LARGE FILING SEPARATOR SHEET

CASE NUMBER 14-1693-EL-RDR
14- 1694-EL-AAM

FILE DATE 10/13/15

SECTION: 1 of 3

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Volume II

FILE

PUCO EXHIBIT FILING

Date of Hearing: 9-29-2015

Case No. 14-1693-EL-RDR, 14-1694-EL-AAM

PUCO Case Caption: In the Matter of the Application Seeking Approval of Ohio Power Company's Proposal to Enter into an Affiliate Power Purchase Agreement for Inclusion in the Power Purchase Agreement Rider.

In the Matter of the Application of Ohio Power Company for approval of Certain ~~accoun~~ accounting authority.

List of exhibits being filed: Volume II

SC 1-2-3

OMAEG 1-2-3-4-5

OCC 1-2-3-4-5-6-7

ELPC 1

Reporter's Signature: [signature]

Date Submitted: 10-13-15

BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO

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In the Matter of the Application Seeking Approval of Ohio Power Company's Proposal to Enter into an Affiliate Power Purchase Agreement for Inclusion in the Power Purchase Agreement Rider.	:	Case No. 14-1693-EL-RDR
In the Matter of the Application of Ohio Power Company for Approval of Certain Accounting Authority.	:	Case No. 14-1694-EL-AAM

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PROCEEDINGS

before Ms. Greta See and Ms. Sarah Parrot, Attorney Examiners, at the Public Utilities Commission of Ohio, 180 East Broad Street, Room 11-D, Columbus, Ohio, called at 9:00 a.m. on Tuesday, September 29, 2015.

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VOLUME II

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ARMSTRONG & OKEY, INC.
222 East Town Street, Second Floor
Columbus, Ohio 43215-5201
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SC&41

Summary of Major Terms
Power Purchase and Sale Agreement ("Agreement")

Buyer:	Ohio Power Company ("OPCo" or "Buyer")
Seller:	AEP Generation Resources Inc. or a subsidiary thereof ("AEPGR" or "Seller")
Agreement Start Date:	October 1, 2015
Generation Facilities:	OPCo will receive entitlement to all of the power output (capacity, energy and ancillary services) associated with Seller's ownership interest in the generation facilities listed in Attachment A (collectively, the "PPA Units" or individually a "Unit").
Term:	Agreement term is through the entire commercial operational life of all of the PPA Units, including any post-retirement period necessary to fulfill all asset retirement obligations and complete any other removal projects. The currently planned retirement dates are set forth in Attachment A. Alternative Agreement end dates will be by mutual agreement between the Buyer and Seller.
Operating Committee:	The Agreement will provide for establishment of an Operating Committee and representatives of OPCo, Seller and American Electric Power Service Corporation ("AEPSC") shall each name one representative to act for it in matters pertaining to the Agreement and to develop, as necessary, arrangements for the generation, delivery and receipt of energy hereunder, including the items designated below and such other mutually agreed upon contract administration procedures. With respect to the Agreement, the Operating Committee, or its designees, shall review and approve: (a) capital budgets and any major Operations and Maintenance ("O&M") expenditures for the PPA Units, (b) operating parameters or capability of a Unit or changes thereto (c) Fuel and consumable procurement practices, including fuel specifications, and any new substantive supply contracts, and (d) Unit retirement decisions. The representative for AEPSC shall not vote except in the case of a tie between OPCo and Seller. The Operating Committee shall meet at least annually. For co-owned PPA Units, the Operating Committee determinations will be utilized in voting actions in co-owner meetings.
Delivery Points:	The PJM nodes located at each of the PPA Units.

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EXHIBIT
SC-1

Fuel: Seller will arrange, provide, procure, supply, transport, manage, transact and deliver Fuel to Units, and at jointly owned Facilities, Buyer will have the right to monitor the fuel transaction and *logistics process and provide input on this activity to Seller at* Operating Committee meetings. Seller agrees to conduct Fuel purchases using competitive methods, and Buyer will have the right to monitor and approve the results of such competitive methods, but Fuel agreements in place as of the Start Date will continue to be utilized for the Units. Any other fuel transaction that is not obtained through competitive methods must be approved by Buyer, including extensions or renewals of Fuel agreements in place as of the Start Date.

Offers and Scheduling: Buyer or its agent will dispatch the generation associated with the Facilities by reviewing and determining the parameters associated with PJM generation offers, including how such generation will be offered to PJM, for the Energy and Ancillary Services associated with Buyer's Contractual Capacity and Seller will, subject to the requirements of PJM and the operating parameters of the Facilities, as determined by the Facility operator, operate and control the Facilities and schedule with PJM pursuant to Buyer's dispatch criteria and PJM's requirements and instructions.

Capacity Entitlement: OPCo will receive all of the net capacity revenues of the PPA Units.

Energy Entitlement: OPCo will receive all of the net energy revenues of the PPA Units.

Ancillary Services Entitlement: OPCo will receive all of the net ancillary services revenues from the PPA Units.

Buyer Payments: In exchange for the above entitlements, OPCo will reimburse Seller for all costs associated with the PPA units. OPCo will make monthly payments to Seller equal to the sum of the following: (a) Fuel Payment, (b) O&M Payment, (c) Depreciation Payment, (d) Capital Payment, (e) Tax Reimbursement Payment, and (f) Other Miscellaneous Payment.

Fuel and O&M: OPCo will reimburse Seller monthly for the total actual monthly fuel and O&M costs incurred by Seller at the PPA Units. Fuel costs include, without limitation, fuel, fuel handling, fuel storage, transportation, transloading, fuel hedging, sales, consumables/chemicals and emission costs. O&M costs include, without limitation, O&M costs plus Administrative and General costs, accretion expense and overheads.

Depreciation: OPCo will make a monthly depreciation payment equal to actual depreciation and amortization expense on the PPA Units. The deprecation rates expected to be in effect at the Agreement Start Date are presented in Attachment B. These rates will remain the same for the first 15 months of the Agreement and will be updated thereafter no less frequently than every five years.

Any remaining net book value that exceeds zero at the end of life of a given unit will be depreciated at an adjusted rate of other units at the same plant. If the final Unit or Units of a plant is/are retired, any remaining net book value of that plant will be payable by OPCo at that time unless other payment arrangements are made between OPCo and Seller.

Capital: OPCo will make a monthly Capital payment consisting of the net book value of the PPA Units times a cost of capital. Net book value will include plant in service, construction work-in-progress, accumulated depreciation, fuel and materials and supplies inventory, other working capital, asset retirement obligations, and accumulated deferred income taxes. For purposes of computing the cost of capital, the capital structure will be based on a fixed "50/50" capital structure that includes 50% equity and 50% debt. The cost of debt will be the actual debt cost of the Seller beginning with 2017. Until then, debt cost will be based on Moody's Baa corporate bond index average for the month of December of the previous year. The cost of equity shall be equal to the Moody's Long-term Baa corporate bond index interest rate (averaged for each day in December and adjusted annually) plus a fixed 650 basis point adder. The cost of equity will not be less than 8.9% or greater than 15.9%.

Tax Reimbursement: For each calendar month, OPCo shall pay Seller an amount equal to all taxes for that month applicable to the PPA Units and the Agreement. Any tax based upon income, gross receipts, commercial activity or any similar tax for which the inclusion of such tax in the monthly payment increases Seller's tax liability shall be grossed-up at the applicable statutory rate. All other taxes (e.g., property tax) will be billed as incurred.

Other Miscellaneous: Other miscellaneous payment shall include any other costs and credits as described within the Agreement not already included in the other payment components or any other costs or credits reasonably associated with the Facilities which may be billed monthly or if incurred less frequently, on either a quarterly or as incurred basis. Beginning five (5) years prior to the Planned Retirement Year of each Unit as shown in Attachment A, Other Miscellaneous payments will also include a component for recovery of forecasted retirement-related costs associated with the Unit.

Cost Computation:

The FERC Uniform System of Accounts will be utilized by Seller and costs to be paid by OPCo will be formulaically computed based on the actual costs as recorded in Seller's books and records.

Billing and Payment:

The calendar month shall be the standard period for all payments under the Agreement. As soon as practicable after the end of each month, Seller will render to Buyer an invoice for the payment obligations incurred during the preceding month. Each component of the invoice will be described in reasonable detail. All invoices under the Agreement shall be due and payable on or before the twentieth (20^{th}) day of each month. Buyer will make payments by electronic funds transfer to the account designated by Seller, or by other mutually agreeable method(s).

Books, Records and Audit Rights:

Seller shall keep, or shall cause to be kept, all necessary books of record, books of account, and memoranda of all transactions involving the PPA units, in conformance, where required, with the FERC's Uniform System of Accounts. Seller shall make, or shall cause to be made, all computations relating to the PPA Units and all allocations of the costs and expenses of these Units. Buyer has the right to examine the records of Seller to the extent reasonably necessary to verify the accuracy of any statement, charge or computation made pursuant to the Agreement (including any statements evidencing the energy quantities delivered to Buyer at the Delivery Points) within twelve (12) months of receipt of the statement, charge or computation. If any such examination reveals any inaccuracy in any statement, the necessary adjustments in such statement and the payments thereof will be made promptly, along with interest, provided, however, that any claim by a Party for overpayment or underpayment with respect to an invoice is waived unless the other Party is notified of the claim within twelve (12) months after the invoice is rendered or any specific adjustment to the invoice is made.

Unit Contingent: Failure to deliver power, including capacity, energy and/or ancillary services is excused to the extent any of the PPA Units are unavailable as a result of (a) an outage, (b) force majeure or (c) Buyer's failure to perform.

Early Termination Buyer can terminate the Agreement upon notice to the Seller if retail cost recovery for Buyer's Agreement costs is discontinued or substantially diminished, including through a one-time significant disallowance for retail rate recovery of costs, provided Buyer must pay Seller an amount equal to the sum of the net book value and retirement-related costs associated with the PPA Units at that time.

Unit Dispositions: Decisions regarding retirement or pre-retirement divesture of any of the PPA Units shall be by mutual agreement of the Buyer and Seller.

Buckeye: Seller shall extend, and Buyer shall accept extension of, the entitlements and obligations under the Cardinal Station Agreement related to unit dispatch, capacity, energy and ancillary service entitlements and back-up obligations related to Buckeye Power Inc.'s Cardinal Units 2 and 3.

Other Agreement Terms & Conditions: The foregoing provides a summary of the Major Terms of the Agreement. The Agreement contains such other terms and conditions as are customarily set forth in such agreements, including, but not limited to events of default, assignment, limitation of liabilities and a Mobile Sierra provision. The summary is provided for convenience and any conflicts between the summary and the Agreement will be governed by the terms of the Agreement.

Additional Items

Attachments	Attachment A: PPA Units Attachment B: Initial Depreciation Rates

Attachment A

PPA Units

Plant	Unit	Average Annual Capacity (MW)	AEPGR Ownership (%)	AEPGR Ownership (MW)	Currently Planned Retirement Year
Cardinal	1	592	100.0%	592	2033
Conesville	4	779	43.5%	339	2033
Conesville	5	405	100.0%	405	2036
Conesville	6	405	100.0%	405	2038
Stuart	1	577	26.0%	150	2033
Stuart	2	577	26.0%	150	2033
Stuart	3	577	26.0%	150	2033
Stuart	4	577	26.0%	150	2033
Zimmer	1	1,300	25.4%	330	2051
Total		5,789		**2,671**	

Attachment B
INITIAL PLANT DEPRECIATION RATES

Plant	Annual Depreciation Rate (%)
Cardinal	3.55%
Conesville	3.01%
Stuart	3.27%
Zimmer	1.42%

Sierra Club Ex. 2

POWER PURCHASE AND SALE AGREEMENT

by and between

[GENCO]

and

OHIO POWER COMPANY

dated as of

_____________, 2014

EXHIBIT
SC-2
PENGAD 800-631-6989

TABLE OF CONTENTS

TABLE OF CONTENTS
(continued)

TABLE OF CONTENTS
(continued)

POWER PURCHASE AND SALE AGREEMENT

THIS POWER PURCHASE AND SALE AGREEMENT (this "**Agreement**"), dated as of _______, 2014, is by and between [GenCo], a Delaware corporation ("**Seller**"), and OHIO POWER COMPANY, an Ohio corporation ("**Buyer**"). Buyer and Seller are sometimes referred to herein individually as a "**Party**" and collectively as the "**Parties.**"

RECITALS

A. Seller, an indirect subsidiary of American Electric Power Company, Inc., with its principal place of business in the State of Ohio, owns or will have an ownership interest in the Ohio based generation facilities shown in Schedule A entitled Ohio Generation Facilities.

B. The Parties desire to enter into a transaction in which Seller sells and Buyer purchases the Capacity, and associated Unit Contingent Energy and Ancillary Services, as delivered or made available from Seller's ownership interest in the generation facilities in Schedule A for a term through the remaining commercial operational life of each of the Schedule A Generation Facilities.

C. The Parties desire to set forth certain terms and conditions applicable to such transaction.

In consideration of mutual covenants and agreements contained herein, the Parties agree as follows:

ARTICLE I

DEFINITIONS

1.1 Defined Terms. Unless otherwise defined herein, the following terms, when used herein, shall have the meaning set forth below:

"**Affected Party**" has the meaning set forth in Section 3.7.

"**Affiliate**" means, with respect to any Person, any other Person (other than an individual) that, directly or indirectly, through one or more intermediaries, controls, or is controlled by, or is under common control with, such Person. For this purpose, "control" means the direct or indirect ownership of fifty percent (50%) or more of the outstanding capital stock or other equity interests having ordinary voting power.

"**Agreement**" means this Power Purchase and Sale Agreement entered into pursuant to Seller's market based rate authority.

"**Allowance Transfer Deadline**" means the date by which Allowances must be submitted for recordation with the EPA or other relevant Governmental Authority in order to meet the applicable Allowance obligation for the control period immediately preceding that deadline.

"**Allowances**" means emission allowances, emission credits, and any similar rights related to emissions of NO_x, SO_2, CO_2, mercury, particulates or any other substance under any relevant federal, state or local law or recognized by any Governmental Authority or other entity, and all other environmental attributes.

"**Ancillary Services**" means regulation and frequency response services; energy imbalance services; automatic generating control services; spinning, non-spinning, supplemental and replacement reserve services, reactive power and voltage support services, black start services and all other services or products ancillary to the operation of the Facility that are defined as ancillary services in the Transmission Operator's relevant transmission tariff or are commonly sold or saleable, to the extent that the assets comprising the Facilities provide those services or products.

"**Approvals**" means all approvals, permits, licenses, consents, waivers or other authorizations from, notifications to, or filings or registrations with, third parties, including without limitation, Governmental Approvals.

"**Business Day**" means any day except a Saturday, Sunday, or a United States Federal Reserve Bank holiday. A Business Day shall open at 8:00 a.m. and close at 5:00 p.m. local time at the relevant Party's principal place of business. The relevant Party, in each instance unless otherwise specified, shall be the Party from whom the notice, payment or delivery is being sent and by whom the notice or payment or delivery is to be received.

"**Buyer**" has the meaning set forth in the preamble hereto.

"**Buyer's Contractual Capacity**" means Seller's Capacity of the Facilities identified in Schedule A subject to the applicable Facility Operating Agreement, which entitlement is approximately 2,671 MW as of the date set forth in the preamble to this Agreement.

"**Capacity**" means the output level, expressed in MW, that a Facility, or the components of equipment thereof, is capable, as of a given moment, of continuously producing and making available at the Delivery Point, taking into account the operating condition of the equipment at that time, the auxiliary loads, the Facility Operating Agreement and other relevant factors.

"**Capital Improvements Work**" shall mean (i) for wholly owned Seller Facilities, the modeling, studying, engineering, design, procurement, purchasing, construction, inspection, start-up and testing of (a) minor or non-material capital improvements, replacements, repairs or additions to the Facility (b) mutually agreed to costs by both Buyer and Seller for any major or material capital improvements, replacements, repairs or additions to the Facility or (ii) for Seller Facilities that are jointly owned, capital improvements, replacements, repairs or additions to the Facility.

"Capacity Payment" has the meaning set forth in <u>Section 5.5</u>.

"Cardinal Station Agreement" means the agreement, dated as of January 1, 1968, by and between the Seller, Buckeye Power, Inc. and Cardinal Operating Company, including all amendments and any future amendments thereto.

"**Change-in-Law**" means, after the date set forth in the preamble to this Agreement, the adoption, imposition, promulgation, change in interpretation or modification by a Governmental Authority of any law, regulation or Governmental Approval, or the issuance of a final and non-appealable order, judgment, award or decree of a Governmental Authority having the effect of the foregoing.

"**Change-in-Law Taxes**" means, after the date set forth in the preamble to this Agreement, any change (increase or decrease) in Taxes imposed on Seller on (a) the sale or use of fuel for generation of electricity, (b) the sale of Capacity or (c) the production or sale of Energy or Ancillary Services, in any case, resulting from a Change-in-Law.

"**Claims**" means all claims or actions, threatened or filed and, whether groundless, false, fraudulent or otherwise, that directly or indirectly relate to the subject matter of an indemnity, and the resulting losses, damages, expenses (including reasonable attorneys' fees and disbursements) and court costs, whether incurred by settlement or otherwise, and whether such claims or actions are threatened or filed prior to or after the termination of this Agreement.

"**Closing**" and "**Closing Date**" means the date upon which the Parties obtain all regulatory approvals for this Agreement.

"**Contract Price**" means the price to be paid by Buyer to Seller for the purchase of the Buyer's Contractual Capacity and associated Energy and Ancillary Services, as determined in accordance with the provisions of Article V.

"**Contract Year**" means the period beginning at 12:01 a.m. EPT on the Start Date and ending on December 31st of the same year, and each succeeding calendar year thereafter during the Delivery Period. If the first or last Contract Year consists of a shorter period than a full calendar year, including by reason of the termination of this Agreement prior to the expiration of the Delivery Period, then that Contract Year may consist of a shorter period than a full calendar year, in which case with respect to that Contract Year, all terms and provisions of this Agreement that refer to or are based on a Contract Year shall be adjusted ratably downward to reflect such shorter period.

"**Delivery Period**" has the meaning set forth in Section 2.2.

"**Delivery Point**" has the meaning set forth in Section 3.4.

"**Depreciation Payment**" has the meaning set forth in Section 5.4.

"**Effective Date**" means the date on which all of the conditions precedent set forth in Section 11.1 have been satisfied or waived, which date shall not be earlier than the Closing Date.

"**End Date**" has the meaning set forth in Section 2.2.

"**Energy**" means three-phase, 60-cycle alternating current electric energy, expressed in MWh.

"**EPA**" means the United States Environmental Protection Agency or any successor agency with similar jurisdiction.

"**EPT**" or "**Eastern Prevailing Time**" means the local time at the geographical location of the Delivery Point.

"**Equitable Defenses**" means any bankruptcy, insolvency, reorganization and other laws affecting creditors' rights generally, and with regard to equitable remedies, the discretion of the court before which proceedings to obtain same may be pending.

"**Facility**" means any unit identified on Schedule A entitled Ohio Generation Facilities.

"**Facility Operating Agreement**" means the applicable operating agreement(s) by and among Seller and the other co-owners thereto, as amended or supplemented from time to time, and shall include all exhibits, schedules and annexes thereto, and, for purposes of Section 10.5, such term shall be deemed to include all other agreements, documents, certificates and instruments to which Seller is a party with respect to or in connection with a Facility, as the same may be supplemented or amended from time to time. Upon execution and delivery of this Agreement, Seller will, to the extent not already in the possession of Buyer, deliver to Buyer a true and correct copy of the operating agreement(s) as of that date, including any amendments thereto.

"**Facilities**" means the generation facilities or units on Schedule A entitled Ohio Generation Facilities.

"**Facility LMP Point**" means the location at each Facility recognized by the PJM's scheduling and settlement systems.

"**FERC**" means the Federal Energy Regulatory Commission or any successor entity with similar jurisdiction.

"**Force Majeure**" means an event or circumstance which prevents one Party from performing its obligations under this Agreement, which event or circumstance was not reasonably anticipated as of the date set forth in the preamble to this Agreement, which is not within the reasonable control of, or the result of the negligence of, the Affected Party, and which, by the exercise of due diligence, the Affected Party is, by using reasonable efforts, unable to overcome or avoid or cause to be avoided. Force Majeure shall not be based on (a) Seller's ability to sell Seller's Capacity Entitlement or associated Energy or Ancillary Services at a price greater than the Contract Price; (b) the loss of Buyer's markets; or (c) a Party's inability economically to purchase, use, sell or resell fuel, equipment or services or the Capacity, Energy or Ancillary Services purchased hereunder. Force Majeure includes events of "Force Majeure" as defined in a Facility Operating Agreement, to the extent excusing the performance of the Facility operator or the other joint owners thereto from their obligations under that agreement, but only to the extent affecting the Parties' performance under this Agreement.

"**Fuel Costs**" means without limitation, all fixed or variable costs, expenses, losses, gains, liabilities, fuel hedging, claims and charges related to the acquisition, sale, storage, inventory, transloading, handling, balancing and transportation and delivery of fuel and all expenses recorded to FERC accounts 501 and 502 including, without limitation, coal, natural gas, diesel fuel, oil, consumables, chemicals, trona, urea, limestone, lime hydrated lime, ammonium carbonate, activated carbon, ash, scrubber waste, plant waste and gypsum disposal expense and sales credits, emission Allowance expenses (including all Allowance expenses recorded in Account 509, along with gains/losses in Accounts 411.8 and 411.9), for the Schedule A Generation Facilities, including related costs of credit,

"**Fuel Payment**" has the meaning set forth in Section 5.2.

"**Governmental Approval**" means any permit, authorization, registration, consent, action, waiver, exception, variance, order, judgment, decree, license, exemption, publication, filing, notice to, or declaration of or with, or required by any Governmental Authority or applicable law.

"**Governmental Authority**" means any federal, state, tribal, local, or municipal government body; and any governmental, regulatory, or administrative agency, commission, body, agency, instrumentality, or other authority exercising or entitled to exercise any executive, judicial, legislative, administrative, regulatory, or taxing authority or power, including any court or other tribunal.

"**Imbalance Charges**" means any penalties, fees or charges assessed by a Transmission Operator or Transmission Provider for failure to satisfy requirements for balancing of electric energy receipts and deliveries or loads and generation, or payable to any other Person in connection with the delivery of electrical energy in an amount(s) different from the amount(s) scheduled.

"**Income Tax**" means any Tax imposed by any Taxing Authority (i) based upon, measured by or calculated with respect to gross or net income, profits, commercial activity, or receipts (including municipal gross receipt Taxes, capital gains Taxes and minimum Taxes) or (ii) based upon, measured by or calculated with respect to multiple bases (including corporate franchise Taxes) if one or more of such bases is described in clause (i), in each case together with any interest, penalties or additions attributable to such Tax.

"**Indemnified Parties**" has the meaning set forth in Section 13.2.

"**Letter(s) of Credit**" means one or more irrevocable, unconditional, transferable standby letters of credit issued by a major U.S. commercial bank or the U.S. branch office of a foreign bank with, in either case, a Credit Rating of at least (a) "A-" by S&P and "A3" by Moody's, if such entity is rated by both S&P and Moody's or (b) "A-" by S&P or "A3" by Moody's, if such entity is rated by either S&P or Moody's but not both, in a form acceptable to the Party in whose favor the Letter of Credit is issued. Costs of a Letter of Credit shall be borne by the applicant for such Letter of Credit.

"**Mobile-Sierra Doctrine**" has the meaning set forth in Section 13.13.

"**Monthly Payment**" has the meaning set forth in Section 5.1.

"**Moody's**" means Moody's Investors Services, Inc. or its successor.

"**MW**" means megawatt.

"**MWh**" means megawatt-hour.

"**NERC**" means the North American Electric Reliability Corporation or any successor entity with similar jurisdiction.

"**O&M Payment**" has the meaning set forth in Section 5.3.

"**Operation and Maintenance Costs**" means all fixed or variable costs, expenses, losses, liabilities, claims, charges and associated credits incurred directly or indirectly in the performance of Operating Work, including a ratable portion of retirement costs, but not including Fuel Costs.

"**Operating Work**" means the operation, maintenance, use, repair or retirement of a Facility on or after the Start Date, including but not limited to labor; parts; supplies; insurance; permits; related taxes; community relations; procurement of ancillary services, fuel and other consumables; fuel acquisition or sales, transportation balancing and storage; waste handling and disposal; filing, defense and settlement of claims, suits and causes of action; procurement (or sale) of Allowances and settlement of all other environmental charges (or credits) pertaining to the operation of a Facility; but excluding any Capital Improvements Work.

"**Outage**" shall mean any unavailability, in whole or in part, of the Facility whereby it is not capable of fully operating at its rated capability due to (i) a forced derating, Forced outage maintenance derating, maintenance outage, planned derating, planned outage, (all as defined in the NERC Generating Unit Availability Data System ("**GADS**") Data Reporting Instructions); (ii) the actual or anticipated failure of component(s); (iii) external restrictions; (iv) testing; (v) work being performed; (vi) maintenance; (vii) construction, or (viii) any other condition or circumstance that reduces electrical generating output from time to time from the Facility so as to prevent Seller from performing its obligations in whole or in part.

"**Party**" has the meaning set forth on the preamble hereto.

"**Performance Assurance**" means collateral in the form of Cash, Letter(s) of Credit, or other security or assurances acceptable to the Requesting Party.

"**Person**" means any individual, corporation, partnership, limited liability company, other business organization of any kind, association, trust, or governmental entity, agency or instrumentality.

"**PJM**" means the PJM Interconnection, LLC or any successor entity with similar responsibilities.

"**Property Tax**" means any Tax resulting from and relating to the assessment of real or personal property by any Taxing Authority.

"**Seller**" has the meaning set forth in the preamble hereto.

"**Seller's Debt Percentage**" or "**DP**" means for purposes of this Agreement the percentage of 50%.

"**Seller's Equity Percentage**" or "**EP**" means for purposes of this Agreement the percentage of 50%.

"**Seller's Facilities Net Book Value**" or "**FNBV**" means the net book value of the Facilities as reflected on the books and records of Seller immediately prior to the Contract Year, and including all electric plant in service and capital lease assets net of accumulated depreciation and other investment (e.g. fuel and materials and supplies inventories, prepayments, plant held for future use, working capital, construction work in progress ("CWIP"), asset retirement obligations including ash pond closure costs, other deferred credits and accumulated deferred taxes).

"**Seller's Long Term Debt Rate**" or "**LTDR**" means from June 1, 2015 through December 31, 2016 an initial rate of 4.73%. Thereafter, starting on January 1, 2017, it will be Seller's average annual cost of long-term debt (i.e., debt having maturities of greater than twelve calendar months) as reflected on Seller's books and records as of the relevant determination date, updated as of January 1st of each calendar year thereafter, or updated at more frequent intervals as reasonably determined by Seller.

"**Seller's Return on Equity**" or "**ROE**" means Seller's post-tax rate of return on equity, which amount will equal, for each Contract Year, the average of the daily Moody's Long-Term Baa Corporate Bond Index for the month of December of the preceding calendar year, plus 650 basis points; provided, however, such amount not to be less than 8.90% or greater than 15.90%.

"**Seller's Weighted Average Cost of Capital**" or "**WACOC**" has the meaning set forth in Section 5.5.

"**Start Date**" has the meaning set forth in Section 2.2.

"**Straddle Period**" means, as appropriate, either any Tax Period beginning before the beginning of the first Contract Year and ending either during or as of the end of the first Contract Year or any Tax Period that is longer than one month. For example, pursuant to Section 8.5, the Tax Period for Property Taxes is each calendar year. Hence, the Tax Period for Property Taxes is a Straddle Period.

"**Tax**" **or** "**Taxes**" means any federal, state, local, or foreign income, commercial activity, gross receipts, value added, windfall or other profits, alternative or add-on minimum, estimated, franchise, profits, sales, use, real property, personal property, ad valorem, vehicle, airplane, boat, license, payroll, employment, workers' compensation, unemployment compensation, withholding, social security, disability, excise, severance, stamp, occupation, premium, environmental (including taxes under Code section 59A or any cost, charge or other financial burden on emissions), carbon dioxide, other greenhouse gases, charges on consumption, transportation or use of energy from such sources, customs duties, import fees, capital stock transfer, title, documentary, or registration, or other tax, duty, or impost of any kind whatsoever, whether disputed or not, and on either side of the Delivery Point. "Taxes" includes (i) any liability for the payment of any amounts described in the preceding sentence as a result of being a member of an affiliated, consolidated, combined, or unitary group for any taxable period, (ii) any liability for the payment of any amount described in clause (i) above as a result of being a Person required to withhold or collect Taxes imposed on another Person, (iii) any liability for the payment of any amount described in the preceding sentence or in clause (i) or (ii) of this sentence as a result of being a transferee of, or successor in interest to, any Person or as a result of an express or implied obligation to indemnify any Person, and (iv) any and all interest, penalties, additions to tax, or additional amounts imposed in connection with or with respect to any amount described above in this definition.

"**Taxing Authority**" shall mean, with respect to any Tax, the governmental entity (national, local, municipal or otherwise) or political subdivision thereof that imposes such Tax, the agency (if any) charged with the collection of such Taxes for such entity or subdivision, including any governmental or quasi-governmental entity, a council (if any) or agency that imposes, grants or monitors Taxes or the abatements thereof, or is charged with collecting social security or similar charges or premiums.

"**Tax Period**" means the time period for which or during which a Tax is imposed by any Taxing Authority.

"**Tax Reimbursement Payment**" has the meaning set forth in Section 5.6.

"**Term**" has the meaning set forth in Section 2.1.

"**Transmission Operator**" means PJM or any Transmission Provider, independent system operator, regional transmission operator or other transmission operator from time to time having authority to control the transmission control area to which the Facility is interconnected.

"**Transmission Provider**" means any Person or Persons that owns, operates or controls facilities used for the transmission of electrical energy in interstate commerce.

"**Unit Contingent**" or reference to "**Unit Contingency**" means, with respect to Energy or Ancillary Services associated with Buyer's Contractual Capacity, that such Energy or Ancillary Services are intended to be supplied from the Facility and Seller's failure to deliver such Energy or Ancillary Services is excused to the extent the Facility (including all facilities on Seller's side of the Delivery Point) is unavailable as a result of (i) an Outage, (ii) Force Majeure or (iii) Buyer's failure to perform.

1.2 Interpretation. Unless the context otherwise requires:

(a) Words singular and plural in number will be deemed to include the other and pronouns having masculine or feminine gender will be deemed to include the other.

(b) Any reference herein to any Person includes its successors and permitted assigns and, in the case of any Government Authority or Taxing Authority, any Person succeeding to its functions and capacities.

(c) Any reference herein to any Article, Section, clause, or schedule means and refers to the appropriate Article, Section or clause or schedule in this Agreement.

(d) Other grammatical forms of defined words or phrases have corresponding meanings.

(e) The term "including" when used in this Agreement means "including without limitation."

(f) Unless otherwise specified, a reference to a specific time for the performance of an obligation is a reference to that time in the place where that obligation is to be performed.

(g) A reference to a document or agreement, including this Agreement, includes all appendices and schedules thereto.

(h) A reference to a document or agreement, including this Agreement, includes a reference to that document or agreement as amended, supplemented, amended and restated or otherwise modified from time to time.

(i) If any payment, act, matter or thing hereunder would occur on a day that is not a Business Day, then such payment, act, matter or thing shall, unless otherwise expressly provided for herein, occur on the next succeeding Business Day.

(j) The words "hereof," "hereunder," "herein," "herewith," and "hereto," and similar words refer to this Agreement as a whole and not to any particular Article, Section or clause in this Agreement.

1.3 <u>Technical Meanings</u>. Words not otherwise defined herein that have well-known and generally accepted technical or trade meanings are used herein in accordance with such recognized meanings, as of the date set forth in the preamble to this Agreement.

ARTICLE II

TERM

2.1 <u>Term</u>. The term of this Agreement ("**Term**") shall commence on the date set forth in the preamble to this Agreement and shall continue, unless earlier terminated in accordance with the provisions of this Agreement, until the End Date.

2.2 <u>Delivery Period</u>. Subject to Section 2.3 or Section 2.4, the period during which the Parties will be obligated to purchase and sell Capacity, Energy and Ancillary Services as set forth in this Agreement ("**Delivery Period**") will commence on June 1, 2015, or such other earlier date as may be jointly specified by the Parties ("**Start Date**"), and run through the conclusion of the commercial operational life of the generation facilities listed on Schedule A, including any post-retirement period to complete all asset retirement obligations and any other removal projects ("**End Date**"), unless the Parties otherwise mutually agree in writing upon an alternative End Date.

2.3 <u>Early Termination Right</u>. Subject to Buyer complying with its obligations under Article V and provided Buyer is not a Defaulting Party, Buyer will have on or after the first anniversary of the Start Date, the right, but not the obligation, upon no less than three hundred and sixty five (365) days notice to Seller to terminate, in whole, this Agreement prior to the End Date if retail cost recovery for Buyer's costs hereunder is discontinued or substantially diminished, including through a one-time significant disallowance for retail rate recovery of costs.

2.4 Other Early Termination Rights. In the event the Parties are unable to reach agreement upon the retirement date of a Unit or Facility, the Parties may mutually agree to remove such Unit or Facility from this Agreement, subject to Buyer complying with its obligations under Article V.

ARTICLE III

PURCHASE AND SALE OBLIGATION

3.1 Seller's and Buyer's Obligations. Subject to, and in accordance with, the terms and conditions of this Agreement, Seller agrees to sell and deliver, and Buyer agrees to purchase, receive, and pay for, Buyer's Contractual Capacity and the Energy and Ancillary Services associated with Buyer's Contractual Capacity delivered by Seller to the Delivery Point during each hour of the Delivery Period.

3.2 Unit Contingent. All Energy and Ancillary Services associated with Buyer's Contractual Capacity and all of Seller's obligations to sell and deliver the Energy and Ancillary Services associated with the Buyer's Contractual Capacity are Unit Contingent.

3.3 Fuel. During the Delivery Period, Seller will arrange, provide, procure, supply, manage, transact, transport and deliver Fuel to Facilities where Seller performs this function, and at all remaining Facilities, Seller will provide input to the plant operator on Fuel purchases and Fuel related matters for such Facility. Buyer will have the rights to monitor the Fuel procurement and logistics process and provide reasonable direction on the activity to the Seller at Operating Committee Meetings. When Seller needs to acquire Fuel on behalf of Buyer, Seller agrees to conduct such purchases of Fuel, whenever reasonably possible, using competitive methods, including, without limitation, requests for proposals, and Buyer will have the right, but not the obligation, to observe, monitor, and approve the results of such competitive methods. Excluding emergency situations, Fuel procurements not purchased through competitive methods must first be approved by Buyer. Any fuel purchase contracts used to supply fuel to the Facilities that are in effect prior to and extend beyond the Start Date will continue to be utilized for the Facilities. Buyer acknowledges and agrees that existing contracts entered into prior to the Start Date will continue to be utilized to supply fuel to Seller's generation covered by this Agreement and if any such fuel is also utilized to supply fuel to Seller's generation that is not part of this Agreement the allocation of such fuel between the Facilities and the Seller's other units will be performed in an equitable manner approved by both the Seller and the Buyer. Any such pre-existing contracts will not be renewed or extended to serve the Facilities covered by this Agreement unless approved by the Buyer.

3.4 Delivery Point. The Delivery Point for Energy and Ancillary Services associated with Buyer's Contractual Capacity will be the location of the PJM node at each facility, typically located at the high side of the transformers located at each of the generating facilities identified in Schedule A, at which point the quantities of such Energy or Ancillary Services delivered by Seller to Buyer will be recorded and measured by the relevant revenue meters.

3.5 Scheduling and Dispatch. Buyer or its agent will dispatch the generation associated with the Facilities by reviewing and determining the parameters associated with PJM generation offers, including how such generation will be offered to PJM, for the Energy and Ancillary Services associated with Buyer's Contractual Capacity and Seller will, subject to the requirements of PJM and the operating parameters of the Facilities, as determined by the Facility operator, operate and control the Facilities and schedule with PJM pursuant to Buyer's dispatch criteria and PJM's requirements and instructions. Buyer acknowledges and agrees that it will be obligated at all times to receive Seller's allocation of minimum output of a Facility, consistent with unit operation limitations and any Facility Operating Agreement. Schedules will be adjusted to the extent necessary to allow Seller or the Facility operator to start-up, operate, curtail or shut-down any of the Facilities as required to comply with instructions from the Transmission Operator. Seller will cooperate and provide any assistance to Buyer so that Buyer can determine how such generation will be offered to PJM. Buyer will be allocated any excess (or deficit) amount of Energy or Ancillary Services made available by Seller at the Delivery Point over (or under) the amount of Energy or Ancillary Services Scheduled by the Buyer. Buyer will be responsible for all Imbalance Charges associated with the Energy made available to it by Seller at the Delivery Point, provided, however, that any such Imbalance Charges resulting from Seller's unexcused failure to dispatch, or to cause the Facility operator to dispatch, the Energy associated with the Seller's Capacity Entitlement that are designated by Buyer will be the responsibility of the Seller. The Energy and Ancillary Services associated with Buyer's Contractual Capacity will be recorded by the Parties in PJM's scheduling and settlement systems at the Facility LMP Point.

3.6 Transmission And Related Costs. Seller shall make all Energy and Ancillary Services associated with Seller's Capacity Entitlement available to Buyer at the Delivery Point. Buyer shall be responsible for transmission service at and from the Delivery Point and shall coordinate, as necessary, for scheduling services with the Transmission Operator to receive all Energy and Ancillary Services associated with the Seller's Capacity Entitlement at the Delivery Point. Buyer shall have the right to designate an agent for coordinating, as needed, with PJM related to the Capacity, Energy and Ancillary Services received under this Agreement. Buyer shall be responsible (i) for all costs or charges imposed on or associated with the Seller's Capacity Entitlement and associated Energy and Ancillary Services and the delivery of all Energy and Ancillary Services associated with the Seller's Capacity Entitlement at and after the Delivery Point, and (ii) for any and all Imbalance Charges consistent with Section 3.5. Subject to reimbursement as set forth in Article IV, Seller shall be responsible for all costs or charges imposed on or associated with the Seller's Capacity Entitlement and associated Energy and Ancillary Services and the delivery of all Energy and Ancillary Services associated with the Seller's Capacity Entitlement up to the Delivery Point.

3.7 Force Majeure. To the extent either Party is prevented by Force Majeure from carrying out, in whole or part, its obligations under this Agreement (other than an obligation to pay money), and such Party (the "**Affected Party**") gives notice and details of the Force Majeure to the other Party as soon as practicable (but not later than thirty (30) days thereafter to the extent such details are then available) then the Affected Party shall be excused from the performance of its obligations under this Agreement (other than the obligation to make payments) so long as the Affected Party shall be using all reasonable efforts to overcome the Force Majeure and resume performance as soon as possible. The non-Affected Party shall not be required to perform or resume performance of its obligations (excluding payment obligations) to the Affected Party corresponding to the obligations of the Affected Party excused by Force Majeure, until such time and to the extent the Affected Party resumes its performance.

3.8 Allowances. Seller shall separate the Allowance inventories associated with the Facilities and maintain them in a separate subaccount for Buyer's benefit. To the extent Seller has any Allowances prior to the Start Date that are not associated with the Facilities or any of the Seller's other generation units, such Allowances will be allocated to Buyer's separate subaccount and the Seller's other Allowance subaccounts based on the emissions of the applicable units over the 5 prior calendar years. The applicable units will be all the units required to provide Allowances for its emissions, excluding any units retired prior to the Start Date. Following the Start Date, the subaccount established for Buyer shall be used to record all Allowances arising from or associated with a Facility that Seller is granted or to which it is entitled for the Delivery Period, within thirty (30) days of such grant or other effective date, whether such grant or entitlement is made on a one-time, annual or other periodic basis. Allowances will be removed from the subaccount established for Buyer as needed to comply with surrender requirements associated with any applicable emissions from the Facilities by the Allowance Transfer Deadline, and the associated Allowance expense will be borne by the Buyer. Buyer shall manage all Allowances in the subaccount established for Buyer, including the purchasing, selling or other disposition of the Allowances and will receive any gains or any losses associated with such management.

3.9 Failure to Deliver Energy/Ancillary Services. If Seller fails to or Seller fails to cause the Facility operator under the Facility Operating Agreement to Schedule, Dispatch and/or deliver all or any part of the Energy and/or Ancillary Services that are Scheduled and Dispatched by Buyer pursuant to this Agreement and it is not the result of an Outage or a Force Majeure, Seller shall pay Buyer an amount equal to the sum of (a) the positive difference, if any between the Contract Price of the Energy and/or Ancillary Services to be supplied by Seller and (b) the price for a corresponding amount of replacement Energy and/or Ancillary Services.

3.10 Consent Decree. Due to certain of the Facilities being subject to the Consent Decree between U.S. EPA and Ohio Power Company entered on December 10, 2007 and as issued in Civil Action No. C2-99-1182 and consolidated cases by the United States District Court for the Southern District of Ohio, Eastern Division, as modified from time to time ("Consent Decree"), Seller will constrain the dispatch of impacted Facilities if or when needed to ensure compliance with any emission limitations required by the Consent Decree. Such limitations will be reasonably economically imposed and applied on a consistent basis between the Agreement Facilities and other generating units of the Seller that are not part of this Agreement. Buyer shall bear the full cost of any fines or penalties resulting from non-compliance with any resulting emission limitations of the Agreement Facilities associated with Buyer's rights to dispatch the Facilities hereunder. Seller shall bear the full cost of any fines or penalties resulting from Seller's failure to constrain the use of impacted Facilities needed to ensure compliance with any emission limitations required by the Consent Decree.

3.11 Cardinal Station Agreement. Buyer acknowledges and agrees that Buyer's entitlements and obligations under this Agreement shall be subject to, conditioned upon, and net of all the entitlements and obligations of Buckeye under the Cardinal Station Agreement related to capacity, energy and ancillary service entitlements and back-up obligations. Accordingly, Buyer shall provide for Buckeye's use and bear all of the net cost of providing all such entitlements directly to Buckeye or to Seller for Buckeye's benefit. Consistent with Section 3.5, the Buckeye's Units shall be dispatched and the Buyer shall receive the corresponding capacity, energy and ancillary service revenues, net of any applicable costs, as described under and subject to the Cardinal Station Agreement. During the Delivery Period, Seller shall not agree to any amendment, waiver or other modification of the Cardinal Station Agreement without obtaining the prior written consent of Buyer. During the 2015/2016 Planning Year, Seller will credit to Buyer Capacity revenues associated with Buckeye's Units in an amount equal to the Capacity revenues of the Facilities that have been provided to Buckeye for that Planning Year.

ARTICLE IV

FACILITY OPERATIONS

4.1 Operation and Maintenance. At all times during the Delivery Period, Seller shall perform the Operating Work, or cause the Operating Work to be performed, in accordance with good commercial and prudent utility practice consistent with the procedures employed by Seller at similar generating stations or the procedures followed by the operator of units that are not wholly owned by Seller. Subject to reimbursement as set forth in Article V, Seller shall be responsible for all costs, expenses, losses, liabilities and charges incurred by it, or on its behalf, in the performance of Operating Work, including the procurement of Ancillary Services sufficient to satisfy Ancillary Service obligations to the Transmission Operator related to the Facility.

4.2 Capital Improvements. From time to time during the Term, Seller shall perform, or cause to be performed, Capital Improvements Work related to a Facility. For major or material projects at a wholly owned Seller Facility, Buyer's prior written approval and agreement must first be obtained before proceeding with such Capital Improvements Work. For a unit at a Facility that is jointly owned, Seller will obtain and communicate to the third party operator Buyer's input on any Capital Improvements Work proposed. Subject to reimbursement as set forth in Article V, Seller shall be responsible for all costs, expenses, losses, liabilities and charges incurred by it, or on its behalf, in the performance of Capital Improvements Work. Annually, Seller will provide Buyer with a confidential three year forecast of projected Capital Improvements Work.

4.3 Planned Outage Schedule. Seller will develop and implement, or cause to be developed and implemented, a planned outage and maintenance schedule for Facilities that Seller operates that is coordinated with American Electric Power Service Corporation. For Facilities that are not operated by Seller, Seller will communicate Buyer's input on planned outages and maintenance schedules for such Facilities to the Facility operator.

4.4 Auxiliary Power. During any hour that the Facility is out of service, Seller or the applicable Facility operator will procure the energy used by Facility auxiliaries during that hour, the cost of which will be borne by the Buyer.

ARTICLE V

PRICING

5.1 Monthly Payments. For each calendar month during the Delivery Period, Buyer shall pay Seller an amount (the "**Monthly Payment**") equal to the sum of (i) a Fuel Payment, (ii) an O&M Payment, (iii) a Depreciation Payment, (iv) a Capacity Payment, (v) a Tax Reimbursement Payment, and (vi) Other Miscellaneous Payment. The Monthly Payment will be Seller's sole compensation for Seller's sale and delivery to Buyer of Buyer's Contractual Capacity and the Energy and Ancillary Services associated with Buyer's Contractual Capacity.

5.2 Fuel Payment. For each calendar month during each Contract Year, Buyer shall pay Seller an amount (the "**Fuel Payment**") equal to the Fuel Costs incurred by or invoiced to Seller at the Facilities for that month.

5.3 O&M Payment. For each calendar month during each Contract Year, Buyer shall pay Seller an amount (the "**O&M Payment**") equal to the Operation and Maintenance Costs at the Facilities for that month.

5.4 Depreciation Payment. For each calendar month during each Contract Year, Buyer shall pay Seller an amount (the "**Depreciation Payment**") equal to the sum of the *depreciation expenses incurred by Seller for each Facility in Schedule A at the actual rate of* depreciation during the relevant month and, in the case of jointly owned units, those expenses directly related to its ownership interest in the applicable Facility. The depreciation rates will be updated periodically at intervals that will not exceed five (5) years and the new rates will become effective on the subsequent January 1st during the Term of this Agreement. Any positive net book value at the end of the commercial life of a given Facility will be included in the net book value of the other units at the same Facility and depreciated at an adjusted rate of those other units. If the final Facility or Facilities at a plant are retired, any remaining net book value will be payable by Buyer at that time, unless the Parties mutually agree upon an alternative payment arrangement.

5.5 Capacity Payment. For each calendar month during each Contract Year, Buyer shall pay Seller an amount (the "**Capacity Payment**") equal to the following:

$$CapacityPayment = \frac{FNBV \times WACOC}{12}$$

where,

FNBV = Seller's Net Book Value of the Facilities.

WACOC = (DP% x LTDR) + (EP% x ROE)

LTDR	=	Seller's Long Term Debt Rate
ROE	=	Seller's Return on Equity
DP%	=	Seller's Debt Percentage
EP%	=	Seller's Equity Percentage

Each component of the Capacity Payment that is subject to change under the terms of this Agreement will be updated as of January 1st of each calendar year during the Term of this Agreement, or at more frequent intervals as elected by Seller.

5.6 Tax Reimbursement Payment. For each calendar month during each Contract Year, Buyer shall pay Seller an amount (the "**Tax Reimbursement Payment**") equal to all Taxes (other than taxes included in Sections 5.2 through 5.5, above, such that there will be no duplication of Tax reimbursement to Seller) for that month applicable to Buyer's Contractual Capacity and the Energy and Ancillary Services associated with Buyer's Contractual Capacity, as more fully set forth in Article IX. Any Tax based upon income, gross receipts, commercial activity, or any similar Tax for which the inclusion of such Tax in the Monthly Payment would increase Seller's liability for any Tax including WACOC shall be grossed-up so as to make the receipt of any such Tax neutral to the Seller. Any Tax for any Straddle Period shall be included in the Monthly Payment based upon the ratio of the days in the month for the Monthly Payment over the total number of days in the Tax Period. Taxes included in the Monthly Payment may be estimated by Seller. The difference between estimated Taxes and the actual Taxes for which Buyer is responsible will be billed or credited to Buyer, as appropriate, in one or more installments following the end of the relevant Tax Period. For purposes of Taxes subject to the provisions of this Section 5.6, all Taxes shall be based upon the amount accrued for the relevant calendar month billing period, including any deferred tax amount.

5.7 Other Miscellaneous Payment.

For each calendar month during each Contract Year, Buyer shall pay Seller an amount (the "Other Miscellaneous Payment") which shall include:

(A) Any other costs and credits as described within this Agreement not already included in the other payment components or any other costs or credits reasonably associated with the Facilities which may be billed monthly or if incurred less frequently, on either a quarterly or as incurred basis. For example, the Parties understand and agree that the cost of Ancillary Services associated with the Facility Capacity that are requested and delivered in accordance with regular dispatch of a Facility in accordance with this Agreement is included in and compensated for by the Monthly Payment. The Other Miscellaneous Payment shall also include, but not necessarily be limited to, any PJM charges and credits associated with the Facilities.

(B) Where Buyer exercises its right under Section 2.3 to terminate this Agreement or an Early Termination Date is declared due to a Buyer Event of Default, Seller will invoice Buyer, and Buyer shall pay Seller, an amount equal to the sum of the then undepreciated net book value of the Generating Facilities and the expected retirement-related costs associated with such

Generating Facilities at the time this Agreement is terminated as determined by the Seller in a commercially reasonable manner.

(C) Where the Parties exercise their right under Section 2.4 to remove Unit(s) or Facilities terminate this Agreement, Seller will invoice Buyer, and Buyer shall pay Seller, an amount, determined by Seller in a commercially reasonable manner, equal to the sum of the then undepreciated net book value of the Unit(s) or Generating Facilities that are to be removed from this Agreement and the expected retirement-related costs associated with such Unit(s) or Generating Facilities at the time the Unit(s) or Facilities are removed from this Agreement. At Buyer's request and at Buyer's sole expense, the fair market value of the Unit(s) or Facilities, including all of the associated liabilities thereto will be determined by Seller, such values may be developed by Seller through the use of an independent appraisal or other competitive solicitation conducted by Seller to obtain bids to purchase the Unit(s) or Generating Facilities. To the extent any appraisal or competitive solicitation would result in positive revenues to Seller as a result of such sale, Seller will apply a credit on Buyer's invoice for such positive revenues, up to, but not exceeding, the amount invoiced by Seller hereunder. Seller retains the right of first refusal to match any bona fide offer that complies with all of the terms of any competitive solicitation. Where there is a disagreement over a retirement date for Unit(s) or Facilities and this Agreement is terminated under Section 2.4, in the event Seller intends to continue operating such Unit or Facility after it is removed from this Agreement in accordance with Section 2.4, Seller will also apply a credit to Buyer's invoice referenced above with respect to allocating the retirement related costs of such Unit(s) or Facilities to account for the additional time Seller intends to operate the Unit(s) or Facilities after it is removed from this Agreement, in relation to the period of time Buyer purchased Energy and Capacity from such Unit(s) or Facilities hereunder.

ARTICLE VI

BILLING AND PAYMENT

6.1 Billing and Payment. The calendar month shall be the standard period for all payments under this Agreement. As soon as practicable after the end of each month, Seller will render to Buyer an invoice for the payment obligations incurred during the preceding month. Each component of the invoice will be described in reasonable detail. All invoices under this Agreement shall be due and payable on or before the twentieth (20^{th}) day of each month, or tenth (10^{th}) day after receipt of the invoice or, if such day is not a Business Day, then on the next Business Day. Buyer will make payments by electronic funds transfer to the account designated by Seller, or by other mutually agreeable method(s). Any amounts not paid by the due date will be deemed delinquent and will accrue interest at the then current short term borrowing rate of the Seller ("Interest Rate"), such interest to be calculated from and including the due date to but excluding the date the delinquent amount is paid in full.

6.2 Books and Records; Audit. Seller shall keep, or shall cause to be kept, all necessary books of record, books of account, and memoranda of all transactions involving the Facility, in conformance, where required, with the FERC's Uniform System of Accounts. Seller shall make, or shall cause to be made, all computations relating to the Facilities and all allocations of the costs and expenses of the Facilities. Buyer has the right to examine the records of Seller to the extent reasonably necessary to verify the accuracy of any statement, charge or computation made pursuant to this Agreement (including any statements evidencing the quantities delivered to Buyer at the Delivery Point) within twelve (12) months of receipt of the statement, charge or computation. If any such examination reveals any inaccuracy in any statement, the necessary adjustments in such statement and the payments thereof will be made promptly, along with interest accrued at the Interest Rate, provided, however, that any claim by a Party for overpayment or underpayment with respect to an invoice is waived unless the other Party is notified of the claim within twelve (12) months after the invoice is rendered or any specific adjustment to the invoice is made. If an invoice is not rendered within twelve (12) months after the close of the month during which performance occurred, the right to payment for such performance is waived.

6.3 Netting of Payments. The Parties hereby agree that they shall discharge mutual debts and payment obligations due and owing to each other under this Agreement through netting, in which case all amounts owed by each Party to the other Party under this Agreement, including any related damages, interest, and payments or credits, shall be netted so that only the excess amount remaining due shall be paid by the Party who owes it.

ARTICLE VII

CREDIT REQUIREMENTS

7.1 Credit Assurances. If a Party (the "**Requesting Party**") has reasonable grounds to believe that the other Party's (the "**Posting Party**") creditworthiness or performance under this Agreement has become unsatisfactory, the Requesting Party will provide the Posting Party with written notice requesting Performance Assurance in an amount determined by the Requesting Party in a commercially reasonable manner. Upon receipt of such notice, the Posting Party shall remedy the situation within a reasonable period (not exceeding thirty (30) days) by providing such Performance Assurance to the Requesting Party.

7.2 Grant of Security Interest/Remedies. To secure its obligations under this Agreement and to the extent either or both Parties deliver Performance Assurance hereunder, each Party (a "**Pledgor**") hereby grants to the other Party (the "**Secured Party**") a present and continuing security interest in, and lien on (and right of setoff against), and assignment of, all cash collateral and cash equivalent collateral and any and all proceeds resulting therefrom or the liquidation thereof, whether now or hereafter held by, on behalf of, or for the benefit of, such Secured Party, and each Party agrees to take such action as the other Party reasonably requires in order to perfect the Secured Party's first-priority security interest in, and lien on (and right of setoff against), such collateral and any and all proceeds resulting therefrom or from the liquidation thereof. Upon or any time after the occurrence or deemed occurrence and during the continuation of an Event of Default or an Early Termination Date, the Non-Defaulting Party may do any one or more of the following: (i) exercise any of the rights and remedies of a Secured Party with respect to all Performance Assurance, including any such rights and remedies under law then in effect; (ii) exercise its rights of setoff against any and all property of the Defaulting Party in the possession of the Non-Defaulting Party or its agent; (iii) draw on any outstanding Letter of Credit issued for its benefit; and (iv) liquidate all Performance Assurance then held by or for the benefit of the Secured Party free from any claim or right of any nature whatsoever of the Defaulting Party, including any equity or right of purchase or redemption by the Defaulting

Party. The Secured Party shall apply the proceeds of the collateral realized upon the exercise of any such rights or remedies to reduce the Pledgor's obligations under the Agreement (the Pledgor remaining liable for any amounts owing to the Secured Party after such application), subject to the Secured Party's obligation to return any surplus proceeds remaining after such obligations are satisfied in full.

ARTICLE VIII

EVENTS OF DEFAULT, REMEDIES & LIMITATIONS

8.1 Events of Default. An "**Event of Default**" shall mean, with respect to a Party (a "**Defaulting Party**"), the occurrence of any of the following:

(i) the failure to make, when due, any payment required pursuant to this Agreement if such failure is not remedied within ten (10) Business Days after written notice;

(ii) any representation or warranty made by such Party herein is false or misleading in any material respect when made or when deemed made or repeated, and if not remedied within thirty (30) Business Days after written notice;

(iii) the failure to perform any material covenant or obligation set forth in this Agreement (except to the extent constituting a separate Event of Default), if such failure is not remedied within thirty (30) Business Days after written notice;

(iv) such Party becomes Bankrupt;

(v) the failure of such Party to satisfy the creditworthiness/collateral requirements agreed to pursuant to Article VII; or

(vi) such Party consolidates or amalgamates with, or merges with or into, or transfers all or substantially all of its assets to, another Person and, at the time of such consolidation, amalgamation, merger or transfer, the resulting, surviving or transferee Person fails to assume all the obligations of such Party under this Agreement to which it or its predecessor was a Party by operation of law or pursuant to an agreement reasonably satisfactory to the other Party.

8.2 Remedies. If an Event of Default with respect to a Defaulting Party shall have occurred and be continuing, the other Party (the "**Non-Defaulting Party**") shall have the right, at its sole discretion, to take any one or more of the following actions: (i) to exercise any rights and remedies under this Agreement or law with respect to any Performance Assurance or other financial assurance; (ii) to withhold any payment due to the Defaulting Party under this Agreement; (iii) to suspend its performance; (iv) to cancel this Agreement by declaring a date for its early termination (an "**Early Termination Date**"); or (v) exercise such other rights or remedies it may have in contract, in equity, or at law. An Early Termination Date shall not relieve a Party of its obligation to payments hereunder. None of the remedies conferred upon the Parties above is intended to be exclusive of any other remedy or remedies now or hereafter existing and every such remedy will be cumulative and shall be in addition to the remedies set forth above and every other remedy. Each party may commence such suits, actions or proceedings, at law or in equity, including suits for specific performance, as may be necessary or appropriate to enforce this Agreement.

8.3 Limitation of Remedies, Liability and Damages. EXCEPT AS SET FORTH HEREIN, THERE IS NO WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE, AND ANY AND ALL IMPLIED WARRANTIES ARE DISCLAIMED. FOR BREACH OF ANY PROVISION OF THIS AGREEMENT, THE OBLIGOR'S LIABILITY SHALL BE LIMITED TO DIRECT DAMAGES ONLY, SUCH DIRECT DAMAGES SHALL BE THE SOLE AND EXCLUSIVE REMEDY AND ALL OTHER REMEDIES OR DAMAGES AT LAW OR IN EQUITY ARE WAIVED. NEITHER PARTY SHALL BE LIABLE FOR CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR CONTRACT, UNDER ANY INDEMNITY PROVISION OR OTHERWISE. IT IS THE INTENT OF THE PARTIES THAT THE LIMITATIONS HEREIN IMPOSED ON REMEDIES AND THE MEASURE OF DAMAGES BE WITHOUT REGARD TO THE CAUSE OR CAUSES RELATED THERETO, INCLUDING THE NEGLIGENCE OF ANY PARTY, WHETHER SUCH NEGLIGENCE BE SOLE, JOINT OR CONCURRENT, OR ACTIVE OR PASSIVE.

ARTICLE IX

TAXES

9.1 Cooperation. Each Party shall use reasonable efforts to implement the provisions of and to administer this Agreement in accordance with the intent of the parties to minimize all Taxes, so long as neither Party is materially adversely affected by such efforts.

9.2 Taxes. Subject to reimbursement by Buyer as set forth in Article V, Seller shall pay or cause to be paid all Taxes imposed on or with respect to the Buyer's Contractual Capacity and associated Energy and Ancillary Services arising prior to the Delivery Point. Buyer shall pay the Tax Reimbursement Payment and pay or cause to be paid all Taxes on or with respect to the Buyer's Contractual Capacity and associated Energy and Ancillary Services at and from the Delivery Point. In the event Seller is required by law or regulation to remit or pay Taxes which are Buyer's responsibility hereunder, Buyer shall promptly reimburse Seller for such Taxes as set forth in Article V. If Buyer is required by law or regulation to remit or pay Taxes which are Seller's responsibility hereunder, Buyer may deduct the amount of any such Taxes from the sums due to Seller under Article V of this Agreement. Nothing shall obligate or cause a Party to pay or be liable to pay any Taxes for which it is exempt under the law.

9.3 Change-in-Law Taxes. Buyer shall be responsible for (or receive the benefit of) all Change-in-Law Taxes.

9.4 Exemptions. Either Party, upon written request of the other, shall provide a certificate of exemption or other reasonably satisfactory evidence of exemption if either Party is exempt from any Taxes and shall use all reasonable efforts to obtain or maintain, or to enable the other Party to obtain or maintain, any exemption from or reduction of any Taxes, whether currently available or becoming available in the future. Without limiting the generality of the foregoing, the Parties agree that, if beneficial to the efforts of either Party to obtain or maintain any exemption from or reduction of any Taxes, whether currently available or becoming available in the future, the Parties will cooperate to restructure the transactions contemplated by this Agreement so as to enable either Party to obtain or maintain such exemption or reduction, as the case may be; provided, however, that any such restructuring shall not affect adversely the economic consequences of this Agreement to either Party or subject either Party to any regulatory jurisdiction other than that to which it is subject on the date set forth in the preamble to this Agreement.

ARTICLE X

COMPLIANCE WITH LAWS; ADMINISTRATION

10.1 Seller's Compliance. Seller shall, at its expense, comply with all applicable laws and obtain and maintain all Governmental Approvals applicable to Seller and/or the Facilities or necessary for Seller's performance of its obligations hereunder. Notwithstanding the foregoing, Seller shall not be deemed in default of this obligation if it is contesting the application, interpretation, order, or other legal direction or Governmental Approval of any Governmental Authority in good faith and with due diligence through appropriate proceedings and if such non-compliance does not have a material adverse effect on Seller's performance of this Agreement. Seller agrees to adhere to the applicable operating policies, criteria and guidelines of NERC.

10.2 Buyer's Compliance. Buyer shall at its expense, at all times, comply with all applicable laws and obtain and maintain all Governmental Approvals applicable to Buyer or necessary for Buyer's performance of its obligations hereunder. Notwithstanding the foregoing, Buyer shall not be deemed in default of this obligation if Buyer is contesting the application, interpretation, order, or other legal direction or Governmental Approval of any Governmental Authority in good faith and with due diligence through appropriate proceedings and if such non-compliance does not have a material adverse effect on Buyer's performance of this Agreement. Buyer agrees to adhere to the applicable operating policies, criteria and guidelines of the NERC.

10.3 Administration. Seller will promptly provide Buyer with copies of all written notices from the operator or other co-owners pertaining to the Facilities that materially affect, or potentially materially affect, Buyer's rights and obligations under this Agreement, including all invoices, budgets, maintenance schedules, outage/derating notices, availability forecasts, and material contracts, to the extent not restricted by an obligation of confidentiality for which Seller cannot obtain a waiver or other appropriate relief. At all times during the Term, Seller shall cause the Facility operator to perform its responsibilities and otherwise discharge its obligations in respect of the applicable Facility, and maintain accurate records regarding the foregoing, in accordance with all relevant Governmental Approvals and all applicable statutes, codes, regulations, standards, and guidelines adopted by Governmental Authorities, NERC and the Transmission Operator from time to time.

10.4 Operating Committee. By written notice to each other, the Parties and American Electric Power Service Corporation each shall name one representative ("Representative") to act for it in matters pertaining to the Parties' obligations under this Agreement and to develop, if necessary, operating procedures for the generation, delivery and receipt of Energy hereunder, and such other mutually agreed upon contract administration procedures. Any Party may change its Representative at any time by written notice to the other Parties. The Representatives for the respective Parties shall comprise the Operating Committee. The Representative for American Electric Power Service Corporation shall be free to express the views of such Party, but shall not have a vote on the Committee except in the case of a tie between the other Parties. The Operating Committee shall meet at least annually, and at such other times as any Party may reasonably request. The Parties shall cooperate in providing to the Operating Committee the information it reasonably needs to carry out its duties. The Operating Committee will review and approve decisions regarding the retirement or early retirement of any of the Facilities, annual budgets, capital expenditures, procedures and systems for dispatch and notification of dispatch, procedures for communication and coordination with respect to Facility capacity availability, discuss scheduling of outages for maintenance, as well as the return to availability following an unplanned outage, approval of material contracts for Fuel, establishment of specifications for Fuels, and other duties as assigned by agreement of the Representatives.

10.5 Seller's Negative Covenants. Seller will not take any action or fail to take any action that would cause a default by Seller under the Facility Operating Agreement(s). Seller shall not, without the prior written consent of Buyer, (i) terminate or suspend any Facility Operating Agreement(s) or its interest in such Facility, (ii) amend or modify a Facility Operating Agreement(s), or (iii) grant any waiver or consent with respect to Facility Operating Agreement(s) or its interest in such Facility that would, in the case of (ii) and (iii) above, materially affect, or potentially materially affect, Buyer's rights and obligations under this Agreement, unless Seller shall first have obtained Buyer's written consent, which consent shall not be unreasonably withheld, conditioned or delayed.

ARTICLE XI

CONDITIONS

11.1 Conditions. Subject to Section 11.2 and except to the extent waived in writing by the Parties in their sole and absolute discretion, the obligation of the Parties to consummate the transactions contemplated hereunder shall be subject to fulfillment of the following conditions:

(i) The occurrence of the Closing.

(ii) If required, Seller shall have filed with the FERC and received acceptance of this Agreement that is satisfactory to Seller and Buyer in their sole judgment and discretion, without any limitation thereto whatsoever.

