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October 11, 2012

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

**Re: PJM Open Access Transmission Tariff Revisions to Modify Cost  
Allocation for PJM Required Transmission Enhancements  
Docket No. ER13-\_\_\_\_ - 000**

Dear Secretary Bose:

Pursuant to section 205 of the Federal Power Act (“FPA”),<sup>1</sup> Part 35 of the regulations of the Federal Energy Regulatory Commission (“FERC” or “Commission”),<sup>2</sup> and Section 9.1(a) of the PJM Interconnection, L.L.C. (“PJM”) Open Access Transmission Tariff (“PJM Tariff”), the PJM Transmission Owners, acting through the PJM Consolidated Transmission Owners Agreement (“CTOA”),<sup>3</sup> respectfully submit revised tariff sheets showing modifications to Schedule 12 of the PJM Tariff, relating to the allocation of costs of transmission system expansions and enhancements approved by PJM in its development of its Regional Transmission Expansion Plan (“RTEP”). The PJM Transmission Owners propose an effective date of February 1, 2013 for the revised tariff sheets.<sup>4</sup>

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<sup>1</sup> 16 U.S.C. § 824d (2006).

<sup>2</sup> 18 C.F.R. Pt. 35 (2012).

<sup>3</sup> PJM Interconnection, L.L.C., Consolidated Transmission Owners Agreement, Rate Schedule F.E.R.C. No. 42 (June 19, 2008). This filing has been authorized pursuant to the individual and weighted voting requirements in Section 8.5 of the CTOA. In addition, pursuant to section 9.1(b) of the PJM Tariff, the PJM Transmission Owners consulted with PJM and the PJM Members Committee during a meeting on July 18, 2012; during a conference call on September 5, 2012; and through invitations to submit written comments by August 1, 2012 and September 19, 2012. Notices of the PJM Transmission Owners’ intention to file these PJM Tariff revisions were distributed to the PJM Members Committee and posted on the PJM website on June 13, 2012; August 29, 2012; and September 7, 2012.

<sup>4</sup> Pursuant to *Order No. 714*, this filing is being submitted by PJM on behalf of the PJM Transmission Owners as part of an XML filing package that conforms with the Commission’s regulations. Pursuant to Section 9.1(b) of the PJM Tariff, PJM has agreed to make all filings on behalf of the PJM Transmission Owners in order to retain administrative control over the PJM Tariff. Thus, the PJM Transmission Owners

As explained below, the PJM Tariff revisions proposed in this filing ensure that these costs are allocated in a manner that is just, reasonable, and not unduly discriminatory or preferential, as section 205 requires, and also complies with the requirements of *Order No. 1000* relating to regional cost allocation.<sup>5</sup> The proposed revisions would resolve on a prospective basis a long-standing controversy concerning the allocation of the cost of high-voltage transmission projects included in the RTEP and have been reviewed with PJM stakeholders.

The PJM Transmission Owners note that PJM will be separately submitting a filing to demonstrate its compliance with other requirements of *Order No. 1000*, including those relating to the regional transmission planning process. Under section 9.1 of the PJM Tariff and Article 7 of the CTOA, the PJM Transmission Owners have the exclusive authority and responsibility to submit filings under section 205 “in or relating to . . . the transmission rate design under the PJM Tariff.” The PJM Transmission Owners understand that PJM plans to point to this filing to demonstrate compliance with the regional cost allocation requirements of the order.<sup>6</sup>

## I. INTRODUCTION

The purpose of this filing is to propose modifications to provisions of Schedule 12 of the PJM Tariff establishing the allocation of costs of regional transmission projects that PJM determines in the RTEP process to be needed. As modified, Schedule 12 will reflect prospectively a newly emerged consensus among the PJM Transmission Owners on a just and reasonable cost allocation methodology for such projects.<sup>7</sup> The consensus cost allocation methodology proposed in this filing also complies fully with the regional cost allocation requirements of *Order No. 1000*. With these changes, Schedule 12 will contain cost allocation provisions applicable to all categories of Required Transmission Enhancements approved by the PJM Board of Managers (“PJM Board”) in the RTEP

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have requested that PJM submit the revised Schedule 12 to the PJM Tariff in the eTariff system as part of PJM's electronic Intra PJM Tariff.

<sup>5</sup> *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, FERC Stats. & Regs. ¶ 31,323 (2011), *order on reh'g and clarification*, Order No. 1000-A, 139 FERC ¶ 61,132 (2012).

<sup>6</sup> The PJM Transmission Owners note that PJM's compliance filing will be submitted in accordance with the requirements of the Commission's September 19, 2012 “Notice of Filing Procedures for Order No. 1000 Electronic Compliance Filings,” issued in Docket No. RM10-23-000. Inasmuch as this filing is submitted under section 205 of the FPA, those requirements are inapplicable. *See Order No. 1000* at P 797 (“public utility transmission owners that are part of Commission-jurisdictional RTOs and ISOs may demonstrate compliance through that RTO's or ISO's compliance filing and are not required to make a separate compliance filing”). The PJM Transmission Owners reserve their rights to take any position, either individually or jointly, on PJM's compliance filing.

<sup>7</sup> These projects are referred to in Schedule 12 as “Required Transmission Enhancements.”

process as set forth in the current PJM Operating Agreement<sup>8</sup> or in revisions to the RTEP process that PJM is proposing in its own compliance filing for *Order No. 1000*.<sup>9</sup>

The existing cost allocation for high voltage Required Transmission Enhancements found necessary in the RTEP, which was first approved in *Opinion No. 494*,<sup>10</sup> has been the subject of considerable controversy and litigation, which remains ongoing. The most recent Commission ruling was issued on remand from the U.S. Court of Appeals<sup>11</sup> and requests for rehearing are pending. In the *Opinion No. 494* litigation, various parties, including individual PJM Transmission Owners, have argued for two very different approaches to the cost allocation of regional high capacity transmission facilities: a “postage-stamp” approach and a “violation-based” distribution factor (or “DFAX”) analysis, each of which is discussed in more detail below. Each side of this debate has asserted that its preferred approach is consistent with the cost causation principles articulated by the Commission and the courts and that the other side’s approach is not.<sup>12</sup>

The proposed revisions to the cost allocation for Required Transmission Enhancements represent a compromise among the PJM Transmission Owners’ positions. They incorporate a hybrid cost allocation methodology that includes elements from the positions advocated by both sides of the *Opinion No. 494* debate. It has the near unanimous support of the PJM Transmission Owners. The Commission recognized in the *Order on Remand* that it would be appropriate to consider such a hybrid approach in the context of *Order No. 1000* compliance<sup>13</sup> and Commissioner LaFleur specifically endorsed a hybrid approach in her dissent to the *Order on Remand*.<sup>14</sup> The PJM Transmission Owners believe that, as shown below, the cost allocation methodology resulting from this compromise is just, reasonable, and not unduly discriminatory or preferential and satisfies the regional cost allocation principles set forth in *Order No. 1000*.

The PJM Transmission Owners note that the proposed revisions will apply only to Required Transmission Enhancements approved by the PJM Board for inclusion in an

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<sup>8</sup> Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., Schedule 6 (the “RTEP Protocol”).

<sup>9</sup> Whenever changes are proposed to the regional planning process, the PJM Transmission Owners consider whether changes to cost allocation are necessary and appropriate.

<sup>10</sup> *PJM Interconnection, L.L.C.*, Opinion No. 494, 119 FERC ¶ 61,063 (2007), *vacated and remanded*, *Ill. Commerce Comm’n v. FERC*, 576 F.3d 470 (7th Cir. 2009).

<sup>11</sup> *PJM Interconnection, L.L.C.*, 138 FERC ¶ 61,230 (2012) (“*Order on Remand*”).

<sup>12</sup> Although they today jointly propose a compromise cost allocation to be applied on a prospective basis, each PJM Transmission Owner explicitly preserves all rights and positions in the *Opinion No. 494* remand litigation, including rights to seek and take any position on judicial review.

<sup>13</sup> *Order on Remand* at P 2.

<sup>14</sup> *Id.*, La Fleur dissent at 3. See also Statement of Commissioner Philip D. Moeller on the PJM Remand Order, at 4, Docket No. EL05-121-006 (Mar. 30, 2012).

RTEP after the effective date of these revisions. As discussed below, the PJM Transmission Owners propose a February 1, 2013 effective date. The proposed revisions will not apply to or require reallocation of the costs of transmission facilities already completed or included in an RTEP prior to the effective date of these revisions.

## II. BACKGROUND

### A. Current PJM Cost Allocation Methodology

The existing cost allocation methodology for Required Transmission Enhancements PJM determines in the RTEP to be needed is set forth in Schedule 12 of the PJM Tariff. Facilities planned through the RTEP are divided into two categories: (1) Regional Facilities and Necessary Lower Voltage Facilities; and (2) Lower Voltage Facilities.

Regional Facilities are Required Transmission Enhancements that are included in the RTEP and operate at or above 500 kV. Necessary Lower Voltage Facilities are Required Transmission Enhancements that are below the voltage threshold for a Regional Facility but that must be constructed or strengthened to support new Regional Facilities. Schedule 12 allocates the cost of these facilities through a postage-stamp rate, *i.e.*, to load Zones on an annual load ratio share basis and to Merchant Facilities according to Firm Transmission Withdrawal rights.<sup>15</sup> The justness and reasonableness of this allocation methodology is the subject of the pending rehearing requests of the *Order on Remand*.

Required Transmission Enhancements included in the RTEP that are planned to operate below 500 kV and are not Necessary Lower Voltage Facilities are subject to two different cost allocation methodologies, depending on the reason PJM has determined that the upgrade is needed. Costs of Required Transmission Enhancements that are included in the RTEP in order to resolve a reliability criteria violation or for operational performance are allocated using a DFAX analysis if the estimated cost of the project is \$5 million or greater.<sup>16</sup> The distribution factor analysis is “Violation-Based,” *i.e.*, the cost allocation is based on the relative contributions of loads and merchant facilities to flows on the constrained facility that would violate reliability criteria if the upgrade were not installed. This methodology is described in the attached testimony of Mr. Steven R. Herling, PJM’s Vice-President of Planning.<sup>17</sup> Schedule 12 allocates costs for new below 500 kV facilities

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<sup>15</sup> PJM Tariff, Schedule 12, § (b)(i).

<sup>16</sup> *Id.* § (b)(iii)(C). If the cost of a lower voltage upgrade included in the RTEP for reliability or operational purposes is estimated to be less than \$5 million, the cost is assigned to the load Zone in which the upgrade is to be located.

<sup>17</sup> Testimony of Steven R. Herling, attached as Exh. No. PTO-1, at 3-7 (“Exh. No. PTO-1”). The current PJM Tariff provisions implementing use of Violation-Based DFAX to allocate the costs of Lower Voltage Facilities were adopted in a September 14, 2007 settlement agreement approved by the Commission on July 29, 2008 in Docket Nos. ER06-456-013, *et al.* See *PJM Interconnection, L.L.C.*, 124 FERC ¶ 61,112 (2008).

included in the RTEP to resolve an economic constraint based on each load zone's pro rata share of the decreases in load energy payments that result from the new facility in the zones that experience a decrease.<sup>18</sup>

As described below, the costs of certain types of transmission projects are not allocated under Schedule 12 of the Tariff. These transmission projects include attachment facilities and network upgrades required to interconnect new generators or merchant transmission facilities. The Tariff allocates the costs of such attachment facilities and network upgrades to interconnection customers in accordance with a "but for" test.<sup>19</sup> Similarly, the allocation of the costs of transmission expansions and enhancements that are required to ensure the simultaneous feasibility of certain auction revenue rights and included in the RTEP is addressed under the PJM Operating Agreement.<sup>20</sup> The costs of a merchant transmission facility, which is included in the RTEP for informational purposes, provided it meets the tariff requirements, including compatibility with reliability criteria, are the responsibility of its owner and are not eligible for cost allocation under Schedule 12.<sup>21</sup> The RTEP Protocol also recognizes that a transmission project that PJM does not find to be necessary to satisfy the requirements for the RTEP can proceed as a Supplemental Project.<sup>22</sup> A Supplemental Project, too, is included in the RTEP for informational purposes and its costs are not eligible for cost allocation under Schedule 12.<sup>23</sup> The PJM Transmission Owners do not propose to modify the cost allocation for any of these categories of transmission projects.

## **B. Development of the Cost Allocation Revisions Proposed in this Filing and Consultation with Stakeholders**

Over a year ago, following the issuance of *Order No. 1000*, the PJM Transmission Owners began an intense process to explore the possibility of a compromise cost allocation methodology for Required Transmission Enhancements that would satisfy the just and

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<sup>18</sup> PJM Tariff, Schedule 12, § (b)(iii)(C). If PJM modifies a below 500 kV reliability project to address an economic constraint, the project's costs are still allocated using the DFAX methodology. *Id.*, § (b)(iii)(B). If PJM accelerates a below 500 kV reliability project to address an economic constraint, the project's costs are allocated based on a comparison between the results of a DFAX analysis and an analysis of the expected benefits from the reduced locational marginal prices. *Id.*, § (b)(iii)(A).

<sup>19</sup> See PJM Tariff, §§ 217.1, 217.3.

<sup>20</sup> RTEP Protocol, § 1.5.6(g)(C).

<sup>21</sup> *Id.* § 1.5.6(e).

<sup>22</sup> *Id.* § 1.42A.02.

<sup>23</sup> *Id.* § 1.6(a). The proposed tariff revisions do, however, clarify, that a transmission project that addresses a public policy requirement, but is not included in the RTEP to meet reliability or economic needs could be pursued as a Supplemental Project (whether or not it is the result of the "State Agreement" approach discussed below). See Proposed Schedule 12, § (b)(xii)(A). The owner of a Supplemental Project can recover the costs of its project from transmission customers through rates filed pursuant to section 205 of the FPA.

reasonable standard and comply with the requirements of *Order No. 1000*. In the period from August 23, 2011, through June 7, 2012, the PJM Transmission Owners, including various task forces and subgroups, participated in dozens of meetings and conference calls regarding cost allocation. PJM participated in this process and provided necessary guidance regarding the RTEP process, including changes proposed in connection with *Order No. 1000* compliance, and the feasibility of various proposed cost allocation solutions. By the end of the process, the participants had reached near unanimous agreement on the principles that form the basis of the cost allocation methodology proposed in this filing.<sup>24</sup>

Consistent with the CTOA and *Order No. 1000*, on June 18, 2012, the PJM Transmission Owners presented the principles of the cost allocation methodology to the Organization of PJM States, the PJM Members Committee, and posted the principles for the information of other PJM stakeholders.<sup>25</sup> On July 18, 2012, the PJM Transmission Owners along with representatives from PJM convened a meeting of PJM stakeholders to introduce, discuss, and answer questions about the proposed cost allocation. PJM stakeholders were also given the opportunity to submit written comments on the proposed rate design. The PJM Transmission Owners received written comments from ten stakeholders, some of which sought additional clarification of the proposed rate design.<sup>26</sup> On August 29, 2012, the PJM Transmission Owners provided additional clarification of their proposal, based in part on consideration of the stakeholder comments, and, on September 5, 2012, held a second stakeholder meeting via conference call. Two stakeholders provided written comments after that meeting.

The PJM Transmission Owners gave final approval to the proposed tariff revisions on September 20, 2012. Twelve of the fourteen PJM Transmission Owners that have the right to approve amendments to Schedule 12, which together represent 99.9 percent of the regulated transmission investment in the PJM region, supported the revisions. None of those PJM Transmission Owners opposed the revisions.<sup>27</sup>

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<sup>24</sup> The tariff revisions proposed in this filing use different terminology than was used in the statement of principles on which the PJM Transmission Owners agreed in order to conform to the terminology used in the PJM Tariff.

<sup>25</sup> Section 7.3.2 of the CTOA provides that the PJM Transmission Owners will “consult with PJM and the PJM Members Committee beginning no less than thirty (30) days prior to any Section 205 filing,” with certain exceptions not relevant here. In *Order No. 1000*, the Commission stated that transmission providers should consult with stakeholders in connection with the development of cost allocation methodologies. See *Order No. 1000* at PP 588, 794.

<sup>26</sup> The stakeholders’ comments, as well as the PJM Transmission Owners’ response to those comments, may be found at <http://www.pjm.com/forms/registration/Meeting%20Registration.aspx?ID={A5C9D1B6-8BCC-4FEA-A9C9-09ADB6650E33}>.

<sup>27</sup> One Transmission Owner abstained; one Transmission Owner was absent.

### III. PROPOSED TARIFF REVISIONS

The PJM Transmission Owners propose revisions to Schedule 12 of the PJM Tariff to modify the current cost allocation methodology for Required Transmission Enhancements. Like the existing cost allocation methodology, the revised cost allocation methodology proposed in this filing implements PJM's RTEP process, as embodied in the RTEP Protocol (Schedule 6 of the PJM Operating Agreement).<sup>28</sup> The RTEP Protocol currently authorizes PJM to approve transmission additions and enhancements to address reliability violations or operational adequacy and performance issues ("Reliability Projects")<sup>29</sup> and to relieve economic constraints ("Economic Projects").<sup>30</sup> PJM's separate *Order No. 1000* compliance proposal preserves these categories of transmission enhancements or additions and this filing includes cost allocation methodologies for both of these categories. PJM's *Order No. 1000* compliance filing also provides for the development of additional transmission upgrades to address public policy requirements through a "State Agreement" approach.<sup>31</sup> As discussed below, this filing also addresses the allocation of the costs of such projects. Thus, the revised cost allocation methodology establishes methods for allocating the costs of each type of project that PJM is authorized to approve under the RTEP process as currently in place and as PJM proposes to amend it in compliance with *Order No. 1000*.

This filing builds upon the framework of the current cost allocation methodology, proposing revisions to implement the compromise among the PJM Transmission Owners. The PJM Transmission Owners making this filing have a variety of viewpoints regarding the "best" allocation methodology, as do other stakeholders, but the PJM Transmission Owners have concluded that the consensus proposal presented in this filing represents a just and reasonable methodology that meets the six regional cost allocation principles set forth in *Order No. 1000*.<sup>32</sup> This discussion summarizes the significant features of the proposal, which is described in greater detail in the joint testimony of Michelle Henry and Frank J. Richardson.<sup>33</sup>

#### A. Distinction Between Regional Facilities and Lower Voltage Facilities

The proposed cost allocation continues to distinguish between Regional Facilities and Necessary Lower Voltage Facilities, on one hand, and lower voltage facilities on the

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<sup>28</sup> Joint Testimony of Michelle Henry and Frank J. Richardson on behalf of the PJM Transmission Owners, attached hereto as Exh. No. PTO-2, at 5-8 ("PTO-2").

<sup>29</sup> RTEP Protocol, § 1.5.6.

<sup>30</sup> *Id.* § 1.5.7.

<sup>31</sup> Exh. No. PTO-2 at 38-39.

<sup>32</sup> The consistency of this proposal with the *Order No. 1000* regional cost allocation principles is addressed in section IV, below.

<sup>33</sup> Exh. No. PTO-2.

other. The proposal revises the definition of Regional Facilities to include double-circuit facilities planned to operate at voltages of at least 345 kV, but less than 500 kV, as well as all facilities planned to operate at 500 kV or above.<sup>34</sup> In order to qualify as a Regional Facility, each of the circuits of a double-circuit 345 kV facility must begin at a single substation and end at a single substation, but they need not share a single right-of-way. As discussed in the testimony of Ms. Henry and Mr. Richardson, the revised definition of Regional Facilities recognizes the fact that double-circuit 345 kV facilities serve a purpose in the western portion of PJM that is substantially similar to the purpose served by 500 kV facilities in the eastern portion.<sup>35</sup> The revised definition thus provides comparable treatment to projects in the different portions of the PJM region.<sup>36</sup> Necessary Lower Voltage Facilities are defined in the same manner as the current tariff: new facilities or expansions or enhancements to existing Transmission Facilities that are below the applicable voltage limit for a Regional Facility, but that must be constructed or strengthened to support new Regional Facilities.<sup>37</sup> Lower Voltage Facilities are defined as Required Transmission Enhancements that are neither Regional Facilities nor Necessary Lower Voltage Facilities.<sup>38</sup>

## **B. Hybrid Methodology for Allocating the Costs of Regional Facilities**

The proposal uses a hybrid approach to allocate the cost of Regional Facilities and Necessary Lower Voltage Facilities. As explained below, this approach allocates a portion of the costs of these projects to beneficiaries that PJM identifies specifically and the remainder to customers throughout the region, in recognition of the other benefits that these projects provide. Under this approach, one-half of each project's cost is allocated on a postage-stamp basis, *i.e.*, to zones on a load ratio share basis and to merchant transmission facilities in proportion to awarded Firm Transmission Withdrawal Rights.<sup>39</sup> This is the method used in the current PJM Tariff for the entire cost of Regional Facilities. The methodologies used to allocate the other half of the cost of Regional Facilities and Necessary Lower Voltage Facilities allocate costs to specifically identified beneficiaries of each project. The proposal uses different methodologies to identify specific beneficiaries of Reliability Projects and Economic Projects.

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<sup>34</sup> Proposed Schedule 12, § (b)(i). If a double-circuit 345 kV facility included in the RTEP is a combination of an existing and a new facility, only the cost of the new facility will be allocated as a Regional Facility, along with the remaining undepreciated cost of the existing facility, provided it has previously been included in an appendix to Schedule 12 as an RTEP-planned facility. Except with respect to Commission-authorized construction work in progress, a double-circuit 345 kV facility is only allocated as a Regional Facility after both circuits enter service. *Id.* § (b)(i)(C).

<sup>35</sup> Exh. No. PTO-2 at 18-19.

<sup>36</sup> *Id.*

<sup>37</sup> Proposed Schedule 12, § (b)(i).

<sup>38</sup> *Id.* § (b)(ii).

<sup>39</sup> *Id.* § (b)(i)(A)(1).

## 1. Reliability Projects

For Regional Facilities that are Reliability Projects, the proposal allocates fifty percent of each project's cost using a DFAX analysis.<sup>40</sup> The DFAX analysis that would be used differs from the approach currently used for lower voltage facilities. As described in Mr. Herling's testimony, the current Violation-Based DFAX analysis evaluates the contribution of load in each zone and each merchant transmission facility to flows on the facility that without reinforcement would lead to a reliability violation, *i.e.*, it evaluates users' relative contribution to the situation that creates the need for a Required Transmission Enhancement to be included in the RTEP.<sup>41</sup> In contrast, the proposal uses a "Solution-Based" DFAX analysis to evaluate the relative use that load in each Zone and withdrawals by merchant transmission facilities are projected to make of the new facility.<sup>42</sup> This analysis focuses on the benefits that users derive from the use of the Required Transmission Enhancement. Uses of the new facility in both directions will be taken into account, as described in Mr. Herling's testimony.<sup>43</sup> PJM will update this analysis annually in order to take into account changes in the relative use of the facility due to modifications of the grid, including new facilities, generation additions and retirements, and the growth and distribution of load.<sup>44</sup> The Zonal loads that form the basis of the postage-stamp allocation of the other half of the facilities' costs will continue to be updated annually as well.<sup>45</sup>

## 2. Economic Projects

For new Regional Facilities included in the RTEP as Economic Projects, the proposal allocates fifty percent of each project's cost based on each Zone's and each merchant transmission facility's share of the zonal decreases in load energy payments that result from the new facility. This is the same methodology that PJM currently uses for lower voltage Economic Projects.<sup>46</sup> This methodology identifies the customers that are projected to receive the specific benefits of new Economic Projects in the form of reduced

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<sup>40</sup> *Id.* § (b)(i)(A)(2)(a).

<sup>41</sup> Exh. No. PTO-1 at 3-7.

<sup>42</sup> *Id.* at 8-10.

<sup>43</sup> *Id.* at 10-11.

<sup>44</sup> *Id.* at 14; Exh. No. PTO-2 at 25-26.

<sup>45</sup> The annual update to Solution-Based DFAX results will be implemented at the beginning of each calendar year, when zonal loads used for the postage-stamp-based portion of the allocation are also updated. Exh. No. PTO-2 at 25.

<sup>46</sup> Proposed Schedule 12, § (b)(ii)(2)(b). As is the case currently under Schedule 12 for lower voltage projects, if PJM expands a Reliability Project to address an economic constraint, the proposal allocates costs for economic project that are modifications of Reliability Projects according to the DFAX analysis used for Reliability Projects. This applies both to the fifty percent of the costs of Regional Facilities that are not allocated according to load share and to all costs of Lower Voltage Facilities.

load energy payments over the first fifteen years of each project's operation. As discussed below, combining the result of the load payment analysis with the postage-stamp methodology recognizes that Regional Facilities installed to address economic constraints can also benefit customers in other Zones.

### 3. Benefits of the Hybrid Methodology and Solution-Based DFAX

The proposed hybrid cost allocation methodology for Regional Facilities and Necessary Lower Voltage Facilities represents a compromise between the principal approaches advocated by different PJM stakeholders, including PJM Transmission Owners. As explained above and in the testimony of Ms. Henry and Mr. Richardson, some stakeholders advocate the allocation of all costs of these facilities on a postage-stamp basis.<sup>47</sup> Other stakeholders support the allocation of all costs of these facilities to specific beneficiaries identified through a DFAX or load energy payment analysis.<sup>48</sup> By combining both approaches, the hybrid methodology represents a reasonable compromise that many stakeholders can accept, even though some of them would prefer a different approach.<sup>49</sup> The hybrid methodology also allocates the costs of these projects in a manner that is just and reasonable and consistent with the requirements of *Order No. 1000*. In the *Order on Remand*, the Commission found that Regional Facilities provide benefits that are broadly shared among customers in the region and that customers' use of the transmission system, including new Regional Facilities, changes over time.<sup>50</sup> The hybrid methodology reasonably allocates costs both to specifically identified beneficiaries of the projects – through the portion of the allocation based on Solution-Based DFAX or a load energy payment analysis – as well as to users that receive more difficult-to-quantify benefits and users who might benefit in the future as usage of the projects changes over time – through the portion based on the postage-stamp methodology.<sup>51</sup> In this way, the hybrid methodology allocates costs in a manner that is “at least roughly commensurate” with the benefits of the projects.<sup>52</sup>

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<sup>47</sup> Exh. No. PTO-2 at 9-11.

<sup>48</sup> *Id.*

<sup>49</sup> *Id.* at 9-13.

<sup>50</sup> *Order on Remand* at PP 59, 82.

<sup>51</sup> Exh. No. PTO-2 at 9-11, 13-18.

<sup>52</sup> *Ill. Comm. Comm'n v. FERC*, 576 F.3d 470, 476-77 (7th Cir. 2009); *Order No. 1000* at P 558. The PJM Transmission Owners do not contend that the hybrid methodology represents the only approach to cost allocation that would satisfy this standard. Under settled precedent, the PJM Transmission Owners are only required to show that their proposal satisfies this standard, not that it constitutes the *only* just and reasonable cost allocation methodology. See *City of Bethany v. FERC*, 727 F.2d 1131, 1136 (D.C. Cir. 1984), *cert. denied*, 469 U.S. 917 (1984) (utility need only establish that its proposed rate design is reasonable, not that it is superior to alternatives); *OXY USA, Inc. v. FERC*, 64 F.3d 679, 692 (D.C. Cir. 1995) (“[T]he Commission may approve the methodology proposed in the settlement agreement if it is ‘just and reasonable’; it need not be the only reasonable methodology or even the most accurate.”).

The introduction of the Solution-Based DFAX methodology is an important element of the PJM Transmission Owners' proposal and has significant advantages over the current Violation-Based DFAX approach.<sup>53</sup> As explained in Mr. Herling's testimony, the Solution-Based DFAX approach will be simpler for PJM to implement.<sup>54</sup> Under the proposal, PJM will only need to calculate a single set of distribution factors for each new facility.<sup>55</sup> In addition, because Solution-Based DFAX is based on the analysis of flows on the new facility the analysis can be updated annually to capture changes in the distribution of the benefits of the new transmission facility in a manner that avoids abrupt shifts in cost responsibility.<sup>56</sup> As discussed in the testimony of Ms. Henry and Mr. Richardson, these differences address concerns that the Commission addressed in the *Order on Remand* regarding the Violation-Based DFAX analysis.<sup>57</sup>

### C. Lower Voltage Facilities

The proposal allocates all of the cost of Lower Voltage Facilities to the beneficiaries of those facilities identified in PJM's analysis, as the current cost allocation methodology does. Like the current methodology and the proposal's treatment of Regional Facilities, the methodology used depends upon whether the Lower Voltage Facility is a Reliability Project or an Economic Project.<sup>58</sup> In each case, the cost of the project is allocated using the same method that would be applied to a Regional Facility, but the result is applied to all of the project's costs. Thus, the full cost of a reliability-based Lower Voltage Facility is allocated according to the Solution-Based DFAX analysis discussed above.<sup>59</sup> Similarly, the full cost of a new Lower Voltage Facility that is an Economic Project is allocated based on the load payment reduction analysis described above.<sup>60</sup> The

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<sup>53</sup> Exh. No. PTO-2 at 22-26.

