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January 22, 2014

The Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

Re: ***Southwest Power Pool, Inc.*, Docket No. ER12-1179-00_**
Submission of Tariff Revisions to Implement Order No. 745 in the SPP Integrated Marketplace

Pursuant to the Federal Energy Regulatory Commission's ("Commission") "Order Conditionally Accepting Tariff Revisions to Establish Energy Markets" issued on October 18, 2012,[1] Southwest Power Pool, Inc. ("SPP") submits revisions to its Open Access Transmission Tariff[2] to incorporate for the Integrated Marketplace provisions required by SPP's Order No. 745[3] compliance proceeding.[4] SPP requests an effective date of March 1, 2014 for the Tariff revisions submitted in this filing.

I. BACKGROUND

A. Integrated Marketplace Filing

On February 29, 2012, as amended on May 15, 2012, SPP submitted to the Commission proposed revisions to its Tariff to transition from its current Real-Time

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1 *Sw. Power Pool, Inc.*, 141 FERC ¶ 61,048 (2012) ("October 18 Order"), *order on reh'g and clarification*, 142 FERC ¶ 61,205 (2013).

2 Southwest Power Pool, Inc., FERC Electric Tariff, Sixth Revised Volume No. 1 ("Tariff"). For clarity, SPP refers in this filing to Tariff language applicable in the Integrated Marketplace, effective March 1, 2014, as "Integrated Marketplace Tariff."

3 *Demand Response Compensation in Organized Wholesale Energy Markets*, Order No. 745, III FERC Stats. & Regs., Regs. Preambles ¶ 31,322, *order on reh'g and clarification*, Order No. 745-A, 137 FERC ¶ 61,215 (2011), *reh'g denied*, Order No. 745-B, 138 FERC ¶ 61,148 (2012), *appeal docketed*, *Elec. Power Supply Corp. v. FERC, et al.*, Nos. 11-1486, et al. (D.C. Cir. Dec. 23, 2011).

4 October 18 Order at P 62.

Energy Imbalance Service ("EIS") Market to the SPP Integrated Marketplace in March of 2014.[5] The Integrated Marketplace includes (among other things) Day-Ahead and Real-Time Energy and Operating Reserve Markets, a Transmission Congestion Rights market, and the formation of a new SPP Balancing Authority to consolidate and assume the responsibilities of the 16 separate Balancing Authority Areas currently operating within the SPP footprint. In the Integrated Marketplace Filing, SPP explained that, because its efforts to address compliance with Order No. 745 were ongoing before the Commission, SPP was not proposing any Tariff language in that filing to address Order No. 745 compliance requirements in the Integrated Marketplace.[6] Instead, SPP indicated that it would submit an additional filing to propose any necessary Tariff revisions for the Integrated Marketplace at the conclusion of its Order No. 745 compliance proceeding.[7]

In orders issued on October 18, 2012[8] and September 20, 2013,[9] the Commission conditionally accepted SPP's Integrated Marketplace, subject to additional compliance filings. In the October 18 Order, the Commission required SPP, within 30 days of the final order accepting in its Order No. 745 compliance in the EIS Market, to submit a further filing "to incorporate any Tariff revisions for the Integrated Marketplace required by its ongoing Order No. 745 compliance proceeding."[10]

B. Order No. 745

On March 15, 2011, the Commission issued Order No. 745, mandating that Regional Transmission Organizations ("RTO") pay demand response resources the market price for energy, typically the locational marginal price ("LMP"), when the demand response resource has the capability to balance supply and demand as an alternative to a generation resource and when dispatch of the demand response resource is cost-effective as determined by a new net benefits test required by Order No. 745.[11]

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5 Submission of Tariff Revisions to Implement SPP Integrated Marketplace, Docket No. ER12-1179-000 (Feb. 29, 2012) ("Integrated Marketplace Filing"); Amendatory Filing of Tariff Revisions to Implement SPP Integrated Marketplace, Docket No. ER12-1179-001 (dated May 15, 2012).

6 Integrated Marketplace Filing, Transmittal Letter at 64. SPP's Order No. 745 compliance proceeding is in Docket No. ER11-4105-000.

7 *Id*.

8 October 18 Order at P 2.

9 *Sw. Power Pool, Inc.*, 144 FERC ¶ 61,224, at P 2 (2013), *reh'g pending*.

10 October 18 Order at P 62.

11 Order No. 745 at PP 2, 47-48.

Order No. 745 set forth the parameters for adoption of the net benefits test to be used for determining when compensating a demand response resource at the market price is cost-effective, which the order defined as the market price level at which dispatch of the demand response resource lowers LMP sufficiently to offset the additional cost of compensating the resource at full market price.[12] The Commission also directed RTOs to: (1) review their current requirements for measurement and verification of demand response resource performance and propose any necessary modifications to ensure that demand response resource baselines remain accurate;[13] and (2) demonstrate that their current cost allocation methodology for demand response appropriately allocates costs to those that benefit from lower market prices, or propose any necessary tariff revisions.[14]

SPP submitted its filing in response to Order No. 745 on July 22, 2011, indicating that SPP already compensates demand response at the locational imbalance price ("LIP") at all times.[15] SPP also stated that its demand response baseline, measurement, and verification provisions and cost allocation methodology then pending in its Order No. 719[16] compliance proceeding were developed in light of the current EIS Market demand response compensation methodology.[17]

On January 19, 2012, the Commission issued an order rejecting SPP's compliance with the demand response compensation and cost allocation aspects of Order No. 745 and directing SPP to provide further explanation regarding how its measurement and verification provisions will continue to ensure that appropriate baselines are set and that demand response will continue to be adequately measured and verified.[18] The Commission indicated that SPP did not address the multiple purposes of the net benefits

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12 *Id.* at PP 3-4, 79-80.

13 *Id.* at PP 6, 94.

14 *Id.* at PP 5-6, 100, 102.

15 Order No. 745 Compliance Filing of Southwest Power Pool, Inc., Docket No. ER11-4105-000, at 4-6 (July 22, 2011) ("July 22 Compliance Filing"). LIP in the EIS Market is calculated in the same manner as LMP in other RTO markets.

