limitation, transformer, switchgear, meters, and other station equipment, (2) the nature and estimated cost of the Transmission Provider's Interconnection Facilities and Upgrades necessary to accomplish the interconnection, and (3) an estimate of the time required to complete the construction and installation of such facilities.

5.0 The Transmission Provider may propose to group facilities required for more than one Interconnection Customer in order to minimize facilities costs through economies of scale, but any Interconnection Customer may require the installation of facilities required for its own Small Generating Facility if it is willing to pay the costs of those facilities.

6.0 A deposit of the good faith estimated facilities study costs may be required from the Interconnection Customer.

7.0 In cases where Upgrades are required, the facilities study must be completed within 45 Business Days of the receipt of this Agreement. In cases where no Upgrades are necessary, and the required facilities are limited to Interconnection Facilities, the facilities study must be completed within 30 Business Days.

8.0 Once the facilities study is completed, a facilities study report shall be prepared and transmitted to the Interconnection Customer. Barring unusual circumstances, the facilities study must be completed and the facilities study report transmitted

within 30 Business Days of the Interconnection Customer's agreement to conduct a facilities study.

9.0 Interconnection Customer may, within 30 Calendar Days after receipt of the draft report, provide written comments to Transmission Provider, which Transmission Provider shall include in the final report. Transmission Provider shall issue the final Interconnection Facilities Study report within 15 Business Days of receiving Interconnection Customer’s comments or promptly upon receiving Interconnection Customer’s statement that it will not provide comments. Transmission Provider may reasonably extend such fifteen-day period upon notice to Interconnection Customer if Interconnection Customer’s comments require Transmission Provider to perform additional analyses or make other significant modifications prior to the issuance of the final Interconnection Facilities Report. Upon request, Transmission Provider shall provide Interconnection Customer supporting documentation, workpapers, and databases or data developed in the preparation of the

Interconnection Facilities Study, subject to confidentiality arrangements consistent with Section 4.5 of the standard Small Generator Interconnection Procedures.

10.0 Within ten Business Days of providing a draft Interconnection Facilities Study report to Interconnection Customer, Transmission Provider and Interconnection Customer shall meet to discuss the results of the Interconnection Facilities Study.

11.0 Any study fees shall be based on the Transmission Provider's actual costs and will be invoiced to the Interconnection Customer after the study is completed and delivered and will include a summary of professional time.

12.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 calendar days on receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the Transmission Provider shall refund such excess within 30 calendar days of the invoice without interest.

13.0 Governing Law, Regulatory Authority, and Rules
The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the state of________________________ (where the Point of Interconnection is located), without regard to its conflicts of law principles. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.

14.0 Amendment
The Parties may amend this Agreement by a written instrument duly executed by both Parties.

15.0 No Third-Party Beneficiaries
This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and where permitted, their assigns.

16.0 Waiver

16.1 The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

16.2 Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this

Agreement. Termination or default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Transmission Provider. Any waiver of this Agreement shall, if requested, be provided in writing.

17.0 Multiple Counterparts

This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

18.0 No Partnership

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

19.0 Severability

If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

20.0 Subcontractors

Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Party for the performance of such subcontractor.

20.1 The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made;provided, however, that in no event shall the Transmission Provider be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

20.2 The obligations under this article will not be limited in any way by any limitation of subcontractor’s insurance.

21.0 Reservation of Rights

The Transmission Provider shall have the right to make a unilateral filing with FERC to modify this Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and the Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this Agreement under any applicable provision of the Federal Power Act and FERC's rules and regulations; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this Agreement shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations, except to the extent that the Parties otherwise agree as provided herein.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

[Insert name of Transmission Provider]	**[Insert name of Interconnection Customer]**
______________________________	______________________________
Signed: ______________________	Signed: ______________________
Name (Printed):	Name (Printed):
______________________________	______________________________
Title: ______________________	Title: ______________________

Data to Be Provided by the Interconnection Customer with the Facilities Study Agreement

Provide location plan and simplified one-line diagram of the plant and station facilities. For staged projects, please indicate future generation, transmission circuits, etc.

> On the one-line diagram, indicate the generation capacity attached at each metering location. (Maximum load on CT/PT)
>
> On the one-line diagram, indicate the location of auxiliary power. (Minimum load on CT/PT) Amps

One set of metering is required for each generation connection to the new ring bus or existing Transmission Provider station. Number of generation connections: ____________

Will an alternate source of auxiliary power be available during CT/PT maintenance?
Yes No

Will a transfer bus on the generation side of the metering require that each meter set be designed for the total plant generation? Yes ______No

_____
(Please indicate on the one-line diagram).

What type of control system or PLC will be located at the Small Generating Facility?

What protocol does the control system or PLC use?

Please provide a 7.5-minute quadrangle map of the site. Indicate the plant, station, transmission line, and property lines.

Physical dimensions of the proposed interconnection station:

Bus length from generation to interconnection station:

Line length from interconnection station to Transmission Provider's Transmission System.

Tower number observed in the field. (Painted on tower leg)*:

Number of third party easements required for transmission lines*:

* To be completed in coordination with Transmission Provider.

Is the Small Generating Facility located in Transmission Provider's service area?

Yes _____No ______ If No, please provide name of local provider:

Please provide the following proposed schedule dates:

Begin Construction	Date:
Generator step-up transformers receive back feed power	Date:
Generation Testing	Date:
Commercial Operation	Date:

Attachment B

Redlined Tariff Sheets of Amended OATT Sections

FERC ELECTRIC TARIFF
~~TENTH REVISED VOLUME NO. 7~~
OF
PUGET SOUND ENERGY, INC.

filed with the

FEDERAL ENERGY REGULATORY COMMISSION

OPEN ACCESS TRANSMISSION TARIFF

Communication concerning this Tariff should be addressed to:

~~Tom DeBoer~~George E. Marshall
~~Director, Federal and State Regulatory Affairs~~Manager, Transmission Policy and Contracts
Puget Sound Energy, Inc.
P.O. Box 97034
~~10885 N.E. 4th Street~~110th Ave NE, EST06E
Bellevue, WA 98004

TABLE OF CONTENTS

~~**TABLE OF CONTENTS (CONTD.)**~~

~~TABLE OF CONTENTS (CONTD.)~~

Bonds

5.2 Alternative Procedures for Requesting Transmission Service

~~**TABLE OF CONTENTS (CONTD.)**~~

~~**TABLE OF CONTENTS (CONTD.)**~~

~~**TABLE OF CONTENTS (CONTD.)**~~

III. NETWORK INTEGRATION TRANSMISSION SERVICE

Preamble

28 Nature of Network Integration Transmission Service

28.1 Scope of Service
28.2 Transmission Provider Responsibilities
28.3 Network Integration Transmission Service
28.4 Secondary Service
28.5 Real Power Losses
28.6 Restrictions on Use of Service
28.7 Participation in the EIM

~~**TABLE OF CONTENTS (CONTD.)**~~

~~TABLE OF CONTENTS (CONTD.)~~

~~TABLE OF CONTENTS (CONTD.)~~

ATTACHMENT O	Energy Imbalance Market
ANNEX A	Standard Large Generator Interconnection Procedures
ANNEX B	Standard Small Generator Interconnection Procedures

1 Definitions

1.1 Affiliate

With respect to a corporation, partnership or other entity, each such other corporation, partnership or other entity that directly or indirectly, through one or more intermediaries, controls, is controlled by, or is under common control with, such corporation, partnership or other entity.

1.2 Ancillary Services

Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

1.3 Annual Transmission Costs

The total annual cost of the Transmission System for purposes of Network Integration Transmission Service shall be the amount specified in Attachment H until amended by the Transmission Provider or modified by the Commission.

1.3A Annual Transmission ~~Reveue~~Revenue Requirement (ATRR~~):~~)

The transmission revenue requirement calculated annually using the formula rate set forth in Attachment H-1.

1.4 Application

A request by an Eligible Customer for transmission service pursuant to the provisions of the Tariff.

1.4A Balancing Authority (BA)

The responsible entity that integrates resource plans ahead of time, maintains load-Interchange-generation balance within a BAA, and supports interconnection frequency in real time.

1.4B Balancing Authority Area (BAA)

The collection of generation, transmission, and loads within the metered boundaries of the BA. The BA maintains load-resource balance within this area. For purposes of this Tariff, "BAA" shall have the same meaning as "Control Area."

1.4C Balancing Authority Area Resource

A resource owned by PSE, or voluntarily contracted for by PSE to provide EIM Available Balancing Capacity, that can provide regulation and load following services to enable the PSE EIM Entity to meet reliability criteria. No resource unaffiliated with the

PSE EIM Entity shall be a Balancing Authority Area Resource solely on the basis of one or more of the following reasons: (1) the resource is a Designated Network Resource; (2) the resource flows on a Point-to-Point Transmission Service reservation; and/or (3) the resource is an Interconnection Customer under the Tariff.

1.4D Bid Cost Recovery (BCR)

The MO EIM settlements process through which PSE EIM Participating Resources recover their bid costs.

1.4E California Independent System Operator Corporation (CAISO)

A state-chartered, California non-profit public benefit corporation that operates the transmission facilities of all CAISO participating transmission owners and dispatches certain generating units and loads. The CAISO is the MO for the EIM.

1.4F CAISO BAA or CAISO Controlled Grid

The system of transmission lines and associated facilities of the CAISO participating transmission owners that have been placed under the CAISO's operational control.

1.5 Commission

The Federal Energy Regulatory Commission.

1.6 Completed Application

An Application that satisfies all of the information and other requirements of the Tariff, including any required deposit.

1.7 Control Area

An electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

1. match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

2. maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

3. maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and

4. provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

1.8 Curtailment

A reduction in firm or non-firm transmission service in response to a transfer capability shortage as a result of system reliability conditions.

1.9 Delivering Party

The entity supplying capacity and energy to be transmitted at Point(s) of Receipt.

1.10 Designated Agent

Any entity that performs actions or functions on behalf of the Transmission Provider, an Interconnection Customer, an Eligible Customer, or the Transmission Customer required under the Tariff.

1.11 Direct Assignment Facilities

Facilities or portions of facilities that are constructed by the Transmission Provider for the sole use/benefit of a particular Transmission Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer and shall be subject to Commission approval.

1.11A Dispatch Instruction

An instruction by the MO for an action with respect to a specific PSE EIM Participating Resource or Balancing Authority Area Resource for increasing or decreasing its energy supply or demand.

1.11B Dispatch Operating Point

The expected operating point, in MW, of a PSE EIM Participating Resource that has received a Dispatch Instruction from the Market Operator or a Balancing Authority Area Resource to which the PSE EIM Entity has relayed a Dispatch Instruction received from the Market Operator. For purposes of Attachment O of this Tariff, the Dispatch Operating Point means the change, in MW output, of (i) a PSE EIM Participating Resource due to an EIM bid being accepted and the PSE EIM Participating Resource receiving a Dispatch Instruction; or (ii) a Balancing Authority Area Resource for which a Dispatch Instruction has been issued by the CAISO with respect to EIM Available Balancing Capacity. The Dispatch Operating Point is expressed either as a negative MW quantity for the downward movement of generation, or a positive MW quantity for the upward movement of generation.

1.11C Dynamic Transfer

The provision of the real-time monitoring, telemetering, computer software, hardware, communications, engineering, energy accounting (including inadvertent Interchange), and administration required to electronically move all or a portion of the real energy services associated with a generator or load out of one BAA into another. A Dynamic Transfer can be either:

(1) a Dynamic Schedule: a telemetered reading or value that is updated in real time and used as a schedule in the AGC/ACE equation and the integrated value of which is treated as an after-the-fact schedule for Interchange accounting purposes; or

(2) a Pseudo-Tie: a functionality by which the output of a generating unit physically interconnected to the electric grid in a native BAA is telemetered to and deemed to be produced in an attaining BAA that provides BA services for and exercises BA jurisdiction over the generating unit.

1.11D Energy Imbalance Market (EIM)

The real-time market to manage transmission congestion and optimize procurement of imbalance energy (positive or negative) to balance supply and demand deviations for the EIM Area through economic bids submitted by EIM Participating Resource Scheduling Coordinators in the fifteen-minute and five-minute markets.

1.11E EIM Area

The combination of PSE's BAA, the CAISO BAA, and the BAAs of any other EIM Entities.

1.11F EIM Available Balancing Capacity

Any upward or downward capacity from a Balancing Authority Area Resource that has not been bid into the EIM and is included in the PSE EIM Entity's Resource Plan.

1.11G EIM Entity

A BA, other than the PSE EIM Entity, that enters into the MO's pro forma EIM Entity Agreement to enable the EIM to occur in its BAA.

1.11H EIM Transfer

The transfer of real-time energy resulting from an EIM Dispatch Instruction: (1) between a PSE BAA and the CAISO BAA; (2) between the PSE BAA and an EIM Entity BAA; or (3) between the CAISO BAA and an EIM Entity BAA using transmission capacity available in the EIM.

1.12 Eligible Customer

i. Any electric utility (including the Transmission Provider and any power marketer), Federal power marketing agency, or any person generating electric energy for sale for resale is an Eligible Customer under the Tariff. Electric energy sold or produced by such entity may be electric energy produced in the United States, Canada or Mexico.

However, with respect to transmission service that the Commission is prohibited from ordering by Section 212(h) of the Federal Power Act, such entity is eligible only if the service is provided pursuant to a state requirement that the Transmission Provider offer the unbundled transmission service, or pursuant to a voluntary offer of such service by the Transmission Provider.

ii. Any retail customer taking unbundled transmission service pursuant to a state requirement that the Transmission Provider offer the transmission service, or pursuant to a voluntary offer of such service by the Transmission Provider, is an Eligible Customer under the Tariff.

1.12A e-Tag

An electronic tag associated with a schedule in accordance with the requirements of the North American Electric Reliability Corporation (NERC), the Western Electricity Coordinating Council (WECC), or the North American Energy Standards Board (NAESB).

1.13 Facilities Study

An engineering study conducted by the Transmission Provider to determine the required modifications to the Transmission Provider's Transmission System, including the cost and scheduled completion date for such modifications, that will be required to provide the requested transmission service.

1.14 Firm Point-To-Point Transmission Service

Transmission Service under this Tariff that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to Part II of this Tariff.

1.14A Flexible Ramping Constraint

A requirement, established by the MO, that may be enforced in the MO's EIM optimization to ensure that the unit commitment or dispatch of resources for intervals beyond the applicable commitment or dispatch period provide for the availability of required capacity for dispatch in subsequent real-time dispatch intervals.

1.14B Forecast Data

Information provided by Transmission Customers regarding expected load (as determined pursuant to Section 4.2.4.3 of Attachment O of this Tariff), generation, Intrachange, and Interchange, as specified in Section 4.2.4 of Attachment O and the PSE EIM BP. The Transmission Customer Base Schedule includes Forecast Data that is used by the PSE EIM Entity as the baseline by which to measure Imbalance Energy for purposes of EIM settlement.

1.15 Good Utility Practice

Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act section 215(a)(4).

1.15A Hourly Pricing Proxy

The on-peak or off-peak price reported for the IntercontinentalExchange (ICE) Mid-Columbia Firm Power Index for the hour in which Transmission Service is provided. In the event that Transmission Service is provided during a time where no volumes are reported at the Mid-Columbia hub, the most recent firm on-peak and off-peak prices will be carried forward. If ICE permanently ceases to report day ahead pricing at the Mid-Columbia hub, or if the methodology used to determine the index at the Mid-Columbia hub is materially modified, Transmission Provider shall select a permanent replacement index, reported by a reputable third party, that reflects the actual same-day firm transactions at the Mid-Columbia hub.

1.15B Interconnection Customer

Any Eligible Customer (or its Designated Agent) that executes an agreement to receive generation interconnection service pursuant to Annexes A or B of this Tariff.

1.15C Imbalance Energy

The deviation of supply or demand from the Transmission Customer Base Schedule, positive or negative, as measured by metered generation, metered load, or real-time Interchange or Intrachange schedules.

1.15D Instructed Imbalance Energy (IIE)

There are three scenarios that can lead to settlement of imbalance as IIE: (1) operational adjustments of the Transmission Customer's affected Interchange or Intrachange, which includes changes by the Transmission Customer after T-57, (2) resource imbalances created by Manual Dispatch or an EIM Available Balancing Capacity dispatch, or (3) an adjustment to resource imbalances created by adjustments to resource forecasts pursuant to Section 11.5 of the MO Tariff. IIE will be settled at either the RTD or FMM price at the applicable PNode depending on the nature and timing of the imbalance.

1.15E Interchange

E-Tagged energy transfers from, to or through the PSE BAA or other BAAs, not including EIM Transfers.

1.15F Intrachange

E-Tagged energy transfers within the PSE BAA, not including real-time actual energy flows associated with EIM Dispatch Instructions.

1.16 Interruption

A reduction in non-firm transmission service due to economic reasons pursuant to Section 14.7.

1.17 ~~[Reserved]~~Load Aggregation Point (LAP)

A set of Pricing Nodes that is used for the submission of bids and settlement of demand in the EIM.

1.17A Locational Marginal Price (LMP)

The marginal cost ($/MWh) of serving the next increment of demand at that PNode consistent with existing transmission constraints and the performance characteristics of resources.

1.18 Load Shedding

The systematic reduction of system demand by temporarily decreasing load in response to transmission system or area capacity shortages, system instability, or voltage control considerations under Part III of the Tariff.

1.19 Long-Term Firm Point-To-Point Transmission Service

Firm Point-To-Point Transmission Service under Part II of the Tariff with a term of one year or more.

1.19A Monthly Network Load

The monthly load of an entity receiving service under Part III of the Tariff as measured pursuant to Section 34.2 of the Tariff.

1.19B Manual Dispatch

An operating order issued by the PSE EIM Entity to a Transmission Customer with a PSE EIM Participating Resource or a Non-Participating Resource in PSE's BAA, outside of the EIM optimization, when necessary to address reliability or operational issues in PSE's BAA that the EIM is not able to address through economic dispatch and congestion management.

1.19C Market Operator (MO)

The entity responsible for operation, administration, settlement, and oversight of the EIM.

1.19D Measured Demand

Includes (1) Metered Demand, plus (2) e-Tagged export volumes from the PSE BAA (excluding EIM Transfers).

1.19E Metered Demand

Metered load volumes in PSE's BAA.

1.19F MO Tariff

Those portions of the MO's approved tariff, as such tariff may be modified from time to time, that specifically apply to the operation, administration, settlement, and oversight of the EIM.

1.20 Native Load Customers

The wholesale and retail power customers of the Transmission Provider on whose behalf the Transmission Provider, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Transmission Provider's system to meet the reliable electric needs of such customers.

1.21 Network Customer

An entity receiving transmission service pursuant to the terms of the Transmission Provider's Network Integration Transmission Service under Part III of the Tariff.

1.22 Network Integration Transmission Service

The transmission service provided under Part III of the Tariff.

1.23 Network Load

The load that a Network Customer designates for Network Integration Transmission Service under Part III of the Tariff. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where a Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Part II of the Tariff for any Point-To-Point Transmission Service that may be necessary for such non-designated load.

1.24 Network Operating Agreement

An executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service under Part III of the Tariff.

1.25 Network Operating Committee

A group made up of representatives from the Network Customer(s) and the Transmission Provider established to coordinate operating criteria and other technical considerations required for implementation of Network Integration Transmission Service under Part III of this Tariff.

1.26 Network Resource

Any designated generating resource owned, purchased or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program or output associated with an EIM Dispatch Instruction.

1.27 Network Upgrades

Modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all users of such Transmission System.

1.28 Non-Firm Point-To-Point Transmission Service

Point-To-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Section 14.7 under Part II of this Tariff. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.

1.29 Non-Firm Sale

An energy sale for which receipt or delivery may be interrupted for any reason or no reason, without liability on the part of either the buyer or seller.

1.29A Non-Participating Resource

A resource in PSE's BAA that is not a PSE EIM Participating Resource.

1.30 Open Access Same-Time Information System (OASIS)

The information system and standards of conduct contained in Part 37 of the Commission's regulations and all additional requirements implemented by subsequent Commission orders dealing with OASIS.

1.30A Operating Hour

The hour during the day when the EIM runs and energy is supplied to load.

1.30B PSE

Refers to Puget Sound Energy, Inc.

1.30C PSE's BAA

Refers to the BAA operated by PSE.

1.30D PSE BAA Transmission Owner

A transmission owner, other than the PSE EIM Entity, who owns transmission facilities in PSE's BAAs.

1.30E PSE EIM Business Practice (PSE EIM BP)

The business practice posted on PSE's OASIS that contains procedures related to PSE's implementation of EIM and the rights and obligations of Transmission Customers and Interconnection Customers related to EIM.

1.30F PSE EIM Entity

The Transmission Provider in performance of its role as an EIM Entity under the MO Tariff and this Tariff, including, but not limited to, Attachment O.

1.30G PSE EIM Entity Scheduling Coordinator

The Transmission Provider or the entity selected by the Transmission Provider who is certified by the MO and who enters into the MO's *pro forma* EIM Entity Scheduling Coordinator Agreement.

1.30H PSE EIM Participating Resource

A resource or a portion of a resource: (1) that has been certified in accordance with Attachment O by the PSE EIM Entity as eligible to participate in the EIM; and (2) for which the generation owner and/or operator enters into the MO's *pro forma* EIM Participating Resource Agreement.

1.30I PSE EIM Participating Resource Scheduling Coordinator

A Transmission Customer with one or more PSE EIM Participating Resource(s) or a third-party designated by the Transmission Customer with one or more PSE EIM Participating Resource(s), that is certified by the MO and enters into the MO's *pro forma* EIM Participating Resource Scheduling Coordinator Agreement.

1.30J PSE Interchange Rights Holder

A Transmission Customer who has informed the PSE EIM Entity that it is electing to make reserved firm transmission capacity available for EIM Transfers without compensation.

1.31 Part I

Tariff Definitions and Common Service Provisions contained in Sections 2 through 12.

1.32 Part II

Tariff Sections 13 through 27 pertaining to Point-To-Point Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.33 Part III

Tariff Sections 28 through 35 pertaining to Network Integration Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.34 Parties

The Transmission Provider and the Transmission Customer receiving service under the Tariff.

1.35 Point(s) of Delivery

Point(s) on the Transmission Provider's Transmission System where capacity and energy transmitted by the Transmission Provider will be made available to the Receiving Party under Part II of the Tariff. The Point(s) of Delivery shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

1.36 Point(s) of Receipt

Point(s) of interconnection on the Transmission Provider's Transmission System where capacity and energy will be made available to the Transmission Provider by the Delivering Party under Part II of the Tariff. The Point(s) of Receipt shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

1.37 Point-To-Point Transmission Service

The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Part II of the Tariff.

1.38 Power Purchaser

The entity that is purchasing the capacity and energy to be transmitted under the Tariff.

1.39 Pre-Confirmed Application

An Application that commits the Eligible Customer to execute a Service Agreement upon receipt of notification that the Transmission Provider can provide the requested Transmission Service.

1.39A Pricing Node (PNode)

A single network node or subset of network nodes where a physical injection or withdrawal is modeled by the MO and for which the MO calculates an LMP that is used for financial settlements by the MO and the PSE EIM Entity.

1.39B Real Power Losses

Electrical losses associated with the use of the Transmission Provider's Transmission System and, where applicable, the use of the Transmission Provider's distribution system. Such losses are provided for in Sections 15.7 and 28.5 of the Tariff and settled financially under Schedule 12 and Schedule 12A.

1.40 Receiving Party

The entity receiving the capacity and energy transmitted by the Transmission Provider to Point(s) of Delivery.

1.41 Regional Transmission Group (RTG)

A voluntary organization of transmission owners, transmission users and other entities approved by the Commission to efficiently coordinate transmission planning (and expansion), operation and use on a regional (and interregional) basis.

1.42 Reserved Capacity

The maximum amount of capacity and energy that the Transmission Provider agrees to transmit for the Transmission Customer over the Transmission Provider's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II of the Tariff. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

1.42A Resource Plan

The combination of load, resource and Interchange components of the Transmission Customer Base Schedule, ancillary services plans of the PSE EIM Entity, bid ranges submitted by PSE EIM Participating Resources, and the EIM Available Balancing Capacity of Balancing Authority Area Resources.

1.43 Service Agreement

The initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the Transmission Provider for service under the Tariff.

1.44 Service Commencement Date

The date the Transmission Provider begins to provide service pursuant to the terms of an executed Service Agreement, or the date the Transmission Provider begins to provide service in accordance with Section 15.3 or Section 29.1 under the Tariff.

1.45 Short-Term Firm Point-To-Point Transmission Service

Firm Point-To-Point Transmission Service under Part II of the Tariff with a term of less than one year.

1.46 System Condition

A specified condition on the Transmission Provider's system or on a neighboring system, such as a constrained transmission element or flowgate, that may trigger Curtailment of Long-Term Firm Point-to-Point Transmission Service using the curtailment priority pursuant to Section 13.6. Such conditions must be identified in the Transmission Customer's Service Agreement.

1.47 System Impact Study

An assessment by the Transmission Provider of (i) the adequacy of the Transmission System to accommodate a request for either Firm Point-To-Point Transmission Service or Network Integration Transmission Service and (ii) whether any additional costs may be incurred in order to provide transmission service.

1.48 Third-Party Sale

Any sale for resale in interstate commerce to a Power Purchaser that is not designated as part of Network Load under the Network Integration Transmission Service.

1.49 Transmission Customer

Any Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) requests in writing that the Transmission Provider file with the Commission, a proposed unexecuted Service Agreement to receive transmission service under Part II of the Tariff. This term is used in the Part I Common Service Provisions to include customers receiving transmission service under Part II and Part III of this Tariff.

1.49A Transmission Customer Base Schedule

An energy schedule that provides Transmission Customer hourly-level Forecast Data and other information that is used by the PSE EIM Entity as the baseline by which to measure Imbalance Energy for purposes of EIM settlement. The term "Transmission Customer Base Schedule" as used in this Tariff may refer collectively to the components of such schedule (resource, Interchange, Intrachange, and load determined pursuant to Section 4.2.4.3 of Attachment O) or any individual components of such schedule.

1.50 Transmission Provider

The public utility (or its Designated Agent) that owns, controls, or operates facilities used for the transmission of electric energy in interstate commerce and provides transmission service under the Tariff.

1.51 Transmission Provider's Monthly Transmission System Peak

The maximum firm usage of the Transmission Provider's Transmission System in a calendar month.

1.52 Transmission Service

Point-To-Point Transmission Service provided under Part II of the Tariff on a firm and non-firm basis.

1.53 Transmission System

The facilities owned, controlled or operated by the Transmission Provider that are used to provide transmission service under Part II and Part III of the Tariff.

1.54 Unreserved Use Penalty

Any penalty rate charged for unreserved use of Point-to-Point Transmission Service. Any Unreserved Use Penalty shall be as stated in Section 13.7(~~c~~d) or Section 14.5 of this Tariff. Any Overrun System Use Charge specified in any Service Agreement shall not be assessed.

~~**1.55 [Reserved]**~~

1.55 Uninstructed Imbalance Energy (UIE)

For Non-Participating Resources in an EIM Entity BAA, the MO shall calculate UIE as either (1) the algebraic difference between the resource's 5-minute meter data and the resource component of the Transmission Customer Base Schedule, or, if applicable, (2) the 5-minute meter data and any Manual Dispatch or EIM Available Balancing

Capacity dispatch. For Transmission Customers with load in the PSE EIM Entity's BAA, the PSE EIM Entity shall calculate UIE as the algebraic difference between the Transmission Customer's actual hourly load and the Transmission Customer Base Schedule.

1.56 ~~[Reserved]~~Variable Energy Resource

A device for the production of electricity that is characterized by an energy source that: (1) is renewable; (2) cannot be stored by the facility owner or operator; and (3) has variability that is beyond the control of the facility owner or operator.

1.57 Working Day

The days Monday through Friday, excluding any prescheduling holiday observed by the Western Electricity Coordinating Council.

10 Force Majeure and Indemnification

10.1 Force Majeure

An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a Party's control. A Force Majeure event with respect to a Party does not include an act of negligence or intentional wrongdoing by such Party. Neither the Transmission Provider nor the Transmission Customer will be considered in default as to any obligation under this Tariff if prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Tariff is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Tariff.

10.2 Indemnification

The Transmission Customer shall, to the maximum extent permitted by applicable law, at all times indemnify, defend, and save the Transmission Provider harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the Transmission Provider's performance of its obligations under this Tariff on behalf of the Transmission Customer, except to the extent of negligence or intentional wrongdoing by the Transmission Provider. Provided, however, that the standard of liability for the actions of the PSE EIM Entity performed consistent with Attachment O of this Tariff shall be gross negligence or intentional wrongdoing.

12 Dispute Resolution Procedures

12.1 Internal Dispute Resolution Procedures

Any dispute between a Transmission Customer and the Transmission Provider involving transmission service under the Tariff (excluding applications for rate changes or other changes to the Tariff, or to any Service Agreement entered into under the Tariff, which shall be presented directly to the Commission for resolution) shall be referred to a designated senior representative of the Transmission Provider and a senior representative of the Transmission Customer for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days [or such other period as the Parties may agree upon] by mutual agreement, such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below.

12.2 External Arbitration Procedures

Any arbitration initiated under the Tariff shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) days of the referral of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with the Commercial Arbitration Rules of the American Arbitration Association and any applicable Commission regulations or any applicable provisions of the Governing Agreement of the Northwest Regional Transmission Association.

12.3 Arbitration Decisions

Unless otherwise agreed, the arbitrator(s) shall render a decision within ninety (90) days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of the Tariff and any Service Agreement entered into under the Tariff and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be appealed solely on the grounds that the conduct of the arbitrator(s), or the decision itself, violated the standards set forth in the Federal Arbitration Act and/or the Administrative Dispute Resolution Act. The final decision of the arbitrator must also be filed with the Commission if it affects jurisdictional rates, terms and conditions of service or facilities.

12.4 Costs

Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable:

1. the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or

2. one half the cost of the single arbitrator jointly chosen by the Parties.

12.4A EIM Disputes

12.4A.1 Disputes between the PSE EIM Entity and a Transmission Customer or Interconnection Customer Related to Allocation of Charges or Payments from the MO

To the extent a dispute arises between the PSE EIM Entity and a Transmission Customer or Interconnection Customer regarding the PSE EIM Entity's implementation of this Tariff's provisions regarding the manner in which the PSE EIM Entity allocates charges or payments from the MO, the parties shall follow the dispute resolution procedures in Sections 12.1 to 12.4 of this Tariff.

12.4A.2 Disputes between the MO and PSE EIM Participating Resource Scheduling Coordinators Related to EIM Charges and Payments Directly From the MO

Disputes involving settlement statements between the MO and PSE EIM Participating Resource Scheduling Coordinators shall be resolved in accordance with the dispute resolution process of the MO Tariff. A Transmission Customer with a PSE EIM Participating Resource shall provide notice to the PSE EIM Entity if it raises a dispute with the MO, and such notice shall be provided in accordance with the process set forth in the PSE EIM BP.

12.4A.3 Disputes between the MO and the PSE EIM Entity

The PSE EIM Entity may raise disputes with the MO regarding the settlement statements it receives from the MO in accordance with the process specified in the MO Tariff. If the PSE EIM Entity submits a dispute it shall provide notice to Transmission Customers in accordance with the PSE EIM BP.

12.4A.4 Disputes Regarding MO Charges or Payments to the PSE EIM Entity Raised by Transmission Customers or Interconnection Customers

To the extent a dispute arises regarding a MO charge or a MO payment to the PSE EIM Entity that is subsequently charged or paid by the PSE EIM Entity to a Transmission Customer or an Interconnection Customer, and such Transmission Customer or Interconnection Customer wishes to raise a dispute with the MO, the PSE EIM Entity shall file a dispute on behalf of such Transmission Customer or Interconnection Customer in accordance with the MO Tariff and work with the Transmission Customer or the Interconnection Customer to resolve the dispute pursuant to the process specified in the MO Tariff.

12.5 Rights Under The Federal Power Act

Nothing in this section shall restrict the rights of any party to file a Complaint with the Commission under relevant provisions of the Federal Power Act.

13 Nature of Firm Point-To-Point Transmission Service

13.1 Term

The minimum term of Firm Point-To-Point Transmission Service shall be one day and the maximum term shall be specified in the Service Agreement.

13.2 Reservation Priority

(i) Long-Term Firm Point-To-Point Transmission Service shall be available on a first-come, first-served basis, i.e., in the chronological sequence in which each Transmission Customer has requested service.

(ii) Reservations for Short-Term Firm Point-To-Point Transmission Service will be conditional based upon the length of the requested transaction or reservation. However, Pre-Confirmed Applications for Short-Term Point-to-Point Transmission Service will receive priority over earlier-submitted requests that are not Pre-Confirmed and that have equal or shorter duration. Among requests or reservations with the same duration and, as relevant, pre-confirmation status (pre-confirmed, confirmed, or not confirmed), priority will be given to an Eligible Customer's request or reservation that offers the highest price, followed by the date and time of the request or reservation.

(iii) If the Transmission System becomes oversubscribed, requests for service may preempt competing reservations up to the following conditional reservation deadlines: one day before the commencement of daily service, one week before the commencement of weekly service, and one month before the commencement of monthly service. Before the conditional reservation deadline, if available transfer capability is insufficient to satisfy all requests and reservations, an Eligible Customer with a reservation for shorter term service or equal duration service and lower price has the right of first refusal to match any longer term request or equal duration service with a higher price before losing its reservation priority. A longer term competing request for Short-Term Firm Point-To-Point Transmission Service will be granted if the Eligible Customer with the right of first refusal does not agree to match the competing request within 24 hours (or earlier if necessary to comply with the scheduling deadlines provided in section 13.8) from being notified by the Transmission Provider of a longer-term competing request for Short-Term Firm Point-To-Point Transmission Service. When a longer duration request preempts multiple shorter duration reservations, the shorter duration reservations shall have simultaneous opportunities to exercise the right of first refusal. Duration, price and time of response will be used to determine the order by which the multiple shorter duration reservations will be able to exercise the right of first refusal. After the conditional reservation deadline, service will commence pursuant to the terms of Part II of the Tariff.

(iv) Firm Point-To-Point Transmission Service will always have a reservation priority over Non-Firm Point-To-Point Transmission Service under the Tariff. All Long-Term Firm Point-To-Point Transmission Service will have equal reservation priority with Native Load Customers and Network Customers. Reservation priorities for existing firm service customers are provided in Section 2.2.

(v) For any requests for Firm Transmission Service for which the Transmission Provider's business practices establish the earliest time such requests are permitted to be submitted, any requests for such service submitted within the five (5) minute window immediately following such earliest time shall be deemed to have been submitted simultaneously during such window. If sufficient transfer capability is not available to meet all such requests submitted within any such five minute window, the otherwise applicable priorities shall apply to allocation of transfer capability to such requests; provided that, if the otherwise applicable priorities would be to allocate transfer capability to transmission requests on a first-come, first-served basis (i.e., in the chronological sequence in which each Transmission Customer has requested service), transfer capability shall instead be allocated in equal amounts to each Transmission Customer that has submitted one or more of such requests but not in excess of the requested amount for any such request.

13.3 Use of Firm Transmission Service by the Transmission Provider

The Transmission Provider will be subject to the rates, terms and conditions of Part II of the Tariff when making Third-Party Sales under (i) agreements executed on or after May 13, 1997, or (ii) agreements executed prior to the aforementioned date that the Commission requires to be unbundled, by the date specified by the Commission. The Transmission Provider will maintain separate accounting, pursuant to Section 8, for any use of the Point-To-Point Transmission Service to make Third-Party Sales.

13.4 Service Agreements

The Transmission Provider shall offer a standard form Firm Point-To-Point Transmission Service Agreement (Attachment A) to an Eligible Customer when it submits a Completed Application for Long-Term Firm Point-To-Point Transmission Service. The Transmission Provider shall offer a standard form Firm Point-To-Point Transmission Service Agreement (Attachment A) to an Eligible Customer when it first submits a Completed Application for Short-Term Firm Point-To-Point Transmission Service pursuant to the Tariff. Executed Service Agreements that contain the information required under the Tariff shall be filed with the Commission in compliance with applicable Commission regulations. An Eligible Customer that uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved and that has not executed a Service Agreement will be deemed, for purposes of assessing any appropriate charges and penalties, to have executed the appropriate Service Agreement. The Service Agreement shall, when applicable, specify any conditional curtailment options selected by the Transmission Customer. Where the Service Agreement contains conditional curtailment options and is subject to a biennial reassessment as described in Section 15.4, the Transmission Provider shall provide the Transmission Customer notice of any changes to the curtailment conditions no less than 90 days prior to the date for imposition of new curtailment conditions. Concurrent with such notice, the Transmission Provider shall provide the Transmission Customer with the reassessment study and a narrative description of the study, including the reasons for changes to the number of hours per year or System Conditions under which conditional curtailment may occur.

13.5 Transmission Customer Obligations for Facility Additions or Redispatch Costs

In cases where the Transmission Provider determines that the Transmission System is not capable of providing Firm Point-To-Point Transmission Service without (1) degrading or impairing the reliability of service to Native Load Customers, Network Customers and other Transmission Customers taking Firm Point-To-Point Transmission Service, or (2) interfering with the Transmission Provider's ability to meet prior firm contractual commitments to others, the Transmission Provider will be obligated to expand or upgrade its Transmission System pursuant to the terms of Section 15.4. The Transmission Customer must agree to compensate the Transmission Provider for any necessary transmission facility additions pursuant to the terms of Section 27. To the extent the Transmission Provider can relieve any system constraint by redispatching the Transmission Provider's resources, it shall do so, provided that the Eligible Customer agrees to compensate the Transmission Provider pursuant to the terms of Section 27 and agrees to either (i) compensate the Transmission Provider for any necessary transmission facility additions or (ii) accept the service subject to a biennial reassessment by the Transmission Provider of redispatch requirements as described in Section 15.4. Any redispatch, Network Upgrade or Direct Assignment Facilities costs to be charged to the Transmission Customer on an incremental basis under the Tariff will be specified in the Service Agreement prior to initiating service.

13.6 Curtailment of Firm Transmission Service

In the event that a Curtailment on the Transmission Provider's Transmission System, or a portion thereof, is required to maintain reliable operation of such system and the system directly and indirectly interconnected with Transmission Provider's Transmission System, Curtailments will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint. If multiple transactions require Curtailment, to the extent practicable and consistent with Good Utility Practice, the Transmission Provider will curtail service to Network Customers and Transmission Customers taking Firm Point-To-Point Transmission Service on a basis comparable to the curtailment of service to the Transmission Provider's Native Load Customers. All Curtailments will be made on a non-discriminatory basis, however, Non-Firm Point-To-Point Transmission Service shall be subordinate to Firm Transmission Service. Long-Term Firm Point-to-Point Service subject to conditions described in Section 15.4 shall be curtailed with secondary service in cases where the conditions apply, but otherwise will be curtailed on a pro rata basis with other Firm Transmission Service. When the Transmission Provider determines that an electrical emergency exists on its Transmission System and implements emergency procedures to Curtail Firm Transmission Service, the Transmission Customer shall make the required reductions upon request of the Transmission Provider. However, the Transmission Provider reserves the right to Curtail, in whole or in part, any Firm Transmission Service provided under the Tariff when, in the Transmission Provider's sole discretion, an emergency or other unforeseen condition impairs or degrades the reliability of its Transmission System. The Transmission Provider will notify all affected Transmission Customers in a timely manner of any scheduled Curtailments. Transmission Provider shall take necessary measures to ensure reliability in PSE's BAA in accordance with Section 6 of Attachment O.

13.7 Classification of Firm Transmission Service

(a) The Transmission Customer taking Firm Point-To-Point Transmission Service may (1) change its Receipt and Delivery Points to obtain service on a non-firm basis consistent with the terms of Section 22.1 or (2) request a modification of the Points of Receipt or Delivery on a firm basis pursuant to the terms of Section 22.2.

(b) The Transmission Customer may purchase transmission service to make sales of capacity and energy from multiple generating units that are on the Transmission Provider's Transmission System. For such a purchase of transmission service, the resources will be designated as multiple Points of Receipt, unless the multiple generating units are at the same generating plant in which case the units would be treated as a single Point of Receipt.

(c) The Transmission Provider shall provide firm deliveries of capacity and energy from the Point(s) of Receipt to the Point(s) of Delivery. Each Point of Receipt at which firm transfer capability is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement for Long-Term Firm Transmission Service along with a corresponding capacity reservation associated with each Point of Receipt. Points of Receipt and corresponding capacity reservations shall be as mutually agreed upon by the Parties for Short-Term Firm Transmission. Each Point of Delivery at which firm transfer capability is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement for Long-Term Firm Transmission Service along with a corresponding capacity reservation associated with each Point of Delivery. Points of Delivery and corresponding capacity reservations shall be as mutually agreed upon by the Parties for Short-Term Firm Transmission. The greater of either (1) the sum of the capacity reservations at the Point(s) of Receipt, or (2) the sum of the capacity reservations at the Point(s) of Delivery shall be the Transmission Customer's Reserved Capacity. The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedule 7. The Transmission Customer may not exceed its firm capacity reserved at each Point of Receipt and each Point of Delivery except as otherwise specified in Section 22. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third-Party Sales by the Transmission Provider) exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved.

~~(d) In~~(d) Subject to Attachment O, Section 8.7 of this Tariff, in the event that a Transmission Customer exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery or uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved, the Transmission Customer shall pay an Unreserved Use Penalty charge equal to the sum of

(i) a charge for the unreserved service equal to twice the applicable rate(s) for Firm Point-to-Point Transmission Service (exclusive of any Ancillary Services rate(s)) and

(ii) a charge equal to the applicable rate(s) for any Ancillary Services (exclusive of charges pursuant to Schedules 4, 4R and 9) associated with such unreserved service and which is provided by Transmission Provider but for which Transmission Customer does not otherwise pay under the Tariff.

For unreserved use within a single day, the penalty charge shall be based on the daily rate. For unreserved use in two or more days in a calendar week, the penalty charge shall be based on the weekly rate. For multiple instances of unreserved use in more than one calendar week in a calendar month, the penalty charge shall be based on the monthly rate.

13.8 Scheduling of Firm Point-To-Point Transmission Service

Schedules for the Transmission Customer's Firm Point-To-Point Transmission Service must be submitted to the Transmission Provider no later than 10:00 a.m. (Pacific time) [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] of the day prior to commencement of such service. Schedules submitted after 10:00 a.m. will be accommodated, if practicable. Hour-to-hour and intra-hour (four intervals consisting of fifteen minute schedules) schedules of any capacity and energy that is to be delivered must be stated in increments of 1,000 kW per hour [or a reasonable increment that is generally accepted in the region and is consistently adhered to by the Transmission Provider]. Transmission Customers within the Transmission Provider's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 1,000 kW per hour, may consolidate their service requests at a common point of receipt into units of 1,000 kW per hour for scheduling and billing purposes. Scheduling changes will be permitted up to twenty (20) minutes [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] before the start of the next scheduling interval, provided that the Delivering Party and Receiving Party also agree to the schedule modification. The Transmission Provider will furnish to the Delivering Party's system operator, hour-to-hour and intra-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules; provided, however, that Transmission Customer's ability to schedule intra-hour transactions into, out of, or through-and-out of the Transmission Provider's Control Area may be subject to restrictions on intra-hour scheduling imposed by transmission providers in other Control Areas along the scheduled path. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the Transmission Provider, and the Transmission Provider shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

14 Nature of Non-Firm Point-To-Point Transmission Service

14.1 Term

Non-Firm Point-To-Point Transmission Service will be available for periods ranging from one (1) hour to one (1) month. However, a Purchaser of Non-Firm Point-To-Point Transmission Service will be entitled to reserve a sequential term of service (such as a sequential monthly term without having to wait for the initial term to expire before requesting another monthly term) so that the total time period for which the reservation applies is greater than one month, subject to the requirements of Section 18.3.

14.2 Reservation Priority

Non-Firm Point-To-Point Transmission Service shall be available from transfer capability in excess of that needed for reliable service to Native Load Customers, Network Customers and other Transmission Customers taking Long-Term and Short-Term Firm Point-To-Point Transmission Service. A higher priority will be assigned first to requests or reservations with a longer duration of service and second to Pre-Confirmed Applications. In the event the Transmission System is constrained, competing requests of the same Pre-Confirmation status and equal duration will be prioritized based on the highest price offered by the Eligible Customer for the Transmission Service. Eligible Customers that have already reserved shorter term service have the right of first refusal to match any longer term request before being preempted. A longer term competing request for Non-Firm Point-To-Point Transmission Service will be granted if the Eligible Customer with the right of first refusal does not agree to match the competing request: (a) immediately for hourly Non-Firm Point-To-Point Transmission Service after notification by the Transmission Provider; and, (b) within 24 hours (or earlier if necessary to comply with the scheduling deadlines provided in section 14.6) for Non-Firm Point-To-Point Transmission Service other than hourly transactions after notification by the Transmission Provider. Transmission service for Network Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service. Non-Firm Point-To-Point Transmission Service over secondary Point(s) of Receipt and Point(s) of Delivery will have the lowest reservation priority under the Tariff.

For any requests for Non-Firm Transmission Service for which this Tariff establishes the earliest time such requests are permitted to be submitted, any requests for such service submitted within the five (5) minute window immediately following such earliest time shall be deemed to have been submitted simultaneously during such window. If sufficient transfer capability is not available to meet all such requests submitted within any such five minute window, the otherwise applicable priorities shall apply to allocation of transfer capability to such requests; provided that, if the otherwise applicable priorities would be to allocate transfer capability to transmission requests on a first-come, first-served basis (i.e., in the chronological sequence in which each Transmission Customer has requested service), transfer capability shall instead be allocated in equal amounts to each Transmission Customer that has submitted one or more of such requests but not in excess of the requested amount for any such request.

