No. ______

SHORT RECORD
NO. 13-2052
FILED 5/16/13

IN THE
UNITED STATES COURTS OF APPEALS
FOR THE SEVENTH CIRCUIT

PUBLIC UTILITIES COMMISSION OF OHIO Petitioner, v. FEDERAL ENERGY REGULATORY COMMISSION, Respondent.	: : : : : ; : : : : :	Petition for Review of an Order of the Federal Energy Regulatory Commission Nos. EL05-121-006 EL05-121-008

PETITION FOR REVIEW

Pursuant to rule 15(a) of the Federal Rules of Appellate Procedure, and Section 313(b) of the Federal Power Act, 16 U.S.C. § 825l(b), Petitioner PUBLIC UTILITIES COMMISSION OF OHIO, through its attorney, hereby petitions for review of the actions of the Respondent FEDERAL ENERGY REGULATORY COMMISSION ("FERC") in the following orders:

1. PJM Interconnection, L.L.C., Order on Remand, FERC Docket No. EL05-121-006, 138 FERC ¶ 61,320 (March 30, 2012).
2. PJM Interconnection, L.L.C., Order on Rehearing, FERC Docket No. EL05-121-008, 142 FERC ¶ 61,203 (March 22, 2013).

Dated: May 16, 2013

Respectfully submitted,

Mike DeWine
Attorney General of Ohio

By: *__/s/Thomas G. Lindgren__*
Assistant Attorney General
180 East Broad Street, 6th Floor
Columbus Ohio 43215
(614) 466-4395
thomas.lindgren@puc.state.oh.us

CERTIFICATE OF SERVICE

I hereby certify that, pursuant to Rule 15(c) of the Federal Rules of Appellate Procedure, I have caused a true and correct copy of the foregoing Petition for Review of the Public Utilities Commission of Ohio to be sent via overnight delivery, on this 16th day of May, 2013 to the following persons:

Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
Room 11G-1
888 First Street, NE
Washington, DC 20426

Robert H. Solomon
Solicitor
Federal Energy Regulatory Commission
Room 9A-01
888 First Street, NE
Washington, DC 20426

I further certify that, pursuant to Rule 15(c) of the Federal Rules of Appellate Procedure, I have caused a true and correct copy of the foregoing Petition for Review of the FirstEnergy Companies to be sent via first class mail, on this 16th day of May, 2013 to the following persons:

RAYMOND WUSLICH
PARTNER
WINSTON & STRAWN LLP
1700 K STREET N.W.
WASHINGTON, DC 20006

ALLEGHENY ENERGY INC.
800 CABIN HILL DRIVE
GREENSBURG, PENNSYLVANIA 15601

STEVEN ROSS
STEPTOE & JOHNSON LLP
1330 CONNECTICUT AVE, NW
WASHINGTON, DC 20036

RAJ D RANA
DIRECTOR TRANSMISSION POLICY
AMERICAN ELECTRIC POWER SYSTEM CORP.
1 RIVERSIDE PLAZA
23RD FLOOR
COLUMBUS, OHIO 43061

ANNE M VOGEL
AMERICAN ELECTRIC POWER SERVICE CORPORATION
1 RIVERSIDE PLAZA
FLOOR 29
COLUMBUS, OHIO 43215

LAURIE HOLMES
AMERICAN FOREST & PAPER ASSOCIATION
1111 19TH STREET NW
STE 800
WASHINGTON, DC 20036

CAROL L. KRYSEVIG
DIRECTOR, PERFORMANCE AND COMP
ALLEGHENY ENERGY SUPPLY COMPANY, LLC
800 CABIN HILL DRIVE
GREENSBURG, PENNSYLVANIA 15601

JOSEPH STUBBS
STEPTOE & JOHNSON LLP
1330 CONNECTICUT AVE NW
WASHINGTON, DC 200361704

KEVIN DUFFY
ASSISTANT GENERAL COUNSEL
AMERICAN ELECTRIC POWER SERVICE CORP.
1 RIVERSIDE PLAZA
29TH FLOOR
COLUMBUS, OHIO 43215

JAMES BACHA
ASSOCIATE GENERAL COUNSEL
AMERICAN ELECTRIC POWER SERVICE CORPORATION
1 RIVERSIDE PLAZA
COLUMBUS, OHIO 43215-2373

DONALD SIPE
PRETI, FLAHERTY, BELIVEAU, PACHIOS & HAL
PO BOX 1058
AUGUSTA,MAINE 04332-1058

JOHN W BENTINE, ESQ
SENIOR VICE PRESIDENT/GENERAL
AMERICAN MUNICIPAL POWER, INC.
1111 SCHROCK RD.
SUITE 100
COLUMBUS, OHIO 43229

GARY NEWELL
THOMPSON COBURN LLP
1909 K STREET, N.W.
SUITE 600
WASHINGTON, DC 20006

CHRISTOPHER J NORTON
DIRECTOR OF MARKET REGULATORY
AMERICAN MUNICIPAL POWER-OHIO, INC.
1111 SCHROCK ROAD
SUITE 100
COLUMBUS, OHIO 43229

KENNETH JAFFE
ALSTON & BIRD LLP
950 F STREET, N.W.
WASHINGTON, DC 20004

EUGENE GRACE
REGULATORY ATTORNEY
AMERICAN WIND ENERGY ASSOCIATION
1501 M ST NW, STE 1000
WASHINGTON, DC 20005

DAVID GOROFF
PARTNER
SCHIFF HARDIN LLP
1701 PENNSYLVANIA AVENUE, NW
SUITE 900
WASHINGTON, DC 20006

KATHERINE GENSLER
MANAGER, REGULATORY & LEGISLAT
SOLAR ENERGY INDUSTRIES ASSOCIATION
575 7TH STREET NW
SUITE 400
WASHINGTON, DC 20004

DANIEL GAHAGAN
ASSOC. GEN. COUNSEL
BALTIMORE GAS & ELECTRIC
COMPANY
110 W FAYETTE ST # 2
BALTIMORE, MARYLAND 212013708

AMY L BLAUMAN
PEPCO HOLDINGS, INC.
701 NINTH STREET, N.W.
SUITE 1100
WASHINGTON, DC 20068

PHYLLIS KIMMEL
MILLER, BALIS & O'NEIL, P.C.
1015 15TH STREET, NW
12TH FLOOR
WASHINGTON, DC 20005

GARY E. GUY
BGE - CHIEF FERC COUNSEL
BALTIMORE GAS & ELECTRIC COMPANY
110 WEST FAYETTE STREET
2 CENTER PLAZA, SUITE 1301
BALTIMORE, MARYLAND 21201

JOHN ADRAGNA
MILLER, BALIS & O'NEIL, P.C.
TWELFTH FLOOR
1015 15TH STREET, N.W.
WASHINGTON, DC 20005

RON PEZON
SUPERINTENDENT OF ELECTRIC DEP
BOROUGH OF CHAMBERSBURG, PENNSYLVANIA
100 SOUTH SECOND STREET
CHAMBERSBURG, PENNSYLVANIA 17201

STEVEN L GAARDE
DIR OF TRANS AND REG STRAT
CONSUMERS ENERGY COMPANY
1945 PARNELL ROAD
ROOM P13-105
JACKSON, MICHIGAN 49201

M. BRYAN LITTLE
SENIOR ATTORNEY
CONSUMERS ENERGY COMPANY
ONE ENERGY PLAZA
ROOM EP11-240
JACKSON, MICHIGAN 49201

JANICE LOWER
PRINCIPAL
DUNCAN, WEINBERG, GENZER &
PEMBROKE PC
DUNCAN WEINBERG GENZER &
PEMBROKE PC
1615 M STREET, NW SUITE 800
WASHINGTON, DC 20036

EDWARD RIZER
ASSOCIATE COUNSEL
DAYTON POWER AND LIGHT COMPANY, THE
1065 WOODMAN DRIVE
DAYTON, OHIO 45432

JAY KUMAR
ECONOMICS AND TECHNICAL
CONSULTANTS, INC.
6241 EXECUTIVE BLVD.
ROCKVILLE, MARYLAND 20852

PATRICK E MCCULLAR
PRESIDENT & CEO
DELAWARE MUNICIPAL ELECTRIC CORP., INC.
22 ARTISAN DRIVE
SMYRNA, DELAWARE 19977

LINDA L. MURRAY-KIMBALL
SECRETARY
DELAWARE MUNICIPAL ELECTRIC
CORP., INC.
1615 M STREET, NW
SUITE 800
WASHINGTON, DC 20036

THOMAS RUDEBUSCH
PARTNER
DUNCAN, WEINBERG, GENZER & PEMBROKE PC
1615 M STREET, NW
SUITE 800
WASHINGTON, DC 20036

**BRUCE H BURCAT
EX. DIRECTOR
DELAWARE PUBLIC SERVICE
COMMISSION
CANNON BUILDING, SUITE 100
821 SILVER LAKE BLVD
DOVER, DELAWARE 199042458

JANIS DILLARD
SECRETARY
DELAWARE PUBLIC SERVICE COMMISSION
861 SILVER LAKE BLVD.
CANNON BUILDING, SUITE 100
DOVER, DELAWARE 19904

WILLIAM DERASMO
ATTORNEY
TROUTMAN SANDERS LLP
401 9TH STREET, N.W.
SUITE 1000
WASHINGTON, DC 20004

RICHARD HERSKOVITZ
D.C. PUBLIC SERVICE COMMISSION
1333 H STREET, N.W.
7TH FLOOR, EAST TOWER
WASHINGTON, DC 20005

GARY JACK
ASSOCIATE GENERAL COUNSEL
DUQUESNE LIGHT COMPANY
411 7TH AVENUE
MAIL DROP 16-5
PITTSBURGH, PENNSYLVANIA 15219

DAVID POMPER
ATTORNEY
SPIEGEL & MCDIARMID LLP
1333 NEW HAMPSHIRE AVENUE, N.W.
WASHINGTON, DC 20036

**HUGH E GRUNDEN, PE
MANAGER
EASTON UTILITIES COMMISSION
PO BOX 1189
EASTON,DC 21601-8923

JOHN P HUGHES
VICE PRESIDENT, TECHNICAL AFFA
ELECTRICITY CONSUMERS RESOURCE
COUNCIL
1111 19TH ST NW
WASHINGTON, DC 20036

MARC WILLIAMS
ATTORNEY ADVISOR
DC PUBLIC SERVICE COMMISSION
2ND FLOOR, WEST TOWER
1333 H ST NW
WASHINGTON, DC 200054707

SHERI MAY
STAFF COUNSEL
INDIVIDUAL
139 EAST FOURTH ST.
CINCINNATI, OHIO 45202

DUANE DAHLQUIST
GENERAL MANAGER
BLUE RIDGE POWER AGENCY
742 MAIN STREET
DANVILLE, VIRGINIA 24541

W. RICHARD BIDSTRUP
CLEARY, GOTTLIEB, STEEN & HAMILTON LLP
2000 PENNSYLVANIA AVE, NW
WASHINGTON, DC 20006

KAREN HILL
VICE PRESIDENT FED REGULATORY
EXELON CORPORATION
101 CONSTITUTION AVE.
SUITE 400 E
WASHINGTON, DC 20001

SANDY GRACE
ASSISTANT GENERAL COUNSEL
EXELON CORPORATION
101 CONSTITUTION AVE NW
STE 400 EAST
WASHINGTON, DC 20001

STEVEN T NAUMANN
VP, WHOLESALE MARKET DEV.
EXELON CORPORATION
10 SOUTH DEARBORN STREET
50TH FLOOR
CHICAGO, ILLINOIS 60603

IRENE E SZOPO
FEDERAL ENERGY REGULATORY COMMISSION
888 FIRST ST.
ROUTING CODE: AL-2.2
MAIL STOP: 32.23
WASHINGTON, DC 20426

EUGENE BERNSTEIN
ASSISTANT GENERAL COUNSEL
EXELON CORPORATION
10 S. DEARBORN STREET
35TH FLOOR
CHICAGO, ILLINOIS 60603

JONATHAN L SIEMS
ENERGY INDUSTRY ANALYST
FEDERAL ENERGY REGULATORY COMMISSION
888 FIRST ST, N.E.
ROOM 71-31
WASHINGTON, DC 20426

JAMES A PEPPER
TRIAL ATTORNEY
FEDERAL ENERGY REGULATORY COMMISSION
888 FIRST STREET, N.E.
32-19
WASHINGTON, DC 20426

SEJAL SHAH
DUNCAN, WEINBERG, GENZER & PEMBROKE PC
1615 M ST.
SUITE 800
WASHINGTON, DC 20036

SAUNDRA W. RHODE
LEGAL SECRETARY
HAGERSTOWN, CITY OF
1615 M STREET, NW
SUITE 800
WASHINGTON, DC 20006

JAMES N. BRODER
GENERAL COUNSEL
HUDSON TRANSMISSION PARTNERS, LLC
PO BOX 7320
PORTLAND, 04112-7320

ROBERT WEISHAAR
MCNEES WALLACE & NURICK LLC
777 NORTH CAPITOL STREET, NE
SUITE 401
WASHINGTON, DC 20002

DENNIS P. JAMOUNEAU
MCNEES WALLACE & NURICK LLC
777 NORTH CAPITOL STREET N.E.
SUITE 401
WASHINGTON, DC 20002

CHRISTINE ERICSON
DEPUTY SOLICITOR GENERAL
ILLINOIS COMMERCE COMMISSION
160 N. LASALLE ST.
SUITE C-800
CHICAGO, ILLINOIS 60601

RANDY RISMILLER
MANAGER, FED. ENERGY PROGRAM
ILLINOIS COMMERCE COMMISSION
527 EAST CAPITOL AVENUE
SPRINGFIELD, ILLINOIS 62701

JOHN CONWAY
BRICKFIELD BURCHETTE RITTS &
STONE, PC
1025 THOMAS JEFFERSON STREET NW
EIGHTH FLOOR, WEST TOWER
WASHINGTON, DC 20007

TANJA SHONKWILER
1615 M STREET NW
SUITE 800
WASHINGTON, DC 20036

JOSHUA E. ADRIAN
DUNCAN, WEINBERG, GENZER &
PEMBROKE PC
1615 M. STREET, NW
SUITE 800
WASHINGTON, DC 20036

RICHARD KALMAS
MANAGER, ELECTRIC AND REGULATO
SQUIRE SANDERS & DEMPSEY, LLP
3300 DICKEY ROAD
EAST CHICAGO, INDIANA 46312

MORGAN PARKE ESQ
ATTORNEY
FIRSTENERGY SERVICE COMPANY
76 SOUTH MAIN STREET
AKRON, OHIO 44308-1890

DONALD KAPLAN
K&L GATES LLP
1601 K STREET, NW
WASHINGTON, DC 20006

PAUL D REISING
CONSULTANT
ILLINOIS MUNICIPAL ELECTRIC AGENCY
8409 QUAIL HOLLOW ROAD
INDIANAPOLIS, INDIANA 46260-2206

JOHN GRIFFITH
PRESIDENT, IMMDA
805 N CENTERVILLE RD
STURGIS, MICHIGAN 490919364

THOMAS BAINBRIDGE
FIRSTENERGY
PO BOX 16001
READING,DC 19612-6001

**THOMAS BURGESS
DIRECTOR
FIRSTENERGY CORP.
76 S MAIN ST
AKRON, OHIO 443081812

WILLIAM KEYSER, III
K&L GATES LLP
1601 K STREET, NW
WASHINGTON, DC 20006

JON MOSTEL
ATTORNEY
STROOK, STROOK & LAVAN
180 MAIDEN LANE
NEW YORK, NEW YORK 10038-4982

RICHARD BERTELSON
ATTORNEY
PO BOX 615
FRANKFORT,KENTUCKY 40602-0615

DONALD LIGHT
ASSISTANT GENERAL COUNSEL
VAN NESS FELDMAN, LLP
121 SW SALMON STREET
1WTC1301
PORTLAND, OREGON 97204

JOSEPH NELSON
MEMBER
VAN NESS FELDMAN, LLP
1050 THOMAS JEFFERSON ST, NW; STE 700
WASHINGTON, DC 20007

MILES MITCHELL
DEPUTY GENERAL COUNSEL
MARYLAND PUBLIC SERVICE COMMISSION
WILLIAM DONALD SCHAEFER TOWER
6 ST. PAUL ST, 16TH FLR
BALTIMORE, MARYLAND 21202

THOMAS H. WRENBECK
DIRECTOR, REGULATORY STRATEGY
MIDWEST STAND-ALONE TRANSMISSION COMPANIES
27175 ENERGY WAY
NOVI, MICHIGAN 48377

DAVID P. YAFFE, ESQ
MEMBER
VAN NESS FELDMAN, LLP
1050 THOMAS JEFFERSON STREET, N.W.
WASHINGTON, DC 20007

RONI F EPSTEIN
LONG ISLAND POWER AUTHORITY
333 EARLE OVINGTON BLVD
SUITE 403
UNIONDALE, NEW YORK 11553

DOUGLAS JOHN
JOHN & HENGERER
1730 RHODE ISLAND AVENUE, N.W.
SUITE 600
WASHINGTON, DC 20036-3116

ANA LOUD
PARALEGAL
MIRANT CORPORATION
601 13 ST., NW
STE. 850N
WASHINGTON, DC 20005

WALLACE TILLMAN
GENERAL COUNSEL
NATIONAL RURAL ELECTRIC COOPERATIVE ASSN.
4301 WILSON BLVD
ARLINGTON, VIRGINIA 22203

RICHARD MEYER
SENIOR REGULATORY COUNSEL
NATIONAL RURAL ELECTRIC
COOPERATIVE ASSN.
4301 WILSON BOULEVARD
MC EP11-256
ARLINGTON, VIRGINIA 22203-1860

VICTORIA FLYNN
DECOTIIS, FITZPATRICK & COLE, LLP
500 FRANK W. BURR BLVD
TEANECK, NEW JERSEY 07666

TARA THOMAS
PARALEGAL
NEW JERSEY OFFICE OF RATEPAYER
ADVOCATE
31 CLINTON STREET
11TH FLOOR
NEWARK, NEW JERSEY 07101

BRENDA LYNAM
LEGAL
NORTH CAROLINA ELECTRIC
MEMBERSHIP CORPORATION
PO BOX 27306
RALEIGH,DC 27611-7306

RICHARD FEATHERS
ASSOCIATE GENERAL COUNSEL
NORTH CAROLINA ELECTRIC
MEMBERSHIP CORPORATION
PO BOX 27306
RALEIGH,DC 27611-7306

KENNETH SIMON
ATTORNEY
LATHAM & WATKINS LLP
555 ELEVENTH STREET, N.W., SUITE 1000
WASHINGTON, DC 20004-1304

HENRY OGDEN
ASST. DEP. PUBLIC ADVOCATE
NEW JERSEY OFFICE OF RATEPAYER ADVOCATE
PO BOX 46005
NEWARK,NEW JERSEY 07101-8003

DENISE GOULET
COUNSEL
MILLER, BALIS & O'NEIL, P.C.
1015 FIFTHTEENTH STREET, N.W.
SUITE 1200
WASHINGTON, DC 20005

SEAN BEENY
ATTORNEY
MILLER, BALIS & O'NEIL, P.C.
1015 15TH ST, NW
TWELFTH FLOOR
WASHINGTON, DC 20005

CAROLYN KAUKL
WISCONSIN TRANSMISSION CUSTOMER GROUP
PO BOX 927
MADISON,WISCONSIN 53701-0927

LOUIS WATSON
SENIOR STAFF ATTORNEY
NORTH CAROLINA UTILITIES
COMMISSION
4325 MAIL SERVICE CENTER
RALEIGH, NORTH CAROLINA 27699-
4325

ABRAHAM SILVERMAN
SR. COUNSEL - REGULATORY
NRG ENERGY, INC
211 CARNEGIE CENTER DRIVE
PRINCETON, NEW JERSEY 08540

PATRICIA ESPOSITO
DIRECTOR, REGULATORY AFFAIRS
NRG ENERGY, INC
211 CARNEGIE CENTER
PRINCETON, NEW JERSEY 08540

EDMUND BERGER
ASSISTANT CONSUMERS' COUNSEL
10 WEST BROAD ST
18TH FLOOR
COLUMBUS, OHIO 43215

JACQUELINE ROBERTS
ASSISTANT CONSUMERS' COUNSEL
OHIO CONSUMERS' COUNSEL
10 W. BROAD STREET
SUITE 1800
COLUMBUS, OHIO 43215

RICHARD SPARLING
ALSTON & BIRD LLP
THE ATLANTIC BUILDING
950 F STREET, NW
WASHINGTON, DC 20004

THOMAS MCNAMEE
ASSISTANT ATTORNEY GENERAL
OHIO PUBLIC UTILITIES COMMISSION
180 EAST BROAD STREET - 6TH FL
COLUMBUS, OHIO 43215-3793

DON L HOWARD
UTILITY SPECIALIST
OHIO PUBLIC UTILITIES COMMISSION
180E. BROAD ST
COLUMBUS, OHIO 43215

ADRIENNE CLAIR
STINSON MORRISON HECKLER LLP
STINSON MORRISON HECKER LLP
1150 18TH STREET, NW, SUITE 800
WASHINGTON, DC 20036

MAREK SMIGIELSKI
ATTORNEY
ORMET PRIMARY ALUMINUM CORP
76 SOUTH MAIN STREET
A-GO-15
AKRON, OHIO 44308

J CATHY FOGEL
SULLIVAN & WORCESTER LLP
3804 WOODBINE STREET
CHEVY CHASE, MARYLAND 20815

WHITFIELD RUSSELL
ORMET PRIMARY ALUMINUM CORP
4232 KING STREET
ALEXANDRIA, VIRGINIA 22302-1507

PAUL MOHLER
ATTORNEY
HELLER EHRMAN WHITE &
MCAULIFFE LLP
4525 N 40TH ST
ARLINGTON, VIRGINIA 22207

KENT MURPHY
ASSISTANT GENERAL COUNSEL
EXELON BUSINESS SERVICES
PO BOX 8699
PHILADELPHIA,PENNSYLVANIA 19101-8699

CRAIG GLAZER
V.P., FEDERAL GOV'T POLICY
PJM INTERCONNECTION, L.L.C.
1200 G STREET, N.W.
SUITE 600
WASHINGTON, DC 20005

VASILIKI KARANDRIKAS
MCNEES WALLACE & NURICK LLC
PO BOX 1166
HARRISBURG,DC 17108-1166

STEVEN R PINCUS, ESQ
SENIOR COUNSEL - REGULATORY
PJM INTERCONNECTION, L.L.C.
955 JEFFERSON AVENUE
VALLEY FORGE CORPORATE CENTER
EAGLEVILLE, PENNSYLVANIA 19403