16 *Wholesale Competition in Regions with Organized Electric Markets*, Order No. 719, III FERC Stats. & Regs., Regs. Preambles ¶ 31,281 (2008), *as amended*, 126 FERC ¶ 61,261, *order on reh'g*, Order No. 719-A, III FERC Stats. & Regs., Regs. Preambles ¶ 31,292, *reh'g denied*, Order No. 719-B, 129 FERC ¶ 61,252 (2009).

17 July 22 Compliance Filing at 7-10.

18 *Sw. Power Pool, Inc.*, 138 FERC ¶ 61,041, at PP 1, 13, 19, 22, 29-30 (2012) ("January 19 Order").

test and directed SPP to "propose a net benefits test as detailed in Order No. 745, or [] seek to demonstrate that the net benefits test requirements are satisfied by showing that, given the characteristics of its system and market, its existing practice of compensating demand response resources at the LIP is cost-effective . . . ."[19] The Commission directed SPP to submit a compliance filing within 90 days.

On May 2, 2012, SPP submitted the compliance filing required by the January 19 Order.[20] In that filing, SPP explained that it had adopted Order No. 745's formulaic definition of the desired threshold price (i.e., the price where (Delta LIP x MWh consumed) > (LIP_{NEW} x CL), where LIP_{NEW} is the market clearing price after Controllable Load (CL)), and that it had developed a six step process for identifying the threshold price that will satisfy the Net Benefits Test.[21]

In addition, SPP proposed to allocate on a regional basis through its revenue neutrality uplift ("RNU") charge the costs for demand response that is committed and dispatched in cost-effective hours, as determined by the Net Benefits Test described above.[22] Under SPP's proposal, EIS Market participants would be allocated demand response costs through the RNU charge, which is based on each participant's net generation and reported load at each Settlement Location. By including such demand response costs in the RNU, the costs would be allocated on a system-wide basis to all EIS Market participants.[23] SPP explained that, because states in the SPP region have not widely authorized participation in wholesale demand response programs to date, demand response from load reductions is relatively limited. Thus, the costs of load reductions that SPP would be allocating through RNU are relatively small. SPP, however, indicated that it would monitor the costs of demand response that are being allocated through RNU, and if a different allocation is warranted, it would propose modifications in its Integrated Marketplace to be implemented in 2014.[24]

SPP also provided further explanation regarding the two alternative methodologies for calculating and measuring demand response it proposed in its Order

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[19] *Id.* at P 19.

[20] Compliance Filing of Southwest Power Pool, Inc., Docket No. ER11-4105-001, (May 2, 2013) ("May 2 Compliance Filing").

[21] *Id.* at 4.

[22] *Id.* at 11.

[23] *Id.*

[24] *Id.* at 12.

No. 719 proceeding,[25] the Calculated Real-Time Response Methodology and the Submitted Real-Time Response Methodology.[26] SPP asserted that its planned Order No. 719 measurement and verification rules would ensure that appropriate baselines are set and that demand response performance will be adequately measured and verified. It further noted that the Commission had authorized SPP to defer implementation of SPP's Order No. 719 measurement and verification processes until implementation of its Integrated Marketplace in 2014.[27] Therefore, SPP could not compare or evaluate the performance of these measurement and verification tools, but would monitor the use and effectiveness of these tools once implemented to ensure that they meet the Commission's requirements.[28]

On December 13, 2012, the Commission requested additional information regarding SPP's May 2 Compliance Filing.[29] SPP filed a response on January 18, 2013.[30] In its Additional Response, SPP, among other things, further justified including the costs of demand response in the RNU charge and demonstrated that its cost allocation methodology allocates cost to those that benefit from a decreased LIP as required by

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25 *See* Compliance Filing Revising Tariff of Southwest Power Pool, Inc., Docket Nos. ER09-1050-004 & ER09-748-002 (May 19, 2010).

26 *See id.* at 11-13 and Exhibit IV §§ 1.2.9.1 & 1.2.9.2. In the Integrated Marketplace Filing, SPP proposed substantially similar methodologies, called the "Calculated Resource production option" and the "Submitted Resource production option," respectively. *See* Integrated Marketplace Filing, Proposed Tariff, Attachment AE §§ 4.1.2.1(1)(a) & (b). For convenience, SPP refers to these methodologies herein as the "Calculated Option" and the "Submitted Option."

27 On November 18, 2011, SPP filed a motion for an extension of time to implement the demand response baseline calculation, measurement, and verification provisions required by Order No. 719 in order to permit it to implement the requirements as part of the Integrated Marketplace effective in March 2014, rather than as part of the current EIS Market. The Commission granted this extension on November 30, 2011. *Sw. Power Pool, Inc.*, Notice of Extension of Time, Docket Nos. ER09-1050-001, et al., (Nov. 30, 2011).

28 *See* May 2 Compliance Filing at 13-19.

29 *See Sw. Power Pool, Inc.*, Letter, Docket No. ER11-4105-001 (Dec. 13, 2012).

30 Order No. 745 Compliance Filing—Response to Request for Information of Southwest Power Pool, Inc., Docket No. ER11-4105-001 (Jan. 18, 2013) ("Additional Response").

Order No. 745.[31] SPP also noted that "[t]he methodology filed in the May 2 [Compliance] Filing only applies to the EIS Market," and thus SPP would need to "file additional Tariff amendments to comply with Order No. 745 for the Integrated Marketplace."[32] SPP also provided additional explanation of and justification for its proposed Net Benefits Test.[33]

On December 20, 2013, the Commission issued a letter order in Docket No. ER11-4105-001 accepting SPP's proposed EIS Market Tariff revisions to comply with Order No. 745.[34]

II. COMPLIANCE FILING

As discussed above, the Commission "direct[ed] SPP to submit a subsequent filing to incorporate any Tariff revisions for the Integrated Marketplace required by its ongoing Order No. 745 compliance proceeding within 30 days of the final order accepting provisions for its EIS market."[35] Accordingly, SPP submits in this filing Tariff revisions to adopt its Net Benefits Test and associated demand response compensation and cost allocation provisions for the Integrated Marketplace.

A. Net Benefits Test

1. Explanation

In the EIS Market, SPP adopted Order No. 745's formulaic definition of the desired threshold price[36] and a six step process for identifying the threshold price that will satisfy the Net Benefits Test. These steps, which were set forth in Section 1.3.9 of

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31 *See id.* at 1-4.