<sup>54</sup> Exh. No. PTO-1 at 9-10.

<sup>55</sup> *Id.*

<sup>56</sup> *Id.* at 12.

<sup>57</sup> *Order on Remand* at P 38.

<sup>58</sup> For clarity, the proposal revises the definition of "Lower Voltage Facilities" to encompass all Required Transmission Enhancements that are not Regional Facilities, regardless of whether they are Reliability Projects or Economic Projects.

<sup>59</sup> Proposed Schedule 12, § (b)(ii). As noted above, the current Violation-Based DFAX was adopted in a 2007 settlement agreement in Docket Nos. ER06-456-013, *et al.* See *PJM Interconnection, L.L.C.*, 124 FERC ¶ 61,112 (2008). Although controversy has continued to surround the cost allocation for higher voltage facilities in PJM (including the establishment of voltage cut-offs), there has not been any meaningful dispute that it is appropriate to allocate 100 percent of the costs of lower voltage reliability projects using a DFAX-based methodology. Further, as discussed above, the Solution-Based DFAX approach proposed here has significant advantages over the current Violation-Based DFAX method.

<sup>60</sup> Proposed Schedule 12, § (b)(v).

allocation of all costs of Lower Voltage Facilities to the identified beneficiaries reflects the more localized benefits that these projects provide.<sup>61</sup>

#### **D. High Voltage Direct Current Transmission Facilities**

The PJM Transmission Owners propose to employ the same cost allocation methodology used for alternating current (“A.C.”) transmission facilities to high voltage direct current (“D.C.”) transmission projects approved by the PJM Board for inclusion in the RTEP and made available for PJM to schedule.<sup>62</sup> Thus, Regional Facilities and Necessary Lower Voltage Facilities that employ D.C. technology will be allocated using a hybrid methodology in which fifty percent of the costs are allocated on a postage-stamp basis and fifty percent are allocated to specifically identified beneficiaries. All of the costs of Lower Voltage Facilities using D.C. technology will be allocated to specific beneficiaries.

The PJM Transmission Owners propose to classify those D.C. projects in a manner that corresponds to the classification of A.C. projects, based on how they connect to the A.C. transmission system. A D.C. Required Transmission Enhancement will be classified as a Regional Facility if two conditions are satisfied. First, the D.C. facility is connected to at least one substation or switching station that is also connected to either at least one A.C. line operated at 500 kV or above or at least one double-circuit A.C. line operating at 345 kV or above that, as discussed above, is classified as a Regional Facility.<sup>63</sup> Second, the transformer between the D.C. converter and the A.C. substation or switching station has a low side phase-to-phase voltage rating of at least 345 kV, which PJM has determined to be necessary in the RTEP planning process.<sup>64</sup> Alternatively, a D.C. Required Transmission Enhancement will be classified as a Regional Facility if it is connected to a D.C. facility that has previously been classified as a Regional Facility.<sup>65</sup> Any other D.C. project will be classified as a Lower Voltage Facility.<sup>66</sup> This classification approach affords comparable treatment to A.C. and D.C. facilities.

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<sup>61</sup> Exh. No. PTO-2 at 21.

<sup>62</sup> *Id.* at 32. D.C. projects not included in this category include those that are installed for interconnection of generation or merchant transmission or for which users subscribe for service or a share of the project’s capacity.

<sup>63</sup> *Id.* at 33.

<sup>64</sup> *Id.*

<sup>65</sup> *Id.*

<sup>66</sup> *Id.*

To conduct the DFAX analysis for D.C. projects, PJM will remove the D.C. facility from the DFAX model and replace it with a proxy A.C. facility.<sup>67</sup> PJM will then perform the Solution-Based DFAX analysis using the proxy A.C. facility.<sup>68</sup>

#### **E. Other Revisions**

Currently, Schedule 12 applies only to cost allocation of RTEP facilities constructed by PJM Transmission Owners. Although any entity owning transmission facilities in service that has transferred functional control over those facilities to PJM must become a PJM Transmission Owner (by becoming a party to the CTOA),<sup>69</sup> PJM may designate in the RTEP an entity that does not yet have transmission facilities in service to construct and own and/or finance a Required Transmission Enhancement. The proposed amendments apply Schedule 12 to facilities constructed by such entities, as well as those constructed by PJM Transmission Owners.<sup>70</sup>

The proposal also modifies the application of the \$5 million threshold for the allocation of costs of Required Transmission Enhancements.<sup>71</sup> As noted above, the current Tariff applies that threshold only to below 500 kV Reliability Projects. The proposal would apply that threshold to all Required Transmission Enhancements.<sup>72</sup>

The proposal also clarifies the manner in which PJM will associate transformers, spare parts, replacement equipment, and circuit breakers with Regional Facilities or Lower Voltage Facilities for the purposes of cost allocation. Transformers connected to Lower Voltage facilities are not considered Regional Facilities unless they are an integral component of a Regional Facility.<sup>73</sup> Spare parts and circuit breakers that are part of the design specifications of a facility are allocated in the same manner as the facility. If the owner of the spare part is not a Transmission Owner with a Zone (or is not required to be shared with such a Transmission Owner), its costs are allocated pro rata to the zones that bear cost responsibility for the owner's Required Transmission Enhancements. Replacement equipment that is part of the design specifications of a facility is allocated in the same manner as the facility. Other replacement equipment is allocated in the same manner as the equipment it is replacing.

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<sup>67</sup> Exh. No. PTO-1 at 12-14.

<sup>68</sup> *Id.*; Exh. No. PTO-2 at 33-34.

<sup>69</sup> CTOA § 3.1.

<sup>70</sup> Proposed Schedule 12, § (a).

<sup>71</sup> Exh. No. PTO-2 at 30-31.

<sup>72</sup> Proposed Schedule 12, § (b)(vi).

<sup>73</sup> *Id.* § (b)(i)(B).

The proposed revisions also address the allocation of the costs of replacement transmission facilities, *e.g.*, new facilities necessary to replace existing facilities that have reached the end of their operating lives. The proposal allocates those costs to the entities responsible for the costs of the facilities being replaced, unless PJM identifies the new facility as a Required Transmission Enhancement in the RTEP.<sup>74</sup> In that case, the costs of the new facility will be allocated as a Reliability Project or an Economic Project, as applicable.<sup>75</sup>

The proposed revisions clarify that, as discussed above, the cost allocation provisions of Schedule 12 do not apply to interconnection-related upgrades (Attachment Facilities, Network Upgrades, Local Upgrades, and Merchant Network Upgrades), Merchant Transmission Facilities, or Supplemental Projects, as those terms are defined in the PJM Tariff or PJM Operating Agreement.<sup>76</sup> In addition, the revisions clarify, as discussed above, that Schedule 12 does not apply to D.C. transmission projects whose capacity is subscribed by specific users and therefore not made available for PJM to schedule.<sup>77</sup> None of these types of projects are Required Transmission Enhancements that PJM has included in the RTEP to meet an identified system need. Finally, the proposed revisions clarify a few instances in which Schedule 12 used defined terms imprecisely.<sup>78</sup>

#### **IV. COMPLIANCE WITH ORDER NO. 1000**

The Tariff revisions proposed in this filing ensure that the costs of transmission expansions and enhancements approved by PJM in its RTEP are allocated in a manner that complies with the requirements of *Order No. 1000* relating to regional cost allocation. The proposed Tariff revisions satisfy these requirements both generally and as applied to transmission upgrades that address public policy requirements, as those requirements are taken into account in PJM's planning process.

##### **A. *Order No. 1000's* Regional Cost Allocation Principles**

In *Order No. 1000*, the Commission directed public utility transmission providers, including RTOs, to include in their tariffs a method to allocate the costs of new facilities selected in the regional transmission plan for purposes of cost allocation.<sup>79</sup> *Order No.*

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<sup>74</sup> Exh. No. PTO-2 at 31.

<sup>75</sup> Proposed Schedule 12, § (b)(xiv).

<sup>76</sup> Exh. No. PTO-2 at 32, 37-38.

<sup>77</sup> The Commission accepted a similar limitation in *Midwest Independent Transmission System Operator, Inc.* 137 FERC ¶ 61,074 at P 383 (2011).

<sup>78</sup> In particular, the incorrect use of the defined phrase "Transmission Enhancement Charge" in several places was corrected. *See* Proposed Schedule 12 §§ (b)(ix), (c)(4), (c)(5).

<sup>79</sup> *Order No. 1000* at P 558.

1000 requires that the cost allocation methodology for regional facilities conform to six principles:

1. The methodology must allocate the costs of regional facilities to those within the transmission planning region that benefit from those facilities in a manner that is at least roughly commensurate with estimated benefits. In determining the beneficiaries of regional facilities, the methodology may consider the extent to which transmission facilities provide for maintaining reliability and sharing reserves, production cost savings and congestion relief, or meeting public policy requirements.<sup>80</sup>
2. The methodology must not allocate costs to entities that receive no benefit from the regional transmission facilities unless the entities voluntarily accept the allocation.<sup>81</sup>
3. If the planning process uses a benefit-cost threshold to determine which transmission facilities have sufficient net benefits to be selected in a regional transmission plan for the purpose of cost allocation, the threshold must not exceed 1.25 unless the transmission planning region or public utility transmission provider justifies and FERC approves a higher ratio.<sup>82</sup>
4. The methodology must allocate the costs of a regional facility solely within that transmission planning region unless another entity outside the region or another transmission planning region voluntarily agrees to assume a portion of those costs.<sup>83</sup>
5. The methodology and data requirements for determining benefits and identifying beneficiaries for a transmission facility must be transparent and provide stakeholders with sufficient documentation to determine how the methodology and data apply to a proposed transmission facility.<sup>84</sup>
6. A methodology may use a different cost allocation method for different types of transmission facilities in the regional transmission plan, such as transmission facilities needed for reliability or congestion relief, or to

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<sup>80</sup> *Id.* at P 622.

<sup>81</sup> *Id.* at P 637.

<sup>82</sup> *Id.* at P 646.

<sup>83</sup> *Id.* at P 657.

<sup>84</sup> *Id.* at P 668.

achieve public policy requirements, but it must set out each cost allocation method clearly and in detail in the compliance filing.<sup>85</sup>

As discussed in the testimony of Ms. Henry and Mr. Richardson, the proposed revisions comply fully with these six principles. In summary:

First, the proposed methodology satisfies the first regional cost allocation principle.<sup>86</sup> The hybrid approach to cost allocation for Regional Facilities combines an analysis that identifies the specific beneficiaries of a new transmission facility (either through distribution factors for Reliability Projects or energy cost reductions for Economic Projects) with a postage-stamp rate that takes into account the more difficult to quantify benefits that the Commission found in the *Order on Remand* that Regional Facilities provide. The use of Solution-Based DFAX analysis identifies specific beneficiaries of Reliability Projects, including both Regional Facilities and Lower Voltage Facilities. Because that analysis is updated annually, it recognizes changes in the distribution of these specific benefits over time. In the case of Economic Projects, the change in load energy payments analysis is based on the net present value of projected energy cost savings over the first fifteen years of a project's operation. Thus, the proposal allocates costs in a manner that is at least roughly commensurate with estimated benefits, as *Order No. 1000* requires.<sup>87</sup>

Second, the proposal does not allocate any costs to customers that receive no benefits from the transmission facilities either at present or in a likely future scenario.<sup>88</sup> Costs of Lower Voltage Facilities are allocated entirely to specifically identified beneficiaries in accordance with the methods described above. Costs of Regional Facilities are allocated, through the Solution-Based DFAX or change in load energy payment analysis, to specifically identified beneficiaries in accordance with the methods described above and, through the postage-stamp methodology, to other customers throughout the region who, because of the regional nature of the facilities, receive some benefits from them.

Third, the proposal does not use a cost-benefit threshold for cost allocation, but applies to all projects PJM finds in the RTEP to be needed.<sup>89</sup> PJM does use a benefit-to-cost threshold in its planning process to determine whether to include projects in the RTEP

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<sup>85</sup> *Id.* at P 685.

<sup>86</sup> Exh. No. PTO-2 at 40-41.

<sup>87</sup> *Order No. 1000* at P 622.

<sup>88</sup> *Id.* at P 637; Exh. No. PTO-2 at 41-42.

<sup>89</sup> Exh. No. PTO-2 at 42.

as Economic Projects.<sup>90</sup> That threshold, however, is 1.25:1, and thus is consistent with the limitation in *Order No. 1000*.<sup>91</sup>

Fourth, the proposal allocates costs solely within PJM's transmission planning region.<sup>92</sup>

Fifth, the proposal uses transparent cost allocation methodologies.<sup>93</sup> As revised by this filing, Schedule 12 clearly describes the cost allocation methodology to be applied to each category of Required Transmission Enhancement. Where PJM is required to conduct an analysis to implement the methodology, Schedule 12 specifies the manner in which PJM is to perform the analysis and the assumptions it is to use. In the case of the DFAX analysis used for Reliability Projects, the proposed Solution-Based DFAX methodology is based on the DFAX methodology that PJM currently employs. The Commission has accepted the description in Schedule 12 of the DFAX methodology as sufficiently detailed, after finding an earlier description in the PJM Tariff to be overly vague.<sup>94</sup> The Solution-Based DFAX proposal uses the same basic methodology with certain modifications, as discussed above and in Mr. Herling's testimony; the proposed PJM Tariff revisions use the existing, previously accepted language in Schedule 12, modified to describe the proposed changes to the methodology. Further, the proposal makes no change to the accepted methodologies for identifying changes to load energy payments used in the cost allocation for Economic Projects.<sup>95</sup>

Sixth and finally, as discussed above, the PJM Tariff, as revised, uses different cost allocation methods for new Required Transmission Facilities that address reliability violations and those that address economic constraints.<sup>96</sup> It also distinguishes between Regional Facilities and Lower Voltage Facilities, recognizing the difficult to quantify benefits that the Commission has found the former provide. The nature of the transmission facilities within each category is set forth and explained in Schedule 6 of the PJM Operating Agreement. The proposal sets out each cost allocation method clearly and in detail, as discussed above.<sup>97</sup> In addition, as also noted above, the PJM Tariff also

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<sup>90</sup> CTOA, Schedule 6, § 1.5.7(d).

<sup>91</sup> *Order No. 1000* at P 646.

<sup>92</sup> *Id.* at P 657; Exh. No. PTO-2 at 42.

<sup>93</sup> *Order No. 1000* at P 668; Exh. No. PTO-2 at 42-43.

<sup>94</sup> *See Order on Remand* at P 35.

<sup>95</sup> However, the language of Schedule 12 § (b)(v)(C) is clarified to correct the use of defined terms.

<sup>96</sup> Exh. No. PTO-2 at 44-45.

<sup>97</sup> *Order No. 1000* at P 686.

addresses cost allocation for other transmission upgrades, including those required for interconnection, in other provisions that are not affected by this filing.<sup>98</sup>

## **B. Public Policy Requirements**

In *Order No. 1000*, the Commission stated that the allocation of the costs of any transmission project included in a regional plan to satisfy public policy requirements must satisfy the cost allocation principles discussed above.<sup>99</sup> The Schedule 12 provisions proposed in this filing ensure that the cost allocation methodology under the PJM Tariff fulfills this requirement in a manner that is consistent with the ways in which public policy requirements are addressed in PJM's planning process. The PJM Tariff and Operating Agreement currently provide three distinct ways for transmission projects that advance public policy requirements to be considered in the planning process; PJM's *Order No. 1000* compliance filing adds a fourth way for public policy-driven projects to be considered.<sup>100</sup>

First, the RTEP process currently takes Public Policy Requirements and Public Policy Objectives (as defined in the PJM Operating Agreement) into account in PJM's identification of transmission enhancements that are required for reliability or economic purposes.<sup>101</sup> Thus, Public Policy Requirements are considered along with other factors, such as load growth and generation retirements, in assessing whether transmission reinforcements are necessary to address future reliability concerns or relieve economic constraints. As explained above, the revisions that the PJM Transmission Owners propose to Schedule 12 to allocate the costs of Reliability Projects and Economic Projects included in the RTEP for those purposes satisfy *Order No. 1000*'s cost allocation principles. In particular, Reliability Projects and Economic Projects that also address public policy requirements and objectives are "allocated within the region in a manner that is at least roughly commensurate with estimated benefits."<sup>102</sup>

Second, as noted above, PJM separately identifies attachment facilities and network upgrades required to accommodate the interconnection of generation and merchant transmission facilities.<sup>103</sup> Costs for any interconnection-related transmission project that advances Public Policy Requirements, such as a transmission upgrade required to interconnect renewable generation that would be used to satisfy a renewable portfolio

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<sup>98</sup> The Commission excluded interconnection cost recovery from the scope of *Order No. 1000*. *Id.* at P 760.

<sup>99</sup> *Id.* at P 219.

<sup>100</sup> Exh. No. PTO-2 at 37-39.

<sup>101</sup> See PJM Operating Agreement, §§ 1.38A, 1.38B, 1.3B, 1.4, 1.5.1, 1.5.3, 1.5.4; Exh. No. PTO-2 at 38.

<sup>102</sup> *Order No. 1000* at P 219.

<sup>103</sup> Exh. No. PTO-2 at 38.

requirement, will be allocated under the “but for” test applicable to interconnection upgrades. This approach allocates the costs of the interconnection-related upgrades in a manner that is at least roughly commensurate with causation and the facilities’ estimated benefits.

Third, a transmission upgrade that PJM has not determined to be necessary for reliability or economic reasons, but which advances a public policy requirement or objective, may be proposed as a Supplemental Project.<sup>104</sup> The proponent of such a Supplemental Project is responsible for addressing any allocation of the project’s costs, consistent with the requirements of the PJM Tariff and the CTOA.

Fourth, PJM’s *Order No. 1000* compliance filing will propose to add a fourth path for the development of transmission upgrades that address public policy requirements.<sup>105</sup> That filing proposes that one or more states may identify a transmission enhancement or expansion that PJM has not found to be necessary for reliability or economic reasons, but which the state or states have determined to be required to address Public Policy Requirements. PJM’s proposal requires that the states sponsoring the project voluntarily agree to be responsible for its costs and that, if the project is not pursued as a Supplemental Project, as discussed above, the costs are to be allocated only to customers in those states. Consistent with PJM’s proposal for projects identified through this “State Agreement” approach, the PJM Transmission Owners’ filing provides that the cost allocation for any such project (which, under PJM’s proposal, will allocate project costs among customers in the sponsoring states) will be submitted to the Transmission Owners Agreement Administrative Committee for consideration and filing under section 205 pursuant to Section 7.3 of the CTOA and Section 9.1(a) of the PJM Tariff.<sup>106</sup> If that Committee elects not to file the cost allocation under section 205, the sponsoring states or PJM can file it under section 206.<sup>107</sup> Allocating the costs of such facilities to customers in the states that have determined that the facilities are necessary to advance public policies maintains consistency between cost allocation and the distribution of benefits, as *Order No. 1000* requires.

## V. ADDITIONAL SUPPORTING MATERIAL

The PJM Transmission Owners submit the following additional information in substantial compliance with relevant provisions of Section 35.13:

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<sup>104</sup> Proposed Schedule 12, § (b)(xii)(A); Exh. No. PTO-2 at 38.

<sup>105</sup> Exh. No. PTO-2 at 38-39.

<sup>106</sup> Proposed Schedule 12, § (b)(xii)(B). By including a provision in this filing to address cost allocation for such projects, the PJM Transmission Owners do not waive their rights to take any position, either individually or jointly, on PJM’s compliance filing.

<sup>107</sup> Exh. No. PTO-2 at 38-39.

**A. Contents of this Filing – Section 35.13(b)(1)**

This filing consists of the following documents:

- The instant Transmittal Letter;
- Attachment A: Clean Tariff Sheets of Proposed Schedule 12 and Schedule 12, Appendix A;
- Attachment B: Redlined Tariff Sheets of Proposed Schedule 12 and Schedule 12, Appendix A;
- Exhibit No. PTO-1: Testimony of Steven R. Herling; and
- Exhibit No. PTO-2: Testimony of Michelle Henry and Frank J. Richardson.

The documentation submitted with this filing demonstrates that there is no need for an evidentiary hearing.

**B. Proposed Effective Date– Section 35.13(b)(2)**

Pursuant to 18 C.F.R. § 35.3, the PJM Transmission Owners request an effective date of for this filing of February 1, 2013. The PJM Transmission Owners request that the Commission accept the proposed revisions without suspension or hearing or, if the Commission determines that further investigation is required, with no more than a nominal suspension.

The PJM Transmission Owners recognize that the Commission will assess the revisions proposed in this filing both against section 205's just and reasonable standard and under the cost allocation principles of *Order No 1000*. The Commission should be able to determine before the requested effective date that the proposed cost allocation methodology satisfies both standards, based on the showing presented above and in the accompanying testimony. A prompt ruling would be consistent with the Commission's policy objective of promoting the development of critically needed transmission infrastructure by removing the uncertainty over cost allocation that has hung over the PJM region for almost a decade.

In this regard, the Commission need not and should not defer consideration of the PJM Transmission Owners' cost allocation proposal pending the completion of its review of transmission planning reforms that PJM is proposing in its separate compliance filing. While the Commission has noted the close relationship between transmission planning and the allocation of the costs of the facilities planned,<sup>108</sup> the proposed cost allocation

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<sup>108</sup> *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, at P 557, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007),

methodology for Required Transmission Enhancements is consistent with *Order No. 1000*'s cost allocation principles as well as the process through which PJM selects projects for inclusion in the RTEP. The Commission recently approved changes in PJM's RTEP protocol designed to enhance its planning process, including the consideration of public policy requirements in that process,<sup>109</sup> and the additional changes PJM is expected to propose in its *Order No. 1000* compliance filing will not affect the significant elements of the compromise cost allocation proposal submitted in this filing.

**C. List of Persons Receiving a Copy of This Filing – Section 35.13(b)(3)**

On behalf of the PJM Transmission Owners, PJM has served a copy of this filing on all PJM Members and on all state utility regulatory commissions in the PJM Region by posting this filing electronically. In accordance with the Commission's regulations,<sup>110</sup> PJM will post a copy of this filing to the FERC filings section of its internet site, located at the following link: <http://www.pjm.com/documents/ferc-manuals/ferc-filings.aspx> with a specific link to the newly-filed documents, and will send an e-mail on the same date as this filing to all PJM Members and all state utility regulatory commissions in the PJM Region<sup>111</sup> alerting them that this filing has been made by PJM and is available by following such link. PJM also serves the parties listed on the Commission's official service list for this docket. If the documents are not immediately available by using the referenced link, the documents will be available through the referenced link within 24 hours of the filing. Also, a copy of this filing will be available on the Commission's eLibrary website located at the following link: <http://www.ferc.gov/docs-filing/elibrary.asp> in accordance with the Commission's regulations and *Order No. 714*.

**D. Description of Rate Schedule Change – Section 35.13(b)(4)**

*See* discussion above.

**E. Reasons for the Rate Schedule Change – Section 35.13(b)(5)**

*See* discussion above.

**F. Showing of Requisite Agreements – Section 35.13(b)(6)**

Not applicable.

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*order on reh'g*, Order No. 890-B, 123 FERC ¶ 61,299 (2008), *order on reh'g*, Order No. 890-C, 126 FERC ¶ 61,228, *order on clarification*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

<sup>109</sup> *PJM Interconnection, L.L.C.*, 139 FERC ¶ 61,080 (2012).

<sup>110</sup> *See* 18 C.F.R. §§ 35.2(e) and 385.2010(f)(3) (2012).

<sup>111</sup> PJM already maintains, updates and regularly uses e-mail lists for all PJM members and affected state commissions.

**G. Costs or expenses that have been alleged or judged to be illegal, duplicative or unnecessary that are the product of discriminatory employment practices – Section 35.13(b)(7)**

None.

**VI. REQUEST FOR WAIVERS**

The PJM Transmission Owners request that the Commission grant any additional waivers of its rules and regulations as necessary to accept the PJM Tariff modifications.

**VII. NOTICE AND CORRESPONDENCE**

The PJM Transmission Owners request that all communications regarding this filing be directed to the individuals listed below in their capacity as representatives of the PJM Transmission Owners acting at the direction of the CTOA Administrative Committee, and that their names be entered on the official service list maintained by the Secretary for this proceeding:

Paul D. Napoli  
Managing Director – Transmission  
Business  
Public Service Electric and Gas  
Company  
80 Park Plaza, T13  
Newark, NJ 07102  
(973) 430-3724  
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Chairman of the CTOA Administrative  
Committee

Kenneth G. Jaffe  
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950 F Street, N.W.  
Washington, D.C. 20004  
(202) 239-3154  
[kenneth.jaffe@alston.com](mailto:kenneth.jaffe@alston.com)

The PJM Transmission Owners request that the Commission waive the requirements of Rule 203 of its regulations<sup>112</sup> to the extent necessary to allow each of the listed persons to be included on the official service list for this proceeding.

### **VIII. CONCLUSION**

For the reasons set forth herein, the PJM Transmission Owners respectfully request that the Commission accept these modifications to Schedule 12 of the PJM Tariff, and authorize them to take effect without suspension, condition or modification as of February 1, 2013.

Should additional information be required, please contact the undersigned.

Respectfully submitted,

Donald A. Kaplan and Kenneth G. Jaffe

*On behalf of the PJM Transmission Owners*

Enclosures

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<sup>112</sup> 18 C.F.R. § 385.203(b).

# Attachment A

## Revisions to the PJM Open Access Transmission Tariff

(Clean Format)

**SCHEDULE 12**  
**Transmission Enhancement Charges**

**(a) Establishment of Transmission Enhancement Charges.** One or more of the Transmission Owners may be designated to construct and own and/or finance Required Transmission Enhancements (as defined in Section 1.38C of the Tariff) by (1) the Regional Transmission Expansion Plan periodically developed pursuant to Schedule 6 of the Operating Agreement or (2) the Coordinated System Plan periodically developed pursuant to the Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (collectively, for purposes of this Schedule 12 only, “Regional Transmission Expansion Plan”). Section 1.7 of Schedule 6 of the Operating Agreement recognizes that Transmission Owners, subject to obtaining any necessary regulatory approvals, may seek to recover the costs of Required Transmission Enhancements and obligates PJM Settlement to collect on behalf of Transmission Owner(s) any charges established by Transmission Owners to recover the costs of Required Transmission Enhancements. If a Transmission Owner is designated by the Regional Transmission Expansion Plan to construct and own and/or finance a Required Transmission Enhancement, such Transmission Owner may choose any of the following cost recovery mechanisms, subject to the crediting procedures set forth in section (e) below:

- (1) Decline to seek to recover the costs of Required Transmission Enhancements from customers until such time as it makes a filing pursuant to Section 205 of the Federal Power Act to revise its Network Integration Transmission Service rates;
- (2) Make a filing pursuant Section 205 of the Federal Power Act and the FERC’s rules and regulations to establish the revenue requirement with respect to a Required Transmission Enhancement, without filing to revise its rates for Network Integration Transmission Service generally; or
- (3) Establish the revenue requirement with respect to a Required Transmission Enhancement through the operation of a formula rate in effect applicable to its rates for Network Integration Transmission Service.

A charge established to recover the revenue requirement with respect to a Required Transmission Enhancement is hereafter referred to as a “Transmission Enhancement Charge.” Transmission Enhancement Charges of one or more Transmission Owners for Required Transmission Enhancements shall be established in accordance with this Schedule 12. Transmission Enhancement Charges of one or more transmission owners within the Midwest Independent System Operator, Inc. (“MISO”) shall be determined in accordance with the MISO Tariff. Any alternating current (“A.C.”) facilities or direct current (“D.C.”) facilities that are Attachment Facilities, Local Upgrades, Merchant Network Upgrades, Merchant Transmission Facilities, Network Upgrades, Supplemental Projects as defined in Section 1.42A.02 of the Operating Agreement, or any other Transmission Facilities that operate or are planned to be operated in a manner that requires customers to subscribe to transmission service over such facilities or to a portion of the electric capability of such facilities shall not be eligible for cost responsibility assignment pursuant to this Schedule 12. For purposes of this Schedule 12 only, the term,

“Transmission Owner,” shall include any entity that undertakes to construct and own and/or finance a Required Transmission Enhancement pursuant to a designation in the Regional Transmission Expansion Plan to construct and own and/or finance such Required Transmission Enhancement, even if such entity is not yet eligible to become a party to the Consolidated Transmission Owners Agreement.