BARRY SPECTOR
WRIGHT & TALISMAN, PC
1200 G ST NW STE 600
WASHINGTON, DC 20005

**JAMES HANEY
V. PRESIDENT
PJM TRANSMISSION OWNERS
AGREEMENT ADMINI
800 CABIN HILL DR
GREENSBURG, PENNSYLVANIA
156011650

SAMUEL C. RANDAZZO
McNees Wallace & Nurick
21 EAST STATE STREET
17TH FLOOR
COLUMBUS, OHIO 43215

SUSAN E BRUCE
PJMICC ET AL
100 PINE ST
HARRISBURG, PENNSYLVANIA 17101

**THOMAS C BURGESS
DIRECTOR
PJM TRANSMISSION OWNERS AGREEMENT
ADMINI
76 S MAIN ST
AKRON, OHIO 443081812

PAUL RUSSELL
PPL SERVICES CORPORATION
TWO NORTH NINTH STREET
ALLENTOWN, PENNSYLVANIA 18101

DAVID KLEPPINGER
PJMICC ET AL
PO BOX 1166
HARRISBURG,PENNSYLVANIA 17108-1166

TAMARA LINDE
VICE PRESIDENT - REGULATORY
PSEG COMPANIES
80 PARK PLAZA
T5G
NEWARK, NEW JERSEY 07102

JILL BARKER
BETTS & HOLT LLP
1333 H ST., NW
WEST TOWER 10TH FLOOR
WASHINGTON, DC 20005

MARGARET COMES
SENIOR ATTORNEY
CONSOLIDATED EDISON COMPANY OF
NEW YORK, INC.
4 IRVING PLACE - ROOM 1815-S
NEW YORK, NEW YORK 10003

MARY KRAYESKE
SENIOR ATTORNEY
CONSOLIDATED EDISON
DEVELOPMENT, INC.
4 IRVING PLACE
18TH FLOOR
NEW YORK, NEW YORK 10003

ROBERT WEINBERG
ATTORNEY
DUNCAN, WEINBERG, GENZER &
PEMBROKE PC
1615 M ST., N.W.
SUITE 800
WASHINGTON, DC 20036

DAVID RASKIN
STEPTOE & JOHNSON LLP
1330 CONNECTICUT AVE., NW
WASHINGTON, DC 20036

RICHARD HITT
GENERAL COUNSEL
PO BOX 812
CHARLESTON,WEST VIRGINIA 25323

JANE QUIN
ASSOCIATE COUNSEL
CONSOLIDATED EDISON DEVELOPMENT, INC.
4 IRVING PLACE
ROOM 1450S
NEW YORK, NEW YORK 10003

STUART NACHMIAS
VP, ENGY PLCY AND REG AFF
ROCKLAND ELECTRIC COMPANY
4 IRVING PLACE
ROOM 1425
NEW YORK, NEW YORK 10003

**A. JOSEPH SLATER
SOUTHERN MARYLAND ELECTRIC COOP. INC.
PO BOX 1937
HUGHESVILLE,DC 20637-1937

ELIZABETH WHITTLE
PARTNER
NIXON PEABODY LLP
401 NINTH STREET, N.W
SUITE 900
WASHINGTON, DC 20004

CAROL OVERLAND
LEGALECTRIC
P.O. BOX 176
LEGALECTRIC
RED WING, MINNESOTA 55066

RICHARD ZIEGLER
MANAGER
FIRSTENERGY SERVICE COMPANY
76 S MAIN ST
AKRON, OHIO 44308-1812

MICHAEL R BEITING
ASSOCIATE GENERAL COUNSEL
FIRSTENERGY CORP.
CONSOLIDATED HYDRO & CT PLANTS
76 SOUTH MAIN ST.
AKRON, OHIO 44308

ERIN MURPHY
SENIOR COUNSEL
MORGAN LEWIS & BOCKIUS LLP
101 CONSTITUTION AVE., N.W.
SUITE 200-E
WASHINGTON, DC 20001

MARK CHRISTIAN MORROW
SENIOR COUNSEL
UGI CORPORATION
PO BOX 858
VALLEY FORGE, 19482-0858

ROBERT DAILEADER
NIXON PEABODY LLP
401 9TH STREET N.W.
SUITE 900
WASHINGTON, DC 20004

JOHN D. MCGRANE
PARTNER
UGI CORPORATION
1111 PENNSYLVANIA AVE NW
WASHINGTON, DC 20004

MICHAEL REGULINSKI
ASSISTANT GENERAL COUNSEL
DOMINION RESOURCES SERVICES, INC.
120 TREDEGAR STREET
RS-2
RICHMOND, VIRGINIA 23231

MATT ROUSSY
ASSISTANT ATTORNEY GENERAL
VIRGINIA OFFICE OF ATTORNEY GENERAL
900 EAST MAIN STREET
RICHMOND, VIRGINIA 23219

**WILLIAM H CHAMBLISS
GENERAL COUNSEL
VIRGINIA STATE CORPORATION COMMISSION
PO BOX 1197
RICHMOND,DC 23218-1197

JOHN ROBERT LILYESTROM, ESQ
VIRGINIA ELECTRIC & POWER COMPANY
500 8TH STREET, NW
WASHINGTON, DC 20004

EVAN REESE
VAN NESS FELDMAN, LLP
1040 THOMAS JEFFERST ST., NW
7TH FLOOR
WASHINGTON, DC 20007

REGINA SPEED-BOST
PARTNER
SCHIFF HARDIN LLP
1666 K STREET, N.W.
SUITE 300
WASHINGTON, DC 20006

MARY B. BENGE, ESQ
COUNSEL
WISCONSIN ELECTRIC POWER
COMPANY
333 W. EVERETT STREET, A292
MILWAUKEE, WISCONSIN 53203

RICHARD E HITT, ESQ
GENERAL COUNSEL
WEST VIRGINIA PUBLIC SERVICE COMMISSION
PO BOX 812
CHARLESTON, 25323

JAMES R. KELLER
WISCONSIN ELECTRIC POWER COMPANY
231 WEST MICHIGAN
MILWAUKEE, WISCONSIN 53203

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)

Paragraph Numbers

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

[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

---

[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.

---

[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]

---

[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.

---

[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

---

[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:

---

[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

---

[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

---

[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]

---

[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

---

[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

---

[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

(continued…)

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

---

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]

---

[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]

---

[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. <u>System-Wide Allocation of Costs for New 500 kV and Above Facilities Is Just and Reasonable</u>

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

---

[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. <u>Standard Established in *Illinois Commerce Commission*</u>

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

---

[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

---

[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

---

[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

---

[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

---

[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,

(continued…)

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

---

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,

---

[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

---

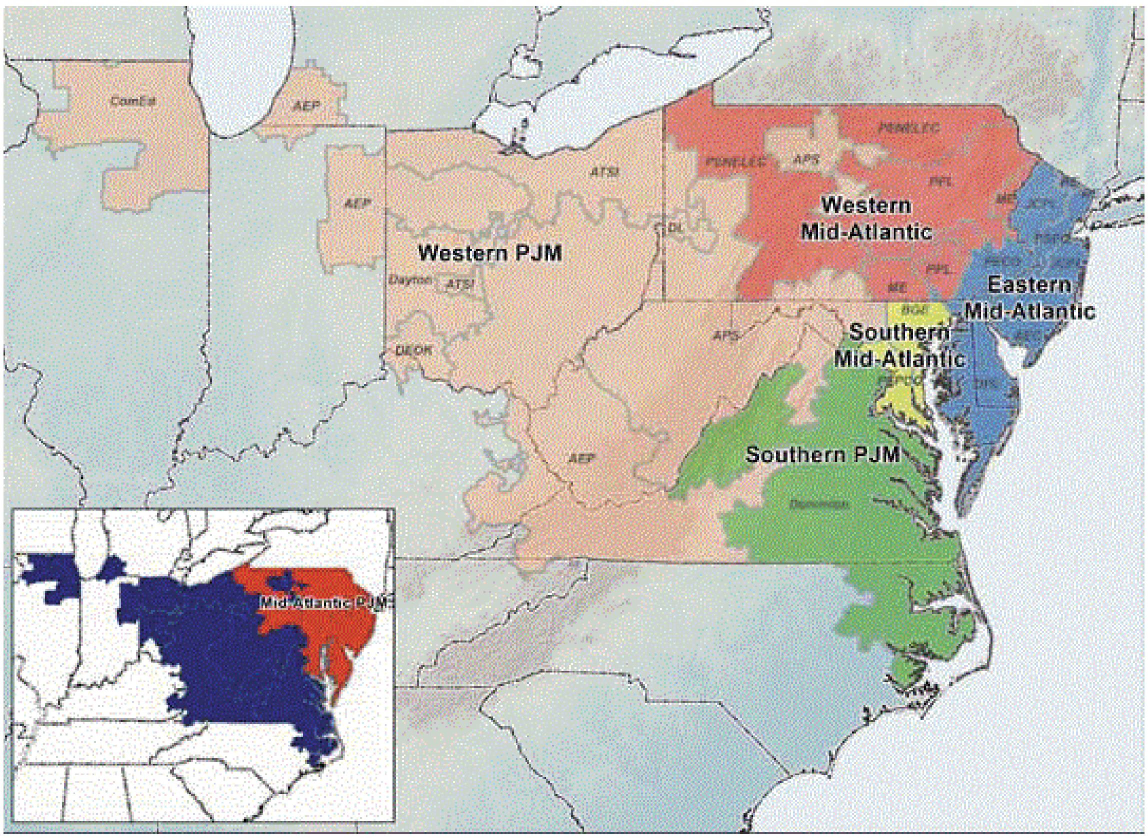
[96] PJM White Paper at 3, 16-17.

[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]



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

---

[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

---

[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

---

[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

---

[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.

Case: 13-2052 Document: 1-1 Filed: 05/16/2013 Pages: 149

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

---

[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. <u>PJM Has Demonstrated the Economic and Engineering Basis to Attribute System-wide Reliability Benefits Delivered by 500 kV and Above Transmission Facilities.</u>

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.

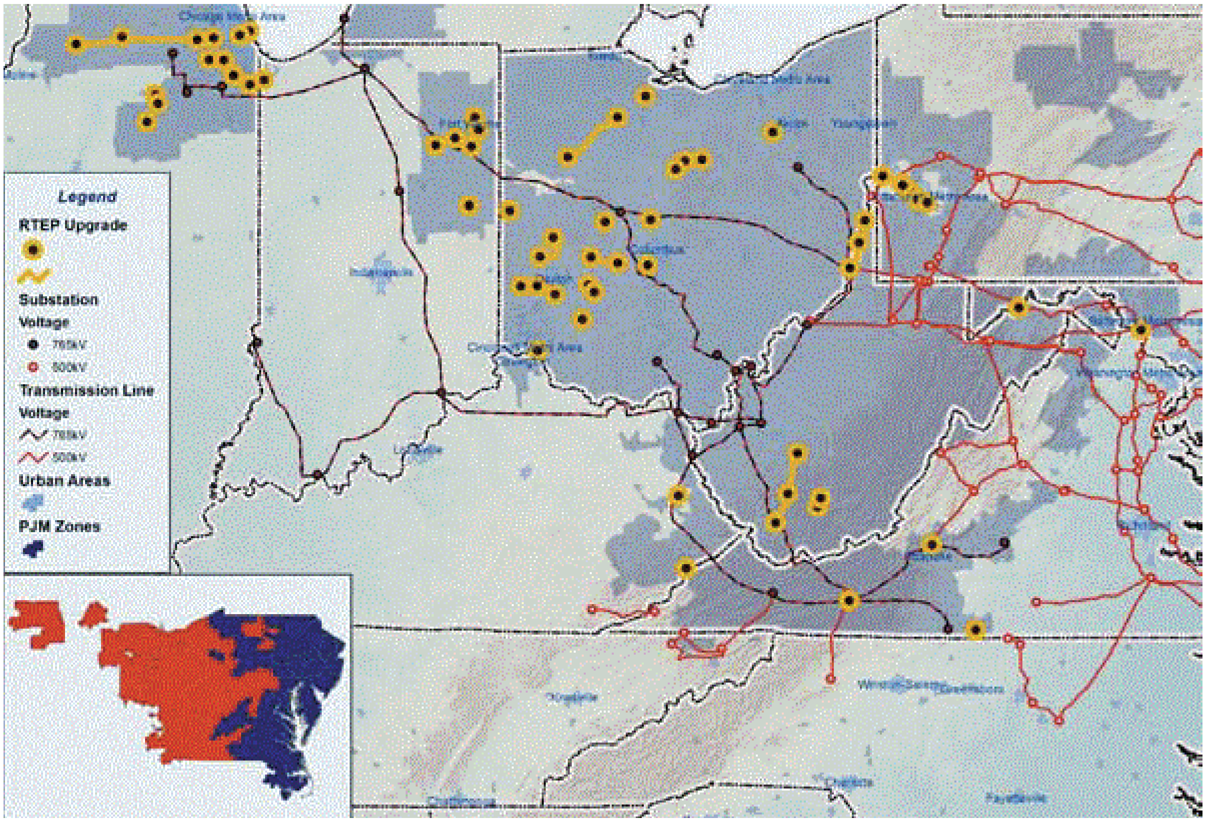
81. As illustrated in the 2011 RTEP, 500 kV and above facilities allow the western zones to be fully integrated into the PJM system, enabling these zones to share the benefits provided by a robust and flexible grid.[144] As demonstrated by the map below, 500 kV and above voltage facilities connect the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

---

[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]

---

[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.

---

[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.

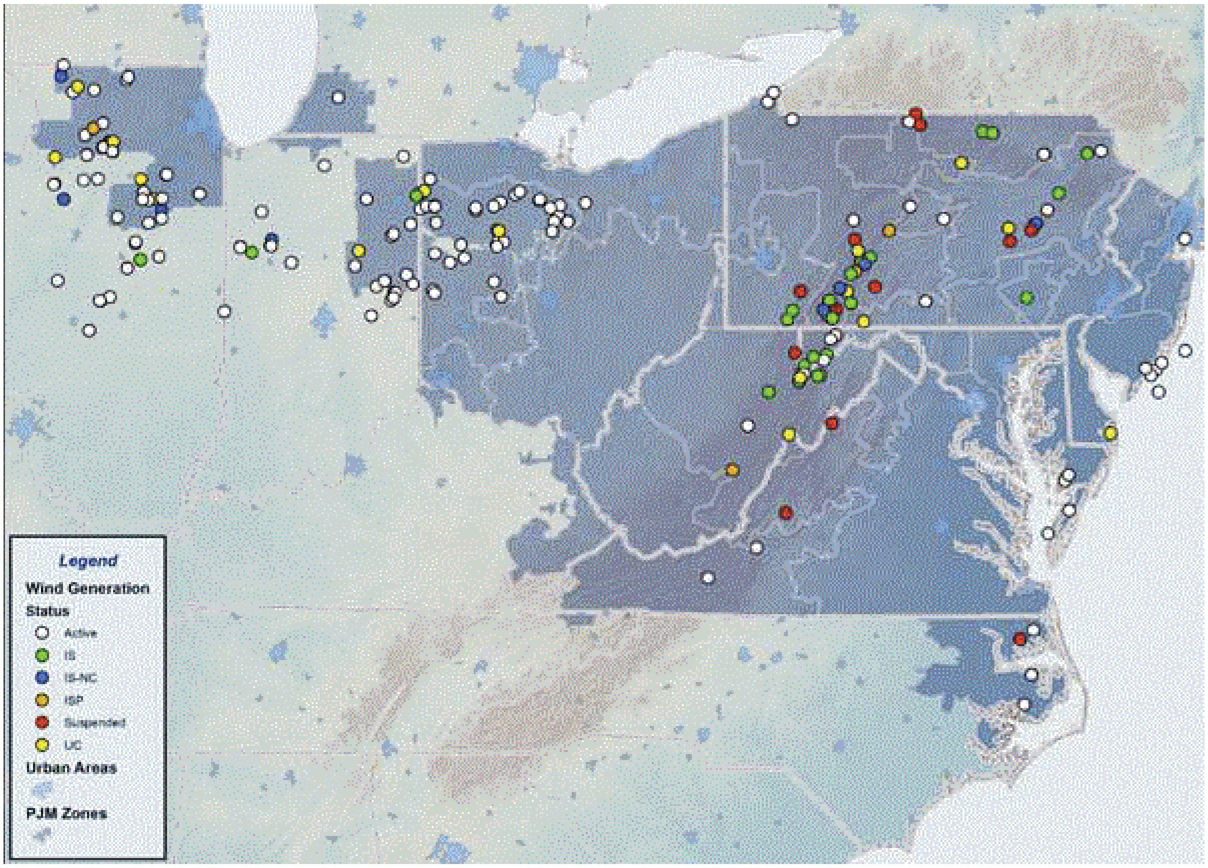
[157] PJM 2011 RTEP, Book 2 at 25.

[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.

---

[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

---

[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

(continued…)

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

---

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

---

[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]

---

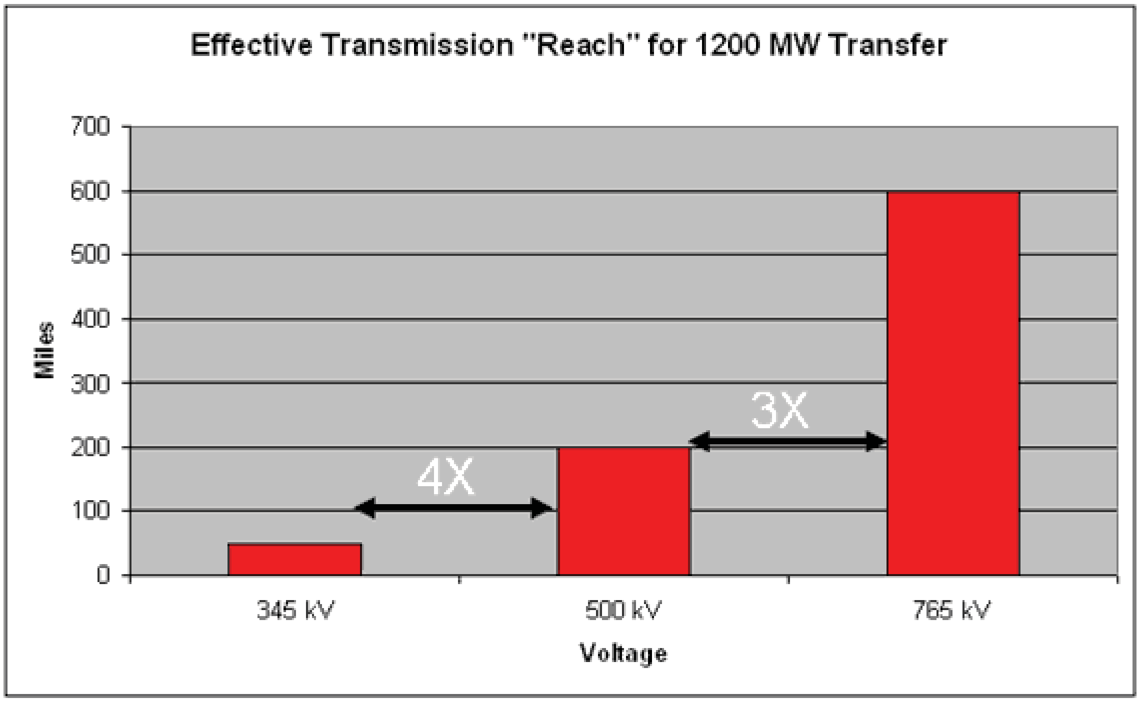
[192] *See* PJM Manual 13 (Emergency Operations) § 2.2 (Reserve Requirements).

[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

---

[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]

---

[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

(continued…)

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

---

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,

---

[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

(continued…)

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

---

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

---

[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]

---

[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

---

[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

Case: 13-2052 Document: 1-1 Filed: 05/16/2013 Pages: 149

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

---

[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.

____
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).

142 FERC ¶ 61,216
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

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

PJM Interconnection, L.L.C. Docket No. EL05-121-008

ORDER ON REHEARING

(Issued March 22, 2013)

Paragraph Numbers

1. On March 30, 2012, the Commission issued an order in response to a remand by the United States Court of Appeals for the Seventh Circuit regarding cost allocation for new transmission facilities that operate at or above 500 kV.[1] Several parties have requested rehearing of the Order on Remand. In this order we affirm the finding that, in this context, using the static distribution factor (DFAX) modeling for PJM transmission facilities operating at 500 kV and above is unjust and unreasonable.[2] Having made that determination, we are required to choose a just and reasonable rate and, based on the record, conclude that using a postage-stamp allocation of the costs of those facilities results in a just and reasonable rate.[3]

2. In making these findings, we acknowledge that issues of cost allocation are some of the most contentious and difficult issues that face the industry and the Commission. They are contentious because the transmission costs to be allocated are usually precise, concrete, and quantifiable whereas the benefits that arise from the improved transmission grid are generally difficult to quantify with precision, involving a greater need for prediction about the future use and operation of electricity systems. As we acknowledged in the Order on Remand, there may be more than one reasonable way to allocate the costs of transmission facilities. We recognize that this is the case in PJM. Indeed, subsequent to this proceeding, the PJM transmission owners submitted an alternative approach to cost allocation, which we accept in a concurrent order as consistent with Order No. 1000.[4]

---

[1] *PJM Interconnection, L.L.C.*, 138 FERC ¶ 61,230 (2012) (Order on Remand). *See Illinois Commerce Comm'n* v. *FERC*, 576 F.3d 470 (7th Cir. 2009) (Seventh Circuit Opinion).

[2] 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.

[3] 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.

[4] *See PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,214 (2013). *See also Transmission Planning and Cost Allocation by Transmission Owning and Operating*

(continued…)

3. In this proceeding on remand, in which we consider cost assignment for a now-limited number of new high voltage facilities planned and approved before February 1, 2013, the Commission must reach a reasoned decision about cost allocation that is based on substantial evidence. The record before us contains only two well-developed methodologies: the static DFAX and the postage-stamp methodology. We have selected the methodology that is the best supported on this record in the context of high voltage facilities planned and approved by the PJM Board of Directors before February 1, 2013. The other approaches suggested by parties in this proceeding, proposing a blend of these two methodologies, are mere outlines of a methodology lacking in implementation details and, importantly, supporting evidence that the proposed methodology would meet the cost causation principle. Although alerted to these deficiencies by the Commission, proponents of these blended or hybrid approaches did not submit such evidence on rehearing of the Order on Remand. Therefore, on the record before us, we do not find evidence, substantial or otherwise, for a hybrid cost allocation methodology.