32 *Id.* at 13.

33 *Id.* at 5-11.

34 *Sw. Power Pool, Inc.*, Letter Order, Docket No. ER11-4105-001 (Dec. 20, 2013) ("December 20 Order").

35 October 18 Order at P 62.

36 SPP has slightly modified the language to account for terminology differences between the EIS Market and the Integrated Marketplace, as explained in further detail in Section II.A.2 below.

Attachment AE for the EIS Market,[37] were fully explained by SPP and accepted by the Commission in Docket No. ER11-4105.

For the first year that the Integrated Marketplace is in operation, SPP proposes to continue to use this same Net Benefits Test. SPP will initially use the same test because the Net Benefits Test requires use of data from the prior year,[38] which by necessity until March of 2015 must be EIS Market data (as the Integrated Marketplace will not have been in operation long enough to provide such data). Because EIS Market data must be used, it is just and reasonable to use the same test that that was developed based on that data.[39] However, as SPP indicated in Docket No. ER11-4105, the Integrated Marketplace will have different systems in place, which will necessitate adjusting the Net Benefits Test methodology once SPP has access to a full prior year's data, which will occur beginning in March of 2015. SPP will make any necessary adjustments to the Net Benefits Test to enable the appropriate use of such data in its Net Benefits Test analysis and file any necessary Tariff revisions to be effective in March of 2015.

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[37] SPP notes that, due to administrative error, Attachment AE of the EIS Market Tariff contains two sections labeled as 1.3.9, one submitted in Docket No. ER11-4105-001 addressing the Net Benefits Test, and one submitted in Docket No. ER12-2479-000 addressing the Commission's electronic data requirements. *See* Submission of Tariff Revisions to Comply with Order No. 760 of Southwest Power Pool, Inc., Docket No. ER12-2479-000 (Aug. 20, 2012), *accepted by Sw. Power Pool, Inc.*, Letter Order, Docket No. ER12-2479-000 (Oct. 15, 2012). SPP plans to submit a filing in the near future to address the inadvertent duplicative numbering of these sections. References to Section 1.3.9 herein are intended to refer to the language filed and accepted in Docket No. ER11-4105-001.

[38] Order No. 745 at PP 79-80 (explaining that the net benefits test price threshold should be determined using historical data).

[39] For example, it continues to be just and reasonable to analyze peak load hours and to smooth the daily supply curves individually rather than first averaging the fuel adjusted curves and then smoothing the averaged curve. Because EIS Market data will be used for the first year that the Net Benefits Test is implemented in the Integrated Marketplace, analyzing peak load hours will continue to present the set of offers that best represents the true market supply. *See* May 2 Compliance Filing at 6; Additional Response at 5-6. As SPP also explained in Docket No. ER11-4105, individually smoothing the offer curves is appropriate because average offer curves created from EIS Market data would result in average offer curve data that include hours that do not represent the full potential supply available. Additional Response at 7.

2. Tariff Revisions

To incorporate the current Net Benefits Test into the Integrated Marketplace Tariff, SPP makes two revisions to the Integrated Marketplace version of Attachment AE effective March 1, 2014. First, SPP adds the new defined term "Net Benefits Test" to the definitions in Section 1.1 of Attachment AE. The definition is identical to the definition accepted by the Commission for the EIS Market in Docket No. ER11-4105, except for changing the term "Controllable Load" to "Demand Response Load," consistent with terminology used in the Integrated Marketplace.

Second, SPP includes a new Section 3.9 of Attachment AE (Calculation of Net Benefits Test for Compensation of Demand Response Resources), which is substantively similar to Net Benefits Test language adopted for the EIS Market. SPP has modified the language slightly to match the terminology used in the Integrated Marketplace Tariff provisions and to clarify the Net Benefits Test formula, but has not made any substantive changes to the Net Benefits Test formula or the six steps. Section 3.9 also contains a new term "Net Benefits Threshold" to refer to the "price on a supply curve, representative of economic conditions expected for that month, at which the benefits of dispatching Demand Response Load exceed the costs of the load reductions to other loads." This term is used for clarity and is not intended to be a substantive change.

These Tariff changes are just and reasonable and comply with the October 18 Order because they incorporate into the Integrated Marketplace, without substantive change, the current Commission-accepted Net Benefits Test that is being used by SPP today, the use of which is appropriate until SPP has access to a year's worth of prior Integrated Marketplace data, as discussed in Section II.A.1 above.

B. Demand Response Compensation and Cost Allocation

1. Explanation

As discussed above, in the EIS Market, SPP adopted a cost allocation methodology that allocates on a regional basis through the RNU charge the costs of compensating demand response at the locational price. As SPP explained in its Additional Response, the effect of dispatching a Demand Response Resource on energy prices is regionally distributed, because the congestion component is generally small in comparison to the system marginal price and the effect on the system marginal price is regional whereas the effect on the congestion component is locational (meaning that the effect of demand response dispatch is largely regional).[40] SPP also presented an analysis of 20 randomly selected hours in which the Net Benefits Test threshold price was

[40] Additional Response at 2-3. Using data from the 2012 calendar year, SPP demonstrated that the congestion component typically constitutes less than 20% of the system marginal price, except in one zone where it reached 30%. *Id.*

exceeded at a registered Demand Response Resource, which showed that the average percentage change on LIPs was roughly the same in each of the zones in the SPP region.[41]

In its May 2 Compliance Filing, SPP also noted that demand response in the SPP region is limited, particularly demand response involving load-reducing Resources.[42] SPP attributed the limited penetration by load-reducing Resources primarily to the fact that states in the SPP region have not widely authorized participation in wholesale demand response programs.[43] SPP committed to continue monitoring the costs of demand response that are being allocated through the RNU, and "if a different allocation is warranted in the future," to "propose modifications in its Integrated Marketplace to be implemented in 2014."[44] The Commission approved SPP's regional cost allocation via RNU in its December 20 Order.