14.3 Use of Non-Firm Point-To-Point Transmission Service by the Transmission Provider

The Transmission Provider will be subject to the rates, terms and conditions of Part II of the Tariff when making Third-Party Sales under (i) agreements executed on or after May 13, 1997, or (ii) agreements executed prior to the aforementioned date that the Commission requires to be unbundled, by the date specified by the Commission. The Transmission Provider will maintain separate accounting, pursuant to Section 8, for any use of Non-Firm Point-To-Point Transmission Service to make Third-Party Sales.

14.4 Service Agreements

The Transmission Provider shall offer a standard form Non-Firm Point-To-Point Transmission Service Agreement (Attachment B) to an Eligible Customer when it first submits a Completed Application for Non-Firm Point-To-Point Transmission Service pursuant to the Tariff. Executed Service Agreements that contain the information required under the Tariff shall be filed with the Commission in compliance with applicable Commission regulations.

14.5 Classification of Non-Firm Point-To-Point Transmission Service

Non-Firm Point-To-Point Transmission Service shall be offered under terms and conditions contained in Part II of the Tariff. The Transmission Provider undertakes no obligation under the Tariff to plan its Transmission System in order to have sufficient capacity for Non-Firm Point-To-Point Transmission Service. Parties requesting Non-Firm Point-To-Point Transmission Service for the transmission of firm power do so with the full realization that such service is subject to availability and to Curtailment or Interruption under the terms of the Tariff. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that a Transmission Customer (including Third-Party Sales by the Transmission Provider) exceeds its non-firm capacity reservation. Non-Firm Point-To-Point Transmission Service shall include transmission of energy on an hourly basis and transmission of scheduled short-term capacity and energy on a daily, weekly or monthly basis, but not to exceed one month's reservation for any one Application, under Schedule 8.

~~In~~Subject to Attachment O, Section 8.7 of this Tariff, in the event that a Transmission Customer exceeds its non-firm reserved capacity at any Point of Receipt or Point of Delivery or uses Transmission Service at a Point of Receipt or Point of Delivery that it has not reserved, the Transmission Customer shall pay an Unreserved Use Penalty charge equal to the sum of

(i) a charge for the unreserved service equal to twice the applicable rate(s) for Firm Point-to-Point Transmission Service (exclusive of any Ancillary Services rate(s)) and

(ii) a charge equal to the applicable rate(s) for any Ancillary Services (exclusive of charges pursuant to Schedules 4, 4R and 9) associated with such unreserved service and which is provided by Transmission Provider but for which Transmission Customer does not otherwise pay under the Tariff.

For unreserved use within a single day, the penalty charge shall be based on the daily rate. For unreserved use in two or more days in a calendar week, the penalty charge shall be based on the weekly rate. For multiple instances of unreserved use in more than one calendar week in a calendar month, the penalty charge shall be based on the monthly rate.

14.6 Scheduling of Non-Firm Point-To-Point Transmission Service

Schedules for Non-Firm Point-To-Point Transmission Service must be submitted to the Transmission Provider no later than 2:00 p.m. (Pacific time) [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] of the day prior to commencement of such service. Schedules submitted after 2:00 p.m. will be accommodated, if practicable. Hour-to-hour and intra-hour (four intervals consisting of fifteen minute schedules) schedules of energy that is to be delivered must be stated in increments of 1,000 kW per hour [or a reasonable increment that is generally accepted in the region and is consistently adhered to by the Transmission Provider]. Transmission Customers within the Transmission Provider's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 1,000 kW per hour, may consolidate their schedules at a common Point of Receipt into units of 1,000 kW per hour. Scheduling changes will be permitted up to twenty (20) minutes [or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider] before the start of the next scheduling interval, provided that the Delivering Party and Receiving Party also agree to the schedule modification. The Transmission Provider will furnish to the Delivering Party's system operator, hour-to-hour and intra-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules; provided, however, that Transmission Customer's ability to schedule intra-hour transactions into, out of, or through-and-out of the Transmission Provider's Control Area may be subject to restrictions on intra-hour scheduling imposed by transmission providers in other Control Areas along the scheduled path. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the Transmission Provider, and the Transmission Provider shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

14.7 Curtailment or Interruption of Service

The Transmission Provider reserves the right to Curtail, in whole or in part, Non-Firm Point-To-Point Transmission Service provided under the Tariff for reliability reasons when an emergency or other unforeseen condition threatens to impair or degrade the reliability of its Transmission System or the systems directly and indirectly interconnected with Transmission Provider's Transmission System. The Transmission

Provider reserves the right to Interrupt, in whole or in part, Non-Firm Point-To-Point Transmission Service provided under the Tariff for economic reasons in order to accommodate (1) a request for Firm Transmission Service, (2) a request for Non-Firm Point-To-Point Transmission Service of greater duration, (3) a request for Non-Firm Point-To-Point Transmission Service of equal duration with a higher price, (4) transmission service for Network Customers from non-designated resources, or (5) transmission service for Firm Point-to-Point Transmission Service during conditional curtailment periods as described in Section 15.4. The Transmission Provider also will discontinue or reduce service to the Transmission Customer to the extent that deliveries for transmission are discontinued or reduced at the Point(s) of Receipt. Where required, Curtailments or Interruptions will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint, however, Non-Firm Point-To-Point Transmission Service shall be subordinate to Firm Transmission Service. If multiple transactions require Curtailment or Interruption, to the extent practicable and consistent with Good Utility Practice, Curtailments or Interruptions will be made to transactions of the shortest term (e.g., hourly non-firm transactions will be Curtailed or Interrupted before daily non-firm transactions and daily non-firm transactions will be Curtailed or Interrupted before weekly non-firm transactions). Transmission service for Network Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service under the Tariff. Non-Firm Point-To-Point Transmission Service over secondary Point(s) of Receipt and Point(s) of Delivery will have a lower priority than any Non-Firm Point-To-Point Transmission Service under the Tariff. The Transmission Provider will provide advance notice of Curtailment or Interruption where such notice can be provided consistent with Good Utility Practice. Transmission Provider will take necessary measures to ensure reliability in PSE's BAA in accordance with Section 6 of Attachment O.

15 ~~15~~ Service Availability

15.1 General Conditions

The Transmission Provider will provide Firm and Non-Firm Point-To-Point Transmission Service over, on or across its Transmission System to any Transmission Customer that has met the requirements of Section 16.

15.2 Determination of Available Transfer Capability

A description of the Transmission Provider's specific methodology for assessing available transfer capability posted on the Transmission Provider's OASIS (Section 4) is contained in Attachment C of the Tariff. In the event sufficient transfer capability may not exist to accommodate a service request, the Transmission Provider will respond by performing a System Impact Study.

15.3 Initiating Service in the Absence of an Executed Service Agreement

If the Transmission Provider and the Transmission Customer requesting Firm or Non-Firm Point-To-Point Transmission Service cannot agree on all the terms and conditions of the Point-To-Point Service Agreement, the Transmission Provider shall file with the Commission, within thirty (30) days after the date the Transmission Customer provides written notification directing the Transmission Provider to file, an unexecuted Point-To-Point Service Agreement containing terms and conditions deemed appropriate by the Transmission Provider for such requested Transmission Service. The Transmission Provider shall commence providing Transmission Service subject to the Transmission Customer agreeing to (i) compensate the Transmission Provider at whatever rate the Commission ultimately determines to be just and reasonable, and (ii) comply with the terms and conditions of the Tariff including posting appropriate security deposits in accordance with the terms of Section 17.3.

15.4 Obligation to Provide Transmission Service that Requires Expansion or Modification of the Transmission System, Redispatch or Conditional Curtailment

(a) If the Transmission Provider determines that it cannot accommodate a Completed Application for Firm Point-To-Point Transmission Service because of insufficient capability on its Transmission System, the Transmission Provider will use due diligence to expand or modify its Transmission System to provide the requested Firm Transmission Service, consistent with its planning obligations in Attachment K, provided the Transmission Customer agrees to compensate the Transmission Provider for such costs pursuant to the terms of Section 27. The Transmission Provider will conform to Good Utility Practice and its planning obligations in Attachment K, in determining the need for new facilities and in the design and construction of such facilities. The obligation applies only to those facilities that the Transmission Provider has the right to expand or modify.

(b) If the Transmission Provider determines that it cannot accommodate a Completed Application for Long-Term Firm Point-To-Point Transmission Service because of insufficient capability on its Transmission System, the Transmission Provider will use due diligence to provide redispatch from its own resources until (i) Network Upgrades are completed for the Transmission Customer, (ii) the Transmission Provider determines through a biennial reassessment that it can no longer reliably provide the redispatch, or (iii) the Transmission Customer terminates the service because of redispatch changes resulting from the reassessment. A Transmission Provider shall not unreasonably deny self-provided redispatch or redispatch arranged by the Transmission Customer from a third party resource.

(c) If the Transmission Provider determines that it cannot accommodate a Completed Application for Firm Point-To-Point Transmission Service because of insufficient capability on its Transmission System, the Transmission Provider will offer the Firm Transmission Service with the condition that the Transmission Provider may curtail the service prior to the curtailment of other Firm Transmission Service for a specified number of hours per year or during System Condition(s). If the Transmission Customer accepts the service, the Transmission Provider will use due diligence to provide the service until (i) Network Upgrades are completed for the Transmission Customer, (ii) the Transmission Provider determines through a biennial reassessment that it can no longer reliably provide such service, or (iii) the Transmission Customer terminates the service because the reassessment increased the number of hours per year of conditional curtailment or changed the System Conditions.

15.5 Deferral of Service

The Transmission Provider may defer providing service until it completes construction of new transmission facilities or upgrades needed to provide Firm Point-To-Point Transmission Service whenever the Transmission Provider determines that providing the requested service would, without such new facilities or upgrades, impair or degrade reliability to any existing firm services.

15.6 Other Transmission Service Schedules

Eligible Customers receiving transmission service under other agreements on file with the Commission may continue to receive transmission service under those agreements until such time as those agreements may be modified by the Commission.

15.7 Real Power Losses

Real Power Losses are associated with all transmission service. The Transmission Provider is not obligated to provide Real Power Losses. The Transmission Customer ~~is responsible for replacing~~shall compensate Transmission Provider for losses associated with all transmission service as ~~calculated by the Transmission Provider~~provided in Schedule 12 and Schedule 12A. The applicable Real Power Loss factors are as follows:

(1) The loss factor for determining the amount of losses associated with any

Transmission Service over the Colstrip Transmission Line facilities and the Southern Intertie transmission facilities shall be two point seven percent (2.7%) of the scheduled capacity and energy for which Transmission Service is provided.

(2) The loss factor for determining the amount of losses associated with any Transmission Service over the Washington Area transmission facilities shall be two point seven percent (2.7%) of the scheduled capacity and energy for which Transmission Service is provided.

15.8 Distribution of Unreserved Use Penalty Amounts

For any month for which Transmission Provider assesses any Unreserved Use Penalty under Section 13.7(c) or Section 14.5 of this Tariff. Transmission Provider shall credit to Qualified Transmission Customers for such month an amount equal to fifty percent (50%) of the amount of such Unreserved Use Penalty (exclusive of any such amount arising from any charge for Ancillary Services). For each such month, the amount of such credit shall be allocated among Qualified Transmission Customers for such month in proportion to their respective Qualified Transmission Loads for such month.

For purposes of this Section 15.8, the following definitions shall apply:

(a) "Qualified Transmission Customer" for any month means each of the following in such month:

(i) Point-to-Point Transmission Service Customer for Transmission Service,

(ii) Network Customer for Transmission Service, or

(iii) Transmission Provider on behalf of its Native Load Customers;

provided, that any Transmission Customer that is assessed any Unreserved Use Penalty for such month shall not be a Qualified Transmission Customer under this Section 15.8 for such month.

(b) "Qualified Transmission Load" for any month means the following with respect to each Qualified Transmission Customer:

(i) for each Point-to-Point Transmission Service Customer, its Reserved Capacity for Transmission Service;

(ii) for each Network Customer, its monthly Network Load in such month computed in accordance with Section 34.2 of the Tariff; or

(iii) for Transmission Provider on behalf of its Native Load Customers, the hourly load in such month of its Native Load Customers coincident with the Transmission System Provider's Monthly Transmission System Peak for such month (computed consistent with computations pursuant to Section 34 of the Tariff).

16 Transmission Customer Responsibilities

16.1 Conditions Required of Transmission Customers

Point-To-Point Transmission Service shall be provided by the Transmission Provider only if the following conditions are satisfied by the Transmission Customer:

(a) The Transmission Customer has pending a Completed Application for service;

(b) The Transmission Customer meets the creditworthiness criteria set forth in Section 11;

(c) The Transmission Customer will have arrangements in place for any other transmission service necessary to effect the delivery from the generating source to the Transmission Provider prior to the time service under Part II of the Tariff commences;

(d) The Transmission Customer agrees to pay for any facilities constructed and chargeable to such Transmission Customer under Part II of the Tariff, whether or not the Transmission Customer takes service for the full term of its reservation;

(e) The Transmission Customer provides the information required by the Transmission Provider's planning process established in Attachment K; and

(f) The Transmission Customer has executed a Point-To-Point Service Agreement or has agreed to receive service pursuant to Section 15.3.

(g) The Transmission Customer must comply with the requirements of Attachment O regarding the EIM.

16.2 Transmission Customer Responsibility for Third-Party Arrangements

Any scheduling arrangements that may be required by other electric systems shall be the responsibility of the Transmission Customer requesting service. The Transmission Customer shall provide, unless waived by the Transmission Provider, notification to the Transmission Provider identifying such systems and authorizing them to schedule the capacity and energy to be transmitted by the Transmission Provider pursuant to Part II of the Tariff on behalf of the Receiving Party at the Point of Delivery or the Delivering Party at the Point of Receipt. However, the Transmission Provider will undertake reasonable efforts to assist the Transmission Customer in making such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

28 Nature of Network Integration Transmission Service

28.1 Scope of Service

Network Integration Transmission Service is a transmission service that allows Network Customers to efficiently and economically utilize their Network Resources (as well as other non-designated generation resources) to serve their Network Load located in the Transmission Provider's Control Area and any additional load that may be designated pursuant to Section 31.3 of the Tariff. The Network Customer taking Network Integration Transmission Service must obtain or provide Ancillary Services pursuant to Section 3, and must comply with the requirements of Attachment O regarding the EIM.

28.2 Transmission Provider Responsibilities

The Transmission Provider will plan, construct, operate and maintain its Transmission System in accordance with Good Utility Practice and its planning obligations in Attachment K in order to provide the Network Customer with Network Integration Transmission Service over the Transmission Provider's Transmission System. The Transmission Provider, on behalf of its Native Load Customers, shall be required to designate resources and loads in the same manner as any Network Customer under Part III of this Tariff. This information must be consistent with the information used by the Transmission Provider to calculate available transfer capability. The Transmission Provider shall include the Network Customer's Network Load in its Transmission System planning and shall, consistent with Good Utility Practice and Attachment K, endeavor to construct and place into service sufficient transfer capability to deliver the Network Customer's Network Resources to serve its Network Load on a basis comparable to the Transmission Provider's delivery of its own generating and purchased resources to its Native Load Customers.

28.3 Network Integration Transmission Service

The Transmission Provider will provide firm transmission service over its Transmission System to the Network Customer for the delivery of capacity and energy from its designated Network Resources to service its Network Loads on a basis that is comparable to the Transmission Provider's use of the Transmission System to reliably serve its Native Load Customers.

28.4 Secondary Service

The Network Customer may use the Transmission Provider's Transmission System to deliver energy to its Network Loads from resources that have not been designated as Network Resources. Such energy shall be transmitted, on an as-available basis, at no additional charge. Secondary service shall not require the filing of an Application for Network Integration Transmission Service under the Tariff. However, all other requirements of Part III of the Tariff (except for transmission rates) shall apply to secondary service. Deliveries from resources other than Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service under Part II of the Tariff.

28.5 Real Power Losses

Real Power Losses are associated with all transmission service. The Transmission Provider is not obligated to provide Real Power Losses. The Network Customer ~~is responsible for replacing~~shall compensate Transmission Provider for losses associated with all transmission service as ~~calculated by the Transmission Provider~~provided in Schedule 12 and Schedule 12A. The applicable Real Power Loss factors are as follows:

(1) The loss factor for determining the amount of losses associated with any Network Integration Transmission Service over the Colstrip Transmission Line facilities and the Southern Intertie transmission facilities shall be two point seven percent (2.7%) of the scheduled capacity and energy for which Network Integration Transmission Service is provided.

(2) The loss factor for determining the amount of losses associated with any Network Integration Transmission Service over the Washington Area transmission facilities shall be two point seven percent (2.7%) of the scheduled capacity and energy for which Transmission Service is provided.

28.6 Restrictions on Use of Service

The Network Customer shall not use Network Integration Transmission Service for (i) sales of capacity and energy to non-designated loads, or (ii) direct or indirect provision of transmission service by the Network Customer to third parties. All Network Customers taking Network Integration Transmission Service shall use Point-To-Point Transmission Service under Part II of the Tariff for any Third-Party Sale which requires use of the Transmission Provider's Transmission System. The Transmission Provider shall specify any appropriate charges and penalties and all related terms and conditions applicable in the event that a Network Customer uses Network Integration Transmission Service or secondary service pursuant to Section 28.4 to facilitate a wholesale sale that does not serve a Network Load.

28.7 Participation in the EIM

Notwithstanding the limitations in Section 28.6, Network Customers may participate in the EIM utilizing a Network Integration Transmission Service Agreement without a requirement to terminate the designation of any Network Resource that is a PSE EIM Participating Resource consistent with Section 30.3 of this Tariff and without a requirement to reserve additional Point-To-Point Transmission Service for such transactions.

29 Initiating Service

29.1 Condition Precedent for Receiving Service

Subject to the terms and conditions of Part III of the Tariff, the Transmission Provider will provide Network Integration Transmission Service to any Eligible Customer, provided that (i) the Eligible Customer completes an Application for service as provided under Part III of the Tariff, (ii) the Eligible Customer and the Transmission Provider complete the technical arrangements set forth in Sections 29.3 and 29.4, (iii) the Eligible Customer executes a Service Agreement pursuant to Attachment F for service under Part III of the Tariff or requests in writing that the Transmission Provider file a proposed unexecuted Service Agreement with the Commission, and (iv) the Eligible Customer executes a Network Operating Agreement with the Transmission Provider pursuant to Attachment G, or requests in writing that the Transmission Provider file a proposed unexecuted Network Operating Agreement.

29.2 Application Procedures

An Eligible Customer requesting service under Part III of the Tariff must submit an Application, with a deposit approximating the charge for one month of service, to the Transmission Provider as far as possible in advance of the month in which service is to commence. Unless subject to the procedures in Section 2, Completed Applications for Network Integration Transmission Service will be assigned a priority according to the date and time the Application is received, with the earliest Application receiving the highest priority. Applications should be submitted by entering the information listed below on the Transmission Provider's OASIS. Prior to implementation of the Transmission Provider's OASIS, a Completed Application may be submitted by (i) transmitting the required information to the Transmission Provider by telefax, or (ii) providing the information by telephone over the Transmission Provider's time recorded telephone line. Each of these methods will provide a time-stamped record for establishing the service priority of the Application. A Completed Application shall provide all of the information included in 18 CFR § 2.20 including but not limited to the following:

(i) The identity, address, telephone number and facsimile number of the party requesting service;

(ii) A statement that the party requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) A description of the Network Load at each delivery point. This description should separately identify and provide the Eligible Customer's best estimate of the total loads to be served at each transmission voltage level, and the loads to be served from each Transmission Provider substation at the same transmission voltage level. The description should include a ten (10) year forecast of summer and winter load and resource requirements beginning with the first year after the service is scheduled to commence;

(iv) The amount and location of any interruptible loads included in the Network Load. This shall include the summer and winter capacity requirements for each interruptible load (had such load not been interruptible), that portion of the load subject to interruption, the conditions under which an interruption can be implemented and any limitations on the amount and frequency of interruptions. An Eligible Customer should identify the amount of interruptible customer load (if any) included in the 10 year load forecast provided in response to (iii) above;

(v) A description of Network Resources (current and 10-year projection). For each on-system Network Resource, such description shall include:

- Unit size and amount of capacity from that unit to be designated as Network Resource
- VAR capability (both leading and lagging) of all generators
- Operating restrictions
  - Any periods of restricted operations throughout the year
  - Maintenance schedules
  - Minimum loading level of unit
  - Normal operating level of unit
  - Any must-run unit designations required for system reliability or contract reasons
- Approximate variable generating cost ($/MWH) for redispatch computations
- Arrangements governing sale and delivery of power to third parties from generating facilities located in the Transmission Provider Control Area, where only a portion of unit output is designated as a Network Resource;

For each off-system Network Resource, such description shall include:

- Identification of the Network Resource as an off-system resource
- Amount of power to which the customer has rights
- Delivery point(s) to the Transmission Provider's Transmission System
- Transmission arrangements on the external transmission system(s)

- Operating restrictions, if any

  – Any periods of restricted operations throughout the year

  – Maintenance schedules

  – Minimum loading level of unit

  – Normal operating level of unit

  – Any must-run unit designations required for system reliability or contract reasons

- Approximate variable generating cost ($/MWH) for redispatch computations;

(vi) Description of Eligible Customer's transmission system:

- Load flow and stability data, such as real and reactive parts of the load, lines, transformers, reactive devices and load type, including normal and emergency ratings of all transmission equipment in a load flow format compatible with that used by the Transmission Provider

- Operating restrictions needed for reliability

- Operating guides employed by system operators

- Contractual restrictions or committed uses of the Eligible Customer's transmission system, other than the Eligible Customer's Network Loads and Resources

- Location of Network Resources described in subsection (v) above

- 10 year projection of system expansions or upgrades

- Transmission System maps that include any proposed expansions or upgrades

- Thermal ratings of Eligible Customer's Control Area ties with other Control Areas;

(vii) Service Commencement Date and the term of the requested Network Integration Transmission Service. The minimum term for Network Integration Transmission Service is one year;

(viii) A statement signed by an authorized officer from or agent of the Network Customer attesting that all of the network resources listed pursuant to

Section 29.2(v) satisfy the following conditions: (1) the Network Customer owns the resource, has committed to purchase generation pursuant to an executed contract, or has committed to purchase generation where execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff; and (2) the Network Resources do not include any resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program; and

(ix) Any additional information required of the Transmission Customer as specified in (1) the Transmission Provider's planning process established in Attachment K; or (2) Attachment O.

Unless the Parties agree to a different time frame, the Transmission Provider must acknowledge the request within ten (10) days of receipt. The acknowledgement must include a date by which a response, including a Service Agreement, will be sent to the Eligible Customer. If an Application fails to meet the requirements of this section, the Transmission Provider shall notify the Eligible Customer requesting service within fifteen (15) days of receipt and specify the reasons for such failure. Wherever possible, the Transmission Provider will attempt to remedy deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the Transmission Provider shall return the Application without prejudice to the Eligible Customer filing a new or revised Application that fully complies with the requirements of this section. The Eligible Customer will be assigned a new priority consistent with the date of the new or revised Application. The Transmission Provider shall treat this information consistent with the standards of conduct contained in Part 37 of the Commission's regulations.

29.3 Technical Arrangements to be Completed Prior to Commencement of Service

Network Integration Transmission Service shall not commence until the Transmission Provider and the Network Customer, or a third party, have completed installation of all equipment specified under the Network Operating Agreement consistent with Good Utility Practice and any additional requirements reasonably and consistently imposed to ensure the reliable operation of the Transmission System. The Transmission Provider shall exercise reasonable efforts, in coordination with the Network Customer, to complete such arrangements as soon as practicable taking into consideration the Service Commencement Date.

29.4 Network Customer Facilities

The provision of Network Integration Transmission Service shall be conditioned upon the Network Customer's constructing, maintaining and operating the facilities on its side of each delivery point or interconnection necessary to reliably deliver capacity and energy from the Transmission Provider's Transmission System to the Network Customer. The Network Customer shall be solely responsible for constructing or installing all facilities on the Network Customer’s side of each such delivery point or interconnection.

29.5 Filing of Service Agreement

The Transmission Provider will file Service Agreements with the Commission in compliance with applicable Commission regulations.

30 Network Resources

30.1 Designation of Network Resources

Network Resources shall include all generation owned, purchased or leased by the Network Customer designated to serve Network Load under the Tariff. For purposes of temporary termination under Section 30.3, all or part of such generation associated with a NERC-registered Point of Receipt, behind which there are no transmission constraints, may be treated as a single Network Resource. Network Resources may not include resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program~~.~~ or participating in the EIM in accordance with Attachment O. Any owned or purchased resources that were serving the Network Customer's loads under firm agreements entered into on or before the Service Commencement Date shall initially be designated as Network Resources until the Network Customer terminates the designation of such resources.

30.2 Designation of New Network Resources

The Network Customer may designate a new Network Resource by providing the Transmission Provider with as much advance notice as practicable. A designation of a new Network Resource must be made through the Transmission Provider's OASIS by a request for modification of service pursuant to an Application under Section 29. This request must include a statement that the new network resource satisfies the following conditions: (1) the Network Customer owns the resource, has committed to purchase generation pursuant to an executed contract, or has committed to purchase generation where execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff; and (2) The Network Resources do not include any resources, or any portion thereof, that are committed for sale to non-designated third party load or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis, except for purposes of fulfilling obligations under a reserve sharing program. The Network Customer's request will be deemed deficient if it does not include this statement and the Transmission Provider will follow the procedures for a deficient application as described in Section 29.2 of the Tariff.

30.3 Termination of Network Resources

The Network Customer may terminate the designation of all or part of a generating resource as a Network Resource by providing notification to the Transmission Provider through OASIS as soon as reasonably practicable, but not later than the firm scheduling deadline for the period of termination. Any request for termination of Network Resource status must be submitted on OASIS, and should indicate whether the request is for indefinite or temporary termination. A request for indefinite termination of Network Resource status must indicate the date and time that the termination is to be effective, and the identification and capacity of the resource(s) or portions thereof to be indefinitely terminated. A request for temporary termination of Network Resource status must include the following:

(i) Effective date and time of temporary termination;

(ii) Effective date and time of redesignation, following period of temporary termination;

(iii) Identification and capacity of resource(s) or portions thereof to be temporarily terminated or, where appropriate, identification of the NERC-registered Point of Receipt to which Network Resources are assigned and the capacity to be temporarily terminated;

(iv) Resource description and attestation for redesignating the network resource following the temporary termination, in accordance with Section 30.2; and

(v) Identification of any related transmission service requests to be evaluated concomitantly with the request for temporary termination, such that the requests for undesignation and the request for these related transmission service requests must be approved or denied as a single request. The evaluation of these related transmission service requests must take into account the termination of the network resources identified in (iii) above, as well as all competing transmission service requests of higher priority.

A Network Customer's redesignation of a Network Resource following a temporary termination may incorporate by reference the description of such Network Resource as submitted to Transmission Provider pursuant to Section 29.2 of this Tariff prior to such temporary termination (to the extent such description is not changed by such temporary termination), provided that such Network Customer confirms that such description (to the extent not so changed) is and remains accurate. As part of a temporary termination, a Network Customer may only redesignate the same resource that was originally designated, or a portion thereof. Requests to redesignate a different resource and/or a resource with increased capacity will be deemed deficient and the Transmission Provider will follow the procedures for a deficient application as described in Section 29.2 of the Tariff.

30.4 Operation of Network Resources

The Network Customer shall not operate its designated Network Resources located in the Network Customer's or Transmission Provider's Control Area such that the output of those facilities exceeds its designated Network Load, plus Non-Firm Sales delivered pursuant to Part II of the Tariff, plus losses, plus power sales under a reserve sharing program, plus sales that permit curtailment without penalty to serve its designated Network Load. This limitation shall not apply to PSE EIM Participating Resources responding to Dispatch Instructions or to changes in the operation of a Transmission Customer's Network Resources at the request of the Transmission Provider to respond to an emergency or other unforeseen condition which may impair or degrade the reliability of the Transmission System. For all Network Resources not physically connected with the Transmission Provider's Transmission System, the Network Customer may not schedule delivery of energy in excess of the Network Resource's capacity, as specified in the Network Customer's Application pursuant to Section 29, unless the Network Customer supports such delivery within the Transmission Provider's Transmission System by either obtaining Point-to-Point Transmission Service or utilizing secondary service pursuant to Section 28.4. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that a Network Customer's schedule at the delivery point for a Network Resource not physically interconnected with the Transmission Provider's Transmission System exceeds the Network Resource's designated capacity, excluding energy delivered using secondary service or Point-to-Point Transmission Service.

30.5 Network Customer Redispatch Obligation

As a condition to receiving Network Integration Transmission Service, the Network Customer agrees to redispatch its Network Resources as requested by the Transmission Provider pursuant to Section 33.2. To the extent practical, the redispatch of resources pursuant to this section shall be on a least cost, non-discriminatory basis between all Network Customers, and the Transmission Provider.

30.6 Transmission Arrangements for Network Resources Not Physically Interconnected With The Transmission Provider

The Network Customer shall be responsible for any arrangements necessary to deliver capacity and energy from a Network Resource not physically interconnected with the Transmission Provider's Transmission System. The Transmission Provider will undertake reasonable efforts to assist the Network Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice.

30.7 Limitation on Designation of Network Resources

The Network Customer must demonstrate that it owns or has committed to purchase generation pursuant to an executed contract in order to designate a generating resource as a Network Resource. Alternatively, the Network Customer may establish that execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff.

30.8 Use of Interface Capacity by the Network Customer

There is no limitation upon a Network Customer's use of the Transmission Provider's Transmission System at any particular interface to integrate the Network Customer's Network Resources (or substitute economy purchases) with its Network Loads. However, a Network Customer's use of the Transmission Provider's total interface capacity with other transmission systems may not exceed the Network Customer's Load.

30.9 Network Customer Owned Transmission Facilities

The Network Customer that owns existing transmission facilities that are integrated with the Transmission Provider's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration the Network Customer must demonstrate that its transmission facilities are integrated into the plans or operations of the Transmission Provider, to serve its power and transmission customers. For facilities added by the Network Customer subsequent to the May 14, 2007, the Network Customer shall receive credit for such transmission facilities added if such facilities are integrated into the operations of the Transmission Provider's facilities; provided however, the Network Customer's transmission facilities shall be presumed to be integrated if such transmission facilities, if owned by the Transmission Provider, would be eligible for inclusion in the Transmission Provider's ATRR. Calculation of any credit under this subsection shall be addressed in either the Network Customer's Service Agreement or any other agreement between the Parties.

SCHEDULE 1A
EIM Administrative Service

This service recovers the administrative costs assessed by the CAISO as the MO of the EIM to the PSE EIM Entity in accordance with Sections 4.5.1.1.4, 4.5.1.3, 11.22.8, and 29.11(i) of the MO Tariff (EIM Administrative Costs). All Transmission Customers purchasing Long-Term Firm Point-to-Point Transmission Service, Short-Term Firm Point-to-Point Transmission Service, Non-Firm Point-to-Point Transmission Service, or Network Integration Transmission Service from the Transmission Provider shall be required to acquire EIM Administrative Service from the Transmission Provider.

EIM Administrative Costs assigned to the PSE EIM Entity shall be sub-allocated to Transmission Customers on the basis of Measured Demand for the month in which the EIM Administrative Costs were incurred.

SCHEDULE 4
Energy Imbalance Service

This Schedule 4 shall apply to Transmission Service for Transmission Customers other than ~~retail customers, including retail customers~~Transmission Customers receiving service pursuant to Transmission Provider's Schedules 448 and 449, on file with the Washington Utilities and Transportation Commission. ~~Retail customers~~Transmission Customers receiving service pursuant to Transmission Provider's Schedules 448 and 449 shall take Energy Imbalance Service under Schedule 4R.

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a Control Area over a single hour. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements, which may include use of non-generation resources capable of providing this service, to satisfy its Energy Imbalance Service obligation. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator. ~~The Transmission Provider may charge a Transmission Customer a penalty for either hourly energy imbalances under this Schedule or a penalty for hourly generator imbalances under Schedule 9 for imbalances occurring during the same hour, but not both unless the imbalances aggravate rather than offset each other.~~

~~The Transmission Provider shall establish charges for energy imbalance based on the deviation bands as follows: (i) deviations within +/- 1.5 percent (with a minimum of 2 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be netted on a monthly basis and settled financially, at the end of the month, at 100 percent of incremental or decremental cost; (ii) deviations greater than +/- 1.5 percent up to 7.5 percent (or greater than 2 MW up to 10 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month, at 110 percent of incremental cost or 90 percent of decremental cost, and (iii) deviations greater than +/- 7.5 percent (or 10 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month, at 125 percent of incremental cost or 75 percent of decremental cost.~~

~~For purposes of this Schedule 4, (a) incremental cost shall be the product of (i) the amount of power by which the Scheduled Energy exceeds the Transmission Customer's load and (ii) the on-peak or off-peak price reported for the IntercontinentalExchange ("ICE") Mid-Columbia Firm Power Index for the hour in which Energy Imbalance Service is provided, and (b) decremental cost shall be the product of (i) the amount of power by which the Scheduled Energy exceeds the Scheduled Energy Transmission Customer's load and (ii) the on-peak or off-peak price reported for the ICE Mid-Columbia Firm Power Index for the hour in which Energy Imbalance Service is provided. In the event that Energy Imbalance Service is provided during a time where no volumes are reported at the Mid-Columbia hub, the most recent firm on-peak and off-peak prices will be carried forward. If ICE permanently ceases to report day ahead pricing at the~~

~~Mid-Columbia hub, or if the methodology used to determine the index at the Mid-Columbia hub is materially modified, Transmission Provider shall select a permanentreplacement index, reported by a reputable third party, that reflects the actual same-day firm transactions at the Mid-Columbia hub.~~

~~For any hour for which Transmission Provider assesses any charge for Energy Imbalance Service under this Schedule 4 based on 110 percent or 125 percent of incremental cost, Transmission Provider shall credit to Qualified Transmission Customers for such hour the amount by which such charge exceeded incremental cost. For each such hour, the amount of such credit shall be allocated among Qualified Transmission Customers for such hour in proportion to their respective Qualified Transmission Loads for such hour.~~

~~For purposes of this Schedule 4, the following definitions shall apply:~~

~~(a) "Qualified Transmission Customer" for any hour means each of the following in such hour:~~

~~(i) Point-To-Point Transmission Service Customer for Transmission Service over the Washington Area transmission facilities,~~

~~(ii) Network Customer for Transmission Service over the Washington Area transmission facilities, or~~

~~(iii) Transmission Provider on behalf of its Native Load Customers;~~

~~provided that any Transmission Customer that is assessed any charge for such hour for Energy Imbalance Service under this Schedule 4 based on 110 percent or 125 percent of incremental cost shall not be a Qualified Transmission Customer under this Schedule 4 for such hour.~~

~~(b) "Qualified Transmission Load" for any hour means the following with respect to each Qualified Transmission Customer:~~

~~(i) for each Point-To-Point Transmission Service Customer, its Reserved Capacity for Transmission Service over the Washington Area transmission facilities applicable to such hour,~~

~~(ii) for each Network Customer, its Network Load on the Washington Area transmission facilities in such hour computed in accordance with Section 34.2 of the Tariff; or~~

~~(iii) for Transmission Provider on behalf of its Native Load Customers, the hourly load in such hour of its Native Load Customers coincident with the Transmission Provider's Transmission System Peak for such hour (computed consistent with computations pursuant to Section 34 of the Tariff).~~

A Transmission Customer shall be charged or paid for Energy Imbalance Service measured as the deviation of the Transmission Customer's metered load compared to the load component of the Transmission Customer Base Schedule (as determined pursuant to Section 4.2.4 of Attachment O of this Tariff) settled as UIE for the period of the deviation at the applicable LAP price where the load is located, as determined by the MO under Section 29.11(b)(3)(C) of the MO Tariff.

SCHEDULE 4R

Energy Imbalance Service ~~For Retail~~ for Transmission Customers Taking Service Under Transmission Provider's Schedule 448 and Schedule 449

This Schedule shall apply to Transmission Service for ~~retail customers pursuant to the~~Transmission Customers taking service under Transmission Provider's Schedule 448 and Schedule 449, on file with the Washington Utilities and Transportation Commission. Such service will not be subject to charges under Schedule 4~~, which applies only to Transmission Service to serve wholesale customers.~~.

~~**4R.0** Transmission Provider shall provide, and Retail Customer will obtain Energy Imbalance Service to meet hourly variations in Supplied Power and Customer Metered Energy. Transmission Provider pricing for such service will be a charge of 105% of the Mid-Columbia Firm Index for negative imbalances outside a Deviation Band equal to the greater of +/- 1 MW or +/- 7.5% of the scheduled hourly Supplied Power ("Deviation Band") and a credit of 95% of the Mid-Columbia Firm Index for positive imbalances outside the Deviation Band. Deviations between Retail Customer Metered Energy and Supplied Power within the Deviation Band shall be settled at 100% of the Mid-Columbia Firm Index for the hour in which the deviation occurred for negative or positive imbalances. The charges for Energy Imbalance Service shall be set based on the peak and off-peak index prices applicable to the time period for which the service is provided.~~

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a Control Area over a single hour. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements, which may include use of non-generation resources capable of providing this service, to satisfy its Energy Imbalance Service obligation. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator.

4R.0 A Transmission Customer shall be charged or paid for Energy Imbalance Service measured as the deviation of the Transmission Customer's metered load compared to the load component of the Transmission Customer Base Schedule corresponding to the Transmission Customer's load (as determined pursuant to Section 4.2.4 of Attachment O of this Tariff) settled as UIE for the period of the deviation at the applicable LAP price where the load is located, as determined by the MO under Section 29.11(b)(3)(C) of the MO Tariff.

4R.1 ~~Retail~~Transmission Customers shall have the right to aggregate their Loads and Supplied Power for purposes of determining the hourly imbalance energy. Transmission Provider has no obligation to provide excess energy required for ~~retail load following~~Energy Imbalance Service using its own generation resources, but shall make commercially reasonable efforts to obtain in the market such excess energy.

~~**4R.2** A Retail Customer who elects to transfer its Load to another control area~~

~~through dynamic scheduling will not be subject to energy imbalances with the Transmission Provider and will thus not incur energy imbalance charges. However, if the dynamic scheduling fails so that the Transmission Provider does provide Load following to a dynamically scheduled customer, then such Retail Customer will pay for such service at the rates specified for Energy Imbalance Service for Retail Customers.~~

~~**4R.3**~~ ~~If the Dow Jones permanently ceases to report any of the indices at the Mid-Columbia, or if the methodology used to determine any of said reported indices is materially modified or changed, Retail Customer and Transmission Provider shall select a mutually agreeable permanent replacement, reported by a reputable third party, that reflects actual same day firm transactions at the Mid-Columbia. If, after thirty (30) days, Retail Customer and Transmission Provider are at impasse, the determination of the replacement index to be used shall be made under Dispute Resolution procedures set forth below.~~

~~**4R.4**~~**4R.2** Prior to commencing any complaint or court proceeding regarding any dispute between Transmission Provider and ~~Retail~~Transmission Customer, (i) Transmission Provider and ~~Retail~~Transmission Customer shall each make good faith efforts to resolve such dispute pursuant to alternative dispute resolution (ADR) procedures consistent with WAC 480-09-465 and (ii) pursuant to the foregoing, the Transmission Provider and ~~Retail~~Transmission Customer shall make use of ADR procedures to the maximum extent practicable in resolving such dispute.

~~**4R.5**~~ ~~If Dow Jones reports none of the indices at Mid-Columbia for any given period, or if any permanent replacement index which is subsequently established is not reported for any given period, then Transmission Provider shall calculate the energy imbalance for each hour of such unreported period, using the quantity-weighted average of the prices of energy delivered or received by the Transmission Provider during such hour under short term (twenty-four (24) hours or less) wholesales sales and purchases by the Transmission Provider.~~

~~For any hour for which Transmission Provider assesses any charge for Energy Imbalance Service under this Schedule 4R based on 105 percent of the Mid-Columbia Firm Index, Transmission Provider shall credit to Qualified Transmission Customers for such hour the amount by which such charge exceeded the applicable Mid-Columbia Firm Index. For each such hour, the amount of such credit shall be allocated among Qualified Transmission Customers for such hour in proportion to their respective Qualified Transmission Loads for such hour.~~

~~For purposes of this Schedule 4R, the following definitions shall apply:~~

~~(a)~~ ~~"Qualified Transmission Customer" for any hour means each of the following in such hour~~

~~(i)~~ ~~Long-Term Firm Point-To-Point Transmission Service Customer for Transmission Service over the Washington Area transmission facilities,~~

~~(ii)~~ ~~Network Customer for Transmission Service over the Washington Area transmission facilities, or~~

~~(iii)~~ ~~Transmission Provider on behalf of its Native Load Customers;~~

~~provided that any Transmission Customer that is assessed any charge for such hour for Energy Imbalance Service under this Schedule 4R based on 105 percent of the Mid-Columbia Firm Index shall not be a Qualified Transmission Customer under this Schedule 4R for such hour.~~

~~(b) "Qualified Transmission Load" for any hour means the following with respect to each Qualified Transmission Customer:~~

~~(i) for each Point-To-Point Transmission Service Customer, its Reserved Capacity for Transmission Service over the Washington Area transmission facilities applicable to such hour,~~

~~(ii) for each Network Customer, its Network Load on the Washington Area transmission facilities in such hour computed in accordance with Section 34.2 of the Tariff; or~~

~~(iii) for Transmission Provider on behalf of its Native Load Customers, the hourly load in such hour of its Native Load Customers coincident with the Transmission Provider's Transmission System Peak for such hour (computed consistent with computations pursuant to Section 34 of the Tariff).~~

SCHEDULE 9
Generator Imbalance Service

Generator Imbalance Service is provided when a difference occurs between the output of a generator, that is not a PSE EIM Participating Resource, located in the Transmission Provider's Control Area and ~~a delivery schedule~~the resource component of the Transmission Customer Base Schedule from that generator to (1) another Control Area or (2) a load within the Transmission Provider's Control Area over a single hour. The Transmission Provider must offer this service, to the extent it is physically feasible to do so from its resources or from resources available to it, when Transmission Service is used to deliver energy from a generator located within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements, which may include use of non-generation resources capable of providing this service, to satisfy its Generator Imbalance Service obligation. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area Operator. ~~The Transmission Provider may charge a Transmission Customer a penalty for either hourly generator imbalances under this Schedule or a penalty for hourly energy imbalances under Schedule 4 for imbalances occurring during the same hour, but not both unless the imbalances aggravate rather than offset each other.~~

~~The Transmission Provider shall establish charges for generator imbalance based on the deviation bands as follows: (i) deviations within +/- 1.5 percent (with a minimum of 2 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be netted on a monthly basis and settled financially, at the end of each month, at 100 percent of incremental or decremental cost, (ii) deviations greater than +/- 1.5 percent up to 7.5 percent (or greater than 2 MW up to 10 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month, at 110 percent of incremental cost or 90 percent of decremental cost, and (iii) deviations greater than +/- 7.5 percent (or 10 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled at 125 percent of incremental cost or 75 percent of decremental cost, except that an intermittent resource will be exempt from this deviation band and will pay the deviation band charges for all deviations greater than the larger of 1.5 percent or 2 MW. An intermittent resource, for the limited purpose of this Schedule is an electric generator that is not dispatchable and cannot store its fuel source and therefore cannot respond to changes in system demand or respond to transmission security constraints.~~

~~For purposes of this Schedule 9, (a) incremental cost shall be the product of (i) the amount by which the delivery schedule from the generator exceeds the output of that generator and (ii) the on-peak or off-peak price reported for the IntercontinentalExchange ("ICE") Mid-Columbia Firm Power Index for the hour in which Generator Imbalance Service is provided, and (b) decremental cost shall be the product of (i) the amount of power by which the output of the generator exceeds the delivery schedule from that generator and (ii) the on-peak or off-peak price reported for the ICE Mid-Columbia Firm Power Index for the hour in which Generator Imbalance Service is provided. In the event that Generator Imbalance Service is provided during a time where no~~

~~volumes are reported at the Mid-Columbia hub, the most recent firm on-peak and off-peak prices will be carried forward. If ICE permanently ceases to report day ahead pricing at the Mid-Columbia hub, or if the methodology used to determine the index at the Mid-Columbia hub is materially modified, Transmission Provider shall select a permanent replacement index, reported by a reputable third party, that reflects the actual same-day firm transactions at the Mid-Columbia hub.~~

~~For any hour for which Transmission Provider assesses any charge for Generator Imbalance Service based on 110 percent or 125 percent of incremental cost, Transmission Provider shall credit to Qualified Transmission Customers for such hour the amount by which such charge exceeded incremental cost. For each such hour, the amount of such credit shall be allocated among Qualified Transmission Customers for such hour in proportion to their respective Qualified Transmission Loads for such hour.~~

~~For purposes of this Schedule 9, the following definitions shall apply:~~

~~(a) "Qualified Transmission Customer" for any hour means each of the following in such hour~~

~~(i) Point-To-Point Transmission Service Customer for Transmission Service over the Washington Area transmission facilities,~~

~~(ii) Network Customer for Transmission Service over the Washington Area transmission facilities, or~~

~~(iii) Transmission Provider on behalf of its Native Load Customers;~~

~~provided that any Transmission Customer that is assessed any charge for such hour for Generator Imbalance Service under this Schedule 9 based on 110 percent or 125 percent of incremental cost shall not be a Qualified Transmission Customer under this Schedule 9 for such hour.~~

~~(b) "Qualified Transmission Load" for any hour means the following with respect to each Qualified Transmission Customer:~~

~~(i) for each Point-To-Point Transmission Service Customer, its Reserved Capacity for Transmission Service over the Washington Area transmission facilities applicable to such hour,~~

~~(ii) for each Network Customer, its Network Load on the Washington Area transmission facilities in such hour computed in accordance with Section 34.2 of the Tariff; or~~

~~(iii) for Transmission Provider on behalf of its Native Load Customers, the hourly load in such hour of its Native Load Customers coincident with the Transmission Provider's Transmission System Peak for such hour (computed consistent with computations pursuant to Section 34 of the Tariff).~~

The Transmission Provider shall establish charges for Generator Imbalance Service as follows (the following provisions do not apply to Transmission Customers which have received a Manual Dispatch or EIM Available Balancing Capacity dispatch, or which have communicated physical changes in the output of resources to the MO):

(1) A Transmission Customer shall be charged or paid for Generator Imbalance Service measured as the deviation of the Transmission Customer's metered generation compared to the resource component of the Transmission Customer Base Schedule settled as UIE for the period of the deviation at the applicable PNode RTD price where the generator is located, as determined by the MO under Section 29.11(b)(3)(B) of the MO Tariff.

