138 FERC ¶ 61,230
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Jon Wellinghoff, Chairman;
Philip D. Moeller, John R. Norris,
and Cheryl A. LaFleur.

PJM Interconnection, L.L.C. Docket No. EL05-121-006

ORDER ON REMAND

(Issued March 30, 2012)

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1. This order responds to the decision by the United States Court of Appeals for the Seventh Circuit remanding to the Commission the issue of the appropriate methodology to be used by PJM Interconnection, L.L.C. (PJM) to allocate costs associated with new transmission facilities that will operate at or above 500 kV.[1] In this order, the Commission finds that PJM's pre-existing tariff and practice, as specified in the implementation manuals, of utilizing exclusively a static flow-based model for allocating the costs of high voltage transmission lines is unjust and unreasonable, and that allocating costs of transmission enhancements that operate at or above 500 kV to utility zones using a postage-stamp cost allocation methodology is a just, reasonable and not unduly discriminatory method of allocating the costs of these new facilities.

2. At the outset, we acknowledge that this order is being issued as PJM and its stakeholders are considering how the region will comply with Order No. 1000.[2] While it is necessary that we issue this order at this time to respond to the court's remand, our determination here should not be construed as preventing PJM and its stakeholders from developing other cost allocation methodologies in response to Order No. 1000 or other relevant stakeholder processes. For example, we note below the interest of some parties in a hybrid methodology. PJM and its stakeholders are not precluded from considering such approaches, which combine the attributes of flow-based modeling and the realization that 500 kV and above facilities in PJM provide broad regional benefits (as discussed in more detail in this order), in development of the Order No. 1000 compliance filing or other relevant stakeholder processes.

3. Further, as described herein, PJM explains that its planning process will select facilities at different voltage levels, to resolve multiple violations in multiple areas over a long period of time. PJM and its stakeholders are also not precluded from considering whether there are broader benefits at the different voltage levels for the type of facility selected to meet the needs of the PJM system, both when selected and over time, and whether the appropriate voltage threshold for regional cost allocation should be modified to recognize these broad benefits, as part of the development of its Order No. 1000 compliance filing or other relevant stakeholder processes. In addition, to the extent PJM makes adjustments to its planning process for selecting facilities to meet the needs of the region in the course of compliance with Order No. 1000 or other relevant stakeholder

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[1] *Illinois Commerce Commission v. FERC*, 576 F.3d 470 (7th Cir. 2009).

[2] *See Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 76 Fed. Reg. 49,842 (Aug. 11, 2011), FERC Stats. & Regs. ¶ 31,323 (2011).

processes, it is not precluded from considering whether those changes also necessitate changes in cost allocation.

I. Background

4. This proceeding began as an investigation under section 206 of the Federal Power Act into whether PJM's allocation of transmission costs for existing and new transmission facilities is just and reasonable.[3] On April 19, 2007, the Commission issued Opinion No. 494, an order on an initial decision concerning PJM's transmission rates for existing and new transmission contained in PJM's then current Open Access Transmission Tariff (Tariff).[4] In Opinion No. 494, the Commission found that the existing license-plate methodology for cost recovery for existing facilities had not been shown to be unjust and unreasonable.[5] With respect to PJM's methodology to recover investment in new facilities, the Commission found that PJM's then current Tariff was not just and reasonable.

5. Prior to this proceeding, PJM's operating agreement provided that designations of cost responsibility shall "be based on the Office of the Interconnection's assessment of the contributions to the need for, and benefits expected to be derived from, the pertinent enhancement or expansion by affected Market Participants."[6] In its manuals, PJM used a flow-based model in its determination of these benefits, although all the details of the model's implementation were not specified. The Commission found that, because the flow-based methodology was not included in the PJM Tariff in sufficient detail, the Tariff was not just and reasonable. With respect to lower voltage facilities, the Commission found that PJM's previous use of a flow-based model would be acceptable, but required that PJM set forth in its Tariff a detailed methodology for cost recovery of investment in new facilities below 500 kV. The Commission accepted a settlement submitted by PJM that set forth the details and assumptions used in applying the static, flow-based

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[3] 16 U.S.C. § 824e (2006). *See Allegheny Power System Operating Cos.*, 111 FERC ¶ 61,308 (2005), *order on reh'g and clarification*, 115 FERC ¶ 61,156 (2006).

[4] *PJM Interconnection, L.L.C.*, Opinion No. 494, 119 FERC ¶ 61,063 (2007), *order on reh'g*, Opinion No. 494-A, 122 FERC ¶ 61,082 (2008).

[5] Under a license-plate (or zonal) rate design, a customer pays the embedded cost of transmission facilities that are located in the same zone as the customer. A customer does not pay for other transmission facilities outside of the zone, even if the customer engages in transactions that rely on those zones.

[6] PJM Operating Agreement, Schedule 6 § 1.5.6(g).

allocation methodology for new facilities that operate below 500 kV in Schedule 12, section (b)(ii).[7]

6. The Commission found, however, that the flow-based model for allocating the costs of above 500 kV facilities failed to account for the system-wide benefits of those facilities. The Commission found that allocating the costs of those facilities using a postage-stamp methodology was a reasonable method for allocating those facilities.[8] In compliance with Opinion No. 494,[9] PJM revised its Tariff to adopt the postage-stamp methodology to allocate the cost of investment in all new transmission facilities included in the Regional Transmission Expansion Plan (RTEP) that operate at or above 500 kV.[10]

7. On appeal, the court affirmed the Commission's determination that the license-plate methodology for existing facilities had not been shown to be unjust and unreasonable. The court, however, granted the petition for review regarding the use of a postage-stamp cost allocation methodology for new transmission facilities that operate at or above 500 kV and, on October 28, 2009, remanded the case to the Commission for further proceedings.

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[7] *PJM Interconnection, L.L.C.*, 124 FERC ¶ 61,112 (2008).

[8] Under a region-wide, postage-stamp methodology, all transmission service customers in a region pay a uniform rate per unit-of-service, based on the aggregated costs of all covered transmission facilities in the region.

[9] The Commission accepted PJM's compliance filing in Opinion No. 494-A, 122 FERC ¶ 61,082 at PP 87-92.

[10] In the Commission order granting PJM full status as a regional transmission organization, the Commission directed PJM to revise its RTEP protocol (Schedule 6 of the Operating Agreement) to "more fully explain[] how PJM's planning process will identify expansions that are needed to support competition" and to "provide authority for PJM to require upgrades both to ensure system reliability and to support competition." *PJM Interconnection, L.L.C.*, 101 FERC ¶ 61,345 at P 24 (2002). PJM's system planning process was later approved consistent with Order No. 890 to include open and transparent planning at both regional and local levels. *See Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, FERC Stats. & Regs. ¶ 31,241, *order on reh'g*, Order No. 890-A, FERC Stats. & Regs. ¶ 31,261 (2007), *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 (2009), *order on reh'g*, Order No. 890-D, 129 FERC ¶ 61,126 (2009).

8. The court found that the Commission had not provided sufficient record evidence to justify its findings that the existing allocation practice for new facilities at and above 500 kV was unjust and unreasonable, and the Commission had not adequately supported its conclusion that the postage-stamp methodology was just and reasonable. The court first found that the Commission's reliance on the difficulty of measuring benefits for above 500 kV facilities, and the resulting likelihood of litigation, failed to justify the Commission's decision. The court stated that the Commission had failed to show "the absence of any indication that the difficulty exceeds that of measuring benefits to particular utilities of a smaller-capacity transmission line."[11]

9. The court further found that the Commission failed to justify requiring PJM to adopt a region-wide, postage-stamp cost allocation methodology for new transmission facilities that operate at or above 500 kV:

> FERC is not authorized to approve a pricing scheme that requires a group of utilities to pay for facilities from which its members derive no benefits, or benefits that are trivial in relation to the costs sought to be shifted to its members. "[A]ll approved rates [must] reflect to some degree the costs actually caused by the customer who must pay them." [citations omitted]. "Not surprisingly, we evaluate compliance with this unremarkable principle by comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party."[12]

10. The court also stated that the Commission had not justified the allocation of these costs on the basis of the reliability benefits provided to the PJM system. The court recognized that, in an interconnected grid, "a failure in one part of the region can affect the supply of electricity in other parts of the network. So utilities and their customers in the western part of the region could benefit from higher-voltage transmission lines in the east."[13] The court found, however, that "nothing in FERC's opinions in this case enables even the roughest of ballpark estimates of those benefits."[14]

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[11] *Illinois Commerce Commission*, 576 F.3d 470 at 475.

[12] *Id.* at 476.

[13] *Id.*

[14] *Id*.

11. The court recognized that, in comparing costs and benefits, the Commission "does not have to calculate benefits to the last penny, or for that matter to the last million or ten million or perhaps hundred million dollars."[15] The court concluded that:

> If [the Commission] cannot quantify the benefits to the midwestern utilities from new 500 kV lines in the East, even though it does so for 345 kV lines, but it has an articulable and plausible reason to believe that the benefits are at least roughly commensurate with those utilities' share of total electricity sales in PJM's region, then fine; the Commission can approve PJM's proposed pricing scheme on that basis. For that matter it can presume that new transmission lines benefit the entire network by reducing the likelihood or severity of outages. But it cannot use the presumption to avoid the duty of "comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party. "[16]

II. Procedures Established on Remand

12. On January 21, 2010, the Commission established paper hearing procedures to allow parties to supplement the record in this proceeding.[17] As part of the paper hearing procedures, the Commission gave PJM and other parties an opportunity to provide additional information to supplement the existing record. PJM and the other parties were encouraged to provide studies, methodologies or other evidence to support their positions.

13. The Commission provided a 30-day period for PJM to provide certain information which would give all parties a framework on which to submit responses.[18] All parties, including PJM, were given 45 days from the date of PJM's Filing to address the appropriate cost allocation methodology to allocate the cost of new transmission facilities that operate at or above 500 kV. Reply comments were due within 30 days.

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[15] *Id.*

[16] *Id*. (citations omitted).

[17] *PJM Interconnection, L.L.C.*, 130 FERC ¶ 61,052 (2010) (January 21, 2010 Order).

[18] On February 22, 2010, the Commission granted a request by PJM for an extension of time for submission of its initial responses, and on March 25, 2010, granted a request for rehearing by Exelon to provide additional factual information.

III. Interventions

14. Motions to intervene were submitted by the District of Columbia Public Service Commission (DC Commission), Duke Energy Corporation (Duke), the Office of the Ohio Consumer's Counsel (Ohio Consumer Counsel), NRG Companies,[19] American Transmission System, Incorporated (ATSI),[20] American Forest & Paper Association (AF&PA), American Wind Energy Association and Solar Energy Industries Association (American Wind and Solar Energy Associations), Industrial Energy Users-Ohio (IEU-Ohio), Electricity Consumers Resource Council (Elcon), New Jersey Municipal Intervenors,[21] and Stop the Lines.[22] The PSEG Companies filed answers objecting to the interventions of the New Jersey Municipal Intervenors and Stop the Lines.[23]

IV. Comments

15. PJM submitted a response to the Commission's request for additional information.[24] The following parties submitted comments in support of the use of the postage-stamp cost allocation methodology: American Electric Power Service Corporation (AEP), Allegheny Energy Companies, Baltimore Gas and Electric Company (BG&E), Fair Pricing Group,[25] Public Service Commission of Maryland, Maryland

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[19] NRG Power Marketing LLC, Conemaugh Power LLC, Indian River Power LLC, Keystone Power LLC, NRG Energy Center Dover LLC, NRG Energy Center Paxton LLC, NRG Rockford LLC, NRG Rockford II LLC, and Vienna Power LLC.

[20] With Ohio Edison Company, Pennsylvania Power Company, The Cleveland Electric Illuminating Company and The Toledo Edison Company, all subsidiaries of FirstEnergy Corp.

[21] The New Jersey Municipal Intervenors include the townships of Andover, Byram, East Hanover, Fredon, Hardwick, Montville, and Parsippany.

[22] A group of landowners and residents along the proposed easement for the Susquehanna-Roseland 500 kV transmission project.

[23] Public Service Electric and Gas Company and PSEG Energy Resources & Trade LLC.

[24] PJM April 13, 2010 Response.

[25] PPL Electric Utilities Corporation, Public Service Electric and Gas Company, and Rockland Electric Company.

Office of People's Counsel, New Jersey Board of Public Utilities, New Jersey Division of Rate Counsel, and Mid-Atlantic Entities.[26]

16. The following parties submitted comments opposing the use of the postage-stamp cost allocation methodology: AF&PA, Dayton Power and Light Company (Dayton), Duquesne Light Company (Duquesne), Electricity Consumers Resource Council (Elcon), Exelon Corporation (Exelon), FirstEnergy Companies, Illinois Commerce Commission (Illinois Commission), Industrial Energy Users – Ohio (IEU-Ohio), Office of Ohio Consumers' Counsel, and Public Utilities Commission of Ohio.

17. The Pennsylvania Office of Consumer Advocate (Pennsylvania OCA) and Long Island Power Authority and LIPA (LIPA) also filed comments. Reply comments were filed by AEP,[27] Mid-Atlantic Entities, Fair Pricing Group, BG&E, Exelon, Dayton, Duquesne, Virginia Electric Power Company (VEPCO), Pennsylvania Public Utility Commission (Pennsylvania PUC), LIPA, FirstEnergy Companies, Illinois Commission, Public Power Association of New Jersey, and IEU-Ohio.[28]

A. Summary of PJM Response

18. As part of its April 13, 2010 Response, PJM also submitted its White Paper from March 10, 2010 entitled "A Survey of Transmission Cost Allocation Issues, Methods, and Practices" (PJM White Paper). In this White Paper, PJM reviews the benefits of transmission expansion and analyzes various transmission cost allocation methodologies. As most relevant here, PJM explains, "when all costs are allocated to parties impacting the transmission facility based on the distribution factors in power flow analyses, no costs are allocated to others who may benefit from enhanced reliability, reduced losses, or other potential public good or positive externality benefits that may not be quantified in transmission planning studies."[29] In contrast, PJM notes that a methodology which allocates costs to all users of the system assumes:

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[26] PEPCO Holdings, Inc., Potomac Electric Power Company, Delmarva Power & Light Company, Atlantic City Electric Company, Old Dominion Electric Cooperative, and Southern Maryland Electric Cooperative.

[27] AEP also submitted a motion to file out of time.

[28] LIPA filed a motion and answer, and BG&E filed a motion and responsive pleading.

[29] PJM White Paper at 37.

> "that all users of the transmission system benefit from the transmission upgrade/project due to the public good or positive externality of reliability that transmission provides. Or because there may be additional benefits in the form of positive externalities that can accrue to all users of the transmission system in the form of reduced losses which are manifested in the price of energy in LMP markets. In addition, there may be other benefits that are derived at least one step removed from what can be identified through transmission planning analyses."[30]

19. Additionally, in the White Paper, PJM describes how transmission planning can inform cost allocation. PJM notes that there are two steps in transmission planning: (1) using power flow models to identify potential reliability or deliverability violations at forecast system peaks and to develop transmission solutions that resolve the identified reliability or deliverability violation; and (2) using a market simulation tool to examine the market efficiency impacts of proposed transmission solutions. According to PJM, transmission planning identifies the benefits of transmission expansion in terms of maintaining or improving reliability and reducing production costs. PJM states that understanding the locations of generation and load and impacts on the transmission system is one step toward identifying parties that might be considered beneficiaries of transmission expansion.[31]

20. PJM explains that its RTEP process identifies transmission system additions and improvements needed to keep electricity flowing throughout the PJM system. In particular, PJM tests the transmission system, using mandatory national standards and ReliabilityFirst Corporation (RFC) regional standards, to identify transmission overloads, voltage limitations, and other reliability standards violations up to 15 years into the future. PJM then develops transmission plans to resolve violations that could otherwise lead to overloads and blackouts. These plans are examined for their feasibility, impact, and costs and are discussed throughout the development process with PJM stakeholders.

21. While reliability planning addresses the fundamental need to keep the lights on, PJM notes that there is also a market efficiency component of planning, which seeks to identify transmission enhancements that lower costs to consumers by relieving congested lines and allowing lower-cost power to flow to customers. However, PJM states that projects that improve reliability also will likely reduce congestion costs and overall production costs. According to PJM, higher voltage transmission facilities will generally

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[30] *Id.* at 19.

[31] *Id.* at 17.

provide a broader range of reliability and market efficiency benefits than lower voltage transmission facilities. For example, PJM provides that the scope of the violations addressed by projects such as the Trans-Allegheny Interstate Line ("TrAIL") and Susquehanna – Roseland are clearly broader than the scope of violations resolved by the many 230 kV transmission projects included in the PJM RTEP over the last ten years. As a result, PJM explains that, on its system, lower voltage transmission assets support local needs, and transmission at higher voltages is generally used to move large amounts of power over long distances as higher voltages result in reduced power losses over long distances.[32]

22. PJM also discusses its examination of the effectiveness of alternative transmission facilities designed to solve multiple reliability issues. PJM explains that it must use its professional engineering judgment to select a transmission project from among multiple alternatives that will address the violations. When a number of alternative packages of new transmission facilities are found to resolve all issues, PJM will compare the projects based on factors such as cost, the likelihood of siting and constructing the facilities, the time to construct the facilities, and the secondary benefits related to capability beyond the minimum amount required to resolve the reliability issues.

23. PJM explains that it applies a flow-based methodology, the distribution factor (DFAX) methodology, to allocate the costs of below 500 kV facilities selected to be in the RTEP by PJM and its stakeholders. The DFAX methodology utilizes a computer model of the electric network and power flow modeling software to calculate individual distribution factors for each facility on which a reliability violation has been identified, performing this calculation prior to the addition of the reinforcement identified to resolve the violation. The distribution factors, represented as percentages, 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 facilities, and which represent a measure of the effect of the load of each transmission zone on the transmission constraints being analyzed. PJM notes that the DFAX methodology utilizes a number of assumptions, including basing cost allocation on the violations identified the first time the project was approved by the PJM Board of Managers and included in the RTEP. PJM explains that this historic analysis does not reflect the continual updating of the RTEP's analysis of reliability violations, which is undertaken each year in connection with the preparation of the most recent RTEP.

24. Despite noting the challenges of using the DFAX method for analysis of the costs and benefits of high voltage transmission facilities, in response to the Commission's

[32] PJM White Paper at 6, fn. 3.

January 21, 2010 Order, PJM provided an analysis of the total costs assigned to each PJM zone for eighteen PJM Board-approved at or above 500 kV facilities using the postage-stamp methodology, as well as estimates of the total costs that would be assigned to each zone using PJM's DFAX methodology[33] for below 500 kV facilities.[34] According to PJM's calculations for these eighteen facilities, more costs would be allocated to the western zones under the postage-stamp methodology than based on the DFAX methodology. Specifically, PJM estimated that the costs allocated for the AEP, Commonwealth Edison (ComEd),[35] Dayton, and Duquesne zones based on the DFAX methodology would be approximately $88 million, $15 million, $0.92 million, and $0.59 million, respectively, while approximately $1,194 million, $1,038 million, $164 million, and $134 million, respectively, would be allocated under the postage-stamp methodology.