(iii) The Parties shall each have obtained any and all other Approvals required with respect to the performance of their respective obligations hereunder and such Approvals shall be in form and substance satisfactory to Seller and Buyer in their sole and absolute discretion.

11.2 Obligations of Buyer and Seller. Commencing on the date set forth in the preamble to this Agreement, on the terms and subject to the conditions of this Agreement, each Party shall use its commercially reasonable efforts to take, or cause to be taken, all appropriate action, and do, or cause to be done, and assist and cooperate with the other Party in taking or doing, all things necessary, proper or advisable to consummate the transactions contemplated hereby, including, without limitation the satisfaction of the conditions set forth in Section 11.1.

11.3 Failure of Conditions Generally. This Agreement may be terminated by either Party in the event that the conditions set forth in Section 11.1 are not satisfied or waived by the Parties in accordance with such Section.

ARTICLE XII

REPRESENTATIONS AND WARRANTIES

12.1 Representations and Warranties of Both Parties. On the date set forth in the *preamble to this Agreement each Party represents and warrants to the other Party that:*

(i) it is duly organized, validly existing and in good standing under the laws of the jurisdiction of its formation;

(ii) subject to the fulfillment of the conditions set forth in Section 11.1, it has all Governmental Approvals necessary for it legally to perform its obligations under this Agreement;

(iii) the execution, delivery and performance of this Agreement are within its powers, have been duly authorized by all necessary action and do not violate any of the terms and conditions in its governing documents, any contracts to which it is a party or any law, rule, regulation, order or the like applicable to it;

(iv) this Agreement constitutes a legally valid and binding obligation enforceable against it in accordance with its terms; subject to any Equitable Defenses;

(v) it is not bankrupt, however evidenced, and there are no proceedings pending or being contemplated by it or, to its knowledge, threatened against it which would result in it being or becoming bankrupt;

(vi) there is not pending or, to its knowledge, threatened against it any legal proceedings that could materially adversely affect its ability to perform its obligations under this Agreement;

(vii) no material breach of this Agreement with respect to it has occurred and is continuing and no such event or circumstance would occur as a result of its entering into or performing its obligations under this Agreement; and

(viii) it has entered into this Agreement in connection with the conduct of its business and it has the capacity or ability to make or take delivery of the Buyer's Contractual Capacity and associated Energy and Ancillary Services.

ARTICLE XIII

MISCELLANEOUS

13.1 Title and Risk of Loss. Title to and risk of loss related to the Capacity and associated Energy and Ancillary Services shall transfer from Seller to Buyer at the Delivery Point. Seller warrants that it will deliver to Buyer the Capacity and associated Energy and Ancillary Services free and clear of all liens, security interests, claims and encumbrances or any interest therein or thereto by any Person arising prior to the Delivery Point.

13.2 Indemnity. Each Party shall indemnify, defend and hold harmless the other Party and such Party's partners, directors, officers, employees, agents and representatives (the "**Indemnified Parties**") from and against any Claims arising from or out of any event, circumstance, act or incident first occurring or existing during the period when control of, risk of loss related to, and title to the Capacity and associated Energy and Ancillary Services is vested in such Party as provided in Section 13.1, except to the extent, as to any Indemnified Party, such Claims are attributable to the gross negligence or willful misconduct of such Indemnified Party. Each Party shall indemnify, defend and hold harmless the other Party against any Taxes for which such Party is responsible under Article IX. The foregoing indemnities shall forever survive the termination of the Agreement.

13.3 Amendments and Waivers. Neither this Agreement nor any provisions hereof may be waived, amended or modified except pursuant to an agreement or agreements in writing entered into by both Parties.

13.4 Notices. All notices, requests, statements or payments shall be made as specified in Schedule 13.4. Notices, other than notices regarding availability, Scheduling and Dispatch of a Facility shall, unless otherwise specified herein, be in writing and shall be deemed to be given or made if delivered by (a) hand delivery, electronic mail or other electronic transmission device capable of written record or facsimile, in each case, effective at the close of business on the day actually received, if received during business hours on a Business Day, otherwise shall be effective at the close of business on the next Business Day, or (b) United States mail or overnight courier service, in each case, effective on the next Business Day after it was sent. Notices regarding the availability, Scheduling and Dispatch of a Facility may be made (x) telephonically, effective when made, or (y) by electronic mail or other electronic device capable of written record, effective when received. A Party may change its notice details by providing a notice of same to the other Party in accordance herewith.

13.5 Successors and Assigns; Assignment. The provisions of this Agreement shall be binding upon and inure to the benefit of the Parties and the Parties' successors and assigns permitted hereby and no other Person shall acquire or have any rights under or by virtue of this Agreement. Neither Party shall assign this Agreement or its rights hereunder without the prior written consent of the other Party, which consent may be withheld in the exercise of its sole discretion; provided, however, that either Party may, without the consent of the other Party (and without relieving itself from liability hereunder) (i) transfer, sell, pledge, encumber or assign this Agreement or the accounts, revenues or proceeds hereof in connection with any financing or other financial arrangements, (ii) transfer or assign this Agreement to an Affiliate, or (iii) transfer or assign this Agreement to a successor to all or substantially all of Seller's Schedule A Units and Facilities provided such assignee shall agree in writing to be bound by the terms and conditions of this Agreement, and, as applicable, be a qualified operator of the Schedule A Units and Facilities. In addition to the foregoing, Seller shall require as a condition of said sale, assignment or other transfer that such other Person agree in writing to be bound by the terms and conditions of this Agreement to the same extent, such that Buyer's right to purchase such products shall continue uninterrupted and in the same manner as set forth in this Agreement without material alteration.

13.6 Integration. This Agreement constitutes the entire agreement between the Parties relating to the subject matter hereof and supersedes any and all previous and understandings, oral or written, between the Parties relating to the subject matter hereof.

13.7 Acknowledgments. This Agreement shall be considered for all purposes as prepared through the joint efforts of the Parties and shall not be construed against one Party or the other as a result of the preparation, substitution, submission or other event of negotiation, drafting or execution hereof.

13.8 Waiver. No failure to exercise and no delay in exercising by a Party any right, remedy, power or privilege hereunder shall operate as a waiver thereof; nor shall any single or partial exercise of any right, remedy, power, power or privilege hereunder preclude any other or further exercise thereof or the exercise of any right, remedy power or privilege.

13.9 Counterparts. This Agreement may be executed by the Parties in any number of counterparts, which, taken together, shall constitute one and the same legal binding instrument. Delivery of an executed counterpart of a signature page of this Agreement by facsimile transmission shall be effective as delivery of a manually executed counterpart of this Agreement.

13.10 Headings. The headings used herein are for convenience and reference purposes only.

13.11 Confidentiality. Neither Party shall disclose the terms or conditions of this Agreement to a third party (other than the Parties' employees, lenders, counsel, accountants or advisors who have a need to know such information and have agreed to keep such terms confidential) except in order to comply with any applicable law, regulation, or any exchange, control area or independent system operator rule or in connection with any court or regulatory proceeding; provided, however, that each Party shall, to the extent practicable, use reasonable efforts to prevent or limit the disclosure. Subject to the provisions of Section 8.3, the Parties shall be entitled to all remedies available at law or in equity to enforce, or seek relief in connection with this confidentiality obligation.

13.12 Governing Law. THIS AGREEMENT AND THE RIGHTS AND DUTIES OF THE PARTIES HEREUNDER SHALL BE GOVERNED BY AND CONSTRUED, ENFORCED AND PERFORMED IN ACCORDANCE WITH THE LAWS OF THE STATE OF OHIO, WITHOUT REGARD TO PRINCIPLES OF CONFLICTS OF LAW. EACH PARTY WAIVES ITS RESPECTIVE RIGHT TO ANY JURY TRIAL WITH RESPECT TO ANY LITIGATION ARISING UNDER OR IN CONNECTION WITH THIS AGREEMENT.

13.13 Mobile/Sierra Doctrine. Absent the agreement of all Parties to the proposed change, the standard of review for changes to any rate, charge, classification, term or condition of this Agreement, whether proposed by a Party, a non-party or FERC acting sua sponte, shall be the "public interest" standard of review set forth in United Gas Pipe Line Co. v. Mobile Gas Service Corp., 350 U.S. 332 (1956) and Federal Power Commission v. Sierra Pacific Power Co., 350 U.S. 348 (1956) and Federal Power Commission v. Sierra Pacific Power Co., 350 U.S. 348 (1956) and clarified by Morgan Stanley Capital Group, Inc. v. Public Util. Dist. No. 1 of Snohomish, 554 U.S. 527 (2008), and NRG Power Marketing LLC v. Maine Public Utilities Commission, 558 U.S. 165 (2010) (the "**Mobile-Sierra Doctrine**").

13.14 Severability. Should any provision of this Agreement be held to be invalid or unenforceable, such provision shall be invalid or unenforceable only to the extent of such invalidity or unenforceability without invalidating or rendering unenforceable any other provision hereof.

[signatures appear on next page]

IN WITNESS WHEREOF, the Parties hereto have caused this Agreement to be executed and delivered by their duly authorized representatives as of the date set forth in the preamble to this Agreement.

[GENCO]

By: ______________________________
Name:
Title:

OHIO POWER COMPANY

By: ______________________________
Name:
Title:

Schedule A

Ohio Generation Facilities

Facility	Unit(s)	Location	Unit Capacity (MW)	Seller Ownership (%)	Seller Ownership (MW)
Cardinal	1	OH	592	100.0%	592
Conesville	4	OH	779	43.5%	339
Conesville	5	OH	405	100.0%	405
Conesville	6	OH	405	100.0%	405
Stuart	1	OH	577	26.0%	150
Stuart	2	OH	577	26.0%	150
Stuart	3	OH	577	26.0%	150
Stuart	4	OH	577	26.0%	150
Zimmer	1	OH	1,300	25.4%	330
Total			5,789		2,671

SCHEDULE 13.4

Notice Information

<u>If to Seller</u>:

[GENCO]
155 W. Nationwide Blvd. Suite 400
Columbus, Ohio 433215
Attention: President

with a copy to:

[GENCO]
One Riverside Plaza
Columbus, Ohio 433215
Attention: Secretary

<u>If to Buyer</u>:

Ohio Power Company
One Riverside Plaza
Columbus, Ohio 433215
Attention: President

with a copy to:

Ohio Power Company
One Riverside Plaza
Columbus, Ohio 433215
Attention: Secretary

Sierra Club Ex. 3

~~Execution Copy~~

AMENDED AND RESTATED

INTER-COMPANY POWER AGREEMENT

DATED AS OF SEPTEMBER 10, 2010

AMONG

OHIO VALLEY ELECTRIC CORPORATION,
ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C.
APPALACHIAN POWER COMPANY,
BUCKEYE POWER GENERATING, LLC,
COLUMBUS SOUTHERN POWER COMPANY,
THE DAYTON POWER AND LIGHT COMPANY,
DUKE ENERGY OHIO, INC.,
FIRSTENERGY GENERATION CORP.,
INDIANA MICHIGAN POWER COMPANY,
KENTUCKY UTILITIES COMPANY,
LOUISVILLE GAS AND ELECTRIC COMPANY,
MONONGAHELA POWER COMPANY,
OHIO POWER COMPANY,
PENINSULA GENERATION COOPERATIVE, and
SOUTHERN INDIANA GAS AND ELECTRIC COMPANY

EXHIBIT
PENGAD 800-631-6989
SC-3

AMENDED AND RESTATED

INTER-COMPANY POWER AGREEMENT

THIS AGREEMENT, dated as of September 10, 2010 (the "Agreement"), by and among OHIO VALLEY ELECTRIC CORPORATION (herein called OVEC), ALLEGHENY ENERGY SUPPLY COMPANY, L.L.C. (herein called Allegheny), APPALACHIAN POWER COMPANY (herein called Appalachian), BUCKEYE POWER GENERATING, LLC (herein called Buckeye), COLUMBUS SOUTHERN POWER COMPANY (herein called Columbus), THE DAYTON POWER AND LIGHT COMPANY (herein called Dayton), DUKE ENERGY OHIO, INC. (formerly known as The Cincinnati Gas & Electric Company and herein called Duke Ohio), FIRSTENERGY GENERATION CORP. *(herein called FirstEnergy)*, *INDIANA MICHIGAN* POWER *COMPANY (herein called Indiana)*, KENTUCKY UTILITIES COMPANY (herein called Kentucky), LOUISVILLE GAS AND ELECTRIC COMPANY (herein called Louisville), MONONGAHELA POWER COMPANY (herein called Monongahela), OHIO POWER COMPANY (herein called Ohio Power), PENINSULA GENERATION COOPERATIVE (herein called Peninsula), and SOUTHERN INDIANA GAS AND ELECTRIC COMPANY (herein called Southern Indiana, and all of the foregoing, other than OVEC, being herein sometimes collectively referred to as the Sponsoring Companies and individually as a Sponsoring Company) hereby amends and restates in its entirety, the Inter-Company Power Agreement dated as of March 13, 2006, as amended by Modification No. 1, dated as of March 13, 2006 (herein called the Current Agreement), by and among OVEC and the Sponsoring Companies.

WITNESSETH THAT:

WHEREAS, the Current Agreement amended and restated the original Inter-Company Power Agreement, dated as of July 10, 1953, as amended by Modification No. 1, dated as of June 3, 1966; Modification No. 2, dated as of January 7, 1967; Modification No. 3, dated as of November 15, 1967; Modification No. 4, dated as of November 5, 1975; Modification No. 5, dated as of September 1, 1979; Modification No. 6, dated as of August 1, 1981; Modification No. 7, dated as of January 15, 1992; Modification No. 8, dated as of January 19, 1994; Modification No. 9, dated as of August 17, 1995; Modification No. 10, dated as of January 1, 1998; Modification No. 11, dated as of April 1, 1999; Modification No. 12, dated as of November 1, 1999; Modification No. 13, dated as of May 24, 2000; Modification No. 14, dated as of April 1, 2001; and Modification No. 15, dated as of April 30, 2004 (together, herein called the Original Agreement); and

WHEREAS, OVEC designed, purchased, and constructed, and continues to operate and maintain two steam-electric generating stations, one station (herein called Ohio Station) consisting of five turbo-generators and all other necessary equipment, at a location on the Ohio River near Cheshire, Ohio, and the other station (herein called Indiana Station) consisting of six turbogenerators and all other necessary equipment, at a location on the Ohio River near Madison, Indiana, (the Ohio Station and the Indiana Station being herein called the Project Generating Stations); and

WHEREAS, OVEC also designed, purchased, and constructed, and continues to operate and maintain necessary transmission and general plant facilities (herein called the Project Transmission Facilities) and OVEC established or cause to be established interconnections between the Project Generating Stations and the systems of certain of the Sponsoring Companies; and

WHEREAS, OVEC entered into an agreement, attached hereto as Exhibit A, with Indiana-Kentucky Electric Corporation (herein called IKEC), a corporation organized under the laws of the State of Indiana as a wholly owned subsidiary corporation of OVEC, which has been amended and restated as of the date of this Agreement and embodies the terms and conditions for the ownership and operation by IKEC of the Indiana Station and such portion of the Project Transmission Facilities which are to be owned and operated by it; and

WHEREAS, transmission facilities were constructed by certain of the Sponsoring Companies to interconnect the systems of such Sponsoring Companies, directly or indirectly, with the Project Generating Stations and/or the Project Transmission Facilities, and the Sponsoring Companies have agreed to pay for Available Power, as hereinafter defined, as may be available at the Project Generating Stations; and

WHEREAS, the parties hereto desire to amend and restate in their entirety, the Current Agreement to define the terms and conditions governing the rights of the Sponsoring Companies to receive Available Power from the Project Generating Stations and the obligations of the Sponsoring Companies to pay therefor.

NOW, THEREFORE, the parties hereto agree with each other as follows:

ARTICLE 1

DEFINITIONS

1.01. For the purposes of this Agreement, the following terms, wherever used herein, shall have the following meanings:

1.011 "Affiliate" means, with respect to a specified person, any other person that directly or indirectly through one or more intermediaries controls, is controlled by, or is under common control with, such specified person; provided that "control" for these purposes means the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of a person, whether through the ownership of voting securities, by contract or otherwise.

1.012 "Arbitration Board" has the meaning set forth in Section 9.10.

1.013 "Available Energy" of the Project Generating Stations means the energy associated with Available Power.

1.014 "Available Power" of the Project Generating Stations at any particular time means the total net kilowatts at the 345-kV busses of the Project Generating Stations which Corporation in its sole discretion will determine that the Project Generating Stations will be capable of safely delivering under conditions then prevailing, including all conditions affecting capability.

1.015 "Corporation" means OVEC, IKEC, and all other subsidiary corporations of OVEC.

1.016 "Decommissioning and Demolition Obligation" has the meaning set forth in Section 5.03(f) hereof.

1.017 "Effective Date" means September 10, 2010, or to the extent necessary, such later date on which Corporation notifies the Sponsoring Companies that all conditions to effectiveness, including all required waiting periods and all required regulatory acceptances or approvals, of this Agreement have been satisfied in form and substance satisfactory to the Corporation.

1.018 "Election Period" has the meaning set forth in Section 9.183(a) hereof.

1.019 "Minimum Generating Unit Output" means 80 MW (net) for each of the Corporation's generation units; provided that such "Minimum Generating Unit Output" shall be confirmed from time to time by operating tests on the Corporation's generation units and shall be adjusted by the Operating Committee as appropriate following such tests.

1.0110 "Minimum Loading Event" means a period of time during which one or more of the Corporation's generation units are operating at below the Minimum Generating Output as a result of the Sponsoring Companies' failure to schedule and take delivery of sufficient Available Energy.

1.0111 "Minimum Loading Event Costs" means the sum of the following costs caused by one or more Minimum Loading Events: (i) the actual costs of any of the Corporation's generating units burning fuel oil; and (ii) the estimated actual additional costs to the Corporation resulting from Minimum Loading Events, including without limitation the incremental costs of additional emissions allowances, reflected in the schedule of charges prepared by the Operating Committee and in effect as of the commencement of any Minimum Loading Event, which schedule may be adjusted from time to time as necessary by the Operating Committee.

1.0112 "Month" means a calendar month.

1.0113 "Nominal Power Available" means an individual Sponsoring Company's Power Participation Ratio share of the Corporation's current estimate of the maximum amount of Available Power available for delivery at any given time.

1.0114 "Offer Notice" means the notice required to be given to the other Sponsoring Companies by a Transferring Sponsor offering to sell all or a portion of such Transferring Sponsor's rights, title and interests in, and obligations under this Agreement. At a minimum, the Offer Notice shall be in writing and shall contain (i) the rights, title and interests in, and obligations under this Agreement that the Transferring Sponsor proposes to Transfer; and (ii) the cash purchase price and any other material terms and conditions of such proposed transfer. An Offer Notice may not contain terms or conditions requiring the purchase of any non-OVEC interests.

1.0115 "Permitted Assignee" means a person that is (a) a Sponsoring Company or its Affiliate whose long-term unsecured non-credit enhanced indebtedness, as of the date of such assignment, has a Standard & Poor's credit rating of at least BBB- and a Moody's Investors Service, Inc. credit rating of at least Baa3 (provided that, if the proposed assignee's long-term unsecured non-credit enhanced indebtedness is not currently rated by one of Standard & Poor's or Moody, such assignee's long-term unsecured non-credit enhanced indebtedness, as of the date of such assignment, must have either a Standard & Poor's credit rating of at least BBB- or a Moody's Investors Service, Inc. credit rating of at least Baa3); or (b) a Sponsoring Company or its Affiliate that does not meet the criteria in subsection (a) above, if the Sponsoring Company or its Affiliate that is assigning its rights, title and interests in, and obligations under, this Agreement agrees in writing (in form and substance satisfactory to Corporation) to remain obligated to satisfy all of the obligations related to the assigned rights, title and interests to the extent such obligations are not satisfied by the assignee of such rights, title and interests; provided that, in no event shall a person be deemed a "Permitted Assignee" if counsel for the Corporation reasonably determines that the assignment of the rights, title or interests in, or obligations under, this Agreement to such person could cause a termination, default, loss or payment obligation under any security issued, or agreement entered into, by the Corporation prior to such transfer.

1.0116 "Postretirement Benefit Obligation" has the meaning set forth in Section 5.03(e) hereof.

1.0117 "Power Participation Ratio" as applied to each of the Sponsoring Companies refers to the percentage set forth opposite its respective name in the tabulation below:

Company	Power Participation Ratio—Percent

Allegheny	3.01
Appalachian	15.69
Buckeye	18.00
Columbus	4.44
Dayton	4.90
Duke Ohio	9.00
FirstEnergy	4.85
Indiana	7.85
Kentucky	2.50
Louisville	5.63
Monongahela	0.49
Ohio Power	15.49
Peninsula	6.65
Southern Indiana	1.50
Total	100.0

1.0118 "Tariff" means the open access transmission tariff of the Corporation, as amended from time to time, or any successor tariff, as accepted by the Federal Energy Regulatory Commission or any successor agency.

1.0119 "Third Party" means any person other than a Sponsoring Company or its Affiliate.

1.0120 "Total Minimum Generating Output" means the product of the Minimum Generating Unit Output times the number of the Corporation's generation units available for service at that time.

1.0121 "Transferring Sponsor" has the meaning set forth in Section 9.183(a) hereof.

1.0122 "Uniform System of Accounts" means the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission as in effect on January 1, 2004.

ARTICLE 2

TRANSMISSION AGREEMENT AND FACILITIES

2.01. *Transmission Agreement.* The Corporation shall enter into a transmission service agreement under the Tariff, and the Corporation shall reserve and schedule transmission service, ancillary services and other transmission-related services in accordance with the Tariff to provide for the delivery of Available Power and Available Energy to the applicable delivery point under this Agreement.

2.02. *Limited Burdening of Corporation's Transmission Facilities.* Transmission facilities owned by the Corporation, including the Project Transmission Facilities, shall not be burdened by power and energy flows of any Sponsoring Company to an extent which would impair or prevent the transmission of Available Power.

ARTICLE 3

[RESERVED]

ARTICLE 4

AVAILABLE POWER SUPPLY

4.01. *Operation of Project Generating Stations.* Corporation shall operate and maintain the Project Generating Stations in a manner consistent with safe, prudent, and efficient operating practice so that the Available Power available from said stations shall be at the highest practicable level attainable consistent with OVEC's obligations under Reliability*First* Reliability Standard BAL-002-RFC throughout the term of this Agreement.

4.02. *Available Power Entitlement.* The Sponsoring Companies collectively shall be entitled to take from Corporation and Corporation shall be obligated to supply to the Sponsoring Companies any and all Available Power and Available Energy pursuant to the provisions of this Agreement. Each Sponsoring Company's Available Power Entitlement hereunder shall be its Power Participation Ratio, as defined in *subsection* 1.0117, of Available Power.

4.03. *Available Energy.* Corporation shall make Available Energy available to each Sponsoring Company in proportion to said Sponsoring Company's Power Participation Ratio. No Sponsoring Company, however, shall be obligated to avail itself of any Available Energy. Available Energy shall be scheduled and taken by the Sponsoring Companies in accordance with the following procedures:

4.031 Each Sponsoring Company shall schedule the delivery of all or any portion (in whole MW increments) of its entitlement to Available Energy in accordance with scheduling procedures established by the Operating Committee from time to time.

4.032 In the event that any Sponsoring Company does not schedule the delivery of all of its Power Participation Ratio share of Available Energy, then each such other Sponsoring Company may schedule the delivery of all or any portion (in whole MW increments) of any such unscheduled share of Available Energy (through successive allotments if necessary) in proportion to their Power Participation Ratios.

4.033 Notwithstanding any Available Energy schedules made in accordance with this Section 4.03 and the applicable scheduling procedures, (i) the Corporation shall adjust all schedules to the extent that the Corporation's actual generation output is less than or more than the expected Nominal Power Available to all Sponsoring Companies, or to the extent that the Corporation is unable to obtain sufficient transmission service under the Tariff for the delivery of all scheduled Available Energy; and (ii) immediately following a Minimum Loading Event, any Sponsoring Company causing (in whole or part) such Minimum Loading Event shall have its Available Energy schedules increased after the schedules of the Sponsoring Companies not causing such Minimum Load Event, in accordance with the estimated ramp rates associated with the shutdown and start-up of the Corporation's generation units as reflected in the schedules prepared by the Operating Committee and in effect as of the commencement of any Minimum Loading Event, which schedules may be adjusted from time to time as necessary by the Operating Committee.

4.034 Each Sponsoring Company availing itself of Available Energy shall be entitled to an amount of energy (herein called billing kilowatt-hours of Available Energy) equal to its portion, determined as provided in this Section 4.03, of the total Available Energy after deducting therefrom such Sponsoring Company's proportionate share, as defined in this Section 4.03, of all losses as determined in accordance with the Tariff incurred in transmitting the total of such Available Energy from the 345-kV busses of the Project Generating Stations to the applicable delivery points, as scheduled pursuant to Section 9.01, of all Sponsoring Companies availing themselves of Available Energy. The proportionate share of all such losses that shall be so deducted from such Sponsoring Company's portion of Available Energy shall be equal to all such losses multiplied by the ratio of such portion of Available Energy to the total of such Available Energy. Each Sponsoring Company shall have the right, pursuant to this Section 4.03, to avail itself of Available Energy for the purpose of meeting the loads of its own system and/or of supplying energy to other systems in accordance with agreements, other than this Agreement, to which such Sponsoring Company is a party.

4.035 To the extent that, as a result of the failure by one or more Sponsoring Companies to take its respective Power Participation Ratio share of the applicable Total Minimum Generating Output during any hour, a Minimum Loading Event shall occur, then such one or more Sponsoring Companies shall be assessed charges for any Minimum Loading Event Costs in accordance with Section 5.05.

ARTICLE 5

CHARGES FOR AVAILABLE POWER AND MINIMUM LOADING EVENT COSTS

5.01. *Total Monthly Charge.* The amount to be paid to Corporation each month by the Sponsoring Companies for Available Power and Available Energy supplied under this

Agreement shall consist of the sum of an energy charge, a demand charge, and a transmission charge, all determined as set forth in this *Article 5*.

5.02. *Energy Charge*. The energy charge to be paid each month by the Sponsoring Companies for Available Energy shall be determined by Corporation as follows:

5.021 Determine the aggregate of all expenses for fuel incurred in the operation of the Project Generating Stations, in accordance with Account 501 (Fuel), Account 506.5 (Variable Reagent Costs Associated With Pollution Control Facilities) and 509 (Allowances) of the Uniform System of Accounts.

5.022 Determine for such month the difference between the total cost of fuel as described in subsection 5.021 above and the total cost of fuel included in any Minimum Loading Event Costs payable to the Corporation for such month pursuant to Section 8.03. For the purposes hereof the difference so determined shall be the fuel cost allocable for such month to the total kilowatt-hours of energy generated at the Project Generating Stations for the supply of Available Energy. For Available Energy availed of by the Sponsoring Companies, each Sponsoring Company shall pay Corporation for each such month an amount obtained by multiplying the ratio of the billing kilowatt-hours of such Available Energy availed of by such Sponsoring Company during such month to the aggregate of the billing kilowatt-hours of all Available Energy availed of by all Sponsoring Companies during such month times the total cost of fuel as described in this subsection 5.022 for such month.

5.03. *Demand Charge*. During the period commencing with the Effective Date and for the remainder of the term of this Agreement, demand charges payable by the Sponsoring Companies to Corporation shall be determined by the Corporation as provided below in this Section 5.03. Each Sponsoring Company's share of the aggregate demand charges shall be the percentage of such charges represented by its Power Participation Ratio.

The aggregate demand charge payable each month by the Sponsoring Companies to Corporation shall be equal to the total costs incurred for such month by Corporation resulting from its ownership, operation, and maintenance of the Project Generating Stations and Project Transmission Facilities determined as follows:

> As soon as practicable after the close of each calendar month the following components of costs of Corporation (eliminating any duplication of costs which might otherwise be reflected among the corporate entities comprising Corporation) applicable for such month to the ownership, operation and maintenance of the Project Generating Stations and the Project Transmission Facilities, including additional facilities and/or spare parts (such as fuel processing plants, flue gas or waste product processing facilities, and facilities reasonably required to enable the Corporation to limit the emission of pollutants or the discharge of wastes in compliance with governmental requirements) and

replacements necessary or desirable to keep the Project Generating Stations and the Project Transmission Facilities in a dependable and efficient operating condition, and any provision for any taxes that may be applicable to such charges, to be determined and recorded in the following manner:

(a) Component (A) shall consist of fixed charges made up of (i) the amounts of interest properly chargeable to Accounts 427, 430 and 431, less the amount thereof credited to Account 432, of the Uniform System of Accounts, including the interest component of any purchase price, interest, rental or other payment under an installment sale, loan, lease or similar agreement relating to the purchase, lease or acquisition by Corporation of additional facilities and replacements (whether or not such interest or other amounts have come due or are actually payable during such Month), (ii) the amounts of amortization of debt discount or premium and expenses properly chargeable to Accounts 428 and 429, and (iii) an amount equal to the sum of (I) the applicable amount of the debt amortization component for such month required to retire the total amount of indebtedness of Corporation issued and outstanding, (II) the amortization requirement for such month in respect of indebtedness of Corporation incurred in respect of additional facilities and replacements, and (III) to the extent not provided for pursuant to clause (II) of this clause (iii), an appropriate allowance for depreciation of additional facilities and replacements.

(b) Component (B) shall consist of the total operating expenses for labor, maintenance, materials, supplies, services, insurance, administrative and general expense, etc., properly chargeable to the Operation and Maintenance Expense Accounts of the Uniform System of Accounts (exclusive of Accounts 501, 509, 555, 911, 912, 913, 916, and 917 of the Uniform System of Accounts), minus the total of all non-fuel costs included in any Minimum Loading Event Costs payable to the Corporation for such month pursuant to Section 8.03, minus the total of all transmission charges payable to the Corporation for such month pursuant to Section 5.04, and plus any additional amounts which, after provision for all income taxes on such amounts (which shall be included in Component (C) below), shall equal any amounts paid or payable by Corporation as fines or penalties with respect to occasions where it is asserted that Corporation failed to comply with a law or regulation relating to the emission of pollutants or the discharge of wastes.

(c) Component (C) shall consist of the total expenses for taxes, including all taxes on income but excluding any federal income taxes arising from payments to Corporation under Component (D) below, and all operating or other costs or expenses, net of income, not included or specifically excluded in Components (A) or (B) above, including tax adjustments, regulatory adjustments, net losses for the disposition of property and other net costs or expenses associated with the operation of a utility.

(d) Component (D) shall consist of an amount equal to the product of $2.089 multiplied by the total number of shares of capital stock of the par value of $100 per share of Ohio Valley Electric Corporation which shall have been issued and which are outstanding on the last day of such month.

(e) Component (E) shall consist of an amount to be sufficient to pay the costs and other expenses relating to the establishment, maintenance and administration of life insurance, medical insurance and other postretirement benefits other than pensions attributable to the employment and employee service of active employees, retirees, or other employees, including without limitation any premiums due or expected to become due, as well as administrative fees and costs, such amounts being sufficient to provide payment with respect to all periods for which Corporation has committed or is otherwise obligated to make such payments, including amounts attributable to current employee service and any unamortized prior service cost, gain or loss attributable to prior service years ("Postretirement Benefit Obligation"); provided that, the amount payable for Postretirement Benefit Obligations during any month shall be determined by the Corporation based on, among other factors, the Statement of Financial Accounting Standards No. 106 (Employers' Accounting For Postretirement Benefits Other Than Pensions) and any applicable accounting standards, policies or practices as adopted from time to time relating to accruals with respect to all or any portion of such Postretirement Benefit Obligation.

(f) Component (F) shall consist of an amount that may be incurred in connection with the decommissioning, shutdown, demolition and closing of the Project Generating Stations when production of electric power and energy is discontinued at such Project Generating Stations, which amount shall include, without limitation the following costs (net of any salvage credits): the costs of demolishing the plants' building structures, disposal of non-salvageable materials, removal and disposal of insulating materials, removal and disposal of storage tanks and associated piping, disposal or removal of materials and supplies (including fuel oil and coal), grading, covering and reclaiming storage and disposal areas, disposing of ash in ash ponds to the extent required by regulatory authorities, undertaking corrective or remedial action required by regulatory authorities, and any other costs incurred in putting the facilities in a condition necessary to protect health or the environment or which are required by regulatory authorities, or which are incurred to fund continuing obligations to monitor or to correct environmental problems which result, or are later discovered to result, from the facilities' operation, closure or post-closure activities ("Decommissioning and Demolition Obligation") provided that, the amount payable for Decommissioning and Demolition Obligations during any month shall be calculated by Corporation based on, among other factors, the then-estimated useful life of the Project Generating Stations and any applicable accounting standards, policies or practices as adopted from time to time relating to accruals with respect to all or any portion of such Decommissioning and Demolition Obligation, and provided further that, the Corporation shall recalculate the amount payable under this Component (F) for future months from time to time, but in no event later than five (5) years after the most recent calculation.

5.04. *Transmission Charge*. The transmission charges to be paid each month by the Sponsoring Companies shall be equal to the total costs incurred for such month by Corporation for the purchase of transmission service, ancillary services and other transmission-related services under the Tariff as reserved and scheduled by the Corporation to provide for the delivery of Available Power and Available Energy to the applicable delivery point under this Agreement. Each Sponsoring Company's share of the aggregate transmission charges shall be the percentage of such charges represented by its Power Participation Ratio.

5.05. *Minimum Loading Event Costs*. To the extent that, as a result of the failure by one or more Sponsoring Companies to take its respective Power Participation Ratio share of the applicable Total Minimum Generating Output during any hour, a Minimum Loading Event shall occur, then the sum of all Minimum Loading Event Costs relating to such Minimum Loading Event shall be charged to such Sponsoring Company or group of Sponsoring Companies that failed take its respective Power Participation Ratio share of the applicable Total Minimum Generating Output during such period, with such Minimum Loading Event Costs allocated among such Sponsoring Companies on a pro-rata basis in accordance with such Sponsoring Company's MWh share of the MWh reduction in the delivery of Available Energy causing any Minimum Loading Event. The applicable charges for Minimum Loading Event Costs as determined by the corporation in accordance with Section 5.05 shall be paid each month by the applicable Sponsoring Companies.

ARTICLE 6

Metering of Energy Supplied

6.01. *Measuring Instruments*. The parties hereto shall own and maintain such metering equipment as may be necessary to provide complete information regarding the delivery of power and energy to or for the account of any of the parties hereto; and the ownership and expense of such metering shall be in accordance with agreements among them. Each party will at its own expense make such periodic tests and inspections of its meters as may be necessary to maintain them at the highest practical commercial standard of accuracy and will advise all other interested parties hereto promptly of the results of any such test showing an inaccuracy of more than 1%. Each party will make additional tests of its meters at the request of any other interested party. Other interested parties shall be given notice of, and may have representatives present at, any test and inspection made by another party.

ARTICLE 7

COSTS OF REPLACEMENTS AND ADDITIONAL FACILITIES; PAYMENTS FOR EMPLOYEE BENEFITS; DECOMMISSIONING, SHUTDOWN, DEMOLITION AND CLOSING CHARGES

7.01. *Replacement Costs.* The Sponsoring Companies shall reimburse Corporation for the difference between (a) the total cost of replacements chargeable to property and plant made by Corporation during any month prior thereto (and not previously reimbursed) and (b) the amounts received by Corporation as proceeds of fire or other applicable insurance protection, or amounts recovered from third parties responsible for damages requiring replacement, plus provision for all taxes on income on such difference; provided that, to the extent that the Corporation arranges for the financing of any replacements, the payments due under this Section 7.01 shall equal the amount of all principal, interest, taxes and other costs and expenses related to such financing during any month. Each Sponsoring Company's share of such payment shall be the percentage of such costs represented by its Power Participation Ratio. The term cost of replacements, as used herein, shall include all components of cost, plus removal expense, less salvage.

7.02. *Additional Facility Costs.* The Sponsoring Companies shall reimburse Corporation for the total cost of additional facilities and/or spare parts purchased and/or installed by Corporation during any month prior thereto (and not previously reimbursed), plus provision for all taxes on income on such costs; provided that, to the extent that the Corporation arranges for the financing of any additional facilities and/or spare parts, the payments due under this Section 7.02 shall equal the amount of all principal, interest, taxes and other costs and expenses related to such financing during any month. Each Sponsoring Company's share of such payment shall be the percentage of such costs represented by its Power Participation Ratio.

7.03. *Payments for Employee Benefits.* Not later than the effective date of termination of this Agreement, each Sponsoring Company will pay to Corporation its Power Participation Ratio share of additional amounts, after provision for any taxes that may be applicable thereto, sufficient to cover any shortfall if the amount of the Postretirement Benefit Obligation collected by the Corporation prior to the effective date of termination of the Agreement is insufficient to permit Corporation to fulfill its commitments or obligations with respect to both postemployment benefit obligations under the Statement of Financial Accounting Standards No. 112 and postretirement benefits other than pensions, as determined by Corporation with the aid of an actuary or actuaries selected by the Corporation based on the terms of the Corporation's then-applicable plans.

7.04. *Decommissioning, Shutdown, Demolition and Closing.* The Sponsoring Companies recognize that a part of the cost of supplying power to it under this Agreement is the amount that may be incurred in connection with the decommissioning, shutdown, demolition and closing of the Project Generating Stations when production of electric power and energy is discontinued at such Project Generating Stations. Not later than the effective date of termination of this Agreement, each Sponsoring Company will pay to Corporation its Power Participation Ratio share of additional amounts, after provision for any taxes that may be applicable thereto, sufficient to cover any shortfall if the amount of the Decommissioning and Demolition Obligation collected by the Corporation prior to the effective date of termination of the Agreement is insufficient to permit Corporation to complete the decommissioning, shutdown, demolition and closing of the Project Generating Stations, based on the Corporation's recalculation of the Decommissioning and Demolition Obligation in accordance with Section 5.03(f) of this Agreement no earlier than twelve (12) months before the effective date of termination of this Agreement.

ARTICLE 8

BILLING AND PAYMENT

8.01. *Available Power, and Replacement and Additional Facility Costs.* As soon as practicable after the end of each month Corporation shall render to each Sponsoring Company a statement of all Available Power and Available Energy supplied to or for the account of such Sponsoring Company during such month, specifying the amount due to the Corporation therefor, including any amounts for reimbursement for the cost of replacements and additional facilities and/or spare parts incurred during such month, pursuant to *Articles* 5 and 7 above. Such Sponsoring Company shall make payment therefor promptly upon the receipt of such statement, but in no event later than fifteen (15) days after the date of receipt of such statement. In case any factor entering into the computation of the amount due for Available Power and Available Energy cannot be determined at the time, it shall be estimated subject to adjustment when the actual determination can be made.

8.02. *Provisional Payments for Available Power.* The Sponsoring Companies shall, from time to time, at the request of the Corporation, make provisional semi-monthly payments for Available Power in amounts approximately equal to the estimated amounts payable for Available Power delivered by Corporation to the Sponsoring Companies during each semi-monthly period. As soon as practicable after the end of each semi-monthly period with respect to which Corporation has requested the Sponsoring Companies to make provisional semi-monthly payments for Available Power, Corporation shall render to each Sponsoring Company a separate statement indicating the amount payable by such Sponsoring Company for such semi-monthly period. Such Sponsoring Company shall make payment therefor promptly upon receipt of such statement, but in no event later than fifteen (15) days after the date of receipt of such statement and the amounts so paid by such Sponsoring Company shall be credited to the account of such Sponsoring Company with respect to future payments to be made pursuant to *Articles* 5 and 7 above by such Sponsoring Company to Corporation for Available Power.

8.03. *Minimum Loading Event Costs.* As soon as practicable after the end of each month, Corporation shall render to each Sponsoring Company a statement indicating any applicable charges for Minimum Loading Event Costs pursuant to Section 5.05 during such month, specifying the amount due to the Corporation therefor pursuant to *Article* 5 above. Such Sponsoring Company shall make payment therefor promptly upon the receipt of such statement, but in no event later than fifteen (15) days after the date of receipt of such statement. In case the computation of the amount due for Minimum Loading Event Costs cannot be determined at the time, it shall be estimated subject to adjustment when the actual determination can be made, and all payments shall be subject to subsequent adjustment.

8.04. *Unconditional Obligation to Pay Demand and Other Charges.* The obligation of each Sponsoring Company to pay its specified portion of the Demand Charge under Section 5.03, the Transmission Charge under Section 5.04, and all charges under *Article* 7 for any Month shall not be reduced irrespective of:

(a) whether or not any Available Power or Available Energy are supplied by the Corporation during such calendar month and whether or not any Available Power or Available Energy are accepted by any Sponsoring Company during such calendar month;

(b) the existence of any claim, set-off, defense, reduction, abatement or other right (other than irrevocable payment, performance, satisfaction or discharge in full) that such Sponsoring Company may have, or which may at any time be available to or be asserted by such Sponsoring Company, against the Corporation , any other Sponsoring Company, any creditor of the Corporation or any other Person (including, without limitation, arising as a result of any breach or alleged breach by either the Corporation, any other Sponsoring Company, any creditor of the Corporation or any other Person under this Agreement or any other agreement (whether or not related to the transactions contemplated by this Agreement or any other agreement) to which such party is a party); or

(c) the validity or enforceability against any other Sponsoring Company of this Agreement or any right or obligation hereunder (or any release or discharge thereof) at any time.

ARTICLE 9

GENERAL PROVISIONS

9.01. *Characteristics of Supply and Points of Delivery.* All power and energy delivered hereunder shall be 3-phase, 60-cycle, alternating current, at a nominal unregulated voltage designated for the point of delivery as described in this *Article* 9. Available Power and Available Energy to be delivered between Corporation and the Sponsoring Companies pursuant to this Agreement shall be delivered under the terms and conditions of the Tariff at the points, as scheduled by the Sponsoring Company in accordance with procedures established by the Operating Committee and in accordance with Section 9.02, where the transmission facilities of Corporation interconnect with the transmission facilities of any Sponsoring Company (or its successor or predecessor); provided that, to the extent that a joint and common market is established for the sale of power and energy by Sponsoring Companies within one or more of the regional transmission organizations or independent system operators approved by the Federal Energy Regulatory Commission in which the Sponsoring Companies are members or otherwise participate, then Corporation and the Sponsoring Companies shall take such action as reasonably necessary to permit the Sponsoring Companies to bid their entitlement to power and energy from Corporation into such market(s) in accordance with the procedures established for such market(s).

9.02. *Modification of Delivery Schedules Based on Available Transmission Capability.* To the extent that transmission capability available for the delivery of Available Power and Available Energy at any delivery point is less than the total amount of Available Power and Available Energy scheduled for delivery by the Sponsoring Companies at such delivery point in accordance with Section 9.01, then the following procedures shall apply and the Corporation and the applicable Sponsoring Companies shall modify their delivery schedules accordingly until the total amount of Available Power and Available Energy scheduled for delivery at such delivery point is equal to or less than the transmission capability available for the delivery of Available Power and Available Energy: (a) the transmission capability available for the delivery of Available Power and Available Energy at the following delivery points shall be allocated first on a pro rata basis (in whole MW increments) to the following Sponsoring Companies up to their Power Participation Ratio share of the total amount of Available Energy available to all Sponsoring Companies (and as applicable, further allocated among Sponsoring Companies entitled to allocation under this Section 9.02(a) in accordance with their Power Participation Ratios): (i) to Allegheny, Appalachian, Buckeye, Columbus, FirstEnergy, Indiana, Monongahela, Ohio Power and Peninsula (or their successors) for deliveries at the points of interconnection between the Corporation and Appalachian, Columbus, Indiana or Ohio Power, or their successors; (ii) to Duke Ohio (or its successor) for deliveries at the points of interconnection between the Corporation and Duke Ohio or its successor; (iii) to Dayton (or its successor) for deliveries at the points of interconnection between the Corporation and Dayton or its successor; and (iv) to Kentucky, Louisville and Southern Indiana (or their successors) for deliveries at the points of interconnection between the Corporation and Louisville or Kentucky, or their successors; and (b) any remaining transmission capability available for the delivery of

Available Power and Available Energy shall be allocated on a pro rata basis (in whole MW increments) to the Sponsoring Companies in accordance with their Power Participation Ratios.

9.03. *Operation and Maintenance of Systems Involved.* Corporation and the Sponsoring Companies shall operate their systems in parallel, directly or indirectly, except during emergencies that temporarily preclude parallel operation. The parties hereto agree to coordinate their operations to assure maximum continuity of service from the Project Generating Stations, and with relation thereto shall cooperate with one another in the establishment of schedules for maintenance and operation of equipment and shall cooperate in the coordination of relay protection, frequency control, and communication and telemetering systems. The parties shall build, maintain and operate their respective systems in such a manner as to minimize so far as practicable rapid fluctuations in energy flow among the systems. The parties shall cooperate with one another in the operation of reactive capacity so as to assure mutually satisfactory power factor conditions among themselves.

The parties hereto shall exercise due diligence and foresight in carrying out all matters related to the providing and operating of their respective power resources so as to minimize to the extent practicable deviations between actual and scheduled deliveries of power and energy among their systems. The parties hereto shall provide and/or install on their respective systems such communication, telemetering, frequency and/or tie-line control facilities essential to so minimizing such deviations; and shall fully cooperate with one another and with third parties (such third parties whose systems are either directly or indirectly interconnected with the systems of the Sponsoring Companies and who of necessity together with the parties hereto must unify their efforts cooperatively to achieve effective and efficient interconnected systems operation) in developing and executing operating procedures that will enable the parties hereto to avoid to the extent practicable deviations from scheduled deliveries.

In order to foster coordination of the operation and maintenance of Corporation's transmission facilities with those facilities of Sponsoring Companies that are owned or functionally controlled by a regional transmission organization or independent system operator, Corporation shall use commercially reasonable efforts to enter into a coordination agreement with any regional transmission organization or independent system operator approved by the Federal Energy Regulatory Commission that operates transmission facilities that interconnect with Corporation's transmission facilities, and to enter into a mutually agreeable services agreement with a regional transmission organization or independent system operator to provide the Corporation with reliability and security coordination services and other related services.

9.04. *Power Deliveries as Affected by Physical Characteristics of Systems.* It is recognized that the physical and electrical characteristics of the transmission facilities of the interconnected network of which the transmission systems of the Sponsoring Companies, Corporation, and other systems of third parties not parties hereto are a part, may at times preclude the direct delivery at the points of interconnection between the transmission systems of one or more of the Sponsoring Companies and Corporation, of some portion of the energy supplied under this Agreement, and that in each such case, because of said characteristics, some of the energy will be delivered at points which interconnect the system of one or more of the Sponsoring Companies with systems of companies not parties to this Agreement. The parties hereto shall cooperate in the development of mutually satisfactory arrangements among themselves and with such companies not parties hereto whereby the supply of power and energy contemplated hereunder can be fulfilled.

9.05. *Operating Committee.* There shall be an "Operating Committee" consisting of one member appointed by the Corporation and one member appointed by each of the Sponsoring Companies electing so to do; provided that, if any two or more Sponsoring Companies are Affiliates, then such Affiliates shall together be entitled to appoint only one member to the Operating Committee. The "Operating Committee" shall establish (and modify as necessary) scheduling, operating, testing and maintenance procedures of the Corporation in support of this Agreement, including establishing: (i) procedures for scheduling delivery of Available Energy under Section 4.03, (ii) procedures for power and energy accounting, (iii) procedures for the reservation and scheduling of firm and non-firm transmission service under the Tariff for the delivery of Available Power and Available Energy, (iv) the Minimum Generating Unit Output, and (v) the form of notifications relating to power and energy and the price thereof. In addition, the Operating Committee shall consider and make recommendations to Corporation's Board of Directors with respect to such other problems as may arise affecting the transactions under this Agreement. The decisions of the Operating Committee, including the adoption or modification of any procedure by the Operating Committee pursuant to this Section 9.04, must receive the affirmative vote of at least two-thirds of the members of the Operating Committee, regardless of the number of members of the Operating Committee present at any meeting.

9.06. *Acknowledgment of Certain Rights.* For the avoidance of doubt, all of the parties to this Agreement acknowledge and agree that (i) as of the effective date of the Current Agreement, certain rights and obligations of the Sponsoring Companies or their predecessors under the Original Agreement were changed, modified or otherwise removed, (ii) to the extent that the rights of any Sponsoring Company or their predecessors were thereby changed, modified or otherwise removed as of the effective date of the Current Agreement, such Sponsoring Company may be entitled to rights under applicable law, regulation, rules or orders under the Federal Power Act or otherwise adopted by the Federal Energy Regulatory Commission ("FERC"), (iii) as a result of the elimination as of the effective date of the Current Agreement of the firm transmission service previously provided during the term of the Original Agreement to Sponsoring Companies or their predecessors whose transmission systems were only indirectly connected to the Corporation's facilities through intervening transmission systems by certain Sponsoring Companies or their predecessors whose transmission systems were directly connected to the Corporation's facilities, such Sponsoring Companies or their predecessors whose transmission systems were only indirectly connected to the Corporation's facilities through intervening transmission systems shall have been entitled to such "roll over" firm transmission service for delivery of their entitlement to their Power Participation Ratio share of Surplus Power and Surplus Energy under this Agreement, to the border of such Sponsoring Company system and intervening Sponsoring Company system, as would be accorded a long-term firm point-to-point transmission service reservation under the then otherwise applicable FERC Open Access Transmission Tariff ("OATT"), (iv) the obligation of any Sponsoring Company to maintain or expand transmission capacity to accommodate another Sponsoring Company's "roll over" rights to transmission service for delivery of their entitlement to their Power Participation Ratio share of Surplus Power and Surplus Energy under this Agreement shall be consistent with the obligations it would have for long-term firm point-to-point transmission service provided pursuant to the then otherwise applicable OATT, and (v) the parties shall cooperate with any Sponsoring Company that seeks to obtain and/or exercise any such rights available under applicable law, regulation, rules or orders under the Federal Power Act or otherwise adopted by the FERC.

9.07. *Term of Agreement.* This Agreement shall become effective upon the Effective Date and shall terminate upon the earlier of: (1) June 30, 2040 or (2) the sale or other disposition of all of the facilities of the Project Generating Stations or the permanent cessation of operation of such facilities; provided that, the provisions of *Articles* 5, 7 and 8, this Section 9.07 and Sections 9.08, 9.09, 9.10, 9.11, 9.12, 9.14, 9.15, 9.16, 9.17 and 9.18 shall survive the termination of this Agreement, and no termination of this Agreement, for whatever reason, shall release any Sponsoring Company of any obligations or liabilities incurred prior to such termination.

9.08. *Access to Records.* Corporation shall, at all reasonable times, upon the request of any Sponsoring Company, grant to its representatives reasonable access to the books, records and accounts of the Corporation, and furnish such Sponsoring Company such information as it may reasonably request, to enable it to determine the accuracy and reasonableness of payments made for energy supplied under this Agreement.

9.09. *Modification of Agreement.* Absent the agreement of all parties to this Agreement, the standard for changes to provisions of this Agreement related to rates proposed by a party, a non-party or the Federal Energy Regulatory Commission (or a successor agency) acting sua sponte shall be the "public interest" standard of review set forth in *United Gas Pipeline Co. v. Mobile Gas Serv. Corp.*, 350 U.S. 332 (1956) and *Federal Power Comm'n v. Sierra Pacific Power Co.*, 350 U.S. 348 (1956).

9.10. *Arbitration.* Any controversy, dispute or claim arising out of this Agreement or the refusal by any party hereto to perform the whole or any part thereof, shall be determined by arbitration, in the City of Columbus, Franklin County, Ohio, in accordance with the Commercial Arbitration Rules of the American Arbitration Association or any successor organization, except as otherwise set forth in this Section 9.10.

The party demanding arbitration shall serve notice in writing upon all other parties hereto, setting forth in detail the controversy, dispute or claim with respect to which arbitration is demanded, and the parties shall thereupon endeavor to agree upon an arbitration board, which shall consist of three members ("Arbitration Board"). If all the parties hereto fail so to agree within a period of thirty (30) days from the original notice, the party demanding arbitration may, by written notice to all other parties hereto, direct that any members of the Arbitration Board that have not been agreed to by the parties shall be selected by the American Arbitration Association, or any successor organization. No person shall be eligible for appointment to the Arbitration Board who is an officer, employee, shareholder of or otherwise interested in any of the parties hereto or in the matter sought to be arbitrated.

The Arbitration Board shall afford adequate opportunity to all parties hereto to present information with respect to the controversy, dispute or claim submitted to arbitration and may request further information from any party hereto; provided, however, that the parties hereto may, by mutual agreement, specify the rules which are to govern any proceeding before the Arbitration Board and limit the matters to be considered by the Arbitration Board, in which event the Arbitration Board shall be governed by the terms and conditions of such agreement.

The determination or award of the Arbitration Board shall be made upon a determination of a majority of the members thereof. The findings and award of the Arbitration Board shall be final and conclusive with respect to the controversy, dispute or claim submitted for arbitration and shall be binding upon the parties hereto, except as otherwise provided by law. The award of the Arbitration Board shall specify the manner and extent of the division of the costs of the arbitration proceeding among the parties hereto.

9.11. *Liability.* The rights and obligations of all the parties hereto shall be several and not joint or joint and several.

9.12. *Force Majeure.* No party hereto shall be held responsible or liable for any loss or damage on account of non-delivery of energy hereunder at any time caused by an event of Force Majeure. "Force Majeure" shall mean the occurrence or non-occurrence of any act or event that could not reasonably have been expected and avoided by exercise of due diligence and foresight and such act or event is beyond the reasonable control of such party, including to the extent caused by act of God, fire, flood, explosion, strike, civil or military authority, insurrection or riot, act of the elements, or failure of equipment. For the avoidance of doubt, "Force Majeure" shall in no event be based on any Sponsoring Company's financial or economic conditions, including without limitation (i) the loss of the Sponsoring Company's markets; or (ii) the Sponsoring Company's inability economically to use or resell the Available Power or Available Energy purchased hereunder.

9.13. *Governing Law.* This Agreement shall be governed by, and construed in accordance with, the laws of the State of Ohio.

9.14. *Regulatory Approvals.* This Agreement is made subject to the jurisdiction of any governmental authority or authorities having jurisdiction in the premises and the performance thereof shall be subject to the following:

(a) The receipt of all regulatory approvals, in form and substance satisfactory to Corporation, necessary to permit Corporation to perform all the duties and obligations to be performed by Corporation hereunder.

(6) The receipt of all regulatory approvals, in form and substance satisfactory to the Sponsoring Companies, necessary to permit the Sponsoring Companies to carry out all transactions contemplated herein.

9.15. *Notices.* All notices, requests or other communications under this Agreement shall be in writing and shall be sufficient in all respects: (i) if delivered in person or by courier, upon receipt by the intended recipient or an employee that routinely accepts packages or letters from couriers or other persons for delivery to personnel at the address identified above (as confirmed by, if delivered by courier, the records of such courier), (ii) if sent by facsimile transmission, when the sender receives confirmation from the sending facsimile machine that such facsimile transmission was transmitted to the facsimile number of the addressee, or (iii) if mailed, upon the date of delivery as shown by the return receipt therefor.

9.16. *Waiver*. Performance by any party to this Agreement of any responsibility or obligation to be performed by such party or compliance by such party with any condition contained in this Agreement may by a written instrument signed by all other parties to this Agreement be waived in any one or more instances, but the failure of any party to insist in any one or more instances upon strict performance of any of the provisions of this Agreement or to take advantage of any of its rights hereunder shall not be construed as a waiver of any such provisions or the relinquishment of any such rights, but the same shall continue and remain in full force and effect.

9.17. *Titles of Articles and Sections.* The titles of the Articles and Sections in this Agreement have been inserted as a matter of convenience of reference and are not a part of this Agreement.

9.18. *Successors and Assigns.* This Agreement may be executed in any number of counterparts, all of which shall constitute but one and the same document.

9.181 This Agreement shall inure to the benefit of and be binding upon the parties hereto and their respective successors and assigns, but a party to this Agreement may not assign this Agreement or any of its rights, title or interests in or obligations (including without limitation the assumption of debt obligations) under this Agreement, except to a successor to all or substantially all the properties and assets of such party or as provided in Section 9.182 or 9.183, without the written consent of all the other parties hereto.

9.182 Notwithstanding the provisions of Section 9.181, any Sponsoring Company shall be permitted to, upon thirty (30) days notice to the Corporation and each other Sponsoring Company, without any further action by the Corporation or the other Sponsoring Companies, assign all or part of its rights, title and interests in, and obligations under this Agreement to a Permitted Assignee, <u>provided that</u>, the assignee and assignor of the rights, title and interests in, and obligations under, this Agreement have executed an assignment agreement in form and substance acceptable to the Corporation in its reasonable discretion (including, without limitation, the agreement by the Sponsoring Company assigning such rights, title and interests in, and obligations under, this Agreement to reimburse the Corporation and the other Sponsoring Companies for any fees or expenses required under any security issued, or agreement entered into, by the Corporation as a result of such assignment, including without limitation any consent fee *or additional financing costs to the Corporation under the Corporation's then-existing* securities or agreements resulting from such assignment).

9.183 Notwithstanding the provisions of Section 9.181, any Sponsoring Company shall be permitted to, subject to compliance with all of the requirements of this Section 9.183, assign all or part of its rights, title and interests in, and obligations under this Agreement to a Third Party without any further action by the Corporation or the other Sponsoring Companies.

(a) A Sponsoring Company (the "Transferring Sponsor") that desires to assign all or part of its rights, title and interests in, and obligations under this Agreement to a Third Party shall deliver an Offer Notice to the Corporation and each other Sponsoring Company. The Offer Notice shall be deemed to be an irrevocable offer of the subject rights, title and interests in, and obligations under this Agreement to each of the other Sponsoring Companies that is not an Affiliate of the Transferring Sponsor, which offer must be held open for no less than thirty (30) days from the date of the Offer Notice (the "Election Period").

(b) The Sponsoring Companies (other than the Transferring Sponsor and its Affiliates) shall first have the right, but not the obligation, to purchase all of the rights, title and interests in, and obligations under this Agreement described in the Offer Notice at the price and on the terms specified therein by delivering written notice of such election to the Transferring Sponsor and the Corporation within the Election Period; provided that, irrespective of the terms and conditions of the Offer Notice, a Sponsoring Company may condition its election to purchase the interest described in the Offer Notice on the receipt of approval or consent from such Sponsoring Company's Board of Directors; provided further that, written notice of such conditional election must be delivered to the Transferring Sponsor and the Corporation within the Election Period and such conditional election shall be deemed withdrawn (as if it had never been provided) unless the Sponsoring Company that delivered such conditional election subsequently delivers written notice to the Transferring Sponsor and the Corporation on or before the tenth (10th) day after the expiration of the Election Period that all necessary approval or consent of such Sponsoring Company's Board of Directors have been obtained. To the extent that more than one Sponsoring Company exercises its right to purchase all of the rights, title and interests in, and obligations under this Agreement described in the Offer Notice in accordance with the previous sentence, such rights, title and interests in, and obligations under this Agreement shall be allotted (successively if necessary) among the Sponsoring Companies exercising such right in proportion to their respective Power Participation Ratios.

(c) Each Sponsoring Company exercising its right to purchase any rights, title and interests in, and obligations under this Agreement pursuant to this Section 9.183 may choose to have an Affiliate purchase such rights, title and interests in, and obligations under this Agreement; provided that, notwithstanding anything in this Section 9.183 to the contrary, any assignment to a Sponsoring Company or its Affiliate hereunder must comply with the requirements of Section 9.182.

(d) If one or more Sponsoring Companies have elected to purchase all of the rights, title and interests in, and obligations under this Agreement of the Transferring Sponsor pursuant to the Offer Notice, the assignment of such rights, title and interests in, and obligations under this Agreement shall be consummated as soon as practical after the delivery of the election notices, but in any event no later than fifteen (15) days after the filing and receipt, as applicable, of all necessary governmental filings, consents or other approvals and the expiration of all applicable waiting periods. At the closing of the purchase of such rights, title and interests in, and obligations under this Agreement from the Transferring Sponsor, the Transferring Sponsor shall provide representations and warranties customary for transactions of this type, including those as to its title to such securities and that there are no liens or other encumbrances on such securities (other than pursuant to this Agreement) and shall sign such documents as may reasonably be requested by the Corporation and the other Sponsoring Companies. The Sponsoring Companies or their Affiliates shall only be required to pay cash for the rights, title and interests in, and obligations under this Agreement being assigned by the Transferring Sponsor.

(e) To the extent that the Sponsoring Companies have not elected to purchase all of the rights, title and interests in, and obligations under this Agreement described in the Offer Notice, the Transferring Sponsor may, within one-hundred and eighty (180) days after the later of the expiration of the Election Period or the deemed withdrawal of a conditional election by a Sponsoring Company under Section 9.183(b) hereof (if applicable), enter into a definitive agreement to, assign such rights, title and interests in, and obligations under this Agreement to a Third Party at a price no less than 92.5% of the purchase price specified in the Offer Notice and on other material terms and conditions no more favorable to the such Third Party than those specified in the Offer Notice; <u>provided that</u> such purchases shall be conditioned upon: (i) such Third Party having long-term unsecured non-credit enhanced indebtedness, as of the date of such assignment, with a Standard & Poor's credit rating of at least BBB- and a Moody's Investors Service, Inc. credit rating of at least Baa3 (provided that, if such Third Party's long-term unsecured non-credit enhanced indebtedness is not currently rated by one of Standard & Poor's or Moody, such Third Party's long-term unsecured non-credit enhanced indebtedness, as of the date of such assignment, must have either a Standard & Poor's credit rating of at least BBB- or a Moody's Investors Service, Inc. credit rating of at least Baa3); (ii) the filing or receipt, as applicable, of any necessary governmental filings, consents or other approvals; (iii) the determination by counsel for the Corporation that the assignment of the rights, title or interests in, or obligations under, this Agreement to such Third Party would not cause a termination, default, loss or payment obligation under any security issued, or agreement entered into, by the Corporation prior to such transfer; and (iv) such Third Party executing a counterpart of this Agreement, and both such Third Party and the Sponsoring Company which is assigning its rights, title and interests in, and obligations under, this Agreement executing such other documents as may be reasonably requested by the Corporation (including, without limitation, an assignment agreement in form and substance acceptable to the Corporation in its reasonable discretion and containing the agreement by such Sponsoring Company to reimburse the Corporation and the other Sponsoring Companies for any fees or expenses required under any security issued, or agreement entered into, by the Corporation as a result of such assignment, including without limitation any consent fee or additional financing costs to the Corporation under the Corporation's then-existing securities or agreements resulting from such assignment). In the event that the Sponsoring Company and a Third Party have not entered into a definitive agreement to assign the interests specified in the Offer Notice to such Third Party within the later of one-hundred and eighty (180) days after the expiration of the Election Period or the deemed withdrawal of a conditional election by a Sponsoring Company under Section 9.183(b) hereof (if applicable) for any reason or if either the price to be paid by such Third Party would be less than 92.5% of the purchase price specified in the Offer Notice or the other material terms of such assignment would be more favorable to such Third Party than the terms specified in the Offer Notice, then the restrictions provided for herein shall again be effective, and no assignment of any rights, title and interests in, and obligations under this Agreement may be made thereafter without again offering the same to Sponsoring Companies in accordance with this Section 9.183.

ARTICLE 10

REPRESENTATIONS AND WARRANTIES

10.01. *Representations and Warranties.* Each Sponsoring Company hereby represents and warrants for itself, on and as of the date of this Agreement, as follows:

(a) it is duly organized, validly existing and in good standing under the laws of its state of organization, with full corporate power, authority and legal right to execute and deliver this Agreement and to perform its obligations hereunder;

(b) it has duly authorized, executed and delivered this Agreement, and upon the execution and delivery by all of the parties hereto, this Agreement will be in full force and effect, and will constitute a legal, valid and binding obligation of such Sponsoring Company, enforceable in accordance with the terms hereof, except as enforceability may be limited by applicable bankruptcy, insolvency, fraudulent conveyance, reorganization, moratorium or other similar laws affecting the enforcement of creditors' rights generally;

(c) Except as set forth in Schedule 10.01(c) hereto, no consents or approvals of, or filings or registrations with, any governmental authority or public regulatory authority or agency, federal state or local, or any other entity or person are required in connection with the execution, delivery and performance by it of this Agreement, except for those which have been duly obtained or made and are in full force and effect, have not been revoked, and are not the subject of a pending appeal; and

(d) the execution, delivery and performance by it of this Agreement will not conflict with or result in any breach of any of the terms, conditions or provisions of, or constitute a default under its charter or by-laws or any indenture or other material agreement or instrument to which it is a party or by which it may be bound or result in the imposition of any liens, claims or encumbrances on any of its property.