The assignment of cost responsibility or classification of Required Transmission Enhancements either (1) made by the Transmission Provider prior to the effective date of the amendments to this Schedule 12 filed in Docket No. \_\_\_\_ on October 11, 2012, or (2) applicable to Required Transmission Enhancements approved by the PJM Board pursuant to Section 1.6 of the PJM Operating Agreement prior to such effective date are set forth in Schedule 12-Appendix. Except as specifically set forth herein, nothing in this Schedule 12 shall change the assignment of cost responsibility or classification of Required Transmission Enhancements included in Schedule 12-Appendix. The assignment of cost responsibility or classification of all other Required Transmission Enhancements shall be set forth in Schedule 12-Appendix A.

**(b) Designation of Customers Subject to Transmission Enhancement Charges.**

**(i) Regional Facilities and Necessary Lower Voltage Facilities.** Transmission Provider shall assign cost responsibility on a region-wide basis for Required Transmission Enhancements included in the Regional Transmission Expansion Plan that are (1) Transmission Facilities as defined in section 1.27 of the Consolidated Transmission Owners Agreement (Rate Schedule FERC No. 42) that (a) are A.C. facilities that operate at or above 500 kV; (b) constitute a single Required Transmission Enhancement comprising two A.C. circuits operating at or above 345 kV and below 500 kV, where both circuits originate from a single substation or switching station at one end and terminate at a single substation or switching station at the other end, regardless of whether or not the two circuits are routed in the same right-of-way (“Double-circuit 345 kV Required Transmission Enhancement”); (c) are A.C. or D.C. shunt reactive resources (such as capacitors, static var compensators, static synchronous condenser (STATCON), synchronous condensers, inductors, other shunt devices, or their equivalent) connected to a Transmission Facility described in clause (a) or (b) of this subsection, or (d) are D.C. facilities meeting the criteria set forth in subsection (b)(i)(D) (collectively, “Regional Facilities”), or (2) new A.C. Transmission Facilities or expansions or enhancements to existing Transmission Facilities that operate below 500 kV (or 345 kV in the case of a Regional Facility described in clause (1)(b) of this subsection) that must be constructed or strengthened to support new Regional Facilities, based on the planning criteria used by the Transmission Provider in developing the applicable Regional Transmission Expansion Plan (“Necessary Lower Voltage Facilities”) as follows:

(A) Cost responsibility for Regional Facilities and Necessary Lower Voltage Facilities shall be allocated among Responsible Customers as defined in this Schedule 12 as follows:

(1) Fifty percent (50%) shall be assigned annually on a load-ratio share basis as follows:

(a) With respect to each Zone, using, consistent with section 34.1 of the Tariff, the applicable zonal loads at the time of such Zone's annual peak load from the 12-month period ending October 31 preceding the calendar year for which the annual cost responsibility allocation is determined; and

(b) With respect to Merchant Transmission Facilities, (1) for the calendar year following the year in which it initiates operation, the actually awarded Firm Transmission Withdrawal Rights associated with its existing Merchant Transmission Facility; and (2) for all subsequent calendar years, the annual peak load of the Merchant Transmission Facility (not to exceed its actual Firm Transmission Withdrawal Rights) from the 12-month period ending October 31 of the calendar year preceding the calendar year for which the annual cost responsibility allocation is determined.

(2) Fifty percent (50%) shall be assigned as follows:

(a) In the case of a Required Transmission Enhancement included in the Regional Transmission Expansion Plan to address one or more reliability violations or to address operational adequacy and performance issues (collectively, "Reliability Project"), in accordance with the distribution factor ("DFAX") analysis described in subsection (b)(iii) of this Schedule 12; and

(b) In the case of a Required Transmission Enhancement included in the Regional Transmission Expansion Plan to relieve one or more economic constraints as described in section 1.5.7(b)(iii) of Schedule 6 of the Operating Agreement ("Economic Project"), in accordance with the methodology described in subsection (b)(v) of this Schedule 12.

(B) (1) Except for transformers that are an integral component of an A.C. Regional Facility and transformers that are an integral component of a D.C. Regional Facility with a low side phase-to-phase voltage rating of not less than 345kV, transformers connected to Lower Voltage Facilities, as defined in section (b)(ii) of this Schedule 12 and transformers connected to D.C. Regional Facilities with a low side phase-to-phase voltage rating of less than 345kV, shall not be considered Regional Facilities or Necessary Lower Voltage Facilities; and (2) Transmission Facilities that are not Regional Facilities and deliver energy from a Regional Facility to load shall not be considered Necessary Lower Voltage Facilities.

(C) With respect Required Transmission Enhancements that qualify as Regional Facilities under subsection (b)(i)(1)(b) of this Schedule 12,

(1) where the Required Transmission Enhancement includes both new Transmission Facilities and pre-existing Transmission Facilities, cost responsibility under this section (b)(i) shall apply only to the cost of the new Transmission Facilities plus the original cost less accumulated depreciation of pre-existing Transmission Facilities that are included in Schedule 12-Appendix or Schedule 12-Appendix A;

(2) cost responsibility shall be assigned under this section (b)(i) only after the Required Transmission Enhancement goes into service as a Double-circuit 345 kV Required Transmission Enhancement; and

(3) cost responsibility shall be assigned under this section (b)(i) for any CWIP permitted to be recovered before the Required Transmission Enhancement goes into service only after such Transmission Facilities are approved in a Regional Transmission Expansion Plan as a Double-circuit 345 kV Required Transmission Enhancement.

(D) A Required Transmission Enhancement included in the Regional Transmission Expansion Plan that is a D.C. facility shall be a Regional Facility only if:

(1) (a) such D.C. facility is connected to at least one substation or switching station that is also connected to either (i) at least one A.C. transmission line operated at 500 kV or above; or (ii) at least one Double-circuit 345 kV Required Transmission Enhancement; and

(b) any transformer between the substation or switching station described in subsection (b)(i)(D)(1)(a) above and the D.C. converter has a low side phase-to-phase voltage rating of not less than 345kV, such voltage having been determined by Transmission Provider in the Regional Transmission Expansion Plan to be necessary and appropriate; or

(2) such D.C. facility is connected directly to a D.C. facility that is a Regional Facility.

**(ii) Lower Voltage Facilities.** Transmission Provider shall assign cost responsibility for Required Transmission Enhancements that (a) are not Regional Facilities; and (b) are not “Necessary Lower Voltage Facilities” as defined in section (b)(i) of this Schedule 12 (collectively “Lower Voltage Facilities”), as follows:

(A) If the Lower Voltage Facility is a Reliability Project, Transmission Provider shall use the DFAX analysis described in subsection (b)(iii) of this Schedule 12; and

(B) If the Lower Voltage Facility is an Economic Project, Transmission Provider shall use the methodology described in subsection (b)(v) of this Schedule 12.

**(iii) DFAX Analysis for Reliability Projects.**

(A) For purposes of the assignment of cost responsibility for Reliability Projects under subsection (b)(i)(A)(2)(a) and subsection (b)(ii)(A) of Schedule 12, the Transmission Provider, based on a computer model of the electric network and using power flow modeling software, shall calculate distribution factors, represented as decimal values or percentages, which express the portions of a transfer of energy from a defined source to a defined sink that will flow across a particular transmission facility or group of transmission facilities. These distribution factors represent a measure of the use by the load of each Zone or Merchant Transmission

Facility of the Required Transmission Enhancement, as determined by a power flow analysis. In general, a distribution factor can be represented as:

*Distribution Factor = (After-shift power flow – pre-shift power flow) / Total amount of power shifted*

*Total amount of power shifted = Modeled incremental megawatt transfer to a given Load Deliverability Area or Merchant Transmission Facility*

*Pre-shift power flow = Megawatt flow over the Required Transmission Enhancement before the incremental megawatt transfer*

*After-shift power flow = Megawatt flow over the Required Transmission Enhancement after the incremental megawatt transfer*

When calculating such distribution factors:

(1) All distribution factors are calculated with respect to the Required Transmission Enhancement subject to cost allocation under subsection (b)(i)(A)(2)(a) and subsection (b)(ii)(A) of this Schedule 12.

(2) Use of a Required Transmission Enhancement is determined based on distribution factors to the aggregate load within a Zone or, in the case of a Merchant Transmission Facility, distribution factors determined to the point of withdrawal associated with Firm Transmission Withdrawal Rights over such Merchant Transmission Facility.

(3) The calculation of distribution factors shall be determined using linear matrix algebra, such that distribution factors represent the ratio of (i) a change in megawatt flow on a Required Transmission Enhancement to (ii) a change in megawatts transferred to aggregate load within a Zone or, in the case of a Merchant Transmission Facility, the point of withdrawal associated with Firm Transmission Withdrawal Rights over such Merchant Transmission Facility.

(B) In the DFAX analysis, to determine the impact of zonal loads and Merchant Transmission Facilities on a Required Transmission Enhancement, Transmission Provider shall calculate a distribution factor for each Zone and each Merchant Transmission Facility by modeling a transfer from all generation in the PJM Region (a) individually to the loads in each Zone and (b) individually to each Merchant Transmission Facility based on its associated existing or planned Firm Transmission Withdrawal Rights, as applicable, identified in the Interconnection Service Agreement in effect for such Merchant Transmission Facility. To establish the use by the zonal load or Merchant Transmission Facility, in megawatts, of a Required Transmission Enhancement, the distribution factor of a Required Transmission Enhancement associated with the resulting transfer modeled by the Transmission Provider to an individual Zone or a Merchant Transmission Facility shall be multiplied, as applicable, by (c) zonal peak load of the Zone being evaluated or (d) (i) for a Merchant Transmission Facility, the

existing Firm Transmission Withdrawal Rights of the Merchant Transmission Facility being evaluated, if the Merchant Transmission Facility is in service, or (ii) for a Merchant Transmission Facility that is not yet in service, the planned Firm Transmission Withdrawal Rights of the Merchant Transmission Facility being evaluated as identified in the Interconnection Service Agreement in effect for such Merchant Transmission Facility. The products, so determined, for each Zone and each Merchant Transmission Facility, shall determine the relative allocation shares for each Zone and each Merchant Transmission Facility.

(C) In the DFAX analysis, when Transmission Provider models a transfer from generation to all load within an individual Zone, Transmission Provider shall model the transfer to the Zone as a whole (not on a bus-by-bus basis).

(D) In the DFAX analysis, Transmission Provider shall model generation both external and internal to individual Zones and Merchant Transmission Facilities to reflect (a) the boundaries of Locational Deliverability Areas (“LDAs”), as defined in Attachment DD to the Tariff, and (b) limitations with respect to the reliability objective for moving generation capacity across the transmission system. Transmission Provider shall adopt the Capacity Emergency Transfer Objective (“CETO”), as defined in Attachment DD to the Tariff, associated with that LDA and calculated for the applicable planning year to be the transfer limitation into the LDA. In modeling the system generation and load, Transmission Provider shall assume that the percentage of the zonal load in the LDA served by external (or internal) generation to the LDA shall equal the ratio of (i) the CETO associated within that LDA (or generation internal with the LDA) to (ii) the sum of (a) the internal generation within the LDA and (b) the CETO associated with that LDA. For the generation dispatch used in calculating the distribution factor, Transmission Provider shall distribute these amounts of external/internal generation among all generation in the PJM Region external to/internal within the LDA, respectively, in proportion to their capacity. The use by each zonal load or Merchant Transmission Facility of the Required Transmission Enhancement shall be determined by multiplying the resulting distribution factor by the peak load of a Zone or the planned or existing Firm Transmission Withdrawal Rights associated with a Merchant Transmission Facility, as applicable. For Zones and Merchant Transmission Facilities that are located within LDAs that are also entirely contained in other larger LDAs, the modeling approach and distribution factor calculations shall be repeated for such Zones or Merchant Transmission Facilities as above for each LDA. The lowest distribution factor derived from these calculations shall be applied to the Zone or Merchant Transmission Facility in the calculation of the use of the Required Transmission Enhancement. A distribution factor threshold of 0.01 shall be applied to all cost responsibility assignment calculations such that any distribution factor less than 0.01 shall be set equal to zero.

(E) In the DFAX analysis, the Zones of Public Service Electric and Gas Company and Rockland Electric Company will be treated as one Zone unless and until Rockland Electric Company elects to be treated as a separate Zone in accordance with the terms of the Settlement Agreement And Offer Of Partial Settlement approved by FERC in Docket Nos. ER06-456-000, et al.

(F) Transmission Provider shall round cost responsibility assignments determined using the DFAX analysis described in subsection (b)(iii) of this Schedule 12 to the nearest one-hundredth of one percent.

(G) Transmission Provider shall not account for the ability to adjust use of phase angle regulators (“PARs”) in the DFAX analysis described in subsection (b)(iii) of this Schedule 12. In the DFAX analysis, all PAR angles shall be fixed at their base case settings.

(H) In the DFAX analysis, if the Required Transmission Enhancement is a D.C. facility, the Transmission Provider shall determine cost responsibility assignment as follows:

(1) The Required Transmission Enhancement shall be replaced in the model with a comparable proxy A.C. facility, the impedance of which shall be calculated based on the length of the D.C. facility that was removed from the model multiplied by an approximate per unit/mile impedance value for the proxy A.C. facility.

(2) Where a D.C. facility is an integral part of a Required Transmission Enhancement that also includes A.C. facilities, the methodology described in Subsection (b)(iii)(H)(1) above shall be used only for the D.C. facility segment of such Required Transmission Enhancement.

(3) A D.C. facility used to control flow over portions of the Transmission System shall be modeled with a zero impedance and no control shall be applied.

(I) If Transmission Provider determines in its reasonable engineering judgment that, as a result of applying the provisions of this Section (b)(iii), the DFAX analysis cannot be performed or that the results of such DFAX analysis are objectively unreasonable, the Transmission Provider may use an appropriate substitute proxy for the Required Transmission Enhancement in conducting the DFAX analysis. If a proxy is used that is not specified in this Schedule 12, Transmission Provider shall state in a written report (a) the reasons why it determined the DFAX analysis could not be performed or that the results of the DFAX analysis were objectively unreasonable; (b) why the substitute proxy produced objectively reasonable results; and (3) a recommendation as to what changes, if any, should be considered in conducting the DFAX analysis.

(J) The Transmission Provider shall make a preliminary cost responsibility determination for each Required Transmission Enhancement subject to this section (b)(iii) of Schedule 12 at the time such Required Transmission Enhancement is included in the Regional Transmission Expansion Plan.

(1) When CWIP in connection with a Required Transmission Enhancement subject to this section (b)(iii) of Schedule 12 is entitled to be recovered, the preliminary determination of cost responsibility made at the time that the Required Transmission Enhancement was included in the Regional Transmission Expansion Plan shall be used to assign cost responsibility for such CWIP and such cost responsibility shall remain unchanged until the

date the Required Transmission Enhancement goes into service. Once a Required Transmission Enhancement has gone into service, the updated cost responsibility determination provided for in subsection (b)(iii)(J)(2) shall apply.

(2) Beginning with the calendar year in which a Required Transmission Enhancement is scheduled to enter service, and thereafter annually at the beginning of each calendar year, the Transmission Provider shall update the preliminary cost responsibility determination for each Required Transmission Enhancement using the values and inputs used in the base case of the most recent Regional Transmission Expansion Plan approved by the PJM Board prior to the date of the update. All values and inputs used in the calculation of the distribution factor in a determination of cost responsibility shall be the same values and inputs as used in the base case of the most recent Regional Transmission Expansion Plan approved by the PJM Board prior to the determination of cost responsibility.

**(iv) Spare Parts, Replacement Equipment And Circuit Breakers.** Transmission Provider shall assign cost responsibility for spare parts, replacement equipment, and circuit breakers and associated equipment, included in the Regional Transmission Expansion Plan as follows:

(A) Spare parts that are part of the design specifications of a Required Transmission Enhancement at the time such Required Transmission Enhancement is first included in the Regional Transmission Expansion Plan shall be considered part of the Required Transmission Enhancement for the purpose of applying the cost threshold described in subsection (b)(vi) of this Schedule 12 and cost responsibility for such spare parts shall be assigned in the same manner as the Required Transmission Enhancement. Cost responsibility for spare parts independently included in the Regional Transmission Expansion Plan and not a part of the design specifications of a Required Transmission Enhancement as described above in this subsection shall be assigned to the Zone of the owner of the spare part, if the owner of the spare part is a Transmission Owner listed in Attachment J of the Tariff. If the owner of the spare part is not a Transmission Owner listed in Attachment J of the Tariff, cost responsibility shall be assigned on a *pro rata* basis to the zones that bear cost responsibility for the owner's Required Transmission Enhancements.

(B) Replacement equipment that is part of the design specifications of a Required Transmission Enhancement at the time the Required Transmission Enhancement is first included in the Regional Transmission Expansion Plan shall be considered part of the Required Transmission Enhancement for the purpose of applying the cost threshold described in section (b)(vi) of this Schedule 12 and cost responsibility for such replacement equipment shall be assigned in the same manner as the Required Transmission Enhancement. Cost responsibility for Required Transmission Enhancement replacement equipment independently included in the Regional Transmission Expansion Plan and not a part of the design specifications of a Required Transmission Enhancement as described above in this subsection, shall be assigned to the same Zones and/or Merchant Transmission Facilities and in the same proportions as the then-existing assignments of cost responsibility for the facilities that the replacement equipment is replacing.

(C) Circuit breakers and associated equipment that are part of the design specifications of a Required Transmission Enhancement at the time the Required Transmission Enhancement is first included in the Regional Transmission Expansion Plan shall be considered part of the Required Transmission Enhancement for the purpose of applying the cost threshold described in subsection (b)(vi) of this Schedule 12 and cost responsibility for such circuit breakers and associated equipment shall be assigned in the same manner as the Required Transmission Enhancement. Cost responsibility for circuit breakers and associated equipment independently included in the Regional Transmission Expansion Plan and not a part of the design specifications of a transmission element of a Required Transmission Enhancement as described above in this subsection, shall be assigned to the Zone of the owner of the circuit breaker and associated equipment if the owner of the circuit breaker is a Transmission Owner listed in Attachment J of the Tariff. If the owner of the circuit breaker is not a Transmission Owner listed in Attachment J of the Tariff, cost responsibility shall be assigned on a *pro rata* basis to the zones that bear cost responsibility for the owner's Required Transmission Enhancements.

(v) **Economic Projects.** Transmission Provider shall assign (i) fifty percent (50%) of cost responsibility for Economic Projects that are Regional Facilities; and (ii) full cost responsibility for Economic Projects that are Lower Voltage Facilities; as follows:

(A) Transmission Provider shall assign cost responsibility for Economic Projects that are accelerations of Reliability Projects as described in section 1.5.7(b)(i) of Schedule 6 of the Operating Agreement ("Acceleration Projects") by performing and comparing (1) a DFAX analysis consistent with the methodology described in subsection (b)(iii) of this Schedule 12, and (2) a methodology that is intended to act as a proxy for expected economic benefits from reduced Locational Marginal Prices ("LMP Benefit") over the period that the reliability-based enhancement or expansion is to be accelerated ("LMP Benefits Methodology"). The LMP Benefits Methodology shall determine cost responsibility assignment percentages to Zones and Merchant Transmission Facilities in the following manner. The LMP Benefit to a Zone shall be deemed to be equal to the reduction in Locational Marginal Price payments made by Load Serving Entities as a result of the Acceleration Project assuming the customers purchase all energy needs from the PJM Interchange Energy Market, and LMP Benefits so calculated shall be converted into percentage cost responsibility assignments for the affected Zones. The LMP Benefits Methodology shall not incorporate the financial effects of allocations of Auction Revenue Rights or Financial Transmission Rights. The LMP Benefit to a Merchant Transmission Facility shall be deemed to be equal to the proportionate share of assigned cost responsibility using the DFAX analysis and the assignments of cost responsibility to other Zones in the LMP Benefits Methodology shall be proportionately adjusted, as necessary, to reflect this treatment of Merchant Transmission Facilities to ensure that the total allocation for any economic-based Required Transmission Enhancement equals one hundred percent. If, after performing both analyses and comparing the percentage cost responsibility assignments for the affected Zones calculated pursuant to the DFAX analysis and the LMP Benefits Methodology, the results do not indicate at least a ten percentage point cost responsibility assignment differential between the two methods for any Zone, cost responsibility for the Acceleration Project shall be assigned using the DFAX analysis. If, after performing both analyses and comparing the percentage cost responsibility assignments for the affected Zones calculated pursuant to the DFAX analysis and LMP Benefits Methodology, the results indicate at least a ten

percentage point cost responsibility assignment differential between the DFAX analysis and the LMP Benefits Methodology for any Zone, cost responsibility for the Acceleration Project for the period of time the Reliability Project is accelerated (i.e. the period between the date the Reliability Project actually goes into service and the date the Reliability Project originally was scheduled to go in service in the PJM Board approved Regional Transmission Expansion Plan) shall be assigned using the LMP Benefits Methodology. For all periods other than the period of time the Reliability Project is accelerated, cost responsibility for such an Acceleration Project shall be assigned in accordance with the provisions of this Schedule 12 governing the assignment of cost responsibility of Regional Facility Reliability Projects or Lower Voltage Facility Reliability Projects, as applicable.

(B) Transmission Provider shall assign cost responsibility for Economic Projects that are modifications to Reliability Projects as described in section 1.5.7(b)(ii) of Schedule 6 of the Operating Agreement in accordance with the provisions of this Schedule 12 governing the assignment of cost responsibility of Regional Facility Reliability Projects or Lower Voltage Facility Reliability Projects, as applicable.

(C) Transmission Provider shall assign cost responsibility for Economic Projects that are new enhancements or expansions that could relieve one or more economic constraints as described in section 1.5.7(b)(iii) of Schedule 6 of the Operating Agreement to the Zones that show a decrease in the net present value of the Changes in Load Energy Payment determined for the first 15 years of the life of the Economic Project. The Change in Load Energy Payment for each year shall be determined using the methodology set forth in Section 1.5.7(d) of Schedule 6 of the Operating Agreement. Cost responsibility shall be assigned based on each Zone's pro rata share of the sum of the net present values of the Changes in Load Energy Payment only of the Zones in which the net present value of the Changes in Load Energy Payment shows a decrease.

**(vi) Required Transmission Enhancements Costing Less Than \$5 Million.** Notwithstanding Section (b)(i), (b)(ii), (b)(iv) and (b)(v), cost responsibility for a Required Transmission Enhancement for which the good faith estimate of the cost of the Required Transmission Enhancement (a) prepared in connection with the development of the Regional Transmission Expansion Plan and (b) provided to the PJM Board at the time the Required Transmission Enhancement is included for the first time in the Regional Transmission Expansion Plan, does not equal or exceed \$5 million shall be assigned to the Zone where the Required Transmission Enhancement is to be located. The determination of whether the estimated cost of a Required Transmission Enhancement does not equal or exceed \$5 million shall be based solely on such good faith estimate of the cost of the Required Transmission Enhancement regardless of the actual costs incurred. The estimated cost of a Required Transmission Enhancement shall include the aggregate estimated costs of all of the transmission elements approved by the PJM Board at the time such elements are included in the Regional Transmission Expansion Plan that collectively are intended (i) in the case of a Reliability Project, to resolve a specific reliability criteria violation, or (ii) in the case of an Economic Project, provide a specific LMP Benefit. Where a Required Transmission Enhancement subject to this section (b)(vi) consists of a single transmission element or multiple transmission elements that will be located in more than one Zone, each Zone shall be assigned cost responsibility for the transmission elements or portions of

the transmission elements located in such Zone. Merchant Transmission Facilities shall not be assigned cost responsibility for a Required Transmission Enhancement subject to this Section (b)(vi).

**(vii) Modifications of Required Transmission Enhancements.** Once a Required Transmission Enhancement is included in the Regional Transmission Expansion Plan, any modification to such Required Transmission Enhancement that subsequently is included in the Regional Transmission Expansion Plan as a separate Reliability or Economic Project shall be considered a separate and distinct Required Transmission Enhancement for purposes of cost responsibility assignment under this Schedule 12. Except as provided in Section (b)(iv) of this Schedule 12, any cost responsibility assignment that has been made for a previously approved Required Transmission Enhancement shall have no impact on the cost responsibility assignment of such modification.

**(viii) FERC Filing.** Within 30 days of the approval of each Regional Transmission Expansion Plan or an addition to such plan by the PJM Board pursuant to Section 1.6 of Schedule 6 of the PJM Operating Agreement, the Transmission Provider shall designate in the Schedule 12-Appendix A and in a report filed with the FERC the customers using Point-to-Point Transmission Service and/or Network Integration Transmission Service and Merchant Transmission Facility owners that will be subject to each such Transmission Enhancement Charge (“Responsible Customers”) based on the cost responsibility assignments determined pursuant to subsections (b)(i) through (v) of this Schedule 12. Those customers designated by the Transmission Provider as Responsible Customers shall have 30 days from the date the filing is made with the FERC to seek review of such designation. Such cost responsibility designations shall be the same as those made for the relevant Regional Facility, Necessary Lower Voltage Facility, or Lower Voltage Facility in the Regional Transmission Expansion Plan.

**(ix) MISO.** For purposes of this Schedule 12, where the Responsible Customers are subject to the Open Access Transmission and Energy Markets Tariff for the Midwest Independent System Operator, Inc. (“MISO Tariff”), MISO shall be the Responsible Customer with respect to all such Required Transmission Enhancements. Cost responsibility with respect to Required Transmission Enhancements for which MISO has been designated the Responsible Customer shall be allocated within MISO in accordance with the MISO Tariff.

**(x) Merchant Transmission Facilities.**

(A) For purposes of this Schedule 12, where the Transmission Provider has allocated all or a portion of a Required Transmission Enhancement to a Merchant Transmission Facility, the owner of the Merchant Transmission Facility shall be the Responsible Customer with respect to such Required Transmission Enhancement, and shall pay the Transmission Enhancement Charges associated with the Required Transmission Enhancement.

(B) (1) Transmission Provider shall defer collection of Transmission Enhancement Charges from a Merchant Transmission Facility until the Merchant Transmission Facility goes into commercial operation; provided, however, in the event the commercial operation of a Merchant Transmission Facility is delayed beyond the commercial operation

milestone date(s) specified in the Interconnection Service Agreement associated with the Merchant Transmission Facility and the Transmission Provider or Transmission Owner constructing the Required Transmission Enhancement demonstrates that the Merchant Transmission Facility is responsible for such delay, Transmission Provider may begin collecting Transmission Enhancement Charges from the Merchant Transmission Facility prior to the Merchant Transmission Facility going into commercial operation. Transmission Enhancement Charges allocated to a Merchant Transmission Facility for which collection is deferred in accordance with this section (b)(x)(B)(1) shall be recorded in appropriate Transmission Provider accounts for deferred charges and collected in accordance with section (b)(x)(B)(3), below.

(2) Transmission Provider shall base the collection of Transmission Enhancement Charges associated with Required Transmission Enhancements from a Merchant Transmission Facility on the actual Firm Transmission Withdrawal Rights that have been awarded to the Merchant Transmission Facility; provided, however, to the extent that a Merchant Transmission Facility has been awarded less than the amount of Firm Transmission Withdrawal Rights specified in the Interconnection Service Agreement associated with the Merchant Transmission Facility, then Transmission Provider shall record the difference between the amount of Transmission Enhancement Charges collected based on the lesser amount of Firm Transmission Withdrawal Rights and the amount of Transmission Enhancement Charges based on the full amount of Firm Transmission Withdrawal Rights specified in the applicable Interconnection Service Agreement in appropriate accounts for deferred charges and, after the Merchant Transmission Facility has been awarded the full amount of Firm Transmission Withdrawal Rights specified in the Interconnection Service Agreement, collect such deferred amounts in accordance with section (b)(x)(B)(3), below. Notwithstanding the foregoing, Transmission Provider may collect Transmission Enhancement Charges based on more than a Merchant Transmission Facility's actually awarded Firm Transmission Withdrawal Rights (not to exceed the Firm Transmission Withdrawal Rights specified in the applicable Interconnection Service Agreement) if the Transmission Provider or Transmission Owner demonstrates that the Merchant Transmission Facility is responsible for receiving fewer Firm Transmission Withdrawal Rights than are specified in the applicable Interconnection Service Agreement.