SPP proposes to continue to allocate Demand Response Resource compensation costs regionally in the Integrated Marketplace. However, SPP will no longer use its RNU mechanism to allocate the costs in the Integrated Marketplace, but instead has developed separate hourly charges (the Day-Ahead Demand Reduction Distribution Amount and Real-Time Demand Reduction Distribution Amount, as discussed in Section II.B.2 below) to allocate and recover the costs of demand response. As SPP's analysis in the EIS Market demonstrated, the effect of Demand Response Resource dispatch on prices was roughly the same across each pricing zone in the region. SPP expects this trend to continue in the Integrated Marketplace. Currently, there are 48 MW of load-reducing Demand Response Resources registered for participation in the Integrated Marketplace. These Resources, located in Kansas, are centrally located in the SPP footprint in an area with minimal transmission constraints. Moreover, as SPP explained in its Additional Response, the impact of Demand Response Resources on the system marginal price is regional while the impact on the congestion component is local.[45] SPP's analysis demonstrated that the congestion component makes up a small percentage of the locational price, meaning that the effect of demand response dispatch on prices is largely regional.[46] Because SPP is not significantly modifying its methodology for calculating

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41 *See* Additional Response at 4-5. The average percentage changes in LIP varied from -1% to -2%. *Id.*

42 *See* May 2 Compliance Filing at 12.

43 *See id.*

44 *See id.*

45 Additional Response at 2.

46 *Id.* at 2-5.

LMPs in the Integrated Marketplace from its LIP calculation, this analysis remains valid for the Integrated Marketplace. Thus, continuing to allocate costs regionally remains just and reasonable. Consistent with its commitment in its May 2 Compliance Filing,[47] SPP will continue to monitor the costs of demand response that are being allocated regionally, and if a different allocation is warranted, SPP will propose any necessary changes in a future filing.

The proposed charge types are just and reasonable because they allocate the costs of demand response regionally on an hourly basis to load, based on each Asset Owner's net Energy withdrawals at each Settlement Location. In this manner, the costs of demand response are allocated to each entity that benefits from a lower LMP in proportion to each entity's benefit (i.e., entities with larger withdrawals will benefit more from a reduced LMP than entities with smaller withdrawals), consistent with Order No. 745.[48]

The demand response compensation and cost allocation Tariff language proposed in this filing (described in Section II.B.2 below) applies across all hours in the Integrated Marketplace. While SPP acknowledges that the Order No. 745 mandates were limited to hours where the Net Benefits Test was met or exceeded,[49] allocating the costs of demand response regionally in all hours is just and reasonable given the current level of demand response participation in the SPP footprint and the expected level at the start of the Integrated Marketplace. In the EIS Market, of the approximately 1,500 MW of registered Demand Response Resources, 70 MW represented load-reducing demand response.[50] This load-reducing demand response withdrew from the EIS market in June of 2012. At the start of the Integrated Marketplace, 48 MW of load-reducing Demand Response Resources will be registered for participation.

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[47] May 2 Compliance Filing at 12.

[48] *See, e.g.*, Order No. 745 at P 102 ("We therefore find just and reasonable the requirement that each RTO and ISO allocate the costs associated with demand response compensation *proportionally* to all entities that purchase from the relevant energy market in the area(s) where the demand response reduces the market price for energy *at the time* when the demand response resource is committed or dispatched.") (emphasis added).

[49] Order No. 745-A at P 131 ("The Commission's section 206 action in Order No. 745 did not extend, however, to situations where the LMP is not greater than or equal to the threshold price.").

[50] As SPP noted in its Additional Response, the remaining demand response represents on-site generators that typically participate directly in the market by offering their generation as a Resource instead of offering in load reduction. Additional Response at 12 n.29. SPP expects this trend to continue in the Integrated Marketplace.

Given this level of demand response compared to the entire generation capacity in the SPP footprint, allocating the costs of all demand response on a regional basis will not have a significant impact on market prices or charges. As noted above, SPP will continue to monitor the impact of regional allocation of demand response costs and propose any necessary changes in a future filing after the Integrated Marketplace commences and SPP gains experience with demand response participation in its Day-Ahead Market and Real-Time Balancing Market ("RTBM").

2. Tariff Provisions

SPP proposes in this filing four new sections of Attachment AE to address the compensation of Demand Response Load in the Day-Ahead Market and RTBM and associated cost allocation for such payments. The proposed provisions dictate that Demand Response Load will be compensated at the LMP at the load's Settlement Location and that the costs of demand response will be allocated regionally.

With regard to demand response compensation in the Day-Ahead Market, SPP proposes Attachment AE Section 8.5.24 setting forth the methodology for calculating the "Day-Ahead Demand Reduction Amount," a payment calculated for each Asset Owner with registered load Settlement Locations containing one or more Demand Response Loads that are associated with cleared Demand Response Resource Offers in the Day-Ahead Market. Under Section 8.5.24, SPP calculates for each hour a Day-Ahead Demand Reduction Hourly Amount, which is the Day-Ahead LMP (at the Settlement Location containing the Demand Response Load(s)) multiplied by the Day-Ahead Total Demand Response Resource Hourly Quantity. The Day-Ahead Total Demand Response Resource Hourly Quantity is the sum of the MW quantities for cleared Demand Response Resources in the Day-Ahead Market that is associated with the Demand Response Load(s) at the Settlement Location.

For the RTBM, SPP proposes a similar compensation methodology in Attachment AE Section 8.6.21, with certain modifications necessary to account for the differences between the Day-Ahead Market and RTBM and the reporting of actual Demand Response Resource output (based on whether the Resource uses the Calculated Option or the Submitted Option). First, to account for differences between the amount of Demand Response Load offered and cleared in the Day-Ahead Market and the amount of actual demand response provided in the RTBM, SPP proposes to calculate the Real-Time Demand Reduction Amount as a payment or charge that results from multiplying the Real-Time LMP by the difference between the Real Time Total Demand Response Resource Billing Meter Quantity and the Day-Ahead Total Demand Response Resource Hourly Quantity (as calculated under Section 8.5.24), and then dividing by twelve to account for the twelve five-minute dispatch intervals in the RTBM. The Asset Owner's Real-Time Total Demand Response Resource Billing Meter Quantity is based on the actual metered value submitted by the Meter Agent. For Resources using the Submitted

Option, the value provided by the Meter Agent is the actual demand response output value;[51] for Resources using the Calculated Option (including all Block Demand Response Resources), the meter value must be multiplied by -1 to calculate the difference from the Resource's Baseline. Once the Real-Time Demand Reduction Dispatch Interval Amounts are calculated, they are summed to determine the Real-Time Demand Reduction Hourly Amount.