The following provisions shall apply to Transmission Customers which have received a Manual Dispatch or EIM Available Balancing Capacity dispatch, or which have communicated physical changes in the output of resources to the MO:

(1) (a) A Transmission Customer shall be charged or paid for Generator Imbalance Service measured as the deviation of the Transmission Customer's metered generation compared to the Manual Dispatch amount, the EIM Available Balancing Capacity dispatch amount, or physical changes in the output of resources incorporated by the MO in the FMM, settled as UIE for the period of the deviation at the applicable PNode RTD price where the generator is located, as determined by the MO under Section 29.11(b)(3)(B) of the MO Tariff; or

(b) A Transmission Customer shall be charged or paid for Generator Imbalance Service measured as the deviation of the Transmission Customer's metered generation compared to the Manual Dispatch amount, the EIM Available Balancing Capacity dispatch amount, or physical changes in the output of resources incorporated by the MO in RTD, settled as UIE for the period of the deviation at the applicable PNode RTD price where the generator is located, as determined by the MO under Section 29.11(b)(3)(B) of the MO Tariff

(2) (a) A Transmission Customer shall be charged or paid for Generator Imbalance Service measured as the deviation of either the Manual Dispatch amount, the EIM Available Balancing Capacity dispatch amount, or physical changes in the output of resources incorporated by the MO in the FMM, compared to the resource component of the Transmission Customer Base Schedule, settled as IIE for the period of the deviation at the applicable PNode FMM price where the generator is located, as determined by the MO under Section 29.11(b)(1)(A)(ii) of the MO Tariff; or

(b) Generator Imbalance Service measured as the deviation of either the Manual Dispatch amount, the EIM Available Balancing Capacity dispatch amount, or physical changes in the output of resources incorporated by the MO in RTD, compared to the FMM schedule, as IIE for the period of the deviation at the applicable PNode RTD price where the generator is located, as determined by the MO under Section 29.11(b)(2)(A)(ii) of the MO

Tariff.

Applicability to Interconnection Customers:

To the extent the Interconnection Customer is a different entity than the Transmission Customer and controls the output of a generator located in the Transmission Provider's Control Area, the Interconnection Customer may be subject to charges for Generator Imbalance Service (rather than the Transmission Customer) in accordance with this Schedule 9.

~~**SCHEDULE 12**~~

~~**[[RESERVED FOR FUTURE USE]]**~~SCHEDULE 12

Real Power Losses on Washington Area Transmission Facilities

The Transmission Customer taking Network Integration Transmission Service, Firm Point-to-Point, or Non-Firm Point-to-Point Transmission Service, excluding Energy Imbalance Service and Generator Imbalance Service, shall reimburse the Transmission Provider for Real Power Losses as provided in Sections 15.7 and 28.5 of this Tariff. The Transmission Customer must financially settle for Real Power Losses by reimbursement as specified herein.

Settlement of Real Power Losses associated with Energy Imbalance Service provided under Schedule 4 or Schedule 4R shall be pursuant to Schedule 4 or Schedule 4R of this Tariff, and settlement of Real Power Losses associated with Generator Imbalance Service provided under Schedule 9 shall be pursuant to Schedule 9 of this Tariff. The procedures to determine the amount of Real Power Losses associated with a Transmission Customer Base Schedule, as well as the reimbursement for Real Power Losses are set forth below.

The amount of Real Power Losses assessed to a Transmission Customer in a given hour shall be the product of such-Transmission Customer Base Schedule during the hour in MWhs and the applicable loss factor provided in Sections 15.7 and 28.5.

The Transmission Customer shall compensate the Transmission Provider at a rate equal to the amount of Real Power Losses assessed to such Transmission Customer in a given hour multiplied by the hourly LAP price for the PSE BAA in that hour as established by the MO under section 29.11 (b)(3)(C) of the MO Tariff.

SCHEDULE 12A
Real Power Losses on Colstrip and Southern Intertie Transmission Lines

The Transmission Customer taking service over the Colstrip and Southern Intertie High Voltage Direct Assignment Facilities pursuant to Schedule 10 shall reimburse Transmission Provider for Real Power Losses as provided in Sections 15.7 and 28.5 of this Tariff. The Transmission Customer must financially settle the losses by reimbursement as specified herein.

The Transmission Customer shall compensate the Transmission Provider for Real Power Losses assessed to such Transmission Customer in a given hour at a rate equal to the hourly LAP price for the PSE BAA as established by the MO under section 29.11 (b)(3)(C) of the MO Tariff based on the product of the actual transmission service provided (scheduled service less any curtailments, corrections or adjustments mutually agreed on by the Transmission Provider and the Transmission Customer) during each hour in MWhs and the applicable loss factor provided in Sections 15.7 and 28.5 of the Tariff.

ATTACHMENT O
Energy Imbalance Market

ATTACHMENT O
EIM

1. General Provision - Purpose and Effective Date of Attachment O

Attachment O provides for Transmission Provider's participation as the PSE EIM Entity in the EIM administered by the MO. Attachment O shall be in effect upon its acceptance by the Commission, with the exceptions provided below, for as long as Transmission Provider implements the EIM and until all final settlements are finalized resulting from such implementation. Sections 4.1.5, 4.1.6, 8 and 10 of this Attachment O take effect no earlier than October 1, 2016 or the implementation date of Transmission Provider's participation in the EIM, whichever is later. All other sections of this Attachment O take effect no earlier than July 25, 2016 or seven (7) days prior to the start of parallel operations

This Attachment O shall apply to all Transmission Customers and Interconnection Customers, as applicable, with new and existing service agreements under Articles II and III and Annexes A and B of this Tariff, as well as all Transmission Customers with legacy transmission agreements that pre-existed this Tariff and that expressly incorporate by reference the applicability of PSE's Tariff and/or this Attachment O in particular. To the extent an Interconnection Customer controls the output of a generator located in PSE's BAA, the PSE EIM Entity may require the Interconnection Customer to comply with a requirement in this Attachment O that on its face applies to a Transmission Customer to the extent that the PSE EIM Entity makes a determination, in its sole discretion, that the Interconnection Customer is the more appropriate party to satisfy the requirements of Attachment O than any Transmission Customer.

This Attachment O shall work in concert with the provisions of the MO Tariff implementing the EIM to support operation of the EIM. To the extent that this Attachment O is inconsistent with a provision in the remainder of this Tariff with regard to the PSE EIM Entity's administration of the EIM, this Attachment O shall prevail.

This Attachment O governs the relationship between the PSE EIM Entity and all Transmission Customers and Interconnection Customers subject to this Tariff. This Attachment O does not establish privity between Transmission Customers and the MO or make a Transmission Customer subject to the MO Tariff. Any Transmission Customer duties and obligations related to the EIM are those identified in this Tariff, unless the Transmission Customer voluntarily elects to participate directly in the EIM with PSE EIM Participating Resources, in which case the MO Tariff provisions for EIM Participating Resources and EIM Participating Resource Scheduling Coordinators shall also apply.

2. Election of Transmission Customers to become PSE EIM Participating Resources

The decision of a Transmission Customer to participate in the EIM with resources as PSE EIM Participating Resources is voluntary. A Transmission Customer that chooses to have a resource become a PSE EIM Participating Resource must:

(1) Meet the requirements specified in Section 3 of this Attachment O and the PSE EIM BP;

(2) Become or retain a MO-certified EIM Participating Resource Scheduling Coordinator; and

(3) Follow the application and certification process specified in this Attachment O and the PSE EIM BP posted on the Transmission Provider's OASIS.

Transmission Customers which own or control multiple resources may elect to have any or all of their resources be PSE EIM Participating Resources, in which case any resources that are not elected by the Transmission Customer to be PSE EIM Participating Resources shall be treated as Non-Participating Resources for purposes of this Attachment O.

3. Eligibility to be a PSE EIM Participating Resource

3.1 Internal Resources - Transmission Rights

Resources owned or controlled by Transmission Customers and located within the metered boundaries of PSE's BAA are eligible to become PSE EIM Participating Resources. The Transmission Customer that owns or controls the resource must have associated transmission rights based on one of the following:

(1) The resource is a designated Network Resource of a Network Customer and the Network Customer elects to participate in the EIM through its Network Integration Transmission Service Agreement; or

(2) The resource is associated with either (i) a Service Agreement for Firm Point-to-Point Transmission Service or (ii) Service Agreement for Non-Firm Point-to-Point Transmission Service, and such Transmission Customer elects to participate in the EIM.

3.2 Resources External to PSE's BAA

3.2.1 Use of Pseudo-Ties

A resource owned or controlled by a Transmission Customer that is not physically located inside the metered boundaries of PSE's BAA may participate in the EIM as a PSE EIM Participating Resource if the Transmission Customer (1) implements a Pseudo-Tie into PSE's BAA, consistent with PSE's business practice posted on Transmission Provider's OASIS, (2) has arranged firm transmission over any third-party transmission systems to a PSEI BAA intertie boundary equal to the amount of energy that will be Dynamically Transferred through a Pseudo-Tie into PSE's BAA, consistent with PSE's business practice posted on Transmission Provider's OASIS, and (3) has secured transmission service consistent with Section 3.1 of this Attachment O.

3.2.2 Pseudo-Tie Costs

Pseudo-Tie implementation costs shall be allocated in a manner consistent with the treatment of Network Upgrades and Direct Assignment Facilities to facilitate a Pseudo-Tie into PSE's BAA.

3.3 Application and Certification of PSE EIM Participating Resources

3.3.1 Application

To become a PSE EIM Participating Resource, an applicant must submit a completed application, as set forth in the PSE EIM BP, and shall provide a deposit of $1,500 for the PSE EIM Entity to process the application. Upon completion of processing the completed application, the PSE EIM Entity shall charge and the applicant shall pay the actual costs of the application processing. Any difference between the deposit and the actual costs of the application processing shall be paid by or refunded to the PSE EIM Participating Resource applicant, as appropriate.

At the time of application, any PSE EIM Participating Resource applicant must elect to perform the duties of either a CAISO Metered Entity or Scheduling Coordinator Metered Entity, consistent with the MO's requirements and additional technical requirements set forth in the PSE EIM BP, as applicable.

3.3.2 Processing the Application

The PSE EIM Entity shall make a determination as to whether to accept or reject the application within 45 days of receipt of the application. At minimum, the PSE EIM Entity shall validate through the application that the PSE EIM Participating Resource applicant has satisfied Sections 3.1 and 3.2 of this Attachment O, as applicable, and met minimum telemetry and metering requirements, as set forth in the MO's requirements and the PSE EIM BP. Within 45 days of receipt of the application and in accordance with the process outlined in the PSE EIM BP, the PSE EIM Entity may request additional information and will attempt to resolve any minor deficiencies in the application with the Transmission Customer. The PSE EIM Entity may extend the 45-day period to accommodate the resolution of minor deficiencies in the application in order to make a determination on an application.

If the PSE EIM Entity approves the application, it shall send notification of approval to both the PSE EIM Participating Resource applicant and the MO. The process by which the PSE EIM Entity sends notification of approval shall be set forth in the PSE EIM BP.

If the PSE EIM Entity rejects the application, the PSE EIM Entity shall send notification stating the grounds for rejection to the PSE EIM Participating Resource applicant. Upon request, the PSE EIM Entity may provide guidance to the applicant as to how the PSE EIM Participating Resource applicant may cure the grounds for the rejection. In the event that the PSE EIM Entity has granted an extension of the 45-day period but the applicant has neither provided the additional requested information nor otherwise resolved identified deficiencies within six (6) months of the PSE EIM Entity's initial receipt of the application, the application shall be deemed rejected by the PSE EIM Entity.

If an application is rejected, the PSE EIM Participating Resource applicant may resubmit its application at any time (including submission of a new processing fee deposit).

3.3.3 Certification Notice

Upon approval of an application and in accordance with the process specified in the PSE EIM BP, certification by the PSE EIM Entity of the PSE EIM Participating Resource to participate in the EIM shall occur once the Transmission Customer has demonstrated and the MO has confirmed that the Transmission Customer has:

(1) Met the MO's criteria to become an EIM Participating Resource and executed the MO's *pro forma* EIM Participating Resource Agreement;

(2) Qualified to become or retained the services of a MO-certified EIM Participating Resource Scheduling Coordinator;

(3) Met the necessary metering requirements of this Tariff and Section 29.10 of the MO Tariff and the EIM Participating Resource Scheduling Coordinator has executed the MO's *pro forma* Meter Service Agreement for Scheduling Coordinators; and

(4) Met communication and data requirements of this Tariff and Section 29.6 of the MO Tariff; and has the ability to receive and implement Dispatch Instructions every five minutes from the MO.

Upon receiving notice from the MO of the completion of the enumerated requirements by the Transmission Customer, the PSE EIM Entity shall provide notice to both the Transmission Customer with a PSE EIM Participating Resource and the MO that the PSE EIM Participating Resource is certified and therefore eligible to participate in the EIM. The process by which the PSE EIM Entity certifies Transmission Customers with a PSE EIM Participating Resource shall be set forth in the PSE EIM BP.

3.3.4 Status of Resource Pending Certification

If the Transmission Customer (i) has submitted an application for a resource to be a PSE EIM Participating Resource but the application has not been approved, or (ii) has not yet been certified by the PSE EIM Entity consistent with Section 3.3.3 of this Attachment O, the resource shall be deemed to be a Non-Participating Resource.

3.3.5 Notice and Obligation to Report a Change in Information

Each Transmission Customer with a PSE EIM Participating Resource has an ongoing obligation to inform the PSE EIM Entity of any changes to any of the information submitted as part of the application process under this Attachment O. The PSE EIM BP shall set forth the process and timing requirements for notifying the PSE EIM Entity of such changes.

This information includes, but is not limited to:

(1) Any change in the PSE EIM Participating Resource Scheduling Coordinator representing the resource;

(2) Any change in the ownership or control of the resource;

(3) Any change to the physical characteristics of the resource required to be reported to the MO in accordance with Section 29.4(c)(4)(C) of the MO Tariff; or

(4) If either the MO terminates the participation of the PSE EIM Participating Resource in the EIM or the Transmission Customer has terminated the PSE EIM Participating Resource's participation in the EIM; in either case, that resource shall be considered to be a Non-Participating Resource for purposes of this Tariff, including Attachment O.

4. Roles and Responsibilities

4.1 Transmission Provider as the PSE EIM Entity and the PSE EIM Entity Scheduling Coordinator

4.1.1 Responsibilities

4.1.1.1 Identification of EIM Entity Scheduling Coordinator

The PSE EIM Entity can serve as the PSE EIM Entity Scheduling Coordinator or retain a third-party to perform such role. If the PSE EIM Entity is not the PSE EIM Entity Scheduling Coordinator, the PSE EIM Entity shall communicate to the PSE EIM Entity Scheduling Coordinator the information required by the PSE EIM Entity Scheduling Coordinator to fulfill its responsibilities in the EIM.

The PSE EIM Entity Scheduling Coordinator shall coordinate and facilitate the EIM in accordance with the requirements of the MO Tariff. The PSE EIM Entity Scheduling Coordinator must meet the certification requirements of the MO and enter into any necessary MO agreements.

4.1.1.2 Processing PSE EIM Participating Resource Applications

The PSE EIM Entity shall be responsible for processing applications of Transmission Customers seeking authorization to participate in the EIM with resources as PSE EIM Participating Resources in accordance with Section 3.3 of this Attachment O.

4.1.1.3 Determination of EIM Implementation Decisions for PSE's BAA

The PSE EIM Entity is solely responsible for making any decisions with respect to EIM participation that the MO requires of EIM Entities. The PSE EIM Entity has made the following determinations:

(1) **Eligibility requirements**: Eligibility requirements are set forth in Section 3 of Attachment O.

(2) **Load Aggregation Points:** There shall be one LAP for PSE's BAA.

(3) **MO load forecast:** The PSE EIM Entity shall utilize the MO load forecast but shall retain the right to provide the load forecast to the MO in accordance with the MO Tariff.

(4) **MO metering agreements**: The PSE EIM Entity and all Transmission Customers with PSE EIM Participating Resources shall have the option to elect to be Scheduling Coordinator Metered Entities or CAISO Metered Entities in accordance with Section 29.10 of the MO Tariff. The PSE EIM Entity shall be a Scheduling Coordinator Metered Entity on behalf of all Transmission Customers with Non-Participating Resources in accordance with Section 29.10 of the MO Tariff.

4.1.1.4 PSE EIM Business Practice

The PSE EIM Entity shall establish and revise, as necessary, procedures to facilitate implementation and operation of the EIM through the PSE EIM BP that shall be posted on the Transmission Provider's OASIS.

4.1.1.5 Determination to Take Corrective Actions or Permanently Terminate Participation in the EIM

The PSE EIM Entity may take corrective actions in PSE's BAA in accordance with the requirements of Section 10.3 of Attachment O.

In addition, the PSE EIM Entity, in its sole and absolute discretion, may permanently terminate its participation in the EIM by providing notice of termination to the MO pursuant to applicable agreements and by making a filing pursuant to Section 205 of the Federal Power Act to revise this Tariff consistent with the Commission's requirements.

4.1.2 Responsibilities of the PSE EIM Entity to Provide Required Information

4.1.2.1 Provide Modeling Data to the MO

The PSE EIM Entity shall provide the MO information associated with transmission facilities within PSE's BAA, including, but not limited to, network constraints and associated limits that must be observed in PSE's BAA' network and interties with other BAAs.

4.1.2.2 Registration

The PSE EIM Entity shall register all Non-Participating Resources with the MO. The PSE EIM Entity may choose to obtain default energy bids from the MO for Non-Participating Resources that are Balancing Authority Area Resources. The PSE EIM Entity shall update this information in accordance with the MO's requirements as revised information is received from Transmission Customers with Non-Participating Resources in accordance with Section 4.2.1.2 of this Attachment O.

4.1.3 Day-to-Day EIM Operations

4.1.3.1 Submission of Transmission Customer Base Schedule, Forecast Data for Non-Participating Resources that are Variable Energy Resources, and Resource Plans

The PSE EIM Entity is responsible for providing the data required by the MO in accordance with Section 29.34 of the MO Tariff, including but not limited to: (1) hourly Transmission Customer Base Schedules; (2) Forecast Data for Non-Participating Resources that are Variable Energy Resources; and (3) Resource Plans.

4.1.3.2 Communication of Manual Dispatch Information

The PSE EIM Entity shall inform the MO of a Manual Dispatch by providing adjustment information for the affected resources in accordance with Section 29.34 of the MO Tariff.

4.1.3.3 Confirmation

The MO shall calculate, and the PSE EIM Entity shall confirm, actual values for Dynamic Schedules reflecting EIM Transfers to the MO within 60 minutes after completion of the Operating Hour to ensure the e-Tag author will be able to update these values in accordance with WECC business practices through an update to the e-Tag.

4.1.3.4 Dispatch of EIM Available Balancing Capacity of a Non-Participating Resource

Upon notification by the MO, the PSE EIM Entity shall notify the Non-Participating Resource of the Dispatch Operating Point for any EIM Available Balancing Capacity from the Non-

Participating Resource, except in circumstances in which the PSE EIM Entity determines the additional capacity is not needed for the BAA or has taken other actions to meet the capacity need.

4.1.4 Provision of Meter Data

The PSE EIM Entity shall submit load, resource, and Interchange meter data to the MO in accordance with the format and timeframes required in the MO Tariff on behalf of Transmission Customers with Non-Participating Resources, loads, and Interchange.

4.1.5 Settlement of MO Charges and Payments

The PSE EIM Entity shall be responsible for financial settlement of all charges and payments allocated by the MO to the PSE EIM Entity. The PSE EIM Entity shall sub-allocate EIM charges and payments in accordance with Schedules 1, 1A, 4, 4R and 9 of this Tariff or Section 8 of Attachment O, as applicable.

4.1.6 Dispute Resolution with the MO

The PSE EIM Entity shall manage dispute resolution with the MO for the PSE EIM Entity settlement statements consistent with Section 29.13 of the MO Tariff, Section 12 of this Tariff, and the PSE EIM BP. Transmission Customers with PSE EIM Participating Resources shall manage dispute resolution with the MO for any settlement statements they receive directly from the MO.

4.2 Transmission Customer Responsibilities

The following must comply with the information requirements of this section: (1) Transmission Customers with a PSE EIM Participating Resource; (2) Transmission Customers with a Non-Participating Resource; (3) Transmission Customers with load within PSE's BAA; and (4) Transmission Customers wheeling through PSE's BAA.

4.2.1 Initial Registration Data

4.2.1.1 Transmission Customers with a PSE EIM Participating Resource

A Transmission Customer with a PSE EIM Participating Resource shall provide the MO and the PSE EIM Entity with data necessary to meet the requirements established by the MO to register all resources with the MO as required by Section 29.4(e)(4)(D) of the MO Tariff.

4.2.1.2 Transmission Customers with Non-Participating Resources

A Transmission Customer with Non-Participating Resources shall provide the PSE EIM Entity with data necessary to meet the requirements established by the MO as required by Section 29.4(c)(4)(C) of the MO Tariff.

4.2.2 Responsibility to Update Required Data

4.2.2.1 Transmission Customers with a PSE EIM Participating Resource

Each Transmission Customer with a PSE EIM Participating Resource has an ongoing obligation to inform the MO and PSE EIM Entity of any changes to any of the information submitted by the Transmission Customer provided under Section 4.2.1 of this Attachment O that reflects changes in operating characteristics as required by Section 29.4(e)(4)(D) of the MO Tariff. The PSE EIM BP shall set forth the process and timing requirements of notifying the PSE EIM Entity of such changes.

4.2.2.2 Transmission Customers with Non-Participating Resources

Each Transmission Customer with a Non-Participating Resource has an ongoing obligation to inform the PSE EIM Entity of any changes to any of the information submitted by the Transmission Customer with a Non-Participating Resource provided under Section 4.2.1 of this Attachment O. The PSE EIM BP shall set forth the process and timing requirements of notifying the PSE EIM Entity of such changes.

4.2.3 Outages

Transmission Customers with PSE EIM Participating Resources and Transmission Customers with Non-Participating Resources shall be required to provide planned and unplanned outage information for their resources in accordance with Section 7 of this Attachment O. The PSE EIM BP shall set forth the outage information requirements for PSE EIM Participating Resources and Non-Participating Resources.

4.2.4 Submission of Transmission Customer Base Schedule

A Transmission Customer shall submit the Transmission Customer Base Schedule to the PSE EIM Entity. This submission must include Forecast Data on all resources, Interchange, and Intrachange which balance to the Transmission Customer's anticipated load, as applicable. If the Transmission Customer does not serve load within PSE's BAA, submission of the Transmission Customer Base Schedule shall include Forecast Data on all resources, Interchange, and Intrachange which shall balance to the Transmission Customer's anticipated actual generation within PSE's BAA. The submissions shall be in the format and within the timing requirements established by the MO and the PSE EIM Entity as required in Section 4.2.4.5 of this Attachment O and the PSE EIM BP.

4.2.4.1 Transmission Customers with a PSE EIM Participating Resource or Non-Participating Resource in the PSE BAA

A Transmission Customers with a PSE EIM Participating Resource or a Non-Participating Resource is not required to submit Forecast Data for:

(1) resources located in PSE's BAA that are less than five MW; or

(2) behind-the-meter generation which is not contained in the MO's network model.

Each PSE EIM Participating Resource Scheduling Coordinator shall provide to the PSE EIM Entity the energy bid range data (without price information) of the respective resources it represents that are participating in the EIM.

Each PSE EIM Participating Resource Scheduling Coordinator shall also provide the PSE EIM Entity with Dispatch Operating Point data of the respective resources it represents that are participating in the EIM.

4.2.4.2 Transmission Customers with Non-Participating Resources that are Variable Energy Resources

A Transmission Customer with a Non-Participating Resource that is a Variable Energy Resource shall submit (i) resource Forecast Data with hourly granularity and (ii) resource Forecast Data with 5-minute or 15-minute granularity. A Transmission Customer with a Non-Participating Resource that is a Variable Energy Resource shall provide, at minimum, a three-hour rolling forecast with 15-minute granularity, updated every 15 minutes, and may provide, in the alternative, a three-hour rolling forecast with 5-minute granularity, updated every 5 minutes, and in accordance with any additional procedures set forth in the PSE EIM BP.

A Transmission Customer with a Non-Participating Resource that is a Variable Energy Resource shall submit resource Forecast Data consistent with this Section 4.2.4.2 using any one of the following methods:

(1) The Transmission Customer may elect to use the PSE EIM Entity's Variable Energy Resource reliability forecast prepared for Variable Energy Resources within PSE's BAA, which shall be considered to be the basis for physical changes in the output of the resource communicated to the MO, for purposes of settlement pursuant to Schedule 9 of this Tariff;

(2) The Transmission Customer may elect to self-supply the Forecast Data and provide such data to the PSE EIM Entity, which shall be considered to be the basis for physical changes in the output of the resource communicated to the MO, for purposes of settlement pursuant to Schedule 9 of this Tariff. The PSE EIM BP will specify the manner in which Transmission Customers may self-supply Forecast Data; or

(3) The Transmission Customer may elect that the MO produce Forecast Data for the Variable Energy Resource, made available to the Transmission Customer in a manner consistent with Section 29.11(j)(1) of the MO Tariff, which shall be considered to be the basis for physical changes in the output of the resource communicated to the MO, for purposes of settlement pursuant to Schedule 9 of this Tariff.

A Transmission Customer with a Non-Participating Resource that is a Variable Energy Resource must elect one of the above methods prior to commencement of the EIM or prior to such other date in accordance with the procedures set forth in the PSE EIM BP. A Transmission Customer with a Non-Participating Resource that is a Variable Energy Resource may change its election by providing advance notice to the PSE EIM Entity, in accordance with the procedures set forth in the PSE EIM BP.

To the extent a Transmission Customer with a Non-Participating Resource that is a Variable Energy Resource elects method (2) above, and such Transmission Customer fails to submit resource Forecast Data for any time interval as required by this Section 4.2.4.2 of this Attachment O, the PSE EIM Entity shall apply method (1) for purposes of settlement pursuant to Schedule 9 of this Tariff.

4.2.4.3 Transmission Customers with Load

As set forth in Sections 4.2.4 of this Attachment O, a Transmission Customer is required to submit Forecast Data on all resources, Interchange, and Intrachange which balance to the Transmission Customer's anticipated load, as applicable.

For purposes of settling Energy Imbalance Service pursuant to Schedule 4 and Schedule 4R of this Tariff, the PSE EIM Entity shall calculate the load component of the Transmission Customer Base Schedule as the resource Forecast Data net of its Interchange Forecast Data and net of its Intrachange Forecast Data, as applicable.

4.2.4.4 Transmission Customers Without Resources or Load in PSE's BAA

A Transmission Customer which does not have any resources or load within PSE's BAA shall submit a Transmission Customer Base Schedule that includes Interchange and Intrachange Forecast Data to the PSE EIM Entity.

4.2.4.5 Timing of Transmission Customer Base Schedules Submission

4.2.4.5.1 Preliminary Submission of Transmission Customer Base Schedules

Transmission Customers shall submit their initial Transmission Customer Base Schedules 7 days prior to each Operating Day ("T - 7 days"). Transmission Customers may modify the proposed Transmission Customer Base Schedule at any time but shall submit at least one update by 10 a.m of the day before the Operating Day.

4.2.4.5.2 Final Submissions of Transmission Customer Base Schedules

Transmission Customers shall submit proposed final Transmission Customer Base Schedules, at any time but no later than 77 minutes prior to each Operating Hour ("T-77"). Transmission Customers may modify Transmission Customer Base Schedules up to and until 57 minutes prior to the Operating Hour ("T-57"). As of 55 minutes prior to each Operating Hour ("T-55"), the Transmission Customer Base Schedule data for the Operating Hour will be considered financially binding and Transmission Customers may not submit further changes. If the Transmission Customer fails to enter a Forecast Data value, the default will be 0 MW for that Operating Hour.

4.2.5 Metering for Transmission Customers with Non-Participating Resources

To assess imbalance, the MO shall disaggregate meter data into 5-minute intervals if the meter intervals are not already programmed to 5-minute intervals pursuant to a Transmission Customer's applicable interconnection requirements associated with any agreement pursuant to Annexes A and B of this Tariff. To the extent that a Transmission Customer owns the meter or communication to the meter, the Transmission Customer shall be responsible to maintain accurate and timely data accessible for the PSE EIM Entity to comply with Section 4.1.4 of this Attachment O.

5. Transmission Operations

5.1 Provision of Information Regarding Real-Time Status of the Transmission Provider's Transmission System

The PSE EIM Entity shall provide the MO information on:

(1) real time data for the Transmission System and interties; and

(2) any changes to transmission capacity and the Transmission System due to operational circumstances.

5.2 Provision of EIM Transfer Capacity by a PSE Interchange Rights Holder

The PSE EIM Entity shall facilitate the provision of transmission capacity for EIM Transfers offered by a PSE Interchange Rights Holder by providing the MO with information about the amounts made available by the PSE Interchange Rights Holder for EIM Transfers.

The provision of EIM Transfer capacity shall be implemented through the PSE Interchange Rights Holder's submission of an e-Tag by 75 minutes prior to the Operating Hour ("T-75"). The PSE Interchange Rights Holder shall include on the e-Tag the OASIS identification reservation number(s) associated with the transmission rights made available for EIM Transfers and shall also include the Market Operator, all transmission providers, and path operators associated with the OASIS identification reservation number(s) identified on the e-Tag. The PSE Interchange Rights Holder's rights associated with the submitted e-Tag shall be available for the EIM, subject to approval of the e-Tag by all required e-Tag approval entities.

The amount made available for EIM Transfers shall never exceed the PSE Interchange Rights Holder's transmission rights.

5.3 Provision of EIM Transfer Capability by the PSE EIM Entity

The PSE EIM Entity shall facilitate the provision of transmission capacity for EIM Transfers by providing the MO with information about the amounts available for EIM Transfers utilizing Available Transfer Capability ("ATC"). Such amounts shall be in addition to any amounts made available by PSE Interchange Rights Holders pursuant to Section 5.2 of this Attachment O.

The provision of EIM Transfer capacity corresponding to ATC shall be implemented by 40 minutes prior to the Operating Hour ("T-40") by the PSE EIM Entity. The PSE EIM Entity shall include an e-Tag, with an OASIS identification reservation number(s) created for EIM Transfers utilizing ATC, and shall also include the MO, all transmission providers, and path operators associated with the OASIS identification reservation number(s) identified in the e-Tag. The amount of ATC indicated on the e-Tag will be based upon the lower of the amount of ATC calculated by each EIM Entity at that interface by T-40. The ATC associated with the submitted e-Tag shall be available for the EIM, subject to approval of the e-Tag by all required e-Tag approval entities.

6. System Operations Under Normal and Emergency Conditions

6.1 Compliance with Reliability Standards

Participation in the EIM shall not modify, change, or otherwise alter the manner in which the Transmission Provider operates its Transmission System consistent with applicable reliability standards, including adjustments.

Participation in the EIM shall not modify, change, or otherwise alter the obligations of the PSE EIM Entity, Transmission Customers with PSE EIM Participating Resources, or Transmission Customers with Non-Participating Resources to comply with applicable reliability standards.

The PSE EIM Entity shall remain responsible for:

(1) maintaining appropriate operating reserves and for its obligations pursuant to any reserve sharing group agreements;

(2) NERC and WECC responsibilities including, but not limited to, informing the Reliability Coordinator of issues within PSE's BAA;

(3) processing e-Tags and managing schedule curtailments at the interties; and

(4) monitoring and managing real-time flows within system operating limits on all transmission facilities within PSE's BAA, including facilities of PSE BAA Transmission Owners. If requested by a Transmission Customer that is also a PSE BAA Transmission Owner, the PSE EIM Entity will provide additional information or data related to EIM operation as it may relate to facilities of a PSE BAA Transmission Owner.

6.2 Good Utility Practice

The PSE EIM Entity, Transmission Customers with Non-Participating Resources, and Transmission Customers with PSE EIM Participating Resources shall comply with Good Utility Practice with respect to this Attachment O.

6.3 Management of Contingencies and Emergencies

6.3.1 EIM Disruption

If the MO declares an EIM disruption in accordance with Section 29.7(j) of the MO Tariff, the PSE EIM Entity shall, in accordance with Section 29.7(j)(4) of the MO Tariff, promptly inform the MO of actions taken in response to the EIM disruption by providing adjustment information, updates to e-Tags, transmission limit adjustments, or outage and de-rate information, as applicable.

6.3.2 Manual Dispatch

The PSE EIM Entity may issue a Manual Dispatch order to a Transmission Customer with a PSE EIM Participating Resource or a Non-Participating Resource in PSE's BAA, to address reliability or operational issues in PSE's BAA that the EIM is not able to address through normal economic dispatch and congestion management.

The PSE EIM Entity shall inform the MO of a Manual Dispatch as soon as possible.

7. Outages

7.1. PSE EIM Entity Transmission Outages

7.1.1 Planned Transmission Outages and Known Derates

The PSE EIM Entity shall submit information regarding planned transmission outages and known derates to the MO's outage management system in accordance with Section 29.9(b) of the MO Tariff. The PSE EIM Entity shall update the submittal if there are changes to the transmission outage plan.

7.1.2 Unplanned Transmission Outages

The PSE EIM Entity shall submit information as soon as possible regarding unplanned transmission outages or derates to the MO's outage management system in accordance with Section 29.9(e) of the MO Tariff.

7.2 PSE BAA Transmission Owner Outages

Transmission Customers that are also PSE BAA Transmission Owners shall provide the PSE EIM Entity with planned and unplanned transmission outage data. Planned outages shall be reported to the PSE EIM Entity 7 or more days in advance and preferably at least 30 days in advance of the outage. Unplanned outages shall be reported to the PSE EIM Entity as soon as possible but no later than 30 minutes after the outage commences.

The PSE EIM Entity shall communicate information regarding planned and unplanned outages of PSE BAA Transmission Owner facilities to the MO as soon as practicable upon receipt of the information from the PSE BAA Transmission Owner.

7.3 PSE EIM Participating Resource Outages

7.3.1 Planned PSE EIM Participating Resource Outages and Known Derates

PSE EIM Participating Resource Scheduling Coordinators shall submit information regarding planned resource outages and known derates to the PSE EIM Entity. Planned outages and known derates shall be reported to the PSE EIM Entity 7 or more days in advance and preferably at least 30 days in advance of the outage or known derate. The PSE EIM Entity shall then submit this outage information to the MO's outage management system in accordance with Section 29.9(c) of the MO Tariff. PSE EIM Participating Resource Scheduling Coordinators shall update the submittal if there are changes to the resource outage plan.

7.3.2 Unplanned PSE EIM Participating Resource Outages

In the event of an unplanned outage required to be reported under Section 29.9(e) of the MO Tariff, the PSE EIM Participating Resource Scheduling Coordinator is responsible for notifying the PSE EIM Entity of required changes. Unplanned outages shall be reported to the PSE EIM Entity as soon as possible but no later than 30 minutes after the outage commences. The PSE EIM Entity shall then submit this information to the MO's outage management system.

7.3.3 Unplanned Derates

Changes in availability of 10 MW or 5% of Pmax (whichever is greater) lasting 15 minutes or longer must be reported to the PSE EIM Entity. These reports are due within 30 minutes of discovery, and are required only to include effective time and MW availability. The PSE EIM Entity shall then submit this information to the MO's outage management system.

7.4 Outages of Transmission Customers with Non-Participating Resources

7.4.1 Planned Outages and Known Derates of Transmission Customers with Non-Participating Resources

Transmission Customers with Non-Participating Resources shall report information regarding planned outages and known derates of resources to the PSE EIM Entity 7 or more days in advance and preferably at least 30 days in advance of the outage. The Transmission Customer with a Non-Participating Resource shall update the submittal if there are changes to the resource's outage plan.

The PSE EIM Entity shall submit planned resource outages and known derates of Non-Participating Resources to the MO's outage management system in accordance Section 29.9(c) of the MO Tariff.

7.4.2 Unplanned Outages of Resources of Transmission Customers with Non-Participating Resources

Unplanned outages of resources of a Transmission Customer with Non-Participating Resources shall be reported to the PSE EIM Entity as soon as possible but no later than 30 minutes after the outage commences.

In the event of a forced outage required to be reported under Section 29.9(e) of the MO Tariff, the PSE EIM Entity is responsible for notifying the MO of required changes through the MO's outage management system.

7.4.3 Unplanned Derates

Changes in availability of 10 MW or 5% of Pmax (whichever is greater) lasting 15 minutes or longer must be reported to the PSE EIM Entity. These reports are due within 30 minutes of discovery, and are required only to include effective time and MW availability. The PSE EIM Entity shall then submit this information to the MO's outage management system.

8. EIM Settlements and Billing

The PSE EIM BP shall include information on the specific charge codes applicable to EIM settlement.

8.1 Instructed Imbalance Energy (IIE)

The PSE EIM Entity shall settle as IIE imbalances that result from (1) operational adjustments of a Transmission Customer's affected Interchange or Intrachange, which includes changes by a Transmission Customer after T-57, (2) resource imbalances created by Manual Dispatch or an EIM Available Balancing Capacity dispatch, or (3) an adjustment to resource imbalances created by adjustments to resource forecasts pursuant to Section 11.5 of the MO Tariff and using the RTD or FMM price at the applicable PNode. Any allocations to the PSE EIM Entity pursuant to

Section 29.11(b)(1) and (2) of the MO Tariff for IIE that is not otherwise recovered under Schedule 9 of this Tariff shall be settled directly with each Transmission Customer according to this Section 8.1.

8.2 Uninstructed Imbalance Energy (UIE)

Any charges or payments to the PSE EIM Entity pursuant to Section 29.11(b)(3)(B) and (C) of the MO Tariff for UIE not otherwise recovered under Schedule 4, Schedule 4R, or Schedule 9 shall not be sub-allocated to Transmission Customers.

8.3 Unaccounted for Energy (UFE)

Any charges to the PSE EIM Entity pursuant to Section 29.11(c) of the MO Tariff for UFE shall not be sub-allocated to Transmission Customers.

8.4 Charges for Under-Scheduling or Over-Scheduling Load

8.4.1 Under-Scheduling Load

Any charges to the PSE EIM Entity pursuant to Section 29.11(d)(1) of the MO Tariff for under-scheduling load shall be assigned to the Transmission Customers subject to Schedule 4 and Schedule 4R based on each Transmission Customer's respective under-scheduling imbalance ratio share, which is the ratio of the Transmission Customer's under-scheduled load imbalance amount relative to all other Transmission Customers' under-scheduled load imbalance amounts who have under-scheduled load for the Operating Hour, expressed as a percentage.

8.4.2 Over-Scheduling Load

Any charges to the PSE EIM Entity pursuant to Section 29.11(d)(2) of the MO Tariff for over-scheduling load shall be assigned to the Transmission Customers subject to Schedule 4 and Schedule 4R based on each Transmission Customer's respective over-scheduling imbalance ratio share, which is the ratio of the Transmission Customer's over-scheduled load imbalance amount relative to all other Transmission Customers' over-scheduled load imbalance amounts who have over-scheduled load for the Operating Hour, expressed as a percentage.

8.4.3 Distribution of Under-Scheduling or Over-Scheduling Proceeds

Any payment to the PSE EIM Entity pursuant to Section 29.11(d)(3) of the MO Tariff shall be distributed to Transmission Customers that were not subject to underscheduling or over-scheduling charges during the Trading Day on the basis of Metered Demand and in accordance with the procedures outlined in the PSE EIM BP.

8.5 EIM Uplifts

8.5.1 EIM BAA Real-Time Market Neutrality (Real-Time Imbalance Energy Offset - BAA)

Any charges to the PSE EIM Entity pursuant to Section 29.11(e)(3) of the MO Tariff for EIM BAA real-time market neutrality shall be sub-allocated to Transmission Customers on the basis of Measured Demand.

8.5.2 EIM Entity BAA Real-Time Congestion Offset

Any charges to the PSE EIM Entity pursuant to Section 29.11(e)(2) of the MO Tariff for the EIM real-time congestion offset shall be allocated to Transmission Customers on the basis of Measured Demand.

8.5.3 EIM Entity Real-Time Marginal Cost of Losses Offset

Any charges to the PSE EIM Entity pursuant to Section 29.11(e)(4) of the MO Tariff for real-time marginal cost of losses offset shall be sub-allocated to Transmission Customers on the basis of Measured Demand.

8.5.4 EIM Neutrality Settlement

Any charges to the PSE EIM Entity pursuant to Section 29.11(e)(5) of the MO Tariff for EIM neutrality settlement shall be sub-allocated as follows:

Description	**Allocation**
Neutrality Adjustment (monthly and daily)	Measured Demand
Rounding Adjustment (monthly and daily)	Measured Demand

8.5.5 Real-Time Bid Cost Recovery

Any charges to the PSE EIM Entity pursuant to Section 29.11(f) of the MO Tariff for EIM real-time bid cost recovery shall be sub-allocated to Transmission Customers on the basis of Measured Demand.

8.5.6 Flexible Ramping Constraint

Any charges to the PSE EIM Entity pursuant to Section 29.11(g) of the MO Tariff for the Flexible Ramping Constraint shall be sub-allocated to Transmission Customers on the basis of Measured Demand.

8.5.7 Inaccurate or Late Actual Settlement Quality Meter Data Penalty

To the extent the PSE EIM Entity incurs a penalty for inaccurate or late actual settlement quality meter data, pursuant to Section 37.11.1 of the MO Tariff, the PSE EIM Entity shall directly assign the penalty to the offending Transmission Customer.

8.5.8 Other EIM Settlement Provisions

Any charges to the PSE EIM Entity pursuant to the MO Tariff for the EIM settlement provisions shown in the following table shall be sub-allocated as follows:

Description	**Allocation**
Invoice Deviation (distribution and allocation)	PSE EIM Entity
Generator Interconnection Process Forfeited Deposit Allocation	PSE EIM Entity
Default Invoice Interest Payment	PSE EIM Entity
Default Invoice Interest Charge	PSE EIM Entity
Invoice Late Payment Penalty	PSE EIM Entity
Financial Security Posting (Collateral) Late Payment Penalty	PSE EIM Entity
Shortfall Receipt Distribution	PSE EIM Entity
Shortfall Reversal	PSE EIM Entity
Shortfall Allocation	PSE EIM Entity
Default Loss Allocation	PSE EIM Entity

8.6 MO Tax Liabilities

Any charges to the PSE EIM Entity pursuant to Section 29.22(a) of the MO Tariff for MO tax liability as a result of the EIM shall be sub-allocated to those Transmission Customers triggering the tax liability.

8.7 EIM Transmission Service Charges

There shall be no incremental transmission charge assessed for transmission use related to the EIM.

Unreserved Use Penalties shall apply to any amount of actual metered generation in an Operating Hour, if any, which is in excess of the sum of both: (1) the greatest positive Dispatch Operating Point or Manual Dispatch of the PSE EIM Participating Resource received during the Operating Hour, and (2) the Transmission Customer's Reserved Capacity. Any ancillary service charges that are applicable to Unreserved Use Penalty charges shall apply.

8.8 Variable Energy Resource Forecast Charge

Any costs incurred by the PSE EIM Entity related to the preparation and submission of resource Forecast Data for a Transmission Customer with a Non-Participating Resource electing either method (1) or (2), as set forth in Section 4.2.4.2 of this Attachment O, shall be allocated to the Transmission Customer with a Non-Participating Resource electing to use either such method.

For a Transmission Customer with a Non-Participating Resource electing method (3), as set forth in Section 4.2.4.2 of this Attachment O, any charges to the PSE EIM Entity pursuant to Section 29.11(j)(1) of the MO Tariff for Variable Energy Resource forecast charges shall be sub-allocated to the Transmission Customer with a Non-Participating Resource requesting such forecast.

8.9 EIM Payment Calendar

Pursuant to Section 29.11(l) of the MO Tariff, the PSE EIM Entity shall be subject to the MO's payment calendar for issuing settlement statements, exchanging invoice funds, submitting meter data, and submitting settlement disputes to the MO. The PSE EIM Entity shall follow Section 7 of this Tariff for issuing invoices regarding the EIM.

8.10 EIM Residual Balancing Account

To the extent that MO EIM-related charges or payments to the PSE EIM Entity are not captured elsewhere in Attachment H-1, Schedules 1, 1A, 4, 4R, and 9 of this Tariff, or this Section 8, those charges or payments shall be placed in a balancing account, with interest accruing at the rate established in 18 C.F.R. § 35.19(a)(2)(iii), until PSE makes a filing with the Commission pursuant to Section 205 of the Federal Power Act proposing an allocation methodology.