ARTICLE 11

EVENTS OF DEFAULT AND REMEDIES

11.01. *Payment Default.* If any Sponsoring Company fails to make full payment to Corporation under this Agreement when due and such failure is not remedied within ten (10) days after receipt of notice of such failure from the Corporation, then such failure shall constitute a "Payment Default" on the part of such Sponsoring Company. Upon a Payment Default, the

Corporation may suspend service to the Sponsoring Company that has caused such Payment Default for all or part of the period of continuing default (and such Sponsoring Company shall be deemed to have notified the Corporation and the other Sponsoring Companies that any Available Energy shall be available for scheduling by such other Sponsoring Companies in accordance with Section 4.032). The Corporation's right to suspend service shall not be exclusive, but shall be in addition to all remedies available to the Corporation at law or in equity. No suspension of service or termination of this Agreement shall relieve any Sponsoring Company of its obligations under this Agreement, which are absolute and unconditional.

11.02. *Performance Default.* If the Corporation or any Sponsoring Company fails to comply in any material respect with any of the material terms, conditions and covenants of this Agreement (and such failure does not constitute a Payment Default under Section 11.01), the Corporation (in the case of a default by any Sponsoring Company) and any Sponsoring Company (in the case of a default by the Corporation) shall give the defaulting party written notice of the default ("Performance Default"). To the extent that a Performance Default is not cured within thirty (30) days after receipt of notice thereof (or within such longer period of time, not to exceed sixty (60) additional days, as necessary for the defaulting party with the exercise of reasonable diligence to cure such default), then the Corporation (in the case of a default by any Sponsoring Company) and any Sponsoring Company (in the case of a default by the Corporation) shall have all of the rights and remedies provided at law and in equity, other than termination of this Agreement or any release of the obligation of the Sponsoring Companies to make payments pursuant to this Agreement, which obligation shall remain absolute and unconditional.

11.03. *Waiver.* No waiver by the Corporation or any Sponsoring Company of any one or more defaults in the performance of any provision of this Agreement shall be construed as a waiver of any other default or defaults, whether of a like kind or different nature.

11.04. *Limitation of Liability and Damages.* TO THE FULLEST EXTENT PERMITTED BY LAW, NEITHER THE CORPORATION, NOR ANY SPONSORING COMPANY SHALL BE LIABLE UNDER THIS AGREEMENT FOR ANY CONSEQUENTIAL, INCIDENTAL, PUNITIVE, EXEMPLARY OR INDIRECT DAMAGES, LOST REVENUES, LOST PROFITS OR OTHER BUSINESS INTERRUPTION DAMAGES, BY STATUTE, IN TORT OR CONTRACT, OR OTHERWISE.

[Signature pages follow]

OHIO POWER COMPANY'S RESPONSES TO
INDUSTRIAL ENERGY USERS-OHIO DISCOVERY REQUESTS
PUCO CASE NO. 14-1693-EL-RDR
SECOND SET

INTERROGATORY

INT-2-017 Other than the plants identified in AEP-Ohio's application and testimony, did AEP-Ohio consider adding additional plants and units into the PPA Rider?

RESPONSE

No.

Prepared by: Pablo A. Vegas

OMAEG EX. 1

Analysis of Operational Events and Market Impacts During the January 2014 Cold Weather Events

May 8, 2014
PJM Interconnection

OMAEG EX. 2

Contents

Executive Summary

January 2014 was an extremely challenging month for much of the U.S. energy industry, particularly the electricity and natural gas sectors. Power system operators, power producers and consumers – both within the PJM Interconnection[1] footprint and in surrounding regions – endured prolonged periods of bitterly cold temperatures that drove up energy use, increased uncertainty for grid operators and stressed available power supplies. Throughout January 2014, PJM experienced tight operational conditions and a significantly higher number of forced generator outages – compared to a more typical January – due to the extreme weather, mechanical problems and natural gas market inflexibility.

Eight of the ten highest winter demands for electricity on the PJM system occurred in January 2014. Peak demand for electricity was 35,000 megawatts, or 25 percent, higher than typical January peaks– an amount approximately equivalent to the electricity demand of Chicago, Washington, D.C. and Baltimore combined. On some days, even the lowest hours of demand were 10,000 MW higher than typical winter peak demands of recent years.

Although PJM and its members successfully met the unprecedented demand, heavy electricity use for heating and high natural gas prices sharply drove up the costs of wholesale power. For example, January 2014 total net billings to PJM members were one-third of the entire year's total net billings in 2013.

The Polar Vortex

The January 6-8 Polar Vortex brought prolonged, deep cold to the entire PJM footprint and surrounding regions. PJM set a new wintertime peak demand record of 141,846 MW the evening of January 7 while dealing with higher than normal generation outages. During the peak demand hour, 22 percent of generation capacity – including coal, gas and nuclear – was out of service.

The generation forced outage rate was two to three times higher than the normal peak winter[2] outage rate of around 7 to 10 percent. Equipment issues associated with both coal and natural gas units caused the greatest proportion of forced outages. Natural gas interruptions comprised approximately 25 percent of the total outages.

Reserves were tight during the Polar Vortex. Synchronized Reserves (those supplied to the system from resources that are synchronized/connected to the grid and able to load within 10 minutes) were at their lowest point the morning of January 7. For a five-minute period, synchronized reserves were reduced to about 500 MW, compared to a 1,372 MW PJM requirement. These are not, however, the only reserves available to PJM. During that hour, PJM had an additional 1,167 MW of primary reserves (reserves available in 10 minutes but not synchronized / connected to the grid) for a total of 1,667 MW of ten-minute reserves at the lowest point of the hour.

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1 PJM coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia. The Operations function of PJM (overseeing the flow of electricity) resembles an air traffic controller – PJM neither owns nor flies the planes, but instead makes sure all the planes can get where they need to go without incident. PJM does not own the transmission wires or the generators, but it directs the operation of those resources to serve electricity consumers. The Market function of PJM can be compared to a stock exchange. PJM neither buys nor sells, but operates the markets in which parties can conduct transactions.

2 Normal peak winter outages were defined by looking at most recent five years December through February forced outage rates.

Although reserves were low, several steps remained available to operators before electricity interruptions might have been necessary. For example, in the event of the loss of a very large generator or a spike in electricity demand on January 7, PJM could have implemented a temporary voltage reduction. A reduction in distribution system voltage, although unnoticeable to almost all consumers, can reduce the load by about 1,100-2,000 MW. In addition, PJM also has formal reserve sharing agreements with its neighbors (Northeast Power Coordinating Council and Virginia-Carolinas Reliability Agreement) that could have been called upon if needed.

Winter Storms

Following the Polar Vortex, a second series of winter storms and extremely cold weather hit the region January 17 through January 29. PJM used its experience from the Polar Vortex to prepare for operations during this second cold spell in preparing load forecasts and anticipating generator performance and outages.

In spite of this preparation, scheduling constraints in natural gas markets – combined with frigid weather across the region, very high power demand and the lack of alignment between natural gas and wholesale electricity markets – created extreme difficulty in scheduling natural gas-fired generation to meet demand.

Natural gas scheduling problems were the key contributor to operational challenges – and high operating reserve costs – during this second period of cold weather. For example, to ensure that gas would be delivered to some generators during the few hours per day they needed to be in service, generators were required to schedule gas deliveries and operate for a full day at extremely high prices – even if less expensive power was available. Natural gas scheduling issues caused most of the $597 million in out-of-market make-whole (uplift) charges for January 2014.

How Reliability Was Maintained

Throughout January, PJM employed a number of its pre-defined steps to maintain the stability of the grid and ensure a reliable power supply for consumers. PJM called on all available resources, issued public appeals for conservation and called on load management resources, which responded voluntarily because January was not yet part of the period when load management capacity resources were required to respond. However, even on the day with the tightest power supplies – January 7 – several steps remained before electricity interruptions might have been necessary.

During these periods of unprecedented winter demand, PJM undertook extensive advance communications to its stakeholders, state and federal officials and the public in order to ensure they had full information and awareness of system conditions. The value of increased communication and coordination of information was clearly demonstrated with states and stakeholders as both the public and the summer-only demand response customers were asked to voluntarily reduce demand.

Action Items

While PJM and its members met the challenges from the extreme January 2014 weather, the lessons learned will be used to improve operations and market processes. The PJM community will consider ways to:

- Improve generator availability and performance during extreme weather events,
- Implement performance verification or testing of generation in advance of winter operations,
- Continue to engage in discussions with industry and regulators to improve natural gas and electricity market alignment,
- Implement market mechanisms that encourage better generator availability, such as incentives for ensuring fuel availability or dual-fuel capability, and
- Review the cost allocation for uplift charges and investigate a mechanism to allocate uplift costs during emergency operations that minimizes volatility.

Organization of this Report

The following report provides the operational planning and actions and the market impacts of the extremely cold weather in the PJM footprint in January 2014. The report consolidates data and responses provided to stakeholders, Congress and the Federal Energy Regulatory Commission and provides additional analysis that PJM has conducted to better understand and learn from the cold weather operations.

The report is structured into discussions of the Polar Vortex of January 6-8, the Winter Storms of January 17-29, the operational conditions and ultimate market implications of the extreme weather. The final section shares recommendations.

Typical Preparation for an Operating Day

Beginning a week prior to an operating day, PJM creates and publishes a forecast of expected demand for electricity (load forecast) and monitors factors driving the load forecast, such as weather forecasts and historical patterns of usage. The forecast is updated multiple times every day leading up to the operating day as the driving factors are updated. Because some generators require long notification and start-up times (up to six days), PJM examines expected system conditions to determine if it is necessary to notify these generators that they are expected to be needed.

Approximately three days prior to an operating day, PJM's planning becomes more detailed. PJM staff begins studying transmission and generator outages, load forecasts, weather and other expected factors to prepare for expected conditions during the operating day. The expected system conditions dictate the amount of preparation required. (For example, due to the combination of the weather and the Martin Luther King Jr. Day holiday, preparations began early prior to the severe winter storm expected around January 21, 2014.) PJM will analyze, communicate, study and revise its analysis and operating strategy multiple times as needed as more information about an operating day becomes available. For instance, PJM may request that transmission outages in progress be restored as quickly as possible to prepare for extreme weather conditions and then will update the analysis to reflect these conditions.

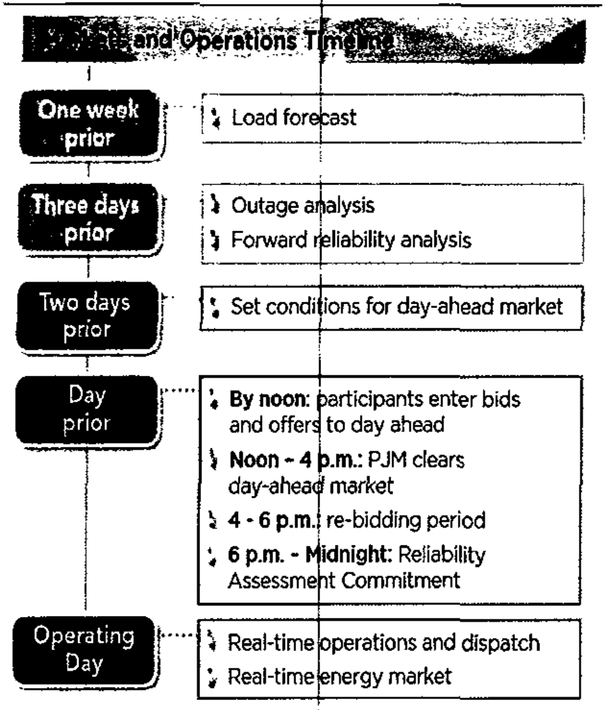
Two days prior to an operating day, PJM will begin to set up the conditions such as the expected outages and conditions for the operating day in the model for the Day-Ahead Energy Market. (The Day-Ahead Energy Market offers an opportunity for market participants to lock in their positions in advance of an operating day in a financially firm way to reduce their risk of exposure to real-time prices.)

Market participants have until noon of the day prior to the operating day to submit their bids and offers for the Day-Ahead Market. Several types of entities participate in the Day-Ahead Energy Market. Generation owners submit their offers to supply power and will adjust offers for factors such as the cost of fuel. Load serving entities will submit bids for their expected need for electricity for the operating day. For a typical operating day, a load serving entity often will procure 90 to 95 percent of its expected demand in the Day-Ahead Market with the remainder being held back to account for forecast uncertainty. Market participants also may submit various "virtual transactions," which are offers to buy or sell at particular locations that are not associated with physical generation or customers. Market participants typically use virtual transactions to hedge risk, mirror physical commitments or account for their expectations of market conditions.

When the Day-Ahead Market closes at noon on the day prior to an operating day, PJM begins the process of clearing the market, and the results are made available by 4 p.m. the day prior to the operating day. The Day-Ahead Market is cleared so that the cost to serve physical and virtual demand is minimized while still respecting the physical operating limits of the transmission system. Commitments in the Day-Ahead Market are financially binding on participants. Any differences between those commitments and what actually occurs in the operating day is addressed in the Real-Time Energy Market.

Between 4 p.m. and 6 p.m. the day prior to the operating day, generators which were not committed in the Day-Ahead Market can revise their offers to sell power. The window allows a generator to adjust its offer prior to the operating day to better reflect the cost of fuel. The uncertainty of both natural gas costs and availability makes these types of adjustments necessary and useful.

Figure 1: Market and Operations Timeline



As mentioned above, the load levels bid into the Day-Ahead Market typically do not meet the levels expected during the operating day. So, after 6 p.m. PJM begins the Reliability Assessment Commitment (informally called the "Reliability Run"), which ensures that adequate generation is committed to meet the demand plus reserves, while minimizing start-up and no-load cost. (Reserves are used to keep the lights on when unexpected events occur, such as a large generator going off line.) Using the most up-to-date weather forecast, load forecast, transmission facility and generator availability, and other information, PJM commits additional generation, if necessary, to satisfy both expected loads and the needed reserves for the operating day. PJM also performs additional reliability analysis to ensure all transmission facilities will be operated within their equipment limits when committing generation. During the severe winter weather events, PJM also communicated extensively with both generation owners and gas pipeline operators in order to adequately understand the likelihood that natural-gas-fueled generators would be able to procure the gas they needed to operate.

On a typical winter day, PJM's peak load for the day averages approximately 106,000 MW. Beyond the expected demand, PJM also will commit approximately 4,000 MW of reserves. In order to provide a sense of scale, the combination would be enough power to serve about 91,200,000 homes. (One megawatt is enough power to serve *800 homes. A typical large nuclear power plant provides 1,000 MW of energy.)*

Leading up to and throughout the operating day, PJM examines updated information and system conditions and acts to continually balance generation with the need for electricity and maintain adequate reserves to prepare for unexpected issues. PJM manages changes from day-ahead commitments and schedules in the Real-Time Energy

Market using the offers from generation resources and demand resources to jointly minimize the cost of energy and reserves while maintaining energy balance and respecting the limits of the transmission system. Any differences in generation or demand from the Day-Ahead Energy Market commitments are cleared at price levels determined by the Real-Time Energy Market.

The Polar Vortex, January 6-8

Conditions

The January 6-8, 2014, Polar Vortex brought prolonged, deep cold temperatures throughout the entire PJM Interconnection footprint. System operators had to contend both with record high electricity use and much higher than normal generator outages. Nevertheless, power supplies were maintained without interruption.

Demand for electricity because of heating needs set a new wintertime peak demand record of 141,846 MW the evening of January 7. However, during the peak demand hour, 22 percent of generation capacity – including coal, gas and nuclear – was out of service. The generation forced outage rate was two to three times higher than the normal peak winter outage rate of around 7 to 10 percent. During the coldest two days of the period, PJM called upon all available resources: all available generation was scheduled, demand response was called on throughout PJM, shortage pricing went into effect when reserves were low, and emergency power was purchased above normal offer caps. Demand response and shortage pricing raised locational marginal prices[3], which reflected real-time grid conditions and costs.

This section will detail the advance actions PJM took to prepare for the extremely cold weather. The events that occurred during the operating days of January 6-8 will be discussed along with the actions taken by PJM to maintain reliability. Finally, this section will review the market outcomes as a direct result of the conditions and PJM operator actions.

Advance Preparations

Weather and Load Forecast

In the days leading up to the January 2014 Polar Vortex, PJM expected extremely cold weather. Starting Tuesday, December 31, 2013, meteorologists were tracking a weather front likely to hit the PJM region on January 6-7. On January 2, PJM began tracking a snow storm for January 4-6, to be followed by extreme cold. PJM's staff meteorologist and load forecasting experts reviewed the load forecasting computer models, which forecasted peak demand of 134,000 MW for the evening of Tuesday, January 7, and revised the internal forecast, used for operational planning, up to 140,000 MW based on PJM load forecasting experts' worst-case analysis.

One lesson PJM implemented from the September 2013 Heat Wave[4] was to alert PJM's load forecasting experts when the temperature forecast, an input into the load forecasting engine, changes more than 8-10 degrees from the previous day. In such scenarios PJM can experience corresponding load forecast errors. On December 31, PJM load

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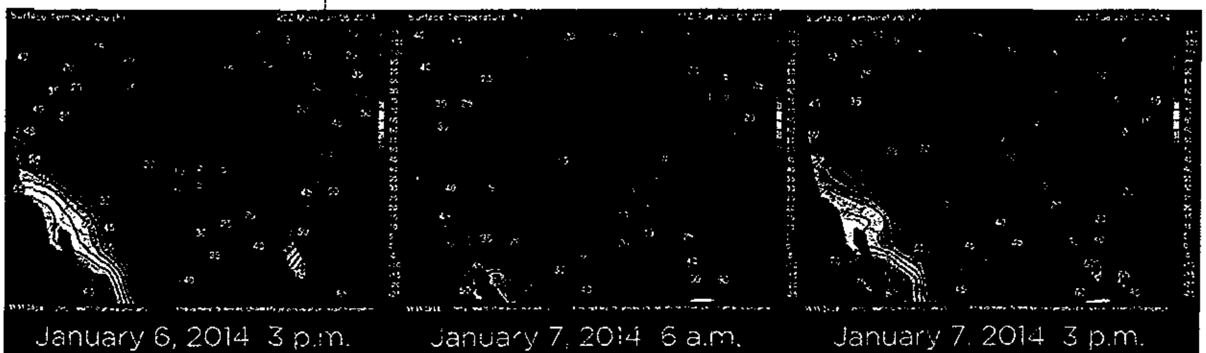
3 Locational marginal price (LMP) is the wholesale price for electricity on different parts of the system. This price includes a system energy price, transmission congestion cost, cost of marginal losses and the effect of reserve shortages.

4 http://www.pjm.com/~/media/documents/reports/20131223-technical-analysis-of-operational-events-and-market-impacts-during-the-september-2013-heat-wave.ashx

forecasting experts were alerted to large temperature changes expected on January 6. Using historical load curves, load and weather forecast models, and experience, the load forecast was adjusted to 140,000 MW for reliability study and generation commitment purposes. This revised load forecast was communicated to PJM's transmission and generation owners.

Figure 2: Cold Temperatures Envelope the Region



Source: University of Illinois at Urbana-Champaign

In response to actual temperatures projected to fall near or below 10 degrees Fahrenheit, PJM issued Cold Weather Alerts. (A Cold Weather Alert is the first step PJM takes to prepare PJM staff and PJM member company personnel and facilities for expected extremely cold weather conditions.) PJM issued the first Cold Weather Alert on Friday, January 3 for January 6 and 7.

Operational Planning and Advanced Communications

PJM held conference calls with transmission and generation owners as well as neighboring entities to ensure full awareness of the pending weather and the projections for load. PJM instructed members to begin taking steps to ensure availability of all transmission and generation resources, which includes cancelling planned outages, recalling existing outages where possible and communicating to PJM any concerns about equipment, fuel, unit restrictions, etc. It was very important for PJM to get the messages out prior to the weekend when staffing would have been at reduced levels, making it more difficult to prepare. PJM requested units which could not acquire primary fuel to switch to alternate fuel.

Each day leading up to the Polar Vortex, PJM updated its operating plan based on new information on system conditions. PJM issued alerts, increased the frequency of communications with appropriate parties (transmission owners, generators, natural gas pipelines and other relevant stakeholders) and finalized staffing plans.

Waiver to Communicate Freely with Natural Gas Pipelines

In expectation of the high natural gas demand due to extremely cold weather and the potential for subsequent increases in both electric generation and heating later in the winter, PJM sought to better coordinate operations with the natural gas pipelines by sharing market sensitive information.[5] On January 3, 2014, PJM submitted two requests

[5] The Federal Energy Regulatory Commission recently had issued Order 787 allowing such information exchange, but there had not been sufficient time to implement the changes to PJM's governing documents before the severe weather events.

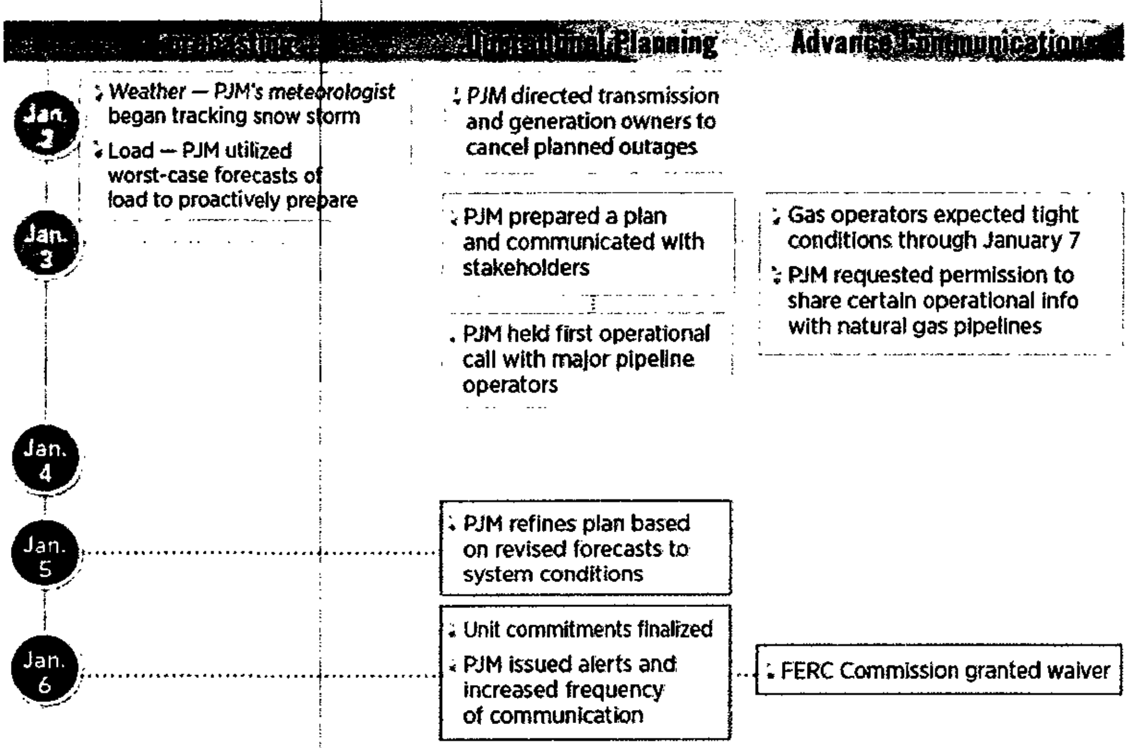
to the Federal Energy Regulatory Commission for waivers of certain provisions of PJM's governing documents that would permit PJM to share certain non-public information with natural gas pipeline operators during the forecasted extreme weather conditions. The waivers, the first covering one week in duration and the other until March 31, 2014, were to allow such communications until appropriate language could be incorporated into the PJM governing documents. FERC responded promptly to PJM's filing, which enabled those communications to commence quickly.

On January 3, PJM held its first operational call with the major pipeline operators to discuss natural gas conditions through the week starting January. 5. Overall, natural gas pipeline operators expected the capacity on the pipelines and the natural gas market to be very tight and expressed doubt any interruptible transportation would be available through most of the coming week and particularly on January 7. However, pipeline operators indicated that firm transportation customers would still be served. Throughout the course of the Polar Vortex and the Winter Storm later in the month, PJM held conference calls with all available interstate pipelines and had individual discussions with some of the pipelines.

Several pipeline operators also issued notices that limited non-firm natural gas deliverability. More information about pipeline notices can be found in

Appendix C: Natural Gas System Critical Notices. The effect of these pipeline issues in the electricity market becomes apparent when examining the generation which was unable to operate on January 7 as discussed further in the Generator Performance: Outages subsection on page 24 of this report.

Figure 3: PJM Preparation for the Polar Vortex



Emergency Procedures

PJM reliably met the demand on January 6 employing several Emergency Procedures and market mechanisms. Although the 131,142 MW peak load on the evening of January 6 was not one of PJM's top ten peak winter load days, it was roughly 25,000 MW above a typical winter peak day. The load curve on January 6 also was very unusual and challenging as the extreme cold front moved into the PJM territory during the day. Typically, PJM winter load curves produce two distinct peaks. This twin peak consists of one peak in the morning and one in the evening, both usually similar in magnitude and each approximately four hours long with a slight valley in between. As the extreme cold front moved into the PJM region throughout the day, the load shape looked more like a summer day, with a lower morning valley that ramped up throughout the day. This steep slope from valley to peak challenged the operators to keep up with the load that was coming in fast and high. PJM needed to bring on many units that had not run in months: close to 50,000 MW (approximately 175 – 200 units) in a short period and during extreme cold. The speed and magnitude of the load change coupled with units' start failures (approximately 45 percent for combustion turbines) and other issues caused by extreme weather made the day extremely challenging.

Figure 4: PJM Load, January 6, 2014

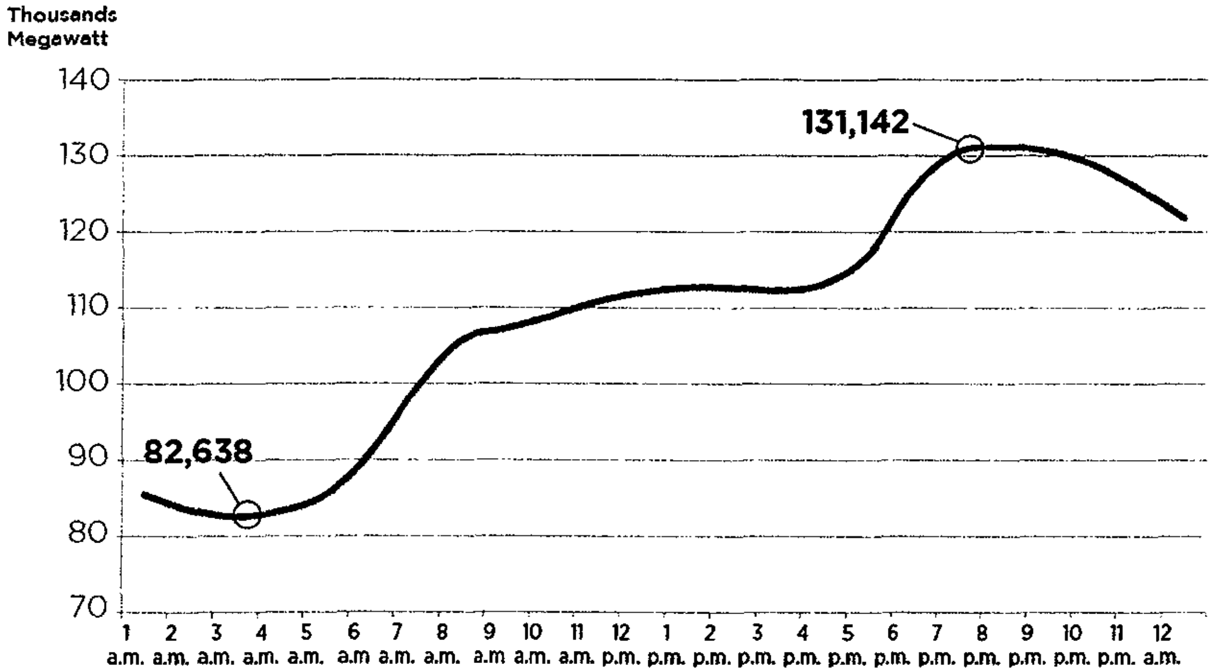
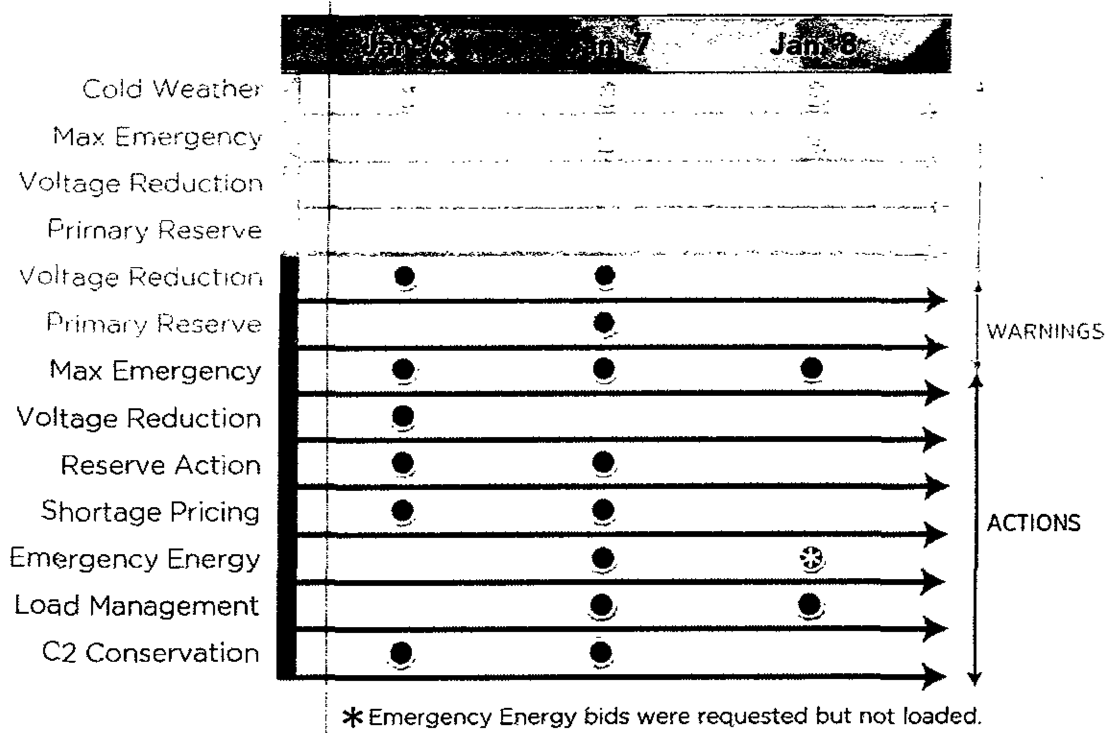

Thousands
Megawatt
140
130
120
110
100
90
80
70
131,142
82,638
1 a.m. 2 a.m. 3 a.m. 4 a.m. 5 a.m. 6 a.m 7 a.m. 8 a.m. 9 a.m 10 a.m. 11 a.m. 12 p.m. 1 p.m. 2 p.m. 3 p.m. 4 p.m. 5 p.m. 6 p.m. 7 p.m. 8 p.m. 9 p.m. 10 p.m. 11 p.m. 12 a.m.

Figure 5: Emergency Procedures during the Polar Vortex



A detailed listing of emergency procedures taken can be found in Appendix E: Emergency Procedures in January.

In addition to the Cold Weather Alerts issued prior to January 6, PJM issued a Max Emergency Generation Alert[6] for Tuesday, January 7 for the entire RTO. PJM also issued at the same time a North American Electric Reliability Corporation (NERC) Energy Emergency Alert (EEA) Level 1 to inform PJM's neighboring systems that PJM expected to run all available generating resources to meet the demand for electricity. The Max Emergency Generation Alert occurs when PJM forecasts that current reserves may not be high enough to meet the PJM operating reserve requirement. At the time, PJM's Energy Management System was calculating the operating reserve requirement to be 9,939 MW and estimated the reserve amount to be 8,075 MW. PJM issued this alert to notify all capacity and energy resources that they likely would be needed on Tuesday during the peak hours.

At just about 5 p.m. on Monday, January 6, PJM initiated a synchronized reserve event to maintain system reliability in response to the nearly concurrent, but unrelated, loss of two large generating units totaling 1,562 MW.[7] The Northeast Power Coordinating Council provided 775 MW of shared reserves to PJM from 5:01 p.m. to 5:15 p.m. to assist with the unit losses.

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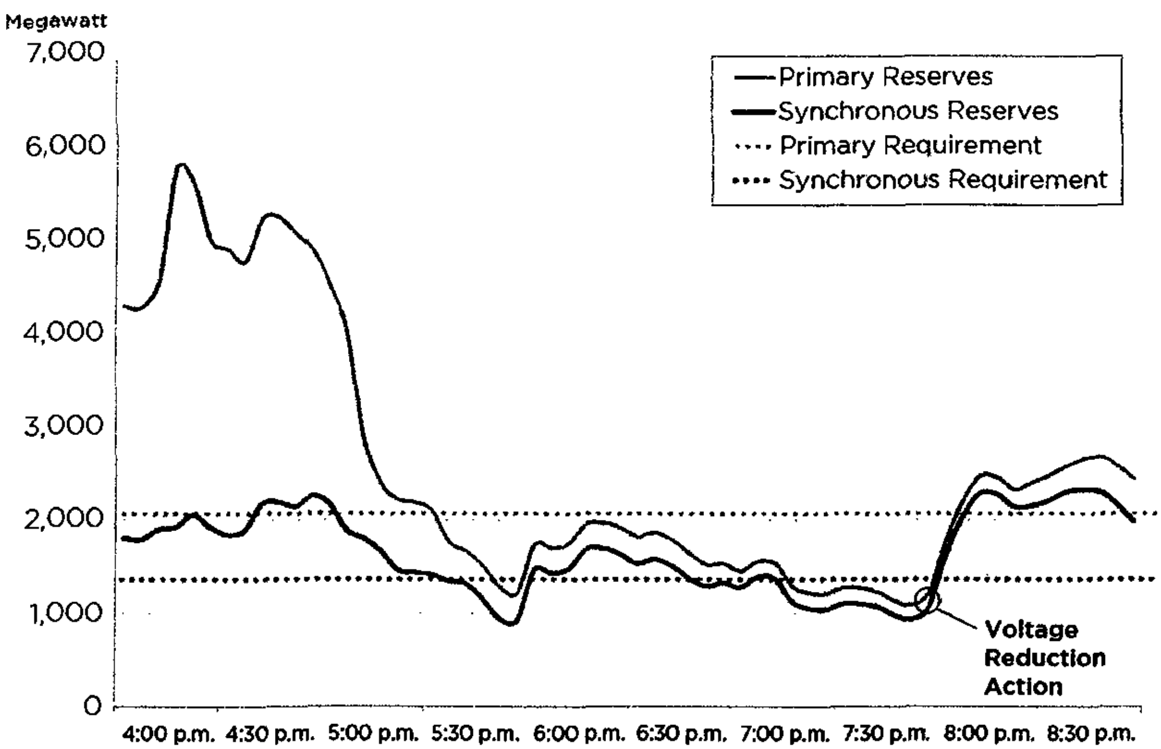
6 The *Maximum Emergency Generation Alert provides a day-ahead alert that system conditions may require generation to be loaded above* the maximum economic level and that use of the PJM emergency procedures may be implemented. This requirement varies each day and is used by PJM to ensure adequate backup generation is available for the grid in the event of an emergency. Operating reserve is generation available from either offline or online units within 30 minutes of PJM's request. Reserves are scheduled to meet operating reserve requirements in the Day-Ahead Market. PJM Manual 13, Emergency Operations, Section 2.

7 Synchronized reserve is either generation that can begin producing electricity within 10 minutes or customer use of electricity that can be removed from the system within 10 minutes. This procedure is used to direct all available generation resources to quickly increase (or decrease for demand response resources) their output to respond to the request.

In addition to the two large units that were lost, between 5:00 p.m. and 7:30 p.m. on Monday, January 6, PJM lost an additional 6,400 MW of capacity due to unit trips, unplanned generator reductions and fuel restrictions. At that time, PJM issued a Voltage Reduction Warning[8] followed immediately by a Maximum Emergency Generation Action, both for the entire RTO. This real-time Voltage Reduction Warning notified members that the available synchronized reserve was less than the requirement and that a voltage reduction might be required. Synchronous reserves were approximately 900 MW compared to a 1,372 MW PJM requirement at the time. Approximately 20 minutes after issuing the warning, PJM issued a Voltage Reduction Action. Shortage pricing[9] was triggered by this Voltage Reduction Action. The combination of the load reduced by the Voltage Reduction Action and the power imports attracted by the Shortage Pricing event helped restore primary reserves to above 2,400 MW.

Figure 6: Voltage Reduction Restores Reserves



In addition to the emergency procedures that PJM implemented, PJM also communicated throughout the day with its neighboring operators and reliability coordinators to ensure the overall reliability of the Eastern Interconnection. PJM's neighboring entities were affected by the same extremely cold temperatures and generator forced outage rates experienced by PJM. The evening of January 6, power imports to PJM averaged 1,000-1,500 MW compared to more typical power imports of 4,000-5,000 MW.

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8 A Voltage Reduction Warning (and Reduction of Non-critical Plant Load) informs members that Synchronized Reserve is less than required and present operation has deteriorated such that a voltage reduction may be required. It is trigger when actual Synchronized Reserve is less than the Synchronized Requirement. All secondary and primary reserve (except megawatts in Max Emergency) are first moved to Synchronized Reserve status.

9 Shortage Pricing is a methodology for accurately pricing energy and reserves so the resulting prices reflect the state of the system both approaching and during times of reserve shortages.

PJM participates in two shared reserves groups[10], Northeast Power Coordinating Council (NPCC) and the Virginia-Carolinas Reliability Agreement (VACAR). PJM supplies shared reserves when requested by those groups, and PJM also requests shared reserves to help recover from the loss of internal PJM generation. Below are the times on January 6 when PJM relied on electricity reserve imports from other systems to meet its own energy needs, outside of normal operations:

- Monday, January 6, 2014: 5:01 p.m.-5:15 p.m., PJM received 775 MW from NPCC.
- Monday, January 6, 2014: 11:20 p.m.-11:34 p.m., PJM received 800 MW from NPCC.

Shared Reserves were cancelled once PJM restored the generation/load balance with internal resources and market-priced imports.

On Monday, January 6, 2014, 9:15 p.m.-9:56 p.m., PJM provided 163 MW of shared reserves to NPCC.

Operations – January 7

Based on the actual conditions experienced on Monday evening, load coming in as high and as fast as it did and high forced outage rates (approximately 17 percent[11] during the Monday evening peak), PJM took additional steps to prepare for operations on Tuesday, January 7. The Cold Weather and Max Emergency Alerts for Tuesday remained in place. In addition PJM issued a Level 2 Statement for Cold Weather for the entire RTO. This statement is a request to the public to conserve electricity because of developing power supply problems. PJM issued the Level 2 Statement to the PJM transmission owners the evening of January 6, indicating the request would be for Tuesday, January 7, during the morning and evening peaks.

Tuesday, January 7, was the coldest day of the week across the PJM footprint. Daily low temperature records were set or tied in Philadelphia, Richmond, Pittsburgh, Cleveland and Columbus. High temperatures were in the single digits and low teens for many areas of PJM, and lows were 10-30° F below normal. On January 7, PJM experienced the highest winter peak demand in its history.

10 Reserve sharing groups allow entities to share reserves on a routine basis and deploy those reserves to recover from a system event such as loss of generation.

11 http://www.pjm.com/~/media/documents/reports/20140113-pjm-response-to-data-request-for-january%202014-weather-events.ashx

Figure 7: Minimum Temperature for Each Day in January 2014: Columbus, Chicago, Philadelphia and Richmond

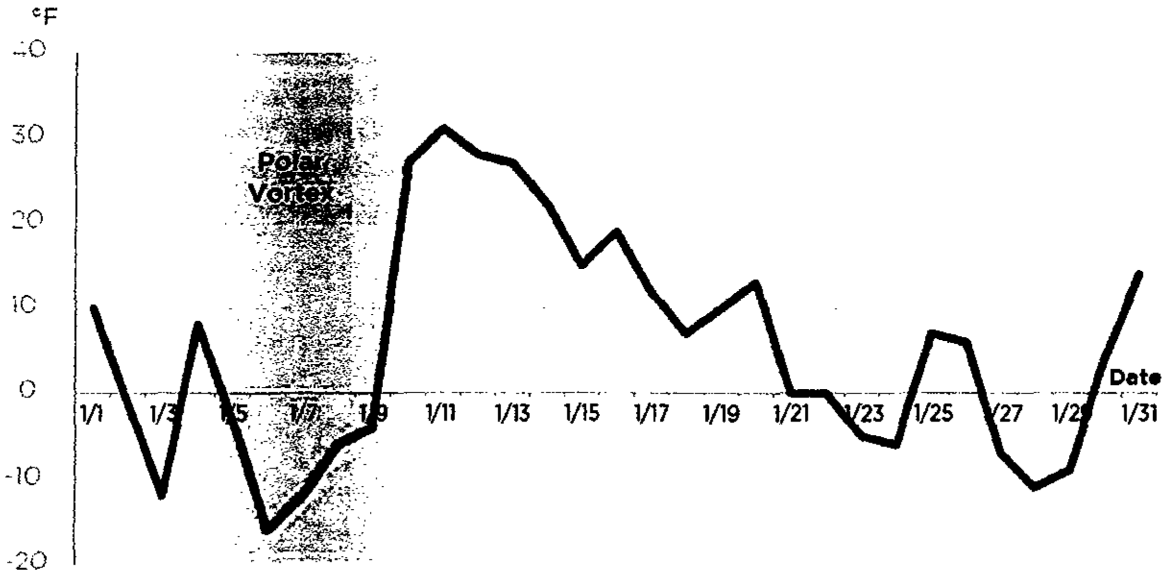
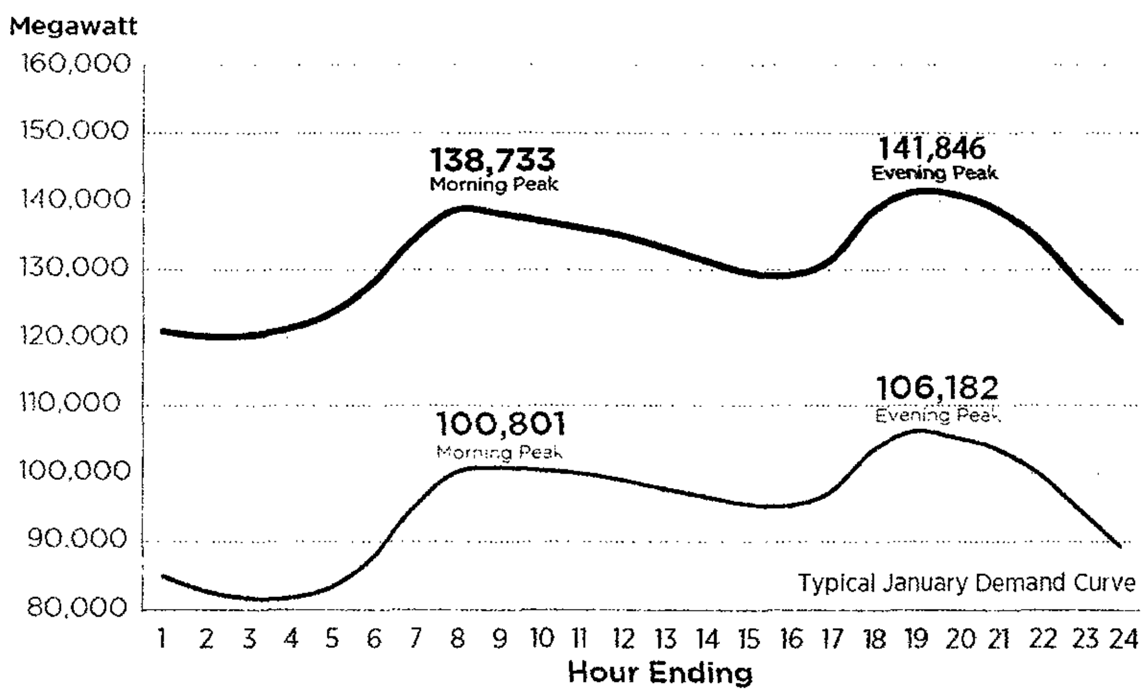


Figure 8: January 7 – Peak Load vs. Typical Load (Winter load peaks twice each day.)

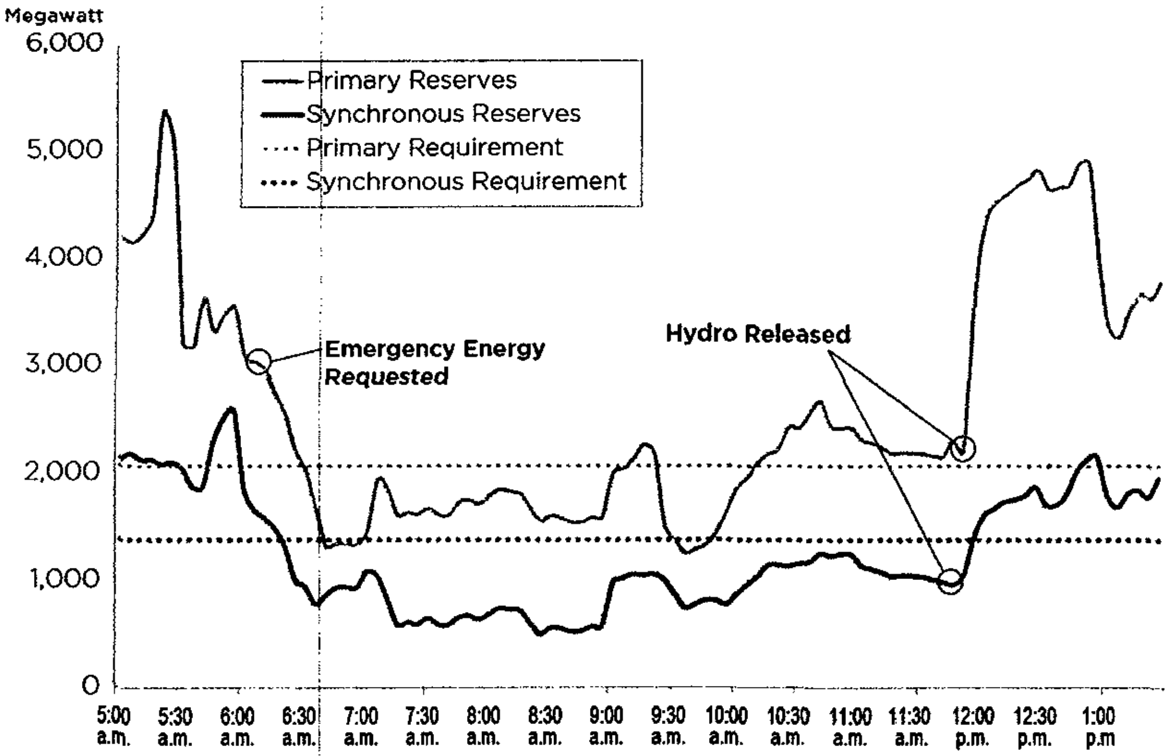


The PJM demand curve for January 7, 2014, was 35,000 MW higher than typical of a January peak load.

Emergency Procedures – January 7

Early on Tuesday morning, PJM initiated a number of steps to prepare for the operating day. First, at 12:55 a.m., PJM issued a Primary Reserve Warning[12] for all day Tuesday. This warning was issued to warn members that the available primary reserves were forecasted to be less than the required amount for the peak later that day and that operations were becoming critical. PJM estimated 1,950 MW of primary reserves were available compared to its 1,980 MW reserve requirement. The Primary Reserve Warning triggered shortage pricing. (See Energy Prices and Shortage Conditions Market Outcome on page 27 for more discussion on shortage pricing.) PJM also issued a Voltage Reduction Warning at 2:51 a.m. for the morning peak to allow time for transmission owners to staff substations as appropriate.

Figure 9: Reserves – January 7, 2014



While reserves were tight, a Voltage Reduction Action, one of the next emergency procedures to be implemented, was not needed to meet the evening peak because of a combination of the other emergency procedures issued, such as Max Generation Action (at 3:00 p.m.), Load Management and pricing changes triggered by shortage pricing, which attracted additional power imports.

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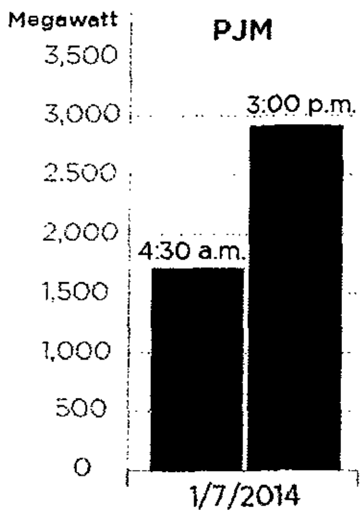
12 The purpose of a Primary Reserve Warning is to warn the members that the primary reserve is less than required and operations are getting critical. It is issued when the primary reserve is less than the primary reserve requirement but greater than the synchronized reserve requirement. Transmission and generation dispatchers move secondary reserve to primary status (so that it can be producing electricity within 10 minutes from a request) and schedule all available generation. Secondary reserve is reserve capability that can be fully supplying electricity within 10 to 30 minutes following the request of PJM. In addition, Transmission and generation dispatchers ensure that all deferrable maintenance or testing affecting capacity or critical transmission is halted. By deferring maintenance or testing, the equipment can remain online to provide energy, and the system will not have to draw from emergency backup sources.

More at: http://www.pjm.com/~/media/training/core-curriculum/ip-ops-101/ops-101-capacity-shortages.ashx. Slide #22

Demand Response

On January 7, 2014, PJM deployed Emergency Load Management, or demand response, twice. PJM's dispatch personnel first notified DR resources at 4:30 a.m. with a reduction time of 5:30 a.m. for short lead-time registrations[13] and 6:30 a.m. for long lead-time registrations[14]. The load management event ended at 11:00 a.m. For the second event, dispatch personnel notified DR resources at 3:00 p.m. with a start time of 4:00 p.m. and 5:00 p.m. for short and long lead-time registrations, respectively. The second event of January 7 ended at 6:16 p.m. Emergency Load Management reductions were mandatory for only the summer months and voluntary during the winter period.

Figure 10: Estimated Demand Response during the Polar Vortex



The responding, voluntary demand response resources, while only about 20 percent of the demand response capacity, performed very well. Deploying the Emergency Load Management in addition to the Max Generation Action at 3:00 p.m. January 7 not only made additional resources available for the evening peak but also attracted significant additional power imports into the PJM system. The load management deployment in particular attracted imports because it set high prices in PJM ($1,800/ MWh). This combination of emergency procedures and PJM market responses helped PJM successfully meet an all-time record winter peak of 141,846 MW at 7:00 p.m. January 7 with no reliability issues.

Emergency Energy Purchases – January 7

PJM also has the ability to purchase emergency energy from neighbors. Given the amount of forced outages and the Primary Reserve Warning in effect for the day, PJM requested Emergency Energy bids for January 7 between 6:00 a.m. and 11:00 a.m. PJM obtained emergency energy from the following neighboring regions:

- 600 MW: 6:00 a.m. - 11:00 a.m., five hours duration, from the New York Independent System Operator.
- 500 MW: 6:00 a.m. - 9:00 a.m., three hours duration, from Midcontinent Independent System Operator

[13] Short lead-time applies to any site registered in the PJM demand response program as a demand resource type that needs up to one hour lead time to make its reductions.

[14] Long lead-time applies to any site registered in the PJM demand response program as a demand resource type that needs one to two hours lead time to make its reductions.

On January 7, PJM also provided shared reserves to neighbors during the following times:

- 200 MW: 6:27 a.m. - 7:30 a.m. to VACAR
- 200 MW: 8:45 a.m. - 9:28 p.m. to VACAR
- 200 MW: 8:49 a.m. - 10:35 a.m. to Duke Energy Progress

PJM had to recall the 200 MW of shared reserve obligations to VACAR on January 7 due to PJM's own internal reserve shortages caused by additional units tripping off-line (approximately 900 MW). At this point, PJM was at its lowest reserve level with approximately 500 MW synchronous reserves and 1,167 MW primary reserves available. Once reserves were restored, PJM offered and reactivated the 200 MW shared reserve flow to VACAR. While it may appear counter-intuitive to be import emergency energy from some neighbors while sharing reserves with other neighbors, system conditions across much of the Eastern Interconnection required such teamwork and the ability to adjust plans in real time as the situation demanded.

Operations – January 8

PJM continued to prepare for cold weather operations on Wednesday, January 8. Forecasted load was 134,107 MW at 9:00 a.m. with forecasted temperatures slightly higher across the RTO than the previous day. The expected conditions prompted PJM to issue a Cold Weather Alert and a Maximum Emergency Generation Alert. As the morning load pickup began, PJM developed a plan to implement specific emergency procedures in order to meet expected system load. At 5:00 a.m., PJM called for voluntary demand response resources and posted a NERC EEA Level 2 to notify other reliability coordinators of its actions.

A Maximum Emergency Generation Action was declared in conjunction with the implementation of voluntary demand response, but generation owners were advised not to load maximum emergency capability until PJM specifically contacted them. PJM also issued a request for emergency energy bids at 5:30 a.m. in order to identify options for meeting system load and to see if the bids were more economic than voluntary demand response resources. As system load was trending below forecasted load in the morning hours, PJM reevaluated the operational plan and cancelled the voluntary demand response. PJM did not need to issue any additional emergency procedures on January 8. Actual load at the morning peak was 133,288 MW at 8:00 a.m. with actual temperatures 4-7 degrees higher across the RTO than on the previous day.

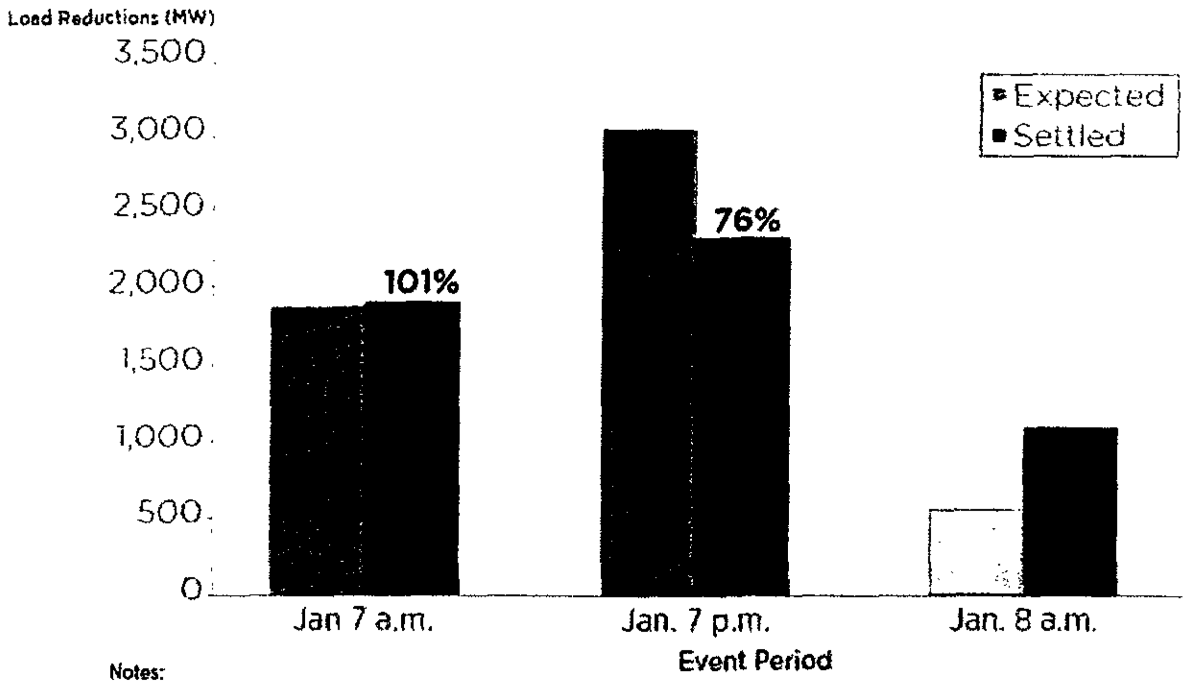
Operational Observations and Challenges

Demand Response and Renewables

Although operational conditions were tight during the Polar Vortex, some variables exceeded PJM's expectations in real-time: the availability and response of voluntary demand response, the response of the stakeholders to the public appeal for conservation, and the performance of wind-powered generation.

Demand response, although not required to respond during the winter this year, did respond and assisted in maintaining the reliability of the system. In fact, the total amount of demand response provided was larger than most generating stations. During the Polar Vortex, PJM called on demand response three times – the morning and evening of January 7 and the morning of January 8 throughout the RTO. Even though demand resources were not obligated to respond during this period, close to 25 percent of the demand response resources registered in PJM did respond and helped PJM manage the grid on the all-time winter peak day. This experience demonstrates the year-round value of demand response.

Figure 11: Polar Vortex Demand Response Performance

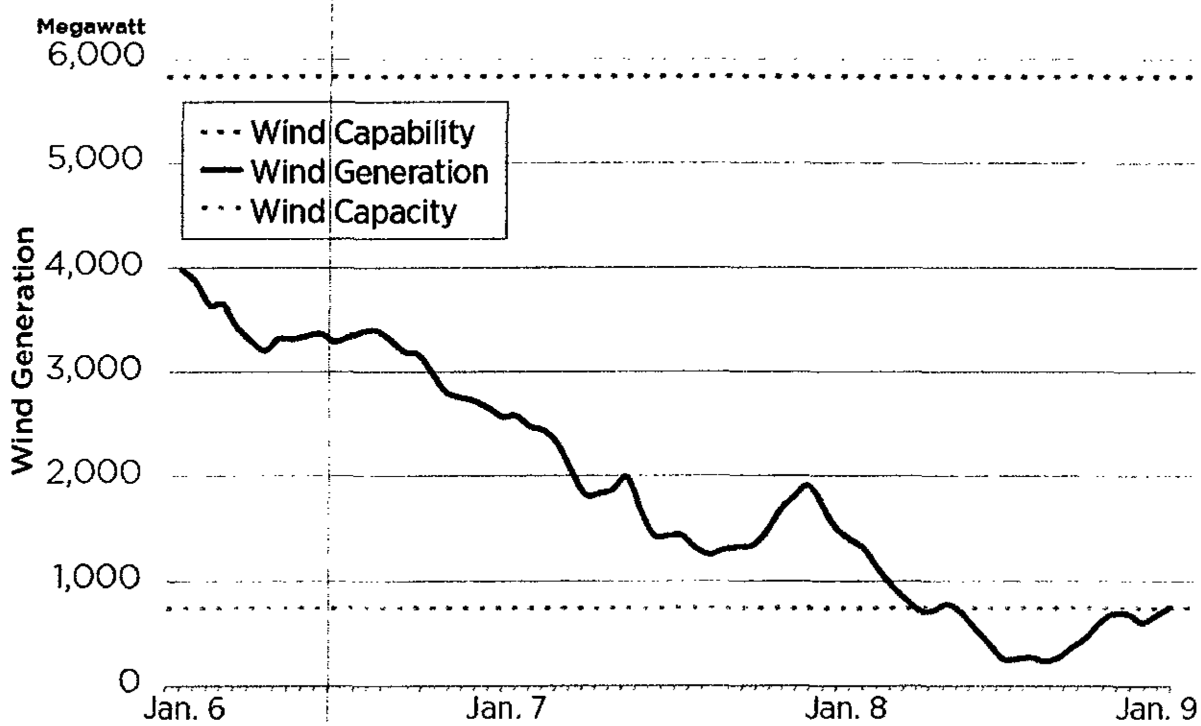


Notes:
1. DR events dispatched during non-compliance period.
2. Expected Energy Load Reductions (MW) - CSP reported estimate based on current market rule.
3. MW value is average hourly load reduction for non-ramp in hours.
4. Event on Jan. 8 was cancelled by PJM prior to official start time. In order to honor the Emergency DR resource 2-hour minimum down time, PJM allowed CSPs to settle if their load reduction had started prior to cancellation and/or needed to reduce for 2 hours. PJM estimated amount of DR that needed to continue to reduce for 2 hours. "Performance" for this event cannot be measured based on the circumstances of this event

PJM issued a public appeal for conservation for the entire RTO, the evening of January 6 for Tuesday, January 7, during the morning and evening peaks. The statement was shared with the communications departments of transmission owners, which in turn communicated to their stakeholders. While PJM does not currently have a measurement of the energy conservation achieved, it believes the request for conservation had a positive impact on the real-time conditions.

PJM also saw up to 4,000 MW produced by wind power during the peak load periods of January 6-7. Figure 12: shows that wind power produced at a level above the calculated wind capacity, (typically 13 percent of total wind capability). The wind power produced had a positive impact on supply and contributed to PJM's ability to maintain reliability.

Figure 12: Polar Vortex Wind Generation



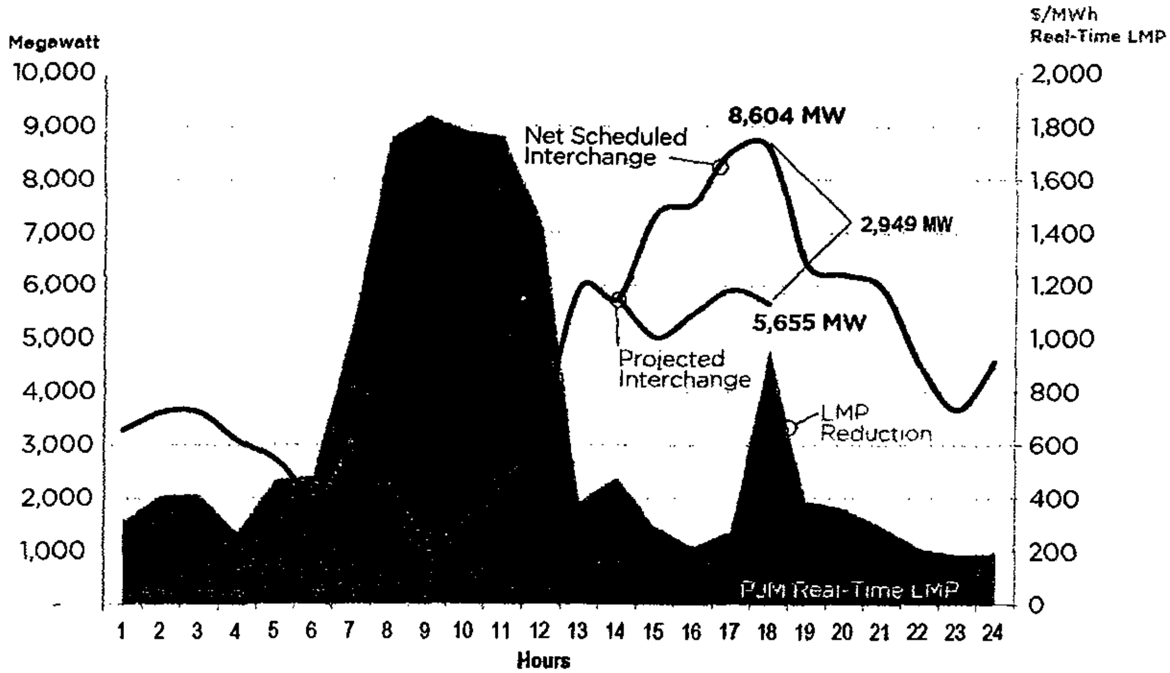
Managing Interchange

Managing interchange, or energy transfers across the RTO, was a challenge during the Polar Vortex, particularly during the afternoon of January 7. PJM expected (based on energy imports scheduled four hours ahead) about 5,600 MW of interchange into PJM during the evening peak. PJM received almost 3,000 MW more than expected. Hourly energy prices in PJM during the evening peak were $750-$800, and prices in MISO were approximately $400-$500 less than in PJM. The NYISO's prices were approximately $50-$100 less than PJM's prices. Market participants responded to the disparity in neighboring prices and began importing power into PJM during the evening peak. In particular, imports from MISO increased significantly when compared to imports during the morning peak.

When PJM receives more energy transferring into the RTO than expected, the market becomes flooded with supply, and prices drop accordingly. This interchange volatility changed the situation for which PJM had planned and impacted energy prices, generation dispatch and costs.

Accurately forecasting interchange is a challenge. PJM operators can see only current energy transfers across the system with no certainty of end time or advance notice of future swings. PJM had generation operating with the expectation of a lower level of imports given the conditions across the grid. Imports increased substantially in response to the expectation of higher locational marginal prices set by demand response. This increase in supply caused LMPs to drop, and the generation PJM had operating for reliability was left operating at costs above the locational marginal price, resulting in uplift payments to these generators. Though not a reliability concern, the situation impacted the economics of the system, which will be discussed further in the Uplift subsection on page 44.