4. Nor do we adopt parties' suggestion that we set for another administrative hearing or settlement judge proceedings the allocation of these costs. We are now addressing a defined universe of projects – those planned and approved by the PJM Board before February 1, 2013. Because of canceled projects and the Commission's action in the concurrently-issued order on prospective PJM cost allocation, the facility costs are now limited to approximately half of the amount under review when we issued the Order on Remand. Moreover, the costs at issue in this proceeding may decrease further as PJM continues its transmission planning process. The Commission has, after significant process – both initially and on remand – selected the postage-stamp cost allocation methodology as a just and reasonable cost allocation method that is supported by substantial evidence on the record in this proceeding. Moreover, given the context noted above – *i.e.*, the lack of evidence on this record supporting a hybrid cost allocation methodology, the now defined universe of projects, and the reduced amount of costs at issue - we do not find a sufficient basis to warrant expending additional time and resources of the parties and the Commission on still further administrative procedures. We act today to provide some certainty to parties concerning the cost allocation for this discrete set of facilities, ending this phase of the litigation.

I. Background

5. On April 19, 2007, the Commission issued Opinion No. 494, an order on an initial decision concerning PJM's transmission rates for the allocation of costs for existing and new transmission contained in PJM's then current Open Access Transmission Tariff

---

Public Utilities, Order No. 1000, 76 Fed. Reg. 49842 (Aug. 11, 2011), FERC Stats. & Regs. ¶ 31,323 (2011), *order on reh'g*, Order No. 1000-A, 139 FERC ¶ 61,132 (2012).

(Tariff).[5] In Opinion No. 494, the Commission found the existing methodology for cost recovery for existing facilities just and reasonable.[6]

6. Regarding the cost allocation for new transmission, the Commission also found that, because the DFAX 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 DFAX 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.[7] Of particular relevance here, with respect to facilities that operate at 500 kV and above, the Commission found that the static, flow-based model for allocating costs was not just and reasonable because it failed to account for the system-wide benefits of those facilities. The Commission concluded that allocating the costs of those facilities using a postage-stamp methodology is a just and reasonable rate.

7. Several parties sought review of Opinion No. 494 and the subsequent Opinion No. 494-A. The Seventh Circuit affirmed the Commission's determination that the cost allocation methodology for existing facilities was reasonable. The Seventh Circuit, 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 remanded the case to the Commission for further proceedings.

8. The Commission established paper hearing procedures to allow parties to supplement the record in this proceeding.[8] As part of the paper hearing procedures, PJM and the other parties were encouraged to provide studies, methodologies or other evidence to support their positions. Two cost allocation methodologies were developed on the record in this proceeding, the static DFAX and postage-stamp methodology. In affirming use of a postage-stamp methodology, the Commission dismissed suggestions

---

[5] *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).

[6] For existing facilities, a customer pays the cost of transmission facilities that are located in the same zone as the customer.

[7] The Commission accepted a settlement submitted by PJM that set forth the details and assumptions used in applying the static, flow-based allocation methodology for new facilities that operate below 500 kV in Schedule 12, section (b)(ii). *PJM Interconnection, L.L.C.*, 124 FERC ¶ 61,112 (2008).

[8] *PJM Interconnection, L.L.C.*, 130 FERC ¶ 61,052 (2010).

that it should have adopted alternative cost allocation methods, such as the hybrid approaches. In the Order on Remand, the Commission considered these approaches and found that, when fully developed, such approaches could be just and reasonable.[9]

9. In the Order on Remand, the Commission also recognized that PJM and its stakeholders were considering, in response to Order No. 1000, new approaches for new high voltage transmission cost allocation.[10] The Commission found that PJM and its stakeholders were not precluded by the Order on Remand from considering an approach that combines the attributes of flow-based modeling and the realization that 500 kV and above facilities provide broad regional benefits in development of the Order No. 1000 compliance filing. On October 11, 2012, PJM Transmission Owners proposed such a hybrid cost allocation methodology for new high voltage transmission facilities planned and approved on or after February 1, 2013. As a result the cost allocation methodology approved in this proceeding applies only to those facilities planned and approved by PJM before February 1, 2013.

10. The costs to be allocated under the methodology approved in the Order on Remand have been significantly reduced by the cancellation of several 500 kV transmission upgrades, including both the Branchburg-Roseland-Hudson and Potomac Appalachian Transmission Highline (PATH) project, discussed by the Seventh Circuit, and the Mid-Atlantic Power Pathway (MAPP) project.[11] At the time of the Order on Remand, there were approximately $6.6 billion in new 500 kV and above facilities at issue. Using the estimates provided by PJM in the Order on Remand proceeding, the cancellation of projects reduces the estimated costs of the new 500 kV and above facilities from approximately $6.6 to $2.7 billion. Even with inclusion of construction work in progress and abandonment costs, estimated costs at issue are half of the original $6.6 billion.

---

[9] *PJM Interconnection, L.L.C.*, 138 FERC ¶ 61,230 at P 49 & n.70.

[10] *Id.* at P 2.

[11] *See* PJM Transmission Expansion Advisory Committee, August 2012 (http://www.pjm.com/committees-and-groups/committees/teac.aspx).

II. March 30, 2012 Order on Remand

A. DFAX Static Modeling of PJM Transmission Facilities Operating at 500 kV and Above

11. The Order on Remand found that PJM's use of a static, flow-based model for allocating the costs of new transmission facilities that operate at or above 500 kV is unjust and unreasonable and unduly discriminatory. In support of this finding, the Commission noted that the DFAX methodology used by PJM is static insofar as it models at a single point in time, and fails to account for changes that occur over time that affect the benefits received by parties from these facilities. These changes can be to generator's, loads, and flow patterns, as well as structural changes such as new transmission facilities and changes to, or retirement of, old transmission facilities.[12]

12. The Commission recognized that a snapshot-in-time model does not reflect these changes in power flows, instead looking at the system as it existed at one point in time prior to the upgrade, and found that the deficiencies in aligning costs and benefits were particularly acute with respect to high voltage lines that serve large portions of the PJM system.[13] The Commission concluded that PJM's static DFAX methodology used 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.[14]

B. Postage-Stamp Allocation of PJM Transmission Facilities Operating at 500 kV and Above

13. In the Order on Remand, the Commission also found that allocating the costs of new transmission facilities that operate at or above 500 kV using a postage-stamp allocation methodology is a just, reasonable and not unduly discriminatory method of allocating the costs of such new facilities. Specifically, the Commission found that the reliability benefits of these facilities will be sufficiently shared by all in the PJM region, including the western part of PJM, to justify regional cost allocation.

---

[12] Order on Remand, 138 FERC ¶ 61,230 at P 38.

[13] *Id.* PP 38-46.

[14] *Id.* P 47.

14. The Commission found that transmission facilities operating at 500 kV and above provide benefits in: (1) moving large amounts of power to multiple zones of the region;[15] (2) addressing multiple reliability violations over wide areas; (3) readily accommodating changing power flows (daily, seasonal and in emergencies) and needs of the region; and (4) protecting all parts of the region from significant disruptions. The Commission acknowledged that reliability is a benefit that is difficult to quantify, but that the evidence in this proceeding illustrates that this is a valuable benefit that is enjoyed by all customers interconnected to the integrated PJM system.[16] The Commission further acknowledged that 500 kV and above Regional Transmission Expansion Plan (RTEP) projects, while not all 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.[17] The Commission predicted that, but for such 500 kV facilities, the PJM system would be unable to provide reliable transmission service. Thus, the Commission concluded that the transmission facilities that directly address such region-wide reliability concerns are reasonably allocated on a *pro rata* basis among all PJM customers.

15. For example, in support of its finding, the Commission recognized the ability of transmission facilities that operate at or above 500 kV to reduce reserve margins by enabling utilities to share resources. The Commission noted that 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. The Commission stated that the evidence shows that transmission facilities that operate at or above 500 kV have greater transfer capability than 345 kV transmission facilities.[18] For instance, the Commission noted that 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. The Commission concluded that 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, the Commission noted that, for every mile of wire installed, the greater reach of higher

---

[15] *See* Attachment A (PJM Pricing Zones). http://www.pjm.com/~/media/about-pjm/pjm-zones.ashx

[16] *Id.* P 97.

[17] *Id.*

[18] *Id.* P 103 (citing Fair Pricing Group Comments at 21 (May 28, 2010)).

voltage facilities provides both access to more, geographically diverse sources and a greater ability to share reserves than would lower voltage facilities.

16. In the Order on Remand, the Commission provided an example where Commonwealth Edison Company (ComEd), which is located on the western edge of PJM, operated as a stand-alone entity, would have an operating reserve requirement to meet contingency conditions of 1,175 megawatts (MW),[19] and would have to procure or construct all 1,175 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, the Commission noted that ComEd can reduce its overall cost of maintaining adequate reserves. Specifically, PJM's contingency operating reserve requirement for Western PJM is 150 percent of the largest unit,[20] or 1,950 MW,[21] and ComEd, by being connected to PJM via its robust high-voltage transmission grid, is required to have only its *pro rata* share of the total reserve requirement for Western PJM, approximately 585 MW, rather than having to support its individual 1,175 MW operating reserve requirement.

17. The Commission noted that reliability is not a benefit that can be quantified in absolute terms, and that new high voltage transmission projects in PJM offer a range of reliability benefits to users of the PJM system.[22] The Commission found that the reliability of the PJM transmission system provides for the efficient operation of the PJM markets, which produces up to $2.2 billion in estimated system-wide savings each year, along with additional estimated annual savings associated with decreased service interruptions and power quality disturbances, reduced line losses, and reduced congestion.[23] While the Commission recognized that there is imprecision in valuing the benefits of new transmission facilities that operate at or above 500 kV, the estimated savings provide sufficient justification for the use of 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

---

[19] Order on Remand, 138 FERC ¶ 61,230 at P 102. *See* Exelon Initial Comments (May 28, 2010), Affidavit of Steven T. Naumann at 40.

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

[21] Order on Remand, 138 FERC ¶ 61,230 at P 102 (citing Fair Pricing Group Comments (May 28, 2010), Declaration of Esam A. F. Khadr at 82).

[22] *Id.* P 110.

[23] *Id.* P 109.

for future needs.[24] Accordingly, the Commission concluded that, for transmission facilities that operate at or above 500 kV, the reliability and other benefits to customers in the PJM region, including in the western parts of PJM, are roughly commensurate with the costs of those facilities allocated using a postage-stamp load-ratio share methodology.

18. In addition, the Order on Remand dismissed arguments made by LIPA regarding how the costs of 500 kV and above transmission facilities should be allocated to merchant transmission facilities, finding such arguments to be outside the scope of the proceeding.[25] The Order on Remand noted that the assignment of RTEP costs to merchant transmission facilities has been addressed in Opinion No. 503;[26] in Opinion No. 503, 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, and 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."[27]

III. <u>Requests for Rehearing of the March 30, 2012 Order on Remand</u>

19. Requests for rehearing of the Order on Remand were filed by Illinois Commerce Commission (Illinois Commission), Public Utilities Commission of Ohio (Ohio Commission), Dayton Power and Light Company (Dayton), FirstEnergy Companies (FirstEnergy),[28] and Long Island Power Authority (LIPA).

20. As further discussed below, on rehearing parties contend that: (1) the current DFAX methodology has not been shown to be unjust and unreasonable, and (2) the

---

[24] *Id.*

[25] *Id.* P 34.

[26] *PJM Interconnection, L.L.C.*, Opinion No. 503, 129 FERC ¶ 61,161 (2009), *order on reh'g*, Opinion No. 503-A, 139 FERC ¶ 61,243 (2012).

[27] *Id.* n.27.

[28] FirstEnergy is an electric utility holding company that serves customers in the five PJM transmission pricing zones of Allegheny Power Company, American Transmission Systems, Inc., Jersey Central Power and Light Company, Metropolitan Edison Company, and Pennsylvania Electric Company. First Energy Rehearing Request at 1 n.3; *see also* Attachment B, FirstEnergy Regulated Distribution Companies. https://www.firstenergycorp.com/content/fecorp/about.html

postage-stamp cost allocation methodology has not been shown to be just and reasonable. LIPA also contends that the Commission erred in the treatment of merchant transmission facilities.

IV. Discussion

A. Static DFAX Methodology

1. Rehearing Requests

21. The parties argue that the findings of the Order on Remand that the DFAX methodology for new transmission facilities that operate at or above 500 kV is not just and reasonable, is not supported by substantial evidence and is arbitrary and capricious. In support, the parties maintain that the DFAX methodology allocates cost for transmission facilities that operate at or above 500 kV to customers in reasonable proportion to the extent to which they create the need for the upgrade by stressing the overloaded transmission elements that must be buttressed or relieved to maintain reliability.

22. The parties also contend that the Commission subjected the DFAX methodology to a customer-specific comparison of benefits and costs, and held the DFAX methodology's compliance with cost causation to a far greater degree of precision than was applied when evaluating the postage-stamp methodology. FirstEnergy argues that a rate satisfies the cost causation requirement if it "allocates costs to customers in proportion *either* to the benefits they derive from the incurrence of the costs *or* to their respective contribution to the need for those costs to be incurred."[29] According to FirstEnergy, the Commission failed to consider the second prong of this standard, i.e., the respective contribution to the need for the costs incurred.

23. The parties next maintain that the finding in the Order on Remand that transmission facilities that operate at 500 kV and above may create benefits for other customers by resolving constraints other than the constraint that creates the immediate need for the upgrade fails to invalidate the existing methodology. Dayton takes issue with the Commission's statement that the solution for resolving a reliability violation identified in a DFAX analysis often mitigates or solves other potential reliability problems. Dayton disagrees with the implicit assumption that those other potential reliability problems are in some far-off zone that is not being allocated the proper level of costs under the DFAX methodology. Dayton further suggests that there is no record evidence that establishes that midwestern utilities receive any reliability benefits from

---

[29] FirstEnergy Rehearing Request at 24 (emphasis in original).

eastern transmission projects.[30] According to Dayton, the midwestern utilities have "zero 'need'" for the new transmission lines.[31]

24. The Illinois Commission also sees shortcomings in the way PJM conducted its evaluation of multiple violations contributing to the need for a line and argues that the Commission erred by basing its rejection of the DFAX methodology on these analyses. The Illinois Commission further argues that the Commission wrongly concludes from PJM's evaluation that the static DFAX methodology fails to identify all of the cost causers. Even if it is reasonable to conclude that the DFAX analysis misses some cost causers, Illinois Commission argues that the DFAX methodology is still reasonable because the changes in allocations are small.[32] The parties also take issue with the Order on Remand findings that the DFAX methodology fails to account for changes in usage and flow direction over time. It also states that nothing in the record suggests that the flows across transmission lines projected to relieve eastern congestion will suddenly reverse and start flowing power to the Midwest.

25. Finally, the parties offer suggestions on how to alleviate some of the concern about the snapshot analysis and allege that the Commission failed to demonstrate that the DFAX method is unreasonably burdensome. Dayton suggests employing multiple scenario runs and taking an average of those results or performing a DFAX analysis when the facility is first planned and then again when it goes into service. The Ohio Commission and the Illinois Commission make similar suggestions.[33] Such proposals, according to these parties, do not represent an excessive burden to PJM. Dayton notes that one of the hired experts in this proceeding prepared five different DFAX scenario runs. Furthermore, given the magnitude of costs being allocated, Dayton argues that the administrative burden of doing additional DFAX analyses periodically should not be a fatal impediment. The Ohio Commission notes that PJM routinely collects data and analyzes it to determine the transmission and grid impacts and thus argues that a periodic review is worth any administrative burden it may create for PJM.

---

[30] Dayton Rehearing Request at 76.

[31] *Id*.

[32] Illinois Commission Rehearing Request at 33.

[33] Illinois Commission Rehearing Request at 34; Ohio Commission Rehearing Request at 8.

2. Commission Determination

26. On rehearing we affirm that PJM's static DFAX methodology is an unjust and unreasonable mechanism for allocating the costs of the PJM transmission facilities that operate at or above 500 kV. PJM's static DFAX methodology does not allocate the costs of high-voltage facilities in a way that is roughly commensurate with the benefits that these facilities will deliver in the near future or over their useful lives.

27. The Seventh Circuit required that the Commission's decision must comport with the principle of cost causation, by comparing the costs assessed against parties to the burdens imposed or benefits drawn by those parties.[34] Courts have recognized that the Commission must take into account both the immediate cause of cost incurrence as well as the ultimate beneficiaries of the construction.[35] In evaluating the reasonableness of PJM's cost allocation mechanism, the Commission therefore has considered both the immediate cause of the construction and the resulting benefits in allocating the costs for the construction of the new transmission facilities. Based on its evaluation, the Commission found, and affirms here, that it is not just and reasonable for PJM to use the static DFAX methodology to allocate costs of transmission facilities that operate at or above 500 kV because the static DFAX methodology fails to appropriately identify those parties that cause the need for the facilities and that benefit from the construction of the facilities.

28. As the Order on Remand noted, the higher voltage transmission facilities provide benefits beyond those identified in PJM's static DFAX modeling analysis. Specifically, the Commission recognized that PJM's static DFAX methodology for allocating the cost of lower voltage, localized projects does not capture the regional reach nor accurately identify all the benefits,[36] and beneficiaries, of PJM's planned high voltage system,

---

[34] Seventh Circuit Opinion, 576 F.3d at 476 (citing *Midwest ISO*, 373 F.3d at 1368).

[35] *KN Energy, Inc. v. FERC*, 968 F. 2d 1295, 1302 (D.C. Cir 1992) ("the benefit principle may simply prove to be another prism through which to view the question of cost causation — one that admittedly extends the chain of causation further than FERC has done traditionally. That is, rather than focusing us on the most immediate and proximate cause of the cost incurred, the benefit principle may only ask us to look at a host of contributing causes for the cost incurred (as ascertained by a review of those who benefit from the incurrence of the cost) and assign them liability too").

[36] DFAX does not quantify the long-term benefits of the new lines – it identifies those that are currently flowing power over a facility that is a reliability constraint.

particularly with respect to transmission facilities that relieve multiple transmission constraints over long distances, multiple zones, and over long periods of time.[37] In the case of investments that will last upwards of forty years, it is reasonable for the Commission to balance both short-run causes and benefits and long-run benefits. We disagree with FirstEnergy that our analysis of PJM's use of the static DFAX methodology to allocate the cost of transmission facilities that operate at or above 500 kv failed to consider cost causation. As part our analysis, we evaluated the extent to which the static DFAX methodology fails to recognize the benefits that these facilities will provide to a wide range of customers over their useful life.

29. We continue to find that the static DFAX method has limitations that render it unjust and unreasonable to use as the sole basis for allocating the costs of 500 kV and above transmission facilities within PJM. As previously noted,[38] the static DFAX methodology focuses on a single constraint at a single point in time and, as such, cannot capture the full contribution of high-voltage facilities, which relieve multiple constraints over large areas and over long periods of time. The Commission cannot ignore these failings of the DFAX analysis and find the methodology, nevertheless, reasonable as the Illinois Commission requests.[39] This is demonstrated by PJM's evaluation of the Susquehanna-Roseland facility showing that the project will resolve not one, but 143, violations.[40] Under the DFAX analysis, ComEd and Dayton were allocated a portion, albeit a small portion, of the costs of this facility, and under the sensitivity analysis, the DFAX allocation of this facility to those entities increased.[41] The Illinois Commission faults the Commission for relying on this evaluation, but fails to point to anything that shows that the static DFAX methodology properly identifies all of those that cause the need for the transmission facilities that operate at 500 kV and above.[42] The Illinois Commission argues, in essence, that it is preferable to be under-inclusive of beneficiaries

---

[37] Order on Remand, 138 FERC ¶ 61,230 at PP 41-47.

[38] *Id.*

[39] *See* Illinois Commission Rehearing Request at 31-34.

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

[41] *Id.* at 18. PJM submitted a comparison of DFAX analysis requested by the Commission for the Susquehanna-Roseland facility for the time it was included in the 2007 RTEP, and a sensitivity analysis based on violations for the other facilities found to be overloaded by PJM's review of the 2007 RTEP analysis.

[42] *See* Illinois Commission Rehearing Request at 33.

in allocating these costs. We disagree. Where the relevant transmission facilities are higher voltage, networked facilities that resolve multiple constraints and will provide benefits across their entire forty years of operation, we find that it is appropriate to include those beneficiaries.

30. Moreover, Dayton's allegation that it and other Western PJM utilities do not contribute to the need for facilities is also undermined by PJM's evaluation of the Trans Allegheny Interstate Line (TrAIL) facility.[43] Although in some cases the relative contribution to the need for these facilities by certain Western PJM utilities may be small,[44] we reject Dayton's contention that only far-off zones are causing the reliability violations addressed by the transmission facilities that operate at or above 500 kV. In fact, we note that, even under a DFAX analysis, the need for TrAIL is caused in significant part by violations in the FirstEnergy/APS zone, bordering Ohio.[45]

31. We also continue to find that the snapshot approach of the static DFAX methodology inadequately accounts for the greater transfer capability of high-voltage lines, which provides a widely-shared benefit by allowing the grid to better adapt to changing needs and flow patterns.[46] Similarly, high-voltage facilities increase the system's ability to withstand extreme disturbances, such as the loss of an entire switching station or load center, another benefit not accounted for under the static DFAX methodology. The Commission found in the Order on Remand, and we continue to find, that the static DFAX methodology fails to account for the broad and often difficult-to-measure benefits of high-voltage facilities within PJM. Based on these considerations, for transmission facilities that operate at or above 500 kV, we find that PJM's static DFAX methodology, because of its limitations, is unjust and unreasonable.

32. FirstEnergy alleges that the Commission was arbitrary and capricious in subjecting the static DFAX methodology to a customer-specific comparison of costs and benefits while applying no such analysis to the postage-stamp method. We disagree. The Order on Remand recognized that, unlike lower voltage, localized facilities, high-voltage facilities possess certain inherent characteristics that make measurement of their widely-

---

[43] PJM April 13 Response at 7 (showing contributions to need for the lines by APS).

[44] *See* Dayton Rehearing Request, Appendix B at 16.

[45] PJM April 13 Response at 7.