25. However, PJM notes that applying the DFAX methodology to 500 kV and above projects has inherent limitations.[36] Specifically, while below 500 kV facilities are typically identified to resolve one, or a small number of, violations in year five of the planning horizon, 500 kV and above facilities are identified to resolve multiple reliability criteria violations across a 15 year planning horizon. Additionally, PJM states that it is highly likely that the violations driving the need for 500 kV and above new transmission facilities will change, since the modeling assumptions used in the RTEP analysis are constantly changing. For example, changes in load forecasts, generator deactivations, the entrance of new merchant transmission projects in the PJM queue, the execution of new transmission service agreements and interconnection service agreements, and the addition of demand response resources are all changes that can impact PJM's planning process. Further, 500 kV and above facilities provide benefits beyond the resolution of violations identified through RTEP, by making the grid more robust (i.e., less likely to face significant disruptions) with respect to less probable and unforeseen events. While the

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[33] As explained further below, PJM's DFAX methodology measures the flows across a particular facility that is constrained as the way to determine which zonal loads use the facility at a particular time (typically the peak hour of the year) and thus are considered the cause of the need for the addition of an upgrade to relieve that constraint.

[34] PJM notes that the DFAX methodology could not be replicated in every detail to previously approved 500 kV and above transmission facilities; however, PJM applied the DFAX methodology to the greatest degree possible to 500 kV and above RTEP facilities.

[35] A subsidiary of Exelon.

[36] PJM April 13, 2010 Response at 2.

static DFAX methodology is well suited to a one-time identification of parties affecting flows on a particular facility, PJM states that it cannot capture the benefits associated with the robustness of 500 kV and above projects with respect to changing system parameters.

B. Summary of Comments

26. Parties filing comments in support of the postage-stamp methodology assert that it is a just and reasonable methodology because it captures the full spectrum of benefits associated with 500 kV and above facilities. To begin with, the supporting parties state that 500 kV and above facilities contribute significantly to the reliability of the PJM transmission system, and assert that such facilities played a role in stopping the widespread cascading outages experienced in the eastern United States and Canada during the 2003 Blackout. The supporting parties also state that, compared to lower voltage facilities, 500 kV and above facilities incur less power losses, permit greater access to generation, can carry substantially more power, and lead to reduced congestion. The supporting parties assert that these benefits have allowed PJM members to reduce operating reserve requirements at reduced costs to customers. Further, the supporting parties state that the 500 kV grid is the foundation of the PJM system, and thus is the primary facilitator of efficient transmission operations and access to developed markets.

27. The supporting parties contend that the DFAX methodology, in contrast, focuses only on the flows over a particular facility under specific modeling assumptions, and thus does not account for all of the broad regional and economic benefits associated with 500 kV and above facilities. As a result, if the DFAX methodology were applied to 500 kV and above facilities, some zones would be forced to subsidize other zones. In particular, the supporting parties criticize the DFAX methodology because it is a "snapshot" in time methodology, asserting that the DFAX methodology cannot remain relevant over the useful life of 500 kV and above facilities. The supporting parties list a number of factors that could result in changing the benefits that a customer may receive from transmission over time, such as the development of more renewable generation resources, changes in the direction of power flows, changes in the price of fuels, changes in the existence and nature of generation in one portion of the region or another, and changes in the membership of Regional Transmission Organizations (RTOs).

28. Parties filing comments opposing the postage-stamp methodology state that most of the regional benefits claimed to be associated with 500 kV and above facilities cannot be quantified and assert that no party has shown that the postage-stamp methodology distributes these benefits in rough proportion to load. Moreover, opposing parties contend that many of the benefits of 500 kV and above facilities accrue disproportionately to eastern zones. For example, the parties state that reduced congestion largely benefits eastern zones, since these zones will see reduced Locational Marginal Prices (LMP), while LMPs will actually rise for western zones. Additionally,

opposing parties question whether the postage-stamp methodology sends the correct economic signal to PJM's planning process.

29. The parties opposing the postage-stamp methodology further assert that the DFAX methodology is a more equitable method for assigning costs roughly commensurate with benefits, since, by measuring the relative contribution of different loads to the constraint, the DFAX methodology reasonably identifies the beneficiaries of a project. These parties note that, under the DFAX methodology, western zones are shown to cause the need for only a few of the eighteen at or above 500 kV transmission facilities at issue. However, the cost shifts that would be incurred by switching from the DFAX methodology to the postage-stamp methodology are significant, resulting in western zones paying between 1,260 percent and 22,500 percent more for these facilities. While the DFAX methodology has been criticized for being a snapshot methodology, these parties state that, because the decision to build a new at or above 500 kV upgrade is based on an assessment of reliability concerns driving the need for the upgrade, it is not unreasonable that costs should be allocated according to that assessment. Additionally, the parties contend that there is no reason to believe that power flows will change dramatically in the future.

30. While most parties support either the postage-stamp or DFAX methodology, the Pennsylvania OCA, the Pennsylvania PUC, and VEPCO support hybrid methodologies. These parties note that both the DFAX and postage-stamp methodologies have weaknesses: the DFAX methodology does not recognize the benefits of a robust, extra high voltage network or that benefits may change over time, while the postage-stamp methodology does not provide the proper economic signals regarding the factors driving the need for construction of an upgrade. Thus, the Pennsylvania OCA recommends that PJM assign 75 percent of the costs of a new high voltage project according to the DFAX methodology, and 25 percent according to the postage-stamp methodology.[37] Similarly, VEPCO recommends that costs be divided equally between the two methodologies.[38]

31. LIPA, a purchaser of power from PJM over a merchant transmission facility owned by Neptune Regional Transmission System, LLC, asserts that the benefits derived from at or above 500 kV projects by merchant transmission facility owners are markedly different from those derived by internal network load customers. Specifically, LIPA

[37] The Pennsylvania OCA also recommended that, over the life of a 500 kV or above facility, the use of the DFAX methodology be phased out.

[38] The Pennsylvania PUC suggested that a hybrid methodology be determined through a mediation or stakeholder process.

states that a merchant transmission facility cannot exceed its level of approved firm withdrawal rights without submitting an interconnection request, and a merchant transmission facility does not rely on the reliability of the transmission system to the same extent as network load. According to LIPA, neither the postage-stamp nor the DFAX methodologies take these differences into consideration. Therefore, LIPA proposes that PJM adopt measures to exclude load-growth related cost allocations to merchant transmission facilities.

V. Procedural Matters

32. Pursuant to Rule 214(d),[39] the Commission will grant the untimely, unopposed motions to intervene of the DC Commission, Duke, Ohio Consumers' Counsel, Elcon, ATSI, AF&PA, American Wind and Solar Energy Associations, and IEU-Ohio given their interest in the proceeding, the early stage of this proceeding, and the absence of undue prejudice or delay. Given the early stage of this proceeding on remand, their interest, and the absence of undue prejudice or delay, we also grant the opposed motions to intervene of the New Jersey Municipal Intervenors and Stop the Lines.

33. The Commission is taking official notice of certain reports and other information pursuant to Rule 508(d) of the Commission's Rules of Practice.[40] This information is included in eLibrary in this docket. Parties will have the right to address the use of the officially noticed material in their timely filed petitions for rehearing.

34. As an initial matter, we find that LIPA's arguments regarding merchant transmission facilities are outside the scope of this proceeding. The assignment of RTEP costs to merchant transmission facilities was addressed in Opinion No. 503.[41] Specifically, the Commission noted that the presiding judge's Initial Decision directed PJM to calculate a merchant transmission facility's load-ratio share for 500 kV and above RTEP facilities. The Commission stated that "[n]o party excepted to the Initial Decision's finding regarding at or above 500 kV upgrades, and we affirm the Initial Decision's determination on this matter."[42]

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[39] 18 C.F.R. § 385.214(d) (2011).

[40] 18 C.F.R. § 385.508(d) (2011).

[41] *PJM Interconnection, L.L.C.*, Opinion No. 503, 129 FERC ¶ 61,161 (2009), *reh'g pending*.

[42] *Id.* at fn. 27.

VI. Discussion

A. PJM's Pre-Existing Tariff Is Not Just and Reasonable

1. Pre-Existing Tariff Does Not Specify Cost Allocation Methodology

35. When acting under section 206 of the Federal Power Act, in order to change an existing cost allocation, the Commission must show that the existing cost allocation of a utility is unjust and unreasonable and then must establish a new just and reasonable cost allocation to replace the existing cost allocation. PJM's Tariff as it existed prior to the initiation of this section 206 proceeding did not contain a sufficiently detailed methodology for the allocation of the costs of new transmission facilities;[43] rather, the operating agreement contained a principle that new transmission costs would be allocated "based on the Office of the Interconnection's assessment of the contributions to the need for, and benefits expected to be derived from, the pertinent enhancement or expansion by affected Market Participants."[44] PJM's practice at that time as outlined in its manuals was to use a flow-based model as one of its tools to determine the benefits to be provided from an enhancement, although all the details of the model's implementation were not specified. In Opinion No. 494, the Commission determined that continued use of a flow-based model is appropriate for lower voltage facilities, provided that the details of such a methodology are specified in PJM's Tariff. PJM subsequently filed tariff revisions for use of the DFAX method to allocate the costs of new transmission facilities below 500 kV. However, PJM's response indicates that the process in the Tariff cannot be applied to 500 kV and above facilities in a straightforward manner, instead requiring normalization and other assumptions that are not in the Tariff.[45]

2. PJM's Static DFAX Methodology Is Inadequate for Analysis of Costs and Benefits of High Voltage Transmission Lines

36. The court found that the Commission had not explained why the static DFAX model would not be appropriate for high voltage facilities when the Commission had accepted such a model for lower voltage facilities: "The second reason the Commission gave for approving PJM's pricing scheme -- the difficulty of measuring benefits and the resulting likelihood of litigation over them -- fails because of the absence of any

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[43] Opinion No. 494, 119 FERC ¶ 61,063 at P 65.

[44] PJM Operating Agreement, Schedule 6 § 1.5.6(g) at Sheet No. 185A.

[45] PJM April 13, 2010 Response at 7.

indication that the difficulty exceeds that of measuring the benefits to particular utilities of a smaller-capacity transmission line."[46]

37. As discussed below, the Commission finds that using PJM's static DFAX model as the sole basis for allocating costs has limitations that render it unjust and unreasonable for PJM's transmission facilities that operate at and above 500 kV. While PJM's static DFAX model reasonably can be used for lower voltage lines that serve more predominantly local requirements to resolve one or a small number of constraints, we conclude that the use of only PJM's static DFAX model for allocating the costs of higher voltage lines is not just and reasonable given the significant differences between the way these types of lines are selected in the PJM RTEP process to address multiple reliability and economic constraints over long periods of time.[47] The record shows that the DFAX method is inadequate for the analysis of the costs and benefits of high voltage transmission lines. The DFAX model is unable to identify the causes of multiple constraints, fails to account for the fact that a high voltage upgrade will resolve multiple constraints in multiple areas in addition to the constraint that is the focus of a DFAX analysis, and fails to account for changes in usage and flow direction over time, particularly given the 40 year or longer life span for transmission facilities.

38. The record before the Commission shows that, although PJM's static DFAX model can provide a snapshot of flows existing prior to installation of the upgrade, this static model is not appropriate for determining the allocation of costs for the spectrum of benefits that PJM's customers receive from high voltage transmission projects when initially installed and over their useful life. Changes occur over time to generator, load, and flow patterns,[48] as well as other structural changes, such as new transmission

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[46] *Illinois Commerce Commission*, 576 F.3d at 475.

[47] *See Public Service Co. v. FERC*, 575 F.2d 1204, 1217 (7th Cir. 1978) (affirming the Commission's allocation of "backbone grid" facilities differently from other facilities).

[48] For example, AEP cites electricity flow data from the Dumont-Wilton Center 765 kV line, which demonstrates that power flows west to east from the ComEd system toward the AEP system and into the rest of PJM approximately 70 percent of the time and 30 percent of the time power flows in the reverse direction from east to west. (AEP May 28, 2010 Comments at 25.) Similarly, data on ComEd's yearly actual interchange received and delivered from 2001 to 2004 demonstrates that power flowed east to west approximately 25 percent to 35 percent of the time. (Specifically, actual interchange delivered from ComEd to AEP was 10,522,697 MWh, 9,908,770 MWh, 9,501,823 MWh, and 3,175,304 MWh from 2001 to 2004, respectively. During this time period, the actual

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facilities and changes to, or retirement of, old transmission facilities.[49] However, a "snapshot in time" model does not reflect these changes in power flows, instead looking at the system as it existed at one time prior to the upgrade, and does not provide the information needed to annually calculate the allocation of costs of 500 kV and above lines.[50] Finally, PJM's static DFAX model also fails to recognize and capture the significant reliability benefits that higher voltage lines provide to network users. As PJM explains, "when all costs are allocated to parties impacting the transmission facility based on the distribution factors in power flow analyses, no costs are allocated to others who may benefit from enhanced reliability, reduced losses, or other potential public good or positive externality benefits that may not be quantified in transmission planning studies."[51] On the other hand, as discussed further below, PJM's regional transmission planning process is designed to examine the PJM system as a whole, and this examination may result in high voltage facilities that provide a range of reliability and economic benefits for all users of the networked system; thus as discussed in depth below, we find that the postage stamp allocation methodology is an appropriate basis for allocating the costs of high voltage projects that are in the plan.

39. In general, flow-based modeling methodologies use computer modeling techniques to identify the flows across a proposed new transmission facility under specified conditions. For example, PJM's static DFAX methodology, which it uses to allocate costs of facilities below 500 kV, measures the flows across a particular constrained facility prior to the addition of the reinforcement identified to resolve the

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interchange received from AEP was 4,986,491 MWh, 4,931,662 MWh, 5,006,529 MWh, and 1,090,726 MWh, respectively. See Commonwealth Edison Co., FERC Form No. 714, Annual Electric Control and Planning Area Reports for the Years Ending December 31, 2001-2004, Part II-Schedule 5, Control Area Scheduled and Actual Interchange.)

[49] PJM April 13, 2010 Response at 28-30.

[50] PJM makes an annual filing to adjust the allocation of costs of 500 kV and above transmission facilities to zones based on the zone's previous year's load-ratio share. It is an important feature of the RTEP process to annually review projects included in the regional plan. The cost allocations for the high voltage projects are based on this annual planning review process.

[51] PJM White Paper at 37.

violation.[52] Specifically, PJM calculates distribution factors which measure the effect of the loads of each transmission zone (or the load of a merchant transmission facility) on the transmission constraint being analyzed, and thus provide a measure of the relative contribution of each load to the constraint at a particular point in time.[53]

40. The parties that support the use of PJM's static DFAX model for the allocation of costs of high voltage facilities argue that such a methodology is appropriate because, by measuring the relative contribution of different loads to the constraint, the methodology reasonably identifies the beneficiaries of a project, and thus better matches costs and benefits than a methodology that simply assumes all benefits occur uniformly throughout the system.

41. We find that the static DFAX model used by PJM for lower voltage facilities has sufficient limitations that render it unjust and unreasonable to use it as the sole basis for allocating the costs of high voltage facilities. While the difficulties of using flow-based analyses apply, to some extent, to lower voltage facilities as well, we agree with PJM that these deficiencies have more significant implications for PJM's higher voltage lines. Specifically, the number of violations resolved by 500 kV and above facilities can be substantial (for example, 143 violations were identified as resolved by the Susquehanna-Roseland line), and they are typically spread throughout the fifteen year long-term planning horizon utilized in the RTEP process.[54] In contrast, below 500 kV facilities are typically identified to resolve a small number of violations, or even a single violation, that occurs within PJM's five year near-term planning assessment.[55] Lower voltage facilities therefore generally address fewer and shorter timeframe constraints than higher

[52] PJM does not use the DFAX methodology in its planning process to identify reliability problems or assess the costs and benefits of solutions. Distribution factors are applied to transmission facilities that are identified through the planning analysis to be in violation of reliability criteria. The distribution factor is calculated for the transmission facility prior to the addition of the reinforcement identified to resolve the violation (PJM April 13, 2010 Response at 4). The DFAX methodology does not attach a monetary value to the benefits associated with the resolution of violations by the 345 kV or below lines (PJM April 13, 2010 Response at 6). It is applied after-the-fact to allocate the costs of local 345 kV and below facilities that are in the regional plan.

[53] PJM April 13, 2010 Response at 3-4. Details of the DFAX methodology are also set forth in PJM's Tariff, Schedule 12 § (b)(iii).

[54] PJM April 13, 2010 Response at 7.

[55] *Id.* at 24.

voltage facilities. The static DFAX focus on a single constraint at a single point in time cannot capture the ability of high voltage facilities to relieve multiple constraints over broad areas and long periods of time.

42. We find that, compared to lower voltage facilities in PJM that are more local in their impact and provide smaller and more localized incremental transfer capability, 500 kV and above facilities in PJM provide greater transfer capability (i.e., have the ability to transmit more MW of electricity) over a broader geographic area and are more likely "to make the grid more robust and flexible to adapt to changing needs and drivers."[56] PJM cites the flexibility of 500 kV and above lines to accommodate regional power flows and shifts. The snapshot approach presents a significant limitation when applied to higher voltage facilities in PJM because it cannot reflect the benefits provided by these facilities over their extended life as flows change over time. For instance, PJM's static DFAX model provides no determination of benefits from high voltage transmission facilities when flow patterns change because of changes in daily, seasonal and annual usage, generation construction, or a significant reliability event that distorts the typical flow patterns.

43. Parties supporting the use of a DFAX method for allocating costs of high voltage transmission facilities assert that system conditions will not change much over their lifespan or that cost allocation should be based on what we know now. We disagree. PJM states that modeling assumptions constantly change which can have a significant impact on the planning process.[57] For example, PJM notes that, due to significant changes in the underlying modeling assumptions, the Potomac-Appalachian Transmission Highway (PATH) line, which was originally approved with a required in-service date of 2012, was delayed in the 2007 RTEP until 2013, and it was delayed in the 2008 RTEP until 2014.[58] In the most recent RTEP, the PATH line and the Mid-Atlantic Power Path (MAPP) line have both been placed into abeyance.[59]

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[56] *Id.* at 27.

[57] *Id.* at 30. PJM performs a retool each year to re-examine the previously approved RTEP projects and its experience is that the number and severity of violations driving the need for a project change from year to year. (*Id.* at 6.)

[58] *Id.* at 28-30.