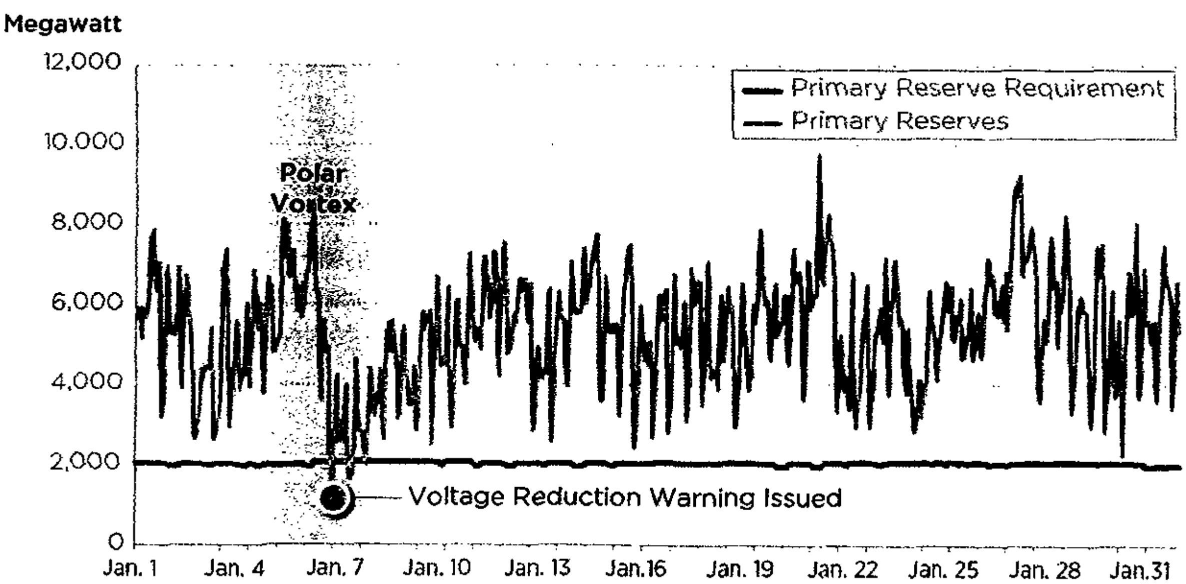
Figure 13: Interchange and Locational Marginal Prices on January 7, 2014



Managing Reserves

PJM had adequate reserves for most of January – with the exception of the evening of January 6 and the morning of January 7 when available reserves dipped below the PJM reserve requirement prompting PJM to issue a series of emergency procedures to ensure adequate reserves on the system. The reserve shortfalls largely were due to a combination of generator outages and extremely cold weather demand. See Figure 14: for January's primary reserves compared to the reserve requirement.

Figure 14: Primary Reserve and Requirement – January 2014



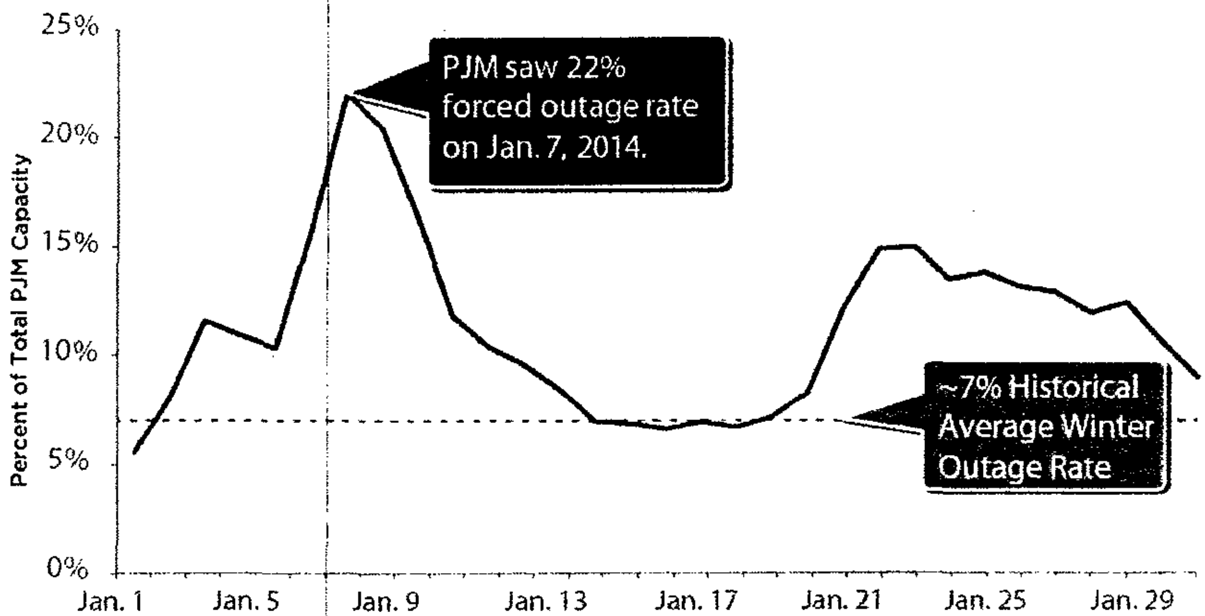
When PJM has a sustained shortfall of its primary reserve capability, a Primary Reserve Warning is issued as notification of the reserve shortage. On the evening of January 6, PJM additionally issued a Voltage Reduction Warning and Action to maintain reliability. If needed, PJM could have initiated additional emergency procedures to regain its reserve capability. Following the Voltage Reduction Action, primary reserves were restored above the requirement. PJM also had available shared reserves from NPCC and VACAR during this period.

Generator Performance: Outages

Unplanned generator shutdowns and the inability of generators to start – due to the cold, the stress of extended run times, natural gas interruptions and fuel-oil delivery problems – challenged grid reliability and adequate power supplies during the month. A generator's inability to run due to any type of unexpected mechanical or fuel issue is considered a forced outage. Forced outages on January 7, 2014, were 94 percent of the all outages that day.

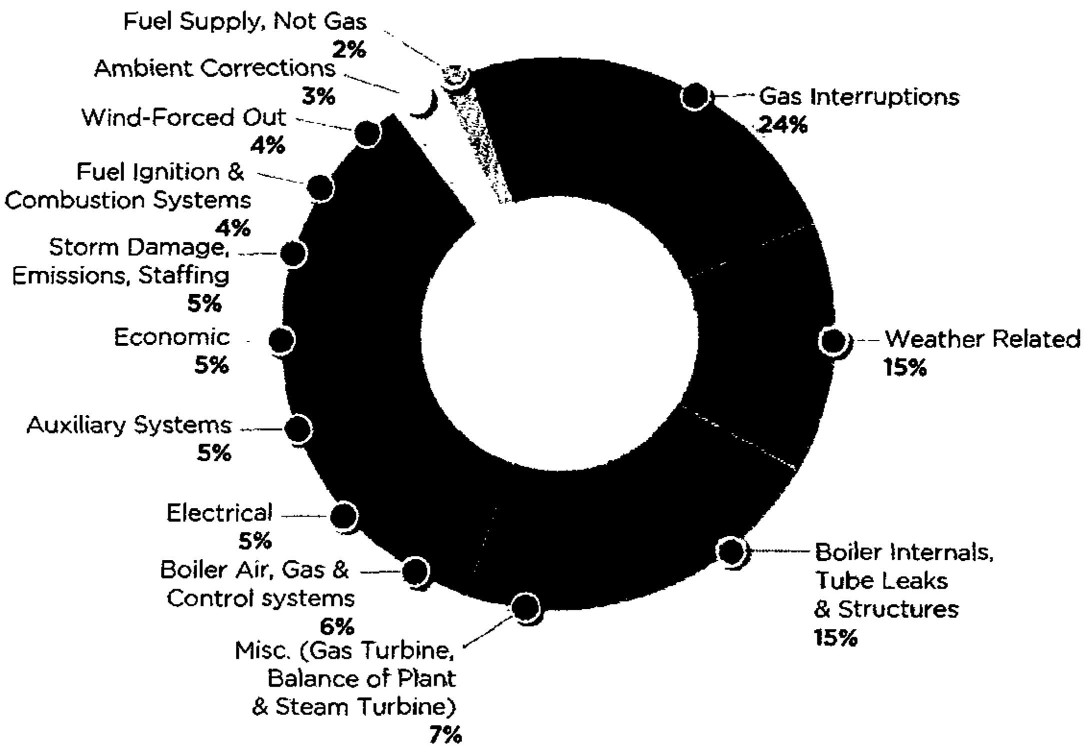
PJM experienced very tight operational conditions and a significantly higher number of forced outages, due to both mechanical problems and natural gas deliverability, throughout January 2014 as compared to a more typical January. At the all-time winter peak at 7 p.m. on January 7, PJM experienced a 22 percent forced outage rate, which was far above the historical average of 7 percent, with a total of 40,200 MW unavailable due to forced outages.

Figure 15: Generator Outage Rate – January 2014



All conventional forms of generation, including natural gas, coal and nuclear plants, were challenged by the extreme conditions. Generators are required to submit outage data after the outage has occurred. Figure 16: shows that the 42 percent of forced outages were due to equipment failures. The other key reason (24 percent of the forced outages) was a lack of fuel to start up and/or run generating units.

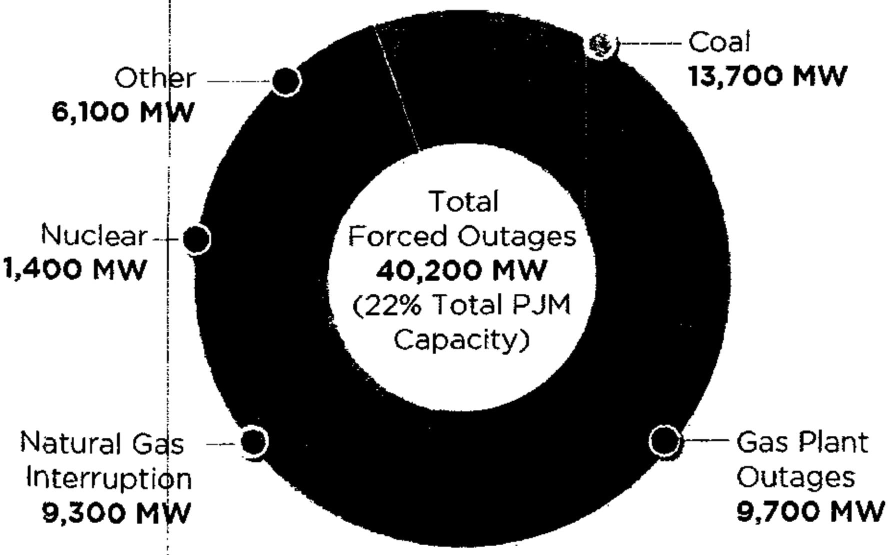
Figure 16: Causes of Forced Outages – January 7, 7:00 p.m.



The breakdown of forced outages by primary fuel type shows that natural-gas-fired generators accounted for 47 percent of the unavailable megawatts and coal-fired generators were 34 percent. For a frame of reference, in PJM, gas-fired plants represent 29 percent of total generation (in megawatts), and coal-fired plants represent 41 percent.[15] These unavailable megawatts were due to either the generator's entire output being unavailable or a limitation on the amount of megawatts the generator could supply to the system.

[15] Installed capacity as of December 31, 2013

Figure 17: Outages by Primary Fuel – January 7, 7:00 p.m.



The 9,300 MW of generation that was unavailable due to natural gas interruptions is a larger amount than PJM reported immediately after January 7. Subsequent to January, PJM worked with generation owners to further validate the outage reasons, and, based on these additional discussions, natural gas issues were found to be larger than initially reported largely due to other generation fuel types being dependent on natural gas and the natural gas infrastructure. An example is a generator that burns oil but that needs natural gas to start up. In a few cases, this startup gas was not available. Please see the Lessons Learned and Recommendations section on page 53 for PJM's preliminary recommendations relative to generation forced outages.

Communication

PJM implemented additional communication procedures based on lessons learned from the September 2013 heat wave and put those practices into effect, such as improved coordination and communication with PJM stakeholders. Internally, PJM activated a new Operation Event Response Team, a cross-divisional group designed to help prepare for, respond to and communicate about operational events, such as capacity emergencies and severe weather. This team was in place nearly every day in January not only to provide PJM dispatch personnel additional analysis and data but also to coordinate information through the appropriate internal and external channels.

PJM communicated with state commissions, state emergency management agencies and state consumer advocates before, during and after key operational events. PJM provided information about system conditions and emergency procedure alerts, warnings and actions via email and group conference calls in addition to ad hoc discussions.

PJM also provided power supply status updates to member communications staff counterparts, held conference calls with member communicators and created and distributed news releases and media advisories. In addition, advisories were provided to the FERC throughout the day during each of the cold weather events in January.

Market Outcomes: Polar Vortex

Energy Prices and Shortage Conditions

As explained above, PJM issued a Voltage Reduction Action on the night of January 6 and a Primary Reserve Warning on January 7. Both actions triggered shortage pricing, a market rule that accurately prices energy and reserves so the resulting prices reflect the state of the system both approaching and during times of reserve shortages.[16]

Shortage Pricing is triggered under either of the following conditions:

- The amount of available reserves is below the reserve requirement for a predetermined amount of time and dispatch systems confirm that the shortage exists. This situation can be due either to the available synchronized reserve megawatts being less than the requirement or available primary reserve megawatts less than required
- A Voltage Reduction Action or a Manual Load Shed Action is implemented.

PJM operators triggered shortage pricing by calling the Voltage Reduction Action across the entire RTO on the evening of January 6, and shortage pricing was triggered by an RTO reserve shortage on the morning of January 7.

Locational marginal prices are determined based on the cost to provide the next increment of energy while respecting the primary and synchronized reserve requirements. PJM's real-time dispatch system and LMP calculation systems include operating reserve demand curves for both primary and synchronized reserves, which are used in the calculation of LMPs to reflect both the price of energy and the price of reserves in an area experiencing a reserve shortage. This coordination is necessary because providing another megawatt of energy will cause an additional megawatt of reserve shortage.

On January 7, 2014, LMPs exceeded $1,800 per megawatt-hour. The price of $1,800 was set by emergency demand response offers, which means that demand response participants responded to calls for emergency energy and high prices to voluntarily curtail their use of electricity in exchange for curtailment payments. Because of the higher offer caps for demand response[17], LMPs may reach $1,800 per megawatt-hour without the existence of a reserve shortage. In January, there were instances where emergency demand response set the price at $1,800 either for the energy component of the locational marginal prices or for congestion.

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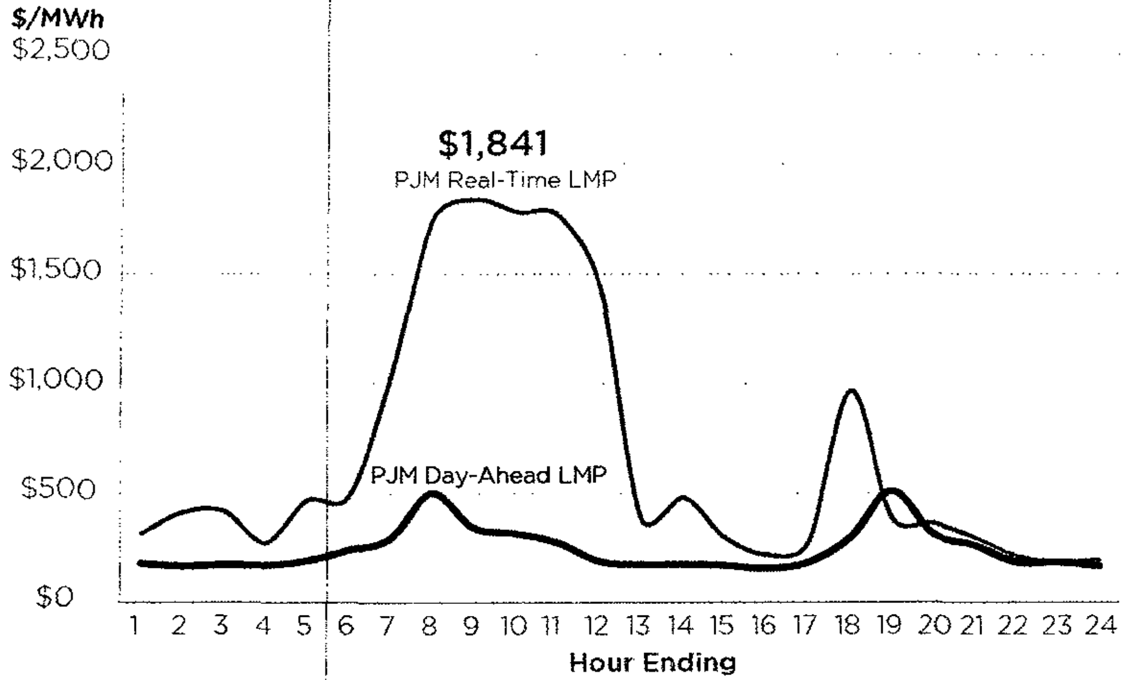
[16] For more information on the shortage pricing rules, view training material PJM previously has provided at http://www.pjm.com/markets-and-operations/energy/shortage-pricing.aspx.

[17] PJM initially had filed to limit demand resources to the legacy $1,000/megawatt-hour offer cap that has existed for some time for all resources. The FERC conditionally approved PJM's filing subject to several adjustments including the removal of the $1,000/MWh offer cap for capacity demand resources. As a result, demand resources are not limited to the $1,000 offer cap that applies to generation resources. Instead, these resources can offer up to $1,000 plus two times the reserve penalty factor. For the 2013-2014 delivery years, the penalty factor is $400. So, the offer cap applicable to demand resources is $1,800.

Figure 18: Locational Marginal Prices in Shortage

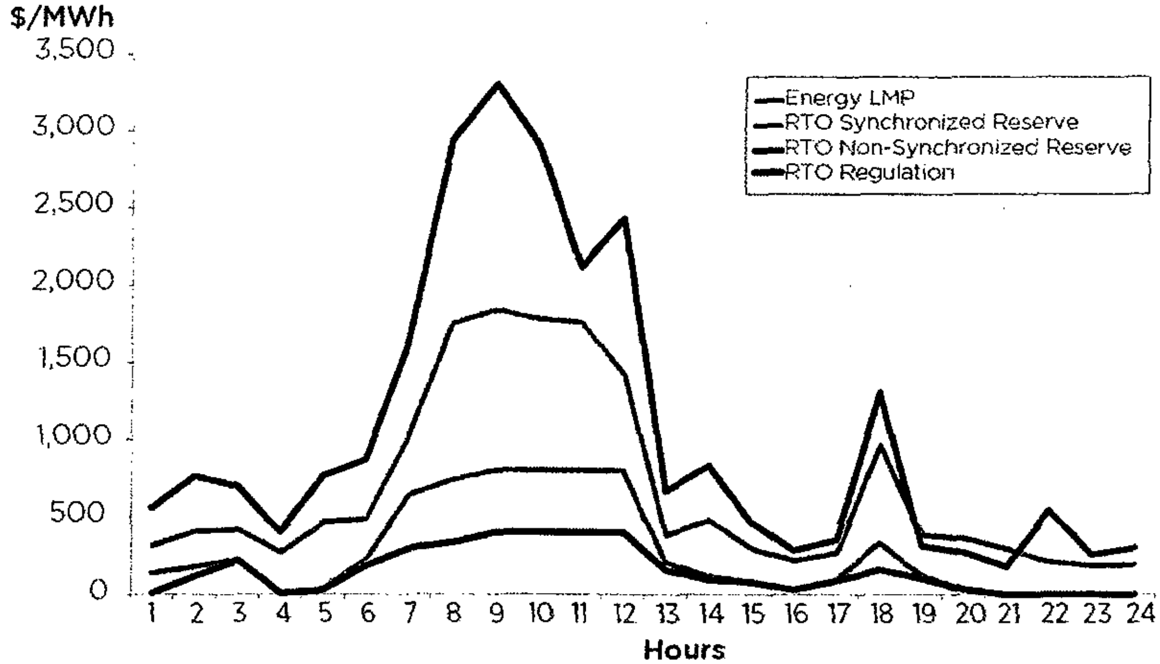


Real Time Locational Marginal Prices are calculated based on five minutes intervals. Although generation usually is the marginal resource setting the price, on January 7, demand response set prices for 63 five-minute energy pricing intervals during the day. Additional information on interval analysis of prices can be found in Appendix A: Locational Marginal Pricing Marginal Unit Type Intervals.

Ancillary Services: Regulation, Synchronized and Non-Synchronized Reserve

During the Polar Vortex, high prices for regulation, synchronized and non-synchronized reserves occurred at the same time as high real-time energy LMPs. During these stressed conditions, ancillary service prices increased as the reserve margin decreases, and system capacity competes to meet the ancillary services requirement while maintaining power balance.

Figure 19: Ancillary Service Price and Energy Price

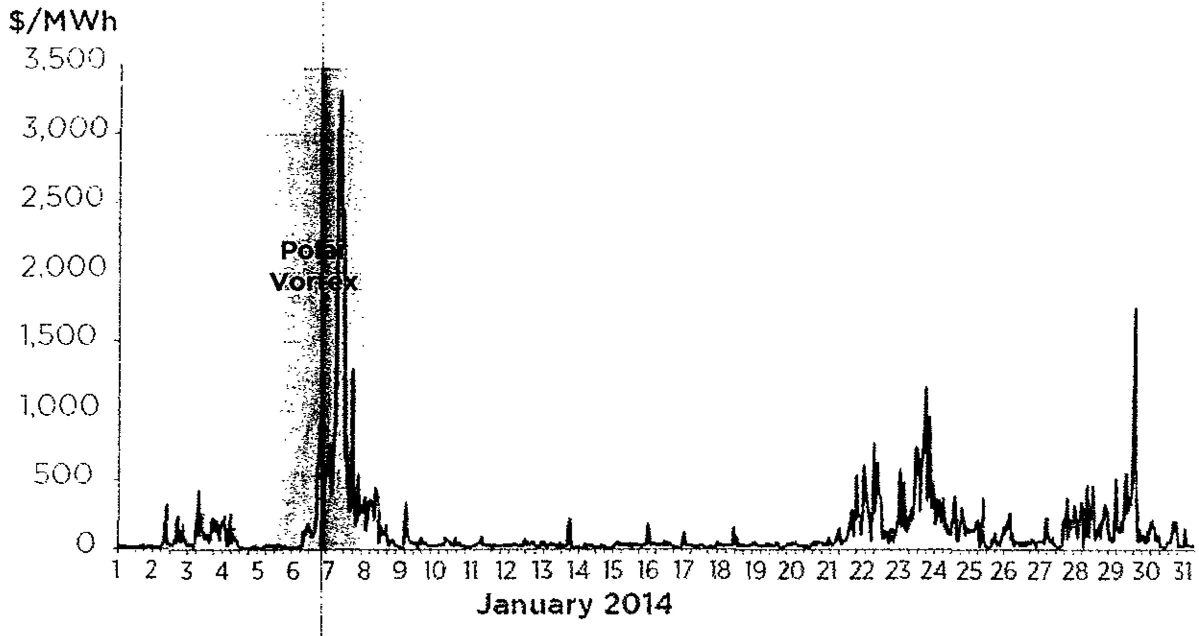


Regulation

Regulation service corrects for short-term changes in electricity use that might affect the stability of the power system. It helps match generation and load and adjusts generation output to maintain the desired system frequency of 60 hertz.

In October 2012, PJM implemented a new market structure called Performance Based Regulation, which aligns compensation with actual performance for resources that provide regulation service. Resources are compensated for their accuracy, speed and precision of response in providing regulation service to the system.

Figure 20: Regulation Prices



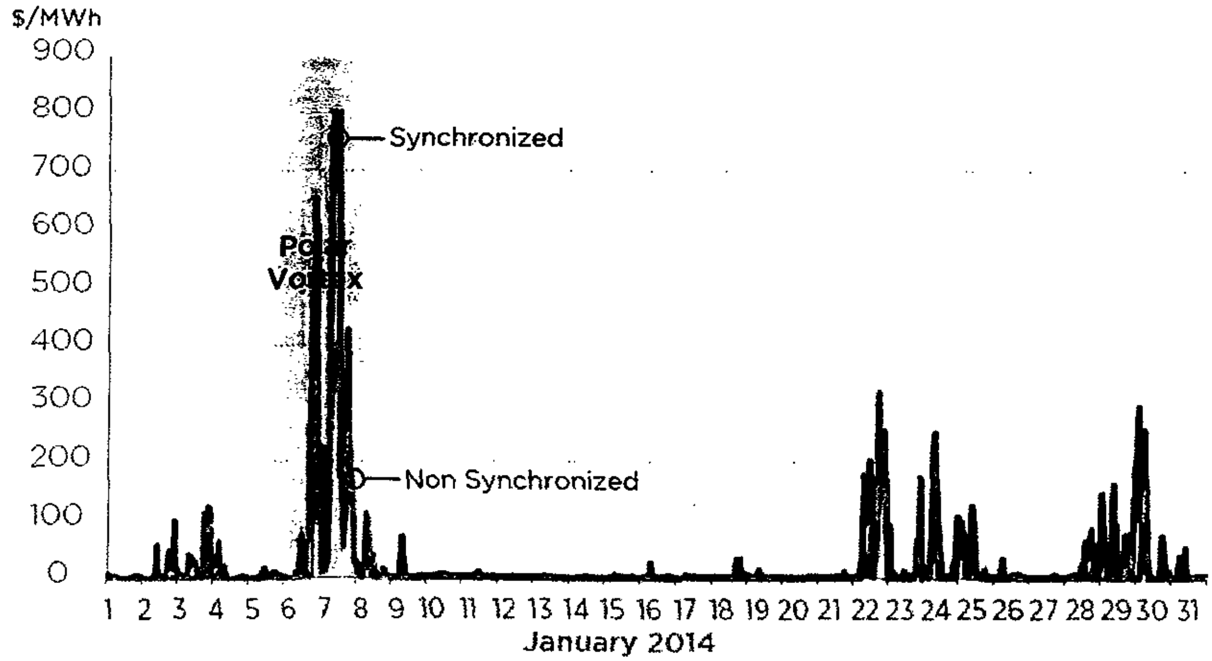
Regulation lost opportunity cost is the revenue foregone or increase in costs relative to the energy market for providing regulation service. Performance Based Regulation was designed to calculate and include resource specific regulation lost opportunity cost in the regulation market clearing price on a real-time five-minute basis (similar to real-time locational marginal prices). Real-time locational marginal prices in excess of $1,800 per megawatt-hour caused the high regulation market clearing price of $3,296 per megawatt-hour. This high price occurred as PJM triggered shortage conditions.

The regulation price spike seen during shortage pricing periods on January 6 and 7 also can be attributed to the poor performance factor in the regulation market as high-performing generators were being used for energy and reserves instead of regulation. The poorer performance factor inflates the total regulation price. Increasing the performance score requirements is discussed in the Lessons Learned and Recommendations section. The total credit paid for regulation price and lost opportunity cost not included in the regulation price was approximately $65 million for the month of January 2014.

Reserves

As displayed below, synchronized and non-synchronized reserve prices hit their maximums, $800 and $400 respectively, on January 7, 2014. These prices reflected system conditions during shortage pricing. The total Synchronous Reserve Tier One Market Price Credit and Synchronous Reserve Lost Opportunity Cost Credit was $87,890,200. Total non-synchronous reserve cost was nearly $6 million for January 2014.

Figure 21: Synchronous and Non-Synchronous Reserve Prices



Winter Storm, January 17-29

Conditions

A second, longer cold weather period in January 2014 again challenged the PJM system and operators. Prolonged cold temperatures January 17-29 came with a snow storm that dropped about a foot of snow on the East Coast. While, during the Polar Vortex, power supply issues centered on the unavailability of generation because of forced outages, during this second cold period, the key contributor to operational challenges was scheduling natural gas-fired generation to meet demand.

Having experienced the month's previous generator startup problems and a far above average 22 percent forced outage rate, PJM planned for similar generator performance as well as limits on the natural gas infrastructure. The scheduling of natural gas-fired resources became increasingly difficult through this period because of the rigid and expensive terms and conditions generators needed to accept in order to procure gas. Certain gas-fired generators notified PJM that they could get gas only if they committed to operate at a fixed output for an extended period of 24 hours or more in some cases. The fact that the period included two weekends – one of them a holiday weekend – exacerbated the fuel procurement-related situation. The timing difference between the gas and electricity markets also resulted in generation owners having to commit to buy gas before knowing whether their units would be scheduled to operate.

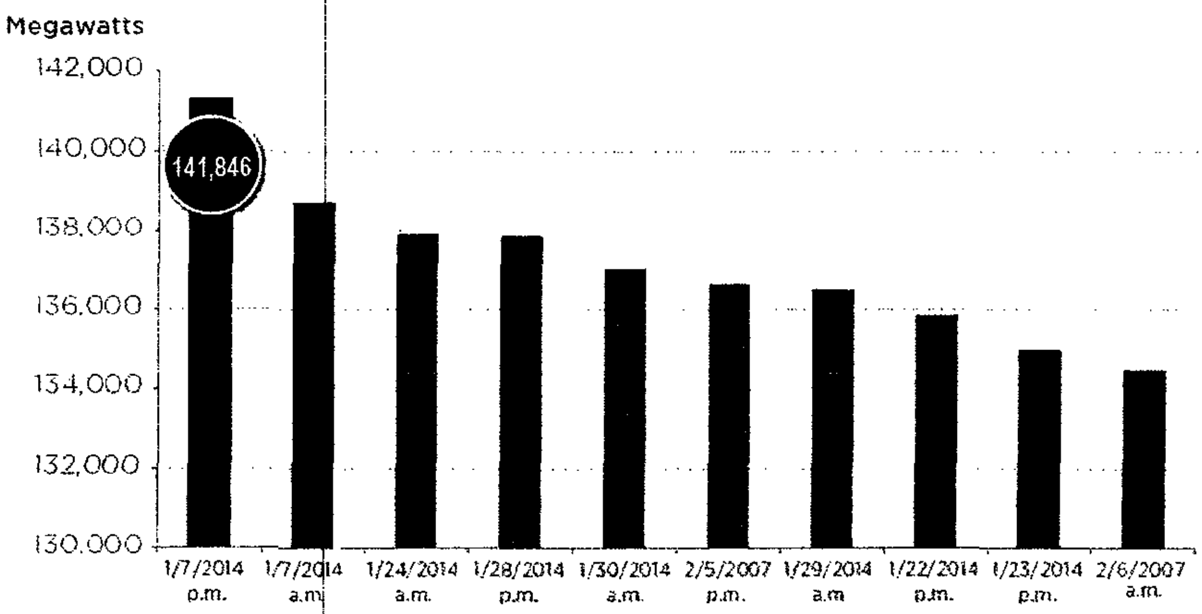
Meanwhile, spot natural gas prices soared; for example, on January 22 spot natural gas prices were 27 times the previous four months' average. Alternative fuels (usually oil) were a challenge for dual-fuel units for reasons that included fuel deliverability or minimum allowed run times because of emission limits. Because of the resource *limitations, PJM made scheduling decisions without pricing certainty to ensure that sufficient resources were* available to meet forecasted conditions.

Reliability was preserved during the entire month of January, but with record high out-of-market (uplift) costs. The costs were higher at the end of January because of resource fuel limitations, high natural gas prices, contractual constraints of gas units and the uncertainty of demand and of resource availability.

Weather and Load Forecast

The January 2014 Winter Storm had a more extended duration compared to the Polar Vortex earlier in the month. Extreme weather conditions were predicted during the last two weeks of January. As shown in Figure 22:, PJM reached eight of the top 10 winter peak demands in all of PJM's history in the month of January 2014. Six of these peaks were set in the later part of January during the Winter Storm.

Figure 22: Top 10 Historic Winter Peak Demands



Near-term weather projections indicated that this stretch of cold weather would be both as severe as the Polar Vortex and much longer in duration. However, when the Winter Storm dropped over a foot of snow along the East Coast, it decreased load as many people stayed home due to work and school cancellations. Because the severity and impact of storms on the population are variables that often cannot be predicted, load forecasters and system operators often cannot consider these variables when committing generation to meet the expected load and reserve requirements. As a result, more generation may be scheduled than is needed in real time if the forecasted load does not materialize, as was the case on January 21 and January 29 because of the snow storm. The market impact of this forecasting effect is discussed in Load and Weather Impact to Markets on page 51.

Operational Planning and Advanced Communications

Based on the load forecasts, PJM developed an operating strategy based on real-time operations experienced during January 6-8. The strategy anticipated high forced outage rates again and considered the amount of voluntary

Demand Response available, performance from renewables and the potential relief from a public appeal for conservation.

PJM held conference calls with transmission and generation owners as well as neighboring entities to ensure full awareness of the pending weather and the load projections. Similar to actions taken during the Polar Vortex, PJM instructed its members to take steps to ensure availability of all transmission and generation resources, which included cancelling planned outages and recalling existing outages where possible, and communicating to PJM any concerns about equipment, fuel, unit restrictions, etc. PJM requested units which could not acquire their primary fuel to switch to the alternate fuel. PJM also recognized the need to plan for an extended reliance on fuel-limited and environmentally-limited generation. To account for this need, PJM closely coordinated with generator owners to ensure fuel-limited and/or environmentally-limited units were placed into the maximum emergency generator status and then scheduled to run only when needed.

Natural Gas Markets Coordination

Because temperatures were expected to match the lows of early January, going into the Winter Storm, PJM was concerned about having sufficient generation. Low temperatures would increase the demand for electricity for heating and strain the gas pipelines serving residential heating load.

The following operators of pipelines issued critical notices restricting natural gas availability in the PJM footprint. The amount of megawatts of generation capacity in PJM which could have been impacted is in parentheses:

- ANR (TransCanada) in the Chicago area (approximately 2,550 MW)
- Columbia in Ohio and western Pennsylvania (approximately 5,460 MW)
- Dominion in Ohio, Pennsylvania, Maryland and Virginia (approximately 8,680 MW)
- Natural Gas Pipeline of America in Commonwealth Edison (approximately 1,125 MW)
- Texas Eastern in Ohio, Pennsylvania and New Jersey (approximately 2,215 MW)
- Transcontinental in Virginia; Washington, D.C.; Maryland; Delaware; Pennsylvania and New Jersey (approximately 2,310 MW)

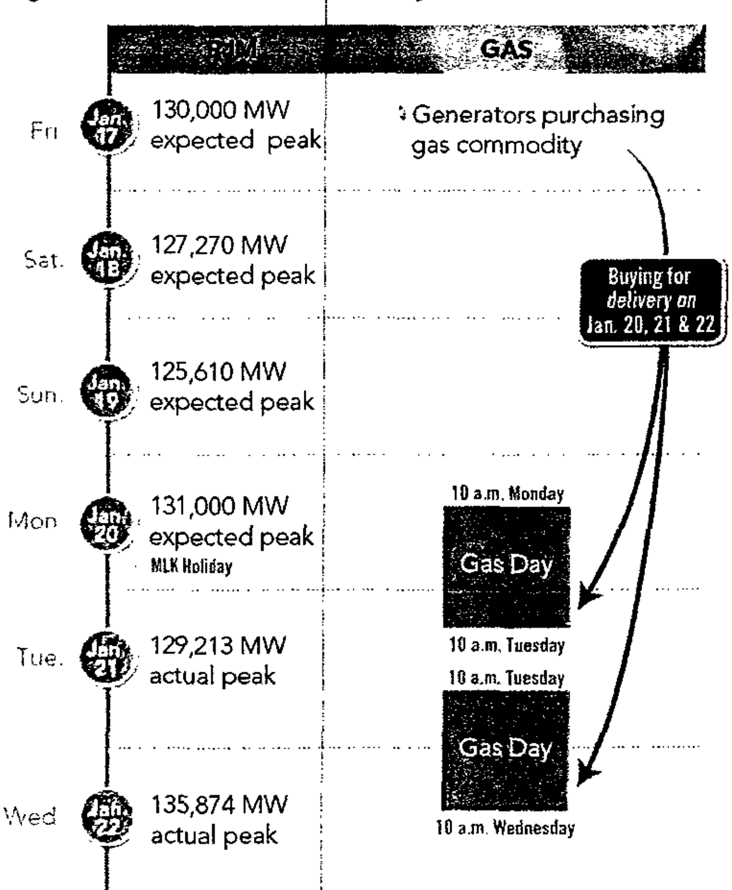
A timeline of critical notices on the natural gas pipelines in the PJM footprint can be found in

Appendix C: Natural Gas System Critical Notices.

In preparation for tighter gas conditions, PJM coordinated with gas pipelines and generation owners to ensure sufficient resources were available. A challenge with this coordination was the differences between the timing of generators' required natural gas purchase commitments and PJM's Day-Ahead Energy Market commitment timing. In some cases, gas commitments were required to be made by 9:30 a.m. EST before the natural gas day and before the PJM Day-Ahead Market commitment. Sometimes, PJM had to decide whether generators were needed without forward-looking information available on the price of natural gas, without certainty the generator ultimately would be able to procure natural gas with delivery to the plant and without certainty the plant actually would be needed as the load forecast was updated. For example, on a Friday PJM was told that natural gas would not be available for purchase by a generator throughout the weekend; therefore, PJM needed to decide whether the generator would be necessary for Monday, on the preceding Friday, so that the unit could determine whether to procure gas.

Other generation owners alerted PJM that gas marketers required them to buy a weekend package that forced PJM to run the generator through the weekend if it was needed on a Monday. Other generation owners required advanced commitments prior to the start of the natural gas day and had to buy a 24-hour package of natural gas that forced PJM to run the generators longer than needed under PJM's least-cost commitment model.

Figure 23: Natural Gas and Electricity Market Coordination Issues

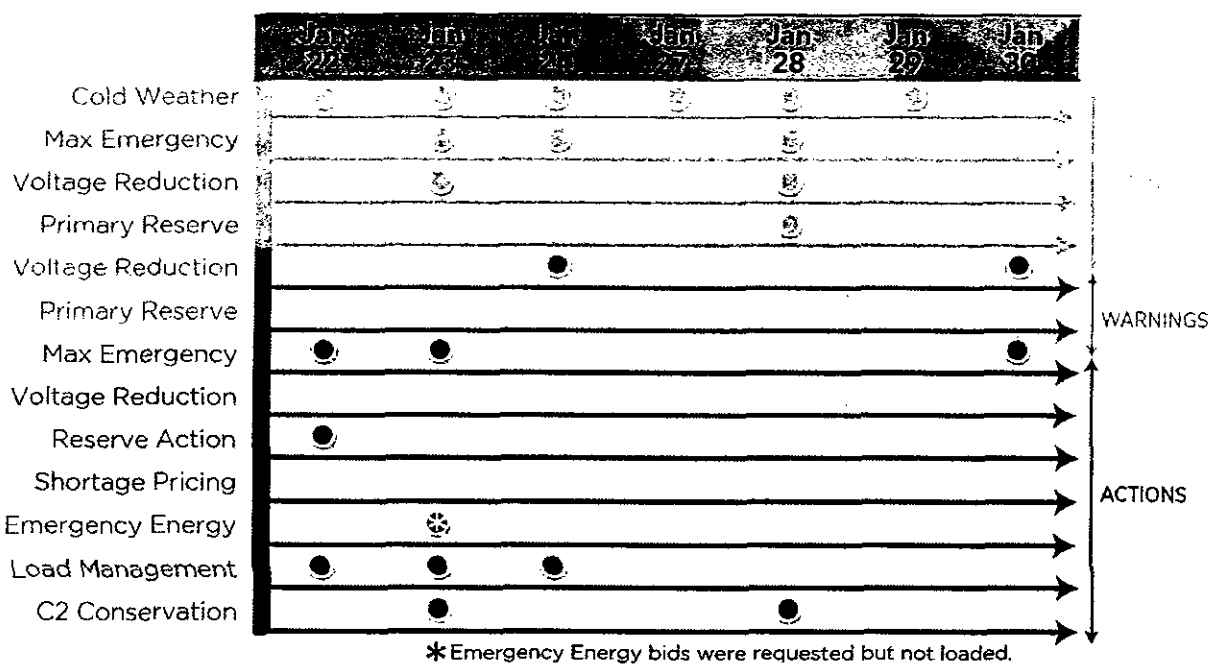


The market timing issues were further exacerbated by the three-day Martin Luther King Jr. Day holiday weekend. High electricity demand for was expected the Tuesday and Wednesday mornings after Martin Luther King Jr. Day, January 20, which coincided with the Tuesday-Wednesday 10 a.m. to 10 a.m. gas day. Generation owners told PJM that they needed to know on Friday, January 17, whether their units would be scheduled to run in order to ensure they had natural gas for Tuesday and Wednesday mornings. Although in some instances the units were needed only to cover the morning peak from about 5:00 a.m. to 9:00 a.m., the units had to buy 24 hours' worth of gas. PJM's need to make these unit/gas scheduling requests outside of the Day-Ahead Energy Market increased the level of uplift (out-of-market) payments in the latter half of January. These natural gas terms and conditions requiring multi-day commitments from generators were significantly at odds to the traditional Day-Ahead Market commitment and, along with the record high gas prices, increased the level of uplift.

Operations

In preparation for and in response to the real-time conditions, PJM issued multiple notices, alerts and emergency actions. The following figure summarized the emergency procedures that were issued for January 22 to January 30.

Figure 24: Emergency Procedures during the Winter Storm of January 2014



For the second blast of cold weather, PJM implemented many of the same actions taken prior to and during the Polar Vortex. Cold Weather Alerts were issued in advance of each operating day, and conference calls were held with members and neighbors multiple times each day to develop and adjust the operating strategy based on real-time conditions.

On Tuesday evening, January 21, the loss 1,783 MW of generation in the Baltimore Gas and Electric Company (BGE) and Pepco zones required a reassessment of generation and transmission plans for the next day. PJM's analysis identified potential thermal transmission constraints in the BGE and Pepco zones as power outside of those zones would flow into them to replace the loss of local generation. As a result of the expected transmission constraints in the BGE and Pepco zones, PJM loaded Maximum Emergency Generation at 2:00 p.m. on January 22 and called for Emergency Load Management for the two zones during for the evening peak hour. PJM also issued a Voltage Reduction Alert for the BGE and Pepco zones at 8:00 p.m.; however, an actual voltage reduction was not ordered. PJM reliably met the peak demand on January 22 without additional emergency procedures and provided shared reserves to the NYISO (117 MW at 5:36 p.m. and 73 MW at 8:56 p.m.). The day's peak demand was 135,061 MW at 7:00 p.m. At that time, 6,427 MW of interchange was being imported into PJM.

Thursday, January 23, was an even more challenging day. In addition to the constraints in the BGE and Pepco zones, higher loads than January 22 throughout the PJM footprint led to west-to-east constraints on the transmission system causing tighter capacity conditions in the PJM Mid-Atlantic Region. To meet the forecasted load given the anticipated system constraints, PJM loaded Maximum Emergency Generation at 4:30 a.m., called for voluntary Emergency Load Management and issued a NERC Alert Level 2 to inform neighbor systems that load management would be deployed, for the Mid-Atlantic Region, Dominion and the FirstEnergy South/Allegheny Power zones during the morning and evening peaks on January 23. At 4:50 a.m. PJM requested Emergency Energy bids, which was cancelled at 8:05 a.m. No emergency bids were loaded. PJM also issued a request for public conservation of power for the BGE and Pepco zones for the evening of January 23. Actual peak loads on January 23 were 132,431 MW at 8:00 a.m. and 134,302 MW at 8:00 p.m. (The forecasted loads had been 135,579 MW for 9:00 a.m. and 136,572 MW for 9:00 p.m.) Interchange into PJM during the peak hours (5,409 MW) was less than the interchange into PJM January 22, resulting in more internal resources running to meet the load.

Load and transmission constraints on Friday, January 24, were similar to January 22. Forecasted peak load was 133,902 MW at 9:00 a.m. with an actual peak load of 136,982 MW occurring at 8:00 a.m. The regional temperatures increased after the Friday morning peak. Interchange during the morning peak hour was 4,007 MW into PJM. The 1,783 MW of generation in the BGE and Pepco zones was still out though a partial return was anticipated that evening. PJM loaded Maximum Emergency Generation at 4:30 a.m., called for Emergency Load Management for the BGE and Pepco zones for the morning peak on January 24. PJM also issued a Voltage Reduction Warning at 7:20 a.m. for the BGE and PEPCO zones in anticipation of additional emergency procedures in the two zones.

The weekend of January 25-26 provided some reprieve from the cold temperature. Weekend loads typically are lower than weekday loads making operations less challenging. The return to service of 1,783 MW of generation in the BGE and Pepco zones helped alleviate west-to-east constraints previously experienced that week. However, temperatures across the region were still colder and demand higher than normal. While the peak on Saturday, January 25 was 118,275 MW and 114,006 MW on Sunday January 26, typical winter weekend peaks are around 90,000 MW.

On Monday, January 27, a Cold Weather Alert was the only emergency procedure issued. Although the forecasted peak demand for January 27 was 131,825 MW, the actual peak demand was lower, at 126,379 MW at 8:00 p.m. Total interchange into PJM during the peak was 3,640 MW.

Despite the lower demand on Monday, demand for Tuesday, was projected to be similar to January 7, when PJM set its all-time winter peak of 141,846 MW. Load forecasts for Tuesday, January 28, were 137,663 MW at 9:00 a.m. and 140,411 MW at 9:00 p.m. To prepare for Tuesday's expected high demand, PJM on Monday issued a Cold Weather Alert, a Maximum Emergency Generation Alert, a Voltage Reduction Alert, a Primary Reserve Alert and requested public conservation of power on Tuesday. All these emergency procedures were used on January 7 to successfully meet the record demand.

However, actual demand was less than forecasted on January 28, and generating resources performed better than expected with an 11 percent forced outage rate (compared to 22 percent on January 7). Interchange during the evening peak was 6,504 MW. Actual system loads were 133,137 MW at 9:00 a.m. and 137,336 MW at 7:00 p.m. As a result, no additional emergency procedures were needed that day.

The weather and load for the January 29 did not require any procedures beyond a Cold Weather Alert. Forecasted peak load on January 29 was 133,823 MW at 9:00 a.m., and the actual peak load was 136,020 MW at 9:00 a.m. Interchange during the morning peak was 4,722 MW.

After the peak the evening of January 29 and during the overnight period, 1,370 MW of generation across the system were unavailable. With cold temperatures forecast to linger, PJM on the morning of January 30 loaded Maximum Emergency Generation in the BGE and Pepco zones and issued a Voltage Reduction Warning for the rest of the system. The primary concern in the BGE and Pepco zones was thermal constraints. All available resources in those zones were committed via the Maximum Emergency Generation action to control for those constraints. Following the morning peak, temperatures moderated, and system conditions returned to normal. Forecasted peak demand for January 30 was 131,965 MW at 9:00 a.m., and the actual peak demand was 136,215 MW at 8:00 a.m. Interchange during the peak was 4,330 MW into PJM.

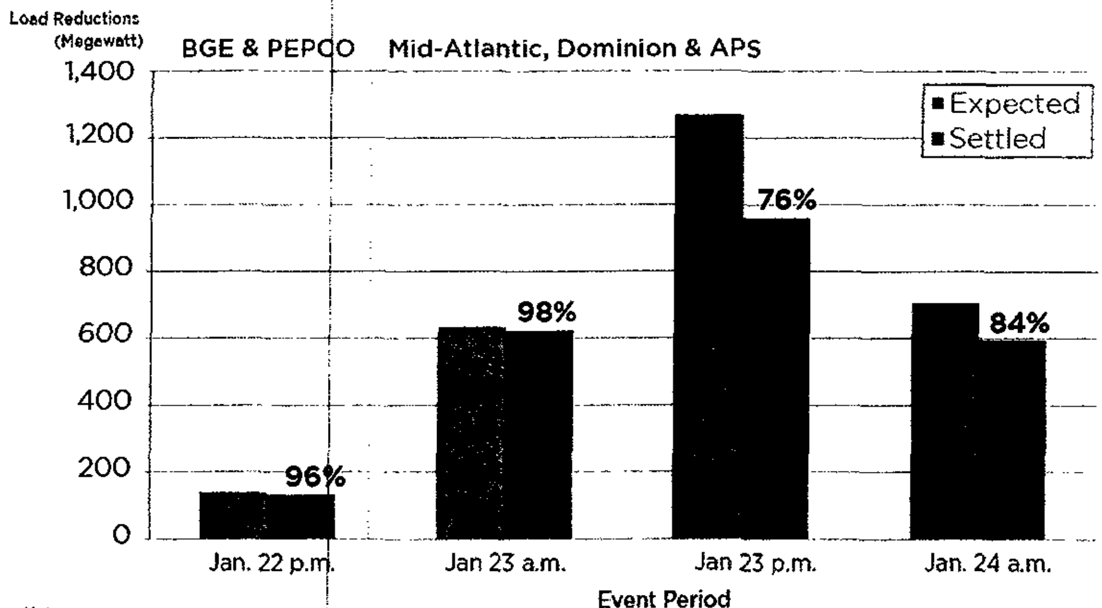
Demand Response

Demand response during the Winter Storm was used to reduce peak loads in some eastern areas rather than for the entire region as it was during the Polar Vortex. This was due in part to issues with transfers, MW flows across the transmission paths within PJM, and units tripping offline. During the Winter Storm, PJM called on demand response four times to handle with issues with transfers, transmission limits and generating units shutting down:

- January 22 for the evening peak in the Baltimore Gas and Electric Company and Pepco zones
- January 23 for the morning peak in the Mid-Atlantic Region, Dominion Zone and Allegheny Power System Zone
- January 23 for the evening peak in the Mid-Atlantic Region, Dominion Zone and Allegheny Power System Zone
- On January 24 for the Mid-Atlantic, Dominion and Allegheny Power System (APS) zones.

Demand resources were not obligated to respond to these requests because they were made outside of the June 1 - September 30 mandatory demand resource response compliance windows. Regardless, many demand response resources answered the calls for reduction.

Figure 25: Demand Response during the Winter Storm

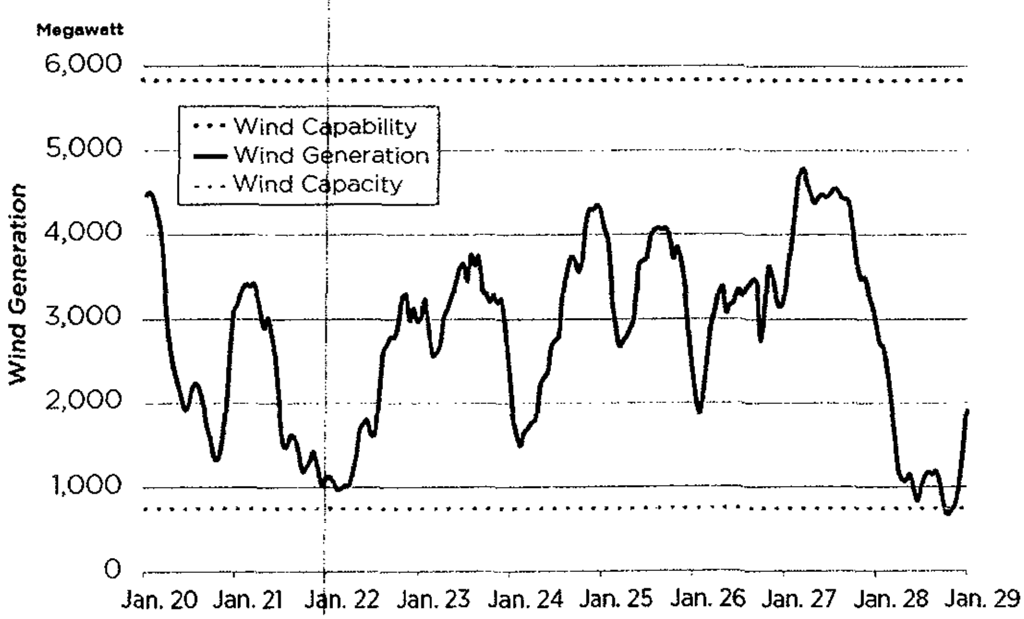


Notes:
1. DR events dispatched during non-compliance period.
2. Expected Energy Load Reductions (MW) - CSP reported estimate based on current market rule.
3. MW value is average hourly load reduction for non-ramp in hours.

Operational Observations and Challenges

Similar to operations during the Polar Vortex, some variables exceeded PJM's expectations. Demand response's availability and response was one of those variables. The requests to the general public for conservation again were considered to have had a positive impact. Wind power again produced at a level above the calculated annual wind capacity during the January 20-29 timeframe.

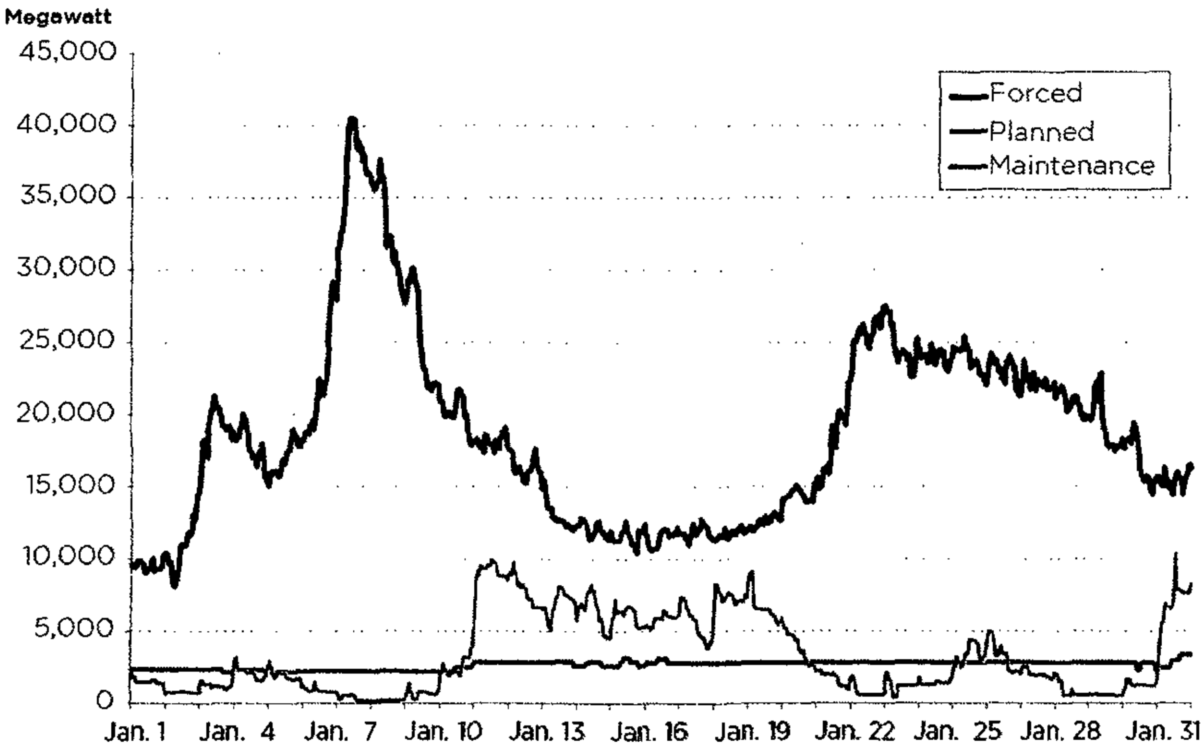
Figure 26: Winter Storm Wind Generation



Generator Performance: Outages

Because PJM experienced a 22 percent generation forced outage rate on January 7, similar forced outage rates were expected during the Winter Storm because of the similar forecasted weather conditions. The amount of generation available during the Winter Storm improved as compared to the Polar Vortex but was still worse than PJM's historical average winter forced outage rate.

Figure 27: Generator Outages – January 2014



PJM also coordinated with generator owners to manage available run hours based on fuel inventories. PJM and generators that could still run on oil communicated to maintain awareness of the generator's status and possible issues.

Generation Performance: Fuel Limitations

Some gas-fired units have the capability to use an alternate fuel (dual-fuel capability), which increases flexibility when gas supply becomes tight. The predominant alternate fuel is oil. While dual-fuel units increase flexibility, there were still challenges operating the units on oil. PJM requested dual-fuel generation owners unable to secure gas to operate their units on oil during the extremely cold weather events. Even with this flexibility, generation owners encountered issues including run-time limits related to permit-defined environmental restrictions, resupply challenges and increased failure rates for unit startup. Units that switch to oil operate with increased emissions, which limits their maximum run times due to environmental constraints. In other cases, units operating on oil may have had only limited ability to make and store demineralized water for the injection systems that must be operated to reduce nitrogen oxide emissions when running on oil. PJM coordinated with generation owners that needed to decrease the maximum run time per day for their units in order to conserve emission credits. Identification and tracking of fuel limitations was done manually by PJM and the generator owners. There were approximately 1,000 MW of generation with decreased run times for emission reasons.

The increase in demand for oil caused another challenge for generation owners. Many units in the Northeast switched to oil as gas became unavailable increasing demand for oil. In some cases, oil suppliers began to run low on inventory or deliveries were slow because increased demand was unexpected and available delivery trucks were limited. Generation owners found it difficult to keep oil tanks full on a daily basis and had to limit run hours for their units. There were approximately 2,000-3,000 MW of generation affected by oil supply and delivery issues. Also, generating units running on oil have an increased failure-to-start rate due to clogged fuel lines.

Contractual Constraints

During January PJM used the Day-Ahead Market, load forecasts and the experience of generation outages earlier in the month to schedule the necessary resources for reliable operations. Contractual constraints on generators' availability challenged PJM operators and contributed to the January uplift that will be discussed in the Market Outcomes: Winter Storm section below. The contractual constraints included natural gas generators with:

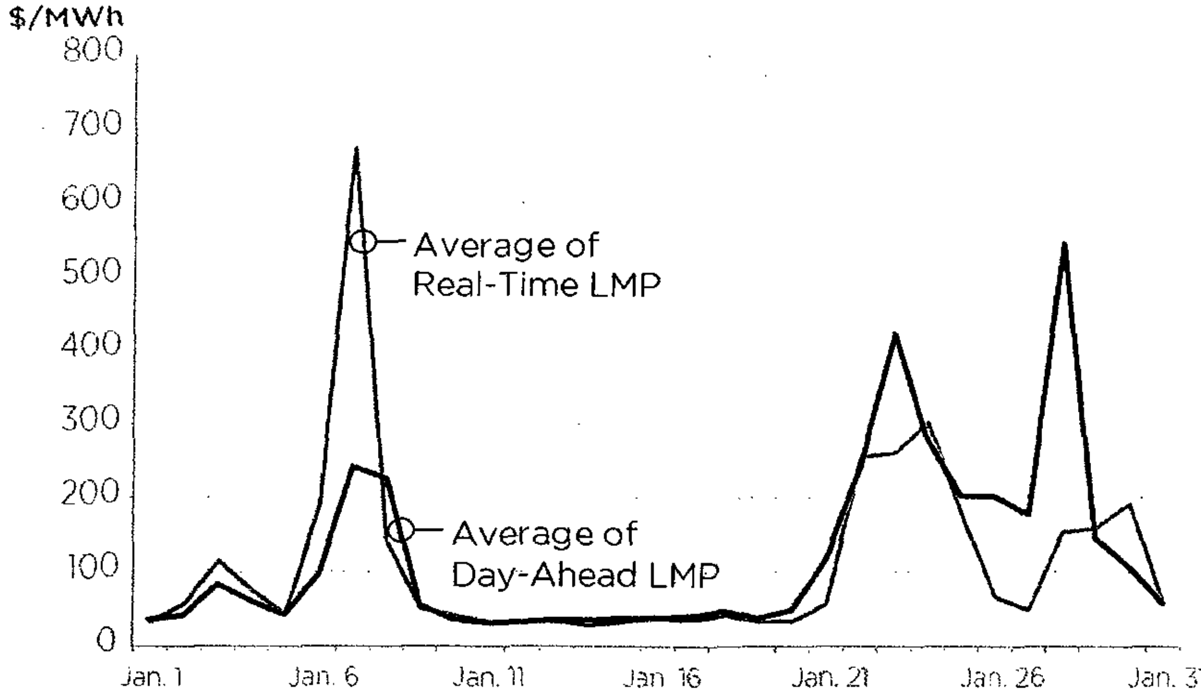
- the need for early commitment, days ahead of the Day-Ahead Energy Market, to ensure fuel deliverability;
- inflexible scheduling criteria such as 24-hour and multi-day commitment; and,
- purchase of gas for an entire weekend.

Market Outcomes: Winter Storm

Energy Prices

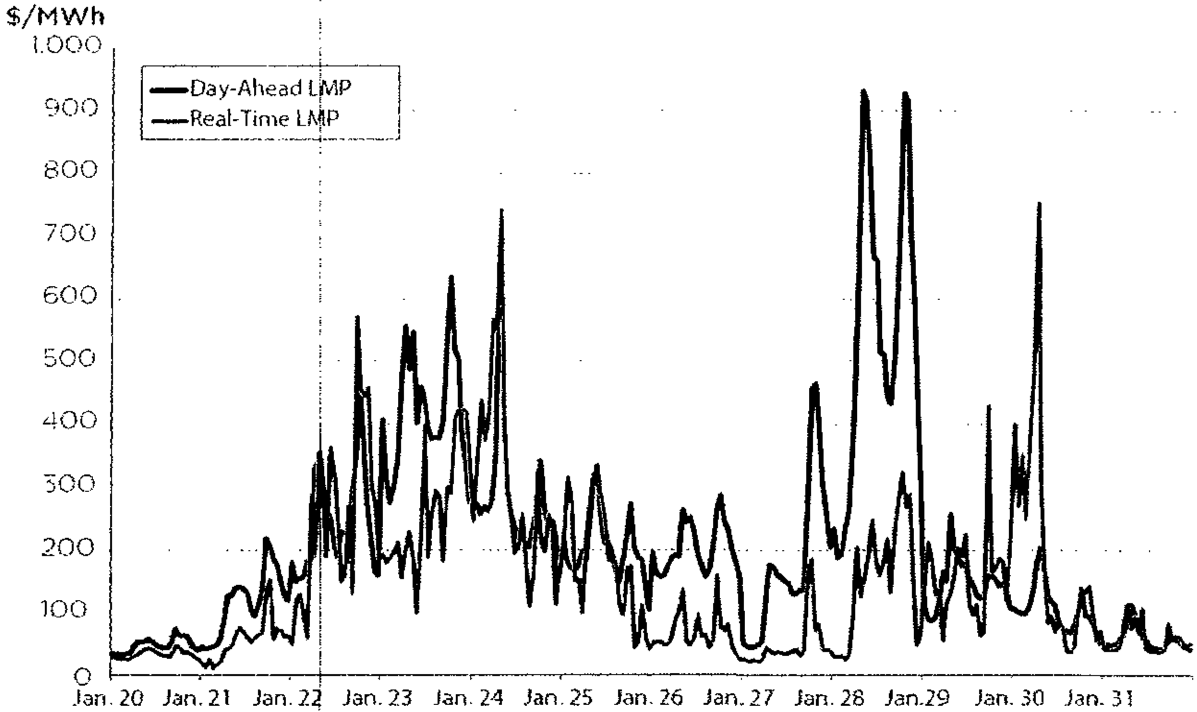
Energy prices were high during the Winter Storm but not as high as during the Polar Vortex. Shortage pricing conditions were not present during the Winter Storm because sufficient generation was available to meet the forecasted demand. Day-Ahead Energy Market prices were higher than real-time prices during the Winter Storm. The price difference resulted in part from PJM's scheduling of resources to ensure that primary and synchronous reserve requirements were met throughout the Winter Storm while taking into consideration the uncertainties surrounding whether loads, interchange, generation availability and natural gas/electric coordination issues would occur as did earlier in the month.