[46] The cancellation of the MAPP and PATH projects highlights the uncertainty of changing needs and flow patterns over time.

distributed benefits on an individualized basis imprecise. As previously discussed, the Commission noted, for example, that the static DFAX methodology fails to account for widely shared benefits such as enhanced reliability of the grid, reduced losses, and other non-quantifiable reliability benefits of higher voltage new transmission facilities.[47] Moreover, the Commission demonstrated that these non-quantifiable reliability benefits accrue to the entire interconnected network. The Commission drew a distinction between the appropriateness of the static DFAX methodology for lower voltage, localized facilities and the inability of the static DFAX methodology to identify beneficiaries for transmission facilities that operate at or above 500 kV.

33. Finally, Dayton, the Illinois Commission and the Ohio Commission contend that the Commission failed to demonstrate that performing periodic or multiple analyses using the static DFAX methodology is unreasonably burdensome. They argue that these identified problems with the static DFAX methodology could be remedied, thereby creating a new type of analysis that is not unjust and unreasonable. This argument, however, lends support to the Commission's finding that the static DFAX methodology is unjust and unreasonable. In fact, it suggests, just as the Commission found, that model is flawed when used for this purpose because it fails to account for changes over time.

34. Dayton, the Illinois Commission, and the Ohio Commission may be arguing that, in determining the just and reasonable rate to replace the current DFAX, their version – a periodic DFAX – is superior to the postage-stamp methodology, adopted by the Commission. We recognize that there may be many just and reasonable methods of cost allocation that the Commission could adopt (or that PJM and its transmission owners may propose).[48] However, as discussed in the Order on Remand and below, we need only

---

[47] Order on Remand, 138 FERC ¶ 61,230 at P 38.

[48] In acting under section 206, the Commission is not required to choose the best solution, only a just and reasonable one. *Petal Gas Storage, L.L.C. v. FERC*, 496 F.3d 695, 703 (D.C. Cir. 2007); *see also Wisconsin Public Power, Inc. v. FERC*, 493 F.3d 239, 266 (D.C. Cir. 2007) (merely because petitioners can conceive of a refund allocation method that they believe would be superior to the one FERC approved does not mean that FERC erred in concluding the latter was just and reasonable); *ExxonMobil Oil Corp. v. FERC*, 487 F.3d 945, 955 (D.C. Cir. 2007) (we 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); *United Distribution Companies v. FERC*, 88 F.3d 1105, 1169 (D.C. Cir. 1996) ("FERC correctly counters that the fact that AEPCO may have proposed a reasonable alternative to SFV rate design is not compelling. The existence of a second reasonable course of action does not invalidate the agency's determination").

select a just and reasonable methodology and we find that the postage-stamp methodology is just and reasonable. Moreover, as we found in the Order on Remand, the parties suggesting periodic DFAX analysis did not put forward a complete proposal demonstrating how such an analysis could be performed without requiring the unwinding of the transmission grid to determine whether the impacts driving the need for a previously approved project had changed.[49] Moreover, such a periodic analysis that allocates costs solely based on the static DFAX methodology would only identify the immediate direct reliability beneficiaries of these lines and would continue to allow others a free ride for the additional benefits that the lines will provide.

B. Postage-Stamp Cost Allocation

1. Requirement to Compare Costs and Benefits

a. Rehearing Requests

35. The parties contend that the Commission did not fulfill its duty to compare the costs assessed against a party to the burdens imposed or benefits drawn by that party, as required by the Seventh Circuit Opinion. Although all of the parties that requested rehearing argue that the Commission's analysis was incorrect, the parties propose different interpretations of the comparison required by the Seventh Circuit. For example, the Ohio Commission argues that, under a postage-stamp methodology, transmission customers in their state are required to pay costs for which they receive little or no benefit, and that this is contrary to the requirements of the Seventh Circuit. The Ohio Commission states that the Commission's findings of sufficiently broad benefits does not meet the Seventh Circuit's directive to demonstrate how the costs of new transmission facilities that operate at or above 500 kV are roughly commensurate with benefits received. The Ohio Commission contends that the Seventh Circuit's Opinion requires quantification of actual sub-regional or state-by-state benefits associated with each transmission expansion project. The Illinois Commission argues that the Seventh Circuit requires a comparison of the costs and benefits for each customer, and that a comparison be made even if the Commission intended to rely on a presumption that new transmission lines benefit the entire network by reducing the likelihood or severity of outages.

36. The Illinois Commission contends that the Seventh Circuit Opinion does not allow the Commission to rely on presumption of benefits if it can quantify benefits. It asserts that the Commission failed to follow this requirement because nothing in the record indicates that benefits cannot be quantified and clear evidence shows that they are

---

[49] Order on Remand, 138 FERC ¶ 61,230 at P 44.

quantifiable.[50] It further argues that the postage-stamp methodology is unduly preferential to utilities in Eastern PJM and unduly discriminatory to utilities in Western PJM. The Illinois Commission contends that in applying the postage-stamp allocation methodology, the Commission does not reasonably address these asymmetries. Dayton argues that the costs and benefits must be quantified on a sub-regional or utility-by-utility basis for new transmission facilities that operate at or above 500 kV. It also argues that, when compared to the results of the DFAX methodology, use of the postage-stamp allocation methodology results in an unjustified cost shift. FirstEnergy contends that the Commission did not fulfill its duty of comparing the costs assessed against a party to the burdens imposed or benefits drawn by the party to determine whether customers in different pricing zones benefit from transmission facilities that operate at or above 500 kV or contribute to the need for them in at least rough proportion to their shares of the PJM load.

37. The parties maintain that the Commission's reading in the Order on Remand of the *Midwest ISO* and *Western Massachusetts* cases cited by the Seventh Circuit is erroneous.[51] For example, FirstEnergy and Dayton argue that the Seventh Circuit imposed a burden of comparing the costs assessed against a party to the burdens imposed or benefits received by that party, and that this duty is not excused by a presumption that 500 kV and above facilities benefit the entire network. FirstEnergy also argues that neither *Midwest ISO* nor *Western Massachusetts* excuse the requirement to conduct a customer-focused or sub-regional comparison for the allocation of upgrade costs among transmission customers in a region. Specifically, FirstEnergy contends that the allocation of administrative costs were at issue in *Midwest ISO*, and that the Seventh Circuit distinguished the administrative costs of having a regional transmission organization (RTO) from the cost of using the transmission system. FirstEnergy also contends that while the court in *Western Massachusetts* took note that any enhancements to a utility's integrated system in connection with a generator interconnection are presumed to benefit the entire system, such reliance was based on identifying the beneficiary of the upgrades, and that customers other than the generator will make use of and benefit from the upgrade. Dayton similarly argues that the Commission's interpretation of *Midwest ISO* and *Western Massachusetts* lead to an unwarranted conclusion that a utility-by-utility evaluation is unnecessary. The Illinois Commission argues that *Western Massachusetts* is inapposite because the case involves a single utility in a very small geographic region. According to the Illinois Commission, *Western Massachusetts* also included evidence from flow-based models that showed how customers other than an interconnecting

---

[50] Illinois Commission Rehearing Request at 23-24.

[51] *Midwest ISO*, 373 F.3d at 1368-69; *Western Massachusetts Electric Company v. FERC*, 165 F.3d 922 (D.C. Cir. 1999) (*Western Massachusetts*).

generator benefited from the upgrade, and here the Commission ignores that same type of evidence.

b. <u>Commission Determination</u>

38. As discussed below, we affirm that the Order on Remand is consistent with the requirements of the Seventh Circuit and deny the requests for rehearing. FirstEnergy argues that the Seventh Circuit did not mandate a particular method of comparing costs and benefits or a numerical target that the comparison must satisfy, but the Seventh Circuit did explicitly require a comparison. In their rehearing requests, the other parties argue for different levels of precision in making this comparison, each asserting that quantification of benefits is required. The Seventh Circuit recognized that, in comparing costs and benefits, the Commission does not have to calculate benefits with exacting precision.[52] The Seventh Circuit further stated that the Commission can approve PJM's proposed pricing scheme even if the Commission cannot quantify the benefits to the Midwestern utilities from new 500 kV lines in the East.[53] In fact, the Illinois and Ohio Commissions, Dayton, and Exelon initially interpreted the Seventh Circuit Opinion as "not require[ing] 'a monetization of benefits,' a 'numerical boundary,' or a 'dollars-and-cents quantification'."[54] Those four parties to the original appeal in the Seventh Circuit agreed, in fact, that "it is perfectly 'fine' for FERC to base a[n] . . . allocation formula on nothing more than an 'articulable and plausible reason to believe benefits are roughly commensurate with [each] utilities' share of total electricity sale in PJM's region.[55] No quantification is necessary."[56] And we agree with their initial interpretation of the Seventh Circuit's Opinion and conclude, as they did, that, in this remand proceeding, "if it cannot quantify the benefits to the midwestern utilities from new 500 kV lines in the East, … but has an articulable and plausible reason to believe that the benefits are at least

---

[52] Seventh Circuit Opinion, 576 F.3d at 476 (citing *KN Energy, Inc. v. FERC*, 968 F. 2d 1295, at 1300 (D. C. Cir. 1992) (*KN Energy*) (rates [must] reflect to some degree the costs actually caused by the customer who must pay them)).

[53] *Id.*

[54] *See* Illinois and Ohio Commissions Joint Answer in Opposition to Petition for Rehearing and Rehearing en banc, at 4 (October 6, 2009).

[55] *Id.* (citing Seventh Circuit Opinion, 576 F.3d at 477).

[56] Illinois and Ohio Commissions Joint Answer, at 4.

roughly commensurate with those utilities share of total electricity sale in PJM's region, … the Commission can approve PJM's proposed pricing scheme on that basis."[57]

39. Parties on rehearing contend that, when PJM's static DFAX methodology would not assign them cost responsibility, they are not benefiting from the upgrade. Our analysis, in contrast, recognizes that the new transmission facilities that operate at or above 500 kV are part of PJM's dynamic and integrated system, and we view the benefits of that network system more broadly than the benefits indicated solely by static flow-based modeling. *Western Massachusetts* supports this position.

40. The cost allocation methodology affirmed in *Western Massachusetts* assigned to all network customers the costs of a transmission project that allowed a generator to transmit its electricity across one utility's grid for sale to a neighboring utility in the New England Power Pool.[58] The ability to move power across large areas is one of the broad-based benefits provided by new transmission facilities that operate at or above 500 kV. Even though a generator was the sole proximate cause of the transmission project at issue in *Western Massachusetts*,[59] the Commission based its broader allocation of costs on both (1) a presumption that new transmission lines benefit the entire network; and (2) a study of flows on the system that showed other grid customers would use the upgraded facilities.[60] That study did not show that each and every customer on the grid would, or even could, make use of the facilities once they were built as the Illinois Commission suggests. Rather, it showed that "customers other than [the generator] will make use of and benefit from the grid upgrades," in those few times when the power flowing from the generator is "lower than expected."[61] In fact, the administrative law judge found that although Commission trial staff "suggests that some benefit to the system may have resulted, [its witness] was unable to identify any specific added system benefits accruing to either [Western Massachusetts Electric Company] or to its transmission customers" from the new line.[62] Thus, in *Western Massachusetts*, the only decision cited in the Seventh Circuit Opinion that concerns allocation of the costs of electric transmission

---

[57] Seventh Circuit Opinion, 576 F.3d at 477.

[58] *Western Massachusetts*, 165 F.3d at 923.

[59] *Id*. at 925.

[60] *Id*. at 927.

[61] *Id*.

[62] *Western Massachusetts Electric Company*, 64 FERC ¶ 63,028 at 65,128 (1993).

lines, there was no evidence showing with precision how much or even which transmission customers would benefit from the new line. And yet, *Western Massachusetts* affirmed a cost allocation methodology broadly assigning costs.

41. We similarly emphasize, as discussed above, that PJM's static DFAX methodology, while flow-based, does not show how specific customers will actually benefit from the transmission lines once they are built. In this way the DFAX flow-based modeling is unlike the load-flow analysis performed in *Western Massachusetts* that sought to predict future flows.

42. We do not find that the Seventh Circuit required a utility-by-utility or state-by-state assessment; nothing in the Seventh Circuit Opinion mentioned or even alluded to a comparison of costs and benefits for each state, and we do not believe that the Seventh Circuit intended to establish new precedent in defining the required analysis. *Midwest ISO* similarly does not require such a granular approach. *Midwest ISO* recognized that all approved rates reflect "to some degree" the costs actually caused by the customer who must pay them, but noted compliance does not require exacting precision.[63] That the rates at issue in Midwest ISO concerned administrative costs does not undermine the point that there was no party-by-party analysis of costs and benefits submitted by the rate proponent in that case. It was enough, *Midwest ISO* noted, that the cost allocation mechanism not be arbitrary and capricious in light of the burdens imposed or the benefits received. *Midwest ISO* also noted that even if transmission owners are not in some sense using the [system], they benefit from having the [system], and they should share in the costs of having the [system].[64]

43. The parties seeking rehearing state that the Commission is obligated to comply with the Seventh Circuit's requirement that a transmission rate match to some degree the costs allocated to each party and the burdens imposed or benefits drawn by that party. FirstEnergy argues that the Seventh Circuit explicitly imposed this requirement, and contends that the Commission cannot deviate from this prescribed analysis. We agree that we must conduct an analysis that meets the Seventh Circuit's requirements, and that addresses those cost causation concerns upon which that decision was founded, as closely as possible. And we have done that in the Order on Remand and in this Order.

---

[63] *Midwest ISO*, 373 F.3d at 1368-69 (citing *KN Energy, Inc. v. FERC*, 968 F.2d at 1300).

[64] *Midwest ISO*, 373 F.3d at 1370-71 (drawing an analogy to the federal court system, which costs a considerable amount to set up and maintain, even though the vast majority of taxpayers will have no contact with that system).

44. While the parties contend that the Commission is required to perform an analysis of the benefits from the new transmission facilities, *KN Energy* did not limit its holding to an analysis of the benefits of each added facility to each and every customer. As previously noted, while articulating a requirement that rates be cost supported, *KN Energy* noted that, under the circumstances, rather than focusing on the most immediate and proximate cause of the cost incurred, consideration of a host of contributing causes may be inquired.[65]

45. The Seventh Circuit stated that the Commission can presume that new transmission lines benefit the entire network by reducing the likelihood or severity of outages, but held that the Commission cannot use that presumption to avoid the duty of comparing the costs assessed against a party to the burdens imposed or benefits drawn by that party.[66] We have not relied solely or even predominately on a presumption, but also reviewed evidence of the reliability benefits that the new high voltage lines provide to an interconnected system, and to the extent that these benefits are quantifiable, provided such a quantification. For instance, the Order on Remand described the regional reliability benefits of an interconnected network, finding that new transmission facilities that operate at or above 500 kV have the ability to resolve multiple reliability violations over a broad geographic area.[67] Specifically, the Commission identified resolution of reliability violations,[68] load deliverability, increased transfer capability, and as discussed above, reserve sharing. The Order on Remand further discussed a quantification of these benefits.[69] These findings are discussed below.

46. Rather than a granular analysis of the benefits of each new facility to each and every customer, the Seventh Circuit sought a comparison of the costs assessed against a party to the burdens imposed or benefits received by that party, noting an east/west asymmetry. But transmission facilities that operate at or above 500 kV are not limited to

---

[65] *See KN Energy*, 968 F.2d at 1301 (the Commission allowed the cost-spreading of take-or-pay costs to be assessed to those who may not have caused the take-or-pay problem, but nevertheless ultimately benefit from their resolution).

[66] Seventh Circuit Opinion, 576 F.3d at 477. *See Algonquin Gas Transportation Co. v. FERC*, 948 F.2d at 1313 (D.C. Cir. 1991) (the Commission must produce evidence to support the presumption of system benefits).

[67] Order on Remand, *L.L.C.*, 138 FERC ¶ 61,230 at P 80.

[68] *Id.* P 60.

[69] *Id.* PP 78-79.

Eastern PJM. While transmission facilities that operate at 500 kV are primarily located in Eastern PJM, transmission facilities that operate above 500 kV (e.g., 765 kV transmission facilities) also are located in Western PJM. In fact, the function of many 345 kV transmission facilities in Western PJM is to provide local transmission and address more local reliability violations much the way 230 kV transmission facilities address local reliability violations in Eastern PJM.[70] The allocation of costs of upgrades to the 230 kV transmission system in Eastern PJM, like the allocation of costs of the upgrades to the 345 kV transmission system in Western PJM, is based on DFAX modeling, and provides further symmetry between Eastern and Western PJM.[71]

47. Nor are flows on the 765 kV transmission system exclusively west to east. The Commission noted that the flows on the Dumont to Wilton Center 765 kV transmission facility, which is proximate to Chicago, are east to west approximately 30 percent of the time.[72] While the Seventh Circuit did not require a utility-by-utility comparison, the Commission did address the east/west asymmetry and found substantial reliance by Western PJM customers on transmission facilities that operate at or above 500 kV. In fact, as reliance on the 765 kV Dumont to Wilton Center transmission facility indicates, Western PJM customers "will make use of and benefit from" the transmission facilities that operate at or above 500 kV, and Eastern PJM customers receive an allocation of the costs of upgrades to those 765 kV transmission facilities.[73] Flows on the transmission facilities that operate at or above 500 kV also can change over time, including the east/west and west/east orientation, which the Commission's Order on Remand relied on in its findings regarding the integrated nature of such facilities.

48. Moreover, we find that the connections between Eastern and Western PJM have grown stronger since the beginning of this proceeding. First Energy's ten distribution company holdings that stretch from Ohio to New Jersey, and cover vast areas in between,

---

[70] *See* Fair Pricing Group Comments at 41-43. The 765 kV transmission facilities in Western PJM, like the 500 kV transmission facilities in Eastern PJM, provide broad reliability benefits across the entire PJM region.

[71] In fact, the ratio of 765 kV/345 kV transmission facilities in Western PJM (0.76) is comparable to the ratio of 500/230 kV transmission facilities in Eastern PJM (1.01). PJM Whitepaper at Table 1.

[72] *PJM Interconnection, L.L.C.*, 138 FERC ¶ 61,230 at P 107. The Order on Remand also noted Commonwealth Edison's reliance on the strong transmission infrastructure in joining PJM. *Id.* P 93.

[73] *See Western Massachusetts*, 165 F.3d 922 at 927-28.

show that there is greater commonality now between Eastern and Western PJM in terms of ownership and control.[74] ComEd and Baltimore Gas & Electric, former adversaries in this proceeding representing the far Eastern and Western boundaries of PJM, are now both subsidiaries of the same utility holding company.[75] It is reasonable to expect that a parent company's views of the benefits that these subsidiaries receive from the new high voltage connections facilities will change over time as corporate structures change, blurring distinctions between Eastern and Western PJM.

49. The parties also contend that there is not a sufficient connection between the costs for specific projects and the benefits to actual sub-regions (or states). Such a facility-by-facility analysis was not required by the Seventh Circuit. Nor does the static DFAX methodology provide such information, allocated by state. As further discussed below, the Commission recognized that each of the transmission facilities that operate at or above 500 kV is part of an interconnected transmission network. The Seventh Circuit recognized that a failure in one part of the network can affect the supply of electricity in other parts of the network; the Commission noted that not all projects are proximate to all PJM utilities, but that specific projects have been selected by the PJM planning process as the most effective way to resolve reliability violations. We agree that failure in one part of the system can affect the reliability of other parts of the system. As such, these projects are necessary to maintain the reliability of the interconnected network, and the benefits of the interconnected network are realized by all customers. The new transmission facilities that operate at or above 500 kV provide system-wide reliability benefits, and, while difficult to quantify, where the benefits of the interconnected network are broadly realized by all customers, a postage-stamp allocation is a just and reasonable rate.

50. We understand the results of the postage-stamp allocation methodology vary significantly from the results of the static DFAX allocation methodology. But we do not find the use of a postage-stamp allocation methodology to be a cost shift because PJM did not allocate the costs of any 500 kV and above facility using the static DFAX methodology. Dayton acknowledges that the static DFAX methodology did not received final Commission approval because the Commission reversed its decision and included the new transmission cost allocation methodology in the hearing.[76] Given this acknowledgement, Dayton argues in the alternative that the Commission should examine the cost shifts from the pre-existing allocation of costs to the customers in the zone in

---

[74] *See* Attachment B.

[75] *See* Attachment A.

[76] Dayton Rehearing Request at 86-87.

which the project is built to the postage-stamp allocation of costs to a broader range of customers. This is not required. The Commission would need to examine the cost-shifting effect that a roll-in of existing costs (those already incurred) would have on customers.[77] In this case, however, none of the costs for the transmission facilities at issue were allocated under the zonal method. Thus, there are no actual cost shifts for the Commission to consider.

51. As discussed above, we have found that the static DFAX methodology is an unjust and unreasonable cost allocation methodology for PJM's new transmission facilities that operate at or above 500 kV.[78] Further, as discussed here and in the Order on Remand, we find the postage-stamp cost allocation methodology to be a just and reasonable replacement. While the allocation of costs under the different methodologies will produce different results, the limitations of the DFAX methodology would also result in unjustified subsidies of some ratepayers by other ratepayers, in that, under the static DFAX analysis, there are no costs allocated to those who receive the broader benefits discussed herein. We continue to find that the just and reasonable rate must include a methodology that recognizes both the quantifiable and difficult to quantify benefits, and the beneficiaries of the new transmission facilities that operate at or above 500 kV, and it is not unduly discriminatory to assign costs to all regions of PJM based on load-ratio shares.

2. <u>Postage-Stamp Allocation of Costs</u>

a. <u>Rehearing Requests</u>

52. Dayton, the Illinois Commission, the Ohio Commission, and FirstEnergy assert that the Order on Remand erred in finding the postage-stamp methodology is a just and reasonable method for allocating the costs of new 500 kV and above facilities, and is not the product of reasoned decision making supported by substantial evidence. The parties argue that the new 500 kV and above transmission facilities at issue are too far away to have any impact on western parts of PJM. The parties further contend that the Commission ignored relevant benefits provided by the new 500 kV and above lines at issue, such as the resolution of identified reliability violations and the impact on Locational Marginal Prices (LMPs), and instead, inappropriately focused on the benefits of membership in a large RTO. The parties state that while the materials relied on in the

---

[77] *See Algonquin Gas Transmission Co. v. FERC*, 948 F.2d 1305, 1315 (D.C. Cir. 1991).

[78] As Dayton notes, PJM's prior practice of allocating cost of transmission enhancements under a flow-based modeling had not been approved by the Commission.