[59] PJM 2011 RTEP, Book 1 at 14-15. Further demonstrating that conditions on the PJM system can and do change, the Commission recently approved transmission rate incentives for the RITELine Project, a 420-mile 765 kV project that will strengthen the transmission system in Illinois, Indiana, and Ohio, conditioned upon the RITELine

(continued…)

44. In fact, the annual reconsideration of assumptions and inputs is a key feature of the RTEP process and as an important test of the robustness of RTEP, PJM conducts various scenario analyses around these assumptions. PJM has significantly expanded its scenario analysis to further consider the aggregate effects of many system trends, including long-term changes in electricity usage, generating plant retirements, broader generation development patterns such as the evolution of renewable resources, and demand-side management and energy efficiency programs.[60] This provides an up-to-date needs-based analysis of transmission solutions. In contrast, as PJM observes, shifting modeling assumptions also highlights the difficulty of locking in a cost allocation based on a one-time DFAX snapshot of conditions which contribute to the original need for a given transmission upgrade.[61] Thus, we find that system conditions do change in ways significant enough to change the RTEP planning assumptions, including the portfolio and timing of projects in the RTEP, and the number and severity of reliability violations that a facility is credited with resolving.

45. Moreover, according to PJM, performing recurring DFAX allocations over a period of years would be virtually impossible as this would require unwinding the transmission grid, line by line, to determine whether the impacts driving the need for a previously approved project had changed. For this reason, PJM explains that the static DFAX methodology will not capture the benefits associated with the robustness of above 500 kV projects with respect to changing system parameters.[62]

Project being included in the PJM RTEP. *See RITELine Illinois, LLC and RITELine Indiana, LLC*, 137 FERC ¶ 61,039 (2011).

[60] PJM 2011 RTEP, Book 1 at 39.

[61] PJM April 13, 2010 Response at 30. PJM's Tariff, as it existed prior to Opinion No. 494, and as it exists today for below 500 kV facilities, provided that allocations were only to be filed upon the project's first approval into the RTEP. (*Id.* at 6.) PJM performed a sensitivity analysis on the DFAX results to compare the cost allocation derived from the original justification for the Susquehanna-Roseland line with the allocations that would result from the RTEP retool analyses for the subsequent two years. The cost allocations shifted each year both in terms of percentage contribution to the overload and the estimated dollars allocated for each responsible utility. (*Id.* at 18-21).

[62] *Id.* at 26-27. PJM further finds that making modifications to the flow-based model to accommodate changes would be administratively burdensome. (PJM White Paper at 18, 37).

46. PJM also explains that the static DFAX methodology does not capture the general benefits associated with a more robust high voltage grid that is less likely to face significant disruptions.[63] PJM assesses its system for compliance with NERC Reliability Standards, including NERC Standard TPL-004, which deals with extreme disturbance events, such as the loss of an entire switching station or load center. Higher voltage facilities may increase the system's ability to withstand such extreme events. However, PJM states that a static, DFAX analysis, would not be applicable to the extreme disturbance events required to be analyzed by TPL-004 because analysis of such events looks for the likelihood of cascading outages or system collapse as opposed to individual system overloads examined by DFAX.[64] The DFAX method cannot account for the reliability protection that high voltage facilities provide, should such events occur. Similarly, we agree with BG&E's assertion that, if a project is not designed to address system overloads, but is solely intended to improve the stability of the system, DFAX will not allocate costs accurately as system stability[65] is not one of the benefits accounted for under the DFAX methodology.[66] As a result, costs will not be allocated to all who would benefit from the facility.

47. We conclude that PJM's static DFAX methodology for allocating the costs of lower voltage localized projects does not capture the regional reach nor accurately identify all the benefits, and beneficiaries, of PJM's planned high voltage system, particularly with respect to transmission facilities that relieve multiple transmission constraints over long distances, multiple zones, and long periods of time. Therefore, consistent with our finding in Opinion No. 494, we conclude based on the record before us here that PJM's static DFAX misaligns the costs and benefits of 500 kV and above transmission facilities to such an extent that it is an unjust and unreasonable basis for allocating the costs of these facilities.[67]

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[63] PJM April 13, 2010 Response at 26-27.

[64] *Id.* at 25-26.

[65] Stability is defined as the ability of an electric system to maintain a state of equilibrium during normal and abnormal system conditions or disturbances. *See* Final Report on the August 14, 2003 blackout (Final Report), Appendix F.

[66] BG&E May 28, 2010 Comments, Affidavit of Charles P. Matassa at 11-20.

[67] Opinion No. 494, 119 FERC ¶ 61,063 at P 52.

B. System-Wide Allocation of Costs for New 500 kV and Above Facilities Is Just and Reasonable

48. Having found significant deficiencies with reliance on PJM's static DFAX model for determining cost allocation for higher voltage facilities and that reliance on such a methodology would result in allocations that are unjust and unreasonable, the Commission under section 206 must establish a just, reasonable, and not unduly discriminatory cost allocation methodology.[68] We recognize there may be several just and reasonable methodologies available, but the Commission need not "choose the best solution, only a reasonable one."[69]

49. As previously noted, the Commission provided all parties with the opportunity to present evidence supporting proposed cost allocation methodologies. While other methodologies suggested by the parties could also be just and reasonable,[70] based on the record before us, we find that a region-wide postage-stamp allocation of the costs of new transmission facilities that operate at and above 500 kV is a just, reasonable and not unduly discriminatory method of allocating the costs of these facilities to those utilities

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[68] *See Maryland PSC v. FERC*, 632 F.3d 1283, 1285 n.1 (D.C. Cir. 2011) ("[w]henever the Commission, after a hearing held upon its own motion or upon complaint, shall find that any rate … [under its jurisdiction] is unjust, unreasonable, unduly discriminatory or preferential, the Commission shall determine the just and reasonable rate . . . to be thereafter observed and in force, and shall fix the same by order." 16 U.S.C. § 824e(a)).

[69] *Petal Gas Storage, L.L.C. v. FERC*, 496 F.3d 695, 703 (D.C. Cir. 2007); *ExxonMobil Oil Corp. v. FERC*, 487 F.3d 945, 955 (D.C. Cir. 2007) (the court need not decide whether the Commission has adopted the best possible policy as long as the agency has acted within the scope of its discretion and reasonably explained its actions).

[70] For example, various hybrid approaches blending the DFAX and postage stamp methodologies were proposed by the Pennsylvania OCA, the Pennsylvania PUC, and VEPCO, but the structure and implementation of such approaches were not adequately addressed in the record of this proceeding. Order No. 1000, among other things, requires public utility transmission providers to include a cost allocation method consistent with the principles of Order No. 1000 in its Tariff. Consistent with the recommendations of the parties that a hybrid approach be further developed, such approaches may be examined within the context of compliance with Order No. 1000, which we think is a more efficient commitment of the Commission and stakeholder resources than further evidentiary hearings in this proceeding.

that use the integrated transmission system and receive the system-wide benefits of these facilities.

1. **Standard Established in *Illinois Commerce Commission***

50. Some parties argue that the expression of the cost causation principle in *Illinois Commerce Commission* departs from the application of the principle by the Commission and other Courts of Appeals.[71] On this point, the Illinois Commission argues that the Seventh Circuit decision requires a more granular application of the cost causation analysis: a utility-by-utility comparison of the benefits with the costs expected to be allocated to each utility over the next 40 to 50 years.[72] These readings of the *Illinois Commerce Commission* decision are not supported by the precedent or directive contained in that decision.

51. We read the Seventh Circuit decision as consistent with the cost causation precedent of other courts.[73] Neither the Seventh Circuit decision, nor the District of Columbia Circuit decisions upon which it relies, require a comparison of costs and

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[71] *See*, *e.g.*, IEU-Ohio Comments at 13-16; FirstEnergy Comments at 5; Illinois Commission Reply Comments at 6.

[72] Illinois Commission Reply Comments at 2-6.

[73] *See*, *e.g.*, *Sacramento Mun. Util Dist. v. FERC*, 616 F.3d 520, 534-35 (D.C. Cir. 2010) (upholding, as consistent with cost causation principles, a *pro rata* allocation of over-collected revenues to all customers in the California ISO based on their electricity usage); *Alcoa Inc. v. FERC*, 564 F.3d 1342, 1346-48 (D.C. Cir. 2009) (finding a nation-wide allocation of costs of the national organization which develops and enforces electric reliability standards meets the cost causation principle); *Pacific Gas & Elec. Co. v. FERC*, 373 F.3d 1315, 1320-21 (D.C. Cir. 2004) (rejecting, as inconsistent with costs causation principles, an allocation of costs commensurate with each utility's benefits as measured by account balances); and *KN Energy, Inc v. FERC,* 968 F.2d 1295, 1301 (D.C. Cir. 1992) (upholding the Commission's allocation of cost to one of three classes of customers that did not cause the problem for which costs would be incurred, but would benefit as a class from the resolution of the problem) (because "all segments of the industry [will] ultimately benefit from their resolution [of the problem,] . . . all segments can rightly be assessed a portion of [those] costs"); *Cal. Dep't of Water Res. v. FERC*, 489 F.3d 1029, 1038 (9th Cir. 2007) (The Commission presumes that "an integrated system is designed to achieve maximum efficiency and reliability at a minimum cost on a system-wide basis [and that] all customers . . . receive the benefits that are inherent in such an integrated system").

benefits for each customer (or party or utility zone) served by a transmission provider, prior to determining allocations.[74] The Seventh Circuit's analysis relies on the discussion of the cost causation principle in *Midwest ISO* and *Western Massachusetts*.[75] In *Midwest ISO*, the court stated that it "evaluate[s] compliance with this unremarkable principle by comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party,"[76] but it did not require the narrow, entity-by-entity analysis of costs and benefits that the remand commentors pursue.[77] Instead, the D.C. Circuit relied on the Commission's analysis of system-wide benefits and agreed with the Commission's premise that all users of the grid operated by Midwest ISO, not only those transmission loads subject to the tariff rates, benefit from the services provided by the Midwest ISO, and should therefore bear a load-ratio share of the Midwest ISO's costs.[78] In citing

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[74] *Accord* Order No. 1000, FERC Stats. & Regs. ¶ 31,323 at P 537 ("under this Final Rule, transmission planning regions are not required to analyze the distribution of benefits on an entity-by-entity basis").

[75] *Illinois Commerce* Commission, 576 F.3d at 477 (citing *Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361 at 1368-1369 (D.C. Cir. 2004) (*Midwest ISO*); *Western Massachusetts Electric Company v. FERC*, 165 F.3d 922 (D.C. Cir. 1999) (*Western Massachusetts*)).

[76] *Midwest ISO*, 373 F.3d at 1369.

[77] "Not surprisingly, we have never required a ratemaking agency to allocate costs with exacting precision." *Id*.

[78] *Id.* at 1370-71. *See Midwest Indep. Transmission Sys. Operator, Inc.*, Opinion No. 453, 97 FERC ¶ 61,033, at 61,169 (2001) ("We agree with the presiding judge that all users of the grid operated by the Midwest ISO will benefit from the Midwest ISO's operational and planning responsibilities for the Midwest ISO transmission system, as well as increased grid reliability of the transmission system."); *Midwest Indep. Transmission Sys. Operator, Inc.*, Initial Decision, 89 FERC ¶ 63,008, at 65,045 (1999) (same).

Western Massachusetts, the Seventh Circuit approved the application of this long-applied premise for transmission upgrade costs in any integrated transmission network.[79]

52. In *Western Massachusetts*, the D.C. Circuit approved the Commission's rationale that "[w]hen a system is integrated, any system enhancements are presumed to benefit the entire system."[80] The D.C. Circuit also approved the Commission's analysis in *Western Massachusetts*, which was not a party-by-party or customer-by-customer analysis. Rather, the analysis examined whether any "other grid customers" besides the qualifying generator "will make use of and benefit from the grid upgrades."[81] The Commission based its cost allocation on findings that one purpose of the upgrade was to "enhance a system used by many customers" and a load flow study prediction that other customers would be able to make use of the upgraded grid facilities.[82] Because this analysis was cited by the Seventh Circuit as an example of the analysis that it sought from the Commission in the orders underlying *Illinois Commerce Commission*,[83] we conclude that the Seventh Circuit does not require a party-by-party or utility-by-utility cost-benefit analysis.

53. Under another view of the *Illinois Commerce Commission* decision, the court requires the Commission to show on remand that benefits for "midwestern utilities," as a group, are "roughly commensurate with those utilities' share of total electric sales in PJM's region."[84] But even this level of granularity, that is, conducting one cost-benefit

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[79] *Illinois Commerce Commission*, 576 F.3d at 477 (citing *Western Massachusetts* for an example of when "[FERC] can presume that new transmission lines benefit the entire network" and what it is required to do in addition to presuming benefits); *see Western Massachusetts*, 165 F.3d at 927 (noting the Commission's "consistent policy to assign the costs of system-wide benefits to all customers on an integrated transmission grid").

[80] *Western Massachusetts*, 165 F.3d at 927 (upholding the roll-in of grid upgrades necessary to integrate power purchased from a PURPA qualifying facility generator).

[81] *Id*.

[82] *Id*.

[83] *Illinois Commerce Commission*, 576 F.3d at 477 (FERC did not avoid the duty of "comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party" in *Western Massachusetts*).

[84] *Id*.

comparison for each sub-regional group in the RTO,[85] does not appear to be required on remand. Because the Seventh Circuit suggests that the Commission follow the analysis used in *Western Massachusetts*,[86] we believe we need only show that some customer zone in the PJM grid other than those zones currently flowing power over the existing facilities in need of upgrades will make use of and benefit from the new high-voltage facilities. But particularly in the RTO setting, we believe that there is no requirement to match costs to benefits on a zone-by-zone basis and such a requirement could excessively restrict the Commission's ability to consider the individual circumstances in, and possible proposals by, the various RTOs and other regions. Instead, the correct cost causation principle is whether the planned 500 kV and above facilities will provide sufficient benefits to the entire PJM region to justify a regional allocation of those costs.

54. Furthermore, requiring an entity-by-entity or a zone-by-zone analysis of costs and benefits would be inconsistent with the regional nature of RTOs. In Order No. 2000, the Commission detailed the benefits independent RTOs could provide, including helping to eliminate the opportunity for undue discrimination by transmission providers and improving transmission grid management efficiencies and reliability.[87] The Commission explained that RTOs would increase efficiency through regional transmission pricing and the elimination of rate pancaking, and provide more efficient planning for transmission and generation investments. These benefits, however, are due to the regional networked nature of RTOs. Requiring PJM to trace the costs and benefits to individual entities or zones would ignore the benefits provided by PJM as an integrated system. It also would undermine the structure and intended purpose of PJM's operation as an RTO to provide increased efficiencies and benefits that are unachievable except through regionally coordinated operation.

55. Although the evidence presented in this record does not permit a monetization or utility-specific quantification of all of the benefits of these facilities, particularly over time, we find that, as discussed below, the system-wide benefits of higher voltage facilities are significant and inure to all members of PJM. Moreover, in this case the

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[85] PJM has three sub-regional planning areas. The "midwestern utilities" are those utilities in the Western PJM Sub-Region. *See supra* n.98.

[86] *Illinois Commerce Commission*, 576 F.3d at 477.

[87] *Regional Transmission Organizations*, Order No. 2000, FERC Stats. & Regs. ¶ 31,089, at 31,024 (1999), *order on reh'g*, Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom. Pub. Util. Dist. No. 1 of Snohomish County, Washington v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

record demonstrates that there are not sufficient engineering standards to directly measure the benefits of 500 kV facilities over their lifetimes, but, as discussed below, the benefits provided by these facilities are sufficiently widely shared across all of PJM to justify the postage stamp methodology as a just and reasonable method for allocating these costs.

2. **The Planned 500 kV and Above Facilities Will Provide Sufficient Benefits to the Entire PJM Region to Justify a Regional Allocation of Those Costs**

56. The parties have not directly quantified an economic value of the benefits of a reliable system, or more particularly, the benefits of the new 500 kV and above projects.[88] This is not remarkable because planning for a reliable transmission system is primarily preventative; that is, the purpose of reliability planning is to prevent degradation of the reliability of a networked transmission system.[89] PJM and its stakeholders look forward five and 15 years into the future to identify potential reliability standards violations and then design solutions that will resolve the conditions that would lead to transmission overloads and blackouts if not timely addressed.[90] Like any piece of

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[88] PJM explains that, on its system, 345 kV and lower transmission assets support local needs and transmission at higher voltages (500 kV and above) is generally used to move large amounts of power over long distances as higher voltages result in reduced power losses over long distances. PJM White Paper at 6, fn. 3.

[89] In other words, reliability planning addresses the fundamental need to keep the lights on. PJM White Paper at 15.

[90] Among the major 500 kV and above projects at issue here are:

500 kV and above projects located in the State of West Virginia in western PJM, as well as in the States of Maryland and Virginia in eastern PJM:

- Trans-Allegheny Interstate Line (TrAIL) project – this is a 500 kV project that was identified in the PJM RTEP 2006 to mitigate overloads of the Pruntytown – Mt. Storm – Doubs 500 kV line, which is in western PJM (PJM 2007 RTEP at 92).

- PATH project – this is a 765 kV project that was identified in the PJM RTEP 2007 to mitigate overloads of five 500 kV lines in the west and eight 500 kV lines in the east (PJM 2007 RTEP at 65).

500 kV and above projects located in the States of Pennsylvania, New Jersey,

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equipment, a transmission network must be maintained and parts upgraded and replaced to keep the whole machine running.

57. No party disputes that new high voltage projects in PJM provide reliability benefits, but parties differ on how to measure such benefits. It is evident from the record that reliability is not a benefit that can be quantified in absolute terms. Rather, the record shows that new high voltage transmission projects in PJM offer a range of reliability benefits to users of the PJM system.

58. PJM states that it allocates all costs associated with transmission facilities at 500 kV and above based on each zone's contribution to non-coincident zonal peak.[91] Further, PJM allocates all costs associated with transmission facilities below 500 kV built for reliability based on the contribution of load at system peak to flows contributing to violations. Those load zones contributing to the violations are considered to be the beneficiaries of the upgrade and are allocated costs based on their DFAX contribution to flows that resulted in the violation. Given the prospective nature of the beneficiary determination, the DFAX cost allocation remains fixed over the life of the upgraded asset.[92] The Commission has found that the DFAX method for allocating costs is appropriate for projects that address limited violations in a localized geographic area, which as PJM indicates are projects operated at voltages of 345 kV and below on its system. Some parties argue that the DFAX methodology should be used to allocate the costs of new 500 kV and above transmission facilities.

59. Solving potential reliability violations is a fundamental aspect of reliability planning. DFAX measures those who are using the line at issue at a point in time and contribute to the conditions that could lead to a violation. This is consistent with the concept of reliability planning as preventive. Nevertheless, the distributed effects of

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Virginia, Maryland, and Delaware in eastern PJM:

- Susquehanna-Roseland project – this is a 500 kV project that was identified in the PJM RTEP 2007 to mitigate overloads of twenty-one 230 kV and two 500 kV lines in the east (PJM 2007 RTEP at 58).

- MAPP project – this is a 500 kV project that was identified in the PJM RTEP 2007 to mitigate overloads of six 230 kV and three 500 kV lines in the east (PJM RTEP 2007 at 70).

[91] PJM White Paper at 31.