(3) Transmission Provider shall record: (i) in an appropriate deferred asset account, the Transmission Enhancement Charges associated with Required Transmission Enhancements for which collection is deferred in accordance with sections (b)(x)(B)(1) and (b)(x)(B)(2); and (ii) in an appropriate deferred liability account, the revenues associated with the Transmission Enhancement Charges that, absent the deferred charges, would have been due to Transmission Owners or to Transmission Owners' customers as directed by the applicable Transmission Owner. At such time as collection of such deferred Transmission Enhancement Charges are permitted in accordance with sections (b)(x)(B)(1) and (b)(x)(B)(2), the deferred charges (along with appropriate interest) shall be collected from the Merchant Transmission Facility in equal installments over the twelve months following the commencement of the collection of the deferred charges. Such amounts shall be distributed to Transmission Owners or to Transmission Owners' customers as directed by the applicable Transmission Owner, and the Transmission Provider shall make appropriate adjustments to the deferred asset and liability accounts. Transmission Provider shall not be responsible for distributing revenues associated with deferred Transmission Enhancement Charges unless and until such charges are collected in

accordance with this section (b)(x)(B), and uncollected deferred Transmission Enhancement Charges shall not be subject to Default Allocation Assessments to the Members pursuant to section 15.2 of the Operating Agreement.

**(xi) Consolidated Edison Company of New York.** (A) Cost responsibility assignments to Consolidated Edison Company of New York for Required Transmission Enhancements pursuant to this Schedule 12 with respect to the Firm Point-To-Point Service Agreements designated as Original Service Agreement No. 1873 and Original Service Agreement No. 1874 accepted by the Commission in Docket No. ER08-858 (“ConEd Service Agreements”) shall be in accordance with the terms and conditions of the settlement approved by the FERC in Docket No. ER08-858-000. (B) All cost responsibility assignments for Required Transmission Enhancements pursuant to this Schedule 12 shall be adjusted at the commencement and termination of service under the ConEd Service Agreements to take account of the assignments under subsection (xi)(A).

**(xii) Public Policy Projects.**

(A) Transmission Facilities as defined in section 1.27 of the Consolidated Transmission Owners Agreement constructed by a Transmission Owner pursuant to a Public Policy Requirement as defined in Section 1.38B of the Operating Agreement, but not included in a Regional Transmission Expansion Plan as a Required Transmission Enhancement, shall be considered a Supplemental Project, as defined in Section 1.42A.02 of the Operating Agreement.

(B) If a transmission enhancement or expansion is proposed pursuant to Section 1.5.9(a) of Schedule 6 of the Operating Agreement which is not a Supplemental Project (“State Agreement Public Policy Project”), the Transmission Provider shall submit the assignment of costs to Responsible Customers proposed in connection with such State Agreement Public Policy Project to the Transmission Owners Agreement Administrative Committee for consideration and filing pursuant to Section 7.3 of the Consolidated Transmission Owners Agreement and Section 9.1(a) of the PJM Tariff. Nothing in this Section (b)(xii) shall prevent the Transmission Provider or the state governmental entities proposing such State Agreement Public Policy Project from filing a proposed assignment of costs to Responsible Customers for such project pursuant to Section 206 of the Federal Power Act.

**(xiii) Replacement of Transmission Facilities.** Unless determined by PJM to be a Required Transmission Enhancement included in a Regional Transmission Expansion Plan, cost responsibility for the replacement of Transmission Facilities, as defined in section 1.27 of the Consolidated Transmission Owners Agreement, shall be assigned to the Zonal loads and Merchant Transmission Facilities responsible for the costs of the Transmission Facilities being replaced.

**(c) Determination of Transmission Enhancement Charges.** In the event that any Transmission Owner recovers the cost of a Required Transmission Enhancement through a Transmission Enhancement Charge, such charge shall be determined as follows:

(1) Transmission Provider shall identify in writing and post on the PJM Internet site the Required Transmission Enhancement(s) to which each Transmission Enhancement

Charge corresponds. The Transmission Enhancement Charge with respect to a Required Transmission Enhancement shall recover the applicable Transmission Owner's annual transmission revenue requirement associated with the Required Transmission Enhancement.

(2) Each Transmission Enhancement Charge shall be a monthly charge based on all costs and applicable incentives associated with a particular Required Transmission Enhancement for which the Transmission Owner is responsible.

(3) A Transmission Owner's annual transmission revenue requirement associated with a Required Transmission Enhancement shall be determined pursuant to either (i) a unilateral filing by the Transmission Owner under Section 205 of the Federal Power Act and the FERC's rules and regulations thereunder; or (ii) a formula rate in effect applicable to the Transmission Owner's rates for Network Integration Transmission Service, including the costs associated with Required Transmission Enhancements.

(4) Each Transmission Enhancement Charge applicable to Network Customers and Non-Zone Network Customers shall be recalculated annually to reflect the annual revisions to the billing determinants used by the Transmission Provider to calculate charges to Network Customers for Network Integration Transmission Service under Section 34.1 of the PJM Tariff. The Transmission Provider shall post on its Internet site by October 31 of each calendar year each recalculated Transmission Enhancement Charge that shall be effective during the subsequent calendar year.

(5) Each Transmission Enhancement Charge applicable to customers using Point-To-Point Transmission Service shall be calculated monthly to reflect the billing determinants used by the Transmission Provider to determine charges for customers of Point-To-Point Transmission Service in accordance with Section 25 of the PJM Tariff.

(6) Each Transmission Enhancement Charge payable by an owner of a Merchant Transmission Facility pursuant to Section (b) of this Schedule shall be calculated as a fixed monthly charge.

(7) If a Transmission Owner chooses to recover the cost of Required Transmission Enhancements through the operation of a formula rate as described in Section (a), the Transmission Owner must make an informational filing with the Commission one year from the date the selecting Transmission Owner's formula rates go into effect, and each year thereafter, providing a detailed list of the costs the Transmission Owner has incurred, and the revenues the Transmission Owner has received to provide service.

**(d) Recovery of Transmission Enhancement Charges.**

(1) Responsible Customers shall pay Transmission Provider all applicable Transmission Enhancement Charges as required by this Schedule 12 in addition to

all other charges for transmission service for which such Responsible Customers are responsible under the Tariff.

- (2) Transmission Provider shall collect all applicable Transmission Enhancement Charges from each Responsible Customer on a monthly basis. Transmission Provider shall remit or credit all revenues received from Responsible Customers under this Schedule 12 to the Transmission Owner(s) that established such charge or to MISO in the case of Transmission Enhancement Charges established by one or more transmission owners within MISO to be distributed to said transmission owners in accordance with the MISO Tariff.

**(e) Crediting of Revenue from Transmission Enhancement Charges.** In recognition that a Transmission Owner's charges for Network Integration Transmission Service set forth in Attachment H are established based upon the Transmission Owner's total cost of providing FERC-jurisdictional transmission service, including the costs associated with Required Transmission Enhancements, revenue from a Transmission Owner's Transmission Enhancement Charges for a billing month shall be credited pursuant to this Schedule 12 to the Network Customers in the Transmission Owner's Zone (including, where applicable, the Transmission Owner) and Transmission Customers purchasing Firm Point-to-Point Transmission Service for delivery in the Transmission Owner's Zone in proportion to their Demand Charges (including any imputed Demand Charges for bundled service to Native Load Customers) for Network Integration Transmission Service and Reserved Capacity for Firm Point-to-Point Transmission Service; provided that such credits shall be reduced by the amount of any applicable incentives included in such Transmission Enhancement Charges.

## SCHEDULE 12 – APPENDIX A

### **Required Transmission Enhancements Approved By The PJM Board On Or After The Effective Date Of The Amendments To Schedule 12 Filed In Docket No. \_\_\_\_ On October 11, 2012, Responsible Customers And Associated Transmission Owner Revenue Requirements.**

This Schedule 12 – Appendix A applies only to the assignment of cost responsibility or classification of Required Transmission Enhancements either (1) made by the Transmission Provider on or after the effective date of the amendments to Schedule 12 filed in Docket No. \_\_\_\_\_ on October 11, 2012, or (2) applicable to Required Transmission Enhancements approved by the PJM Board pursuant to Section 1.6 of the PJM Operating Agreement on or after such effective date.

Required Transmission Enhancements that have been placed in service in PJM, the Transmission Owner(s) responsible for constructing and owning and/or financing such Required Transmission Enhancements, the Responsible Customers and the annual revenue requirement upon which Transmission Enhancement Charges determined in accordance with section (c) of Schedule 12 are based, are set forth below. Unless otherwise stated, all designations of Responsible Customers refer collectively to all Firm Point-to-Point Transmission Service and Network Integration Transmission Service customers in each indicated Zone and state the proportional (percentage) cost responsibility allocated to the indicated customers in each Zone. Zones are identified using the short names stated in Attachment J to the Tariff.

# Attachment B

## Revisions to the PJM Open Access Transmission Tariff

(Marked / Redline Format)

## SCHEDULE 12 Transmission Enhancement Charges

**(a) Establishment of Transmission Enhancement Charges.** One or more of the Transmission Owners may be designated to construct and own and/or finance Required Transmission Enhancements (as defined in Section 1.38C of the Tariff) by (1) the Regional Transmission Expansion Plan periodically developed pursuant to Schedule 6 of the Operating Agreement or (2) the Coordinated System Plan periodically developed pursuant to the Joint Operating Agreement Between the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. (~~“Coordinated System~~(collectively, for purposes of this Schedule 12 only, “Regional Transmission Expansion Plan”)). Section 1.7 of Schedule 6 of the Operating Agreement recognizes that Transmission Owners, subject to obtaining any necessary regulatory approvals, may seek to recover the costs of Required Transmission Enhancements and obligates PJM Settlement to collect on behalf of Transmission Owner(s) any charges established by Transmission Owners to recover the costs of Required Transmission Enhancements. If a Transmission Owner is designated by the Regional Transmission Expansion ~~Plan or the Coordinated System~~ Plan to construct and own and/or finance a Required Transmission Enhancement, such Transmission Owner may choose any of the following cost recovery mechanisms, subject to the crediting procedures set forth in section (e) below:

- (1) Decline to seek to recover the costs of Required Transmission Enhancements from customers until such time as it makes a filing pursuant to Section 205 of the Federal Power Act to revise its Network Integration Transmission Service rates;
- (2) Make a filing pursuant Section 205 of the Federal Power Act and the FERC’s rules and regulations to establish the revenue requirement with respect to a Required Transmission Enhancement, without filing to revise its rates for Network Integration Transmission Service generally; or
- (3) Establish the revenue requirement with respect to a Required Transmission Enhancement through the operation of a formula rate in effect applicable to its rates for Network Integration Transmission Service.

A charge established to recover the revenue requirement with respect to a Required Transmission Enhancement is hereafter referred to as a “Transmission Enhancement Charge.” Transmission Enhancement Charges of one or more Transmission Owners for Required Transmission Enhancements shall be established in accordance with this Schedule 12. Transmission Enhancement Charges of one or more transmission owners within the Midwest Independent System Operator, Inc. (“MISO”) shall be determined in accordance with ~~to~~ the MISO Tariff. Any alternating current (“A.C.”) facilities or direct current (“D.C.”) facilities that are Attachment Facilities, Local Upgrades, Merchant Network Upgrades, Merchant Transmission Facilities, Network Upgrades, Supplemental Projects as defined in Section 1.42A.02 of the Operating Agreement, or any other Transmission Facilities that operate or are planned to be operated in a manner that requires customers to subscribe to transmission service over such facilities or to a portion of the electric capability of such facilities shall not be eligible for cost responsibility assignment pursuant to this Schedule 12. For purposes of this Schedule 12 only, the term,

“Transmission Owner,” shall include any entity that undertakes to construct and own and/or finance a Required Transmission Enhancement pursuant to a designation in the Regional Transmission Expansion Plan to construct and own and/or finance such Required Transmission Enhancement, even if such entity is not yet eligible to become a party to the Consolidated Transmission Owners Agreement.

The assignment of cost responsibility or classification of Required Transmission Enhancements either (1) made by the Transmission Provider prior to the effective date of the amendments to this Schedule 12 filed in Docket No. \_\_\_\_\_ on October 11, 2012, or (2) applicable to Required Transmission Enhancements approved by the PJM Board pursuant to Section 1.6 of the PJM Operating Agreement prior to such effective date are set forth in Schedule 12-Appendix. Except as specifically set forth herein, nothing in this Schedule 12 shall change the assignment of cost responsibility or classification of Required Transmission Enhancements included in Schedule 12-Appendix. The assignment of cost responsibility or classification of all other Required Transmission Enhancements shall be set forth in Schedule 12-Appendix A.

**(b) Designation of Customers Subject to Transmission Enhancement Charges.**

**(i) Regional Facilities and Necessary Lower Voltage Facilities.** Transmission Provider shall assign cost responsibility on a region-wide basis ~~cost responsibility~~ for Required Transmission Enhancements included in the Regional Transmission Expansion Plan that are (1) Transmission Facilities as defined in section 1.27 of the Consolidated Transmission Owners Agreement (Rate Schedule FERC No. 42) ~~that operate at or above 500 kV (“Regional Facilities”)~~, that (a) are A.C. facilities that operate at or above 500 kV; (b) constitute a single Required Transmission Enhancement comprising two A.C. circuits operating at or above 345 kV and below 500 kV, where both circuits originate from a single substation or switching station at one end and terminate at a single substation or switching station at the other end, regardless of whether or not the two circuits are routed in the same right-of-way (“Double-circuit 345 kV Required Transmission Enhancement”); (c) are A.C. or D.C. shunt reactive resources (such as capacitors, static var compensators, static synchronous condenser (STATCON), synchronous condensers, inductors, other shunt devices, or their equivalent) connected to a Transmission Facility described in clause (a) or (b) of this subsection, or (d) are D.C. facilities meeting the criteria set forth in subsection (b)(i)(D) (collectively, “Regional Facilities”), or (2) new A.C. Transmission Facilities or expansions or enhancements to existing Transmission Facilities that operate below 500 kV (or 345 kV in the case of a Regional Facility described in clause (1)(b) of this subsection) that must be constructed or strengthened to support new Regional Facilities, based on the planning criteria used by the Transmission Provider in developing the applicable Regional Transmission Expansion Plan (“Necessary Lower Voltage Facilities”) as follows:

**(A)** Cost responsibility for Regional Facilities and Necessary Lower Voltage Facilities shall be allocated ~~annually~~ among Responsible Customers as defined in this Schedule 12 ~~on an annual load ratio share basis using, consistent with section 34.1 of the Tariff, the applicable zonal loads at the time of each Zone’s annual peak load from the 12-month period ending October 31 of the calendar year preceding the calendar year for which the annual cost responsibility allocation is determined.~~ as follows:

~~(B) A Merchant Transmission Facility will be allocated cost responsibility for Regional Facilities and Necessary Lower Voltage Facilities pursuant to subsection (A) above, beginning in the calendar year following the year in which it initiates operation. Cost responsibility allocated to an owner of a Merchant Transmission Facility pursuant to subsection (A) above shall be based on: (1) for the \_\_\_\_\_ (1) Fifty percent (50%) shall be assigned annually on a load-ratio share basis as follows:~~

~~(a) With respect to each Zone, using, consistent with section 34.1 of the Tariff, the applicable zonal loads at the time of such Zone's annual peak load from the 12-month period ending October 31 preceding the calendar year for which the annual cost responsibility allocation is determined; and~~

~~(b) With respect to Merchant Transmission Facilities, (1) for the calendar year following the year in which it initiates operation, the actually awarded Firm Transmission Withdrawal Rights associated with its existing Merchant Transmission Facility; and (2) for all subsequent calendar years, the annual peak load of the Merchant Transmission Facility (not to exceed its actual Firm Transmission Withdrawal Rights) from the 12-month period ending October 31 of the calendar year preceding the calendar year for which the annual cost responsibility allocation is determined.~~

~~(C)(2) Fifty percent (50%) shall be assigned as follows:~~

~~(a) In the case of a Required Transmission Enhancement included in the Regional Transmission Expansion Plan to address one or more reliability violations or to address operational adequacy and performance issues (collectively, "Reliability Project"), in accordance with the distribution factor ("DFAX") analysis described in subsection (b)(iii) of this Schedule 12; and~~

~~(b) In the case of a Required Transmission Enhancement included in the Regional Transmission Expansion Plan to relieve one or more economic constraints as described in section 1.5.7(b)(iii) of Schedule 6 of the Operating Agreement ("Economic Project"), in accordance with the methodology described in subsection (b)(v) of this Schedule 12.~~

~~(B) (1) Except for transformers that are an integral component of an A.C. Regional Facility; and transformers with that are an integral component of a D.C. Regional Facility with a low-side voltages below 500 kV phase-to-phase voltage rating of not less than 345kV, transformers connected to Lower Voltage Facilities, as defined in section (b)(ii) of this Schedule 12 and transformers connected to D.C. Regional Facilities with a low side phase-to-phase voltage rating of less than 345kV, shall not be considered Regional Facilities or Necessary Lower Voltage Facilities; and (2) Transmission Facilities that operate below 500 kV are not Regional Facilities and deliver energy from a Regional Facility to load shall not be considered Necessary Lower Voltage Facilities.~~

~~(D) Transmission Provider shall designate in the Schedule 12 Appendix the cost responsibility allocations determined pursuant to this subsection (b)(i) of this Schedule 12.~~

(C) With respect Required Transmission Enhancements that qualify as Regional Facilities under subsection (b)(i)(1)(b) of this Schedule 12,

(1) where the Required Transmission Enhancement includes both new Transmission Facilities and pre-existing Transmission Facilities, cost responsibility under this section (b)(i) shall apply only to the cost of the new Transmission Facilities plus the original cost less accumulated depreciation of pre-existing Transmission Facilities that are included in Schedule 12-Appendix or Schedule 12-Appendix A;

(2) cost responsibility shall be assigned under this section (b)(i) only after the Required Transmission Enhancement goes into service as a Double-circuit 345 kV Required Transmission Enhancement; and

(3) cost responsibility shall be assigned under this section (b)(i) for any CWIP permitted to be recovered before the Required Transmission Enhancement goes into service only after such Transmission Facilities are approved in a Regional Transmission Expansion Plan as a Double-circuit 345 kV Required Transmission Enhancement.

(D) A Required Transmission Enhancement included in the Regional Transmission Expansion Plan that is a D.C. facility shall be a Regional Facility only if:

(1) (a) such D.C. facility is connected to at least one substation or switching station that is also connected to either (i) at least one A.C. transmission line operated at 500 kV or above; or (ii) at least one Double-circuit 345 kV Required Transmission Enhancement; and

(b) any transformer between the substation or switching station described in subsection (b)(i)(D)(1)(a) above and the D.C. converter has a low side phase-to-phase voltage rating of not less than 345kV, such voltage having been determined by Transmission Provider in the Regional Transmission Expansion Plan to be necessary and appropriate; or

(2) such D.C. facility is connected directly to a D.C. facility that is a Regional Facility.

~~(ii) **Docket No. ER06-456 Settlement.** In Docket Nos. ER06-456-000, et al., the FERC approved a “Settlement Agreement And Offer Of Partial Settlement” filed on September 14, 2007, (“Docket No. ER06-456 Settlement”), that among other things provides procedures and methodologies for Transmission Provider, on an interim basis, to assign cost responsibility in accordance with Schedule 6 of the Operating Agreement for (1) Lower Voltage Facilities as defined in subsection (b)(iii) of this Schedule 12, (2) below 500 kV spare parts, replacement equipment, and circuit breakers and associated equipment, and (3) economic based Required Transmission Enhancements that as planned will operate below 500 kV (collectively “Applicable~~

Facilities”) regarding (1) the assignments of cost responsibility for Applicable Facilities filed in Docket Nos. ER06-456-000, -001, and -002, ER06-954-000, ER06-1271-000, and ER07-424-000, and (2) the assignment of cost responsibility for Applicable Facilities included in Regional Transmission Expansion Plans approved by the PJM Board after June 1, 2007.

**(iii) Lower Voltage Facilities.** Transmission Provider shall assign cost responsibility for Required Transmission Enhancements that (a) are ~~included in the Regional Transmission Expansion Plan to address one or more reliability violations or to address operational adequacy and performance issues; (b) as planned will operate below 500 kV; and (enot Regional Facilities;~~ and (b) are not “Necessary Lower Voltage Facilities” as defined in section (b)(i) of this Schedule 12 (collectively “Lower Voltage Facilities”), as follows:

(A) If the Lower Voltage Facility is a Reliability Project, Transmission Provider shall use the DFAX analysis described in subsection (b)(iii) of this Schedule 12; and

(B) If the Lower Voltage Facility is an Economic Project, Transmission Provider shall use the methodology described in subsection (b)(v) of this Schedule 12.

**(iii) DFAX Analysis for Reliability Projects.**

(A) For purposes of the assignment of cost responsibility ~~under this section (b)(iii)(C) for Reliability Projects under subsection (b)(i)(A)(2)(a) and subsection (b)(ii)(A)~~ of Schedule 12, the Transmission Provider, based on a computer model of the electric network and using power flow modeling software, shall calculate distribution factors, represented as decimal values or percentages, which express the portions of a transfer of energy from a defined source to a defined sink that will flow across a particular transmission facility or group of transmission facilities. These distribution factors represent a measure of the ~~effect of use by~~ the load of each Zone or Merchant Transmission Facility ~~on of the transmission constraint that requires the Lower Voltage Facility Required Transmission Enhancement~~, as determined by a power flow analysis. In general, a distribution factor can be represented as:

*Distribution Factor = (After-shift power flow – pre-shift power flow) / Total amount of power shifted*

*Total amount of power shifted = Modeled incremental megawatt transfer to a given Load Deliverability Area or Merchant Transmission Facility*

*Pre-shift power flow = Megawatt flow over the ~~constrained transmission element~~ Required Transmission Enhancement before the incremental megawatt transfer*

*After-shift power flow = Megawatt flow over the ~~constrained transmission element~~ Required Transmission Enhancement after the incremental megawatt transfer*

When calculating such distribution factors:

~~(a) All distribution factors are calculated with respect to a constrained transmission facility that has been modeled to exceed its capability in violation of reliability criteria or to address operational adequacy and performance issues, requiring the addition of the Lower Voltage Facility identified in the Regional Transmission Expansion Plan to resolve the identified violation(s). The distribution factor is calculated for the transmission facility prior to the addition of the reinforcements identified to resolve the violation(s).~~

(1) All distribution factors are calculated with respect to the Required Transmission Enhancement subject to cost allocation under subsection (b)(i)(A)(2)(a) and subsection (b)(ii)(A) of this Schedule 12.

(2) (b) Contributions to a criteria violation are Use of a Required Transmission Enhancement is determined based on distribution factors to the aggregate load within a Zone or, in the case of a Merchant Transmission Facility, distribution factors determined to the point of withdrawal associated with Firm Transmission Withdrawal Rights over such Merchant Transmission Facility.

~~(c) In the event that a violation is modeled to occur with one or more transmission facilities removed from service, the distribution factor will be calculated with these facilities removed from service.~~

~~(d)~~ (3) The calculation of distribution factors shall be determined using linear matrix algebra, such that distribution factors represent the ratio of (i) a change in megawatt flow on a ~~constrained transmission facility~~ Required Transmission Enhancement to (ii) a change in megawatts transferred to aggregate load within a Zone or, in the case of a Merchant Transmission Facility, the point of withdrawal associated with Firm Transmission Withdrawal Rights over such Merchant Transmission Facility.

~~(e) All values and inputs used in the calculation of the distribution factor shall be the same values and inputs as used in the basecase for the Regional Transmission Expansion Plan.~~

(2) (B) In the DFAX analysis, to determine the impact of zonal loads and Merchant Transmission Facilities on a ~~constrained facility~~ Required Transmission Enhancement, Transmission Provider shall calculate a distribution factor for each Zone and each Merchant Transmission Facility by modeling a transfer from all generation in the PJM Region (a) individually to the loads in each Zone and (b) individually to each Merchant Transmission Facility based on its associated existing or planned Firm Transmission Withdrawal Rights, as applicable, identified in the Interconnection Service Agreement in effect for such Merchant Transmission Facility. To establish the ~~impact of use by~~ the zonal load or Merchant Transmission Facility, in megawatts, ~~on of a constrained facility~~ Required Transmission Enhancement, the distribution factor ~~on of a constrained facility~~ Required Transmission Enhancement associated with the resulting transfer modeled by the Transmission Provider to an individual Zone or a Merchant Transmission Facility shall be multiplied, as applicable, by (c) zonal peak load of the Zone being evaluated or (d) (i) for a Merchant Transmission Facility, the

existing Firm Transmission Withdrawal Rights of the Merchant Transmission Facility being evaluated, if the Merchant Transmission Facility is in service, or (ii) for a Merchant Transmission Facility that is not yet in service, the planned Firm Transmission Withdrawal Rights of the Merchant Transmission Facility being evaluated as identified in the Interconnection Service Agreement in effect for ~~a such Merchant Transmission Facility that is not yet in service.~~ The products, so determined, for each Zone and each Merchant Transmission Facility, shall determine the relative allocation shares for each Zone and each Merchant Transmission Facility.

~~(3)(C)~~ In the DFAX analysis, when Transmission Provider models a transfer from generation to all load within an individual Zone, Transmission Provider shall model the transfer to the Zone as a whole (not on a bus-by-bus basis).

~~(4) In the DFAX analysis, Transmission Provider shall calculate assignments of cost responsibility based on all reliability criteria violations that contribute to the need for a Lower Voltage Facility. If one Lower Voltage Facility or group of Lower Voltage Facilities resolves multiple violations, to determine a Zone or Merchant Transmission Facility's cost responsibility for such facility, the Zone's and Merchant Transmission Facility's individual megawatt contribution to each reliability criteria violation (determined in subsection (b)(iii)(C)(2) of this Schedule 12) shall be proportionally scaled up or down, so that the sum of the adjusted megawatt impacts equals the magnitude of the overload (the "overload" meaning the megawatt flow on the transmission element exceeding the applicable rating therefore violating the reliability criteria, as modeled in the Regional Transmission Expansion Plan). The Zone's or Merchant Transmission Facility's cost responsibility assignment shall be calculated as the ratio of (i) the sum of the contributions, in megawatts, of that Zone or Merchant Transmission Facility, to each of the reliability criteria violations, to (ii) the sum of the overloads, in megawatts, on the constrained facilities that are the subject of the reliability criteria violations. The foregoing notwithstanding, for the cost responsibility assignments for Lower Voltage Facilities already filed in Docket Nos. ER06-456-000, -001, and -002, ER06-954-000, ER06-1271-000, and ER07-424-000, Transmission Provider shall consider only the single worst reliability criteria violation associated with each Lower Voltage Facility.~~

~~(5)~~ (D) In the DFAX analysis, Transmission Provider shall model generation both external and internal to individual Zones and Merchant Transmission Facilities to reflect (a) the boundaries of Locational Deliverability Areas ("LDAs"), as defined in Attachment DD to the Tariff, and (b) limitations with respect to the reliability objective for moving generation capacity across the transmission system. Transmission Provider shall adopt the Capacity Emergency Transfer Objective ("CETO"), as defined in Attachment DD to the Tariff, associated with that LDA and calculated for the applicable planning year to be the transfer limitation into the LDA. In modeling the system generation and load, Transmission Provider shall assume that the percentage of the zonal load in the LDA served by external (or internal) generation to the LDA shall equal the ratio of (i) the CETO associated within that LDA (or generation internal with the LDA) to (ii) the sum of (a) the internal generation within the LDA and (b) the CETO associated with that LDA. For the generation dispatch used in calculating the distribution factor, Transmission Provider shall distribute these amounts of external/internal generation among all generation in the PJM Region external to/internal within the LDA, respectively, in proportion to their capacity. The contribution of use by each zonal load ~~to or~~

Merchant Transmission Facility of the ~~constraint~~ Required Transmission Enhancement shall be determined by multiplying the resulting distribution factor by the peak load of a Zone or the planned or existing Firm Transmission Withdrawal Rights associated with a Merchant Transmission Facility, as applicable. For Zones and Merchant Transmission Facilities that are located within LDAs that are also entirely contained in other larger LDAs, the modeling approach and distribution factor calculations shall be repeated for such Zones or Merchant Transmission Facilities as above for each LDA. The lowest distribution factor derived from these calculations shall be applied to the Zone or Merchant Transmission Facility in the calculation of the ~~contribution to use of the constrained facility.~~ Required Transmission Enhancement. A distribution factor threshold of 0.01 shall be applied to all cost responsibility assignment calculations such that any distribution factor less than 0.01 shall be set equal to zero.