Figure 28: Average of Real-Time and Day-Ahead Locational Marginal Prices – January 2014



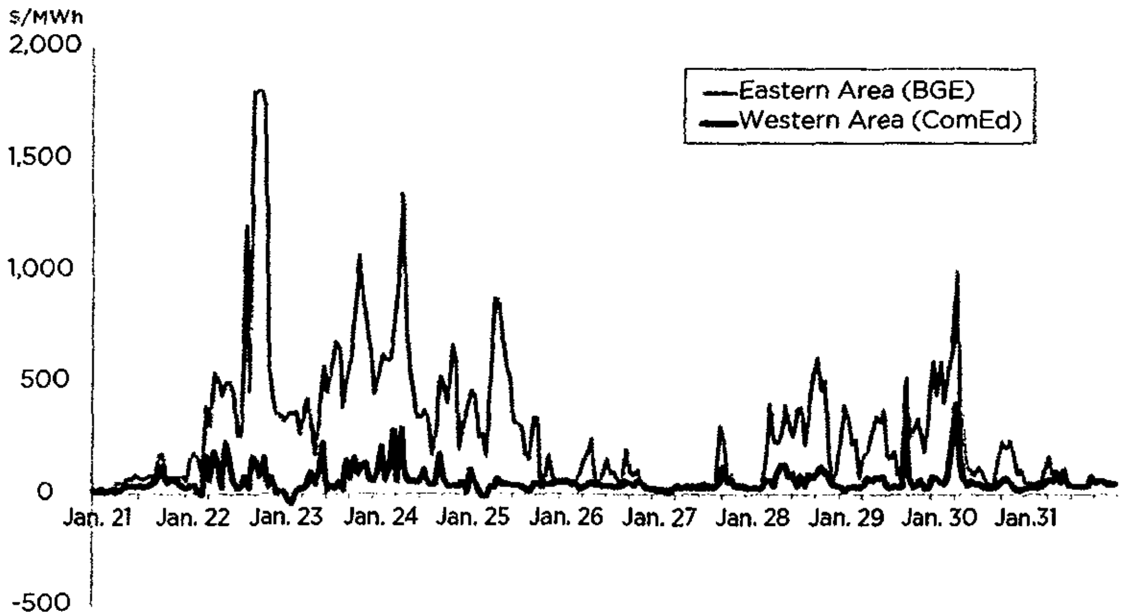
During January 22-25 real-time and day-ahead prices were more closely aligned. During January 27-29, day-ahead prices were higher than real-time prices – an indication of market participants' expectation that conditions would follow the Polar Vortex pattern. Real-time LMPs were lower than day-ahead LMPs due to the mix of 24-hour burn gas units and a better than expected generator forced outage rate. January 30 real-time LMPs exceeded day-ahead prices.

Figure 29: Real-Time and Day-Ahead Locational Marginal Prices during the Winter Storm



Real-time prices were lower in PJM's western area compared to the eastern area due to fewer transfer interface constraints during the Winter Storm than during the Polar Vortex. Eastern zones had more combined-cycle generators fueled by natural gas on the margin resulting in higher prices in the eastern zone than in the western zone. During the Winter Storm, there was variability in temperatures across the region compared to the Polar Vortex, which had persistent, extreme cold across the entire footprint. In preparation for anticipated high forced outages as experienced during the Polar Vortex, PJM called on additional generation in the eastern portion of the footprint. The following chart displays the difference between LMPs in the east versus west.

Figure 30: Eastern and Western Locational Marginal Prices



Locational marginal prices are calculated in five-minute intervals with generation typically being the marginal resource that sets prices. On January 24, demand response set prices for seven five-minute intervals. Additional information on interval analysis of prices can be found in the Appendix A: Locational Marginal Pricing Marginal Unit Type Intervals.

Natural Gas Prices and Offer Caps

The PJM Operating Agreement[18] requires all generation capacity resources in PJM that have been committed as capacity to submit offers into the Day-Ahead Energy Market. The Operating Agreement also limits generation offers into the Day-Ahead Energy Market to $1,000/MWh.

These two provisions had not come into potential conflict before January 2014. To PJM's knowledge, sellers with generation resources offering into PJM's energy market have not had marginal costs in excess of $1,000/MWh or have not notified PJM of their situation. However, it became an issue when natural gas prices spiked with trades on January 21 and delivery on January 22 averaging over $120/MMBtu (and prices as high as $140/MMBtu for the day of delivery) – record-setting gas prices for the PJM footprint. The result of the high gas prices was electricity generation costs that could exceed the $1,000/MWh offer cap. For example, for a combustion turbine in the PJM region with a roughly average 10,000 Btu/kWh heat rate, $120/MMBtu translates to a $1,200/MWh cost to produce energy, ignoring any additional costs such as operations and maintenance.

On January 23, PJM filed with the FERC a waiver of certain provisions of the Operating Agreement in order to allow for make-whole payments for the difference between the capped price and the marginal costs for generating energy that exceeded the $1,000/MWh cap. In a companion filing, PJM requested approval by February 10 to allow cost-based offers to exceed the $1,000/MWh offer-price cap. The FERC approved both waivers.

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[18] at Schedule 1, section 1.10.1A(d)

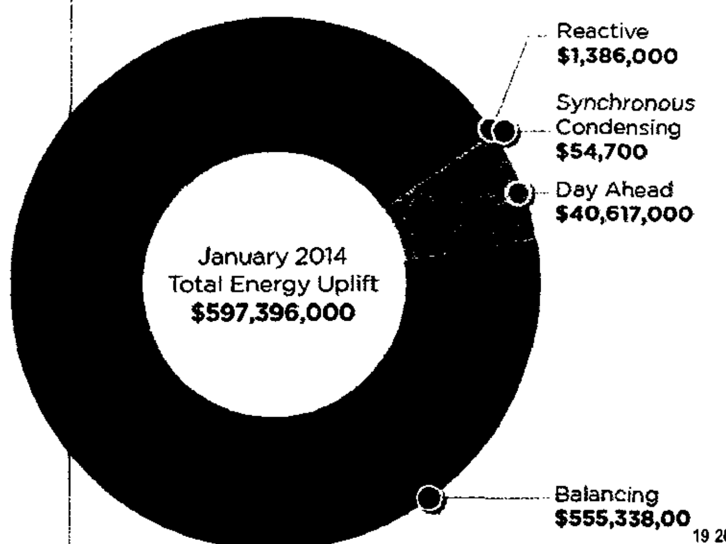
Uplift

PJM expected the possibility of generator outages similar to those experienced in the Polar Vortex and scheduled generation accordingly to ensure reliable operations during the Winter Storm. The lessons learned from the Polar Vortex were to *get natural gas generation online early and keep it online.* However, the later part of January had less extreme weather and better generation performance coupled with inflexible run times and high fuel prices for natural gas-fired generation, which led to uplift/operating reserve costs. Uplift costs were extremely high at the end of January as PJM scheduled sufficient generation to supply consumers and ensure adequate operating reserves to mitigate risk from unscheduled generator outages, volatile interchange and natural gas uncertainty.

To incent generators and demand resources to operate as requested by PJM, resources that are scheduled by PJM and follow PJM dispatch instructions are guaranteed to fully recover their costs of operation. Uplift cost is created when market revenues are insufficient to cover the costs of the resources following PJM's direction. Generators told PJM that, because of gas market constraints, their gas-fired resources in some cases had to be operated at full output each hour and for a longer duration than PJM required them – which created extremely high uplift costs especially because of the extremely high prices for natural gas.

Operating Reserve costs are payments made to economic demand resources and generation resources, which follow PJM's direction, to cover their costs and are the primary form of uplift in PJM. These payments are outside of the market and are not included in the pricing signals that are visible and transparent to market participants.

Figure 31: Uplift Breakdown



[19,20]

A majority of the uplift cost in January, as shown above, was due to generators scheduled by PJM running in real-time to meet reliability needs.

[19] Balancing includes lost opportunity cost, the difference between what a unit receives when providing regulation or synchronized reserve and what it would have received for providing energy output.

[20] Day-ahead uplift includes black start make whole payments for Automatic Load Rejection units and reactive credits.

There can be various scenarios in which market revenues are insufficient to cover generators' costs. The drivers that contributed to high levels of uplift in January 2014 included:

- **Natural Gas Prices** – High natural gas prices exacerbated the cost of uplift as the units operating at PJM's direction were more expensive than there historical costs.
- **Contractual Constraints** – Due to restrictions on natural gas deliveries, many resources required PJM to maintain strict megawatt output levels during periods when they were uneconomic to ensure they were available during peak conditions. Additionally, the lack of alignment between the gas and electric day timing often required PJM to commit to running gas units prior to the PJM Day-Ahead Energy Market.
- **Prudent Operations** – During January, PJM committed resources for expected extreme system conditions. Such operations are typical during Cold Weather Alerts, resulting in the scheduling of additional reserves to account for increased forced outage rates as identified in the PJM Emergency Operations Manual. As a result, more expensive units displaced lower-cost resources and sometimes suppressed locational marginal prices. Throughout January, and particularly early in the month, PJM experienced higher generator outage rates than had ever been observed. PJM needed to schedule additional generation to be available to mitigate any potential power shortfalls due to generator forced outages.
- **Interchange Volatility** – Variable imports and exports of energy, which reacted to PJM energy prices, affected locational marginal prices and commitment decisions by PJM. The amount of power imported is difficult for PJM to forecast and is not under PJM's control; therefore, PJM must schedule internal resources to ensure adequate generation is available.

In the current PJM market design, if a generation resource follows PJM's commitment and dispatch, that generator is guaranteed to fully recover its costs for the hours it runs at PJM's direction. Operating reserve payments are designed so resource owners are incented to follow PJM direction to help maintain control of the grid in the most efficient manner possible and also ensure adequate operating supply plus additional capability for reserves. Day-ahead and real-time operating reserve credits are paid to resource owners; these credits are paid by PJM market participants as operating reserve charges. Operating reserve charges are not part of the energy market price signals as they are based on calculations from data that is not all available on a real-time basis.

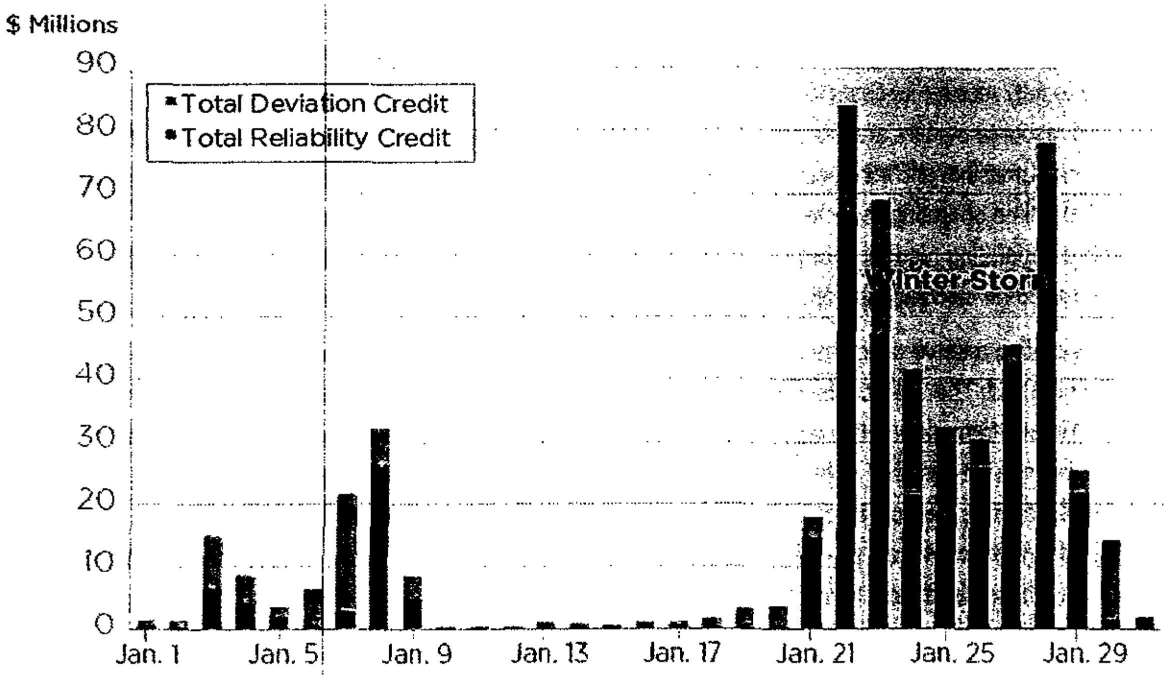
Increased operating reserve costs are a side effect of running additional generation to support outages or other situations on the grid. The uplift costs are high when the primary fuel of additional generation being run is high priced. During the Winter Storm, generation was needed specifically in the northeastern section of PJM where there is a large amount of natural gas-fired generation. Operating reserve payments increased when the additional generation being run was inflexible due to 24-hour gas burn requirements. Due to the tight supplies in the natural gas market, many PJM generators were kept on-line to mitigate the risk of not being able to obtain natural gas after shutting down. Some of these generators were run overnight because they could not shut down and re-start again due to fuel or weather issues.

Figure 32: Balancing Operating Reserve Credits

Reliability Credit	• Generator committed in advance of the operating day and outside of the Day-Ahead Market. • Generator committed during the operating day and is out of the economic merit order.
Deviation Credit	• Generator is needed to meet anticipated load plus reserves. • Generator is committed during the operating day and cost is greater than locational marginal prices most of the time.

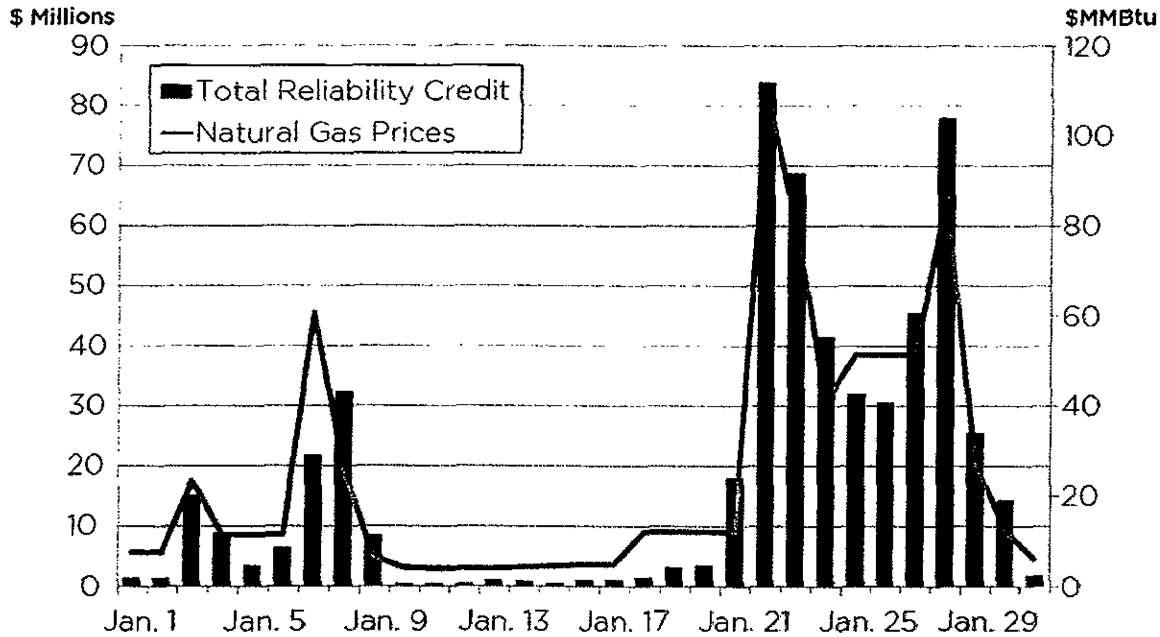
There are two general types of balancing operating reserve charges. If a generator is called to run after the close of the Day-Ahead Market and during the Reliability Assessment Commitment performed after the Day-Ahead Market results are posted, it is dispatched either for prudent operations or "load plus reserves." If a generator is dispatched for prudent operations, then the uplift cost associated with the generator running is categorized as a reliability credit. If a generator is needed for load plus reserves, then its uplift cost is categorized as a deviation credit. When a generator is committed to run during the operating day, if its cost is greater than locational marginal prices most of the time, the uplift credit for the generator also is categorized as a deviation credit. During the operating day, if a generator is not economical (i.e. its cost-based offer is higher than the current LMP), then its associated uplift cost is categorized as a reliability credit.

Figure 33: Balancing Operating Reserve Credits for Deviation and Reliability



The overwhelming majority of balancing operating reserve credits during the Winter Storm was for reliability credits. Overlaying the natural gas prices on top of just the reliability credits demonstrates the impact on the uplift costs of the high natural gas prices, which were exacerbated by contractual constraints.

Figure 34: Reliability Credits vs. Natural Gas Prices

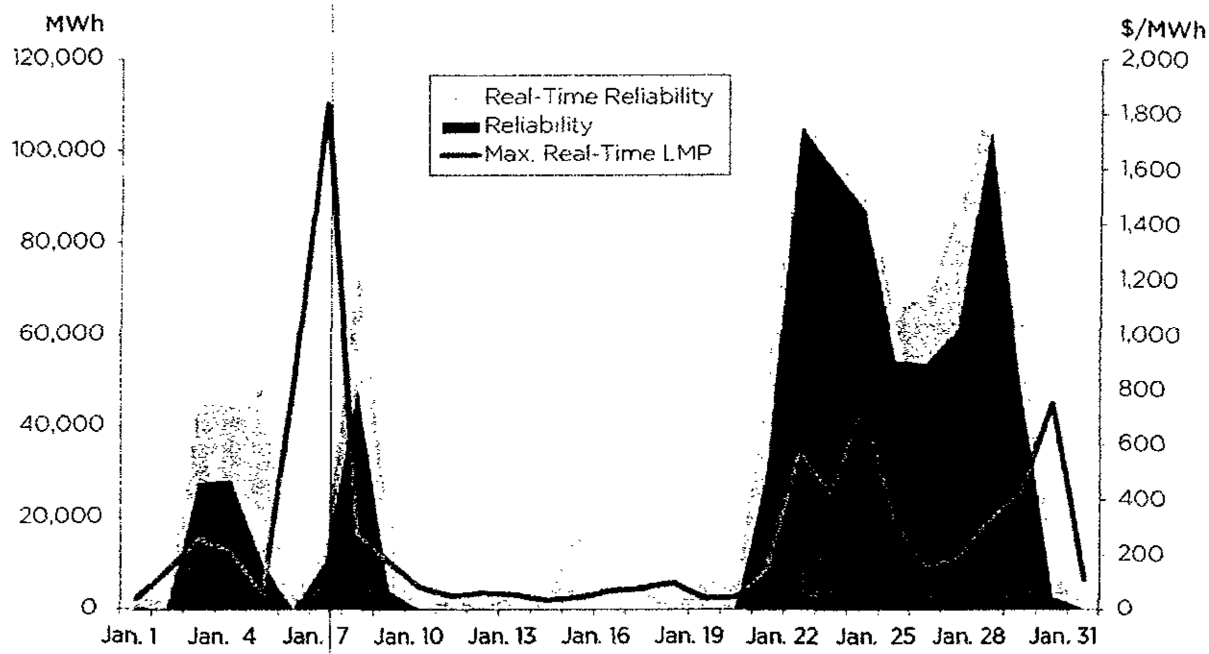


PJM worked in advance of the Winter Storm to mitigate the risk of losing generators and worked with generators which had inflexible parameters to keep them online to ensure reliability would be maintained. An example of inflexible parameters is a long minimum run time. PJM may need a generator only for three hours but must keep it online for the full minimum run time of the resource. The minimum run time constraints can impact uplift costs if a generator is needed for both the morning and evening peaks and is unable to turn off between the peaks. A generator reports to PJM how long it needs to run to not damage the generator (minimum run time), how long it needs to stay off once shut down to not damage the generator (minimum downtime), and how long it needs to know in advance when PJM will needs it online (time to start). During the Polar Vortex and Winter Storm, many generators that can typically operate very flexibly had to operate on significantly more restrictive parameters due to their contractual arrangements for natural gas. Many of natural gas-fired generators had only 24-hour burn offers and, in some cases, 72-hour burn offers due to natural gas terms and conditions.

PJM scheduled generation resources during January using the Day Ahead Market and Reliability Run but also scheduled resources manually to cover forecasted load and generation outage levels experienced earlier in the month. Generators warned that they likely would not be able to procure gas without some certainty on their commitment period in advance of the typical scheduling windows and some accounting for extraordinary scheduling restrictions such as 24-hour ratable takes and multi-day commitments. Often, operators were forced to commit to these units several days in advance to ensure a reliable level of unit commitment prior to the close of the day-ahead market.

The PJM procedures used to make such commitments include section 3.2 of the Emergency Operations Manual and Section 1 of the Transmission Operations Manual. These sections document the conditions and procedures for conservative operations. The procedure includes steps such as increasing margins on reactive interfaces, and scheduling additional generation in the event of significant loss of system resources. PJM provides tools for the system operators to log these steps and subsequently allocate the costs.

Figure 35: Balancing Operating Reserve Megawatt-hours and Locational Marginal Prices in January



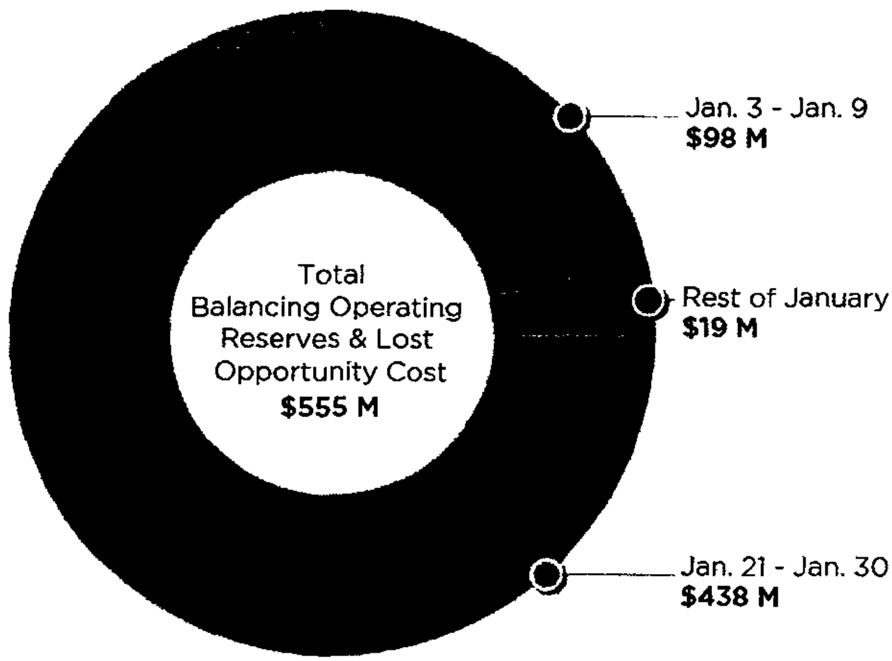
The megawatt-hours associated with real-time reliability credits are shown in the light blue added on top of the megawatt-hours committed prior to the operating day, which are represented in dark blue. The maximum real-time locational marginal price is shown by the green line overlaid on the reliability energy.

In the early part of January, the marginal resources setting the energy market prices had very high offer prices. This period of the month included a period of significantly high prices on the evening of January 6 when PJM initiated a system-wide Voltage Reduction Action, which triggered setting energy and reserve prices consistent with shortages of all reserve products. This Voltage Reduction Action resulted in LMPs in excess of $1,000/MWh that evening. Additionally, PJM deployed emergency demand response resources during the morning and evening periods of January 7. During the morning peak period on January 7, emergency demand resources set LMPs across PJM near $1,800/MWh. Similar system conditions occurred the same evening but for a much shorter period of time due to the increase in interchange.

In the latter part of January, PJM scheduled generation based on the load forecast and expected generation outages. But the inflexible terms and conditions of natural gas supplies caused generators operating on 24-burn minimums to have extremely high offer prices compared to lower-cost resources that set locational marginal prices. Although PJM deployed emergency demand resources during the latter portion of the month, they were not marginal as frequently during this period and, therefore, did not produce the high LMPs seen earlier in the month.

If a generator, such as the gas-fired generators with inflexible supplies, is required to run and would not be the next economic megawatt that PJM would dispatch, the generator will not set locational marginal prices. If the cost of the generator's power is much greater than locational marginal prices, then the generator displaces less-expensive resources. Therefore, these inflexible, expensive megawatts depressed prices, making the system even more uneconomical.

Figure 36: Balancing Operating Reserve Credit by Storm



A majority of the real-time or balancing operating reserve and lost opportunity cost expense was during the winter storm in the latter half of the month.

In summary, operating reserve costs were higher at the end of January because PJM had to commit resources which were both inflexible and expensive in order to maintain reliability and mitigate risk from unscheduled generator outages and natural gas terms and conditions.

Contractual Constraints

PJM works to run as few units as possible and minimize production cost, but operational parameters of individual generation units can limit flexibility. One reason for increased generation contractual constraints during January was natural gas pipeline operational orders. During January 2014 peak natural-gas demand days[21] some pipeline operators required customers, including generators, to take natural gas from their systems in even, incremental amounts over a 24-hour natural gas day, 10:00 a.m. to 10:00 a.m. This process forced generators to run during periods when they traditionally would be uneconomic; the generators must run or face significant operational or economic penalties.

Generator limitations are based on unit type and operational capability and can include issues such as fuel procurement and environmental limitations. Generators are scheduled economically, but, due to the generator's minimum run time or other limiting parameter, it must be run uneconomically through some hours before it can be shut down. When controlling the grid in January, PJM ran additional generation that was relatively inflexible because

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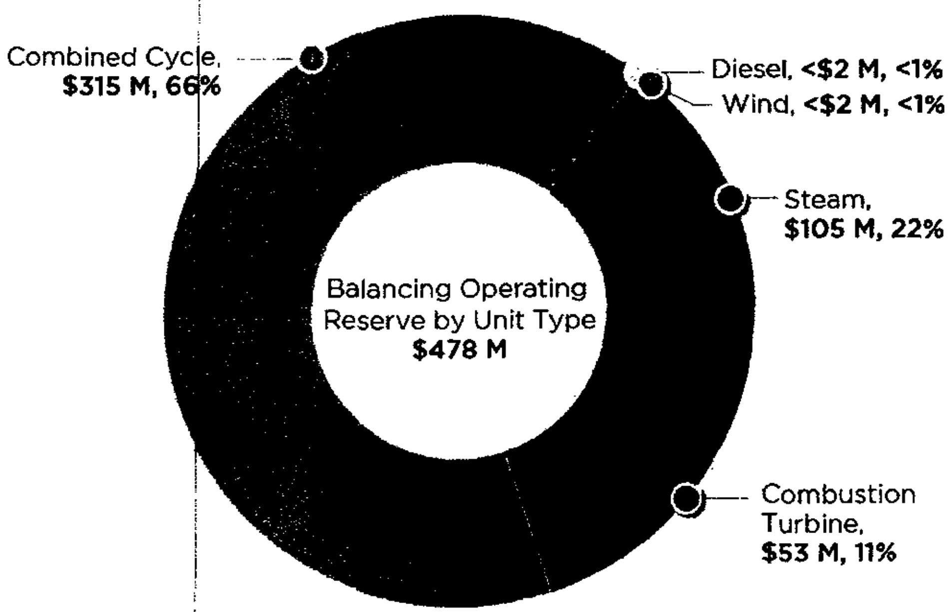
21 Peak gas demand days: January 6-8, 21-23, and 27-28

of the operational issues highlighted above. These generators could not cycle on and off from hour to hour and were kept online through the overnight and uneconomic periods in order to be available during peak electricity demand hours.

Figure 37: Balancing Operating Reserve by Generator Type



The majority of the balancing operating reserves payments went to combined-cycle generators[22]. Much of the uplift to combined-cycle generators was due to limitations on the types of natural gas contracts that could be procured during the storm. Some combined-cycle generator owners told PJM that to ensure their availability they would need to run 24 hours.

Interchange Impact to Markets

Electricity flowing into or out of PJM from neighboring areas, known as interchange, also can lead to uplift when it differs significantly from the expectation PJM operators use to schedule and dispatch resources to maintain reliability. An interchange transaction can either be an import, meaning power is purchased from a neighboring area and sold into PJM, or an export, where power is purchased from PJM and sold in an external area. These transactions can be submitted with as little as 20 minutes notice and are only curtailed or limited due to reliability concerns. In contrast, deploying emergency demand response under today's rules requires upto two hours' notice. This timing difference creates a situation in which system operators must forecast an expected amount of interchange and then operate the system based on that expectation. When that expectation significantly differs from actual system conditions, it can create uplift.

For example, on January 7 at 2:00 p.m. PJM identified the need for emergency demand response and all available generation at the evening peak based on its load forecast, generator availability and an expectation of receiving 5,600 MW of power imports from neighboring areas during the evening peak. However, during the evening peak,

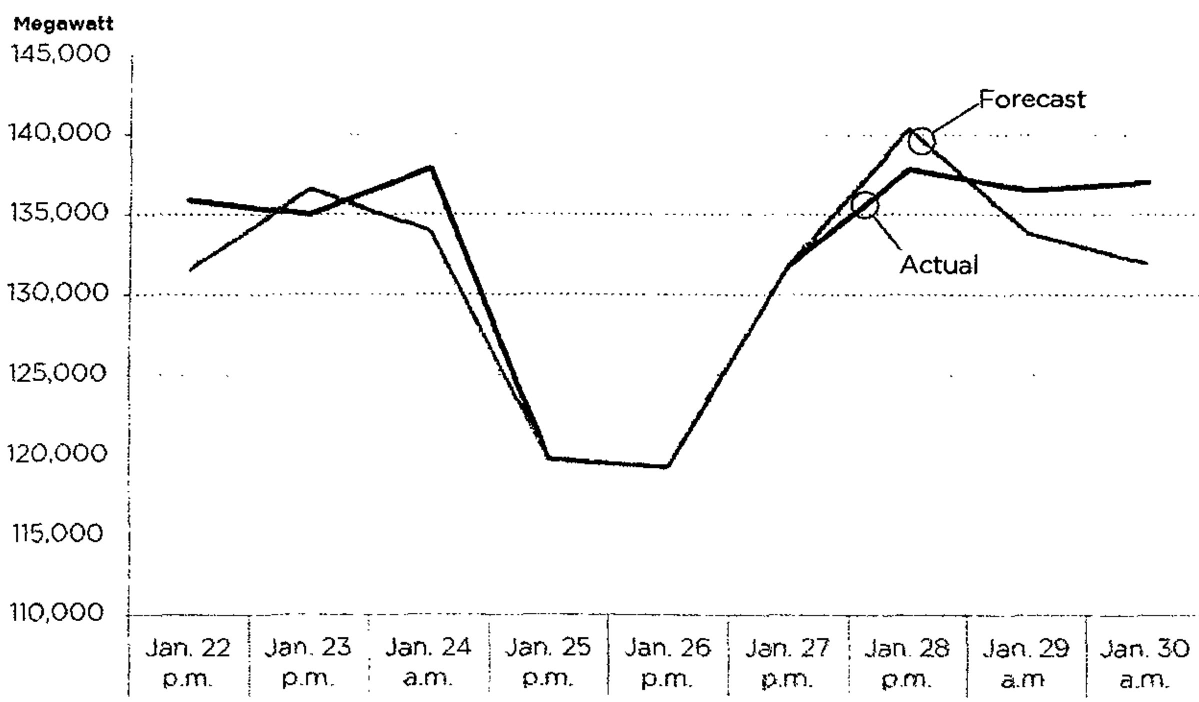
22 Combined-cycle plants are natural gas-fired generators that typically consist of one or more combustion turbines that exhaust into a steam generator. Combined-cycle generators usually are larger and can produce more megawatts than individual combustion turbines alone; they also are generally used throughout the day and not just to generate during the peaks like a combustion turbine would be used.

PJM actually received in excess 8,600 MW of power imports from all neighboring areas. The energy being delivered to PJM above the amount anticpated was roughly equivalent to three nuclear plants and exceeded the total amount of emergency demand response that responded that evening. To maintain system control with the excess power imports, PJM ramped down conventional generating units in order to balance supply and demand, which resulted in lower LMPs across the system. Despite the low LMPs on the system, PJM still ran high-priced supply resources, including gas generation and emergency demand response, in order to meet the minimum run-time requirements on such resources. The combination of low LMPs when expensive supply resources are being run at PJM's direction required make whole payments, and, thus, creating uplift charges.

Load and Weather Impact to Markets

PJM forecasts both load and weather to accurately anticipate power supply needs. In extreme conditions as in January 2014, the accuracy of the load forecast is especially important. Wintertime load forecasting is even more difficult because each day has two peak load periods, morning and evening. Triggers, such as the temperature forecast changing by 7-10 degrees from one day to the next, cause PJM load forecasters and operators to reanalyze and update the load forecast. This updated forecast may necessitate scheduling additional generation, which can increase uplift if the scheduled units are not flexible or the forecast is not accurate.

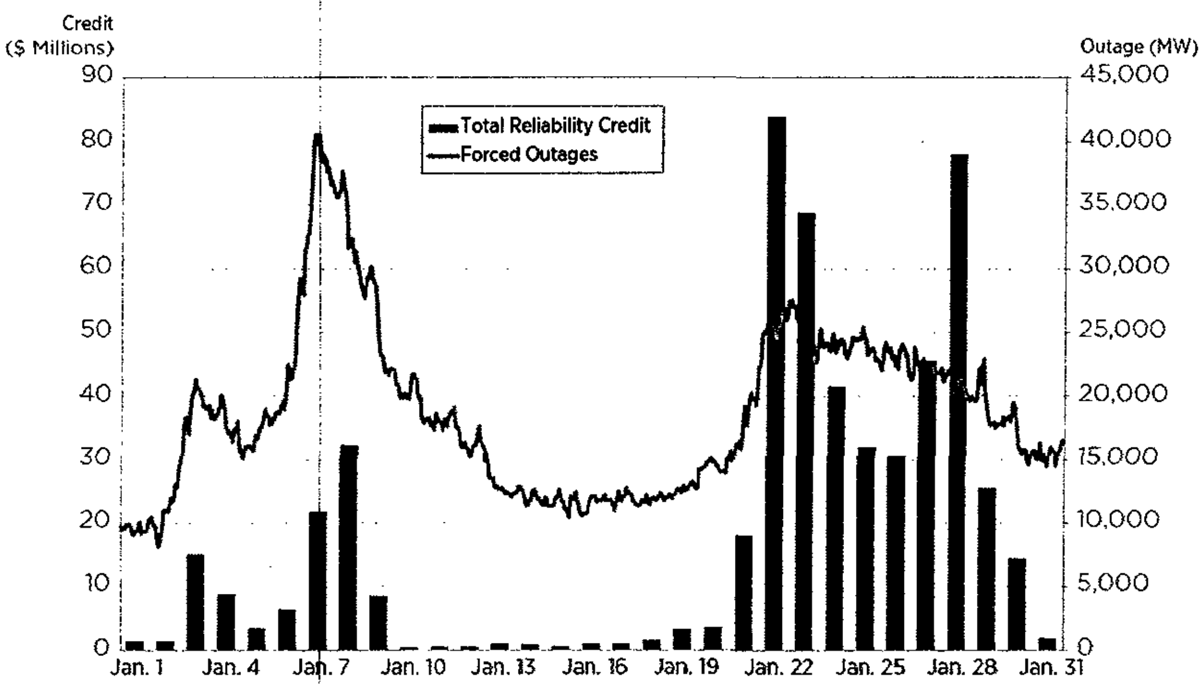
Figure 38: Forecast and Actual Peak Load



Generator Outages

Generating units that do not perform on peak days are assessed performance penalties that affect current year capacity revenues. An explanation of these penalties is in Appendix D: Peak-Hour Period Availability Assessment. The total estimated Daily Peak-Hour Period Availability Charges before the January outage events were $45,586 and including January 2014 increased to $112,388.

Figure 39: Forced Outages and Balancing Operating Reserve Cost



Lessons Learned and Recommendations

In December 2013 PJM published *Technical Analysis of Operational Events and Market Impacts During the September 2013 Heat Wave.*[23] The events of January 2014 provided PJM additional opportunities to build on some of the September 2013 lessons learned and to further enhance several areas in preparation for future winter and summer operations.

ID	Category	Recommendation	Type	Status
1	Unit Performance	PJM, in conjunction with members, should consider the following topics and develop adjustments to improve unit performance: 1. Review the penalties for non-performance during peak days and/or days when emergency procedures are issued for capacity emergencies 2. Review incentives for performance during peak days 3. Investigate a process for unit testing and preparation of resources in advance of winter operations, including testing dual-fuel capability 4. Review generator outage rates outlined in PJM Manual 13: Emergency Operations.	Market Construct	New
2	Unit Characteristics	Work with generation owners to identify opportunities to create or improve information sharing. Consider including the following: 1. Sharing of fuel source and emission limitations by schedule submitted and fuel limitations/certainty of supply 2. Streamlining and standardizing the outage cause types in eDart with additional specificity that provides more insight and consider methods for validation 3. Clarify the rules by which a generator can claim an Outside Management Control event for taking an outage	Process Change or Addition Technology	In progress -- follow-up from Fall 2013 generator survey
3	Gas/Electric Coordination	PJM, in conjunction with stakeholders, should consider the following topics and develop appropriate industry recommendations and PJM rule changes: 1. Investigate opportunities for better harmonization of the timing of the gas and electric operating days 2. Consider potential market rule changes that would allow generators to better include natural gas costs in their energy or capacity market offers, including review of offer caps, and to make changes to energy market offers during the operating day	Market Construct Process Change or Addition Technology	In progress – this is an active discussion in PJM and across the energy industry

23 http://www.pjm.com/~/media/documents/reports/20131223-technical-analysis-of-operational-events-and-market-impacts-during-the-september-2013-heat-wave.ashx

ID	Category	Recommendation	Type	Status
		3. Consider potential market rule changes that would allow generators to reflect fuel availability in their start-up and notification times **4.** Improve the tools and processes for two-way communication with the gas industry to enhance situational awareness and better evaluate impact to PJM generation **5.** Improve reporting of availability for units that are not committed day-ahead to include access to fuel and consider methods for validation		
4	Fuel Limited Resources	For those units with fuel limitations look to: **1.** Improve tools that allow sharing of fuel-limited details with PJM including tracking dual-fuel capability and availability **2.** Review operator communications with respect to fuel-limited generation commitment decisions for accuracy and consistency **3.** Confirm mechanism by which resources' seek waivers for fuel emission limitations and better understand conditions under which relief may be granted	Technology Process Change or Addition	New
5	Fuel Specific Limitations	Examine difficulties experienced by generators during natural gas emergency procedures and consider: **1.** Methods to call on long-lead generation based on fuel procurement limitations during extreme conditions **2.** Changes to allow adjustment of start times based on changes in fuel utilized **3.** Requirements for generation units whose primary fuel may not be natural gas but that require gas to operate	Market Construct Process Change or Addition	New
6	Energy Market Uplift	PJM, in conjunction with stakeholders, should consider the following topics and develop appropriate recommendations and PJM rule changes: **1.** Review the cost allocation of energy market uplift charges **2.** Investigate potential mechanism to allocate uplift during emergency operations when rates are extreme **3.** Investigate methods and procedures for reducing the amount of uplift to be paid	Market Construct	In progress – Energy Market Uplift Senior Task Force
7	Interregional coordination	In order to increase situational awareness with the VACAR Reserve Sharing Group and VACAR Reliability Coordinator: **1.** Define and review PJM emergency procedures and overall communications. Review operating agreements (including VACAR Reserve Sharing Group Agreement) **2.** Include language regarding coordination of emergency procedures	Process Change or Addition Communication & Notification Protocols	New

ID	Category	Recommendation	Type	Status
8	Unit Commitment	Evaluate provisions in Manual 11 to determine where changes may be appropriate such as clarification and training regarding: 1. Start-up costs and cancelled dispatch provisions in Attachment C 2. Switching schedules	Process Change or Addition	New
9	Voltage Reduction Emergency Procedure	Review the voltage reduction capabilities of transmission owners to better understand current capabilities and determine if there are additional requirements that need to be developed: 1. Survey transmission owners to understand existing voltage reduction capabilities (amount, time frame, etc.) 2. Enhance Manual 13 with specifics on Voltage Reduction Warnings for TOs without SCADA control	Process Change or Addition	In Progress –this is being conducted and reviewed in the SOS-T and OC.
10	Emergency Energy Bids	Review and enhance the tools and processes for accepting Emergency Energy Bids	Technology Process Change or Addition	In progress
11	Regulation Market Rules	PJM stakeholders should consider reexamining the performance of the Regulation Market during January. Specifically: 1. Investigate whether the division by the performance score is appropriate 2. Investigate whether the minimum participation requirements are adequately high enough 3. Investigate the possibility of going short regulation during system peaks	Market Construct	New
12	External Capacity	Develop processes and tools that will: 1. Confirm that external capacity resources either bid into the day-ahead market or submitted eDart tickets that they are unavailable 2. Track the output of external capacity resources to ensure they are not submitting an outage into eDart and selling energy into a different market 1. Track the real-time output of external units cleared in the day-ahead market to confirm they are meeting obligations (tag validation versus commitment) 2. Develop ability to notify, track and confirm units that have not cleared in the day-ahead market but are recalled by PJM due to a capacity emergency such as Max Emergency	Process Change or Addition	New
13	Communications & Procedures	Review and improve how the Emergency Procedures tool is used to communicate, both internally and externally, and develop solutions to address the following topics: 1. Consider adjustments to the roles and responsibilities for communications during emergency procedures 2. Refine training to reinforce processes and tools	PJM & Member Dispatcher Training Communication & Notification Protocols	New

ID	Category	Recommendation	Type	Status
14	Public Appeals	In order to better implement and use public appeals for conservation, PJM should: **1.** Evaluate and consider the impact of calls for conservation and investigate where or how to use the data **2.** Improve process for public notification during emergency procedures (C1/C2) **3.** Review triggers for public notifications and associated transmittal protocols **4.** Review both the content and processes for public appeals in Manual 13	Technology	New

In addition to the above recommendations, which are focused largely on PJM practices, PJM's Executive Vice President of Operations and Planning Michael J. Kormos outlined in testimony before FERC as well as the U.S. Senate Energy and Natural Resources Committee the need for a broader look by policymakers on the relative transparency and flexibility of the natural gas markets. As noted above, some of the more onerous and inflexible terms and conditions, such as requiring commitments to take gas ratably throughout a three-day weekend in order to assure supplies on the first business day thereafter, were completely at odds with the more constrained day-ahead and real-time commitments in the wholesale electricity markets. Moreover, the lack of transparency and liquidity in gas markets made it extremely difficult to verify much of the information being provided and undoubtedly contributed to the price spikes and additions of onerous terms and conditions. These reforms are beyond PJM's ability to effectuate. They instead require a larger look from policymakers at the gas markets and their relative flexibility and transparency in the face of rising electric generation dependence on natural gas. PJM reiterates its request for a focused look on these issues by policymakers building on many of the experiences outlined in this report. PJM stands ready to assist in those efforts.

Appendices

Appendix A: Locational Marginal Pricing Marginal Unit Type Intervals

The PJM Real-Time Market is a spot market in which instantaneous locational marginal prices are calculated every five minutes based on actual grid operating conditions. The table below shows the number of five-minute intervals each day that each resource type was marginal and set the LMP. On January 7 and January 24, generation was the marginal price-setting resource for most intervals, except for a few intervals in which demand response set prices. Emergency purchases did not set prices.

Figure 40: Number of Intervals Each Resource Type Set LMP

Day	Generator	Demand Response	Emergency Purchase
Jan. 7	225	63	0
Jan. 22	281	7	0

Appendix B: Locational Marginal Prices in Shortage

This table shows the intervals in which the real-time security constrained economic dispatch engine was in shortage conditions. There are 12 five-minute intervals every hour. For hour 19 (7 p.m.) on January 6, only the last five minutes of the hour were in shortage. For Hour 20 (8 p.m.) shortage conditions were from interval one to interval nine, which means in hour 20 shortage lasted for 45 minutes (nine five-minute intervals).

Figure 41: Intervals in Shortage Conditions

Day	Hour	First Interval	Last Interval
Jan. 6, 2014	19	12	12
	20	1	9
Jan. 7, 2014	7	5	12
	8	1	12
	9	1	12
	10	1	12
	11	1	12
	12	1	4
	17	12	12
	18	1	2

Appendix C: Natural Gas System Critical Notices

<u>**January 6, 2014**</u>

Columbia:

Restricting non-firm natural gas deliveries in Ohio delivery points on through Tuesday (1/7).

Dominion:

Maintaining their restriction on non-firm natural gas deliveries onto the Texas Eastern pipeline in western Pennsylvania.

Maintaining their restriction non-firm natural gas deliveries into two Local Distribution Companies (Peoples Natural gas Company and East Ohio Natural gas).

Texas Eastern:

Restricting non-firm natural gas deliveries off of Leidy line.

Restricting non-firm natural gas deliveries east of Chambersburg, Pa.

Warned that an operational flow order could be issued, which would restrict the flow of non-firm natural gas.

Restricting non-firm natural gas deliveries from producers in Marcellus and Dominion/Rockies Express pipelines due to natural gas quality issues.

Transcontinental:

Issued a system-wide operational flow order beginning today. The OFO restricts shippers (including power plants) from taking any natural gas over and above their nominated quantities on an hourly basis.

<u>**January 7, 2014**</u>

ANR Pipeline (flows into Chicago):

Emergency maintenance will be partially restricting flows into Chicago by 15 percent

Released the previously set OFO, but maintained an advisory that generators rate takes off of pipeline.

Injections have been limited at Joliet and Woodstock, IL, which will lower pressures on the pipeline on points northward.

Columbia:

Restricting non-firm natural gas deliveries in Ohio delivery points on through Tuesday (1/7).

Restricting all non-firm natural gas deliveries at several delivery points throughout Ohio on Tuesday (1/7).

Restrictions on all non-firm natural gas deliveries into eastern Virginia on Tuesday (1/7).

Dominion:

Maintaining their restriction on non-firm natural gas deliveries onto the Texas Eastern pipeline (which flows into NYC) in western Pennsylvania.

Maintaining their restriction non-firm natural gas deliveries into two Local Distribution Companies (Peoples Natural gas Company and East Ohio Natural gas).

Requesting that all shippers maintain offtakes from the system at or below their nominations.

Texas Eastern:

Restricting non-firm natural gas deliveries off of Leidy line.

Restricting non-firm natural gas deliveries east of Chambersburg, Pa.

Restricting non-firm natural gas deliveries into Philadelphia, Pa.

Warned that an operational flow order could be issued, which would restrict the flow of non-firm natural gas.

Restricting non-firm natural gas deliveries from producers in Marcellus and Dominion/Rockies Express pipelines due to natural gas quality issues.

Issued a notice on the morning of the 25th that a compressor east of Delmont, Pennsylvania. This reduced flows east of Delmont by 575,000 MMBtu, which is just east of Pittsburgh.

In the afternoon of 1/7, the Delmont Compressor Station is currently back online and operating at 70 percent capacity, which should help maintain/build pressure on the pipeline into eastern PJM.

Stated that No-Notice Service will be eliminated on 1/7 in response to compressor outage.

Issued operational flow orders on the Philadelphia and Section M-3 (which leads into Philadelphia), due to lower pressures caused by the Delmont Compressor outage.

Issued a critical notice that restricts takes off the pipeline after 4:30pm to their uniform hourly nominated quantity.

The Unionville Compressor station near Pittsburgh is out. Details are currently unavailable on the effect on operations, but it should affect natural gas delivery east of Pittsburgh.

Transcontinental:

Issued a system-wide operational flow order (OFO).

Natural gas deliveries out of the Marcellus are restricted at points due to high demand.

Stated that injections from producers have been lower than expected (the amount was not disclosed) and that nominations on the pipeline will be reduced based on priority (i.e.: non-firm will get cut first).

Suspending the nomination reductions caused by lower injections from producers.

January 21, 2014

ANR:

Issued an "Extreme Condition" warning, which will limit a consumer's hourly takes from the pipeline to their hourly nominated quantity.

Columbia:

Declared a "Critical Transport" advisory for northern Ohio and western Pennsylvania today (1/21) through Thursday (1/23).

Dominion:

Warning that starting 6pm, January 16, and into the next week, that generators need to limit takes from the pipeline to equal of their hourly nominated quantities. If not, Dominion may issue an operational flow order to maintain pipeline reliability.

Restricting non-firm deliveries into two LDC systems: East Ohio and the People's Natural gas Company.

Restricting non-firm deliveries into the southern portions of its pipeline system.

Natural gas Pipeline of America:

Issued an operational flow order starting Monday (January 20).

Texas Eastern:

Restricting non-firm natural gas deliveries east of Chambersburg, Pennsylvania.

Restricting non-firm natural gas deliveries into Philadelphia.

Requiring generators to limit takes off pipeline in Market Area 2 and 3.

Transcontinental:

Issued an operational flow order, effective starting today (1/21), which requires generators to limit takes off the pipeline or face a penalty rate of $50 per MMBtu.

January 22, 2014

ANR:

Issued an "Extreme Condition" warning, which will limit a consumer's hourly, takes from the pipeline to their hourly nominated quantity.

Columbia:

Declared a "Critical Transport" advisory for northern Ohio and western Pennsylvania through Friday (1/24), which will limit natural gas availability.

Dominion:

Advising generators to limit takes from the pipeline to equal of their hourly nominated quantities.

Restricting non-firm deliveries into two LDC systems: East Ohio and the People's Natural gas Company.

Restricting non-firm deliveries into the southern portions of its pipeline system.

Natural gas Pipeline of America:

Issued an operational flow order starting Monday (1/20).

Texas Eastern:

Restricting non-firm natural gas deliveries east of Leidy (in central Pennsylvania).

Restricting non-firm natural gas deliveries east of Chambersburg, Pennsylvania.

Restricting non-firm natural gas deliveries into Philadelphia.

Requiring generators to limit takes off pipeline in Market Area 2 and 3.

Transcontinental:

Issued an operational flow order that requires generators to limit takes off the pipeline or face a penalty rate of $50 per MMBtu.

<u>January 23, 2014</u>

ANR:

Issued an "Extreme Condition" warning, which will limit a consumer's hourly, takes from the pipeline to their hourly nominated quantity.

Columbia:

Declared a "Critical Transport" advisory for northern Ohio and western Pennsylvania through Friday (1/24), which will limit natural gas availability.

Dominion:

Eliminating non-firm deliveries at several points in Pennsylvania and Ohio.

Advising generators to limit takes from the pipeline to equal of their hourly nominated quantities.

Restricting non-firm deliveries into two LDC systems: East Ohio and the People's Natural gas Company.

Restricting non-firm deliveries into the southern portions of its pipeline system.

Natural gas Pipeline of America:

Issued an operational flow order starting Monday (1/20).

Texas Eastern:

Restricting non-firm natural gas deliveries east of Leidy (in central Pennsylvania).

Restricting non-firm natural gas deliveries east of Chambersburg, Pennsylvania.

Restricting non-firm natural gas deliveries into Philadelphia.

Requiring generators to limit takes off pipeline in Market Area 2 and 3.

Transcontinental:

Issued an operational flow order that requires generators to limit takes off the pipeline or face a penalty rate of $50 per MMBtu.

January 24, 2014

ANR:

Issued an "Extreme Condition" warning in Chicago, which will limit a consumer's hourly takes from the pipeline.

Columbia:

Declared a "Critical Transport" advisory for northern Ohio and western Pennsylvania through Friday (1/24), which will limit natural gas availability.

Dominion:

Eliminating non-firm deliveries at several points in Pennsylvania and Ohio.

Advising generators to limit takes from the pipeline.

Natural gas Pipeline of America:

Issued an operational flow order (OFO).

Saturday (1/25), NGPA is limiting firm through some southern segments of its pipeline.

Texas Eastern:

Restricting non-firm natural gas deliveries east of Leidy (in central Pennsylvania).

Restricting non-firm natural gas deliveries east of Chambersburg, Pa.

Restricting non-firm natural gas deliveries into Philadelphia.

Requiring generators to limit takes off pipeline in Market Area 2 and 3 (Ohio to New Jersey).

Transcontinental:

Issued an operational flow order that requires generators to limit takes off the pipeline.

January 27, 2014

ANR:

Issued an "Extreme Condition" warning in Chicago.

Columbia:

Declared a "Critical Transport" advisory for northern Ohio and western Pennsylvania.

Restricting storage withdrawals of natural gas due to low inventories.

Dominion:

Advising generators to limit takes from the pipeline.

Natural gas Pipeline of America:

Issued an operational flow order (OFO).

Texas Eastern:

Restricting non-firm natural gas deliveries east of Leidy (in central Pennsylvania).

Restricting non-firm natural gas deliveries east of Chambersburg, Pennsylvania.

Requiring generators to limit takes off pipeline in Market Area 2 and 3 (Ohio to New Jersey).

Transcontinental:

Issued an operational flow order that limits takes off the pipeline.

January 28, 2014

ANR:

Limiting pipeline withdrawals in Chicago.

Columbia:

Restricting non-firm transportation and storage withdrawals of natural gas due to low natural gas inventories, which can affect natural gas deliveries to generators, until Thursday (1/30).

Dominion:

Advising generators to limit takes from the pipeline.

Natural gas Pipeline of America:

Issued an operational flow order (OFO).

Texas Eastern:

Restricting non-firm natural gas deliveries east of Leidy (in central Pennsylvania).

Restricting non-firm natural gas deliveries east of Chambersburg, Pa.

Requiring generators to limit takes off pipeline in Market Area 2 and 3 (Ohio to New Jersey).

Transcontinental:

Issued an operational flow order that limits takes off the pipeline.

Appendix D: Peak-Hour Period Availability Assessment

For each generation capacity resource having a capacity commitment (Reliability Pricing Model or Fixed Resource Requirement) for a given delivery year, PJM evaluates the resource's availability during the peak-period of that *delivery year[24] relative to its expected availability, and a Capacity Market Seller is credited or charged to the extent* the critical peak-period availability of its committed Generation Capacity Resources exceeds or falls short of the expected availability of such resources.

The peak-period equivalent forced outage rate (EFORp) is the measure of a generation resource's unavailability during the peak-period of the commitment delivery year. This rate is compared to the resource's expected unavailability rate as measured by the resource's five-year average equivalent forced outage rate (EFORd-5). For purposes of this assessment, the EFORp and EFORd-5 exclude outages deemed outside management control. In addition, for single-fueled, natural gas-fired units, a failure to perform during the winter-peak shall be excluded if it can be demonstrated that such failure was due to non-availability of natural gas to supply the unit.

*Generation unit availability for the commitment delivery year (Committed installed capacity * (1 – EFORp)) is* compared to expected generation unit availability (Committed installed capacity * (1 – EFORd-5)) to determine the excess or shortfall in Peak-Hour Period availability for each generation capacity resource[25]. The net Peak-Hour Period availability shortfall or excess for each Capacity Market Seller in each locational delivery area is the net of the shortfalls and excesses of all of the seller's resources in that locational delivery area.

A Peak-Hour Period Availability Charge shall be assessed on each Capacity Market Seller with a net shortfall in an locational delivery area, where such charge is equal to the shortfall quantity times the Seller's weighted average Resource Clearing Price for the locational delivery area.

Preliminary Peak-Hour Period Availability determinations have been made to determine the impact of high forced outage rates experienced in January 2014. The estimates are very preliminary and subject to change upon finalization of EFORp values for delivery year 2014 but the results do show higher EFORp values and higher Peak-Hour Period Availability charges for 2013/14 Delivery Year relative to two prior delivery years.

11/12 Daily Peak-Hour Period Availability Charges: **$12,838.57**

12/13 Daily Peak-Hour Period Availability Charges: **$25,822.98**

13/14 Preliminary Daily Peak-Hour Period Availability Charges: **$45,585.71**

13/14 Preliminary with January Daily Peak-Hour Period Availability Charges: **$112,387.99**

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24 For purposes of this assessment, the peak-period is defined as hours ending 3 p.m. through 7 p.m. for each non-holiday weekday during the calendar months of June through August and hours ending 8 a.m. through 9 a.m. and 7 p.m. through 8 p.m. for each non-holiday *weekday in January and February. This peak-period definition encompasses approximately 500 hours in a delivery year.*

25 The shortfall determined for any Generation Capacity Resource shall not exceed an amount equal to 0.50 times the Unforced Capacity of such resource; provided, however, that if such limitation is triggered as to any Generation Capacity Resource for a Delivery Year, then the decimal multiplier for this calculation as to such resource in the immediately succeeding Delivery Year shall be increased to 0.75, and if such limitation again is triggered in such succeeding Delivery Year, then the multiplier shall be increased to 1.00. The multiplier shall remain at either such elevated level for each succeeding Delivery Year until the shortfall experienced by such resource is less than 0.50 times the Unforced Capacity of such resource for three consecutive Delivery Years.

Appendix E: Emergency Procedures in January

WARNINGS

- Primary Reserve Warning
- Primary Reduction Warning Reduction of Non-Critical Plant Load
- Manual Load Shed Warning
- Emergency Mandatory Load Management Reductions
- Maximum Emergency Generation

ACTIONS

- **Energy Only Option Emergency Load Response**
- **Curtailment of Non-Essential Building Load Voltage Reduction**
- **Manual Load Shed**

Wednesday, January 1

9:10	Cold Weather Alert issued for 12/30/13-01/03/14, ComEd Control Zone	
9:10	Cold Weather Alert issued for 12/30/13-01/03/14, ComEd- Control Zone	

Friday, January 3

6:25	TLR Level 1, PJM-RTM	Canceled: 1/4/2014 12:41
10:55	Cold Weather Alert issued for 1/6/14, PJM - RTO (Except MidAtl & Dom)	Canceled: 1/7/2014 4:10
11:00	Cold Weather Alert issued for 1/7/14, PJM- RTO	Canceled: 1/7/2014 22:56

Saturday, January 4

12:41	TLR Level 0 PJM RTO	Canceled:1/4/2014 17:57

Monday, January 6

11:25	EEA1 and Max Emergency Generation Alert PJM - RTO	Canceled: 1/7/2014 22:56
17:01	Spinning in PJM – RTO	Canceled: 1/6/2014 18:09

17:02	Shared Reserves Scheduled from NPCC – 775 MW PJM – RTO	Canceled: 1/6/2014 17:15
19:27	Voltage Reduction Warning PJM – RTO	Canceled: 1/6/2014 21:23
19:33	Max Emerg Gen - RTO	Canceled: 1/6/2014 21:03
19:50	Voltage Reduction Action of 5% PJM – RTO	Canceled: 1/6/2014 20:45
21:18	Shared Reserves Scheduled to NPCC – 163 MW PJM – RTO	Canceled: 1/6/2014 21:56
21:20	Spinning Reserves in MIDATL	Canceled: 1/6/2014 21:45
23:18	Spinning Reserves in RTO	Canceled: 1/6/2014 23:52
23:21	Shared Reserves Scheduled from NPCC – 800 MW	Canceled: 1/6/2014 23:24

Tuesday, January 7t

0:55	Reserve Reqt -2433MW, Estimated Reserve 1950 MW	Canceled: 1/7/2014 12:14
1:53	Energy Request for 06:00 through 11:00 hours EPT today	Canceled: 1/7/2014 12:12
2:51	Voltage Reduction Warning	Canceled: 1/7/2014 12:14
4:30	Max Emerg Gen	Canceled: 1/7/2014 12:14
4:30	EEA2 and Emergency Mandatory Load Management w/Long Lead Time	Canceled: 1/7/2014 11:00
4:30	EEA2 and Emergency Mandatory Load Management w/Short Lead Time	Canceled: 1/7/2014 11:00
6:27	Spinning in PJM for Max Gen	Canceled: 1/7/2014 6:38
6:27	Shared Reserve: -200MW with VACAR	Canceled: 1/7/2014 7:30
8:14	Shared Reserve: -200MW with VACAR	Canceled: 1/7/2014 8:25
8:20	Spinning in PJM for Unit Trip	Canceled: 1/7/2014 9:01
8:45	Shared Reserve: -200MW with VACAR	Canceled: 1/7/2014 21:28
9:38	Cold Weather Alert for 1/8/2014	
11:00	Member to call Member Relations during cold weather operations	Canceled: 1/8/2014 10:35
12:00	EEA1 and Max Emergency Generation Alert	Canceled: 1/8/2014 18:35
13:30	Energy Request for 17:00 through 21:00 hours EPT	Canceled: 1/7/2014 18:16
15:00	Max Emerg Gen	Canceled: 1/7/2014 18:16
15:00	EEA2 and Emergency Mandatory Load Management w/Long Lead Time	Canceled: 1/7/2014 18:16
15:00	EEA2 and Emergency Mandatory Load Management w/Short Lead Time	Canceled: 1/7/2014 18:16
15:00	Max Emerg Gen Action Trans	Canceled: 1/7/2014 14:52

Wednesday, January 8

5:00	Max Emerg Gen	Canceled: 1/8/2014 8:00
5:00	EEA2 and Emergency Mandatory Load Management w/Long Lead Time	Canceled: 1/8/2014 7:02
5:00	EEA2 and Emergency Mandatory Load Management w/Short Lead Time	Canceled: 1/8/2014 7:02
5:30	Emergency Energy Request	Canceled: 1/8/2014 7:43
9:30	Cold Weather Alert for 01/08/2014	
12:00	EEA1 and Max Emergency Generation Alert	

Friday, January 10

11:46	Spinning in RFC for 2 Units Trip	Canceled: 1/10/2014 11:58

Tuesday, January 21

11:19	Cold Weather Alert for 01/21/2014, PJM - RTO (Except MidAtl & Dom)	
13:52	Spinning in RFC for Unit Trip	Canceled: 1/21/2014 13:58
21:26	Spinning in PJM for Unit Trip	Canceled: 1/21/2014 21:33
21:29	Shared Reserves: 800 MW with NYISO	Canceled: 1/21/2014 21:39

Wednesday, January 22

10:15	Special Notice-may call Max Emerg Gen	Canceled: 1/22/2014 21:01
11:19	Cold Weather Alert for 1/22/2014, PJM- RTO	
14:00	EEA2 and Emergency Load Management w/Short Lead Tm BGE /PEPCO	Canceled: 1/22/2014 21:00
14:00	EEA2 and Emergency Load Management w/Long Lead Tm BGE/PEPCO	Canceled: 1/22/2014 21:00
14:00	Max Emerg Gen BGE / PEPCO	Canceled: 1/22/2014 21:00
17:20	Max Emerg Gen BGE / PEPCO	Canceled: 1/22/2014 21:00
17:36	Shared Reserves: -117MW with NYISO PJM- RTO	Canceled: 1/22/2014 18:00
17:54	Spinning in MIDATL for Transfers	Canceled: 1/22/2014 18:02
19:30	EEA1 and Max Emergency Generation Alert AP/MidAtl/Dom	Canceled: 1/24/2014 0:14
20:03	Voltage Reduction Alert BGE/ PEPCO	Canceled: 1/24/2014 0:14
20:56	Shared Reserves:-73MW with NYISO	Canceled: 1/22/2014 21:06

Thursday, January 23

4:30	EEA2 and Emergency Load Management: Short AP /Mid-Atlantic /Dom	Canceled: 1/23/2014 4:58
4:30	EEA2 and Emergency Load Management: Mid-Atlantic	Canceled: 1/23/2014 8:29
4:30	EEA2 and Emergency Load Management: Long AP/Mid-Atlantic/Dominion	Canceled: 1/23/2014 4:58
4:30	EEA2 and Emergency Load Management: Short AP	Canceled: 1/23/2014 8:29

4:30	EEA2 and Emergency Load Management: Long Dominion	Canceled: 1/23/2014 8:29
4:30	Max Emerg Gen AP/Mid-Atlantic/Dominion	Canceled: 1/23/2014 8:29
4:30	EEA2 and Emergency Load Management: Long AP	Canceled: 1/23/2014 8:29
4:30	EEA2 and Emergency Load Management: Long Dominion	Canceled: 1/23/2014 8:29
4:30	EEA2 and Emergency Load Management: Long Mid-Atlantic	Canceled: 1/23/2014 8:29
4:50	Emergency Energy Request PJM – RTO	Canceled: 1/23/2014 8:05
12:00	Cold Weather Alert for RTO on 1/23/2014	
14:00	Max Emerg Gen Action Trans AP /Mid-Atlantic / Dominion	Canceled: 1/23/2014 19:00
14:00	EEA2 and Emergency Load Management: Short AP /Mid-Atlantic /Dominion	Canceled: 1/23/2014 19:00
14:00	EEA2 and Emergency Load Management: Long AP /Mid-Atlantic /Dominion	Canceled: 1/23/2014 19:00
19:15	EEA1 and Max Emergency Generation Alert Mid-Atlantic	Canceled: 1/25/2014 1:36

Friday, January 24

4:30	Max Emerg Gen AP/Mid-Atlantic/ Dominion	Canceled: 1/24/2014 8:45
4:30	EEA2 and Emergency Load Management: Short AP/Mid-Atlantic/Dominion	Canceled: 1/24/2014 8:45
4:30	EEA2 and Emergency Load Management: Long AP/Mid-Atlantic/Dominion	Canceled: 1/24/2014 8:45
7:20	Voltage Reduction Warning BGE ;PEPCO	Canceled: 1/24/2014 9:37
12:00	Cold Weather Alert for RTO on 1/24/2014	

Saturday, January 25

0:22	Spinning in MIDATL for Transmission West transfers Mid-Atlantic	Canceled: 1/25/2014 00:32
22:30	TRL Level 3a PJM - RTO	Canceled: 1/26/2014 5:28

Sunday, January 26

5:28	TRL Level 1 PJM - RTO	Canceled: 1/26/2014 8:23
8:23	TRL Level 0 PJM - RTO	Canceled: 1/26/2014 8:23
12:11	Spinning in PJM for Unit Trip PJM- RTO	Canceled: 1/26/2014 12:11

Monday, January 27

8:45	Voltage Reduction Alert PJM – RTO	Canceled: 1/28/2014 8:32
8:45	Primary Reserve Alert, PJM – RTO	Canceled: 1/28/2014 8:32
8:45	EEA1 and Max Emergency Generation Alert PJM – RTO	Canceled: 1/28/2014 8:32
16:24	C2 Statement for Cold Weather emergency	Canceled: 1/28/2014 21:02

Tuesday, January 28

10:00 Cold Weather Alert for 1/28/2014 for RTO

Wednesday, January 29

8:45 Cold Weather Alert for 1/29/2014 for RTO

17:45 TLR Level 3a, PJM – RTO — Canceled: 1/30/201414:15

Thursday, January 30

5:51 Max Emerg Gen, Mid-Atlantic/Southern — Canceled: 1/30/2014 9:06

6:50 Voltage Reduction Warning, PJM – RTO — Canceled: 1/30/2014 7:34

14:15 TLR Level 0, PJM – RTO — Canceled: 1/30/2014 14:15

17:49 Shared Reserve: -83MW w/ NYISO — Canceled: 1/30/2014 18:05

Friday, January 31

10:05 Spinning in MIDATL for Unit Trip Mid-Atlantic — Canceled: 1/31/2014 10:17

2015 Winter Report

May 13, 2015
PJM Interconnection

pjm

OMAEG EX. 3

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Table of Contents

Executive Summary

The winter of 2015 marked the second consecutive year in which extreme cold weather conditions affected the PJM Interconnection footprint. In 2015, those conditions occurred in both January and February while in 2014 the polar vortex and winter storms took place in January.