[92] *Id.* at 34-35.

resolving a violation with a high voltage facility extend beyond those who were using the facility at a particular point in time before the upgrades. The Commission and reviewing courts have consistently held that there is a presumption that transmission system enhancements benefit all members of an integrated transmission system.[93] As recognized in the *Illinois Commerce Commission* decision, inadequate voltage and thermal overloads can spread through a networked system and have wide area effects if not addressed.[94] Thus, the preventive effect of a high voltage project in PJM extends to those that would be broadly affected by failure to address the potential violations, not just those using the facility at a particular point in time. Further, as the record indicates, power flows at a particular point in time do not present a complete picture of the current daily and seasonal usage of the PJM high voltage system or the flows that are likely in the future.

60. Therefore, the static DFAX method, as used by PJM to allocate transmission costs, does not reflect the distributed network benefits that radiate out from the upgraded facility. When applied to lower voltage facilities, DFAX need not do so because, as PJM has explained, the 345 kV and below projects primarily address localized problems. However, this method does not capture the full spectrum of reliability benefits that high voltage projects bring to the system by resolving multiple problems in multiple areas to move large amounts of power over long distances. Through the RTEP process, PJM and its stakeholders take the networked effects of high voltage facilities into account and select new transmission facilities and expansions that resolve multiple problems in multiple areas comprehensively and cost-effectively.[95] In this way, the reliability benefits of 500 kV and above projects that ensure operation of the system within voltage,

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[93] *See, e.g.*, Opinion No. 453, 97 FERC ¶ 61,033 at 61,169 (as amended), *aff'd sub nom. Midwest ISO*, 373 F.3d at 1369 ("upgrades designed to preserve the grid's reliability constitute system enhancements that are presumed to benefit the entire system"); *Entergy Servs., Inc. v. FERC*, 319 F.3d 536, 534-44 (D.C. Cir. 2003) (*Entergy*) (system upgrades that prevent degradation of reliability benefit all system users; "benefits" are not limited to increases in capacity or to enhancements other than maintained stability in an expanded system); *Western Massachusetts*, 165 F.3d at 927 ("When a system is integrated, any system enhancements are presumed to benefit the entire system.").

[94] *Illinois Commerce Commission*, 576 F.3d at 476; *see also* Final Report at 81.

[95] The PJM Tariff provides that the RTEP shall consolidate the transmission needs of the region into a single plan which is assessed on the bases of maintaining the reliability of the PJM region in an economic and environmentally acceptable manner and in a manner that supports competition in the PJM region. PJM Operating Agreement, Schedule 6, § 1.4(a).

thermal and stability limits and ensure deliverability are available to all users of the networked transmission system.

61. As described below, the record before us shows that the reliability benefits of the new 500 kV and above projects are sufficiently shared by all in the region, including the western zone, to justify regional cost allocation.

a. PJM's RTEP Process Identifies System-wide Needs for New Transmission Facilities

62. PJM refers us to its regional transmission planning process to understand the benefits of transmission expansion and to place cost allocation methodologies in context.[96] From a regional perspective, PJM can identify economical and optimal solutions that consider all reliability criteria violations and congestions constraints to be mitigated by one comprehensive set of expansion plans. Consideration of reliability criteria violations individually (and mutually exclusive of each other) can lead to economically inefficient resolution of those violations. Transmission facilities that operate at 500 kV and above are justified not only to meet local reliability requirements, but regionally to mitigate reliability issues associated with delivering power to more distant load centers.[97] PJM contends that the regional perspective is key to understanding reliability issues and the relationship to location and the type of upgrade required to solve reliability criteria violations. A key feature of PJM's RTEP process, and of cost allocation based upon it, is to annually restudy and consider modifications to the portfolio of projects in the plan as the needs of the region change. Unlike the one-time allocation of costs of lower voltage projects, providing for an annual reallocation of the costs of high voltage facilities pro rata based on load-ratio share will help ensure that, over time, the costs of these projects are allocated to those who are likely to benefit.

63. PJM's RTEP plans for the reliability of the transmission system for the entire PJM region, which includes three interconnected sub-regions. PJM describes its three sub-regions in its 2011 RTEP.[98] PJM views the transmission planning process as essentially

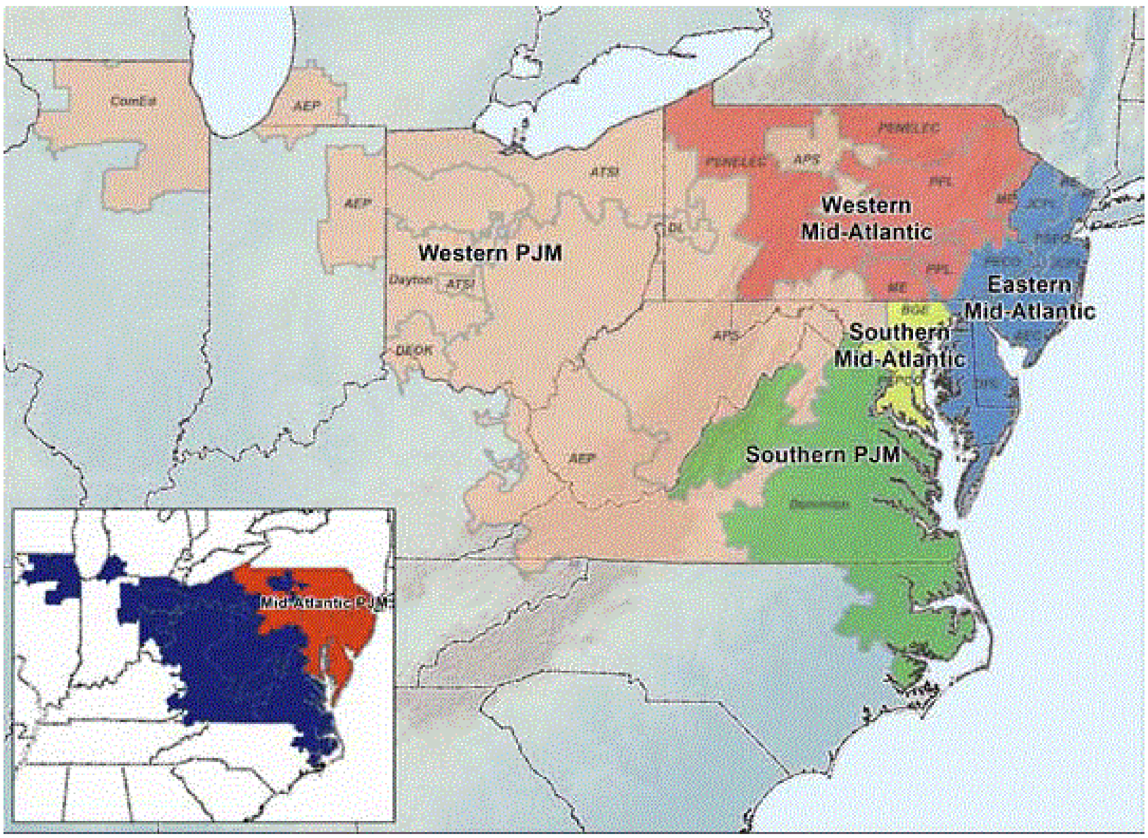
[96] PJM White Paper at 3, 16-17.

[97] PJM 2011 RTEP, Book 5 at 8.

[98] PJM 2011 RTEP , Book 3 at 28: PJM Sub-Regions. The Mid-Atlantic Sub-Region consists of the Atlantic City Electric, BG&E, Delmarva, JCP&L, Metropolitan Edison, Neptune, PECO, Pennsylvania Electric, PEPCO, PPL, PSEG, Rockland Electric, and UGI zones. The Western Sub-Region consists of the Allegheny Power, AEP, ComEd, Dayton, Duke Energy Ohio and Kentucky, Duquesne, and American Transmission Systems, Inc. zones. The Southern Sub-Region consists of the Dominion

(continued…)

identifying the benefits of transmission expansion in terms of maintaining or improving reliability of the region.[99] As noted above, the parties have not directly quantified an economic value of the benefits of a reliable system, or more particularly, the benefits of the new 500 kV and above projects. However, other evidence available to the Commission (which we take official notice of in this order)[100] does provide us a basis to compare the estimated benefits of these facilities in PJM against the costs allocated for them. As discussed further below, as part of the 2011 ISO/RTO Metrics Report, PJM estimates that planning for future reliability needs on a region-wide rather than a utility-by-utility or state-by-state basis results in an estimated $390 million in annual savings.[101]



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zone.

[99] PJM White Paper at 17.

[100] *See supra* P 33.

[101] *See* the six ISOs and RTOs' submittal of the 2011 ISO/RTO Metrics Report, submitted on August 31, 2011 in Docket No. AD10-5-000, at 317-318.

64. PJM defines a transmission system as a collection of physical assets that are *interconnected and operated in a synchronized manner*.[102] Ensuring the reliability of the system drives most new transmission.[103] PJM states that its most fundamental responsibility is to plan and operate a safe and reliable transmission system that serves all long term firm transmission uses on a comparable and not unduly discriminatory basis. Accordingly, PJM conducts transmission planning in order to identify new transmission facilities, enhancements and expansions necessary to address reliability violations across 13 states and the District of Columbia, serving 60 million people, and involving 62,000 miles of transmission facilities, including 9,581 miles operated at or above 500 kV.[104] PJM states that its objective is to plan a networked system that is stable, maintains adequate voltage levels, operates without thermal overloads, delivers power throughout the region and can continue to provide reliable service by accommodating significant disruptions or changes in power flows and other changing system conditions. PJM's RTEP reliability planning is a series of detailed engineering analyses that ensure reliability under the applicable NERC regional, PJM regional and local reliability criteria.[105] PJM uses power flow models which represent the interconnected operations of its system to assess system reliability issues and solutions from a regional perspective. PJM's RTEP studies look 15 years into the future to identify transmission overloads, voltage limitations, and other reliability standard violations.[106]

65. If violations of NERC and other applicable reliability standards are identified, PJM is required to develop and implement solutions to mitigate those violations.[107] Generally, reliability criteria violations identified are (1) reliability criteria violations in a given zone that may be driven by local issues, and (2) reliability violations in two or more zones that may be driven by a combination of system factors in another more

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[102] PJM White Paper at 5 (emphasis added).

[103] *Id.* at 10.

[104] *See* PJM 2011 RTEP, Book 2 at 1; PJM White Paper at 6.

[105] PJM Manual 14B, section 2.3.2.

[106] The RTEP process also includes a five-year, near-term assessment. Five-year planning enables PJM to recommend transmission upgrades to meet forecasted near-term load growth and to ensure the safe and reliable interconnection of new generation and merchant transmission projects. PJM White Paper at 15.

[107] *Id.* at 15.

distant zone.[108] From this assessment, PJM can identify economical and optimal solutions that consider all reliability criteria violations and congestion constraints that could be mitigated by a comprehensive set of transmission plans. For example, detection of violations that occur for multiple deliverability areas or multiple or severe violations clustered in one area of the system may suggest larger projects to collectively address groups of violations.[109] Fair Pricing Group comments that, without a broad network perspective, consideration of reliability violations individually could lead to economically inefficient resolution of those violations, and that transmission facilities operating at higher voltages are able to simultaneously meet both local reliability and regional reliability requirements, such as delivering power to loads throughout the region.[110]

66. When multiple reliability issues exist, PJM examines the effectiveness of alternative transmission facilities, and selects the package of new transmission facilities that resolves all violations that could otherwise lead to overloads and blackouts.[111] In choosing among multiple alternatives, PJM applies its professional engineering judgment in looking at the severity and recurring nature of the violations and the proposed feasible alternatives that could meet the required in-service date.[112] The resulting plans are examined for their feasibility, impact and costs and are discussed throughout the development process with PJM stakeholders.[113]

67. PJM explains that the first step of its transmission planning process is using power flow models to identify potential reliability or deliverability violations that may exist at forecast system peaks and to determine a set of possible transmission solutions that solve

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[108] For example, reactive analysis has emerged as a key transmission expansion driver, and voltage criteria violations, which were alleviated by the MAPP and PATH lines, are identified in 2016 and beyond. PJM 2011 RTEP, Book 1 at 17-18. PJM also notes that while new generation is added, a significant portion of that new generation reflects increases in real power capability, without any corresponding increase in reactive power. PJM 2011 RTEP, Book 4 at 98-101.

[109] PJM Manual 14B, section 2.3.12.

[110] Fair Pricing Group May 28, 2010 Comments, Declaration of Richard A. Wodyka at P 43.

[111] PJM April 13, 2010 Response at 23.

[112] *Id.*

[113] PJM White Paper at 15.

the identified reliability and/or deliverability violations.[114] The RTEP process includes system thermal, voltage, stability[115] and deliverability tests of the system.

68. In RTEP, thermal violations relate to the overheating of transmission facilities – power lines, transformers, etc. If thermal overloads in one area are not mitigated in time, they could result in automatic tripping from overloads on other facilities in other locations. Once several lines trip, the power flows are rerouted to other heavily loaded lines causing depressed voltages and increased currents which may lead to additional lines tripping, as well as system instability across a much larger area.[116]

69. PJM explains in its RTEP that reactive violations relate to failure to maintain adequate voltage levels necessary to reliably support power flows across the transmission system. Significant levels of power transfers cause bus voltages across PJM to decrease. Voltage collapse typically arises following the loss of a transmission line or generator under heavy energy transfers into an area that is experiencing an available generation deficiency. At its most severe, following the loss of a critical line or generator, voltage collapse can occur on heavily loaded systems, leading to a blackout to a portion of the system that can cascade to further instability across a much larger area. On a long term basis, PJM determines that new transmission facilities or enhancements to existing ones become necessary.[117]

70. The August 2003 blackout highlighted the interaction of thermal and voltage reliability criteria within interconnected network operation. The initial trips of the transmission facilities occurred in Ohio because of vegetation contact. While voltage levels were within workable bounds before individual transmission facilities began to overload and trip off, with fewer lines operational, current flowing over the remaining lines increased and voltage decreased, resulting in outages as distant as New York. The U.S. – Canada Power System Outage Task Force's Final Report on the August 23, 2003 Blackout in the U.S. and Canada: Causes and Recommendations (Final Report) concluded that "higher voltage lines and more densely networked lines, such as the 500

[114] *Id.* at 17.

[115] Failure to maintain a stable system may result in forced outages of system elements and interruption in service to customers.

[116] Final Report at 81.

[117] PJM 2011 RTEP, Book 1 at 146.

kV system in PJM and the 765 kV system in AEP, are better able to absorb voltage and current swings" and thus served as a barrier to the spread of the cascade.[118]

71. After PJM identifies efficient solutions to overloads and voltage violations, the next step is to ensure that this reliable power is deliverable to each zone of the region.[119] There must be sufficient transmission network transfer capability to deliver energy wherever and whenever there is a capacity emergency within PJM.[120] PJM determines sufficiency of network transfer capability through a series of deliverability tests consisting of load deliverability and generator deliverability studies.[121] The load deliverability studies are designed to ensure that the transmission system is adequate to deliver each load area's requirements from the aggregate of system generation. The generator deliverability tests are performed to ensure that the transmission system is capable of delivering the aggregate of generators in a given area to the rest of the PJM system.[122]

72. The goal of a PJM load deliverability study is to establish the amount of emergency power that can be reliably transferred to the study area from the remainder of PJM and the areas adjacent to PJM in the event of a generation deficiency within the study area. This transfer limit, the Capacity Emergency Transfer Limit (CETL),[123] in combination with its corresponding Capacity Emergency Transfer Objective (CETO) for the amount of imported capacity assistance needed from the rest of PJM, is then used to

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[118] Final Report at 75.

[119] Deliverability ensures that the transmission system within PJM can be operated within applicable reliability criteria. PJM Manual 14B, section C.1.

[120] As will be discussed in more detail below, the transfer capability and reach of PJM's 500 kV backbone support deliverability to all parts of the system and allow access to energy and reliability benefits.

[121] PJM Manual 14B, section C.1.

[122] *Id.*, section C.6, 2.3.9.

[123] The CETL represents the actual ability of the Transmission System to support deliveries of energy to an electrical area experiencing such a capacity emergency. *Id.*, section C.3, C.4.

determine if the import capability required to meet the reliability objective is sufficient.[124] Transmission facilities are specified by PJM and its stakeholders to achieve the target transfer level as necessary.

73. In PJM's load deliverability test for a particular study area, the "rest of PJM" is modeled to represent the dispatch of the remainder of PJM and surrounding non-PJM areas assuming all generators and transmission facilities in those areas are operating, experiencing only normal levels of unit outages.[125] PJM runs a simulation of power flows following possible generator outages within the study area to test for thermal overloads or inadequate voltage on each of transmission facilities that connect the study area to the rest of PJM, both of which could limit the capability to import power into the study area to serve customers' load during emergencies. In these simulations the RTEP projects expected to be in service in the study timeframe are assumed to be operational and solving the voltage and overload violations which they were designed to address.[126] In this way, the new projects in the RTEP, including the new 500 kV and above projects at issue here, maintain voltage support and prevent overloads in the rest of PJM so that needed transfer capacity will be available to the study area during normal and emergency times.

74. Providing that the CETL for a given area exceeds the CETO for that area, the test is passed and, on a probabilistic level, the area will be able to import sufficient energy during emergencies.[127] Failure of load deliverability tests will result in the initiation of appropriate mitigation actions including enhancement to the transmission system to increase the load area's ability to import power.[128] PJM's CETO/CETL data indicate

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[124] *Id.*, section C.5, 2.0. Currently, eighteen zones and sub-zones have been defined as Locational Deliverability Areas (LDAs) for purposes of deliverability studies. There are also five global study areas which are geographical combinations of zones (e.g., the Western Region study area consists of all load and generation connected to 765 kV and lower facilities in ComEd, ATSI, AEP, Dayton, Duke, Duquesne, and Allegheny Power).

[125] *Id.*, section C.3.

[126] To model this, the RTEP load flow case nearest to the study time period is selected and modified as required (modeling the projected load, generation, and transmission system configuration for the target study period) to serve as the base case. *Id.*, section 4.0.

[127] *Id.*, section C.3.

[128] *Id.*, section C.1.

that, while the western region of PJM generally has sufficient generation as a whole,[129] ComEd and other western zones do require imports from the rest of PJM to avoid loss of load[130] and utilize the 765 kV line in Indiana and Illinois to import power from the east to ensure deliverability.

75. PJM explains that by ensuring sufficient import capability into each area of the region, reliability is a benefit that is enjoyed by load in a constrained location that allows firm load to be served at all times, and enjoyed by others on the system whose risk of cascading failures is significantly reduced.[131] PJM states that the deliverability test ensures comparability of transmission service to all areas within the PJM Region.[132] We conclude that deliverability is the means by which PJM can ensure that the reliability benefits of remaining within thermal and voltage limits are being distributed to each zone in the region. By resolving deliverability problems through the RTEP process, all areas of the PJM region have access to the reliability benefits provided by the new high voltage projects to resolve thermal and voltage issues.