Order on Remand may support the proposition that PJM's planning process provides benefits to customers throughout the PJM region, they are not the type of benefits required by the Seventh Circuit, and that the materials relied on in the Order on Remand have limited probative value. The parties also question specific assumptions that the Commission used in estimating certain benefits included in the Order on Remand.[79]

53. According to Dayton, the Illinois Commission, and FirstEnergy, the Order on Remand erred by failing to give any weight to the fact that all of the new 500 kV and above facilities at issue were proposed to resolve reliability problems in the eastern portion of PJM. The parties state that these identified reliability problems are the cost causative agents for the planned construction of the transmission facilities and should be given more weight than speculation about the potential for a future reversal of load flows, the potential for future cascading outages, or future transmission projects that may be needed to resolve future reliability problems that may arise in the West. Further, given the effective electrical "reaches" of high-voltage lines, the Illinois Commission notes that many load areas within PJM will likely receive minimal benefits from the projects at issue.

54. Dayton and the Illinois Commission also disagree with the Order on Remand's statement that several of the lines at issue were designed to resolve reliability problems in "Western PJM,"[80] noting that these lines are not actually in the West (i.e., Ohio, Indiana, Michigan, and Illinois), but are located in West Virginia, northern Virginia, and eastern Pennsylvania. As such, the Illinois Commission argues that the Commission has redefined Western PJM as the Midwestern utilities that are in PJM's "Western PJM Sub-Region." Regardless of location, Dayton notes that these lines were constructed to solve reliability problems in the east by enhancing west-to-east power flows. Additionally, the Illinois Commission criticizes the Order on Remand for not addressing physical asymmetries between the eastern and western regions of PJM. The Illinois Commission explains that 345 kV is the primary transmission voltage level used to transmit bulk power to load from generators within the western parts of PJM. Thus, according to the Illinois Commission, 500 kV lines will likely never be constructed in the western parts of PJM.

[79] Dayton requests that the Commission withdraw specific information related to reduced outages, load deliverability data, emergency event information, production cost benefits, and the ISO/RTO Metrics Report. Dayton Rehearing Request at 34.

[80] Dayton Request for Rehearing at 55 and Illinois Commission Request for Rehearing at 12-13 (citing *PJM Interconnection, L.L.C.*, 138 FERC ¶ 61,230 at P 56, n.90 and P 87).

55. Dayton, the Illinois Commission, the Ohio Commission, and FirstEnergy argue that the Order on Remand failed to give any weight to the beneficiaries of reduced energy costs. The parties assert that, once the high voltage lines at issue are constructed, the LMPs in the eastern portions of PJM will drop, while LMPs in the western portions of PJM will rise. To illustrate the effect of reduced energy costs, Dayton notes that, under the postage-stamp methodology, the PSEG zone will pay approximately $12.6 million[81] annually for the Branchburg-Roseland-Hudson Project, while it will receive $31 million[82] in annual energy savings in addition to other incentives for rectifying reliability violations and constructing and owning the facility. In contrast, Dayton notes that under the postage-stamp methodology, the ComEd zone pays twice as much, has higher LMPs, and earns nothing on the investment.

56. Dayton, the Illinois Commission, the Ohio Commission, and FirstEnergy argue that the Order on Remand inappropriately focused on the benefits of membership in an RTO, rather than the benefits of the new 500 kV and above lines at issue. Even if certain benefits are partially derived from PJM having a high voltage system, FirstEnergy states that the issue on remand is not cost allocation for the entire PJM high voltage system, including both new and existing facilities, but cost allocation for the new 500 kV and above upgrades. The Illinois Commission argues that the Commission has not refuted the contention that costs allocated under the postage-stamp cost allocation methodology bear no relation to the costs causation, and that the misalignment of costs and benefits increases over time.[83]

57. The parties also object to the Order on Remand's assumption that certain benefits are shared among transmission zones in proportion to each zone's load-ratio share. For example, regarding benefits associated with PJM's ability to re-dispatch, rather than

---

[81] Dayton contends that using PSEG's seven percent load-ratio share, it is responsible for approximately $66 million of the $946 million Branchburg-Roseland-Hudson Project. Using the Order on Remand's 19.1 percent carrying charge rate, the annual cost to PSEG is $12.6 million. Dayton Request for Rehearing at 61.

[82] In applying for incentive rates, PSEG claimed the Branchburg-Hudson-Roseland Project would provide approximately $31 million in annual transmission congestion cost savings to the PSEG zone. *Id.* (citing *Public Service Electric and Gas Co.*, 129 FERC ¶ 61,300, at P 20 (2009)).

[83] Illinois Commission Rehearing Request at 19 (citing Illinois Commission Reply Comments, (June 25, 2010) (referencing Dayton Power and Light Initial Comments, Affidavit of Michael M. Schnitzer at 17), and Exelon Initial Comments at 45, Affidavit of Steven T. Naumann, at 45 (May 28, 2010)).

curtail power-sales transactions, Dayton states that the vast majority of congestion occurs in Eastern PJM. Regarding benefits associated with planning on a region-wide basis, Dayton states that, given the location of the reliability problems that the nineteen high voltage facilities at issue are designed to fix, all of the facilities would almost certainly be constructed regardless of whether the study was conducted on a PJM-wide, subregional, state-by-state, or utility-by-utility basis. Dayton also states that savings due to demand response forestalling the need to construct new generation will not be enjoyed proportionally by ComEd and Dayton, since there has been no showing that these zones need new generation.

58. Dayton disagrees with the Order on Remand's calculation of an estimated $53 million in benefits to PJM, and an estimated $7.8 million in benefits to the ComEd zone, related to decreased service interruptions and power quality disturbances from the use of 500 kV facilities rather than 345 kV lines. Dayton notes that all of the 500 kV and above lines at issue are hundreds of miles away from its system, and that it would be a near impossibility for lines located so far away to provide any meaningful role in reducing the number of momentary or outages of less than an hour experienced on the Dayton system.[84] Second, Dayton notes that the Order on Remand's calculations are based on a Lawrence Berkeley National Laboratory (LBNL) report that was intended to compute the average costs of interruptions and power quality disturbances by customers.[85] Dayton asserts that this calculation is not intended to calculate the costs or savings that would be incurred by an individual utility or an RTO. Finally, Dayton notes that neither it, ComEd, nor AEP's Ohio subsidiaries own any 500 kV facilities, yet these companies do not experience abnormally high outage rates on their transmission systems. Dayton asserts that a comparison of the 500 kV and 345 kV average outage numbers cited by the Commission cannot be properly applied to utilities that own no 500 kV facilities.

59. Dayton also disagrees with the Order on Remand's interpretation of Capacity Emergency Transfer Objective/Capacity Emergency Transfer Limit CETO/CETL data as demonstrating that "ComEd and other western zones require imports from the rest of PJM to avoid loss of load."[86] While Dayton believes that the CETO/CETL data could reasonably be used to show whether ComEd will be able to meet a once-in-twenty-five-years emergency solely through its own facilities and its existing interconnections, Dayton asserts that the data does not establish that ComEd or Dayton will ever rely on

---

[84] Additionally, as noted above, Dayton objects to the Order on Remand's use of load-ratio share to allocate these benefits to the ComEd zone.

[85] Dayton Request for Rehearing at 37.

[86] *Id.* (citing *PJM Interconnection, L.L.C.*, 138 FERC ¶ 61,230 at P 74 and n.130).

any of the new transmission lines being built to the East. Similarly, Dayton asserts that data on hourly power flows has been misinterpreted,[87] and states that this data shows only that power flows from one midwestern utility, AEP, to another midwestern utility, ComEd, during some hours.

60. Dayton asserts that the data on emergency events indicate a decreasing trend in Western PJM, contrary to the Order on Remand's claim. Moreover, Dayton notes that none of those notices of emergency events exceed Transmission Load Relief (TLR) Level 3,[88] which is a notice that curtailments of non-firm transmission are necessary. According to Dayton, the fact that entities that contracted for interruptible service may be interrupted is not a "potential reliability problem." Similarly, the Illinois Commission states that the list of emergency events cannot be used to identify potential reliability problems, as these events may be reasonably addressed through operational or market actions. The Illinois Commission further states that the list of emergency events is not part of PJM's transmission expansion planning process.

61. Dayton objects to the Order on Remand's statement that "the integration of ComEd, AEP, and Dayton into the PJM power market led to production cost savings of approximately $70 million in 2004."[89] Dayton asserts that this statement implies that the ComEd, AEP, and Dayton zones received $70 million in benefits; however, Dayton states that these benefits were created by ComEd, AEP, and Dayton for PJM as a whole. Dayton explains that, prior to integration, transmission costs for power that was flowing into PJM from or through the ComEd, AEP, and Dayton zones would be charged for transmission by these utilities, and then PJM transmission charges would be added for power sinking in the PJM zone of delivery. Dayton states that integration eliminated these "pancaked transmission rates," allowing the pre-existing PJM utilities to enjoy lower delivered prices for power moving west to east.

62. Dayton argues that the Order on Remand misinterprets the Joint U.S. and Canadian Task Force Report on the 2003 blackout (Joint Task Force Report). Dayton notes that the Joint Task Force Report includes forty-six recommendations, but not one of these recommendations is to build new high-voltage transmission lines. Dayton also

---

[87] *Id.* at 38 (citing *PJM Interconnection, L.L.C.*, 138 FERC ¶ 61,230 at P 38 and n.48, PP 74, 94, 96, and 107).

[88] TLR procedures are used to prevent or manage potential or actual System Operating Limit or Interconnection Reliability Operating Limit violations.

[89] *Id.* at 40 (citing *PJM Interconnection, L.L.C.*, 138 FERC ¶ 61,230 at P 108 and n.210).

states that, according to the Joint Task Force Report, the primary reason that the cascading blackout stopped was because the current and voltage swings were attenuated by distance.

63. The Illinois Commission questions the Order on Remand's discussion of queued interconnection requests for wind generation in the western portion of PJM, particularly Northern Illinois. According to the Illinois Commission, the Order on Remand is suggesting that load in Northern Illinois will benefit from the construction of transmission to deliver this energy. The Illinois Commission states that, while wind generation developers may benefit, load will not. The Illinois Commission notes that Illinois generators are not owned within the utility structure; rather, they are owned by Exelon subsidiaries and independent power producers. Thus, according to the Illinois Commission, any profits due to the new transmission facilities will go to the generators and will not flow through to load in the form of retail rate offsets. The Illinois Commission further contends that the new transmission lines that operate at or above 500 kV will result in increased capacity and energy costs to customers primarily located in Illinois and Ohio.

64. The Ohio Commission asserts that the Order on Remand conflicts with Order No. 1000 because the postage-stamp methodology does not comply with the transmission cost allocation principles established in that proceeding.[90] The Ohio Commission requests that the Order on Remand be clarified to reflect that it is not intended to be applied for the cost recovery of new 500 kV or above transmission expansion.

65. Finally, the Illinois Commission states that the Order on Remand erred by failing to consider alternative cost allocation approaches presented in the record. For example, the Illinois Commission states that a hybrid approach, developed under a settlement judge, would have been a more reasonable method. Alternatively, Dayton suggests that the Commission should consider a mechanism that would allocate costs by load-ratio share on a sub-regional basis.

b. <u>Commission Determination</u>

66. We deny the requests for rehearing of Dayton, the Illinois Commission, the Ohio Commission, and FirstEnergy. We affirm the Order on Remand's finding that allocating the costs of new transmission facilities that operate at or above 500 kV to utility zones

[90] Ohio Commission Rehearing Request at 12.

using a postage-stamp allocation methodology is a just, reasonable and not unduly discriminatory method of allocating costs of such new facilities.[91]

67. As the Commission found in the Order on Remand, new 500 kV and above transmission facilities provide a broad range of benefits, including reduced congestion, reduced outages, reduced operating reserve requirements, and reduced losses.[92] These benefits radiate from the upgraded facility, and thus are spread throughout the PJM region. Moreover, these benefits are available throughout the service-life of the transmission facility, which may be forty years or more for higher voltage lines. Against this backdrop, we continue to find that the postage-stamp methodology, which allocates costs to all parties within the PJM region and allows for these allocations to be updated over time, appropriately matches costs to beneficiaries. Specifically, as determined in the Order on Remand, and as affirmed below, the benefits associated with the new 500 kV and above facilities at issue compare favorably with the estimated $516 million annual cost of the new 500 kV and above facilities at issue.[93]

68. The parties requesting rehearing suggest that, in determining the appropriate cost allocation methodology, the Commission should have focused primarily on two benefits associated with new 500 kV and above facilities: the initial resolution of reliability constraints and initial changes in LMPs. However, allocating costs based solely on these two limited measures would ignore the broader benefits mentioned elsewhere in this order. As stated in the Order on Remand, in order to provide a fair allocation of costs among parties, "all of the broad benefits of these high voltage facilities must be considered in determining the appropriate cost allocation methodology,"[94] including those that are difficult to quantify. Contrary to the parties' arguments, the courts do not limit the benefits that the Commission can consider in evaluating cost causation.

69. In particular, the Order on Remand recognized that the majority of new 500 kV and above facilities approved through RTEP were intended to address the most severe

---

[91] As previously noted, the costs to be allocated under the methodology approved in the Order on Remand has been significantly reduced by the cancellation of several 500 kV transmission upgrades, including both the PATH and MAPP projects.

[92] Order on Remand, *L.L.C.*, 138 FERC ¶ 61,230 at P 98.

[93] The $516 million figure is equal to the $2.7 billion in estimated costs times PJM's annual carry charge rate of 19.1 percent.

[94] Order on Remand, *L.L.C.*, 138 FERC ¶ 61,230 at P 111.

reliability violations in the East.[95] In an integrated system, however, the benefits of new transmission facilities are not limited by geographic area. Rather, as the new transmission facilities are integrated into the existing system, they will improve overall reliability, allowing the resulting benefits to extend to a greater number of parties. The parties requesting rehearing suggest that the Commission's reference to "reach" demonstrates that benefits are contained within a radius of approximately 50 miles for a 345 kV line, 200 miles for a 500 kV line, and 600 miles for a 765 kV line. When the Commission discussed reach, it referred to the ability for a single line to transfer a given amount of power, and it simply intended to demonstrate the differences among lines of different voltages. Thus, reach is not a measure of how far benefits are expected to radiate from the terminals of a line. If geographic distance from new transmission facilities were the key, even the static DFAX methodology, which the parties requesting rehearing favor, would be flawed, since in certain instances, it shows that the benefits of 345 kV or lower voltage lines are expected to reach far greater distances than 50 miles.[96]

70. Dayton and the Illinois Commission take issue with the Order on Remand's definition of the midwestern utilities that are located in Western PJM. While these parties may disagree with this definition of Western PJM, PJM has, for planning purposes, chosen to designate the Allegheny Power zone, which includes portions of West Virginia, Virginia, Maryland, and Pennsylvania as the Western PJM Sub-Region for planning purposes. That is, PJM, not the Commission, has defined the PJM regions for planning purposes. Moreover, by referencing the purely geographical nature of the PJM footprint, Dayton and the Illinois Commission discount the broader benefits of new transmission facilities that operate at or above 500 kV.

71. Additionally, the record does not provide a method for accurately separating the benefits of addressing the single worst reliability violation that supported the immediate need for the upgrade from the additional, broader benefits associated with the new transmission facility. While the static DFAX methodology has been suggested, the static DFAX methodology cannot sufficiently identify the benefits of new 500 kV and above facilities. In fact, as noted, the static DFAX methodology does not quantify the long-term benefits, it identifies those that cause the need for the line and their proportional use of lines that cause constraints. Even in the near term, static DFAX does not fully account for all of the unquantifiable benefits associated with a new 500 kV or above facility. This

[95] *Id.* P 87.

[96] For example, baseline upgrades b0831, b0834, b0835, and b0836 are all lower voltage lines located in northern New Jersey. Application of the static DFAX methodology resulted in a portion of costs being allocated to the Dayton and ComEd zones. *See* PJM's January 5, 2009 RTEP Filing in Docket No. ER09-497-000.

weakness of the static DFAX methodology becomes more pronounced over time, as changes in facility usage and flow direction occur. The Illinois Commission argues that costs allocated under the postage-stamp cost allocation methodology bear no relation to cost causation, but we have identified the inability of the static DFAX methodology to identify, let alone quantify, all the benefits of new transmission facilities that operate at or above 500 kV, and the evidence cited by the Illinois Commission, in light of these concerns, is insufficient.[97]

72. Regarding the suggestion that the Commission focus on changes in LMP for cost allocation purposes, we note that the Order on Remand considered that new 500 kV and above transmission facilities may cause LMPs to converge across the entire PJM region.[98] The Order on Remand correctly found that "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."[99] Even though, at a particular point in time, LMPs in one zone may be higher than they would be without access to this reliable and robust grid, we cannot find that access to the grid is a disadvantage to such parties. Further, over time, as generation and power flows change, all parties will benefit from a system that supports energy flows in any direction.[100] Based on the evidence in this record, the postage-stamp methodology is the best methodology to reflect such benefits.

73. The parties requesting rehearing also contend that the broad benefits identified by the Order on Remand are benefits of RTO membership generally, or at the most, benefits of a high voltage system, and not benefits specifically related to the new 500 kV and above facilities at issue. We agree that, without the high voltage transmission system, parties would not have been able to achieve the level of benefits noted in the Order on Remand. In fact, as discussed below and in the Order on Remand,[101] without the high

---

[97] The affidavits of Schnitzer and Naumann cited by the Illinois Commission do not address the limitations identified by the Commission.

[98] *PJM Interconnection, L.L.C.*, 138 FERC ¶ 61,230 at P 96.

[99] *Id.* at P 96 (citing *Gainesville Utilities Department v. Florida Power Corp.*, 402 U.S. 515, 527 (1971)).

[100] While the parties argue that the new transmission facilities that operate at or above 500 kV are being constructed to enhance west to east power flows, we note that the cancellation of the MAPP and PATH projects highlights that, over the long-term, west to east flows may not be predominate.

[101] *See infra* P 76.

voltage transmission system, ComEd may not have been able to join PJM. However, the fact that any particular new transmission line is interconnected with and its operation depends on the overall integrated transmission system is simply a reflection of the nature of an integrated transmission system; it does not mean that the new transmission facilities don't themselves have broader benefits. As noted in the Order on Remand, a transmission network is an integrated machine that, in light of changing system conditions over time, e.g. changes in load and flows, must be maintained and upgraded in order to keep the machine running reliably.[102] Without the addition of new transmission facilities that operate at or above 500 kV, the integrity of the transmission system would deteriorate, and the benefits of the integrated system would be reduced. Each of the new 500 kV and above facilities referenced in this proceeding play a significant role in supporting system reliability, reducing congestion, reducing operating reserve requirements, and reducing losses.

74. The parties requesting rehearing also question specific assumptions made in the Order on Remand in describing the benefits of new 500 kV and above transmission facilities. As an initial matter, we note that the Order on Remand made clear that the benefits presented were estimates.[103] Nevertheless, we believe that the benefits presented are reasonable benefits to anticipate from a reliable integrated system. These benefits include savings related to reserve sharing, reduced incidence of transmission facility outages, reduced line losses, and production cost savings. The Order on Remand, based on information from the 2011 ISO/RTO Metrics Report and other record information, estimated these savings to be approximately $2.2 billion.[104] While many of these benefits are not directly quantifiable, they are not possible without a reliable, integrated transmission system, and the reliability of the transmission system overtime is made possible by upgrades.[105]

75. We continue to find that the Order on Remand's finding that decreased service interruptions and power quality disturbances are a benefit of higher voltage facilities and is supported by the record. In calculating the $53.2 million in estimated system-wide

---

[102] *PJM Interconnection, L.L.C.*, 138 FERC ¶ 61,230 at P 56.

[103] *Id.* P 109 ("we recognize that there is imprecision in valuing the benefits of new 500 kV and above facilities…").

[104] *Id.*

[105] As we have noted, even under the static DFAX methodology, some costs would be allocated to ComEd and Dayton. That ComEd and Dayton also receive unquantifiable benefits further support our position.

benefits, the Commission was not looking at simply the benefits that accrue to utilities or an RTO; rather, it was looking at the benefits that accrue to each sub-region as a whole, including transmission owners, generators, and consumers. This approach is a fair and equitable way to calculate whether the costs incurred by a zone are roughly commensurate with the benefits that accrue to that zone. Further, the Commission never intimated that the outage rate in Western PJM was "abnormally high." The Commission was simply noting that higher voltage lines have statistically been shown to be subject to fewer outages. Comparison of outage statistics by voltage is a useful metric to differentiate regional transmission facilities from local facilities. We noted that when the comparison is between 765 kV and 345 kV facilities, higher voltage facilities are subject to even fewer outages.[106]

76. Dayton argues that the Commission has misused information related to local area load deliverability. Specifically, Dayton contends that the Commission's use of Capacity Emergency Transfer Limit (CETL), in combination with its corresponding Capacity Emergency Transfer Objective (CETO) data, does not stand for the proposition that Commonwealth Edison (ComEd) and other western zones of PJM require imports from the rest of PJM to avoid loss of load. We disagree. The Order on Remand noted that western regions of PJM generally have sufficient generation, but that ComEd and other western zones still do require imports from the rest of PJM to avoid loss of load. As previously discussed, flows on the Dumont to Wilton Center 765 kV transmission facility, which is proximate to Chicago, are east to west approximately 30 percent of the time. Moreover, the Commission noted that ComEd 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.[107]

77. In fact, the Commission noted that 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

[106] *Id.* P 100.

[107] *PJM Interconnection, L.L.C.*, 138 FERC ¶ 61,230 at P 93 (citing Exelon Corp., *et al.*, March 17, 2003 Motion for Expedited Decision, Docket No. ER03-262-000 at 22-23).

a direct benefit of that system. Specifically, the Commission noted when ComEd initially joined PJM, it could do so only because it had a 500 MW pathway connecting its service territory to PJM.[108] Where ComEd benefits from the reliability of the PJM transmission system, it must also benefit from the upgrades that maintain the reliability of that system.

78. We also maintain that a reliable, high voltage system can play a role in preventing system-wide blackouts. As the Order on Remand noted, the August 2003 blackout highlighted the interaction of thermal and voltage reliability criteria within interconnected network operation. 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 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.[109] While we agree that building additional high-voltage transmission is not the only solution to arresting wide-area outages, we continue to believe that a solid infrastructure can improve reliability, and this benefit should be considered when determining how costs are allocated.