System performance during the 2015 cold weather events of Jan. 7 and 8 and Feb. 19 and 20 showed improvements over the winter of 2014. In part, the improvements reflected actions taken by PJM and its members as a result of analysis, lessons learned, and implementation of recommendations from the 2014 experience. With generation outage rates remaining above historical norms[1] in 2015, PJM continues to see the need for sustained incentives to improve generation performance, particularly during peak winter demand periods.

Key points from the report are summarized below.

Temperatures and Peaks

The winter of 2015 was marked by cold temperatures similar to the winter of 2014 – with the coldest temperatures experienced during February 2015 throughout the entire PJM footprint. Numerous cities across PJM hit their daily low-temperature records during February 2015. Due to the low temperatures and associated high electricity demand for heating needs, PJM set a new wintertime peak demand record of 143,086 megawatts the morning of Feb. 20 (hour ending 0800). The new peak record surpassed the previous all-time winter peak of 142,863 MW set Jan. 7, 2014. Some of the individual transmission zones within the PJM footprint also set all-time record winter peaks.

In addition to the extremely cold temperatures, PJM also reviewed effective temperatures or wind chill data, for select cities throughout the footprint for both 2014 and 2015. This analysis indicated January 2014 actually felt colder just about everywhere when compared to 2015, especially in Columbus, Cleveland and Chicago, where effective temperatures were between 14 and 16 degrees warmer in 2015. The significant wind chill experienced during 2014 could have contributed to the higher amount of generator forced outages encountered in 2014. By comparison, the less severe warmer effective temperature, wind chill, in 2015 may have contributed to improved generator performance.

Generator Performance

Generator performance in February 2015 showed improvement, with forced outage rates better than in January 2014. For the morning of Feb. 20, 2015, when PJM reached a new all-time winter peak, the forced outage rate was 13.4 percent, representing 24,805 MW of generation forced out of service. Although the 2015 winter peak forced outage rates represent an improvement over the 22 percent forced outage rate during the Jan. 7, 2014, peak, the 2015 rates were still above historical "normal" winter peak outage rate of between 7 and 10 percent.

The performance improvements of winter 2015 over 2014 are attributed to steps PJM and generation owners initiated after the winter of 2014 experience: pre-winter operational testing for dual-fuel and infrequently run units, a winter-

[1] The PJM Capacity Performance proposal currently pending before FERC is designed to address the lack of generation performance incentive that currently exists in PJM region.

preparation checklist program, better communication of fuel status and increased coordination with natural gas pipelines.

A total of 168 units (9,919 MW) participated in the pre-winter operational testing. Units that participated in the pre-winter operational testing had a lower rate of forced outages compared to those that did not test.

While the 2015 improvements were effective, PJM does not believe that short-term measures are adequate to ensure long-term generation performance improvements on a sustained and dependable basis. As PJM explained in its Capacity Performance discussions, the current performance generation incentives are inadequate and longer-term solutions are necessary.

Operations

PJM used winter of 2014 data in its load forecasting tool to improve the accuracy of its forecasting this winter. Accurate forecasting is one of the most important aspects of planning and preparing for daily operations and is the primary driver for scheduling generation. The average load forecasting error for the four highest peak days in February 2015 was 1.52 percent, compared with 2.29 percent for the six highest peak days in January 2014. The February improvement is equivalent to 1,050 MW of load.

PJM met its Feb. 20, 2015 peak, the new all-time winter peak, with internal capacity and interchange without the need for emergency demand response, shortage pricing, emergency energy purchases or emergency procedures beyond a cold weather alert. PJM also maintained its reserve requirements at all times.

Gas/Electric Coordination

PJM reviewed the availability of natural gas and liquefied natural gas as well as gas restrictions issued in the PJM footprint, plus the price of natural gas and heating oil. In summary, more natural gas and liquefied natural gas was available in the PJM market area in 2015 compared to 2014. Natural gas storage increased in 2015. Prices for both natural gas and heating oil were lower than winter of 2014 prices. The highest natural gas spot price observed in 2015 was about $75/MMBtu; 2014 spot prices went higher than $125/MMBtu. The highest heating oil prices observed in 2015 was equivalent to about $13/MMBtu while 2014 spot prices went up to $22/MMBtu.

Despite more natural gas, LNG and storage, there were just as many, if not more, restrictions issued by the pipelines. Units that had gas supply restricted by their pipelines were forced to take an outage, ask for an exception to some of their unit parameters (e.g. minimum run time) or run on an alternate fuel, if the unit was capable of doing so and the alternate fuel was available. On the morning of Feb. 20, forced outages from gas issues totaled 7,420 MW, or 29.9 percent of total forced outages. In comparison, at the Jan. 7, 2014, peak, 9,300 MW of gas-fired capacity was out of service because of natural gas unavailability, or about 25 percent of the total outages.

PJM established a gas-electric coordination team, as recommended in the 2014 Winter Report, to establish closer coordination with natural gas pipelines and assist PJM Dispatch in factoring gas availability data into its cold weather planning and scheduling with generators. Dispatch also benefited from improved reporting on gas status by generators.

Impact on Market Operations

Due to the record-setting winter peak, on the morning of Feb. 20, 2015, the RTO real-time LMP hit a high of $418.67 per megawatt-hour (hour beginning 0600) – the highest LMP reached this winter. By comparison, on Jan. 7, 2014, LMPs exceeded $1,800 per megawatt-hour.

Ancillary services prices, specifically prices for regulation and reserves, trended with energy prices during the winter of 2015. The highest regulation price was just over $600 per megawatt-hour for two hours during the extreme cold periods in 2015, compared to approximately $3,300 per megawatt-hour during the 2014 Polar Vortex. Synchronized reserve prices hit a maximum of $243.14 on Feb. 20, 2015, (hour beginning 2000), and the non-synchronized reserve prices hit a maximum of $189.24 on Feb. 20, 2015, (hour beginning 0700), both coinciding with rising real-time energy prices during the respective timeframes.

Uplift moderated in January and February 2015 compared to the same period in 2014. Uplift for the combined months of January and February 2015 was $150.5 million, compared to the $653 million for the same period in 2014. However, uplift levels during the winter were still elevated above average levels, which indicate an ongoing need to address the drivers for uplift such as inflexible unit parameters and gas generation operational inflexibility caused by pipeline constraints and other issues.

2015 Recommendations

Many recommendations identified from winter 2014 were implemented in whole or in part for the winter of 2015 and had a positive impact on operations and market outcomes. Even with better performance in winter 2015, PJM has identified areas for continued improvement. These include:

- Continue with the implementation of the Capacity Performance proposal to address resource performance incentives on a sustained basis
- Coordination between the gas and electric industries
- Enhance the ability for generators to communicate operational parameters to PJM
- Build upon the success of the cold weather unit exercise and preparation checklist to improve the value while balancing the costs
- Investigate methods and procedures for reducing the amount of uplift to be paid

Report Organization

This report is organized by key topic, including Weather and Load, Generator Performance, Natural Gas Conditions, Market Outcomes, Emergency Procedures, Reserves, Interchange and Bulk Electric System Status, followed by a summary of implemented 2014 recommendations and their impacts, new recommendations from the winter of 2015 and appendices.

Weather and Load

The winter of 2015 was marked by cold temperatures similar to the winter of 2014, with the entire PJM Interconnection footprint experiencing its coldest temperatures during February 2015. Numerous cities throughout PJM hit their daily low temperature record during February 2015. PJM set a new wintertime peak demand record of 143,086 MW for the RTO in the morning of Feb. 20, 2015, (hour ending 0800), due to low temperatures and associated high-electricity demand for heating needs. In addition, some of the individual zones within the PJM footprint also set all-time record winter peaks.

While temperatures in the PJM footprint during January 2015 were slightly below statewide average temperature ranges, *temperatures in February were significantly lower than the average.*

Cities – including Philadelphia, Washington D.C., Richmond, Cleveland, Columbus, Lexington and Chicago – hit their daily low temperature record on Feb. 19 and 20. On Feb. 19, Philadelphia (8 degrees Fahrenheit), Washington, D.C. (11 degrees F), Richmond (9 degrees F), Cleveland (minus 4 degrees F), Columbus (minus 3 degrees F) and Lexington (minus 8 degrees F) experienced their record daily low temperatures; on Feb. 20, Washington (5 degrees F), Cleveland (minus 17 degrees F), Columbus (minus 8 degrees F), Lexington (minus 18 degrees F) and Chicago (minus 7 degrees F) experienced their record daily low temperatures. The cold temperatures were persistent, and most of these cities also experienced the extreme cold temperatures for multiple days.

Figure 1. 2015 Lowest Temperatures (Fahrenheit)

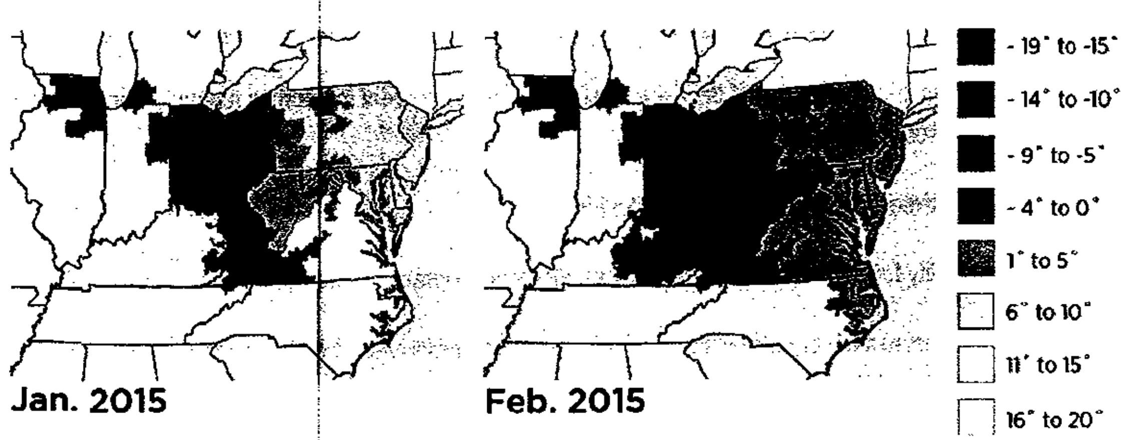
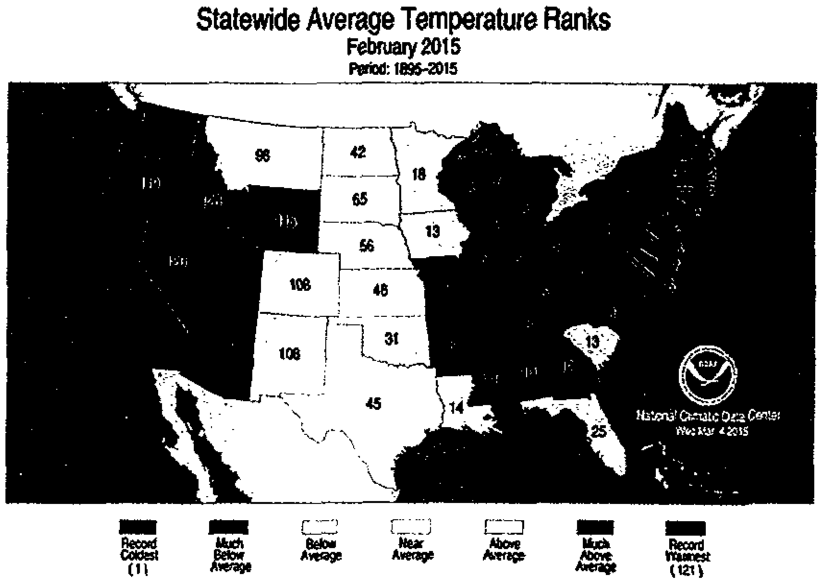
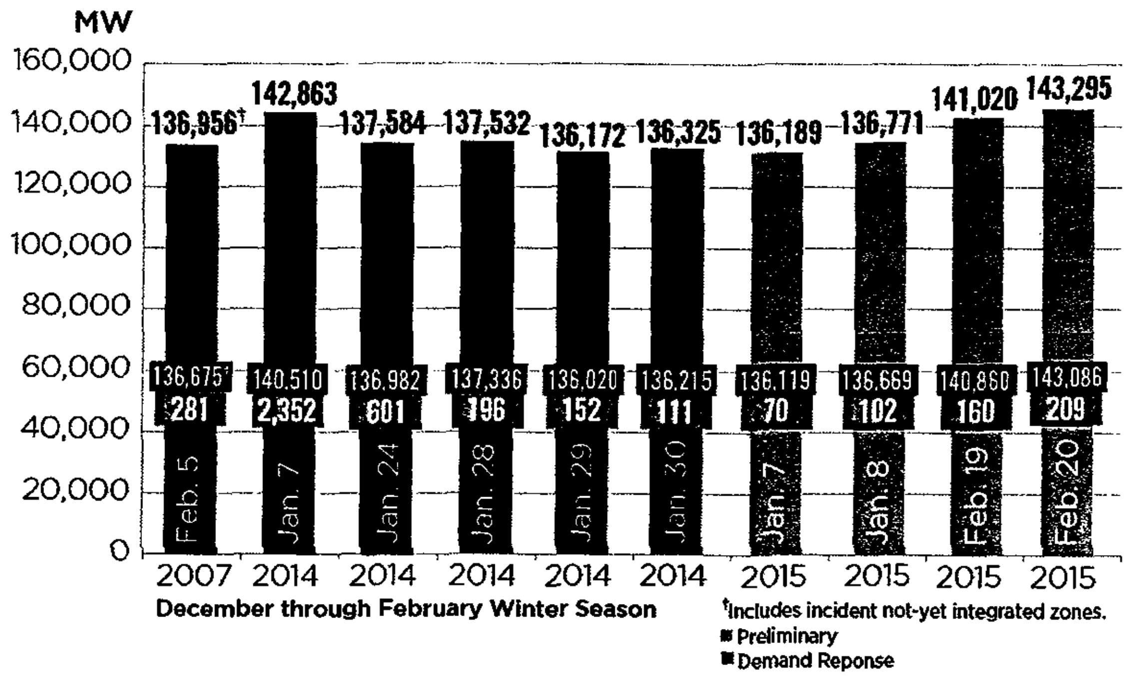


Figure 2. Statewide Average Temperature Ranks February 2015



The persistence of these extreme cold temperatures drove the high load values and all-time winter peaks for the winter of 2015. PJM set four new RTO winter peaks (of the top 10 winter peaks), with one of them being the new wintertime peak demand record of 143,086 MW set the morning of Feb. 20 (hour ending 0800). Two of the 2015 peak load days were set on Jan. 7 and 8 and two on Feb. 19 and 20. Although the new record winter peak was set this winter, no emergency demand response or any other capacity emergency actions were required.

Figure 3. Top Ten RTO Winter Peaks



In addition to the RTO winter peak records set this winter, some of the individual zones within the PJM footprint also set all-time record winter peaks. PP&L, BG&E, Pepco, DP&L, AEP, EKPC and Dominion zones set new all-time winter peak demand records during the winter of 2015.

Figure 4. Zones with All-Time Winter Peaks

Zone	All Time Winter Peak Feb. 20, 2015, Metered Load (MW)	Previous Winter Peak Metered Load (MW)
PP&L	8,055	7,577 (2/1/2007)
BG&E	6,712	6,347 (2/1/2007)
Pepco	6,066	5,606 (2/1/2007)
DP&L	4,114	3,603 (2/1/2007)
FE South (AP)	9,594	8,664 (2/1/2007)
AEP	24,739	24,434 (1/1/2009)
EKPC	3,490	2,478 (1/1/2013)
Dominion	21,608	18,079 (2/1/2007)

Load Forecasting

Load forecasting and the accuracy of the forecast are critical to PJM operations. The forecasted load is the basis upon which generation scheduling decisions are made. Any error, high or low, can significantly impact both reliability and prices. PJM's goal is to forecast load with a less-than-3 percent error rate. The average load forecast error for winter the peak days in 2015 was 1.52 percent.

PJM uses a neural net load forecasting model, which uses historical data, including "similar load day" and "similar weather day" to develop the forecast. A PJM dispatcher and on-staff meteorologist review the forecast and make adjustments based on experience and system conditions to develop the published forecast. This process begins a week prior to an operating day and continues until the operating day. During that time, PJM monitors weather projections and historical load patterns to update the published load forecast, sometimes multiple times per day.

Although the average load forecast error for the winter peak days in 2015 was 1.52 percent, there was one outlier day on the evening peak of Jan. 7, 2015, which was 3.98 percent under forecast. The chart below shows the forecast accuracy for each peak during the winter of 2015.

Figure 5. 2015 Peak Error

Date	Rank	Peak Hour	Peak Load Actual (MW)	Peak Forecast (1800 hrs.)	Peak Error (%)
1/7/2015	9	20	136,119	130,703	-3.98
1/8/2015	3	8	136,669	135,651	-0.74
2/19/2015	7	20	140,860	140,855	0.02
2/20/2015	1	8	143,826	141,851	-1.37
				Average	-1.52

In 2015, PJM improved its load forecasting over the winter peaks from an average 2.29 percent error in 2014 to an average 1.52 percent error. The 0.77 percent, or 1,078 MW, improvement is the equivalent of one nuclear unit or two combined-cycle units. The availability of "similar load days" from the winter of 2014, as input into the neural net, was the key factor in this improvement.

By contrast, at the time of the 2014 Polar Vortex, virtually no similar days existed in the past 10-to-15 years for the neural net to reference, and the load forecasting model accuracy was negatively impacted. With similar weather and load days in its recent history, the neural net and operator experience helped improve the load forecasting in 2015.

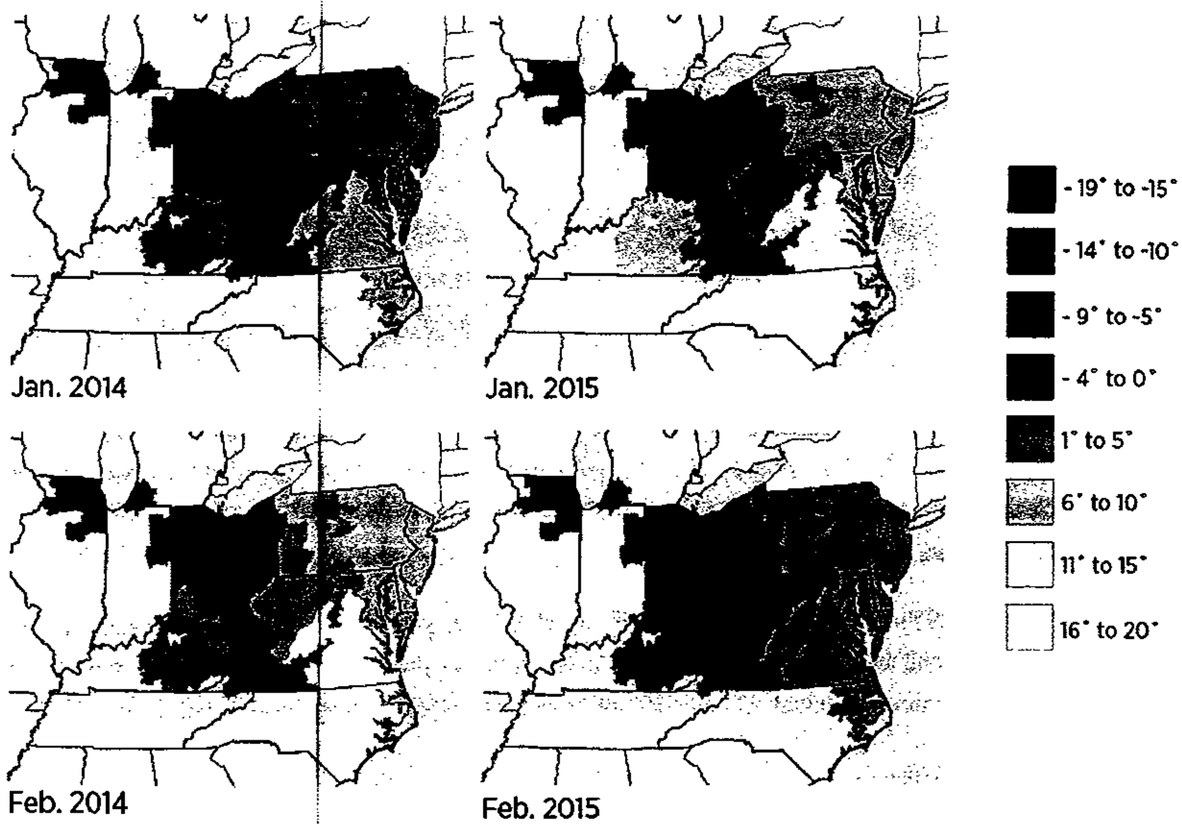
2014 Compared to 2015

To better understand the winter of 2015 compared to 2014, PJM evaluated temperatures, wind chill, duration of extreme cold weather days and progression of temperatures and their impact on load.

Temperatures by Month

The months in the respective winters with the extreme low temperatures were January 2014 and February 2015. When compared to January 2014, in February 2015 temperatures were slightly colder in the east and south by 4-6 degrees F but milder in Ohio by 1-3 degrees F and northern Illinois by about 9 degrees F. The milder areas were still well below zero degrees F. Comparing the two coldest months across the two years, the temperatures were similar, if not slightly colder on average, in 2015.

Figure 6. Lowest Temperatures by Month 2014 and 2015 (Fahrenheit)



Wind Chill

In addition to the extreme temperatures, PJM also reviewed the effective temperatures or wind chill data, for select cities throughout the footprint (as shown in the table below). The wind chill provides a perspective of how cold the temperature "feels." This analysis yielded contradictory data that indicated January 2014 actually felt colder just about everywhere when compared to 2015, especially in Columbus, Cleveland and Chicago. The wind power output during January and February is reviewed in the Generation Section of the report. In both years, the wind power output was greater than the 13 percent capacity factor.

Wind can have a significant impact on generator performance. Wind carries the heat away from improperly, poorly or uninsulated surfaces faster than cold still air. Wind could cause a higher rate of fuel burn for a fossil-fueled plant, possible freezing of drain and water supply piping, river water intake problems for steam plants and possible formation of frazil ice for steam and hydro plants. *Coal plants could experience an increase in problems with ash-*handling equipment and associated pollution control equipment as well. Wind chill impacts are amplified for generators and component equipment that are not constructed with building enclosures.

The significant wind chill experienced during 2014 (as shown in the table below) could have contributed to the higher amount of generator forced outages encountered in 2014. The warmer effective temperature, or wind chill, in 2015 also could have helped improve generator performance.

Figure 7. Wind Chill Comparison 2014 and 2015 (Fahrenheit)

	January 2014		February 2015		
	Lowest Temp Fahrenheit	Lowest Effective Temperature (wind chill)	Lowest Temp	Lowest Effective Temperature (wind chill)	Effective Degrees warmer(+)/colder (-) in Feb 2015 vs Jan 2014
Philadelphia	4	-10	2	-8	2
Washington, DC	7	-2	6	-3	-1
Richmond	4	0	5	0	0
Cleveland	-11	-30	-13	-14	16
Columbus	-11	-24	-10	-10	14
Lexington	-5	-14	-13	-18	-4
Chicago	-16	-31	-8	-17	14

Extreme Cold Weather Days and Persistence of Cold Weather

PJM also reviewed the number of extreme cold weather days, defined as any day when the effective temperature was below zero degrees F. January 2014 and February 2015 are comparable in the number of sub-zero days observed by city, 63 days in both years.

In addition to comparing the extreme cold weather days, PJM also evaluated the maximum number of consecutive days with temperatures below 10 degrees F per city to understand the persistence of the cold weather. The threshold of below 10 degrees was used because that is the trigger temperature for PJM to issue a cold weather alert. Almost every city experienced slightly more extended cold weather in 2015 versus 2014. PJM has observed that extended extreme weather, hot or cold, tends to drive peak loads higher after the first day. Some possible explanations for this higher load could be: changes in residual heating in buildings, which drives HVAC load changes, and changes in human behavior as extreme weather persists, such an increasing or decreasing thermostats and staying inside using more electricity. In addition, the net energy usage also was evaluated. Out of January and February 2014 and 2015, January 2014 had the highest net energy usage, but, when looking at the total for January and February 2014 compared to January and February 2015, 2015, had higher net energy usage.

Figure 8. Number of Days with Effective Temperatures Less than 0 Degrees F (Note – coldest months in 2014 and 2015 are next to each other for better comparison)

	January 2014	February 2015	February 2014	January 2015
	Days with Effective Temp. < 0			
Philadelphia	4	2	0	0
Washington, DC	1	2	0	0
Richmond	0	0	0	0
Cleveland	12	9	6	6
Columbus	10	9	3	4
Lexington	4	7	0	2
Chicago	14	15	9	7

Figure 9. Maximum Number of Consective Days below 10 Degrees (Fahrenheit)

	Max Number of Consecutive Days below 10-degrees	
	2014	2015
Philadelphia	4	7
Washington, DC	4	2
Richmond	3	3
Cleveland	10	11
Columbus	5	10
Lexington	5	7
Chicago	9	17

Temperature and Peak Load Progression

One of the most notable differences between the two years is the progression of temperature and load changes in the period of time leading up to the peak. The top two winter peak days, Jan. 7, 2014, and Feb. 20, 2015, experienced drastically different temperature changes across the PJM footprint from the prior peak period.

For example, the temperature drop in Philadelphia between Jan. 6 and Jan. 7, 2014, was 38 degrees in 10 hours, dropping from 30 degrees to minus 8 degrees. In contrast, there was only a 14-degree drop from 7 degrees to minus 7 degrees leading into the morning of Feb. 20, 2015. The drastic temperature drop was consistent across most of the cities in 2014 versus 2015. This temperature drop at the onset of the Polar Vortex in 2014 translated to a major and rapid increase in system load. The chart below shows the progression of the peak load for five days leading up to, and including, the peak winter days in 2014 and 2015.

Even though the peak load values were similar for the two peak days in each year, the substantial change in load leading up to the peak in 2014 made a big difference. The two-day load change just before the Polar Vortex in 2014 was greater than 32,000 MW (22 percent change) compared to an approximate 16,000 MW load change two days prior to the peak day in 2015.

The rapid load change required a correspondingly rapid amount of generation to come on-line. PJM experienced the majority of the unit failures during the time of the largest load increase leading into the 2014 peak. In 2015, there was a slower progression of load change leading to the all-time peak, allowing generation to come on line more gradually. PJM experienced 40 percent less forced outages in 2015 during the peak period. Generation performance is discussed in the section below.

Figure 10. Day to Day Peak Load Progress for 2014 and 2015

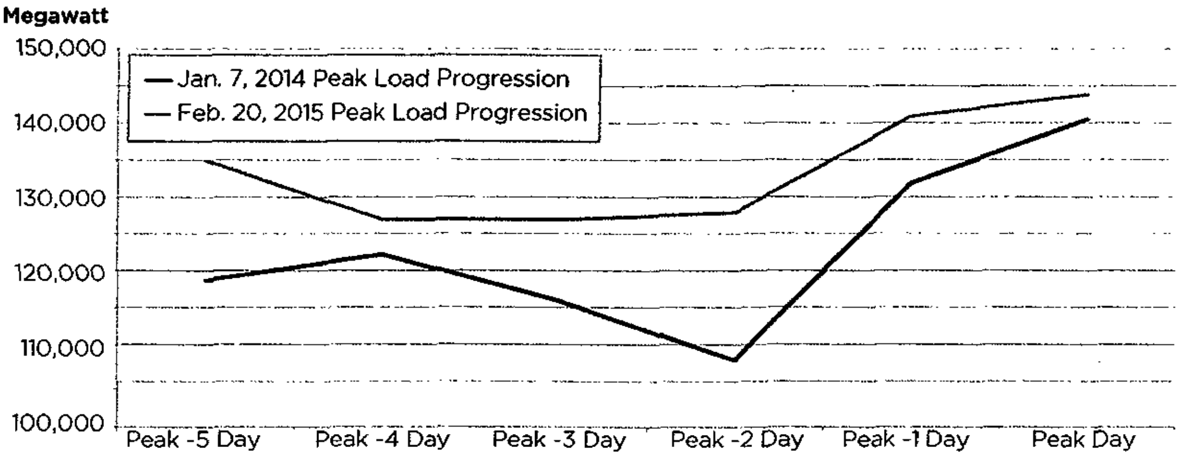


Figure 11. 2014 Temperature Drops (Fahrenheit)

	Jan. 6, 2014 18:00	Jan. 7, 2014 18:00	Change in Temp.
Philadelphia	30	4	26
Washington, DC	27	16	11
Richmond	39	13	26
Cleveland	-21	-8	13
Columbus	-15	0	15
Lexington	-7	4	11
Chicago	-28	-5	23

Figure 12. 2015 Temperature Drops (Fahrenheit)

	Feb. 19, 2015 8:00	Feb. 20, 2015 8:00	Change in Temp
Philadelphia	3	-7	10
Washington, DC	6	0	6
Richmond	8	0	8
Cleveland	-4	-11	7
Columbus	-9	-10	1
Lexington	-11	-16	5
Chicago	-17	-6	11

2015 Generator Performance

As stated in the Weather and Load analysis section of this report, the winter of 2015 was similar to the winter of 2014 in terms of temperatures and had a higher all-time peak load. The performance of the generation fleet improved in 2015 compared to 2014 but the generation performance in winter of 2015 remained below historical norms. To better understand what contributed to the improved performance from the winter of 2014 to the winter of 2015, PJM reviewed the online generation, outage amounts and causes, and implementation of lessons learned from the winter of 2014 and their impacts.

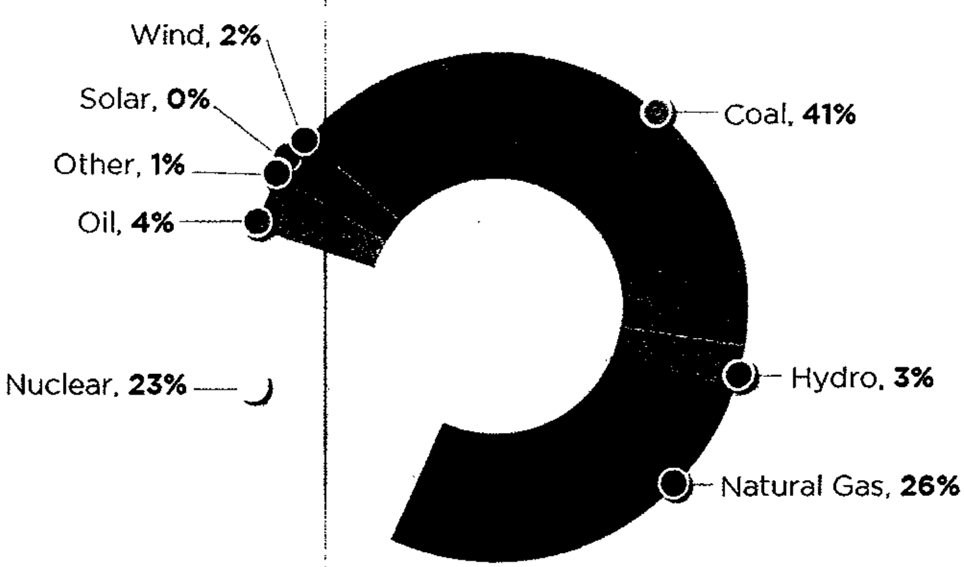
Generation Online

PJM was able to reliably meet the all-time peak load and maintain reserve requirements in winter of 2015 without the need to activate emergency demand response resources, use of market mechanisms such as shortage pricing, purchase of emergency energy, or taking emergency procedures beyond cold weather alerts. There was also a 1,200 MW net decrease in installed generation from 2014 due to unit retirements. Improved generator performance was a key contributing factor to this outcome.

The following amount of generation was online in the PJM footprint during the all-time peak on Feb. 20, 2015:

Date/Time	Installed Generation (MW)	Generation Online (MW)
02/20/2015 08:00:00	185,462	138,796

Figure 13. Breakdown of generation online for all fuel types during the Feb. 20, 2015 peak

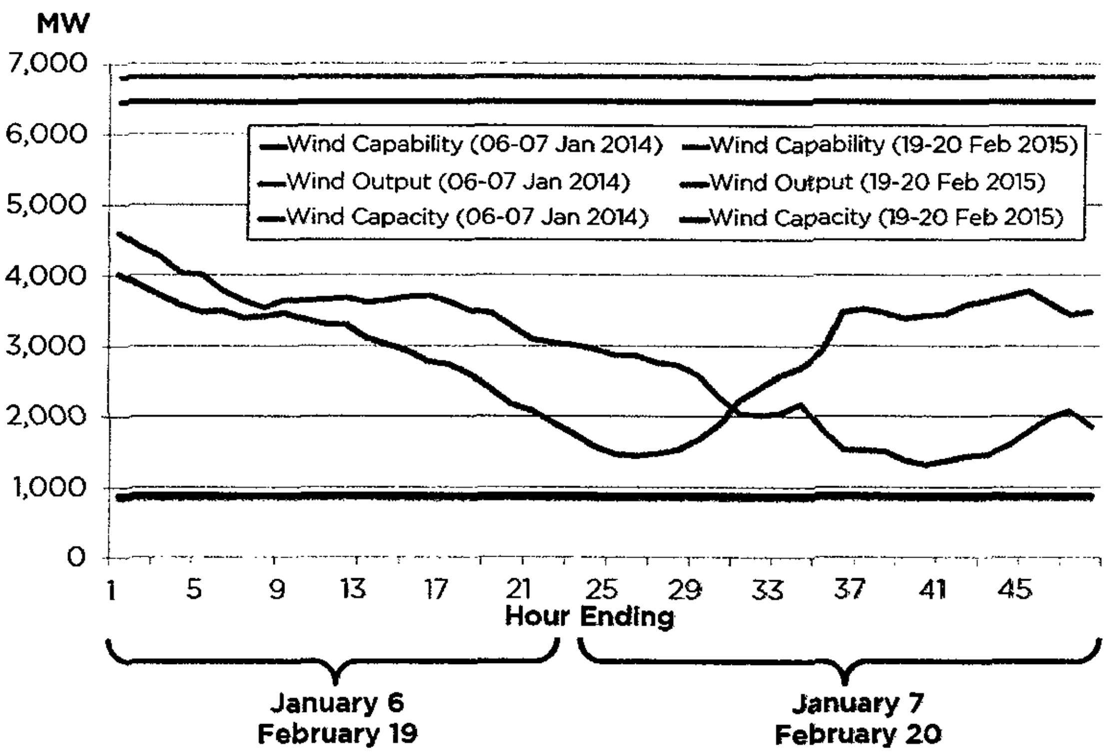


This generation mix is similar to the generation mix that was online at the peak in 2014 with a small increase in coal generation output in 2015.

Performance of Wind Units

The chart below shows the trending wind generation output during the Jan. 6-7, 2014, and Feb. 19-20, 2015, winter peaks compared to the total capability and capacity of the wind generation resources in PJM. (Note that currently in PJM the average wind capacity factor is 13 percent of total wind capability.) Wind production over the winter peak hour in 2014 (Jan. 7, 1900 hours) was approximately 1,590 MW out of a total capability of 6,457 MW (capacity factor of 25 percent). Wind production over the winter peak hour in 2015 (Feb. 20, 2000 hours) was approximately 2,575 MW out of a total capability of 6,811 MW (capacity factor of 38 percent).

Figure 14. Wind Generation Performance at Peaks (2014 Vs 2015)



Performance of Retiring Generation

Environmental regulations have resulted in approximately 11,560 MW of generation retiring between 2015 and 2018. Until the units retire, they are still available for PJM dispatch to meet load. The table below indicates how the units scheduled to retire performed during the winter peaks of 2014 and 2015.

Figure 15. Retiring Generation during the winter peaks of 2014 and 2015

Retiring Generation	Jan. 7, 2014 19:00	Feb. 20, 2015 08:00
Installed Generation	14,036	11,560
Generation Online	7,273 (52%)	5,655 (49%)
Total Outages (Planned, Maintenance, Forced)	5,333 (38%)	3,549 (31%)
Forced Outages	5,222 (37%)	3,496 (30%)
Not Called	1,041 (7%)	1,971 (17%)

The forced outage rates for retiring units in 2015 was not as high as the forced outage rate for retiring units in 2014, but the pool of retiring resources was also reduced by unit retirements in 2014. More noteworthy, the forced outage rate for retiring units continues to be significantly higher, at 31 percent, than the entire generation fleet average, which was 13.4 percent at the winter 2015 peak. These results indicate a need for improved generation performance incentives to ensure generation capacity resources remain operationally dependable for the entire period for which they are receiving capacity payments.

Generator Outages

As mentioned earlier, the biggest difference in generator performance between winter of 2014 and winter of 2015 was a reduction in generator forced outages. Outages can be planned[2], maintenance[3], or unplanned[4]. Unplanned, or forced, generator outages challenge grid reliability and are the most difficult to manage in real-time operations.

The chart below shows the trending of forced, maintenance and planned[5] outages during January and February 2015. As indicated in the chart, forced/unplanned outages are responsible for a large portion of the generator unavailability, similar to the winter of 2014

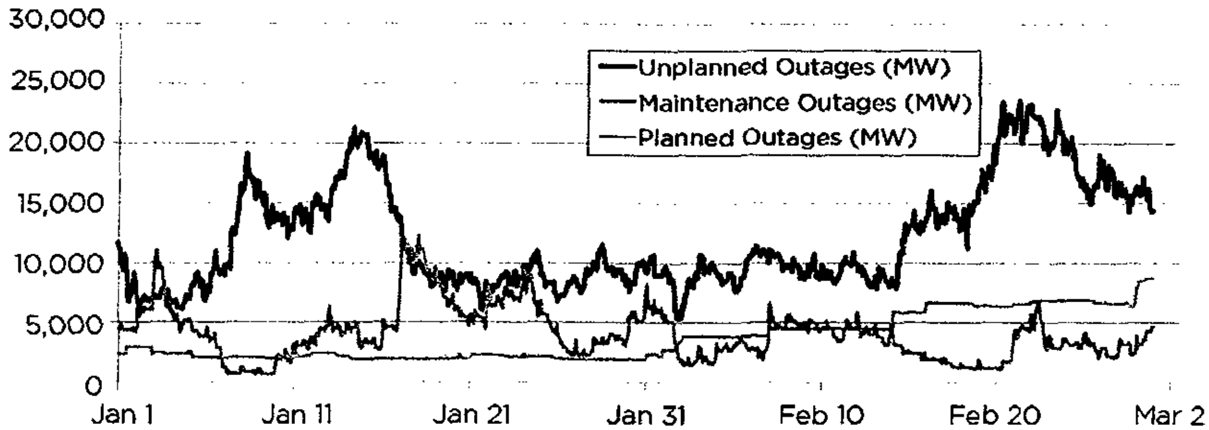
[2] Planned Outage - The scheduled removal from service, in whole or in part, of a generating unit for inspection, maintenance or repair with approval of PJM. Planned outages may last for several weeks and usually occur only once or twice per year.

[3] Maintenance Outage - The scheduled removal from service, in whole or in part, of a generating unit in order to perform necessary repairs on specific components of the facility with approval of PJM. Maintenance outages may be deferred beyond the next weekend and are typically much shorter than planned outages.

[4] Unplanned/Forced Outage - An immediate reduction in output or capacity or removal from service of a generating unit by reason of an emergency or threatened emergency, unanticipated failure, or other cause beyond the control of the owner or operator of the facility.

[5] Training on forced, maintenance, and planned outages can be found in the 2014 Winter Webinar Training http://www.pjm.com/~/media/training/webex-documents/winter-weather-procedure-changes.ashx

Figure 16. Forced Outage Peaks: January – February 2015



The forced outages at the peaks on Jan. 7-8, 2015, aligned with colder temperatures that occurred during the first part of the month. Prior to that extreme cold-weather period, there was a rise in temperatures that was most pronounced in the Southern and Eastern regions of PJM, which resulted in the cycling of marginal coal units. The extreme cold temperatures on Jan. 7-8, 2015, resulted in the restart of the higher-cost marginal coal/steam units. As these units returned online and run times increased, the failure rate from tube leaks increased over the following week, with forced outage rates peaking on Jan. 15, 2015, at 20,788 MW (11.2 percent).

Following the cold weather of Jan. 7-8, temperatures moderated and load decreased; PJM needed less generation to meet demand. This provided an appropriate time for generation owners to make repairs, as evidenced by the increased number of maintenance outages in the graph above. Towards the end of January, the number of planned outages began to increase. The increase primarily reflects the increase in environmental retrofit outages needed for spring 2015 compliance dates.

The forced outage peaks on Feb. 19, 2015, and Feb. 20, 2015, aligned with even colder temperatures experienced on these days. During the new all-time winter peak load on Feb. 20, 2015, the forced outage rate was 13.4 percent, representing 24,805 MW.

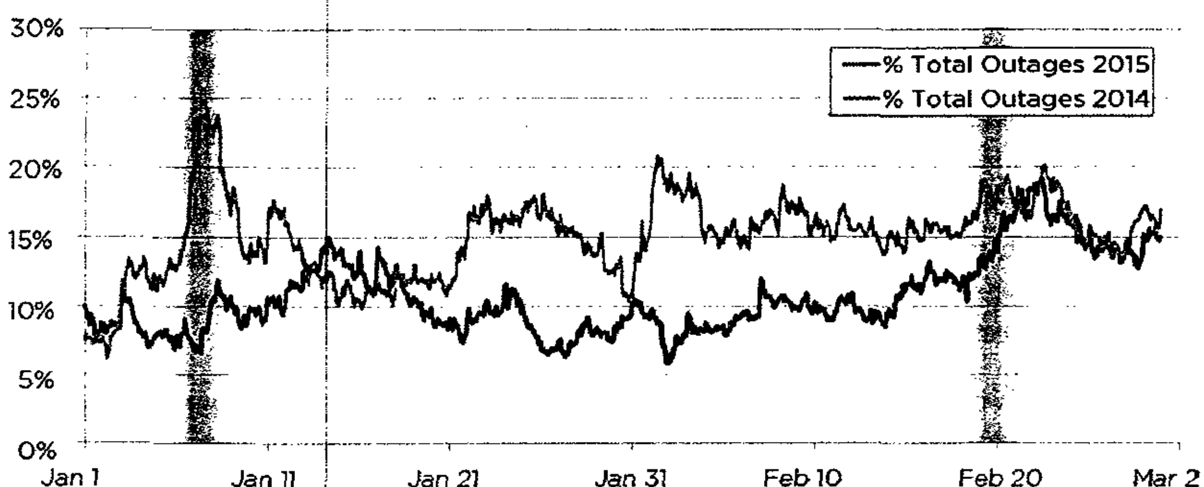
Another way to look at generator performance is by the number of hours during which forced outages were equal to, or greater than, 10 percent of the installed generation. Seven percent is the historical average winter outage rate. Using 10 percent as a threshold is a statistically significant amount above the historical average. The table below shows the hours for January and February in 2014 and 2015, as well as the average forced outage rate.

Figure 17. Number of hours during January and February when forced outages were equal or greater than 10 percent of the installed generation

	2014	2015
Number of Hours >=10% Forced Outage Rate	639	159
Average Forced Outage Rate (Jan-Feb)	10.05%	6.5%

Also shown below are the total outage rate (sum of forced, maintenance and planned outages expressed as percent of installed generation) comparisons between 2014 and 2015.

Figure 18. Total Outage Rate



Forced Outage Causes

Generators are required to submit forced outage data after the outage has occurred. From this data, PJM can analyze and understand the cause of the outage, as designated by the unit owner. As was the case in 2014, the extreme conditions of 2015 challenged all conventional forms of generation, including natural gas, coal and nuclear.

The charts below breakdown the forced outages by generator primary fuel at the two winter peaks across the two years, Feb. 20, 2015, and Jan. 7, 2014.

Figure 19. Outages by Primary Fuel Feb. 20, 2015

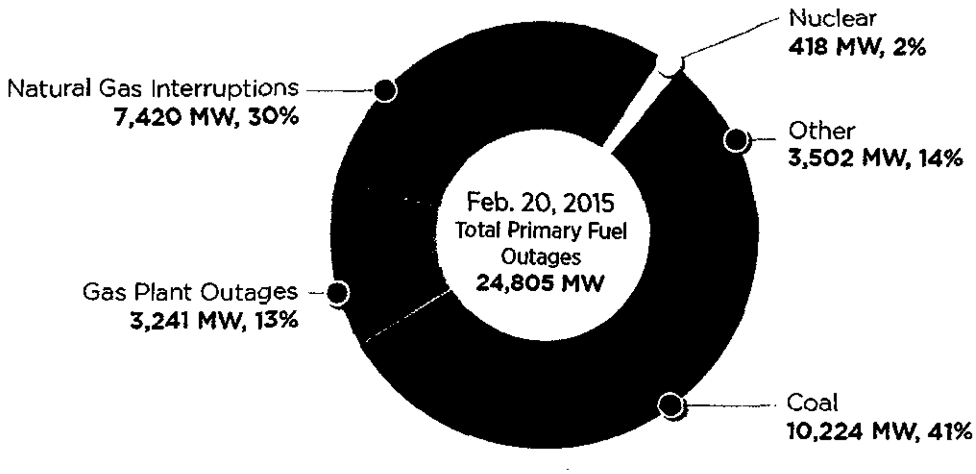
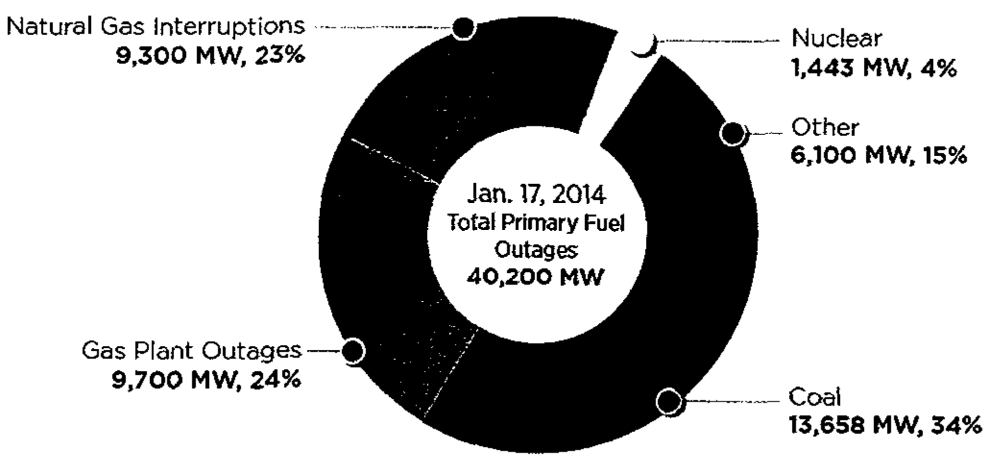


Figure 20. Outages by Primary Fuel Jan. 7, 2014



Note: "Other" includes heavy oil, kerosene, landfill gas, light oil, waste, water, wood, ambient corrections, wind, solar and batteries.

The charts below provide a more detailed breakdown of the forced outages at the 2015 and 2014 peaks, based on cause or reason for the outage. The outage codes used in the charts below are assigned by the generation owner/operators, and there may be some difference in interpretation between owners/operators regarding which outage codes to assign.

Figure 21. Causes of Forced Outages (MW) Feb. 20, 2015, 08:00

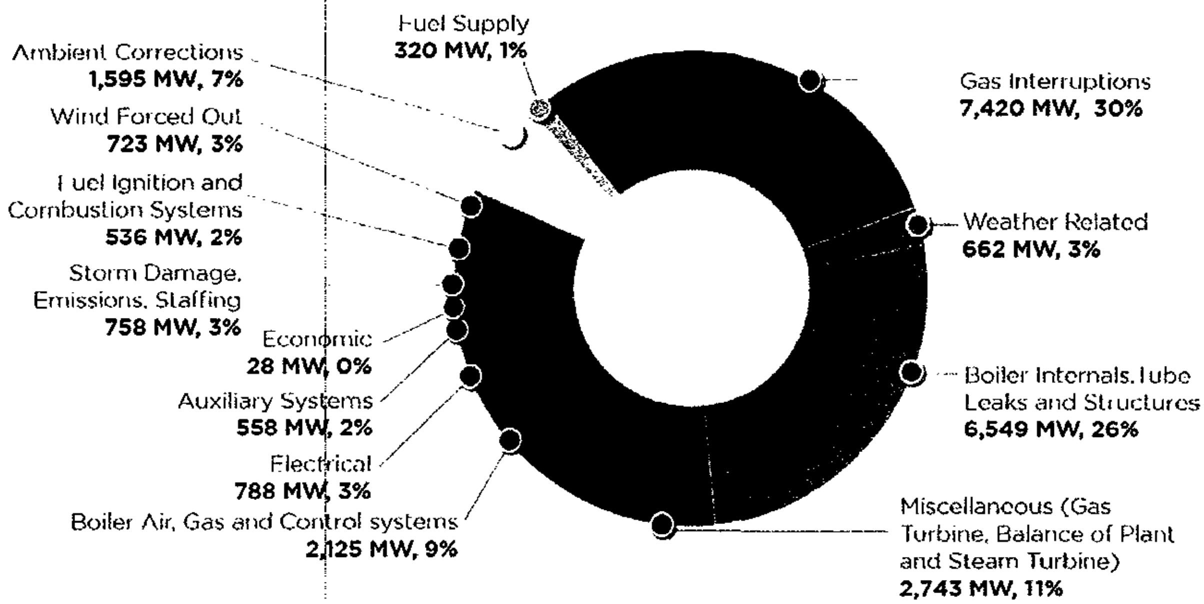
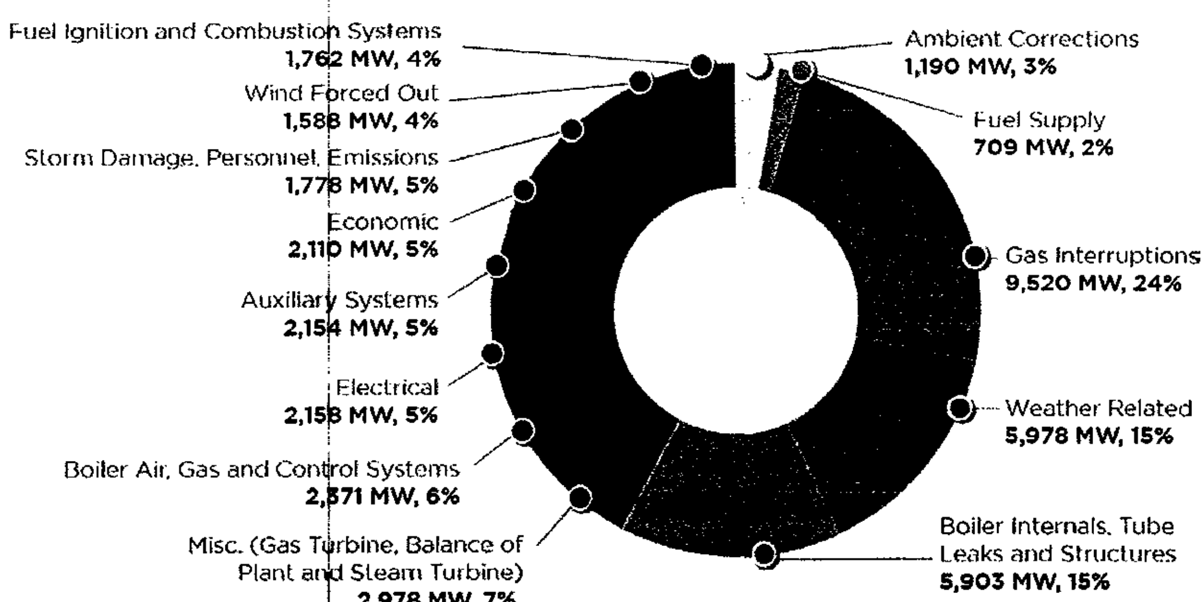


Figure 22. Causes of Forced Outages (MW) Jan. 7, 2014, 19:00



There was an overall reduction in total forced outage megawatts for each component type in 2015, when compared with 2014. While there are some differences in certain outage causes between 2014 and 2015, these differences are difficult to analyze when compared on a percentage basis, given the smaller total megawatts involved. However, a few areas with more significant differences are further discussed below.

Weather-related outages that may have been caused by extreme cold temperatures, such as problems on auxiliary systems, electrical systems and fuel ignition and combustion systems, were reduced in 2015. This reduction indicates better preparation by generation owners – such as additional freeze protection – may have improved performance. The cold weather programs initiated by PJM, which include a cold weather resource operational exercise and generator winter preparation checklist, contributed to improving generator preparation as well.

Weather-related outages also can include forced outages on units that experienced coal-related issues, such as coal exposure to extreme weather. Any wet coal or coal-quality events may have been considered weather-related since, once crushed, coal that initially may have been frozen can plug chutes when it refreezes, which can cause handling issues as well as combustion and slagging issues. These types of outages were somewhat comparable in 2014 and 2015. The mitigating efforts of the cold weather preparation programs mentioned above did not mitigate the risks of fuel exposure to the elements.

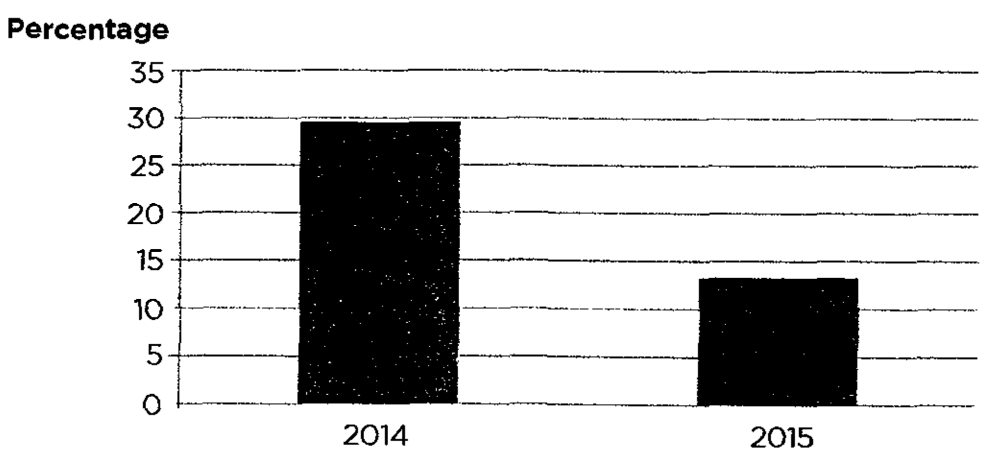
Although the amount of gas interruptions still was significant in 2015, several factors contributed to the better management of these interruptions over the peaks. These contributing factors include enhanced communications among PJM, the gas pipelines and the natural gas plant owner/operators; better performance by dual-fuel capable units; and independent actions taken by the generation owners to improve performance and availability. The enhanced communications, facilitated by the PJM gas/electric coordination team, will be further discussed in the Natural Gas Conditions section of the report.

The actions taken this winter by the Generation owners as well as by PJM to improve generator performance and communications were effective. In many cases however, these actions were voluntary and may not be sustainable over time. PJM believes a longer-term solution is required to ensure resource performance at times when it is most needed.

Dual-Fuel Unit Performance

In 2015, there were fewer forced outages for dual-fuel units than in 2014 (approximately 13 percent in 2015 and 30 percent in 2014).

Figure 23. Dual Fuel Forced Outage Rate- 2014 vs. 2015



Dual-fuel units experienced several problems in 2014 for both primary and alternative types of fuel, including gas availability issues, low oil inventories, run-time limits related to permit-defined environmental restrictions, oil resupply challenges, as well as increased failure rates for units starting on their alternative fuel. While gas availability still was a challenge in winter of 2015, some of the oil-related issues experienced in 2014 (2,000 - 3,000 MW of generation affected by oil supply and delivery issues) did not reoccur in 2015.

Reasons for this change include:

- Generators actively managed their oil inventories by proactively procuring and maintaining higher inventory levels, even taking deliveries during the winter, and monitoring run times on oil more closely to maintain oil inventories.
- Less expensive oil prices (see Natural Gas Conditions section of this report) that made it more cost-effective to procure and run on oil than in 2014.
- Generators more actively managed their emissions throughout the year (by managing run times on oil) to enable them to better prepare and have more flexibility in the winter. (See below: 5 percent forced outage rate for emissions in 2014 compared to 3 percent at its highest in 2015.)
- Less snow and ice in some areas that, in 2014, impacted truck and barge deliveries.
- Cold weather testing exercise, during which the majority of dual-fuel units that tested performed the exercise on their alternate fuel. (See Cold Weather Operational Exercise appendix.)

Contractual Constraints

Units that did not have dual-fuel capability had fewer options for handling gas restrictions. The impact on generators of gas delivery restrictions were defined in the 2014 winter report, as contractual constraints. Contractual constraints are constraints realized by generators because of the type of gas and delivery service they have. Generators without firm service could experience operational restrictions when pipelines issue operational flow orders (OFOs) or critical notices. A generator could experience the following conditions:

- the need to take a forced outage because of the inability to get gas
- the need for early commitment, days ahead of the Day-Ahead Energy Market, to ensure fuel deliverability
- inflexible scheduling criteria, such as limited dispatchable range, 24-hour minimum run time and multi-day commitment.

In 2015, approximately 7,400 MW of generation was unavailable because of lack of natural gas, compared to 9,500 MW in 2014, which still equates to about 30 percent of the 2015 total forced outages. Of the unavailable generation in 2015, 1,760 MW had day-ahead commitments. A significant difference between 2014 and 2015, however, was the impact of the contractual constraints on PJM's scheduling of resources.

Longer unit notification times may be required by generators impacted by a pipeline restriction, to ensure the generator can get gas. If PJM anticipates needing that unit to meet the peak, it would then be called on by PJM, in advance of the operating day and outside of the energy market.

During the winter of 2014, PJM called on units approximately 140 times outside of the Day-Ahead Market compared to 47 times in 2015. Units called outside of the Day-Ahead Market, include units called before the Day-Ahead Market and after the Day-Ahead Market during the Reliability Assessment Commitment.

In addition to longer notification times, there are other reasons a unit may be called on outside of the market; for example, to help control a local constraint or to support a reactive interface. The majority of the units brought on outside of the market, however, are to help meet anticipated demand and reserve requirements. In 2015, because generator owners updated the notification and minimum run parameters to reflect accurately the unit's capabilities, based on both physical and contractual constraints, PJM could rely on the results of the reliability assessment commitment to schedule the appropriate amount of generation to meet the requirements.

In January 2014, PJM anticipated high forced outage rates, high demand and tight reserves. As not all unit operational parameters were accurately reflected in the PJM systems, PJM relied less on the reliability assessment commitment results to schedule generation and scheduled additional units outside of the market to meet the anticipated operational conditions. Some of these units had limited operational flexibility because of gas pipeline restrictions, which impacted unit parameters such as notification times, minimum and maximum run times, and the ability to cycle on and off during uneconomic times. This inflexibility, in turn, impacted the market outcomes, specifically balancing operating reserves ($478 million during January 2014), a large portion of which was attributable to contractual constraints. Market impacts and differences between 2014 and 2015 will be further reviewed in the Markets Outcomes section of the report.

While PJM still anticipated peak load days in 2015, differences in a few key factors resulted in PJM scheduling less generation outside of the market:

- Improved generator performance and availability
- More accurate reporting of unit availability and operational parameters in the PJM systems
- More insight into the gas pipeline conditions and impact on generation

Combustion Turbine Availability

Normal combustion turbine availability in PJM is over 30,000 MW, which was the case in January 2015. Even leading into the cold weather, more than 20,000 MW of combustion turbines were available. PJM uses combustion turbine availability as a gauge for whether to call on units with a long lead time. Because of the lack of performance incentives for resources, Operations' conservative rule of thumb is to assume a 50 percent start-up failure for combustion turbines.

For 2015, even with a more conservative estimate of 10,000 MW of combustion turbines available, PJM had sufficient generation available and did not call for long-lead units. Even at the peak on Feb. 20, 2015, (at 0800 hours), with 13,000 MW of combustion turbines available, PJM did not need to call long-lead generation.

In contrast, combustion turbine availability in early January of 2014 was approximately 6,000 MW. Adding to the challenge was the lack of transparency into unit availability, as many of these outages were not entered into the PJM systems in advance. Instead, they were communicated to Dispatch over the phone during the operating day heading into the peaks. Toward the latter part of January 2014, combustion turbine availability was in the 15,000-16,000 MW range. However, Dispatch was conservative in its scheduling decisions based on the most recent history and unit performance availability from earlier in the month.

Reporting of Unit Availability

Another lesson learned from 2014 was to reinforce the need for, and provide the ability to, generators to report availability, unit parameters and operational restrictions accurately in the PJM tools[6]. Throughout the winter of 2015, generator reporting improved regarding unit availability, fuel inventory, operational restrictions and more accurate unit parameters.

PJM developed a generator database to consolidate the information to further leverage the more accurate information being provided. This single source enabled more timely tracking and reporting of unit performance to PJM real-time operations. Information such as forced outage rates that had taken days to see in real-time operations during the winter of 2014 was available to PJM operators the next day in 2015 as a result of these improvements.

Cold Weather Operational Exercise

PJM also implemented the 2014 recommendation to develop a cold weather exercise designed to give generators that run infrequently or have dual-fuel capability the opportunity to test their units prior to the onset of cold weather. The goal of the testing is to identify and resolve start-up, operational and fuel switching issues to improve unit reliability during peak periods. Further details on the exercise can be found in the Appendix.

Generation resource owners were given the opportunity to voluntarily exercise some of their generation resources to determine their readiness to respond to PJM's dispatch instructions in cold weather. Generation resource owners were compensated based on the cost-based schedule for the identified fuel type. Alternatively, a generation resource owner could elect to self-schedule a resource to validate its cold weather operation.

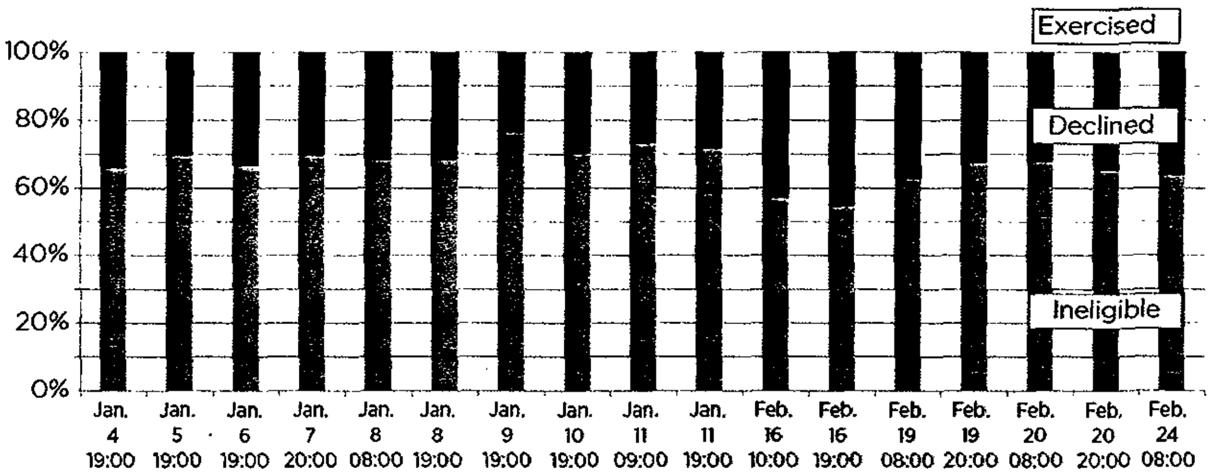
In total, 168 units with a combined 9,919 MW (11,054 MW ICAP) performed the cold weather generation operational exercise. The total cost of these tests was approximately $4,883,000.