76. In addition to planning for reliability, PJM seeks to identify transmission enhancements that lower costs to consumers by relieving congested lines and allowing lower-cost power to flow to customers.[133] These economic transmission facilities may involve accelerating reliability-based enhancements or expansions already included in the RTEP, modifying reliability-based enhancements or expansions already included in the RTEP, or may take the form of new enhancements or expansions that could relieve one or more economic constraints, but for which no reliability-based need has been identified.[134] In order for an economic upgrade to be included in the RTEP, the relative benefits and

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[129] Although declining CETO/CETL margins have revealed the need for transmission expansion to support west to east transfers. PJM 2011 RTEP, Book 1 at 17.

[130] CETO/CETL data is posted as part of the planning period parameters for each Reliability Pricing Model auction. *See* http://pjm.com/markets-and-operations/rpm/rpm-auction-user-info.aspx#Item01.

[131] PJM White Paper at 10.

[132] PJM Manual 14B, section C.4.

[133] PJM White Paper at 15.

[134] PJM Operating Agreement, Schedule 6 § 1.5.7(b).

costs of the economic-based enhancement or expansion must meet a benefit/cost ratio threshold of at least 1.25:1.[135]

77. In summary, PJM's RTEP process assesses the system as a whole, and plans new transmission facilities that will provide for transmission security and reliability benefits to all PJM members cost-effectively. The studies PJM performs within the RTEP process are designed to provide system-wide benefits of adequate voltage, operations within thermal and stability limits, and the ability to deliver power throughout the system in normal and emergency operating conditions. The system's reliability needs and potential solutions are examined using multiple criteria, and with open and transparent participation by stakeholders. Every year customers' needs are identified, and although different customers may have different needs at different times, all are addressed in a comprehensive, cost-effective plan. Regional solutions are selected to resolve multiple reliability issues across the system and through changing conditions over the ensuing 15 years. This planning process ensures a network that can be reliably and economically used by all customers connected to it. In the judgment of PJM and its stakeholders, the RTEP projects, including the 500 kV and above projects at issue here, are the most effective way to maintain reliability of the system going forward and prepare for future challenges. The postage stamp cost allocation for 500 kV and above facilities flows from the process by which PJM and its stakeholders plan the high voltage system because it accounts for the fact that high voltage facilities address multiple reliability issues across multiple areas and under changing system conditions.

78. As further discussed below, the benefits of a reliable, high voltage transmission system are significant. Specifically, in its ISO/RTO Metrics Report, PJM estimates that planning and operating a reliable transmission system produces as much as $2.2 billion in annual savings for the region.[136] While it is difficult to precisely value a reliable transmission system, the ISO/RTO Metrics Report provides estimates of several categories of savings: $78 to $98 million in annual savings by using redispatch procedures to maintain reliability rather than power sales curtailments; $390 million in annual savings by planning for future reliability needs on a region-wide rather than a utility-by-utility or state-by-state basis; $640 million to $1.2 billion in annual savings from reduced reserve requirements and increased demand response; and $420 million to

[135] PJM Operating Agreement, Schedule 6 § 1.5.7(d). The current RTEP contains primarily new projects for reliability, thus our focus here is on the reliability benefits that those new projects are designed to provide to the PJM system.

[136] *See* the six ISOs and RTOs' submittal of the 2011 ISO/RTO Metrics Report, at 317.

$550 million in annual savings as a result of reduced production costs, operating reserve costs and ancillary services costs.[137] In addition to the benefits identified in the ISO/RTO Metrics Report, the PJM high voltage system allows for annual savings from decreased service interruptions and power quality disturbances, reduced line losses, and reduced congestion.

79. These savings would not be possible but for the high voltage facilities, and the planned new transmission facilities at issue here, that allow the entire PJM system to be interconnected and continue to be operated reliably. All parties benefit from having a reliable and robust system and therefore these estimates are a reasonable measure of the annual benefits of the planned high voltage lines. The system-wide savings mentioned above, although they are an approximate estimate of the benefits of new 500 kV and above facilities, do compare favorably to the estimated $1.3 billion[138] annual cost of the new 500 kV and above facilities designed to maintain the integrity and reliability of the transmission network that provides access to these annual savings. In comparing costs to benefits, we note that the $1.3 billion in estimated annual costs of new 500 kV facilities may be conservative in that it includes two projects (i.e., PATH and MAPP) placed into abeyance by the PJM Board on February 28, 2011 and August 18, 2011, respectively.[139] Illustrating the estimated benefits and costs for the western utilities through examining the effect on ComEd, the westernmost member of PJM, ComEd could receive annual estimated savings of $225 million to $325 million[140] related to the benefits identified in the ISO/RTO Metrics Report, and annual estimated savings of $95 million to $143 million from reduced outages and reduced losses.[141] These total estimated savings of

[137] *See Id.* at 317-318.

[138] The $1.3 billion figure is equal to the total estimated costs of new 500 kV and above facilities (approximately $6.6 billion) times PJM's annual carrying charge rate of 19.1 percent. *See* Fair Pricing Group April 13, 2010 Comments, Declaration of Richard A. Wodyka at 63 for explanation of the carrying charge.

[139] PJM 2011 RTEP, Book 1 at 14-15.

[140] Determined by taking ComEd's load-ratio share of the system-wide savings. At 14.7 percent, ComEd has the second highest load on the PJM system. AEP has the highest load (15.2 percent) and Dominion is third at 12.4 percent. The remaining members of PJM have loads of 9 percent or less. The current load-ratio shares are stated in the PJM Tariff, Schedule 12 – Appendix.

[141] *See infra* PP 97 and 109.

$320 million to $468 million exceed the annual cost allocation of $198 million[142] to ComEd under the postage stamp allocation.

b. PJM Has Demonstrated the Economic and Engineering Basis to Attribute System-wide Reliability Benefits Delivered by 500 kV and Above Transmission Facilities.

80. In examining the Commission's justification for allocating the costs of 500 kV and above facilities, the court also questioned whether the Commission had a reasonable basis for determining that high voltage lines should begin at 500 kV and be allocated differently than 345 kV lines:

> [The Commission] did not compare the reliability of a 500 kV line to that of a 345 kV line, even though network reliability is the benefit the Commission thinks the Midwestern utilities will obtain from new 500 kV lines in the East.[143]

As explained below, we find there are reasonable engineering and economic bases for distinguishing the system-wide reliability benefits provided by the high voltage projects at and above 500 kV from lower voltage facilities.

81. As illustrated in the 2011 RTEP, 500 kV and above facilities allow the western zones to be fully integrated into the PJM system, enabling these zones to share the benefits provided by a robust and flexible grid.[144] As demonstrated by the map below, 500 kV and above voltage facilities connect the western zones to the rest of the PJM system, allowing power to flow either west-to-east or east-to-west.

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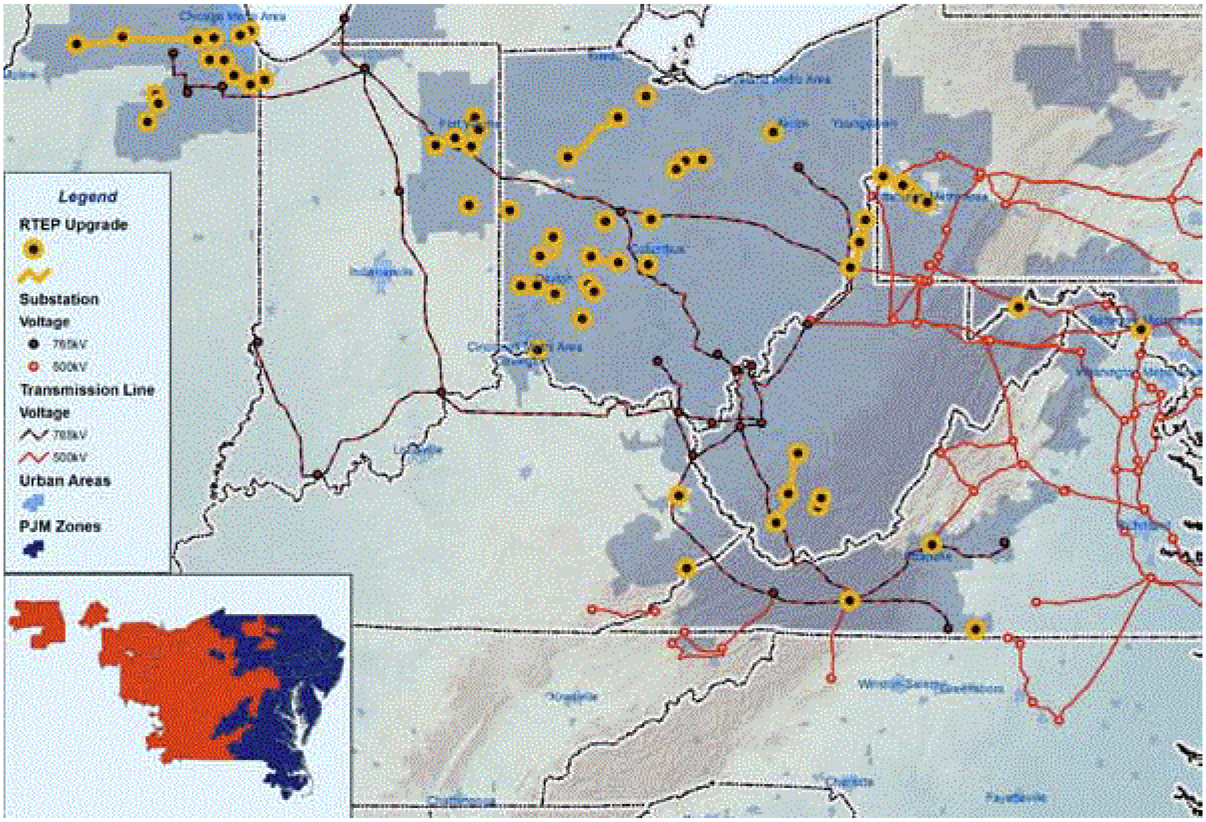
[142] The $198.21 million figure is equal to ComEd's total allocation under the postage stamp methodology ($1,037.76 million) times PJM's annual carrying charge rate of 19.1 percent. While PJM estimated that ComEd's total allocation would be $1,037.76 million in its April 13, 2010 response, this total will vary over time as ComEd's load-ratio share changes. For example, using ComEd's 2011 load-ratio share of 14.7 percent would lower its annual cost allocation to approximately $187 million.

[143] *Illinois Commerce Commission*, 576 F.3d at 477.

[144] PJM 2011 RTEP, Book 3 at 37, Map 3.13: PJM Western Sub-Region Transmission Upgrades.



82. PJM's regionally-integrated transmission network provides benefits to all that are interconnected to it by creating a highly reliable system that provides access to the annual system-wide savings previously discussed. For example, because PJM's high voltage transmission system is robust and the region is large and diverse, PJM is able to absorb unexpected changes in frequency that occur from time to time that would otherwise pose serious reliability risks.[145] As discussed previously, PJM plans its system to support voltage levels in all parts of the region in order to avoid voltage collapse and thermal overloads anywhere in the region.[146]

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[145] Fair Pricing Group May 28, 2010 Comments, Declaration of Esam A. F. Khadr at P 83.

[146] While opposing parties assert that the new 500 kV and above facilities are intended to address reliability problems in the east, western PJM has been experiencing more potential reliability problems in recent years. PJM provides a comprehensive list of emergency events over the past several years at https://emergproc.pjm.com/ep/guest_login.htm. Moreover, as noted above, while flows within PJM have predominantly been west to east, the direction of flows does change on a regular basis and may change during peak load periods in the future.

83. PJM explains that higher voltage transmission facilities will generally provide a broader range of reliability and market efficiency benefits than lower voltage transmission facilities, although no specific studies are available on this subject other than the past RTEP analyses. According to PJM, the scope of the violations addressed by projects such as the TrAIL and Susquehanna – Roseland lines are clearly broader than the scope of violations resolved by the many 230 kV transmission projects included in the PJM RTEP over the last ten years.[147] Projects at 500 kV and above are also less costly than 345 kV projects on a gigawatt-per-mile basis. Based on a review of projects under development in the U.S., the costs of 500 kV ($1.45 million/GW-mile) and 765 kV ($1.32 million/GW-mile) are lower on a per unit basis than costs of 345 kV transmission lines ($2.85 million/GW-mile).[148]

84. Higher voltage facilities may also be the "economical and 'optimal' solutions that resolve reliability criteria violations and congestion constraints with one comprehensive set of expansion plans."[149] As previously discussed, while lower voltage facilities are used by PJM planners to be more local in their impact, PJM explains that the RTEP process identifies higher voltage facilities to address multiple violations across many zones. PJM also explains that it plans for such new transmission facilities by looking at the system over longer time frames, taking into account a variety of system factors. Because of their ability to dramatically unload lower voltage facilities across a wide area, high-voltage lines are capable of solving multiple deliverability violations, allowing PJM to reliably balance demand and supply at the lowest possible cost.

85. While all transmission lines provide general reliability benefits and economic efficiency to the grid, in addition to resolving specific reliability criteria violations, PJM concludes based on its operational experience and engineering analyses that "500 kV and above lines provide these benefits to a greater degree than below 500 kV lines."[150] As noted by the Fair Pricing Group, if PJM were to plan for higher voltage facilities by dividing PJM into sub-regions and studying the sub-regions' reliability problems and reliability solutions, the transmission projects that would emerge as solutions would differ from what is produced by the application of the reliability planning process across

[147] PJM April 13, 2010 Response at 26.

[148] PJM White Paper at 9 (*citing* Brattle Group, Transforming America's Power Industry: The Investment Challenge for 2010-2030 at 35, *available at* http://www.brattle.com/documents/UploadLibrary/Upload725.pdf).

[149] PJM 2011 RTEP, Book 2 at 7.

[150] PJM April 13, 2010 Response at 27.

the larger regional footprint. The results of such sub-regional planning would produce smaller more localized transmission solutions for each sub-region as the planning process would be examining a smaller footprint to examine the problems and solutions.[151] Moreover, the Fair Pricing Group states that relying on one high voltage facility to resolve 100 violations expected over a 10-year period is much more efficient (and cost-effective) than annually proposing multiple low voltage facilities to resolve those violations one by one as they arise over the same 10-year period.[152]

86. PJM also explains that generally, higher voltage facilities are more likely than lower voltage facilities to make the grid more robust and flexible to adapt to changing needs and drivers. This is due to the fact that lower voltage facilities in PJM are typically more local in their impact and provide smaller and more localized incremental transfer capability. According to PJM's experience, 500 kV and above transmission facilities can make the transmission system sufficiently robust to accommodate and provide for major shifts in the resource mix within the region and to respond to significant disruptions. Such disruptions can impact wide-spread areas, ranging far beyond the geographical location of an initiating event.[153] Indeed, the record indicates that the PJM region is not static, but that changing needs are anticipated.

87. To date, the majority of 500 kV and above facilities approved through RTEP were intended to address reliability violations in the East, which parties opposing the postage stamp methodology argue is a signal that eastern zones will disproportionately benefit from such projects. However, as discussed above, all parties benefit from an integrated system that ensures deliverability to all areas of the region. Further, as discussed above, we note that certain major 500 kV and above projects were approved to be located in western PJM, and to address reliability violations in western PJM.[154] High voltage facilities can accommodate changes to the PJM transmission system over time and may serve very different purposes daily, seasonally and over their lives, which may be 40 years or more.

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[151] Fair Pricing Group May 28, 2010 Comments, Declaration of Esam A. F. Khadr at P 79.

[152] Fair Pricing Group May 28, 2010 Comments at 3.

[153] PJM April 13, 2010 Response at 26-27.

[154] Specifically, the TrAIL and PATH projects are both located in the State of West Virginia in western PJM, as well as the States of Maryland and Virginia in eastern PJM.

88. Even though power flows in PJM today are largely west to east, power does flow in the reverse direction, into the western region, approximately 25 to 35 percent of the time. As noted above, this is illustrated by data on ComEd's yearly actual interchange received and delivered from 2001 to 2004. Likewise, AEP cites 2006 hourly flow data from the Dumont-Wilton Center 765 kV line, a major electrical connection between eastern and western PJM, which demonstrates that power flows east to west approximately 30 percent of the time.[155] Further, exactly where new resources will be constructed is unknown and so current power flow patterns may not reveal the power that various utilities ultimately would receive from such resources. A simulation conducted by PJM showed that the MAPP 500 kV project, while originally intended to solve reliability criteria violations associated with delivering energy into eastern PJM from western resources, also has the ability to transmit power from off-shore Atlantic Ocean wind west into the PJM system.[156]

89. Moreover, the construction of high voltage transmission lines in PJM will permit accommodation for future changes in resource mix. The PJM RTEP indicates that, as of January 31, 2012, nearly 9,500 MW of new generating resources are presently under construction, with over 64,000 MW currently active in PJM's interconnection process.[157] As of January 31, 2012, transmission interconnection requests have been submitted for nearly 40,000 MW of wind generation (nameplate capacity).[158] Many of the queued transmission requests for wind generation are in the western part of PJM, with 14,505 MW in Illinois, 7,762 MW in Indiana, 7,975 MW in Ohio, and 5,200 MW in Michigan and South Dakota.[159] NERC estimates that in the ReliabilityFirst Corporation region (which comprises most of PJM and part of the Midwest Independent System Operator) there will be more than 45,700 MW of wind generation by 2018.[160] PJM explains that it is well understood that a number of 500 kV and above lines will be required to integrate

[155] *See supra* section VI.A.2.

[156] PJM 2010 RTEP at 84.

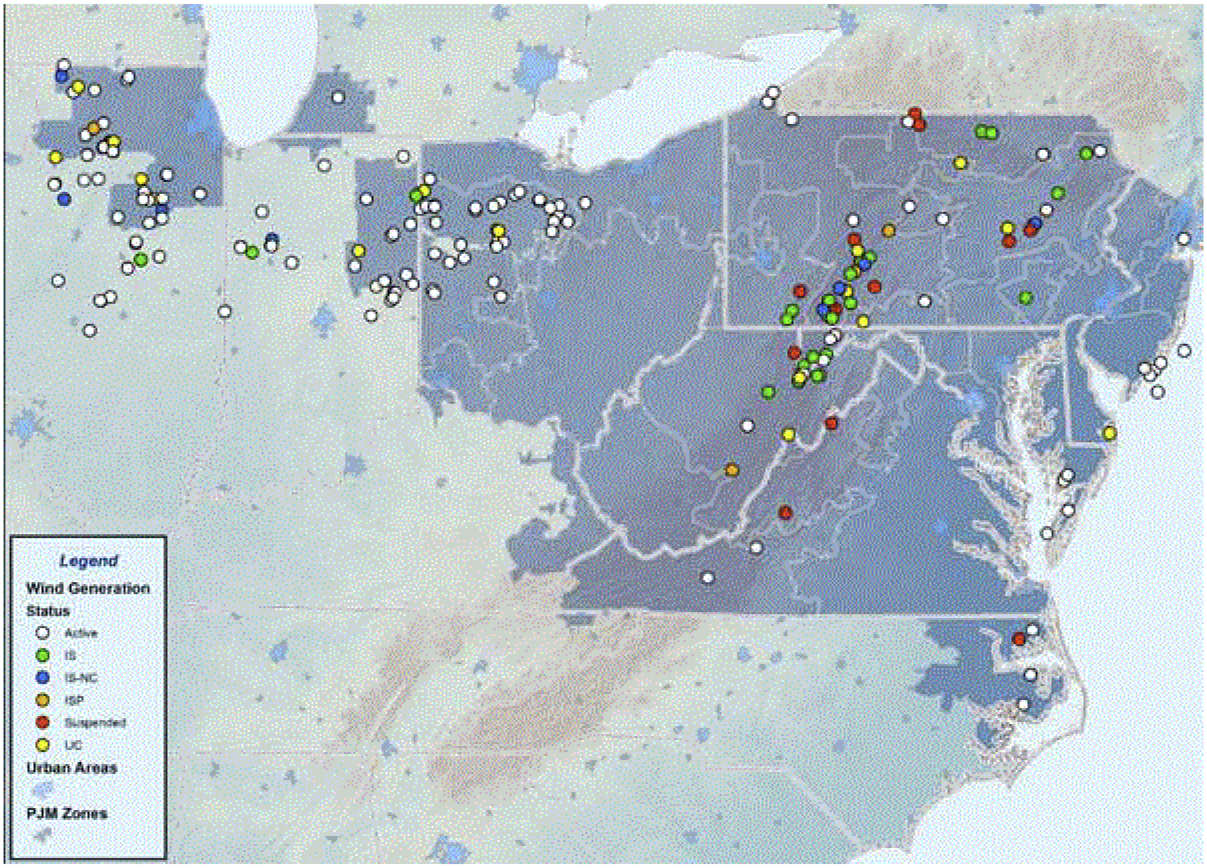
[157] PJM 2011 RTEP, Book 2 at 25.