79. Dayton suggests that the ComEd, AEP, and Dayton zones did not receive production cost savings of $50-$70 million as a result of their integration into PJM. However, Dayton admits that the Western PJM zones received some benefit from their integration into PJM.[110] The Order on Remand did not suggest that only the western zones benefited from the integration of ComEd, AEP, and Dayton. The Order on Remand noted that, on an annual basis, parties throughout the PJM region benefit from the reduction of seams, and that this reduction is one of the many benefits of an integrated system that relies on high voltage connections.

80. Dayton and the Illinois Commission also take issue with the Order on Remand's discussion of emergency events in Western PJM as well as its discussion of the large number of interconnection requests for wind generation in Western PJM. Regarding the emergency events experienced in Western PJM, Dayton correctly notes that emergency events have decreased in 2010 and 2011. Such a decrease is not unexpected as economic conditions reduced the level of demand in 2010 and 2011.

---

[108] *PJM Interconnection, L.L.C.*, 138 FERC ¶ 61,230 at P 105 (citing *PJM Interconnection, L.L.C.*, 106 FERC ¶ 61,253 at PP 5, 25-29 (2004)).

[109] Final Report at 75.

[110] Dayton Request for Rehearing at 40 ("ComEd, AEP, and Dayton Power may realize some portion of those benefits…").

81. The Order on Remand further discussed the reliability benefits of reduced outage frequency and shortened restoration times for transmission facilities operating at 500 kV compared to transmission facilities operating at 345 kV.[111] Specifically, the Commission noted that 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,[112] and that 500 kV lines suffer 36.8 percent fewer sustained outages than 345 kV lines.[113] Further, NERC reported that the duration of outages on 500 kV facilities is significantly lower than for 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).[114]

82. The Illinois Commission contends that the wind generation currently in the queue will not provide an initial benefit to customers in Western PJM. However, in discussing the possibility of increased emergency events and increased wind interconnections, the Commission's intention was not to quantify an immediate benefit to the western zones. The Commission illustrated the dynamic nature of the PJM transmission system. Over the forty year life of high voltage transmission facilities, as some portions of the grid experience decreased reliability, and other portions of the grid see an increase in generation, the direction of flows will change. And the dynamic nature of the transmission system supports the use of a postage-stamp methodology, a methodology that can be updated periodically, such as on a load-ratio basis.

83. The parties requesting rehearing object to the Order on Remand's allocation of certain benefits among zones based on load-ratio share. We continue to find that, for 500 kV and above projects, peak load is a reasonable basis to allocate costs that provide benefits to everyone. A conclusion that a party that uses more energy at peak times receives greater benefits than a party that uses less energy at peak times is not

---

[111] *PJM Interconnection, L.L.C.*, 138 FERC ¶ 61,230 at P 100.

[112] *Id.* (citing 2009 NERC Transmission Availability Data System Report at 16 June 14, 2010).

[113] The Commission noted that 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.

[114] *Id.*

unreasonable. In its White Paper,[115] PJM notes that "higher peak-load consumers... value reliability especially at peak."[116] PJM also notes that consumers with higher peak usage enjoy greater benefit from reduced losses.[117] Additionally, transmission is generally planned to meet the system peak.[118] Using peak load as a measure of benefits is a common practice and, as noted in the Order on Remand, most RTOs in the United States allocate some or all transmission costs based upon some idea of peak load or generation.[119]

84. In sum, the benefits identified in the Order on Remand, and discussed above, will only continue to be available as a result of the new 500 kV and above facilities that will ensure a reliable, integrated transmission system. While the exact amount of benefits that the western parts of PJM receive is not quantifiable, our expectation that these zones, which are part of PJM's integrated transmission system, will receive some portion of benefits is reasonable. Using ComEd as representative of the western parts of PJM, the benefits available to the ComEd zone include approximately $95 million to $143 million per year in reduced outages and reduced losses, and approximately $225 to $325 million in annual estimated benefits associated with the estimated savings that would not have been available without PJM's reliable high voltage transmission system.[120] And these estimated annual savings to the ComEd zone, totaling approximately $320 million to $468 million, compare favorably to the approximately $76 million in annual costs allocated to the ComEd zone.[121]

---

[115] As part of its April 13, 2010 Response, PJM also submitted a White Paper from March 10, 2010 entitled "A Survey of Transmission Cost Allocation Issues, Methods, and Practices" (PJM White Paper).

[116] PJM White Paper at 33.

[117] *Id.*, Appendix A at 47-48.

[118] *Id.* at 32.

[119] Order on Remand, 138 FERC ¶ 61,230 at n.225 (citing PJM White Paper at 31-32).

[120] *Id.* P 120.

[121] The $76 million figure is equal to the total annual costs of the new 500 kV and above facilities, $516 million, as discussed above times ComEd's load-ratio share of 14.7 percent.

85. Substantial evidence thus supports using a postage-stamp cost allocation methodology as a just and reasonable and not unduly discriminatory mechanism for allocating the costs of new transmission facilities that operate at or above 500 kV. Substantial evidence turns not on how many discrete pieces of evidence the Commission relies on, but on whether the evidence supports its ultimate decision.[122] Here, the evidence is sufficient to support the Commission's decision. Specifically, the Commission noted that the record supported that upgrades to transmission facilities that operate at or above 500 kV provide benefits over a broad geographic area – reduced incidence of transmission facility outages, reduced line losses, and production cost savings.[123] In addition, the Commission has identified savings related to reduced operating reserve requirements.[124] We find that the quantifiable benefits plus the unquantifiable benefits are at least roughly commensurate with those utilities' share of the costs of those facilities allocated under a postage-stamp methodology.

86. In affirming use of a postage-stamp methodology, we dismiss suggestions that we should have adopted alternative cost allocation methods, such as a hybrid approach, or a mechanism that allocates costs by load-ratio share on a sub-regional basis. In the Order on Remand, the Commission did consider these approaches and found that, when fully developed, such approaches could be just and reasonable. However, these approaches were mere suggestions without any analysis in the record showing in this proceeding that they would better match costs and benefits.[125] And no sufficient basis has been presented for establishing further evidentiary or settlement procedures in this proceeding; the parties have not justified that such further procedures would be necessary or worthwhile

---

[122] *Florida Gas Transmission Company v. FERC*, 604 F.3d 636, 645 (D.C. Cir. (2010) (*Florida Gas*) (citing *Florida Mun. Power Agency v. FERC*, 315 F.3d 362, 368 (D.C. Cir. 2003) (applying court's deferential standard in reviewing the Commission's decision under substantial evidence standard)). *See Arkansas Elec. Energy Consumers v. FERC*, 290 F.3d 362, 367 (D.C. Cir. 2002). *Florida Gas* further explains, "the 'substantial evidence' standard requires more than a scintilla, but it can be satisfied by something less than a preponderance of the evidence."

[123] Order on Remand, 138 FERC ¶ 61,230 at PP 80-109.

[124] *Id.* PP 101-102.

[125] The Commission suggested that alternative approaches could be examined more thoroughly within the context of compliance with Order No. 1000. *PJM Interconnection, L.L.C.*, 138 FERC ¶ 61,230 at n.70.

in this proceeding.[126] As noted earlier, the fact that there may be alternative just and reasonable approaches does not prevent the Commission from selecting a different just and reasonable methodology.[127] We have, in fact, selected the postage-stamp cost allocation methodology as such a just and reasonable alternative.

87. We also dismiss suggestions that the Commission should have evaluated the postage-stamp methodology for compliance with the six cost allocation principles established in Order No. 1000. In Order No. 1000, the Commission specifically stated that the principles adopted apply only to new facilities, defined as those facilities that are subject to evaluation, or revaluation, "after the effective date of the public utility transmission provider's filing adopting the relevant requirements of this Final Rule."[128] The Commission will evaluate the PJM cost allocation methodology for compliance with the Order No. 1000 cost allocation principles in the context of PJM's Order No. 1000 compliance filing.[129]

C. Record Evidence

1. Rehearing Requests

88. Several parties contend that the Commission erred by failing to make a reasoned decision in taking official notice of materials on which the Commission based the Order on Remand. Specifically, the Illinois Commission and Dayton contend that, by failing to provide notice of the evidence being relied on and opportunity to comment prior to the March 30, 2012 Order on Remand, the Commission did not provide adequate due

[126] While the Commission established hearing procedures in response to the Seventh Circuit's remand, nothing prevented the parties from settling this issue. In fact, PJM transmission owners have submitted a hybrid cost allocation methodology in response to Order No. 1000, but did not propose use of such a mechanism for the projects at issue in this proceeding.

[127] *See supra*, P 28.

[128] Order No. 1000, 76 FR 49,842, FERC Stats. & Regs. ¶ 31,323 at P 65.

[129] As previously noted, on October 11, 2012, the PJM Transmission Owners submitted revisions to the PJM cost allocation method to comply with Order No. 1000 in Docket No. ER13-90-000.

process.[130] The Illinois Commission and Dayton further contend that the material on which the Commission relied was inappropriate for official notice, was not relevant or, to the extent relevant, was misapplied by the Commission.

2. **Commission Determination**

89. We find that the Commission properly relied on materials both submitted by the parties and in the record through official notice, and provided an adequate opportunity to rebut those materials,[131] thereby meeting due process requirements of the U.S. Constitution and section 556(e) of the Administrative Procedure Act. We therefore deny rehearing of the Order on Remand on this issue.

90. The Illinois Commission and Dayton contend that the Order on Remand violates due process requirements. Dayton argues that the Commission failed to meet the two prerequisites for use of official notice: (1) that the information noticed must be appropriate for official notice; and (2) that the Commission must follow proper procedures in using the information, disclosing it to the parties and affording them a suitable opportunity to "parry its effect."[132] In this regard, the Illinois Commission and Dayton argue that the Commission provided no opportunity for parties to respond to the material prior to issuing the Order on Remand and that any opportunity to respond in their requests for rehearing is inadequate.

91. In the Order on Remand, the Commission took official notice of certain material, including the 2011 ISO/RTO Metrics Report, pursuant to Rule 508(d) of the Commission's Rules of Practice and Procedure.[133] At the time that the Commission made this material part of the official record in Docket No. EL05-121-006, the Commission observed that this material was publicly available, specific to PJM, and

---

[130] Illinois Commission Rehearing Request at 15, Dayton Rehearing Request at 30 (citing the 5th and 14th Amendments to the U.S. Constitution, and Section 556(e) of the Administrative Procedure Act).

[131] *PJM Interconnection, L.L.C.*, 138 FERC ¶ 61,230 at P 33.

[132] Dayton Rehearing Request at 30-31 (citing *Union Electric Co. v. FERC*, 890 F.2d 1193, 1202 (D.C. Cir. 1989) (*Union Electric*)), (citing *Ohio Bell Telephone Co. v. Public Utilities Commission of Ohio*, 301 U.S. 292 (1937)) (requiring an opportunity to dispute findings based on officially-noticed evidence)).

[133] *PJM Interconnection, L.L.C.*, 138 FERC ¶ 61,230 at PP 33, 63 (citing 18 C.F.R. § 385.508(d)).

available on the internet.[134] The Commission also invited the parties to address this officially-noticed material in their petitions for rehearing.[135]

92. As Dayton acknowledges, administrative agencies are permitted to take official notice of technical or scientific facts that are within the agency's area of expertise.[136] The Commission's Rules of Practice and Procedure also allow for official notice "of any matter about which the Commission, by reasons of its functions, is expert."[137] And that is what the Commission has done; nothing more. Dayton and the Illinois Commission also contend that the standard for official notice requires that the facts incorporated into the record must not be in dispute.[138] But this is not a reasonable restriction where parties have an opportunity to dispute the officially-noticed facts as they have in this proceeding.[139] The scope of official notice is expansive "since 'administrative agencies necessarily acquire special knowledges in their sphere of activity,' [and] certain highly technical facts 'may become … obvious and notorious'" to the agencies.[140] The Commission, in performing its functions under the Federal Power Act, has had reason to

---

[134] The Order on Remand adopting the material into the record issued on a Friday and, for the convenience of the parties, the Commission collected and collated all of officially-noticed materials and made them electronically available in this docket on the following Monday. The spreadsheet provided by the Commission of estimated savings related to decreased service interruptions is the Commission's computation based on publicly available information, and the underlying computations are included.

[135] *PJM Interconnection, L.L.C.*, 138 FERC ¶ 61,230 at P 33; *see also Boston Edison Co. v. F.E.R.C.*, 885 F.2d 962, 967 (1st Cir. 1989) (Boston Edison had an opportunity to argue against the adjustment or any other factual matter in its request for rehearing).

[136] Dayton Rehearing Request at 33 (citing *McLeod v. INS*, 802 F.2d 89, at 93 n.4 (3rd Cir. 1986) (*McLeod*)).

[137] 18 C.F.R. § 385.508(d)(1) (2012).

[138] Illinois Commission Rehearing Request at 16; Dayton Rehearing Request at 33 citing *Mississippi Industries v. FERC*, 808 F.2d 1525, 1568 (D.C. Cir. 1987) (reversed on other grounds) (*Mississippi Industries*).

[139] *See Mississippi Industries*, 808 F.2d at 1568 (extraordinary circumstances necessary to compel reopening the record when extra-record evidence not subject to dispute).

[140] *Union Electric*, 890 F.2d at 1202.

acquire that special knowledge about the reliability and operations of PJM. Moreover, the agency is an expert about any of its own proceedings, including the proceeding to develop, implement, and review performance metrics for regional transmission organizations. Thus, we conclude that the material was of the type that was appropriate for official notice.

93. We further find that the Commission followed its own procedures in noticing the material, disclosing the material and how it was used to demonstrate benefits in the Order on Remand, and inviting parties to contest the data and its use in their requests for rehearing. We find the 30-day rehearing period is sufficient for parties to review the materials and the Commission's conclusions from PJM factual material upon which parties rely in the course of doing business with PJM, especially where this information has been at issue in proceedings before the Commission. This is particularly true of the 2011 ISO/RTO Metric Report, cited in the Order on Remand, which is both publicly available on the PJM web site, and has been submitted in another proceeding before the Commission.[141] In fact, Dayton and the Illinois Commission have availed themselves of the opportunity to rebut the use of this evidence and we address these arguments in this order. The courts have found similar opportunities sufficient to satisfy due process requirements.[142]

94. Dayton states that the 2011 ISO/RTO Metrics Report is devoid of any detailed analysis to explain how the benefits cited were developed. Dayton also contends that the 2011 ISO/RTO Metrics report is at least partially self-serving, as it was submitted in the context of proceedings in which each ISO and RTO was attempting to show the Commission how it adds value to the market. Of course, the same could be said of any evidence; Dayton's evidence in a proceeding in which Dayton was involved would likely be no less self-serving. Dayton, however, has failed to supply any basis for us to conclude that the factual data presented by PJM, on which we rely, is inaccurate. And where the Commission finds that a rate is unreasonable, as it has in this proceeding, we

---

[141] *See* Docket No. AD10-5-000. The Ohio Commission and the Illinois Attorney General participated directly in this Commission proceeding, and the state commissions were further represented in the proceeding by the National Association of Regulatory Utility Commissioners. These parties were also served the 2011 ISO/RTO Metrics Report when it was filed by PJM on August 31, 2011.

[142] *BNSF Railway Co. v. Surface Transportation Board*, 453 F.3d 473 (D.C. Cir. 2006) (agency satisfied due process when it used a rate forecast not proffered by the parties in the proceeding because railway, in its application for rehearing, did not make a good showing that it could contest the evidence); *Union Electric*, 890 F.2d at 1203; *McLeod*, 802 F.2d at 93.

have an obligation to fix the just and reasonable rate under section 206 of the FPA.[143] Like any complainant, the Commission properly used the data available to it. And it used its expertise to evaluate that data.

95. Dayton contends that, because the atmosphere is prejudiced by the Order on Rehearing, it is too late to submit rebuttal evidence. We disagree. This argument, if true, would make the statutory provision for rehearing virtually meaningless since every request for rehearing, by definition, is a challenge to a Commission order ruling against the party seeking rehearing. It is not true, though. In fact, the Commission can and does grant rehearing – considering its earlier ruling. In fact, the Commission established the hearing procedures on remand in response to a motion by Exelon,[144] and granted rehearing of a request by Exelon to require PJM to provide additional factual information bearing upon the established hearing procedures.[145] The purpose of rehearing is to allow for reconsideration of the Commission's decision, and, here, we invited rebuttal evidence. No such evidence was submitted.

D. Treatment of Merchant Transmission Facilities

1. Rehearing Request

96. On rehearing, LIPA contends that the Commission's decision to dismiss LIPA's testimony and evidence was erroneous. LIPA asserts that the proceeding in Docket No. ER06-456, *et al.*, which is the proceeding that ultimately resulted in Opinion No. 503,[146] specifically excluded 500 kV and above facilities. LIPA refers to a partial settlement in Docket No. ER06-456, *et al.*, which reserved for hearing the treatment of merchant transmission facilities, but only with respect to cost-allocations for below 500 kV RTEP

[143] *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)).

[144] *PJM Interconnection, L.L.C.*, 130 FERC ¶ 61,052 (2010).

[145] *PJM Interconnection, L.L.C.*, 130 FERC ¶ 61,233 (2010).

[146] *PJM Interconnection, L.L.C.*, Opinion No. 503, 129 FERC ¶ 61,161 (2009), *order on reh'g*, Opinion No. 503-A, 139 FERC ¶ 61,234 (2012).

upgrades.[147] LIPA notes that, during the hearing proceedings, PJM's witness stated that the cost responsibility assignments for 500 kV and above facilities were not at issue.[148]

97. LIPA also states that the Commission's dismissal of LIPA's testimony and evidence is based on a misreading of a footnote in Opinion No. 503. LIPA notes that the complete footnote reads*:*

> *See infra*, section H (collection of RTEP costs when a Merchant Transmission Facility is late going into service). The Initial Decision also directed PJM to calculate a Merchant Transmission Facility's load-ratio share for 500 kV and above RTEP upgrades based on the Merchant Transmission Facility's actual peak load in any given hour of the applicable prior year, or for the Merchant Transmission Facility's first year of operation, the amount of Firm Transmission Withdrawal Rights actually awarded to the Merchant Transmission Facility by PJM. No 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 issue. However, PJM's allocation method for at or above 500 kV facilities was recently remanded to the Commission. *See supra* n.23.

98. LIPA asserts that Opinion No. 503 did not address the broad issue of whether the allocation of RTEP costs to merchant transmission facilities for 500 kV and above facilities is just and reasonable. Rather, Opinion No. 503 addressed the limited issue of whether Firm Transmission Withdrawal Rights or actual peak demand should be used for allocating costs. Further, LIPA asserts that the next to last sentence of the footnote acknowledges that the substantive issue of cost allocation for 500 kV and above RTEP facilities will be addressed in a separate docket.

99. LIPA contends that the Commission's failure to address LIPA's evidence pertaining to cost allocation for 500 kV and above facilities was arbitrary and capricious. LIPA also states that the Commission's rejection contravened LIPA's due process rights by retroactively narrowing the scope of Docket No. EL05-121, *et al.* Thus, LIPA asserts that on rehearing, its arguments regarding whether the allocation of costs to merchant transmission facilities for 500 kV and above facilities is consistent with the "roughly commensurate" standard, must be revisited on the merits.

---

[147] LIPA Request for Rehearing at 3 (citing *PJM Interconnection, L.L.C.*, 121 FERC ¶ 63,012 at P 36).

[148] LIPA Request for Rehearing at 7 (citing Exhibit No. PJM-1 at 12:12-14:3 (filed in Docket No. ER06-456, *et al.*)).

2. **Commission Determination**

100. We deny LIPA's request for rehearing. The assignment of RTEP costs to merchant transmission providers was addressed in Opinion No. 503, and no party excepted to the Initial Decision findings regarding the allocation to merchant transmission providers of the costs of 500 kV and above facilities.[149] Moreover, the assignment of costs to merchant transmission providers was not addressed in Opinion No. 494, presented to the Seventh Circuit on appeal, nor addressed in the Seventh Circuit Opinion. Thus, we affirm our finding that this issue is beyond the scope of this proceeding. Further, as discussed below, we find that LIPA has misinterpreted the prior Commission orders, as well as omitted discussion of other orders and documents which establish that the appropriate allocation of costs to merchant transmission providers for 500 kV and above facilities was instead at issue in Opinion No. 503.

101. LIPA is correct that, initially, the proceeding in Docket No. ER06-456, *et al.*, dealt with only below 500 kV transmission facilities. The Commission's April 19, 2007 order in that proceeding bifurcated the treatment of at or above 500 kV and below 500 kV transmission facilities, finding that the costs of at or above 500 kV facilities should be allocated regionally, while expanding the scope of the hearing in Docket No. ER06-456, *et al.*, to include the appropriate cost allocation methodology for below 500 kV facilities.[150] In accordance with the Commission's directives, the partial settlement reached in Docket No. ER06-456, *et al.*, and filed on September 14, 2007, established the methodology by which PJM would assign the costs of RTEP upgrades that are planned to operate below 500 kV.[151] The partial settlement reserved one issue for hearing, the assignment of cost responsibility to merchant transmission facilities, but only with respect to below 500 kV facilities.[152]

102. However, on January 31, 2008, in Docket No. EL05-121, *et al.*, the Commission reserved the issue of how PJM is to allocate RTEP costs for 500 kV and above upgrades to merchant transmission facilities for the hearing proceeding in Docket No. ER06-456, *et al.* In reserving the issue, the Commission was specifically responding to a request from LIPA and Linden VFT, L.L.C. The Commission agreed that no party had provided

---

[149] Order on Remand, 138 FERC ¶ 61,230 at P 34.

[150] *PJM Interconnection, L.L.C.*, 119 FERC ¶ 61,063 at PP 2-3.