8.11 Market Validation and Price Correction

If the MO modifies the PSE EIM Entity settlement statement in accordance with the MO's market validation and price correction procedures in the MO Tariff, the PSE EIM Entity reserves the right to make corresponding or similar changes to the charges and payments sub-allocated under this Attachment O.

8.12 Allocation of Operating Reserves

8.12.1 Payments

Any payments to the PSE EIM Entity pursuant to Section 29.11(n)(1) of the MO Tariff for operating reserve obligations shall be sub-allocated to Transmission Customers with PSE EIM Participating Resources in the PSE BAA for Operating Hours during which EIM Transfers from the PSE BAA to another BAA occurred. Payments shall be sub-allocated on a ratio-share basis, defined as the proportion of the volume of Operating Reserves provided by a PSE EIM Participating Resource in the PSE BAA dispatched during the Operating Hour compared to the total volume of Operating Reserves provided by all PSE EIM Participating Resources dispatched in the PSE BAA for the Operating Hour.

8.12.2 Charges

Any charges to the PSE EIM Entity pursuant to Section 29.11(n)(2) of the MO Tariff for operating reserve obligations shall be sub-allocated to Transmission Customers on the basis of Measured Demand.

9. Compliance

9.1 Provision of Data

Transmission Customers with PSE EIM Participating Resources and PSE EIM Participating Resource Scheduling Coordinators are responsible for complying with information requests they receive directly from the EIM market monitor or regulatory authorities concerning EIM activities.

A Transmission Customer with PSE EIM Participating Resources or a Transmission Customer with Non-Participating Resources must provide the PSE EIM Entity with all data necessary to respond to information requests received by the PSE EIM Entity from the MO, the EIM market monitor, or regulatory authorities concerning EIM activities.

If the PSE EIM Entity is required by applicable laws or regulations, or in the course of administrative or judicial proceedings, to disclose information that is otherwise required to be maintained in confidence, the PSE EIM Entity may disclose such information; provided, however, that upon the PSE EIM Entity learning of the disclosure requirement and, if possible, prior to making such disclosure, the PSE EIM Entity shall notify any affected party of the requirement and the terms thereof. The party can, at its sole discretion and own cost, direct any challenge to or defense against the disclosure requirement. The PSE EIM Entity shall cooperate with the affected party to obtain proprietary or confidential treatment of confidential information by the person to whom such information is disclosed prior to any such disclosure.

The PSE EIM Entity shall treat all Transmission Customer and Interconnection Customer data and information provided to it as market-sensitive and confidential, unless the PSE EIM Entity is otherwise allowed or required to disclose. The PSE EIM Entity shall continue to abide by the Commission's Standards of Conduct and handle customer information accordingly.

9.2 Rules of Conduct

These rules of conduct are intended to provide fair notice of the conduct expected and to provide an environment in which all parties may participate in the EIM on a fair and equal basis. Transmission Customers must:

(1) Comply with Dispatch Instructions and PSE EIM Entity operating orders in accordance with Good Utility Practice. If some limitation prevents the

Transmission Customer from fulfilling the action requested by the MO or the PSE EIM Entity, the Transmission Customer must immediately and directly communicate the nature of any such limitation to the PSE EIM Entity;

(2) Submit bids for resources that are reasonably expected to both be and remain available and capable of performing at the levels specified in the bid, based on all information that is known or should have been known at the time of submission;

(3) Notify the MO and/or the PSE EIM Entity, as applicable, of outages in accordance with Section 7 of this Attachment O;

(4) Provide complete, accurate, and timely meter data to the PSE EIM Entity in accordance with the metering and communication requirements of this Tariff, and maintain responsibility to ensure the accuracy of such data communicated by any customer-owned metering or communications systems. To the extent such information is not accurate or timely when provided to the PSE EIM Entity, the Transmission Customer shall be responsible for any consequence on settlement and billing;

(5) Provide information to the PSE EIM Entity, including the information requested in Sections 4.2.1, 4.2.2, 4.2.3, 4.2.4 and 9.1 of this Attachment O, by the applicable deadlines; and

(6) Utilize commercially-reasonable efforts to ensure that forecasts are accurate and based on all information that is known or should have been known at the time of submission to the PSE EIM Entity.

9.3 Enforcement

The PSE EIM Entity may refer a violation of Section 9.2 of this Attachment O to FERC. Violations of these rules of conduct may be enforced by FERC in accordance with FERC's rules and procedures. Nothing in this Section 9 is meant to limit any other remedy before FERC or any applicable judicial, governmental, or administrative body.

10. Market Contingencies

10.1 Temporary Suspension by the MO

In the event that the MO implements a temporary suspension in accordance with Section 29.1(d)(1) of the MO Tariff, including the actions identified in Section 29.1(d)(5), the PSE EIM Entity shall utilize Temporary Schedules 4, 4R, 9, 12, and 12A in accordance with Sections 10.4.1, 10.4.2, 10.4.3, 10.4.4, and 10.4.5 of this Attachment O until the temporary suspension is no longer in effect or, if the MO determines to extend the suspension, for a period of time sufficient to process termination of the PSE EIM Entity's participation in the EIM in accordance with Section 29.1(d)(2) of the MO Tariff.

10.2 Termination of Participation in EIM by the PSE EIM Entity

If the PSE EIM Entity submits a notice of termination of its participation in the EIM to the MO in accordance with the applicable agreements and Section 4.1.1.5 of this Attachment O, in order to mitigate price exposure during the 180-day period between submission of the notice and the termination effective date, the PSE EIM Entity may invoke the following corrective actions by requesting that the MO:

(1) prevent EIM Transfers and separate the PSE EIM Entity's BAA from operation of the EIM in the EIM Area; and

(2) suspend settlement of EIM charges with respect to the PSE EIM Entity.

Once such corrective actions are implemented by the MO, the PSE EIM Entity shall utilize Temporary Schedules 4, 4R, 9, 12 and 12A in accordance with Sections 10.4.1, 10.4.2, 10.4.3, 10.4.4, and 10.4.5 of this Attachment O.

If the PSE EIM Entity takes action under this Section 10.2, the PSE EIM Entity shall notify the MO and Transmission Customers.

10.3 Corrective Actions Taken by the PSE EIM Entity for Temporary Contingencies

The PSE EIM Entity may declare a temporary contingency and invoke corrective actions for the EIM when in its judgment -

(1) operational circumstances (including a failure of the EIM to produce feasible results in PSE's BAA) have caused or are in danger of causing an abnormal system condition in PSE's BAA that requires immediate action to prevent loss of load, equipment damage, or tripping system elements that might result in cascading outages, or to restore system operation to meet the applicable Reliability Standards and reliability criteria established by NERC and WECC; or

(2) communications between the MO and the PSE EIM Entity are disrupted and prevent the PSE EIM Entity, the PSE EIM Entity Scheduling Coordinator, or a PSE EIM Participating Resource Scheduling Coordinator from accessing MO systems to submit or receive information.

10.3.1 Corrective Actions for Temporary Contingencies

If either of the above temporary contingencies occurs, the PSE EIM Entity may invoke the following corrective actions by requesting that the MO:

(1) prevent EIM Transfers and separate the PSE EIM Entity's BAA from operation of the EIM in the EIM Area; and/or

(2) suspend settlement of EIM charges with respect to the PSE EIM Entity.

When corrective action under 10.3.1 (2) is implemented or if the MO Tariff requires the use of these temporary schedules to set an administrative price, the PSE EIM Entity shall utilize Temporary Schedules 4, 4R, 9, 12, and 12A in accordance with Sections 10.4.1, 10.4.2, 10.4.3, ~~and~~ 10.4.4, and 10.4.5 of this Attachment O.

If the PSE EIM Entity takes action under this Section 10.3, the PSE EIM Entity shall notify the MO and Transmission Customers. The PSE EIM Entity and the MO shall cooperate to resolve the temporary contingency event and restore full EIM operations as soon as is practicable.

10.4 Temporary Schedules 4, 4R, 9, 12, and 12A

10.4.1 Temporary Schedule 4 Energy Imbalance Service

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a Control Area over a single hour (plus real power losses). The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements, which may include use of non-generation resources capable of providing this service, to satisfy its Energy Imbalance Service obligation. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator. The Transmission Provider may charge a Transmission Customer a penalty for either hourly energy imbalances under this Temporary Schedule or a penalty for hourly generator imbalances under Temporary Schedule 9 for imbalances occurring during the same hour, but not both unless the imbalances aggravate rather than offset each other.

The Transmission Provider shall establish charges for energy imbalance based on the deviation bands as follows: (i) deviations within +/- 1.5 percent (with a minimum of 2 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be netted on a monthly basis and settled financially, at the end of the month, using the Hourly Pricing Proxy, (ii) deviations greater than +/- 1.5 percent up to 7.5 percent (or greater than 2 MW up to 10 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer’s scheduled transaction(s) will be settled financially, at the end of each month, at 110 percent of the Hourly Pricing Proxy for under-scheduling or 90 percent of the Hourly Pricing Proxy for over-scheduling, and (iii) deviations greater than +/- 7.5 percent (or 10 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer’s scheduled transaction(s) will be settled financially, at the end of each month, at 125 percent of the Hourly Pricing Proxy for under-scheduling or 75 percent of the Hourly Pricing Proxy for over-scheduling.

For any hour for which Transmission Provider assesses any charge for Energy Imbalance Service under this Temporary Schedule 4 based on 110 percent or 125 percent of the Hourly Pricing

Proxy, Transmission Provider shall credit to non-offending Transmission Customers for such hour the amount by which such charge exceeded the Hourly Pricing Proxy.

10.4.2 Temporary Schedule 4R Energy Imbalance Service for Transmission Customers Taking Service Under Transmission Provider's Schedule 448 and Schedule 449

This Temporary Schedule 4R applies only to Transmission Customers that take service under Transmission Provider's Schedules 448 and 449, on file with the Washington Utilities and Transportation Commission. Temporary Schedule 4R applies in place of Temporary Schedule 4 for any such customer; Transmission Customers will be charged or paid for imbalance energy under Temporary Schedule 4 or Temporary Schedule 4R but not both. Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a Control Area over a single hour (plus real power losses). The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must purchase this service from the Transmission Provider or make alternative comparable arrangements, which may include use of non-generation resources capable of providing this service, to satisfy its Energy Imbalance Service obligation. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator. The Transmission Provider may charge a Transmission Customer a penalty for either hourly energy imbalances under this Temporary Schedule or a penalty for hourly generator imbalances under Temporary Schedule 9 for imbalances occurring during the same hour, but not both unless the imbalances aggravate rather than offset each other.

The Transmission Provider shall establish charges for energy imbalance based on the deviation bands as follows: (i) deviations within +/- 1.5 percent (with a minimum of 2 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be netted on a monthly basis and settled financially, at the end of the month, using the Hourly Pricing Proxy, (ii) deviations greater than +/- 1.5 percent up to 7.5 percent (or greater than 2 MW up to 10 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month, at 110 percent of the Hourly Pricing Proxy for under-scheduling or 90 percent of the Hourly Pricing Proxy for over-scheduling, and (iii) deviations greater than +/- 7.5 percent (or 10 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month, at 125 percent of the Hourly Pricing Proxy for under-scheduling or 75 percent of the Hourly Pricing Proxy for over-scheduling.

For any hour for which Transmission Provider assesses any charge for Energy Imbalance Service under this Temporary Schedule 4R based on 110 percent or 125 percent of the Hourly Pricing Proxy, Transmission Provider shall credit to non-offending Transmission Customers for such hour the amount by which such charge exceeded the Hourly Pricing Proxy.

10.4.3 Temporary Schedule 9 Generator Imbalance Service

Generator Imbalance Service is provided when a difference occurs between the output of a generator located in the Transmission Provider's Control Area and a delivery schedule from that generator to (1) another Control Area or (2) a load within the Transmission Provider's Control Area over a single hour (plus real power losses). The Transmission Provider must offer this service, to the extent it is physically feasible to do so from its resources or from resources available to it, when transmission service is used to deliver energy from a generator located within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements, which may include use of non-generation resources capable of providing this service, to satisfy its Generator Imbalance Service obligation. To the extent the Control Area operator performs this service for the Transmission Provider, charges to the Transmission Customer are to reflect only a pass-through of the costs charged to the Transmission Provider by that Control Area operator. The Transmission Provider may charge a Transmission Customer a penalty for either hourly generator imbalances under this Temporary Schedule 9 or a penalty for hourly energy imbalances under Temporary Schedule 4 for imbalances occurring during the same hour, but not both unless the imbalances aggravate rather than offset each other. To the extent the Interconnection Customer is a different entity than the Transmission Customer and controls the output of a generator located in the Transmission Provider's Control Area, the Interconnection Customer may be subject to charges for Generator Imbalance Service (rather than the Transmission Customer) in accordance with this Temporary Schedule 9.

The Transmission Provider shall establish charges for generator imbalance based on the deviation bands as follows: (i) deviations within +/- 1.5 percent (with a minimum of 2 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be netted on a monthly basis and settled financially, at the end of each month, at the Hourly Pricing Proxy, (ii) deviations greater than +/- 1.5 percent up to 7.5 percent (or greater than 2 MW up to 10 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled financially, at the end of each month, at 110 percent of the Hourly Pricing Proxy for under-scheduling or 90 percent of the Hourly Pricing Proxy for over-scheduling, and (iii) deviations greater than +/- 7.5 percent (or 10 MW) of the scheduled transaction to be applied hourly to any generator imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s) will be settled at 125 percent of the Hourly Pricing Proxy for under-scheduling or 75 percent of the Hourly Pricing Proxy for over-scheduling, except that an intermittent resource will be exempt from this deviation band and will pay the deviation band charges for all deviations greater than the larger of 1.5 percent or 2 MW. An intermittent resource, for the limited purpose of this Schedule is an electric generator that is not dispatchable and cannot store its fuel source and therefore cannot respond to changes in system demand or respond to transmission security constraints.

Notwithstanding the foregoing, deviations from scheduled transactions in order to respond to directives by the Transmission Provider, a balancing authority, or a reliability coordinator shall not be subject to the deviation bands identified above and, instead, shall be settled financially, at the end of the month, at 100 percent of the Hourly Pricing Proxy. Such directives may include instructions to correct frequency decay, respond to a reserve sharing event, or change output to relieve congestion.

For any hour for which Transmission Provider assesses any charge for Generator Imbalance Service under this Temporary Schedule 9 based on 110 percent or 125 percent of the Hourly Pricing Proxy, Transmission Provider shall credit to non-offending Transmission Customers for such hour the amount by which such charge exceeded the Hourly Pricing Proxy.

10.4.4 Temporary Schedule 12 – Real Power Losses on Washington Area Transmission Facilities

A transmission customer taking Network Integration Transmission Service, Firm or Non-Firm Point-to-Point Transmission Service shall be responsible for Real Power Losses as provided for in Sections 15.7 and 28.5 of the Tariff. For each hour where the Transmission Provider provides loss service, the Transmission Customer shall compensate the Transmission Provider at a rate equal to the Hourly Pricing Proxy for energy for such hour based on the product of the actual transmission service provided (scheduled service less any curtailments, corrections or adjustments mutually agreed on by the Transmission Provider and the Transmission Customer) during each hour in MWhs and the applicable loss factor provided in Sections 15.7 and 28.5 of the Tariff.

10.4.5 Temporary Schedule 12A – Real Power Losses on Colstrip and Southern Intertie Transmission Lines

A transmission customer taking service over the Colstrip and Southern Intertie High Voltage Direct Assignment Facilities pursuant to Schedule 10 of the Tariff shall be responsible for Real Power Losses as provided for in Sections 15.7 and 28.5 of the Tariff. For each hour where the Transmission Provider provides loss service, the Transmission Customer shall compensate the Transmission Provider at a rate equal to the Hourly Pricing Proxy for energy for such hour based on the product of the actual transmission service provided (scheduled service less any curtailments, corrections or adjustments mutually agreed on by the Transmission Provider and the Transmission Customer) during each hour in MWhs and the applicable loss factor provided in Sections 15.7 and 28.5 of the Tariff.

TABLE OF CONTENTS

~~TABLE OF CONTENTS (CONTD.)~~

~~**TABLE OF CONTENTS (CONTD.)**~~

~~TABLE OF CONTENTS (CONTD.)~~

Section 2 Scope and Application

2.1 Application of Standard Large Generator Interconnection Procedures

Sections 2 through 13 apply to processing an Interconnection Request pertaining to a Large Generating Facility.

2.2 Comparability

Transmission Provider shall receive, process and analyze all Interconnection Requests in a timely manner as set forth in this LGIP. Transmission Provider will use the same Reasonable Efforts in processing and analyzing Interconnection Requests from all Interconnection Customers, whether the Generating Facilities are owned by Transmission Provider, its subsidiaries or Affiliates or others.

2.3 Base Case Data

Transmission Provider shall provide base power flow, short circuit and stability databases, including all underlying assumptions, and contingency list upon request subject to confidentiality provisions in LGIP Section 13.1. Transmission Provider is permitted to require that Interconnection Customer sign a confidentiality agreement before the release of commercially sensitive information or Critical Energy Infrastructure Information in the Base Case data. Such databases and lists, hereinafter referred to as Base Cases, shall include all (1) generation projects and (ii) transmission projects, including merchant transmission projects that are proposed for the Transmission System for which a transmission expansion plan has been submitted and approved by the applicable authority.

2.4 No Applicability to Transmission Service

Nothing in this LGIP shall constitute a request for transmission service or confer upon an Interconnection Customer any right to receive transmission service.

2.5 EIM Requirements

The Interconnection Customer shall have a continuing duty to comply with Attachment O of this Tariff, as applicable.

Annex B

SMALL GENERATOR
INTERCONNECTION PROCEDURES (SGIP)
()
(For Generating Facilities No Larger Than 20 MW)

TABLE OF CONTENTS

Section 1. Application

1.1 Applicability

1.1.1 A request to interconnect a certified Small Generating Facility (See Attachments 3 and 4 for description of certification criteria) to the Transmission Provider's Distribution System shall be evaluated under the section 2 Fast Track Process if the eligibility requirements of section 2.1 are met. A request to interconnect a certified inverter-based Small Generating Facility no larger than 10 kilowatts (kW) shall be evaluated under the Attachment 5 10 kW Inverter Process. A request to interconnect a Small Generating Facility no larger than 20 megawatts (MW) that does not meet the eligibility requirements of section 2.1, or does not pass the Fast Track Process or the 10 kW Inverter Process, shall be evaluated under the section 3 Study Process. If the interconnection Customer wishes to interconnect its Small Generating Facility using Network Resource Interconnection Service, it must do so under the Standard Large Generator Interconnection Procedures and execute the Standard Large Generator Interconnection Agreement.

1.1.2 Capitalized terms used herein shall have the meanings specified in the Glossary of Terms in Attachment 1 or the body of these procedures.

1.1.3 Neither these procedures nor the requirements included hereunder apply to Small Generating Facilities interconnected or approved for interconnection prior to 60 Business Days after the effective date of these procedures.

1.1.4 Prior to submitting its Interconnection Request (Attachment 2), the Interconnection Customer may ask the Transmission Provider's interconnection contact employee or office whether the proposed interconnection is subject to these procedures. The Transmission Provider shall respond within 15 Business Days.

1.1.5 Infrastructure security of electric system equipment and operations and control hardware and software is essential to ensure day-to-day reliability and operational security. The Federal Energy Regulatory Commission expects all Transmission Providers, market participants, and Interconnection Customers interconnected with electric systems to comply with the recommendations offered by the President's Critical Infrastructure Protection Board and best practice recommendations from the electric reliability authority. All public utilities are expected to meet basic standards for electric system infrastructure and operational security, including physical, operational, and cyber-security practices.

1.1.6 References in these procedures to interconnection agreement are to the Small Generator Interconnection Agreement (SGIA).

1.2 Pre-Application

1.2.1 The Transmission Provider shall designate an employee or office from which information on the application process and on an Affected System can be obtained through informal requests from the Interconnection Customer presenting a proposed project for a specific site. The name, telephone number, and e-mail address of such contact employee or officeshall be made available on the Transmission Provider's Internet web site. Electric system information provided to the Interconnection Customer should include relevant system studies, interconnection studies, and other materials useful to an understanding of an interconnection at a particular point on the Transmission Provider's Transmission System, to the extent such provision does not violate confidentiality provisions of prior agreements or critical infrastructure requirements. The Transmission Provider shall comply with reasonable requests for such information.

1.2.2 In addition to the information described in section 1.2.1, which may be provided in response to an informal request, an Interconnection Customer may submit a formal written request form along with a non-refundable fee of $300 for a pre-application report on a proposed project at a specific site. The Transmission provider shall provide the pre-application data described in section 1.2.3 to the Interconnection Customer within 20 Business Days of receipt of the completed request form and payment of the $300 fee. The pre-application report produced by the Transmission Provider is non-binding, does not confer any rights, and the Interconnection Customer must still successfully apply to interconnect to the Transmission Provider’s system. The written pre-application report request form shall include the information in sections 1.2.2.1 through 1.2.2. below to clearly and sufficiently identify the location of the proposed Point of Interconnection.

1.2.2.1 Project contact information, including name, address, phone number, and email address.

1.2.2.2 Project location (street address with nearby cross streets and town)

1.2.2.3 Meter number, pole number, or other equivalent information identifying proposed Point of Interconnection, if available.

1.2.2.4 Generator Type (e.g., solar, wind, combined heat and power, etc.)

1.2.2.5 Size (alternating current kW)

1.2.2.6 Single or three phase generator configuration

1.2.2.7 Stand-alone generator (no onsite load, not including station service - Yes or No?)

1.2.2.8 Is new service requested? Yes or No? If there is existing service, include the customer account number, site minimum and maximum current or proposed electric loads in kW (if available) and specify if the load is expected to change.

1.2.3. Using the information provided in the pre-application report request form in section 1.2.2, the Transmission Provider will identify the substation/area bus, bank or circuit likely to serve the proposed Point of Interconnection. This selection by the Transmission Provider does not necessarily indicate, after application of the screens and/or study, that this would be the circuit the project ultimately connects to. The Interconnection Customer must request additional pre-application reports if information about multiple Points of Interconnection is requested. Subject to section 1.2.4, the pre-application report will include the following information:

1.2.3.1 Total capacity (in MW) of substation/area bus, bank or circuit based on normal or operating ratings likely to serve the proposed Point of Interconnection.

1.2.3.2 Existing aggregate generation capacity (in MW) interconnected to a substation/area bus, bank or circuit (i.e., amount of generation online) likely to serve the proposed Point of Interconnection.

1.2.3.3 Aggregate queued generation capacity (in MW) for a substation/area bus, bank or circuit (i.e., amount of generation in the queue) likely to serve the proposed Point of Interconnection.

1.2.3.4 Available capacity (in MW) of substation/area bus or bank and circuit likely to serve the proposed Point of Interconnection (i.e., total capacity less the sum of existing aggregate generation capacity and aggregate queued generation capacity).

1.2.3.5 Substation nominal distribution voltage and/or transmission nominal voltage if applicable.

1.2.3.6 Nominal distribution circuit voltage at the proposed Point of Interconnection.

1.2.3.7 Approximate circuit distance between the proposed Point of Interconnection and the substation.

1.2.3.8 Relevant line section(s) actual or estimated peak load and minimum load data, including daytime minimum load as described in section 2.4.4.1.1 below and absolute minimum load, when available.

1.2.3.9 Number and rating of protective devices and number and type (standard, bi-directional) of voltage regulating devices between the proposed Point of Interconnection and the substation/area. Identify whether the substation has a load tap changer.

1.2.3.10 Number of phases available at the proposed Point of Interconnection. If a single phase, distance from the three-phase circuit.

1.2.3.11 Limiting conductor ratings from the proposed Point of Interconnection to the distribution substation.

1.2.3.12 Whether the Point of Interconnection is located on a spot network, grid network, or radial supply.

1.2.3.13 Based on the proposed Point of Interconnection, existing or known constraints such as, but not limited to, electrical dependencies at that location, short circuit interruptingcapacity issues, power quality or stability issues on the circuit, capacity constraints, or secondary networks.

1.2.4 The pre-application report need only include existing data. A pre-application report request does not obligate the Transmission Provider to conduct a study or other analysis of the proposed generator in the event that data is not readily available. If the Transmission Provider cannot complete all or some of a pre-application report due to lack of available data, the Transmission Provider shall provide the Interconnection Customer with a pre-application report that includes the data that is available. The provision of information on “available capacity” pursuant to section 1.2.3.4 does not imply that an interconnection up to this level may be completed without impacts since there are many variables studied as part of the interconnection review process, and data provided in the pre-application report may become outdated at the time of the submission of the complete Interconnection Request. Notwithstanding any of the provisions of this section, the Transmission Provider shall, in good faith, include data in the pre-application report that represents the best available information at the time of reporting.

1.3 Interconnection Request

The Interconnection Customer shall submit its Interconnection Request to the Transmission Provider, together with the processing fee or deposit specified in the Interconnection Request. The Interconnection Request shall be date- and time-stamped upon receipt. The original date- and time-stamp applied to the Interconnection Request at the time of its original submission shall be accepted as the qualifying date- and time-stamp for the purposes of any timetable in these procedures. The Interconnection Customer shall be notified of receipt by the Transmission Provider within three Business Days of receiving the Interconnection Request. The Transmission Provider shall notify the Interconnection Customer within ten Business Days of the receipt of the Interconnection Request as to whether the Interconnection Request is complete or incomplete. If the Interconnection Request is incomplete, the Transmission Provider shall provide along with the notice that the Interconnection Request is incomplete, a written list detailing all information that must be provided to complete the Interconnection Request. The Interconnection Customer will have ten Business Days after receipt of the notice to submit the listed information or to request an extension of time to provide such information. If the Interconnection Customer does not provide the listed information or a request for an extension of time within the deadline, the Interconnection Request will be deemed withdrawn. An Interconnection Request will be deemed complete upon submission of the listed information to the ~~TransmissionProvider~~Transmission Provider.

1.4 Modification of the Interconnection Request

Any modification to machine data or equipment configuration or to the interconnection site of the Small Generating Facility not agreed to in writing by the Transmission Provider and the Interconnection Customer may be deemed a withdrawal of the Interconnection Request and may require submission of a new Interconnection Request, unless proper notification of each Party by the other and a reasonable time to cure the problems created by the changes are undertaken.

1.5 Site Control

Documentation of site control must be submitted with the Interconnection Request. Site control may be demonstrated through:

1.5.1 Ownership of, a leasehold interest in, or a right to develop a site for the purpose of constructing the Small Generating Facility;

1.5.2 An option to purchase or acquire a leasehold site for such purpose; or

1.5.3 An exclusivity or other business relationship between the Interconnection Customer and the entity having the right to sell, lease, or grant the Interconnection Customer the right to possess or occupy a site for such purpose.

1.6 Queue Position

The Transmission Provider shall assign a Queue Position based upon the date- and time-stamp of the Interconnection Request. The Queue Position of each Interconnection Request will be used to determine the cost responsibility for the Upgrades necessary to accommodate the interconnection. The Transmission Provider shall maintain a single queue per geographic region. At the Transmission Provider's option, Interconnection Requests may be studied serially or in clusters for the purpose of the system impact study.

1.7 Interconnection Requests Submitted Prior to the Effective Date of the SGIP

Nothing in this SGIP affects an Interconnection Customer's Queue Position assigned before the effective date of this SGIP. The Parties agree to complete work on any interconnection study agreement executed prior the effective date of this SGIP in accordance with the terms and conditions of that interconnection study agreement. Any new studies or other additional work will be completed pursuant to this SGIP.

Section 2. Fast Track Process

2.1 Applicability

The Fast Track Process is available to an Interconnection Customer proposing to interconnect its Small Generating Facility with the Transmission Provider's Distribution System if the Small Generating Facility's capacity does not exceed the size limits identified in the table below. Small Generating Facilities below these limits are eligible for Fast Track review. However, Fast Track eligibility is distinct from the Fast Track Process itself, and eligibility does not imply or indicate that a Small Generating Facility will pass the Fast Track screens in section 2.2.1 below or the Supplemental Review screens in section 2.4.4 below.

Fast Track eligibility is determined based upon the generator type, the size of the generator, voltage of the line and the location of and the type of line at the Point of Interconnection. All Small Generating Facilities connecting to lines greater than 69 kilovolt (kV) are ineligible for the Fast Track Process regardless of size. All synchronous and induction machines must be no larger than 2 MW to be eligible for the Fast Track Process, regardless of location. For certified inverter-based systems, the size limit varies according to the voltage of the line at the proposed Point of Interconnection. Certified inverter-based Small Generating Facilities located within 2.5 electrical circuit miles of a substation and on a mainline (as defined in the table below) are eligible for the Fast Track Process under the higher thresholds according to the table below. In addition to the size threshold,the Interconnection Customer's proposed Small Generating Facility must meet the codes, standards, and certification requirements of Attachments 3 and 4 of these procedures, or the Transmission Provider has reviewed the design or tested the proposed Small Generating Facility and is satisfied that it is safe to operate.

Fast Track Eligibility for Inverter-Based Systems		
Line Voltage	Fast Track Eligibility Regardless of Location	Fast Track Eligibility on a Mainline and ≤ 2.5 Electrical Circuit Miles from Substation
< 5 kV	≤ 500 kW	≤ 500 kW
≥ 5 kV and < 15 kV	≤ 2 MW	≤ 3 MW
≥ 15 kV and < 30 kV	≤ 3 MW	≤ 4 MW
≥ 30 kV and ≤ 69 kV	≤ 4 MW	≤ 5 MW

2.2 Initial Review

Within 15 Business Days after the Transmission Provider notifies the Interconnection Customer it has received a complete Interconnection Request, the Transmission Provider shall perform an initial review using the screens set forth below, shall notify the Interconnection Customer of the results, and include with the notification copies of the analysis and data underlying the Transmission Provider's determinations under the screens.

2.2.1 Screens

2.2.1.1 The proposed Small Generating Facility's Point of Interconnection must be on a portion of the Transmission Provider's Distribution System that is subject to the Tariff.

2.2.1.2 For interconnection of a proposed Small Generating Facility to a radial distribution circuit, the aggregated generation, including the proposed Small Generating Facility, on the circuit shall not exceed 15 % of the line section annual peak load as most recently measured at the substation. A line section is that portion of a Transmission Provider's electric system connected to a customer bounded by automatic sectionalizing devices or the end of the distribution line.

2.2.1.3 For interconnection of a proposed Small Generating Facility to the load side of spot network protectors, the proposed Small Generating Facility must utilize an inverter-based equipment package and, together with the aggregated other inverter-based generation, shall not exceed the smaller of 5 % of a spot network's maximum load or 50 kW.

2.2.1.4 The proposed Small Generating Facility, in aggregation with other generation on the distribution circuit, shall not contribute more than 10 % to the distribution circuit's maximum fault current at the point on the high voltage (primary) level nearest the proposed point of change of ownership.

2.2.1.5 The proposed Small Generating Facility, in aggregate with other generation on the distribution circuit, shall not cause any distribution protective devices and equipment (including, but not limited to, substation breakers, fuse cutouts, and line reclosers), or Interconnection Customer equipment on the system to exceed 87.5 % of the short circuit interrupting capability; nor shall the interconnection be proposed for a circuit that already exceeds 87.5 % of the short circuit interrupting capability.

2.2.1.6 Using the table below, determine the type of interconnection to aprimary distribution line. This screen includes a review of the type of electrical service provided to the Interconnecting Customer, including line configuration and the transformer connection tolimit the potential for creating over-voltages on the Transmission Provider's electric power system due to a loss of ground during the operating time of any anti-islanding function.

Primary Distribution Line Type	Type of Interconnection to Primary Distribution Line	Result/Criteria
Three-phase, three wire	3-phase or single phase, phase-to-phase	Pass screen
Three-phase, four wire	Effectively-grounded 3 phase or Single-phase, line--to-neutral	Pass screen

2.2.1.7 If the proposed Small Generating Facility is to be interconnected on single-phase shared secondary, the aggregate generation capacity on the shared secondary, including the proposed Small Generating Facility, shall not exceed 20 kW.

2.2.1.8 If the proposed Small Generating Facility is single-phase and is to be interconnected on a center tap neutral of a 240 volt service, its addition shall not create an imbalance between the two sides of the 240 volt service of more than 20 % of the nameplate rating of the service transformer.

2.2.1.9 The Small Generating Facility, in aggregate with other generation interconnected to the transmission side of a substation transformer feeding the circuit where the Small Generating Facility proposes to interconnect shall not exceed 10 MW in an area where there are known, or posted, transient stability limitations to generating units located in the general electrical vicinity (e.g., three or four transmission busses from the point of interconnection).

2.2.1.10 No construction of facilities by the Transmission Provider on its own system shall be required to accommodate the Small Generating Facility.

2.2.2 If the proposed interconnection passes the screens, the Interconnection Request shall be approved and the Transmission Provider will provide the Interconnection Customer an executable interconnection agreement within five Business Days after the determination.

2.2.3 If the proposed interconnection fails the screens, but the Transmission Provider determines that the Small Generating Facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards, the ~~TransmissionProvider~~Transmission Provider shall provide the Interconnection Customer an executable interconnection agreement within five Business Days after the determination.

2.2.4 If the proposed interconnection fails the screens, and the Transmission Provider does not or cannot determine from the initial review that the Small Generating Facility may nevertheless be interconnected consistent with safety, reliability, and power quality standards unless the Interconnection Customer is willing to consider minor modifications or further study, the Transmission Provider shall provide the Interconnection Customer with the opportunity to attend a customer options meeting.

2.3 Customer Options Meeting

If the Transmission Provider determines the Interconnection Request cannot be approved without (1) minor modifications at minimal cost,(2) a supplemental study or other additional studies or actions, or (3) incurring significant cost to address safety, reliability, or power quality problems, the Transmission Provider shall notify the Interconnection Customer of that determination within five Business Days after the determination and provide copies of all data and analyses underlying its conclusion. Within ten Business Days of the Transmission Provider's determination, the Transmission Provider shall offer to convene a customer options meeting with the Transmission Provider to review possible Interconnection Customer facility modifications or the screen analysis and related results, to determine what further steps are needed to permit the Small Generating Facility to be connected safely and reliably. At the time of notification of the Transmission Provider's determination, or at the customer options meeting, the Transmission Provider shall:

2.3.1 Offer to perform facility modifications or minor modifications to the Transmission Provider's electric system(e.g., changing meters, fuses, relay settings) and provide a non-binding good faith estimate of the limited cost to make such modifications to the Transmission Provider's electric system. If the Interconnection Customer agrees to pay for the modifications to the Transmission Provider’s electric system, the Transmission Provider will provide the Interconnection Customer with an executable interconnection agreement within ten Business Days of the customer options meeting; or

2.3.2 Offer to perform a supplemental review in accordance with section 2.4 and provide a non-binding good faith estimate of the costs of such review; or

2.3.3 Obtain the Interconnection Customer's agreement to continue evaluating the Interconnection Request under the section 3 Study Process.

2.4 Supplemental Review

2.4.1 To accept the offer of a supplemental review, the Interconnection Customer shall agree in writing, and submit a deposit for the estimated costs of the supplemental review in the amount of the Transmission Provider’s good faith estimate of the costs of such review, both within 15 Business Days of the offer. If the written agreement and deposit have not been received by the Transmission Provider within that timeframe, the Interconnection Request shall continue to be evaluated under section 3 Study Process unless it is withdrawn by the Interconnection Customer.

2.4.2 The Interconnection Customer may specify the order in which the Transmission Provider will complete the screens in section 2.4.4.

2.4.3 The Interconnection Customer shall be responsible for the Transmission Provider's actual costs for conducting the supplemental review. The Interconnection Customer must pay any review costs that exceed the deposit within 20Business Days of receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced costs, the Transmission Provider will return such excess within 20 Business Days of the invoice without interest.

2.4.4 Within 30 Business Days following receipt of the deposit for a supplemental review, the Transmission ~~Providershall~~Provider shall (1) perform a supplemental review using the screens set forth below; (2) notify in writing the Interconnection Customer of the results; and (3) include with the notification copies of the analysis and data underlying the Transmission Provider's determinations under the screens. Unless the Interconnection Customer provided instructions for how to respond to the failure of any of the supplemental review screens below at the time the Interconnection Customer accepted the offer of supplemental review, the Transmission Provider shall notify the Interconnection Customer following the failure of any of the screens, or if it is unable to perform the screen in section 2.4.4.1, within two Business Days of making such determination to obtain the Interconnection Customer's permission to: (1) continue evaluating the proposed interconnection under this section 2.4.4; (2) terminate the supplemental review and continue evaluating the Small Generating Facility under section 3; or (3) terminate the supplemental review upon withdrawal of the Interconnection Request by the Interconnection Customer.

2.4.4.1 Minimum Load Screen: Where 12 months of line section minimum load data (including onsite load but not station service load served by the proposed Small Generating Facility) are available, can be calculated, can be estimated from existing data, or determined from a power flow model, the aggregate Generating Facility capacity on the line section is less than 100% of the minimum load for all line sections bounded by automatic sectionalizing devices upstream of the proposed Small Generating Facility. If minimum load data is not available, or cannot be calculated, estimated or determined, the Transmission Provider shall include the reason(s) that it is unable to calculate, estimate or determine minimum load in its supplemental review results notification under section 2.4.4.

2.4.4.1.1 The type of generation used by the ~~proposedSmall~~proposed Small Generating Facility will be taken into account when calculating, estimating, or determining circuit or line section minimum load relevant for the application of screen 2.4.4.1. Solar photovoltaic (PV) generation systems with no battery storage use daytime minimum load (i.e. 10 a.m. to 4 p.m. for fixed panel systems and 8 a.m. to 6 p.m. for PV systems utilizing tracking systems), while all other generation uses absolute minimum load.

2.4.4.1.2 When this screen is being applied to a Small Generating Facility that serves some station service load, only the net injection into the Transmission Provider's electric system will be considered as part of the aggregate generation.

2.4.4.1.3 Transmission Provider will not consider as part of the aggregate generation for purposes of this screen generating facility capacity known to be already reflected in the minimum load data.

2.4.4.2 Voltage and Power Quality Screen: In aggregate with existing generation on the line section: (1) the voltage regulation on the line section can be maintained in compliance with relevant requirements under all system conditions; (2) the voltage fluctuation is within acceptable limits as defined by Institute of Electrical and Electronics Engineers (IEEE) Standard 1453, or utility practice similar to IEEE Standard 1453; and (3) the harmonic levels meet IEEE Standard 519 limits.

2.4.4.3 Safety and Reliability Screen: The location of the proposed Small Generating Facility and the aggregate generation capacity on the line section do not create impacts to safety or reliability that cannot be adequately addressed without application of the Study Process. The Transmission Provider shall give due consideration to the following and other factors in determining potential impacts to safety and reliability in applying this screen.

2.4.4.3.1 Whether the line section has significant minimum loading levels dominated by a small number of customers (e.g., several large commercial customers).

2.4.4.3.2 Whether the loading along the line section uniform or even.

2.4.4.3.3 Whether the proposed Small Generating Facility is located in close proximity to the substation (i.e., less than 2.5 electrical circuit miles), and whether the line section from the substation to the Point of Interconnection is a Mainline rated for normal and emergency ampacity.

2.4.4.3.4 Whether the proposed Small Generating Facility incorporates a time delay function to prevent reconnection of the generator to the system until system voltage and frequency are within normal limits for a prescribed time.

2.4.4.3.5 Whether operational flexibility is reduced by the proposed Small Generating Facility, such that transfer of the line section(s) of the Small Generating Facility to a neighboring distribution circuit/substation may trigger overloads or voltage issues.

2.4.4.3.6 Whether the proposed Small Generating Facility employs equipment or systems certified by a recognized standards organization to address technical issues such as, but not limited to, islanding, reverse power flow, or voltage quality.

2.4.5 If the proposed interconnection passes the supplemental screens in sections 2.4.4.1, 2.4.4.2, and 2.4.4.3 above, the Interconnection Request shall be approved and the Transmission Provider will provide the Interconnection Customer with an executable interconnection agreement within the timeframes established in sections 2.4.5.1 and 2.4.5.2 below. If the proposed interconnection fails any of the supplemental review screens and the Interconnection Customer does not withdraw its Interconnection Request, it shall continue to be evaluated under the section 3 Study Process consistent with section 2.4.5.3 below.

2.4.5.1 If the proposed interconnection passes the supplemental screens in sections 2.4.4.1, 2.4.4.2, and 2.4.4.3 above and does not require construction of facilities by the Transmission Provider on its own system, the interconnection agreement shall be provided within ten Business Days after the notification of the supplemental review results.

2.4.5.2 If interconnection facilities or minor modifications to the Transmission Provider's system are required for the proposed interconnection to pass the supplemental screens in sections 2.4.4.1, 2.4.4.2, and 2.4.4.3 above, and the Interconnection Customer agrees to pay for the modifications to the Transmission Provider’s electric system, the interconnection agreement, along with a non-binding good faith estimate for the interconnection facilities and/or minor modifications, shall be provided to the Interconnection Customer within 15 Business Days after receiving written notification of the supplemental review results.

2.4.5.3 If the proposed interconnection would require more than interconnection facilities or minor modifications to the Transmission Provider’s system to pass the supplemental screens in sections 2.4.4.1, 2.4.4.2, and 2.4.4.3 above, the Transmission Provider shall notify the Interconnection Customer, at the same time it notifies the Interconnection Customer with the supplemental review results, that the Interconnection Request shall be evaluated under the section 3 Study Process unless the Interconnection Customer withdraws its Small Generating Facility.

Section 3. Study Process

3.1 Applicability

The Study Process shall be used by an Interconnection Customer proposing to interconnect its Small Generating Facility with the Transmission Provider's Transmission System or Distribution System if the Small Generating Facility (1) is larger than 2 MW but no larger than 20 MW, (2) is not certified, or (3) is certified but did not pass the Fast Track Process or the 10 kW Inverter Process.

3.2 Scoping Meeting

3.2.1 A scoping meeting will be held within ten Business Days after the Interconnection Request is deemed complete, or as otherwise mutually agreed to by the Parties. The Transmission Provider and the Interconnection Customer will bring to the meeting personnel, including system engineers and other resources as may be reasonably required to accomplish the purpose of the meeting.

3.2.2 The purpose of the scoping meeting is to discuss the Interconnection Request and review existing studies relevant to the Interconnection Request. The Parties shall further discuss whether the Transmission Provider should perform a feasibility study or proceed directly to a system impact study, or a facilities study, or an interconnection agreement. If the Parties agree that a feasibility study should be performed, the Transmission Provider shall provide the Interconnection Customer, as soon as possible, but not later than five Business Days after the scoping meeting, a feasibility study agreement (Attachment 6) including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study.

3.2.3 The scoping meeting may be omitted by mutual agreement. In order to remain in consideration for interconnection, an Interconnection Customer who has requested a feasibility study must return the executed feasibility study agreement within 15 Business Days. If the Parties agree not to perform a feasibility study, the Transmission Provider shall provide the Interconnection Customer, no later than five Business Days after the scoping meeting, a system impact study agreement (Attachment 7) including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study.

3.3 Feasibility Study

3.3.1 The feasibility study shall identify any potential adverse system impacts that would result from the interconnection of the Small Generating Facility.

3.3.2 A deposit of the lesser of 50 percent of the good faith estimated feasibility study costs or earnest money of $1,000 may be required from the Interconnection Customer.

3.3.3 The scope of and cost responsibilities for the feasibility study are described in the attached feasibility study agreement (Attachment 6).

3.3.4 If the feasibility study shows no potential for adverse system impacts, the Transmission Provider shall send the Interconnection Customer a facilities study agreement, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study. If no additional facilities are required, the Transmission Provider shall send the Interconnection Customer an executable interconnection agreement within five Business Days.

3.3.5 If the feasibility study shows the potential for adverse system impacts, the review process shall proceed to the appropriate system impact study(s).

3.4 System Impact Study

3.4.1 A system impact study shall identify and detail the electric system impacts that would result if the proposed Small Generating Facility were interconnected without project modifications or electric system modifications, focusing on the adverse system impacts identified in the feasibility study, or to study potential impacts, including but not limited to those identified in the scoping meeting. A system impact study shall evaluate the impact of the proposed interconnection on the reliability of the electric system.

3.4.2 If no transmission system impact study is required, but potential electric power Distribution System adverse system impacts are identified in the scoping meeting or shown in the feasibility study, a distribution system impact study must be performed. The Transmission Provider shall send the Interconnection Customer a distribution system impact study agreement within 15 Business Days of transmittal of the feasibility study report, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study, or following the scoping meeting if no feasibility study is to be performed.

3.4.3 In instances where the feasibility study or the distribution system impact study shows potential for transmission system adverse system impacts, within five Business Days following transmittal of the feasibility study report, the Transmission Provider shall send the Interconnection Customer a transmission system impact study agreement, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study, if such a study is required.

3.4.4 If a transmission system impact study is not required, but electric power Distribution System adverse system impacts are shown by the feasibility study to be possible and no distribution system impact study has been conducted, the Transmission Provider shall send the Interconnection Customer a distribution system impact study agreement.

3.4.5 If the feasibility study shows no potential for transmission system or Distribution System adverse system impacts, the Transmission Provider shall send the Interconnection Customer either a facilities study agreement (Attachment 8), including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the study, or an executable interconnection agreement, as applicable.

3.4.6 In order to remain under consideration for interconnection, the Interconnection Customer must return executed system impact study agreements, if applicable, within 30 Business Days.

3.4.7 A deposit of the good faith estimated costs for each system impact study may be required from the Interconnection Customer.

3.4.8 The scope of and cost responsibilities for a system impact study are described in the attached system impact study agreement.