[158] *Id.* at 31.

[159] *Id.* at 35.

[160] PJM White Paper at 10.

large amounts of renewable generation resources into the grid.[161] PJM provides an illustration of the major clusters of wind-powered generation interconnection requests.[162]



90. As detailed in PJM's 2011 RTEP, PJM has under active review 16,023 MW of new generating resources proposed in northern Illinois, approximately twice the queued interconnection requests active in 2006.[163] While not yet fully evaluated, PJM states that it will require significant new transmission capability not only to deliver this energy to

[161] PJM April 13, 2010 Response at 27-28.

[162] PJM 2011 RTEP, Book 2 at 34: Wind-Powered Generation Interconnection Request Clusters.

[163] *Id.* at 85, PJM 2006 RTEP at 195.

northern Illinois, but also to address the network facilities within ComEd and eastern regions of the PJM footprint needed to ensure deliverability of these new resources.[164]

91. PJM notes that wind generator interconnection requests have clustered in remote areas, suitable to their operating characteristics and economics, but with a less than robust transmission system, and constitute a significant driver of transmission expansion needs.[165] PJM recognizes that the integration of renewable generation is driven by a variety of factors, and in response to the uncertainty surrounding these considerations, has proposed to include scenario studies.[166] As an example, in the 2011 RTEP, PJM has provided a renewable integration study that includes two end-state wind generation scenarios under both peak and light load conditions. This information indicates that, depending on the balance of these resources, additional transmission in western PJM may be required to accommodate the higher concentration of on-shore resources,[167] or more transmission in eastern PJM may be required to support the greater penetration of off-shore resources.[168] Additionally, Mid-Atlantic Entities state that maintaining and enhancing high voltage transmission facilities under a sound regional plan will be necessary to achieve applicable renewable portfolio standard objectives.[169]

92. As previously noted, the Final Report on the August 2003 blackout concluded that higher voltage lines and more densely networked lines, such as the 500 kV system in PJM and the 765 kV system in AEP, are better able to absorb voltage and current swings and thus serve as a barrier to the spread of a cascading outage. The costs of failing to provide for such security can be significant. The August 2003 blackout is an example of a low-probability, but high-impact event and highlights the broad geographic impacts associated with interconnected network operation. The causes of such interruptions are often unpredictable and unrelated to the types of analyses included in PJM's DFAX studies. The Final Report estimates that the costs associated with the August 2003

[164] PJM 2010 RTEP at 272.

[165] PJM 2011 RTEP, Book 1 at 43.

[166] *See* Docket No. ER12-1178-000.

[167] The PJM 2011 RTEP identifies significant 765 kV construction in western PJM to interconnect these resources under this scenario.

[168] PJM has not proposed any specific projects based on these scenarios, and indicates that further analysis is required.

[169] Mid-Atlantic Entities May 28, 2010 Comments at 20.

blackout range from $4 to $10 billion.[170] We understand that such events occur infrequently, but given the magnitude of such costs, the unpredictable timing and location of power outages, and our previous finding that events in an area of PJM can affect all areas to some extent, the costs sustained during an outage could be significant for zones affected.

93. Based on its experience, PJM explains that transmission lines 500 kV and above provide these reliability benefits to a greater degree than below 500 kV lines and certainly provide those benefits to areas producing energy as well as to areas requiring energy.[171] Indeed, when ComEd joined PJM, it relied on the reliability benefits provided by a strong transmission infrastructure as justifications for belonging to PJM. Specifically, ComEd stated:

> ComEd sought membership in PJM first of all because of the reliability benefits that membership would bring. ComEd's strongest transmission interconnections are with PJM through AEP, and the most likely source from which ComEd could import energy to prevent loss of load during system emergencies is PJM.[172]

94. High voltage transmission lines not only benefit those that import power. These projects provide benefits to the exporting area as well. For example, greater transmission capacity facilitates the development and construction of additional generation capacity, leading to increased capacity and diversity of generation. Accordingly, access to markets at lowered delivered cost provides significant benefits to the exporting utility and area.[173] And, as previously discussed, PJM members do flow power in both directions on the high voltage system in support of their market transactions.

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[170] Final Report at 1.

[171] PJM April 13, 2010 Response at 27.

[172] Exelon Corp., *et al.*, March 17, 2003 Motion for Expedited Decision, Docket No. ER03-262-000 at 22-23.

[173] ComEd recognized these benefits as well in seeking membership in PJM: "ComEd sought membership in PJM because PJM is the natural market for generators connected to the ComEd system and has historically been the most important sink for exports from the ComEd area. PJM has the most developed market structure in the United States and generators connected to the ComEd system could thus obtain access to a developed market most quickly and easily by joining PJM." *Id*.

95. ComEd too recognizes the wide distribution of benefits associated with new, regionally-planned, high voltage transmission facilities:

> Because renewable resources like wind generation tend to be located in remote areas and are not evenly distributed throughout the country, it would be unfair to burden just the customers in those locations with the costs of transmitting these nationally important resources to the grid. This national priority calls for a new approach to planning and funding. Just as the nation has answered the call in the past for broadly based investment in infrastructure with broad benefits to the citizenry as a whole, we believe the Commission should approach investment in new transmission infrastructure in a similar broadly-based way.[174]

96. Parties opposed to the postage-stamp methodology assert that the ability of eastern zones to import low cost power from the west may harm western customers as LMPs converge. Specifically, they allege prices will fall in areas that lower-cost generators formerly could not serve because of congestion, while prices may rise near generators that previously could not export energy to other portions of this region. However, the relative prices between the resources in the eastern and western zones may change as the direction of power flows change (for example, on a daily basis due to the comparative price advantage of generators in some areas versus others or to changes in the generation fleet seasonally or over time), and PJM's static DFAX model (which these commenters support) cannot capture such indeterminate potential changes. Moreover, converging prices signal that the grid is reliable and robust enough to support energy flows in any direction and that the benefits will accrue to the market as a whole.[175]

97. In sum, the record indicates that 500 kV and above transmission facilities provide advantages in moving large amounts of power to multiple zones of the region, addressing multiple reliability violations over wide areas, readily accommodating changing power flows (daily, seasonal and in emergencies) and needs of the region and in protecting all parts of the region from significant disruptions. While reliability is admittedly a difficult benefit to quantify, the evidence before us illustrates that this is a valuable benefit that is enjoyed by all customers interconnected to the networked PJM system.[176] The 500 kV

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[174] Exelon Remarks, Docket No. AD09-8-000, at 3 (Sept. 21, 2009). *See* http://www.exeloncorp.com/performance/policypositions/overview.aspx#section_3

[175] *PJM Interconnection, L.L.C.*, 123 FERC ¶ 61,051, at P 64 (2008).

[176] *See Gainesville Utilities Department v. Florida Power Corp.*, 402 U.S. 515, 527 (1971) ("Among the specific benefits the Commission found would accrue to Florida

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RTEP projects at issue here, while not all are located proximate to all PJM utilities, have been selected by the PJM planning process as the most effective way to resolve looming reliability violations that, left unaddressed, would jeopardize the reliability of the entire integrated system. But for the planned 500 kV facilities, the PJM system could become unable to provide reliable transmission service. Thus, it is plausible to reason that the transmission facilities that directly address such region-wide reliability concerns are reasonably allocated on a *pro rata* basis among all the PJM customers. As discussed previously, the ISO/RTO Metrics Report estimates that maintaining the reliability of the PJM transmission system provides up to $2.2 billion of annual savings system-wide. These savings would not be possible but for the high voltage facilities that allow the entire PJM system to be interconnected and operated reliably. Using ComEd, the westernmost member of PJM, to illustrate the extent of these benefits to western utilities, ComEd would receive estimated annual reliability benefits of $225 million to $325 million.

98. The record and other documents provide further evidence of the incremental value of some of the network reliability benefits provided by a 500 kV and above facility versus lower voltage projects: in particular, reduced congestion, reduced outages, reduced operating reserve requirements,[177] and reduced losses.

99. PJM explains that transmission expansion driven by reliability will also likely reduce congestion costs for transmission users.[178] PJM's 2008 RTEP indicates that, if proposed "backbone" projects had been in place for 2008, congestion savings would have been nearly $2 billion, and for 2011, the proposed backbone projects were expected to produce congestion savings of $1.25 billion relative to simulated congestion absent the backbone reliability facilities.[179] Similar savings are attributed to the large high voltage projects in the 2009 and 2010 RTEPs.[180] Although PJM notes that reductions in

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Power were increased reliability of Florida Power's service to customers in the Gainesville area, the availability of 60 to 100 mw of reserve capacity during certain periods of the year, and savings from coordinated planning to achieve use at all times of the most efficient generating equipment in both systems").

[177] An operating reserve is an amount of capacity above the utility's peak load that it must maintain in order to satisfy reliability requirements.

[178] PJM White Paper at 12.

[179] *Id.*; citing PJM 2008 RTEP at 135-136.

[180] PJM 2009 RTEP at 155-156 and PJM 2010 RTEP at 244.

congestion do not benefit all market participants equally,[181] this reduction in congestion is a significant annual system-wide benefit to customers in the PJM footprint from the large long-distance high voltage reliability projects. Further, although congestion may affect customers differently based on their location relative to constraints, as a general matter congestion increases the loading on lines and can lead to overloads and voltage drops that can affect all customers in the interconnected network.

100. The U.S.-Canada Power System Outage Task Force in its report on the 2003 Blackout stated that reliability may be measured by the frequency, duration and magnitude of adverse effects on the electricity supply.[182] As noted by AEP, outage statistics show that 765 kV circuits, on average, experience significantly fewer forced outages than their 345 kV counterparts.[183] The North American Electric Reliability Corp. (NERC) reports that 500 kV facilities operating in North America in 2009 had sustained outage frequency per 100 circuit miles per year of .4381, compared to 0.6938 for 345 kV facilities.[184] This indicates that 500 kV lines suffer 36.8 percent fewer sustained outages than 345 kV lines. NERC further reports that the duration of outages on 500 kV facilities is significantly lower than outages on 345 kV facilities, the mean outage duration for 345 kV facilities is 50.2 hours, almost twice that of 500 kV facilities (28.1 hours).[185] The NERC report is consistent with long-term data collected by the Mid-Continent Area Power Pool, who has tracked transmission outage data by voltage since 1991. Mid-Continent Area Power Pool statistics show that, from 1991-2000, 500 kV lines had a failure rate per 100 circuit miles per year of 0.85, compared to 2.15 for 345 kV lines. Similarly, the average duration of a 500 kV outage was 3.85 hours, compared to 52.45 hours for 345 kV. These results from multiple sources demonstrate that 500 kV facilities are consistently less likely to experience a forced outage, and require less time to restore service.[186] It is estimated that the benefits that would accrue to the PJM region as a result of decreased service interruptions and power quality disturbances could be as much as

[181] PJM White Paper at 12.

[182] Final Report at 23.

[183] AEP May 28, 2010 Comments at 6.

[184] 2009 NERC Transmission Availability Data System Report (2009 NERC TADS Report) June 14, 2010 at 16.

[185] *Id.*

[186] *Available at* www.ee.iastate.edu/~jdm/ee653/ChowdhuryPMAPSData.doc.

$53 million per year.[187] Assuming that all load in PJM benefits equally from decreased service interruptions and power quality disturbances, ComEd's share of this benefit would be $7,791,000 annually[188] When combined with ComEd's share of the savings of $11 million to $14 million ($78 million to $98 million system-wide savings[189] times ComEd's 14.7 percent load-ratio share) from avoiding the need to curtail transactions, the estimated savings to ComEd customers of the lower number of transmission outages experienced by 500 kV and above facilities ranges from $19 million to $22 million annually.

101. Transmission lines can reduce reserve margins by enabling utilities to share resources. Without a reliable interconnected transmission system, the individual companies would be required to provide reserves separately. In reality, the individual member companies share the overall PJM requirement, and can depend on each other's resources, thereby significantly reducing their costs. The extent to which the members can share reserves is a direct function of the capability of the transmission system to transfer and deliver power throughout the region.[190]

102. For example, if ComEd, which is located on the western edge of PJM, operated as a stand-alone entity, it would have an operating reserve requirement to meet contingency conditions of 1,175 MW.[191] Therefore, it would have to procure or construct all 1,175

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[187] Estimated Value of Lost Load (VOLL), forced outage rates, loss of load events, and power quality disturbance events were compiled from the 2009 NERC TADS Report for the RFC region, 2009 NERC System Disturbance Reports, EIA Form 861, FERC Form 1, and the 2009 Lawrence Berkeley National Lab report "Estimated Value of Service Reliability for Electric Utility Customers in the United States."

[188] Based on ComEd's 14.7 percent load-ratio share.

[189] *See* the six ISOs and RTOs' submittal of the 2011 ISO/RTO Metrics Report, at 317-318.

[190] While our focus here is on operating reserves, we note that high voltage lines can also support the planning reserve margin. For example, as noted by Mid-Atlantic Entities, as new companies were integrated into PJM, the robust high voltage interconnections allowed for expanded reserve sharing over significant distances. This enhancement of reserve sharing enabled PJM to reduce the installed capacity reserve margin by approximately 2,000 MW. Mid-Atlantic Entities May 28, 2010 Comments at 18.

[191] ComEd notes that the largest unit in its control area is approximately 1,175 MW. Reply Comments, Affidavit of Steven Naumann at 40.

MWs from its own resources, and its customers would have to compensate ComEd for those resources. However, with PJM's robust high voltage transmission grid, ComEd can reduce its overall cost of maintaining adequate reserves. PJM's contingency operating reserve requirement for western PJM is 150 percent of the largest unit,[192] or 1,950 MW.[193] By being connected to PJM via its robust high-voltage transmission grid, ComEd pays only its *pro rata* share of the total reserve requirement for western PJM, which is approximately 30 percent of the 1,950 MW western PJM zone reserve requirement, or 585 MW,[194] rather than having to support its individual 1,175 MW operating reserve requirement on its own.

103. The evidence shows 500 kV and above transmission lines have greater transfer capability than 345 kV lines.[195] For instance, a transmission facility operating at 500 kV has approximately twice the power transfer capability of a transmission facility operating at 345 kV. The transfer capability of transmission facilities operating at 765 kV is even greater; roughly six single-circuit (or three double-circuit) 345 kV lines are required to achieve the load carrying ability of a single 765 kV line. AEP states that a basic engineering measure to assess transmission benefits is the electrical distance or "reach" of transmission facilities, which is essentially the distance that energy can be delivered without overstressing the system. AEP states that 500 kV transmission facilities can deliver 1,200 MW four times the distance of transmission facilities operating at 345 kV. AEP provides the following graph to illustrate how far (in miles) a 345 kV line, a 500 kV line, and a 765 kV line can transfer 1200 MW.[196]

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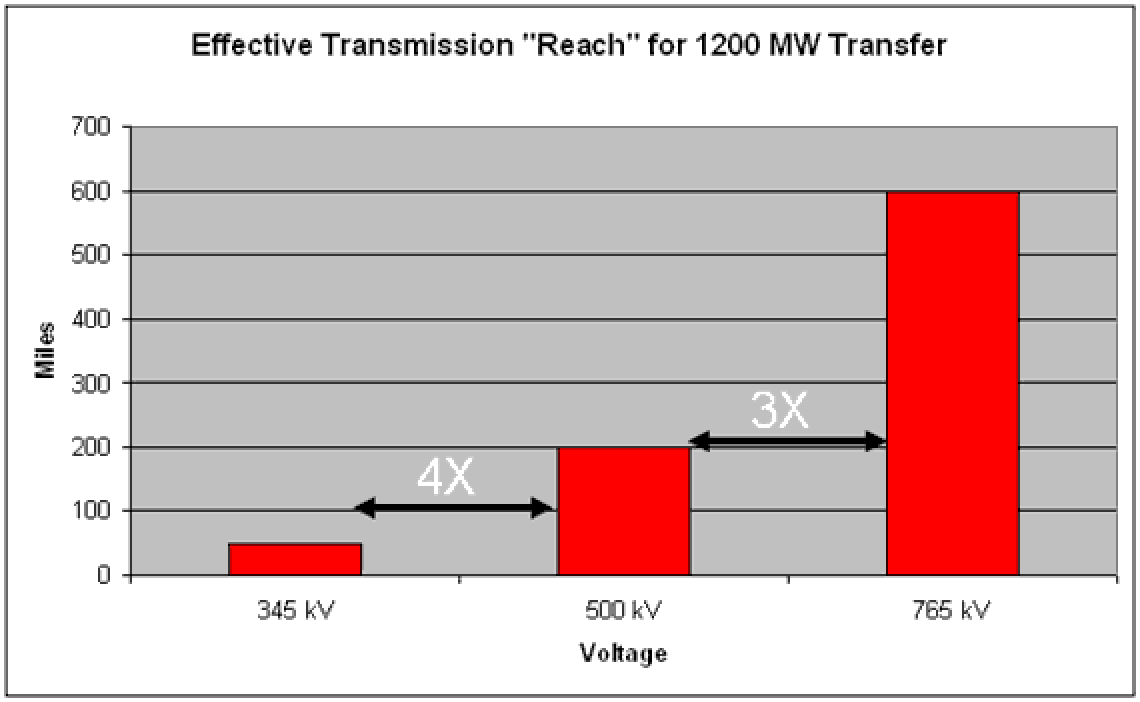
[192] *See* PJM Manual 13 (Emergency Operations) § 2.2 (Reserve Requirements).