~~(6)(E)~~ In the DFAX analysis, the Zones of Public Service Electric and Gas Company and Rockland Electric Company will be treated as one Zone unless and until Rockland Electric Company elects to be treated as a separate Zone in accordance with the terms of the ER06-456 Settlement Settlement Agreement And Offer Of Partial Settlement approved by FERC in Docket Nos. ER06-456-000, et al.

~~(7)(F)~~ Transmission Provider shall round cost responsibility assignments determined using the DFAX analysis described in subsection (b)(iii)~~(C)~~ of this Schedule 12 to the nearest one-hundredth of one percent.

~~(8)(G)~~ Transmission Provider shall not account for the ability to adjust use of phase angle regulators (“PARs”) in the DFAX analysis described in subsection (b)(iii)~~(C)~~ of this Schedule 12. In the DFAX analysis, all PAR angles shall be fixed at their base case settings.

(H) In the DFAX analysis, if the Required Transmission Enhancement is a D.C. facility, the Transmission Provider shall determine cost responsibility assignment as follows:

(1) The Required Transmission Enhancement shall be replaced in the model with a comparable proxy A.C. facility, the impedance of which shall be calculated based on the length of the D.C. facility that was removed from the model multiplied by an approximate per unit/mile impedance value for the proxy A.C. facility.

(2) Where a D.C. facility is an integral part of a Required Transmission Enhancement that also includes A.C. facilities, the methodology described in Subsection (b)(iii)(H)(1) above shall be used only for the D.C. facility segment of such Required Transmission Enhancement.

(3) A D.C. facility used to control flow over portions of the Transmission System shall be modeled with a zero impedance and no control shall be applied.

(I) If Transmission Provider determines in its reasonable engineering judgment that, as a result of applying the provisions of this Section (b)(iii), the DFAX analysis cannot be

performed or that the results of such DFAX analysis are objectively unreasonable, the Transmission Provider may use an appropriate substitute proxy for the Required Transmission Enhancement in conducting the DFAX analysis. If a proxy is used that is not specified in this Schedule 12, Transmission Provider shall state in a written report (a) the reasons why it determined the DFAX analysis could not be performed or that the results of the DFAX analysis were objectively unreasonable; (b) why the substitute proxy produced objectively reasonable results; and (3) a recommendation as to what changes, if any, should be considered in conducting the DFAX analysis.

(J) The Transmission Provider shall make a preliminary cost responsibility determination for each Required Transmission Enhancement subject to this section (b)(iii) of Schedule 12 at the time such Required Transmission Enhancement is included in the Regional Transmission Expansion Plan.

(1) When CWIP in connection with a Required Transmission Enhancement subject to this section (b)(iii) of Schedule 12 is entitled to be recovered, the preliminary determination of cost responsibility made at the time that the Required Transmission Enhancement was included in the Regional Transmission Expansion Plan shall be used to assign cost responsibility for such CWIP and such cost responsibility shall remain unchanged until the date the Required Transmission Enhancement goes into service. Once a Required Transmission Enhancement has gone into service, the updated cost responsibility determination provided for in subsection (b)(iii)(J)(2) shall apply.

(2) Beginning with the calendar year in which a Required Transmission Enhancement is scheduled to enter service, and thereafter annually at the beginning of each calendar year, the Transmission Provider shall update the preliminary cost responsibility determination for each Required Transmission Enhancement using the values and inputs used in the base case of the most recent Regional Transmission Expansion Plan approved by the PJM Board prior to the date of the update. All values and inputs used in the calculation of the distribution factor in a determination of cost responsibility shall be the same values and inputs as used in the base case of the most recent Regional Transmission Expansion Plan approved by the PJM Board prior to the determination of cost responsibility.

**(iv) ~~Below 500 kV Spare Parts, Replacement Equipment And Circuit Breakers.~~** Transmission Provider shall assign cost responsibility for ~~below 500 kV~~ spare parts, replacement equipment, and circuit breakers and associated equipment, included in the Regional Transmission Expansion Plan as follows:

(A) ~~Below 500 kV spare~~ Spare parts that are part of the design specifications of a ~~transmission element of a Lower Voltage Facility~~ Required Transmission Enhancement at the time ~~the Lower Voltage Facility~~ such Required Transmission Enhancement is first included in the Regional Transmission Expansion Plan shall be considered part of the ~~Lower Voltage Facility~~ Required Transmission Enhancement for the purpose of applying the cost threshold described in subsection (b)(~~iii~~)(A vi) of this Schedule 12 and cost responsibility for such spare parts shall be assigned in the same manner as the ~~Lower Voltage Facility~~ Required Transmission Enhancement. Cost responsibility for ~~below 500 kV~~ spare parts independently included the

Regional Transmission Expansion Plan and not a part of the design specifications of a ~~transmission element of a Lower Voltage Facility~~Required Transmission Enhancement as described above in this subsection shall be assigned to the Zone of the owner of the spare part, if the owner of the spare part is a Transmission Owner listed in Attachment J of the Tariff. If the owner of the spare part is not a Transmission Owner listed in Attachment J of the Tariff, cost responsibility shall be assigned on a pro rata basis to the zones that bear cost responsibility for the owner's Required Transmission Enhancements.

(B) ~~Below 500 kV replacement~~ Replacement equipment that is part of the design specifications of a ~~transmission element of a Lower Voltage Facility~~Required Transmission Enhancement at the time the ~~Lower Voltage Facility~~Required Transmission Enhancement is first included in the Regional Transmission Expansion Plan shall be considered part of the ~~Lower Voltage Facility~~Required Transmission Enhancement for the purpose of applying the cost threshold described in ~~subsection~~section (b)(~~iii~~)(Avi) of this Schedule 12 and cost responsibility for such replacement equipment shall be assigned in the same manner as the ~~Lower Voltage Facility~~Required Transmission Enhancement. Cost responsibility for ~~below 500 kV~~Required Transmission Enhancement replacement equipment independently included in the Regional Transmission Expansion Plan and not a part of the design specifications of a ~~transmission element of a Lower Voltage Facility~~Required Transmission Enhancement as described above in this subsection, shall be assigned to the same Zones and/or Merchant Transmission Facilities and in the same proportions as the then-existing assignments of cost responsibility for the facilities that the replacement equipment is replacing.

(C) ~~Below 500 kV circuit~~ Circuit breakers and associated equipment that are part of the design specifications of a ~~transmission element of a Lower Voltage Facility~~Required Transmission Enhancement at the time the ~~Lower Voltage Facility~~Required Transmission Enhancement is first included in the Regional Transmission Expansion Plan shall be considered part of the ~~Lower Voltage Facility~~Required Transmission Enhancement for the purpose of applying the cost threshold described in subsection (b)(~~iii~~)(Avi) of this Schedule 12 and cost responsibility for such circuit breakers and associated equipment shall be assigned in the same manner as the ~~Lower Voltage Facility~~Required Transmission Enhancement. Cost responsibility for ~~below 500 kV~~ circuit breakers and associated equipment independently included in the Regional Transmission Expansion Plan and not a part of the design specifications of a transmission element of a ~~Lower Voltage Facility~~ Required Transmission Enhancement as described above in this subsection, shall be assigned to the Zone of the owner of the circuit breaker and associated equipment if the owner of the circuit breaker is a Transmission Owner listed in Attachment J of the Tariff. If the owner of the circuit breaker is not a Transmission Owner listed in Attachment J of the Tariff, cost responsibility shall be assigned on a pro rata basis to the zones that bear cost responsibility for the owner's Required Transmission Enhancements.

(v) ~~Economic-Based Required Transmission Enhancements That As Planned Will Operate Below 500 kV. Projects.~~ Transmission Provider shall assign (i) fifty percent (50%) of cost responsibility for ~~economic-based Required Transmission Enhancements~~Economic Projects that as planned will operate below 500 kV are Regional Facilities; and (ii) full cost responsibility for Economic Projects that are Lower Voltage Facilities; as follows:

(A) Transmission Provider shall assign cost responsibility for ~~economic-based Required Transmission Enhancements that as planned will operate below 500 kV and Economic Projects~~ that are accelerations of ~~reliability-based Required Transmission Enhancements~~ Reliability Projects as described in section 1.5.7(b)(i) of Schedule 6 of the Operating Agreement (“Acceleration Projects”) by performing and comparing (1) a DFAX analysis consistent with the methodology described in subsection (b)(iii)~~(C)~~ of this Schedule 12, and (2) a methodology that is intended to act as a proxy for expected economic benefits from reduced Locational Marginal Prices (“LMP Benefit”) over the period that the reliability-based enhancement or expansion is to be accelerated (“LMP Benefits Methodology”). The LMP Benefits Methodology shall determine cost responsibility assignment percentages to Zones and Merchant Transmission Facilities in the following manner. The LMP Benefit to a Zone shall be deemed to be equal to the reduction in Locational Marginal Price payments made by Load Serving Entities as a result of the Acceleration Project assuming the customers purchase all energy needs from the PJM Interchange Energy Market, and LMP Benefits so calculated shall be converted into percentage cost responsibility assignments for the affected Zones. The LMP Benefits Methodology shall not incorporate the financial effects of allocations of Auction Revenue Rights or Financial Transmission Rights. The LMP Benefit to a Merchant Transmission Facility shall be deemed to be equal to the proportionate share of assigned cost responsibility using the DFAX analysis and the assignments of cost responsibility to other Zones in the LMP Benefits Methodology shall be proportionately adjusted, as necessary, to reflect this treatment of Merchant Transmission Facilities to ensure that the total allocation for any economic-based Required Transmission Enhancement ~~that as planned will operate below 500 kV~~ equals one hundred percent. If, after performing both analyses and comparing the percentage cost responsibility assignments for the affected Zones calculated pursuant to the DFAX analysis and the LMP Benefits Methodology, the results do not indicate at least a ten percentage point cost responsibility assignment differential between the two methods for any Zone, cost responsibility for the Acceleration Project shall be assigned using the DFAX analysis. If, after performing both analyses and comparing the percentage cost responsibility assignments for the affected Zones calculated pursuant to the DFAX analysis and LMP Benefits Methodology, the results indicate at least a ten percentage point cost responsibility assignment differential between the DFAX analysis and the LMP Benefits Methodology for any Zone, cost responsibility for the Acceleration Project for the period of time the ~~reliability-based Required Transmission Enhancement~~ Reliability Project is accelerated (i.e. the period between the date the ~~Required Transmission Enhancement~~ Reliability Project actually goes into service and the date the ~~Required Transmission Enhancement~~ Reliability Project originally was scheduled to go in service ~~as a Lower Voltage Facility~~ in the PJM Board approved Regional Transmission Expansion Plan) shall be assigned using the LMP Benefits Methodology. For all periods other than the period of time the ~~reliability-based Required Transmission Enhancement~~ Reliability Project is accelerated, cost responsibility for such an Acceleration Project shall be assigned ~~based on a DFAX analysis consistent with the methodology set forth in subsection (b)(iii)(C) of this Schedule 12 in accordance with the provisions of this Schedule 12 governing the assignment of cost responsibility of Regional Facility Reliability Projects or Lower Voltage Facility Reliability Projects, as applicable.~~

(B) Transmission Provider shall assign cost responsibility for ~~economic-based Required Transmission Enhancements that as planned will operate below 500 kV and Economic Projects~~ that are modifications to ~~reliability-based Required Transmission Enhancements~~ Reliability Projects as described in section 1.5.7(b)(ii) of Schedule 6 of the Operating Agreement ~~based on a DFAX analysis consistent with the methodology set forth in subsection (b)(iii)(C) of this Schedule 12~~ in accordance with the provisions of this Schedule 12 governing the assignment of cost responsibility of Regional Facility Reliability Projects or Lower Voltage Facility Reliability Projects, as applicable.

(C) Transmission Provider shall assign cost responsibility for ~~economic-based Required Transmission Enhancements that as planned will operate below 500 kV and Economic Projects that~~ are new enhancements or expansions that could relieve one or more economic constraints as described in section 1.5.7(b)(iii) of Schedule 6 of the Operating Agreement ~~based on a to the Zones that show a decrease in the net present value of the Changes~~ in Load Energy Payment ~~consistent~~ determined for the first 15 years of the life of the Economic Project. The Change in Load Energy Payment for each year shall be determined using ~~with~~ the methodology set forth in ~~S~~section 1.5.7(d) of Schedule 6 of the Operating Agreement. Cost responsibility shall be ~~allocated~~ assigned based on each Zone's pro rata share of ~~the Change in Load Energy Payment. The Change in Load Energy Payment shall be~~ the sum of the net present values of the Changes in ~~the~~ Load Energy Payment only of the Zones ~~that show a decrease in which the net present value of the Changes~~ in Load Energy Payment shows a decrease.

**(vi) Required Transmission Enhancements Costing Less Than \$5 Million.** Notwithstanding Section (b)(i), (b)(ii), (b)(iv) and (b)(v), cost responsibility for a Required Transmission Enhancement for which the good faith estimate of the cost of the Required Transmission Enhancement (a) prepared in connection with the development of the Regional Transmission Expansion Plan and (b) provided to the PJM Board at the time the Required Transmission Enhancement is included for the first time in the Regional Transmission Expansion Plan, does not equal or exceed \$5 million shall be assigned to the Zone where the Required Transmission Enhancement is to be located. The determination of whether the estimated cost of a Required Transmission Enhancement does not equal or exceed \$5 million shall be based solely on such good faith estimate of the cost of the Required Transmission Enhancement regardless of the actual costs incurred. The estimated cost of a Required Transmission Enhancement shall include the aggregate estimated costs of all of the transmission elements approved by the PJM Board at the time such elements are included in the Regional Transmission Expansion Plan that collectively are intended (i) in the case of a Reliability Project, to resolve a specific reliability criteria violation, or (ii) in the case of an Economic Project, provide a specific LMP Benefit. Where a Required Transmission Enhancement subject to this section (b)(vi) consists of a single transmission element or multiple transmission elements that will be located in more than one Zone, each Zone shall be assigned cost responsibility for the transmission elements or portions of the transmission elements located in such Zone. Merchant Transmission Facilities shall not be assigned cost responsibility for a Required Transmission Enhancement subject to this Section (b)(vi).

**(vii) Finality of Cost Responsibility Assignment.** ~~Once a Lower Voltage Facility or an economic-based Required Transmission Enhancement that as planned will operate below 500~~

~~kV~~ **Modifications of Required Transmission Enhancements.** Once a Required Transmission Enhancement is included in the Regional Transmission Expansion Plan, any modification to ~~the Lower Voltage Facility or economic based~~ such Required Transmission Enhancement ~~that as planned will operate below 500 kV, respectively,~~ that subsequently is included in the Regional Transmission Expansion Plan as a separate Reliability or Economic Project shall be considered a separate ~~additional project subject to its own~~ and distinct Required Transmission Enhancement for purposes of cost responsibility assignment under this Schedule 12. ~~Such subsequent modification shall not impact or be impacted by the.~~ Except as provided in Section (b)(iv) of this Schedule 12, any cost responsibility assignments that already have has been made for ~~the~~ previously approved ~~Lower Voltage Facility or economic based~~ Required Transmission Enhancement, as applicable shall have no impact on the cost responsibility assignment of such modification.

**(viii) FERC Filing.** Within 30 days of the approval of each Regional Transmission Expansion Plan or an addition to such plan by the PJM Board pursuant to Section 1.6 of Schedule 6 of the PJM Operating Agreement, the Transmission Provider shall designate in the Schedule 12-Appendix A and in a report filed with the FERC the customers using Point-to-Point Transmission Service and/or Network Integration Transmission Service and Merchant Transmission Facility owners that will be subject to each such Transmission Enhancement Charge (“Responsible Customers”) based on the cost responsibility assignments determined pursuant to subsections (b)(i) through (v) of this Schedule 12. Those customers designated by the Transmission Provider as Responsible Customers shall have 30 days from the date the filing is made with the FERC to seek review of such designation. Such cost responsibility designations shall be the same as those made for the relevant Regional Facility, Necessary Lower Voltage Facility, or Lower Voltage Facility, ~~and economic based Required Transmission Enhancement that as planned will operate below 500 kV~~ in the Regional Transmission Expansion ~~Plan or in the Coordinated System~~ Plan.

**(viiiix) MISO.** For purposes of this Schedule 12, where the Responsible Customers are subject to the Open Access Transmission and Energy Markets Tariff for the Midwest Independent System Operator, Inc. (“MISO Tariff”), MISO shall be the Responsible Customer with respect to all such Required Transmission Enhancements. Cost responsibility with respect to Required Transmission Enhancements ~~Transmission Enhancement Charges~~ for which MISO has been designated the Responsible Customer shall be allocated within MISO in accordance with the MISO Tariff.

**(ix) Merchant Transmission Facilities.**

(A) For purposes of this Schedule 12, where the Transmission Provider has allocated all or a portion of a Required Transmission Enhancement to a Merchant Transmission Facility, the owner of the Merchant Transmission Facility shall be the Responsible Customer with respect to such Required Transmission Enhancement, and shall pay the Transmission Enhancement Charges associated with the Required Transmission Enhancement.

(B) (1) Transmission Provider shall defer collection of Transmission Enhancement Charges ~~associated with Lower Voltage Facilities~~ from a Merchant Transmission

Facility until the Merchant Transmission Facility goes into commercial operation; provided, however, in the event the commercial operation of a Merchant Transmission Facility is delayed beyond the commercial operation milestone date(s) specified in the Interconnection Service Agreement associated with the Merchant Transmission Facility and the Transmission Provider or Transmission Owner constructing the ~~Lower Voltage Facility~~Required Transmission Enhancement demonstrates that the Merchant Transmission Facility is responsible for such delay, Transmission Provider may begin collecting Transmission Enhancement Charges from the Merchant Transmission Facility prior to the Merchant Transmission Facility going into commercial operation. Transmission Enhancement Charges allocated to a Merchant Transmission Facility for which collection is deferred in accordance with this section ~~(b)(1)~~(x)(B)(1) shall be recorded in appropriate Transmission Provider accounts for deferred charges and collected in accordance with section ~~(b)(3)~~(x)(B)(3), below.

                    (2) Transmission Provider shall base the collection of Transmission Enhancement Charges associated with ~~Lower Voltage Facilities~~Required Transmission Enhancements from a Merchant Transmission Facility on the actual Firm Transmission Withdrawal Rights that have been awarded to the Merchant Transmission Facility; provided, however, to the extent that a Merchant Transmission Facility has been awarded less than the amount of Firm Transmission Withdrawal Rights specified in the Interconnection Service Agreement associated with the Merchant Transmission Facility, then Transmission Provider shall record the difference between the amount of Transmission Enhancement Charges collected based on the lesser amount of Firm Transmission Withdrawal Rights and the amount of Transmission Enhancement Charges based on the full amount of Firm Transmission Withdrawal Rights specified in the applicable Interconnection Service Agreement in appropriate accounts for deferred charges and, after the Merchant Transmission Facility has been awarded the full amount of Firm Transmission Withdrawal Rights specified in the Interconnection Service Agreement, collect such deferred amounts in accordance with section ~~(b)(3)~~(x)(B)(3), below. Notwithstanding the foregoing, Transmission Provider may collect Transmission Enhancement Charges based on more than a Merchant Transmission Facility's actually awarded Firm Transmission Withdrawal Rights (not to exceed the Firm Transmission Withdrawal Rights specified in the applicable Interconnection Service Agreement) if the Transmission Provider or Transmission Owner demonstrates that the Merchant Transmission Facility is responsible for receiving fewer Firm Transmission Withdrawal Rights than are specified in the applicable Interconnection Service Agreement.

                    (3) Transmission Provider shall record: (i) in an appropriate deferred asset account, the Transmission Enhancement Charges associated with ~~Lower Voltage Facilities~~Required Transmission Enhancements for which collection is deferred in accordance with sections ~~(b)(1)~~(x)(B)(1) and ~~(b)(2)~~(x)(B)(2); and (ii) in an appropriate deferred liability account, the revenues associated with the Transmission Enhancement Charges that, absent the deferred charges, would have been due to Transmission Owners or to Transmission Owners' customers as directed by the applicable Transmission Owner. At such time as collection of such deferred Transmission Enhancement Charges are permitted in accordance with sections ~~(b)(1)~~(x)(B)(1) and ~~(b)(2)~~(x)(B)(2), the deferred charges (along with appropriate interest) shall be collected from the Merchant Transmission Facility in equal installments over the twelve months following the commencement of the collection of the deferred charges. Such amounts shall be

distributed to Transmission Owners or to Transmission Owners' customers as directed by the applicable Transmission Owner, and the Transmission Provider shall make appropriate adjustments to the deferred asset and liability accounts. Transmission Provider shall not be responsible for distributing revenues associated with deferred Transmission Enhancement Charges unless and until such charges are collected in accordance with this section (b)(~~ix~~)(B), and uncollected deferred Transmission Enhancement Charges shall not be subject to Default Allocation Assessments to the Members pursuant to section 15.2 of the Operating Agreement.

**(xi) Consolidated Edison Company of New York.** (A) Cost responsibility assignments to Consolidated Edison Company of New York for Required Transmission Enhancements pursuant to this Schedule 12 with respect to the Firm Point-To-Point Service Agreements designated as Original Service Agreement No. 1873 and Original Service Agreement No. 1874 accepted by the Commission in Docket No. ER08-858 ("ConEd Service Agreements") shall be in accordance with the terms and conditions of the settlement approved by the FERC in Docket No. ER08-858-000. (B) All cost responsibility assignments for Required Transmission Enhancements pursuant to this Schedule 12 shall be adjusted at the commencement and termination of service under the ConEd Service Agreements to take account of the assignments under subsection (xi)(A).

**(xii) Public Policy Projects.**

(A) Transmission Facilities as defined in section 1.27 of the Consolidated Transmission Owners Agreement constructed by a Transmission Owner pursuant to a Public Policy Requirement as defined in Section 1.38B of the Operating Agreement, but not included in a Regional Transmission Expansion Plan as a Required Transmission Enhancement, shall be considered a Supplemental Project, as defined in Section 1.42A.02 of the Operating Agreement.

(B) If a transmission enhancement or expansion is proposed pursuant to Section 1.5.9(a) of Schedule 6 of the Operating Agreement which is not a Supplemental Project ("State Agreement Public Policy Project"), the Transmission Provider shall submit the assignment of costs to Responsible Customers proposed in connection with such State Agreement Public Policy Project to the Transmission Owners Agreement Administrative Committee for consideration and filing pursuant to Section 7.3 of the Consolidated Transmission Owners Agreement and Section 9.1(a) of the PJM Tariff. Nothing in this Section (b)(xii) shall prevent the Transmission Provider or the state governmental entities proposing such State Agreement Public Policy Project from filing a proposed assignment of costs to Responsible Customers for such project pursuant to Section 206 of the Federal Power Act.

(xiii) Replacement of Transmission Facilities. Unless determined by PJM to be a Required Transmission Enhancement included in a Regional Transmission Expansion Plan, cost responsibility for the replacement of Transmission Facilities, as defined in section 1.27 of the Consolidated Transmission Owners Agreement, shall be assigned to the Zonal loads and Merchant Transmission Facilities responsible for the costs of the Transmission Facilities being replaced.

(c) **Determination of Transmission Enhancement Charges.** In the event that any Transmission Owner recovers the cost of a Required Transmission Enhancement through a Transmission Enhancement Charge, such charge shall be determined as follows:

(1) Transmission Provider shall identify in writing and post on the PJM Internet site the Required Transmission Enhancement(s) to which each Transmission Enhancement Charge corresponds. The Transmission Enhancement Charge with respect to a Required Transmission Enhancement shall recover the applicable Transmission Owner's annual transmission revenue requirement associated with the Required Transmission Enhancement.

(2) Each Transmission Enhancement Charge shall be a monthly charge based on all costs and applicable incentives associated with a particular Required Transmission Enhancement for which the Transmission Owner is responsible.

(3) A Transmission Owner's annual transmission revenue requirement associated with a Required Transmission Enhancement shall be determined pursuant to either (i) a unilateral filing by the Transmission Owner under Section 205 of the Federal Power Act and the FERC's rules and regulations thereunder; or (ii) a formula rate in effect applicable to the Transmission Owner's rates for Network Integration Transmission Service, including the costs associated with Required Transmission Enhancements.

(4) Each Transmission Enhancement Charge ~~assigned by the Transmission Provider~~ applicable to Network Customers and Non-Zone Network Customers shall be recalculated annually to reflect the annual revisions to the billing determinants used by the Transmission Provider to calculate charges to Network Customers for Network Integration Transmission Service under Section 34.1 of the PJM Tariff. The Transmission Provider shall post on its Internet site by October 31 of each calendar year each recalculated Transmission Enhancement Charge that shall be effective during the subsequent calendar year.

(5) Each Transmission Enhancement Charge ~~assigned by the Transmission Provider~~ applicable to customers using Point-To-Point Transmission Service shall be calculated monthly to reflect the billing determinants used by the Transmission Provider to determine charges for customers of Point-To-Point Transmission Service in accordance with Section 25 of the PJM Tariff.

(6) Each Transmission Enhancement Charge payable by an owner of a Merchant Transmission Facility pursuant to Section (b) of this Schedule shall be calculated as a fixed monthly charge.

(7) If a Transmission Owner chooses to recover the cost of Required Transmission Enhancements through the operation of a formula rate as described in Section (a), the Transmission Owner must make an informational filing with the Commission one year from the date the selecting Transmission Owner's formula rates go into effect, and each

year thereafter, providing a detailed list of the costs the Transmission Owner has incurred, and the revenues the Transmission Owner has received to provide service.

**(d) Recovery of Transmission Enhancement Charges.**

- (1) Responsible Customers shall pay Transmission Provider all applicable Transmission Enhancement Charges as required by this Schedule 12 in addition to all other charges for transmission service for which such Responsible Customers are responsible under the Tariff.
- (2) Transmission Provider shall collect all applicable Transmission Enhancement Charges from each Responsible Customer on a monthly basis. Transmission Provider shall remit or credit all revenues received from Responsible Customers under this Schedule 12 to the Transmission Owner(s) that established such charge or to MISO in the case of Transmission Enhancement Charges established by one or more transmission owners within MISO to be distributed to said transmission owners in accordance with the MISO Tariff.

**(e) Crediting of Revenue from Transmission Enhancement Charges.** In recognition that a Transmission Owner's charges for Network Integration Transmission Service set forth in Attachment H are established based upon the Transmission Owner's total cost of providing FERC-jurisdictional transmission service, including the costs associated with Required Transmission Enhancements, revenue from a Transmission Owner's Transmission Enhancement Charges for a billing month shall be credited pursuant to this Schedule 12 to the Network Customers in the Transmission Owner's Zone (including, where applicable, the Transmission Owner) and Transmission Customers purchasing Firm Point-to-Point Transmission Service for delivery in the Transmission Owner's Zone in proportion to their Demand Charges (including any imputed Demand Charges for bundled service to Native Load Customers) for Network Integration Transmission Service and Reserved Capacity for Firm Point-to-Point Transmission Service; provided that such credits shall be reduced by the amount of any applicable incentives included in such Transmission Enhancement Charges.

**SCHEDULE 12 – APPENDIX A**

**Required Transmission Enhancements Approved By The PJM Board  
On Or After The Effective Date Of The Amendments To Schedule 12  
Filed In Docket No. \_\_\_\_\_ On October 11, 2012, Responsible Customers  
And Associated Transmission Owner Revenue Requirements.**

This Schedule 12 – Appendix A applies only to the assignment of cost responsibility or classification of Required Transmission Enhancements either (1) made by the Transmission Provider on or after the effective date of the amendments to Schedule 12 filed in Docket No. \_\_\_\_\_ on October 11, 2012, or (2) applicable to Required Transmission Enhancements approved by the PJM Board pursuant to Section 1.6 of the PJM Operating Agreement on or after such effective date.