SPP's cost allocation provisions for the Day-Ahead Market and RTBM, which are set forth in Sections 8.5.25 and 8.6.22 of Attachment AE respectively, are substantially similar and establish region-wide cost allocation as discussed in Section II.B.1 above. Specifically, for the Day-Ahead Market, SPP calculates a Day-Ahead Demand Reduction Distribution Amount, which is calculated by multiplying the Day-Ahead Demand Reduction Distribution Rate by the Day-Ahead Demand Reduction Distribution Quantity. The Day-Ahead Demand Reduction Distribution Rate is the sum of all demand response payments as calculated under Section 8.5.24 of Attachment AE multiplied by -1 and then divided by the sum of all Asset Owners' Day-Ahead Demand Reduction Distribution Quantities for all Settlement Locations for the Hour. An individual Asset Owner's Day-Ahead Demand Reduction Distribution Quantity at a Settlement Location for an hour is equal to the Asset Owner's net cleared Energy withdrawals at that Settlement Location for the hour. By summing the market-wide demand response payments and dividing by the sum of all individual Asset Owner distribution quantities, the methodology establishes a single region-wide value that is then allocated to each Asset Owner based on its net withdrawal at each Settlement Location. In the RTBM, the Real-Time Demand Reduction Distribution Amount is calculated in a similar manner, but can either be a charge or a payment based on the value calculated under Section 8.6.21, which considers the difference between Day-Ahead Market clearing and actual RTBM performance.

III. EFFECTIVE DATE

SPP requests an effective date of March 1, 2014 for the Tariff revisions proposed in this filing, consistent with the effective date granted in the October 18 Order. To the extent required, SPP requests a waiver of the Commission's 60-day notice requirement[52] to permit a March 1, 2014 effective date. Good cause exists to grant the requested waiver because such an effective date will enable the Net Benefits Test to be effective on the same date the Integrated Marketplace commences, and because SPP is submitting this

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51 As SPP explained in its Order No. 719 compliance proceeding, under the Submitted Option, a demand response value is reported to SPP either by a retail service provider submitting the value or through net metering that reports both a load value and an output value. *See* Compliance Filing Revising Tariff of Southwest Power Pool, Inc., Docket No. ER12-550-001, at 8-9 (Dec. 17, 2012).

52 18 C.F.R. § 35.3.

filing within 30 days of the completion of its Order No. 745 compliance process for the EIS Market,[53] as directed by the October 18 Order.[54]

IV. ADDITIONAL INFORMATION REQUIRED BY THE COMMISSION

A. Documents Submitted With This Filing

In addition to this transmittal letter, SPP submits with this filing clean and redlined versions of revised Integrated Marketplace Tariff provisions in electronic format.

B. Effective Date

SPP requests that the Commission accept the proposed revisions to the SPP Tariff effective March 1, 2014, as discussed in more detail above.

C. Service

SPP has served a copy of this filing on all parties designated on the official service list compiled by the Secretary in Docket Nos. ER12-1179 and ER11-4105, as well as SPP's Members and Customers and all affected state commissions. A complete copy of this filing will be posted on the SPP web site, www.spp.org.

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53 The thirtieth day after the Commission issued the December 20 Order was January 19, 2014, which was a Sunday. The Commission was closed on Monday, January 20, 2014 and Tuesday, January 21, 2014, for a federal holiday and inclement weather, respectively, making Wednesday, January 22, 2014 the due date for this filing. 18 C.F.R. § 385.2007(a)(2).

54 October 18 Order at P 62.

V. CONCLUSION

For all of the foregoing reasons, SPP requests that the Commission accept the Tariff revisions proposed in this filing as just and reasonable and compliant with Order No. 745 and the October 18 Order, effective as discussed above. SPP also requests that the Commission grant all necessary waivers as discussed above.

Respectfully submitted,

/s/ Matthew J. Binette

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CERTIFICATE OF SERVICE

I hereby certify that I have this day served the foregoing document upon each person designated on the official service list compiled by the Secretary in Docket Nos. ER12-1179 and ER11-4105.

Dated at Washington, D.C., this 22nd day of January, 2014.

/s/ Matthew J. Binette
Matthew J. Binette

Attorney for
Southwest Power Pool, Inc.

ATTACHMENT AE
INTEGRATED MARKETPLACE

Attachment AE
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1.1 Definitions N

Net Benefits Test

A calculation that measures the threshold price at which the benefits of dispatching Demand Response Load outweigh the costs.

Network Integration Transmission Service

As defined in Section 1 of the Tariff.

Network Integration Transmission Service Auction Revenue Right Nomination Cap

The maximum amount of Network Integration Transmission Service Candidate Auction Revenue Rights that an Eligible Entity may nominate in each month and season in the annual Auction Revenue Right allocation process and the monthly Auction Revenue Right allocation process.

Network Integration Transmission Service Candidate Auction Revenue Right

The Megawatt quantity associated with Network Integration Transmission Service from Network Resources that the holder of the Network Integration Transmission Service can nominate for conversion into an Auction Revenue Right, subject to the Network Integration Transmission Service Auction Revenue Right Nomination Cap.

Network Model

A representation of the transmission, generation, and load elements of the interconnected Transmission System and the transmission systems of other regions in the Eastern Interconnection.

No-Load Offer

The compensation request in a Resource Offer, in dollars, by a Market Participant representing the hourly fee for operating a synchronized Resource at zero (0) Megawatt output. For a generating unit, No-Load Offers are generally representative of the fuel expense required to maintain synchronous speed at zero (0) Megawatt output. For a Dispatchable Demand Response Resource or Block Demand Response Resource, No-Load Offers are generally representative of a combination of the fuel expense required to maintain synchronous speed at zero (0) Megawatt output for Behind-The-Meter Generation and the ongoing hourly costs associated with manufacturing process changes associated with a reduction in load consumption.

Non-Conforming Load

Load that is process driven that does not follow a predictable pattern.