[193] As noted by the Fair Pricing Group, the largest unit in AEP is approximately 1,300 MW. May 28, 2010 Comments, Declaration of Esam A. F. Khadr at P 82.

[194] 585 MW represents an estimate of ComEd's pro rata share of the total reserve requirement for western PJM, based on the current load-ratio shares stated in the PJM Tariff, Schedule 12-Appendix. With the addition of Duke in PJM, ComEd's *pro rata* share of the reserve requirement would be even lower.

[195] Fair Pricing Group May 28, 2010 Comments at 21.

[196] AEP May 28, 2010 Comments at 18.



104. The greater reach of 500 kV and above voltage transmission facilities displaces the need for a larger number of lower voltage facilities that would otherwise be constructed. Importantly for reliability, for every mile of wire installed, the greater reach of higher voltage facilities provide access to more and geographically wider sources of energy to prevent loss of load during local emergencies.[197] The transmission facilities that operate at 500 kV and above provide for greater deliverability into a zone and ability to share reserves than would lower voltage facilities. PJM estimates that customers save between $366 million and $900 million annually by avoiding investment to meet higher levels of planning reserves that would be required, but for the 500 kV facilities that support the reserve sharing.[198] Further, PJM estimates savings in grid services necessary for reliability (i.e., ancillary services) of between $80 million and $105 million on an annual basis, with annual production cost savings estimated at between $340 million and

[197] In a postage stamp cost allocation methodology, transmission costs are allocated as a function of peak usage and/or generation. This methodology reinforces the incentive that would exist in the energy market to reduce peak energy costs and in the capacity market to reduce capacity costs.

[198] Additionally, the commitment of demand response resources to reduce load during system peaks forestalls the cost of building additional generating facilities. PJM estimates these savings at $275 million annually.

$445 million associated with the centralized dispatch for the region.[199] Assuming ComEd's share of this benefit is equal to its load-ratio share, it receives benefits in the form of reduced ancillary services purchases and production cost savings of $62 million to $81 million annually through participation in PJM's high voltage network. In addition, ComEd's share of the annual savings from reduced planning reserve requirements (generation and demand resources) are $94 million to $176 million per year, made possible by the increased transfer level of transmission facilities that operate at or above 500 kV.[200]

105. Savings related to a reduction in reserve requirements are only available to ComEd because of PJM's interconnected high voltage transmission system and the associated deliverability to load, and thus can be considered a direct benefit of that system.[201] While we recognize that the ability to share reserves is not solely dependent on high voltage lines, large capacity pathways are important in carrying power across the region and provide access to the benefits associated with reserve sharing. As an example, when ComEd initially joined PJM, it could do so only because it had a 500 MW pathway connecting its territory to PJM.[202]

106. In addition, the planned high voltage lines provide benefits to all members of PJM by reducing the energy losses of transmission. PJM explains that the movement of electricity over distances results in losses. "For a given flow of power, transmission

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[199] *See* the six ISOs and RTOs' submittal of the 2011 ISO/RTO Metrics Report, submitted on August 31, 2011 in Docket No. AD10-5-000, at 317-318.

[200] $640 million to $1.2 billion in savings from a decreased need for infrastructure investment times ComEd's load-ratio share of 14.7 percent. *See* the six ISOs and RTOs' submittal of the 2011 ISO/RTO Metrics Report, submitted on August 31, 2011 in Docket No. AD10-5-000, at 317-318.

[201] ComEd maintains that it could also share operating reserves by joining some group of utilities other than PJM. Certainly ComEd had choices among RTOs, not all of which have a high voltage 500 kV and above system. Each regional system builds transmission according to its needs, existing resources, topology, etc. For example, Midwest ISO is presently built on a 345 kV framework. However, ComEd chose to join PJM, rather than another RTO in part because of the strong interconnection via the high voltage (500 kV and above in operation and being planned) lines to its markets and to its pool of resources that ComEd could draw upon to avoid loss of load in its zone during emergencies.

[202] *PJM Interconnection, L.L.C.*, 106 FERC ¶ 61,253, at P 5, PP 25-29 (2004).

losses are reduced exponentially with higher voltages."[203] PJM's White Paper shows that 500 kV and 765 kV transmission lines reduce line losses by approximately 75 percent, and between 85 and 90 percent, respectively, relative to 345 kV transmission lines.[204] At a 2008 PJM load-weighted average LMP of $71.00/MWh, PJM states that the difference in losses between a 345 kV line and a 500 kV line moving 2,000 MW over 100 miles in every hour of the year would be approximately $75 million per year. The total length of the major 500 kV and above facilities approved through RTEP to date is approximately 1,045 miles.[205] Assuming that these facilities carry 2,000 MW in every hour of the year, the new facilities result in total savings from reduced line losses of $783,750,000 at 2008 prices ($75,000,000/year * 1,045 miles/100). However, the load-weighted average LMP may vary from year to year, and was $45.94/MWh in 2011. Valuing the reduced losses associated with the new facilities based on the formula set forth in the PJM White Paper results in savings of $504,653,000 at 2011 prices (120 MW[206] * $45.94/MWh[207] * 8,760 hours per year * 1,045 miles/100).

107. The savings from reducing line losses redound to transmission owners, customers, and generators by reducing unnecessarily incurred costs of transacting business. Moreover, although parties opposing the postage stamp methodology contend that eastern customers are the primary beneficiaries of reduced transmission losses, data presented by AEP on the Dumont-Wilton Center 765 kV line shows that power flows east to west approximately 30 percent of the time. Thus, all customers benefit from reduced line losses; eastern customers benefit when flows are from west to east, and western customers benefit when flows are from east to west. Assuming that ComEd can receive benefits up to its percentage share of marginal loss costs in 2011 (17.3 percent),[208]

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[203] PJM White Paper at 6.

[204] *Id.* at 6.

[205] Regarding the major 500 kV and above lines approved through RTEP through April 13, 2010, Branchburg-Roseland-Hudson is a 50 to 70-mile 500 kV line; Carson-Suffolk is a 60-mile 500 kV line; Susquehanna-Roseland is a 130-mile 500 kV line; TrAIL is a 240-mile 500 kV line; MAPP is a 230-mile 500 kV line; and PATH consists of 335-miles of 765 kV and 500 kV facilities.

[206] PJM assumes that losses for a 345 kV line are 165 MW and losses for a 500 kV line are 45 MW, for a difference in losses of 120 MW. PJM White Paper at 6-7, fn. 5.

[207] PJM 2011 State of the Market Report at 45.

[208] PJM calculates transmission loss charges for each PJM member. The loss charge is based on the applicable day-ahead and real-time loss component of LMP. (PJM

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ComEd may receive benefits of up to $135,589,000 annually ($783,750,000 * 17.3%) in 2008 prices and $87,305,000 annually in 2011 prices ($504,653,000 * 17.3 %) in reduced line losses on 500 kV and above facilities.[209]

108. Finally, a study performed by Global Energy Decisions, LLC estimated that the integration of ComEd, AEP, and Dayton into the PJM power market led to production cost savings of approximately $70 million in 2004 due to the reduction of seams between the new companies and PJM, with its energy market.[210] Also, in a 2004 PJM annual market simulation assessing ComEd's integration into PJM, PJM identified annual production cost savings in the ComEd control area of $50 million resulting from ComEd belonging to the PJM network.[211] While such savings initially resulted from the reduction of seams between the new companies and PJM, these savings are realized on an annual basis. The reliability and market efficiency benefits of the PJM RTO would not be available to ComEd if it did not have access to PJM's integrated high voltage grid.

109. In summary, ComEd, along with the other western utilities, will receive significant benefits from the new 500 kV and above projects that prevent the degradation of the PJM transmission system and maintain the capability to continue to produce up to $2.2 billion in estimated system-wide savings each year, as indicated by the ISO/RTO metrics report, along with additional estimated annual savings associated with decreased service interruptions and power quality disturbances, reduced line losses, and reduced

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2011 State of the Market Report at 270.) PJM's Market Monitor provides total marginal loss costs by control zone for 2011. ComEd's total costs are $247.7 million, out of total costs for the PJM region of $1,430.5 million. (PJM 2011 State of the Market Report at 413.)

[209] This percentage reflects ComEd's proportion of the total marginal loss costs allocated to PJM zones in 2011; the value does not account for the geographical location of the new transmission lines in PJM nor that the losses savings in ComEd may not be directly proportional to the total losses savings created by these new lines. Additionally, the 17.3 percent value may vary based on PJM's selection of reference buses in its calculation of LMP.

[210] Mid-Atlantic Entities May 28, 2010 Comments at 18 (*citing* Global Energy Decisions, LLC, "Putting Competitive Power Markets to the Test - The Benefits of Competition in America's Electric Grid: Cost Savings and Operating Efficiencies," (July 2005)).

[211] *Id.* at 11 (*citing* PJM/ComEd Market Integration, PJM presentation Market Integration Working Group meeting, June 10, 2003 at 8).

congestion. These estimated annual, system-wide savings totaling approximately $2.2 billion compare favorably to the annual, system wide costs of approximately $1.3 billion for the facilities at issue here. In total, PJM's transmission system provides ComEd's customers with access to savings of approximately $320 million to $468 million each year.[212] While we recognize that there is imprecision in valuing the benefits of new 500 kV and above facilities, these estimated savings identified herein provide sufficient justification for allocating approximately $198 million per year in costs to ComEd under the postage stamp methodology for new transmission facilities necessary to maintain the integrity and reliability of the existing system so that customers will continue to have access to savings and to provide for future needs.[213]

c. PJM's RTEP Process and Its Analyses and Criteria Serve as an Appropriate Basis to Determine Just and Reasonable Cost Allocations for 500 kV and Above Transmission Facilities

110. We recognize that there may be no universal, precise point for determining when certain lines provide sufficient benefits such that their costs should be shared. The current state of modeling used by PJM does not estimate with exacting precision the reliability and other benefits for facilities that operate at or above 500 kV. The allocation of fixed costs in the context of transmission illustrates the Supreme Court's observation that "allocation of costs is not a matter for the slide rule."[214] The evidence shows that,

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[212] This reflects ComEd's savings from the lower number of outages and lower losses experienced with the new 500 kV facilities plus ComEd's 14.7 percent load-ratio share of annual system-wide reliability benefits, made possible by maintaining and upgrading PJM's high voltage network, of reduced reserve requirements and increased demand response; using redispatch procedures to maintain reliability rather than power sales curtailments; planning for future reliability needs on a region-wide rather than a utility-by-utility or state-by-state basis; reduced production costs, operating reserve costs and ancillary services costs. (*See* the six ISOs and RTOs' submittal of the 2011 ISO/RTO Metrics Report, at 317-318.)

[213] We note that the benefits to ComEd from the new 500 kV and above facilities are greater than ComEd's annual allocation of costs of approximately $2.9 million under the DFAX methodology. The $2.9 million figure is equal to ComEd's total allocation under the DFAX methodology ($15.17 million) times the annual carrying charge rate of 19.1 percent.

[214] *Colorado Interstate Co. v. FPC*, 324 U.S. 581, 589 (1945). *See Alabama Electric Cooperative, Inc. v. FERC*, 684 F.2d 20, 27 (D.C. Cir. 1982) (ratemaking is, of

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within the PJM system, 500 kV lines do differ significantly from lower voltage lines in ensuring reliability of the networked region. The record shows that 500 kV and above transmission facilities, as planned for the PJM system, are more effective in providing the networked system with system-wide benefits including voltage support, stability, avoiding overloads and managing those that do occur, and ensuring that power is deliverable to all parts of the region during normal and emergency operating conditions. Further, the record demonstrates that the higher voltage system is more effective in responding to and accommodating systems conditions that change daily, seasonally and over time. Thus, customers who may not currently be flowing power over a particular facility do indeed benefit from maintaining it as part of a reliable regional network, and indeed may find themselves in a different posture as system conditions change. While many of these benefits are not quantified in this record, others are, including savings related to reduced operating reserve requirements, lower losses, and lower outages. We find 500 kV is a reasonable place to draw a line for purposes of cost allocation for the PJM transmission system.

111. Based on the evidence discussed above, we find that significant reliability and cost benefits accrue to all participants from higher voltage facilities in PJM. Indeed, we have sought to approximate, given the current data available, some benefits of the high voltage system. But the difficulty in quantifying benefits does not suggest that it is appropriate to simply ignore such benefits. It would be unfair to permit parties who receive broader benefits from these facilities to avoid paying their share of the costs of such facilities, simply because the methodology fails to account for all benefits. Instead, all of the broad benefits of these high voltage facilities must be considered in determining the appropriate cost allocation methodology. PJM's static DFAX method cannot consider all of these benefits, because when all costs are allocated to parties impacting the transmission facility based on the distribution factors in power flow analyses, no costs are allocated to others who benefit from enhanced reliability, reduced losses, or other potential benefits that may not be quantified in transmission planning studies.[215] In contrast, PJM asserts that the peak MW usage method does provide implicit recognition that all consumers enjoy reliability benefits of higher voltage facilities. For example, reduced losses are enjoyed by all users. According to PJM, consumers with higher peak usage enjoy greater

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course, much less a science than an art); *United Distribution Cos. v. FERC*, 88 F.3d 1105, 1171 (D.C. Cir. 1996) ("there is no neutral or inherently fair allocation of fixed costs, as the history of rate design amply demonstrates)."

[215] PJM White Paper at 37, Appendix A, 47-48.

benefit from reduced losses and pay more relative to consumers with lower peak usage.[216]

112. This is also the view that the Commission took in *Southwest Power Pool, Inc.*, when it found that the regional benefits provided by high voltage facilities "represent real and substantial benefits."[217] The Commission found that "relying solely on the costs and benefits identified in a quantitative study at a single point in time may not accurately reflect the true beneficiaries of a given transmission facility, particularly because such tests do not consider any of the qualitative, (i.e., less tangible) regional benefits inherently provided by [a high voltage] transmission network."[218] Similarly, in *Midwest Independent Transmission System Operator*, *Inc.*, the Commission found that, "[t]he inability of a model to economically quantify the reliability benefit of any particular transmission line does not mean that there is no value to reliability."[219] The Commission further found that, "[t]he strong regionally-integrated transmission network that results from MISO's independent regional planning provides reliability and efficiency benefits to all that are interconnected with it."[220]

113. As is the case with other RTOs, we find that PJM's regionally integrated transmission network that emerges from PJM's regional transmission planning process that is open to all stakeholders, provides benefits that accrue to all parties connected to the transmission system regardless of nominal power flows, such as enhanced reliability, reduced impact of fuel price and fuel market variations, reduced opportunity for the exercise of market power, and the ability to better meet public policy goals.[221] These benefits cannot be identified through power flow studies or market efficiency analyses, rather they are one or more steps removed from transmission planning analyses.[222] We

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[216] *Id.*

[217] *Southwest Power Pool, Inc.*, 131 FERC ¶ 61,252, at P 77 (2010).

[218] *Id.* P 76.

[219] *Midwest Independent Transmission System Operator, Inc.*, 133 FERC ¶ 61,221, at P 202 (2010).

[220] *Id.* P 236.

[221] *See* PJM's White Paper at 13-14.

[222] *Id.* at 18.

find that a postage-stamp allocation of costs based on load ratios recognizes the wide-spread externalities of a broad transmission infrastructure.[223]

114. Further, one of the major advantages of PJM's postage-stamp cost allocation methodology is that it allows the relative cost allocation shares to individual loads to change over time as their peak usage changes from year to year.[224] Allocating costs according to peak usage reinforces the incentives in the energy market to reduce peak energy costs, and in the capacity market to reduce capacity costs. While parties opposing the postage stamp methodology argue that such a methodology will not send the correct economic signals to PJM's planning process, we disagree. As discussed above, all load benefits from a reliable integrated transmission network, and thus a methodology that allocates costs based on load-ratio share sends the correct incentives to plan new transmission facilities that benefit all parties. Load on the transmission system is a measure of the usage of reliable transmission service. A customer's share of the regional load is a reasonable basis upon which to allocate costs in a manner that is roughly commensurate with the benefits of the improved service made possible as a result of these costs.[225]

115. The Seventh Circuit recognized that the Commission does not need "to calculate benefits to the last penny, or for that matter to the last million or ten million or perhaps hundred million dollars."[226] On this point, the Seventh Circuit cited to the decision by the District of Columbia Circuit in *Midwest ISO.*[227] In that case, the District of Columbia Circuit found that all customers reap sufficient benefits from belonging to an RTO that it is reasonable for them to be responsible in equal shares for the administrative costs of the

[223] *Id.* at 33.

[224] This can be distinguished from the criticisms of PJM's DFAX method which in contrast to the postage stamp method, examines only a single on-peak hour at a point in time, and the cost allocation established by DFAX remains fixed over the life of a facility.

[225] In fact, most RTOs in the United States allocate some or all transmission costs based upon some idea of peak load or generation. The allocation of costs over peak megawatts of consumption recognizes that certain benefits, such as reliability, are difficult to assign and may be enjoyed by all users of the transmission system. PJM White Paper at 31-33.

[226] *Illinois Commerce Commission*, 576 F.3d 477.

[227] *Midwest ISO*, 373 F.3d 1361.

RTO despite potential differences between customers in the precise amount of use they make of various RTO functions. Similarly, in its review of Commission decisions in Natural Gas Act (NGA) cases, the District of Columbia Circuit has not required a precise quantification of benefits:

> *Algonquin* undoubtedly does require a reasonably specific qualitative description of the systemwide benefits of an integrated facility. But the Court was careful not to require a balancing of costs and benefits (much less a quantification thereof)….[228]

116. While parties cite to these NGA cases for general principles of cost allocation, some care must be exercised in analogizing between the interstate natural gas pipeline and electric industries.[229] Notably, however, the Commission did indicate that enhancements undertaken to improve system reliability, as is the case here, would be eligible for rolled-in or postage-stamp treatment.[230]

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[228] *Transcanada Pipelines v. FERC*, 24 F.3d 305, 309 (D.C. Cir. 1994) (*citing Algonquin Gas Transmission Co. v. FERC*, 948 F.2d 1305 (D.C. Cir. 1991)).

[229] Many interstate natural gas pipeline construction projects are initiated to extend or expand the pipeline in order to provide service to particular customers who sign long term firm contracts for such service, rather than, as is the case here, as part of a regional transmission planning process with a focus of ensuring the overall reliability and security of the network. Because of the contract specific nature of natural gas pipeline projects, the Commission has followed a general policy of incremental pricing in which only the customers who have contracted for service on the new facilities pay for the costs of those facilities. This policy is intended to ensure that existing customers do not subsidize the construction of new facilities built to serve others. *Certification of New Interstate Natural Gas Pipeline Facilities*, 88 FERC ¶ 61,227 (1999), *order on clarification*, 90 FERC ¶ 61,128, *order on clarification*, 92 FERC ¶ 61,094 (2000).