[6] Link to Problem Statement http://www.pjm.com/~/media/committees-groups/committees/oc/20150407/20150407-item-21-gas-fired-unit-committment-coordination-problem-statement.ashx

Correlation of PJM Cold Weather Operational Exercise to Forced Outages in 2015 and 2014:

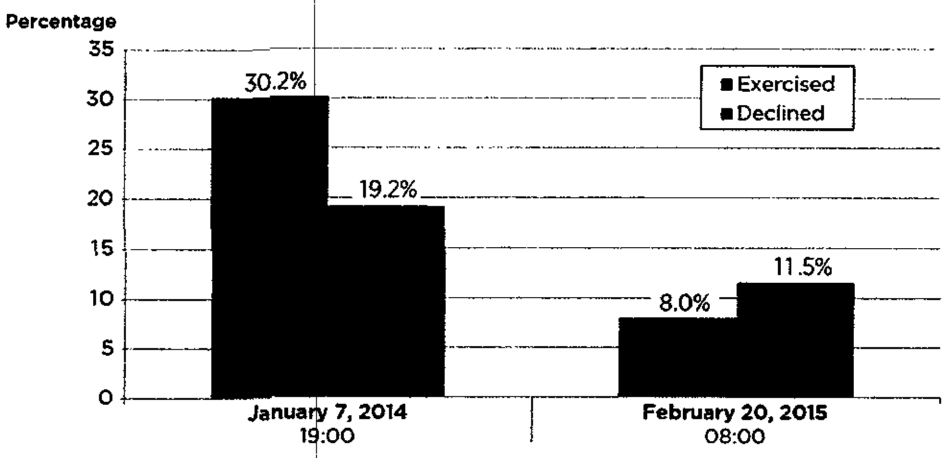
To determine the exercise's impact, PJM analyzed unit winter performance in 2014 and 2015 relative to participation in the cold weather operational exercise. The chart below shows a percentage breakdown of forced outages for January and February 2015 by megawatts and shows that eligible units that performed the exercise had a lower magnitude of forced outages compared to those that did not test.

Figure 24. Percentage Breakdown of Forced Outage MW for January and February 2015



Comparing unit performance in winter of 2015 with winter of 2014, PJM looked at the forced outage rate of units that tested and those that did not, over the two peaks, Jan. 7, 2014, and Feb. 20, 2015. The chart below shows all of the exercised and declined units that experienced forced outages during either the 2014 or 2015 peak. This analysis shows that units that elected to participate in the cold weather operational exercise experienced lower forced outage rates during the peak in February 2015 than those units that declined to perform the cold weather operational exercise. These results indicate that generation performance can be improved if specific actions are taken. While the short term efforts to improve performance through voluntary testing were effective, it is another voluntary action that may not be sustained over time.

Figure 25. 2014 vs 2015 Unit Performance of Winter Exercised and Declined Units with Forced Outage Rates



Cold Weather Resource Preparation Checklist

PJM also implemented a cold weather generation checklist program in the fall of 2014, which required resource owners to confirm the completion of the PJM checklist in Manual M14D or a substantially equivalent one developed and maintained by the generation resource owner. This program's intent was to increase awareness of winter preparedness and provide generators a guide to reduce and hopefully eliminate similar problems experienced during the 2014 cold weather events. Generation resource owners were to review their plant designs and configurations, identify areas with potential exposure to the elements, ambient temperatures, or both, and tailor their plans to address them accordingly.

The response level across the PJM footprint on the cold weather generation checklist was very good. Approximately 91 percent of all generation resources confirmed completion of either the PJM checklist or equivalent checklist. Many generation owners noted that PJM's winter exercise and the checklist program raised awareness and garnered support within the company for more thorough testing and winter preparation. While the efforts to improve performance through awareness were effective, PJM looks to ensure sustained improvement over time through performance incentives and requirements.

Summary of Generation Owner Outreach

PJM reached out to several generation owners in the PJM footprint to understand winter operations and the reasons for improved unit performance from their perspective. Some of these observations are summarized here:

- Whenever possible, generators would start on gas then switch to oil instead of attempting to start on oil.
- Starting units earlier than expected, due to anticipated colder temperatures, helped to mitigate the risk of taking more time to start.
- Keeping stations in service overnight, with a reduced output level, was beneficial to ensuring the unit would stay warm and on-line when needed for the peak.

- More thorough testing of the plant and more testing on the alternate fuel, if applicable, proved effective in proactively identify issues.
- Proactive staffing of typically unmanned stations enabled more rapid response.

Natural Gas Conditions 2015

As highlighted in the Generator Performance 2015 and Reserves sections of the report, PJM saw 7,420 MW of forced outages at the peak on Feb. 20, 2015, resulting from natural gas interruptions. While fewer than the 9,300 MW of forced outages Jan. 7, 2014, it is still a large number of megawatts. In order to better understand what may have contributed to these outages, PJM reviewed the availability of gas and gas restrictions issued in the PJM footprint, as well as the price of natural gas and heating oil.

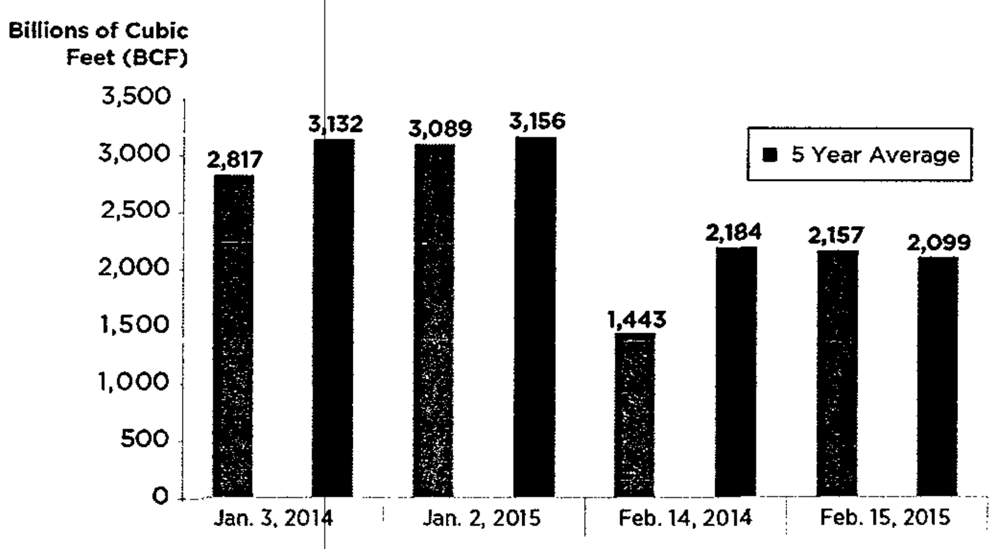
Natural Gas and Liquid Natural Gas Availability and Storage

Pipeline capacity, natural gas storage, and availability of liquid natural gas (LNG) were reviewed to understand gas availability for the winter of 2014/2015.

In November 2014, the Texas Eastern pipeline placed an additional 600 MMcf/d of capacity in the Pennsylvania, New Jersey and New York service areas. This pipeline serves approximately 11,000 MW of PJM installed generation capacity.

The summer of 2014 was characterized by lower generation loads, which contributed to increased storage injections. The storage levels increased from where they were the previous winter. During the winter of 2014, the pipelines also permitted their customers excess storage injections. The increase in storage meant more mainline transportation capacity was available to the generators. The surplus of storage inventory was as follows:

Figure 26. Storage Comparison



Operators of LNG facilities also arranged for late-season imports, increasing access to LNG supplies in the winter of 2015. Distrigas, the owner/operator of the Everett LNG facility in Boston, imported 8 Bcf of supply in January 2015, as compared to 5.5 Bcf in 2014. Excelerate's Northeast Gateway facilities, located in the Massachusetts Bay, received its first LNG shipment since 2010.

While these LNG additions at facilities in New England more directly benefited New England units, other units in the same gas market area received an indirect benefit. Within the market area, there was more capacity available from the pipelines that ran through the PJM region and into the New England area, due to less offtakes from units that also had access to the LNG supply.

The Cove Point LNG facility in the Dominion zone, which directly supplies some PJM units, also received LNG shipments of 6 Bcf in December 2014 versus none in 2013. This was an increase in the availability of LNG in the PJM area in the winter of 2015 that was not available during the winter of 2014.

Gas Restrictions

Despite the increased amounts of capacity, storage, and LNG, colder temperatures and increased demand caused gas restrictions on the pipelines. When low temperatures increase the demand for gas used for residential heating, it strains the gas pipelines that also serve electric generation. Pipeline operators and local distribution companies then issue critical notices and operational flow orders and restrict interruptible services in anticipation of adverse weather, which have the potential to restrict natural gas fired generators access to supplies.

Generators located behind local distribution companies are additionally challenged. Local distribution companies' policies give higher priority to heating customers on days of extreme cold. The policy, called "priority on human needs," prioritizes residential heating over gas-fired generators, making it very difficult for a generator to get gas in any way during these conditions.

The following pipeline operators and local distribution companies issued critical notices restricting natural gas availability in the PJM footprint during the cold periods of Jan. 7-8 and Feb. 19-20, 2015, due to anticipated temperatures and pipeline conditions. A timeline of critical notices and operational flow orders can be found in Appendix. At a high level, there were 13 operational flow orders effective across all but one of the pipelines in the PJM footprint during January 2015 and eight operational flow orders effective during February 2015.

Figure 27. Number of Effective Operational Flow Orders in PJM

Pipeline	# of Effective OFOs (or Force Majeure) in PJM			
	Jan-14	Jan-15	Feb-14	Feb-15
Transco	4	3	1	2
TCO	0	1	0	0
ANR	0	0	0	0
NGPL	2	1	0	1
TETCO	3	1	0	2
TGP	0	4	0	2
DTI	4	3	0	1
Total	13	13	1	8

The operational flow orders and critical notices often included ratable take restrictions, which required units to purchase gas evenly across all hours of the gas day. PJM generators connected to those restricted pipelines with interruptible service or those located behind local distribution companies were most impacted by these restrictions.

On forecast peak load days, there were consistent constrained areas that limited the ability to get gas to some units in the PJM footprint. These areas tended to persist throughout the winter and became effective starting in the December timeframe as temperatures dropped. Most at-risk generation was geographically located in areas behind local distribution companies or constrained by the physical pipeline limits. The northeastern part of the PJM footprint tends to be where most of the constrained areas occur, and will most likely continue to occur, until additional pipeline capacities are added. This is an area of concern as more generation within PJM is projected to use natural gas as its primary fuel.

In reviewing specifically the peak load days in January and February 2015, the split between interstate pipeline and local distribution companies' restrictions was nearly even with respect to installed capacity megawatts. Another observation in 2015 was that the same units were consistently affected throughout the cold days.

Natural Gas and Heating Oil Prices

The prices of natural gas and heating oil for 2015 were approximately 50 percent lower than in 2014 when compared to the average. The chart below shows the prices of natural gas and heating oil for the past two years for comparison purposes.

Figure 28. Prices of Natural Gas and Heating Oil

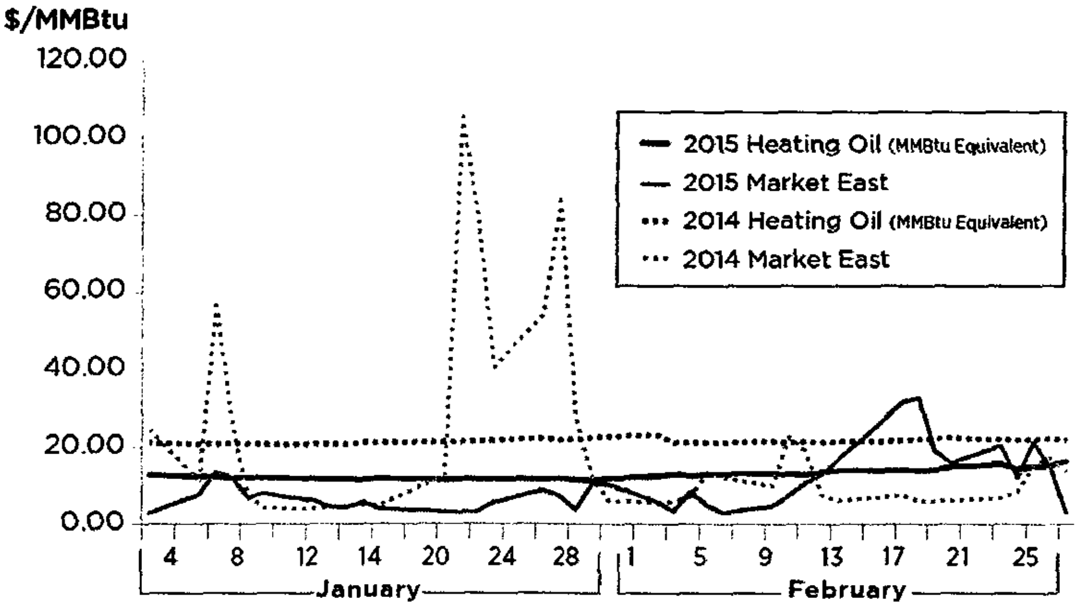
Year	Natural Gas Spot Price ($/MMBtu)	Natural Gas Daily Max ($/MMBtu)	Natural Gas Daily Average $MMBtu	Heating Oil Prices (equivalent $/MMBtu)
2015	75	30	10	13
2014	125	100	20	22
Percent Change	-40%	-70%	-50%	-41%

The following trends were noted in comparing prices to the winter of 2014 to the winter of 2015:

- 2015 natural gas spot prices did not reach the 2014 levels. (In 2014 spot prices were greater than $125/MMBtu; in 2015 the highest price observed was approximately $75/MMBtu.)
- The 2015 natural gas daily average for Market East[7] prices did not reach 2014 levels as shown in the figure below. (In 2014 the highest daily average was a little over a $100 dollars; in 2015, slightly over $30 dollars.)
- 2015 heating oil prices were lower this year than the winter of 2014. In 2014, the price for oil was around $22/MMBtu gas equivalent; in 2015, the price was closer to $13/MMBtu gas equivalent prices.

[7] Market East is an average of the following receipt locations: TETCO-M3, TRANCO-Z6 (NY) and TRANSCO-Z5 (non-WGL); heating oil is the daily heating oil average converted to MMBtu.

Figure 29. 2014 vs. 2015 Oil and Gas Comparison



The difference in natural gas prices between the winters of 2014 and 2015 was primarily driven by the relationship between supply and demand. In 2014, natural gas was in high demand and there was less supply; as mentioned above, supply was more in abundant in 2015. Generator dispatch changed in 2015 as well, which could have put a downward pressure on gas prices. For example, in 2014, lower oil prices offered dual-fuel capable generators a less-expensive fuel supply option. PJM also called on fewer units outside of the Day-Ahead Market with long lead unit times, and less flexible unit parameters such as minimum run times, which may have contributed to more stable and lower prices.

2014 Compared to 2015

To summarize the observations from the previous section, there seemed to be more natural gas and LNG available in the PJM market area in 2015 compared to 2014. There was an increase in storage in 2015. Prices for both natural gas and heating oil were lower than 2014 prices. There were just as many (comparing January 2014 / 2015) if not more (comparing February 2015 / 2014) restrictions issued by the pipelines, however.

The gas industry may have done some things differently both in preparations for and during real-time operations for the winter of 2014 / 2015 that had an impact on generators. For example, they added operational flow orders to reinforce firm transportation contractual rights on the pipeline and to manage pressure on the pipelines more actively. In 2014, the pipelines also limited the withdrawal from storage because of the effect on the operations of the storage facilities. In 2014, the pipelines required their customers to first fill their firm capacity from wellhead supply points, then from storage. This past winter that was not a requirement because of increased natural gas storage levels. When the pipelines require their customers take from the wellhead first, it limits the amount of capacity for generators to get access to supplies.

So while there were some actions taken by the pipelines to maximize capacity, there were also actions taken to ensure the capacity and pressure was available for firm transportation contractual rights. PJM units, particularly those *who had non-firm service or were in operational flow order situations, were still impacted.*

Units that had gas supply restricted by their pipelines either had to make themselves unavailable, ask for an exception to some of their unit parameters (e.g. minimum run time), or run on an alternate fuel, if the unit was capable and the alternate fuel available. As mentioned in the Generation section, there were approximately 7200 MWs of gas units that were unavailable because of their inability to get gas. This was less than the 9,300 MW forced out for the same reasons in 2015, but still 30 percent of the total forced outages for gas units in 2015.

Parameter Limited Schedules and Exceptions

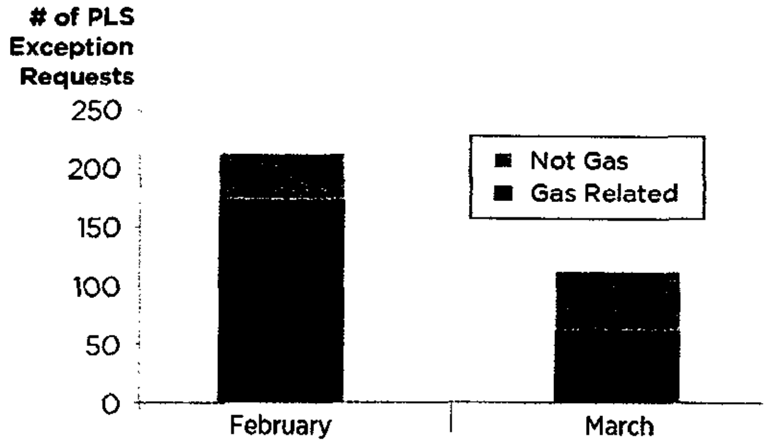
Generators have the ability to request exceptions to parameter limited schedule values due to conditions that impact the operations of their plant. This process is explained in detail in Section 6.6(f) of Attachment K-Appendix of the PJM Tariff, Section 6.6(f) of Schedule 1 of the Operating Agreement and Manual 11, but in summary, a generation resource may request an exception to certain parameters, such as minimum run time and turn down ratio, when conditions impact a unit's physical operational parameters.

One of the recommendations coming out of the winter 2014 operations was to allow generators, under a pipeline operational flow order or critical notice to use the unit parameters and parameter limited schedule exception process to communicate their operational conditions to PJM. PJM stakeholders approved this recommendation as part of the Gas Unit Commitment Coordination stakeholder group under the Operations Committee[8]. Units that elected to use this process could request a temporary exception to certain unit parameters to reflect their operational conditions because of pipeline constraints.

The primary reason for the exceptions requested during the winter of 2015 were due to ratable takes, or a pipeline restriction requiring units to take gas at an equal amount for every hour of the gas day. The number of parameter limited schedule exceptions requested because of gas restrictions is shown below. This information is not available for 2014 because gas-related parameter limited schedule exceptions were not permitted at that time.

[8] *Link to Gas Unit Commitment Coordination Problem Statement http://www.pjm.com/~/media/committees-groups/committees/oc/20140603/20140603-item-09-gas-fired-unit-committment-coordination-problem-statement.ashx*

Figure 30. Number of Parameter Limited Schedule Exception Requests for Winter 2015



Approving a unit's exception request allowed a unit to remain available that otherwise may have been forced out or unavailable to produce MWs to serve load. The process also increased the transparency to PJM dispatchers of the unit's true operational parameters, which allowed for more informed PJM Dispatch scheduling decisions.

Dual-Fuel Units

The high forced outage rates in winter of 2014 were a catalyst for PJM to better understand primary and secondary fuel types as well as more details about gas units and their gas supply, such as natural gas pipeline connection, location relative to a local distribution company, fuel supply contract (e.g. firm or interruptible), and dual-fuel capability. Implementing a 2014 winter recommendation, generators were required to provide this information to PJM.

As of March 1, 2015, approximately 40,000 MW's of generation within the PJM footprint were connected to interstate pipelines, and 22,000 MW's of generation were connected to a local distribution company. These numbers represent generation capable of burning natural gas as the primary fuel; they do not include generation that requires gas to start, typically large coal units that use natural gas as an igniter source.

Approximately 14 percent of the PJM fleet is dual-fuel capable, which means the unit is capable of running on a primary or alternative fuel source. Almost 60 percent of the generation located behind a local distribution company is capable of burning an alternate fuel. PJM observed that, during the cold weather peaks in January and February of 2015, a significant percentage of units located on a pipeline or behind a local distribution company that were at risk of getting gas because of pipeline or local distribution company-issued restrictions, were, in fact, able to run at some point during the cold weather events. (See the Generation section for outage information for dual-fueled units.) At the time of the report, there was no way to determine what type of fuel units were running on because the eMKT application change requiring units to designate fuel type on each schedule was not implemented until April 1.

While there is no direct measurement of the number of units running on their alternate fuel at this time, several indirect measurements point to improved generator performance for reasons that could include running on an alternate fuel. Those measurements include reduced forced outage rates and sufficient reserves, leading to a reduced number of emergency procedures. During informal interviews conducted by PJM, generation owners also shared information that pointed to low oil prices, their own proactive oil inventory and emissions management, more prudent start-up procedures, and additional testing on alternate fuels, facilitated by the cold weather testing exercise, as reasons they elected to run more often on their alternate fuel when gas availability was restricted.

PJM Gas-Electric Coordination Team

One other change from 2014 that PJM believes contributed to improving the overall performance of the RTO this winter was the establishment of a PJM gas-electric coordination team. PJM established the team in response to a 2014 winter recommendation to improve PJM's tools and processes for two-way communication with the gas industry. Its mission is to enhance situational awareness and better understanding the impact of gas conditions to PJM generation.

The team provides regular communication to PJM Dispatch about natural gas-fired generation units that are at risk of obtaining gas based on available pipeline capacity. The team summarizes this unit and pipeline information daily and communicates to PJM markets, operations and dispatch groups. Additionally, as system and gas conditions change, the team conducts further analysis, examining scheduled gas on pipelines for the multiple nomination cycles throughout the day.

Another primary function of the team is to improve communication with the natural gas pipelines so the pipelines and PJM are more aware of grid conditions, estimated gas demands, and availability. Since the winter of 2014, PJM has established communication protocols with the majority of the pipelines located within the PJM footprint. This protocol allows for the exchange of non-pubic information between the gas and electric industries, under FERC Order 787 and subject to the No-Conduit rule, which prohibits disclosing non-public transmission-function information (e.g. day-ahead commitments) to marketing-function employees.

Acting on this newly established protocol, the team conducted regular calls with all the major pipelines to discuss gas conditions and generator impacts. Included in these discussions are any effective critical notices, capacity constraints or operational flow orders, units located in those constrained areas with Day-Ahead Energy Market commitments, and natural gas scheduled quantities by generator by gas pipeline nomination cycle. This information helps determine whether generation, potentially needed for the morning and/or evening peak, has purchased the required fuel to burn for their day-ahead unit commitment, and thus the risk to unit availability.

The team also monitors natural gas prices throughout the trading day as well as the daily average gas prices for key hubs and receipt points in order to determine the fuel supply risk. The higher the prices, the more constraints expected, and the higher the risk to generators with non-firm gas contract to procure gas.

The goal of this analysis is to determine the risk level of available units to meet the RTO load. PJM Dispatch will conduct analysis to determine the impact of the at-risk generation units and then reach out to generators that may be required for additional discussion on availability. PJM believes the daily risk profile of gas-fired generation units improved dispatcher scheduling decisions, enabled well-informed discussions with generation owners about unit flexibility, and contributed to improved generator availability and performance.

An important note is that generators located behind a local distribution company are much less transparent to PJM and, unless dual-fuel capable, are much more at risk of not being available during emergency conditions. Of the 7,420 MW of forced outages on the morning of Feb. 20, 2015, 60 percent of the units were located behind a local distribution company. PJM currently does not have any communication protocol in place with any local distribution companies in the PJM footprint. PJM is unable to see which generators behind a local distribution company have scheduled gas. Local distribution companies have a policy which gives higher priority to heating customers on extreme cold days. The "priority on human needs" policy was utilized to prioritize residential heating over gas-fired generators. For these reasons, a recommendation for this team is to work on increasing transparency and coordination with local distribution companies in the PJM footprint so PJM can better forecast local distribution company gas generator curtailments.

2015 Market Outcomes

In the winter of 2015, locational marginal prices (LMPs) and ancillary service market clearing prices (MCP) reflected systems conditions throughout the duration of the winter. Increased LMPs and MCPs for regulation, non-synchronized reserve and synchronized reserve occurred close to the winter peak periods. During the winter of 2015, there were no shortage pricing or emergency demand response events.

Locational Marginal Pricing

LMPs are determined based on the cost to provide the next increment of energy while respecting the primary and synchronized reserve requirements, congestion and marginal losses. PJM's real-time dispatch and LMP calculation systems jointly optimize energy, reserves and regulation to ensure that all system requirements are met using the least cost resource set. This construct allows accurate reflection of price signals with a higher degree of consistency between ancillary services and prevailing energy prices.

The chart below show the real-time and day-ahead energy prices during January 2015.

Figure 31. Locational Marginal Pricing Jan. 7 and Jan. 8, 2015

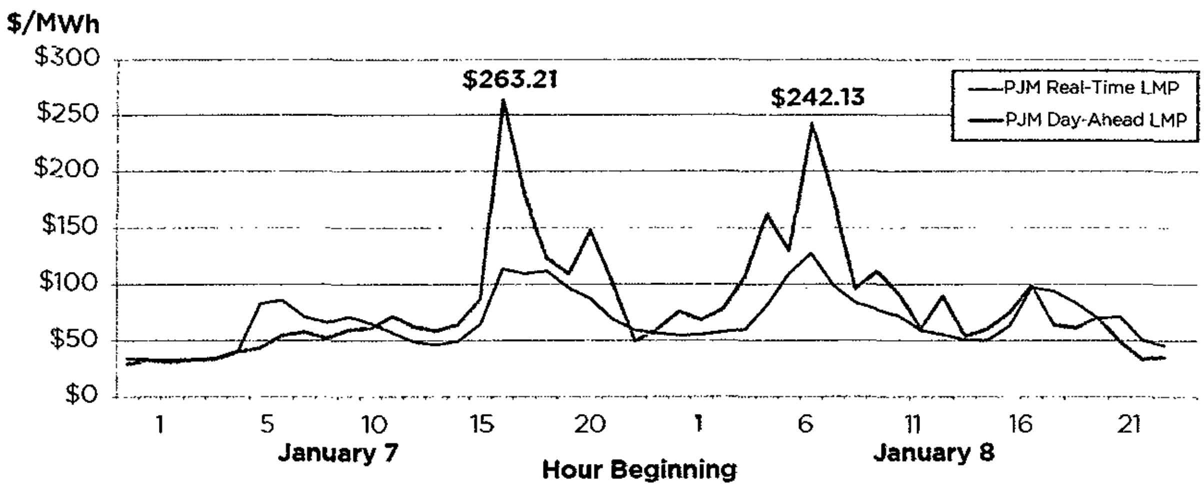
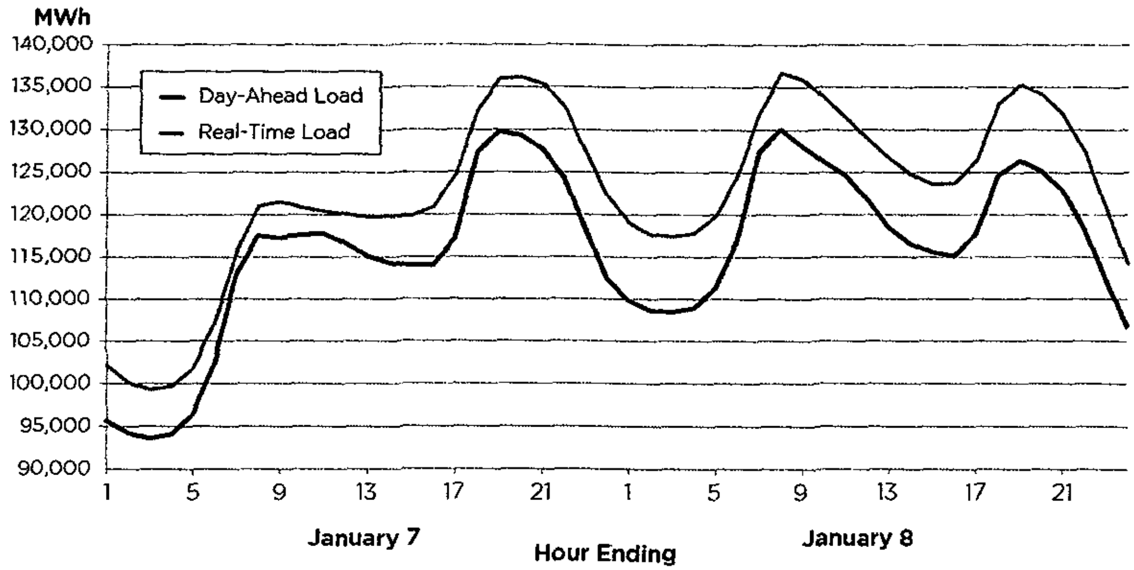


Figure 2 Day-Ahead versus Real-Time Megawatts Jan. 7 and Jan. 8 2015



The average RTO real-time energy market prices exceeded the average RTO day-ahead energy market prices consistently for the evening peak on Jan. 7, 2015, and the morning peak on Jan. 8, 2015. The highest RTO real-time LMP during the evening peak on Jan. 7 was $263.21 per megawatt-hour (hour beginning 1700), which exceeded RTO day-ahead LMP by $149.88 per megawatt-hour. The trend continued during the morning peak of Jan. 8, 2015, as RTO real-time LMPs exceeded day-ahead LMPs, which peaked at $242.13 per megawatt-hour (hour beginning 0700). For both Jan. 7, 2015, and Jan. 8, 2015, generation was the marginal resource setting prices. On average, RTO real-time LMP exceeded that of RTO day-ahead LMP consistently from Jan. 1, 2015, through Jan. 14, 2015, while this pattern reversed itself during the second half of January 2015 with RTO day-ahead LMP exceeding RTO real-time LMP

In January, the culmination of under-bid load, lower fuel prices in the day-ahead market and increased constraints in the eastern portion of the PJM system lead to the differences in the RTO real-time and the RTO day-ahead prices. Under-bid load and lower fuel prices in the PJM Day-Ahead Market could have dampened the day-ahead prices while an increase in congestion in the PJM Real-Time Market would have the effect of increasing prices. Real-time prices were lower in PJM's western area compared to the eastern area due to congestion on the bulk power system, a result of heavy transfers of energy across the RTO from the western portion of the footprint to the eastern portion. This necessitated the operation of more resources on the margin in the Eastern Region resulting in higher prices in that region compared to the rest of the footprint.

Figure 32. Locational Marginal Pricing Feb. 19 and 20, 2015

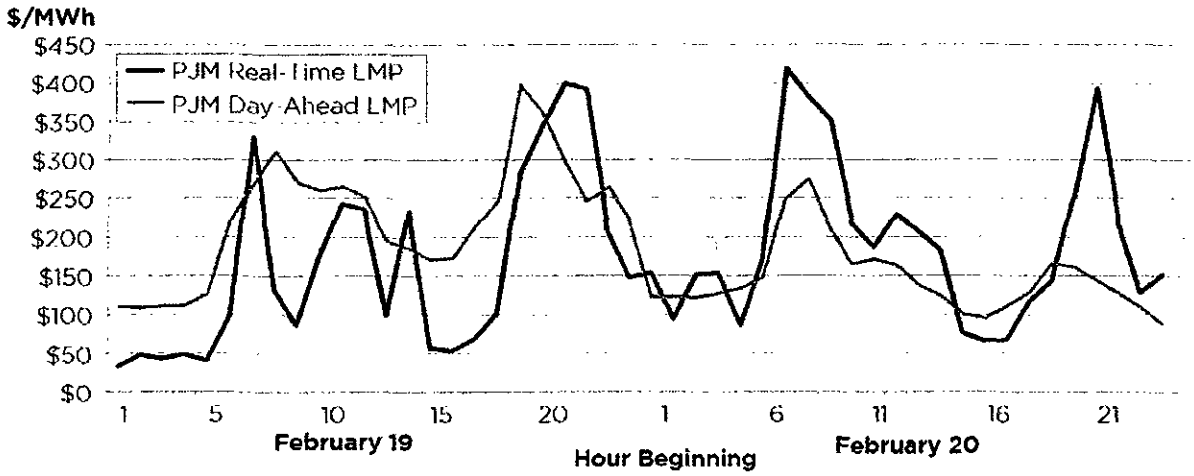
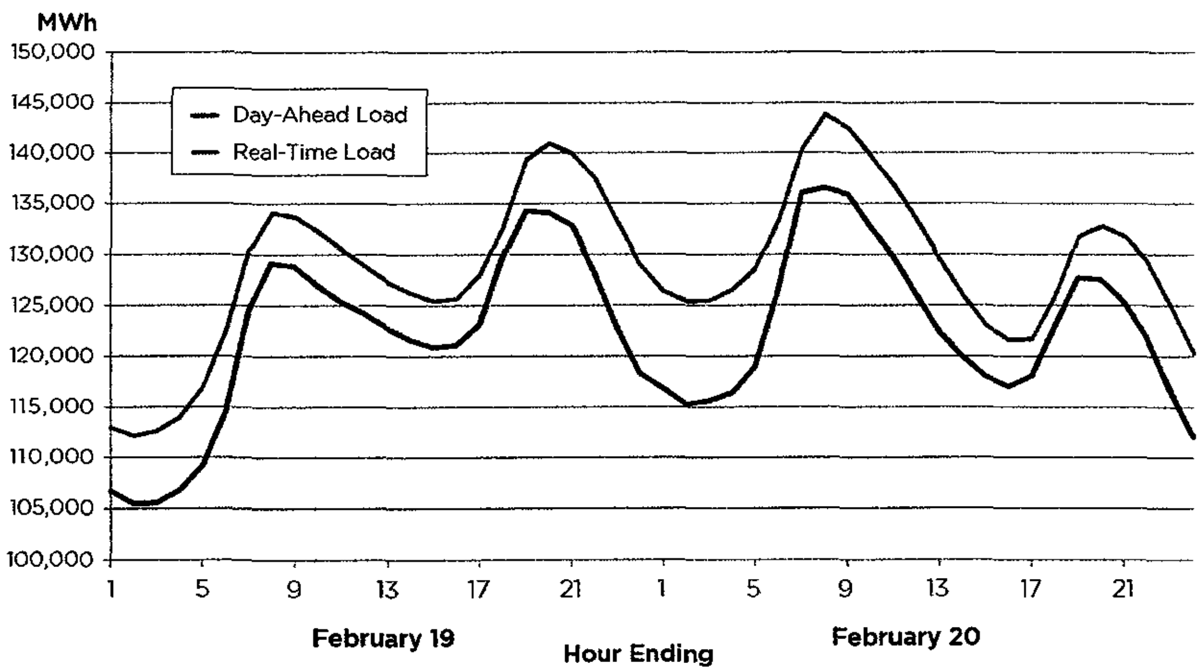


Figure 33. Day-Ahead versus Real-Time Megawatts Feb. 19 and 20. 2015



During the evening peak of Feb. 19, 2015, the RTO real-time LMP reached $399.76 per megawatt-hour (hour beginning 2000). Subsequently, on the morning of Feb. 20, 2015, the RTO real-time LMP, due to the record setting winter peak, hit a high of $418.67 per megawatt-hour (hour beginning 0600). On the other hand, from the evening peak on Feb. 19, 2015, to the morning peak on Feb. 20, 2015, the RTO day-ahead LMP decreased by 30.78 percent (maximum price of $396.89 per megawatt-hour (hour beginning 1800)).

The reduction of day-ahead LMP during the evening peak of Feb. 19, 2015, to the morning peak of Feb. 20, 2015, could be attributed to the lower fuel costs, under- bid load and units back in service from outages. Also contributing to lower day-ahead prices was the low number of long lead units that needed to be called outside of the Day-Ahead Market. The reduced number of long lead units that needed to be called outside of the Day-Ahead Market was attributed by the increased amount of day-ahead self-scheduled units that were available during this period.

Ancillary Services: Regulation, Synchronized and Non-Synchronized Reserve

During the peaks in January and February 2015, high prices for regulation, synchronized and non-synchronized reserves occurred around the same time as the real-time energy LMPs peak. The simultaneous pricing of these products with energy leads to a harmonized set of prices that are reflective of actual system conditions.

During both the winter of 2015 and 2014 Polar Vortex, the high clearing prices for regulation, synchronized and non-synchronized reserves occurred around the same time as real-time energy LMPs peaks. During these stressed conditions, ancillary service prices increased as the reserve margin decreased, and system capacity competed to meet the ancillary services requirements while maintaining power balance. Unlike 2014, PJM did not experience extreme ancillary services prices during the winter of 2015; the regulation price was just over $500 per megawatt-hour for two hours during the extreme winter periods in 2015, compared to approximately $3,300 per megawatt-hour during the 2014 Polar Vortex.

Figure 34. January 2015 Ancillary Service Price and Energy Price

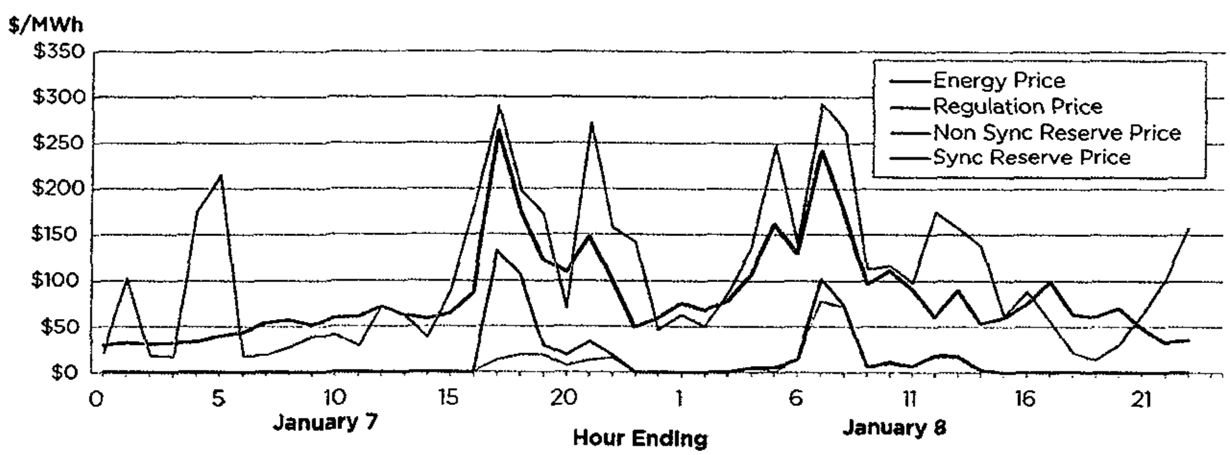
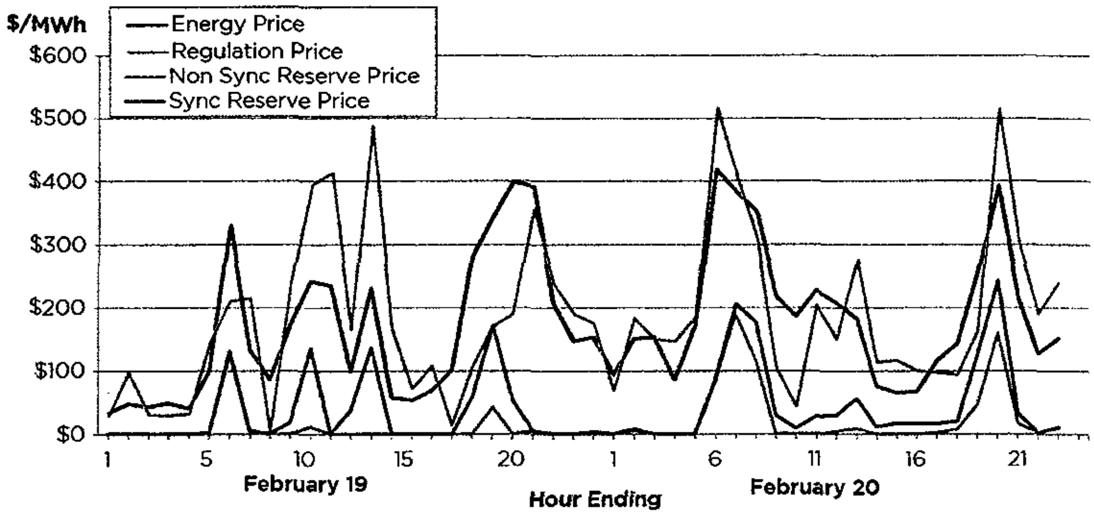


Figure 35. February 2015 Ancillary Service Price and Energy Price

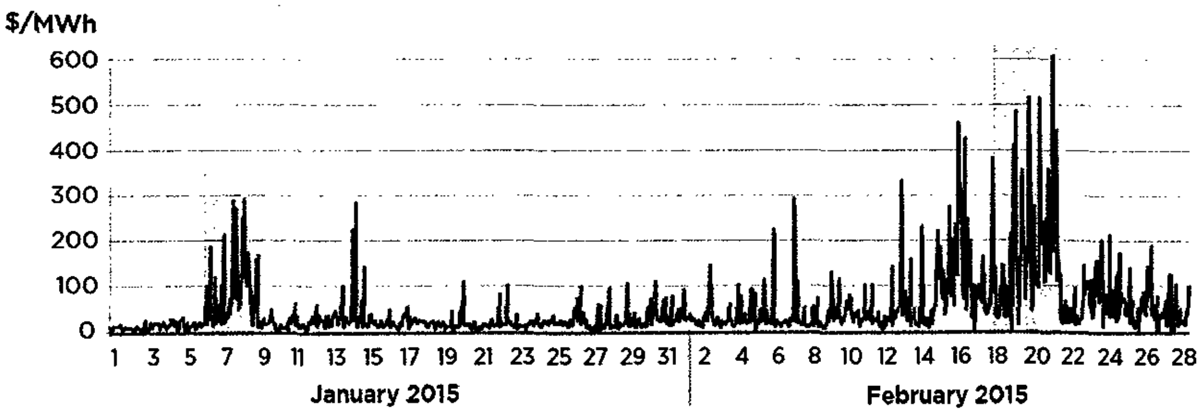


Regulation

Regulation service corrects for short-term changes in electricity use that might affect the stability of the power system. It helps match generation and load and adjusts generation output to maintain the desired system frequency of 60 hertz.

During the winter of 2015, the top three highest regulation market clearing prices were $289.51 per megawatt-hour (hour beginning 1700) on Jan. 7, $293.34 per megawatt-hour (hour beginning 0700) Jan. 7, and $516.13 per megawatt-hour (hour beginning 0600) on Feb. 20. All three of these high-regulation market clearing price spikes occurred close to the real-time energy price peaks.

Figure 36. Regulation Market Clearing Price for January and February 2015



The spike in the regulation market clearing price on the morning of Jan. 7, 2015, of $214.03 per megawatt-hour (hour ending 0600) was due to a localized transmission constraint that occurred in the Jersey Central Power & Light zone. Real-time LMP for that zone reached a high of $175.69 per megawatt-hour (hour beginning 0600) on the morning of Jan. 7, 2015.

The spike in the regulation market clearing price on the morning of Feb. 20, 2015, of $516.13 per megawatt-hour (hour beginning 0600) was in part a combination of higher load and increased in regulation lost opportunity cost. Regulation lost opportunity cost is the revenue foregone or increase in costs relative to the energy market for providing regulation service.

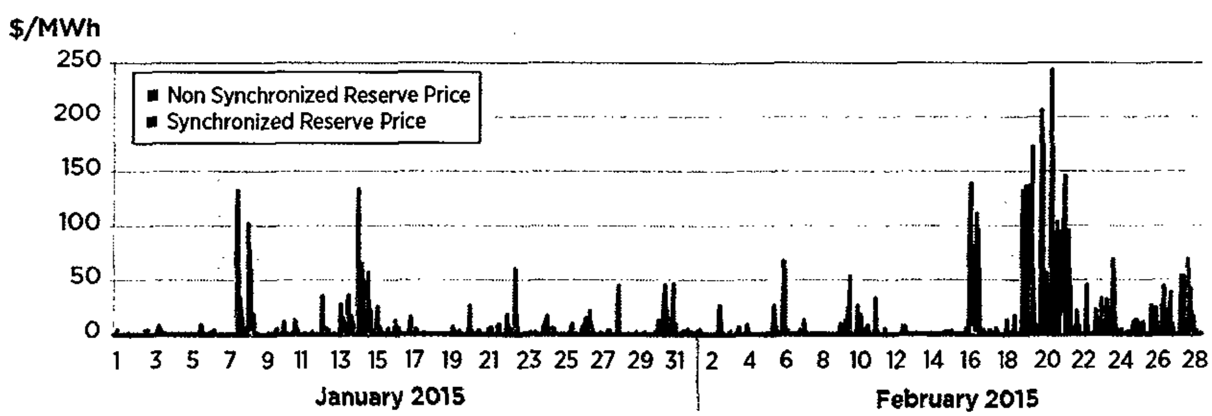
Regulation lost opportunity cost was the primary contributing factor to the increase of the regulation prices during the winter of 2015. During the 2014 Polar Vortex, the increase of regulation prices was due to the poor performance factor in the regulation market as high-performing generators were used for energy or reserves instead of regulation. Performance-based regulation was designed to calculate and include resource specific regulation lost opportunity cost in the regulation market clearing price on a real-time five-minute basis (similar to real-time LMPs).

Reserves Pricing

Reserve market clearing prices trended with energy prices during the winter of 2015 without any unanticipated excursions.

In January, both synchronized and non-synchronized reserves saw relatively small spikes in prices and volatility for both Jan. 7, 2015, and Jan. 8, 2015. Synchronized reserve prices hit a maximum of $132.10 on Jan. 7, 2015, (hour beginning 1700), coinciding with rising real-time energy prices. The rising energy prices were a result of the high loads and a reserve event that occurred during this hour. Reserve events typically produce higher energy prices due to the short-term need for more energy on the system.

Figure 37. Synchronous and Non-Synchronous Reserve Prices



During February, prices for both synchronized and non-synchronized reserves peaked on Feb. 20, 2015, along with the morning and evening peak cycle. Synchronized reserve prices hit a maximum of $243.14 on Feb. 20, 2015, (hour beginning 2000), and the non-synchronized reserve prices hit a maximum of $189.24 on Feb. 20, 2015, (hour beginning 0700), both coinciding with rising real-time energy prices during the respective timeframes. In anticipation of high loads for the morning of Feb. 20, PJM carried excess reserves on the system to ensure system reliability. These excess reserves resulted in lower synchronized reserve prices during the morning peak. During the evening peak, because of lower forecasted demand, PJM did not need to carry excess reserves. This had the effect of slightly increasing the reserve prices.

Uplift

To incent generators and demand response resources to operate as requested by PJM, resources that are scheduled by PJM and follow PJM dispatch instructions are guaranteed to fully recover their costs of operation. Uplift cost is created when market revenues are insufficient to cover the costs of the resources following PJM's direction.

The level of uplift for the combined months of January and February 2015 was $150.5 million, compared to the $653 million for the same period in 2014. The latter part of February 2015 brought an increase in the amount of uplift as PJM forecasted a greater need for generation in the day ahead, given load demand and extreme weather, to supply consumers and ensure adequate operating reserves to mitigate risk from unscheduled generator outages and natural gas uncertainty.

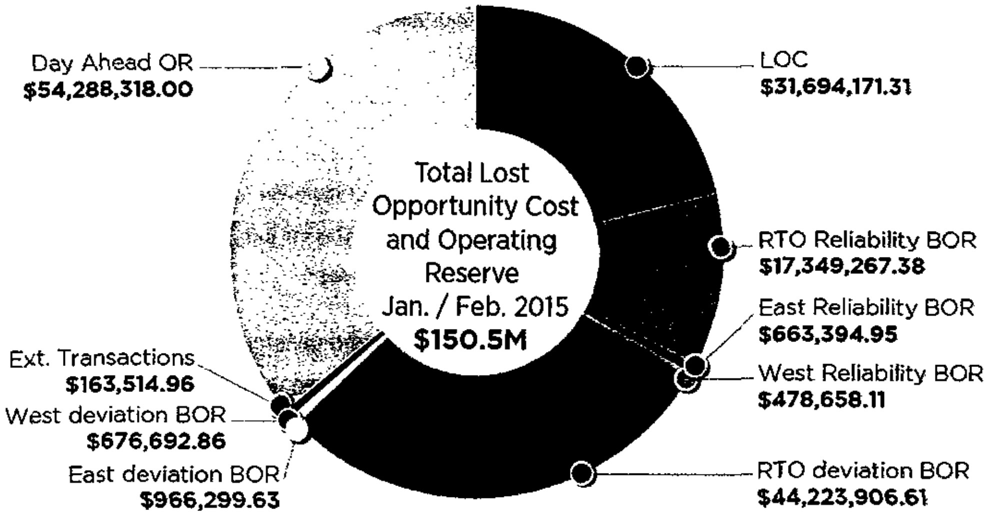
January 2015 and February 2015 experienced a noticeable uplift reduction compared to the same period in 2014. The uplift reduction can be attributed to numerous factors: improved generator performance and flexibility, improved communication and transparency with the natural gas pipelines, improved data accuracy from generators about their operational flexibility, and lower fuel prices that enabled dual-fuel units to run on oil during times of gas pipeline restrictions. These improvements provided PJM the ability to enhance energy scheduling accuracy and minimize the need to commit long-lead, large combined-cycle resources as was done in 2014.

Uplift incentivizes appropriate behavior from all supply resources and aids PJM in maintaining system control because only resources that operate at PJM's direction are eligible for uplift payments. For reliable operation, PJM requires supply resources to follow directives without hesitation. When resources follow dispatch instructions, uplift is sometimes necessary to guarantee that supply resources cover the total value of their energy offer. These payments are outside of the market and are not included in the pricing signals that are visible and transparent to market participants. Therefore, PJM strives to minimize uplift costs and operate the system so that the vast majority of a resource's costs of operation are reflected in transparent market clearing prices.

Some scenarios that lead to increased uplift involve PJM committing resources for expected extreme system conditions. As a result, more expensive resources are sometimes required to cover reserves and operate at their minimum output levels. In such cases, these resources are placed at the bottom of the supply stack and sometimes suppress LMPs. PJM may need to schedule additional generation to be available to mitigate any potential power shortfalls due to generator forced outages. The additional generation needed and committed after the execution of the Day-Ahead Energy Market increases the differences between day-ahead and real-time energy prices, but also creates situations where the resources called to supply reserves are not marginal, causing them to operate at their economic minimums. This may require uplift payments to these generators when LMPs are not adequate to cover their operational costs.

Operating reserve costs are payments made to economic demand resources and generation resources, which follow PJM's direction, to cover their costs and are the primary form of uplift in PJM. These payments are outside of the market and are not included in the pricing signals that are visible and transparent to market participants.

Figure 38. Total Lost Opportunity Cost and Operating Reserve January/February 2015



There can be various scenarios in which market revenues are insufficient to cover generators' costs. The drivers that contributed to high levels of uplift particularly during February 2015 included:

- Contractual Constraints – At times, due to gas delivery operation inflexibility restrictions, some resources operated within strict megawatt output levels during periods when they were uneconomic to ensure they were available during peak conditions. The winter of 2015 experienced less contractual constraints than the winter of 2014.

- Prudent Operations – During February 2015, based on the extreme weather forecast and expected system conditions, PJM committed resources to meet the forecasted load and maintain system reserve requirements. Such operations are typical during cold weather alerts, resulting in the scheduling of reserves to account for increased load demand. Additional resources that were committed to meet the increased load demand plus planned outages, unplanned outages and expected transmission congestion resulted in elevated balancing operating reserve deviation charges.

  In addition, the lower fuel prices seen in 2015 compared to 2014 prompted some generation owners to start their resources early and self-scheduled those resources in the PJM market prior to the anticipated extreme weather conditions to ensure their availability in the PJM market. Throughout February, particularly the latter part of the month, PJM procured adequate generation to meet forecasted load and maintain system reserve requirements. The Day-Ahead Market committed much of this generation in the Western Region of PJM in the form of combustion turbines based on the market-clearing engine. In real-time operations, there was a large amount of energy imports across the western border, resulting in heavy west-to-east transfers across the PJM system. These energy imports displaced the need for the combustion turbines committed in the Day-Ahead Market, which then were de-committed in real time. The heavy transfers across the system also caused the real-time LMPs to be higher in the Eastern Region of PJM. These issues contributed to the overall total energy uplift credits.

Uplift is an important feature in the PJM Energy Market design due to the number of variables associated with dispatching the system and maintaining control. While there is a tradeoff between lower energy prices and uplift because, generally, as uplift is reduced, energy prices will rise, and vice versa. No solution eliminates uplift completely. Through the Energy Market Uplift Senior Task Force, PJM and its stakeholders have made progress to provide solutions for the reduction of uplift. The task force has focused on uplift credit methodology and specific units parameters that would enable the reduction of uplift.

Balancing Operating Reserve Credits

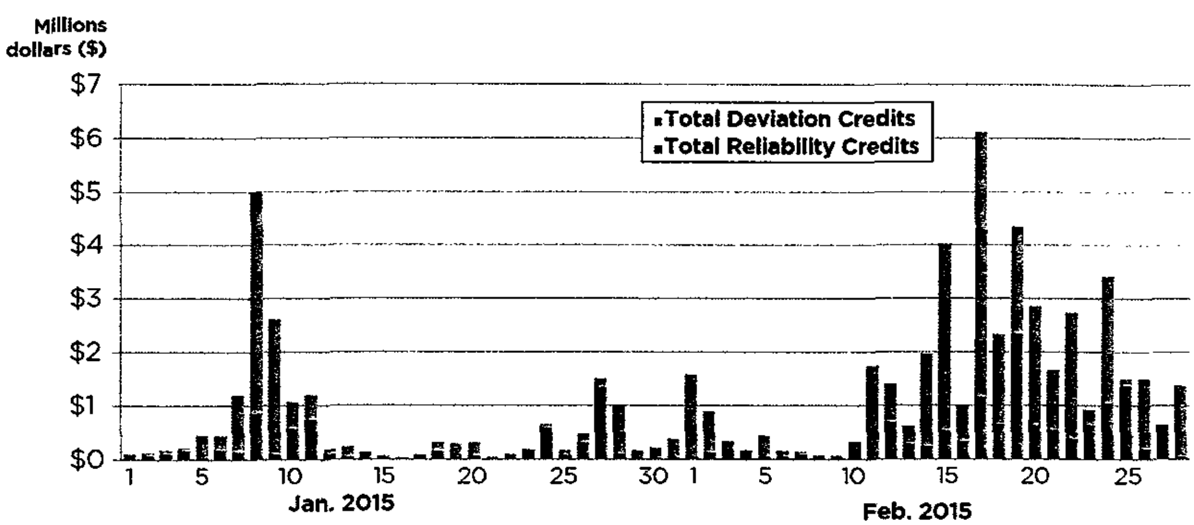
There are two general types of balancing operating reserve charges. If a generator is called to run after the close of the Day-Ahead Market and during the reliability assessment commitment performed after the Day-Ahead Market results are posted, it is either dispatched for prudent operations or "load plus reserves."

If a generator is dispatched for prudent operations, the uplift cost associated with the generator running is categorized as a reliability credit. If a generator is dispatched for 'load plus reserves', the uplift cost is categorized as a deviation credit. When a generator is committed to run during the operating day, if its cost is greater than locational marginal prices most of the time, the uplift credit for the generator also is categorized as a deviation credit. During the operating day, if a generator is not economical (i.e. its cost-based offer is higher than the current LMP), its associated uplift cost is categorized as a reliability credit. This is summarized in the table below.

Figure 39. Balancing Operating Reserve Credits

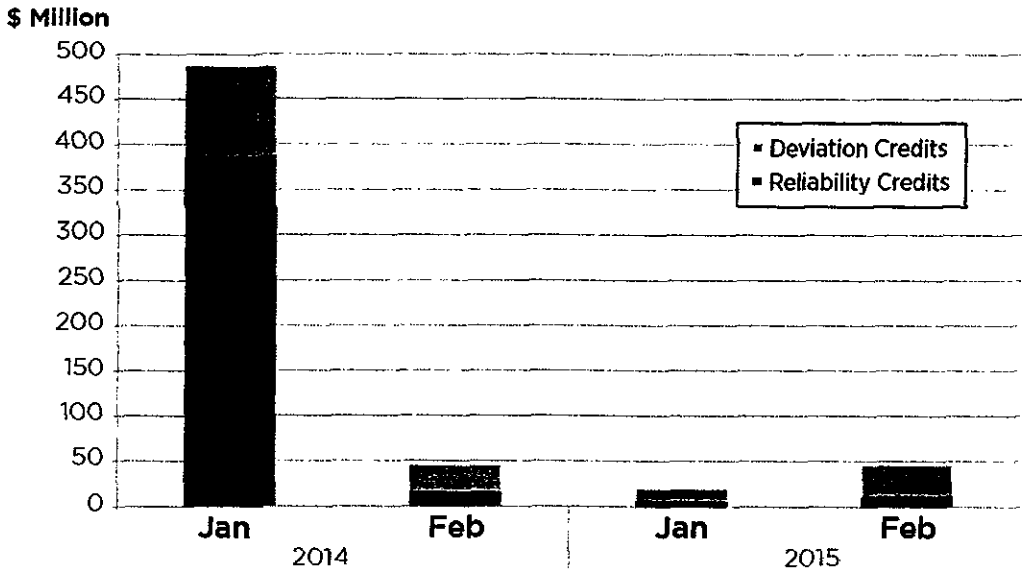
[illegible]	• Generator committed in advance of the operating day and outside of the Day-Ahead Market • Generator committed during the operating day and is out of the economic merit order
Deviation Credit	• Generator is needed to meet anticipated load plus reserves • Generator is committed during the operating day and cost is greater than locational marginal prices most of the time

Figure 40. Balancing Operating Reserve Credits for the months of January and February 2015



PJM did experience higher-than-average operating reserve credits this winter. However, in comparison, February 2015's operating reserve credits were less than 20 percent of the credits for January 2014.

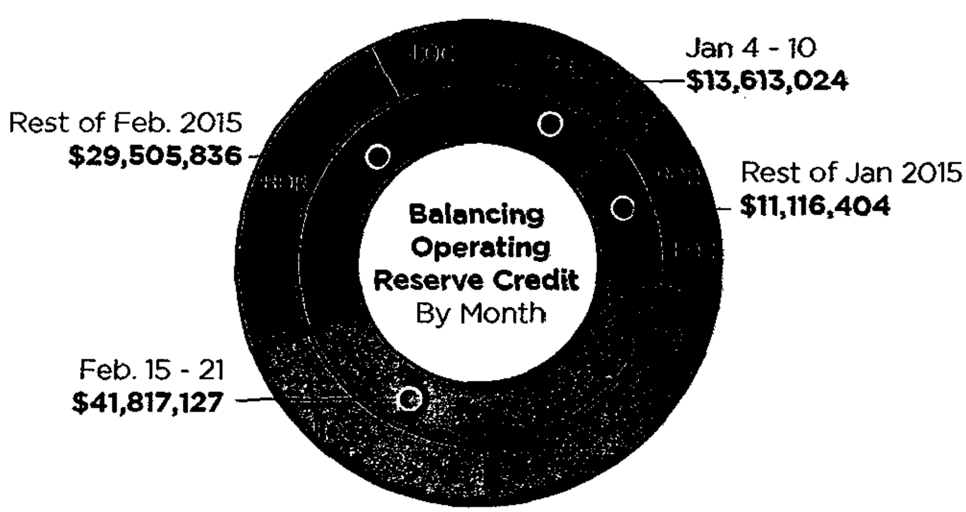
Figure 41. Comparison of 2014 to 2015 Operating Reserves Credits



Large contributing factors to the decreased operating reserve dollars, despite the similar weather conditions, were the improved unit performance, a result of winter readiness and preparation activities, as well as more informed dispatched scheduling decisions, a result of improved communications, better coordination with generators and gas pipelines and improved data accuracy.

The majority of the balancing operating reserve credits incurred during February 2015 were for deviation credits. Units that are called on by PJM can incur balancing operating reserve costs that can either be allocated as part of the reliability analysis or as part of the operating day. During the latter part of February, the majority of balancing operating reserve credits was allocated as part of the reliability assessment and specifically under load plus reserves deviation credits.

Figure 42. Balancing Operating Reserve Credits in January and February 2015



Time Period	Balancing Operating Reserve	Lost Opportunity Cost
Jan 4 - Jan 10	$11,045,414.00	$2,567,610.00
Total Month Jan 2015	$19,355,493.00	$ 5,373,935.00
Feb 15 - Feb 21	$ 22,649,517.00	$19,167,610.00
Total Month Feb 2015	$45,002,726.00	$26,320,236.00

The cold weather spikes Jan. 4-10, 2015, and Feb. 15-21, 2015, represented the majority of balancing operating reserve credit and lost opportunity cost credit for each respective month. February 2015 exhibited a high amount of lost opportunity costs, as resources scheduled in the Day-Ahead Market were not run in real time and subsequently compensated via lost opportunity cost based on the existing market rules.

Lost Opportunity Cost

Lost opportunity cost is an uplift cost and results primarily from PJM scheduling a resource to operate in the Day-Ahead Energy Market but then not calling the resource to operate in real time. For example, a resource may be committed in the Day-Ahead Energy Market to operate during specified times but is not needed in real time due to factors such as anticipated lower demand, increased supply from interchange transactions, or increased self-scheduled generation that was not modeled in the Day-Ahead Energy Market.

A resource is compensated for lost opportunity cost if it received a Day-Ahead Energy Market award but was not run in real time. This payment covers the resource's Day-Ahead Energy Market position and any Real-Time Energy Market charges the resource would have to pay. A generation resource's output could be also reduced in real time due to an operational issue on the system. In these cases, if the real-time LMP does not reflect the resource's offer during the time its output is reduced, the resource is made whole to the amount it could have earned had it operated at a level of output corresponding to the real-time LMP.

Figure 43. Lost Opportunity Cost in January and February 2015

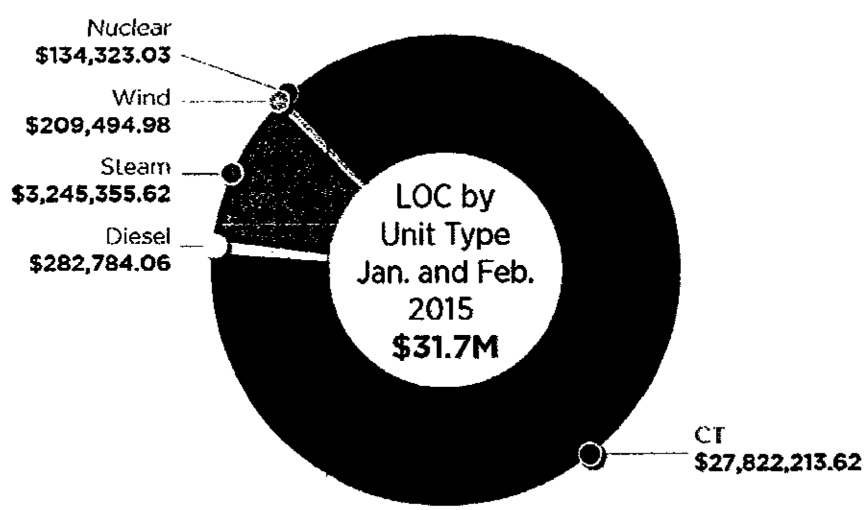
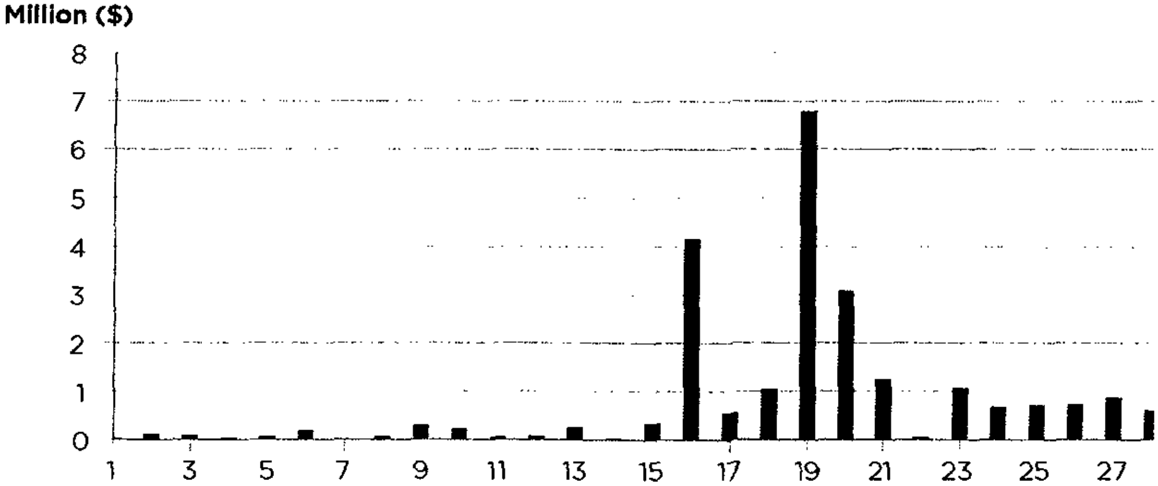


Figure 44. February 2015 CT Lost Opportunity Cost



The majority of lost opportunity cost expense was during the end of February 2015. The cause of the increase in lost opportunity cost expense was a combination of prudent operations and challenging load projections. Heavy west-to-east transfers across the system restricted the ability for PJM to load already committed internal western generation. The impact of not being able to run these generators impacted both real-time LMPs and lost opportunity cost for those generators.