Non-Dispatchable Variable Energy Resource

A Variable Energy Resource that is not capable of being incrementally dispatched by the Transmission Provider.

3.9 Calculation of Net Benefits Test for Compensation of Demand Response Load

The Transmission Provider shall identify each month the price on a supply curve, representative of economic conditions expected for that month, at which the benefits of dispatching Demand Response Load exceed the costs of the load reductions to other loads ("Net Benefits Threshold"). In formulaic terms, the Net Benefits Threshold is deemed to be realized at the price point on the supply curve where the market price ("P") change attributable to dispatching Demand Response Load times the MWh consumed is greater than the new market price (after dispatching Demand Response Load) times the Demand Response Load, as set forth in the following formula:

(Delta P x MWh consumed) > (P_{NEW} x Demand Response Load),

where Delta P = P before Demand Response Load is dispatched minus P_{NEW}.

The Transmission Provider shall update and post the Net Benefits Test results and analysis for a calendar month no later than the 15th day of the preceding calendar month. The Net Benefits Threshold shall be calculated using the following steps:

Step 1: Retrieve historical energy imbalance service market offers for the peak hour of each day from the same calendar month (of the prior calendar year) for which the calculation is being performed

Step 2: Adjust a portion of each prior-year offer representing the typical share of fuel costs in energy offers in the SPP Region for changes in fuel prices based on the ratio of the reference month spot price to the study month forward price. For such purpose, natural gas shall be priced at the Henry Hub price, number 2 oil shall be priced at the Gulf Coast price, and coal shall be priced at the Powder River Basin price.

Step 3: Combine the offers to create an hourly supply curve for each daily peak hour in the period.

Step 4: Smooth each supply curve by fitting the following function to the raw data using a non-linear, least-squares regression:

$$P(MW) = A + B * MW + C * MW^2 + D * MW^3 + e^{(E*MW+F)},$$

where *P(MW)* is the historical energy imbalance service market offer price in \$/MWh, and *MW* is cumulative capacity. *A* through *F* are the parameters to be estimated.

Step 5: Compute the price elasticity of the smoothed supply curves at each *MW* point, finding the threshold price for each supply curve at which elasticity falls below one for the duration of the curve.

Step 6: Compute the average of the threshold prices identified in Step 5. This is the Net Benefits Threshold for the month.

8.5.24 Day-Ahead Demand Reduction Amount

A Day-Ahead Market payment will be calculated for each Asset Owner with registered load Settlement Locations containing one or more Demand Response Loads associated with cleared Demand Response Resource Offers for each applicable Settlement Location and each hour as follows:

Day-Ahead Demand Reduction Hourly Amount =

(Day-Ahead LMP) * (Day-Ahead Total Demand Response Resource Hourly Quantity)

(1) Day-Ahead LMP, as defined under Section 1 of this Attachment AE, for a load Settlement Location containing one or more Demand Response Loads associated with cleared Demand Response Resources Offers.

(2) An Asset Owner's Day-Ahead Total Demand Response Resource Hourly Quantity is the sum of the MW quantities for cleared Demand Response Resources in the Day-Ahead Market, as described under Section 5.1.3 of this Attachment AE, that are associated with one or more Demand Response Loads contained within the load Settlement Location referenced in (1) above.

8.5.25 Day-Ahead Demand Reduction Distribution Amount

The Day-Ahead demand reduction distribution amount is an hourly charge to Asset Owners at each Settlement Location to recover the sum of the demand reduction payments made under Section 8.5.24 of this Attachment AE and is calculated as:

Day-Ahead Demand Reduction Distribution Amount =
(Day-Ahead Demand Reduction Distribution Rate) * (Day-Ahead Demand Reduction Distribution Quantity))

(1) The Day-Ahead Demand Reduction Distribution Rate is the sum of all demand reduction payments for the Hour as calculated under Section 8.5.24 of this Attachment AE multiplied by (-1), divided by the sum of all Asset Owners' Day-Ahead Demand Reduction Distribution Quantities for all Settlement Locations for the Hour.

(2) An Asset Owner's Day-Ahead Demand Reduction Distribution Quantity at a Settlement Location for an hour is equal to that Asset Owner's net cleared Energy withdrawals at that Settlement Location for that hour. An Asset Owner's net cleared Energy withdrawal at a Settlement Location is calculated as the sum of the positive MWh value for the Asset Owner's cleared Demand Bids, the positive MWh value for the Asset Owner's net cleared Export and Import Interchange Transactions, the positive MWh value for the Asset Owner's net cleared Virtual Energy Bids and Offers at that Settlement Location.

8.6.21 Real-Time Demand Reduction Amount

A Real-Time Balancing Market payment or charge will be calculated for each Asset Owner with registered load Settlement Locations containing one or more Demand Response Loads associated with the difference between actual Demand Response Resource output and cleared Day-Ahead Market Demand Response Resource Offers for each applicable Settlement Location and each Dispatch Interval as follows:

(1) Real-Time Demand Reduction Dispatch Interval Amount =

[(Real-Time LMP) * (Real-Time Total Demand Response Resource Billing Meter Quantity – Day-Ahead Total Demand Response Resource Hourly Quantity)] / 12

(a) Real-Time LMP, as defined under Section 1 of this Attachment AE, for a load Settlement Location containing one or more Demand Response Loads associated with committed and dispatched Demand Response Resources.

(b) An Asset Owner's Real-Time Total Demand Response Resource Billing Meter Quantity is equal to the sum of that Asset Owner's Real-Time Demand Response Resource Billing Meter Quantities for each Demand Response Resource associated with the load Settlement Location referenced in (1) above.

(c) An Asset Owner's Real-Time Demand Response Resource Billing Meter Quantity for each Demand Response Resource Settlement Location is:

(i) For a Dispatchable Demand Response Resource selecting the submitted Resource production option as described under Section 4.1.2.1(1)(a) of this Attachment AE, either (i) the five (5) minute actual meter MWh Resource output quantity submitted by the Meter Agent to the Transmission Provider, multiplied by twelve (12); or (ii) the hourly actual meter MWh Resource output quantity profiled into five (5) minute increments by the Transmission Provider using the method described under Section 8.6 of this Attachment AE if the Asset Owner elects to submit hourly meter data; or

(ii) For a Dispatchable Demand Response Resource selecting the calculated Resource production option as described under Section 4.1.2.1(1)(b) of this Attachment AE and Block Demand Response Resources, either (i) the five (5) minute actual meter MWh output quantity of the associated Demand Response Load submitted by the Meter Agent to the Transmission Provider, multiplied by twelve (12) or (ii) the hourly actual meter MWh output quantity of the associated Demand Response Load profiled into five (5) minute increments by the Transmission Provider using the method described under Section 8.6 of this Attachment AE if the Asset Owner elects to submit hourly meter data. The Transmission Provider then calculates the Demand Response Resource output as described under Section 4.1.2.1(1)(b)(ii) and multiplies the result by (-1).