[230] *Great Lakes Gas Transmission*, 80 FERC ¶ 61,105 (1997) (In applying that policy, the Commission permitted the pipeline to raise rates for all customers to recover the costs of a looping project where the pipeline demonstrated that the project provided increased reliability and flexibility and was not tied to the provision of service to specific customers). Similarly, in its regulation of the electric industry, especially in the RTO setting, it is the Commission's general policy to broadly allocate costs in integrated networks. *Pub. Serv. Comm'n of Wis. v. FERC*, 545 F.3d 1058, 1067 (D.C. Cir. 2008) (upholding application of principle to system-wide cost allocation of transmission upgrades); *W. Area Power Admin. v. FERC*, 525 F.3d 40, 50, 57-58 (D.C. Cir. 2008) (upholding allocation of costs incurred "to ensure reliable, safe operation of the

(continued…)

117. Having found that there are system-wide reliability benefits associated with PJM's new 500 kV and above facilities, it is reasonable to conclude that these benefits are broadly shared by all users of the system.[231] It is reasonable to further find that the reliability benefits of these high voltage projects are roughly distributed or conveyed in rough proportion to the use of the transmission system. Transmission customers are able to make sales and purchases (i.e. load) because the 500 kV and above backbone networked system ensures that there is available transmission capability to make these transfers and to do so at the lowest delivered cost (minimizing losses, outages and operating reserve requirements). The postage stamp allocation reflects this distribution of benefits by allocating costs based on peak usage of the reliable networked system, which is consistent with the way the system is planned.

118. As discussed above, in determining whether an allocation methodology is just and reasonable we need not find that each utility within a system will see benefits in proportion to the costs that are allocated to it.[232] Based on the record in this case, however, we conclude that the reliability and other benefits of transmission investment in higher voltage facilities are sufficient to demonstrate that the benefits to customers in the PJM region, including in the western zones of PJM, are roughly commensurate with the costs of those facilities allocated using a postage-stamp load-ratio share methodology.

119. Parties opposing the postage-stamp methodology assert that the costs that would be allocated to western zones under this method are so substantial that they cannot possibly be commensurate with benefits. They similarly argue that there are significant cost shifts that occur between the use of a static, flow-based and a region-wide cost allocation. For example, under an application of the DFAX methodology, the western

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[California ISO] transmission grid" to all loads within the ISO control area); *Entergy Servs., Inc. v. FERC*, 319 F.3d 536, 544, 545 (D.C. Cir. 2004) (recognizing "the consistent application of the Commission's long-held view . . . that the transmission grid is an integrated whole" and "the Commission's long-standing rejection of direct assignment of network costs"); *id.* at 543-44 ("The Commission's rationale for crediting network upgrades, based on a less cramped view of what constitutes a 'benefit,' reflects its policy determination that a competitive transmission system, with barriers to entry removed or reduced, is in the public interest.").

[231] *See Midwest ISO*, 373 F.3d 1361*; Western Massachusetts*, 165 F.3d at 922.

[232] *See Western Massachusetts*, 165 F.3d at 927 (Upholding system-wide cost allocation based on a showing that "customers other than [the generator,]" which was the proximate cause of the new line, "will be making use of the upgraded grid facilities").

zones (ComEd, Dayton, Duquesne, and AEP) are shown to benefit from only a few of the eighteen at or above 500 kV facilities at issue. However, in comparison, using the postage-stamp methodology would increase the western zone's cost allocation substantially more than using the DFAX method. Exelon notes, based on PJM's qualified estimates, that total cost shifts to the western zones would be approximately $2.4 billion.[233] Exelon asserts that this equates to western zones paying between 1,260 percent and 22,500 percent more than the benefits they receive. Such a comparison raises several concerns.

120. First, the analysis reflected in these comments is misleading because it is predicated on a comparison of the full capital costs, rather than annualized costs, of the projects to annual benefits. The majority of the costs of a project are collected from zones after that project has been constructed, over the depreciable life of the facility (which, for 500 kV and above facilities, could be 40 years or more). A more accurate analysis of the relative impacts of the postage-stamp cost allocation methodology results from applying PJM's annual transmission carrying charge rate of 19.1 percent to the total costs. This approach using annual costs provides a better estimate of the costs customers would actually be paying for the 500 kV and above projects. For example, the annual costs to the ComEd zone for the 500 kV and above facilities approved in the RTEP through April 13, 2010 would be approximately $198 million. As discussed above, using ComEd to illustrate the benefits that are available to the group of utilities in the western planning region of PJM from these facilities, ComEd receives significant yearly cost savings from having a robust transmission grid in terms of operating reserve costs and transmission construction and operation costs. Estimated benefits that can be monetized to the ComEd zone from the new higher voltage facilities range from approximately $95 million to $143 million per year in reduced outages and reduced losses. Additionally, based on its load-ratio share, ComEd has access to approximately $225 million to $325 million in annual estimated benefits associated with the estimated savings produced by PJM planning and operating a reliable transmission system. These estimated savings totaling approximately $320 million to $468 million would not be possible but for the

[233] The projects in the current RTEP are an example of changing system conditions. As previously noted, the PJM RTEP involves continuous monitoring and re-evaluation of previous RTEP results to reflect changing assumptions and system conditions (retooling). As a result of this retooling, projects are added, accelerated, deferred or canceled based on the updated analysis of economic, technological, and resource sector changes. This retooling could significantly affect the projects in the RTEP, and the subsequent postage stamp cost allocation. For example, as previously noted, both the PATH and MAPP 500 kV transmission lines have been placed in abeyance in the most recent RTEP.

high voltage facilities that allow the entire PJM system to be interconnected and operated reliably.

121. Second, the DFAX methodology understates each utility's contribution to the need for high voltage facilities. As performed, it did not consider all the violations that the RTEP projects are expected to resolve.[234] PJM explains that the allocations presented for the backbone facilities are based on the worst violations for each identified overloaded facility, but do not reflect the secondary violations related to the overloaded facility. PJM states that for 500 kV and above facilities the number of lesser violations resolved can be substantial. As an example, PJM explains that the 20 violations used to perform the DFAX calculation for the Susquehanna-Roseland line had 143 associated secondary violations that were not reflected in the calculation.[235] As PJM added more secondary violations to a revised calculation for a given overloaded facility, some saw their share of contribution to the overload, and their resulting allocation of costs, increase.[236]

122. Third, the analysis that purports to show cost shifts from PJM's static DFAX model is inapposite because such an analysis is predicated on the assumption that this cost allocation methodology correctly identifies the benefits of these facilities. As discussed above, there are significant weaknesses associated with the use of PJM's static model to allocate the cost of higher voltage transmission lines. Accordingly, a comparison of the costs allocated using PJM's static methodology with the costs allocated using a region-wide cost allocation methodology does not identify cost shifts. As noted earlier, the Commission never specifically approved the use of the DFAX

[234] It also did not assign costs to utilities with a distribution factor below 0.001. *See* PJM Tariff, Schedule 12 § (b)(iii)(C)(5).

[235] PJM April 13, 2010 Response at 7. PJM's DFAX analysis indicates that several utilities in the western zone contributed in some part to the violations that were modeled for the Susquehanna-Roseland line. (*Id.* at 9.) These contributions almost doubled in the sensitivity analysis that examined secondary violations. (*Id.* at 19).

[236] *Id.* at 18.

methodology as a means to allocate costs for high voltage transmission lines.[237] PJM provided the DFAX based allocation of costs in the April 13, 2010 Response solely as part of a data response and used the methodology that was approved for facilities that operate below 500 kV.[238] Because the DFAX methodology employed by PJM in its April 13, 2010 Response is not a Commission-approved tariff methodology for facilities that operate at or above 500 kV, and because no costs at issue here were ever allocated based on the April 13, 2010 Response methodology, parties cannot show the starting point for a cost shift analysis. Accordingly, there are no cost shifts for the Commission to consider because there is no final, previously-approved allocation for which a comparison may be made for these particular facilities

123. Considering the evidence before us, particularly the role that new 500 kV and above transmission projects play in ensuring reliability and deliverability of power to all areas of the region, we find that the DFAX methodology that PJM employed at the time this proceeding was initiated does not adequately reflect the benefits of new high voltage projects. As PJM explains, costs pursuant to a DFAX method are not necessarily allocated to those who may benefit from enhanced reliability, reduced losses, and other potential benefits that the new high voltage projects produce. Further, because the DFAX methodology determines beneficiaries based on contributions to the violation that is to be resolved, it does not permit cost allocation to reflect use of the system after the problem is resolved, such as daily and seasonal changes in power flows, protection from severe disruptions and adaptability to changing system conditions that affect the use of the project after construction.[239] In short, DFAX's "snapshot" approach does not capture the benefits to system users *after* the reliability violation has been cured. As discussed above, new 500 kV and above facilities carry larger amounts of power over longer distances and resolve multiple violations over wider areas and multiple zones and can accommodate more severe disruptions and changing conditions than lower-voltage

[237] While PJM apparently used DFAX prior to Opinion No. 494 to allocate costs, the Commission never found this methodology just and reasonable. At this time, the PJM operating agreement did include Commission-approved language stating that designations of cost responsibility shall be "based on the Office of the Interconnection's assessment of the contributions to the need for, and benefits expected to be derived from, the pertinent enhancement or expansion," but the details of this model were not approved by the Commission.

[238] See PJM April 13, 2010 Response at 1.

[239] PJM White Paper at 37.

facilities. As such, PJM's pre-existing DFAX method cannot serve as the sole basis for allocation of costs for new 500 kV and above transmission facilities.

124. The Commission has found that the DFAX method for allocating costs is reasonable for projects that address one or a few violations in a localized geographic area, which as PJM indicates are projects operated at voltages of 345 kV and below. However, as discussed, the DFAX method does not capture a large portion of the reliability benefits that high voltage projects bring to the PJM system. In fact, as previously noted, because costs are not necessarily allocated to those who may benefit from the enhanced reliability, reduced losses, and other potential benefits that the new high voltage projects produce, the DFAX methodology employed by PJM at the time the proceeding was initiated may allow those who benefit from the facilities to pay none of the facilities' costs. We find that the postage stamp cost allocation methodology appropriately reflects the system-wide reliability benefits of the PJM's high voltage system, while the DFAX methodology used here cannot, and is an appropriate methodology upon which to determine cost allocations that are just and reasonable.

125. In sum, as discussed above, existing and future 500 kV and above high voltage facilities will provide PJM members with various benefits, including greater reliability, greater transfer capability, greater opportunities for reserve sharing, and reduced transmission losses, as well as various market efficiency benefits. Transmission facilities that operate at 500 kV and above in PJM provide a reliable, integrated transmission network, to the benefit of all parties that are interconnected with it. Since all load interconnected to the transmission network receives benefits, it is reasonable to allocate costs based on a methodology that recognizes the benefits of PJM's integrated high voltage regional transmission system. The postage-stamp (load-ratio shares) cost allocation methodology, based on PJM's open and transparent RTEP process, is one such methodology. As discussed above, using ComEd to illustrate the benefits and costs allocated to the western region of PJM, the postage stamp method will result in ComEd being assigned approximately $198 million annually for the 500 kV and above projects at issue in this proceeding. The approximately $320 million to $468 million of benefits that ComEd receives from these projects each year exceed the costs, and therefore provide an articulable and plausible reason for ComEd to be allocated costs under the postage stamp method.

126. On balance, given the continuum in which the different methodologies allocate the costs of new transmission facilities either discreetly or more broadly, we find that the broader and more widespread benefits that result from new transmission facilities that operate at 500 kV and above are better captured by a cost allocation method based on customer's usage at peak times (load-ratio shares), which matches the way the PJM

transmission system is planned,[240] and, based upon the record in this proceeding, is the more credible basis upon which to set just and reasonable rates.

The Commission orders:

The Commission finds, based on the full record in this proceeding, that PJM's use of a flow-based model for allocating the costs of above 500 kV facilities is not just and reasonable, and the postage-stamp cost allocation methodology for transmission enhancements to the PJM system that operate at or above 500 kV is just and reasonable, and not unduly discriminatory or preferential, as discussed in the body of the order.

By the Commission. Commissioner LaFleur is dissenting with a separate statement attached.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

[240] *Id.* at 32.

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C. Docket No. ER05-121-006

(Issued March 30, 2012)

LaFLEUR, Commissioner, *dissenting*:

Two and a half years ago, in *Illinois Commerce Commission v. FERC*,[1] the United States Court of Appeals for the Seventh Circuit remanded this case to the Commission for further review. Because I believe the postage-stamp cost allocation methodology required by the majority on remand is an overbroad solution to the shortcomings of the flow-based DFAX methodology, I respectfully dissent.

I believe that the majority has persuasively demonstrated that a cost allocation methodology for 500 kV lines that relies *exclusively* on DFAX is not just and reasonable. The lives of transmission lines are measured in decades, not years, and while DFAX may provide the immediate and short term justification for a new line, that justification may not reflect the entire universe of beneficiaries over the line's useful life.

Thus, I agree with the majority that DFAX is a limited and time-specific snapshot that cannot capture the range of regional benefits that may develop over time. As the majority states, these benefits may include enhanced long-term reliability under changing patterns of loads, flows, and supply sources; greater system stability; and greater access to new sources of power, including generation procured to meet renewable portfolio standards. Even in the near term, DFAX does not fully account for all of the unquantifiable benefits of new lines that accrue to all members of an interconnected network, simply by virtue of being members of an interconnected network.

The fact that DFAX has inherent limitations, however, is not a sufficient reason to ignore its undisputed utility in identifying the immediate and short-term needs that justify the decision to build today. For example, not even the majority disputes that the lines in the 2004 RTEP were all included in the RTEP because they were identified by DFAX as specific solutions to specific reliability problems. In other words, these lines were not included in the RTEP because they were regarded as having broad regional benefits, or because they were part of a portfolio approach calculated to ensure that the overall transmission plan in any given year had broad regional benefits; they were "but for"

[1] 576 F.3d 470 (7th Cir. 2009).

lines, intended to benefit specific and identifiable customers.[2]

While the majority ably describes the shortcomings of the DFAX methodology, it fails to explain why the remedy for these shortcomings is a postage-stamp approach that does not account at all for the reliable information DFAX does provide. Indeed, it is difficult to understand why the majority believes that DFAX has no place allocating the cost of 500 kV lines when DFAX is the only method in the record that provides certain information, albeit time-limited information, about who will benefit from these lines.

In essence, the majority's remedy to the problems with DFAX is overbroad; rather than beginning with what is valuable and searching for a solution that bridges the gap, the majority imposes a postage-stamp cost allocation methodology that produces results that do not correlate at all with the reasons why the projects were included in the RTEP.

The majority has persuasively demonstrated that 500 kV lines have both present and future unquantifiable benefits not captured by DFAX, and the record already demonstrates that DFAX identifies the most immediate present and short-term beneficiaries. Therefore, I believe that the Commission should require a cost allocation methodology in this proceeding that accounts for both the benefits and drawbacks of DFAX and postage-stamp allocation.

Three parties in this docket have suggested such a hybrid approach. The Pennsylvania Office of Consumer Advocate (Pennsylvania Consumer Advocate), the Pennsylvania Public Utilities Commission, and Virginia Electric Power Company all propose cost allocation methodologies that incorporate flow-based and postage-stamp cost allocation. The Pennsylvania Consumer Advocate, for example, has proposed a methodology that would allocate costs based on a 75 percent DFAX / 25 percent postage-stamp split for five years, with the ratio then transitioning to 100 percent postage-stamp allocation. I believe this approach would allocate costs in a manner roughly commensurate with benefits, as it captures the known present and short term specific

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[2] *Cf. Midwest Indep. Transmission Sys. Operator Inc*., 114 FERC ¶ 61,106, at P 108-115 (2006) (approving a proposal to exclude transmission projects on an "Excluded Project List" from a newly created region wide cost allocation plan because the projects in question were planned assuming no cost sharing); *order on reh'g*, 117 FERC ¶ 61,241, at P 96 (2006) (affirming approval of the Excluded Project List on the grounds that "when the MTEP 05 (and all MTEPs prior to 2005) was being negotiated and planned, parties had no way of foreseeing how the RECB Task Force negotiations would come out on the cost allocation mechanism. Parties moved forward with those projects without any assurance that such projects would be candidates for regional cost sharing.").

reliability benefits that justify building a line today, while also accounting for potential future benefits and unquantifiable present benefits to the entire network. Consistent with the record in this case, the Pennsylvania Consumer Advocate's approach also recognizes that the value of DFAX diminishes over time, and appropriately phases it out as a part of the cost allocation methodology.

Therefore, I would require PJM to adopt a hybrid approach, and send the case to a settlement judge to work with all relevant stakeholders to develop the appropriate ratio and the schedule on which it would phase to full postage-stamp cost allocation.

I am mindful that the passage of time since the court's remand may make it difficult for PJM to determine the impacts driving the need for previously approved projects. Specifically, PJM may be required to "unwind" these projects to determine whether those impacts had changed in order to employ the DFAX methodology as part of a hybrid approach. Accordingly, I would be flexible in allowing PJM to make reasonable proposals on compliance to apply the principles agreed upon to the facts at issue. I would also be open to proposals to phase in new rates over time, if necessary to avoid rate shock. The fact that a limited number of facilities at and above 500 kV have come on line during the pendency of this case should make the compliance burden, while not inconsiderable, manageable. In any event, the difficulty of applying a just and reasonable rate does not justify the retention on remand of an overbroad solution to the problems the majority identified.

I note that, since this case originally arose, the Commission has issued Order No. 1000, its Final Rule on Transmission Planning and Cost Allocation.[3] In that Rule, we required all public utility transmission providers, including PJM, to engage in regional transmission planning, and to have in place a methodology for allocating the costs of new transmission facilities selected in a regional transmission plan for purposes of cost allocation. Order No. 1000 establishes principles to guide planners in deciding on cost allocation, including the principle that costs must be allocated in a manner that is at least roughly commensurate with benefits. It also recognizes that planners may propose different cost methodologies for different types of projects (e.g., reliability, economic, and public policy-driven projects).

I anticipate that we will receive a wide range of proposals from planning regions, and believe that we should be open to different proposals for cost allocation that accord

[3] *Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities*, Order No. 1000, 76 Fed. Reg. 49,842 (Aug. 11, 2011), FERC Stats. & Regs. ¶ 31,323 (2011).

with the principles set forth in Order No. 1000 and meet regional needs. These might include region-wide cost sharing for projects selected by the region based on established criteria to ensure that they provide region-wide benefits.[4] In each case, the Commission will be called upon to decide if the approach proposed accords with the principles set forth in Order No. 1000 and with the requirements of the Federal Power Act, given the circumstances of the projects and region involved.

I offer these thoughts to make clear that I do not in the instant case prejudge Order No. 1000 compliance in PJM or elsewhere, or seek to establish an inalterable template of cost allocation for PJM. Rather, I have sought only to apply the law that binds us to the record of the case presented, and to reach what I believe to be a just and reasonable result.

Accordingly, I respectfully dissent.

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Cheryl A. LaFleur
Commissioner

[4] *See Midwest Indep. Transmission Sys. Operator, Inc.*, 133 FERC ¶ 61,221 (2010), *reh'g denied in part*, 137 FERC ¶ 61,074 (2011).