3.4.9 Where transmission systems and Distribution Systems have separate owners, such as is the case with transmission-dependent utilities ("TDUs") - whether investor-owned or not - the Interconnection Customer may apply to the nearest Transmission Provider (Transmission Owner, Regional Transmission Operator, or Independent Transmission Provider) providing transmission service to the TDU to request project coordination. Affected Systems shall participate in the study and provide all information necessary to prepare the study.

3.5 Facilities Study

3.5.1 Once the required system impact study(s) is completed, a system impact study report shall be prepared and transmitted to the Interconnection Customer along with a facilities study agreement within five Business Days, including an outline of the scope of the study and a non-binding good faith estimate of the cost to perform the facilities study. In the case where one or both impact studies are determined to be unnecessary, a notice of the fact shall be transmitted to the

Interconnection Customer within the same timeframe.

3.5.2 In order to remain under consideration for interconnection, or, as appropriate, in the Transmission Provider's interconnection queue, the Interconnection Customer must return the executed facilities study agreement or a request for an extension of time within 30 Business Days.

3.5.3 The facilities study shall specify and estimate the cost of the equipment, engineering, procurement and construction work (including overheads) needed to implement the conclusions of the system impact study(s).

3.5.4 Design for any required Interconnection Facilities and/or Upgrades shall be performed under the facilities study agreement. The Transmission Provider may contract with consultants to perform activities required under the facilities study agreement. The Interconnection Customer and the Transmission Provider may agree to allow the Interconnection Customer to separately arrange for the design of some of the Interconnection Facilities. In such cases, facilities design will be reviewed and/or modified prior to acceptance by the Transmission Provider, under the provisions of the facilities study agreement. If the Parties agree to separately arrange for design and construction, and provided security and confidentiality requirements can be met, the Transmission Provider shall make sufficient information available to the Interconnection Customer in accordance with confidentiality and critical infrastructure requirements to permit the Interconnection Customer to obtain an independent design and cost estimate for any necessary facilities.

3.5.5 A deposit of the good faith estimated costs for the facilities study may be required from the Interconnection Customer.

3.5.6 The scope of and cost responsibilities for the facilities study are described in the attached facilities study agreement.

3.5.7 Upon completion of the facilities study, and with the agreement of the Interconnection Customer to pay for Interconnection Facilities and Upgrades identified in the facilities study, the Transmission Provider shall provide the Interconnection Customer an executable interconnection agreement within five Business Days.

Section 4. Provisions that Apply to All Interconnection Requests

4.1 Reasonable Efforts

The Transmission Provider shall make reasonable efforts to meet all time frames provided in these procedures unless the Transmission Provider and the Interconnection Customer agree to a different schedule. If the Transmission Provider cannot meet a deadline provided herein, it shall notify the Interconnection Customer, explain the reason for the failure to meet the deadline, and provide an estimated time by which it will complete the applicable interconnection procedure in the process.

4.2– Disputes

4.2.1 The Parties agree to attempt to resolve all disputes arising out of the interconnection process according to the provisions of this article.

4.2.2 In the event of a dispute, either Party shall provide the other Party with a written Notice of Dispute. Such Notice shall describe in detail the nature of the dispute.

4.2.3 If the dispute has not been resolved within two Business Days after receipt of the Notice, either Party may contact FERC's Dispute Resolution Service (DRS) for assistance in resolving the dispute.

4.2.4 The DRS will assist the Parties in either resolving their dispute or in selecting an appropriate dispute resolution venue (e.g., mediation, settlement judge, early neutral evaluation, or technical expert) to assist the Parties in resolving their dispute. DRS can be reached at 1-877-337-2237 or via the internet at<http://www.ferc.gov/legal/adr.asp.>

4.2.5 Each Party agrees to conduct all negotiations in good faith and will be responsible for one-half of any costs paid to neutral third-parties.

4.2.6 If neither Party elects to seek assistance from the DRS, or if the attempted dispute resolution fails, then either Party may exercise whatever rights and remedies it may have in equity or law consistent with the terms of these procedures.

4.3 Interconnection Metering

Any metering necessitated by the use of the Small Generating Facility shall be installed at the Interconnection Customer's expense in accordance with Federal Energy Regulatory Commission, state, or local regulatory requirements or the Transmission Provider's specifications.

4.4 Commissioning

Commissioning tests of the Interconnection Customer's installed equipment shall be performed pursuant to applicable codes and standards. The Transmission Provider must be given at least five Business Days written notice, or as otherwise mutually agreed to by the Parties, of the tests and may be present to witness the commissioning tests.

4.5. Confidentiality

4.5.1 Confidential information shall mean any confidential and/or proprietary information provided by one Party to the other Party that is clearly marked or otherwise designated "Confidential." For purposes of these procedures all design, operating specifications, and metering data provided by the Interconnection Customer shall be deemed confidential information regardless of whether it is clearly marked or otherwise designated as such.

4.5.2 Confidential Information does not include information previously in the public domain, required to be publicly submitted or divulged by Governmental Authorities (after notice to the other Party and after exhausting any opportunity to oppose such publication or release), or necessary to be divulged in an action to enforce these procedures. Each Party receiving Confidential Information shall hold such information in confidence and shall not disclose it to any third party nor tothe public without the prior written authorization from the Party providing that information, except to fulfill obligations under these procedures, or to fulfill legal or regulatory requirements.

4.5.2.1 Each Party shall employ at least the same standard of care to protect Confidential Information obtained from the other Party as it employs to protect its own Confidential Information.

4.5.2.2 Each Party is entitled to equitable relief, by injunction or otherwise, to enforce its rights under this provision to prevent the release of Confidential Information without bond or proof of damages, and may seek other remedies available at law or in equity for breach of this provision.

4.5.3 Notwithstanding anything in this article to the contrary, and pursuant to 18 CFR § 1b.20, if FERC, during the course of an investigation or otherwise, requests information from one of the Parties that is otherwise required to be maintained in confidence pursuant to these procedures, the Party shall provide the requested information to FERC, within the time provided for in the request for information. In providing the information to FERC, the Party may, consistent with 18 CFR § 388.112, request that the information be treated as confidential and non-public by FERC and that the information be withheld from public disclosure. Parties are prohibited from notifying the other Party prior to the release of the Confidential Information to FERC. The Party shall notify the other Party when it is notified by FERC that a request to release Confidential Information has been received by FERC, at which time either of the Parties may respond before such information would be made public, pursuant to 18 CFR § 388.112. Requests from a state regulatory body conducting a confidential investigation shall be treated in a similar manner if consistent with the applicable state rules and regulations.

4.6 Comparability

The Transmission Provider shall receive, process and analyze all Interconnection

Requests in a timely manner as set forth in this document. The Transmission Provider shall use the same reasonable efforts in processing and analyzing Interconnection Requests from all Interconnection Customers, whether the Small Generating Facility is owned or operated by the Transmission Provider, its subsidiaries or affiliates, or others.

4.7 Record Retention

The Transmission Provider shall maintain for three years records, subject to audit, of all Interconnection Requests received under these procedures, the times required to complete Interconnection Request approvals and disapprovals, and justification for the actions taken on the Interconnection Requests.

4.8 Interconnection Agreement

After receiving an interconnection agreement from the Transmission Provider, the Interconnection Customer shall have 30 Business Days or another mutually agreeable timeframe to sign and return the interconnection agreement, or request that the Transmission Provider file an unexecuted interconnection agreement with the Federal Energy Regulatory Commission. If the Interconnection Customer does not sign the interconnection agreement, or ask that it be filed unexecuted by the Transmission Provider within 30 Business Days, the Interconnection Request shall be deemed withdrawn. After the interconnection agreement is signed by the Parties, the interconnection of the Small Generating Facility shall proceed under the provisions of the interconnection agreement.

4.9 Coordination with Affected Systems

The Transmission Provider shall coordinate the conduct of any studies required to determine the impact of the Interconnection Request on Affected Systems with Affected System operators and, if possible, include those results (if available) in its applicable interconnection study within the time frame specified in these procedures. The Transmission Provider will include such Affected System operators in all meetings held with the Interconnection Customer as required by these procedures. The Interconnection Customer will cooperate with the Transmission Provider in all matters related to the conduct of studies and the determination of modifications to Affected Systems. A Transmission Provider which may be an Affected System shall cooperate with the Transmission Provider with whom interconnection has been requested in all matters related to the conduct of studies and the determination of modifications to Affected Systems.

4.10 Capacity of the Small Generating Facility

4.10.1 If the Interconnection Request is for an increase in capacity for an existing Small Generating Facility, the Interconnection Request shall be evaluated on the basis of the new total capacity of the Small Generating Facility.

4.10.2 If the Interconnection Request is for a Small Generating Facility that includes multiple energy production devices at a site for which the Interconnection Customer seeks a single Point of Interconnection, the Interconnection Request shall be evaluated on the basis of the aggregate capacity of the multiple devices.

4.10.3 The Interconnection Request shall be evaluated using the maximum capacity that the Small Generating Facilityis capable of injecting into the Transmission Provider's electric system. However, if the maximum capacity that the Small Generating Facility is capable of injecting into the Transmission Provider's electric system is limited (e.g., through use of a control system, power relay(s), or other similar device settings or adjustments), then the Interconnection Customer must obtain the Transmission Provider's agreement, with such agreement not to be unreasonably withheld, that the manner in which the Interconnection Customer proposes to implement such a limit will not adversely affect the safety and reliability of the Transmission Provider's system. If the Transmission Provider does not so agree, then the Interconnection Request must be withdrawn or revised to specify the maximum capacity that the Small Generating Facility is capable of injecting into the Transmission Provider's electric system without such limitations. Furthermore, nothing in this section shall prevent a Transmission Provider from considering an output higher than the limited output, if appropriate, when evaluating system protection impacts.

5. EIM Requirements

5.1 The Interconnection Customer shall have a continuing duty to comply with Attachment O of this Tariff, as applicable.

Attachment 1

Glossary of Terms

10 kW Inverter Process - The procedure for evaluating an Interconnection Request for a certified inverter-based Small Generating Facility no larger than 10 kW that uses the section 2 screens. The application process uses an all-in-one document that includes a simplified Interconnection Request, simplified procedures, and a brief set of terms and conditions. See SGIP Attachment 5.

Affected System - An electric system other than the Transmission Provider's Transmission System that may be affected by the proposed interconnection.

Business Day - Monday through Friday, excluding Federal Holidays.

Distribution System - The Transmission Provider's facilities and equipment used to transmit electricity to ultimate usage points such as homes and industries directly from nearby generators or from interchanges with higher voltage transmission networks which transport bulk power over longer distances. The voltage levels at which Distribution Systems operate differ among areas.

Distribution Upgrades - The additions, modifications, and upgrades to the Transmission Provider's Distribution System at or beyond the Point of Interconnection to facilitate interconnection of the Small Generating Facility and render the transmission service necessary to effect the Interconnection Customer's wholesale sale of electricity in interstate commerce. Distribution Upgrades do not include Interconnection Facilities.

Fast Track Process - The procedure for evaluating an Interconnection Request for a certified Small Generating Facility that meets the eligibility requirements of section 2.1 and includes the section 2 screens, customer options meeting, and optional supplemental review.

Good Utility Practice - Any of the practices, methods and acts engaged in or approved by a ~~significantportion~~significant portion of the electric industry during the relevant ~~timeperiod~~time period, or any of the practices, methods and acts which, ~~inthe~~in the exercise of reasonable judgment in light of the ~~factsknown~~facts known at the time the decision was made, could have ~~beenexpected~~been expected to accomplish the desired result at a ~~reasonablecost~~reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is ~~notintended~~not intended to be limited to the optimum practice, method, ~~oract~~or act to the exclusion of all others, but rather to ~~beacceptable~~be acceptable practices, methods, or acts generally ~~acceptedin~~accepted in the region.

Interconnection Customer - Any entity, including the Transmission Provider, the Transmission Owner or any of the affiliates or subsidiaries of either, that proposes to interconnect its Small Generating Facility with the Transmission Provider's Transmission System.

Interconnection Facilities - The Transmission Provider's Interconnection Facilities and the Interconnection Customer's Interconnection Facilities. Collectively, Interconnection Facilities include all facilities and equipment between the Small Generating Facility and the Point of Interconnection, including any modification, additions or upgrades that are necessary to physically and electrically interconnect the Small Generating Facility to the Transmission Provider's Transmission System. Interconnection Facilities are sole use facilities and shall not include Distribution Upgrades or Network Upgrades.

Interconnection Request - The Interconnection Customer's request, in accordance with the Tariff, to interconnect a new Small Generating Facility, or to increase the capacity of, or make a Material Modification to the operating characteristics of, an existing Small Generating Facility that is interconnected with the Transmission Provider's Transmission System.

Material Modification - A modification that has a material impact on the cost or timing of any Interconnection Request with a later queue priority date.

Network Resource - Any designated generating resource owned, purchased, or leased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

Network Resource Interconnection Service - An Interconnection Service that allows the Interconnection Customer to integrate its Generating Facility with the Transmission Provider's System (1) in a manner comparable to that in which the Transmission Provider integrates its generating facilities to serve native load customers; or (2) in an RTO or ISO with market based congestion management, in the same manner as Network Resources. Network Resource Interconnection Service in and of itself does not convey transmission service.

Network Upgrades - Additions, modifications, and upgrades to the Transmission Provider's Transmission System required at or beyond the point at which the Small Generating Facility interconnects with the Transmission Provider's Transmission System to accommodate the interconnection with the Small Generating Facility to the Transmission Provider's Transmission System. Network Upgrades do not include Distribution Upgrades.

Party or Parties - The Transmission Provider, Transmission Owner, Interconnection Customer or any combination of the above.

Point of Interconnection - The point where the Interconnection Facilities connect with the Transmission Provider's Transmission System.

Queue Position - The order of a valid Interconnection Request, relative to all other pending valid Interconnection Requests, that is established based upon the date and time of receipt of the valid Interconnection Request by the Transmission Provider.

Small Generating Facility - The Interconnection Customer's device for the production and/or storage for later injection of electricity identified in the Interconnection Request, but shall not include the Interconnection Customer's Interconnection Facilities.

Study Process - The procedure for evaluating an Interconnection Request that includes the section 3 scoping meeting, feasibility study, system impact study, and facilities study.

Transmission Owner - The entity that owns, leases or otherwise possesses an interest in the portion of the Transmission System at the Point of Interconnection and may be a Party to the Small Generator Interconnection Agreement to the extent necessary.

Transmission Provider - The public utility (or its designated agent) that owns, controls, or operates transmission or distribution facilities used for the transmission of electricity in interstate commerce and provides transmission service under the Tariff. The term Transmission Provider should be read to include the Transmission Owner when the Transmission Owner is separate from the Transmission Provider.

Transmission System - The facilities owned, controlled or operated by the Transmission Provider or the Transmission Owner that are used to provide transmission service under the Tariff.

Upgrades - The required additions and modifications to the Transmission Provider's Transmission System at or beyond the Point of Interconnection. Upgrades may be Network Upgrades or Distribution Upgrades. Upgrades do not include Interconnection Facilities.

Attachment 2

SMALL GENERATOR INTERCONNECTION REQUEST
(Application Form)

Transmission Provider: ____

Designated Contact Person: ____

Address: ____

Telephone Number: ____

Fax: ____

E-Mail Address:

An Interconnection Request is considered complete when it provides all applicable and correct information required below. Per SGIP section 1.5, documentation of site control must be submitted with the Interconnection Request.

Preamble and Instructions

An Interconnection Customer who requests a Federal Energy Regulatory Commission jurisdictional interconnection must submit this Interconnection Request by hand delivery, mail, e-mail, or fax to the Transmission Provider.

Processing Fee or Deposit:

If the Interconnection Request is submitted under the Fast Track Process, the non-refundable processing fee is $500.

If the Interconnection Request is submitted under the Study Process, whether a new submission or an Interconnection Request that did not pass the Fast Track Process, the Interconnection Customer shall submit to the Transmission Provider a deposit not to exceed $1,000 towards the cost of the feasibility study.

Interconnection Customer Information

Legal Name of the Interconnection Customer (or, if an individual, individual's name)

Name: ____

Contact Person: ____

Mailing Address: ____

City: ____________________ State: ____________________ Zip: ____________________

Facility Location (if different from above): ____

Telephone (Day): __________________ Telephone (Evening):__________________

Fax: ___________________________E-Mail Address: _____________________________

Alternative Contact Information (if different from the Interconnection Customer)

Contact Name: ____

Title: ____

Address:

Telephone (Day): __________________ Telephone (Evening):

Fax: E-Mail Address:

Application is for: _____ New Small Generating Facility
_____ Capacity addition to Existing Small Generating Facility

If capacity addition to existing facility, please describe: __________________________

Will the Small Generating Facility be used for any of the following?

Net Metering? Yes ___ No ___
To Supply Power to the Interconnection Customer? Yes ___No
___ To Supply Power to Others? Yes ____ No ____

For installations at locations with existing electric service to which the proposed Small Generating Facility will interconnect, provide:

(Local Electric Service Provider*) (Existing Account Number*)

[*To be provided by the Interconnection Customer if the local electric service provider is different from the Transmission Provider]

Contact Name: ____

Title: ____

Address:

Telephone (Day): _________________________ Telephone (Evening):__________________

Fax: ___________________________________ E-Mail Address:_____________________

Requested Point of Interconnection:____

Interconnection Customer's Requested In-Service Date: ____

Small Generating Facility Information
Data apply only to the Small Generating Facility, not the Interconnection Facilities.

Energy Source: ___ Solar ___ Wind ___ Hydro ___ Hydro Type (e.g. Run-of-River):
Diesel ___ Natural Gas ___ Fuel Oil ___ Other (state type) _________________

Prime Mover: Fuel Cell Recip Engine Gas Turb Steam Turb
Microturbine PV Other

Type of Generator: ____Synchronous ____Induction ____ Inverter

Generator Nameplate Rating: ________kW (Typical) Generator Nameplate kVAR:

Interconnection Customer or Customer-Site Load: ________________ kW (if none, so state)

Typical Reactive Load (if known):_________________

Maximum Physical Export Capability Requested:______________ kW

List components of the Small Generating Facility equipment package that are currently certified:

Equipment Type	Certifying Entity
1. ____________________	
2. ____________________	
3. ____________________	
4. ____________________	
5.	

Is the prime mover compatible with the certified protective relay package? ____Yes ____No

Generator (or solar collector)
Manufacturer, Model Name & Number:____
Version Number:

Nameplate Output Power Rating in kW: (Summer)______________ (Winter)
Nameplate Output Power Rating in kVA: (Summer)_____________ (Winter)
Individual Generator Power Factor
Rated Power Factor: Leading:_____________Lagging:

Total Number of Generators in wind farm to be interconnected pursuant to this
Interconnection Request: __________ Elevation: ______ ___Single phase ___Three phase

Inverter Manufacturer, Model Name & Number (if used):________________________________

List of adjustable set points for the protective equipment or software: ______________________

Note: A completed Power Systems Load Flow data sheet must be supplied with the Interconnection Request.

Small Generating Facility Characteristic Data (for inverter-based machines)

Max design fault contribution current: ____________ Instantaneous or RMS?

Harmonics Characteristics: ____

Start-up requirements: ____

Small Generating Facility Characteristic Data (for rotating machines)

RPM Frequency: _____________
(*) Neutral Grounding Resistor (If Applicable):

Synchronous Generators:

Direct Axis Synchronous Reactance, Xd: _______ P.U.
Direct Axis Transient Reactance, X'_d: __________ P.U.
Direct Axis Subtransient Reactance, X''_d: _____________ P.U.
Negative Sequence Reactance, X_2: _________P.U.
Zero Sequence Reactance, X_0: ____________P.U.
KVA Base: _________________________
Field Volts: _____________
Field Amperes: _____________

Induction Generators:

Motoring Power (kW): _______
$I_2{}^2t$ or K (Heating Time Constant):
Rotor Resistance, Rr: ________

Stator Resistance, Rs: _____________
Stator Reactance, Xs: ______________
Rotor Reactance, Xr: ______________
Magnetizing Reactance, Xm: _____________
Short Circuit Reactance, Xd": _____________
Exciting Current: ______________
Temperature Rise: ______________
Frame Size: _____________
Design Letter: ______________
Reactive Power Required In Vars (No Load): _____________
Reactive Power Required In Vars (Full Load): ______________

Total Rotating Inertia, H: _______________ Per Unit on kVA Base

Note: Please contact the Transmission Provider prior to submitting the Interconnection Request to determine if the specified information above is required.

Excitation and Governor System Data for Synchronous Generators Only

Provide appropriate IEEE model block diagram of excitation system, governor system and power system stabilizer (PSS) in accordance with the regional reliability council criteria. A PSS may be determined to be required by applicable studies. A copy of the manufacturer's block diagram may not be substituted.

Interconnection Facilities Information

Will a transformer be used between the generator and the point of common coupling? ___Yes ___No

Will the transformer be provided by the Interconnection Customer? ____Yes ____No Transformer Data

(If Applicable, for Interconnection Customer-Owned Transformer):

Is the transformer: ____single phase _____three phase? Size:___________ kVA
Transformer Impedance:_______ % on_________ kVA Base

If Three Phase:
Transformer Primary: _____ Volts _____ Delta _____Wye _____ Wye Grounded
Transformer Secondary: _____ Volts _____ Delta _____Wye _____ Wye Grounded
Transformer Tertiary: _____ Volts _____ Delta _____Wye _____ Wye Grounded

Transformer Fuse Data (If Applicable, for Interconnection Customer-Owned Fuse):

(Attach copy of fuse manufacturer's Minimum Melt and Total Clearing Time-Current Curves)

Manufacturer: ___________________Type:________________ Size:________Speed:_____

Interconnecting Circuit Breaker (if applicable):

Manufacturer: ______________________________ Type: _________
Load Rating (Amps): _______Interrupting Rating (Amps): ________ Trip Speed (Cycles): _______

Interconnection Protective Relays (If Applicable):

If Microprocessor-Controlled:

List of Functions and Adjustable Setpoints for the protective equipment or software:

Setpoint Function Minimum Maximum

1. ____ ______________ ______________

3. ______________________________________ _____________ _____________

5. ______________________________________ _____________ _____________

If Discrete Components:

(Enclose Copy of any Proposed Time-Overcurrent Coordination Curves)

Manufacturer:	Type:	Style/Catalog No.:	Proposed Setting:
Manufacturer:	Type:	Style/Catalog No.:	Proposed Setting:
Manufacturer:	Type:	Style/Catalog No.:	Proposed Setting:
Manufacturer:	Type:	Style/Catalog No.:	Proposed Setting:
Manufacturer:	Type:	Style/Catalog No.:	Proposed Setting:

Current Transformer Data (If Applicable):

(Enclose Copy of Manufacturer's Excitation and Ratio Correction Curves)

Manufacturer: ____
Type: ______________ Accuracy Class: Proposed Ratio Connection: ____

Manufacturer: ____
Type: ______________ Accuracy Class: Proposed Ratio Connection: ____

Potential Transformer Data (If Applicable):

Manufacturer:

Type: _______________ Accuracy Class: Proposed Ratio Connection: ____

Manufacturer: ____
Type: _______________ Accuracy Class: Proposed Ratio Connection: ____

General Information

Enclose copy of site electrical one-line diagram showing the configuration of all Small Generating Facility equipment, current and potential circuits, and protection and control schemes. This one-line diagram must be signed and stamped by a licensed Professional Engineer if the Small Generating Facility is larger than 50 kW. Is One-Line Diagram Enclosed? ____Yes ____No

Enclose copy of any site documentation that indicates the precise physical location of the proposed Small Generating Facility (e.g., USGS topographic map or other diagram or documentation).

Proposed location of protective interface equipment on property (include address if different from the

Interconnection Customer's address)

Enclose copy of any site documentation that describes and details the operation of the protection and control schemes. Is Available Documentation Enclosed? ___Yes ____No

Enclose copies of schematic drawings for all protection and control circuits, relay current circuits, relay potential circuits, and alarm/monitoring circuits (if applicable). Are Schematic Drawings Enclosed? ___Yes ____No

Applicant Signature

I hereby certify that, to the best of my knowledge, all the information provided in this Interconnection Request is true and correct.

For Interconnection Customer: Date:

Attachment 3

Certification Codes and Standards

IEEE1547 Standard for Interconnecting Distributed Resources with Electric Power Systems (including use of IEEE 1547.1 testing protocols to establish conformity)

UL 1741 Inverters, Converters, and Controllers for Use in Independent Power Systems

IEEE Std 929-2000 IEEE Recommended Practice for Utility Interface of Photovoltaic (PV) Systems

NFPA 70 (2002), National Electrical Code

IEEE Std C37.90.1-1989 (R1994), IEEE Standard Surge Withstand Capability (SWC) Tests for Protective Relays and Relay Systems

IEEE Std C37.90.2 (1995), IEEE Standard Withstand Capability of Relay Systems to Radiated Electromagnetic Interference from Transceivers

IEEE Std C37.108-1989 (R2002), IEEE Guide for the Protection of Network Transformers

IEEE Std C57.12.44-2000, IEEE Standard Requirements for Secondary Network Protectors

IEEE Std C62.41.2-2002, IEEE Recommended Practice on Characterization of Surges in Low Voltage (1000V and Less) AC Power Circuits

IEEE Std C62.45-1992 (R2002), IEEE Recommended Practice on Surge Testing for Equipment Connected to Low-Voltage (1000V and Less) AC Power Circuits

ANSI C84.1-1995 Electric Power Systems and Equipment - Voltage Ratings (60 Hertz)

IEEE Std 100-2000, IEEE Standard Dictionary of Electrical and Electronic Terms
NEMA MG 1-1998, Motors and Small Resources, Revision 3

IEEE Std 519-1992, IEEE Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems

NEMA MG 1-2003 (Rev 2004), Motors and Generators, Revision 1

Attachment 4

Certification of Small Generator Equipment Packages

1.0 Small Generating Facility equipment proposed for use separately or packaged with other equipment in an interconnection system shall be considered certified for interconnected operation if (1) it has been tested in accordance with industry standards for continuous utility interactive operation in compliance with the appropriate codes and standards referenced below by any Nationally Recognized Testing Laboratory (NRTL) recognized by the United States Occupational Safety and Health Administration to test and certify interconnection equipment pursuant to the relevant codes and standards listed in SGIP Attachment 3, (2) it has been labeled and is publicly listed by such NRTL at the time of the interconnection application, and (3) such NRTL makes readily available for verification all test standards and procedures it utilized in performing such equipment certification, and, with consumer approval, the test data itself. The NRTL may make such information available on its website and by encouraging such information to be included in the manufacturer's literature accompanying the equipment.

2.0 The Interconnection Customer must verify that the intended use of the equipment falls within the use or uses for which the equipment was tested, labeled, and listed by the NRTL.

3.0 Certified equipment shall not require further type-test review, testing, or additional equipment to meet the requirements of this interconnection procedure; however, nothing herein shall preclude the need for an on-site commissioning test by the parties to the interconnection nor follow-up production testing by the NRTL.

4.0 If the certified equipment package includes only interface components (switchgear, inverters, or other interface devices), then an Interconnection Customer must show that the generator or other electric source being utilized with the equipment package is compatible with the equipment package and is consistent with the testing and listing specified for this type of interconnection equipment.

5.0 Provided the generator or electric source, when combined with the equipment package, is within the range of capabilities for which it was tested by the NRTL, and does not violate the interface components' labeling and listing performed by the NRTL, no further design review, testing or additional equipment on the customer side of the point of common coupling shall be required to meet the requirements of this interconnection procedure.

6.0 An equipment package does not include equipment provided by the utility.

7.0 Any equipment package approved and listed in a state by that state's regulatory body for interconnected operation in that state prior to the effective date of these small generator interconnection procedures shall be considered certified under these procedures for use in that state.
~~interconnected operation in that state prior to the effective date of these small generator~~

~~interconnection procedures shall be considered certified under these procedures for use in that state.~~

Attachment 5

Application, Procedures, and Terms and Conditions for Interconnecting a Certified Inverter-Based Small Generating Facility No Larger than 10 kW ("10 kW Inverter Process")

1.0 The Interconnection Customer ("Customer") completes the Interconnection Request ("Application") and submits it to the Transmission Provider ("Company").

2.0 The Company acknowledges to the Customer receipt of the Application within three Business Days of receipt.

3.0 The Company evaluates the Application for completeness and notifies the Customer within ten Business Days of receipt that the Application is or is not complete and, if not, advises what material is missing.

4.0 The Company verifies that the Small Generating Facility can be interconnected safely and reliably using the screens contained in the Fast Track Process in the Small Generator Interconnection Procedures (SGIP). The Company has 15 Business Days to complete this process. Unless the Company determines and demonstrates that the Small Generating Facility cannot be interconnected safely and reliably, the Company approves the Application and returns it to the Customer. Note to Customer: Please check with the Company before submitting the Application if disconnection equipment is required.

5.0 After installation, the Customer returns the Certificate of Completion to the Company. Prior to parallel operation, the Company may inspect the Small Generating Facility for compliance with standards which may include a witness test, and may schedule appropriate metering replacement, if necessary.

6.0 The Company notifies the Customer in writing that interconnection of the Small Generating Facility is authorized. If the witness test is not satisfactory, the Company has the right to disconnect the Small Generating Facility. The Customer has no right to operate in parallel until a witness test has been performed, or previously waived on the Application. The Company is obligated to complete this witness test within ten Business Days of the receipt of the Certificate of Completion. If the Company does not inspect within ten Business Days or by mutual agreement of the Parties, the witness test is deemed waived.

7.0 Contact Information - The Customer must provide the contact information for the legal applicant(i.e., the Interconnection Customer). If another entity is responsible for interfacing with the Company, that contact information must be provided on the Application.

8.0 Ownership Information - Enter the legal names of the owner(s) of the Small Generating

Facility. Include the percentage ownership (if any) by any utility or public utility holding company, or by any entity owned by either.

9.0 UL1741 Listed - This standard ("Inverters, Converters, and Controllers for Use in Independent Power Systems") addresses the electrical interconnection design of various forms of generating equipment. Many manufacturers submit their equipment to a Nationally Recognized Testing Laboratory (NRTL) that verifies compliance with UL1741. This "listing" is then marked on the equipment and supporting documentation.

Application for Interconnecting a Certified Inverter-Based SmallGenerating Facility No Larger than 10kW

This Application is considered complete when it provides all applicable and correct information required below. Per GSIP section 1.5, documentation of site control must be submitted with the Interconnection Request. Additional information to evaluate the Application may be required.

Processing Fee

A non-refundable processing fee of $100 must accompany this Application.

Interconnection Customer

Name: ____

Contact Person: ____

Address: ____

City: ___________________________________ State: ____________________ Zip: ____________

Telephone (Day): _________________________ (Evening): _________________________________

Fax: E-Mail Address:

Contact (if different from Interconnection Customer)

Name: ____

Address: ____

City: ___________________________________ State: ____________________ Zip: ____________

Telephone (Day): _________________________ (Evening): _________________________________

Fax: E-Mail Address:

Owner of the facility (include % ownership by any electric utility): ____________________________

Small Generating Facility Information

Location (if different from above): ____

Electric Service Company: ____

Account Number:

Inverter Manufacturer: ______________________ Model ____________________________________

Nameplate Rating: ______ (kW)_____ (kVA) _______(AC Volts)

Single Phase _______ Three Phase _____

System Design Capacity: _________ (kW) ______ (kVA)

Prime Mover: Photovoltaic Reciprocating Engine Fuel Cell

Turbine Other

Energy Source: Solar Wind Hydro Diesel Natural Gas

Fuel Oil Other (describe) _________________

Is the equipment UL1741 Listed? Yes _____ No

If Yes, attach manufacturer's cut-sheet showing UL1741 listing

Estimated Installation Date: Estimated In-Service Date:

The 10 kW Inverter Process is available only for inverter-based Small Generating Facilities no larger than 10 kW that meet the codes, standards, and certification requirements of Attachments 3 and 4 of the Small Generator Interconnection Procedures (SGIP), or the Transmission Provider has reviewed the design or tested the proposed Small Generating Facility and is satisfied that it is safe to operate.

List components of the Small Generating Facility equipment package that are currently certified:

Equipment Type Certifying Entity

1. ____________________
2. ____________________
3. ____________________
4. ____________________
5.

Interconnection Customer Signature

I hereby certify that, to the best of my knowledge, the information provided in this Application is true. I agree to abide by the Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW and return the Certificate of Completion when the Small Generating Facility has been installed.

Signed: ____

Title: ____ Date:_____________

Contingent Approval to Interconnect the Small Generating Facility (For Company use only)

Interconnection of the Small Generating Facility is approved contingent upon the Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW and return of the Certificate of Completion.

Company Signature: ________________________________

Title: _______________________________________ Date:

Application ID number: _________________

Company waives inspection/witness test? Yes___No___

Small Generating Facility Certificate of Completion

Is the Small Generating Facility owner-installed? Yes______ No ______

Interconnection Customer:____

Contact Person: ____

Address:____

Location of the Small Generating Facility (if different from above):

City:____________________________________ State: ____________________ Zip Code: ________

Telephone (Day):___________________________ (Evening): ___________________________________

Fax: ____________________________________ E-Mail Address: _____________________________

<u>Electrician:</u>

Name:____

Address:____

City:____________________________________ State: ____________________ Zip Code: ________

Telephone (Day):___________________________ (Evening): ___________________________________

Fax: ____________________________________ E-Mail Address: _____________________________

License number:

Date Approval to Install Facility granted by the

Company: Application ID number:

<u>Inspection:</u>

The Small Generating Facility has been installed and inspected in compliance with the local

building/electrical code of ____

Signed (Local electrical wiring inspector, or attach signed electrical inspection):

Print Name:

Date:

As a condition of interconnection, you are required to send/fax a copy of this form along with a copy of the signed electrical permit to (insert Company information below):

Name: ____

Company: ____

Address:

City,

State

ZIP:

Fax:

Approval to Energize the Small Generating Facility (For Company use only)

Energizing the Small Generating Facility is approved contingent upon the Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW

Company Signature: ____

Title: Date:

Terms and Conditions for Interconnecting an Inverter-Based Small Generating Facility No Larger than 10kW

1.0 **Construction of the Facility**

The Interconnection Customer (the "Customer") may proceed to construct (including operational testing not to exceed two hours) the Small Generating Facility when the Transmission Provider (the "Company") approves the Interconnection Request (the "Application") and returns it to the Customer.

2.0 **Interconnection and Operation**

The Customer may operate Small Generating Facility and interconnect with the Company's electric system once all of the following have occurred:

2.1 Upon completing construction, the Customer will cause the Small Generating Facility to be inspected or otherwise certified by the appropriate local electrical wiring inspector with jurisdiction, and

2.2 The Customer returns the Certificate of Completion to the Company, and

2.3 The Company has either:

2.3.1 Completed its inspection of the Small Generating Facility to ensure that all equipment has been appropriately installed and that all electrical connections have been made in accordance with applicable codes. All inspections must be conducted by the Company, at its own expense, within ten Business Days after receipt of the Certificate of Completion and shall take place at a time agreeable to the Parties. The Company shall provide a written statement that the Small Generating Facility has passed inspection or shall notify the Customer of what steps it must take to pass inspection as soon as practicable after the inspection takes place; or

2.3.2 If the Company does not schedule an inspection of the Small Generating Facility within ten business days after receiving the Certificate of Completion, the witness test is deemed waived (unless the Parties agree otherwise); or

2.3.3 The Company waives the right to inspect the Small Generating Facility.

2.4 The Company has the right to disconnect the Small Generating Facility in the event of improper installation or failure to return the Certificate of Completion.

2.5 Revenue quality metering equipment must be installed and tested in accordance with applicable ANSI standards.

3.0 **Safe Operations and Maintenance**

The Customer shall be fully responsible to operate, maintain, and repair the Small Generating Facility as required to ensure that it complies at all times with the interconnection standards to which it has been certified.

4.0 **Access**

The Company shall have access to the disconnect switch (if the disconnect switch is required) and metering equipment of the Small Generating Facility at all times. The Company shall provide reasonable notice to the Customer when possible prior to using its right of access.

5.0 **Disconnection**

The Company may temporarily disconnect the Small Generating Facility upon the following conditions:

5.1 For scheduled outages upon reasonable notice.

5.2 For unscheduled outages or emergency conditions.

5.3 If the Small Generating Facility does not operate in the manner consistent with these Terms and Conditions.

5.4 The Company shall inform the Customer in advance of any scheduled disconnection, or as is reasonable after an unscheduled disconnection.

6.0 **Indemnification**

The Parties shall at all times indemnify, defend, and save the other Party harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demand, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the other Party's action or inactions of its obligations under this agreement on behalf of the indemnifying Party, except in cases of gross negligence or intentional wrongdoing by the indemnified Party.

7. 0 **Insurance**

The Parties agree to follow all applicable insurance requirements imposed by the state in which the Point of Interconnection is located. All insurance policies must be maintained with insurers authorized to do business in that state.

8.0 **Limitation of Liability**

Each party’s liability to the other party for any loss, cost, claim, injury, liability, or expense, including reasonable attorney’s fees, relating to or arising from any act or omission in its performance of this Agreement, shall be limited to the amount of direct damage actually incurred. In no event shall either party be liable to the other party for any indirect, incidental, special, consequential, or punitive damages of any kind whatsoever, except as allowed under paragraph 6.0.

9.0 **Termination**

The agreement to operate in parallel may be terminated under the following conditions:

9.1 **By the Customer**

By providing written notice to the Company.

9.2 **By the Company**

If the Small Generating Facility fails to operate for any consecutive 12 month period or the Customer fails to remedy a violation of these Terms and Conditions.

9.3 **Permanent Disconnection**

In the event this Agreement is terminated, the Company shall have the right to disconnect its facilities or direct the Customer to disconnect its Small Generating Facility.

9.4 **Survival Rights**

This Agreement shall continue in effect after termination to the extent necessary to allow or require either Party to fulfill rights or obligations that arose under the Agreement.

10.0 **Assignment/Transfer of Ownership of the Facility**

This Agreement shall survive the transfer of ownership of the Small Generating Facility to a new owner when the new owner agrees in writing to comply with the terms of this Agreement and so notifies the Company.~~**Attachment 6**~~

Attachment 6

Feasibility Study Agreement

THIS AGREEMENT is made and entered into this_____day of__________________ 20___ by and between ____ , a__________________________________ organized and existing under the laws of the State of ____, ("Interconnection Customer,") and ____ , a ________________ existing under the laws of the State of ____ , ("Transmission Provider"). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, Interconnection Customer is proposing to develop a Small Generating Facility or generating capacity addition to an existing Small Generating Facility consistent with the Interconnection Request completed by Interconnection Customer on___________________________ ; and

WHEREAS, Interconnection Customer desires to interconnect the Small Generating Facility with the Transmission Provider's Transmission System; and

WHEREAS, Interconnection Customer has requested the Transmission Provider to perform a feasibility study to assess the feasibility of interconnecting the proposed Small Generating Facility with the Transmission Provider's Transmission System, and of any Affected Systems;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the standard Small Generator Interconnection Procedures.

2.0 The Interconnection Customer elects and the Transmission Provider shall cause to be performed an interconnection feasibility study consistent the standard Small

Generator Interconnection Procedures in accordance with the Open Access Transmission Tariff.

3.0 The scope of the feasibility study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 The feasibility study shall be based on the technical information provided by the Interconnection Customer in the Interconnection Request, as may be modified as the result of the scoping meeting. The Transmission Provider reserves the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the feasibility study and as designated in accordance with the standard Small Generator Interconnection Procedures. If the Interconnection Customer modifies its Interconnection Request, the time to complete the feasibility study may be extended by agreement of the Parties.

5.0 In performing the study, the Transmission Provider shall rely, to the extent reasonably practicable, on existing studies of recent vintage. The Interconnection Customer shall not be charged for such existing studies; however, the Interconnection Customer shall be responsible for charges associated with any new study or modifications to existing studies that are reasonably necessary to perform the feasibility study.

6.0 The feasibility study report shall provide the following analyses for the purpose of identifying any potential adverse system impacts that would result from the interconnection of the Small Generating Facility as proposed:

6.1 Initial identification of any circuit breaker short circuit capability limits exceeded as a result of the interconnection;

6.2 Initial identification of any thermal overload or voltage limit violations resulting from the interconnection;

6.3 Initial review of grounding requirements and electric system protection; and

6.4 Description and non-binding estimated cost of facilities required to interconnect the proposed Small Generating Facility and to address the identified short circuit and power flow issues.

7.0 The feasibility study shall model the impact of the Small Generating Facility regardless of purpose in order to avoid the further expense and interruption of operation for reexamination of feasibility and impacts if the Interconnection Customer later changes the purpose for which the Small Generating Facility is being installed.

8.0 The study shall include the feasibility of any interconnection at a proposed project site where there could be multiple potential Points of Interconnection, as requested by the Interconnection Customer and at the Interconnection Customer's cost.

9.0 A deposit of the lesser of 50 percent of good faith estimated feasibility study costs or earnest money of $1,000 may be required from the Interconnection Customer.

10.0 Once the feasibility study is completed, a feasibility study report shall be prepared and transmitted to the Interconnection Customer. Barring unusual circumstances, the feasibility study must be completed and the feasibility study report transmitted within 30 Business Days of the Interconnection Customer's agreement to conduct a feasibility study.

11.0 Any study fees shall be based on the Transmission Provider's actual costs and will be invoiced to the Interconnection Customer after the study is completed and delivered and will include a summary of professional time.

12.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 calendar days on receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the Transmission Provider shall refund such excess within 30 calendar days of the invoice without interest.

13.0 Governing Law, Regulatory Authority, and Rules

The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the state of________________________ (where the Point of Interconnection is located), without regard to its conflicts of law principles. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.

14.0 Amendment

The Parties may amend this Agreement by a written instrument duly executed by both Parties.

15.0 No Third-Party Beneficiaries

This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and where permitted, their assigns.

16.0 Waiver

16.1 The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

16.2 Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Termination or default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Transmission Provider. Any waiver of this Agreement shall, if requested, be provided in writing.

17.0 Multiple Counterparts

This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

18.0 No Partnership

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

19.0 Severability

If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to

restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

20.0 Subcontractors

Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Party for the performance of such subcontractor.

20.1 The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall the Transmission Provider be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

20.2 The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.

21.0 Reservation of Rights

The Transmission Provider shall have the right to make a unilateral filing with FERC to modify this Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and the Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this Agreement under any applicable provision of the Federal Power Act and FERC's rules and regulations; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this Agreement shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations, except to the extent that the Parties otherwise agree as provided herein.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

[Insert name of Transmission Provider]	**[Insert name of Interconnection Customer]**
Signed ______________________________	Signed
Name (Printed):	Name (Printed):
Title	Title

Assumptions Used in Conducting the Feasibility Study

The feasibility study will be based upon the information set forth in the Interconnection Request and agreed upon in the scoping meeting held on ____________________ :

1) Designation of Point of Interconnection and configuration to be studied.

2) Designation of alternative Points of Interconnection and configuration.

1) and 2) are to be completed by the Interconnection Customer. Other assumptions (listed below) are to be provided by the Interconnection Customer and the Transmission Provider.

Attachment 7

System Impact Study Agreement

THIS AGREEMENT is made and entered into this_____day of__________________ 20___ by and between ____ , a__________________________________ organized and existing under the laws of the State of ____, ("Interconnection Customer,") and ____ , a ________________ existing under the laws of the State of ____ , ("Transmission Provider"). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Small Generating Facility or generating capacity addition to an existing Small Generating Facility consistent with the Interconnection Request completed by the Interconnection Customer on__________________________; and

WHEREAS, the Interconnection Customer desires to interconnect the Small Generating Facility with the Transmission Provider's Transmission System;

WHEREAS, the Transmission Provider has completed a feasibility study and provided the results of said study to the Interconnection Customer (This recital to be omitted if the Parties have agreed to forego the feasibility study.); and

WHEREAS, the Interconnection Customer has requested the Transmission Provider to perform a system impact study(s) to assess the impact of interconnecting the Small Generating Facility with the Transmission Provider's Transmission System, and of any Affected Systems;

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the standard Small Generator Interconnection Procedures.

2.0 The Interconnection Customer elects and the Transmission Provider shall cause to be performed a system impact study(s) consistent with the standard Small Generator Interconnection Procedures in accordance with the Open Access Transmission Tariff.

3.0 The scope of a system impact study shall be subject to the assumptions set forth in Attachment A to this Agreement.

4.0 A system impact study will be based upon the results of the feasibility study and the technical information provided by Interconnection Customer in the Interconnection Request. The Transmission Provider reserves the right to request additional technical information from the Interconnection Customer as may reasonably become necessary consistent with Good Utility Practice during the course of the system impact study. If the Interconnection Customer modifies its designated Point of Interconnection, Interconnection Request, or the technical information provided therein is modified, the time to complete the system impact study may be extended.

5.0 A system impact study shall consist of a short circuit analysis, a stability analysis, a power flow analysis, voltage drop and flicker studies, protection and set point coordination studies, and grounding reviews, as necessary. A system impact study shall state the assumptions upon which it is based, state the results of the analyses, and provide the requirement or potential impediments to providing the requested interconnection service, including a preliminary indication of the cost and length of time that would be necessary to correct any problems identified in those analyses and implement the interconnection. A system impact study shall provide a list of facilities that are required as a result of the Interconnection Request and non-binding good faith estimates of cost responsibility and time to construct.

6.0 A distribution system impact study shall incorporate a distribution load flow study, an analysis of equipment interrupting ratings, protection coordination study, voltage drop and flicker studies, protection and set point coordination studies, grounding reviews, and the impact on electric system operation, as necessary.

7.0 Affected Systems may participate in the preparation of a system impact study, with a division of costs among such entities as they may agree. All Affected Systems shall be afforded an opportunity to review and comment upon a system impact study that covers potential adverse system impacts on their electric

systems, and the Transmission Provider has 20 additional Business Days to complete a system impact study requiring review by Affected Systems.