(d) An Asset Owner's Day-Ahead Total Demand Response Resource Hourly Quantity is the value calculated under Section 8.5.24(2) of this Attachment AE for the applicable load Settlement Location.

(2) Real-Time Demand Reduction Hourly Amount =

Sum of Real-Time Demand Reduction Dispatch Interval Amount over all Dispatch Intervals in the Hour.

8.6.22 Real-Time Demand Reduction Distribution Amount

The Real-Time demand reduction distribution amount is an hourly payment or charge to Asset Owners at each Settlement Location to account for the sum of the demand reduction amounts calculated under Section 8.6.21 of this Attachment AE and is calculated as:

Real-Time Demand Reduction Distribution Amount =

(Real-Time Demand Reduction Distribution Rate) * (Real-Time Demand Reduction Distribution Quantity)

(1) Real-Time Demand Reduction Distribution Rate is the sum of all demand reduction payments for the Hour as calculated under Section 8.6.21 of this Attachment AE multiplied by (-1), divided by the sum of all Asset Owner's Real-Time Demand Reduction Distribution Quantities for all Settlement Locations for the hour.

(2) An Asset Owner's Real-Time Demand Reduction Distribution Quantity for an hour is equal to that Asset Owner's net actual Energy withdrawals at that Settlement Location for that hour. An Asset Owner's net actual Energy withdrawal at a Settlement Location is calculated as the sum of the positive MWh value for the Asset Owner's metered withdrawals and the positive MWh value for the Asset Owner's net Export and Import Interchange Transactions at that Settlement Location.

ATTACHMENT AE
INTEGRATED MARKETPLACE

Attachment AE
Table of Contents

1.1 Definitions N

Net Benefits Test

A calculation that measures the threshold price at which the benefits of dispatching Demand Response Load outweigh the costs.

Network Integration Transmission Service

As defined in Section 1 of the Tariff.

Network Integration Transmission Service Auction Revenue Right Nomination Cap

The maximum amount of Network Integration Transmission Service Candidate Auction Revenue Rights that an Eligible Entity may nominate in each month and season in the annual Auction Revenue Right allocation process and the monthly Auction Revenue Right allocation process.

Network Integration Transmission Service Candidate Auction Revenue Right

The Megawatt quantity associated with Network Integration Transmission Service from Network Resources that the holder of the Network Integration Transmission Service can nominate for conversion into an Auction Revenue Right, subject to the Network Integration Transmission Service Auction Revenue Right Nomination Cap.

Network Model

A representation of the transmission, generation, and load elements of the interconnected Transmission System and the transmission systems of other regions in the Eastern Interconnection.

No-Load Offer

The compensation request in a Resource Offer, in dollars, by a Market Participant representing the hourly fee for operating a synchronized Resource at zero (0) Megawatt output. For a generating unit, No-Load Offers are generally representative of the fuel expense required to maintain synchronous speed at zero (0) Megawatt output. For a Dispatchable Demand Response Resource or Block Demand Response Resource, No-Load Offers are generally representative of a combination of the fuel expense required to maintain synchronous speed at zero (0) Megawatt output for Behind-The-Meter Generation and the ongoing hourly costs associated with manufacturing process changes associated with a reduction in load consumption.

Non-Conforming Load

Load that is process driven that does not follow a predictable pattern.

Non-Dispatchable Variable Energy Resource

A Variable Energy Resource that is not capable of being incrementally dispatched by the Transmission Provider.

3.9 Calculation of Net Benefits Test for Compensation of Demand Response Load

The Transmission Provider shall identify each month the price on a supply curve, representative of economic conditions expected for that month, at which the benefits of dispatching Demand Response Load exceed the costs of the load reductions to other loads ("Net Benefits Threshold"). In formulaic terms, the Net Benefits Threshold is deemed to be realized at the price point on the supply curve where the market price ("P") change attributable to dispatching Demand Response Load times the MWh consumed is greater than the new market price (after dispatching Demand Response Load) times the Demand Response Load, as set forth in the following formula:

(Delta P x MWh consumed) > (P_{NEW} x Demand Response Load),

where Delta P = P before Demand Response Load is dispatched minus $P_{NEW.}$

The Transmission Provider shall update and post the Net Benefits Test results and analysis for a calendar month no later than the 15th day of the preceding calendar month. The Net Benefits Threshold shall be calculated using the following steps:

Step 1: Retrieve historical energy imbalance service market offers for the peak hour of each day from the same calendar month (of the prior calendar year) for which the calculation is being performed

Step 2: Adjust a portion of each prior-year offer representing the typical share of fuel costs in energy offers in the SPP Region for changes in fuel prices based on the ratio of the reference month spot price to the study month forward price. For such purpose, natural gas shall be priced at the Henry Hub price, number 2 oil shall be priced at the Gulf Coast price, and coal shall be priced at the Powder River Basin price.

Step 3: Combine the offers to create an hourly supply curve for each daily peak hour in the period.

Step 4: Smooth each supply curve by fitting the following function to the raw data using a non-linear, least-squares regression:

$$P(MW) = A + B * MW + C * MW^2 + D * MW^3 + e^{(E*MW+F)},$$

where *P(MW)* is the historical energy imbalance service market offer price in \$/MWh, and *MW* is cumulative capacity. *A* through *F* are the parameters to be estimated.

Step 5: Compute the price elasticity of the smoothed supply curves at each *MW* point, finding the threshold price for each supply curve at which elasticity falls below one for the duration of the curve.

Step 6: Compute the average of the threshold prices identified in Step 5. This is the Net Benefits Threshold for the month.