Required Transmission Enhancements that have been placed in service in PJM, the Transmission Owner(s) responsible for constructing and owning and/or financing such Required Transmission Enhancements, the Responsible Customers and the annual revenue requirement upon which Transmission Enhancement Charges determined in accordance with section (c) of Schedule 12 are based, are set forth below. Unless otherwise stated, all designations of Responsible Customers refer collectively to all Firm Point-to-Point Transmission Service and Network Integration Transmission Service customers in each indicated Zone and state the proportional (percentage) cost responsibility allocated to the indicated customers in each Zone. Zones are identified using the short names stated in Attachment J to the Tariff.

**UNITED STATES OF AMERICA  
BEFORE THE  
FEDERAL ENERGY REGULATORY COMMISSION**

**PJM Transmission Owners**                    )  
  )  
  )  
**Docket No. ER13-\_\_\_\_-000**

**TESTIMONY OF STEVEN R. HERLING  
ON BEHALF OF THE PJM TRANSMISSION OWNERS**



1 efficiency of the transmission grid and develops the Regional Transmission  
2 Expansion Plans (“RTEP”).

3

4 **Q. Please provide your professional background while at PJM.**

5 A. I have been employed by PJM since May 1990. While at PJM, I have contributed  
6 to or led initiatives that resulted in a wide range of milestone achievements in its  
7 evolution and growth as a regional transmission organization, including the  
8 creation of the RTEP process, the development of procedures and standard terms  
9 and conditions for generator and merchant transmission interconnections, and the  
10 reliability and adequacy aspects of successive integrations of additional control  
11 areas that have more than doubled the size of the PJM market area in the last ten  
12 years.

13 In addition to my work for PJM, I have contributed to a wide range of  
14 activities of the North American Electric Reliability Council (“NERC”), as vice  
15 chair of the NERC Planning Committee and on various regional and industry  
16 working groups and committees addressing reliability and planning matters.

17

18 **Q. Please describe your educational and professional credentials.**

19 A. I hold a Bachelor of Science in Electrical Power Engineering and a Master of  
20 Engineering in Electric Power Engineering, both from Rensselaer Polytechnic  
21 Institute. I am a licensed Professional Engineer in the State of Ohio.

1 **Q. Have you previously provided testimony?**

2 A. I have testified in transmission line Certificate of Public Convenience and  
3 Necessity proceedings in Pennsylvania, West Virginia, Virginia, and New Jersey.  
4 I have also testified on a number of occasions on system planning and reliability  
5 issues in proceedings before the Federal Energy Regulatory Commission  
6 (“Commission”), and various state commissions and legislative task forces.

7

8 **Q. What is the purpose of your testimony?**

9 A. The purpose of my testimony is to describe PJM’s current use of distribution  
10 factors in allocating the costs of certain transmission upgrades and expansions  
11 and to discuss how PJM would implement the distribution factor allocation  
12 proposed by the PJM Transmission Owners.

13

14 **Q. What is a distribution factor?**

15 A. A distribution factor is a number, represented as either a percentage or a decimal,  
16 that expresses the portion of a transfer of energy from a defined source to a  
17 defined sink that will flow across a particular transmission facility or group of  
18 transmission facilities. In a simple example, if three identical circuits connect  
19 generation at point A to load at point B, a transfer from A to B will be distributed  
20 equally on all three circuits. The distribution factor for the transfer with respect  
21 to any one of the three circuits will be 0.33 or 33%. Calculated in this manner,  
22 the distribution factor represents the distribution of flow over a specific  
23 transmission facility for a given transfer with all transmission elements in service.

1 Another form of distribution factor is the outage transfer distribution  
2 factor, or “OTDF.” An OTDF represents the distribution of flow over a specific  
3 transmission facility for a given transfer when a second transmission element is  
4 removed from service. In the same example described above, if one of the three  
5 identical circuits is removed from service, flow will be distributed evenly over the  
6 remaining two circuits and the OTDF for the transfer from A to B with respect to  
7 either of the two identical remaining circuits will be 0.50 or 50%.

8  
9 **Q. How does PJM currently use distribution factors?**

10 A. Under Schedule 12 of the PJM Open Access Transmission Tariff, as approved by  
11 the Commission, PJM uses a “distribution factor” analysis, or “DFAX” analysis,  
12 to determine the allocation of costs of transmission expansions and enhancements  
13 that (a) are included in the RTEP to address one or more reliability violations or  
14 to address operational adequacy and performance issues; (b) as planned will  
15 operate below 500 kV; and (c) are not “Necessary Lower Voltage Facilities,” *i.e.*,  
16 are not necessary to support new facilities that as planned will operate at 500 kV  
17 or above.

18  
19 **Q. How does PJM use the DFAX analysis in the cost assignment process for  
20 these facilities?**

21 A. PJM uses distribution factors in the cost assignment process to reflect the  
22 contribution of loads in different transmission zones and the withdrawal rights of  
23 merchant transmission facilities to reliability criteria violations for which

1 transmission upgrades are identified. These contributions represent one measure  
2 of the relative extent to which these loads and withdrawal rights create the need  
3 for the transmission upgrades. In some cases, violations are observed with all  
4 transmission facilities in service and the distribution factor will be calculated with  
5 all facilities in service. In many cases, however, violations are observed with one  
6 or more facilities removed from service, depending on the nature of the particular  
7 reliability criteria being assessed. In those cases, the distribution factor will be  
8 calculated in the manner of an OTDF with those facilities removed from service.  
9 Transmission systems must be designed to withstand the loss of individual  
10 elements and, therefore, OTDF is important to the analysis.

11  
12 **Q. How does PJM use distribution factors to determine the contribution of load**  
13 **to reliability criteria violations that would be addressed by a transmission**  
14 **upgrade or enhancement?**

15 A. PJM determines the impact of the load on a constrained facility that gives rise to  
16 the reliability criteria violations that create the need for the transmission upgrade.  
17 For this reason, the current approach can be described as a “Violation-Based  
18 DFAX” methodology. Based on a computer model of the electric network and  
19 using power flow modeling software, PJM calculates the portion of the power that  
20 flows on the constrained facility for consumption by the load in each transmission  
21 zone and withdrawal by each merchant transmission facility. PJM performs this  
22 calculation by modeling a transfer from all generation in the PJM Region  
23 individually to the loads in each transmission zone and individually to each

1 merchant transmission facility that has the right to withdraw power from the PJM  
2 network. This calculation yields distribution factors for each transmission zone  
3 and merchant transmission facility. These distribution factors represent a  
4 measure of the effect of the load of each transmission zone or merchant  
5 transmission facility on the transmission constraint that required the new facility  
6 to be added to the RTEP. Because the objective of this calculation is to measure  
7 the relative effect of these loads and withdrawals on the constrained transmission  
8 facility, the distribution factor is calculated for the transmission facility prior to  
9 the addition of the reinforcement(s) identified to resolve the violation(s).

10

11 **Q. How does PJM calculate the distribution factors?**

12 A. The calculation of distribution factors is determined using linear matrix algebra,  
13 such that distribution factors represent the ratio of (a) the change in megawatt  
14 flow on a constrained transmission facility to (b) a change in megawatts  
15 transferred to aggregate load within a transmission zone or, in the case of a  
16 merchant transmission facility, the point of withdrawal associated with  
17 Firm Transmission Withdrawal Rights over the merchant transmission facility.

18

19 **Q. What is the next step?**

20 A. Finally, to establish the impact of load, in megawatts, on the constrained facility,  
21 the distribution factor on a constrained facility associated with the resulting  
22 transfer modeled by PJM to an individual transmission zone or a merchant  
23 transmission facility is multiplied, as applicable, by the (a) zonal peak load of the

1 transmission zone being evaluated or (b) the awarded Firm Transmission Rights  
2 associated with the merchant facility. These products, for each transmission zone  
3 and each merchant transmission facility, will determine the relative allocation  
4 shares for the loads in each transmission zone and the withdrawal rights of each  
5 merchant transmission facility.

6  
7 **Q. Can the DFAX analysis you described be repeated during the operating life**  
8 **of the transmission enhancement to identify changes in the relative impact of**  
9 **loads in the various transmission zones and withdrawals by merchant**  
10 **transmission facilities on the constrained facility?**

11 A. Practically speaking, no. The Violation-Based DFAX methodology I have  
12 described cannot practically be replicated during the operating life of a  
13 transmission enhancement that has been installed to resolve reliability violations  
14 created by a constrained transmission element. This is because PJM does the  
15 analysis based on the flows as they exist before the new facility is constructed and  
16 energized, using the planning model that is current at the time. This is logical  
17 because that is the time when the need is determined. Over time, the flows on the  
18 PJM transmission network are affected by the addition of the new transmission  
19 facility, as well as the numerous other changes to the system, such as generation  
20 additions, generation retirements, changes in loads both in PJM and in  
21 neighboring systems, and other transmission additions and modifications to the  
22 configuration of existing transmission facilities or even the new facility, itself. In  
23 order to isolate the impact of changes in loads in different zones and changes in

1 the withdrawal rights of merchant transmission facilities on the constrained  
2 element, it would be necessary to zero out or unwind the impact of all subsequent  
3 transmission system modifications that have affected flows on the PJM network  
4 since the transmission upgrade was determined to be needed. After a number of  
5 years, this could amount to removing from power flow models thousands of  
6 transmission upgrades across the PJM system in order to recreate the conditions  
7 that existed when a violation was first identified and a particular transmission  
8 upgrade first identified so that a new set of DFAX and cost allocation calculations  
9 could be performed. Making all of these adjustments would be complex and  
10 costly, and the assumptions used to make them would be subject to debate and  
11 potential challenge. From a practical perspective, it would not be possible to  
12 replicate a Violation-Based DFAX analysis periodically over the life of a  
13 transmission addition or enhancement.

14  
15 **Q. How does the use of distribution factors in the cost allocation methodology**  
16 **proposed by the PJM Transmission Owners differ from the current use of**  
17 **distribution factors?**

18 A. The cost allocation methodology proposed by the PJM Transmission Owners will  
19 use the same basic methodology for calculating distribution factors as PJM uses  
20 today for allocating the costs of new transmission facilities below 500 kV that are  
21 included in the RTEP. The only difference is that the current methodology  
22 examines flows on the constrained facility that gave rise to the need for a new  
23 facility, while the new methodology will examine flows on the new facility itself.

1           In other words, while the current methodology evaluates the relative  
2 contribution to the need for a new facility of loads in different zones and  
3 withdrawals by merchant facilities, the new methodology will evaluate the  
4 relative use of the new facility by those same loads and merchant facilities. To  
5 distinguish this new approach from the current Violation-Based DFAX  
6 methodology, the new approach could be described as a “Solution-Based DFAX”  
7 methodology.

8

9   **Q. Will PJM be able to implement the proposed Solution-Based DFAX**  
10 **allocation methodology?**

11   A. Yes. Because the methodology for determining distribution factors does not  
12 change, PJM will be able to utilize the same models and software to allocate costs  
13 under the proposed methodology. The costs of the necessary changes to apply  
14 PJM’s existing tools to the Solution-Based DFAX approach will be minimal.  
15 And once those initial changes are made, the Solution-Based DFAX methodology  
16 will be simpler to implement than the existing Violation-Based DFAX  
17 methodology.

18

19   **Q. Why will Solution-Based DFAX be simpler to implement?**

20   A. The identification of the constrained element or elements to be analyzed in the  
21 Violation-Based DFAX methodology requires a measure of planning and  
22 engineering judgment that limits the extent to which the process can be  
23 automated. For example, when a new transmission facility is included in the

1 RTEP to resolve multiple reliability criteria violations, under the Violation-Based  
2 DFAX methodology, PJM must calculate the impact of load on each constrained  
3 facility separately, and then combine these calculations into a single allocation.  
4 In contrast, identifying the transmission element to be analyzed in the Solution-  
5 Based DFAX methodology is straightforward: it is the transmission expansion or  
6 addition that is being added in the RTEP. PJM will be calculating only a single  
7 set of distribution factors for each new facility included in the RTEP to address  
8 reliability criteria violation or violations. The list of transmission facilities added  
9 to the RTEP each year, and for which allocations must be performed, is already  
10 maintained in a database. The database becomes a cumulative listing of the  
11 facilities that would be reallocated, over time. Accordingly, the process can be  
12 automated to a much greater extent.

13

14 **Q. Are there any other practical differences between the methodologies?**

15 A. Yes. Under the current Violation-Based DFAX methodology, only flows in the  
16 direction of a constraint are measured, since the purpose of the analysis is to  
17 identify the relative contribution of different users to the constraint. Under the  
18 proposed Solution-Based DFAX methodology, the analysis measures the use of  
19 the new facility and the PJM Transmission Owners accordingly propose that  
20 contributions to the power flows by loads and merchant transmission on the new  
21 facility in both directions over the course of the year be analyzed.

1   **Q.   How will this be done?**

2   A.   First, PJM will perform a power flow analysis to ascertain the use of the studied  
3       facility by the load in each particular zone (or the firm withdrawal rights of each  
4       merchant transmission facility) at peak load conditions utilizing the Solution-  
5       Based DFAX methodology discussed earlier. This analysis will include the  
6       calculation of a direction and magnitude of flow. Then, PJM will perform a  
7       production cost analysis to determine the total energy use of the studied facility  
8       that is made by all zones and merchant transmission facilities in each direction  
9       over the course of a year, effectively determining the proportion of the cost of the  
10      facility attributable to use in one direction versus the other. PJM will take the  
11      total usage that is being made of the studied facility in each direction (as  
12      determined through the production cost analysis) and allocate that usage to those  
13      zones that have the same direction of flow (as determined through the power flow  
14      analysis). This allocation to zones will be performed on a pro rata basis using  
15      each zone's magnitude of flow (as determined through that same power flow  
16      analysis). The mathematical combination of the results from these power flow  
17      and production cost analyses for each particular zone will yield a reasonable  
18      measure of that zone's relative use of the studied facility. This approach allocates  
19      the costs of the new facilities among all users, taking into account the wider range  
20      of benefits that are created by the transmission upgrade solution.

1 **Q. Is there an additional practical difference between the methodologies?**

2 A. Yes. As I explained earlier, because the Violation-Based DFAX methodology  
3 requires PJM to analyze flows on the constrained element before the new facility  
4 is constructed and energized, the analysis cannot practically be updated to reflect  
5 system changes over time. This restriction does not apply, however, to the  
6 proposed Solution-Based DFAX methodology. Because the proposed  
7 methodology examines flow on the new line or other transmission facility after  
8 the resolution of the reliability criteria violations, it can be repeated periodically  
9 to reflect changes in the relative degree to which the facility is used by  
10 transmission zone loads and merchant transmission facilities. In this manner, the  
11 Solution-Based DFAX methodology can be employed to capture changes in the  
12 distribution of benefits of the new transmission facility, represented by the use of  
13 the new facility by loads and merchant transmission facilities.

14

15 **Q. Can the DFAX methodology be applied to a direct current (“D.C.”)  
16 transmission upgrade?**

17 A. A strict application of the DFAX methodology to a D.C. transmission facility  
18 does not produce meaningful results. This is because flows on a D.C.  
19 transmission facility are controlled, rather than free-flowing as on an alternating  
20 current (“A.C.”) system. The constant flow on a controlled D.C. transmission  
21 facility does not facilitate the determination of distribution factors that represent a  
22 change of flow on a facility due to a change in the transfer from a source to a  
23 sink. Consequently, the DFAX methodology and its assumptions in the model

1 with respect to the D.C. transmission facility need to be modified. I should note  
2 that where the D.C. transmission facility is operated in a manner that requires  
3 users to subscribe for the right to use the facility or otherwise allocates the  
4 capacity of the facility among specific users, there is no reason to use a DFAX  
5 analysis or any other methodology to allocate the costs of the facility to anyone  
6 other than the users to which its capacity is allocated.

7 Where, however, the operational control of a D.C. transmission facility is  
8 turned over to PJM in a manner that makes its capacity available for PJM to use  
9 for the benefit of all customers, it is appropriate to use a Solution-Based DFAX  
10 methodology to identify the users that benefit from the facility. To produce  
11 meaningful results, the DFAX calculation for the D.C. transmission facility will  
12 be performed by substituting a proxy A.C. transmission facility for the D.C.  
13 transmission facility. PJM currently uses proxy facilities for calculating DFAX  
14 on facilities to address non-thermal limitations such as where there is a reactive  
15 limit and such proxies have produced reasonable results. The use of a proxy A.C.  
16 transmission facility allows the Solution-Based DFAX methodology to identify  
17 the power flow contribution from the load or each load's use of the proxy A.C.  
18 transmission facility in the model and, hence, the D.C. transmission facility. The  
19 DFAX methodology could then be applied to identify the users whose usage of  
20 the PJM transmission system creates power flows on the proxy A.C. transmission  
21 facility in the model. The PJM Transmission Owners' proposal provides for PJM  
22 to use this approach to identify the users who benefit from a D.C. transmission  
23 addition that is not subscribed by specific users.

1 **Q. The PJM Transmission Owners propose to update the results of the**  
2 **Solution-Based DFAX methodology annually. Will PJM be able to**  
3 **implement this annual update?**

4 A. Yes. As I stated earlier, the Solution-Based DFAX methodology can be repeated  
5 and the process can be automated so that the burden and cost of updating the  
6 analysis every year is relatively low.

7 In fact, PJM will perform the Solution-Based DFAX analysis and the  
8 subsequent allocation every year that significant reliability-driven transmission  
9 additions or enhancements are included in the RTEP. The computer model and  
10 software used to perform that analysis will also identify flows on other  
11 transmission facilities, including those added in prior years' RTEPs. Adjusting  
12 the allocations of the costs of transmission facilities added in prior years' RTEPs  
13 that were based wholly or partially on the Solution-Based DFAX methodology  
14 will accordingly be quite simple.

15

16 **Q. In sum, does PJM foresee any problems with implementing the cost**  
17 **allocation methodology proposed by the PJM Transmission Owners?**

18 A. No.

19

20 **Q. Thank you Mr. Herling. There are no additional questions.**

**DECLARATION OF WITNESS**

I, Steven R. Herling, declare under penalty of perjury that the statements contained in the foregoing Testimony of Steven R. Herling submitted on behalf of the PJM Transmission Owners are true and correct to the best of my knowledge, information, and belief.

Executed on this 8th day of October, 2012, in Norristown, Pennsylvania.

/s/ Steven R. Herling

Steven R. Herling  
PJM Interconnection, L.L.C.

**UNITED STATES OF AMERICA  
BEFORE THE  
FEDERAL ENERGY REGULATORY COMMISSION**

**PJM Transmission Owners**                    )  
  )  
  )  
  )

**Docket No. ER13-\_\_\_\_-000**

**JOINT TESTIMONY OF  
MICHELLE HENRY AND FRANK J. RICHARDSON  
ON BEHALF OF THE PJM TRANSMISSION OWNERS**

## TABLE OF CONTENTS

	<u>Page</u>
I. IDENTIFICATION OF WITNESSES .....	1
A. Background And Qualifications Of Michelle Henry .....	1
B. Background And Qualifications Of Frank J. Richardson .....	2
II. PURPOSE OF TESTIMONY .....	3
III. OVERVIEW OF THE PROPOSED RATE DESIGN .....	5
IV. THE PROPOSED RATE DESIGN REPRESENTS A COMPROMISE THAT RECOGNIZES THE ADVANTAGES AND ADDRESSES THE SHORTCOMINGS OF VARYING APPROACHES TO TRANSMISSION COST ALLOCATION. ....	9
A. The PJM TOs Worked To Develop A Hybrid Cost Allocation Methodology For Regional Facilities That Represents A Compromise Of Different Approaches To Cost Allocation While Addressing Recognized Shortcomings Of The Existing Rate Design. ....	9
B. For Regional Facility Reliability Projects, The Allocation of Costs Based Upon A 50% Postage-Stamp Methodology And 50% Solution-Based DFAX Methodology Recognizes The Facilities’ Specifically-Identified Benefits, The Potential For Beneficiaries To Change, And System-Wide Benefits That Are Difficult To Quantify. ....	13
C. The Proposed Rate Design Recognizes That Double Circuit 345 kV Facilities Serve Similar Purposes As 500 kV Facilities.....	18
D. Allocation Of Costs For Lower Voltage Facility Reliability Projects Using A Solution-Based DFAX Methodology Recognizes That Such Projects Have Primarily Local Benefits. ....	20
V. SOLUTION-BASED DFAX ADDRESSES CONCERNS RAISED BY THE COMMISSION REGARDING PJM’S PREVIOUS VIOLATION-BASED DFAX.....	22
VI. ECONOMIC PROJECTS FOLLOW A SIMILAR HYBRID APPROACH ADOPTED FOR REGIONAL FACILITY RELIABILITY PROJECTS. ....	26
VII. THE PJM TOS PROVIDE FURTHER CLARIFICATION REGARDING PROJECTS COSTING UNDER \$5 MILLION AND REPLACEMENT FACILITIES. ....	30
VIII. D.C. FACILITIES WILL BE ALLOCATED IN THE SAME MANNER AS ALTERNATING CURRENT (“A.C.”) TRANSMISSION PROJECTS. ....	32

IX. THE PROPOSED RATE DESIGN ONLY ALLOCATES COSTS FOR THOSE TYPES OF PROJECTS THAT ARE PLANNED FOR AND INCLUDED IN THE PJM RTEP AT THIS TIME ..... 35

X. THE PROPOSED RATE DESIGN IS CONSISTENT WITH *ORDER NO. 1000'S SIX REGIONAL COST ALLOCATION PRINCIPLES*..... 39



1 **Q. Please briefly describe your professional experience as it relates to this**  
2 **proceeding.**

3 A. In my current role as Manager, FERC and Transmission Technical Support, I am  
4 responsible for assisting in the development of corporate positions related to  
5 transmission and Commission policy at FirstEnergy. My past experience of over  
6 16 years in the Regulatory Affairs and Treasury departments aids in providing  
7 perspective to these policies as they relate to the company both financially and  
8 operationally. My staff and I are responsible for participating in PJM  
9 Interconnection, L.L.C. ("PJM") stakeholder discussions related to transmission  
10 initiatives and also are responsible for developing corporate positions and related  
11 comments on Commission issues.

12

13 B. Background And Qualifications Of Frank J. Richardson

14 **Q. Please state your full name and business address.**

15 A. My name is Frank J. Richardson. My business address is 2 North Ninth Street,  
16 Allentown, Pennsylvania 18101.

17

18 **Q. By whom are you employed and in what capacity?**

19 A. Since 2011, I have been employed by PPL Electric Utilities Corporation as  
20 Manager, Transmission Regulatory and Business Affairs.

1 **Q. What is your educational background?**

2 A. I have a Bachelor of Science degree from Salisbury State University and a Master  
3 of Science degree from the University of Pennsylvania.

4

5 **Q. Please briefly describe your professional experience as it relates to this**  
6 **proceeding.**

7 A. I have thirty years of electric utility industry experience. Since 2005, I have  
8 served in management positions with responsibilities for oversight of transmission  
9 rates and the interface with Regional Transmission Organizations. During this  
10 time, I have served as Chair of the PJM Transmission Owners Agreement  
11 Administrative Committee (“TOA-AC”) and been involved in PJM rate design  
12 decisions and the corresponding Commission proceedings. I have also  
13 represented the interests of transmission owners located in both the eastern and  
14 western portions of the PJM footprint.

15

16 **II. PURPOSE OF TESTIMONY**

17 **Q. On whose behalf are you testifying?**

18 A. We are testifying on behalf of the PJM TOA-AC, through which the collective  
19 responsibilities of the PJM Transmission Owners (“PJM TOs”) under the  
20 Consolidated Transmission Owners Agreement (“CTOA”) are exercised. The  
21 proposed rate design discussed herein represents a compromise with virtually  
22 unanimous support among the PJM TOs. Throughout our testimony, references  
23 to the PJM TOs refer to the PJM TOs acting through the PJM TOA-AC.

1 **Q. What is the purpose of your testimony?**

2 A. This joint testimony provides an overview of the PJM TOs' proposed rate design  
3 for new transmission facilities in the PJM region. We will also explain how the  
4 proposed rate design is a compromise proposal that recognizes the advantages and  
5 addresses the shortcomings of varying approaches to transmission cost allocation,  
6 such as a postage-stamp methodology (*i.e.*, allocating costs to each zone in  
7 proportion to the zone's non-coincident annual zonal peak) and a methodology for  
8 allocating the costs to specifically-identified beneficiaries. We will also discuss  
9 how the inclusion of 500 kV and above facilities and double-circuit 345 kV  
10 facilities as regional transmission projects accounts for the different system  
11 designs used in the eastern and western transmission zones in PJM. We will  
12 demonstrate how, for projects undertaken to address reliability violations or  
13 operational performance issues, the application of a new Solution-Based  
14 distribution factor ("DFAX") analysis discussed in more detail in the testimony of  
15 Mr. Steven R. Herling, addresses many of the limitations regarding use of a  
16 Violation-Based DFAX analysis to allocate the costs of high voltage facilities that  
17 the Commission identified in its *Order on Remand* issued in March 2012 in  
18 Docket No. EL05-121-006.

19 We will also explain the cost allocation methodologies to be used for  
20 projects undertaken to address market efficiency issues and High Voltage Direct  
21 Current transmission projects, and how the PJM TOs have addressed public  
22 policy projects. "High Voltage Direct Current" is a common industry term used  
23 to describe direct current transmission level projects, which are defined as Direct

1 Current (“D.C.”) transmission projects in Schedule 12 of the PJM Open Access  
2 Transmission Tariff (“OATT”). To be consistent with the terminology used in  
3 Schedule 12, we will refer to those projects as D.C. Facilities in our testimony.  
4 Finally, we will demonstrate how the proposed rate design satisfies the six  
5 regional cost allocation principles identified by the Commission in *Order No.*  
6 *1000*.

### 8 **III. OVERVIEW OF THE PROPOSED RATE DESIGN**

#### 9 **Q. What are the main features of the proposed rate design?**

10 A. The proposed rate design establishes cost allocation methodologies for reliability  
11 and operational performance projects (collectively, “Reliability Projects”) and  
12 market efficiency projects (“Economic Projects”) that are included in the PJM  
13 Regional Transmission Expansion Plan (“RTEP”). The definition for “Regional  
14 Facilities” in Schedule 12 is being revised to include transmission projects  
15 operated at 500 kV or above and those that are double circuit 345 kV projects.  
16 Costs for these Regional Facilities undertaken to address reliability violations or  
17 operational performance issues, as well as lower voltage facilities that must be  
18 added or strengthened to support these higher voltage projects, will be allocated  
19 50% on a postage-stamp basis and 50% based on a Solution-Based DFAX  
20 methodology. All other RTEP projects will be defined in Schedule 12 as “Lower  
21 Voltage Facilities.” Lower Voltage Facilities that are Reliability Projects will be  
22 allocated 100% based on a Solution-Based DFAX methodology. When we refer  
23 to “Regional Facilities” and “Lower Voltage Facilities,” these terms will have the

1 same meaning as they do in the proposed revisions to Schedule 12 of the PJM  
2 OATT. The Solution-Based DFAX and postage-stamp cost allocations will be  
3 recalculated and updated annually to track changes in system use.

4 Costs for Regional Facilities included in the RTEP to relieve one or more  
5 economic constraints will similarly be allocated 50% on a postage-stamp basis  
6 and 50% to the zones that benefit from the project through decreased load energy  
7 payments. Costs for all other Lower Voltage Facility Economic Projects will be  
8 allocated 100% to the zones that benefit from the project through decreased load  
9 energy payments. Costs for projects to replace existing facilities are allocated in  
10 the same manner as the transmission facilities that they are replacing, unless the  
11 replacement facilities are included in the PJM RTEP as a Reliability or Economic  
12 Project. All Reliability and Economic Projects, regardless of voltage, with an  
13 estimated cost of less than \$5 million will be allocated to the zone in which they  
14 are located.

15 Projects designed to address public policy requirements will be allocated  
16 based on how those projects are initiated, as discussed later.