[151] Settlement Agreement and Offer of Partial Settlement, filed on September 14, 2007 in Docket No. ER06-456, *et al.*

[152] *Id.* P 10.

a reason to allocate RTEP charges to merchant transmission facilities differently for facilities that operate at or above 500 kV and those below 500 kV.[153]

103. While LIPA cites testimony from a PJM witness, which indicates that 500 kV and above facilities were not at issue in Docket No. ER06-456, *et al.*, this testimony was filed on November 30, 2007, several months prior to the order expanding the scope of the hearing. Following the expansion of the scope of the hearing, the statement of issues included the following question: "should [merchant transmission facilities] be allocated the costs of RTEP reliability projects that are 500 kV and above?"[154] While certain parties may have been confused over the hearing issue,[155] the parties did address the broad issue of whether merchant transmission facilities should be allocated costs for 500 kV and above transmission facilities. For example, in their initial post-hearing brief, LIPA and East Coast Power, L.L.C. noted that while the socialization of the costs of 500 kV and above projects to all system users is not at issue in Docket No. ER06-456, *et al.*, "the Commission has made the socialization of such costs to merchant transmission facilities subject to the outcome of this hearing."[156]

104. LIPA would now interpret Opinion No. 503 as not addressing whether it is just and reasonable for merchant transmission facilities to be allocated RTEP costs associated with 500 kV and above facilities. However, the Commission's finding in Opinion No. 503 makes clear that this was not the case; that issue was addressed. Specifically, the Commission noted that PJM, in its initial brief, proposed to allocate the costs of 500 kV and above transmission facilities across the entire PJM region on an annual load ratio share basis.[157] The Commission further noted that the administrative law judge (ALJ) generally upheld PJM's proposal, although for 500 kV and above facilities, the ALJ required the use of actual peak load to calculate the costs assigned to merchant

---

[153] *PJM Interconnection, L.L.C.*, 122 FERC ¶ 61,082 at P 92.

[154] Updated Joint Narrative Statement of Issues, issued on April 30, 2008 in Docket No. ER06-456, *et al.*, Issue # 2.b. The statement of issues also asked whether merchant transmission facilities should be allocated the costs of RTEP economic upgrade projects, in general, without distinguishing between at or above 500 kV and below 500 kV transmission facilities.

[155] *PJM Interconnection, L.L.C.*, 122 FERC ¶ 61,082 at P 92.

[156] Initial Post-hearing Brief of East Coast Power, L.L.C. Long Island Power Authority and LIPA, Docket No. ER06-456, *et al.*, submitted June 16, 2008 at 11.

[157] *PJM Interconnection, L.L.C.*, 129 FERC ¶ 61,161 at P 14.

transmission facilities, when available.[158] After reviewing PJM's proposal, as modified by the ALJ, the Commission found it to be just and reasonable.[159] The fact that Opinion No. 503 did not discuss 500 kV and above facilities at greater length is unremarkable, given that parties primarily focused on below 500 kV facilities in their briefs on exceptions.

105. Further, LIPA’s assertion that footnote 27 of Opinion No. 503 reserved the allocation of RTEP costs associated with 500 kV and above projects to another docket is incorrect. Footnote 27 states that: “No 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 issue.” The reference to the remand order simply pointed out that, if the Commission were to change the methodology for allocating 500 kV and above facilities, that change would affect merchant transmission providers as well. But, it did not reserve this issue for re-litigation in the remand proceeding.

The Commission orders:

Rehearing of the Order on Remand is hereby denied, as discussed in the body of this order.

By the Commission. Commissioners LaFleur and Clark are dissenting with a separate statement attached.

(S E A L)

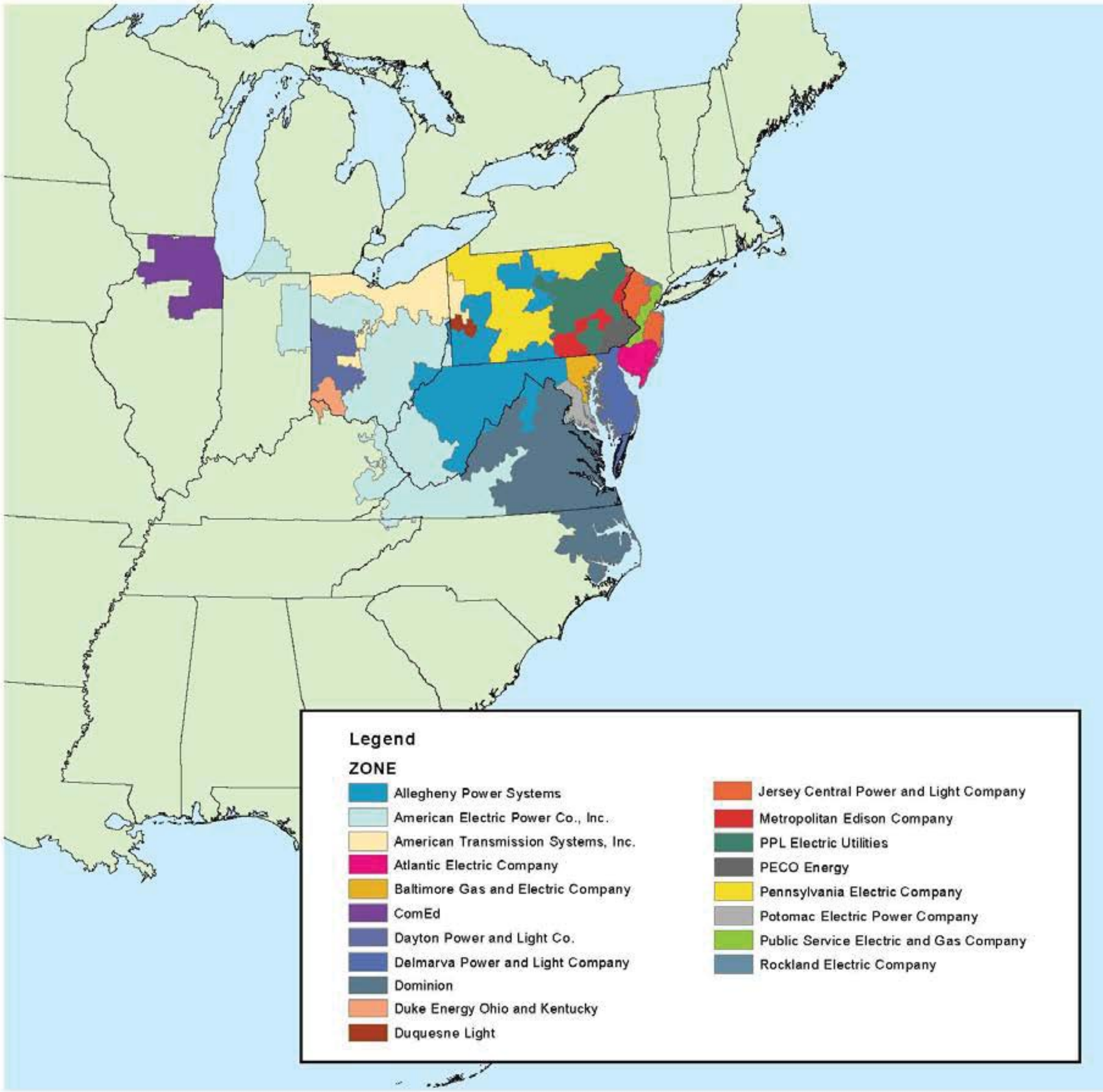
Nathaniel J. Davis, Sr.,
Deputy Secretary.

---

[158] *Id.* PP 15, 19.

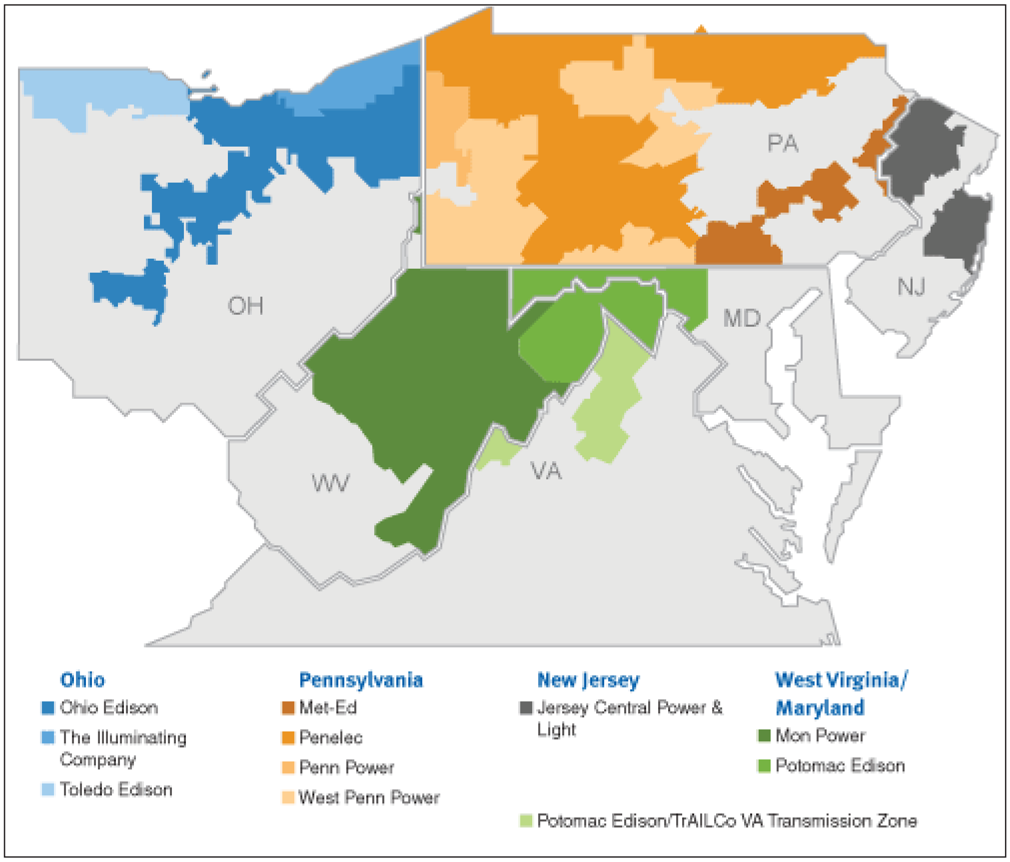
[159] *Id.* P 21.

ATTACHMENT A: PJM Transmission Pricing Zones



Source: http://www.pjm.com/~/media/about-pjm/pjm-zones.ashx

ATTACHMENT B
FirstEnergy Regulated Distribution Companies



Case: 13-2052 Document: 1-1 Filed: 05/16/2013 Pages: 149

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C. Docket No. EL05-121-008

(Issued March 22, 2013)

LaFLEUR, Commissioner, *dissenting*:

For the reasons stated in my dissent on the Order on Remand,[1] I respectfully dissent from today's order. I write further to emphasize the following points.

The majority's decision to mandate RTO-wide postage stamp cost allocation is an overbroad remedy for the shortcomings of the violations-based DFAX methodology. Therefore, it is not a just and reasonable method of allocating costs for the transmission lines at issue in this case.

The majority persuasively demonstrates that violations-based DFAX is unjust and unreasonable as a stand-alone cost allocation methodology because it identifies only immediate beneficiaries and cannot identify beneficiaries that develop over the useful life of a line. As the majority explains, these limitations result in an unjustified subsidy because immediate beneficiaries exclusively bear costs that should be shared by hypothetical future beneficiaries.[2]

But while violations-based DFAX under-identifies beneficiaries, the postage stamp approach imposed by the majority is unjust and unreasonable for the opposite reason: it overstates and overemphasizes the benefits that accrue to hypothetical long-term beneficiaries, to the point that it takes no account of the immediate reliability violations that caused the lines in the first place. Under the majority's approach, there is no recognition that the lines at issue in this proceeding are "but for" lines, designed to benefit specific eastern customers by remedying specific eastern reliability violations. Because there is no attempt to distinguish among beneficiaries based on the degree to which they benefit, the majority's approach results in substantial cost shifts from immediate beneficiaries to hypothetical future beneficiaries, including those in geographically remote areas. But an unjustified subsidy is no less unjustified because it is partial rather than complete. And under the majority's approach, immediate beneficiaries receive a substantial and unjustified subsidy from hypothetical future beneficiaries.

[1] *PJM Interconnection, L.L.C.*, 138 FERC ¶ 61,230 (2012) (Order on Remand)(LaFleur, Comm'r, dissenting).

[2] Order at P 51 ("While the allocation of costs under the different methodologies will produce different results, the limitations of the DFAX methodology would also result in unjustified subsidies of some ratepayers by other ratepayers, in that, under the static DFAX analysis, there are no costs allocated to those who receive the broader benefits discussed herein.").

Further, as petitioners on rehearing point out, many of the potential future benefits the majority relies on to justify postage stamp cost allocation are in fact generic benefits of RTO membership, not benefits in any way resulting from the lines at issue in this proceeding. In effect, the majority reads the court as requiring the Commission to demonstrate that western utilities benefit from membership in PJM, not that they benefit from the lines in the record. I believe this approach is at odds with the task set out by the court, which did not fault the Commission for failing to establish the benefits of a regional transmission grid,[3] but required an explanation of why the regional benefits associated with the eastern transmission lines at issue in this proceeding are at least "roughly commensurate" with the substantial costs shifted to western utilities under the postage stamp approach.

In my dissent on the Order on Remand, I called for a hybrid approach that would account for both the immediate benefits that accrue to those "but-for" beneficiaries who caused the lines at issue, and the hypothetical future benefits that may accrue over time. A hybrid methodology provides a structural basis for believing that costs are allocated in a manner that is "at least roughly commensurate" with benefits because, by definition, it recognizes that transmission lines have immediate, system-wide, and hypothetical future benefits, and there must be some mechanism to allocate costs, even if imperfectly, across these beneficiaries.[4] Therefore, consistent

---

[3] *Illinois Commerce Comm'n* v. *FERC*, 576 F.3d 470, 476 (7th Cir. 2009) (*ICC*) (explaining that a claim of "generalized system benefits" is insufficient to support an unjustified subsidy), 477 (finding that the lines in the record will have some regional benefits "just because the network *is* a network," but that the Commission failed to show that there is "enough of a benefit to justify the costs [it] wants shifted," and that while the Commission "can presume that new transmission lines benefit the entire network. . . . 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.'")(emphasis original).

[4] The majority suggests that there is a lack of evidence, "substantial or otherwise," to support a hybrid approach. Order at P 3. However, in explaining why violations-based DFAX is unjust and unreasonable as a stand-alone cost allocation mechanism, the majority concedes that the nature of transmission as a long-lived asset renders the hybrid approach reasonable in principle. ("In the case of investments that will last upwards of forty years, it is reasonable for the Commission to balance both short-run causes and benefits and long-run benefits.") *Id.* P 28. Moreover, the majority incorrectly suggests that the Commission can adopt a hybrid approach only if it can determine the appropriate split between regionally and locally allocated costs with exacting precision. In contrast to the majority, the Supreme Court has recognized that cost allocation "is not a matter for the slide-rule" and "has no claim to an exact science." *Colo. Interstate Gas Co. v. Fed. Power Comm'n,* 324 U.S. 581, 589 (1945). Consistent with this precedent, the Seventh Circuit made clear that the Commission does not need to "to calculate benefits to the last penny" to show that a cost allocation methodology is just and reasonable. *ICC*, 576 F.3d 470, 477. Therefore, I believe that the Commission has some flexibility in determining an acceptable split between regional and local cost allocation in a hybrid methodology, provided it has some basis to believe that the split is reasonable. *See FPC v.*

(continued…)

with the general principle that the Commission has broad authority to choose a rate from a range of just and reasonable rates,[5] and mindful that cost allocation "is not a matter for the slide-rule" and has "no claim to an exact science," I suggested that the Commission send the case to a settlement judge with instructions to work with stakeholders to develop the appropriate ratio of regional and local costs.

I note that in the Order No. 1000 compliance filing on which the Commission acts today, PJM stakeholders have come forward with a hybrid approach for defined categories of high-voltage transmission lines that they believe offer benefits across the PJM footprint. I am pleased that today the Commission is approving that cost allocation proposal for use going forward.

Having resolved PJM's cost allocation going forward, it becomes even clearer that what is at stake here is cost allocation for a circumscribed set of transmission lines proposed and approved in past regional transmission plans. As I stated in my initial dissent, I would remand this case to PJM stakeholders and a settlement judge to develop a hybrid methodology that reflects both the specific reliability benefits that caused the lines in the first place and the system-wide benefits that may accrue over time.[6]

Accordingly, I respectfully dissent.

____

Cheryl A. LaFleur
Commissioner

Conway Corp., 426 U.S. 271, 278 (1976) (*Conway*) (finding "there is no single cost-recovering rate, but a zone of reasonableness").

[5] *See Montana-Dakota Util. Co. v. Northwestern Pub. Serv. Co.*, 341 U.S. 246, 251 (1951)("Statutory reasonableness is an abstract quality represented by an area rather than a pinpoint. It allows a substantial spread between what is unreasonable because too low and what is unreasonable because too high."); *Conway*, 426 U.S. 271, 278.

[6] The majority indicates that finality and avoiding further proceedings is an important reason for denying rehearing and adhering to its postage-stamp approach. Order at P 4. While I agree that finality is generally important, it is not a reason for sticking with an unjust and unreasonable cost allocation methodology. Additionally, the majority has not explained why it would be particularly difficult for the parties to develop a hybrid methodology before a settlement judge, especially when the stakeholders developed one on Order No. 1000 compliance. In this respect, the majority relies on an administrative convenience rationale very similar to the one the court has already rejected as unsupported. *See ICC*, 576 F.3d 470, 475 ("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 indication that the difficulty exceeds that of measuring the benefits to particular utilities of a smaller-capacity transmission line.").

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C. Docket No. EL05-121-008

(Issued March 22, 2013)

CLARK, Commissioner, *dissenting*:

Today, a majority of the Commission reconfirms its decision to uphold a 100% postage stamp cost allocation methodology for high-voltage transmission facilities in the PJM region. Given the record before us, I cannot support this order.

The benefits used to justify the postage stamp methodology neither drove the development of the new high-voltage transmission facilities nor resulted directly from the new facilities themselves. The order imposes costs across PJM for projects built to resolve Eastern reliability issues on the theoretical basis of potential shifts in power flows and the claim of general system benefits. While these lines do provide secondary benefits, such as congestion savings, the predominantly west-to-east power flows in PJM make it highly likely that these benefits will accrue to Eastern load centers, not Midwestern. Also, while the entire PJM region benefits from region-wide planning and system operations, as recognized in today's order, these are generic benefits that are a product of PJM membership. The benefits cited are not specifically the product of the projects at issue here. Given the fact pattern in this proceeding, I would have established an evidentiary hearing procedure to determine a just and reasonable and not unduly burdensome cost allocation methodology to replace PJM's static flow-based methodology, as discussed below.

Procedural History

In 2009, the United States Court of Appeals for the Seventh Circuit granted[1] the petition for review of the Commission's decision in Opinion No. 494[2] to adopt a postage stamp methodology for allocating the cost of new transmission facilities operating at 500 kV and above. After remand from the Seventh Circuit, the Commission issued the Order on Remand upholding a 100% postage stamp cost allocation methodology. Today, the Order on Rehearing focuses on opposing parties' responses to the Commission's decision in the Order on Remand. The instant order marks the first time I have participated in this proceeding.

---

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

[2] *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).

The court provides us with a straightforward task: make a reasoned decision based upon substantial evidence.[3] The Seventh Circuit stated that "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."[4] The court required us to compare the "costs assessed against a party to the burdens imposed or benefits drawn by that party."[5] However, even if we could not quantify the benefits to the Midwestern utilities from new 500 kV lines in the East, but had a plausible reason to believe that the benefits are at least roughly commensurate with those utilities' share of total electricity sales in PJM's region, the Seventh Circuit gave the Commission latitude to approve the proposed pricing scheme on that basis.[6]

Even given this latitude, I do not believe there is sufficient evidence or reasoning in the record to find that benefits for utilities in the Midwest are even roughly commensurate to the costs incurred under the postage stamp methodology. Inasmuch as this is the case, I believe the Commission's decision has largely ignored the court's clear directive.

Postage Stamp Transmission Facilities

Let us first consider PJM's planning process and the above 500 kV facilities at issue in this proceeding. PJM's 100% postage stamp cost allocation methodology was in effect from June 20, 2006[7] to February 1, 2013.[8] Within that time, several high-voltage facilities and necessary lower-voltage facilities were approved through PJM's Reliability Transmission Expansion Plan (RTEP) process.

PJM's RTEP ensures system reliability and adherence to North American Electric Reliability Corporation (NERC) standards.[9] In its RTEP, PJM analyzes grid system dynamics on a region-wide basis to ensure that the integrated grid is in compliance with NERC standards over a five-year near-term horizon and 15-year long-term horizon.[10] The two largest projects to come out of

---

[3] *Illinois Commerce Comm'n*, 576 F.3d at 478, *citing Town of Norwood v. FERC*, 962 F.2d 20, 22 (D.C. Cir. 1992).

[4] *Id.* at 476.

[5] *Id.* at 477, *citing Midwest ISO Transmission Owners v. FERC*, 373 F.3d 1361, 1368 (D.C. Cir. 2004).

[6] *Id.*

[7] Opinion No. 494-A, 122 FERC ¶ 61,082 at P 92.

[8] *PJM Interconnection, L.L.C.*, 142 FERC ¶ 61,074, at P 1 (2013); *PJM Interconnection, L.L.C., et al.*, 142 FERC ¶ 61,214, at P 1 (2013).

[9] PJM's Operating Agreement provides that the "Regional Transmission Expansion Plan shall conform at a minimum to the applicable reliability principles, guidelines and standards of NERC, ReliabilityFirst Corporation and SERC, and other Applicable Regional Entities in accordance with the planning and operating criteria and other procedures detailed in the PJM Manuals." *See* PJM Operating Agreement, Schedule 6 (Regional Transmission Expansion Planning Protocol), section 1.2(d).

[10] PJM Interconnection, L.L.C., *PJM 2012 RTEP in Review*, Book 1, at 2 *available at* http://www.pjm.com/~/media/documents/reports/2012-rtep/2012-rtep-book-1.ashx.

the RTEP process in recent years are the Susquehanna-Roseland 500 kV line and the 502 Junction – Loudoun [Trans-Allegheny Interstate Line (TrAIL)].[11] According to PJM's April 13, 2010 response[12] to the Commission's January 21, 2010 Order[13] establishing paper hearing procedures, the Susquehanna-Roseland and TrAIL lines cost approximately $1,161 million and $1,117 million, respectively.