Figure 45. Balancing Operating Reserve Credit by Unit Type

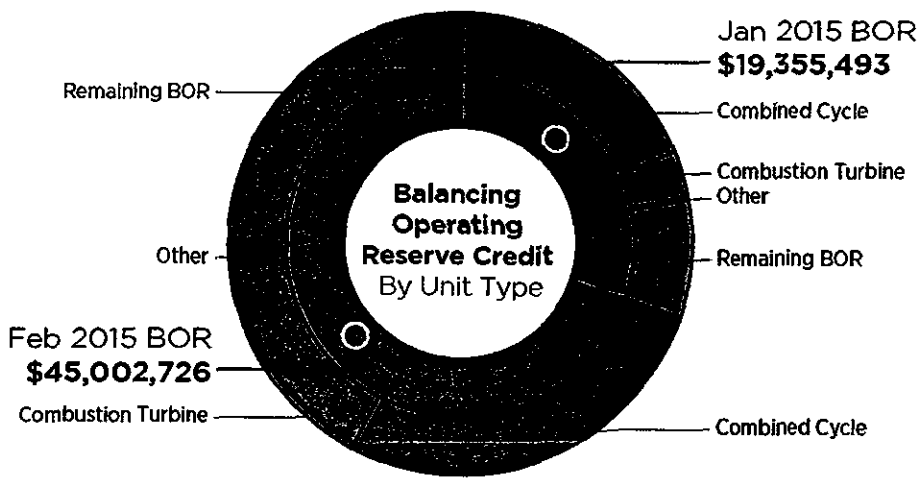


Figure 46. Balancing Operating Reserve by Unit Type in January 2015

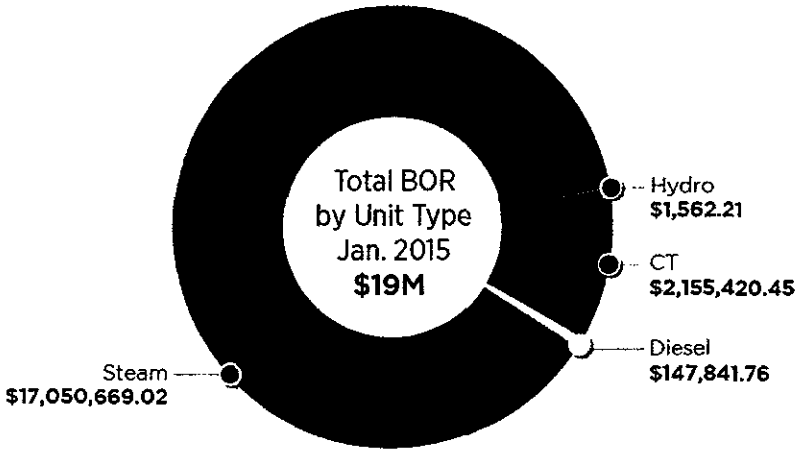
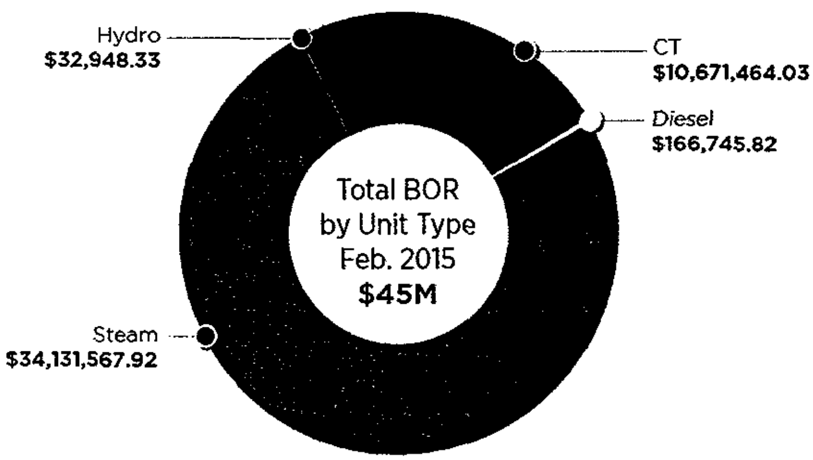


Figure 47. Balancing Operating Reserve by Unit Type in February 2015



Offer Cap

The PJM Operating Agreement requires all generation capacity resources in PJM that have been committed as capacity to submit offers into the Day-Ahead Energy Market. The Operating Agreement also limits generation offers into the Day-Ahead Energy Market to $1,000/MWh.

During the winter of 2014, PJM market participants experienced excessive high spikes of natural gas prices that could make electricity generation costs that could exceed the $1,000/MWh offer cap. To help alleviate this issue, *PJM filed a temporary waiver with the Federal Energy Regulatory Commission (FERC) on Feb. 10, 2014, that* allowed cost-based offers to exceed the $1,000/MWh offer-price cap. The FERC approved the waiver.

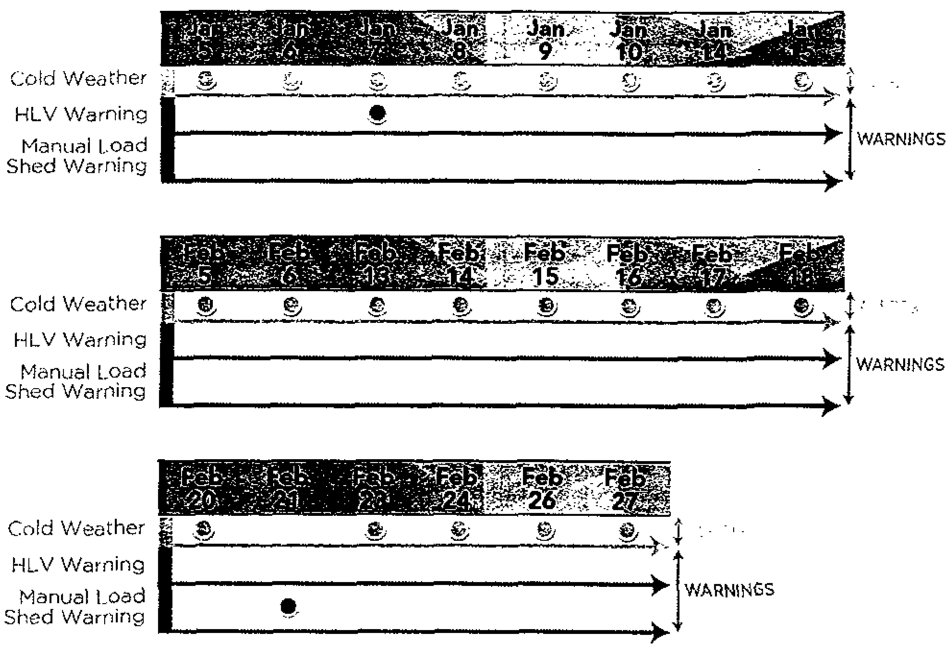
In preparation for the winter of 2015, on Dec. 15, 2014, PJM filed a temporary waiver with FERC that allowed cost-based offers to exceed the $1,000/MWh offer-price cap but capped at $1,800. On Jan. 16, 2015, FERC accepted the filling which was effective through March 31, 2015.

During the winter period from January 16 through March 31, PJM received 54 cost-based offers that were greater or equal to $1,000/MWh. All 54 cost-offers were submitted to PJM between Feb. 17 and March 6, 2015. None of the offers received were accepted, as the system conditions did not warrant running those units.[9]

Emergency Procedures

PJM did not need to take any emergency actions during the winter of 2015. At the highest peak periods, PJM needed only to issue alerts and warnings, which are designed to increase awareness and readiness for weather conditions. The cold weather alert was the most-frequently issued emergency procedure during January and February. PJM issues a cold weather alert in advance of an actual operating day when forecasted temperatures are 10 degrees Fahrenheit or lower, so market participants can prepare for the extreme weather conditions. There were 27 cold weather alerts[10] issued in January and February.

Figure 48. Emergency Procedures in January and February 2015



One of the most significant actions PJM takes in response to a cold weather alert is the deferment of scheduled transmission and generation outages and the commitment of long-lead generating units as needed. Once PJM issues a cold weather alert, it reviews scheduled outages and contacts transmission and generation owners to defer maintenance on an as-needed basis. During the winter of 2015, some transmission owners were able to defer transmission system maintenance once PJM issued the cold weather alert.

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[9] Link to the IMM Informational Filing re: Offer Caps Docket EL13-31-000
http://www.monitoringanalytics.com/reports/Reports/2015/IMM_Informational_Filing_Docket_No_EL15-31-000_20150505.pdf

[10] This total includes alerts called for the entire RTO and separate regions in the RTO

PJM also reviews generating units with long lead times to assess if there is a need to commit those units to ensure availability during the peak. There were very few units called on for this reason in 2015.

PJM issued two other emergency procedures during the winter of 2015 to prepare for weather conditions. They were:

Heavy Load Voltage Schedule Warning

PJM issued a heavy load voltage schedule warning[11] for the afternoon of Jan. 7, 2015, (at 1505). This emergency procedure is designed to improve the voltage profile on the extra high voltage (345 kV and above) system and prompts transmission and generation owners to take the following actions:

- Transmission owners take all appropriate actions on distribution and sub-transmission systems in order to support system voltages. This includes energizing all available capacitor banks.
- Generation owners, working with transmission owners, increase reactive power on all units connected to the 230 kV and below voltage levels. All units connected to the 345 kV and higher voltage levels adjust reactive power accordingly.
- Generation owners report reactive capability and voltage regulator status changes to transmissions owners. There are no costs with taking this action.

As the load came down and system conditions normalized, PJM cancelled the heavy load voltage schedule warning at 2116. PJM did not need to take any further emergency action.

Manual Load Dump Warning

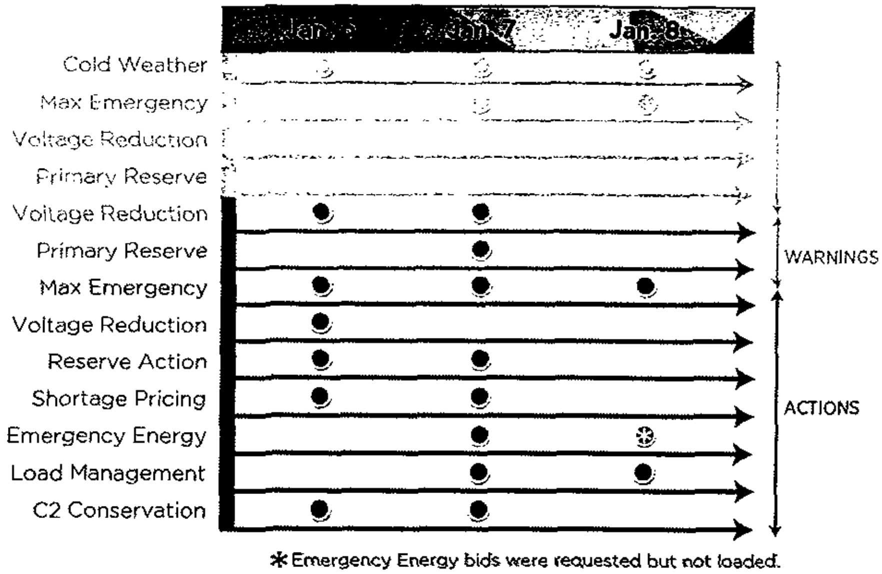
On Saturday, Feb. 21, 2015, PJM issued a manual load dump warning for the AEP transmission zone. This action was taken due to a contingency on the Cloverdale T-10, 765/345 kV transformer for the loss of Joshua Falls T-1, 165/138 kV transformer. PJM and AEP developed a contingency plan and had the Joshua Falls T-1 765/138 kV transformer relayed out of service. The manual load dump warning was in effect from 0624 to 2205 when the contingency cleared. No further action was required.

2014 Compared to 2015

The winter of 2014 was drastically different in the severity and use of emergency procedures. The chart below highlights the peak days in early January 2014 and the different types of emergency procedures that were required. They ranged from alerts to actions, including voltage reduction, emergency demand response, shortage pricing, and public appeals for conservation.

[11] Manual 13, Section 5.1.2

Figure 49. Emergency Procedures During the Polar Vortex 2014



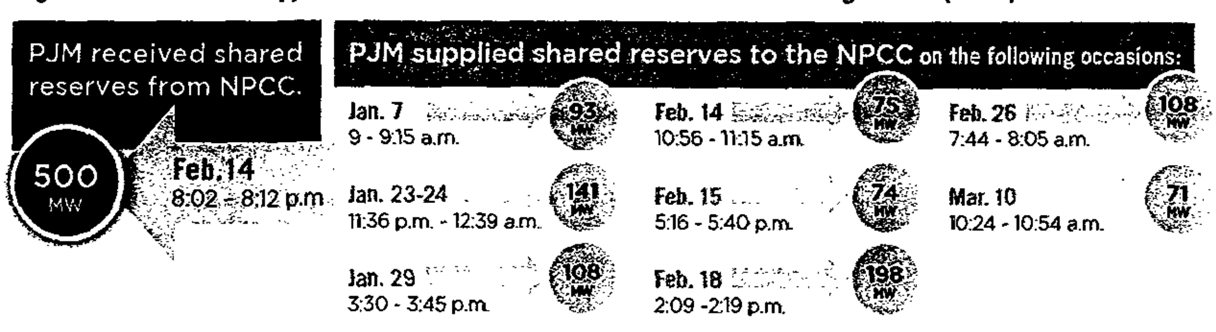
There were several reasons for the differences in number, severity, and type of emergency procedures needed in 2014 versus 2015, despite the all-time peak load being set in 2015. Those reasons include better generator performance, lower forced outages and more available generation, both internally and externally. PJM did not need to rely on emergency procedures in 2015 to reduce the load or call on more capacity; it relied on the generation available, either online or as reserves.

Shared Reserves

PJM participates in two shared reserves groups, Northeast Power Coordinating Council (NPCC) and the Virginia-Carolinas Reliability Agreement (VACAR). PJM supplies shared reserves when requested by those groups, and PJM requests shared reserves to help recover from the loss of internal PJM generation. PJM did not experience an activation of VACAR shared reserves during the winter of 2015. However, PJM activated NPCC shared reserves on one occasion for the loss of a PJM unit: On Wednesday, Feb. 14, 2015, from 2002-2012, PJM received 500 MW from NPCC.

PJM supplied shared reserves to the NPCC on the following occasions:

Figure 50. 2015 PJM Supplied Shared Reserves to Northeast Power Coordinating Council (NPCC)



Shared Reserves in 2014 v. 2015

During the peak of January 2014, PJM relied more heavily on energy imports from NPCC to meet its own energy needs. PJM received between 700 and 800 MW on two different occasions in early January 2014. On one occasion, PJM provided about 150 MW of shared reserves to NPCC.

While shared reserves were not needed with VACAR in 2015, work had been done throughout the year with VACAR's reliability coordinator, transmission operators and the reserve sharing group members to improve emergency procedures and protocols, data sharing, and communication between entities as far as expectations of roles and responsibilities. This helped to improve the overall communication and understanding of the VACAR sharing agreement, particularly when the parties were in tighter capacity situations.

Reserves

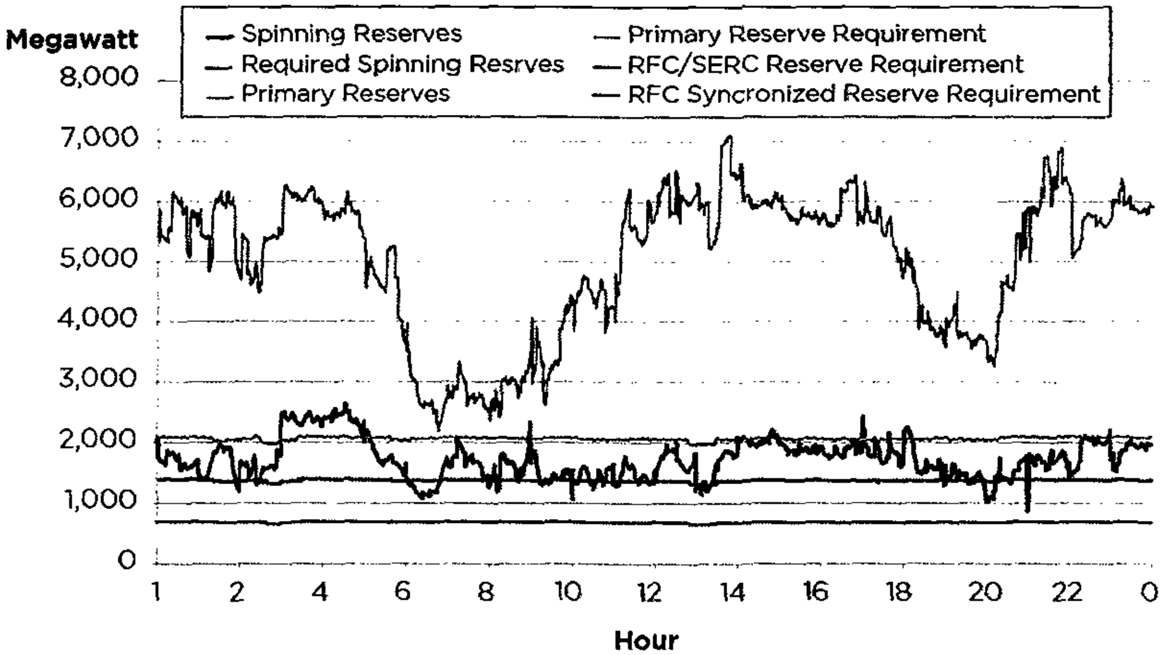
PJM maintains sufficient reserves to handle unexpected conditions on the system. Reserves are defined as capacity that is not currently being used but can be quickly available for an unexpected loss of generation or a grid contingency. To ensure the reliable operation of the grid, as well as to maintain compliance with North American Electric Reliability Corporation, ReliabilityFirst (RF) and SERC Reliability Corporation standards, PJM established a primary (contingency) reserve requirement[12] and a synchronized reserve requirement[13] as further detailed in the PJM Manual 13 - Emergency Operations. If the reserve requirements are not met, emergency procedures and shortage pricing, as indicated in PJM Manual 11 - Energy & Ancillary Services Market Operations, may be implemented.

During the winter of 2015, PJM maintained the primary (contingency) and synchronized reserves estimates above NERC/RF/SERC requirements at all times, and no emergency procedures were required. The graph below shows the primary reserve and synchronized reserves for the 24-hour period during which the new all-time winter peak was set (1200 Feb. 19–1200 Feb. 20).

[12]The Primary Reserve Requirement is capability, consisting of synchronized and non-synchronized resources, which can be converted fully into energy within 10 minutes from the request of PJM. The current PJM value for this objective is 150 percent of the largest single contingency in the RTO.

[13] The Synchronized Reserve Requirement is capability, comprised only of synchronized resources, which can be fully converted into energy within 10 minutes from the request of PJM. The current PJM value for this objective is 100 percent% of the largest single contingency in the RTO.

Figure 51. RTO Reserves



The graph shows the PJM primary and synchronized reserves estimates and their associated requirements. While the primary and synchronized reserves estimates remained above the NERC/RF/SERC requirements at all times, there were brief periods when the synchronized reserves estimates dipped below the PJM requirement, which is higher than the NERC/RF/SERC requirements. No emergency procedures were triggered during these transient periods as the synchronized reserves remained above the Reliability*First* requirement.

These transients occur mainly because of the look-ahead nature of the PJM Reserves Market, which schedules generation in advance to meet both the energy and system reserve requirements. In real time, as system conditions change (e.g. a brief load spike, a sudden swing in interchange, unit trips, failed unit start, or a unit starting later than scheduled), synchronized reserves may be used for short periods of time until additional generation is brought online or catches up. For this reason, PJM sets its reserve requirements higher than the compliance standards dictate.

2014 Compared To 2015

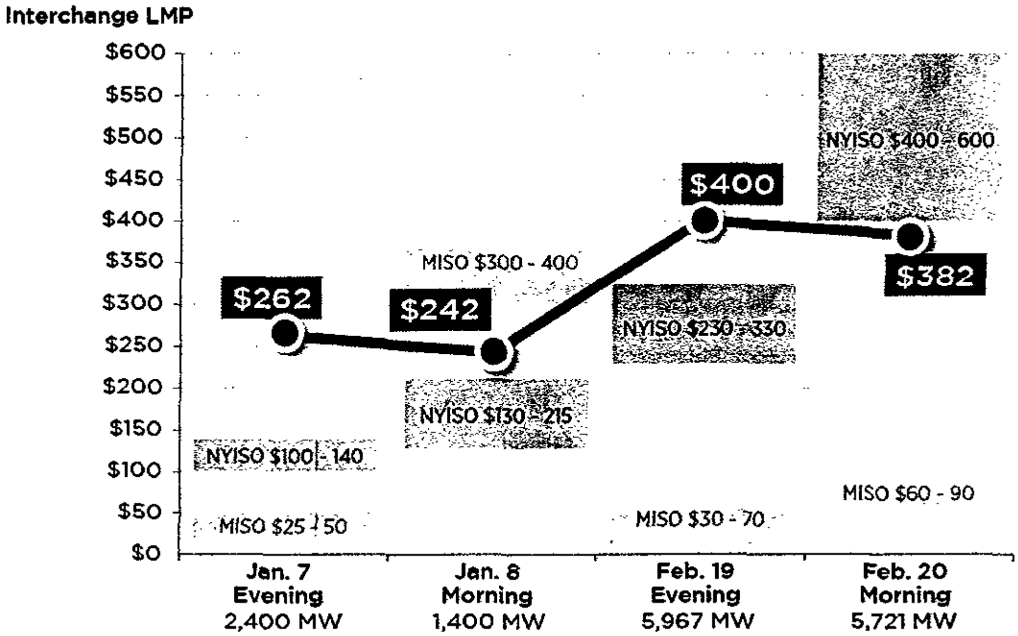
System conditions in January 2014 were significantly worse than the winter of 2015; at times, the reserves requirements were not met. As a result, PJM issued several emergency procedures in January 2014, including a primary reserve warning, voltage reduction warning and action, and a maximum emergency generation action, and triggered shortage pricing. PJM also relied on shared reserves from neighbors.

Improved generator performance was the key contributing factor to the improved reserves condition in 2015, despite the higher load value on Feb. 20, 2015. With 50 percent fewer outages, more generation online and more generation available than 2014, the primary and synchronized reserve requirements were met without implementing any emergency procedures.

Interchange

Managing interchange (energy transfers across the RTO) was not operationally challenging or significant for PJM on the peak winter days in 2015. Interchange for the peak days of January and February are reviewed below as well as a comparison with conditions in 2014.

Figure 52. LMP Interchange for Peak Days of January and February 2015



2014 Compared To 2015

Managing interchange during the peak winter days of 2015 was much less challenging than the winter of 2014. The key difference was interchange volatility during peak hours. While loads were high in 2015, emergency procedures, such as shortage pricing and demand response, were not needed, which had a dramatic impact on energy prices. While PJM LMPs were high compared to neighbors', the difference in prices was not as extreme as when PJM implements emergency procedures.

PJM's unit commitment decisions are made based on expected interchange. The lack of emergency procedures meant that prices were more stable, more expensive internal units were not needed, and in turn, interchange was more manageable.

By contrast, during the evening peak on Jan. 7, 2014, actual interchange into PJM increased 3,000 MW above the forecasted interchange, which was the result of high LMPs set by the call for emergency demand response. While interchange volatility can make operations more challenging, the impact is greater on the economics of the system.

The sudden increase in less-expensive supply, resulted in PJM operators releasing very expensive committed units, before meeting their minimum run times, causing uplift payments to the generators. PJM did not have this same issue in 2015 during the peak.

A recommendation from the winter of 2014 was to implement an interchange volatility cap that gives PJM the ability during emergency procedures to restrict the amount of interchange into PJM in advance of the operating hour. The cap gives PJM a better way to control the system economics and reduce uplift without compromising reliability.

PJM did not need to use the interchange volatility cap in 2015, as there was no real need for emergency procedures during the peak days. PJM did not experience the volatility because system prices overall were lower in 2015 and price spikes were not caused by emergency procedures – which points back to more available generation and better unit performance.

Bulk Electric System Status – Transmission

Just as PJM did in 2014, PJM prepared for 2015 winter peak operations by analyzing winter transmission outage requests to understand impacts to reliability and congestion. The PJM Peak Period Outage Scheduling Guidelines indicate transmission owners should avoid scheduling transmission outages that may result in increased risk to system reliability during the winter peak periods.[14]

For outages that transmission owners needed to schedule over the 2015 winter peak, PJM performed a detailed analysis on each outage request, under winter peak system conditions, to ensure system reliability could be maintained before approving the outage. The detailed analysis also included an assessment of congestion impacts. If there was a significant congestion impact for the outage, considering things like the amount of off-cost operations and number of units and megawatts impacted, PJM suggested that the outage be rescheduled. PJM also communicated long-duration 500 kV or above transmission outages (e.g. those scheduled for the entire season), and projected impacts to PJM members through the PJM committee process.

Prior to the 2015 winter season, PJM performed a winter operations study with the transmission owners as part of the Operations Assessment Task Force. The study results indicated the PJM RTO bulk power transmission system could be operated reliably during the 2015 winter peak load period in accordance with the operating principles and guidelines contained in the PJM manuals. The task force also performed sensitivity studies to simulate extreme system conditions that PJM might encounter during the winter season. The 2015 winter sensitivity studies included the following scenarios: gas pipeline restrictions, high winter loads close to the peak experienced in 2014, and high generation outages. The study results showed all contingencies identified in the sensitivity studies were controllable.

Key Transmission Outages in 2015: Planned and Unexpected Outages

PJM's analysis of transmission outages in this report did not directly correlate to any operational events in 2014 or 2015. However, for completeness, the impacts of the outages over the winter period are reviewed. In January and February 2015 there were 36 outages on 500 kV or above transmission lines and transformers. Twenty-six of the outages were planned outages, and 10 were unplanned emergency outages. Sixteen of the outages, mostly planned, lasted more than five days.

The three transmission outages with the most operational impacts during the winter of 2015 were:

[14] Manual 3: Transmission Operations, Section 4: Reportable Transmission Facility Outages, 4.2.6 Peak Period Outage Scheduling Guidelines

2015 Scheduled Outage:

The Dooms - Lexington 500-kV line (Sept. 8, 2014-June 15, 2015)

This scheduled outage is to rebuild the 500-kV line to accommodate Chesapeake and Yorktown generation deactivation in the Dominion control zone. The required rebuild project completion date is June 1, 2016. Originally, Chesapeake Units 3 and 4 were scheduled to deactivate in December 2015, but it was later decided to advance the deactivation to December 2014. The Dooms - Lexington project now is scheduled to be completed in December 2015. The major impact of this outage is restrictions on Bath County pump-storage hydro plant operations due to stability concerns. PJM implemented a special protection scheme (SPS)[15] *to minimize the stability impact on Bath County operations during the Dooms-Lexington outage.*

2015 Emergency Outages:

The Keystone #3 500/230/20-kV transformer (Nov. 3, 2014-Feb.6, 2015)

On Nov. 3, 2014, a relay operation took out of service the Keystone #3 500/230/20-kV transformer, which is located in the Pennsylvania Electric zone. The transformer remained out of service until Feb. 6, 2015. This emergency outage required PJM to increase the reserve requirement by about 400 MW to cover the potential loss of both the Keystone #1 and Keystone #2 units. The reserve requirement increased from approximately 1,300 MW to 1,700 MW. During this emergency outage, PJM also was required to monitor and control the single contingency loss of both Keystone units, the Juniata-Keystone (5004) 500-kV line and the Conemaugh-Keystone (5003) 500-kV line. This contingency restricted energy transfer into the eastern portion of the RTO and required more frequent off-cost operations, especially on the Bedington-Black Oak transfer interface.

The Black Oak-Hatfield 500-kV line Feb. 9, 2015-Feb. 12, 2015)

The Black Oak-Hatfield 500-kV line, located in the FirstEnergy – South control zone, was removed from service due to emergency overhead bus work at the Hatfield substation. This outage reduced energy transfer capability across the PJM footprint and required more frequent off-cost operations.

2014 Compared to 2015

There were fewer winter transmission outages of 500 kV or above in 2015 than in 2014. There were 36 outages on 500 kV or above transmission in January and February 2015, compared with 52 outages in January and February 2014. In 2014, 33 of the outages were planned outages and 19 were unplanned emergency outages. Nineteen of the outages lasted more than five days.

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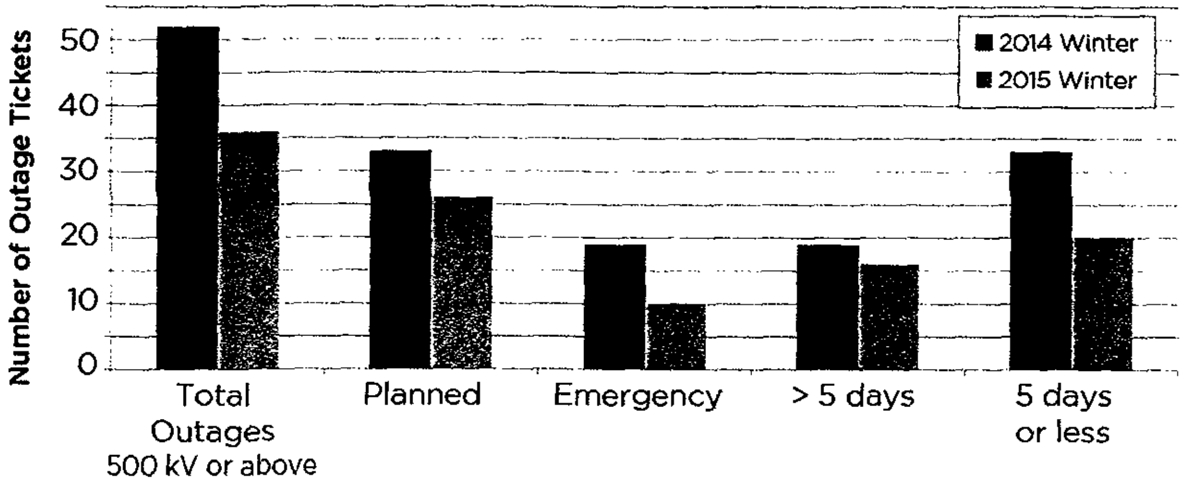
[15] Glossary of Terms Used in NERC Reliability Standards – SPS is an automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows.

Figure 53. Winter Peak 500 kV or above Transmission Outage Comparison for January and February, 2014 and 2015



Many of the planned outages in 2014 were to upgrade the infrastructure to support generator retirements occurring by April 2015. There were fewer of these types of outages in 2015. There were also fewer long-term outages in 2015. The reduction of long-term outages is a trend PJM anticipates continuing during future winter peak periods as Regional Transmission Expansion Plan (RTEP) upgrades required for generation retirements are completed.

The impact to congestion of the 2014 transmission outages with the most operational impacts was about three times greater than the congestion impact observed for the 2015 outages. The lower price of fuel contributed to this difference, as did the greater number and duration of outages in 2014.

The four 500 kV or above transmission outages with most operational impacts during the winter of 2014 include:

2014 Scheduled Outages:

Doubs-Mt. Storm 500-kV line (Sept. 3, 2013-June 3, 2014)

The Doubs-Mt. Storm 500-kV line is an internal tie-line between the Dominion and FirstEnergy-South control zones. This 500 kV or above transmission line reconstruction project was a PJM RTEP backbone project required due to aging infrastructure. The original outage schedule spanned 2012 to 2015. The approval of the requested 2014 winter outage allowed the line reconstruction work to be completed one year ahead of the original schedule. This outage reduced the energy transfer capability across the PJM footprint, causing congestion and requiring more frequent off-cost operations.

Branchburg-Ramapo 500-kV line (Feb. 7, 2014-Feb. 23, 2014)

Branchburg-Ramapo is an external tie-line between PJM and New York. Branchburg substation is located in the northern Public Service zone in New Jersey. This outage was necessary to install a new 500-kV Hopatcong substation, which is part of the Susquehanna-Roseland RTEP backbone project. This outage caused some local transmission constraints in the Public Service zone.

Bath County-Lexington 500-kV line (Feb. 2, 2014-March 21, 2014)

The Bath County-Lexington line is located in the Dominion control zone. The outage was necessary due to a circuit breaker replacement project at the Lexington substation. This outage caused some operational restrictions on the Bath County pump storage hydro plant due to stability concerns.

Keeney AT50 500/230-kV transformer (Feb. 9, 2014-June 18, 2014)

Keeney substation is located in the Delmarva Power zone in Delaware. The four-month outage was necessary to replace the AT50 500/230-kV transformer. The outage started in February to ensure the new transformer could be ready for service before the 2014 summer peak season. The outage did not affect reliability during the peak days of 2014.

2014 Recommendations and Impacts to Operations

In May 2014, PJM published a list of recommendations stemming from the report of the winter of 2014. This is a high-level summary of the results of those recommendations and their impact on 2015 operations

ID	Category	Recommendation	Actions	Impact on 2015 Operations
1	Unit Performance	PJM, in conjunction with members, should consider the following topics and develop adjustments to improve unit performance: 1. Review the penalties for non-performance during peak days and/or days when emergency procedures are issued for capacity emergencies 2. Review incentives for performance during peak days 3. Investigate a process for unit testing and preparation of resources in advance of winter operations, including testing dual-fuel capability 4. Review generator outage rates outlined in PJM Manual 13: Emergency Operations.	• The Capacity Performance filing was developed through the Enhanced Liaison Stakeholder Committee process. PJM and stakeholders developed incentives for peak period performance as well as penalties for underperformance. The FERC has approved a one-time waiver of PJM's tariff to allow a short delay in the annual Reliability Pricing Model capacity auction for the 2018/2019 delivery year to allow the FERC to consider PJM's responses to questions from the FERC. If approved by the FERC, Capacity Performance would begin to impact units in the 2015 / 2016 transition year. • A voluntary winter testing program was developed and approved through a stakeholder process. This program identified units that had not run in more than eight weeks and made them eligible for cost-capped testing. • Manual 13-Emergency Operations was updated to reflect unit outage triggers for peak period operations.	• Heightened awareness and stakeholder engagement in discussions on improving generator performance. • Eligible units that performed the exercise had a lower magnitude of forced outages compared to those that did not test. • Manual 13 updates for Emergency Operations allowed for advanced warning to owners to stop maintenance outages during emergency operations.
2	Unit Characteristics	Work with generation owners to identify opportunities to create or improve information sharing. Consider including the following: 1. Sharing of fuel source and emission limitations by schedule submitted and fuel limitations/certainty of supply 2. Streamlining and standardizing the outage cause types in eDART with additional specificity that provides more insight and consider methods for	• Conducted generator survey to collect important generation data such as fuel type and inventory, dual fuel capability, and operational restrictions in PJM tools. • Enhancements to and member training about PJM's operations and markets tools to capture important, updated unit information. • Internally, completed automation of outage causes in eDART by implementing coding for frequently used outage ticket descriptions.	• This additional data provided PJM Dispatch increased understanding of unit status and flexibility in real-time. • More accurate reporting of unit status and performance improved dispatcher scheduling decisions as well as after-the-fact analysis. • Faster (next morning compared to days later in 2014) data analysis provided to Dispatch regarding unit performance which allowed for much more informed dispatcher scheduling

ID	Category	Recommendation	Actions	Impact on 2015 Operations
		validation 3. Clarify the rules by which a generator can claim an Outside Management Control event for taking an outage	• Update the OMC guidelines posted for GADs reporting	decisions. • The streamlined outage data was aggregated for more accurate assessment of forced outage closer to real time.
3	Gas/Electric Coordination	PJM, in conjunction with stakeholders, should consider the following topics and develop appropriate industry recommendations and PJM rule changes: 1. Investigate opportunities for better harmonization of the timing of the gas and electric operating days. 2. Consider potential market rule changes that would allow generators to better include natural gas costs in their energy or capacity market offers, including review of offer caps, and to make changes to energy market offers during the operating day. 3. Consider potential market rule changes that would allow generators to reflect fuel availability in their start-up and notification times. 4. Improve the tools and processes for two-way communication with the gas industry to enhance situational awareness and better evaluate impact to PJM generation. 5. Improve reporting of availability for units that are not committed day-ahead to include access to fuel and consider methods for validation	In progress. Gas/electric coordination is an active discussion among PJM and stakeholders and across the energy industry. Work is in progress to address the two proposals adopted by the FERC (submitted by the North American Energy Standards Board) to revise the interstate natural gas nomination timeline and make conforming changes to standards. Most of the improvements to this area involved PJM specific business rules, tools or process changes that were developed through the PJM stakeholder process: • Generators were given some ability to change their cost offers intraday. • The offer cap was increased to $1,800 through March 31, 2015. • Procedures for communicating gas availability between generator operators and PJM operators were improved to include emphasis on use of data fields in the PJM tools. • Procedures were approved for generators to reflect gas availability and restrictions through a combination of notification time, or Parameter Limited Schedule exceptions. • In addition, PJM established an internal gas electric coordination team to provide PJM operations information and analysis to assess the impact of natural gas fuel supply on generator availability. • PJM and stakeholder operating training was conducted to review all processes, procedures, and tool changes made in	• Daily risk profile for gas-fired generation units provided to Dispatch improved scheduling decisions and enabled more informed communication with generation owners. • More informed communication with generation owners about the gas supply status as well as unit capability – from the generator survey results mentioned above – facilitated more detailed discussions about generator flexibility. • More information about generator status captured in tools ensured consistency, transparency and availability of information to PJM Operations and Markets staff. • More detailed and weekly conversations with gas pipelines provided the PJM gas/electric coordination team more insight into pipeline restrictions, durations, forecasts and overall status

ID	Category	Recommendation	Actions	Impact on 2015 Operations
4	Fuel Limited Resources	For those units with fuel limitations look to: 1. Improve tools that allow sharing of fuel-limited details with PJM including tracking dual-fuel capability and availability 2. Review operator communications with respect to fuel-limited generation commitment decisions for accuracy and consistency 3. Confirm mechanism by which resources seek waivers for fuel emission limitations and better understand conditions under which relief may be granted	preparation for winter operations. • Conducted generator survey to collect important generation data such as fuel type and inventory, dual fuel capability, and operational restrictions in PJM tools. • Enhancements to PJM's operations and markets tools to capture important, updated unit information. • Procedures for communicating gas availability between generator operators and PJM operators were improved to include emphasis on use of data fields in the PJM tools. • PJM and stakeholder operating training conducted to review all processes, procedures and tool changes made in preparation for winter operations. • Changes were made to PJM manuals (M13) and training to confirm roles and responsibilities and the procedures resources may use to seek waivers.	• Reduced phone calls to PJM Dispatch communicating information that was more appropriately input into the PJM tools. • More informed communication with generation owners about the fuel supply status as well as unit capability, facilitated more detailed discussions about generator flexibility. • More information about generator status captured in tools ensured consistency, transparency and availability of information to PJM Operations and Markets staff.
5	Fuel Specific Limitations	Examine difficulties experienced by generators during natural gas emergency procedures and consider: 1. Methods to call on long-lead generation based on fuel procurement limitations during extreme conditions 2. Changes to allow adjustment of start times based on changes in fuel utilized 3. Requirements for generation units whose primary fuel may not be natural gas but that require gas to operate	In addition to the actions taken for the gas / electric recommendation, PJM also: • Improved internal tools and processes for dispatching units with notification times that were outside of the Day-Ahead Market timeframe. • Market changes implemented to include long-lead units, committed in advance of the Day-Ahead Market because of their notification times in the Day-Ahead Market.	• PJM Dispatch had better visibility into megawatts available with notification times greater than 24 hours, which better informed scheduling decisions.
6	Energy Market Uplift	PJM, in conjunction with stakeholders, should consider the following topics and develop appropriate recommendations and PJM rule changes: 1. Review the cost allocation of energy market uplift charges 2. Investigate potential mechanism to allocate uplift.	• In progress. The PJM Energy Market Uplift Senior Task Force (EMUSTF) worked through this issue without coming to consensus. The EMUSTF continues to work through business rule changes to allocate uplift.	• The EMUSTF is in progress. No recommendations have been implemented so there is no impact to operations to document.

ID	Category	Recommendation	Actions	Impact on 2015 Operations
		during emergency operations when rates are extreme 3. Investigate methods and procedures for reducing the amount of uplift to be paid	• PJM staff also implemented internal metrics and goals to reduce overall uplift.	
7	Interregional Coordination	In order to increase situational awareness with the VACAR Reserve Sharing Group and VACAR Reliability Coordinator: 1. Define and review PJM emergency procedures and overall communications. Review operating agreements (including VACAR Reserve Sharing Group Agreement) 2. Include language regarding coordination of emergency procedures	• PJM worked closely with VACAR over the past year to improve the procedures with VACAR Reliability Coordinator, the VACAR transmission operators, and the VACAR Reserve Sharing Group members. • Updated and improved emergency procedures and protocols, data sharing and communication between entities and expectations of roles and responsibilities. • PJM conducts seasonal meetings with neighboring entities to share winter/summer outlooks and emergency procedures updates.	• These changes were extremely helpful for improved coordination and operations during the winter of 2015 because of consistent terminology and data use and understanding. • The seasonal meetings have led to greater understanding of actions taken during real-time operations.
8	Unit Commitment	Evaluate provisions in Manual 11 to determine where changes may be appropriate such as clarification and training regarding: 1. Start-up costs and cancelled dispatch provisions in Attachment C 2. *Switching schedules*	• In progress. Member waiver requests for gas balancing costs have been filed with the FERC; no FERC ruling has been made. • PJM with stakeholders updated Manual 11 and improved training related to switching schedules and cancelled dispatch instructions. • Generators were given some ability to change their cost offers intraday. • The gas balancing waiver requests are still under review with the FERC	• More informed communication with generation owners about the fuel supply status as well as unit capability, facilitated more detailed discussions about generator flexibility. • More information about generator status captured in tools ensured consistency, transparency and availability of information to PJM Operations and Markets staff.
9	Voltage Reduction Emergency Procedure	Review the voltage reduction capabilities of transmission owners to better understand current capabilities and determine if there are additional requirements that need to be developed: 1. Survey transmission owners to understand existing voltage reduction capabilities (amount, time frame, etc.) 2. Enhance Manual 13 with specifics on Voltage Reduction Warnings for TOs without supervisory control and data acquisition (SCADA) control	• PJM worked with transmission owners to better understand their voltage reduction capabilities. Voltage reduction plans have been added to the PJM Dispatcher SharePoint site. • Manual 13 – Emergency Procedures was updated to specify voltage reduction expectations for those transmission owners without automated SCADA control.	• PJM did not need to invoke the voltage reduction emergency procedure during the winter of 2015.

ID	Category	Recommendation	Actions	Impact on 2015 Operations
10	Emergency Energy Bids	Review and enhance the tools and processes for accepting Emergency Energy Bids	• PJM updated the procedures and the Emergency Procedure tool to improve the communication of and procurement method for emergency energy bids.	• PJM did not need to use emergency procedure bids during the winter of 2015.
11	Regulation Market Rules	PJM stakeholders should consider reexamining the performance of the Regulation Market during January. Specifically: 1. Investigate whether the division by the performance score is appropriate 2. Investigate whether the minimum participation requirements are adequately high enough 3. Investigate the possibility of going short regulation during system peaks	In progress. PJM is reviewing the market rules for regulation service to include performance scoring, minimum participation requirements and regulation during system peaks. PJM will take this issue to stakeholders in spring of 2015.	• The regulation problem statement is going through the stakeholder process. No recommendations have been implemented so there is no impact to operations to document.
12	External Capacity	Develop processes and tools that will: 1. Confirm that external capacity resources either bid into the day-ahead market or submitted eDart tickets that they are unavailable 2. Track the output of external capacity resources to ensure they are not submitting an outage into eDart and selling energy into a different market 3. Track the real-time output of external units cleared in the day-ahead market to confirm they are meeting obligations (tag validation versus commitment) 4. Develop ability to notify, track and confirm units that have not cleared in the day-ahead market but are recalled by PJM due to a capacity emergency such as Max Emergency	PJM updated internal procedures and tools to improve the tracking of external capacity resources.	• If required, the most up to date information on external capacity resources and contact information is captured in one place. External capacity availability was not called in the winter of 2015.
13	Communications & Procedures	Review and improve how the Emergency Procedures tool is used to communicate, both internally and externally, and develop solutions to address the following topics: 1. Consider adjustments to the roles and responsibilities for communications during emergency procedures	• PJM developed procedures and implemented tool enhancements to improve how the Emergency Procedures tool is used to communicate both internally and externally with stakeholders. • PJM improved internal support procedures during operational events to ensure clear roles and responsibilities for	• During the winter peaks, PJM operations was able to quickly staff the operational readiness team to provide Dispatch the extra analysis and support required.

ID	Category	Recommendation	Actions	Impact on 2015 Operations
		2. Refine training to reinforce processes and tools	communications. • These procedures were developed during the winter of 2014, drilled during the 2014 summer and winter emergency procedure drills. • These changes improved operations in the winter of 2015.	
14	Public Appeals	In order to better implement and use public appeals for conservation, PJM should: 1. Evaluate and consider the impact of calls for conservation and investigate where or how to use the data 2. Improve process for public notification during emergency procedures (C1/C2) 3. Review triggers for public notifications and associated transmittal protocols 4. Review both the content and processes for public appeals in Manual 13	• PJM reviewed the use of public appeals for conservation and updated the procedures and details in Manual 13, Attachment A. • PJM continues to look for ways to quantify the impacts of calls for consumer conservation for future operations.	• PJM did not need to use these procedures in the winter of 2015.

2015 Recommendations and Lessons Learned

The recommendations identified in 2015 are a continuation of some recommendations identified in 2014 as well as some new recommendations.

ID	Category	Recommendation	Status
1	Capacity Performance	Continue with the implementation of the Capacity Performance proposal to address resource performance incentives on a sustained basis.	On May 13, 2015, PJM answers protests regarding PJM's April 10 response to FERC's March 31 Deficiency Notice.
2	Gas / Electric Coordination	Continue to improve coordination between the gas and electric industries: 1. Based on the FERC's Final Rule in Docket No. RM14-2-000, Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities, implement changes to better align the scheduling processes. A consideration could be moving the times of the Day-Ahead Market. 2. Offer even more flexibility in changing unit offers during the electric day, as has been discussed in the Gas Unit Commitment Coordination working group. 3. Improve transparency of generation within gas local distribution companies.	PJM has 90 days from Federal Register publication of the April 16, 2015, Final Rule to respond regarding how it intends to meet the requirements.
3	Generator Operational Parameters	Continue to improve the ability for generators to communicate operational parameters to PJM. 1. Improve the ability for PJM tools (e.g. eDART, eMKT, DMT) to better capture and log generator flexibility and unit status information for use in real-time operations as well as after-the-fact analysis. 2. Improve PJM processes (e.g. PLS exception process) to review and assess generator parameters, particularly when they may differ from financial or settlements parameters.	PJM members recently proposed a problem statement to better address generator offer flexibility.
4	Cold Weather Unit Preparation	Build upon the success of the cold weather unit exercise and preparation checklist to improve the value while balancing the costs. Consider: 1. Modifying the criteria for eligibility 2. Refining the testing conditions and timeframe	PJM is discussing next steps for Cold Weather Preparation in the Operating Committee.
5	Energy Market Uplift Reduction	Continue to investigate methods and procedures for reducing the amount of uplift to be paid.	Through the existing Energy Market Uplift Senior Task Force, PJM and its stakeholders continue to work on solutions to reduce uplift.

Appendix

Appendix 1: Capacity Performance

Capacity Performance, currently under consideration by the FERC, would create stronger performance incentives for committed capacity resources. The incentives would ensure more operational availability and flexibility during peak power system conditions.

Generator performance issues during peak conditions in the winter of 2014 identified the need for a more robust capacity product to ensure system reliability. Capacity Performance addresses issues of generation fuel security, performance, winter peak operations and operational characteristics of resources needed to ensure that system reliability will be maintained throughout the current industry transformation and beyond.

While generator performance improved during the winter of 2015, many of the improvements were voluntary, such as winter testing and preparation. Improvements also were a result of lower fuel prices.

To ensure performance, a Capacity Performance resource must deliver energy in all hours if scheduled by PJM, or if self-scheduled, when PJM declares a Hot or Cold Weather Alert and/or a Maximum Emergency Generation Alert.

Had the Capacity Performance Construct Been in Place

PJM provides the following high-level information relative to the winter of 2015 to help understand impacts of the Capacity Performance construct had it been in place during this winter.

A cold weather alert was issued on 19 days during January and February 2015.

Based on the filed Capacity Performance rules for a unit's total start time (notification time plus start time), a unit must be available for scheduling with a maximum of a 14-hour total start time. Had the Capacity Performance rules been in place for the winter of 2015, based on current data:

- Approximately 1,123 units would have had total start times of 14 hours or less.
- Approximately 162 units would have had total start times greater than 14 hours. The impact of this could have been more units self-scheduling, units starting themselves earlier, unit parameter changes or potential forfeiture of uplift payments.

There were five hours that would have qualified as Performance Assessment Hours under the currently filed version of Capacity Performance[16]. On Feb. 21, 2015, PJM issued a manual load dump warning in the AEP transmission zone that was effective from 1842 to 2205. This action was taken due to a contingency on the Cloverdale T-10,

[16] Performance Assessment Hours are delineated by PJM's declaration of Emergency Actions, which are defined as, any emergency action for locational or system-wide capacity shortages that either utilizes pre-emergency mandatory load management reductions or other emergency capacity, or initiates a more severe action including, but not limited to, a Voltage Reduction Warning, Voltage Reduction Action, Manual Load Dump Warning or Manual Load Dump Action.

765/345 kV transformer for the loss of the Joshua Falls T-1, 165/138 kV transformer because PJM would have required a reduction in load to control the facility post-contingency.

PJM may issue a manual load dump warning in all or a portion of the footprint for two primary reasons.

1) If there is a system-wide capacity shortage such that either the primary reserve quantity is less than the largest single generator contingency, or, the loss of a transmission facility jeopardizes reliable operations after all possible measures are taken to increase reserves, PJM will issue a manual load dump warning to notify members that a manual load dump action may be necessary to maintain reliability.

2) If there is a transmission facility that is greater than 230 kV that cannot be controlled post-contingency after without a reduction in load in the affected area after all other measures are taken, PJM will issue a manual load dump warning in particular transmission zones that will relieve the overloaded facility.

Because the manual load dump warning was issued only in the AEP zone due to the post-contingency overload, only capacity resources in the AEP zone would have been eligible for over-performance credits or under-performance charges under the Capacity Performance rules. Under Capacity Performance, the under-performance charges could have been assessed against any units in the zone on a forced outage or units not following PJM dispatch instructions.

Appendix 2: Typical Preparation for an Operating Day

This section provides context and details about the processes, tools, and timelines for the operational actions taken prior to an operating day.

Beginning a week prior to an operating day, PJM creates and publishes a forecast of expected demand for electricity (i.e. the load forecast) and monitors factors driving demand expectations, such as weather forecasts and historical patterns of usage. The forecast is updated multiple times every day leading up to the operating day as the driving factors are updated. Because some generators require long notification and start-up times (up to six days), PJM examines expected system conditions to determine if it will be necessary to notify these generators that they are expected to be needed.

In the winter of 2015, PJM began conducting weekly calls with six interstate pipelines. The pipeline discussions revolved around pipelines status and how it could impact the natural gas supply to PJM generation.

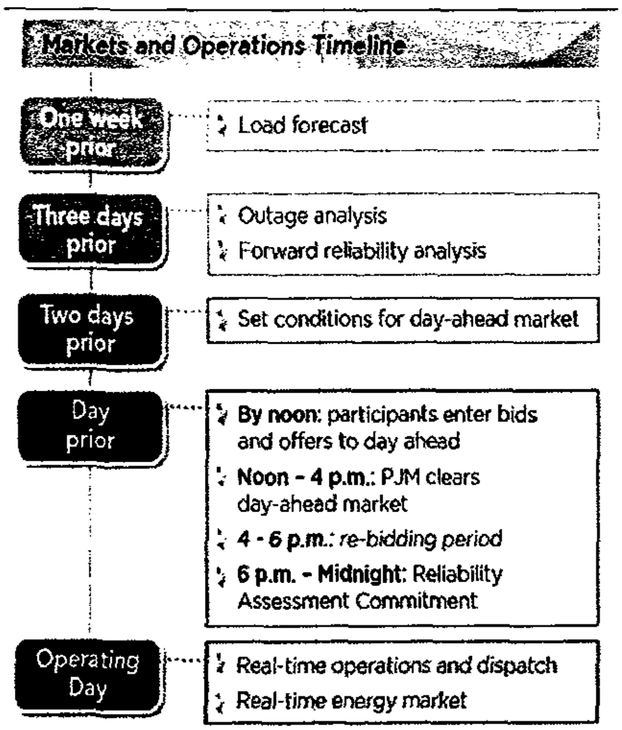
Approximately three days prior to an operating day, PJM's planning becomes more detailed. To prepare for expected conditions during the operating day, PJM staff begins studying transmission and generator outages, load forecasts, natural gas supply, weather and other expected factors. The expected system conditions dictate the amount of preparation required. PJM analyzes, communicates, studies and revises its analysis and operating strategy multiple times as needed as more information about an operating day becomes available. For example, PJM may request that transmission outages in progress be restored as quickly as possible to prepare for extreme weather conditions and then will update the analysis to reflect these conditions.

Two days prior to an operating day, PJM begins to set up the conditions such as the expected outages and conditions for the operating day in the model for the Day-Ahead Energy Market. (The Day-Ahead Energy Market offers an opportunity for market participants to lock in their positions in advance of an operating day in a financially firm way to reduce their risks of exposure to real-time prices.)

When the Day-Ahead Market closes at noon on the day prior to an operating day, PJM begins clearing the market, and the results are made available by 4 p.m. the day prior to the operating day. The Day-Ahead Market is cleared so that the cost to serve physical and virtual demand is minimized while still respecting the physical operating limits of the transmission system. Commitments in the Day-Ahead Market are financially binding on participants. Any differences between those commitments and what actually occurs in the operating day is addressed in the Real-Time Energy Market.

Between 4 p.m. and 6 p.m. the day prior to the operating day, generators which were not committed in the Day-Ahead Market can revise their offers to sell power. The window allows a generator to adjust its offer prior to the operating day to better reflect the cost of fuel. The uncertainty of both natural gas costs and availability makes these types of adjustments necessary and useful.

Figure 54. Market and Operations Timeline



Because the load levels bid into the Day-Ahead Market typically do not meet the levels expected during the operating day, after 6 p.m. PJM begins the reliability assessment commitment (informally called the "reliability run"), which ensures that adequate generation is committed to meet the demand plus reserves, while minimizing start-up and no-load cost. (Reserves are used to keep the lights on when unexpected events occur, such as a large generator going off line.) Using the most up-to-date weather forecast, load forecast, transmission facility and generator availability, and other information, PJM commits additional generation, if necessary, to satisfy both expected loads and the needed reserves for the operating day. PJM also performs additional reliability analysis to ensure all transmission facilities will be operated within their equipment limits when committing generation. During severe winter weather events, PJM also communicates extensively with both generation owners and gas pipeline operators in order to adequately understand the likelihood that natural-gas-fueled generators will be able to procure the gas they needed to operate.

On a typical winter day, PJM's peak load for the day averages approximately 106,000 MW. Beyond the expected demand, PJM also will commit approximately 4,000 MW of reserves [17]. Leading up to and throughout the operating day, PJM examines updated information and system conditions and acts to continually balance generation with the need for electricity and maintain adequate reserves to prepare for unexpected issues. PJM manages changes from day-ahead commitments and schedules in the Real-Time Energy Market using the offers from generation resources and demand resources to jointly minimize the cost of energy and reserves while maintaining energy balance and respecting the limits of the transmission system. Any differences in generation or demand from the Day-Ahead Energy Market commitments are cleared at price levels determined by the Real-Time Energy Market.

Appendix 3: Locational Marginal Pricing – Marginal Unit Type Intervals

Figure 55. Type of Marginal Resources in the Day-Ahead Energy Market

	Generation	Dispatchable Transaction	Up-to Congestion Transaction	Decrement Bid	Increment Offer	Price-Sensitive Demand
Jan	14.2%	0.5%	71.9%	6.9%	6.3%	0.1%
Feb	13.1%	0.4%	73.1%	7.7%	5.6%	0.1%
Mar *	10.2%	0.6%	73.5%	10.7%	5.1%	0.0%

*** March 1 through March 11**

[17] To provide a sense of scale, the combination would be enough power to serve about 91,200,000 homes. (One megawatt is enough power to serve about 800 homes. A typical large nuclear power plant provides 1,000 MW of energy.)

Appendix 4: Natural Gas System Critical Notices

In addition to the individual gas pipeline websites listed below, PJM also has a tool which provides a summary of the Critical Notices. Please see the following website on pjm.com: https://gaspipe.pjm.com/gaspipe/pages/dashboard.jsf

Pipeline	Website
Columbia	http://www.columbiapipeinfo.com/infopost/
Dominion	http://escript.dom.com/jsp/info_post.jsp?&company=dti#
Texas Eastern	https://infopost.spectraenergy.com/infopost/TEHome.asp?pipe=TE&mode=1
Natural Gas Pipeline of America	http://pipeline.kindermorgan.com/infoposting/notices.aspx?type=RECENT
ANR	http://anrebb.transcanada.com/
Tennessee Gas	http://webapps.elpaso.com/PortalUI/DefaultKM.aspx?TSP=TGPD
Nicor	https://www.nicorgas.com/
National Fuel	http://sbsprd2.natfuel.com/supply/infopost/infopost_frame.htm

Appendix 5: Emergency Procedures

Please see Emergency Procedures page on pjm.com for a description of the message and further details.

https://emergencyprocedures.pjm.com/ep/pages/dashboard.jsf

Message ID	Start Time	End Time	Region
94390	3/4/2015 - 8:53	3/6/2015-23:31	Western - Region
94389	3/4/2015 - 8:44	3/5/2015 - 23:30	ComEd - Control Zone
94238	2/24/2015 – 9:45	2/27/2015 – 23:53	Western - Region
94214	2/23/2015 – 12:55	2/27/2015 – 3:17	DLCO - Control Zone ATSI - Control Zone
94190	2/22/2015 – 10:25	2/24/2015 – 23:56	PJM - RTO
94161	2/20/2015 – 9:01	2/24/2015 – 0:00	Western - Region
94071	2/17/2015 - 9:11	2/21/2015 – 0:44	PJM - RTO
94058	2/16/2015 – 9:08	2/20/2015 – 0:41	PJM - RTO
94057	2/16/2015 – 9:08	2/19/2015 – 0:19	AEP - Control Zone AP - Control Zone ComEd - Control Zone DAYTON - Control Zone DLCO - Control Zone Western – Region ATSI - Control Zone CPP - Control Zone DEOK - Control Zone EKPC - Control Zone
93973	2/12/2015 – 8:31	2/18/2015 – 0:00	Mid-Atlantic - Region
93972	2/12/2015 – 8:31	2/17/2015 – 0:01	PJM - RTO
93971	2/12/2015 – 8:29	2/16/2015 – 0:00	Mid-Atlantic – Region Western - Region
93970	2/12/2015 – 8:21	2/15/2015 – 0:00	AEP - Control Zone AP - Control Zone ComEd - Control Zone

Message ID	Start Time	End Time	Region
			DAYTON - Control Zone DLCO - Control Zone ATSI - Control Zone CPP - Control Zone DEOK - Control Zone EKPC - Control Zone
93969	2/12/2015 – 8:17	2/14/2015 – 0:50	AP - Control Zone DLCO - Control Zone ATSI - Control Zone
93849	2/5/2015 – 12:10	2/6/2015 – 11:53	Mid-Atlantic - Region
93829	2/4/2015 – 10:02	2/5/2015 – 23:19	ComEd - Control Zone DLCO - Control Zone
93811	1/30/2015 – 15:21	2/1/2015 – 19:48	PJM - RTO
93810	1/30/2015 – 10:24	2/1/2015 – 19:48	PJM - RTO
93809	1/30/2015 – 10:21	1/30/2015 – 15:39	PJM - RTO
93649	1/14/2015 -10:02	1/15/2015 – 11:30	ATSI - Control Zone
93630	1/13/2015 – 10:06	1/14/2015 – 9:55	Western - Region
93629	1/13/2015 – 10:06	1/14/2015 – 23:59	Western - Region
93580	1/8/2015 – 8:21	1/11/2015 – 0:58	Western - Region
93578	1/8/2015 – 8:21	1/10/2015 - 4:36	Western - Region
93551	1/7/2015 – 9:15	1/8/2015 - 23:43	PJM - RTO
93530	1/6/2015 – 7:44	1/7/2015 - 9:15	AEP - Control Zone AP - Control Zone ComEd - Control Zone DAYTON - Control Zone DLCO - Control Zone Western – Region ATSI - Control Zone CPP - Control Zone DEOK - Control Zone EKPC - Control Zone
93529	1/6/2015 – 7:43	1/8/2015 - 0:35	AEP - Control Zone AP - Control Zone ComEd - Control Zone DAYTON - Control Zone DLCO - Control Zone Western – Region ATSI - Control Zone CPP - Control Zone DEOK - Control Zone EKPC - Control Zone
93509	1/5/2015 – 9:05	1/7/2015 – 0:05	ComEd - Control Zone
93489	1/4/2015 – 9:05	1/6/2015 – 0:12	ComEd - Control Zone

Appendix 6: Cold Weather Operational Exercise

As described in the 2015 Generator Performance section, PJM also implemented the 2014 recommendation to develop a cold weather exercise designed to give generators that run infrequently or have dual fuel capability the opportunity to test their units prior to the onset of cold weather. In total, 168 units with a total of amount of 9,919 MW (11,054 MW ICAP) performed the cold weather generation operational exercise.

Total Units Exercised		Success Rate (By Unit Count)
168 Units	9,919 MW	94%

A summary of eligible units and their participation is below. Of the 214 units initially eligible and interested in participating in the exercise, 46 units were unable to participate either because of warm weather on the day scheduled or subsequent ineligibility because they ran in real-time during the cold days during the month of December 2014. The final number of units exercised this test was 168.

Figure 56. 2014 Winter Exercise Participation Unit Counts

	Total Eligible Units As Of Dec. 1, 2014	Eligible Units That Wanted To Participate	Eligible Units That Declined To Participate	Eligible Units That Did Not Respond
Unit Count	443	214	210	19
Total ICAP MW	45,604	14,558	29,598	1,448

Figure 57. Exercise results were analyzed and the success / failure analysis

			Failures		Success						Success Rate by Unit Count	Success Rate by MW Total
			Failures by Unit Count	Failures by MW	Success		Initial Failure; Success		Total Success			
					Units	MW	Units	MW	Units	MW		
Total	**168**	**9,919**	**10**	**397**	**142**	**8,541**	**16**	**981**	**158**	**9,522**	**94%**	**96%**

26 units out of 168 units experienced initial failures, or failed to complete the exercise ('Failures by Unit Count + Initial Failure ; Success by Unit Count) 16 (Initial Failure; Success by Unit Count) of those 26 units, were able to correct the issue and subsequently successfully completed the exercise. The total unit success rate of 94 percent includes these corrected failures. Causes of failures were also analyzed and are summarized below. The percentages are based on a total of 26 exercise failures. The types of failures include control system, liquid handling, supporting diesel, and electrical failures. Examples of "Miscellaneous" failures include: failed to fire, water injection problems, failed to synchronize, high temperature, vibration, lube oil leak, and thermocouple failures. The majority of units that failed were repaired and retested on the same day or within the same week. Several of the units that failed asked for a retest later during the program. Many other generation owners elected to self-schedule shortly after the repairs were made, which means they were compensated for the MWs but not for the test.

Figure 58. Cold Weather Operational Exercise – Causes of Failures