17  
18 **Q. To what transmission projects will the proposed rate design apply?**

19 A. The proposed rate design applies to the allocation of costs under Schedule 12 of  
20 the PJM OATT of transmission projects that the PJM Board determines to be  
21 needed for reliability, operational performance, market efficiency, or other  
22 purposes and approves for inclusion in the RTEP on and after the effective date of  
23 February 1, 2013. In addition, the proposed revisions to Schedule 12 address

1 public policy projects that are either Supplement Projects under Schedule 6 or  
2 result from a state agreement. The proposed rate design revisions do not apply to  
3 and therefore will make no changes to the cost allocation methodology for  
4 interconnection-related upgrades, including attachment facilities and network  
5 upgrades required to integrate generators or merchant transmission facilities. The  
6 PJM TOs do not propose to modify the existing cost allocation for these facilities,  
7 under which PJM assigns cost responsibility for these facilities to the  
8 interconnection customer on a “but for” basis. The proposed revisions also do not  
9 change the treatment of participant-funded projects (*e.g.*, merchant transmission  
10 facilities), Supplemental Projects, or any other transmission facility that operates  
11 in a manner that requires customers to subscribe to transmission service over the  
12 facility. These projects are not approved by the PJM Board for inclusion in the  
13 RTEP or covered by Schedule 12 of the PJM OATT, and therefore do not qualify  
14 for regional cost allocation. Rather, costs of such projects will continue to be  
15 borne by the entity proposing to build the project.

16  
17 **Q. How does the proposed rate design affect existing transmission projects and**  
18 **projects approved by the PJM Board for inclusion in the PJM RTEP prior to**  
19 **the proposed rate design’s effective date?**

20 A. The currently effective PJM OATT provisions set forth in Schedule 12-Appendix  
21 will continue to govern existing transmission projects and any projects approved  
22 by the PJM Board for inclusion in the PJM RTEP prior to the effective date of the  
23 tariff revisions implementing the rate design proposed by the PJM TOs. To

1 distinguish projects approved under the proposed new rate design from prior  
2 projects, the PJM TOs propose to include the new projects in a new Schedule 12-  
3 Appendix A.

4

5 **Q. What entities are eligible for cost recovery under Schedule 12 of the PJM**  
6 **OATT?**

7 A. Currently, Schedule 12 of the PJM OATT provides cost recovery mechanisms for  
8 a Transmission Owner that is designated in the RTEP to construct and own and/or  
9 finance a transmission project. The PJM Transmission Owners are proposing to  
10 revise the term “Transmission Owner,” for purposes of Schedule 12 only, to  
11 clarify that it includes any entity that undertakes to construct and own and/or  
12 finance a Required Transmission Enhancement pursuant to a designation in the  
13 RTEP even if the entity is not yet eligible to become a party to the CTOA. Parties  
14 to the CTOA are limited to transmission owners that have facilities in service.  
15 Clarifying the definition of “Transmission Owner” for purposes of Schedule 12 in  
16 this manner will ensure that an entity that has no facilities in service in PJM but  
17 that is designated under the RTEP to construct a transmission project will be  
18 eligible to recover construction work in progress, if such recovery is authorized  
19 by the Commission. Of course, when the transmission project is completed and  
20 the facilities are placed in service, the constructing entity will become a PJM  
21 Transmission Owner, as required by Section 3.1 of the CTOA.

1 **IV. THE PROPOSED RATE DESIGN REPRESENTS A COMPROMISE**  
2 **THAT RECOGNIZES THE ADVANTAGES AND ADDRESSES THE**  
3 **SHORTCOMINGS OF VARYING APPROACHES TO TRANSMISSION**  
4 **COST ALLOCATION.**

5 A. The PJM TOs Worked To Develop A Hybrid Cost Allocation  
6 Methodology For Regional Facilities That Represents A Compromise Of  
7 Different Approaches To Cost Allocation While Addressing Recognized  
8 Shortcomings Of The Existing Rate Design.

9 **Q. How did the PJM TOs develop the proposed rate design?**

10 A. PJM stakeholders have been discussing and litigating the appropriate  
11 methodology for allocating costs of high voltage transmission projects before the  
12 Commission and in the courts since at least 2005. Given this contentious history,  
13 this filing is a major breakthrough that encompasses numerous compromises on a  
14 multitude of cost allocation issues among a broad group of stakeholders. Prior to  
15 reaching this agreement, two principal competing approaches emerged in the  
16 litigation, with some parties, including some PJM TOs, supporting a cost  
17 allocation of high voltage transmission facilities based solely on a postage-stamp  
18 methodology. Other PJM TOs and parties have supported a cost allocation based  
19 on the identification of specific beneficiaries using a methodology such as a  
20 DFAX analysis. Using the postage-stamp methodology, costs of transmission  
21 projects are allocated to each zone in proportion to the zone's non-coincident  
22 annual zonal peak. In contrast, the specifically-identified beneficiaries approach  
23 assigns cost responsibility based on the contribution of load to power flows across  
24 a facility using the DFAX analysis for Reliability Projects or to correspond with  
25 lower energy payments by load for Economic Projects. Parties on each side have  
26 argued, as we will discuss in more detail later, that their preferred methodology is  
27 more consistent with cost causation principles articulated by the Commission and

1 the courts, and that the other approach is inconsistent with those principles.

2 Using these two competing methodologies as starting points, the PJM TOs  
3 developed the proposed rate design, which is a hybrid proposal that combines  
4 elements of a postage-stamp methodology and specifically-identified beneficiaries  
5 methodology. Since the issuance of *Order No. 1000*, the PJM TOs have held 18  
6 in-person meetings and 11 conference calls and additional subgroup conference  
7 calls to develop and reach final agreement under the CTOA on a cost allocation  
8 approach that satisfies the Commission's and the courts' cost causation principles  
9 and complies with the regional cost allocation principles articulated by the  
10 Commission in *Order No. 1000*. After much negotiation, the PJM TOs reached  
11 agreement on the proposed rate design and shared the proposal with other PJM  
12 stakeholders by posting the proposed cost allocation methodology on the PJM  
13 website. Groups of the PJM TOs' representatives also met separately with state  
14 regulators to discuss the proposed cost allocation methodology. On July 18,  
15 2012, the PJM TOs, along with representatives from PJM, convened a meeting of  
16 PJM stakeholders to introduce, discuss, and answer questions about the proposed  
17 rate design. Following the meeting, PJM stakeholders were given the opportunity  
18 to submit written comments on the proposed rate design. The PJM TOs received  
19 comments from 10 stakeholders, some of which sought additional clarification of  
20 the proposed rate design. The PJM TOs provided additional clarification on  
21 August 28 and held a second stakeholder meeting via conference call on  
22 September 5. Two stakeholders submitted written comments following the call.

23 The hybrid cost allocation methodology, as set forth in the proposed

1 revisions to Schedule 12 of the PJM OATT, was approved by the PJM TOA-AC  
2 on September 20, 2012.

3

4 **Q. What were the PJM TOs' goals in developing the proposed rate design?**

5 A. Aside from satisfying the Commission's and the courts' cost causation principles,  
6 and complying with the cost allocation principles articulated in *Order No. 1000*, a  
7 primary goal of the PJM TOs was to develop a unified proposal that would  
8 receive support from the broadest group of PJM TOs and stakeholders possible.

9

10 **Q. Please briefly describe the controversy regarding the allocation of costs of**  
11 **transmission facilities in PJM.**

12 A. As we previously mentioned, the controversy surrounding the allocation of costs  
13 of transmission projects in PJM has been ongoing for several years. In January  
14 2005 in Docket No. ER04-156-006, pursuant to a Commission order, several PJM  
15 TOs submitted a proposed cost allocation for the PJM region. This proposal was  
16 opposed by several PJM stakeholders, including several other PJM TOs. The  
17 Commission set the matter for hearing before an administrative law judge in  
18 Docket No. EL05-121-000, but prior to the hearing several rounds of settlement  
19 discussions were held in an attempt to resolve the controversy regarding the rate  
20 design. No compromise was reached, and the issues regarding the cost allocation  
21 methodology were fully litigated before the administrative law judge and briefed  
22 to the Commission. At the conclusion of this litigation, the Commission issued  
23 *Opinion Nos. 494 and 494-A* preserving the zonal cost allocation for existing

1 transmission facilities and adopting a postage-stamp cost allocation methodology  
2 for (then) new high voltage transmission projects and a DFAX methodology for  
3 (then) new low voltage transmission projects. The Commission also ordered the  
4 parties to engage in settlement discussions in Docket No. ER06-456 to address the  
5 details of the DFAX methodology.

6 The Commission's decisions in *Opinion Nos. 494* and *494-A* were  
7 appealed by several parties, including several state commissions and transmission  
8 owners. After reviewing the various arguments raised by the different parties in  
9 that proceeding, the Court of Appeals for the Seventh Circuit remanded the  
10 Commission's decision regarding new high voltage transmission projects for  
11 further explanation. In response to the Seventh Circuit's decision, the  
12 Commission instituted paper proceedings in which several parties participated,  
13 submitting several rounds of written briefs arguing for their preferred method of  
14 cost allocation methodology for high voltage transmission projects in PJM. In its  
15 *Order on Remand*, the Commission upheld its decision in *Opinion Nos. 494* and  
16 *494-A*, but several parties have sought rehearing of this order and may again  
17 appeal the Commission's decision.

18

19 **Q. Does the proposed rate design have broad support?**

20 A. Yes. The PJM TOs have weighed the various positions regarding the appropriate  
21 cost allocation methodology for transmission projects in the PJM region and have  
22 adopted a compromise proposal that seeks to blend the best aspects of many of  
23 those positions. The proposed rate design has received near unanimous support

1 from the PJM TOs. The proposed rate design's combination of methodologies is  
2 also consistent with the principles underlying the hybrid cost allocation  
3 methodology that the Pennsylvania Office of Consumer Advocate, Pennsylvania  
4 Public Utility Commission, and Virginia Electric and Power Company advocated  
5 in Docket No. EL05-121 and that the Commission identified in its *Order on*  
6 *Remand* as a cost allocation alternative that might be considered in complying  
7 with *Order No. 1000*.

8  
9 B. For Regional Facility Reliability Projects, The Allocation Of Costs Based  
10 Upon A 50% Postage-Stamp Methodology And 50% Solution-Based  
11 DFAX Methodology Recognizes The Facilities' Specifically-Identified  
12 Benefits, The Potential For Beneficiaries To Change, And System-Wide  
13 Benefits That Are Difficult To Quantify.

14 **Q. What are the advantages of the postage-stamp methodology that parties have**  
15 **identified in the past?**

16 A. Supporters of the postage-stamp methodology argued that allocating costs of  
17 Regional Facilities across the PJM region based on load ratio share appropriately  
18 captures the full spectrum of benefits associated with those facilities, including  
19 difficult to quantify regional benefits, such as improved reliability, reduced  
20 congestion, reduced power losses, greater carrying capacity, reduced operating  
21 reserve requirements, and improved access to generation. Parties also argued that  
22 the postage-stamp methodology better accounts for changes in system use over  
23 the lifetime of the facility than the current implementation of the DFAX  
24 methodology.

1 **Q. What are the shortcomings of the postage-stamp methodology that parties**  
2 **have identified in the past?**

3 A. Parties opposing the postage-stamp methodology point to the lack of specific  
4 quantification of the regional benefits listed above or of the manner in which  
5 those regional benefits are distributed among PJM customers as evidence that  
6 costs allocated based on the postage-stamp methodology are not roughly  
7 commensurate with benefits. Parties claimed that the benefits of Regional  
8 Facilities accrued disproportionately to PJM eastern zones because, even for  
9 upgrades added to address reliability concerns, eastern zones will experience  
10 reduced congestion and lower locational marginal prices (“LMPs”), while LMPs  
11 in PJM western zones would increase. They also noted that establishing a 500 kV  
12 cut-off for Regional Facilities disfavors customers in western PJM zones, where  
13 345 kV facilities have been deployed to serve substantially the same purpose as  
14 500 kV facilities in eastern PJM zones. Parties argued that the allocation of costs  
15 under a DFAX methodology captures this difference in the distribution of benefits  
16 across zones. They contend that the postage-stamp allocation of costs to zones  
17 based on load ratio share does not equitably address the difference in distribution  
18 of benefits.

19

20 **Q. What are the advantages of the DFAX methodology that parties have**  
21 **identified in the past?**

22 A. Supporters of the DFAX methodology argued that by measuring power flows that  
23 contributed to the constraint remedied by the new transmission project, the DFAX

1 methodology specifically identifies beneficiaries and, thus, better matches costs  
2 and benefits than the postage-stamp methodology, which assumes that benefits  
3 are spread uniformly throughout the system.

4  
5 **Q. What are the shortcomings of the DFAX methodology that parties have**  
6 **identified in the past?**

7 A. The DFAX methodology that parties supported in Docket EL05-121 was based on  
8 PJM's "Violation-Based DFAX," which is described in greater detail in Mr.  
9 Herling's testimony. Using the Violation-Based DFAX methodology, the costs of  
10 a transmission project are allocated based on the impact of load on the constrained  
11 facility that gives rise to the violation that drives the need for the transmission  
12 project. In the *Order on Remand*, the Commission summarized the parties'  
13 concerns with the Violation-Based DFAX methodology. As stated by the  
14 Commission, Violation-Based DFAX: (1) requires a single constraint on which to  
15 perform the DFAX calculation and therefore is unable to identify the causes of  
16 multiple constraints; (2) fails to account for the fact that a higher capacity  
17 transmission project may resolve or mitigate multiple constraints in multiple areas  
18 in addition to the constraint that is the subject of the DFAX calculation; (3) is a  
19 static, snapshot-in-time approach that fails to account for changes in system  
20 conditions over the 40-year life of transmission facilities; and (4) fails to account  
21 for difficult to quantify, system-wide benefits provided by higher voltage  
22 transmission projects.

1 **Q. How does the proposed rate design for Regional Facility Reliability Projects**  
2 **address these concerns about the DFAX and postage-stamp methodologies**  
3 **and make use of the advantages of each methodology?**

4 A. The first three concerns raised regarding the Violation-Based DFAX  
5 methodology are addressed by the adoption of a Solution-Based DFAX  
6 methodology and updating the results of that analysis annually. We will discuss  
7 how Solution-Based DFAX addresses these concerns in more detail later.

8 The concerns that DFAX does not account for high voltage transmission  
9 projects' system-wide benefits or benefits that are difficult to quantify is  
10 addressed by the proposed rate design's 50/50 split between the postage-stamp  
11 methodology and Solution-Based DFAX methodology. Regional Facilities are  
12 more likely to provide system-wide benefits than Lower Voltage Facilities that  
13 are intended to solve a small number of constraints or address predominately local  
14 reliability and operational issues. Therefore, for Regional Facility Reliability  
15 Projects, 50% of the costs will be allocated on a postage-stamp basis, which, as  
16 described above, ensures that the full spectrum of benefits that accrue to load,  
17 including difficult-to-quantify regional benefits, are captured. The uniform  
18 distribution of costs using the annually-updated postage-stamp methodology also  
19 addresses potential shifts in the distributions of these benefits over time.

20 To satisfy concerns that the postage-stamp methodology may not  
21 sufficiently assign costs to the specifically-identified beneficiaries of such  
22 Regional Facilities because benefits may be distributed differently across the PJM  
23 region rather than on the basis of contribution to peak load, the proposed rate

1 design will allocate 50% of Regional Facility Reliability Projects using Solution-  
2 Based DFAX. Using Solution-Based DFAX to allocate a portion of the costs of  
3 Regional Facility Reliability Projects and all of the costs of Lower Voltage  
4 Facility Reliability Projects takes advantage of the ability of a power flow  
5 analysis to specifically quantify benefits, specifically identify beneficiaries, and,  
6 when the analysis is updated (as we will discuss later), recognize changes in  
7 system use over the life of the asset. A 50% cost allocation based on Solution-  
8 Based DFAX ensures that a significant portion of the costs of Regional Facilities  
9 will be allocated to specifically-identified beneficiaries of those facilities based on  
10 immediate benefits to customers in the zones that experience those benefits.  
11 Thus, customers receiving specific, easily quantifiable benefits in addition to  
12 system-wide benefits will pay for a significant portion of the costs of Regional  
13 Facility Reliability Projects.

14 This combined, or “hybrid,” approach ensures both that identifiable,  
15 specific beneficiaries of Regional Facility Reliability Projects pay a significant  
16 share of the costs and that other customers, who receive regional benefits that are  
17 more difficult to quantify, also pay a significant portion of the costs. The net  
18 effect is a methodology that allocates the costs of Regional Facility Reliability  
19 Projects in a manner that is at least roughly commensurate with the benefits they  
20 are projected to provide.

1 C. The Proposed Rate Design Recognizes That Double Circuit 345 kV  
2 Facilities Serve Similar Purposes As 500 kV Facilities.

3 **Q. Why does the proposed rate design include 500 kV and above facilities and**  
4 **double circuit 345 kV facilities as Regional Facilities?**

5 A. The proposed rate design includes 500 kV and above facilities and double circuit  
6 345 kV facilities as Regional Facilities because these types of facilities serve  
7 comparable purposes in the eastern and western transmission zones, respectively.  
8 These types of facilities also have similar thermal capability and similar capability  
9 for delivering power across the transmission system. For example, as Witness  
10 Bernard Pasternack explained in his direct testimony submitted in Docket No.  
11 EL05-121-000, a 100-mile, 500 kV transmission line can deliver 1,820 MW of  
12 energy and a similar 100-mile double circuit 345 kV transmission line can deliver  
13 1,560 MW of energy. While technological advances since Mr. Pasternack's  
14 testimony may have improved line loadability, his testimony nonetheless  
15 demonstrates the similarity between the double circuit 345 kV facility and the 500  
16 kV facility.

17

18 **Q. How are the different types of Regional Facilities used in the different**  
19 **regions of PJM?**

20 A. Although the 500 kV and double circuit 345 kV facilities serve comparable  
21 purposes, system design differences between the eastern and western PJM  
22 transmission zones result in 500 kV facilities generally being used in the east for  
23 the highest capacity transmission facilities, while western transmission zones have  
24 predominantly relied upon double circuit 345 kV facilities for the same purpose.

1 Although 765 kV facilities have been built in a few western zones, in most  
2 western zones, 345 kV facilities are the predominant form of extra high voltage  
3 transmission, with double-circuit 345 kV lines used when additional capability is  
4 required. Double circuit 345 kV facilities are used in all of the western PJM  
5 transmission zones including AEP East; Allegheny Power; American  
6 Transmission Systems, Incorporated; Commonwealth Edison Company; The  
7 Dayton Power and Light Company; Duke Energy Ohio, Inc. and Duke Energy  
8 Kentucky, Inc.; and Duquesne Light Company.

9  
10 **Q. Was the inclusion of 500 kV and above facilities and double circuit 345 kV**  
11 **facilities as Regional Facilities important to reaching agreement on the**  
12 **proposed rate design?**

13 A. Yes. The inclusion of both 500 kV and above facilities and double circuit 345 kV  
14 facilities as Regional Facilities was an integral element in the compromise that  
15 resulted in the proposed rate design. Although justified by the fact that the  
16 facilities serve comparable purposes, the inclusion of both 500 kV and above  
17 facilities and double circuit 345 kV facilities as Regional Facilities leads to more  
18 equitable results given the design of the eastern and western transmission systems  
19 and ensures support for the proposed rate design from parties across the entire  
20 PJM region.

1 D. Allocation Of Costs For Lower Voltage Facility Reliability Projects Using  
2 A Solution-Based DFAX Methodology Recognizes That Such Projects  
3 Have Primarily Local Benefits.

4 **Q. How will the costs of Lower Voltage Facility Reliability Projects be allocated**  
5 **under the proposed rate design?**

6 A. The costs of Lower Voltage Facility Reliability Projects will be allocated based  
7 on specifically-quantified benefits represented by the use of facilities by  
8 specifically-identified customers. These beneficiaries will be identified using the  
9 Solution-Based DFAX methodology that we will discuss in more detail later in  
10 our testimony and that Mr. Herling also discusses in his testimony. Unlike the  
11 controversy associated with the cost allocation for higher voltage facilities in  
12 PJM, there has not been any significant dispute concerning the appropriateness of  
13 allocating 100% of the costs of Lower Voltage Facility Reliability Projects using  
14 some form of DFAX methodology. The current form of Violation-Based DFAX  
15 was adopted as a result of a Settlement Agreement approved by the Commission  
16 in Docket No. ER06-456 to allocate the costs of lower voltage Reliability  
17 Projects. While the use of DFAX for Lower Voltage Facility Reliability Projects  
18 has not been controversial, a number of concerns have been voiced regarding the  
19 implementation and static nature of Violation-Based DFAX. Thus, as we will  
20 discuss later, the PJM Transmission Owners are proposing to use Solution-Based  
21 DFAX to allocate costs for those facilities, which is a significant improvement  
22 over the current Violation-Based DFAX. For Lower Voltage Facility Economic  
23 Projects, specifically-identified beneficiaries will be allocated costs of the project  
24 based on decreased load energy payments, as we will discuss further later.

25

1 **Q. Why are Lower Voltage Facilities allocated differently than Regional**  
2 **Facilities?**

3 A. While 50% of the cost of Regional Facilities will be allocated using the postage-  
4 stamp methodology, the entire cost of Lower Voltage Facilities will be allocated  
5 based on specifically-quantified benefits represented by the use of the facilities by  
6 specifically-identified customers. This allocation of costs to specifically-  
7 identified beneficiaries is appropriate for Lower Voltage Facilities because these  
8 facilities tend to address local reliability and operational performance issues and  
9 support local needs. Regional Facilities, on the other hand, are intended to  
10 address broader reliability and operational performance issues and are generally  
11 used to move large amounts of power over long distances. In comparison to  
12 Regional Facilities, the difficult-to-quantify regional benefits that are attributable  
13 to Lower Voltage Facilities are limited. Therefore, the need to capture regional  
14 benefits and benefits that are difficult to quantify in the cost allocation is not a  
15 determinative factor for the cost allocation methodology for Lower Voltage  
16 Facilities as it is for Regional Facilities. The PJM TOs recognize that the  
17 demarcation between facilities that provide regional benefits and those that  
18 provide predominantly local benefits may not always be clear cut. However, the  
19 line that the PJM TOs are proposing to draw between Regional Facilities and  
20 Lower Voltage Facilities reasonably differentiates between the facilities that  
21 provide regional benefits and those that provide predominantly local benefits.  
22 Further, the difference between Regional Facilities and Lower Voltage Facilities  
23 is transparent and is easy to administer.

1 **V. SOLUTION-BASED DFAX ADDRESSES CONCERNS RAISED BY THE**  
2 **COMMISSION REGARDING PJM'S PREVIOUS VIOLATION-BASED**  
3 **DFAX.**

4 **Q. What is Solution-Based DFAX and how does it compare to Violation-Based**  
5 **DFAX?**

6 A. Like Violation-Based DFAX, Solution-Based DFAX is a power flow analysis.  
7 However, unlike Violation-Based DFAX, Solution-Based DFAX calculates the  
8 non-contingency flow on the new transmission facility. In other words, Solution-  
9 Based DFAX determines the relative use of a new transmission facility, whereas  
10 Violation-Based DFAX determines the relative contribution of load and  
11 withdrawals by merchant facilities to the reliability violation driving the need for  
12 a new transmission facility. The proposed rate design will use Solution-Based  
13 DFAX to allocate 50% of the costs of Regional Facility Reliability Projects and  
14 100% of the costs of Lower Voltage Facility Reliability Projects. Violation-  
15 Based DFAX will no longer be used for cost allocation of future projects as part  
16 of the proposed rate design under Schedule 12.

17  
18 **Q. What are the problems with Violation-Based DFAX that the Commission**  
19 **identified in its *Order on Remand*?**

20 A. The Commission criticized the use of Violation-Based DFAX to allocate costs of  
21 Regional Facilities based on its findings that the benefits of a Regional Facility  
22 extend beyond the parties identified using the Violation-Based DFAX  
23 methodology and that the Violation-Based DFAX methodology failed to account  
24 for multiple violations or reliability issues in other areas that may be resolved by a  
25 new transmission facility. Thus, the Commission found that Violation-Based

1 DFAX fails to identify all customers that specifically benefit when a new  
2 transmission facility eliminates the need for future transmission enhancements.  
3 These criticisms are the same as the first two shortcomings listed above that were  
4 identified by supporters of the postage-stamp methodology.

5 The Commission also criticized Violation-Based DFAX because it was a  
6 static analysis based on a snapshot-in-time that determined beneficiaries of a  
7 transmission facility based on the flows that contributed to the violation driving  
8 the need for the transmission facility. The Commission found that the benefits of  
9 Regional Facilities extend far beyond those customers that contributed to flows at  
10 the point in time when the violation that drove the need for the transmission  
11 facility existed and were not reflected in the Violation-Based DFAX  
12 methodology. The Commission also found in the *Order on Remand* that “power  
13 flows at a particular point in time do not present a complete picture of the current  
14 daily and seasonal usage of the PJM high voltage system or the flows that are  
15 likely in the future.”

16  
17 **Q. How does use of Solution-Based DFAX in the proposed rate design address**  
18 **the problems the Commission identified in its *Order on Remand*?**

19 A. The power flows that contributed to the violations and drove the need for the new  
20 transmission facility are not used in the Solution-Based DFAX methodology.  
21 Rather, Solution-Based DFAX measures power flows over the new transmission  
22 facilities installed to resolve the reliability violation or operational performance  
23 issues and identifies the transmission zones causing those flows. Thus, there is no

1 failure to account for multiple violations or reliability issues in other areas that  
2 may be resolved by a new transmission facility. By focusing on the customers  
3 who benefit by using the new facilities as opposed to focusing only on customers  
4 that were the immediate cause of the constraint, Solution-Based DFAX is able to  
5 reasonably identify the broader group of customers that will benefit from the  
6 installation of the facilities.

7 Adoption of Solution-Based DFAX also solves problems related to the  
8 static nature of Violation-Based DFAX. Solution-Based DFAX, unlike the  
9 Violation-Based DFAX, uses current planning models to evaluate power flows  
10 over the transmission facilities to be cost allocated. Therefore, Solution-Based  
11 DFAX is not limited to a static, snapshot-in-time modeling process and is focused  
12 on allocating costs based on current use of the new facilities, not past  
13 contributions to power flows that caused the violation eliminated by the new  
14 facility. As Mr. Herling explains, PJM can update the Solution-Based DFAX  
15 analysis relatively easily. Accordingly, under the proposed rate design, the  
16 allocation of the portion of costs of Regional and Lower Voltage Facility  
17 Reliability Projects based on Solution-Based DFAX will be updated annually to  
18 reflect current usage of the PJM system.

1 **Q. Does Solution-Based DFAX require PJM to make any assumptions regarding**  
2 **system conditions in determining a cost allocation for a transmission project?**

3 A. Yes. The Solution-Based DFAX methodology requires PJM to make certain  
4 assumptions regarding generation dispatch and the resulting zonal contribution to  
5 the flow on the upgraded transmission project. As described in more detail in Mr.  
6 Herling's testimony, the power flow in both directions over the course of the year  
7 will be taken into account when PJM performs the Solution-Based DFAX  
8 analysis.

9  
10 **Q. When will the Solution-Based DFAX be updated each year?**

11 A. The PJM TOs propose that the Solution-Based DFAX be updated at the same  
12 time as zonal peak load used to allocate the postage-stamp portion of the rates for  
13 Regional Facilities so as to limit the number of changes in rates for Regional  
14 Facilities to once per year (other than any changes resulting from transmission  
15 owner formula rate updates). Currently, the Regional Facility postage-stamp  
16 allocations are updated on a calendar year basis based on zonal peak load for the  
17 year ending the previous October 31. Accordingly, the PJM TOs also propose to  
18 update the Solution-Based DFAX allocation on a calendar year basis. Thus, both  
19 the postage-stamp and Solution-Based DFAX portions of Regional Facility  
20 allocations and Lower Voltage Reliability Project allocations, which are based on  
21 the Solution-Based DFAX alone, will be updated annually on January 1st.

1 **Q. What are the benefits of annually updating the Solution-Based DFAX used to**  
2 **allocate costs of Reliability Projects?**

3 A. Recalculations of the Solution-Based DFAX will ensure that the cost allocation  
4 tracks changes in beneficiaries throughout the lifetime of the transmission  
5 facilities. Additionally, annual recalculations ensure that the cost allocation is  
6 based on reasonably current usage patterns and that cost shifts from changes in  
7 system uses will be incremental and will not cause significant rate shocks for  
8 customers (as might be the case with less frequent recalculations).