The Susquehanna-Roseland 500 kV line has an expected in-service date of June 1, 2015.[14] As approved in PJM's 2007 RTEP, the Susquehanna-Roseland line would extend from northeastern Pennsylvania to Roseland, New Jersey.[15] PJM approved the addition of the Susquehanna – Roseland 500 kV line because it "reduces northern New Jersey overloads to a point that future overloads are not expected until at least 2016."[16] According to PJM's estimate in this proceeding, Commonwealth Edison (ComEd), an Illinois utility, would only have been responsible for 0.28%, or $3.25 million of the total cost of the Susquehanna-Roseland line under the flow-based DFAX methodology.[17] Under the 100% postage stamp methodology, however, the costs allocated to ComEd increase fiftyfold, saddling ComEd customers with over $168 million in costs for Susquehanna-Roseland, a transmission facility built for the sole purpose of alleviating transmission constraints in an area more than 500 miles away from Illinois.[18]

The 500 kV TrAIL transmission facility was placed in service on May 23, 2011.[19] According to PJM's 2011 RTEP, TrAIL improves reliability into such congested areas as Washington, D.C., Baltimore and northern Virginia. It was built in three segments, connecting substations in southwestern Pennsylvania, northern West Virginia and northern Virginia. According to the

---

[11] PJM Interconnection, L.L.C., *PJM 2011 RTEP in Review*, Book 1, at 14-15 *available at* http://www.pjm.com/~/media/documents/reports/2011-rtep/2011-rtep-book-1.ashx.

[12] PJM Interconnection, L.L.C. April 13, 2010 Response to Information Requests, Docket No. EL05-121-006, at 9-10 *available at* http://elibrary.ferc.gov/IDMWS/common/opennat.asp?fileID=12320778.

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

[14] PJM Interconnection, L.L.C., *PJM 2012 RTEP in Review*, Book 1, at 7 *available at* http://www.pjm.com/~/media/documents/reports/2012-rtep/2012-rtep-book-1.ashx.

[15] PJM Interconnection, L.L.C., *PJM 2007 RTEP*, Section 3 at 57-60 *available at* http://www.pjm.com/~/media/documents/reports/2007-rtep/2007-section3a.ashx.

[16] *Id*. at 60. *See* Map 1 in the Appendix for a map demonstrating the drivers of the Susquehanna-Roseland line.

[17] PJM Interconnection, L.L.C. April 13, 2010 Response to Information Requests, Docket No. EL05-121-006, at 9 *available at* http://elibrary.ferc.gov/IDMWS/common/opennat.asp?fileID=12320778. PJM's distribution factor (DFAX) methodology at issue in this proceeding calculates the contribution of load in each zone to flows on the facility that creates the need for the transmission enhancement.

[18] The $168 million total for ComEd is based a conservative load ratio share of 14.5 % for ComEd multiplied by the $1,161 million in total costs for the Susquehanna-Roseland project. Information on cost allocation percentages is on PJM's website *available at* http://www.pjm.com/planning/rtep-upgrades-status/cost-allocation-view.aspx.

[19] PJM Interconnection, L.L.C., *PJM 2011 RTEP in Review*, Book 1, at 14 *available at* http://www.pjm.com/~/media/documents/reports/2011-rtep/2011-rtep-book-1.ashx.

2006 RTEP, TrAIL relieves expected overloads on 500 kV circuits in West Virginia, Virginia, and Maryland.[20] In its decision to approve the TrAIL facility, PJM stated that "[g]rowing west-to east power transfers to serve eastern load centers have been identified as a major driver of the generator deliverability-based overloads now observed on these circuits."[21] Not surprisingly, if ComEd's costs would have been allocated according to the flow-based DFAX methodology, ComEd would not be responsible for *any* of the costs associated with the TrAIL enhancement.[22] In comparison, a 100% postage stamp cost allocation forces ComEd to pay an estimated $162 million for a line that has been built to resolve anticipated reliability violations caused by power demands in the East.[23]

Susquehanna-Roseland and TrAIL are just two examples of the many Eastern-driven projects that will be paid for by consumers who appear to share little of the benefits. These backbone transmission facilities were approved to resolve specific anticipated reliability violations in the East, not to increase the general system-wide benefits discussed in the Order on Remand or the Order on Rehearing.

System-wide Benefits

Upon review, I conclude that even a roughly commensurate standard cannot be satisfied by the system-wide benefits described in this proceeding. The Order on Remand used PJM's estimates from a generic 2011 ISO/RTO Metric Report to conclude that planning and operating a reliable transmission system produces as much as $2.2 billion in annual savings for the region.[24] The order claimed the "benefits" created by planning and operating a reliable transmission system include: (1) using redispatch procedures to maintain reliability rather than power sales curtailments; (2) planning for future reliability needs on a region-wide rather than a utility-by-utility or state-by-state basis; (3) reducing reserve requirements and increasing demand response; and (4) reducing production costs, operating reserve costs and ancillary services costs. The Order on Remand characterized these annual savings as benefits in order to conclude that ComEd benefited from the transmission facilities by $225 million to $325 million.[25]

---

[20] PJM Interconnection, L.L.C., *PJM 2006 RTEP*, Section 3 at 92-93 *available at* http://www.pjm.com/~/media/documents/reports/rtep/2006/20070301-section-03b.ashx. *See also* Map 2 in the Appendix for a map demonstrating the drivers of the TrAIL enhancement.

[21] *Id.*

[22] Response of PJM Interconnection, L.L.C. to Information Requests, April 13, 2010, Docket No. EL05-121-006, at page 10, *available at* http://elibrary.ferc.gov/IDMWS/common/opennat.asp?fileID=12320778.

[23] The $162 million total for ComEd is based on the same conservative load ratio share of 14.5% used for the Susquehanna-Roseland calculation above, multiplied by the $1,117 million in total costs for the TrAIL project.

[24] *PJM Interconnection, L.L.C.*, 138 FERC ¶ 61,230, at P 78 (2012), *citing* 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.

[25] *See id.* at PP 79, 97.

While I agree with the Order on Rehearing that each of the transmission facilities that operate at or above 500 kV is part of an interconnected transmission network, I disagree that planning and operating on a regional basis can be used to justify a 100% postage stamp cost allocation. The benefits comprising the $2.2 billion in the preceding paragraph are not actually benefits provided by the high voltage facilities at issue in this proceeding; they are the benefits utilities receive by virtue of their membership in the PJM RTO.

For instance, the Order on Remand states that planning for future reliability needs on a region-wide basis results in an estimated $390 million in annual savings. The analysis in the Order on Remand then characterizes this $390 million as benefits to the region and applies them, in part, to ComEd. However, PJM's region-wide planning through the RTEP resulted in the development of high-voltage backbone facilities in the East, not projects in the Midwest. I am unable to see how this results in a roughly commensurate benefit to the Midwest. Similarly, while I agree that operating the transmission system on a regional basis provides system-wide benefits, these benefits did not lead to the development of projects like TrAIL and Susquehanna-Roseland, nor do these projects directly lead to greater operational efficiency for utilities hundreds of miles to the west. Put simply, using membership in an RTO as a basis for allocating the costs of high voltage transmission on a pro-rata basis does not fit the circumstances at play here. Effectively, this rationale ignores the court's mandate to engage in some weighing of the benefits and burdens of the actual projects.

The Order on Remand also recognizes that the development of backbone projects results in expected congestion savings, reduced outages, reduced operating reserve requirements, and reduced losses. However, the direct beneficiaries in these instances are the entities closest to the transmission projects, not those located hundreds of miles away. That is, avoiding overloads in northern New Jersey reduces outages first and foremost for those living in New Jersey. Along these same lines, congestion savings from projects like TrAIL are most beneficial to utilities in Maryland, Virginia, and New Jersey.[26]

The Order on Rehearing makes the point that, without the addition of new transmission facilities that operate at or above 500 kV, the integrity of the transmission system would deteriorate, and the benefits of the integrated system would be reduced. I agree. A comprehensive planning process such as PJM's RTEP provides the region with protection against future reliability violations and maintains the integrity of the transmission system. However, this would be the case regardless of the cost allocation mechanism. As PJM explains in its most recent RTEP, "[i]f violations of NERC Reliability Standards are identified, PJM is obligated to develop and

---

[26] The same conclusion can be reached for contingency reserve requirements. Constrained deliverability within the PJM region has led to the establishment of an Eastern subzone (the Mid-Atlantic Dominion sub-zone), which has additional restrictions on reserve requirements relative to the rest of the RTO. It is this Eastern sub-zone, and not the rest of PJM, that generally relies on the market to procure sufficient reserves. *See* Monitoring Analytics (Independent Market Monitor for PJM), *2012 State of the Market Report for PJM*, section 9 (Ancillary Services) at 279 *available at* http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2012/2012-som-pjm-volume2-sec9.pdf.

implement solutions to mitigate them."[27] In addition, PJM recognizes that it is a federally-approved RTO "charged with ensuring the safety, reliability and security of the bulk electric power system." [28] Thus, with expected reliability violations on the horizon, PJM is obligated to develop solutions to prevent or mitigate these system concerns. 100% postage stamp cost allocation is not necessary for these facilities to be built. What is necessary, however, is for the Commission to offer some valid justification for how costs and benefits are allocated in a roughly commensurate manner to the users of the system, and that is where the order's analysis falls short.

In many instances, the order's justification for a postage stamp cost allocation methodology turns to a claim that flows on transmission facilities operating at or above 500 kV can change over time. This reasoning supposes that theoretically power flows could shift and become predominantly east-to-west, thereby benefiting utilities like ComEd in a manner roughly commensurate with the hundreds of millions they will pay under the postage stamp methodology. The record, however, shows no concrete evidence that power flows are going to shift west or that the new transmission facilities would provide direct benefits to the Midwest under such circumstances. I see no basis for saddling ComEd's (or any other Midwestern utility's) customers with costs for transmission projects meant to resolve potential reliability violations hundreds of miles to the East, and for which the Midwestern utilities will see only trivial benefits, on a theory of potentially shifting power flows. Costs need to be allocated in a manner roughly commensurate with actual, not theoretical, benefits.

A Just and Reasonable Cost Allocation Methodology

When acting under section 206 of the Federal Power Act, in order to change an existing cost allocation methodology, 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 as a replacement.

To meet the first prong of its section 206 burden, the Commission concluded that PJM's use of a static, flow-based model for allocating the costs of new transmission facilities that operate at or above 500 kV was unjust and unreasonable and unduly discriminatory. I generally agree with this conclusion and find that PJM's static DFAX methodology did not adequately recognize changes in the system throughout time. Nonetheless, the static DFAX methodology did have one advantage over the postage stamp methodology upheld in today's order—it provided PJM with an objective and quantifiable basis for attributing costs to utilities that caused anticipated reliability violations. In doing so, PJM's static DFAX methodology established a direct link between who pays for a facility and who causes the need for that facility.

While the Commission has adequately demonstrated that the existing DFAX methodology is unjust and unreasonable, today's order fails to establish a just and reasonable replacement for the static DFAX model and thus does not meet its burden under the second prong of section 206 of

---

[27] PJM Interconnection, L.L.C., *PJM 2012 RTEP in Review*, Book 1, at 3 *available at* http://www.pjm.com/~/media/documents/reports/2012-rtep/2012-rtep-book-1.ashx.

[28] *Id.*

the FPA. After applying the Seventh Circuit's evaluation criteria by comparing the costs assessed against the parties in this proceeding to the *burdens imposed or benefits drawn* by these parties, I conclude that a 100% postage stamp cost allocation methodology has not been shown to be just and reasonable for all utilities in the PJM region.

First, a 100% postage stamp methodology does not account for the burdens imposed by the parties on the transmission grid. The Midwestern utilities are not the parties burdening the grid with anticipated reliability violations and are not driving the need for the transmission facilities at issue in this proceeding. Despite this fact, the postage stamp cost allocation methodology in PJM applies costs on a pro-rata basis, even though some utilities in PJM are far-removed from the reliability drivers in the East. Moreover, the predominantly west-to-east power flows in PJM make it highly unlikely that Midwestern utilities will rely on power from the new facilities in an amount equal to their load ratio share.

Second, it is clear that the benefits drawn by Midwestern utilities are trivial compared to the costs they are allocated under a 100% postage stamp methodology. As demonstrated above, the system-wide "benefits" used as evidence in the order are either not directly provided to Midwestern utilities or are not directly applicable to the new high voltage facilities in this proceeding. Thus, these purported benefits do not provide a sufficient foundation to meet the roughly commensurate standard.

However, this is not to say that a 100% postage stamp methodology is necessarily unjust and unreasonable in all circumstances. The Midwest Independent Transmission System Operator, Inc. (MISO) applies such a methodology to its Multi-Value Projects. MISO's Tariff, however, explicitly provides that a Multi-Value Project must be evaluated as part of a portfolio of projects whose benefits are spread broadly across the footprint.[29] In contrast, PJM did not approve the instant projects through such a process and thus did not ensure regional benefits. Additionally, PJM's RTEP plans from 2006 to date[30] did not include any backbone transmission facilities in the Midwest that would balance out the disparity of having Midwestern utilities pay for projects built to resolve potential reliability issues in the East.

While I understand the need to bring this proceeding to a close and establish finality for participants, I must balance this need with the Commission's obligation to ensure just and reasonable rates. I cannot rationalize why Midwestern utilities should be responsible for hundreds of millions of dollars in costs for facilities built to resolve potential reliability violations caused by other utilities.[31] The Commission's position seems to be: a high voltage line

---

[29] *See* MISO, FERC Electric Tariff, Attachment FF, section II.C.1 (8.0.0).

[30] *Regional Transmission Expansion Plan Documents available at* http://www.pjm.com/documents/reports/rtep-documents.aspx.

[31] One does not need to be an electrical engineer to understand why the Commission continues to have such difficulty in trying to get the 100% postage stamp model to fit this case. A quick look at the PJM high voltage transmission map clarifies the issue. PJM is physically large. Not only is it large, the Midwestern utilities and the Eastern utilities have limited connectivity, *i.e.* the transfer capability is quite limited. As such, it is little wonder a project needed for reliability in the East would show little benefit in the Midwest or vice versa.

built anywhere in PJM is necessarily an equal benefit to every consumer everywhere in PJM. Given the overwhelming weight of evidence to the contrary, I cannot support this conclusion.

The Commission should have taken a different direction supported by a record. The static DFAX model may not be ideal, but it should not be replaced by another unjust and unreasonable methodology. The Commission should have established hearing and settlement judge procedures to allow parties an opportunity to build a record by which they could determine a suitable alternative to the static DFAX.[32] One alternative could have been a Solution-Based DFAX.[33] A Solution-Based DFAX is updated annually and would eliminate the Commission's major concern about the static DFAX model. Another approach could have been a hybrid methodology, which the Commission has approved as the cost allocation methodology going forward.[34] Either of these approaches would have been preferable to the imposition of a 100% postage stamp cost allocation on consumers that may never directly benefit from the projects they are now forced to fund.

For these reasons, I respectfully dissent from this order.

____

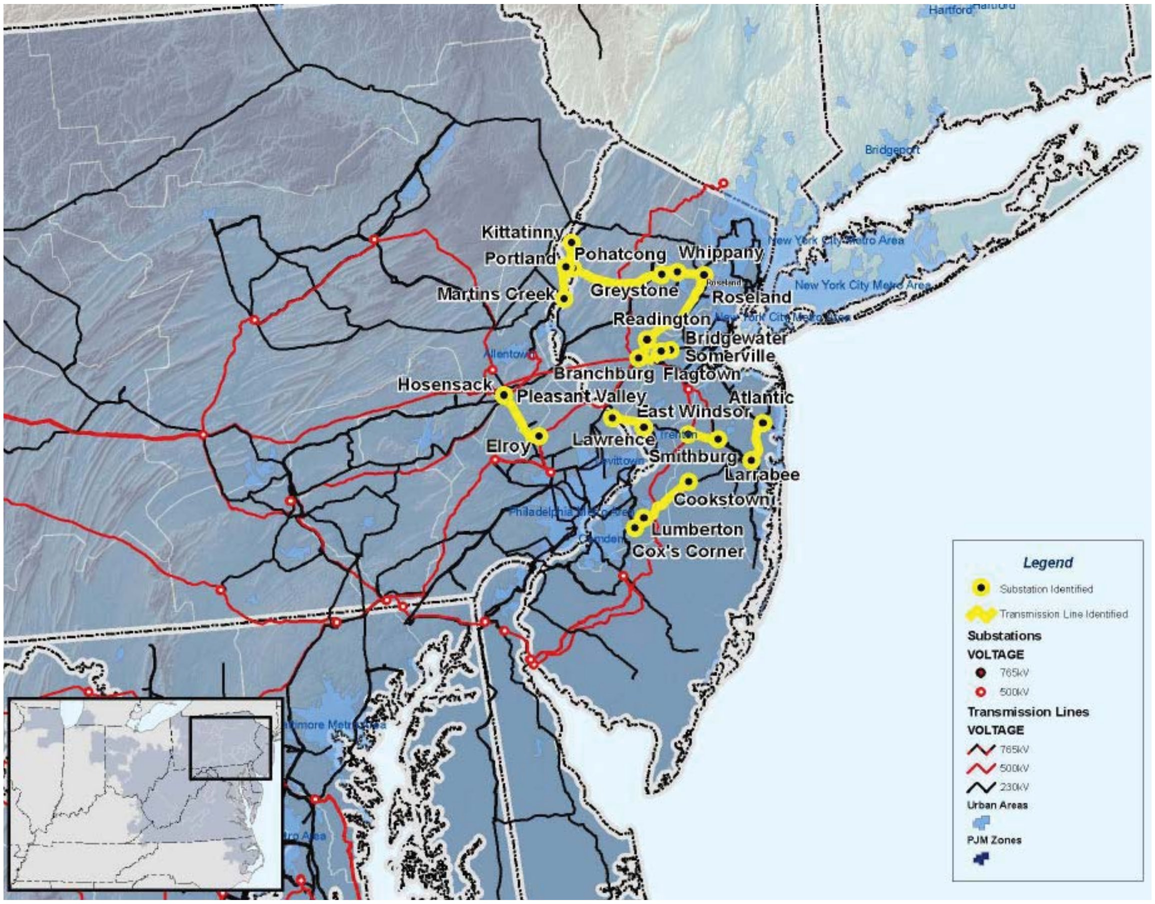
Tony Clark
Commissioner

[32] *See* Illinois Commerce Comm'n April 27, 2012 Request for Rehearing at 34-36 *available at* http://elibrary.ferc.gov/idmws/common/opennat.asp?fileID=12967811

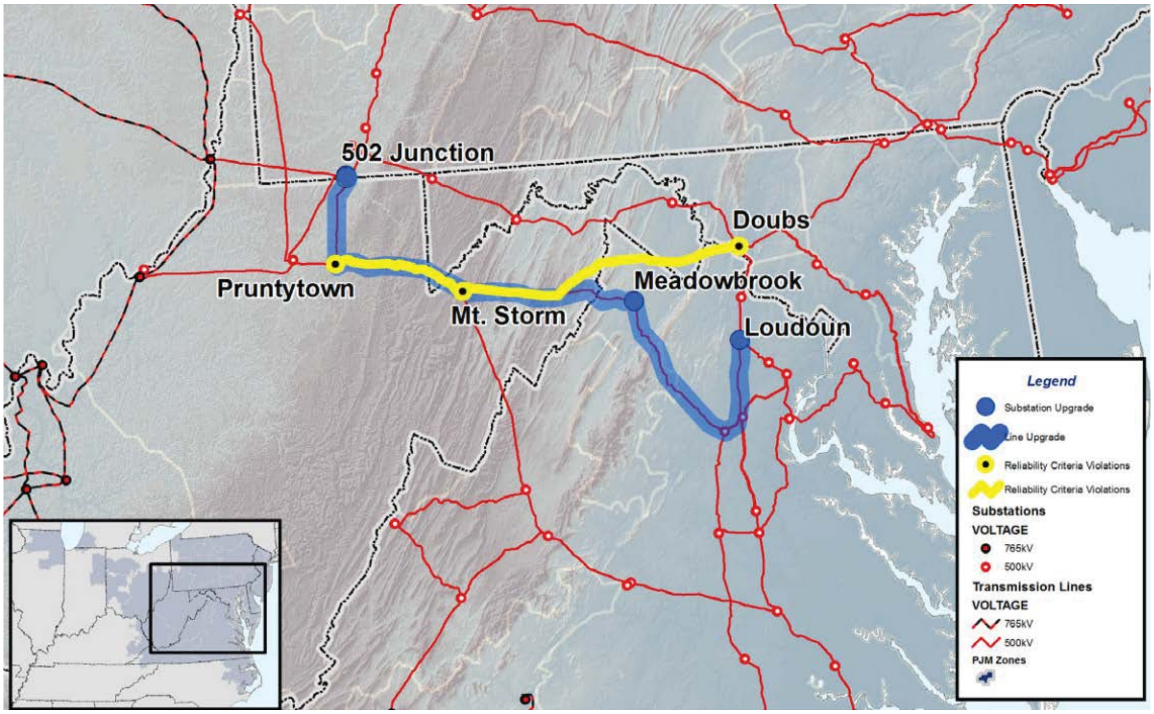
[33] PJM's "Solution-Based DFAX" method will calculate the relative use of a new facility from load in each zone and withdrawals by merchant transmission facilities. This analysis will account for uses of the new facility in both directions, and will be updated annually to account for changes in use due to modifications of the grid. *See PJM Interconnection, L.L.C, et al.*, 142 FERC ¶ 61,214, at P 345 (2013).

[34] Briefly, PJM's "50/50 hybrid" cost allocation method allocates one-half of a Regional or Necessary Lower Voltage Facility's costs based on the postage-stamp method, and one-half based on the "Solution-Based" DFAX method. *See PJM Interconnection, L.L.C, et al.*, 142 FERC ¶ 61,214, at P 345 (2013).

APPENDIX



Map 1: *Reliability Criteria Violations Driving Need for the Susquehanna – Roseland Line*. *See* PJM 2007 RTEP, Section 3 at 59, *available at* http://www.pjm.com/~/media/documents/reports/2007-rtep/2007-section3a.ashx.



Map 2: *Reliability Criteria Violations Driving Need for TrAIL*. *See* PJM 2008 RTEP, Section 3 at 53, *available at* http://www.pjm.com/~/media/documents/reports/2008-rtep/2008-section3.ashx.

This foregoing document was electronically filed with the Public Utilities

Commission of Ohio Docketing Information System on

5/16/2013 12:12:00 PM

in

Case No(s). 93-7000-EL-FAD

Summary: Petition for Review of the order issued by the Federal Energy Regulatory Commission in FERC Docket Nos. EL05-121-006, and EL05-121-008, submitted on behalf of the Public Utilities Commission of Ohio by Assistant Attorney General Thomas Lindgren on May 16, 2013 to the U.S. Court of Appeals for the Seventh Circuit, Case No. 13-2052. electronically filed by Kimberly L Keeton on behalf of Public Utilities Commission of Ohio