8.0 If the Transmission Provider uses a queuing procedure for sorting or prioritizing projects and their associated cost responsibilities for any required Network Upgrades, the system impact study shall consider all generating facilities (and with respect to paragraph 8.3 below, any identified Upgrades associated with such higher queued interconnection) that, on the date the system impact study is commenced -

8.1 Are directly interconnected with the Transmission Provider's electricsystem; or

8.2 Are interconnected with Affected Systems and may have an impacton the proposed interconnection; and

8.3 Have a pending higher queued Interconnection Request tointerconnect with the Transmission Provider's electric system.

9.0 A distribution system impact study, if required, shall be completed and the results transmitted to the Interconnection Customer within 30 Business Days after this Agreement is signed by the Parties. A transmission system impact study, if required, shall be completed and the results transmitted to the Interconnection Customer within 45 Business Days after this Agreement is signed by the Parties, or in accordance with the Transmission Provider's queuing procedures.

10.0 A deposit of the equivalent of the good faith estimated cost of a distribution system impact study and the one half the good faith estimated cost of a transmission system impact study may be required from the Interconnection Customer.

11.0 Any study fees shall be based on the Transmission Provider's actual costs and will be invoiced to the Interconnection Customer after the study is completed and delivered and will include a summary of professional time.

12.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 calendar days on receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the Transmission Provider shall refund such excess within 30 calendar days of the invoice without interest.

13.0 <u>Governing Law, Regulatory Authority, and Rules</u>
The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the state of________________________ (where the Point of Interconnection is located), without regard to its conflicts of law principles. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.

14.0 <u>Amendment</u>
The Parties may amend this Agreement by a written instrument duly executed by both Parties.

15.0 <u>No Third-Party Beneficiaries</u>
This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and where permitted, their assigns.

16.0 Waiver

16.1 The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

16.2 Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this Agreement. Termination or default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Transmission Provider. Any waiver of this Agreement shall, if requested, be provided in writing.

17.0 Multiple Counterparts

This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

18.0 No Partnership

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

19.0 Severability

If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

20.0 Subcontractors

Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Party for the performance of such subcontractor.

20.1 The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made; provided, however, that in no event shall the Transmission Provider be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

20.2 The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.

21.0 Reservation of Rights

The Transmission Provider shall have the right to make a unilateral filing with FERC to modify this Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and the Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this Agreement under any applicable provision of the Federal Power Act and FERC's rules and regulations; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this Agreement shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations, except to the extent that the Parties otherwise agree as provided herein.

IN WITNESS THEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

[Insert name of Transmission Provider]	**[Insert name of Interconnection Customer]**
______________________________	______________________________
Signed: ______________________	Signed: ______________________
Name (Printed):	Name (Printed):
______________________________	______________________________
Title: ______________________	Title: ______________________

Assumptions Used in Conducting the System Impact Study

The system impact study shall be based upon the results of the feasibility study, subject to any modifications in accordance with the standard Small Generator Interconnection Procedures, and the following assumptions:

1) Designation of Point of Interconnection and configuration to be studied.

2) Designation of alternative Points of Interconnection and configuration.

1) and 2) are to be completed by the Interconnection Customer. Other assumptions (listed below) are to be provided by the Interconnection Customer and the Transmission Provider.

Attachment 8

Facilities Study Agreement

THIS AGREEMENT is made and entered into this_____day of___________________ 20___ by and between ____ , a____________________________________ organized and existing under the laws of the State of ____, ("Interconnection Customer,") and ____ , a _________________ existing under the laws of the State of ____, ("Transmission Provider"). Interconnection Customer and Transmission Provider each may be referred to as a "Party," or collectively as the "Parties."

RECITALS

WHEREAS, the Interconnection Customer is proposing to develop a Small Generating Facility or generating capacity addition to an existing Small Generating Facility consistent with the Interconnection Request completed by the Interconnection Customer on________________________ ; and

WHEREAS, the Interconnection Customer desires to interconnect the Small Generating Facility with the Transmission Provider's Transmission System;

WHEREAS, the Transmission Provider has completed a system impact study and provided the results of said study to the Interconnection Customer; and

WHEREAS, the Interconnection Customer has requested the Transmission Provider to perform a facilities study to specify and estimate the cost of the equipment, engineering, procurement and construction work needed to implement the conclusions of the system impact study in accordance with Good Utility Practice to physically and electrically connect the Small Generating Facility with the Transmission Provider's Transmission System.

NOW, THEREFORE, in consideration of and subject to the mutual covenants contained herein the Parties agreed as follows:

1.0 When used in this Agreement, with initial capitalization, the terms specified shall have the meanings indicated or the meanings specified in the standard Small Generator Interconnection Procedures.

2.0 The Interconnection Customer elects and the Transmission Provider shall cause a facilities study consistent with the standard Small Generator Interconnection Procedures to be performed in accordance with the Open Access Transmission Tariff.

3.0 The scope of the facilities study shall be subject to data provided in Attachment A to this Agreement.

4.0 The facilities study shall specify and estimate the cost of the equipment, engineering, procurement and construction work (including overheads) needed to implement the conclusions of the system impact study(s). The facilities study shall also identify (1) the electrical switching configuration of the equipment, including, without limitation, transformer, switchgear, meters, and other station equipment, (2) the nature and estimated cost of the Transmission Provider's Interconnection Facilities and Upgrades necessary to accomplish the interconnection, and (3) an estimate of the time required to complete the construction and installation of such facilities.

5.0 The Transmission Provider may propose to group facilities required for more than one Interconnection Customer in order to minimize facilities costs through economies of scale, but any Interconnection Customer may require the installation of facilities required for its own Small Generating Facility if it is willing to pay the costs of those facilities.

6.0 A deposit of the good faith estimated facilities study costs may be required from the Interconnection Customer.

7.0 In cases where Upgrades are required, the facilities study must be completed within 45 Business Days of the receipt of this Agreement. In cases where no Upgrades are necessary, and the required facilities are limited to Interconnection Facilities, the facilities study must be completed within 30 Business Days.

8.0 Once the facilities study is completed, a facilities study report shall be prepared and transmitted to the Interconnection Customer. Barring unusual circumstances, the facilities study must be completed and the facilities study report transmitted

within 30 Business Days of the Interconnection Customer's agreement to conduct a facilities study.

9.0 Interconnection Customer may, within 30 Calendar Days after receipt of the draft report, provide written comments to Transmission Provider, which Transmission Provider shall include in the final report. Transmission Provider shall issue the final Interconnection Facilities Study report within 15 Business Days of receiving Interconnection Customer’s comments or promptly upon receiving Interconnection Customer’s statement that it will not provide comments. Transmission Provider may reasonably extend such fifteen-day period upon notice to Interconnection Customer if Interconnection Customer’s comments require Transmission Provider to perform additional analyses or make other significant modifications prior to the issuance of the final Interconnection Facilities Report. Upon request, Transmission Provider shall provide Interconnection Customer supporting documentation, workpapers, and databases or data developed in the preparation of the

Interconnection Facilities Study, subject to confidentiality arrangements consistent with Section 4.5 of the standard Small Generator Interconnection Procedures.

10.0 Within ten Business Days of providing a draft Interconnection Facilities Study report to Interconnection Customer, Transmission Provider and Interconnection Customer shall meet to discuss the results of the Interconnection Facilities Study.

11.0 Any study fees shall be based on the Transmission Provider's actual costs and will be invoiced to the Interconnection Customer after the study is completed and delivered and will include a summary of professional time.

12.0 The Interconnection Customer must pay any study costs that exceed the deposit without interest within 30 calendar days on receipt of the invoice or resolution of any dispute. If the deposit exceeds the invoiced fees, the Transmission Provider shall refund such excess within 30 calendar days of the invoice without interest.

13.0 Governing Law, Regulatory Authority, and Rules

The validity, interpretation and enforcement of this Agreement and each of its provisions shall be governed by the laws of the state of________________________ (where the Point of Interconnection is located), without regard to its conflicts of law principles. This Agreement is subject to all Applicable Laws and Regulations. Each Party expressly reserves the right to seek changes in, appeal, or otherwise contest any laws, orders, or regulations of a Governmental Authority.

14.0 Amendment

The Parties may amend this Agreement by a written instrument duly executed by both Parties.

15.0 No Third-Party Beneficiaries

This Agreement is not intended to and does not create rights, remedies, or benefits of any character whatsoever in favor of any persons, corporations, associations, or entities other than the Parties, and the obligations herein assumed are solely for the use and benefit of the Parties, their successors in interest and where permitted, their assigns.

16.0 Waiver

16.1 The failure of a Party to this Agreement to insist, on any occasion, upon strict performance of any provision of this Agreement will not be considered a waiver of any obligation, right, or duty of, or imposed upon, such Party.

16.2 Any waiver at any time by either Party of its rights with respect to this Agreement shall not be deemed a continuing waiver or a waiver with respect to any other failure to comply with any other obligation, right, duty of this

Agreement. Termination or default of this Agreement for any reason by Interconnection Customer shall not constitute a waiver of the Interconnection Customer's legal rights to obtain an interconnection from the Transmission Provider. Any waiver of this Agreement shall, if requested, be provided in writing.

17.0 Multiple Counterparts

This Agreement may be executed in two or more counterparts, each of which is deemed an original but all constitute one and the same instrument.

18.0 No Partnership

This Agreement shall not be interpreted or construed to create an association, joint venture, agency relationship, or partnership between the Parties or to impose any partnership obligation or partnership liability upon either Party. Neither Party shall have any right, power or authority to enter into any agreement or undertaking for, or act on behalf of, or to act as or be an agent or representative of, or to otherwise bind, the other Party.

19.0 Severability

If any provision or portion of this Agreement shall for any reason be held or adjudged to be invalid or illegal or unenforceable by any court of competent jurisdiction or other Governmental Authority, (1) such portion or provision shall be deemed separate and independent, (2) the Parties shall negotiate in good faith to restore insofar as practicable the benefits to each Party that were affected by such ruling, and (3) the remainder of this Agreement shall remain in full force and effect.

20.0 Subcontractors

Nothing in this Agreement shall prevent a Party from utilizing the services of any subcontractor as it deems appropriate to perform its obligations under this Agreement; provided, however, that each Party shall require its subcontractors to comply with all applicable terms and conditions of this Agreement in providing such services and each Party shall remain primarily liable to the other Party for the performance of such subcontractor.

20.1 The creation of any subcontract relationship shall not relieve the hiring Party of any of its obligations under this Agreement. The hiring Party shall be fully responsible to the other Party for the acts or omissions of any subcontractor the hiring Party hires as if no subcontract had been made;provided, however, that in no event shall the Transmission Provider be liable for the actions or inactions of the Interconnection Customer or its subcontractors with respect to obligations of the Interconnection Customer under this Agreement. Any applicable obligation imposed by this Agreement upon the hiring Party shall be equally binding upon, and shall be construed as having application to, any subcontractor of such Party.

20.2 The obligations under this article will not be limited in any way by any limitation of subcontractor's insurance.

21.0 Reservation of Rights

The Transmission Provider shall have the right to make a unilateral filing with FERC to modify this Agreement with respect to any rates, terms and conditions, charges, classifications of service, rule or regulation under section 205 or any other applicable provision of the Federal Power Act and FERC's rules and regulations thereunder, and the Interconnection Customer shall have the right to make a unilateral filing with FERC to modify this Agreement under any applicable provision of the Federal Power Act and FERC's rules and regulations; provided that each Party shall have the right to protest any such filing by the other Party and to participate fully in any proceeding before FERC in which such modifications may be considered. Nothing in this Agreement shall limit the rights of the Parties or of FERC under sections 205 or 206 of the Federal Power Act and FERC's rules and regulations, except to the extent that the Parties otherwise agree as provided herein.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be duly executed by their duly authorized officers or agents on the day and year first above written.

[Insert name of Transmission Provider]	**[Insert name of Interconnection Customer]**
______________________________	______________________________
Signed: ______________________	Signed: ______________________
Name (Printed):	Name (Printed):
______________________________	______________________________
Title: _______________________	Title: _______________________

Data to Be Provided by the Interconnection Customer with the Facilities Study Agreement

Provide location plan and simplified one-line diagram of the plant and station facilities. For staged projects, please indicate future generation, transmission circuits, etc.

> On the one-line diagram, indicate the generation capacity attached at each metering location. (Maximum load on CT/PT)
>
> On the one-line diagram, indicate the location of auxiliary power. (Minimum load on CT/PT) Amps

One set of metering is required for each generation connection to the new ring bus or existing Transmission Provider station. Number of generation connections: _____________

Will an alternate source of auxiliary power be available during CT/PT maintenance?
Yes No

Will a transfer bus on the generation side of the metering require that each meter set be designed for the total plant generation? Yes ______No
_____
(Please indicate on the one-line diagram).

What type of control system or PLC will be located at the Small Generating Facility?

What protocol does the control system or PLC use?

Please provide a 7.5-minute quadrangle map of the site. Indicate the plant, station, transmission line, and property lines.

Physical dimensions of the proposed interconnection station:

Bus length from generation to interconnection station:

Line length from interconnection station to Transmission Provider's Transmission System.

Tower number observed in the field. (Painted on tower leg)*:

Number of third party easements required for transmission lines*:

* To be completed in coordination with Transmission Provider.

Is the Small Generating Facility located in Transmission Provider's service area?

Yes ______No _______ If No, please provide name of local provider:

Please provide the following proposed schedule dates:

Begin Construction	Date:
Generator step-up transformers receive back feed power	Date:
Generation Testing	Date:
Commercial Operation	Date:

<u>Attachment C</u>

Summary of Proposed OATT Changes and Identification of Proposed Effective Dates

ATTACHMENT C

Summary of Proposed OATT Changes and Identification of Proposed Effective Dates

Tariff Section	Reason for the Substantive Change	Proposed Effective Date
OATT Cover Page	Direct communications related to OATT to George Marshall instead of Tom DeBoer.	May 1, 2016
Table of Contents	Changed to reflect revised and new tariff sections from the EIM filing	May 1, 2016
Section 1.4A	Added definition of Balancing Authority (BA) based on NERC Glossary of Terms to reflect PSE's continuing reliability responsibilities under the EIM	May 1, 2016
Section 1.4B	Added definition of Balancing Authority Area (BAA) based on NERC Glossary of Terms to reflect the area for which PSE will continue to exercise BA responsibilities under the EIM and to update terminology in OATT from prior use of "Control Area".	May 1, 2016
Section 1.4C	Added definition of Balancing Authority Area Resource to allow for resources owned or voluntarily contracted for by PSE to provide regulation and load following service.	May 1, 2016
Section 1.4D	Added definition of Bid Cost Recovery (BCR) to reflect that the PSE EIM Entity will be responsible for an allocated share of BCR costs under Section 29.11(f) of the CAISO Tariff	May 1, 2016
Section 1.4E	Added definition of California Independent System Operator Corporation (CAISO) to identify the CAISO as the Market Operator.	May 1, 2016
Section 1.4F	Added definition of CAISO BAA or CAISO Controlled Grid to specify the BAA under the CAISO's operational control as distinct from PSE's BAA or the BAA of other EIM Entities.	May 1, 2016
Section 1.10	Revised definition of Designated Agent to include entities that perform functions on behalf of Interconnection Customers.	May 1, 2016
Section 1.11A	Added definition of Dispatch Instruction, which is issued by the CAISO to PSE EIM Participating Resources or Balancing Authority Area Resources to increase or decrease energy supply or demand.	May 1, 2016
Section 1.11B	Added definition of Dispatch Operating Point, which is the change in operating point, in MW, contained in the Dispatch Instruction from the CAISO.	May 1, 2016
Section 1.11C	Added definition of Dynamic Transfer, including Dynamic Schedule and Pseudo-Tie. Pseudo-Ties may be used to make external resources electrically equivalent to internal resources to enable participation in the EIM.	May 1, 2016

Tariff Section	Reason for the Substantive Change	Proposed Effective Date
Section 1.11D	Added definition of Energy Imbalance Market (EIM) to reflect PSE's participation.	May 1, 2016
Section 1.11E	Added definition of EIM Area to delineate the footprint in which the EIM operates.	May 1, 2016
Section 1.11F	Added definition of EIM Available Balancing Capacity to describe upward or downward capacity from a Balancing Authority Area Resource that is included in the PSE EIM Entity's Resource Plan.	May 1, 2016
Section 1.11G	Added definition of EIM Entity to identify BAs participating in the EIM and for consistency with the CAISO Tariff.	May 1, 2016
Section 1.11H	Added definition of EIM Transfer to identify transfers of real-time energy between the CAISO BAA, PSE's BAA and/or the BAA of other EIM Entities under the EIM and for consistency with the CAISO Tariff.	May 1, 2016
Section 1.12A	Added definition of e-Tag, which is used by the PSE EIM Entity to facilitate Dynamic Transfers under the EIM.	May 1, 2016
Section 1.14A	Added definition of Flexible Ramping Constraint. The PSE EIM Entity will be responsible for submitting Resource Plans that satisfy the Flexible Ramping Requirement and under Section 29.11(g) of the CAISO Tariff will be allocated a portion of Flexible Ramp Constraint Costs.	May 1, 2016
Section 1.14B	Added definition of Forecast Data to identify information supplied by Transmission Customers to serve as a baseline by which to measure Imbalance Energy for purposes of EIM settlement under Schedules 4 and 9.	May 1, 2016
Section 1.15A	Added definition of Hourly Pricing Proxy, which is used to establish the price of imbalance energy during EIM contingencies.	May 1, 2016
Section 1.15B	Added definition of Interconnection Customer, which in some cases may be the party responsible for complying with EIM-related requirements under the OATT.	May 1, 2016
Section 1.15C	Added definition of Imbalance Energy to incorporate EIM into PSE's OATT and for consistency with the CAISO Tariff.	May 1, 2016
Section 1.15D	Added definition of Instructed Imbalance Energy (IIE) to incorporate EIM into PSE's OATT and for consistency with the CAISO Tariff.	May 1, 2016
Section 1.15E	Added definition of Interchange to specify e-Tagged energy transfers from, to, or through PSE's BAA not including EIM Transfers.	May 1, 2016
Section 1.15F	Added definition of Intrachange to specify e-Tagged energy transfers within the PSE BAA, other than energy flows associated with EIM Dispatch Instructions.	May 1, 2016
Section 1.17	Added definition of Load Aggregation Point (LAP) to incorporate the EIM into PSE's OATT and specify nodal aggregations for settlement purposes.	May 1, 2016
Section 1.17A	Added definition of Locational Marginal Price (LMP) to incorporate EIM into PSE's OATT and for consistency with the CAISO Tariff.	May 1, 2016

Tariff Section	Reason for the Substantive Change	Proposed Effective Date
Section 1.19B	Added definition of Manual Dispatch to recognize that while the CAISO will issue Dispatch Instructions as the Market Operator, PSE will be responsible for ensuring reliability and, if necessary, will issue operating orders to Transmission Customers with resources within its BAA.	May 1, 2016
Section 1.19C	Added definition of Market Operator (MO) to incorporate EIM into PSE's OATT and for consistency with the CAISO Tariff.	May 1, 2016
Section 1.19D	Added definition of Measured Demand to identify cost allocations based on (1) metered load volumes, plus (2) e-Tagged export volumes from a PSE BAA (excluding EIM Transfers).	May 1, 2016
Section 1.19E	Added definition of Metered Demand to identify cost allocations based on metered load volumes in PSE's BAA.	May 1, 2016
Section 1.19F	Added definition of MO Tariff to identify references to those portions of the CAISO Tariff that specifically apply to the EIM.	May 1, 2016
Section 1.26	Modified definition of Network Resource to recognize that output of Network Resources may, under the EIM optimization, be used to meet imbalances of loads other than the Network Customer's own Network Load.	May 1, 2016
Section 1.29A	Added definition of Non-Participating Resource to describe generator in PSE's BAA that does not participate in economic bidding in the EIM.	May 1, 2016
Section 1.30A	Added definition of Operating Hour to describe the hour during the day when the EIM runs.	May 1, 2016
Section 1.30B	Added definition of PSE for ease of reference.	May 1, 2016
Section 1.30C	Added definition of PSE's BAA for which PSE serves as the BA.	May 1, 2016
Section 1.30D	Added definition of PSE BAA Transmission Owner to identify transmission owners, other than PSE, who own transmission facilities within PSE BAA.	May 1, 2016
Section 1.30E	Added definition of PSE EIM Business Practice (PSE EIM BP) to identify PSE's Business Practice that addresses implementation issues associated with EIM activities.	May 1, 2016
Section 1.30F	Added definition of PSE EIM Entity for consistency with the CAISO's terminology.	May 1, 2016
Section 1.30G	Added definition of PSE EIM Entity Scheduling Coordinator for consistency with the CAISO's terminology.	May 1, 2016
Section 1.30H	Added definition of PSE EIM Participating Resource for consistency with the CAISO's terminology.	May 1, 2016

Tariff Section	Reason for the Substantive Change	Proposed Effective Date
Section 1.30I	Added definition of PSE EIM Participating Resource Scheduling Coordinator for consistency with the CAISO's terminology.	May 1, 2016
Section 1.30J	Added definition of PSE Interchange Rights Holder to identify customers that make available firm transmission capacity for EIM Transfers.	May 1, 2016
Section 1.39A	Added definition of Pricing Node (PNode) for consistency with the CAISO's terminology as to pricing points.	May 1, 2016
Section 1.39B	Added definition of Real Power Losses to identify product settled under Schedules 12 and 12A.	May 1, 2016
Section 1.42A	Added definition of Resource Plan to incorporate EIM into PSE's OATT and for consistency with the CAISO's terminology. The PSE EIM Entity will be responsible for submitting Resource Plans in accordance with Section 29.34(e) of the CAISO Tariff.	May 1, 2016
Section 1.49A	Added definition of Transmission Customer Base Schedule to refer to the submission required by the PSE EIM Entity as the baseline by which to measure Imbalance Energy for purposes of EIM settlement.	May 1, 2016
Section 1.55	Added definition of Uninstructed Imbalance Energy (UIE) to incorporate EIM LMP pricing into Schedules 4, 4R and 9 and for consistency with the CAISO's terminology.	May 1, 2016
Section 1.56	Added definition of Variable Energy Resource (VER) for use in Attachment O.	May 1, 2016
Section 10.2	PSE proposes that its new market responsibilities as an EIM Entity be subject to a gross negligence or intentional wrongdoing standard of liability. The standard reflects PSE's voluntarily assumption of additional responsibilities required of EIM Entities and is consistent with the standard approved by FERC for Transmission Providers participating in RTO/ISO markets.	July 25, 2016 or seven days prior to the start of parallel operations
Section 12.4A	Section added to explain that EIM disputes will be handled either under PSE's OATT or the CAISO Tariff, as the MO, based on which entity's actions are being challenged.	October 1, 2016 or the implementation date of PSE's participation in the EIM, whichever is later
Section 12.4A.1	Section recognizes that disputes between the PSE EIM Entity and a PSE Transmission Customer regarding the manner in which PSE has sub-allocated EIM payments or charges will be processed in accordance with the existing Sections 12.1 to 12.4 of PSE's OATT, the same as any other dispute between PSE and a Transmission Customer.	October 1, 2016 or the implementation date of PSE's participation in the EIM, whichever is later

Tariff Section	Reason for the Substantive Change	Proposed Effective Date
Section 12.4A.2	Section recognizes that disputes between the CAISO and a PSE EIM Participating Resource Scheduling Coordinator related to settlement statements provided to the PSE EIM Participating Resource Scheduling Coordinator from the CAISO will proceed in accordance with the process specified in the CAISO Tariff.	October 1, 2016 or the implementation date of PSE's participation in the EIM, whichever is later
Section 12.4A.3	Section recognizes that the PSE EIM Entity may raise disputes with the CAISO regarding the settlement statements it receives from the CAISO in accordance with the process specified in the CAISO Tariff.	October 1, 2016 or the implementation date of PSE's participation in the EIM, whichever is later
Section 12.4A.4	Section recognizes the situation where a Transmission Customer may have a dispute not with the PSE EIM Entity's sub-allocation but with the CAISO's allocation of payments or charges to the PSE EIM Entity. To the extent a dispute arises regarding a CAISO charge or payment to the PSE EIM Entity that is subsequently charged or paid by the PSE EIM Entity to a Transmission Customer or an Interconnection Customer, and such Transmission Customer wishes to raise a dispute with the CAISO, the PSE EIM Entity shall file a dispute on behalf of such Transmission Customer in accordance with the CAISO Tariff and work with the Transmission Customer to resolve the dispute pursuant to the process specified in the CAISO Tariff.	October 1, 2016, or the implementation date of PSE's participation in the EIM, whichever is later
Section 13.6	Added language to refer to the Transmission Provider's responsibility to ensure reliability in PSE's BAA consistent with Section 6 of Attachment O.	July 25, 2016 or seven days prior to the start of parallel operations
Section 13.7(d)	Added language referencing Attachment O, Section 8.7 so as to clarify that Unreserved Use Penalties shall not apply where the Transmission Customer has exceeded its reservation for the purpose of complying with an EIM Dispatch Instruction.	July 25, 2016 or seven days prior to the start of parallel operations
Section 14.5	Added language referencing Attachment O, Section 8.7 so as to clarify that Unreserved Use Penalties shall not apply where the transmission customer has exceeded its reservation for the purpose of complying with an EIM Dispatch Instruction.	July 25, 2016 or seven days prior to the start of parallel operations
Section 14.7	Added language to refer to the Transmission Provider's responsibility to ensure reliability in PSE's BAA consistent with Section 6 of Attachment O.	July 25, 2016 or seven days prior to the start of parallel operations
Section 15.7	Added language requiring customers to compensate the Transmission Provider for losses under Schedules 12 or 12A.	October 1, 2016, or the implementation date of PSE's participation in the EIM, whichever is later

Tariff Section	Reason for the Substantive Change	Proposed Effective Date
Section 16.1g	Added section to clarify that Attachment O is applicable to all of PSE's Transmission Customers.	July 25, 2016 or seven days prior to the start of parallel operations
Section 28.1	Added language clarifying that network customers must comply with the requirements of Attachment O regarding the EIM.	July 25, 2016 or seven days prior to the start of parallel operations
Section 28.5	Added language clarify that network customers will compensate Transmission Provider for losses under Schedules 12 and 12A.	October 1, 2016, or the implementation date of PSE's participation in the EIM, whichever is later
Section 28.7	Added section in order to facilitate the EIM, permitting Network Customers to participate in EIM using Network Integration Transmission Service without a requirement to terminate the designation of any Network Resources that are PSE EIM Participating Resource and without a requirement to reserve additional Point-to-Point Transmission Service for such transactions.	July 25, 2016 or seven days prior to the start of parallel operations
Section 29.2	Added language to item (ix) to clarify that the general requirement to update applications for transmission service include the obligation to update information required by Attachment O.	July 25, 2016 or seven days prior to the start of parallel operations
Section 30.1	Added language to existing section to permit designated Network resources to participate in EIM.	July 25, 2016 or seven days prior to the start of parallel operations
Section 30.4	Added language to existing section to permit designated network Resources to participate in EIM.	July 25, 2016 or seven days prior to the start of parallel operations
Schedule 1A	New schedule to provide for a pass- through of the CAISO administrative charges allocated to the PSE EIM Entity in accordance with Sections 4.5.1.1.4, 4.5.1.3, 11.22.8, and 29.11(i) of the CAISO Tariff.	October 1, 2016, or the implementation date of PSE's participation in the EIM, whichever is later
Schedule 4	Amended Schedule 4 to reflect the manner in which PSE shall establish charges for Energy Imbalance Service for load inside the BAA under the EIM.	October 1, 2016, or the implementation date of PSE's participation in the EIM, whichever is later

Tariff Section	Reason for the Substantive Change	Proposed Effective Date
Schedule 4R	Amended Schedule 4R to reflect the manner in which PSE shall establish charges for Energy Imbalance Service for Transmission Customers taking service under retail Schedules 448 and 449 under the EIM.	October 1, 2016, or the implementation date of PSE's participation in the EIM, whichever is later
Schedule 9	Amended Schedule 9 to further clarify the nature of Generator Imbalance Service for generation inside the BAA under the EIM and reflect the manner in which PSE shall establish charges for such service under the EIM.	October 1, 2016, or the implementation date of PSE's participation in the EIM, whichever is later
Schedule 12	Created new Schedule 12 providing for financial settlement of losses related to service on PSE's Washington Area system using the hourly LAP price produced by the EIM.	October 1, 2016, or the implementation date of PSE's participation in the EIM, whichever is later
Schedule 12A	Created new Schedule 12A providing for financial settlement of losses on PSE's Colstrip and Southern Intertie segments using the hourly LAP price produced by the EIM.	October 1, 2016, or the implementation date of PSE's participation in the EIM, whichever is later
Attachment O, Section 1	Section added to provide a general overview of the purpose and operation of Attachment O and to clarify that this Attachment O is applicable to all of PSE's Transmission Customers and Interconnection Customers with new and existing service agreements pursuant to its OATT. Section specifies the effective date of each of its individual provisions.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 2	Section added to explain that the decision of a Transmission Customer to participate in the EIM with resources as PSE EIM Participating Resources is voluntary and, if a Transmission Customer chooses to participate, to identify the basic requirements to become a PSE EIM Participating Resource.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 3	Section added to provide the specific eligibility criteria required to become a PSE EIM Participating Resource and to set forth the application and certification processes.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 3.1	Section describes the transmission requirements for internal resources within PSE's BAA to become eligible as a PSE EIM Participating Resource.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 3.2	Section describes the transmission requirements for resources external to PSE's BAA to become a PSE EIM Participating Resource.	July 25, 2016 or seven days prior to the start of parallel operations

Tariff Section	Reason for the Substantive Change	Proposed Effective Date
Attachment O, Section 3.2.1	Section explains that an external resource may participate in the EIM if the Transmission Customer implements a Pseudo-Tie to PSE's BAA, has arranged third-party firm transmission equal to the amount of energy that will be Pseudo-Tied, and has secured transmission service pursuant to Section 3.1 of Attachment O.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 3.2.2	Section explains the manner in which Pseudo-Tie implementation costs shall be allocated.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 3.3	Section describes the application and certification process for PSE EIM Participating Resources.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 3.3.1	Section describes the requirements for applicants to become a PSE EIM Participating Resource. Section also requires Network Customers to identify the type of transmission service (Network Integration Transmission Service or Non-Firm Point-to-Point Transmission Service) they will utilize for EIM participation.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 3.3.2	Section describes the requirements for the PSE EIM Entity to process the application of Transmission Customers for a PSE EIM Participating Resource.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 3.3.3	Section describes the process under which a PSE EIM Participating Resource becomes certified.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 3.3.4	Section provides that, unless and until certified by the PSE EIM Entity, the resource shall be deemed a Non- Participating Resource while its application for certification is pending.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 3.3.5	Section sets forth an ongoing obligation of a Transmission Customer with a PSE EIM Participating Resource to inform the PSE EIM Entity of any changes in information submitted as part of the application process. This provision is necessary to ensure PSE EIM Participating Resources continue to meet eligibility requirements.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 4	Section describes the roles and responsibilities of the participants in the EIM.	See Specific Subsections below
Attachment O, Sections 4.1	Section describes the responsibilities of the Transmission Provider as the PSE EIM Entity and the PSE EIM Entity Scheduling Coordinator.	See Specific Subsections below
Attachment O, Section 4.1.1.1	Section provides that the PSE EIM Entity may be or retain the services of a Scheduling Coordinator, but must communicate as appropriate with the Scheduling Coordinator if it is not performing the function for itself.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 4.1.1.2	Section describes the responsibility of the PSE EIM Entity to process applications of Transmission Customers seeking authorization to participate in the EIM with PSE EIM Participating Resources.	July 25, 2016 or seven days prior to the start of parallel operations

Tariff Section	Reason for the Substantive Change	Proposed Effective Date
Attachment O, Section 4.1.1.3	Section describes the responsibility of the PSE EIM Entity to make certain implementation decisions for PSE's BAA. Section identifies key implementation decisions made by PSE with respect to eligibility, Load Aggregation Points, CAISO load forecasting, and CAISO metering agreements.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 4.1.1.4	Section recognizes that the PSE EIM Entity shall establish the PSE EIM Business Practice to facilitate implementation and operation of the EIM.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 4.1.1.5	Section permits the PSE EIM Entity to: (1) terminate its participation in the EIM by providing a notice of termination to the CAISO; and (2) take corrective actions in PSE's BAA in accordance with Section 10 of Attachment O.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 4.1.2	Section sets forth the PSE EIM Entity's responsibilities to provide required information to the CAISO.	See specific subsections below.
Attachment O, Section 4.1.2.1	Section requires the PSE EIM Entity to provide the CAISO with information associated with transmission facilities within PSE's BAA, to include in the full network model.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 4.1.2.2	This section requires the PSE EIM Entity to register Non-Participating Resources with the CAISO.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 4.1.3	Section describes the PSE EIM Entity's day-to-day operation of the EIM.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 4.1.3.1	Section describes the PSE EIM Entity's responsibility to provide hourly Transmission Customer Base Schedules and Resource Plans to the CAISO consistent with Section 29.34 of the CAISO Tariff.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 4.1.3.2	Section requires the PSE EIM Entity to inform the CAISO of a Manual Dispatch by providing reliability adjustment information consistent with Section 29.34 of the MO Tariff.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 4.1.3.3	Section provides that the CAISO will calculate the actual values for Dynamic Schedules reflecting EIM Transfers and the PSE EIM Entity shall confirm the values within applicable timeframes.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 4.1.3.4	Section provides that the PSE EIM Entity will notify Non-Participating Resources of Dispatch Operating Points instructed by the CAISO where the Non-Participating Resource has made EIM Available Balancing Capacity available to the EIM.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 4.1.4	Section requires the PSE EIM Entity to submit load, resource, and Interchange meter data to the CAISO on behalf of Transmission Customers with Non-Participating Resources consistent with the CAISO Tariff.	July 25, 2016 or seven days prior to the start of parallel operations

Tariff Section	Reason for the Substantive Change	Proposed Effective Date
Attachment O, Section 4.1.5	Section provides that the PSE EIM Entity shall be responsible for financial settlement of all charges and payments allocated by the CAISO to the PSE EIM Entity.	October 1, 2016, or the implementation date of PSE's participation in the EIM, whichever is later
Attachment O, Section 4.1.6	Section provides that the PSE EIM Entity shall manage dispute resolution with the CAISO consistent with Section 29.13 of the CAISO Tariff and Section 12 of PSE's OATT.	October 1, 2016, or the implementation date of PSE's participation in the EIM, whichever is later
Attachment O, Section 4.2	Section describes the responsibilities of Transmission Customers with respect to the EIM.	See Specific Subsections below
Attachment O, Section 4.2.1.1	Section requires a Transmission Customer with a PSE EIM Participating Resource to provide CAISO and the PSE EIM Entity with data necessary to meet the CAISO's registration requirements.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 4.2.1.2	Section requires a Transmission Customer with Non- Participating Resources to provide the PSE EIM Entity with data necessary to meet the CAISO's registration requirements.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 4.2.2	Section sets forth the responsibility of Transmission Customers to update registration data.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 4.2.2.1	Section sets forth ongoing obligation of a Transmission Customer with a PSE EIM Participating Resource to inform the CAISO and PSE EIM Entity of any changes to the information submitted to the PSE EIM Entity consistent with Section 29.4(e)(4)(D) of the CAISO Tariff.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 4.2.2.2	Section sets forth ongoing obligation of a Transmission Customer with Non-Participating Resources to inform the PSE EIM Entity of any changes to the information submitted to the PSE EIM Entity.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 4.2.3	Section requires all Transmission Customers (with PSE EIM Participating Resources and Non-Participating Resources) to provide planned and unplanned outage information in accordance with Attachment O, Section 7.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 4.2.4	Section sets forth the requirements for submitting Transmission Customer Base Schedules for submission to MO and to settle imbalances.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O Section 4.2.4.1	Section requires Transmission Customers with a PSE EIM Participating Resource or Non-Participating Resource to submit Forecast Data to the PSE EIM Entity.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 4.2.4.2	Provides specifications for submission of Forecast Data by a Transmission Customer with a Non-Participating Resource that is a Variable Energy Resource.	July 25, 2016 or seven days prior to the start of parallel operations

Tariff Section	Reason for the Substantive Change	Proposed Effective Date
Attachment O, Section 4.2.4.3	Section requires Transmission Customers with load within PSE's BAA to submit Forecast Data to the PSE EIM Entity.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 4.2.4.4	Section requires Transmission Customers without resources or load in PSE's BAA to submit Forecast Data to the PSE EIM Entity.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 4.2.4.5	Section specifies timing requirements for Transmission Customers to submit Transmission Customer Base Schedules to the PSE EIM Entity.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 4.2.4.5.1	Section sets forth timing requirements for preliminary submission of Transmission Customer Base Schedules.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 4.2.4.5.2	Section sets forth timing requirements for final submission of Transmission Customer Base Schedules.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 4.2.5	Section describes the metering requirements for Transmission Customers with Non-Participating Resources.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 5	Section describes Transmission Operations related to the EIM.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 5.1	Section requires the PSE EIM Entity to provide information to the CAISO regarding real-time data for PSE's transmission system and interties and any changes to transmission capacity and the transmission system due to operational circumstances.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 5.2	Section describes the provision of transmission capacity for EIM Transfers by a PSE Interchange Rights Holder.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 5.3	Section describes the manner in which the PSE EIM Entity will communicate with the CAISO concerning the provision of Available Transfer Capacity for EIM Transfers.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 6	Section describes operation of the PSE Transmission System under normal and emergency circumstances upon EIM implementation.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 6.1	Section recognizes that participation in the EIM does not modify PSE's obligation to comply with applicable reliability requirements, including NERC and WECC reliability standards. PSE will remain responsible for maintaining appropriate operating reserve levels, processing e- Tags, and monitoring and managing real-time flows in its BAA, among other things.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 6.2	Section affirms the responsibility of the PSE EIM Entity and customers with PSE EIM Participating Resources and Non-Participating Resources to comport with Good Utility Practice in carrying out each party's respective obligations under Attachment O.	July 25, 2016 or seven days prior to the start of parallel operations

Tariff Section	Reason for the Substantive Change	Proposed Effective Date
Attachment O, Section 6.3	Section describes the manner in which the PSE EIM Entity will manage contingencies and emergencies.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 6.3.1	Section describes that if an EIM disruption occurs consistent with Section 29.7(j) of the CAISO Tariff, the PSE EIM Entity shall promptly inform the CAISO consistent with the CAISO Tariff.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 6.3.2	Section permits the PSE EIM Entity to issue a Manual Dispatch order to a Transmission Customer with a PSE EIM Participating Resource or Non-Participating Resources to address an operational or reliability issue in PSE's BAA.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 7	Section describes the responsibilities of parties with regard to outages.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 7.1.1	Section requires the PSE EIM Entity to submit information to the CAISO for planned transmission outages in accordance with Section 29.9(e) of the CAISO Tariff.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 7.1.2	Section requires the PSE EIM Entity to submit information to the CAISO regarding any unplanned transmission outages as soon as possible in accordance with Section 29.9(e) of the CAISO Tariff.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 7.2	Section requires Transmission Customers that are also PSE BAA Transmission Owners to provide the PSE EIM Entity with planned and unplanned transmission outage data within prescribed timeframes.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 7.3	Section sets forth responsibilities for reporting PSE EIM Participating Resource outages.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 7.3.1	Section describes the manner in which planned outages and known derates of a PSE EIM Participating Resource shall be reported consistent with Section 29.9(c) of the CAISO Tariff.	July 25, 2016 or seven days prior to the start of parallel
Attachment O, Section 7.3.2	Section describes the manner in which unplanned outages of a PSE EIM Participating Resource shall be reported consistent with Section 29.9(e) of the CAISO Tariff.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 7.3.3	Section describes the manner in which unplanned derates of a PSE EIM Participating Resource shall be reported to the PSE EIM Entity.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 7.4	Section sets forth responsibilities for reporting Non- Participating Resource outages.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 7.4.1	Section describes the manner in which planned outages and known derates of a Non-Participating Resource shall be reported consistent with Section 29.9(c) of the CAISO Tariff.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 7.4.2	Section describes the manner in which unplanned outages and derates over 50 MW of a Non-Participating Resource shall be reported consistent with Section 29.9(e) of the CAISO Tariff.	July 25, 2016 or seven days prior to the start of parallel operations

Tariff Section	Reason for the Substantive Change	Proposed Effective Date
Attachment O, Section 7.4.3	Section describes the manner in which unplanned derates of a PSE EIM Non-Participating Resource shall be reported to the PSE EIM Entity.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 8	Section sets forth that the PSE EIM BP will specify the specific charge codes applicable to EIM settlement.	See specific subsections below.
Attachment O, Section 8.1	Section describes the method of sub-allocation of IIE by the PSE EIM Entity.	October 1, 2016 or the implementation date of PSE's participation in the EIM, whichever is later
Attachment O, Section 8.2	Section 8.2 sets forth that any charges or payments to the PSE EIM Entity pursuant to Section 29.11(b)(3)(B) and (C) of the CAISO Tariff for UIE that are not otherwise recovered under Schedules 4, 4R or 9 shall not be sub-allocated to Transmission Customers.	October 1, 2016 or the implementation date of PSE's participation in the EIM, whichever is later
Attachment O, Section 8.3	Section provides that any charges to the PSE EIM Entity pursuant to Section 29.11(c) of the CAISO Tariff for UFE shall not be sub-allocated to Transmission Customers.	October 1, 2016 or the implementation date of PSE's participation in the EIM, whichever is later
Attachment O, Section 8.4	Section describes allocation of charges for under-scheduling or over-scheduling load.	October 1, 2016 or the implementation date of PSE's participation in the EIM, whichever is later
Attachment O, Section 8.4.1	Section requires the PSE EIM Entity to assign charges for under-scheduling load pursuant to Section 29.11(d)(1) of the CAISO Tariff to the Transmission Customers subject to Schedule 4 and 4R that contributed to the imbalance based on their respective under-scheduling imbalance ratio share.	October 1, 2016 or the implementation date of PSE's participation in the EIM, whichever is later
Attachment O, Section 8.4.2	Section requires the PSE EIM Entity to assign charges for over-scheduling load pursuant to Section 29.11(d)(2) of the CAISO Tariff to the Transmission Customers subject to Schedule 4 and 4R that contributed to the imbalance based on their respective over-scheduling imbalance ratio share.	October 1, 2016 or the implementation date of PSE's participation in the EIM, whichever is later
Attachment O, Section 8.4.3	Section sets forth the manner in which payment to the PSE EIM Entity pursuant to Section 29.11(d)(3) of the CAISO Tariff shall be distributed to Transmission Customers.	October 1, 2016 or the implementation date of PSE's participation in the EIM, whichever is later

Tariff Section	Reason for the Substantive Change	Proposed Effective Date
Attachment O, Section 8.5	Section regarding settlement of EIM uplifts.	October 1, 2016 or the implementation date of PSE's participation in the EIM, whichever is later
Attachment O, Section 8.5.1	Section sets forth that charges to the PSE EIM Entity pursuant to Section 29.11(e)(3) of the CAISO Tariff for EIM BAA real-time market neutrality will be sub-allocated to Transmission Customers based on Measured Demand.	October 1, 2016 or the implementation date of PSE's participation in the EIM, whichever is later
Attachment O, Section 8.5.2	Section sets forth that charges to the PSE EIM Entity pursuant to Section 29.11(e)(2) of the CAISO Tariff for the EIM real-time congestion offset will be sub-allocated to Transmission Customers based on Measured Demand.	October 1, 2016 or the implementation date of PSE's participation in the EIM, whichever is later
Attachment O, Section 8.5.3	Section sets forth that charges to the PSE EIM Entity pursuant to Section 29.11(e)(4) of the CAISO Tariff for real- time marginal cost of losses offset shall be sub-allocated to Transmission Customers on the basis of Measured Demand.	October 1, 2016 or the implementation date of PSE's participation in the EIM, whichever is later
Attachment O, Section 8.5.4	Section sets forth the manner in which EIM neutrality settlements to the PSE EIM Entity pursuant to Section 29.11(e)(5) of the CAISO Tariff for EIM shall be sub-allocated.	October 1, 2016 or the implementation date of PSE's participation in the EIM, whichever is later
Attachment O, Section 8.5.5	Section provides that charges to the PSE EIM Entity pursuant to Section 29.11(f) of the CAISO Tariff for EIM real-time bid cost recovery shall be sub-allocated to Transmission Customers based on Measured Demand.	October 1, 2016 or the implementation date of PSE's participation in the EIM, whichever is later
Attachment O, Section 8.5.6	Section sets forth that charges to the PSE EIM Entity pursuant to Section 29.11(g) of the CAISO Tariff for Flexible Ramping Constraint shall be sub-allocated to Transmission Customers based on Measured Demand.	October 1, 2016 or the implementation date of PSE's participation in the EIM, whichever is later
Attachment O, Section 8.5.7	Section sets forth that if the PSE EIM Entity incurs a penalty for inaccurate or late settlement quality meter data pursuant to Section 37.11.1 of the CAISO Tariff, the PSE EIM Entity shall directly assign the penalty to the offending Transmission Customer.	October 1, 2016 or the implementation date of PSE's participation in the EIM, whichever is later