9

10 **VI. ECONOMIC PROJECTS FOLLOW A SIMILAR HYBRID APPROACH**  
11 **ADOPTED FOR REGIONAL FACILITY RELIABILITY PROJECTS.**

12 **Q. How do the PJM TOs propose to allocate the costs for Regional Facility**  
13 **Economic Projects?**

14 A. The PJM TOs propose to allocate the costs of new Regional Facility Economic  
15 Projects that are included in the RTEP under Section 1.5.7(b)(iii) of Schedule 6 of  
16 the PJM Operating Agreement in the same basic manner as they propose to  
17 allocate the costs for Regional Facility Reliability Projects. Specifically, costs for  
18 Regional Facility Economic Projects will be allocated 50% on a postage-stamp  
19 basis and 50% to specifically-identified beneficiaries. However, rather than rely  
20 upon Solution-Based DFAX to identify these beneficiaries, for new Economic  
21 Projects, the PJM TOs propose to identify these beneficiaries by determining  
22 those transmission zones that benefit through decreased load payments for energy  
23 based on a 15-year forecast. Relying upon decreased load payments for energy to  
24 specifically identify beneficiaries is consistent with the planning criteria used by

1 PJM to decide whether such facilities should be included in the RTEP and how  
2 the costs of Lower Voltage Facility Economic Projects are currently allocated.

3

4 **Q. How does the proposed approach differ from the current methodology for**  
5 **allocating the costs of Regional Facility Economic Projects?**

6 A. Currently, Regional Facility Economic Projects are allocated using a 100%  
7 postage-stamp methodology. By adopting a hybrid approach, the PJM TOs will  
8 ensure that costs are allocated in a manner that accounts for difficult-to-quantify  
9 benefits as well as specifically-identified benefits from these projects. Some  
10 stakeholders have suggested that 100% of the costs of Regional Facility  
11 Economic Projects should be allocated to these beneficiaries identified through  
12 the decreased load energy payment analysis; however, similar to Regional Facility  
13 Reliability Projects, Regional Facility Economic Projects also provide region-  
14 wide benefits that are difficult to quantify, even if their inclusion in the RTEP was  
15 driven by their expected economic benefits. In addition, the 50% postage-stamp  
16 allocation allows for potential changes in use of Regional Facility Economic  
17 Projects over the life of the facility, relative to the 15-year projection underlying  
18 the change in load energy payment analysis. Thus, a hybrid cost allocation  
19 methodology is the appropriate approach for allocating the costs of these projects  
20 in PJM.

1 **Q. Is the allocation of costs to zones that benefit through decreased load energy**  
2 **payments consistent with the PJM planning criteria?**

3 A. Yes. Pursuant to Schedule 6 of the PJM Operating Agreement, PJM will only  
4 include an Economic Project in the PJM RTEP if the relative benefits and costs of  
5 the project meet a benefit-cost ratio threshold of at least 1.25:1. To determine the  
6 benefits used in this determination, PJM uses the methodology set forth in Section  
7 1.5.7(d) of Schedule 6 of the PJM Operating Agreement, which includes a  
8 determination of changes in load energy payments for each transmission zone.  
9 Cost responsibility for 50% of the Regional Facility Economic Projects will be  
10 allocated pro rata to those zones that show a decrease in the net present value of  
11 changes to the load energy payment determined for the first 15 years of the life of  
12 the Economic Project as calculated using the methodology set forth in Section  
13 1.5.7 of Schedule 6 of the PJM Operating Agreement. Since the decrease in load  
14 energy payments is based on a 15-year forecast, and therefore recognizes future  
15 beneficiaries, no update to this portion of the calculation is necessary after the  
16 initial cost allocation has been determined.

17

18 **Q. How do the PJM TOs propose to allocate the costs for Lower Voltage Facility**  
19 **Economic Projects?**

20 A. The PJM TOs propose no change to the current methodology for the allocation of  
21 costs for these types of projects. Thus, all of the costs for new Lower Voltage  
22 Facility Economic Projects will continue to be allocated to those transmission  
23 zones that benefit from the project through decreased load energy payments. We

1 should note that under the proposed revisions to Schedule 12, the term, “Lower  
2 Voltage Facilities,” which previously applied only to such facilities that were  
3 Reliability Projects, now applies to all RTEP transmission facilities that are not  
4 Regional Facilities, including Economic Projects.

5  
6 **Q. Do the PJM TOs propose a change to the methodology for allocating the  
7 costs of Economic Projects that are accelerations of or modifications to  
8 Reliability Projects?**

9 A. No. The PJM TOs do not propose any substantive changes to the cost allocation  
10 process for these types of Economic Projects. Under that process, the costs of  
11 these types of projects will continue to be allocated in accordance with the  
12 provisions of Schedule 12 governing the allocation of costs of the Reliability  
13 Projects that they accelerate or modify (except, in the case of an accelerated  
14 project, if the economic savings during the acceleration period exceed the stated  
15 threshold).

16  
17 **Q. Will the allocation of costs for Economic Projects require further changes to  
18 the planning process?**

19 A. The proposed changes to the cost allocation methodology for Economic Projects  
20 do not require changes to the planning process set forth in Schedule 6 of the PJM  
21 Operating Agreement, but PJM may wish to consider adjustments to that process.  
22 Currently, Schedule 6 of the PJM Operating Agreement only considers zones that  
23 experience decreases in load energy payments when determining the change in

1 load payment for Lower Voltage Facilities as part of the determination of benefits  
2 necessary to satisfy the benefit-cost threshold of 1.25:1. In contrast, when  
3 determining the benefits of Regional Facilities, Schedule 6 of the PJM Operating  
4 Agreement considers the net change in load energy payments for all zones  
5 (considering both zones in which energy payments decrease and those in which  
6 they increase). Because the proposed cost allocation for both Regional Facility  
7 and Lower Voltage Facility Economic Projects will use the decrease in load  
8 energy payments as part of the allocation of costs of those facilities, PJM may  
9 wish to modify the determination of change in load payments as part of the  
10 Schedule 6 planning criteria. However, to be clear, such a change is not required  
11 for the cost allocation methodology for Economic Projects to be just and  
12 reasonable.

13  
14 **VII. THE PJM TOS PROVIDE FURTHER CLARIFICATION REGARDING**  
15 **PROJECTS COSTING UNDER \$5 MILLION AND REPLACEMENT**  
16 **FACILITIES.**

17 **Q. Have the PJM TOs proposed any changes to the minimum level that a**  
18 **facility must cost before its costs can be allocated outside of the zone in which**  
19 **the facility is built?**

20 **A.** No. However, the PJM TOs propose to extend the current \$5 million threshold  
21 for regional cost allocation of PJM RTEP projects that currently applies only to  
22 Lower Voltage Facility Reliability Projects to all Regional Facilities and Lower  
23 Voltage Facility Economic Projects. Thus, all PJM Board-approved RTEP  
24 projects that cost less than \$5 million will be allocated to the zone in which the  
25 facility is being built. This change is being proposed because the rationale for

1 using a \$5 million threshold with respect to Lower Voltage Facility Reliability  
2 Projects applies equally to Regional Facilities and Lower Voltage Facility  
3 Economic Projects. In each case, the minimal impact on transmission rates of  
4 projects costing less than \$5 million does not justify the time and effort to develop  
5 and file a cost allocation (and with respect to Regional Facilities and Reliability  
6 Projects, to perform an annual update). The parties agreed to the application of a  
7 minimum threshold of \$5 million for Lower Voltage Facility Reliability and  
8 Economic Projects in the settlement agreement in Docket No. ER06-456, which  
9 the Commission approved, and the proposed changes simply seek to consistently  
10 apply this just and reasonable and practical threshold to all Reliability and  
11 Economic Projects.

12

13 **Q. How do the PJM TOs propose to allocate the costs for replacement facilities?**

14 A. Costs for replacement transmission facilities, meaning new transmission facilities  
15 that replace existing facilities, will continue to be allocated in accordance with the  
16 manner in which the costs of the facilities that they are replacing were allocated.  
17 However, if the facilities are included in the PJM RTEP as a separate Reliability  
18 or Economic Project, the costs of that Replacement Facility will be subject to the  
19 cost allocation methodology, respectively, for Reliability or Economic Projects.

1 **Q. Do the PJM TOs propose any changes to allocation of costs for generator**  
2 **interconnection facilities?**

3 A. No. The Commission specifically found that issues related to the generator and  
4 merchant transmission interconnection process and interconnection cost recovery  
5 are outside of the scope of *Order No. 1000*. Moreover, the Commission has  
6 already found that the method for allocating costs for interconnection projects in  
7 the PJM Tariff is just and reasonable and compliant with *Order No. 2003*.  
8 Therefore, no changes are proposed to that methodology.

9  
10 **VIII. D.C. FACILITIES WILL BE ALLOCATED IN THE SAME MANNER AS**  
11 **ALTERNATING CURRENT (“A.C.”) TRANSMISSION PROJECTS.**

12 **Q. How do the PJM TOs propose to allocate the costs of D.C. Facilities?**

13 A. The PJM TOs propose to use the same methodology that will be used for A.C.  
14 projects to allocate the costs of D.C. Facilities under PJM control (*i.e.*, D.C.  
15 Facilities that do not require customers to subscribe for transmission service).  
16 Therefore, D.C. Facilities that are classified as a Regional Facility will be  
17 allocated using a hybrid methodology of 50% postage-stamp and 50%  
18 specifically-identified beneficiary allocation while 100% of the costs of D.C.  
19 Facilities that are classified as a Lower Voltage Facility will be allocated to  
20 specifically-identified beneficiaries. As explained below, because of certain  
21 technical differences between A.C. and D.C. technology, there are some minor  
22 differences in implementation of the DFAX methodology but these differences  
23 still produce similar results that are consistent with the cost allocation principles  
24 established by the Commission in *Order No. 1000*.

1 **Q. How do PJM TOs propose to classify the D.C. Facilities as Regional Facilities**  
2 **or Lower Voltage Facilities?**

3 A. The PJM TOs propose to classify those D.C. Facilities as Regional Facilities if the  
4 D.C. Facility is connected to an A.C. substation that is also connected to either an  
5 A.C. transmission line that is operated at 500 kV or above or a double circuit 345  
6 kV transmission line that meets the definition of a Regional Facility. In addition,  
7 to be classified as a Regional Facility, the phase-to-phase voltage rating of the  
8 transformer between the substation discussed above and the converter at that end  
9 of the line must be rated at least 345 kV on the low side. Alternatively, if the  
10 D.C. Facility connects directly to another D.C. Facility that has previously been  
11 classified as a Regional Facility, the new D.C. Facility will be considered a  
12 Regional Facility. Otherwise, the new D.C. Facility will be treated as a Lower  
13 Voltage Facility.

14  
15 **Q. How do the PJM TOs propose to determine the DFAX allocation for D.C.**  
16 **Facilities?**

17 A. Because the flow on a D.C. line is constant and controllable, and the DFAX is  
18 based on the change of power flow on a line transferring power, the standard  
19 DFAX methodology will not work for D.C. Facilities. Rather, a proxy is needed.  
20 PJM currently uses proxy facilities for calculating DFAX on facilities to address  
21 non-thermal limitations such as where there is a reactive limit and such proxies  
22 have produced reasonable results. To calculate an equivalent DFAX for the D.C.  
23 Facility, PJM will remove the D.C. Facility from the power flow model and

1 replace it with a proxy A.C. transmission project. PJM will then calculate the  
2 DFAX from the change in flow in the proxy A.C. transmission project. PJM will  
3 also adjust the impedance on the proxy A.C. transmission project to reflect an  
4 impedance based on the length and operating voltage of the D.C. Facility.

5  
6 **Q. Why do the PJM TOs propose to allocate the costs of new D.C. Facilities in**  
7 **the same manner as A.C. transmission projects?**

8 A. The PJM TOs have focused the criteria for Regional Facility treatment on one end  
9 of the D.C. Facility, since this will result in treatment comparable to typical A.C.  
10 Regional Facilities, which often are connected at one end to a substation to which  
11 only Lower Voltage Facilities are connected. Thus, like the proposed cost  
12 allocation for A.C. transmission projects, the proposed cost allocation of new  
13 D.C. Facilities that are classified as Regional Facilities properly balances the need  
14 to allocate costs to those customers who directly benefit from the project as well  
15 as those customers that receive benefits that are difficult to quantify. As we will  
16 discuss later, this cost allocation methodology satisfies the cost allocation  
17 principles adopted by the Commission in *Order No. 1000* and the PJM TOs  
18 believe that this is the best allocation methodology for all transmission facilities  
19 included in the RTEP regardless of whether they are A.C. or D.C. Facilities.

1 **IX. THE PROPOSED RATE DESIGN ONLY ALLOCATES COSTS FOR**  
2 **THOSE TYPES OF PROJECTS THAT ARE PLANNED FOR AND**  
3 **INCLUDED IN THE PJM RTEP AT THIS TIME**

4 **Q. Does the proposed rate design address potential changes to PJM’s planning**  
5 **process and types of transmission projects that may be included in future**  
6 **RTEPs that are not part of PJM’s currently effective planning process or**  
7 **proposed in PJM’s *Order No. 1000* compliance filing?**

8 A. No. The proposed rate design is based on PJM’s currently effective planning  
9 process, as well as changes to that process that will be proposed in PJM’s *Order*  
10 *No. 1000* compliance filing. Under PJM’s current planning process, the projects  
11 included in PJM’s RTEP include reliability, operational performance, and market  
12 efficiency projects. With one exception regarding the “State Agreement”  
13 approach that we will discuss later, PJM is not proposing any changes to the  
14 category of projects included in its RTEP as part of its *Order No. 1000*  
15 compliance filing. As to transmission needs driven by public policy  
16 requirements, such as state renewable portfolio standards, PJM considers such  
17 needs in its sensitivity analysis and scenario-based RTEP planning process. Thus,  
18 the PJM Board takes needs created by public policy requirements into account  
19 when it approves projects that address reliability violations. For example, PJM  
20 might consider whether the delivery of energy from renewable resources installed  
21 to satisfy certain states’ renewable portfolio standards creates a need to reinforce  
22 the system to avoid reliability violations. However, PJM’s current planning  
23 process does not separately address projects that address public policy  
24 requirements, but do not also satisfy a reliability, operational performance, or  
25 economic need. PJM’s *Order No. 1000* compliance filing proposes to recognize

1 such projects through the “State Agreement” approach discussed below. If the  
2 PJM planning process is modified to address inclusion of these or other types of  
3 transmission projects in the RTEP, the PJM TOs will accordingly undertake to  
4 revise the rate design and cost allocation process, as necessary, at that time. The  
5 PJM TOs’ Section 205 responsibilities do not extend to the regional planning  
6 process contained in Schedule 6 of the PJM Operating Agreement.  
7

8 **Q. Is use of a 50% postage stamp and 50% specific beneficiary allocation**  
9 **methodology, such as Solution-Based DFAX, consistent with the changes**  
10 **approved by the Commission to the RTEP in Docket No. ER12-1178-000?**

11 A. Yes. As described by PJM in its transmittal letter in that docket, the changes were  
12 intended to allow PJM “to take a broader view of the factors driving the needs on  
13 the transmission system by looking at a much broader array of sensitivities and  
14 scenario analyses.” The revised planning process allows PJM to account for  
15 changes to these factors as part of its transmission planning process. The  
16 proposed transmission cost allocation methodology is both consistent with and  
17 complementary to the recent changes to the planning process since it is designed  
18 to account for changes in system conditions and use of the system over the life of  
19 the facility. As we discussed previously, unlike the Violation-Based DFAX, the  
20 Solution-Based DFAX analysis allows for annual updates to account for changes  
21 in system conditions over the life of the facility. In the case of Regional  
22 Facilities, the use of the 50% postage-stamp allocation accounts for difficult to  
23 quantify regional benefits and is also updated annually to recognize potential

1 changes in the use of such facilities. Thus, the proposed methodology is  
2 consistent with the changes to the RTEP approved by the Commission in Docket  
3 No. ER12-1178-000.

4  
5 **Q. Do the PJM TOs propose to change the treatment of the costs of projects not**  
6 **identified by PJM’s RTEP planning process or included in the RTEP for**  
7 **purposes of cost allocation?**

8 A. No. The PJM TOs’ proposed cost allocation revisions extend only to “Required  
9 Transmission Enhancements,” which are the projects identified in PJM’s RTEP  
10 process to meet one of the system needs that are the focus of that process and  
11 approved by the PJM Board for inclusion in the RTEP. The PJM TOs propose no  
12 change in the treatment of the costs of other transmission projects. Those costs  
13 will continue to be allocated by other, existing cost allocation provisions of the  
14 PJM OATT, as in the case of generation and merchant transmission  
15 interconnection-related projects. In the case of Supplemental Projects, the cost  
16 will continue to be borne by the project’s owner, subject to any rates it files under  
17 Section 205 to recover the project’s costs from its customers.

18  
19 **Q. How would the costs of a project that is intended to satisfy a public policy**  
20 **requirement be allocated?**

21 A. The PJM OATT currently provides three ways in which the costs for a project that  
22 is intended to satisfy a public policy requirement may be allocated, which  
23 correspond to the three ways in which such a project may currently be reflected in

1 the regional plan. First, if the public policy requirement is considered by PJM in  
2 its sensitivity analysis or scenario planning and the project is ultimately included  
3 in the RTEP as a Reliability Project or Economic Project, the costs will be  
4 allocated based upon the applicable provisions of Schedule 12 for such projects.  
5 Second, if the project is not included in the RTEP to meet a need that PJM  
6 identifies, the project would be classified as a Supplemental Project, and the costs  
7 would be allocated in the manner proposed by the project's owner. Any proposal  
8 to allocate costs outside of the owner's zone would also require approval under  
9 the CTOA. Third, if the project is an interconnection project, the costs would be  
10 allocated based upon the "but for" test as set forth in the PJM OATT.

11 In addition, PJM is proposing to modify its planning process to provide a  
12 fourth way for projects that address public policy requirements to be included in  
13 the RTEP: a "State Agreement" approach. Among other things, PJM proposes to  
14 require that states sponsoring such a project agree that the project's costs will be  
15 allocated to customers in those states. Consistent with that approach, where one  
16 or multiple states propose a project to PJM that would otherwise not be included  
17 in the RTEP and such a project is not a Supplemental Project, a proposed cost  
18 allocation for the project that satisfies this requirement will be submitted to the  
19 PJM TOA-AC, which will consider whether the cost allocation proposal should  
20 be filed by the Transmission Owners under Section 205 of the FPA. Although the  
21 PJM TOA-AC is not required to file the cost allocation proposed for the project,

1 the proposed Schedule 12 Amendments make clear that either PJM or the state  
2 governmental entities proposing the State Agreement project may file the  
3 proposed cost allocation for the project under Section 206 of the FPA.

4  
5 **X. THE PROPOSED RATE DESIGN IS CONSISTENT WITH *ORDER NO.***  
6 ***1000*'S SIX REGIONAL COST ALLOCATION PRINCIPLES**

7 **Q. What are the six regional cost allocation principles that the Commission**  
8 **established in *Order No. 1000*?**

9 A. The Commission established the following six regional cost allocation principles  
10 in *Order No. 1000*:

11 (1) "The cost of transmission facilities must be allocated to those within the  
12 transmission planning region that benefit from those facilities in a manner that is  
13 at least roughly commensurate with estimated benefits."

14 (2) "Those that receive no benefit from transmission facilities, either at present or  
15 in a likely future scenario, must not be involuntarily allocated the costs of those  
16 facilities."

17 (3) "If a benefit to cost threshold is used to determine which facilities have  
18 sufficient net benefits to be included in a regional transmission plan for the  
19 purpose of cost allocation, it must not be so high that facilities with significant  
20 positive net benefits are excluded from cost allocation . . . If adopted, such a  
21 threshold may not include a ratio of benefits to costs that exceeds 1.25 unless the  
22 transmission planning region or public utility transmission provider justifies and  
23 the Commission approves a greater ratio."

24 (4) "The allocation method for the cost of a regional facility must allocate costs

1 solely within that transmission planning region unless another entity outside the  
2 region or another transmission planning region voluntarily agrees to assume a  
3 portion of those costs.”

4 (5) “The cost allocation method and data requirements for determining benefits  
5 and identifying beneficiaries for a transmission facility must be transparent with  
6 adequate documentation to allow a stakeholder to determine how they were  
7 applied to a proposed transmission facility.”

8 (6) “A transmission planning region may choose to use a different cost allocation  
9 method for different types of transmission facilities in the regional plan, such as  
10 transmission facilities needed for reliability, congestion relief, or to achieve public  
11 policy requirements established by state or federal laws or regulations. Each cost  
12 allocation method must be set out clearly and explained in detail.”

13

14 **Q. Does the proposed rate design allocate costs of transmission facilities in a**  
15 **manner that is at least roughly commensurate with the estimated benefits of**  
16 **the transmission facilities?**

17 A. Yes. Consistent with the first regional cost allocation principle, the proposed rate  
18 design allocates costs of transmission facilities in a manner that is at least roughly  
19 commensurate with the estimated benefits of the transmission facilities. More  
20 specifically and as described in more detail above, the 50/50 split for allocating  
21 costs of Regional Facility Reliability Projects ensures that customers receiving  
22 difficult to quantify, system-wide benefits are allocated a portion of the costs  
23 through the postage-stamp allocation, while users that are specifically-identified

1 as beneficiaries of the facilities constructed are also allocated a fair portion of the  
2 costs. Use of Solution-Based DFAX, which is updated annually, ensures that the  
3 cost allocation will track changes in the beneficiaries of the facilities as system  
4 uses change. Similarly, the 50/50 split for allocating costs of facilities operating  
5 at 500 kV and above and double circuit 345 kV Economic Projects ensures that  
6 customers receiving difficult to quantify, system-wide benefits provided by the  
7 Regional Facilities are allocated a portion of the costs through the postage-stamp  
8 methodology, while specifically-identified beneficiaries of the facilities are  
9 allocated a portion of costs in proportion to their decreased load energy payments  
10 as a result of the facility. Solution-Based DFAX and decreased load energy  
11 payments are the only methodologies used to allocate costs of Lower Voltage  
12 Facilities because such projects primarily address local issues and do not provide  
13 the same system-wide benefits provided by Regional Facilities. Therefore, the  
14 Solution-Based DFAX and decreased load energy payments sufficiently capture  
15 the universe of customers that receive benefits from facilities and should, thus, be  
16 allocated costs.

17

18 **Q. Does the proposed rate design involuntarily allocate any costs of transmission**  
19 **facilities to those that receive no benefit from the transmission facilities,**  
20 **either at present or in a likely future scenario?**

21 A. No. Consistent with the second regional cost allocation principle, the proposed  
22 rate design will not result in any costs being allocated to those that receive no  
23 benefit. As we have described above, the costs allocated for Reliability and

1 Economic Projects will be roughly commensurate with the benefits received from  
2 the project. In the case of Regional Facilities, entities allocated a portion of the  
3 costs of the facilities only through the postage-stamp methodology still receive  
4 the benefits of improved reliability, reduced congestion, fewer power losses,  
5 greater carrying capacity, reduced operating reserve requirements, and improved  
6 access to generation that are provided by such Regional Facilities.

7  
8 **Q. Does the benefit-to-cost threshold used to determine which facilities have**  
9 **sufficient net benefits to be included in a regional transmission plan exceed**  
10 **1.25 or exclude transmission facilities with significant positive net benefits**  
11 **from cost allocation?**

12 A. No. The PJM TOs propose no change in the manner in which PJM currently uses  
13 a benefit-to-cost threshold. A benefit-to-cost ratio is used to determine inclusion  
14 in the PJM RTEP only for Economic Projects. Consistent with the third regional  
15 cost allocation principle, the benefit-to-cost ratio used in the currently effective  
16 PJM Operating Agreement is 1.25:1.

17  
18 **Q. Does the proposed rate design allocate costs solely within PJM's transmission**  
19 **planning region?**

20 A. Yes. Consistent with the fourth regional cost allocation principle, the proposed  
21 rate design will only allocate costs within PJM's transmission planning region.  
22 The proposed rate design will be implemented through revisions to Schedule 12  
23 of the PJM OATT. Under Schedule 12, costs will be recovered only from the

1 PJM transmission customers that are allocated costs pursuant to the proposed rate  
2 design. Thus, the PJM TOs do not propose to change the PJM border rate, which  
3 has been a stated rate for several years.

4 **Q. Is the proposed rate design's process for determining benefits and identifying**  
5 **beneficiaries for a transmission facility sufficiently transparent to allow a**  
6 **stakeholder to determine how the proposed rate design will be applied to a**  
7 **proposed transmission facility?**

8 A. Yes. The clear breakdown of categories of transmission facilities and  
9 corresponding cost allocation methodologies in the PJM OATT will allow  
10 stakeholders to easily determine what cost allocation methodology will apply to a  
11 particular transmission project. After determining the applicable cost allocation  
12 methodology, how each cost allocation methodology determines benefits and  
13 identifies beneficiaries is also a transparent process and is clearly described in  
14 Schedule 12. Indeed, the Commission has previously accepted the description of  
15 DFAX in the OATT in Docket ER06-456. The only change will be to specify that  
16 the DFAX methodology will be applied to transmission solutions, rather than the  
17 reliability or operational performance violations. The Solution-Based DFAX will  
18 be based on current planning models and power flows and as described by Mr.  
19 Herling, is more transparent than Violation-Based DFAX. Further, the decreased  
20 load energy payment methodology for Economic Projects is transparent because it  
21 tracks the formula used in the transmission planning process set forth in Section  
22 1.5.7 of Schedule 6 of the PJM Operating Agreement. In the case of costs  
23 allocated using the postage-stamp methodology, system-wide benefits flow from

1 the nature of Regional Facilities, and beneficiaries are identified based on the load  
2 ratio share of each zone, which is calculated annually by PJM and filed with the  
3 Commission.

4 **Q. Does the proposed rate design use different cost allocation methods for**  
5 **different categories of transmission facilities?**

6 A. Yes. As we have discussed, the proposed rate design employs different cost  
7 allocation methods to reflect facilities that are engineered and designed for  
8 different purposes. Costs of Regional Facility Reliability and Economic Projects  
9 will be allocated using a 50/50 split because such projects provide both system-  
10 wide benefits that are addressed through the portion of the costs allocated using  
11 the postage-stamp methodology and direct, easily quantifiable benefits that inure  
12 to specific customers that are addressed through the portion of the costs allocated  
13 using either Solution-Based DFAX or decreased load energy payments. Lower  
14 Voltage Facility Reliability and Economic Projects will be allocated using only  
15 Solution-Based DFAX or decreased load energy payments because such projects  
16 do not provide the same system-wide benefits as Regional Facilities. Also, the  
17 benefits and beneficiaries of Lower Voltage Facilities are easier to identify and  
18 quantify because such projects are predominantly intended to address localized  
19 issues.

20 Solution-Based DFAX is used to allocate costs of Reliability Projects,  
21 while decreased load energy payments are used to allocate the costs of Economic  
22 Projects because Reliability Projects are engineered and designed to address  
23 different system needs than Economic Projects. Reliability Projects are

1           engineered and designed to resolve certain reliability or operational issues, and  
2           aside from the system-wide benefits from Regional Facilities, the benefits of  
3           resolving such issues inure to customers that use the facilities, which is what  
4           Solution-Based DFAX measures. Economic Projects, on the other hand, are  
5           engineered and designed to reduce congestion and improve the economic  
6           efficiency of PJM's energy and capacity markets. Again, aside from the system-  
7           wide benefits from Regional Facilities, the benefits of improved economic  
8           efficiency in the energy and capacity markets are measured based on decreased  
9           load energy payments, which is the basis for allocating Economic Projects.

10

11   **Q.    Does this conclude your testimony?**

12   A.    Yes.

**DECLARATION OF WITNESS**

I, Michelle Henry, declare under penalty of perjury that the statements contained in the foregoing Joint Testimony of Michelle Henry and Frank J. Richardson, other than the personal information regarding Frank J. Richardson, of which I have no personal knowledge, submitted on behalf of the PJM Transmission Owners are true and correct to the best of my knowledge, information, and belief.

Executed on this 8th day of October, 2012, in Akron, Ohio.

/s/ Michelle Henry  
Michelle Henry  
FirstEnergy Corp.

**DECLARATION OF WITNESS**

I, Frank J. Richardson, declare under penalty of perjury that the statements contained in the foregoing Joint Testimony of Michelle Henry and Frank J. Richardson, other than the personal information regarding Michelle Henry, of which I have no personal knowledge, submitted on behalf of the PJM Transmission Owners are true and correct to the best of my knowledge, information, and belief.

Executed on this 8th day of October, 2012, in Allentown, Pennsylvania.

/s/ Frank J. Richardson

Frank J. Richardson  
PPL Electric Utilities Corporation