8.5.24 Day-Ahead Demand Reduction Amount

A Day-Ahead Market payment will be calculated for each Asset Owner with registered load Settlement Locations containing one or more Demand Response Loads associated with cleared Demand Response Resource Offers for each applicable Settlement Location and each hour as follows:

Day-Ahead Demand Reduction Hourly Amount =

(Day-Ahead LMP) * (Day-Ahead Total Demand Response Resource Hourly Quantity)

(1) Day-Ahead LMP, as defined under Section 1 of this Attachment AE, for a load Settlement Location containing one or more Demand Response Loads associated with cleared Demand Response Resources Offers.

(2) An Asset Owner's Day-Ahead Total Demand Response Resource Hourly Quantity is the sum of the MW quantities for cleared Demand Response Resources in the Day-Ahead Market, as described under Section 5.1.3 of this Attachment AE, that are associated with one or more Demand Response Loads contained within the load Settlement Location referenced in (1) above.

8.5.25 Day-Ahead Demand Reduction Distribution Amount

The Day-Ahead demand reduction distribution amount is an hourly charge to Asset Owners at each Settlement Location to recover the sum of the demand reduction payments made under Section 8.5.24 of this Attachment AE and is calculated as:

Day-Ahead Demand Reduction Distribution Amount =
(Day-Ahead Demand Reduction Distribution Rate) * (Day-Ahead Demand Reduction Distribution Quantity))

(1) The Day-Ahead Demand Reduction Distribution Rate is the sum of all demand reduction payments for the Hour as calculated under Section 8.5.24 of this Attachment AE multiplied by (-1), divided by the sum of all Asset Owners' Day-Ahead Demand Reduction Distribution Quantities for all Settlement Locations for the Hour.

(2) An Asset Owner's Day-Ahead Demand Reduction Distribution Quantity at a Settlement Location for an hour is equal to that Asset Owner's net cleared Energy withdrawals at that Settlement Location for that hour. An Asset Owner's net cleared Energy withdrawal at a Settlement Location is calculated as the sum of the positive MWh value for the Asset Owner's cleared Demand Bids, the positive MWh value for the Asset Owner's net cleared Export and Import Interchange Transactions, the positive MWh value for the Asset Owner's net cleared Virtual Energy Bids and Offers at that Settlement Location.

8.6.21 Real-Time Demand Reduction Amount

A Real-Time Balancing Market payment or charge will be calculated for each Asset Owner with registered load Settlement Locations containing one or more Demand Response Loads associated with the difference between actual Demand Response Resource output and cleared Day-Ahead Market Demand Response Resource Offers for each applicable Settlement Location and each Dispatch Interval as follows:

(1) Real-Time Demand Reduction Dispatch Interval Amount =

[(Real-Time LMP) * (Real-Time Total Demand Response Resource Billing Meter Quantity – Day-Ahead Total Demand Response Resource Hourly Quantity)] / 12

(a) Real-Time LMP, as defined under Section 1 of this Attachment AE, for a load Settlement Location containing one or more Demand Response Loads associated with committed and dispatched Demand Response Resources.

(b) An Asset Owner's Real-Time Total Demand Response Resource Billing Meter Quantity is equal to the sum of that Asset Owner's Real-Time Demand Response Resource Billing Meter Quantities for each Demand Response Resource associated with the load Settlement Location referenced in (1) above.

(c) An Asset Owner's Real-Time Demand Response Resource Billing Meter Quantity for each Demand Response Resource Settlement Location is:

(i) For a Dispatchable Demand Response Resource selecting the submitted Resource production option as described under Section 4.1.2.1(1)(a) of this Attachment AE, either (i) the five (5) minute actual meter MWh Resource output quantity submitted by the Meter Agent to the Transmission Provider, multiplied by twelve (12); or (ii) the hourly actual meter MWh Resource output quantity profiled into five (5) minute increments by the Transmission Provider using the method described under Section 8.6 of this Attachment AE if the Asset Owner elects to submit hourly meter data; or

(ii) For a Dispatchable Demand Response Resource selecting the calculated Resource production option as described under Section 4.1.2.1(1)(b) of this Attachment AE and Block Demand Response Resources, either (i) the five (5) minute actual meter MWh output quantity of the associated Demand Response Load submitted by the Meter Agent to the Transmission Provider, multiplied by twelve (12) or (ii) the hourly actual meter MWh output quantity of the associated Demand Response Load profiled into five (5) minute increments by the Transmission Provider using the method described under Section 8.6 of this Attachment AE if the Asset Owner elects to submit hourly meter data. The Transmission Provider then calculates the Demand Response Resource output as described under Section 4.1.2.1(1)(b)(ii) and multiplies the result by (-1).

(d) An Asset Owner's Day-Ahead Total Demand Response Resource Hourly Quantity is the value calculated under Section 8.5.24(2) of this Attachment AE for the applicable load Settlement Location.

(2) Real-Time Demand Reduction Hourly Amount =

Sum of Real-Time Demand Reduction Dispatch Interval Amount over all Dispatch Intervals in the Hour.

8.6.22 Real-Time Demand Reduction Distribution Amount

The Real-Time demand reduction distribution amount is an hourly payment or charge to Asset Owners at each Settlement Location to account for the sum of the demand reduction amounts calculated under Section 8.6.21 of this Attachment AE and is calculated as:

Real-Time Demand Reduction Distribution Amount =
(Real-Time Demand Reduction Distribution Rate) * (Real-Time Demand Reduction Distribution Quantity)

(1) Real-Time Demand Reduction Distribution Rate is the sum of all demand reduction payments for the Hour as calculated under Section 8.6.21 of this Attachment AE multiplied by (-1), divided by the sum of all Asset Owner's Real-Time Demand Reduction Distribution Quantities for all Settlement Locations for the hour.

(2) An Asset Owner's Real-Time Demand Reduction Distribution Quantity for an hour is equal to that Asset Owner's net actual Energy withdrawals at that Settlement Location for that hour. An Asset Owner's net actual Energy withdrawal at a Settlement Location is calculated as the sum of the positive MWh value for the Asset Owner's metered withdrawals and the positive MWh value for the Asset Owner's net Export and Import Interchange Transactions at that Settlement Location.