Tariff Section	Reason for the Substantive Change	Proposed Effective Date
Attachment O, Section 8.5.8	Section specifies the sub-allocation of ten other neutrality settlement charges to the PSE EIM Entity.	October 1, 2016 or the implementation date of PSE's participation in the EIM, whichever is later
Attachment O, Section 8.6	Section requires the sub-allocation of charges to the PSE EIM Entity pursuant to Section 29.22(a) of the CAISO Tariff for CAISO tax to the Transmission Customers triggering the tax liability.	October 1, 2016 or the implementation date of PSE's participation in the EIM, whichever is later
Attachment O, Section 8.7	Section providing that there will be no separate EIM transmission service charges.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 8.8	Section sets forth that charges to the PSE EIM Entity pursuant to Section 29.11(j) of the CAISO Tariff for VER forecasts, which shall be charged to the Transmission Customer with a Non-Participating Resource requesting the forecast.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 8.9	Section provides that the PSE EIM Entity is subject to the CAISO's payment calendar for issuing settlement statements, among other things, consistent with Section 29.11(l) of the CAISO Tariff.	October 1, 2016 or the implementation date of PSE's participation in the EIM, whichever is later
Attachment O, Section 8.10	Section establishes a residual balancing account for CAISO EIM-related charges or payments to the PSE EIM Entity to the extent they are not captured elsewhere in the PSE Tariff.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 8.11	Section provides that if the CAISO modifies the PSE EIM Entity settlement statement in accordance with the CAISO's market validation and price correction procedures; the PSE EIM Entity reserves the right to make corresponding or similar changes to the charges and payments sub-allocated under Attachment O.	October 1, 2016 or the implementation date of PSE's participation in the EIM, whichever is later
Attachment O, Section 8.12	Section addresses allocation of operating reserve payments and charges related to EIM Transfers into and out of the CAISO BAA.	October 1, 2016 or the implementation date of PSE's participation in the EIM, whichever is later

Tariff Section	Reason for the Substantive Change	Proposed Effective Date
Attachment O, Section 8.12.1	Payment to the PSE EIM Entity for operating reserve obligations assessed by the CAISO shall be sub-allocated to the Transmission Customers with PSE EIM Participating Resources in the PSE BAA.	October 1, 2016 or the implementation date of PSE's participation in the EIM, whichever is later
Attachment O, Section 8.12.2	Charges to the PSE EIM Entity for operating reserve obligations assessed by the CAISO shall be sub-allocated to the Transmission Customers within the PSE BAA on the basis of Measured Demand.	October 1, 2016 or the implementation date of PSE's participation in the EIM, whichever is later
Attachment O, Section 9	Section sets forth responsibilities related to compliance.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 9.1	Section sets forth requirements regarding the provision of data for the EIM and the treatment of confidential customer information provided to the PSE EIM Entity.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 9.2	Section sets forth six rules of conduct for parties to satisfy associated EIM-related responsibilities.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 9.3	Section permits the PSE EIM Entity to refer a violation of Section 9.2 to FERC.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 10	Section regarding market contingencies.	October 1, 2016, or the implementation date of PSE's participation in the EIM, whichever is later
Attachment O, Section 10.1	Section provides that if the CAISO implements a temporary suspension in accordance with Section 29.1(d)(1) of the CAISO Tariff, the PSE EIM Entity shall utilize Temporary Schedules 4, 4R, 9, 12, and 12A in Attachment O, Section 10.4.	October 1, 2016 or the implementation date of PSE's participation in the EIM, whichever is later
Attachment O, Section 10.2	Section permits the PSE EIM Entity to invoke enumerated corrective actions by the CAISO, if the PSE EIM Entity submits a notice of termination of its participation in the EIM, including the utilization of Temporary Schedules 4, 4R, 9, 12, and 12A.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 10.3	Section permits the PSE EIM Entity to declare a temporary contingency and invoke corrective actions for the EIM to address enumerated events.	July 25, 2016 or seven days prior to the start of parallel operations
Attachment O, Section 10.3.1	Section sets forth the corrective actions the PSE EIM Entity may take to respond to a temporary contingency, including the use of Temporary Schedules 4, 4R, 9, 12, and 12A.	July 25, 2016 or seven days prior to the start of parallel operations

Tariff Section	Reason for the Substantive Change	Proposed Effective Date
Attachment O, Section 10.4	Section sets forth the Temporary Schedules 4, 4R, 9, 12 and 12A that shall be used by the PSE EIM Entity for settlements purposes upon the occurrence of specified market contingencies.	October 1, 2016 or the implementation date of PSE's participation in the EIM, whichever is later
Attachment O, Section 10.4.1	Section sets forth the Temporary Schedule 4, Energy Imbalance Service, that shall be used by the PSE EIM Entity for settlements purposes upon the occurrence of specified market contingencies.	October 1, 2016 or the implementation date of PSE's participation in the EIM, whichever is later
Attachment O, Section 10.4.2	Section sets forth the Temporary Schedule 4R, Energy Imbalance Service for customers taking service under retail Schedules 448 and 449 that shall be used by the PSE EIM Entity for settlements purposes upon the occurrence of specified market contingencies.	October 1, 2016 or the implementation date of PSE's participation in the EIM, whichever is later
Attachment O, Section 10.4.3	Section sets forth the Temporary Schedule 9, Generator Imbalance Service that shall be used by the PSE EIM Entity for settlements purposes upon the occurrence of specified market contingencies.	October 1, 2016 or the implementation date of PSE's participation in the EIM, whichever is later
Attachment O, Section 10.4.4	Section sets forth the Temporary Schedule 12, Real Power Losses on Washington Area Transmission Facilities that shall be used by the PSE EIM Entity for settlements purposes upon the occurrence of specified market contingencies.	October 1, 2016 or the implementation date of PSE's participation in the EIM, whichever is later
Attachment O, Section 10.4.5	Section sets forth the Temporary Schedule 12A, Real Power Losses on Colstrip and Southern Intertie Transmission Lines that shall be used by the PSE EIM Entity for settlements purposes upon the occurrence of specified market contingencies.	October 1, 2016 or the implementation date of PSE's participation in the EIM, whichever is later
Annex A, Table of Contents	Revised Table of Contents to reflect new section 2.5.	July 25, 2016 or seven days prior to the start of parallel operations
Annex A, Section 1	Corrected definition of NERC.	July 25, 2016 or seven days prior to the start of parallel operations
Annex A, Section 2.5	Added section to LGIP to clarify that Attachment O is applicable to PSE's Interconnection Customers.	July 25, 2016 or seven days prior to the start of parallel operations
Annex B, Section 5.0	Added section 5.0 to SGIP to clarify that Attachment O is applicable to PSE's Interconnection Customers.	July 25, 2016 or seven days prior to the start of parallel operations

<u>Attachment D</u>

PSE – ISO Energy Imbalance Market
Economic Assessment (Benefits Analysis)

PSE PUGET SOUND ENERGY

California ISO
Shaping a Renewed Future

Benefits Analysis of Puget Sound Energy's Participation in the ISO Energy Imbalance Market

September 2014

Energy+Environmental Economics

Benefits Analysis of Puget Sound Energy's Participation in the ISO Energy Imbalance Market

September 2014

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Table of Contents

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Acronyms

BA	Balancing Authority
BAA	Balancing Authority Area
CAISO	California Independent System Operator
DA	Day-ahead
EIM	Energy Imbalance Market
FERC	Federal Energy Regulatory Commission
HA	Hour-ahead
NPV	Net Present Value
NVE	NV Energy
PAC	PacifiCorp
PSE	Puget Sound Energy

Executive Summary

This report examines the benefits of Puget Sound Energy's (PSE) participating in the energy imbalance market (EIM) operated by the California Independent System Operator (ISO). The ISO's EIM is a regional 15- and 5-minute balancing energy market, including real-time unit commitment capability, which will go live with binding settlements in November 2014 between the ISO and PacifiCorp, with NV Energy planning to participate starting in October 2015. In this study, the ISO, PacifiCorp, and NV Energy are referred to as "current EIM participants", and they are assumed to be already participating in the EIM before PSE's participation would commence, which is assumed to be in 2016.[1]

This report estimates the benefits of PSE's participation in the EIM for two scenarios with alternative sub-hourly transmission transfer capability levels between PSE and current EIM participants.[2] For the 2020 study year, participation in the EIM is estimated to bring sub-hourly dispatch efficiency and flexibility reserves savings to PSE in the range of $18.3 to $20.1 million per year.

Since an EIM increases operational efficiency and flexibility, it also could facilitate cost effective renewable integration. If feasible, this could allow PSE to save an

[1] Throughout this report, Balancing Authorities (BAs) that participate in the EIM are described as "EIM participants". These participating BAs are referred to in the ISO's EIM Business Practice Manual and tariff as "EIM Entities". See CAISO (2014b).
[2] All benefits are reported in 2014 dollars.

additional $9.1 million per year in wind integration costs. PSE also anticipates that, under certain conditions, EIM participation could help PSE obtain additional cost savings of up to $0.8 million per year related to avoiding curtailment of renewable energy resources if PSE were to balance all of its wind resources within its Balancing Authority Area (BAA).[3]

For the 2020 study year, PSE's participation is also expected to provide benefits of $3.5 to $4.2 million per year for the current EIM participants, and create no incremental implementation costs to those entities. All incremental costs are expected to be recovered from PSE through fixed and administrative charges.

PSE has evaluated the costs and benefits reported in this study and concluded that its participation in the EIM is likely to provide a low-risk means of achieving operational net benefits for PSE and current EIM participants. PSE staff has estimated that PSE would incur one-time EIM startup costs of $14.2 million including contingency costs, and ongoing costs of approximately $3.5 million per year. These startup costs, taken together with a 20-year series of ongoing costs and annual benefits consistent with the level identified in this report, would produce a Net Present Value (NPV) of $153.7 million to $174.4 million.[4] These results also provide further confirmation that total expected EIM benefits can

[3] A Balancing Authority Area (BAA) is the collection of generation, transmission, and loads within the metered boundaries of a BA, which is responsible entity that maintains load-resource balance within this area, integrates resource plans ahead of time, and supports Western Interconnection frequency in real-time. See NERC (2014).

[4] NPV has been estimated for the year 2014. The calculation assumes 20 years of sub-hourly dispatch and flexibility reserves benefits and annual ongoing cost from 2016 through 2035. PSE's participation in the EIM is estimated to go live in Fall 2016 with benefits and ongoing costs assumed to begin then. Startup costs are assumed to be incurred during 2015 and 2016. All values have been discounted using PSE after-tax weighted average cost of capital (WACC) of 6.7% nominal, consistent with PSE's 2013 Integrated Resource Plan (IRP), and have assumed annual inflation rate of 2%. Increasing the NPV calculation to include 30 years of benefits and ongoing costs would raise the NPV range to $190.2 to $216.3 million.

increase as additional participants join the EIM and broaden the regional diversity and footprint of the real-time market.

Two additional material benefits have not been quantified. First, the study team conservatively assumed that PSE's behavior and actions in the hour-ahead (HA) and day-ahead (DA) market would not be influenced by the continuous information flowing from participation in the EIM market; we expect that such information could create learning and additional cost savings for PSE in the HA and DA market over time, but those additional savings are not quantified in the analysis for this report. Second, the study team did not quantify the potential reliability benefits tied to the increased situational awareness and resource control that the EIM creates. Although both of these benefits are difficult to quantify, they are important to consider qualitatively as they are likely to produce substantial benefits.

EIM Background

Changes in the electricity industry in the Western U.S. are making the need for greater coordination between Balancing Authorities (BAs) increasingly apparent. Recent studies have suggested that it will be possible to reliably operate the current Western electric grid both with greater efficiency and higher levels of variable renewable generation. Doing so will require improving and supplementing the bilateral markets used in the Western states with mechanisms that allow shorter time intervals for scheduling and more optimized coordination. The EIM provides such a mechanism.

The EIM is a balancing energy market that optimizes generator dispatch within and between participating BAAs every 15 and 5 minutes. The EIM does not replace the DA or HA markets and scheduling procedures that exist in the Western Interconnection today.

By allowing BAs to pool load and generation resources, the EIM lowers total flexibility reserve requirements and minimizes curtailment of variable energy resources for the region as a whole, thus lowering costs for customers. The EIM is complementary to Federal Energy Regulatory Commission (FERC) Order 764, which emphasizes 15-minute scheduling over interties. The EIM builds value on top of this 15-minute scheduling capability by: (1) using software tools to identify sub-hourly transactions that produce an optimized dispatch and minimize production costs, while respecting reliability limits (known as "Security Constrained Economic Dispatch", or "SCED"); (2) bringing this optimized dispatch down to a 5-minute interval level; (3) incorporating optimized real-time unit commitment of quick-start generation; and (4) enabling better use and compensation of flexible ramping capacity in real-time, which reflects the diversity of loads and resources across the EIM footprint, allowing EIM participants to individually reserve a smaller amount of committed capacity for sub-hourly flexibility, further reducing total operational costs to reliably serve customers.

In advance of the November 2014 go-live date for EIM operations with binding settlements, the ISO and PacifiCorp have worked with stakeholders to finalize details of the EIM's structure and functions, and have received FERC approval for tariff changes that enable EIM implementation.[5] Throughout the EIM stakeholder process, the ISO has emphasized that the EIM is being designed to

[5] For the latest details of the ISO EIM, see CAISO (2014c).

enable other BAs throughout the Western Interconnection to participate. The ISO has established an EIM Governance Transitional Committee, whose members includes stakeholders from throughout the Western Interconnection, to further lead EIM development in a manner that is beneficial for many participants in the region, and to provide participants confidence that their perspectives are reflected in this process.

This Report

PSE and the ISO worked together to jointly assess the potential benefits of PSE's participation in the EIM and retained Energy and Environmental Economics, Inc. (E3), a consulting firm, to conduct an economic study quantifying those potential benefits. To support the study, Energy Exemplar provided technical support by running sub-hourly production simulations cases using PLEXOS, a production simulation modeling tool, to calculate a portion of the benefits. This report describes the findings of E3 and Energy Exemplar, who are together referred to as "the study team" throughout the report.

The report evaluates benefits using an approach that builds upon E3's EIM analyses for the ISO, PacifiCorp, and NV Energy.[6] In addition, the study leverages the modeling improvements summarized in Pacific Northwest National Laboratory's (PNNL) Phase 1 EIM analysis for the Northwest Power Pool (NWPP).[7] This study focuses on the incremental benefits related to PSE's participation in the EIM, while assuming that the ISO, PacifiCorp and NV Energy are already EIM participants in the base case. This study incorporates additional details provided

[6] See E3 (2013 and 2014).
[7] See Samaan et al. (2013).

by PSE to improve the accuracy of PSE's generation and transmission system represented in the production cost simulations.

The primary scenarios in this report assess different categories of potential cost savings from expanding the EIM to include PSE, allowing PSE and the current EIM participants to further improve dispatch efficiency and take advantage of additional diversity in loads and generation resources provided by PSE. Specifically, the participation of PSE in the EIM would yield two principal benefits:

+ *Sub-hourly dispatch benefits*, by realizing the efficiency of optimized combined 15- and 5-minute dispatch and real-time unit commitment across PSE and the current EIM footprint, compared to bilateral transactions typically done on an hourly basis under business-as-usual (BAU) practice for PSE; and
+ *Reduced flexibility reserves*, by reflecting the diversity of load, wind and solar variability and uncertainty across PSE and the footprint of current EIM participants.

In addition, if PSE were to integrate its remote wind resources to within its BAA, the EIM could help PSE realize savings from *reduced wind curtailment*, by allowing PSE to export or reduce imports of renewable generation when they would otherwise need to curtail their own resources, as well as *additional renewable balancing cost savings* related to incremental flexibility reserves required for PSE to balance external wind plants itself.[8]

[8] The PacifiCorp-ISO EIM and NV Energy-ISO EIM analyses modeled a wide range of potential avoided curtailment in the ISO as a result of the EIM. This report assumes that PSE's incremental participation in the EIM would not

E3's PacifiCorp-ISO EIM study included a separate benefit category, intraregional dispatch savings, which arises from PacifiCorp generators being able to be dispatched more efficiently through the ISO's automated nodal dispatch software, reducing transmission congestion within the PacifiCorp BAAs. Based on PSE's experience that there is little internal congestion within the PSE transmission system, the study team assumed this benefit would be small and therefore did not include it in this analysis.

In addition to the quantifiable benefits described above, the EIM is expected to provide additional reliability benefits that are not quantified in this report. A recent FERC staff report identified additional reliability benefits that may arise from an EIM.[9] These include enhanced situational awareness, faster delivery of replacement generation after the end of contingency reserve sharing assistance, and enhanced integration of renewable resources.

Benefit Methodology and Scenarios

The study team estimated the benefits of PSE's participation in the EIM using the PLEXOS production cost modeling software to simulate operations in the Western Interconnection for the calendar year 2020 with and without PSE as an EIM participant. The PLEXOS software and 2020 database developed by PNNL for the NWPP Phase 1 EIM study was selected to leverage the improved characterization of transmission and generation in the Northwest, and to improve the comparability of results from PSE's perspective.

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provide incremental avoided curtailment savings for the ISO, PacifiCorp and NV Energy beyond that enabled through the current EIM; thus, curtailment savings included in this study are strictly related to wind plants owned by PSE.

[9] See FERC (2013).

Like the NWPP Phase 1 EIM study performed by PNNL, this analysis used a three-stage simulation process, including DA, HA, and real-time simulations to mirror actual power system operations. The DA and HA stages are simulated on an hourly basis. The real-time stage is simulated with a 10-minute time-step and incorporates the variability and uncertainty associated with load, wind, and solar. The study team's analysis also incorporates California's greenhouse gas regulations and the associated dispatch costs.

The study team modeled flexibility reserve benefits by analyzing coincident sub-hourly load, wind, and solar generation for each of the EIM members. Within the model, BAs not participating in the EIM are required to maintain flexibility reserves to meet 95% of the upward and downward deviations of their own BAA's 10-minute real-time net load compared to their HA forecast. On the other hand, EIM participants are allowed to collectively meet a joint flexibility reserve requirement. By pooling load, wind and solar variability across a wider geographic area, EIM participants can lower the total variability and forecast error of their net load. As a result of this net load diversity, EIM participants can reduce the amount of flexibility reserves they require compared to the sum of flexibility reserves that they would require as individual non-participants. PSE's participation in the EIM is expected to enable an incremental reduction in flexibility reserve requirements for the current EIM participants, as well as to reduce PSE's own flexibility reserve requirement. The study team valued this reduction in flexibility reserve requirements using historical flexible ramping constraint shadow prices for the ISO from 2013.

The estimated benefits are sensitive to several key assumptions regarding the expected level of real-time transfer capability available for the EIM between PSE and the current EIM participants, as well as the real-time transfer capability over COI that connects the ISO and PacifiCorp. Table 1 below summarizes the real-time transfer capability for the BAU case, in which PSE does not participate in the EIM, and two scenarios that include PSE's participation in the EIM, with different levels of real-time transfer capability between BAs participating in the EIM. These two EIM scenarios produce different levels of sub-hourly dispatch benefits relative to the BAU case.

Table 1. Overview of Scenario Assumptions

Case Name	**Real-time Transfer Capability**		
	PAC-PSE	**CAISO-PAC**	**CAISO-NVE**
BAU	NONE	400	1500
PSE EIM Scenarios:			
Low Transfer	300	400	1500
High Transfer	900	700	1500

Notes: Real-time transfer capability represents the maximum amount (in MW) which a BA's net transfer over a path is allowed to differ in real-time, relative to its HA schedule. PAC-PSE transfer capability utilizes a combination of PSE, PacifiCorp, and BPA transmission.

Benefit Results

Across the two PSE EIM participation scenarios, the study team estimates that PSE's participation in the EIM would produce annual savings to PSE ranging from $18.3 to $20.1 million in 2020. Table 2 shows the range of sub-hourly dispatch and flexibility reserve benefits for each scenario; all benefits shown represent cost savings relative to the BAU scenario.

Table 2. Annual Benefits to PSE by Scenario (2014$ million)

PSE EIM Scenario	Sub-hourly Dispatch	Flexibility Reserves	Total Benefits
Low Transfer	$16.7	$1.6	**$18.3**
High Transfer	$18.5	$1.6	**$20.1**

In addition to the savings shown in Table 2, participation in the EIM may enable PSE to obtain up to $9.1 million per year in incremental balancing cost savings, as well as up to $0.8 million per year in avoided curtailment costs if PSE were to balance all of its wind resources within its BAA.

The study team also estimated the benefits that accrue to the current EIM participants as a result of PSE's participation, as shown in Table 3.

Table 3. Annual Benefits to Current EIM Participants by Scenario (2014$ million)

PSE EIM Scenario	Sub-hourly Dispatch	Flexibility Reserves	Total Benefits
Low Transfer	$0.6	$2.9	**$3.5**
High Transfer	$1.2	$2.9	**$4.2**

PSE's participation provides the opportunity for current EIM participants to realize incremental dispatch cost savings of $0.6 million to $1.2 million, depending on the transmission transfer capability level assumed. PSE's participation in the EIM would also create incremental load, wind, and solar diversity for the EIM, further reducing flexibility reserve requirements for the current EIM participants. This study also estimates that the incremental diversity from PSE's participation would bring $2.9 million in flexibility reserve savings to the current EIM participants. Flexibility reserve savings are the same across both EIM scenarios, because the range of EIM transfer capability levels assumed does not constrain potential flexibility reserve requirement reductions.

Across all scenarios, the incremental sub-hourly dispatch and flexibility reserve benefits for all EIM participants, including PSE, range from $21.8 to $24.3 million per year as a result of PSE's participation in the EIM.

1 Introduction

Puget Sound Energy (PSE) and the California Independent System Operator (ISO) retained Energy and Environmental Economics, Inc. (E3) to estimate the economic benefits of PSE's participation in the energy imbalance market (EIM) operated by the ISO. This report details our approach to identify and quantify the benefits of PSE's participation in the EIM, and presents the results of our analysis. Throughout the study process, the study team of E3 and Energy Exemplar worked closely with PSE and the ISO to refine scenario assumptions and data inputs, and to estimate benefits consistent with how each entity operates today, as well as with their expectation of future operations.

1.1 Background and Objectives

Changes in the electric industry in the Western Interconnection are making the need for greater coordination among Balancing Authorities (BAs) increasingly apparent. In particular, increasing penetrations of variable energy resources is driving interest in options to cost-effectively integrate those resources. One option to improve coordination is an EIM, which has been successful in other regions, such as the Southwest Power Pool (SPP). An EIM optimizes generator dispatch to resolve energy imbalances across multiple Balancing Authority Areas (BAAs), and can capture the value of geographic diversity of load and generation resources.

Several recent studies have examined the potential benefits of an EIM in the Western Interconnection. In 2011, E3 and the Western Electricity Coordination Council (WECC) examined the benefits of an EIM throughout the Western Interconnection, excluding the ISO and Alberta Electric System Operator (AESO).[10] In 2013, the National Renewable Energy Laboratory (NREL), on behalf of the Public Utility Commissions Energy Imbalance Market (PUC EIM) Group, extended the E3-WECC analysis by using a sub-hourly production simulation model.[11] In 2013, the Northwest Power Pool (NWPP) Market Assessment Committee (MC) Initiative examined the benefits of an EIM across the NWPP footprint through a study led by Pacific Northwest National Laboratory (PNNL), and the NWPP is continuing to evaluate opportunities for better regional coordination.[12] Each of these studies identified positive dispatch cost savings attributable to implementation of an EIM.

Starting in 2012, the ISO and PacifiCorp began actively developing a regional EIM in the Western Interconnection. The proposed EIM has received Federal Energy Regulatory Commission (FERC) approval for tariff changes in June 2014. The EIM is expected to go live with binding settlements in November 2014 with the ISO, PacifiCorp East, and PacifiCorp West BAs as the initial participants. In 2014, NV Energy obtained approval by FERC and the Public Utilities Commission of Nevada (PUCN) to begin participating in the EIM in Fall 2015.[13]

PSE has been actively exploring potential benefits of all regional coordination options, including participation in the NWPP MC Initiative. PSE and the ISO also

[10] See E3 (2011).
[11] See Milligan et al. (2013)
[12] See Samaan et al. (2013)
[13] See CAISO (2014f) and PUCN (2014).

engaged E3 to assess the impact of PSE's participation in the EIM. This report summarizes the findings of our analysis, with a focus on sub-hourly dispatch benefits and savings from reductions in flexibility reserve requirements. In addition to those benefits, this report also summarizes the potential cost-savings to PSE if the EIM can enable PSE to balance its own wind plants that are currently balanced in real-time by other BAs.

1.2 Structure of the Report

The remainder of this report is organized as follows:

+ **Section 2** describes the methodologies and assumptions used to estimate the benefits of PSE's participation in the EIM;
+ **Section 3** presents the main results of the study;
+ **Section 4** summarizes the additional potential savings if the EIM enables PSE to balance its wind resources that are currently balanced outside its BAA; and
+ **Section 5** provides the conclusions of the study.

2 Study Assumptions and Approach

2.1 Overview of Approach

The EIM allows Western BAs to voluntarily participate in the ISO's real-time energy market. EIM software will automatically dispatch generation across participating BAAs every 5 minutes to solve imbalances using security constrained economic dispatch (SCED), as well as commit quick-start generation every 15 minutes using security constrained unit commitment (SCUC). Each BA participating in the EIM is still responsible for meeting its own operating reserve and planning reserve requirements, and the EIM does not replace participating BAs' existing operational practices in advance of real-time.

PSE's participation in the EIM is expected to result in two principal benefits resulting from changes in system operations for PSE and the current EIM participants:

1. **Sub-hourly dispatch benefits**. Today, each BA outside of the EIM dispatches its own generating resources to meet imbalances within the hour, while holding schedules with neighboring BAs constant. The EIM nets energy imbalance across participating BAs, and economically dispatches generating resources across the entire EIM footprint to

manage the imbalance, resulting in operational cost savings. PSE's participation in the EIM enables incremental dispatch efficiency improvements relative to the current EIM.

2. **Flexibility reserve reductions**. BAs hold flexibility reserves to balance discrepancies between forecasted and actual net load within the hour. *Load following flexibility reserves* (referred to in this report as simply "*flexibility reserves*") provide ramping capability to meet changes in net load between a 5-minute and hourly timescale.[14] By pooling load, wind, and solar output across the EIM footprint, the EIM allows participants to benefit from greater geographic diversity of forecast error and variability by reducing the quantity of flexibility reserves they require. PSE's participation in the EIM would bring added load and resource diversity to the current EIM footprint, resulting in additional reserve savings.

In addition, if PSE were to integrate its remote wind resources to within its BAA, then the EIM could help PSE realize wind curtailment savings and additional renewable integration cost savings. Participation in the EIM could help PSE reduce or eliminate reliability curtailments of its wind resources by using the EIM to export energy that PSE would otherwise need to curtail, or through reducing energy import in real-time compared to PSE's HA schedule. Through the EIM, PSE would also reduce incremental flexibility reserves required to

[14] Regulating reserves, which address the need for resources to respond to changes on a sub-5 minute interval basis, are sometimes categorized in operational studies as a second type of flexibility reserve product. Since the EIM operates with 5-minute intervals, it is does not directly affect regulating reserve requirements. To be concise, all references to *flexibility reserve* in this report are related to load following reserves; *regulating reserves*, where referenced, are explicitly described by name.

balance external wind plants itself. These savings are addressed separately in Chapter 4 of this report.

Our general approach to estimating the benefits of PSE's participation in the EIM is to compare the total cost under two cases: (1) a "business-as-usual" (BAU) case in which PSE is not an EIM participant, and the operational efficiencies of the "current EIM" (including the ISO, PacifiCorp, and NV Energy) is already reflected; and (2) a "PSE EIM" case in which the PSE BA also participates in the EIM. The cost difference between the BAU and PSE EIM cases represents the incremental benefits of PSE's participating in the EIM.

Sub-hourly dispatch benefits are estimated over a range of real-time transmission transfer capabilities using production simulation modeling. The difference in WECC-wide production costs between the PSE EIM simulations and the BAU simulation represents the societal benefit of PSE's participation. To estimate cost savings from reduced flexibility reserve requirements, the study team used statistical analysis to determine the quantity of incremental flexibility reserve diversity that PSE's participation would bring to the EIM, and then applied that quantity to historical flexible ramping constraint shadow prices from the ISO to calculate operational cost savings.

2.2 Key Assumptions

Five key modeling assumptions are important for understanding the results of this study: (1) sub-hourly dispatch; (2) real-time transmission capability; (3) hurdle rates; (4) flexibility reserves; and (5) hydropower modeling.

2.2.1 SUB-HOURLY DISPATCH

In existing operational practice, BAs in the Western Interconnection exchange energy primarily on an hourly basis using hourly or multi-hour schedules, which require long lead times between scheduling the transaction and actual dispatch.[15] Within the hour, each BA resolves imbalances by manually dispatching generating resources inside its BAA, without the assistance of other BAs. By contrast, the EIM optimizes dispatch of available generating resources in real-time across all of the participating BAAs using 15-minute unit commitment and 5-minute dispatch. These sub-hourly processes increase the efficiency of resolving imbalances.

The study team quantifies the benefit of sub-hourly dispatch capability using a three-stage simulation process in PLEXOS consistent with the approach developed for the WECC Variable Generation Subcommittee (VGS) and refined in PNNL's Phase 1 Report for the NWPP MC Initiative. This methodology is described in detail in the PNNL report, as well as Section 2.3 below.

A PLEXOS simulation was run with hourly intervals in a DA stage, and then in an HA stage, using DA and HA forecasts of expected load, wind, and solar output. In the final stage, a real-time PLEXOS simulation is run with 10-minute intervals, using actual wind, load, and solar output for each interval. During the real-time simulation, BAs not participating in the EIM must maintain a net exchange with neighboring BAs that is equal to the HA exchange level. EIM participants, on the other hand, can re-dispatch generation and exchange power with the rest of the

[15] The ISO and AESO are the exceptions.

EIM footprint during each of the 10-minute intervals, subject to transmission transfer limitations, which are discussed in Section 2.2.2 below. [16]

In E3's analyses assessing the benefits of PacifiCorp and NV Energy participating in the ISO EIM, GridView, an hourly production cost model, was used with input data largely based on TEPPC's 2022 Common Case. The 10-minute time-step capability of PLEXOS allows us to better represent the EIM's 5-minute dispatch interval relative to GridView's hourly time-step capability.[17]

2.2.2 REAL-TIME TRANSMISSION TRANSFER CAPABILITY

Previous studies have indicated that transmission can constrain EIM benefits by limiting the amount of power that can be transferred in real-time between EIM participants. For this sub-hourly modeling analysis, the study team specified the maximum amount, in both the positive and negative direction, by which a BA's net transfer over a path is allowed to differ in real-time, relative to the HA scheduled transfer.[18] For example, if the HA scheduled transfer between two BAAs is 1,000 MW and there is 500 MW of real-time transfer capability modeled, then the real-time transfer over that path may range from 500 to 1,500 MW throughout the hour.

[16] While the EIM will operate down to a 5-minute level, the most validated sub-hourly WECC dataset available for this analysis includes 10-minute intervals. Using the 10-minute intervals is a practical but conservative compromise of modeling 15-minute optimization with higher EIM transfer capability and modeling 5-minute optimization with potentially more limited EIM transfer capability across paths limited by dynamic transfer limitations across COI and BPA network.

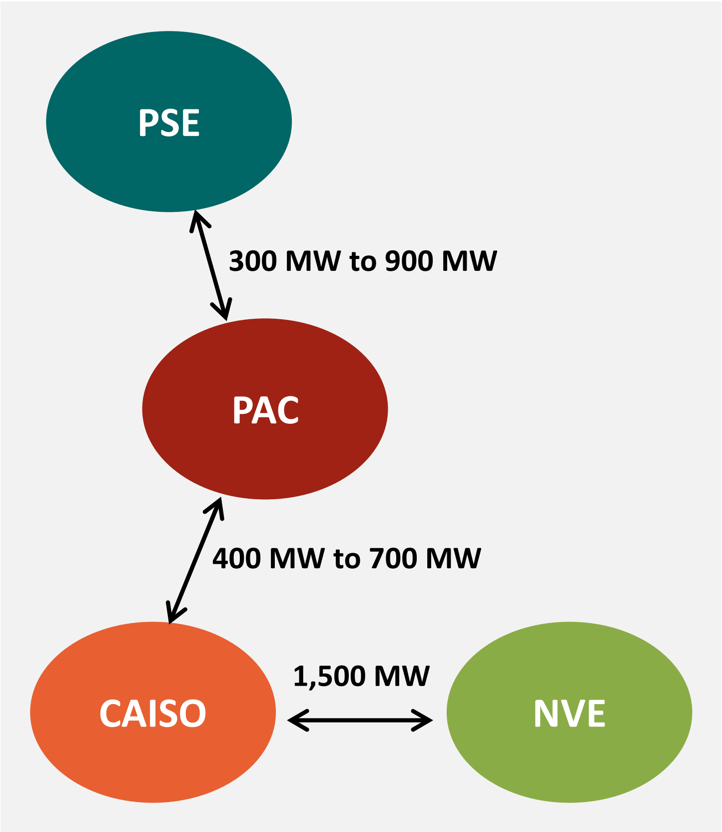
[17] The WECC GridView database is currently developing a sub-hourly modeling capability, but this functionality and the sub-hourly data required were not available at the time of this analysis.

[18] In certain studies in the Northwest, real-time transmission transfer capability has also been termed as "Transfer Variability Limit" or "TVL". See, for example, Columbia Grid (2011).

For the BAU case, the study team adopted real-time transmission transfer capability assumptions from earlier EIM benefit analyses. The study team modeled 400 MW of capability between PacifiCorp and the ISO, and 1,500 MW of capability between the ISO and NV Energy.[19] For the PSE EIM simulation, the study team modeled two scenarios where the real-time transfer capability between PSE and PacifiCorp ranged from 300 to 900 MW, and the capability between PacifiCorp and the ISO ranged from 400 to 700 MW. Figure 1 below characterizes the range of real-time transfer capabilities used in this analysis.

[19] These values are informed by capacity rights owned or controlled by the current EIM participants. Total maximum and minimum flow levels between zones in the model (including HA flow plus incremental changes in real-time) are also subject to physical transmission constraints on rated paths. The flexibility of real-time transfer capability over COI is the subject of an ongoing study by Columbia Grid. The flexibility between ISO and NV Energy is assumed to include transactions over direct interties between the two BAAs, as well as over co-owned transmission facilities. NV Energy and ISO each co-own transmission rights with the Western Area Power Authority (WAPA) to the Mead substation, and NV Energy and the Los Angeles Department of Water and Power (LADWP) co-own transmission rights over the 500 kV lines connecting the Crystal and McCullough Substations. This study conservatively assumed that interties between NV Energy and the PacifiCorp East system will not be utilized for the EIM.

Figure 1. Real-time Transfer Capabilities across the EIM Footprint



2.2.3 HURDLE RATES

Within the Western Interconnection's bilateral markets, there are a number of impediments to efficient trade of energy across BAA boundaries. These include:

+ The need, in many cases, for market participants to pay for the fixed costs of the existing transmission system by redirecting or acquiring additional point-to-point transmission service in order to schedule transactions from one BAA to another;

+ The current tariff practice of requiring short-term transactions to provide real power losses for each transmission provider system that is utilized, resulting, in some cases, in multiple or "pancaked" loss requirements that are added to the fixed costs described above; and
+ Inefficiencies related to having illiquid bulk power and transmission service markets and imperfect information, such as the standard 16-hour "Heavy-Load Hour" and 8-hour "Light-Load Hour" DA trading products defined by the Western Systems Power Pool, minimum transaction quantities of 25 MW, and the bilateral nature of transaction origination and clearing.

These real-world barriers to trade are reflected in production cost simulations as "hurdle rates", $/MWh price adders applied to interfaces between BAAs. Hurdle rates inhibit power flow over transmission paths that cross BAA boundaries, and reduce economic energy exchange between BAAs.

An EIM eliminates the barriers listed above during real-time operations by performing security-constrained economic dispatch across the entire EIM footprint, allowing more efficient (i.e., lower cost) dispatch. Our production simulations in PLEXOS capture this effect by removing hurdle rates between EIM participants during the real-time simulations, while maintaining hurdle rates between non-participants.[20] In the DA and HA simulations, hurdle rates are

[20] Market participants must also acquire CO_2 allowances to deliver "unspecified" energy to California BAAs (i.e., the ISO, LADWP, BANC and IID), as required by California's greenhouse gas cap-and-trade program developed in compliance with AB32. In all production simulation cases modeled, a component of the hurdle rates is used in the model to reflect the need to acquire these allowances when delivering electricity from neighboring states into California.

maintained between all BAAs, including between EIM participants.[21] The study team believes this is a conservative assumption regarding the expected adaptation of DA and HA markets based on information identified by the EIM. In reality, we would expect that BAs would adjust their DA and HA scheduled transactions more efficiently over time based on learning the dynamics of the real-time market results. This learning does not imply a shift away from DA and HA scheduling, but rather a more efficient and better informed selection of scheduling levels for any hour based on learning from real-time market participation. To the extent it is realized, this learning and improved DA and HA efficiency is a non-quantified benefit that would be additional to those quantified in this report.

The removal of hurdles rates in our analysis mirrors proposed changes under the EIM. This modeling is consistent with the FERC-approved ISO tariff amendment associated with the EIM. This modeling approach is also consistent with previous analyses performed to assess the benefits of PacifiCorp and NV Energy participating in the ISO EIM.

2.2.4 FLEXIBILITY RESERVES

BAs hold excess capacity as reserves to balance discrepancies between forecasted and actual net load within the operating hour; these within-hour reserves are in addition to the spinning and supplemental reserves carried against generation or transmission system contingencies.[22] Regulating reserves

[21] This approach—to maintain hurdle rates for the DA and HA simulation and remove them in the real-time simulation run—is consistent with the methodology used by PNNL in the NWPP's MC Phase I EIM Benefit study.
[22] This study assumes that contingency reserves would be unaffected by an EIM, and that PSE would continue to participate in its existing regional reserve sharing agreement for contingency reserves.

automatically respond to control signals or changes in system frequency on a time scale of a few cycles up to 5 minutes. Load following reserves (referred to in this report simply as "flexibility reserves") provide ramping capability to meet changes in net load between a 5-minute and hourly timescale.

Higher penetrations of wind and solar increase the quantity of both regulating and flexibility reserves needed to accommodate the uncertainty and variability inherent in these resources, while maintaining acceptable BA control performance. By pooling load and resource variability across space and time, total variability can be reduced, decreasing the amount of flexibility reserves required to ensure reliable operations. This reduces operating costs by requiring fewer thermal generators to be committed and operated at less efficient set points.

For this study, the study team used statistical analysis to estimate the reduction in flexibility reserves that would occur if PSE participates in the EIM. Flexibility reserve requirements for each BA are a function of the difference between the actual 10-minute net load in real-time versus the HA net load schedule. As a result of geographic diversity, the combined net load profiles for participating BAs have less variability and forecast error than the individual profiles of each BA, resulting in lower flexibility reserve requirements under the EIM.

Units that provide regulating reserves must respond faster than the EIM's 5-minute dispatch interval, so EIM participants are assumed here to receive no regulating reserve diversity savings as a result of participating in the EIM.

There are two implicit assumptions embedded in this approach: (1) that PSE and the current EIM participants would carry the calculated levels of flexibility reserves; and (2) that the EIM includes a mechanism to take advantage of increased net load diversity by reducing the quantities of flexibility reserves that would need to be carried.

With regard to the first assumption, while there is currently no defined requirement for BAs to carry flexibility reserves, all BAs must carry a level of operating reserves in order to maintain Control Performance Standards (CPS) within acceptable limits, and reserve requirements will grow under higher renewable penetration scenarios. In December 2011, the ISO implemented a flexible ramping constraint in the five-minute market optimization to maintain sufficient upward flexibility in the system within the hour.[23] Generators that are chosen to resolve a constraint are compensated at the shadow price, which reflects the marginal unit's opportunity cost. Furthermore, the ISO is in the process of introducing a flexible ramping product, which would allow economic bids to be submitted to procure upward and downward ramping capability.

With regard to the second assumption, while the specific design of the flexible ramping products has not been finalized, it is logical to assume that the ISO's flexi-ramp requirements (for the product or the flexi-ramp constraint) would be calculated in such a way as to maximize diversity benefits across the entire EIM footprint, within the context of its 5-minute operational time-step.[24] It should be noted that this is a product that may not be in place by the time PSE would begin to participate in the EIM, and EIM participants may require a period of

[23] See CAISO (2014d and 2014e).
[24] For a detailed discussion of the proposed approach for determining, procuring and allocating flexibility requirements under EIM, see Section 3.4.3 of CAISO (2013).

operational experience before the full benefits of flexibility reserve savings can be achieved.

At a minimum, however, when the EIM becomes operational, the flexible ramping constraint and settlement will be implemented. The ISO will determine flexible ramp constraint requirements for the ISO and each EIM participant based on the aggregate load, wind, and solar resource forecasts and expected variability. By establishing the requirements based on the aggregate profiles, the benefits of diversity will be realized with the current EIM implementation. Furthermore, the EIM design will compensate resources for their contribution to meeting the flexibility constraint. As a result, the EIM will provide an opportunity both for resources to be compensated and also for load serving entities to efficiently meet their flexibility requirements with recognition of the load and resource diversity benefits.

2.2.5 HYDROPOWER MODELING

Previous EIM analyses indicate that benefits are sensitive to the availability of hydropower to provide flexibility reserves.[25] Dispatchable hydroelectric resources rarely generate at levels that approach maximum nameplate capacity due to limitations on water available for power generation. On many facilities, a portion of the “unloaded” capacity — the difference between the nameplate capacity and the actual generation — can be used to provide contingency and flexibility reserves. However, this unloaded capacity varies by facility and with continually-fluctuating river conditions, making it challenging to generalize for

[25] For example, see E3 (2011) for a discussion of this issue in the context of a WECC-wide EIM excluding the ISO and AESO.

modeling purposes. This leads to uncertainty in the calculation of operating costs using production simulation models.

Generally, EIM benefits are higher when hydro's flexibility is restricted, because a higher proportion of reserves are provided by thermal resources. Conversely, there are fewer production cost savings available when hydro provides a large quantity of flexibility with zero variable costs.

PSE's share of the Mid-Columbia (Mid-C) hydroelectric generating facilities is its primary source of flexibility, and gas-fired simple- and combined-cycle plants provide the remainder. This necessitates a more accurate characterization of hydro resources in the production cost simulations.

The NWPP Analytical Team spent considerable effort improving the modeling of hydro plants in the Northwest, including: (a) specifying hydro units as following a fixed schedule or dispatching using hydro-thermal coordination (HTC); (b) limiting reserve provision from specific hydro plants; (c) correcting ramp rates; and (d) reducing hydro generating capacities to reflect O&M and head obligations.[26] These modeling improvements are particularly important given that both PSE and PacifiCorp have contractual shares of Mid-C hydro plants. This analysis uses the same modeling assumptions and input data from the NWPP EIM Phase 1 Analysis.

The study team made one modification to the approach developed by the NWPP Team for the purposes of this study, optimizing the real-time dispatch of

[26] See Section 2.4 of Samaan et al. (2013) for a detailed discussion of hydropower plant modeling in the NWPP Phase 1 EIM Analysis.

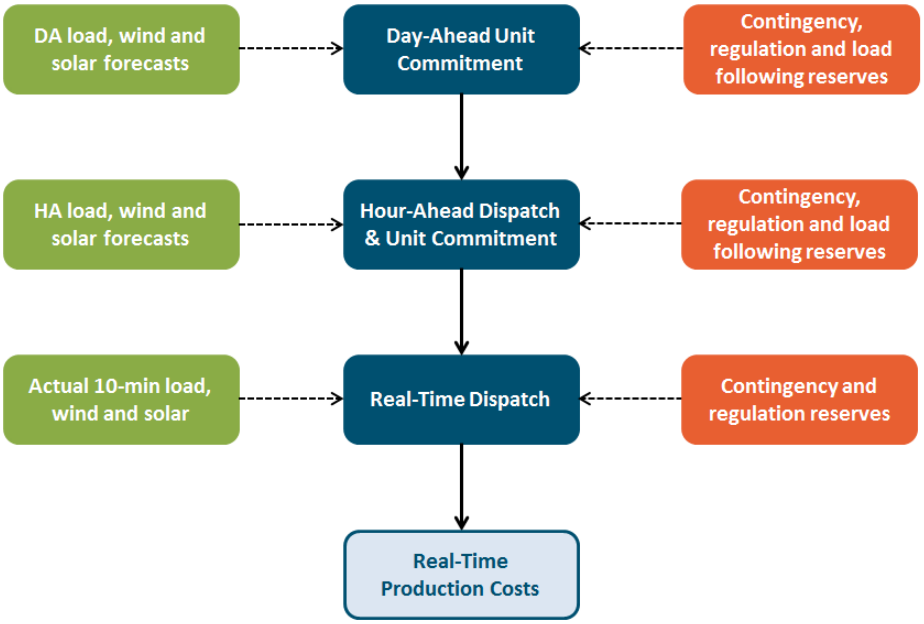
flexible hydro units in 6-hour increments rather than the 1-hour increments used in the NWPP study. This change was based on input from both PSE and the ISO, who felt that the 1-hour hydro optimization was overly restrictive of hydro flexibility. The use of 6-hour increments for hydro energy optimization results in a more conservative estimate of EIM benefits than a 1-hour hydro energy optimization window, because the 6-hour incremental reduces the amount of inefficiency in the BAU case that remains possible for an EIM to address. Importantly, this update also allowed the analysis to largely avoid the impact of hydro energy constraint violations (also termed "excess hydro") on EIM benefits that arose during modeling for the NWPP EIM Phase 1 study.

2.3 Sub-hourly Dispatch Benefits Methodology

2.3.1 PRODUCTION COST MODELING

The study team used PLEXOS, a sub-hourly production cost model, to estimate sub-hourly dispatch benefits in 2020. PLEXOS, like other production cost models, simulates bulk power system operations by minimizing the variable cost of operating the system subject to a number of constraints. PLEXOS includes a three-stage sequential simulation process to model DA, HA, and real-time operations, as shown in Figure 2 below.

Figure 2. PLEXOS Three-Stage Sequential Simulation Process



The primary purpose of the DA simulation is to generate daily unit commitment schedules for long-start units, while the HA simulation determines the HA dispatch and interchange schedules between BAs. During the real-time simulation, the "actual" load, wind, and solar data are used to generate dispatch, and flexibility reserves are "released" so that the capacity reserved from the HA simulation is allowed to serve real-time imbalances.

The DA, HA, and real-time (DA-HA-RT) sequential simulation approach allows PLEXOS to differentiate operations for BAs participating or not participating in an EIM. When a BA is not participating in an EIM, then: (a) hurdle rates apply during the DA, HA and real-time simulations; (b) interchange is unconstrained during the DA and HA simulations; and (c) during the real-time simulation, the

HA interchange schedule is locked down, resulting in the BA managing its imbalances with its own generation. In contrast, when two or more BAs are participating in an EIM, then hurdle rates on transfers between the participating BAs are removed during the real-time stage and generation from anywhere in the footprint can solve imbalances, subject to imposed transmission constraints.

The study team estimated sub-hourly dispatch benefits of PSE's participation in the EIM by running pairs of production cost simulations using PLEXOS. Under each simulation scenario, there is a pair of BAU and PSE EIM cases. In the BAU case, PSE solves its real-time imbalances with internal generation while maintaining interchange equal to the schedule from the HA simulation. Intra-hour interchange is allowed to vary to allow economic transfers between the ISO, PacifiCorp and NV Energy, reflecting the operational efficiencies of the current EIM. The PSE EIM cases simulate the operations of an EIM consisting of the ISO, PacifiCorp, NV Energy and PSE BAs. Hurdle rates between the BAs are removed in real-time and intra-hour interchange is allowed up to the real-time transfer capabilities specified in each scenario. The study quantifies the societal benefit of PSE's participation in the EIM by measuring the reduction in production costs from the BAU case to the PSE EIM case.

2.3.2 INPUT DATA

The initial dataset used for this report is the database used in PNNL analysis for the NWPP's Phase 1 EIM benefit assessment, which was built on the Transmission Expansion Planning Policy Committee (TEPPC) 2020 PC0 database.[27] The NWPP Analytical Team made numerous modeling updates for the purposes of their study, with a particular focus on improving the representation of BAAs in the Northwest.[28] Utilizing this database allowed this study to reflect the best available compiled representation of BAAs in the Northwest, as well as leverage the hourly DA, HA forecast and sub-hourly real-time data which PNNL developed for load, wind, and solar output.

For the purposes of this study, the study team made the following key updates:

+ **Zonal transport model**. The transmission network in PLEXOS was modeled at the zonal level rather than the nodal level. This change was made to more accurately represent commercial behavior of two BAs scheduling transactions between each other through the Mid-C trading hub. Using the zonal model also significantly reduces model run time.
+ **Topology updates**. The transmission transfer capability between PSE and neighboring zones was modeled according to PSE's typical monthly total transmission capability (TTC).[29] The remaining transmission topology and hurdle rate assumptions are based on the zonal model used for the ISO's 2012 Long-Term Procurement Plan (LTPP).
+ **CT commitment during real-time**. Quick-start combustion turbines were allowed to commit and dispatch in the real-time simulations to reflect the ISO's addition of the 15-minute real-time unit commitment process for the EIM.

[27] It is based on PNNL's Base Case (1.86a) for the NWPP, which itself was modified from a data set and had been developed for use with the PLEXOS sub-hourly model for PNNL's 2012 study for the WECC Variable Generation Subcommittee (VGS).
[28] See Section 2 of Samaan et al. (2013) for a detailed discussion of the updates the NWPP Analytical Team made to improve upon the TEPPC PC0 case.
[29] See PSE (2014).

- **Hydro optimization window**. As discussed in Section 2.2.5, the simulations optimize the real-time dispatch of flexible hydro units across a 6-hour window rather than a 1-hour window.
- **Nuclear generation**. All nuclear plants throughout the WECC were modeled as must-run at their maximum capacity to avoid any unrealistic intra-hour changes in nuclear generation.
- **Generation updates in California**. A few generation updates were made to reflect anticipated system changes that PSE and the ISO believed were important to the analysis. In California, the San Onofre Nuclear Generation Station (SONGs) was taken out of service, as well as applying the ISO’s current best estimate of retirement and repowering of once-through cooling generators by 2020; the ISO’s share of Hoover generation was also changed to match the values in the 2012 LTPP.
- **Generation updates in PSE**. A 200 MW quick-start CT generator was added pursuant to PSE’s most recent Integrated Resource Plan. The portion of the Colstrip coal plant owned by PSE was moved into the PSE BAA so that its output could be changed in real-time based on PSE’s needs, because PSE indicated that they can dispatch its share of Colstrip in real-time through a dynamic transfer.

Overall, the study team’s modeling assumptions seek to be consistent with projections for calendar year 2020 in terms of generation, transmission and fuel prices across the WECC. At the same time, the study team sought to limit the number of changes in input data from the information used for the NWPP Phase 1 study.

2.3.3 SCENARIOS

Table 4 summarizes the assumptions used for each case modeled using production simulation: the BAU case (where PSE is not an EIM participant), and two PSE EIM participation scenarios with different levels of real-time transfer capability between BAs participating in the EIM.

Table 4. Overview of EIM Scenario Assumptions

Case Name	Real-Time Transfer Capability		
	PAC-PSE	CAISO-PAC	CAISO-NVE
BAU	NONE	400	1500
PSE EIM Scenarios:			
Low Transfer	300	400	1500
High Transfer	900	700	1500

As noted in Section 2.2.2, the study team anticipated that the real-time transfer capability between EIM participants would affect benefits, so PSE and the ISO worked to develop a range that would characterize low and high end expectations of real-time flexibility of transfers between PSE and PacifiCorp utilizing direct connections between them through their own transmission systems and other transmission system connections. PacifiCorp provided useful descriptions about their system and operations to help develop this range. In addition, PSE believes that it should be able to use a portion of its current Dynamic Transfer Capability (DTC) over the Bonneville Power Administration (BPA) system to enable further real-time EIM transactions for PSE when economic. In total, the study team selected a real-time transfer capability of +/- 300 MW between PSE and PacifiCorp for the PSE EIM Low Transfer Case and +/- 900 MW for the PSE EIM High Transfer Case.

In the BAU and PSE EIM Low Transfer scenarios, real-time transfer capabilities between current EIM participants are consistent with the assumptions in the NVE-ISO EIM study: 1,500 MW for the ISO-NV Energy real-time transactions, and 400 MW for PacifiCorp-ISO transactions, which is also the value for the middle level of transfer capability in the PacifiCorp-ISO EIM study. In the PSE EIM High Transfer Case, the study team increased the capability between PacifiCorp and the ISO by an additional 300 MW (to 700 MW total) to investigate the impact that additional COI transfer capability for the EIM could have on benefits to PSE.

2.3.4 ATTRIBUTION OF BENEFITS TO EIM PARTICIPANTS

WECC-wide production cost savings represent the societal benefits resulting from PSE's participation in the EIM. The study team attributes these benefits to PSE and the current EIM participants by calculating the "Total Operations Cost" for both parties, which is the sum of the following components: (1) HA net import costs, equal to net imports times the zone's locational marginal price; (2) real-time generator production costs; and (3) real-time imbalance costs, equal to imbalance times an EIM-wide market clearing price. The "Total Operations Cost" represents a proxy for the total cost to serve load in a given area, including the production costs to run local generators and the cost of importing power (or revenues from exporting power). The reduction in "Total Operations Costs" under an EIM case versus the BAU case represents the EIM benefit for a given participant.

Since the EIM does not affect HA operations, there is no change in HA net import costs between the BAU and EIM cases. The EIM-wide market clearing price used to calculate real-time imbalance costs is the imbalance-weighted average of the participating BAs. Table 5 is an example of calculating the EIM-wide market clearing price for a single 10-minute interval. The EIM-wide market clearing price is only applied to imbalance transactions.

Table 5. Example of EIM-wide Marketing Clearing Price Calculation

Category	CAISO	PAC	NVE	PSE
Real-time Price ($/MWh)	73.0	56.5	61.9	59.8
HA Net Import Schedule (MW)	7,635	(2,592)	1,463	110
Real-time Net Imports (MW)	7,449	(2,769)	1,587	350
Imbalance (MW)	-186.0	-177.2	123.4	239.9
Absolute Value of Imbalance (MW)	186.0	177.2	123.4	239.9
Share of Imbalance (%)	25.6%	24.4%	17.0%	33.0%
EIM-wide Market Clearing Price ($/MWh)	**62.7**			

2.4 Flexibility Reserve Savings Methodology

The study team estimates the operational cost savings from reduced flexibility reserve requirements using the following methodology. First, a statistical analysis is used to estimate the quantity of flexibility reserve reductions from PSE's participation in the EIM. Next, the avoided cost of flexibility reserves is determined by observing historical flexible ramping constraint shadow prices from 2013. Finally, to estimate the total EIM reserve savings from PSE's participation, the average shadow price from 2013 is applied to the flexibility reserve quantity reductions.

2.4.1 FLEXIBILITY RESERVE REQUIREMENT

To determine flexibility reserve requirements, the study team used the actual (10-minute) and HA schedule load, wind, and solar data from the NWPP EIM study. This data is used to calculate a distribution of flexibility needs (i.e., real-time net load minus the HA net load schedule). Each BA's flexibility reserves requirement for each month and hour are calculated using a 95% confidence interval (CI), where the 2.5th and 97.5th percentiles determine the flexibility down and up requirements, respectively.[30]

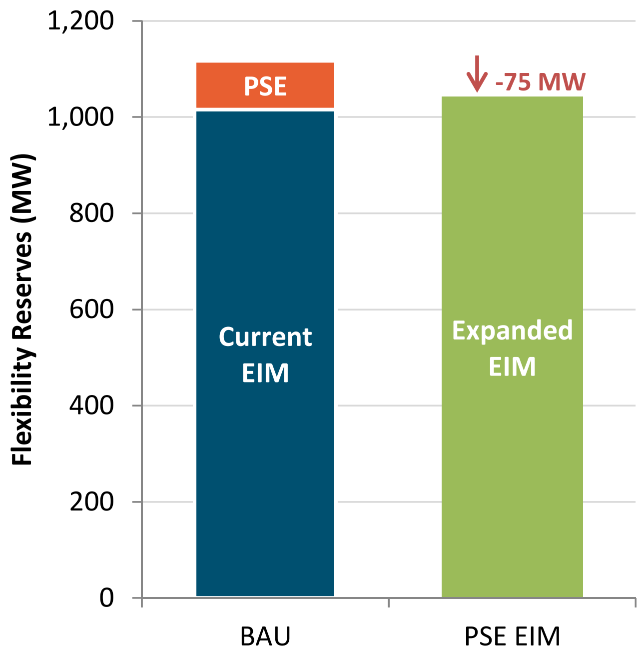
For the BAU case, the study team calculates flexibility requirements for the current EIM by summing the net load profiles for the ISO, PacifiCorp and NV Energy BAs before calculating the 95% CI.[31] PSE's requirements are calculated as a standalone entity. In the PSE EIM case, flexibility requirements are calculated for the Expanded EIM by summing the ISO, PacifiCorp, NV Energy and PSE BA net load profiles. Figure 3 shows the average upward flexibility requirements in 2020 across the BAU and PSE EIM cases. PSE's EIM participation results in a "diversity benefit" that reduces upward flexibility requirements by 74.5 MW on average.[32]

[30] Using the 95% confidence interval to calculate flexibility reserve requirements is consistent with the approach used in the NWPP EIM Phase 1 study.

[31] Due to diversity in forecast error and variability, the 95th percentile of aggregated real-time deviation from HA forecast for the entire EIM is a smaller level (relative to the size of the BAs) than it would be for the sum of individual EIM members.

[32] This reduction is subject to real-time transmission transfer capability limits, and cannot be larger than the levels between individual EIM participants and the rest of the EIM. However, the reduction levels quantified for PSE were well under the levels for the PSE Low Transfer Case, so transmission was assumed to not have a binding impact on flexibility reserve reductions for the PSE EIM scenario, and the resulting flexibility reserve savings are the same for all three PSE EIM scenarios. The reserve savings for PSE would change if PSE had a different renewable generation portfolio, which is addressed in Chapter 4.

Figure 3. Average Upward Flexibility Requirement

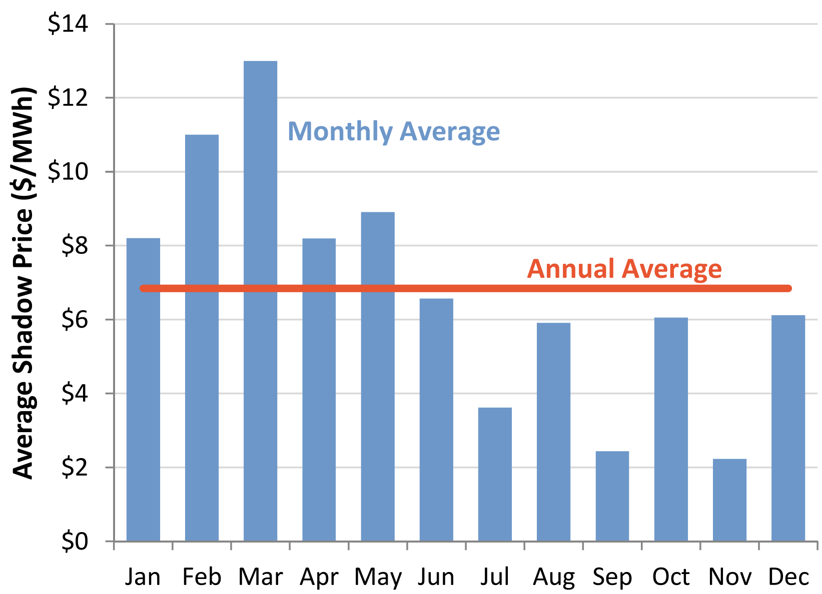


Note: Current EIM consists of the ISO, PacifiCorp and NV Energy BAs. "Expanded EIM" consists of the ISO, PacifiCorp, NV Energy and PSE.

2.4.2 AVOIDED COST OF FLEXIBILITY RESERVES

To value flexibility reserve reductions, the study team first examined flexible ramping constraint shadow prices in 2013. The ISO has applied a flexible ramping constraint in the five-minute market optimization since December 2011 to maintain sufficient upward flexibility. Generators that are chosen to resolve a constraint are compensated at the shadow price, which reflects the marginal unit's opportunity cost. However, if there is sufficient capacity available, the constraint is not binding, resulting in a shadow price of zero. Figure 4 shows the average shadow price for procuring upward flexible ramping capacity for each month in 2013. Reductions in *upward flexibility* requirements in 2020 are valued at the 2013 annual average flexible ramping constraint shadow price of \$6.98/MWh.[33]

Figure 4. 2013 ISO Flexible Ramping Constraint Shadow Prices



Note: Data from CAISO (2014a).

2.4.3 ATTRIBUTION OF FLEXIBILITY RESERVE SAVINGS

Flexibility reserve savings were attributed to PSE and the current EIM participants by comparing their relative reduction in flexibility reserve requirements in the BAU case compared to the PSE EIM cases. The ISO's Business Practice Manual (BPM) details how the ISO will assign flexibility reserve

[33] Inflated here from 2013 to 2014 dollars assuming an annual inflation rate of 2%.

requirements among EIM participants. Each participating BA will be assigned a flexibility requirement equal to the BA's standalone flexibility reserve requirement (i.e., if it were not an EIM participant), reduced by an EIM reserve diversity factor that is equal to the combined EIM flexibility reserve requirement (which reflects diversity benefit across the EIM), and then divided by the sum of standalone flexibility reserve requirement quantity for all EIM participants.[34]

Overall, PSE's participation in the EIM creates more diversity to the full EIM footprint, reducing flexibility reserve requirements for current EIM participants by 48.2 MW on average, which is a five percent reduction compared to their requirements in the current EIM. PSE's own flexibility reserve requirement is reduced by 26.3 MW on average, a 26% reduction from its requirements as a standalone BA.

[34] See CAISO (2014b).

3 Results

3.1 Overview of Benefits Across Scenarios

Table 6 below presents the annual benefits of PSE's EIM participation in 2020 under both transfer scenarios. Each row displays PSE's EIM cost savings in a particular transfer capability scenario relative to the BAU scenario. Annual sub-hourly dispatch and flexibility reserves benefits to PSE range from $18.3 million in the Low Transfer Case to $20.1 million for the High Transfer Case.

Table 6. Annual Benefits to PSE by Transfer Capability Scenario (million 2014$)

PSE EIM Scenario	Sub-hourly Dispatch	Flexibility Reserves	Total Benefits
Low Transfer	$16.7	$1.6	**$18.3**
High Transfer	$18.5	$1.6	**$20.1**

The PSE EIM Low Transfer case, with 300 MW of real-time transfer capability between PSE and PacifiCorp, enables $16.7 million in sub-hourly dispatch benefits for PSE. The High Transfer scenario, in which the PSE-PacifiCorp real-time transfer capability is increased to 900 MW and the PacifiCorp-ISO transfer capability is increased to 700 MW, produces $18.5 million in sub-hourly dispatch benefits for PSE, a modest $1.8 million increase in savings compared to the Low Transfer case. The small size of this incremental savings is discussed later in this chapter, which highlights that the 300 MW of PSE-PacifiCorp real-time transfer capability is sufficient to facilitate most economic real-time transactions in the majority of hours of the year for the simulation of PSE EIM participation.

For both scenarios modeled, the flexibility reserve benefit to PSE is $1.6 million. The Low Transfer scenario uses 300 MW of real-time transfer capability between PSE and the current EIM. This transfer capability is sufficient to not constrain the potential reduction to PSE's flexibility reserve requirement as an EIM participant, which in Section 2.4.3 the study team identified as 26.3 MW on average. Therefore, PSE's flexibility reserve savings are not constrained by the real-tim41e transfer capability in the Low Transfer scenario, and adding additional transfer capability in the other scenario does not produce additional flexibility reserve savings for PSE.

Table 7 below presents the incremental benefit to the current EIM participants as a result of PSE's participation in the EIM. In total, PSE's participation is projected to create $3.5 to $4.2 million per year in incremental benefits for the current EIM participants.

Table 7. Annual Benefits to Current EIM Participants (million 2014$)

PSE EIM Scenario	Sub-hourly Dispatch	Flexibility Reserves	Total Benefits
Low Transfer	$0.6	$2.9	**$3.5**
High Transfer	$1.2	$2.9	**$4.2**

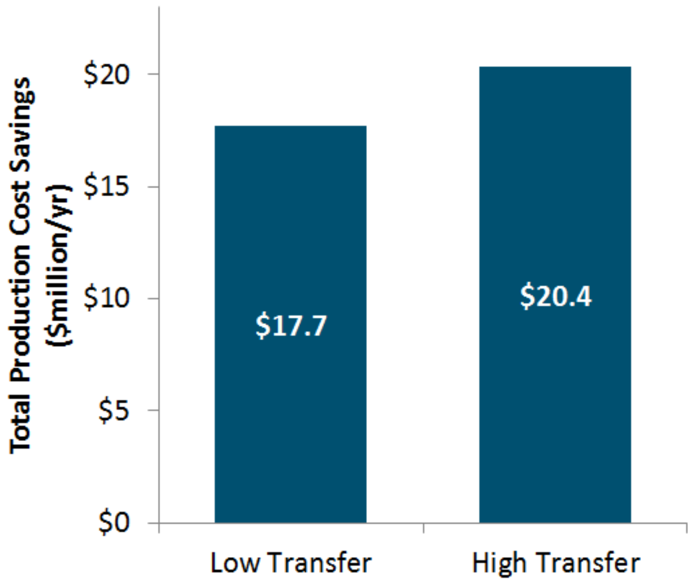
PSE's participation in the EIM provides the current participants opportunities for incremental, sub-hourly dispatch benefits ranging from $0.6 to $1.2 million per year. Under the Low Transfer scenario, current EIM participants see sub-hourly dispatch savings of $0.6 million per year, while under High Transfer scenario, benefits to current participants are $1.2 million. In both of the EIM scenarios considered, PSE's participation in the EIM would also create additional diversity, further reducing flexibility reserve requirements for the current EIM participants and producing $2.9 million in incremental savings for the current EIM participants.

3.2 Detailed Benefit Results by Category

3.2.1 SUB-HOURLY DISPATCH BENEFITS AND IMBALANCE LEVELS

Figure 5 presents the WECC-wide production cost savings under both scenarios of transfer capability between EIM participants. WECC-wide production cost savings from the dispatch analysis should aggregate all transfers between consumers and producers to present the total incremental savings from PSE EIM participation. This total was $17.7 million for the PSE EIM Low Transfer Case and $20.4 million for the PSE EIM High Transfer Case. These totals are slightly larger from the sum of dispatch benefits attributed to PSE and the current EIM participants due to small interactions with BAs outside of the EIM footprint.

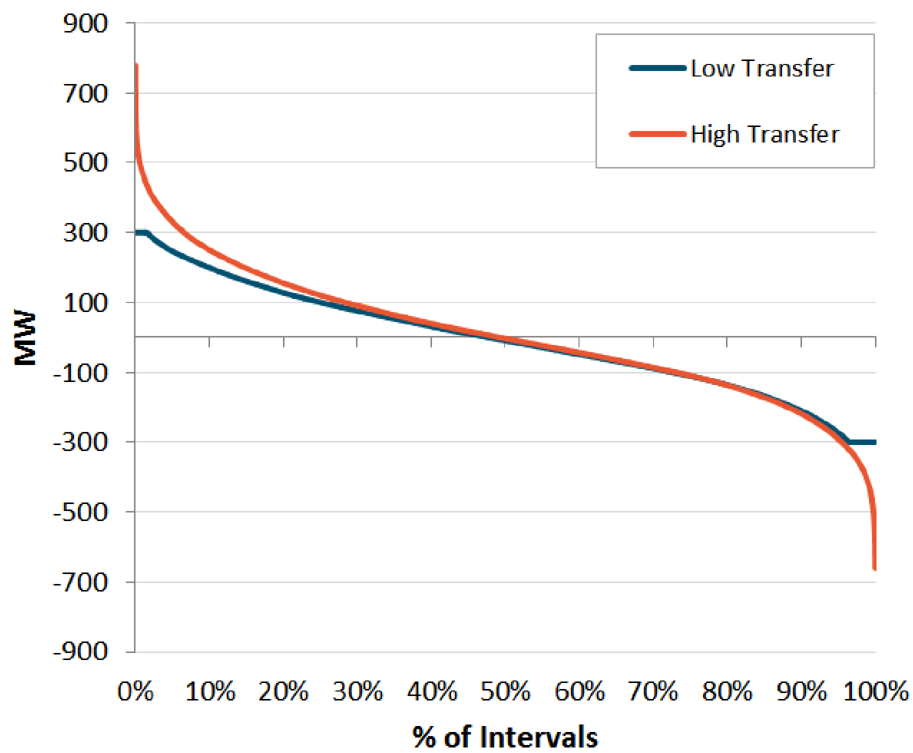
Figure 5. WECC-wide Production Cost Savings



The results presented above highlight that the overwhelming majority of potential sub-hourly dispatch benefits are captured with only 300 MW of real-time transfer capability between PSE and PacifiCorp. A threefold increase in this capability only results in a 15% increase in sub-hourly dispatch benefits. This suggests that there are very few intervals throughout the simulation year where it would be economic for PSE to either increase or decrease its generation dispatch and net exchange with other EIM participants by more than 300 MW.

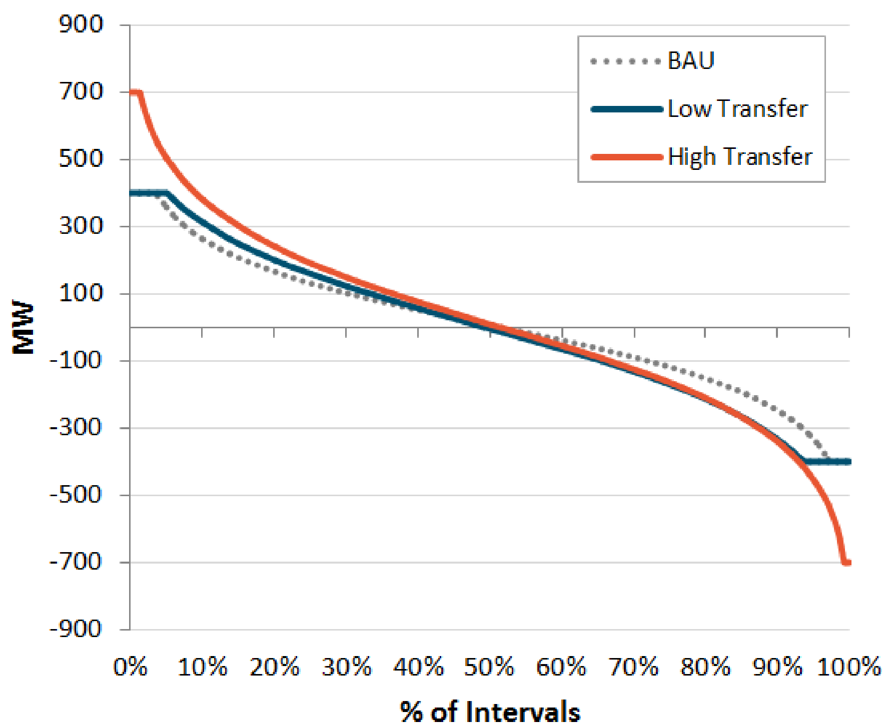
The infrequency of transfers above 300 MW is highlighted in Figure 6. The figure compares imbalance energy duration curves for PSE for the two EIM scenarios. Imbalance shown here is the difference between PSE's real-time (10-minute) net imports and the HA net import schedule produced from the HA simulation. Positive imbalances represent intervals when PSE is importing more in real-time relative to their HA schedule (or exporting less than in the HA schedule), and vice versa. In the PSE EIM Low Transfer case, imbalances are exactly equal to +300 MW or -300 MW in fewer than 2% of the intervals across the year, suggesting that the transfer capability is rarely a binding constraint on EIM transactions. In the High Transfer case, PSE's imbalance exceeds +/-300 MW in 11% of the intervals, with imbalances never reaching 900 MW.

Figure 6. PSE Imbalance Duration Curve



PSE's participation in the EIM also results in incremental increases in the EIM transaction volume over COI relative to the current EIM (in both positive and negative directions for certain sub-hourly intervals). This impact is illustrated in Figure 7 below, where the BAU duration curve represents the PacifiCorp-only EIM transactions over COI, and the remaining curves reflect PSE plus PacifiCorp real-time imbalance over the COI for the two PSE EIM cases analyzed. Positive imbalance represents south to north flow, and negative imbalance represents north to south flow. The 400 MW of real-time transfer capability between PacifiCorp and the ISO modeled in the BAU and Low Transfer scenarios is only binding during a small percentage of real-time intervals. Therefore, increasing this capability from 400 to 700 MW in the High Transfer scenario produces a small marginal increase in EIM dispatch benefits.

Figure 7. PSE plus PacifiCorp Imbalance Duration Curve



3.2.2 DRIVERS OF SUB-HOURLY DISPATCH BENEFITS FOR PSE

The study team reviewed detailed outputs on generation dispatch from each of the simulations to identify key drivers of PSE EIM dispatch benefits. The most significant sources of dispatch saving for PSE was the result of the EIM enabling more efficient use of PSE's internal generation and allowing flexibility in the ability to increase or decrease net imports in real-time. In the BAU case, forecast errors and variability of load and wind in real-time resulted in the need for PSE to commit internal peaking generators in real-time during certain periods when PSE required more energy, but was unable to adjust real-time exchanges scheduled with neighboring BAs. By comparison, under both PSE EIM scenarios, participation in the EIM enables PSE to adjust net exchanges with the other EIM participants in real-time. This capability allowed PSE to frequently avoid the need to commit additional internal peaking generators to address real-time generation shortfalls, and, as a result, PSE is able to produce a higher percentage of energy to serve its load with lower-cost base load generation. The EIM also allows PSE to dispatch its lowest-cost generators for export sales to the other EIM participants in intervals when these units have available capacity in real-time and it is economic to do so.

Figure 8compares PSE’s real-time net imports in the BAU and PSE EIM Low Transfer scenarios for a three-day snapshot period in December 2020. In the BAU scenario (shown in blue), net imports are fixed to the HA schedule. In contrast, net imports in the EIM Low Transfer scenario (shown in orange) are allowed to vary by the real-time transfer capabilities discussed above, resulting in more variable real-time net imports that are both higher and lower than the HA schedule. This net import flexibility allows PSE to optimize the use of its own generation to resolve imbalances. The flexibility of real-time exchange facilitated by the EIM is further illustrated in Figure 9, which displays the level of imbalance for each participating BA across the same three-day snapshot.

Figure 8. PSE Real-Time Net Imports for Three-Day December Period

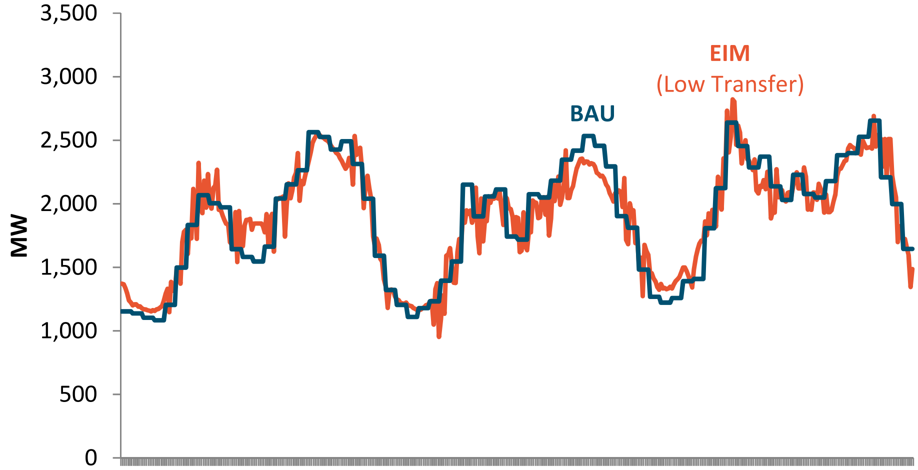
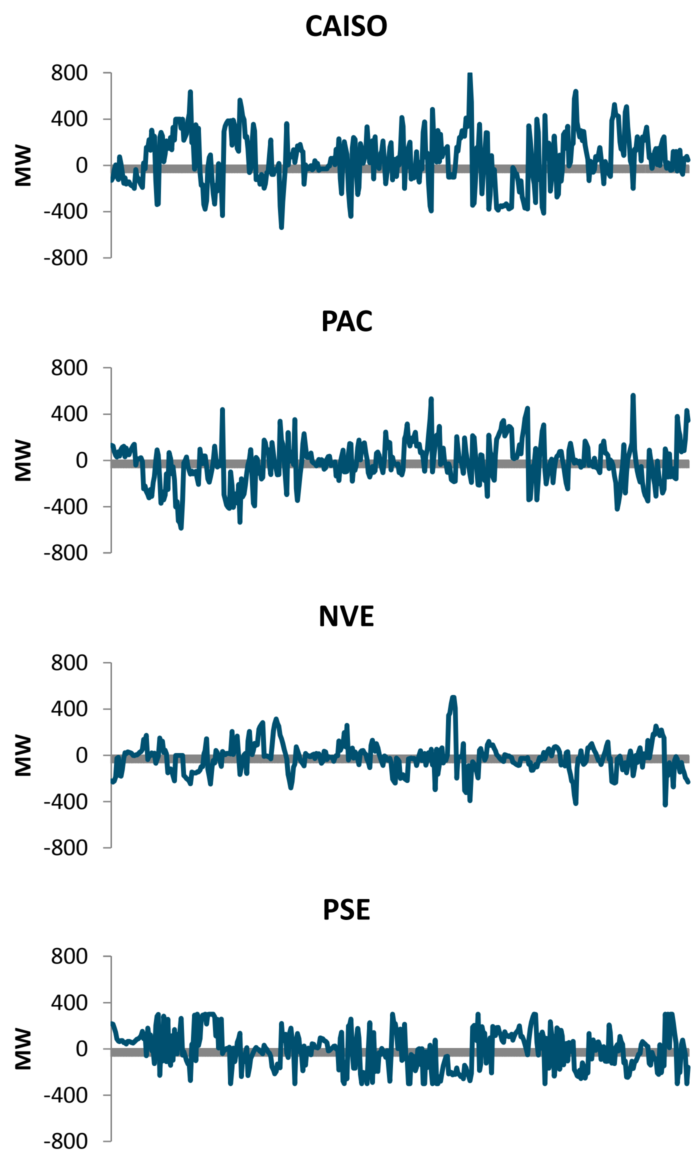


Figure 9. Real-Time Imbalance for EIM Participants for Three Day December Period, Low Transfer Case



Note: sum of imbalances across the four EIM participants is equal to zero for every 10-minute interval.

Table 8 below shows the calculations used to attribute EIM benefits to PSE and the current EIM participants by estimating the "Total Operations Cost" for PSE and the current EIM under the BAU case and both PSE EIM scenarios. Each component is calculated according the methodology described in Section 2.3.4.

Table 8. Total Operations Cost by Component across Scenarios (2014 $ million/year)

	Current EIM (ISO-PAC-NVE)	PSE
BAU		
HA Net Import Cost	$ 2,806.9	$ 489.4
Real-time Imbalance Cost	$ 0.1	$ (0.0)
Real-time Generation Cost	$ 7,727.9	$ 216.4
Total	**$ 10,534.9**	**$ 705.8**
PSE EIM: Low Transfer		
HA Net Import Cost	$ 2,806.9	$ 489.4
Real-time Imbalance Cost	$ 1.6	$ (1.5)
Real-time Generation Cost	$ 7,725.8	$ 201.3
Total	**$ 10,534.3**	**$ 689.1**
PSE EIM: High Transfer		
HA Net Import Cost	$ 2,806.9	$ 489.4
Real-time Imbalance Cost	$ (5.2)	$ 5.3
Real-time Generation Cost	$ 7,732.0	$ 192.7
Total	**$ 10,533.7**	**$ 687.3**

The resulting incremental EIM savings for each participating BA is based on the reduction in total operations cost for that BA in a particular PSE EIM scenario compared to the BAU case. These savings are shown by component in Table 9 below.

Table 9. EIM Savings (Cost) by Scenario (2014 $ million/year)

	Current EIM (ISO-PAC-NVE)		PSE	
PSE EIM: Low Transfer				
HA Net Import Cost	$	-	$	-
Real-time Imbalance Cost	$	(1.5)	$	1.5
Real-time Generation Cost	$	2.1	$	15.2
Total	**$**	**0.6**	**$**	**16.7**
PSE EIM: High Transfer				
HA Net Import Cost	$	-	$	-
Real-time Imbalance Cost	$	5.3	$	(5.3)
Real-time Generation Cost	$	(4.1)	$	23.8
Total	**$**	**1.2**	**$**	**18.5**

3.2.3 FLEXIBILITY RESERVE SAVINGS

As noted in Section 2.4, the additional diversity from PSE's participation in the EIM would bring an incremental 74.5 MW reduction in EIM-wide flexibility reserve requirements compared to the sum of current EIM reserve requirements plus PSE standalone reserve requirements in the BAU case. The EIM assigns flexibility reserve requirements and allocates the diversity reduction among EIM participants based on their relative share of the sum of standalone reserves if each were operating without an EIM. On average, throughout the year, this methodology results in a 26.3 MW flexibility reserve reduction attributed to PSE and an incremental 48.2 MW reserve reduction attributed to the current EIM participants.

This study values these flexibility reserve reductions based on the average historical flexi-ramp value in the ISO for 2013, which was $6.98/MWh.[35] This value results in total flexibility savings for the year 2020 of $4.6 million, of which $1.6 million is for PSE and $2.9 million is for the current EIM participants.

3.3 Results Discussion

The study team applied a number of conservative assumptions in this analysis, which could results in the benefits quantified above to be lower than the actual savings that would accrue to PSE and to the current EIM participants. These assumptions include:

+ **Reliability-related benefits were not quantified.** The study team did not quantify the potential reliability benefits tied to the increased situational awareness and resource control that the EIM will enable. Although these benefits are difficult to quantify, they are important to consider qualitatively as they are likely to produce substantial benefits.
+ **Intra-regional dispatch savings were not quantified.** PSE indicated that internal congestion on the PSE system is usually small, so the analysis did not endeavor to quantify if the EIM can help reduce costs or relieve problems within PSE's BAA.
+ **Average hydro conditions and current renewable generation policy targets.** The analysis evaluated an average hydro year and renewable generation levels equal to current policy targets. It is possible that high hydro runoff in the Pacific Northwest or higher RPS targets in the ISO could lead to greater BAU scenario renewable energy curtailment. In

[35] Adjusted from 2013 to 2014 dollars.

such conditions, PSE's participation in the EIM may be able to produce larger savings than the levels included here. In addition, low hydro conditions could reduce PSE's ability to call on its hydro resources for flexibility, which would lead to greater incremental savings from EIM participation.

+ **Thermal generators were modeled with flat heat rates.** According to the WECC VGS study and PNNL NWPP Phase 1 EIM analysis, each thermal generator in the PLEXOS database was assigned a single heat rate regardless of the unit's current level of dispatch. Other models such as the WECC TEPPC model in GridView typically use step-function incremental heat rates for thermal generators; such heat rates reflect the fact that a generator will typically have a higher average heat rate when operating at minimum dispatch levels (i.e., Pmin) compared to when operating closer to maximum output (i.e., Pmax). The EIM dispatch savings are driven by identifying efficiency opportunities to reduce dispatch of generation in one BAA and increase dispatch on a lower-cost generator located in a different participating BAA. Modeling thermal units with non-flat heat rates could produce greater variation in heat rates across generators (depending on their operating levels) and result in greater opportunities for EIM dispatch savings.

+ **Hydro energy optimization was modeled with a 6-hour horizon**. In the real-time simulation runs with sub-hourly intervals, PLEXOS models dispatchable hydro plants by first allocating each plant's total monthly hydro energy budget to a single hour, or to a window of consecutive hours. The simulation then optimizes overall real-time system dispatch while using the capability to move the hydro energy available during a single hour (or window of hours) among 10-minute intervals within that hour. The simulation uses the hour's available hydro energy during intervals when hydro dispatch has the most value, subject to constraints on generator ramp rates and maximum and minimum output levels for the hydro plant. This allocation procedure limits the ability of a BA to move hydro energy across a wide time period in the real-time simulation to respond to differences in system need across a day or group of days. In actual practice, hydro operators do not have perfect forecasts of load and variable energy, and they similarly must budget available hydro energy under uncertainty, subject to hydrological and environmental constraints. The PNNL EIM Benefit Phase 1 for the NWPP used a 1-hour hydro optimization window, which prevented BAs in the model from shifting real-time hydro energy forward from one hour to the next and contributed to the hydro energy constraint violation included in that analysis. Based on feedback from PSE regarding its own hydro dispatch capabilities, the study team extended the hydro optimization horizon to a 6-hour window. By simulating a longer hydro energy optimization window this study allows the available hydro energy to be used more optimally and flexibly to address intra-hour dispatch challenges. This assumption results in a more conservative EIM dispatch savings estimate because the hydro improves the efficiency of the dispatch in the BAU case, leaving a smaller remaining opportunity for incremental improvement under an EIM.

4 Additional Wind Balancing Cost Savings

In addition to the savings described in Chapter 3, an EIM may enable PSE to realize incremental savings related to wind resource balancing and reduced curtailment. Under current conditions (i.e., without EIM participation), limitations of PSE's internal reserve capability motivate PSE to contract with other BAs to provide reserves and balancing services for current and future wind plants in PSE's generation portfolio.

4.1 Renewable Balancing Cost Savings

Currently, PSE has 500 MW of wind generation located in an external BAA and the energy from that generation is scheduled in hourly block transfers to PSE. PSE expects that it will also need assistance to balance 300 MW of additional wind generation planned by 2020. PSE must pay the external BA for the balancing services it provides, and, based on current balancing service rates, PSE would expect to incur annual costs of $11.5 million to balance the total of 800 MW of external wind resources.

As an EIM participant, PSE would have a lower local flexibility reserve requirement and more opportunities for balancing load and wind variability in sub-hourly intervals. This helpful impact of the EIM would allow PSE to instead provide its own flexibility reserves (with the assistance of the EIM diversity benefit) to balance the PSE wind resources currently integrated by the external BA and thereby avoid all or a substantial portion of the balancing charges it currently incurs each year.

If feasible, this operating change could allow PSE to avoid balancing charges but would require PSE (as an EIM participant) to maintain a higher internal flexibility reserve requirement than it otherwise would as an EIM participant if the 800 MW of remote wind was still balanced outside of the PSE BAA. Using the flexibility reserve methodology described above, the study team estimates that PSE would need to maintain an incremental 22 MW of flexibility reserves, on average, to balance the remote wind as an EIM participant.[36] Based on the ISO's average 2013 flexible ramping constraint shadow price of $6.98/MW-hour, which was used in Chapter 3 of this report to value flexibility reserve requirement savings, the 22 MW increase in average flexibility reserves requirements to balance its remote wind would create $1.3 million in additional cost to PSE. PSE would also need to hold a higher amount of regulating reserves to manage the greater wind variability on a sub-5-minute timescale. Based on previous analysis by PSE, balancing the remote wind internally would also be expected to require PSE to hold an incremental 15 MW of regulating up and 15 MW of regulating down reserves on average. Using the ISO's historical average prices from 2013 of $5.34/MW-hour for regulating up and $3.32/MW-hour for

[36] It is important to note that this incremental amount is 48 MW lower than the amount of flexibility reserves that PSE would require if it were to attempt to balance the remote wind as a standalone entity.

regulating down as a proxy for PSE regulating costs,[37] the incremental regulating requirement would create $1.1 million in incremental regulating costs for PSE.

The annual net cost savings of PSE balancing these remote wind plants locally with the support of the EIM is $9.1 million per year.[38] This benefit is in addition to the cost savings reported in Section 3.1.

4.2 Renewable Curtailment Savings

Renewable curtailment savings estimates were provided by PSE based on historical curtailment of its wind resources both within and external to its BAA. Wind resources external to the PSE BAA are subject to reliability curtailments from the source BA. In addition, under current operational practice, PSE may need to curtail output of wind plants located in its own BAA during periods of elevated reliability concern, such as spring runoff conditions. If PSE were to internally integrate its remote wind plants, then PSE’s historical backcast approach estimates renewable curtailment cost savings for its total wind portfolio range from $0 to $0.8 million per year, depending on a combination of local and regional system conditions. PSE expects that the EIM could help reduce a portion or eliminate all of this curtailment if all of the wind plants were in PSE’s BAA. To cover this range, EIM renewable curtailment related savings for PSE have been assessed as a range of annual benefits from $0 to $0.8 million.

[37] See Section 6.3 of CAISO (2014a). It is not expected that the ISO would provide regulating reserves to PSE under the EIM; rather the ISO’s regulating reserve prices were used as a transparent ancillary services market value as a proxy for potential costs that PSE would incur to meet a higher regulating requirement.

[38] This net savings is calculated by taking the difference of $11.5 million in avoided balancing service charges, less $1.3 million in incremental flexibility reserve costs for PSE and $1.1 million in incremental regulating reserve costs for PSE.

The PacifiCorp-ISO and NV Energy-ISO EIM studies included benefits related to the EIM's assistance in reducing renewable energy curtailment inside the ISO. Due to the renewable energy curtailment benefits already captured by PacifiCorp and NV Energy's participation in the EIM, this study conservatively assumes that PSE's participation in the EIM would not enable any additional avoidance of renewable energy curtailment for current EIM participants.

5 Conclusions

This report assessed the incremental benefits of PSE's participation in the ISO EIM. The study team estimated the benefits for PSE as well as current EIM participants. The gross benefits identified to PSE are substantial, even under the low real-time transmission transfer capability scenario, which includes 300 MW of real-time transfer capability between PSE and PacifiCorp. In addition, if the EIM enables PSE to locally balance its remote wind resources and avoid wind balancing service charges, significant additional cost savings could be possible.

Two additional material benefits have not been quantified. First, the study team assumed that PSE's behavior and actions in the DA and HA market would not be influenced by the continuous information flowing from participation in the EIM market. We believe that over time, PSE may be able to obtain additional benefits, which were not captured in this study, by adjusting its positions more optimally in the HA and DA markets based on information obtained through more transparent awareness of the real-time market as a result of EIM participation.

Second, the study team did not quantify the potential reliability benefits tied to the increased situational awareness and resource control that the EIM creates. Although both of these benefits are difficult to quantify, they are important to consider qualitatively as they are likely to produce substantial benefits.

Relative to the EIM startup and ongoing participation costs estimated by PSE staff, the gross benefits presented in this study are significant. The benefits and costs from PSE's participation in the EIM quantified in this report would produce a positive net present value ranging from $153.7 million to $174.4 million for PSE over a 20-year period. [39]

[39] NPV has been estimated for a project start year of 2014. The calculation assumes 20 years of sub-hourly dispatch and flexibility reserves benefits and annual ongoing costs. PSE's participation in the EIM is estimated to go live in Fall 2016, and startup costs are incurred in 2015 and 2016. All values have been discounted using PSE's after-tax weighted average cost of capital (ATWACC) of 6.7% nominal, consistent with PSE's 2013 IRP, and assumed annual inflation rate of 2%. Increasing the NPV calculation to include 30 years of benefits and ongoing costs results in an NPV ranging from $190.2 to $216.3 million.

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